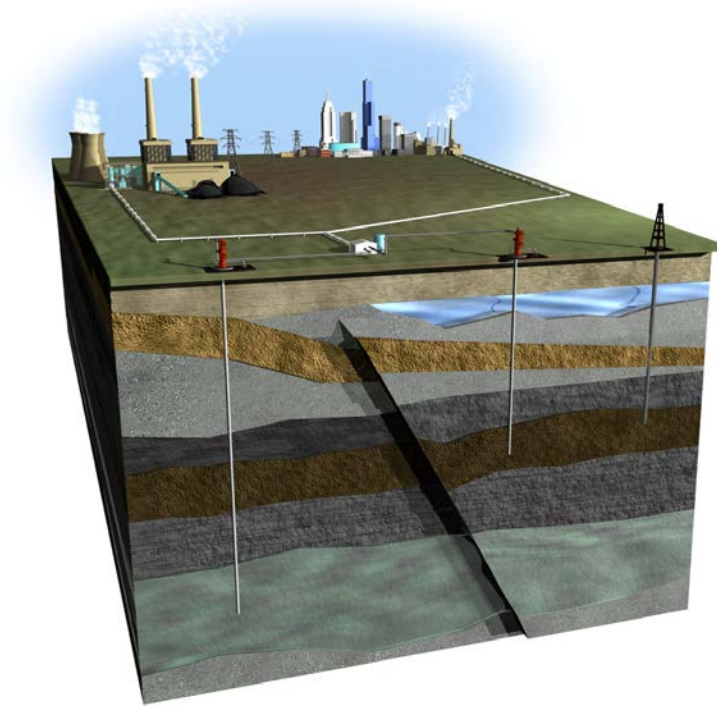


Comprehensive, Quantitative Risk Assessment of CO₂ Geologic Sequestration Final Technical Report



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ABSTRACT

A Quantitative Failure Modes and Effects Analysis (QFMEA) was developed to conduct comprehensive, quantitative risk assessments on CO₂ capture, transportation, and sequestration or use in deep saline aquifers, enhanced oil recovery operations, or enhanced coal bed methane operations. The model identifies and characterizes potential risks; identifies the likely failure modes, causes, effects and methods of detection; lists possible risk prevention and risk mitigation steps; estimates potential damage recovery costs, mitigation costs and costs savings resulting from mitigation; and ranks (prioritizes) risks according to the probability of failure, the severity of failure, the difficulty of early failure detection and the potential for fatalities.

The QFMEA model generates the necessary information needed for effective project risk management. Diverse project information can be integrated into a concise, common format that allows comprehensive, quantitative analysis, by a cross-functional team of experts, to determine: What can possibly go wrong? How much will damage recovery cost? How can it be prevented or mitigated? What is the cost savings or benefit of prevention or mitigation? Which risks should be given highest priority for resolution?

The QFMEA model can be tailored to specific projects and is applicable to new projects as well as mature projects. The model can be revised and updated as new information comes available. It accepts input from multiple sources, such as literature searches, site characterization, field data, computer simulations, analogues, process influence diagrams, probability density functions, financial analysis models, cost factors, and heuristic best practices manuals, and converts the information into a standardized format in an Excel spreadsheet.

Process influence diagrams, geologic models, financial models, cost factors and an insurance schedule were developed to support the QFMEA model. Comprehensive, quantitative risk assessments were conducted on three (3) sites using the QFMEA model: (1) SACROC Northern Platform CO₂-EOR Site in the Permian Basin, Scurry County, TX, (2) Pump Canyon CO₂-ECBM Site in the San Juan Basin, San Juan County, NM, and (3) Farnsworth Unit CO₂-EOR Site in the Anadarko Basin, Ochiltree County, TX. The sites were sufficiently different from each other to test the robustness of the QFMEA model.

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EXECUTIVE SUMMARY

In 2009, Headwaters Clean Carbon Services LLC and its associates (the University of Utah, MMA/Faulkner & Flynn [Marsh], and Los Alamos National Laboratory) received funding from the U.S. Department of Energy to develop tools and methodologies for performing comprehensive, quantitative risk assessments of CO₂ geologic sequestration projects. The end product is a Quantitative Failure Modes and Effects Analysis (QFMEA) model that can be applied to CO₂ capture, transportation, and sequestration/use in deep saline aquifers (DSA), enhanced oil recovery (EOR) operations or enhanced coal bed methane (ECBM) operations. The model:

1. Identifies and characterizes the potential risks associated with CO₂ capture, transport, storage and use operations
2. Identifies the likely failure modes, causes, effects, and methods of detection
3. Lists possible risk prevention and risk mitigation steps
4. Estimates potential damage recovery costs, mitigation costs and cost savings resulting from mitigation
5. Ranks (prioritizes) risks according to the probability of failure, the severity of failure, the difficulty of early failure detection, and the potential for fatalities.

The QFMEA model generates the necessary information needed for effective project risk management. Diverse project information can be integrated into a concise, common format that allows comprehensive, quantitative analysis, by a cross-functional team of experts, to determine: What can possibly go wrong? How much will damage recovery cost? How can it be prevented or mitigated? What is the cost savings or benefit of prevention or mitigation? Which risks should be given highest priority for resolution?

The model can be tailored to specific projects and is applicable to new projects as well as mature projects. The model can be revised and updated as new information becomes available. It accepts input from multiple sources, such as literature searches, site characterization, field data, computer simulations, analogues, process influence diagrams, probability density functions, financial analysis models, cost factors, and heuristic best practices manuals, and converts the information into a standardized format in an Excel spreadsheet.

Process influence diagrams were developed for DSA, EOR and ECBM operations to analyze the interrelationship between risk areas. Simulation models, mass balance models, probability calculations, short cut calculations, and analogues were used to quantify probability of failure and severity of failure for site specific risk areas.

Cost factors and financial models were developed for CO₂ storage/use in DSA, EOR and ECBM operations to quantify project development, capital, operating, maintenance and closure costs. Damage scenarios were developed and potential damage recovery costs were estimated for site-specific risk areas. Risk prevention/mitigation costs were estimated and potential costs savings were calculated for the associated risk prevention/mitigation activity.

The QFMEA model was validated by evaluating the efficacy of the model to quantitatively assess the risks for three (3) existing CO₂ storage (or utilization) sites. The following three (3) sites were selected:

1. SACROC Northern Platform CO₂-EOR Site in the Permian Basin, Scurry County, TX
2. Pump Canyon CO₂-ECBM Site in the San Juan Basin, San Juan County, NM
3. Farnsworth Unit CO₂-EOR Site in the Anadarko Basin, Ochiltree County, TX

The QFMEA model indicates the SACROC and Farnsworth Unit CO₂-EOR operations are technically and commercially feasible at current market prices. The breakeven oil price is estimated to be less than \$60 per barrel.

The active CO₂-EOR operations represent a "not significant" environmental risk as long as the projects remain in compliance with regulations, codes, permits and best practices. Both Sites have excellent subsurface and surface conditions for CO₂ use and sequestration. The project reservoirs are deep. The caprocks are intact. Multiple stacked seals and sinks separate the reservoirs from near surface aquifers. CO₂ and water injection volumes are partially (or fully) offset by EOR production. The surface areas of both sites are sparsely populated. There are no sensitive or significant human or environmental receptors.

Both CO₂-EOR sites have a large number of existing deep wells penetrating the caprock, but operators can mitigate leakage from these wells through preventative maintenance programs consisting of evaluating and reworking "at risk" wells.

The presence of H₂S in the SACROC and Farnsworth Unit reservoirs increases the toxicity of recycled gas, but also provides an earlier detection of small to moderate leaks due to low concentration olfactory reception.

The Pump Canyon CO₂-ECBM operation is technically feasible, but not commercially feasible at current market prices, based on the QFMEA model. The CO₂ cost would need to be close to free or the natural gas price would need to double for the CO₂-ECBM operation to be financially sustainable. The significant issues with the Pump Canyon Site are:

- Coal swelling results in low CO₂ injection rates
- The presence of natural CO₂ (and methane) complicates CO₂ MVA activities
- CBM open-hole cavity completions complicate conversion of CBM wells to CO₂ injection
- Existing methane gas seeps are a more probable risk than CO₂ leakage

As long as current CBM operations remain viable, it is unlikely that CO₂ sequestration would be considered in the Fruitland Formation. CBM is more effective with low reservoir pressure and CO₂ sequestration is more effective with high reservoir pressure. Repressurization of the Fruitland Formation via CO₂ injection may be difficult due to limited injectivity of the formation.

The QFMEA model verifies that most CO₂ sequestration risks can be avoided by proper site selection; however, compliance with site selection, design, construction operation, maintenance and monitoring regulations, codes, permits and best practices is critical to ensure project safety, feasibility and financial viability.

1.0 INTRODUCTION

In 2009, Headwaters Clean Carbon Services LLC and its associates (the University of Utah, MMA/Faulkner & Flynn [Marsh], and Los Alamos National Laboratory) received funding from the U.S. Department of Energy, National Energy Technology Laboratory (“DOE/NETL”) to develop a model and methodology for “Comprehensive, Quantitative Risk Assessment of CO₂ Geologic Sequestration,” (Federal Award Number DE-FE0001112). This project supports the following DOE/NETL program goals:

1. Develop and validate technologies to ensure 99 percent CO₂ storage performance.
2. Develop Best Practice Manuals for Monitoring, Verification and Accounting (MVA); site screening, selection and initial characterization; public outreach, well management activities; and risk analysis and simulation.

The primary object of this project was to develop and apply an innovative, advanced process-based risk assessment model and protocol to determine quantitative risks and predict quantitative impacts for CO₂ geologic sequestration project sites. The model shall be capable of integrating with advanced simulation models and MVA technologies.

The primary objective was successfully achieved by developing a Quantitative Failure Modes and Effects Analysis (“QFMEA”) model. The QFMEA model can be applied to CO₂ capture, transportation, and sequestration/use in deep saline aquifers (DSA), enhanced oil recovery (EOR) operations or enhanced coal bed methane (ECBM) operations. The QFMEA model:

1. Identifies and characterizes the potential risks associated with CO₂ capture, transport, storage and use operations
2. Identifies the likely failure modes, causes of failure, severity of failure effect, and methods of failure detection
3. Lists possible risk prevention and risk mitigation steps
4. Estimates potential damage recovery costs, mitigation costs and cost savings resulting from mitigation
5. Ranks (prioritizes) risks according to the probability of failure, the severity of failure, the difficulty of early failure detection, and the potential for fatalities.

The QFMEA model generates the necessary information needed for effective project risk management. Diverse project information can be integrated into a concise, common format that allows comprehensive, quantitative analysis, by a cross-functional team of experts, to determine: What can possibly go wrong? How much will damage recovery cost? How can it be prevented or mitigated? What is the cost savings or benefit of prevention or mitigation? Which risks should be given highest priority for resolution?

The model can be tailored to specific projects and is applicable to new projects, as well as, mature projects. The model can be revised and updated as new information becomes available. It accepts input from multiple sources, such as literature searches, site characterization, field data, computer simulations, analogues, process influence diagrams, probability density functions, financial analysis

models, cost factors and heuristic best practices manuals, and converts the information into a standardized format in an Excel spreadsheet (see **Figure 1**).

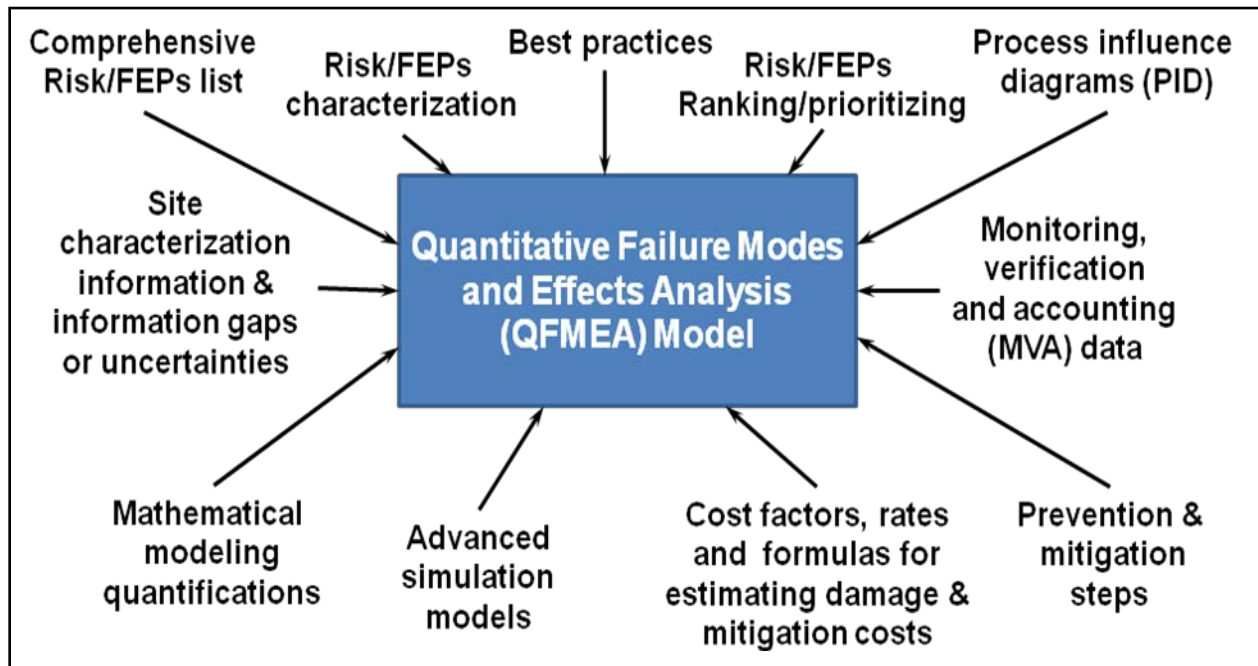


Figure 1: Some of the potential input sources for the QFMEA model

Failure Modes and Effects Analysis(FMEA) models are widely used in the military, space, aeronautics, medical, power and nuclear industries where system reliability is critical. They are used to answer the following questions:

- What could possibly go wrong (failure mode)?
- What would be the likely cause of failure?
- What will happen if a failure occurs, or how will a failure impact system performance?
- What is the probability of failure occurring?
- How severe will the effect of failure be?
- How can the failure be prevented or the effect of failure be mitigated?
- What are the most important risk areas to work on?

The International Electrotechnical Commission (IEC) has published an international standard for performing FMEAs titled: "Analysis techniques for system reliability - Procedure for failure mode and effects analysis (FMEA)" (**IEC 2006**). This was the foundation for the QFMEA model.

The QFMEA model goes beyond the FMEA by quantifying potential damage recovery costs, risk prevention/mitigation costs and potential cost savings associated with risk mitigation. It also takes into consideration the difficulty of detecting a failure early in prioritizing risk areas.

The QFMEA should be initiated early in the project to assess risks and then used throughout the life of the project as a tool to manage risks. It can provide input into:

1. Site screening and selection
2. Permitting
3. Public outreach
4. Project financing
5. Insurance coverage
6. Project "go-no go" decision making based on risk versus reward (cost/benefit analysis)
7. Risk management planning
8. Contract conditions and negotiation
9. Engineering design and design reviews
10. Procurement and construction quality control
11. Reliability availability and maintainability (RAM) studies
12. Hazards and operability (HAZOP) studies
13. Operating procedures
14. Maintenance planning and scheduling
15. Operator training
16. Safety audits
17. Computer simulation
18. Monitoring, verification and accounting (MVA) plans
19. Emergency response and contingency plans
20. Long-term liability transfer

One of the tasks of this project was to evaluate the efficacy of the QFMEA model by using it to conduct quantitative risk assessments for three (3) existing CO₂ storage (or utilization) sites. The following project sites were selected:

1. SACROC Northern Platform CO₂-EOR Site
2. Pump Canyon CO₂-ECBM Site
3. Farnsworth Unit CO₂-EOR Site

The locations of these sites are shown in **Figure 2**.

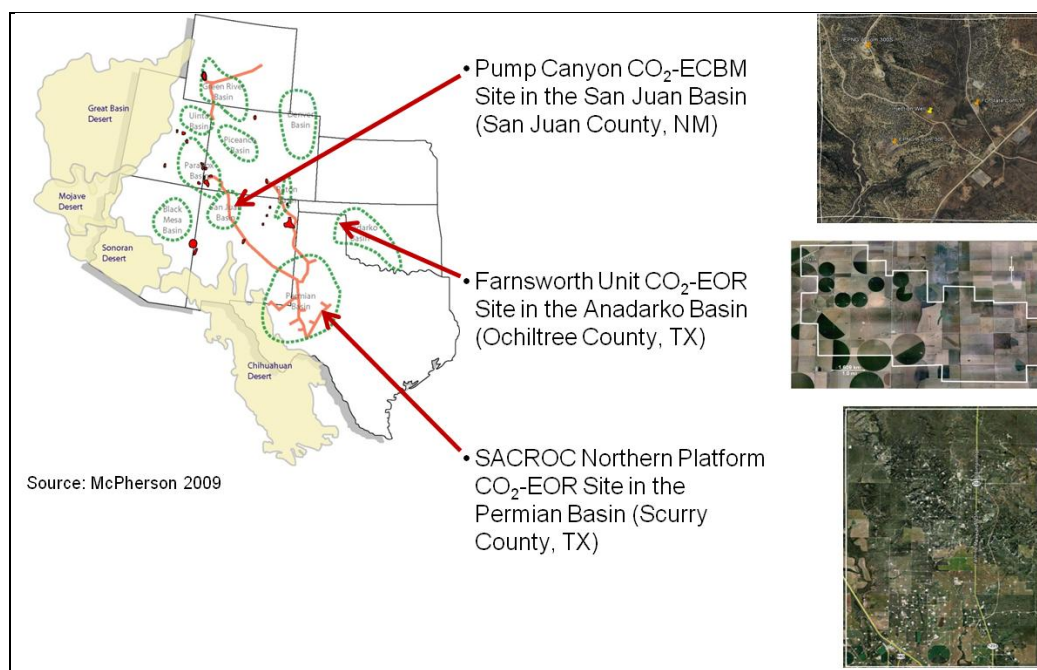


Figure 2: Map showing the locations of the three risk assessment sites

The general features of the three (3) Sites are compared in **Table 1**.

Table 1: Comparison of Site features

Site:	SACROC Unit	Farnsworth Unit	Pump Canyon
Location	Scurry County, TX	Ochiltree County, TX	San Juan, County, NM
Basin	Permian Basin	Anadarko Basin	San Juan Basin
Owner/operator	Kinder Morgan	Chaparral Energy	ConocoPhillips
Type of operation	Mature CO ₂ -EOR	Early CO ₂ -EOR	CO ₂ -ECBM test
Start of CO ₂ -EOR	January 1972.	December 2010.	July 2008
Reservoir lithology	Carbonate	Sandstone	Coal
Reservoir depth	2,042 m (6,700 ft)	2,408 m (7,900 ft)	918 m (3,012 ft)
Reservoir thickness	15 to 244 m (50 to 800 ft)	3 to 16.5 m (10 to 54 ft)	17-20 m (55-65 ft)
Average net pay thickness	48.8 m (160 ft)	6.9 m (22.5 ft)	14.8 m (49 ft)
Reservoir area	202 km ² (50,000 acres)	51.4 km ² (12,698 acres)	2.59 km ² (640 acres)
Formation fluid salinity	159,000 mg/L TDS	4,000 mg/L TDS	16,200 mg/L TDS
CO ₂ type	Natural	Anthropogenic	Natural
CO ₂ injection rate	Purchased: 6,312 t/d Recycled: 46,291 t/d	Purchased: 526 t/d Recycled: 105 t/d	Purchased: 46 t/d Recycled: 0 t/d
Oil production	28,000 STB/d	1,000 STB/d	0 STB/d

The quantitative risk assessments for all three (3) Sites were conducted independently without direct input from the owners/operators.

2.0 METHODOLOGY

The Comprehensive, Quantitative Risk Assessment of CO₂ Geologic Sequestration (CQRA) Project tasks, subtasks, deliverables and schedule are shown in **Figure 3** below. There were (6) tasks and eleven (11) deliverables. Budget Period 3 included a nine-month no-cost extension due to an external delay in selecting one of the quantitative risk assessment sites.

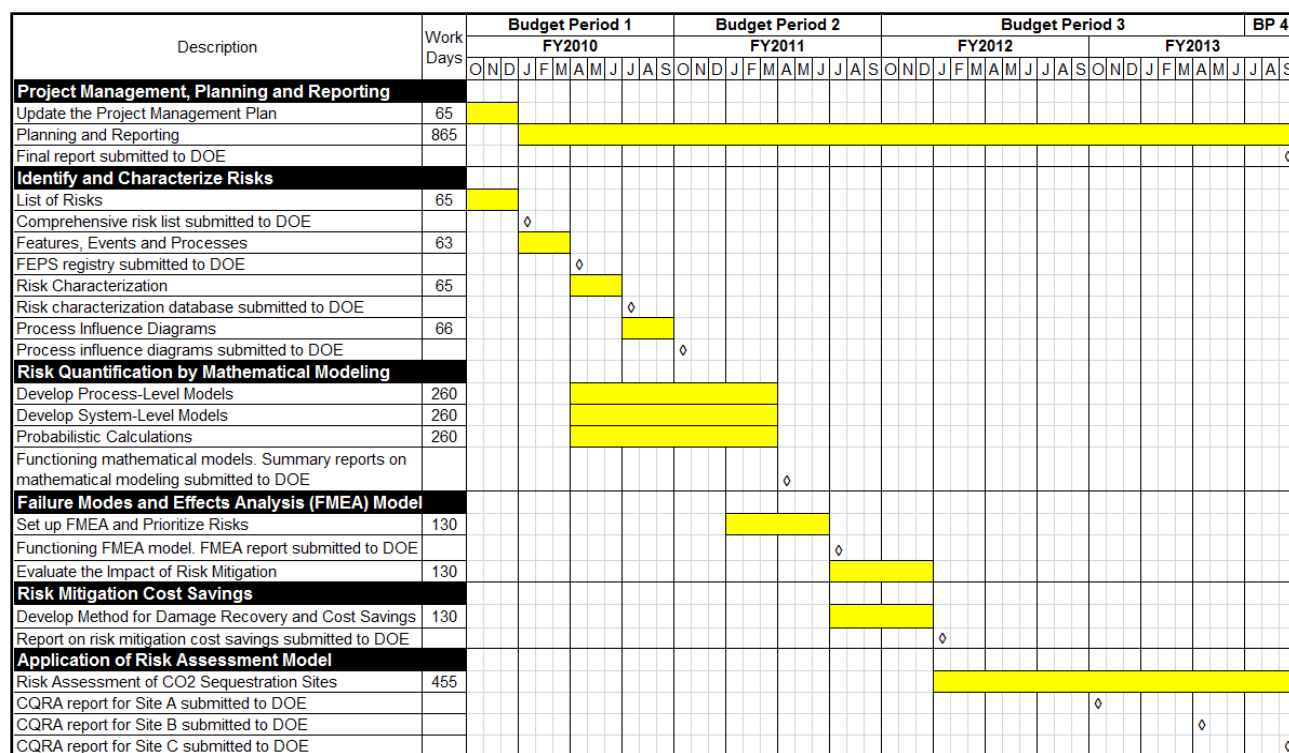


Figure 3: CQRA project tasks, subtasks, deliverables and schedule

The CQRA team consisted of Headwaters Clean Carbon Services LLC (HCCS), The University of Utah (U of U), MMA/Faulkner & Flynn (Marsh), and Los Alamos National Laboratory (LANL). HCCS provided project management, risk identification, risk characterization, process influence diagrams, QFMEA development, financial modeling, estimation of potential damage recovery costs and mitigation costs, and review of the overall work product. James Lepinski was principal investigator with support from John Mavor, Troy Walker, Gina Rau, John Shaal, Pete Fote, and Vicki Bushnell.

Faulkner & Flynn is the environmental risk management consulting subsidiary of Marsh & McLennan Agency LLC, the world's leading insurance broking and risk management company. They reviewed and refined the QFMEA model, financial model, estimates of potential damage recovery costs and mitigation costs; developed an insurance schedule for CO₂ sequestration; and reviewed the overall work product. Neal Drawas was project leader with support from P. J. Smith, Bob Pflueger and Travis Thompson.

The University of Utah provided process-level modeling and probability calculations, and reviewed the overall work product. Milind DeO was project leader, with support from Justin Wreidt, Weon Shik Han, Brian McPherson, Si-Yong Lee, Chuan Lu, Rich Essar, Prashanth Mandalaparty, Surya Sunkavalli, Richard Franz, Robert Krumm, Tareq Al-Najjar, and Varun Gowda.

Los Alamos National Laboratory provided system-level modeling and reviewed the overall work product. Hari Viswanathan and Bruce Letellier were project leaders with support from Gordon Keating and Phil Stauffer.

Other people who contributed to the final product include: Ken Hnottavange-Telleen (Schlumberger), Andrew Duguid (Schlumberger), Ray Hattenbach (Blue Source), and Reid Grigg (New Mexico Tech).

2.1 Comprehensive Risk List

The CQRA team conducted a literature search for risks associated with: CO₂ geologic sequestration, deep saline aquifers (DSA), enhanced oil recovery (EOR), enhanced coal bed methane (ECBM), boreholes, health, safety, environment, programmatic risks, CO₂ capture, dehydration, compression and pipeline transportation.

Approval was obtained from Quintessa to use their FEPs Registry (which is freely accessible at <http://www.quintessa.org/co2fepdb/>) in the project. The CQRA team expanded the Quintessa FEPs Registry from 162 FEPs (risk areas) into a comprehensive list of 1,129 risk areas (462 geologic sequestration technical risks and 667 surface and programmatic risks).

A cross-functional team of experts reviewed the risk lists for accuracy and completeness and their input was incorporated into the final product. The risk lists were submitted to and accepted by DOE/NETL as attachments to the quarterly progress report dated 30 JAN 2010.

2.2 Features, Events and Processes (FEPs) Registry

An expanded version of the Quintessa FEPs registry was used for the CQRA FEPs registry. In preparing the comprehensive risk list, it was determined that the large number of risks (1,129 risks) were too intimidating for people to work with. It took more than a week for an individual to completely review the list. This was resolved by combining and listing detailed risks and scenarios under Risk Areas/FEPs. This allowed the comprehensive nature of the document to be maintained, yet made it easier for people to use and review. The combined list of 414 Risk Areas/FEPs was subdivided into the following 24 Areas of Risk Categories:

0. Assessment basis	8. Economic risks	17. Legal, legislation and regulation risks
1. External factors	9. Permitting risks	18. CO ₂ capture risks
2. CO ₂ storage	10. External risks	19. CO ₂ dehydration risks
3. CO ₂ properties, interactions and transportation	11. Project management risks	20. CO ₂ compression risks
4. Geosphere	12. Engineering risks	21. CO ₂ pipeline risks
5. Boreholes	13. Procurement risks	22. CO ₂ on-site facility risks
6. Near-surface environment	14. Construction risks	23. CO ₂ monitoring risks
7. Impacts	15. Commissioning and startup risks	
	16. Field safety	

Categories 0 through 7 were part of the original Quintessa FEPs Registry. Categories 8 through 23 were added to make the registry more comprehensive, to include surface and programmatic risks as well as CO₂ capture and transportation. The original index structure and integrity of the Quintessa FEPS registry was maintained as much as possible. The CQRA team eliminated redundancies, standardized much of the wording, added key words or phrases in the descriptions to enhance word searches of the document, added reference sources and added or modified risks/FEPs where necessary to include CO₂-EOR and CO₂-ECBM risks/FEPs.

All risks/FEPs were categorized into features, events or processes. The FEPs registry was reviewed by a cross-functional team of experts for accuracy and completeness and their feedback was incorporated into the final product. The FEPs registry was submitted to and accepted by DOE/NETL as attachments to the quarterly progress report dated 30 APR 2010.

2.3 Risk Characterization

The Risk Area/FEPs registry was further characterized as shown in **Table 2**. These are the column headings included in the risk characterization section of the QFMEA model.

Table 2: Column headings included in the risk characterization section of the QFMEA model

				Project Specific Information		FEPs Type	Storage Type			Project Phase Impacted							
Index #	Risk Area/FEP	Description	Relevance	Site Specific Information	Information Gaps or Uncertainties	Feature	Event	Process	DSA	EOR	ECBM	All Storage Types	Site Characterization	Eng. Proc. Const. (EPC)	Startup and Operation	Post-Injection Site Care	All Project Phases

Results were reviewed by a cross-functional group of experts for accuracy and completeness and their feedback was incorporated into the final product. The Risk Characterization Report was submitted to and accepted by DOE/NETL as attachments to the quarterly progress report dated 30 JUL 2010.

2.4 Process Influence Diagrams (PIDs)

Process influence diagrams were developed for DSA, EOR and ECBM operations to analyze the interrelationship between risk areas.

The PIDs were reviewed by a cross-functional team of experts for accuracy and completeness and their feedback was incorporated into the final product. The deliverable was submitted to and accepted by DOE/NETL as attachments to the quarterly progress report dated 30 OCT 2010.

2.5 Process-level Modeling

The objective of this task was to develop methodologies of quantifying the probabilities of the occurrences and magnitude of the effect of certain events or processes given the uncertainties and variations in important system or operational parameters. Some of the typical questions in terms of risks that are addressed in simulation modeling are:

1. What is the risk of not being able to realize the volumetric capacity of a storage unit (for example, a saline aquifer)?
2. How do the reservoir characteristics impact the risk of overpressure?
3. What are the risks of CO₂ migrating out of “designated” boundaries?
4. Will it be possible to maintain a pre-specified injection rate?
5. How many wells are required to reach the target rate without causing overpressure?
6. If CO₂ comes in contact with a leaky borehole, how much will leak out?
7. If CO₂ comes in contact with a fault or fracture zone, how much will leak out?
8. What is the likelihood and magnitude of induced seismicity?
9. What is the likelihood and magnitude of freshwater aquifer contamination due to brine intrusion?
10. What is the likelihood and magnitude of caprock failure (leaky caprock)?
11. How large an area will be impacted by a CO₂ pipeline rupture?

The University of Utah (U of U) developed a process-level model for a generic CO₂ deep saline aquifer reservoir using commercially available software (CMG-GEM). The model evaluated the impact of changes in six (6) key parameters as shown in **Table 3** below:

Table 3: Parameters and the range of values used in the simulation runs.

Parameter	Low	Mid	High
Formation thickness (m)	40	80	120
Formation depth at well (m)	1700	2000	2300
Porosity (fraction)	0.1	0.2	0.3
Permeability (mD)	10	505	1000
Brine density (kg/m ³)	1000	1150	1300
Maximum residual CO ₂ (fraction)	0.1	0.2	0.3

The simulated reservoir domain had lateral dimensions of 45 km x 45 km and thickness varying from 40 to 120 m (see **Figure 4**). A single injection well penetrated the center of the simulated reservoir. Initially the simulated reservoir was designed as an open system (brine flowing freely across lateral boundaries). However, under open system conditions, it was impossible to over pressure the reservoir without injection pressure exceeding fracture pressure. Therefore, the simulation model was changed to a closed system (top, bottom and lateral boundaries closed to brine flow) in order to allow generation of more meaningful results.

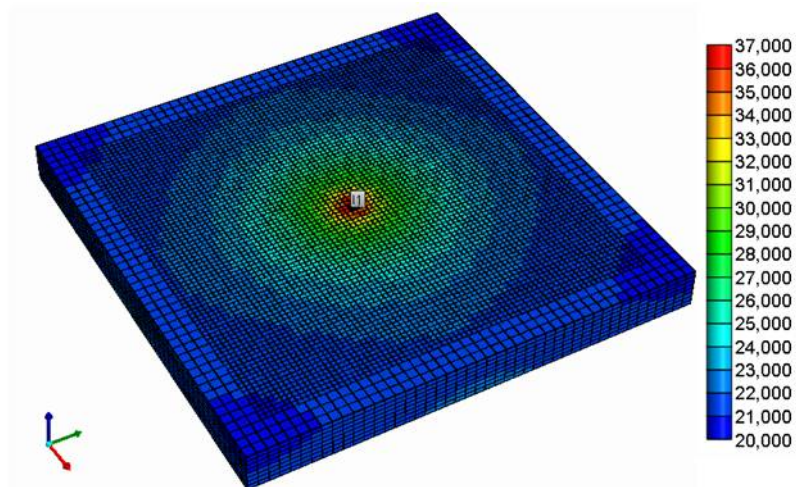


Figure 4: Domain developed for closed boundary overpressure simulations

The simulation modeling timeframe covered 25 years of CO₂ injection and 50 years of monitoring after injection, for a total of 75 years. The 50 years of monitoring was selected to be consistent with USEPA UIC Class VI well regulation expectations.

Two (2) types of CO₂ injection strategies were modeled: constant volume and constant pressure. In the constant volume case, CO₂ was injected at a constant rate of 1 million tonnes per year for 25 years without regard to injection pressure. In the constant pressure case, CO₂ was injected at 90 percent of fracture pressure for 25 years without regard to injection volume.

Forty-nine (49) simulations were run for constant volume injection conditions, and another forty-nine (49) simulations were run for constant pressure injection conditions in order to cover all of the parameter changes. Each simulation generated output files containing data for 100 x100 =10,000 individual cells indicating change in pressure and CO₂ saturation over time. Those output files were incorporated into the *CO₂-PENS* system-level model and were also used in regression analysis to develop a linear polynomial response surface model.

Process-level modeling generate probability factors and quantitative factors that where input into the quantitative section of the QFMEA model when more detailed site-specific information was not available.

The deliverable, "Development of PDFs of Important Sequestration Risk Outcomes," was reviewed by a cross-functional team of experts for accuracy and completeness and submitted to and accepted by DOE/NETL as an attachment to the quarterly progress report dated 29 APR 2011.

2.6 System-level Modeling

The output files from the process-level model were incorporated by Los Alamos National Laboratory (LANL) into the *CO₂-PENS* system-level model in order to develop a quantitative probabilistic understanding of the potential for leakage from a CO₂ reservoir through the geologic seals via

existing wellbores and faults. Additional simulation modeling and analysis was conducted to investigate the impact of CO₂ release and dispersion from a ruptured pipeline.

CO₂-PENS accepts time-dependent pressure and CO₂ saturation information from external simulators as boundary conditions to drive the leakage simulation. The external model calculations must be spatially averaged to match a 100 x 100-cell map of CO₂ saturation and pressure in the reservoir, but there is no limit on the temporal resolution of the surface. These external model results, along with additional CO₂-PENS parameters, were used to predict wellbore and fault leakage.

It was assumed there were four (4) environmental receptors overlying the reservoir: three (3) flat-lying, freshwater aquifers and the ground surface, as shown in **Figure 5**.

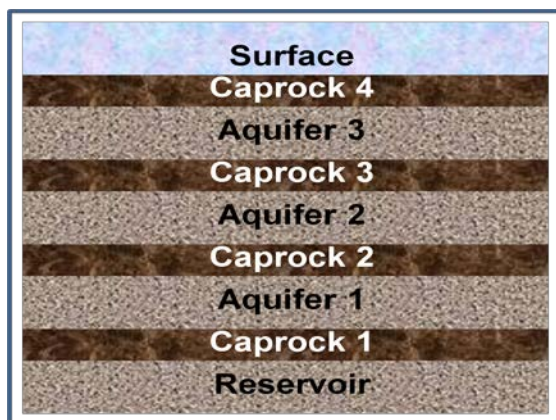


Figure 5: Generic geometry defining the stacked aquifer system used in CO₂-PENS

The CO₂-PENS model predicts leakage through a network flow path using a decision tree reduced-order model (ROM) derived from numerous runs of the multi-phase porous flow simulator FEHM. The FEHM simulations accounted for complex multi-phase processes such as phase change to predict leakage up the wellbore or fault pipe. For a given set of input parameters, the decision tree calculated the leakage of CO₂ and brine as a function of time.

Of the numerous injection scenarios computed by the U of U, LANL chose to examine only the closed boundary reservoir calculations where the increase in reservoir pressure was large enough to drive significant leakage. The two (2) main categories of runs were constant volume injection and constant pressure injection. The hypothetical injection site consisted of one (1) central injector well and either some number of unknown legacy wellbores located at random positions or a fault located at a random position throughout a 45 km x 45 km square domain.

Eight (8) cases were run: 1) poor cement (high leak flowrate) for the wellbores 2) good cement (moderate leak flowrate) for the wellbores, 3) small fault pipe spacing (high leak flowrate) and 4) large fault pipe spacing (moderate leak flowrate); all conditions were replicated for both constant pressure and constant volumetric rate injection. Only the closed-boundary reservoir calculations generated sufficient pressures to drive significant leakage, thus only closed-boundary leakage results were analyzed. **Table 4** below itemizes the definition of all eight (8) case studies.

Table 4. Case study definitions for presentation of random leakage results

Case	Leak path		Leak flowrate		Injection Strategy	
	Wellbore	Fault	High	Moderate	Constant Volume	Constant Pressure
1	X		X			X
2	X			X		X
3	X		X		X	
4	X			X	X	
5		X	X			X
6		X		X		X
7		X	X		X	
8		X		X	X	

LANL also developed the methodology for simulation modeling a pipeline rupture and associated CO₂ cloud dispersion in order to quantify the area and duration of CO₂ concentrations exceeding safe limits. QUIC urban terrain transport model, (publicly available software), was used to simulate CO₂ dispersion.

System-level modeling generated probability factors and quantitative factors that were input into the quantitative section of the QFMEA model when more detailed site-specific information was not available.

The deliverable, “System-level Modeling of Leakage Risk,” was reviewed by a cross-functional team of experts for accuracy and completeness and submitted to and accepted by DOE/NETL as an attachment to the quarterly progress report dated 29 APR 2011.

2.7 Probabilistic Calculations

U of U utilized Box-Behnken experimental design to minimize the number of process-level simulations to be run. A regression analysis was performed on the results of process-level simulations to develop polynomial response surface models for the six (6) parameters listed in **Table 3**. U of U performed Monte Carlo simulations on the response surface models to compile distributions of possible results by substituting a range of values – a probability distribution – for any factor that had uncertainty. Probability distribution functions (PDFs) were developed for overpressure, fracture pressure ratio, areal extent of the CO₂ plume and CO₂ residual trapping under constant volume injection and constant pressure injection conditions in closed systems. The methodology used for experimental design and probability calculations is illustrated in **Figure 6**.

The deliverable, “Development of PDFs of Important Sequestration Risk Outcomes,” was reviewed by a cross-functional team of experts for accuracy and completeness and submitted to and accepted by DOE/NETL as an attachment to the quarterly progress report dated 29 APR 2011.

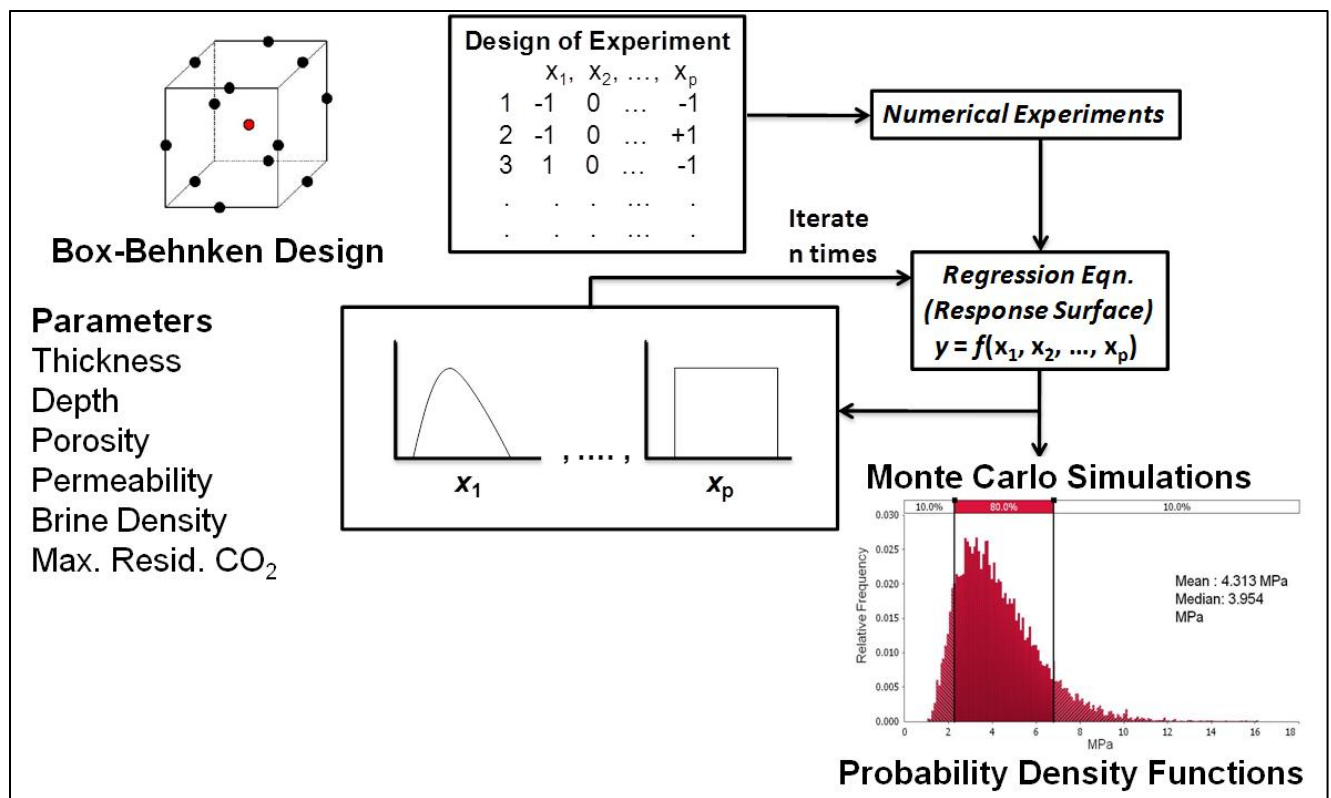


Figure 6: Methodology for experimental design and probability calculations

2.8 Failure Modes and Effects Analysis (FMEA) Model

The comprehensive risk list, risk/FEPs registry and risk characterization deliverables were integrated into the FMEA model. The following additional information was added for each risk/FEP:

1. Potential mode of failure(s)
2. Cause of failure(s)
3. Potential failure effect(s)
4. Method(s) of detecting failure
5. Risk prevention steps that can be taken to reduce probability of failure occurring
6. Risk mitigation steps that can be taken to reduce the severity of the failure effect or improve early detection of the failure.

A quantitative system was included to rank each risk/FEP using the following risk ranking factors:

1. Probability of failure occurring (P = 1 to 5)
2. Severity of failure effect (S = 1 to 5)
3. Difficulty of detecting failure early (D = 1 to 5)

Each of the three (3) risk factors is assigned a value from 1 to 5 based on the definitions provided in **Table 5**. The three (3) risk ranking factors for each risk/FEP are then multiplied together to calculate a Risk Priority Number (RPN) which will have a value of $P \times S \times D = 1$ to 125.

A non-quantitative zero (0) value in the ranking factors is used for headings (non-FEPs) or redundant FEPs which are covered by (combined with) other FEPs.

Table 5: Ranking factors for risks

Ranking factor	Probability of failure occurring	Severity of failure effect	Difficulty of early failure detection
5	Likely: frequency >1E-01 per year (one event every 1 to 10 years)	Catastrophic: Multiple fatalities. Damages exceeding \$100M. Project shut down.	Almost impossible: No known control(s) available to detect failure early.
4	Possible: frequency from 1E-02 to 1E-01 per year (one event every 10 to 100 years)	Serious: Isolated fatality. Damages \$10M-\$100M. Project lost time greater than 1 year.	Low: Low likelihood current control(s) will detect failure early.
3	Unlikely: frequency from 1E-04 to 1E-02 per year (one event every 100 to 10,000 years)	Significant: Injury causing permanent disability, Damages exceeding \$1M to \$10M. Project lost time greater than 1 month. Permit suspension. Area evacuation.	Moderate: Moderate likelihood current control(s) will detect failure early
2	Extremely unlikely: frequency from 1E-06 to 1E-04 per year (one event every 10,000 to 1,000,000 years)	Moderate: Injury causing temporary disability. Damages \$100k to \$1M. Project lost time greater than 1 week. Regulatory notice.	High: High likelihood current control(s) will detect failure early
1	Incredible: frequency <1E-06 per year (less than one event every 1,000,000 years)	Light: Minor injury or illness. Damages less than \$100k. Project lost time less than 1 week.	Almost certain: Current control(s) almost certain to detect the failure early. Reliable detection controls are known with similar processes.
0	Not applicable	Not applicable	Not applicable

The deliverable, "Failure Modes and Effects Analysis for CO₂ Geologic Sequestration," was reviewed by a cross-functional team of experts for accuracy and completeness and submitted to and accepted by DOE/NETL as an attachment to the quarterly progress report dated 29 JUL 2011.

2.9 Risk Mitigation Cost Savings (QFMEA Model)

The FMEA model was expanded into a Quantitative Failure Modes and Effects Analysis (QFMEA) model to quantify potential damage recovery costs (with and without risk prevention/mitigation), risk prevention/mitigation costs, and potential cost savings associated with risk prevention/mitigation (cost benefit analysis).

The QFMEA model is in the form of an Excel spreadsheet. There are forty-two (42) column headings included in the QFMEA model spreadsheet. The QFMEA model incorporates risk characterization (including the FEPs registry), FMEA, and quantitative sections as shown in **Tables 6a, 6b and 6c**.

Table 6a: Column headings for the risk characterization section of the QFMEA model

				Project Specific Information		FEPs Type	Storage Type				Project Phase Impacted						
Index #	Risk Area/FEP	Description	Relevance	Site Specific Information	Information Gaps or Uncertainties	Feature	Event	Process	DSA	EOR	ECBM	All Storage Types	Site Characterization	Eng. Proc. Const. (EPC)	Startup and Operation	Post-Injection Site Care	All Project Phases

Table 6b: Column headings included in the FMEA section of the QFMEA model

Potential failure mode	Cause of failure	Potential failure effect	Method of detecting failure	Risk prevention steps	Risk mitigation steps	Probability of failure (P=1 to 5)	Severity of failure (S=1 to 5)	Difficulty to detect failure (D=1 to 5)	Risk priority number (RPN = P x S x D = 1 to 125)

Table 6c: Column headings included in the quantitative section of the QFMEA model

Damage recovery cost									
Human Health and Safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO ₂ emissions (tonnes and \$)	Fines and legal expense (\$)
Fatalities (\$)	Serious injuries (\$)	Minor injuries (\$)							



Prevention/mitigation cost savings			
A. Damage recovery cost w/o prevention and mitigation (\$)	B. Damage recovery cost w/ prevention and mitigation (\$)	C. Cost of prevention and mitigation (\$)	D. Cost savings with prevention and mitigation (\$) D = A – B – C

The CQRA project team developed methods for estimating the cost of potential damage recovery (with and without risk prevention/mitigation), cost of risk prevention/mitigation steps, and the potential cost savings associated with risk prevention/mitigation. The cost factors and formulas

developed for this project will not be applicable for every site. A more detailed project specific cost analysis should be completed prior to developing a project. It should be noted that variations in the project conditions, including but not limited to, site conditions, operating conditions, regulatory requirements, and project financing, will vary. Should project specific data, or other information, become available in the future, the information contained herein should be reviewed, and the conclusions and recommendations presented herein modified accordingly. The passage of time will result in significant changes in technology, economic conditions, or site variations, that may deviate from the study's parameters. Therefore, the CQRA project team neither guarantees the accuracy nor the applicability of the presented cost factors and formulas for specific project sites.

Estimating potential damage recovery costs may be standardized when an industry has been in existence for decades and there is a large historical data base of damage cases to analyze and to calculate appropriate cost factors and formulas. That is not the case in the carbon capture and storage industry. There has been over 30 years of CO₂ pipeline transportation and CO₂ use in enhanced oil recovery without a single reported fatality to date, but large-scale CO₂ geologic sequestration in deep saline aquifers is a new and not fully proven technology. For example, a regional CO₂ storage facility injecting 5 to 20 million t/y of CO₂ into subsurface formations for more than 25 years without extracting oil or brine to provide physical space for the additional 125 to 500 million t (180 to 722 million cubic meters) of supercritical CO₂.

The following methodology was used to develop damage recovery costs (with and without risk prevention/mitigation), risk mitigation costs and potential savings associated with risk mitigation for the QFMEA model.

Step 1. The first step in estimating damage recovery costs, mitigation costs and calculating costs savings was to define and standardize the various damage scenarios. This was performed by reviewing all of the Risk/FEPs failure modes and failure effects, combining those that were similar or redundant and focusing on those failure effects that were most important. This reduced the number of failure effects down from approximately 400 damage scenarios to 88 damage scenarios.

Step 2. The second step was to analyze each potential damage scenario and devise a method to quantify the extent (limits) of likely damage that would be meaningful and capable of being associated to a dollar value. In estimating potential damage recovery costs, it was evident that the costs had to be broken down into several categories in order to be meaningful. The following categories were selected:

- Human health and safety
- Natural resource damage (environmental)
- Third-party property damage
- Owner property damage
- Owner business interruption
- Owner economics
- CO₂ emissions
- Fines and legal expenses

Step 3. The third step was to review all of the Risk/FEPs prevention and mitigation steps, combining those that were similar or redundant and standardize those that remained. This reduced the FEPs from several hundred down to approximately 240.

Step 4. The fourth step was to estimate the cost of mitigation steps. A financial model was developed to analyze capital costs, operating costs and internal return on investment over the life of the project for CO₂ geologic sequestration in deep saline aquifers. This was helpful in estimating the cost of mitigation steps for various size projects. The financial model assumed best management practices being followed to be in compliance with the USEPA's Underground Injection Control (UIC) Program Class VI regulations (Title 40 of the Code of Federal Regulations, Parts 144-147), and Pipeline and Hazardous Materials Safety Administration (PHMSA) Safety Regulations (Title 49 of the Code of Federal Regulations, Parts 190-199).

Step 5. The fifth step was to estimate damage recovery costs with prevention and mitigation steps. In many cases, this was simple if one assumes that the damage can be completely prevented or mitigated by selecting the appropriate project site. There may be an avoidance cost in site selection that would need to be determined for site specific conditions. If a potential risk can't be avoided, then the cost of mitigation must be considered.

Step 6. The final step was to populate the QFMEA spreadsheet columns for damage recovery costs, mitigation costs and cost savings for each of the approximately 400 Risk Areas/FEPS. Most of the effort was put into Risks/FEPS that impacted human health and safety, natural resource damage, property damage and CO₂ emissions. Less emphasis was put on Risks/FEPS that only impacted project economics.

The deliverable, "Estimating Potential Damage Recovery Costs and Cost Savings Associated with Risk Prevention/Mitigation Steps," was reviewed by a cross-functional team of experts for accuracy and completeness and submitted to and accepted by DOE/NETL as an attachment to the quarterly progress report dated 31 JAN 2012.

2.10 Application of the Risk Assessment Model (QFMEA model)

Task six (6) of this project was to evaluate the efficacy of the QFMEA model by using it to conduct quantitative risk assessments for three (3) CO₂ storage (or utilization) sites. The following three (3) project sites were selected:

1. SACROC Northern Platform CO₂-EOR Site
2. Pump Canyon CO₂-ECBM Site
3. Farnsworth Unit CO₂-EOR Site

The above quantitative risk assessments were conducted independently from site owners/operators to avoid potential bias. Information for the risk assessments was gathered from the public domain.

While we have attempted to obtain reliable information, we do not guarantee the accuracy of this information as most information came from non-verified third-party sources rather than directly from the site owners and operators.

The following methodology was used for completing the quantitative risk assessments:

1. Gather site-specific information
2. Input site-specific information into the QFMEA model
3. Identify information gaps or uncertainties
4. Adjust failure modes, causes, effects, and detection methods to the site-specific case
5. Eliminate risk areas that are not applicable
6. Identify relevant site-specific risk prevention and mitigation steps
7. Develop and run site-specific geologic and economic models
8. Estimate potential damage recovery costs, risk prevention/mitigation costs and potential cost savings
9. Rank and prioritize risk areas for site-specific conditions
10. Submit results to a cross-functional team of experts for review for completeness and accuracy.

The CQRA project team accumulated a substantial amount of site-specific information on the three (3) project Sites. This data included details on regional and local geology, reservoir characteristics, caprock characteristics, aquifer characteristics, historical injection and production data, operation, maintenance and safety issues, CO₂ pipeline and well incidents, seismic activity in the area, surface use, natural hazards, water studies, well data, project economics and more. This information came from over 250 references, including books, technical papers, technical reports, articles, websites, presentations, SEC filings and interviews.

Available site-specific information was entered into the QFMEA model in the appropriate cells under the "site-specific information" column heading for each risk area/FEP. The list of risk areas secondarily function as a project checklist to identify what site-specific project information was needed to complete the risk assessment.

After the site-specific information was entered into the QFMEA model, the information was evaluated to determine if there were any information gaps or uncertainties associated with the site-specific information. These comments were entered into the QFMEA model in the appropriate cells under the "information gaps or uncertainties," column heading to identify any concerns about the lack, or quality, of information. Efforts were made to fill in information gaps where possible.

Existing failure modes, causes, effects, and detection methods were reviewed to assess if they were consistent with site-specific conditions. If they were not consistent, they were adjusted, as necessary, to modify the QFMEA for the site-specific case.

Some risk areas did not apply to the specific sites. For example, risk areas associated with offshore, oceanic or glacial conditions would not specifically apply to the selected sites. These risk areas were noted to be "not applicable or incredible" by highlighting them in blue and assigning "1"

values (i.e. the frequency less than $1\text{E-}06$ per year, or less than one event every event every 1,000,000 years) to the probability of failure occurring.

In cases where risks were redundant with other identified risk areas, the redundant risks were highlighted in blue, a note was provided indicating where to reference the master risk, and a non-quantitative value of "0" was assigned to the probability of failure occurring.

Existing risk prevention and mitigation steps were reviewed to determine if they were consistent with site-specific conditions and adjusted failure modes, causes, effects and detection methods. If they were not consistent, they were appropriately adjusted to make them consistent.

Existing geologic models for the Sites were analyzed by the CQRA project team to assess the structural characteristics of the reservoir and caprock. Reservoir mass balance models were also used. Financial models for CO_2 -DSA, CO_2 -EOR, CO_2 -ECBM, and CBM operations were developed and analyzed to help estimate project development, construction, operation, maintenance and closure costs as needed.

Damage scenarios were developed for each of the applicable risk areas. Potential damage recovery costs, (with and without risk mitigation), risk mitigation costs and potential cost savings (cost/benefit analysis) were estimated with the use of quantity and cost factors.

Failure rates (frequency of failures per year) were estimated for each applicable risk area failure mode. These were developed based on historical or analogue field data wherever possible. Ranking factors were assigned to each failure rate depending on projected order of magnitude. Ranking factors were also assigned to each potential damage recovery cost depending on its order of magnitude. Ranking factors for difficulty of early failure detection were assigned subjectively based on professional experience of the project team. **Table 5** provides the criteria used for the ranking factors.

The end product for the quantitative risk assessment was submitted to a cross-functional team of experts to review for completeness and accuracy. The cross-functional team included geologists, petroleum engineers, research scientists, computer simulation modelers, environmental professionals and risk managers participating in the project.

The following deliverables were submitted to and accepted by DOE/NETL as attachments to quarterly progress reports:

- "Quantitative risk assessment of the SACROC Northern Platform CO_2 -EOR Operation," submitted 31 OCT 2012
- "Quantitative risk assessment of the San Juan Basin Pump Canyon CO_2 -ECBM Site," submitted 26 APR 2013
- "Quantitative risk assessment of the Farnsworth Unit CO_2 -EOR Site," submitted 31 JUL 2013

3.0 RESULTS AND DISCUSSIONS

3.1 Quantitative Failure Modes and Effects Analysis (QFMEA) Model

The QFMEA model is in the form of an Excel spreadsheet with approximately 400 risk areas/FEPs subdivided into the following 24 Areas of Risk Categories:

0. Assessment basis	8. Economic risks	17. Legal, legislation and regulation risks
1. External factors	9. Permitting risks	18. CO ₂ capture risks
2. CO ₂ storage	10. External risks	19. CO ₂ dehydration risks
3. CO ₂ properties, interactions and transportation	11. Project management risks	20. CO ₂ compression risks
4. Geosphere	12. Engineering risks	21. CO ₂ pipeline risks
5. Boreholes	13. Procurement risks	22. CO ₂ on-site facility risks
6. Near-surface environment	14. Construction risks	23. CO ₂ monitoring risks
7. Impacts	15. Commissioning and startup risks	
	16. Field safety	

The QFMEA spreadsheets are best printed out on ledger (11 inch x 17 inch) size paper in landscape mode. However, letter (8.5 inch x 11 inch) size paper can be used if only a few critical columns are selected. The column headings of the QFMEA model are:

1. Line number
2. Index number
3. Risk Area/FEP
4. Description of the Risk Area/FEP
5. Relevance of the Risk Area/FEP
6. Site-specific information
7. Information gaps or uncertainties
8. FEPs type:
 - 8.1. Feature
 - 8.2. Event
 - 8.3. Process
9. Storage type
 - 9.1. DSA
 - 9.2. EOR
 - 9.3. ECBM
 - 9.4. All storage types
10. Project phase impacted
 - 10.1 Site characterization
 - 10.2 Engineering, procurement and construction (EPC)
 - 10.3 Startup and operation
 - 10.4 Post injection site care
 - 10.5 All project phases
11. Potential failure mode
12. Cause of failure
13. Potential effect of failure
14. Method of failure detection
15. Risk prevention steps

16. Risk mitigation steps
17. Probability of failure ($P = 1$ to 5)
18. Severity of failure ($S = 1$ to 5)
19. Difficulty to detect failure ($D = 1$ to 5)
20. Risk priority number ($RPN = P \times S \times D = 1$ to 125)
21. Human health and safety
 - 21.1 Fatalities (\$)
 - 21.2. Serious injuries (\$)
 - 21.3 Minor injuries (\$)
22. Natural resource damage (\$)
23. Third-party property damage (\$)
24. Owner property damage (\$)
25. Owner business interruption (\$)
26. Owner economics (\$)
27. CO₂ emissions (tonnes and \$)
28. Fines and legal expenses (\$)
29. Damage recovery cost without prevention and mitigation (\$)
30. Damage recovery cost with prevention and mitigation (\$)
31. Cost of prevention and mitigation (\$)
32. Cost savings with risk mitigation (\$)
33. Insurance ranking (1 = needed info; 2 = helpful info)

The QFMEA model can be applied to CO₂ capture, transportation, and sequestration or use in deep saline aquifers (DSA), enhanced oil recovery (EOR) operations or enhanced coal bed methane (ECBM) operations. The QFMEA model:

1. Identifies and characterizes the potential risks associated with CO₂ capture, transport, storage and use operations
2. Identifies the likely failure: modes, causes, effects, and methods of detection
3. Lists possible risk prevention and risk mitigation steps
4. Estimates potential damage recovery costs, mitigation costs and cost savings resulting from mitigation
5. Ranks (prioritizes) risks according to the probability of failure, the severity of failure, the difficulty of early failure detection, and the potential for fatalities.

The QFMEA model generates the necessary thought pattern and information needed for effective risk management. The model can be tailored to specific projects and is applicable to new projects, as well as, mature projects. The QFMEA model can be revised and updated as new information comes available. It accepts input from multiple sources, such as literature searches, site characterization, field data, computer simulations, analogues, process influence diagrams, probability density functions, financial analysis models, cost factors and heuristic best practices manuals, and converts the information into a standardized format in an Excel spreadsheet. Failure Modes and Effects Analysis(FMEA) models are widely used in the military, space, aeronautics, medical, power and nuclear industries where system reliability is critical. They are used to answer the following questions:

What could possibly go wrong (failure mode)?

What would be the likely cause of failure?

What will happen if a failure occurs, or how will a failure impact system performance?

What is the probability of failure occurring?

How severe will the effect of failure be?

How can the failure be prevented or the effect of failure be mitigated?

What are the most important risk areas to work on?

The International Electrotechnical Commission (IEC) has published an international standard for performing FMEAs titled: "Analysis techniques for system reliability - Procedure for failure mode and effects analysis (FMEA)" (**IEC 2006**).

The QFMEA goes beyond the FMEA by quantifying potential damage recovery costs, risk prevention/mitigation costs and potential cost savings associated with risk mitigation. It also takes into consideration the difficulty of detecting a failure early in prioritizing risk areas.

The QFMEA should be initiated early in the project to assess risks and then used throughout the life of the project as a tool to manage risks. It can provide input into:

- Site screening
- Permitting
- Public outreach
- Project financing
- Insurance coverage
- Project go-no go decision making based on risk versus reward
- Risk management planning
- Contract conditions and negotiation
- Engineering design and design reviews
- Procurement and construction quality control
- Reliability availability and maintainability (RAM) studies
- Hazards and operability (HAZOP) studies
- Operating procedures
- Maintenance planning and scheduling
- Operator training
- Safety audits
- Computer simulation
- Monitoring, verification and accounting (MVA) plans
- Emergency response and contingency plans
- Long-term liability transfer

3.2 Process Influence Diagrams (PIDs)

Three (3) separate PIDs were developed to address:

1. CO₂ geologic sequestration
2. CO₂ used for Enhanced Oil Recovery (EOR)
3. CO₂ used for Enhanced Coal Bed Methane (ECBM)

These PIDs are included in **Appendix A**.

The following key technical risks were identified as being most significant for CO₂ sequestration/use projects:

1. Loss of containment – CO₂ leakage from reservoir and otherwise unintended migration
2. Over pressuring
3. Displacement of saline formation fluids
4. Caprock or sealing formation failure
5. Reservoir permeability and injectivity loss
6. Reservoir CO₂ storage capacity reduction
7. Contamination of groundwater and/or surface water
8. EOR low oil recovery
9. EOR/ECBM early CO₂ breakthrough
10. ECBM CO₂ storage capacity of coal

The above key risks, or hubs, are identified in the PIDs with bold borders.

Most risks/FEPs listed in the PIDs have an index number included to allow cross referencing with the QFMEA model..

In the EOR PID, some of the risks/FEPs are provided with more detail. For such FEPs, a box with dashed border was used to cluster these sub-risks/FEPs.

PIDs show which FEPs interact with each other. Arrows indicate direction of influence or impact. Solid circles have been added as junction points to identify where lines meet versus where lines cross over each other.

3.3 Quantitative Calculations and Factors

3.3.1 Human Health and Safety

There are several questions to answer when estimating the potential damage recovery cost for human health and safety for each damage scenario.

1. What is the likely compensation award for a fatality or injury?
2. How many fatalities or injuries are likely to occur?

Donlan and Trabucchi estimated the likely compensation award for fatalities and injuries based on average compensation awards to victims of the 911 twin towers attack (**Donlan 2010**). They recommended the following compensation levels be used:

- \$2,200,000 per fatality
- \$500,000 per individual for irreversible injuries
- \$50,000 per individual for adverse (reversible) injuries

In researching other applicable published awards, we came across a multi-million dollar settlement agreement in the 2010 Upper Big Branch underground coal mine disaster that killed 29 people and seriously injured 2 people. The following compensations were awarded in December 2011 (**OH&S 2011**):

\$1.5 million per fatality

\$1.5 million per individual for irreversible injuries

We decided to use the Upper Big Branch compensation awards and added \$50,000 per individual for (reversible) injuries. Compensation for pain and suffering outside of fatalities and injuries was not included in this analysis.

Calculation of fatality rates and injury rates is difficult to do without knowing site-specific conditions. However, we looked at what the likelihood of fatalities would be for the various damage scenarios using rates from similar activities.

We ruled out fatalities from leaks associated with wellbores based on modeling by LANL that indicated the rate of leakage at the surface would be too low to generate fatalities.

The impact of leaky wells and faults was evaluated based on work done by Schlumberger (**Loizzo 2010**) and LANL (**LANL 2011**). Schlumberger looked at the frequency and damage caused by wellbore leakage associated with 705,500 well-years of operation for underground natural gas storage as an analog to CO₂ storage. They concluded that leakage events could be classified as serious, major or catastrophic according to the degree of damage and the rate of leakage. Serious leakage events consist of gas buildup in the intermediate annulus of the wellhead casing or slow leakage through nearby soil resulting in minimum impact and no injuries. Major events have a moderate leakage rate and may cause injury. Catastrophic events have a very high rate of leakage,

equivalent to a well blowout or pipeline rupture, and may result in fatalities. The leakage rates and probability of leakage are summarized in **Table 7**.

Table 7: Classification of leakage events

Event Category	Leakage rate (kg/s)	Leakage rate (t/y)	Probability of leakage events/well/year	
Serious events (gas build up in the intermediate annulus of the wellhead casing or slow leaks through nearby soil resulting in no injuries)	<0.317	<10,000	2E-02	2/100
Major events (moderate leakage through wellbore annulus)	0.317 to 3.17	10,000-100,000	2E-05	14/705500
- Major events without injury	0.317 to 3.17	10,000-100,000	1.7E-05	12/705500
- Major events with injuries	0.317 to 3.17	10,000-100,000	2.8E-06	2/705500
Catastrophic events (well blowout with fatalities)	>31.7	>1,000,000	<1E-06	0/705500

LANL simulated wellbore leakage using *CO₂-PENS* system-level modeling. They concluded that leakage from a single wellbore with high permeability (due to poor quality cement) would result in a CO₂ leakage rate up to 1.6 kg/s (50,000 t/y) at the caprock. This would place wellbore leakage in the major event category listed above. However, as the CO₂ flows upward through the wellbore, much of it is diverted before reaching the surface as it passes through stacked sinks above the caprock. The rate of CO₂ reaching the surface is more likely in the range of 0.001 to 0.23 kg/s (31 to 7,250 t/y). Thus, at the surface, the CO₂ leakage rate falls into the serious event category (therefore no fatalities or injuries are likely).

LANL likewise simulated fault leakage using *CO₂-PENS* system-level modeling. They concluded that CO₂ leakage through a high permeability fault will be less than 0.3 kg/s (<10,000 t/y) with the median rate being in the range of 0.1 kg/s (3,150 t/y). The median rate for a highly permeable fault is on the same order as natural CO₂ leaks in Latera, Italy (0.08 kg/s or 2,500 t/y). According to Schlumberger, the Latera CO₂ leaks cause very little disruption to the ecosystem or human activity. The CO₂ bubbles out of a small water puddle and leaves a 1 meter radius area devoid of vegetation surrounded by a 5 meter radius zone of vegetation that appears to benefit from the added CO₂. Sheep footprints can be seen around the water puddle indicating they may even be drinking water from the puddle.

The LANL simulations suggest that in most cases, CO₂ leakage from wellbores and/or faults will have minimal health, safety or environmental issues at the surface. Faults are likely to have an order of magnitude lower leakage than single wellbores.

The following conditions are required for a single wellbore to achieve a major CO₂ leakage rate (>0.317 kg/s or >10,000 t/y) at the surface:

1. The wellbore must fully penetrate the caprock
2. The CO₂ plume must intercept the wellbore

3. The wellbore must be poorly cemented (high permeability, poor quality annulus cement)
4. There must be an absence of sinks above the caprock (otherwise most of the CO₂ will be diverted before reaching the surface)

To achieve a catastrophic event (fatality) from a leaky wellbore or fault, the CO₂ would need to build up over time to a critical mass near the surface, such as under a deep lake with little current; below a permafrost; or in a confined space or low surface area with poor ventilation.

According to Gouveia and Friedmann, "Crystal Geyser (in Utah) can be considered the maximum example of a surface emission from a deep CO₂ reservoir." The geyser was unintentionally created in 1935 after a prospective oil well was drilled about 800 m deep into a fault zone above a CO₂ reservoir. Shortly after drilling, the open borehole was abandoned and not properly capped. Later, the well was filled in with about 600 meters of dirt, leaving about 200 meters of open borehole. The rate of CO₂ released from the open borehole varies from 2.6 to 5.8 kg/s, (82,000 to 183,000 t/y), during eruptions which can shoot up to 40 meters into the air. The cumulative rate has been calculated to be 11,000 tonnes per year. "Preliminary analysis suggests that even extremely large and rapidly escaping CO₂ at this well present a negligible risk to human health and safety. ... Concentrations of CO₂, even during maximum eruption rates, were less than 12,600 ppm and never reached levels dangerous to human health." (**Gouveia 2006**).

A well blowout or pipeline rupture could achieve a catastrophic rate (>31.7 kg/s or > 1,000,000 t/y), but in those cases, the force associated with that high rate would rapidly disperse CO₂ in the atmosphere. Several CO₂ well blowouts have been reported by **Duncan 2006** and **Skinner 2003** ranging from 6 to 122 kg/s (189,000 to 3,800,000t/y) without any reported fatalities.

The FutureGen Environmental Impact Statement (EIS) for Mattoon, Jewett, Odessa, and Tuscola CO₂ sequestration project sites, indicated that leakage due to rupture of wellhead injection equipment or slow leakage from wells at the sequestration site during operation could result in 0-6 individuals with adverse effects (reversible injuries) and less than 1 individual with irreversible injury but all of these injuries were tied to H₂S rather than CO₂ exposures. The H₂S content in the gas stream was assumed to be 100 ppm (**FutureGen 2007**).

The FutureGen EIS also indicated that a pipeline rupture could result in up to one fatality, up to one individual with irreversible injury and 0 to 52 individuals with adverse effects (minor injuries) depending on the site. Again, all of these events were related to H₂S and not CO₂ exposures (**FutureGen 2007**).

PHMSA records of 57 CO₂ pipeline incidents from 1986 through 2011 show no fatalities or injuries reported even with five (5) pipeline ruptures, (**PHMSA 2012**).

The Texas Clean Energy Project EIS states that the fatality rate for the CO₂ pipeline is less than 1E-06 (one chance in 1 million of fatality per year) directly above the pipeline, decreasing to 1E-07 at approximately 70 m from the pipeline, and to 1E-08 at approximately 140 m from the pipeline. (**TECP 2011**).

A report prepared by Quest Consultants Inc. for the Texas Clean Energy Project estimated that a rupture of the 254 mm (10-inch) diameter pipeline could achieve a 99% mortality level at 77 m from the rupture, a 50% mortality level at 101 m from the rupture and a 1% mortality level at 139 m from the rupture **(TCEP 2010)**.

A report prepared by URS for the Hydrogen Energy California (HECA) Project estimated in the worst case scenario, a rupture of the 305 mm (12-inch) diameter pipeline would generate a temporary plume with the 40,000 ppm CO₂ level (NIOSH IDLH immediate dangerous to life and health) extending out from 230 to 627 m depending on the amount of CO₂ released (4 to 209 t), **(HECA 2009)**.

We have estimated the following fatality rates for disaster scenarios shown in **Table 8**.

Table 8: Estimated fatalities for various disaster scenarios.

Disaster Scenario	No. of fatalities per event
CO ₂ well blowout	1
CO ₂ pipeline rupture	1
CO ₂ stream containing H ₂ S	1
CO ₂ stream containing CO or H ₂	1
Accumulation of CO ₂ in an unventilated low lying or confined space	1-2
Accumulation of CO ₂ under a permafrost	1-2
Hydrocarbon well blowout	1-2
Explosions and crashes	1-2
Accumulation of CO ₂ in an underground mine	1-3
Limnic eruption	1-6

For natural earthquakes and induced seismicity, we developed fatality and injury rates based on a modification of **(ATC 1985)** as reported in **(NAP 1989)** as shown in **Table 9**.

Table 9: Earthquake intensity impact on damage factor, injury and fatality rates

Modified Mercalli Intensity (MMI) Scale*	Description*	Peak ground acceleration (g)**	Minor injury rate ****	Serious injury rate ****	Fatality rate ****
I	Detected only by sensitive instruments.	0.0005-0.0017	0	0	0
II	Felt by a few people at rest, especially on upper floors; delicately suspended objects may swing.	0.0017-0.005	0	0	0
III	Felt noticeably indoors, but not always recognized as earthquake; standing autos rock slightly, vibration like passing truck.	0.005-0.014	0	0	0
IV	Felt indoors by many, outdoors by few, at night, some awoken; dishes, windows, doors disturbed; autos rock noticeably.	0.014-0.039	0	0	0
V	Felt by most people; some breakage of dishes, windows and plaster; disturbance of tall objects.	0.039-0.092	0	0	0
VI	Felt by all; many frightened and run outdoors, walk unsteadily; falling plaster and chimneys; damage small.	0.092-0.18	3/100,000	1/250,000	1/1,000,000
VII	Difficult to stand; damage to buildings varies depending on quality of construction; noticed by people driving autos.	0.18-0.34	3/10,000	1/25,000	1/100,000
VIII	Panel walls thrown out of frames; fall of walls, monuments, chimneys; sand and mud ejected; drivers of autos disturbed.	0.34-0.65	3/1,000	1/2,500	1/10,000
IX	Buildings shifted off foundations, cracked, thrown out of plumb; ground cracked; underground pipes broken.	0.65-1.24	3/100	1/250	1/1,000
X	Most masonry and frame structures destroyed; ground cracked, rails bent, landslides.	>1.24	3/10.	1/25.	1/100
XI	Few structures remain standing; bridges destroyed, fissures in ground, pipes broken, landslides, rails bent.		2/5.	2/5.	1/5.
XII	Total destruction; waves seen on ground surface, lines of sight and level distorted, objects thrown up in air.		2/5.	2/5.	1/5.

*KGS 2007

**Baer 2007

*** Modified from ATC 1985.

For extreme weather, such as flooding, we used Hurricane Katrina fatality rates of 1.5/1000 based on Jonkmann 2009.

3.3.2 Natural Resource Damage (Environmental Damage)

Natural resources are broadly defined to include land, fish, wildlife, biota, air, water, ground water, drinking water supplies, habitats, National Parks, National Wildlife Refuges, National Monuments, beaches, wetlands, coral reefs, archaeological and cultural sites. Natural resource damage recovery costs includes the cost of restoring, replacing or acquiring equivalent of injured natural resources plus the compensable value for public loss in services incurred between the time of the loss and full restoration of the resource. The lost services can include services to other natural resources, recreation, education, cultural, commercial, passive use, etc. The amount of damages can be substantial.

For CO₂ geologic storage, the key concerns for potential natural resource damages are contamination of underground sources of drinking water (USDW) aquifers and contamination of soils and sediments.

Based on work by **LANL 2011** and **Esposito 2010**, it appears that USDW contamination is most likely to come from CO₂ loss of containment due to leaky wellbores, faults, fracture zones or high permeable pathways in the caprock. The rate of CO₂ or brine leakage is likely to be less than 0.3 kg/s or <10,000 t/y. However it is unlikely that these leaks will be detected immediately, and it is possible a leakage could continue for as long as five (5) years before it is detected. Therefore, our disaster scenario assumes 5,000 to 50,000 t of CO₂ are released into a confined USDW aquifer.

The CO₂ migrating into the USDW aquifer will partially dissolve in the water, lower the pH to the 5.5 to 6.0 range and potentially result in mobilization of heavy metals into the water. The reduction in pH and heavy metal mobilization may not occur if the USDW aquifer is in a carbonate formation. The amount of water impacted by the CO₂ could be anywhere from 25 to 250 tonnes per tonne of CO₂ depending on how much of the CO₂ dissolves in the water and the ultimate concentration level in the water. If the maximum amount of CO₂ dissolved in water is 25 kg of CO₂/t of water, then 40 tonnes of water would be required to dissolve 1 tonne of CO₂. Modeling done by Esposito suggests that after 5 years, approximately 70-80% of the CO₂ will dissolve in water and 20-30% will remain gaseous **Esposito 2010**. Esposito found that to remove 99% of a 1000 t CO₂ plume in a USDW aquifer would require extracting 241,000 tonnes of water or 244 tonnes of water per tonne of CO₂ removed.

If we assume that nothing is done to stop the leak or remove the CO₂ from the USDW aquifer, the CO₂ plume will continue to disperse. The ratio of gaseous to aqueous CO₂ would likely increase as the plume near the leak point becomes fully saturated. A large tongue of gaseous CO₂ will fan out across the top of the aquifer and could significantly impact water wells in the area. CO₂ could leak up water wells and accumulate in pump houses or basements leading to risks of asphyxiation in confined areas.

If we were to just look at replacement value for the contaminated water in the USDW aquifer, we could assume that fresh drinking water could be brought from a different aquifer to meet local needs. The average cost of drinking water in the U.S. is \$0.50/t (\$2.00 per 1000 gallons). We have assumed \$0.80/t (\$3.00 per 1,000 gallons) to cover the longer distance of transportation. At 244 tonnes of contaminated water per tonne of CO₂, the replacement cost is approximately \$200/t of CO₂ released into the USDW aquifer. This is comparable to the cost of pump-and-treat technology wherein the CO₂ is pumped to the surface, aerated or pH adjusted and filtered and reinjected or used.

If the contamination includes mobilization of heavy metals and/or brine, the cost of pump-and-treat could double or triple to \$400-600/t of CO₂ or brine released. Note that more sophisticated water treatment technologies become more expensive per unit on smaller scale. **Table 10** provides an indication of how scale may impact treatment cost.

Table 10: Cost analysis of pump and treat methods for remediating a CO₂ plume in a confined USDW aquifer

Basic assumptions			
CO ₂ accumulation (t)	1,000	10,000	50,000
Water extraction required to remove ~99% of CO ₂ (t)	241,000	2,410,000	12,050,000
CO ₂ extracted (t)	989	9,890	49,450
Years of extraction (y)	5	10	10
Maximum extraction rate (gpm)	51	254	1,270
Maximum extraction rate (t/d)	276	1,382	6,918
Pump and treat (surface aeration, filtration and reinjection back into the USDW aquifer)*			
Capex	285,872	866,040	2,588,544
First year opex	40,000	60,000	120,000
Following year opex	20,000	30,000	60,000
Capex plus opex over the life of the project (\$)	405,872	1,196,040	3,248,544
Remediation cost (\$/t water)	1.68	0.50	0.27
Remediation cost (\$/t CO ₂ removed)	410.39	120.93	65.69
Pump and treat (electrochemical treatment with surface discharge)*			
Capex	892,936	2,245,020	7,844,272
First year opex	253,560	427,800	1,724,000
Following year opex	233,560	397,800	1,694,000
Capex plus opex over the life of the project (\$)	2,080,736	6,253,020	24,814,272
Remediation cost (\$/t water)	8.63	2.59	2.06
Remediation cost (\$/t CO ₂ removed)	2103.88	632.26	501.81
Pump and treat (ion exchange with surface discharge)*			
Capex	692,936	1,545,020	3,244,272
First year opex	125,000	310,000	1,210,000
Following year opex	90,000	240,000	968,000
Capex plus opex over the life of the project (\$)	1,177,936	4,015,020	13,166,272
Remediation cost (\$/t water)	4.89	1.67	1.09
Remediation cost (\$/t CO ₂ removed)	1191.04	405.97	266.25
Pump and treat (reverse osmosis + ion exchange polishing and surface discharge)*			
Capex	592,936	1,395,020	3,044,272
First year opex	120,000	290,000	914,450
Following year opex	86,000	221,500	781,000
Capex plus opex over the life of the project (\$)	1,056,936	3,678,520	10,987,722
Remediation cost (\$/t water)	4.39	1.53	0.91
Remediation cost (\$/t CO ₂ removed)	1068.69	371.94	222.20
* Cost includes production well(s), surface storage and treatment facilities, reinjection well(s) or surface discharge. Excludes cost for corrective action to locate and fix leak.			

Soil and sediment contamination is likely to be localized to the release point. We have assumed a compensation value of \$12 per m², (approximately \$1 per square foot, \$50,000 per acre, or \$32 million per square mile). This is the amount estimated by Research Partnership to Secure Energy for America (**RPSEA 2010**). It is “based on restoration to account for temporary or permanent impacts to sensitive habitats, wetlands, floodplains, forested areas, etc.” The estimate is highly variable and should be evaluated as part of an environmental impact report. We believe the value can cover a wide range of treatment required, including adding soil amendments to adjust pH or immobilize heavy metals, PAH mitigation, remediating sodium contamination, replanting or reforestation.

Wildlife kill is not expected to be a significant issue unless the CO₂ accumulates in a low area with poor ventilation. This would typically be localized. **Table 11** lists some typical compensation ranges for wildlife.

Table 11: Typical range of compensation for wildlife.

Type of wildlife (including mammals, fish and birds)	\$/each	Reference
Endangered species	10,000 to 100,000	Modified from Brown 1992
Threatened species	4,000 to 10,000	Modified from NCAC 2002
Common species	5 to 4,000	Modified from NCAC 2002

An oil spill can be devastating on natural resources. This would occur most likely with enhance oil recovery operations. Damage is typically estimated on a \$/barrel released. **Table 12** lists some recent oil spill statistics.

Table 12: Damage recovery costs for recent oil spills

Company	Location	Date	Oil Released (barrels)	Estimated Damage Recovery (\$)	Damage Recovery (\$/bbl)	Reference
Chevron	Red Butte Garden, UT	June and December 2010	1300	\$42.6M	\$32,769	Stettler 2011
Enbridge	Kalamazoo River, MI	July 2010	19,000	\$700M	\$36,750	Klug 2011
ExxonMobil	Yellowstone River, MT	July 2011	1509	\$135M	\$89,463	AP 2012
BP	Gulf of Mexico	July – September 2010	4,900,000	\$40B	\$8,183	Wikipedia 2012

We have estimated a range of 500 to 20,000 barrels released per event and \$30,000 to \$90,000 per barrel as a likely compensation value. The highest dollar value would be associated with the lowest volume released.

It is difficult to estimate natural resource damage caused by induced seismicity. In many cases the damage is not likely to be caused by surface deformation near the earthquake epicenter as much as the secondary damage (e.g. fires, landslides, flooding, water contamination, release of CO₂ accumulations). **Table 13** shows some possible natural resource damage scenarios at key earthquake intensity thresholds.

Table 13: Possible damage scenarios at various earthquake intensity thresholds

Earthquake magnitude at epicenter	Peak ground acceleration (g)	Damage
>4	>0.10	Could initiate public action to shutdown injection Insignificant natural resource damage
>6.5	>0.50	Dam failure - flooding USDW aquifer damage Caprock failure
>7	>0.75	Major landslides Underground pipelines broken

3.3.3 Third-party Property Damage

Third-party property damage is likely to come from induced seismicity, pore space infringement or damage to crops, livestock or timber.

Table 14 shows the potential earthquake damage (as a percentage of building and infrastructure replacement value) versus earthquake intensity. These are very broad estimates and do not include damage due to secondary damage due to fires, landslides, flooding (due to dam failures, seiche or tsunamis), utility outages, nuclear power plant radiation leakage, water contamination, liquefaction, ground settling, soil amplification, release of CO₂ accumulated near the surface, open fissures, and aftershocks.

Suspected induced seismicity has led to class action lawsuits for property damage, loss of property value, reimbursement for earthquake insurance and emotional distress.

Table 14: Potential earthquake damage versus earthquake intensity

Modified Mercalli Intensity (MMI) Scale*	Description*	Peak ground acceleration (g)**	Earthquake damage factor (% of building and infrastructure replacement value) ***
I	Detected only by sensitive instruments.	0.0005-0.0017	0
II	Felt by a few people at rest, especially on upper floors; delicately suspended objects may swing.	0.0017-0.005	0
III	Felt noticeably indoors, but not always recognized as earthquake; standing autos rock slightly, vibration like passing truck.	0.005-0.014	0
IV	Felt indoors by many, outdoors by few, at night, some awaken; dishes, windows, doors disturbed; autos rock noticeably.	0.014-0.039	0
V	Felt by most people; some breakage of dishes, windows and plaster; disturbance of tall objects.	0.039-0.092	0
VI	Felt by all; many frightened and run outdoors, walk unsteadily; falling plaster and chimneys; damage small.	0.092-0.18	0.5
VII	Difficult to stand; damage to buildings varies depending on quality of construction; noticed by people driving autos.	0.18-0.34	5
VIII	Panel walls thrown out of frames; fall of walls, monuments, chimneys; sand and mud ejected; drivers of autos disturbed.	0.34-0.65	20
IX	Buildings shifted off foundations, cracked, thrown out of plumb; ground cracked; underground pipes broken.	0.65-1.24	45
X	Most masonry and frame structures destroyed; ground cracked, rails bent, landslides.	>1.24	80
XI	Few structures remain standing; bridges destroyed, fissures in ground, pipes broken, landslides, rails bent.		100
XII	Total destruction; waves seen on ground surface, lines of sight and level distorted, objects thrown up in air.		100

*KGS 2012

**Baer 2007

*** Modified from ATC 1985

The amount of uplift or subsidence expected with CO₂ sequestration is likely to be in the range of 50 to 75 mm (2 to 3 inches). This could lead to some foundation cracking and associated damages.

Third-party drilling near a CO₂ plume could result in a kick or blowout. This could cause \$500,000 to \$3 million damage depending on whether a well needs to be reworked or plugged and abandoned and relocated.

CO₂ could accumulate in an underground mine creating a human health and safety issue and requiring ventilation and interruption of operations.

Well water could become contaminated by the release of CO₂ and/or brine into a USDW aquifer (covered under natural resource damage).

CO₂ could accumulate and/or release from water as the water depressurizes in pump houses or basements. The CO₂ accumulation can be mitigated by installing monitors, alarms and ventilation in confined areas. CO₂ monitors/alarms cost \$300 to \$1,000 per unit. Capital cost for ventilators range from \$300 to \$500 per unit with operating costs of \$200 per year including power and heating/cooling loss. Capital costs for energy recovery ventilators range from \$1,000 to \$5,000 per unit with operating costs of \$100 per year including power, filter and heating/cooling loss.

A decrease of the water table resulting from coal seam dewatering in enhanced coal bed methane (ECBM) could require the reworking of shallow water wells. We have assumed a cost of \$25,000 per well based on **Kuuskräa 2008**.

Potential compensation values for damage to crops, timberland and livestock are shown in **Table 15**. The crop values are on the expected revenue estimates for Indiana farms for various crops in 2012 (**Purdue 2011**). The livestock replacement costs are based on typical market prices in 2011 for common livestock. They do not address prize winning livestock.

Table 15: Typical crop and livestock values

Crop damage revenue loss	\$/acre per year
Low productivity soil	267 to 702
Average productivity soil	336 to 880
High productivity soil	406 to 1,058
Timberland damage	2,000 to 5,000
Timberland reforestation	300 to 800
Common livestock replacement cost	\$/livestock
Cattle	800 to 2,000
Horses (not race horses)	500 to 5,000
Sheep/hogs	100 to 200
Poultry	1 to 10

If the CO₂ plume migrates outside of the area that the owner has pore space rights for, there is the potential that the CO₂ would infringe on third-party pore space. This may lead to legal action requiring purchase of pore space or extraction of CO₂. The cost of pore space purchase could range from \$60 to \$2,000 per acre (**Gresham 2010**).

CO₂ contamination of hydrocarbon and mineral resources could impact their monetized value. There may be a cost associated with extracting the CO₂ prior to or during recovery of the minerals/hydrocarbons and a cost associated with CO₂ separation, concentration and reinjection or venting. Whether CO₂ is vented or reinjected, it is likely to represent a \$25-75/t CO₂ cost. For EOR, the presence of CO₂ may not be entirely bad if the CO₂ can be incorporated into a flooding or sweeping operation.

3.3.4 Owner Property Damage

Owner property damage can come in the form of damage to equipment and facilities, or damage to the caprock and reservoir.

CO₂ pipeline damage can be caused by earthquakes, extreme weather, erosion, third-party excavation, defective welds, corrosion, fire, explosion, sabotage, equipment failure, or operator error. There were 57 CO₂ pipeline incidents reported from 1986 through 2011. The cumulative property damage for all of these incidents was \$1,919,324 and cumulative CO₂ release was 23,898 t. Property damage per incident ranged from \$0 (malfunction of a control or relief valve) to \$514,905 (fillet weld failure). We have estimated <\$1 million per incident for serious pipeline damage such as a rupture.

Surface facilities damage can be caused by the same events that cause pipeline damage. We have estimated <\$1 million per incident for most serious surface facility damage. However, that number could increase to \$10 million to \$20 million if compressors are damaged.

Caprock (primary seal) damage can be caused by seismic events (faulting and fracturing), hydrothermal activity, operator error (over pressuring), chemical erosion, and third-party penetration. The end result is loss of containment of the CO₂. If multiple stacked sinks and seals are located above the caprock, they may be able to provide suitable containment of the CO₂. Otherwise, if the caprock is seriously damaged, the possible corrective action is limited, costly and may not be completely reliable. It is likely that the project would need to be shut down, representing a total loss of investment plus potential long-term liabilities for remediating damage caused by loss of CO₂, methane, H₂S and hydrocarbon containment. This could represent hundreds of millions of dollars.

Reservoir damage can be caused by such things as seismic events (faulting and fracturing), hydrothermal activity, operator error (over pressuring), mineral precipitation, hydrocarbon precipitation, microbial growth, third-party infringement of pore space, coal matrix swelling, coal plasticization, and compartmentalization. The end result is loss of injectivity and/or loss of CO₂ storage capacity. Possible corrective action may include chemical or fracturing stimulation, changing injection depth, changing injection location, adding injection wells, extracting fluids to increase CO₂ storage capacity, or acquiring more pore space.

3.3.5 Owner Business Interruption

Owner business interruption could be anything from a one-hour power outage to a permanent shutdown of all operations. The cost of an interruption may be \$75,000 per day for a 1 million t/y CO₂ sequestration operation (assuming a storage fee of \$25/t CO₂) to \$1,500,000 per day for a 20 million t/y sequestration operation. For a 30,000 bpd EOR operation, the cost may be over \$2,500,000 per day (assuming an oil price of \$85/bbl).

Interruptions can be forced (unscheduled) or voluntary (scheduled). They may be complete (due to a pipeline shutdown) or partial (due to the decision to clean out one of several injection wells to improve injectivity).

Some interruptions can be avoided by redundancy (backup compressors or wells). In a loss of containment scenario, regulators may require shutdown of all injection or selective shutdown within a given area. It may be possible to redistribute CO₂ injection to other locations.

A list of estimated durations of business interruptions for various damage scenarios is shown in **Table 16**.

Table 16: Estimated duration of business interruptions for various damage scenarios

Business Interruption	Days
Pipeline repair (leak or rupture)	0-7 days (based on PHMSA 2012)
Surface facility repairs (leaks or ruptures)	0-7 days
Clean out well for scale buildup, hydrocarbon precipitation, microbe growth	5 days
Locate and fix leak in injection well	1-7 days
Locate and fix leaky orphan well	5-15 days
Locate and fix leaky fault, fracture zone or high permeability pathway through caprock	15 to 60 days
CO ₂ well blowout repair	1-10 days
Hydrocarbon well blowout repair	5-15 days

Following are some potential events that could contribute to a permanent shutdown of a CO₂ geologic sequestration project:

- Induced seismicity events greater 0.1 g peak ground acceleration
- Serious caprock (primary seal) damage with no secondary seals above it
- Insufficient CO₂ storage capacity
- Mobilization and release of heavy metals in a USDW aquifer
- CO₂ injectivity loss due to coal matrix swelling
- Failure to keep in compliance with regulations
- Legislation/regulation changes making CO₂ sequestration infeasible
- Disruptive CO₂ utilization technology making CO₂ sequestration uncompetitive

Induced seismicity or USDW aquifer contamination could lead to class action lawsuits and court ordered injunctive relief. It should be noted that seismic events and USDW aquifer contamination can occur naturally and it is important that the project develops sufficient baseline studies, simulations, and MVA data to verify whether or not these events are associated with the project.

3.3.6 Owners Economics

There are some Risks/FEPs that do not result in physical damage, but impact owner economics. If the economics are impacted to the point that the project becomes infeasible even with mitigation steps, it is likely that the owner will be forced to shut down the project. Project economics are very site specific and influenced by economies-of-scale. The following are examples that were used in the QFMEA.

The cost of extracting, treating and disposing of produced water or brine ranges between \$3/t to \$30/t of water treated. Significantly higher values have also been reported but the bulk of the cases tend to fall in this range. If brine (1050 kg/m^3) is being extracted to make room for CO_2 (700 kg/m^3) then 1.5 t of brine must be removed per t of CO_2 . Thus the cost per tonne of CO_2 ranges from \$4.50/t to \$45/t.

Kuuskraa estimated the cost of locating and fixing CO_2 leaks as shown in **Table 17 (Kuuskraa 2008)**. The cost for locating and fixing a leaky well is in the range of \$300,000 to \$400,000 while the cost to locate and fix a leaky caprock is in the range of \$13 million to \$21 million.

Table 17: Representative costs for locating and mitigating CO_2 leaks

Remediation activity	Cost estimate
Locating a leaky orphaned legacy well	\$200,000 per well or survey
Locating a leak in an injection well	\$300,000 per well
Locating a leaky fault or fracture zone	\$3 million for seismic survey + \$8 million for horizontal leak detection wells
Well plugging	\$100,000 per well (\$25,000 to \$200,000 per well range)
Remedial recementing of wellbore	\$40,000-\$50,000 per well average (up to \$100,000/well)
Remediation of caprock leak (increasing pressure above the leak)	\$2 million for water plant + \$8 million for horizontal water injection wells

Enhanced oil recovery (EOR) profitability is important for sustainable operation. If EOR performance decreases, profitability is impacted and can threaten continued operation. **Table 18** shows a breakdown of EOR operating economics provided by Fox (**Fox 2011**). Even with a \$22 per barrel profit margin, the rate of return before taxes is only about 20% because CO_2 costs (investment in CO_2 supply infrastructure and startup CO_2 purchases) are expended at the start of the project.

Table 18: Typical CO₂-EOR economics

Category	Value \$/barrel of oil
Royalties and production tax	18
Capital expense	10
Operating expense	20
CO ₂ expense	15
Profit margin	22
Oil price	85

There are many factors which can influence the economics of CO₂ sequestration in a deep saline aquifer. As an example, we selected reservoir geometry. Using our financial model, we adjusted the storage coefficient for different reservoir geometries (based on **Gorecki 2009**) and held all other factors constant. We then calculated the CO₂ storage fee required to achieve a comparable return on investment for each case. The ultimate area of a CO₂ plume will be significantly smaller for a dome or anticline structure than for a flat or monocline topped reservoir because of the lateral trapping mechanism. The size of the ultimate CO₂ plume area impacts the cost of CO₂ storage. **Table19** indicates the impact of reservoir geometry on ultimate area of the plume and cost of storing CO₂ (all other factors held constant).

Table 19: Impact of reservoir geometry on ultimate CO₂ plume area and CO₂ storage costs

Reservoir geometry	Relative ultimate extent of the CO ₂ plume	Relative cost of CO ₂ storage
Dome	1.0	1.00
Anticline	1.4 to 1.8	1.04
Flat Top	2.0 to 3.3	1.10
5% Monocline	2.0 to 3.4	1.10
10% Monocline	2.1 to 3.6	1.11

Using the financial model, it is possible to look at other deep saline aquifer attributes such as reservoir depth, thickness, permeability, and porosity and determine their impact on owner economics.

3.3.7 Carbon Dioxide Emissions

The carbon dioxide emissions column addresses the lost value to the owner associated with emitting CO₂ into the atmosphere. If the owner is paid a fee to store CO₂, it is likely that the owner would lose that fee for every tonne of CO₂ that is released to the atmosphere. The cost to the owner for emitting CO₂ into the atmosphere could be in the range of \$25/t to \$75/t of CO₂. The low end value (\$25/t) is comparable to the carbon tax passed in Australia (**UPI 2011**). It is also comparable to the cost of compressing, transporting and storing CO₂ in a deep saline aquifer. The high end value (\$75/t) includes the cost of capturing the CO₂ from a power plant plus compression, transportation and storage.

CO₂ could be vented at the power plant prior to compression if the CO₂ stream is off-spec or if the CO₂ compressor, pipeline or injection site is down. CO₂ could be accidentally emitted due to a pipeline leak/rupture, a well blowout, a leaky wellbore or a leaky fault/fracture zone. CO₂ could be purposefully vented if it needs to be extracted from a contaminated USDW aquifer or a confined area such as an underground mine, pump house or basement for safety reasons.

For EOR operations a purchase price for CO₂ may be used, equivalent to 2% of the WTI crude oil price. For example, if the WTI crude oil price is \$85 per barrel, the price of CO₂ would be \$1.70 per MSCF (\$32.32 per tonne of CO₂, based on 19,010 standard cubic feet per tonne of CO₂).

Under a worst case scenario, where an earthquake greater than M6.5 seriously damages a caprock and opens up a fissure to the surface, we have assumed that less than 1% of the CO₂ stored in the reservoir could be released to the surface. The amount released from the reservoir may be greater than that, but it is likely that part of the CO₂ would end up in overlying sinks before it reaches the surface. A bolide (1-10 km diameter meteorite) direct impact could result in greater CO₂ release but the release of CO₂ would be insignificant compared to the damage of the bolide impact.

We have assumed the following emission rates for various damage scenarios:

- Leaky wellbore, fault or fracture zone: <10,000 t/y per well (at <0.3 kg/s)
- Pipeline leak: 0 to 1,000 t per leak
- Pipeline rupture: 1,000 to 10,000 t per rupture
- Shallow CO₂ well blowout: 1,000 to 5,000 t per blowout (at 3-10 kg/s)
- Deep CO₂ well blowout: 5,000 t to 50,000 t per blowout (at 10-226 kg/s)
- Limnic eruption: 10,000 to 100,000 t per incident

We assumed that a sudden well blowout would be noticed quickly, and that the well could be brought under control in less than five (5) days. An exception to this was a blowout of an abandoned well in a CO₂-EOR field near Yazoo City, MS in 2011. It took 37 days to bring the well under control because the well pipe had previously been stripped from the well, (**AP 2013**). A limnic eruption is highly unlikely. We would not expect CO₂ to accumulate to the magnitude of the Lake Nyos disaster (1.6 million t) because current monitoring techniques would be able to detect much lower accumulations.

Note that the CO₂ emissions represent CO₂ emitted directly to the atmosphere and does not include CO₂ that may have been released from the primary reservoir that ends up in a shallow USDW aquifer. If the CO₂ released into an USDW aquifer is extracted and released into the atmosphere, an additional lost value of \$25-\$75/t CO₂ should be added to damage recovery costs for each tonne extracted and released into the atmosphere.

3.3.8 Fines and Legal Expenses

We assumed that fines and legal fees will amount to approximately 10% of total damage recovery cost. We realize that this number could vary considerably depending on the specific situation. For example, the cost to defend against class action suits could raise the percentage significantly.

3.3.9 Damage Recovery Cost without Mitigation

Damage recovery cost without mitigation is the sum of the cost for fatalities + serious injuries + minor injuries + natural resource damage + third-party property damage + owner property damage + owner business interruption + owner economics + CO₂ emissions lost value + fines and legal expenses. Note that we have limited the extent of damages to <50,000 t CO₂ for subsurface leakage and <10,000 t for surface leakage (<50,000 t for blowouts). This assumes that today's monitoring technologies (covered under "Cost of prevention and/or mitigation") are readily capable of detecting leaks of this magnitude, and USEPA UIC regulations would mandate that corrective action be taken as soon as leaks are detected. Otherwise, leaks from orphaned wellbores, faults and fractures could go on indefinitely and ultimately result in tens of millions of dollars of damage recovery costs.

3.3.10 Damage Recovery Cost with Prevention and/or Mitigation

Damage recovery cost with prevention and/or mitigation is the sum of damage recovery costs assuming that prevention steps are taken to reduce the probability of a failure and/or mitigation steps are taken to reduce severity of failure or improve early detection of failure. In theory, if the failure is completely prevented, the damage recovery cost would be zero. If the failure occurs, but the severity is significantly lower, the damage recovery cost would be some percentage of the damage recovery cost without prevention and/or mitigation.

3.3.11 Cost of Prevention and/or Mitigation Steps

Prevention steps are taken to reduce the probability of a failure. The best example of this is avoidance cost in site selection. If there are no vulnerable receptors in the area of a CO₂ storage site, it is unlikely that any significant damage will result due to loss of containment or induced seismicity. Therefore, it may be worthwhile to locate a storage site further away from a supply source if risks can be lowered significantly.

We suggest that projects consider a three-tier system for avoidance in site selection. The highest priority is to protect human health and safety. The second priority is to protect natural resources. The third priority is to protect the economic integrity of the project. **Table 20** provides some examples of high risk features to avoid for each tier.

Table 20: Three-tier avoidance system for CO₂ geologic sequestration

Tier	High risk features to avoid
1. Human health and safety threats	Densely populated areas, sensitive receptors (schools, hospitals, prisons, care centers), sensitive groundwater areas, USDW aquifers, dams, nuclear power plants, seismically active (unstable) areas, volcanic sites, flood plains, poor caprock integrity (chemically reactive, permeable, discontinuous, mechanically weak, faulted, fractured), deep lakes, salt caverns, sensitive low areas or confined spaces (underground mines, basements, tunnels, canyons),
2. Natural resources threats	Habitats for endangered/threatened species, National Parks, National Wildlife Refuges, National Monuments, wetlands, coral reefs, coastal areas, archeological/cultural sites, recreational areas,
3. Economic threats	Sites susceptible to natural hazards or liabilities, high density wells penetrating caprock, rugged terrain, heavily forested areas, shallow storage reservoirs (less than 800 m), deep storage reservoirs (greater than 3,000m), thin reservoirs, low permeability storage reservoirs, heavy industrial sites, insufficient trapping mechanism for CO ₂ plume,

Table 21 provides examples of other prevention steps that can be taken to reduce the probability of damage scenarios occurring. A more complete list can be found in the QFMEA model.

Table 21: Examples of prevention steps for various damage scenarios

Damage Scenario to be Prevented	Prevention Steps
CO ₂ leakage through observation wells.	Avoid observation wells penetrating the caprock.
Third-party excavation damage to underground pipeline.	Post warning signs. Use one-call system. Bury pipeline sufficiently deep. Keep right-of-way clear of dense vegetation. Regular site inspection. Supervise third-party excavation.
Operator error.	Install failsafe systems. Train operators.
Fatalities or injuries associated with accumulation of CO ₂ in confined space.	Ventilate confined spaces. Install CO ₂ monitors/alarms.
Natural seismicity mistaken for induced seismicity.	Conduct at least 2 years of passive microseismic baseline studies prior to CO ₂ injection. Continue passive microseismic surveys and modeling during injection and for a period of 2 years after injection.
Natural CO ₂ release mistaken for anthropogenic CO ₂ .	Conduct at least 2 years of CO ₂ flux baseline studies prior to CO ₂ injection. Add tracer to injected CO ₂ .
Well blowout	Use blowout preventer and packers during drilling and workovers.
Caprock damage due to over pressuring.	Maintain CO ₂ bottom hole injection pressure at less than 90% of fracture pressure.

Mitigation steps are taken to reduce severity of failure or improve early detection of failure. Perhaps the best mitigation step for CO₂ geologic sequestration is selection of an injection site with multiple stacked sinks and seals. When it comes to mitigating loss of containment, this is probably one of the best and most efficient solutions. Other examples of mitigation steps are shown in **Table 22**.

Table 22: Examples of mitigation steps for various damage scenarios

Damage Scenario to be Mitigated	Mitigation Steps
Uncontrolled migration of CO ₂ plume	Extraction and/or injection of water/brine to slow or redirect flow
CO ₂ /brine leakage through caprock via a fault, fracture zone or high permeability pathway.	Stop injection of CO ₂ . Inject water into the formation above the caprock leak to increase pressure. Inject cement or chemical sealant into the fault, fracture zone or high permeability pathway.
CO ₂ /brine release into an USDW aquifer	Control CO ₂ plume and contaminated water migration with water injection walls if necessary. Extract CO ₂ and contaminated water (pump-and-treat with surface aeration, pH control and filtration) or inject sodium hydroxide or lime into the aquifer (in-situ pH adjustment).
CO ₂ injectivity drops significantly	Check for and treat to remove scale buildup, salt precipitation, hydrocarbon buildup or microbial growth. Distribute CO ₂ to other injection wells. Consider hydraulic stimulation. Adjust depth of CO ₂ injection.
Insufficient CO ₂ storage	Extract brine to make room for more CO ₂ . Inject CO ₂ into a new formation.

The Quest CCS Project assembled a suite of mitigation steps (monitoring technologies) for early detection of CO₂ leaks (**Quest 2010**). These monitoring technologies are listed in **Table 23** along with their frequency of use, the detection level achievable and resolution expected.

Table 23. Monitoring technologies for early detection of CO₂ leaks

Monitoring technology for early detection of CO₂ leaks	Frequency	Detection level	Resolution
Observation wells with down-hole pressure gauges in the lowest aquifer above the ultimate seal	Continuous	Can detect point leaks if the rate exceeds 3-30 kg/d (0.0000347 to 0.000347 kg/s). The duration of fluid escape prior to detection could be 25 to 150 days for a gauge located 2 to 3 km from the source	
Interferometric Synthetic Aperture Radar (InSAR)	Monthly or quarterly	Smallest detectable mass of escaped fluids is likely 100,000 to 200,000 tonnes.	Lateral resolution of 0.5 to 1.0 of the depth of the anomaly.
Fiber-optics installed in-between two casing strings of injector wells to monitor temperature and acoustic noise along the length of the injector.	Continuous	Flux rates of 3 kg/d (0.0000347 kg/s) detectable.	Resolution of 1 to 10 m along length of injector.
Down-hole electrical conductivity and pH monitoring	Continuous	Can indicate changes in water quality due to CO ₂ or brine ingress.	
Line-of-sight CO ₂ gas flux monitoring	Continuous	Emission rate of 3 kg/h detectable over a 2 km x 2 km area. Emission rate of 250 kg/h detectable over a 6 km x 6 km area.	
Time lapse 3D seismic	Every 1 to 3 years for 3D vertical seismic profiles. Every 5 to 10 years for 3D surface seismic surveys	Smallest detectable mass of escaped fluids is likely 10,000 to 60,000 tonnes.	Lateral resolution of 25 m and vertical resolution of 10 m.

A database of cost factors and formulas was developed to estimate prevention and mitigation costs (see **Appendix B**). This was a compilation of published unpublished and vendor estimates. The cost factors and formulas developed for this project are generic in nature. A more detailed cost analysis should be completed prior to developing a project. It should be noted that variations in the project conditions including but not limited to site conditions, operating conditions, regulatory requirements, and project financing will vary. Should project specific data or other information become available in the future, the information contained herein should be reviewed, and the conclusions and recommendations presented herein modified accordingly. The passage of time will result in significant changes in technology, economic conditions, or site variations that may deviate from the study's parameters. Therefore, the CQRA project team neither guarantees the accuracy nor the applicability of the presented costs factors and formulas for specific project sites.

3.3.12 Cost Savings with Risk Prevention and/or Mitigation

The potential cost saving resulting from applying risk prevention/mitigation steps is calculated based on the following formula

$$\$CS = (\$DR \text{ w/o } P/M) - (\$DR \text{ w/ } P/M) - (\$P/M)$$

Where:

\$CS = cost savings in dollars

\$DR w/o P/M = Damage recovery cost without prevention/mitigation

\$DR w/ P/M = Damage recovery cost with prevention/mitigation

\$P/M = Cost of prevention/mitigation

3.3.13 Insurance Schedule

A schedule of insurable risks and estimated minimum requirements for a CO₂ sequestration facility was developed (see **Appendix C**). Insurance coverage is broken down into property damage, third-party liability, and environmental. The schedule defines each type of insurance in layman and insurance industry terms, and specifies when coverage is needed, the normal term of coverage, the probable minimum required limits, the probable minimum deduction (or self insured retention), the premium rating basis, the probable minimum annual premium rate, the valuation of premium rating basis, and the insurable perils (causes of loss). Surety bond specifications are included on the bottom of the schedule. This includes a surety bond for financial responsibility for compliance with USEPA UIC Class VI regulations.

3.3.14 CO₂ Sequestration Financial Model

A financial model was developed for CO₂ compression, pipeline transportation and sequestration in deep saline aquifers. The financial model is in the form of an Excel spreadsheet. Key inputs and outputs are summarized in **Figure 7**.

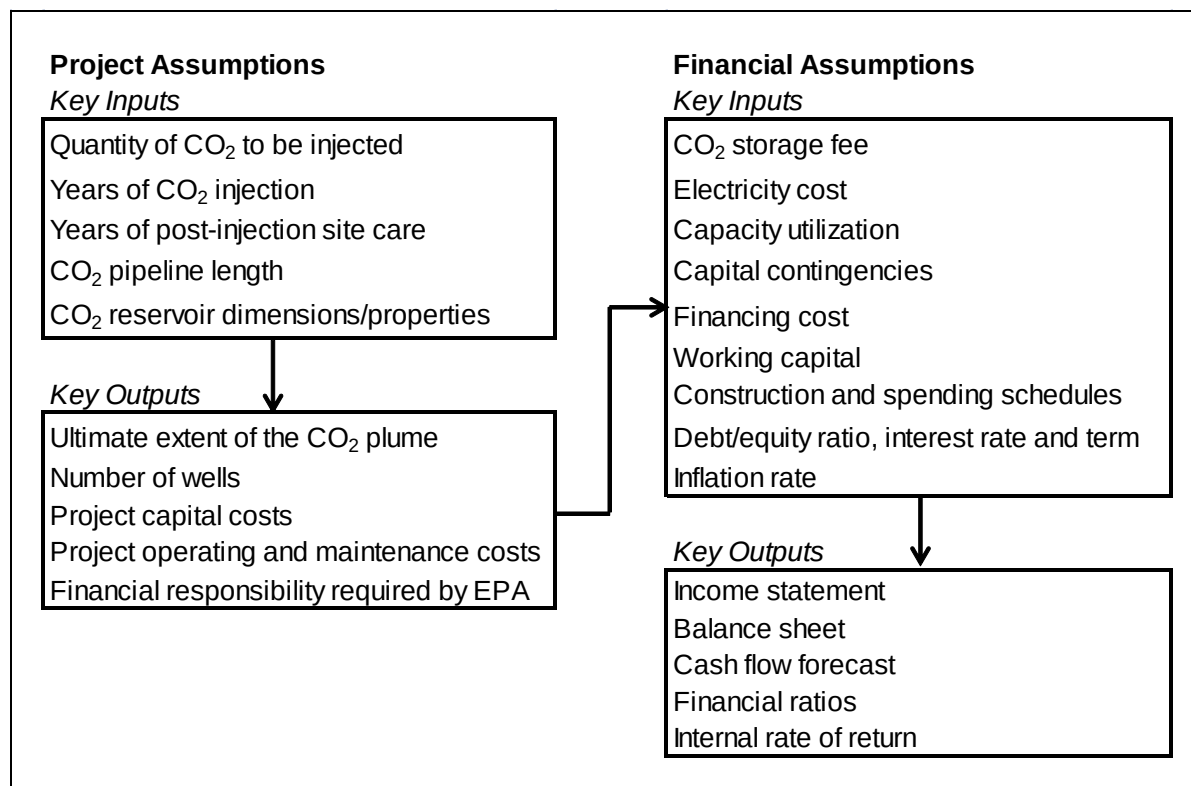


Figure 7. Key inputs and outputs for the financial model

An example of the financial model assumptions is provided in **Appendix D**. This is only an example and does not refer to a specific site. The project assumptions worksheet displays the algorithms, typical range of input values and references for the assumptions and calculations. Five (5) scenarios are displayed with CO₂ injection capacities of 1, 5, 10, 15 and 20 million t/y. The capital and operating costs take into account compliance with USEPA UIC Class VI regulations.

3.4 Quantitative Risk Assessment of the SACROC Northern Platform CO₂-EOR Site

The SACROC Northern Platform Site was selected for a quantitative risk assessment to prove out the CO₂-EOR portion of the QFMEA model because it is a mature CO₂-EOR operation with a significant amount of information available in the public domain.

3.4.1 Background

The SACROC Northern Platform Area represents the northern forty percent of the SACROC Unit. The Scurry Area Canyon Reef Operators Committee (SACROC) Unit is a unitized oil field located in Western Texas, in Scurry County, near the city of Snyder, Texas. The SACROC Unit comprises 202 km² (50,000 acres) or approximately 98 percent of the Kelly-Snyder oil field. The Northern Platform Area is approximately 80 km² (20,000 acres) in size. Maps of the SACROC Unit and Northern Platform Area are shown in **Figure 8**.

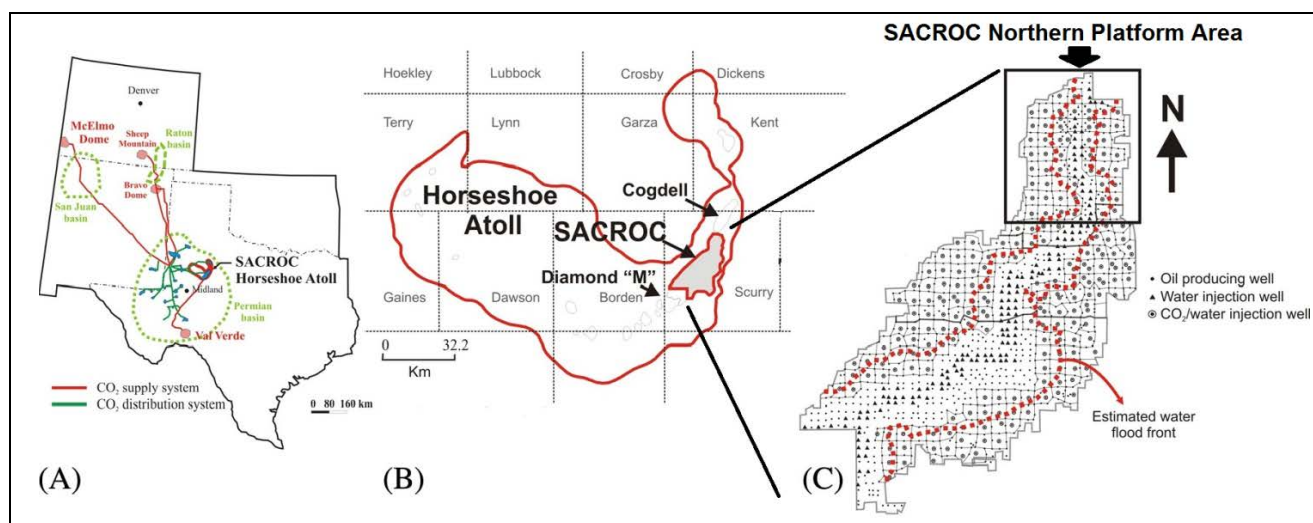


Figure 8A: Horseshoe Atoll in the Permian Basin in Western Texas. Figure 8B: SACROC Unit within the Horseshoe Atoll in Scurry County. Figure 8C: Northern Platform Area of the SACROC Unit (Modified from Han 2010).

The SACROC Unit consists of a limestone coral reef type structure within the Horseshoe Atoll on the Eastern Shelf of the Permian Basin. Most of the oil is produced from the Cisco and Canyon formations. The Wolfcamp Shale Formation provides an effective caprock or primary seal.

The Northern Platform reservoir is thicker and more elevated than the rest of the SACROC Unit. Gross thickness of the section, above the oil-water contact, ranges from 24 m (80 ft) at the periphery of the reservoir to more than 229 m (750 ft) at the center of the platform (see cross-sections in **Figures 9 and 10**). The average depth at the top of the reservoir is 1,981 m (6,500 ft). The reservoir has a complex, mound-shaped geometry with compartmentalization caused by changes in depositional environments, erosion, and possible faulting and karsting. **Table 24** describes the stratigraphy of the Northern Platform Site, identifying aquifer, seal, sink, oil reservoir and basement formations.

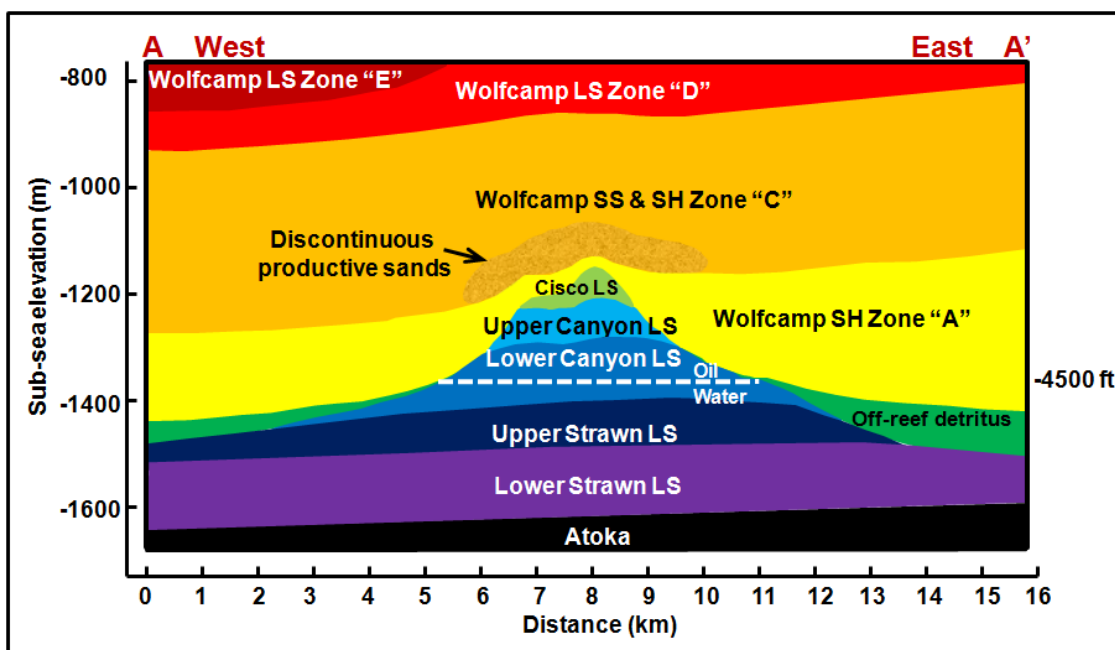


Figure 9: SACROC Northern Platform reservoir west-east cross-section (Vest 1970)

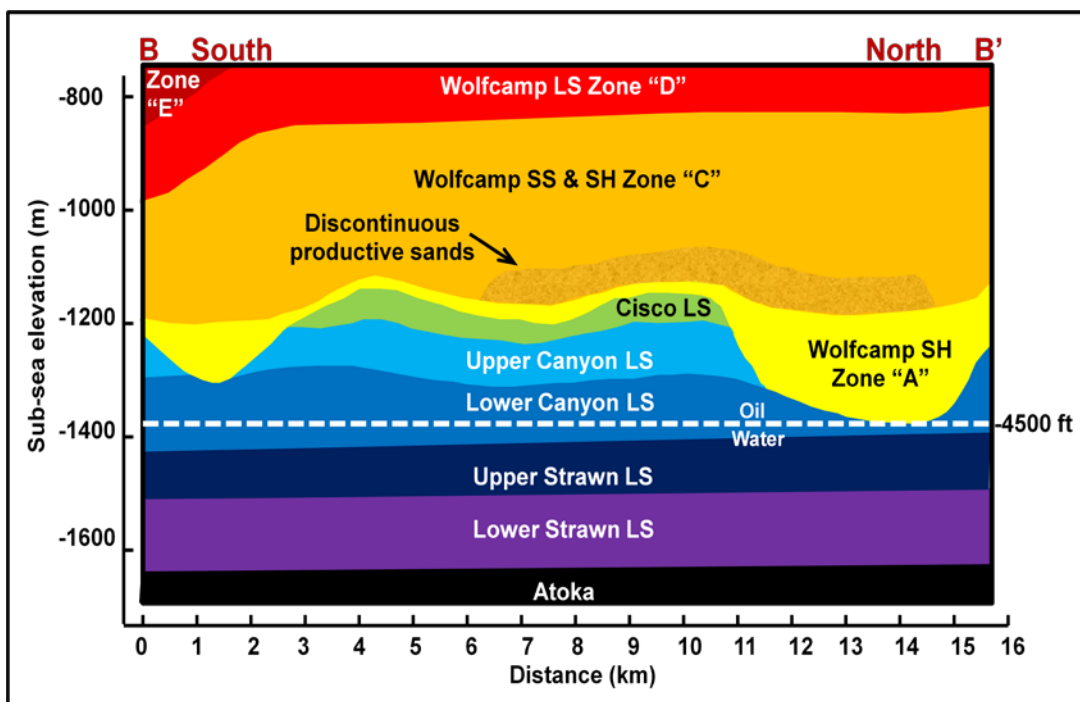


Figure 10: SACROC Northern Platform reservoir south-north cross-section (Vest 1970)

Table 24: Stratigraphy of the SACROC Northern Platform Site, estimated based on literature search

Stratigraphic Units				Lithology	Thickness	Depth (m)		Elevation (m)	
System	Series	Group	Formation	(Primary, secondary, tertiary)	(m)	Top	Bottom	Top	Bottom
Tertiary			Ogallala	Sand, silt, clay, gravel, caliche	23	0	23	744	721
Triassic		Dockum	Santa Rosa	Fine-grained mixed clastics, conglomerate	91	23	114	721	629
Permian	Ochoa		Dewey Lake	Siltstone, shale, evaporite	12	114	126	629	617
Permian	Ochoa		Rustler	Dolomite, evaporite, siltstone	6	126	133	617	611
Permian	Ochoa		Salado	Evaporite, sandstone	70	133	203	611	541
Permian	Guadalupe	Whitehorse	Tansill	Dolomite, limestone	30	203	233	541	511
Permian	Guadalupe	Whitehorse	Yates	Sandstone, dolomite, shale	30	233	264	511	480
Permian	Guadalupe	Whitehorse	Undifferentiated	Sandstone, shale, evaporite	230	264	494	480	250
Permian	Guadalupe	Peace River	San Andres	Carbonate, fine-grained mixed clastics, evaporite	253	494	747	250	-3
Permian	Guadalupe	Peace River	San Angelo	Mudstone, siltstone, evaporite	40	747	786	-3	-43
Permian	Leonard	Clear Fork	Undifferentiated	Mudstone, sandstone, dolomite, siltstone, evaporite	338	786	1125	-43	-381
Permian	Leonard		Undifferentiated	Shale, limestone	351	1125	1475	-381	-732
Permian	Wolfcamp	Wichita	Wolfcamp	Shale, sandstone, limestone	460	1475	1935	-732	-1192
Pennsylvanian	Cisco		Cisco	Limestone	43	1935	1978	-1192	-1234
Pennsylvanian	Canyon		Upper Canyon	Limestone	73	1978	2051	-1234	-1308
Pennsylvanian	Canyon		Lower Canyon*	Limestone	113	2051	2164	-1308	-1420
Pennsylvanian	Strawn		Strawn	Limestone, shale, sandstone	201	2164	2365	-1420	-1622
Pennsylvanian	Atoka		Atoka	Shale, sandstone	9	2365	2374	-1622	-1631
Mississippian			Undifferentiated	Limestone, chert, shale	43	2374	2417	-1631	-1673
Ordovician		Ellenburger	Undifferentiated	Dolomite, chert	158	2417	2576	-1673	-1832
Pre-Cambrian				Granite		2576			
Sources: Smyth 2006 (from Duffin 1992), Bradley 2003, Stafford 1954, Dutton 2004, and Reeves 2008.									
*Oil-water contact at -1,372 m (-4,500 ft) elevation.									
USDW aquifer	Seal	Sink	Oil reservoir	Basement					

It is estimated that the Kelly-Snyder oil field originally had 2.73 billion barrels of oil in place (**Hawkins 1996**). Total production from 1948 through 2011 exceeded 1.34 billion barrels of oil or 48 percent of the original oil in place. Over 89 million tonnes of purchased CO₂ (over 215 million tonnes of purchased plus recycled CO₂) were injected into the field from 1972 through 2011. **Figure 11** shows the SACROC Unit injection and production performance history from 1948 through 2011.

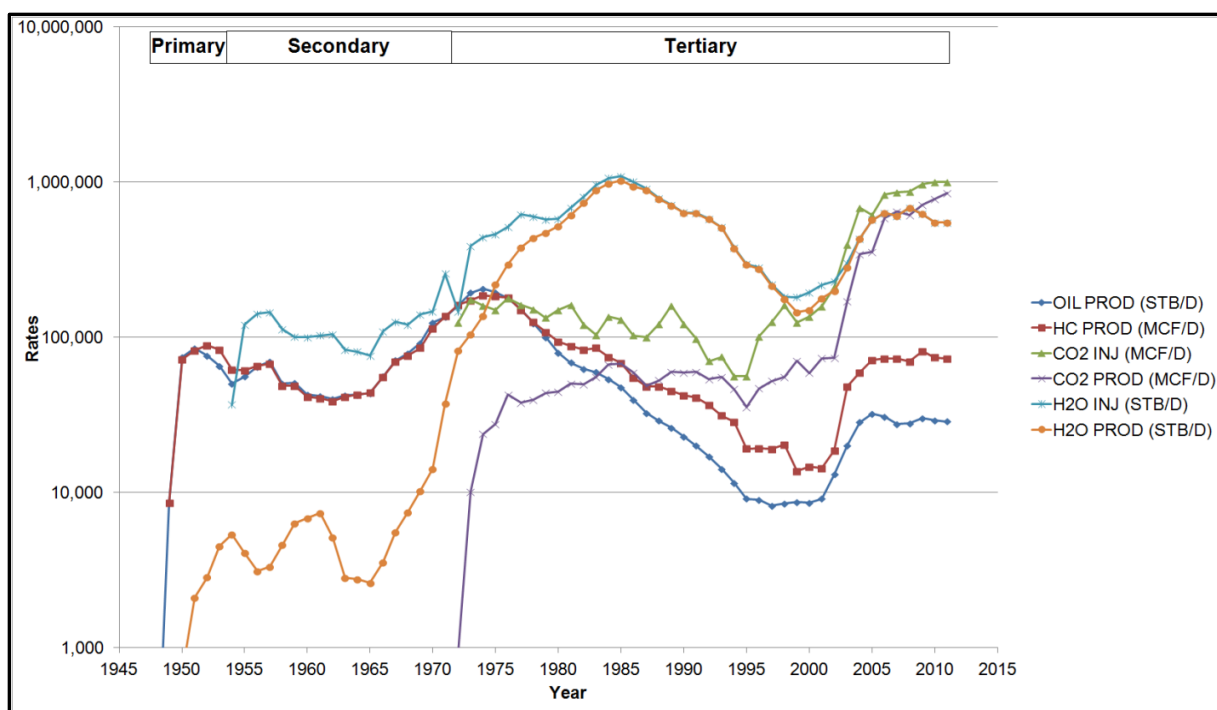


Figure 11: SACROC Unit injection and production performance history from 1948 through 2011

Figure 12 shows the injection and production history for 639 wells in the SACROC Northern Platform Site. Primary solution gas drive operation occurred from 1948 through 1953. Secondary water flooding began in 1954 and continued through 1971. Tertiary CO₂ flooding operation began in 1972 and ended in early 2002. CO₂ flooding was restarted in 2009, but is not shown in this figure.

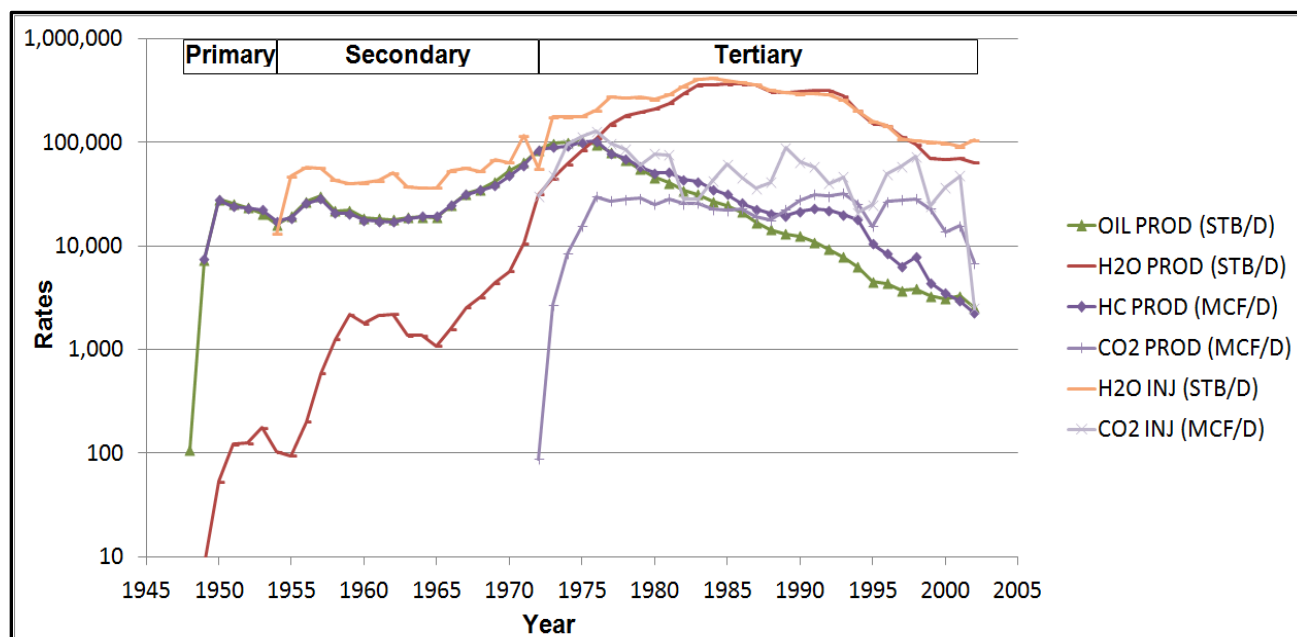


Figure 12: SACROC Northern Platform Site injection and production performance history from 1948 through 2002

3.4.2 Results

The deliverables developed to support this quantitative risk assessment are: a process influence diagram for CO₂-EOR, a site-specific QFMEA model, prioritized lists of risks, an economic analysis (financial model and cost factors), and process-level model history match and projections.

The process influence diagram for CO₂-EOR is shown in **Figure A-2** in **Appendix A**.

Over 400 risk areas were evaluated in the QFMEA model. The SACROC Northern Platform QFMEA model is in **Appendix E**. The top ranking 25 risks, based on risk priority number, are listed in **Table 25**. Six (6) of the top seven prioritized risk areas (hedging, price of oil, EOR oil reservoir heterogeneity, scale buildup, EOR viscosity relationships, and EOR hydrocarbon precipitation) have potentially large economic impacts that would affect the profitability of the operation, but are not potential risks to human safety or the environment.

Table 25: Top 25 prioritized risk areas for the SACROC Northern Platform Site

Line #	SACROC CO2-EOR Technical, Surface and Programmatic Risk Areas Ranked by Risk Priority Number			Risk Ranking			
	Index #	Risk Area/FEP	Potential Failure Mode	Failure Probability (P = 1 to 5)	Failure Severity (S = 1 to 5)	Difficulty of Failure Detection (D = 1 to 5)	Risk Priority Number (P x S x D = 1 to 125)
1	08.08.00	Hedging	Actual oil production level below hedged production level. Counterparty default on hedging agreement obligations. Hedged price significantly below nonhedged price.	5	4	3	60
2	08.03.00.	Price of oil (or other related commodities)	Oil price less than breakeven point.	4	4	3	48
3	03.02.03.06.	EOR oil reservoir heterogeneity	Non uniform flow of CO2/oil. Low sweep efficiency and low oil recovery.	5	4	2	40
4	03.02.13.02.	Precipitation of carbonate minerals (scale buildup)	Pore plugging. Well and equipment plugging.	5	4	2	40
5	07.01.01.00.	Loss of containment	Migration of CO2 into overlying formations, soil, aquifers and/or atmosphere.	4	3	3	36
6	03.02.03.05.	EOR viscosity relations	Flow stratification (fingering) in the reservoir. Decreased sweep efficiency and oil recovery.	4	4	2	32
7	03.02.03.07.	EOR hydrocarbon precipitation	Pore space blockage and reduced permeability. Plugging of production wells and equipment.	4	4	2	32
8	03.02.09.00.	Reservoir water chemistry	Scale buildup. Salt precipitation. Conversion of anhydrite to gypsum in rock formation.	4	4	2	32
9	05.01.01.00.	Formation damage (CO2 leakage through damaged caprock near borehole)	CO2 leakage through damaged/fractured caprock near borehole.	3	3	3	27
10	07.02.03.00.	CO2 release to the atmosphere	Accumulation of CO2/H2S in low surface areas with insufficient wind.	3	4	2	24
11	03.02.03.13.	EOR injection and production well pattern and spacing	Early breakthrough of CO2. Low enhanced oil recovery.	3	4	2	24
12	04.01.08.03.	Reservoir porosity	Low oil in place. Low oil recovery.	3	4	2	24
13	04.01.08.04.	Reservoir permeability and injectivity	Low sweep efficiency and low oil recovery.	3	4	2	24
14	16.01.00.	Accidents and unplanned events (02.01.09.00.)	Human injury/death. Facilities / equipment damage. CO2 release.	3	4	2	24
15	16.03.00.	Excavation/drilling	Pipeline damage. Human injury/death. CO2 release (HSE hazard).	3	4	2	24
16	21.08.10.	Pipeline rupture	Pipeline and property damage. Human injury/death.	3	4	2	24
17	04.01.06.08.	Caprock fracture pressure	Caprock fracturing.	2	4	3	24
18	16.22.00.	Leaks and spills (related to oil spills rather than CO2, H2S and CH4)	Human injury. Environmental damage.	2	4	3	24
19	02.01.10.00.	Over pressuring	Fracturing caprock.	2	5	2	20
20	16.27.00	Explosions and crashes (01.03.10.00.)	Damage to surface facilities. Multiple human injury/death.	2	5	2	20
21	21.02.03.	Pipeline failure history (for existing pipeline)	Pipeline leak	5	2	2	20
22	21.02.04.	Pipeline age (for existing pipeline)	Pipeline leak	5	2	2	20
23	21.08.08.	Pipeline malfunctions	Pipeline flow interruption. Pipeline damage.	5	2	2	20
24	21.08.09.	Pipeline leak	Pipeline and property damage. Human injury/death.	5	2	2	20
25	04.01.05.00.	Reservoir exploitation	Pre-CO2 injection caprock or reservoir damage. Pre-existing CO2 in pore space (e.g. from EOR).	3	3	2	18

There are thirty-six risk areas that potentially result in fatal injuries as shown in **Table 26**. Sixteen (16) risk areas (highlighted in yellow) are associated with CO₂ (and H₂S) release. Nineteen (19) risk

areas (highlighted in orange) are not directly related to CO₂, but are common to most oil field or industrial environments and operations.

Table 26: Potentially fatal risks for the SACROC Northern Platform Site

Line #	SACROC CO ₂ -EOR Technical, Surface and Programmatic Risk Areas with Potential Fatalities			Risk Ranking			
	Index #	Risk Area/FEP	Potential Failure Mode	Failure Probability (P = 1 to 5)	Failure Severity (S = 1 to 5)	Difficulty of Failure Detection (D = 1 to 5)	Risk Priority Number (P x S x D = 1 to 125)
1	16.01.00.	Accidents and unplanned events (02.01.09.00.)	Human injury/death. Facilities / equipment damage. CO ₂ release	3	4	2	24
2	16.03.00.	Excavation/drilling	Pipeline damage. Human injury/death. CO ₂ release (HSE hazard).	3	4	2	24
3	21.08.10.	Pipeline rupture	Pipeline and property damage. Human injury/death.	3	4	2	24
4	16.27.00.	Explosions and crashes (01.03.10.00.)	Damage to surface facilities. Multiple human injury/death.	2	5	2	20
5	07.02.03.00.	CO ₂ release to the atmosphere	Accumulation of CO ₂ /H ₂ S in low surface areas with insufficient wind. Human injury/death.	2	4	2	16
6	03.03.06.00.	CO ₂ release processes	CO ₂ release resulting in a fatality. (1) Blowout or rupture (rapid release of CO ₂). (2) Leak (moderate release of CO ₂). (3) CO ₂ diffusion through soil (slow release of CO ₂).	2	4	2	16
7	07.04.01.00.	Health effects of CO ₂	Human injury/death due to accumulation of CO ₂ in unventilated low lying or confined areas.	2	4	2	16
8	07.04.01.01.	Elevated CO ₂ in air	Human injury/death due to accumulation of CO ₂ in unventilated low	2	4	2	16
9	07.04.02.00.	Toxicity of contaminants	Human injury/death due to accumulation of H ₂ S in unventilated low lying or confined areas.	2	4	2	16
10	16.02.00.	Moving equipment	Facilities / equipment damage. Human injury/death. CO ₂ release (HSE hazard).	2	4	2	16
11	16.04.00.	Defective equipment	Human injury/death. Facilities / equipment damage. CO ₂ release (HSE hazard).	2	4	2	16
12	16.05.00.	Use of power tools	Human injury/death.	2	4	2	16
13	16.06.00.	Contact with rotating equipment	Human injury/death. Equipment damage.	2	4	2	16
14	16.07.00.	Working near pinch points	Human injury/death.	2	4	2	16
15	16.08.00.	Working in confined areas	Human injury/death.	2	4	2	16
16	16.09.00.	Working in high places	Human injury/death.	2	4	2	16
17	16.10.00.	Working in trench/ditch	Human injury/death.	2	4	2	16
18	16.11.00.	Working under a lifted load	Human injury/death.	2	4	2	16
19	16.17.00.	Exposure to hazardous materials	Human injury/death.	2	4	2	16
20	16.18.00.	Struck by object or flying debris	Human injury/death.	2	4	2	16
21	16.19.00.	Release of compressed gases or liquids	Human injury/death.	2	4	2	16
22	16.20.00.	Ignition of flammable gases or liquids	Human injury/death. Facilities / equipment damage.	2	4	2	16
23	16.21.00.	Trips, slips and falls	Human injury/death.	2	4	2	16
24	16.23.00.	Head bumping	Human injury/death.	2	4	2	16
25	16.24.00.	Overexertion from manual heavy lifting, pulling, or pushing	Human injury/death.	2	4	2	16
26	16.25.00.	On-road driving	Human injury/death. Vehicle / property damage.	2	4	2	16
27	16.26.00.	Off-road driving	Human injury/death. Vehicle /property damage.	2	4	2	16
28	16.28.00.	Electric shock	Human injury/death	2	4	2	16
29	02.01.03.01.	CO ₂ containing H ₂ S	Well/piping corrosion leading to leakage or rupture. Human injury/death.	3	4	1	12
30	21.08.06.	Boiling liquid expanding vapor explosion (BLEVE)	Human injury/death due to boiling liquid expanding vapor explosion (BLEVE).	2	5	1	10
31	03.03.07.00.	Co-migration of other gases	Human injury/death due to release of CO ₂ +H ₂ S and other gases into the atmosphere.	2	4	1	8
32	04.02.03.00.	Hydrocarbons	Drilling through a methane gas pocket. Well blowout. Human injury/death.	2	4	1	8
33	05.02.03.00.	Blowouts	Human injury/death due to CO ₂ release through well blowout.	2	4	1	8
34	06.03.06.00.	Buildings	Human injury/death due to migration of CO ₂ /H ₂ S into unventilated confined spaces occupied by humans.	2	4	1	8
35	16.14.00.	Contact with hot surface, or exposure to heat or flame	Human injury/death.	2	4	1	8
36	01.01.07.00.	Bolide impact (meteorite impact)	Caprock failure. Destruction of surface facilities. Human injury/death.	1	5	1	5

SACROC CO₂-EOR performance and economic data was compiled from the public domain. Data for the time frame of 2002 through 2011 is summarized in **Table 27**, showing annual: fluid volumes injected, fluid volumes produced, expansion capital, prices, sales volumes, revenues, operating expenses and earnings. The data was analyzed and used to develop a CO₂-EOR financial model for the SACROC Unit to project potential SACROC performance and economics for 2012 through 2021. Hypothetical assumptions were made for the projections as shown in **Table 28**. The financial model output is presented in **Table 29**. The highlighted cells represent input values. The model is designed to allow input from CO₂ Prophet or CMG-GEM software. This is only one hypothetical case and multiple scenarios can be developed and analyzed to evaluate the impact of unforeseen events. This case was used to quantify damage recovery costs, mitigation costs and cost savings in the QFMEA.

Table 27: SACROC Unit performance and economic data 2002 through 2011

Year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Total
Fluids Injected											
CO2 injected (HCPV)	0.00904	0.01692	0.02918	0.02618	0.03556	0.03685	0.03727	0.04126	0.04284	0.04284	0.31794
Water injected (HCPV)	0.02075	0.02708	0.03882	0.05145	0.05687	0.05461	0.06138	0.05605	0.04965	0.04965	0.46631
Total fluids injected (HCPV)	0.02979	0.04400	0.06800	0.07763	0.09243	0.09146	0.09865	0.09731	0.09249	0.09249	0.78425
Fluids Produced											
Oil produced (HCPV)	0.00173	0.00265	0.00375	0.00426	0.00407	0.00365	0.0037	0.00399	0.00386	0.00378	0.03544
Water produced (HCPV)	0.01798	0.02528	0.03882	0.05145	0.05687	0.05461	0.06138	0.05605	0.04965	0.04965	0.46174
CO2 produced (HCPV)	0.00315	0.00728	0.01465	0.01512	0.02498	0.02776	0.02618	0.03042	0.03342	0.03625	0.21921
Total fluids produced (HCPV)	0.02286	0.03521	0.05722	0.07083	0.08592	0.08602	0.09126	0.09046	0.08693	0.08968	0.71639
Carbon Dioxide (CO2)											
CO2 injected (MCF/D)	210,975	395,000	681,000	610,959	830,000	860,000	870,000	963,014	1,000,000	1,000,000	
CO2 produced (MCF/D)	73,526	170,000	342,000	352,959	583,000	648,000	611,000	710,014	780,000	846,000	
CO2 purchased (MCF/D)	137,449	225,000	339,000	258,000	247,000	212,000	259,000	253,000	220,000	154,000	
CO2 injected (MCF)	77,005,875	144,175,000	248,565,000	223,000,035	302,950,000	313,900,000	317,550,000	351,500,110	365,000,000	365,000,000	2,708,646,020
CO2 produced (MCF)	26,836,990	62,050,000	124,830,000	128,830,035	212,795,000	236,520,000	223,015,000	259,155,110	284,700,000	308,790,000	1,867,522,135
CO2 purchased (MCF)	50,168,885	82,125,000	123,735,000	94,170,000	90,155,000	77,380,000	94,535,000	92,345,000	80,300,000	56,210,000	841,123,885
CO2 purchased (HCPV)	0.00589	0.00964	0.01452	0.01105	0.01058	0.00908	0.0111	0.01084	0.00943	0.0066	0.09873
Oil, Hydrocarbons and Natural Gas Liquids											
Oil produced (STB/D)	13,059	20,056	28,340	32,200	30,795	27,604	27,995	30,149	29,222	28,627	
HC produced (MCF/D)	18,609	48,000	59,000	71,000	73,000	73,000	70,000	81,000	74,000	72,500	
NGL produced (STB/D)	0	3,700	7,700	9,400	8,900	9,600	8,300	9,400	10,000	8,500	
Oil produced (STB)	4,766,535	7,320,440	10,344,100	11,753,000	11,240,175	10,075,460	10,218,175	11,004,385	10,666,030	10,448,855	97,837,155
HC produced (MCF)	6,792,285	17,520,000	21,535,000	25,915,000	26,645,000	26,645,000	25,550,000	29,565,000	27,010,000	26,462,500	233,639,785
NGL produced (STB)	0	1,350,500	2,810,500	3,431,000	3,248,500	3,504,000	3,029,500	3,431,000	3,650,000	3,102,500	
Gross BOE produced (STB)	4,766,535	8,670,940	13,154,600	15,184,000	14,488,675	13,579,460	13,247,675	14,435,385	14,316,030	13,551,355	125,394,655
Water											
Water injected (STB/D)	229,905	300,000	430,000	570,000	630,025	605,000	680,000	620,959	550,000	550,000	
Water produced (STB/D)	199,170	280,000	430,000	570,000	630,000	605,000	680,000	620,959	550,000	550,000	
Water injected (STB)	83,915,325	109,500,000	156,950,000	208,050,000	229,959,125	220,825,000	248,200,000	226,650,035	200,750,000	200,750,000	1,885,549,485
Water produced (STB)	72,697,050	102,200,000	156,950,000	208,050,000	229,950,000	220,825,000	248,200,000	226,650,035	200,750,000	200,750,000	1,867,022,085
Expansion Capital											
Expansion Capital (\$)	183,000,000	244,000,000	278,000,000	196,000,000	204,000,000	256,000,000	347,000,000	258,000,000	227,000,000	257,000,000	2,450,000,000
CO2 capex incl. in opex (\$)	14,046,080	29,975,260	52,552,700	59,294,250	71,985,300	57,115,200	88,811,800	65,481,000	76,368,950	63,663,300	579,293,840
Well work incl. in opex (\$)	0	0	26,276,350	30,305,950	66,933,700	65,444,500	81,891,400	52,888,500	53,833,850	465,685,25	424,142,775
Gas handling incl. in opex (\$)	0	0	39,985,750	43,482,450	36,624,100	57,115,200	55,363,200	36,518,250	52,581,900	49,515,900	371,186,750
Net capex (\$)	168,953,920	214,024,740	159,185,200	62,917,350	28,456,900	76,325,100	120,933,600	103,112,250	44,215,300	97,252,275	1,075,376,635
Prices											
WTI spot price (\$/BBL)	26.18	31.08	41.51	56.64	66.05	72.34	99.67	61.95	79.48	94.88	
Weighted avg oil price (\$/BBL)	22.45	23.73	25.72	27.36	31.42	36.05	49.42	49.55	59.96	69.73	
Weighted avg NGL price (\$/BBL)	18.33	21.77	31.33	39.98	43.9	52.91	63	37.96	51.03	65.61	
Sales Volume											
Net Oil sales (STB/D)	10,317	15,900	23,600	26,700	25,700	23,000	23,300	25,100	24,300	23,800	
Net NGL Sales (STB/D)	0	3,700	7,700	9,400	8,900	9,600	8,300	9,400	10,000	8,500	
Net BOE sales (STB/D)	10,317	19,600	31,300	36,100	34,600	32,600	31,600	34,500	34,300	32,300	
Net Oil sales (STB)	3,765,705	5,803,500	8,614,000	9,745,500	9,380,500	8,395,000	8,504,500	9,161,500	8,869,500	8,687,000	80,926,705
Net NGL Sales (STB)	0	1,350,500	2,810,500	3,431,000	3,248,500	3,504,000	3,029,500	3,431,000	3,650,000	3,102,500	27,557,500
Net BOE sales (STB)	3,765,705	7,154,000	11,424,500	13,176,500	12,629,000	11,899,000	11,534,000	12,592,500	12,519,500	11,789,500	108,484,205
Revenues											
Oil revenue (\$)	84,540,077	137,717,055	221,552,080	266,636,880	294,735,310	302,639,750	420,292,390	453,952,325	531,815,220	605,744,510	3,319,625,597
NGL revenue (\$)	0	29,400,385	88,052,965	137,171,380	142,609,150	185,396,640	190,858,500	130,240,760	186,259,500	203,555,025	1,293,544,305
Total revenue (\$)	84,540,077	167,117,440	309,605,045	403,808,260	437,344,460	488,036,390	611,150,890	584,193,085	718,074,720	809,299,535	4,613,169,902
Expenses											
Taxes other than income (\$/BOE)	0.87	0.88	1.00	1.70	2.00	2.30	2.20	0.00	2.00	1.75	
Power (\$/BOE net)	2.90	2.56									
Well work (\$/BOE net)			2.30	2.30	5.30	5.50	7.10	4.20	4.30	3.95	
CO2 removal (\$/BOE net)	0.74	0.61									
CO2 capitalized (\$/BOE net)	3.73	4.19	4.60	4.50	5.70	4.80	7.70	5.20	6.10	5.40	
CO2 expensed (\$/BOE net)	2.09	2.36	2.60	2.50	3.50	2.50	4.60	2.50	3.20	2.83	
Gas handling (\$/BOE net)			3.50	3.30	2.90	4.80	4.80	2.90	4.20	4.20	
Labor (\$/BOE net)	0.99	0.73	0.30	0.50	0.50	0.75	1.00	0.75	1.30	1.95	
Other (\$/BOE net)	2.83	1.91	0.90	1.30	1.90	1.60	2.30	1.30	1.20	1.30	
Total expenses (\$/BOE net)	13.28	12.35	15.20	16.10	21.80	22.25	29.70	16.85	22.30	21.38	
Total expenses (\$)	49,989,966	88,358,404	173,652,400	212,141,650	275,312,200	264,752,750	342,559,800	212,183,625	279,184,850	252,059,510	2,150,195,155
Earnings											
Calculated EBITDDA* (\$)	34,550,111	78,759,036	135,952,645	191,666,610	162,032,260	223,283,640	268,591,090	372,009,460	438,889,870	557,240,025	2,462,974,748
KM reported EBITDDA (\$)**	31,300,000	72,500,000	112,000,000	203,500,000	167,000,000	162,000,000	203,000,000	361,000,000	478,000,000	593,000,000	2,383,300,000
Purchased CO2 Cost Analysis											
CO2 cost (\$/BOE net)	5.82	6.55	7.20	7.00	9.20	7.30	12.30	7.70	9.30	8.23	
CO2 cost (\$)	21,916,403	46,858,700	82,256,400	92,235,500	116,186,800	86,862,700	141,868,200	96,962,250	116,431,350	97,027,585	
CO2 cost (\$/MCF)	0.44	0.57	0.66	0.98	1.29	1.12	1.50	1.05	1.45	1.73	
CO2 cost % of WTI	1.67	1.84	1.60	1.73	1.95	1.55	1.51	1.69	1.82	1.82	
Revenue Analysis											
Calculated revenue (\$/BOE net)	22.45	23.36	27.10	30.65	34.63	41.01	52.99	46.39	57.36	68.65	
KM reported revenue (\$/BOE net)					35.50	39.50	52.00	47.50	58.00		

*Earnings before interest, taxes, depreciation, depletion and amortization (also called distributable cash flow)

**Including SACROC services and remaining oil and gas assets

Table 28: Assumptions for the CO₂-EOR financial model

Reservoir Data	
Depth (ft)	6500
Thickness (ft)	200
Porosity (fraction)	0.0731
Pattern area (acres)	49,900
Original Saturation	
Oil (fraction)	0.718
Water (fraction)	0.282
Gas (fraction)	0.000
Original Oil in Place	
Initial hydrocarbon pore volume -OOIP (real barrels)	4,063,704,667
Original oil in place (stock tank barrels - STB)	2,760,668,932
Prior Injection and Production	
Prior oil production (STB)	1,342,616,000
Prior purchased CO ₂ injected (MMCF)	1,687,148
Current Saturation	
Oil (fraction)	0.3688
Water (fraction)	0.4332
Gas (fraction)	0.1980
Fluid Data	
Crude oil API	42
Solution HC gas in oil (SCF/STB)	2500
CH ₄ +C ₂ H ₆ in hydrocarbon gas (mol %)	26.06
C ₃ + in hydrocarbon gas (mol %)	13.19
CO ₂ in hydrocarbon gas (mol %)	60.21
NGL C ₃ + conversion factor (SCF/STB)	3000
Excess natural gas (1 = sold 2 =reinjectd)	2
Formation Volume Factors	
Oil (RB/STB)	1.472
Water (RB/STB)	1.005
CO ₂ (RB/MMSCF)	477
Power Consumption Factors	
Purchased CO ₂ (kWh/MMCF)	0
Recycled CO ₂ (kWh/MMCF)	5260
Injected water (kWh/STB)	1.2
Disposed water (kWh/STB)	1.2
Produced water artificial lift (kWh/STB/ft lift)	0.000274
Produced oil artificial lift (kWh/STB/ft of lift)	0.000207
NGL separation using Ryan Holmes (kWh/STB NGL sold)	123
NGL separation using Membrane Benfield (kWh/MMCF HC gas)	500
NGL separation type (1=Ryan Holmes 2=Membrane+Benfield)	2
CO ₂ dehydration non-electric heated reboiler (kWh/MMCF)	28
CO ₂ dehydration with electric heated reboiler (kWh/MMCF)	403
CO ₂ dehydration type (1=non-elect heated 2=elect heated)	1
Other (% of total)	3
Hedging	
Hedged oil price (% of WTI)	100
Hedged oil price escalation (%/y)	2
Portion of oil sales hedged (%)	85
Natural gas liquids price (% of WTI)	69
Escalation Factors	
WTI crude oil price escalation rate (%/y)	2
Natural gas price escalation rate (% per year)	2
Power escalation rate (% per year)	2
Non-energy escalation rate (% per year)	2
Royalty and Tax Rates	
Royalties (% of revenue)	16.67
EOR oil production tax (% of revenue)	2.3
NGL production tax (% of revenue)	4.6
Natural gas production tax (% of revenue)	7.5
Property tax (% of property value)	6
Income tax (% of net income)	38
Operating Costs	
Internal power cost (\$/MWh)	20
External power cost (\$/MWh)	60
Labor (average salaries \$/y)	72000
Well operation and maintenance incl. labor (\$/y per active well)	60,000
Other expenses (% of operating expenses)	25
Purchased CO ₂ cost (\$/MCF)	1.75
Capital Expenses	
Capital expenses (\$/STB oil)	8
Calculation of capital expense (1=\$/STB or 2=capital cost factors)	2
Capital Cost Factors	
Maximum well depth (ft)	6900
Injection well drilling and completion single injection (\$/well)	1,200,600
Injection well drilling and completion dual injection (\$/well)	1,800,900
Production well drilling and completion (\$/well)	1,200,600
Equipment for injection well (\$/well)	248,700
Equipment for production well (\$/well)	285,000
Conversion of existing production well to injection well (\$/well)	116,600
Rework existing well (\$/well)	269,100
CO ₂ recycling facilities (\$/MMCF/D recycled)	1,900,000

Table 29: SACROC Unit performance and economic pro forma 2012 through 2021

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
Year	1	2	3	4	5	6	7	8	9	10	
Fluids Injected											
CO2 injected (HCPV)	0.04285	0.04285	0.04285	0.04285	0.04285	0.04285	0.04285	0.04285	0.04285	0.04285	0.4285
Water injected (HCPV)	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.5715
Total fluids injected (HCPV)	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	1.0000
Fluids Produced											
Oil produced (HCPV)	0.00362	0.00326	0.00326	0.00290	0.00259	0.00254	0.00217	0.00181	0.00145	0.00145	0.0251
Water produced (HCPV)	0.05869	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.05715	0.05570	0.05570	0.5701
CO2 produced (HCPV)	0.03769	0.03959	0.03959	0.03995	0.04026	0.04031	0.04068	0.04104	0.04285	0.04285	0.4048
Total fluids produced (HCPV)	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	0.10000	1.0000
CO2 purchased (HCPV)	0.00516	0.00326	0.00326	0.00290	0.00259	0.00254	0.00217	0.00181	0.00000	0.00000	0.0237
Carbon Dioxide (CO2)											
CO2 injected (MMCF)	365,052	365,052	365,052	365,052	365,052	365,052	365,052	365,052	365,052	365,052	3,650,519
CO2 produced (MMCF)	321,092	337,279	337,279	340,346	342,987	343,413	346,565	349,632	365,052	365,052	3,448,697
CO2 purchased (MMCF)	28,917	14,226	14,226	12,655	11,302	11,084	9,469	7,898	-6,025	-6,025	97,727
CO2 recovered from HC gas (MMSCF)	15,043	13,547	13,547	12,051	10,763	10,555	9,017	7,521	6,025	6,025	104,095
Oil, Hydrocarbons and Natural Gas Liquids											
Oil produced (MSTB)	9,994	9,000	9,000	8,006	7,150	7,012	5,991	4,997	4,003	4,003	69,155
Hydrocarbon gas produced (MMSCF)	24,984	22,499	22,499	20,015	17,875	17,530	14,977	12,492	10,007	10,007	172,887
Natural gas liquids produced (MSTB)	1,098	989	989	880	786	771	658	549	440	440	7,601
Natural Gas											
Natural gas produced (MMSCF)	6,511	5,863	5,863	5,216	4,658	4,568	3,903	3,255	2,608	2,608	45,054
Natural gas consumed (MMSCF)	7,433	7,391	7,391	7,348	7,311	7,305	7,261	7,219	7,176	7,176	73,012
Natural gas sold (MMSCF)	0	0	0	0	0	0	0	0	0	0	0
Natural gas reinjected (MMSCF)	0	0	0	0	0	0	0	0	0	0	0
Natural gas purchased (MMSCF)	923	1,527	1,527	2,132	2,653	2,737	3,359	3,963	4,568	4,568	27,958
Water											
Water injected (MSTB)	231,085	231,085	231,085	231,085	231,085	231,085	231,085	231,085	231,085	231,085	2,310,853
Water produced (MSTB)	237,312	231,085	231,085	231,085	231,085	231,085	231,085	231,085	225,222	225,222	2,305,354
Water disposed of (MSTB)	6,227	0	0	0	0	0	0	0	0	0	6,227
Additional water required (MSTB)	0	0	0	0	0	0	0	0	5,863	5,863	11,726
Power Consumption											
Purchased CO2 booster (kWh/STB oil)	0	0	0	0	0	0	0	0	0	0	0
CO2 recycle compression (kWh/STB oil)	177	205	205	232	260	266	312	376	488	488	
Artificial lift for oil and water (kWh/STB oil)	44	47	47	53	59	60	70	84	104	104	
NGL separation (kWh/STB oil)	1	1	1	1	1	1	1	1	1	1	
Water injection and disposal (kWh/STB oil)	28	31	31	35	39	40	46	55	69	69	
CO2 recycle dehydration (kWh/STB oil)	1	1	1	1	1	1	2	2	3	3	
Other (kWh/STB oil produced)	8	9	9	10	11	11	13	16	21	21	
Total power consumption (kWh/STB oil)	259	294	294	331	372	379	445	534	685	685	
Power consumption (MWh)	2,588,070	2,646,404	2,646,404	2,652,352	2,657,474	2,658,300	2,664,414	2,670,362	2,743,653	2,743,653	
Power load (MW)	295	302	302	303	303	303	304	305	313	313	
Internal power supply (MW)	100	100	100	100	100	100	100	100	100	100	
External power supply (MW)	195	202	202	203	203	203	204	205	213	213	
Labor											
Labor (# of employees)	130	130	130	130	130	130	130	130	130	130	
Active Wells											
Injection wells (# wells)	450	450	450	450	450	450	450	450	450	450	
Production wells (# wells)	400	400	400	400	400	400	400	400	400	400	
Total active wells (# wells)	850	850	850	850	850	850	850	850	850	850	
Capital Expenses											
New injection wells (# wells)	25	23	23	20	18	18	15	13	10	10	175
New production wells (# wells)	25	23	23	20	18	18	15	12	10	10	174
Conversion of producers to injectors (# wells)	50	40	40	40	36	30	30	25	20	20	331
New injection wells (\$ million)	36,233	34,001	34,681	30,760	28,238	28,803	24,482	21,642	16,981	17,320	273
New production wells (\$ million)	37,140	34,852	35,549	31,531	28,945	29,524	25,095	20,478	17,406	17,754	278
Conversions (\$ million)	5,830	4,757	4,852	4,949	4,544	3,862	3,939	3,448	2,732	2,787	42
Total capital expenses (\$ million)	79,203	73,610	75,082	67,240	61,727	62,189	53,517	45,469	37,119	37,862	593
Prices											
WTI crude oil price (\$/bbl)	90.00	91.80	93.64	95.51	97.42	99.37	101.35	103.38	105.45	107.56	
Adjusted crude oil price (\$/bbl)	89.85	91.85	93.49	95.36	97.27	99.22	101.20	103.23	105.30	107.41	
Hedged oil price (\$/bbl)	76.50	78.03	79.59	81.18	82.81	84.46	86.15	87.87	89.63	91.42	
Realized weighted average oil price (\$/bbl)	80.64	82.25	83.90	85.58	87.29	89.04	90.82	92.64	94.49	96.38	
Natural gas liquids price (\$/bbl)	62.10	63.34	64.61	65.90	67.22	68.56	69.93	71.33	72.76	74.22	
Natural gas price (\$/MSCF)	2.50	2.55	2.60	2.65	2.71	2.76	2.82	2.87	2.93	2.99	
Sales Volumes											
Gross oil sold (MSTB)	9994	9000	9000	8006	7150	7012	5991	4997	4003	4003	69,155
Net oil sold (MSTB)	8328	7500	7500	6671	5958	5843	4992	4164	3336	3336	57,627
Natural gas liquids sold (MSTB)	1098	989	989	880	786	771	658	549	440	440	7,601
Natural gas sold (MMSCF)	0	0	0	0	0	0	0	0	0	0	0
Net barrel of oil equivalent (MBOE net)	9,426	8,489	8,489	7,551	6,744	6,614	5,650	4,713	3,776	3,776	65,228
Revenues											
Oil revenues (\$ million)	805,871	740,252	755,065	685,125	624,132	624,331	544,058	462,881	378,236	385,804	6,005,755
Natural gas liquids revenue (\$ million)	68,215	62,660	63,913	57,992	52,829	52,845	46,050	39,179	32,014	32,654	508,350
Natural gas revenues (\$ million)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Gross revenues (\$ million)	874,085	802,911	818,978	743,117	676,960	677,176	590,109	502,059	410,250	418,459	6,514,104
Royalties (\$ million)	-134,339	-123,400	-125,869	-114,210	-104,043	-104,076	-90,695	-77,162	-63,052	-64,314	-1,001,159
Production (severance) taxes (\$ million)	-18,583	-17,070	-17,411	-15,799	-14,392	-14,397	-12,546	-10,674	-8,722	-8,896	-138,490
Net revenues (\$ million)	721,164	662,441	675,697	613,108	558,526	558,703	486,868	414,223	338,476	345,249	5,374,455
Expenses											
Labor (\$ million)	9,360	9,547	9,738	9,933	10,132	10,334	10,541	10,752	10,967	11,186	102,489
Power (\$ million)	120,244	126,219	128,744	131,697	134,664	137,412	140,573	143,794	151,823	154,859	1,370,029
Purchased natural gas (\$ million)	2,307	3,895	3,973	5,657	7,179	7,555	9,456	11,382	13,381	13,648	78,431
Well O&M excl. labor (\$ million)	41,640	42,473	43,322	44,189	45,072	45,974	46,893	47,831	48,788	49,764	455,946
Other (\$ million)	57,081	59,413	60,601	61,940	63,289	64,573	66,002	67,459	70,526	71,936	642,821
Purchased CO2 (\$ million)	50,604	25,393	25,901	23,502	21,409	21,416	18,662	15,878	-12,355	-12,602	177,809
Capital expenses (\$ million)	79,203	73,610	75,082	67,240	61,727	62,189	53,517	45,469	37,119	37,862	593,017
Total expenses (\$ million)	360,439	340,551	347,362	344,157	343,472	349,452	345,645	342,564	320,248	326,653	3,420,543
Earnings											
EBITDDA* (\$ million)	360,725	321,891	328,336	268,951	215,053	209,251	141,224	71,659	18,228	18,595	1,953,912

High lighted cells are input values.

*Earnings before interest, taxes, depreciation, depletion and amortization (also called distributable cash flow)

Figure 13 illustrates the process-level modeling history match results for the Northern Platform Site using CMG-GEM software. In general, the modeling results matched up fairly well with actual injection and production data for the 639 injection and production wells. The cumulative total gas production curve includes hydrocarbons and carbon dioxide.

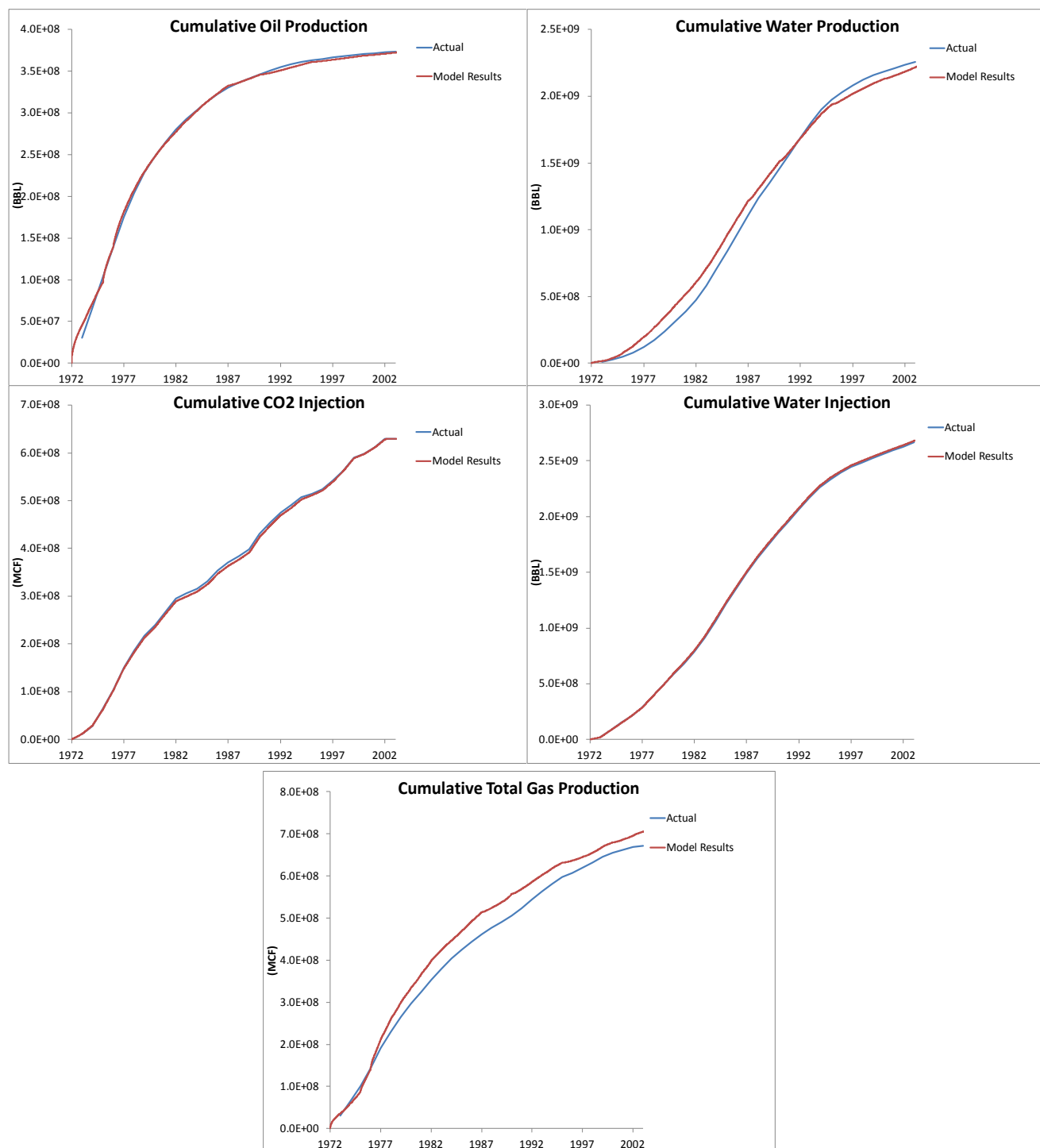


Figure 13: Cumulative production and injection curve comparisons for actual field data and modeling results

3.5 Quantitative Risk Assessment of the San Juan Basin Pump Canyon CO₂-ECBM Site

The San Juan Basin Pump Canyon Site was selected for a quantitative risk assessment to prove out the CO₂-ECBM portion of the QFMEA model because sufficient information was available in the public domain.

3.5.1 Background

The San Juan Basin is an asymmetric structural depression that consists of an area of approximately 16,828 km² (6,500 mi²) with portions in New Mexico and Colorado (see **Figure 14**). Maximum depth of the basin to the Precambrian basement rock exceeds 4,267 m (14,000 ft), as shown in the cross-section in **Figure 15**. It is the second largest natural gas basin in the United States. Original gas in place is estimated at 5.9 to 6.9 Tm³ (208 to 244 TCF). The quantity of natural gas by formation type is shown in **Table 30**. Cumulative natural gas production through 2012 is estimated at 1.32 Tm³ (46.7 TCF) based on extrapolating data compiled by **Fassett 2010, OCD 2013 and COGCC 2013**.



Figure 14: Map of the San Juan Basin (USGS 2013)

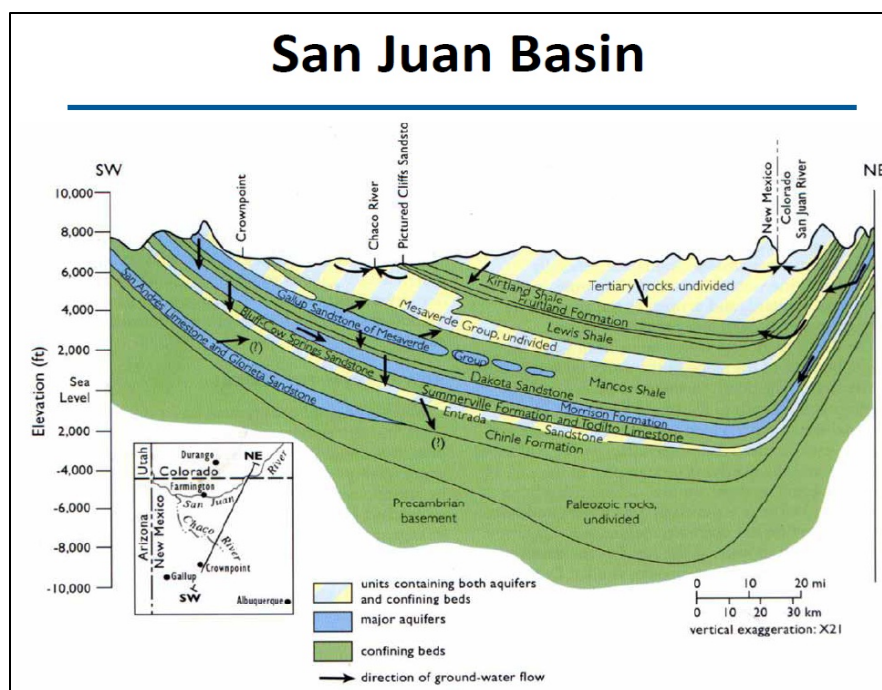


Figure 15: San Juan Basin general cross-section, also showing large-scale hydrogeologic patterns (Grigg 2011)

Table 30: San Juan Basin estimated original gas in place

Type	Formations	Original Gas In Place (Tm ³)	Original Gas In Place (TCF)
Tight sands	Pictured Cliffs Mesaverde Dakota	1.8	63*
Coal bed methane (CBM)	Fruitland Menefee	1.4 1.0	50** 34**
Shale gas	Lewis Mancos	1.7-2.7	61-97***
Total		5.9-6.3	208-244

*(Wilson A 2012) **(Burnett 2010) *** (Holditch 2011)

The Fruitland Formation is the primary source of coal bed methane (CBM) in the San Juan Basin. Additional CBM may be found in the Menefee member of the Mesaverde Group, but the Menefee coal is deeper and is present in thinner seams.

The Fruitland Formation has basin-wide coal resources of 222 Gt (245 billion ST). Formation thickness ranges from 60 to 160 m (197 to 525 ft). Maximum net coal thickness is 33 m (110 ft). Maximum coal seam thickness is 12 m (40 ft). Maximum number of coal seams is 16. Coal depth ranges from 0 to 1,280 m (0 to 4,200 ft). Coal rank ranges from sub-bituminous B to low-volatile bituminous (Fassett 2000). Coalbed gas content of Fruitland coal ranges from 0.7 to 18.3 m³/t (23 to 587 SCF/ST) (Seidle 2011).

The CBM original gas in place, within the Fruitland coal seams greater than 0.6 m (2 ft) thick and deeper than 122 m (400 ft), is estimated at 1.2-1.4 Tm³ (43-49 TCF), (**Ayers 1994**). Bland estimated that 70 to 80% of the CBM original gas in place is recoverable in some areas and at 50% for the entire basin average (**Bland 1992**). Simpson estimated that over 90% of the CBM original gas in place could be recovered if the right deliquification and compression techniques are used but only 50% if the wrong techniques are used (**Simpson 2008**). Commercial-scale CBM production from the Fruitland Formation began in 1988. Cumulative production through 2012 is estimated at 0.49 Tm³ (17.2 TCF), based on extrapolation of data compiled by **Fassett 2010**, **OCD 2013** and **COGCC 2013**.

The Pump Canyon CO₂-ECBM Site is located in the San Juan Basin in San Juan County, New Mexico in Section 32 of T31N R08W. This Site is on the southern edge of the Fairway, a highly productive coalbed methane area in the San Juan Basin characterized by thick, permeable, bituminous coal seams.

The stratigraphy at the Site is shown in **Table 31**. The elevation at the surface is 1,927 m (6,321 ft) above mean sea level. Geological seals are shown in yellow and sinks are shown in orange. The coal beds are shown as sinks, but they also act like seals as they adsorb CO₂.

Table 31: Stratigraphy at the Pump Canyon CO₂ injection well

System	Formation	Lithology	Depth to top of formation*	Relative thickness*	Comments
Tertiary	San Jose Formation	Sandstone with some shale and siltstone	0.0 m (0 ft)	495.6 m (1,626 ft)	
	Nacimiento Formation	Shale and siltstone with some sandstone	495.6m (1,626 ft)	110.6 m (363 ft)	60-75% CH ₄ in formation gas
	Ojo Alamo Formation	Sandstone with some shale	606.2m (1,989 ft)	20.5 m (67 ft)	76% CH ₄ in formation gas
Cretaceous	Kirtland Formation (upper shale)	Shale with some sandstone	626.7m (2,056 ft)	30.8 m (101 ft)	
	Kirtland (Farmington Sandstone)	Sandstone, shale and siltstone	657.5 m (2,157 ft)	123 m (404 ft)	64-70% CH ₄ in formation gas
	Kirtland Formation (lower shale)	Shale with some siltstone and sandstone	780.5 m (2,561 ft)	83.5 m (274 ft)	80-85% CH ₄ in formation gas
	Fruitland Formation (upper clastics)	Shale with some sandstone	864.0 m (2,835 ft)	38.5 m (126 ft)	
	Fruitland Formation (upper coal F)	Coal with some carbonaceous shale	902.5 m (2,961 ft)	1.5 m (5 ft)	Coal-bed methane
	Fruitland formation (upper parting shale)	Shale, sandstone, siltstone and clay	904.0 m (2,966 ft)	3.4 m (11 ft)	
	Fruitland Formation (upper coal E)	Coal with some carbonaceous shale	907.4 m (2,977 ft)	1.2 m (4 ft)	Coal-bed methane
	Fruitland Formation (middle clastics)	Shale with some sandstone and siltstone	908.6 m (2,981 ft)	22.3 m (73 ft)	
	Fruitland Formation (middle coal D)	Coal with some carbonaceous shale	930.9 m (3,054 ft)	3.6 m (12 ft)	Coal-bed methane
	Fruitland Formation (middle parting shale)	Shale	934.5 m (3,066 ft)	0.6 m (2 ft)	
	Fruitland Formation (middle coal C)	Coal with some carbonaceous shale	935.1 m (3,068 ft)	1.9 m (6 ft)	Coal-bed methane
	Fruitland Formation (lower clastics)	Shale with some siltstone and sandstone	937.0 m (3,074 ft)	10.9 m (36 ft)	
	Fruitland Formation (basal coal B)	Coal with some carbonaceous shale	947.9m (3,110 ft)	5.8 m (19 ft)	Coal-bed methane
	Fruitland Formation (basal parting shale)	Shale	953.7 m (3,129 ft)	0.3 m (1 ft)	
	Fruitland Formation (basal coal A)	Coal	954.0 m (3,130 ft)	2.5 m (8 ft)	Coal-bed methane
	Fruitland Formation (basal clastics)	Shale with some coal	956.5m (3,138 ft)	3.9 m (13 ft)	
	Pictured Cliffs Sandstone Formation	Sandstone	960.4m (3,151 ft)	60.7 m (199 ft)	Conventional and tight gas
	Lewis Shale Formation	Shale with some sandstone, siltstone and bentonite	1,021.1 m (3,350 ft)	442.0 m (1,450 ft)	Shale gas
	Mesaverde Group	Sandstone, siltstone, shale and coal	1,463.1 m (4,800 ft)	255.7 m (839 ft)	Conventional and tight gas. CBM in the Menefee member.
	Mancos Shale Formation	Shale with some sandstone and limestone	1,718.8 m (5,639 ft)	607.1 m (1,992 ft)	Potential shale gas
	Dakota Sandstone Formation	Sandstone with some siltstone and shale	2,325.9 m (7,631 ft)	76.2 m (250 ft)	Conventional and tight gas
Jurassic	Morrison Formation	Sandstone and shale with some limestone	2,402.1 m (7,881 ft)	213.4 m (700 ft)	Used for salt water disposal
	Wanakah Formation	Limestone	2,615.5 m (8,581 ft)	45.7 m (150 ft)	
	Entrada Sandstone Formation	Sandstone	2,661.2 m (8,731 ft)	106.7 m (350 ft)	Used for salt water disposal
Triassic	Chinle Formation	Shale, sandstone and siltstone	2,767.9 m (9,081 ft)	304.8 m (1,000 ft)	
Paleozoic	Paleozoic - Undivided rock		3,072.7 m (10,081 ft)	1,264.8 m (4,000 ft)	
Precambrian	Precambrian - Basement		4,291.9 m (14,081 ft)		

*Depths and thicknesses of the Fruitland Formation and overlying units are from **Heath 2010**. Depth and thickness for units underlying the Fruitland Formation are estimated from **OCD 2013**, **Stone 1983** and **Engler 2001**. Seals are yellow and sinks are orange.

The Kirtland Formation is the primary caprock or seal above the Fruitland Formation. It is 237.3 m (779 ft) thick at the Site, and divided into upper and lower shales separated by the Farmington Sandstone. The Kirtland upper and lower shales are argillaceous mudstones with 11-23% illite and

smectite (clays that expand when wet and shrink when dry) and 0-13% iron-bearing chlorite (which will dissolve in acidic fluids). Porosity is 6.56-8.79%. Water saturation is 75-81%, gas saturation is 17-23% and oil saturation is 2%. Permeability is $1\text{E-}20\text{ m}^2$ ($1\text{E-}06\text{ mD}$). Although the Kirtland Formation permeability is very low, all of the overlying formations contain methane that has passed through the Kirtland Formation and methane seeps have been reported in the San Juan River and Animas River areas dating back to the 1880s, suggesting that there are high permeability zones in the Kirtland Formation.

The Fruitland Formation is 864 m (2,835 ft) deep and 96.4 m (316 ft) thick. It contains three (3) coal zones (upper, middle and basal) separated by layers of shale, sandstone, siltstone and clay. Each coal zone has two (2) coal beds separated by shale (volcanic ash) partings (tonsteins). The coal beds range from 1.2 to 5.8 m (4 to 19 ft) thick and the parting range from 0.3 to 3.4 m (1 to 11 ft) thick. The net coal thickness of the Fruitland Formation at the Site is 18.3 m (60 ft). The top of the highest coal bed is 902.5 m (2,961 ft) deep and the bottom of the lowest (basal) coal bed is 956.5 m (3,138 ft) deep.

Prior to CBM production, tests on core samples from the Fruitland coal in the Fairway contained 18% natural CO_2 and 82% methane. When CBM operations began, the CO_2 content in the produced gas was only 6-8%, as CO_2 had a stronger adsorption affinity to coal than methane. Over time, the coal seam pressure decreased and CO_2 on the coal began to desorb with the methane. This resulted in CO_2 content in the produced gas increasing to 20-30%. (**Simpson 2008**).

The original gas in place (OGIP) in the Fruitland Formation in production Section 32 was estimated at 779 Mm^3 (27.512 BSCF) based on an analysis of CBM production from 1989 through July 2008 (prior to CO_2 injection). The breakdown of gas composition is summarized in **Table 32**. Methane content was estimated at 637 Mm^3 (22.05 BSCF). This value is consistent with the value estimated by Ayers (**Ayers 1994**). CO_2 content was estimated at 263,307 t (290,307 ST).

Table 32: Original gas in place in the Fruitland Formation in Section 32

Component	Volume (Mm3)	Volume (BSCF)	Composition (% of OGIP)
CO_2	141.739	5.005	18.19
CH_4	637.181	22.502	81.79
N_2	0.133	0.005	0.02
Total	779.053	27.512	100.00

The Southwest Regional Partnership (SWP) for Carbon Sequestration coordinated an injection test at the Site, where CO_2 was injected through a single well into the Fruitland coal seams, over a one-year period, from 30 JUL 2008 until 12 AUG 2009. The Site was monitored before, during and after the injection for leakage, CO_2 breakthrough, CBM production, produced water quality and surface deformation. After the injection demonstration test was completed, the injection well was plugged and abandoned (**ARI 2010**).

The Pump Canyon test was designed to be fully contained within area Section 32 of T31N R08W. The original plan was to inject 68,000 t (1.29 BSCF) of CO_2 over a one-year period through a single well. However, due to decreased injectivity caused by the coal matrix swelling and permeability reduction as a result of CO_2 being adsorbed onto the coal while displacing methane, as well as

increasing reservoir pressure, it was only possible to inject 16,781 t (319 MMSCF) over the one-year period. Even though injection pressure was maintained close to 90% of fracture pressure, the injection rate dramatically decreased from 200 t/d (3,800 MSCFD) to 13 t/d (250 MSCFD) over the one year period as illustrated in **Figure 16**. This suggests that, without some hydraulic stimulation, the maximum injection capacity for a vertical well at this location would be approximately 17,000 t (323 MMSCF) of CO₂ in the first year and approximately 5,000 t (95 MMSCF) per year thereafter. The injection well was perforated over the entire formation thickness, but 80% of the CO₂ was ultimately injected into the basal coal zone (deepest of the three coal zones). Wellhead pressure was maintained at 7.58 MPa (1100 psig) which resulted in a bottomhole pressure of 13.79-14.82 MPa (2000-2150 psig).

The CO₂ used in the test was natural CO₂ from McElmo Dome in Colorado, delivered via the Cortez Pipeline.

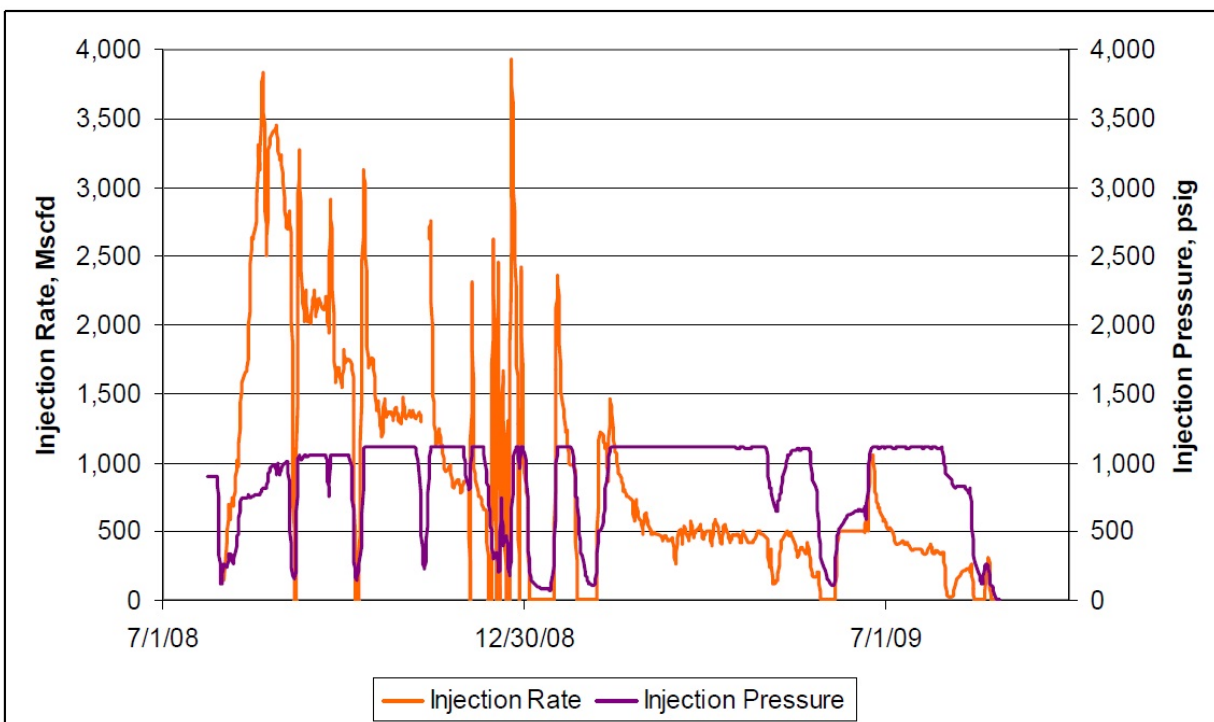


Figure 16: CO₂ injection rate and wellhead pressure during the injection demonstration test (ARI 2010)

The CO₂ injected into the coal seams appeared to be contained within an area of less than 383 m radius as that was the distance to the nearest of three (3) CBM production wells, and no CO₂ breakthrough was detected. However, there were indications that CO₂ breakthrough was imminent based on perfluorocarbon (PFC) tracer detection, increased nitrogen and slightly increased CO₂ in the produced gas. The CO₂ was injected at a bottomhole pressure and temperature of 13.79-14.82 MPa and 32-38°C (2000-2150 psia and 90-100°F), respectively. At these conditions, the CO₂ is in a supercritical state and had a density of approximately 800 kg/m³ (50 lb/ft³). However, the reservoir was under pressured at 0.52 MPa (75 psig) due to previous CBM production and dewatering. Reservoir temperature was 52°C (126°F). At these conditions, free CO₂ is in a gas phase and has a density of 8.6 kg/m³ (0.54 lb/ft³). When CO₂ is adsorbed on coal, it has a density similar to liquid CO₂ of 1,180 kg/m³ (74 lb/ft³).

An earlier CO₂-ECBM test was conducted at the Allison Unit Site located 18 km (11 mi) northeast of the Pump Canyon Site. The test was conducted by Burlington Resources from APR 1995 through AUG 2001. Over the six (6) year period, 336,665 t (6.4 BSCF) of natural CO₂ were injected into the Fruitland Formation coal seams through four (4) injection wells. **Table 33** compares the Pump Canyon and the Allison Unit tests.

The Allison Unit operated at lower CO₂ injection pressures and did not experience the significant decrease in injectivity observed at the Pump Canyon Site. The high injection pressures at Pump Canyon may have contributed to the significant decrease in permeability and injectivity by causing the coal to plasticize.

At the Allison Unit, 4 m³ of injected CO₂ were required to produce 1 m³ of additional methane. At the Pump Canyon Site, 12.3 m³ of injected CO₂ were required to produce 1 m³ of additional methane. Part of this may have been due to the fact that the Allison Unit operated for a longer time and injected more CO₂ in a more uniform manner.

Table 33: Comparison of the Pump Canyon and Allison Unit CO₂-ECBM tests

	Pump Canyon Site	Allison Unit Site
Operator	Burlington Resources	Burlington Resources
Location	Section 32 of T31N R08W of San Juan County, NM	Sections 13, 23, 24 & 25 of T32N R97W and Sections 17, 18, 19, 20, 29 & 30 of T32N R06W of San Juan County, NM
Area	2.59 km ² (1 mi ²)	28.48 m ² (11 mi ²)
Date	30JUL2008-12AUG2009	APR1995-AUG2001
Years of CO ₂ injection	1	6
CO ₂ type & source	Natural CO ₂ from McElmo Dome	Natural CO ₂ from McElmo Dome
Amount of CO ₂ injected	16,781 t (0.319 BSCF)	336,665 t (6.4 BSCF)
No. of injection wells	1	4
No. of offset CBM wells	3	16
No. of monitoring wells	0	1
Well spacing	160 acres	160 acres
Well pattern	Injection-centered 4-spot	Injection-centered 5-spot
Primary sealing formation	Kirtland	Kirtland
Injection formation	Fruitland	Fruitland
Thickness of sealing formation	240 m (787 ft)	174.6 m (573 ft)
Thickness of injection formation	93.6 m (307 ft)	116.5 m (382 ft)
No. of coal zones	3	3
Average depth to top of coal	918 m (3012 ft)	945 m (3,100 ft)
Net coal thickness	Average: 18.3 m (60 ft) Range: 16.8-19.8 m (55-65 ft)	Average: 11.1 m (43 ft) Range: 10.4-14.3 m (34-47 ft)
Coal porosity	0.25%	0.16-0.25%
Coal permeability before CO ₂ injection	10-90 mD	100-140 mD
Coal permeability after CO ₂ injection	0.13 mD	<1 mD
Methane OGIP	246 Mm ³ /km ² (22.502 BSCF/mi ²)	242 Mm ³ /km ² (22.125 BSCF/mi ²)
Initial temperature before CBM production	52.2°C (125°F)	48.9°C (120°F)
Initial pressure before CBM production	11.33 MPa (1644 psi)	11.38 MPa (1650 psi)
Initial pressure gradient before CBM	12.4 MPa/km (0.545 psi/ft)	12 MPa/km (0.53 psi/ft)
Reservoir pressure at start of CO ₂ injection	0.52-0.69 MPa (75-100 psig)	4.14 MPa (600 psi)
Maximum CO ₂ injection rate	200 t/d	Well #140: 82.34 t/d Well #141: 75.63 t/d Well #142: 61.16 t/d Well #143: 51.46 t/d
Average CO ₂ injection rate	45.98 t/d	Well #140: 47.78 t/d Well #141: 46.55 t/d Well #142: 47.31 t/d Well #143: 25.63 t/d
Final CO ₂ injection rate	13 t/d	Well #140: 55.71 t/d Well #141: 39.61 t/d Well #142: 49.13 t/d Well #143: 30.80 t/d
Bottom-hole CO ₂ injection pressure	13.79-14.82 MPa (2000-2150 psia)	9.29-11.00 MPa (1348-1595 psi)
Fracture pressure	15.86-17.24 MPa (2,300-2500 psi) at 945 m (3,100 ft) depth	15.86-17.24 MPa (2,300-2500 psi) at 945 m (3,100 ft) depth
Estimated volumetric ratio of incremental methane production to CO ₂ injected	1 methane:12 CO ₂	1 methane:4 CO ₂

3.5.2 Site Reference Areas

This quantitative risk assessment looked at three (3) Site Reference Areas within the San Juan Basin: One (1) Section, Nine (9) Sections, and Sixteen (16) Townships. These areas are described in **Table 34** and are shown in **Figure 17**. The One-Section Area refers to Section 32 in T31N R08W. This is the location for the Pump Canyon CO₂ injection test coordinated by SWP. The Nine-Section Area represents a 1.6 km (1 mi) buffer zone around Section 32. The Sixteen-Township Area is a square area approximately centered on Section 32, and encompasses the amount of land that would be required to store CO₂ from a typical 500MW coal-fired power plant capturing approximately 3.15 Mt/y (60 BSCF/Y) of CO₂. Note that the townships on the north side of the area are partially cut off at the state line, and therefore the area has only 550 sections instead of 576 sections.

Table 34: Comparison of the three Site Reference Areas

	One-Section Area	Nine-Section Area	Sixteen-Township Area
Location	Section 32 in T31N R08W	Sections 28,29,30, 31, 32 & 33 in T31N R08W and Sections 4, 5 & 6 in T30N R08W.	T29-32N R07-10W
Area	2.59 km ² 1 mi ² 640 acres	23.3 km ² 9 mi ² 3,840 acres	1,424 km ² 550 mi ² 352,000 acres
Estimated coal in place	56.7 Mt 62.5 million ST	510 Mt 563 million ST	28 Gt 31 billion ST
Estimated original methane gas in place	637 Mm ³ 22.5 BCF	5.66 Gm ³ 200 BCF	256 Gm ³ 9 TCF
Number of existing deep wells	Active:10 New not drilled: 0 Temp. abandoned:1 Plugged: 2 Total: 13	Active:76 New not drilled: 0 Temp. abandoned: 1 Plugged: 8 Total: 85	Active: 5,308 New not drilled yet: 71 Temp. abandoned: 25 Plugged: 797 Total: 6,201

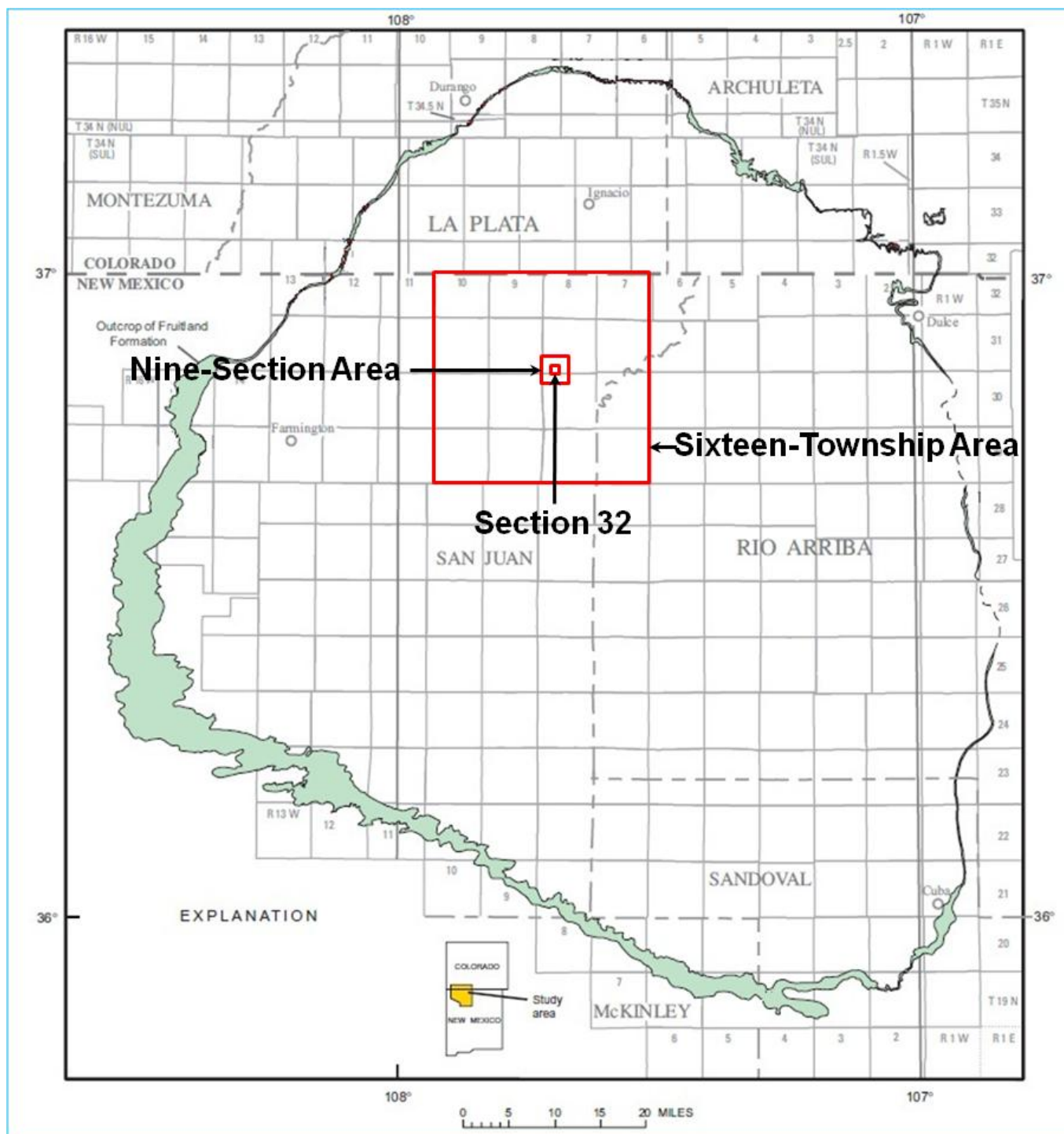


Figure 17: Map of San Juan Basin showing the three Site Reference Areas used in the quantitative risk assessment (modified from Ayers 1994).

3.5.3 One-Section Area

A satellite map of Section 32 is shown in **Figure 18**. An analysis of Section 32 indicates that the Site is suitable for CO₂ injection, but has limitations. The advantages are:

- No residences (zero population density).
- No human activities other than CBM production.
- No buildings other than small utility sheds.
- No agricultural activities.
- No surface water.
- No primary underground sources of drinking water (USDWs), only secondary.
- Minimal flora and fauna.
- No endangered species habitats or wetlands.
- State owned land.
- Major CO₂ pipeline within 5 km (3 mi) of the Site and an existing 102 mm (4-inch) diameter line to the Site.
- Well characterized site with 3D seismic surveys, multiple well logs and baseline studies.
- No reported local earthquakes.
- No significant faults.
- Thick, low-permeability, laterally continuous caprock formation (Kirtland shale)
- Laterally continuous reservoir (Fruitland coal seams) with dip of less than 1%.
- Unmineable coal seams at an acceptable depth and thickness for CO₂-ECBM (part of the CBM high-productivity fairway).
- CBM production nearing completion in the next 5 to 10 years, approximately 89% of the original methane in place already recovered.

The disadvantages are:

- The site is limited in area and insufficient for anything but a small CO₂ demonstration test.
- The Fruitland coal is saturated with up to 159,000 t (175,000 ST) of adsorbed natural CO₂ and would need to be repressurized to store more CO₂.
- Repressurization may be difficult because CO₂ adsorption causes the coal matrix to swell and reduce permeability.
- CO₂ injection may be limited to less than 17,000 t (323 MMSCF) of CO₂ per year per well due to coal matrix swelling and permeability reduction.



Figure 18: Satellite map of Section 32 (one (1) square mile) showing the location of the CO₂ injection well and three CBM producer wells (modified from Google Earth 2013).

3.5.4 Nine-Section Area

Expanding the analysis to the Nine-Section Area, (shown in **Figures 19 and 20**), presents additional aspects:

- The Simon Canyon Area of Critical Environmental Concern (ACEC) is located in the three (3) eastern sections and contains riparian ecological systems, a high profile recreation area, and archaeological sites
- Canyon topography in the area could facilitate CO₂ accumulation if a leak occurs
- The Quintana natural spring is located in the northeast section and could be a natural outlet for CO₂ leakage
- Eighty-five (85) existing deep wells penetrate the primary seal in the area.
- Coal seams in the area are saturated at current reservoir pressure with up to 1.4 Mt (1.54 million ST) of adsorbed natural CO₂.
- Existing natural CO₂ would likely complicate compliance with the USEPA CO₂ storage verification requirements.

These aspects are not project critical, but would add additional permitting requirements due to potential public concerns.

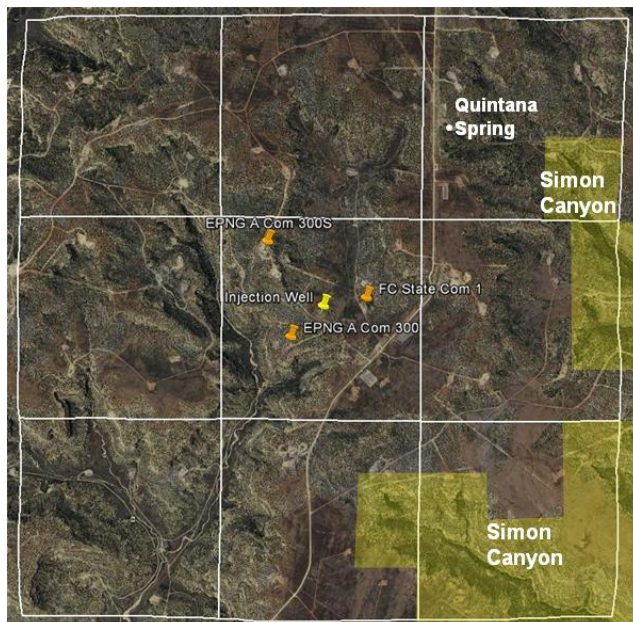


Figure 19: Satellite map of the Nine-Section Area (modified from Google Earth 2013).

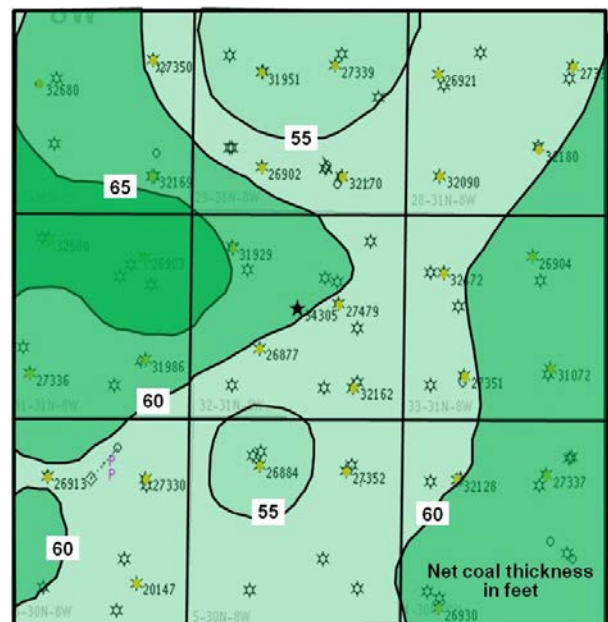


Figure 20: Net coal thickness and well locations in the Nine-Section Area (Modified from ARI 2010).

3.5.5 Sixteen-Township Area

Expanding the area of reference to Sixteen-Townships, (shown in **Figures 21 and 22**), provides the following project critical observations:

- The San Juan River is located 5 km (3 mi) south of the CO₂ injection Site, and is designated “Quality Water” for trout fishing.
- The Navajo Lake State Park (Navajo Reservoir) is located 6 km (4 mi) east of the CO₂ injection Site.
- The Animas River is located 18 km (11 mi) northwest of the CO₂ injection Site.
- Navajo Dam is located 10 km (6 mi) southwest of the CO₂ injection site.
- The San Juan Basin structural hingeline and associated fault zone are located 10 km (6 mi) and 3 km (2 mi) respectively south of the CO₂ injection Site (**Ayers 1994**).
- The fault zone underlies the communities of Navajo Dam (population 281) and Turley (population 443) and the San Juan and Animas Rivers.
- Methane seeps have been observed along the San Juan and Animas River valleys since 1880 (**Finch 1996**).
- The community of Cedar Hill (population 847) is located 19 km (12 mi) northwest of the CO₂ injection Site.
- There are agricultural areas near Cedar Hill along the Animas River.
- There are small anticlines and synclines in the area that have associated fracture zones.
- The Fruitland and Upper Pictured Cliffs Formations form a single hydrogeologic unit and are recharged by artesian effect from the north end of the basin where the Fruitland Formation outcrops at higher elevation. North of the New Mexico/Colorado state line, the Fruitland Formation fluid complies with the USDW quality specification of less than 10,000 mg/L total dissolved solids.
- There are areas of upward hydrologic flow through the Fruitland and Kirtland Formations that correspond to potentiometric groundwater mounds.
- The Federal government owns more than 80% of the coal in the area and approximately 70% of the surface land (**Fassett 2000**).
- Coal seams are very heterogeneous with pinchouts, local fault truncations, channel scour and facies changes. Lateral continuity of subsurface coals over distances of a mile is speculative at best. Although coal seams may appear continuous based on well logs, they may be discontinuous (**ARI 2010**).
- The number of coal seams in the area varies from less than 6 to as many as 16.
- There are 6,201 deep wells in the area (well density of approximately 11 wells per section). State regulations restrict the density of Fruitland Formation wells to 1 per 160 acres (4 wells per section).

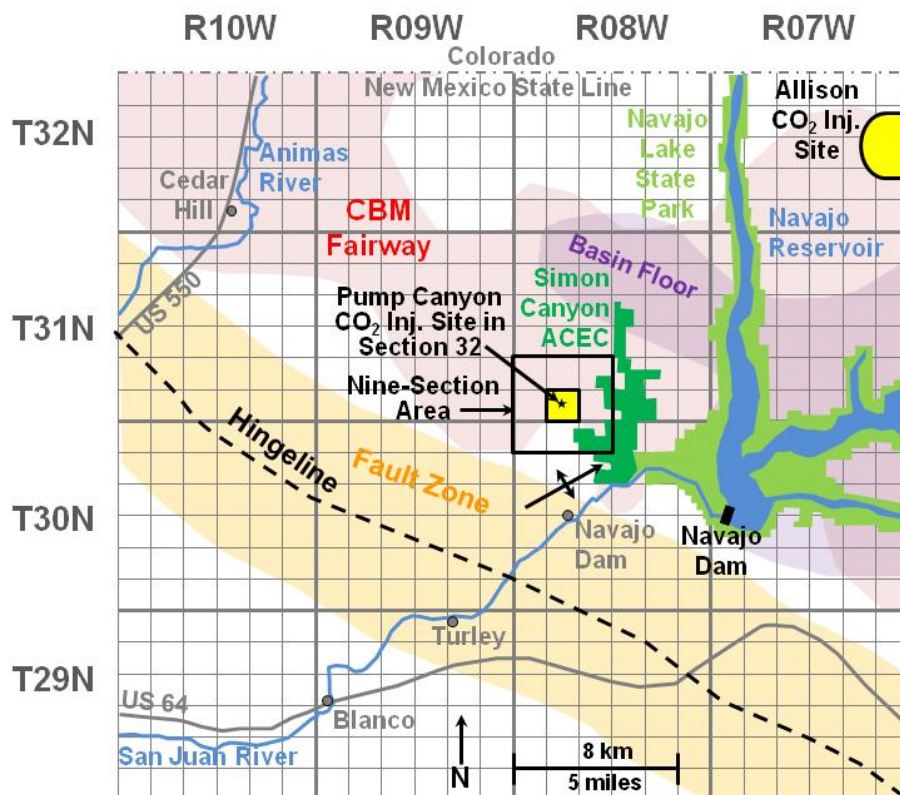


Figure 21: Map of surface and subsurface features in the Sixteen-Township Area

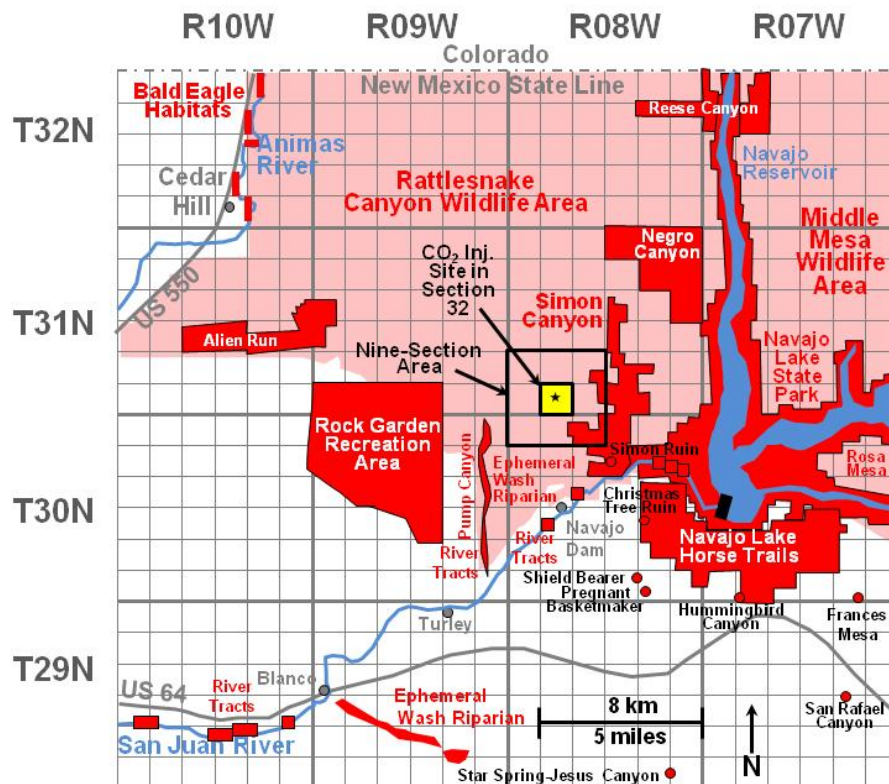


Figure 22: Map of Specially Designated Areas in the Sixteen-Township Area

3.5.6 Results

The deliverables developed to support this quantitative risk assessment are: a site-specific QFMEA model, prioritized lists of risks, list of potential fatal risks, economic analyses (financial models and cost factors) and process-level mass balance model with history match and projections. Over 400 risk areas were evaluated in the QFMEA model. The Pump Canyon QFMEA model is in **Appendix F**. The top ranking 25 risks, based on risk priority number, are listed in **Table 35**.

Table 35: Top 25 prioritized risk areas for the San Juan Basin Pump Canyon Site

Line No.	San Juan Basin Pump Canyon CO2-ECBM Site Prioritized Risks			Risk Ranking			
	Index #	Risk Area/FEP	Potential Failure Mode	Failure Probability (P = 1 to 5)	Failure Severity (S = 1 to 5)	Difficulty of Failure Detection (D = 1 to 5)	Risk Priority Number (P x S x D = 1 to 125)
1	03.02.11.03.	ECBM coal swelling	Decrease in CO2 injectivity.	5	5	2	50
2	03.02.11.18.	ECBM coal seam permeability	Decreased CO2 injectivity and decreased CH4 production.	5	5	2	50
3	04.01.08.04.	Reservoir permeability and injectivity	Decreased CO2 injectivity and decreased CH4 production.	5	5	2	50
4	02.01.02.00.	CO2 quantities, injection rate	CO2 injection wells unable to keep up with planned injection rate	5	5	2	50
5	06.03.06.00.	Buildings	Human injury/death resulting from migration of CO2/CH4 into unventilated confined spaces. Foundation cracking due to subsidence or uplift.	3	4	3	36
6	03.03.06.00.	CO2 release processes	Human injury/death resulting from: Blowout or rupture (rapid release of CO2/CH4). Leak (moderate release of CO2/CH4).	3	4	3	36
7	06.01.01.00.	Topography and morphology	Human injury/death resulting from accumulation of CO2 in low surface areas or CO2/CH4 in confined spaces without sufficient ventilation.	3	4	3	36
8	07.02.03.00.	CO2 release to the atmosphere	Human injury/death resulting from: Accumulation of CO2 in low surface areas with insufficient wind. Accumulation of CO2/CH4 in unventilated confined spaces.	3	4	3	36
9	04.01.01.00.	Geographical location	Siting the project in a high-risk area. Human injury/death.	3	4	3	36
10	03.02.11.16.	ECBM complex structural geology of coal seams	Compartmentalization. Poor CO2 sweep efficiency. Decreased CH4 recovery. Leakage of CO2/CH4 into overlying formations if coal seams are repressurized.	4	3	3	36
11	04.01.04.08.	Reservoir and caprock structural geology complexity	Compartmentalization. Poor CO2 sweep efficiency. Decreased CH4 recovery. Leakage of CO2/CH4 into overlying formations if coal seams are repressurized.	4	3	3	36
12	04.01.11.00.	Fractures and faults	Reactivation of a dormant fault. CO2/CH4 leakage through a fault or fracture zone.	4	3	3	36
13	04.01.06.00.	Caprock or sealing formation	CO2/CH4 migration through caprock.	4	3	3	36
14	04.01.12.00.	Undetected features	CO2/CH4 leakage through an undetected fracture/fault zone, borehole, high permeability zone or other feature.	4	3	3	36
15	07.01.01.00.	Loss of containment	Migration of CO2/CH4 into overlying formations, soil, aquifers and/or atmosphere.	4	3	3	36
16	03.03.01.01.	Fault valving and reactivation	CO2/CH4 leakage through a valving or reactivated fault.	4	3	3	36
17	03.02.11.20.	ECBM coal seam heterogeneity	Compartmentalization. Poor sweep efficiency. Decreased CH4 recovery. Decreased CO2 storage capacity.	4	4	2	32
18	04.01.04.03.	Reservoir lateral continuity (spatial distribution)	Compartmentalization. Poor sweep efficiency. Decreased CH4 recovery. Decreased CO2 storage capacity.	4	4	2	32
19	04.01.04.09.	Reservoir compartmentalization	Pore CO2 sweep efficiency. Decreased CBM recovery. Decreased CO2 storage	4	4	2	32
20	03.02.11.27	ECBM coal plasticization	Irreversible significant decreased permeability. Decreased CO2 adsorption.	3	5	2	30
21	03.02.09.00.	Reservoir water chemistry	Scale buildup and salt precipitation.	5	3	2	30
22	03.02.13.02.	Precipitation of carbonate minerals (scale buildup)	Well and equipment plugging. Pore plugging.	5	3	2	30
23	03.02.13.03.	Salt precipitation	Well and equipment plugging. Pore plugging.	5	3	2	30
24	16.01.00.	Caprock Permeability	CO2/CH4 migration through high permeability zone in caprock.	3	3	3	27
25	16.03.00.	Accidents and unplanned events (02.01.09.00.)	Human injury/death. Facilities / equipment damage. CO2/CH4 release.	3	4	2	24

The top four (4) risk areas (ECBM swelling; ECBM coal seam permeability; reservoir permeability and injectivity; and CO₂ quantities and injection rate) are interrelated technical risks that impact economics rather than safety or the environment. These risks would likely make CO₂-ECBM uneconomic at this site.

The next four (4) risk areas (buildings; CO₂ release processes; topography and morphology; and CO₂ release to the atmosphere) are interrelated and impact safety associated with the buildup of CO₂ and/or methane on the surface to toxic or explosive concentrations that could lead to human injury or death.

The ninth risk area (geographical location) identified sensitive receptors such as human beings in close proximity to the Site. There are four (4) communities located inside the Sixteen-Township Area and two (2) of those communities are located on a fault zone that could be associated with historical methane seeps.

Risk areas 10 through 17 (ECBM complex structural geology of coal seams; reservoir and caprock structural geology complexity; fractures and faults; caprock or sealing formation; undetected features; loss of containment; fault valving and reactivation; and caprock permeability) are related to containment. They could contribute to CO₂/methane leakage or migration into overlying formations or aquifers.

Risk areas 18 through 20 (ECBM coal seam heterogeneity; reservoir lateral continuity; and reservoir compartmentalization) impact project economics. They decrease CBM recovery and CO₂ storage.

Risk area 21 (ECBM coal plasticization) could have a significant economic impact. It is not known if plasticization played a role in reducing permeability during the Pump Canyon CO₂-ECBM test. Not much is known about this reaction of CO₂ contributing to coal plasticization. The Pump Canyon bottomhole injection pressure and temperature appeared to be in the range of coal plasticization. The reduction in coal permeability appeared to be greater at the Pump Canyon Site than at the Allison Unit Site, which operated at lower bottomhole injection pressures. The significance of coal plasticization is that the permeability reduction may be irreversible.

Risk areas 22 through 24 (reservoir water chemistry; precipitation of carbonate minerals; and salt precipitation) are interrelated technical risks that impact project economics due to increased maintenance for cleaning out scale and salt buildup. This becomes important in low-pressure CBM wells, because produced water exits as water vapor and leaves precipitates behind. Risk 25 (Accidents and unplanned events) are related to project economics and human safety. They tend to occur on the surface, and therefore are easier to detect than subsurface events.

There are thirty-four (34) risk areas that potentially result in fatal injuries as listed in **Table 36**. Seven (7) risk areas have an "unlikely" probability of a fatality occurring. Twenty-six (26) risk areas have an "extremely unlikely" probability, and one (1) risk area has an "incredible" probability. All of the top thirteen (13) risk areas involve potential release of CO₂ and methane. Deep subsurface gas leakage may occur through wells, faults, fracture zones or high permeability areas in the caprock. Near surface or surface release may occur through damaged or defective pipelines or equipment.

Table 36: Potentially fatal risk areas for the San Juan Basin Pump Canyon Site

Line No.	San Juan Basin Pump Canyon CO2-ECBM Site Potential Fatal Risks			Risk Ranking			
	Index #	Risk Area/FEP	Potential Failure Mode	Failure Probability (P = 1 to 5)	Failure Severity (S = 1 to 5)	Difficulty of Failure Detection (D = 1 to 5)	Risk Priority Number (P x S x D = 1 to 125)
1	03.03.06.00.	CO2 release processes	Human injury/death resulting from: Blowout or rupture (rapid release of CO2/CH4). Leak (moderate release of CO2/CH4). CO2/CH4 diffusion through soil (slow release of CO2/CH4).	3	4	3	36
2	06.01.01.00.	Topography and morphology	Human injury/death resulting from accumulation of CO2 in low surface areas or CO2/CH4 in confined spaces without sufficient ventilation.	3	4	3	36
3	06.03.06.00.	Buildings	Human injury/death resulting from migration of CO2/CH4 into unventilated confined spaces. Foundation cracking due to subsidence or uplift.	3	4	3	36
4	07.02.03.00.	CO2 release to the atmosphere	Human injury/death resulting from: Accumulation of CO2 in low surface areas with insufficient wind. Accumulation of CO2/CH4 in unventilated confined spaces.	3	4	3	36
5	04.01.01.00.	Geographical location	Siting the project in a high-risk area. Human injury/death.	3	4	3	36
6	16.01.00.	Accidents and unplanned events (02.01.09.00.)	Human injury/death. Facilities / equipment damage. CO2/CH4 release.	3	4	2	24
7	16.03.00.	Excavation/drilling	Pipeline damage. Human injury/death. CO2/CH4 release (HSE hazard).	3	4	2	24
8	16.27.00	Explosions and crashes (01.03.10.00.)	Damage to surface facilities. Multiple human injury/death.	2	5	2	20
9	07.04.01.00.	Health effects of CO2	Human injury/death due to accumulation of CO2 in unventilated low lying or confined areas.	2	4	2	16
10	07.04.01.01.	Elevated CO2 in air	Human injury/death due to accumulation of CO2 in unventilated low lying or confined areas.	2	4	2	16
11	07.04.02.00.	Toxicity of contaminants	Human injury/death due to accumulation of CO2/CH4 in confined spaces or low lying areas.	2	4	2	16
12	16.02.00.	Moving equipment	Facilities / equipment damage. Human injury/death. CO2/CH4 release (HSE hazard).	2	4	2	16
13	16.04.00.	Defective equipment	Human injury/death. Facilities / equipment damage. CO2/CH4 release (HSE hazard).	2	4	2	16
14	16.05.00.	Use of power tools	Human injury/death.	2	4	2	16
15	16.06.00.	Contact with rotating equipment	Human injury/death. Equipment damage.	2	4	2	16
16	16.07.00.	Working near pinch points	Human injury/death.	2	4	2	16
17	16.08.00.	Working in confined areas	Human injury/death.	2	4	2	16
18	16.09.00.	Working in high places	Human injury/death.	2	4	2	16
19	16.10.00.	Working in trench/ditch	Human injury/death.	2	4	2	16
20	16.11.00.	Working under a lifted load	Human injury/death.	2	4	2	16
21	16.14.00.	Contact with hot surface, or exposure to heat or flame	Human injury/death.	2	4	2	16
22	16.17.00.	Exposure to hazardous materials	Human injury/death.	2	4	2	16
23	16.18.00.	Struck by object or flying debris	Human injury/death.	2	4	2	16
24	16.19.00.	Release of compressed gases or liquids	Human injury/death.	2	4	2	16
25	16.20.00.	Ignition of flammable gases or liquids	Human injury/death. Facilities / equipment damage.	2	4	2	16
26	16.21.00.	Trips, slips and falls	Human injury/death.	2	4	2	16
27	16.23.00.	Head bumping	Human injury/death.	2	4	2	16
28	16.24.00.	Overexertion from manual heavy lifting, pulling, or pushing	Human injury/death.	2	4	2	16
29	16.25.00.	On-road driving	Human injury/death. Vehicle / property damage.	2	4	2	16
30	16.26.00.	Off-road driving	Human injury/death. Vehicle / property damage.	2	4	2	16
31	16.28.00.	Electric shock	Human injury/death.	2	4	2	16
32	01.01.03.00.	Seismicity (Natural earthquakes)	Damage to borehole, equipment, pipeline, caprock, or reservoir. Human injury/death.	2	4	1	8
33	05.02.03.00.	Blowouts	Human injury/death. Fire.	2	4	1	8
34	01.01.07.00.	Bolide impact (meteorite impact)	Bolide impact causing caprock failure, destruction of surface facilities, human injury/death.	1	5	1	5

Release of gas (CO₂ and/or methane) is unlikely to cause human endangerment unless the gas accumulates in a low lying area (in the case of CO₂ release) or in an unventilated confined space (in the case of CO₂ and/or methane). CO₂ is toxic or asphyxiating in concentrations greater than 4%. Methane is flammable or explosive in concentrations within the range of 5 to 15%.

The probability of methane deep subsurface release is more likely than a CO₂ release as coal has a higher affinity for CO₂ than methane. Approximately 99% of the CO₂ is adsorbed on the coal matrix and only 1% is likely to be in gas form in the cleat porosity of the coal. Methane seeps have been observed in the San Juan River and Animas River areas dating back to the 1880s. Methane is present in all of the formations overlying the Fruitland Formation and in several of the underlying formations. It will be difficult to determine if methane released to the atmosphere came from the Fruitland Formation or another formation.

Risk areas 14 through 31 are typical for oil and gas production or similar heavy industries and not necessarily attributable to CO₂/methane release. Risk area 32 refers to fatalities in a natural earthquake and may not be attributable to CO₂-ECBM operation. Blowouts, listed as risk area 33, are extremely unlikely considering the low-pressure operation of CO₂-ECBM. Risk area 34, bolide impact, has an "incredible" probability and fatalities would not be attributable to CO₂-ECBM.

CO₂-ECBM and CBM financial models were developed to analyze economics. Performance and cost data in the public domain was used to develop cost factors for the models. Input into the CO₂-ECBM financial model includes the amount of CO₂ purchased each year, performance data for injection and production wells and cost factors for capital and operating costs. The model determines how many wells will be needed and calculates annual performance, expansion capital, revenues, operating costs and gross margin. The model also includes production, recovery and recycling of CO₂.

Input into the CBM financial model includes the number of CBM wells, their performance without CO₂ enhancement, and cost factors for capital expansion and operating costs. The model calculates the comparable values to the CO₂-ECBM model. As a mature brownfield site, it was assumed the original CBM capital costs have been fully depreciated and recovered prior to this assessment.

CO₂-ECBM and CBM financial models were run for the One-Section, Nine-Section, and Sixteen-Township Areas. Examples of the CO₂-ECBM and CBM financial model outputs for the Nine-Section Area are summarized in **Tables 37 and 38**, respectively.

Table 37: CO₂-ECBM financial model output for the Nine-Section Area

CO ₂ -ECBM FINANCIAL MODEL											
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Year (#)	0	1	2	3	4	5	6	7	8	9	10
PERFORMANCE PARAMETERS											
CO ₂ purchased (t/y)	0	236,000	236,000	236,000	236,000	236,000	236,000	236,000	236,000	236,000	236,000
Estimated CO ₂ produced and recycled (t/y)	0	32,765	62,011	66,911	67,050	66,334	65,533	64,790	64,126	63,537	63,015
CO ₂ injected (t/y)	0	268,765	298,011	302,911	303,050	302,334	301,533	300,790	300,126	299,537	299,015
Calculated CO ₂ produced and recycled (t/y)	0	32,765	62,011	66,911	67,050	66,334	65,533	64,790	64,126	63,537	63,015
Number of production wells (#)	36	20	18	18	18	18	18	18	18	18	18
Number of injection wells (#)	0	16	18	18	18	18	18	18	18	18	18
Total number of active wells (#)	36	36	36	36	36	36	36	36	36	36	36
Number of new wells (#)	0	0	0	0	0	0	0	0	0	0	0
Number of well conversions (#)	0	16	18	18	18	18	18	18	18	18	18
CH ₄ production from CBM (MCF)	1,202,652	591,304	470,974	416,812	368,878	326,457	288,915	255,689	226,285	200,262	177,232
CH ₄ production from ECBM (MCF)	0	1,277,306	1,416,297	1,439,585	1,440,245	1,436,842	1,433,036	1,429,504	1,426,349	1,423,550	1,421,069
Total CH ₄ production (MCF)	1,202,652	1,868,610	1,887,271	1,856,396	1,809,123	1,763,300	1,721,950	1,685,194	1,652,634	1,623,812	1,598,301
Water production (Barrels)	962	1495	1840	1877	1850	1815	1781	1750	1723	1699	1678
In situ CO ₂ production (MCF)	400,884	622,870	156,991	138,937	122,959	108,819	96,305	85,230	75,428	66,754	59,077
Injected CO ₂ production (MCF)	0	0	1,021,845	1,133,038	1,151,668	1,152,196	1,149,474	1,146,428	1,143,604	1,141,079	1,138,840
Total CO ₂ production (MCF)	400,884	622,870	1,178,836	1,271,975	1,274,627	1,261,015	1,245,779	1,231,658	1,219,032	1,207,833	1,197,917
Total gas production (MCF)	1,603,536	2,491,479	3,066,107	3,128,371	3,083,750	3,024,315	2,967,729	2,916,852	2,871,666	2,831,645	2,796,218
CH ₄ in produced gas (vol. %)	75	75	62	59	59	58	58	58	58	57	57
CO ₂ in produced gas (vol. %)	25	25	38	41	41	42	42	42	42	43	43
CAPITAL EXPENDITURES											
Permitting (\$)	272,000	34,000	0	0	0	0	0	0	0	0	0
Hot tap into CO ₂ pipeline (\$)	100,000	0	0	0	0	0	0	0	0	0	0
CO ₂ trunk pipeline (\$)	1,200,000	0	0	0	0	0	0	0	0	0	0
CO ₂ lateral pipeline (\$)	1,800,000	0	0	0	0	0	0	0	0	0	0
CO ₂ distribution lines (\$)	800,000	100,000	0	0	0	0	0	0	0	0	0
New well drilling & completion (\$)	0	0	0	0	0	0	0	0	0	0	0
Converted wells (\$)	2,560,000	320,000	0	0	0	0	0	0	0	0	0
Recycled gas compression and dehydration (\$)	2,200,000	0	0	0	0	0	0	0	0	0	0
Total capital expenditures (\$)	8,932,000	454,000	0	0	0	0	0	0	0	0	0
REVENUE											
CH ₄ sales (MCF)	1,142,519	1,775,179	1,792,907	1,763,576	1,718,667	1,675,135	1,635,853	1,600,934	1,570,002	1,542,621	1,518,386
CH ₄ sales (\$)	4,570,078	7,100,716	7,171,629	7,054,305	6,874,669	6,700,538	6,543,411	6,403,737	6,280,009	6,170,486	6,073,544
Total revenues (\$)	4,570,078	7,100,716	7,171,629	7,054,305	6,874,669	6,700,538	6,543,411	6,403,737	6,280,009	6,170,486	6,073,544
OPERATING EXPENSES											
Purchased CO ₂ cost (\$)	0	7,627,520	7,627,520	7,627,520	7,627,520	7,627,520	7,627,520	7,627,520	7,627,520	7,627,520	7,627,520
Well O&M (\$)	432,000	432,000	432,000	432,000	432,000	432,000	432,000	432,000	432,000	432,000	432,000
Injection well CO ₂ maintenance (\$)	0	67,191	74,503	75,728	75,763	75,584	75,383	75,198	75,032	74,884	74,754
Produced gas processing (\$)	801,768	1,245,740	1,533,053	1,564,186	1,541,875	1,512,157	1,483,865	1,458,426	1,435,833	1,415,823	1,398,109
Recycled gas compression & dehydration	0	229,355	434,077	468,377	469,350	464,338	458,731	453,530	448,882	444,759	441,105
Water treatment and disposal (\$)	481	747	920	939	925	907	890	875	861	849	839
General & administrative costs (\$)	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Royalties (\$)	388,457	603,561	609,588	599,616	584,347	569,546	556,190	544,318	533,801	524,491	516,251
Severance & property taxes (\$)	388,457	603,561	609,588	599,616	584,347	569,546	556,190	544,318	533,801	524,491	516,251
Total operating expenses (\$)	2,511,162	11,309,675	11,821,250	11,867,981	11,816,127	11,751,598	11,690,769	11,636,184	11,587,730	11,544,818	11,506,829
GROSS MARGIN (\$)	2,058,915	-4,208,959	-4,649,621	-4,813,675	-4,941,458	-5,051,059	-5,147,358	-5,232,447	-5,307,720	-5,374,332	-5,433,285

Table 38: CBM financial model output for the Nine-Section Area

CBM FINANCIAL MODEL (NO CO ₂ INJECTION)											
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Year (#)	0	1	2	3	4	5	6	7	8	9	10
PERFORMANCE PARAMETERS											
Number of production wells (#)	36	36	36	36	36	36	36	36	36	36	36
CH ₄ production from CBM (MCF)	1,202,652	1,064,347	941,947	833,623	737,757	652,915	577,829	511,379	452,570	400,525	354,464
In situ CO ₂ production (MCF)	400,884	354,782	313,982	277,874	245,919	217,638	192,610	170,460	150,857	133,508	118,155
Total gas production (MCF)	1,603,536	1,419,129	1,255,929	1,111,498	983,675	870,553	770,439	681,839	603,427	534,033	472,619
Water production (Barrels)	962	851	754	667	590	522	462	409	362	320	284
CH ₄ in produced gas (vol. %)	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
CO ₂ in produced gas (vol. %)	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
CAPITAL EXPENDITURES											
Total capital expenditures (\$)	0	0	0	0	0	0	0	0	0	0	0
REVENUE											
CH ₄ sales (MCF)	1,142,519	1,011,130	894,850	791,942	700,869	620,269	548,938	485,810	429,942	380,499	336,741
CH ₄ sales (\$)	4,570,078	4,044,519	3,579,399	3,167,768	2,803,475	2,481,075	2,195,752	1,943,240	1,719,768	1,521,994	1,346,965
Total revenues (\$)	4,570,078	4,044,519	3,579,399	3,167,768	2,803,475	2,481,075	2,195,752	1,943,240	1,719,768	1,521,994	1,346,965
OPERATING EXPENSES											
Well O&M (\$)	432,000	432,000	432,000	432,000	432,000	432,000	432,000	432,000	432,000	432,000	432,000
Produced gas processing (\$)	801,768	709,565	627,965	555,749	491,838	435,276	385,220	340,919	301,714	267,017	236,310
Water treatment and disposal (\$)	481	426	377	333	295	261	231	205	181	160	142
General & administrative costs (\$)	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Royalties (\$)	388,457	343,784	304,249	269,260	238,295	210,891	186,639	165,175	146,180	129,370	114,492
Severance & property taxes (\$)	388,457	343,784	304,249	269,260	238,295	210,891	186,639	165,175	146,180	129,370	114,492
Total operating expenses (\$)	2,511,162	2,329,559	2,168,839	2,026,603	1,900,723	1,789,320	1,690,728	1,603,475	1,526,255	1,457,916	1,397,435
GROSS MARGIN (\$)	2,058,915	1,714,960	1,410,560	1,141,165	902,751	691,755	505,023	339,765	193,512	64,078	-50,471

A comparison of the financial model results for the three (3) Site Reference Areas is provided in **Table 39**. Sensitivity analyses were run to determine what the required CO₂ or natural gas prices would be to achieve a 3-year, 5-year and 10-year payback for CO₂-ECBM. It is clear that the price of CO₂ would have to be significantly subsidized, or the price of natural gas would have to be significantly increased to achieve an acceptable return on investment in the range of a 3-year to 5-year payback.

The CBM operation, without CO₂ injection, is profitable up to 2018 to 2021 time frame at the base case natural gas price of \$3.79/GJ (\$4/MMBTU). The price of natural gas required to keep the operation financially viable through 2022 was calculated and ranges from \$3.97-\$4.98/GJ (\$4.19-\$5.25/MMBTU) depending on the site specific conditions. The required natural gas price for an acceptable payback is greater for the Nine-Section Area and Sixteen-Township Area than the One-Section Area because of the relatively higher capital expense. The One-Section Area already has an existing CO₂ pipeline and distribution line in place.

Table 39: Comparison of financial model results for the three Site Reference Areas

	One-Section Area	Nine-Section Area	Sixteen-Township Area
CO ₂ purchased	26,000 t/y 28,660 ST/Y	236,000 t/y 260,141 ST/Y	3,150,000 t/y 3,472,222 ST/Y
Max. CO ₂ recycled	7,394 t/y 8,150 ST/Y	67,050 t/y 73,909 ST/Y	861.785 t/y 949,939 ST/Y
Max. CO ₂ injected	33,394 t/y 36,810 ST/Y	303,050 t/y 334,050 ST/Y	4,011,785 t/y 4,422,162 ST/Y
Initial number of production wells (CBM)	4	36	648
Initial number of injection wells (CBM)	0	0	0
Final number of production wells (ECBM)	2	18	324
Final number of injection wells (ECBM)	2	18	324
Land area used for CO ₂ -ECBM and CBM	2.59 km ² 1 mi ² 640 acres	23.3 km ² 9 mi ² 5,760 acres	419.4 km ^{2*} 162 mi ^{2*} 103,680 acres*
CO ₂ -ECBM capital expense	\$740,000	\$9,386,000	\$151,148,000
Cumulative CO ₂ purchased over 10 years	260,000 t 286,596 ST	2,360,000 t 2,601,411 ST	31,500,000 t 34,722,220 ST
Cumulative methane produced over 10 years with CO ₂ injection	0.054 Gm ³ 1.920 BSCF	0.496 Gm ³ 17.467 BSCF	6.993 Gm ³ 246.962 BSCF
Cumulative methane produced over 10 years without CO ₂ injection	0.021 Gm ³ 0.725 BSCF	0.185 Gm ³ 6.527 BSCF	3.330 Gm ³ 117.587 BSCF
Base case CO ₂ price	\$32.32/t \$1.70/MCF	\$32.32/t \$1.70/MCF	\$32.32/t \$1/70/MCF
Base case natural gas price	\$3.79/GJ \$4/MMBTU	\$3.79/GJ \$4/MMBTU	\$3.79/GJ \$4/MMBTU
CO ₂ price required to achieve 3-year payback at \$3.79/GJ (\$4/MMBTU) natural gas	\$2.06/t \$0.11/MCF	-\$0.25/t -\$0.01/MCF	-\$2.32/t \$12/MCF
CO ₂ price required to achieve 5-year payback at \$3.79/GJ (\$4/MMBTU) natural gas	\$5.01/t \$0.26/MCF	\$4.31/t \$0.23/MCF	\$2.95/t \$0.16/MCF
CO ₂ price required to achieve 10-year payback at \$3.79/GJ (\$4/MMBTU) natural gas	\$6.58/t \$0.35/MCF	\$7.08/t \$0.37/MCF	\$6.02/t \$0.32/MCF
Natural gas price to achieve 3-year payback at \$32.32/t (\$1.70/MCF) CO ₂ price	\$8.43/GJ \$8.89/MMBTU	\$8.74/GJ \$9.22/MMBTU	\$8.65/GJ \$9.13/MMBTU
Natural gas price to achieve 5-year payback at \$32.32/t (\$1.70/MCF) CO ₂ price	\$8.38/GJ \$8.48/MMBTU	\$8.12/GJ \$8.57/MMBTU	\$8.02/GJ \$8.46/MMBTU
Natural gas price to achieve 10-year payback at \$32.32/t (\$1.70/MCF) CO ₂ price	\$7.98/GJ \$8.42/MMBTU	\$7.90/GJ \$8.33/MMBTU	\$7.83/GJ \$8.26/MMBTU
Natural gas price for CBM operation to break even in 2022	\$4.99/GJ \$5.62/MMBTU	\$3.97/GJ \$4.19/MMBTU	\$4.06/GJ \$4.28/MMBTU

*Thirty percent of total area.

The estimated CO₂ storage capacities for the three (3) Site Reference Areas are summarized in **Table 40**. The One-Section Area and Nine-Section Area utilize 100% of the land area. The Sixteen-Township Area utilizes only 30% of the land area due to land restrictions such as communities,

rivers, reservoir, dam, transportation corridors, specially designated areas, and low capacity areas south of the structural hingeline.

Table 40: Comparison of potential adsorption capacity of Fruitland coal for additional injected CO₂ in the three Site Reference Areas

	One-Section Area	Nine-Section Area	Sixteen-Township Area
Land area utilized	2.59 km ² 1 mi ² 640 acres	23.3 km ² 9 mi ² 3,840 acres	419 km ^{2*} 162 mi ^{2*} 103,680 acres*
CO ₂ storage capacity at 2.83 MPa (411 psia)	562,239 t 619,752 ST	5 million t 5.6 million ST	82 million t 90 million ST
Number of CO ₂ injection wells required	4	36	648

*Thirty (30) percent of total land area.

3.6 Quantitative Risk Assessment of the Farnsworth Unit CO₂-EOR Site

The Farnsworth Unit Site was selected for a quantitative risk assessment because it is an early CO₂-EOR operation with features that are significantly different from the SACROC Site, (see **Table 1**).

3.6.1 Background

The Farnsworth Unit (FWU) is a partially depleted oil reservoir located in west-central Ochiltree County, Texas (shown in **Figure 23**). The Site is sparsely populated and covers an area of 51.4 km² (12,698 acres) of flat farmland. The oil field was discovered in 1955. Primary oil recovery occurred from 1956 through 1967. Secondary oil recovery lasted from 1968 through 2010. Chaparral Energy LLC (CELLC) acquired the FWU in November 2009 and Tertiary CO₂-EOR began in December 2010.

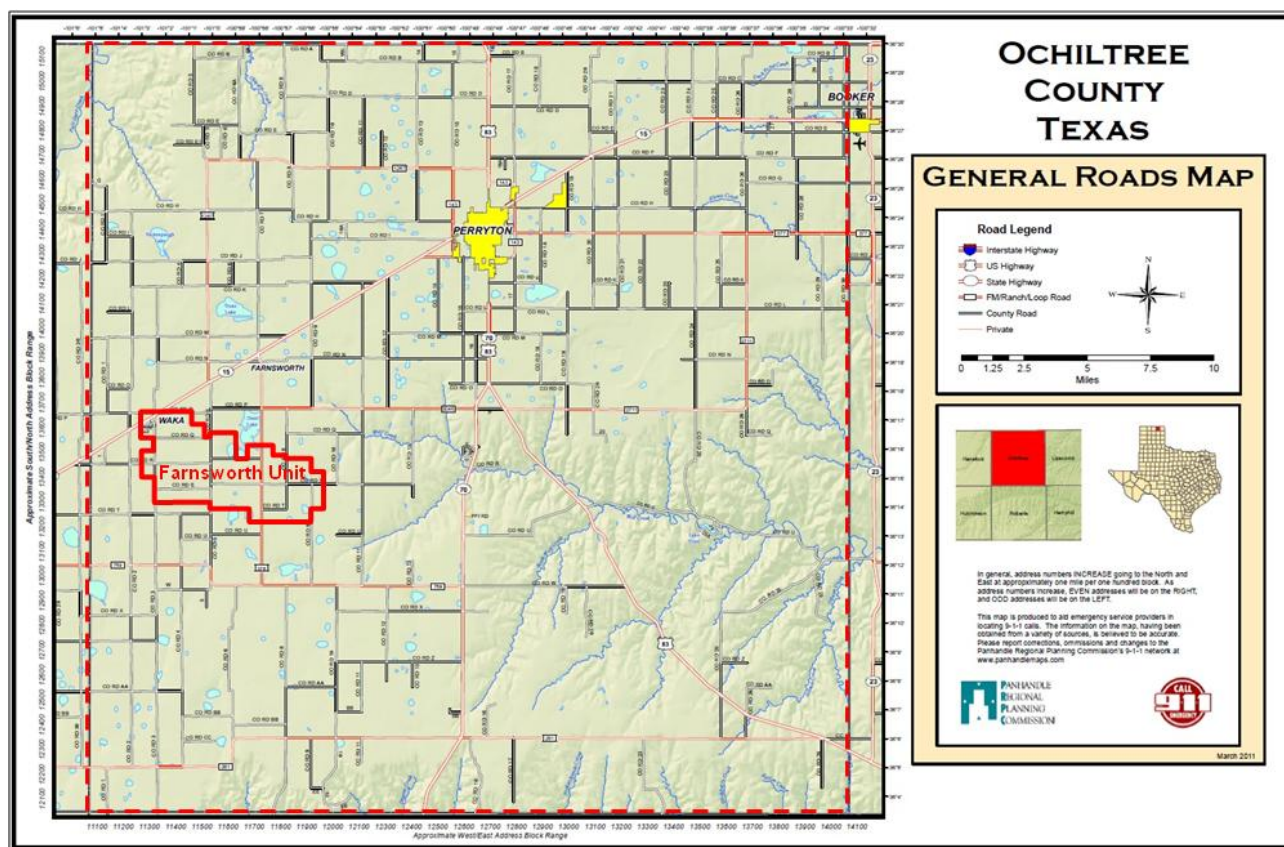


Figure 23: Location of the Farnsworth Unit within Ochiltree County, Texas (modified from PRPC 2011)

Anthropogenic CO₂ is supplied from the Arkalon ethanol plant in Liberal, Kansas. Backup CO₂ is supplied from the Agrium fertilizer plant in Borger, Texas. Both CO₂ sources are connected to the FWU Site via pipelines. CELLC has long-term CO₂ off-take agreements with Arkalon, and Agrium and owns the associated compression and pipeline facilities. The locations of the FWU, CO₂ sources and CELLC pipelines are shown in **Figure 24**.

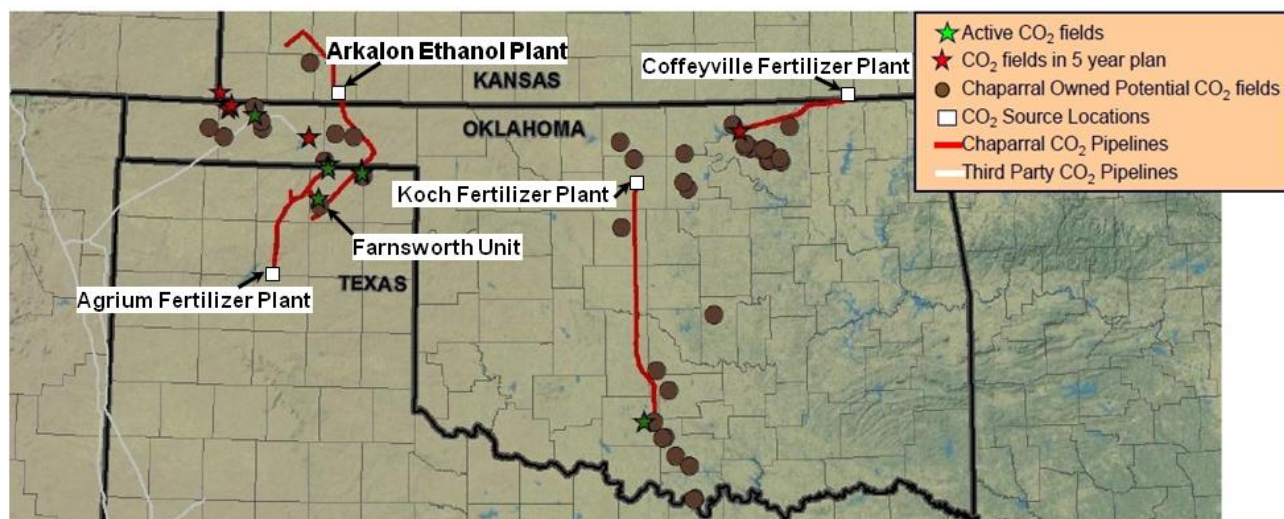


Figure 24: Location of the Farnsworth Unit relative to Chaparral Energy LLC CO₂ sources and pipelines (modified from CELLC 2013c)

The Anadarko Basin is a depositional and structural basin. It covers 150,000 km² (58,000 mi²) in parts of Kansas, Oklahoma, Colorado and Texas. It has a north-south dimension of 563 km (350 miles) and an east-west dimension of 547 km (340 miles). Its maximum thickness at the depocenter is greater than 12,192 m (40,000 ft). The thickness in Ochiltree County is 3,048 m (10,000 ft). It is bound in the South by the Wichita-Amarillo Mountains, in the East by the Nemaha Ridge, in the North by the Central Kansas Uplift, and in the West by the Las Animas Arch. Tectonic subsidence took place throughout the Paleozoic Era. Faulting in the basin peaked in Early Pennsylvanian and died out by the end of the Permian. **Figure 25** shows a structural map of the Anadarko Basin, indicating the location of the FWU Site. The basin has ultimate recoverable oil of 5.1 million barrels and ultimate recoverable gas of 3.8 Tm³ (135 TCF).

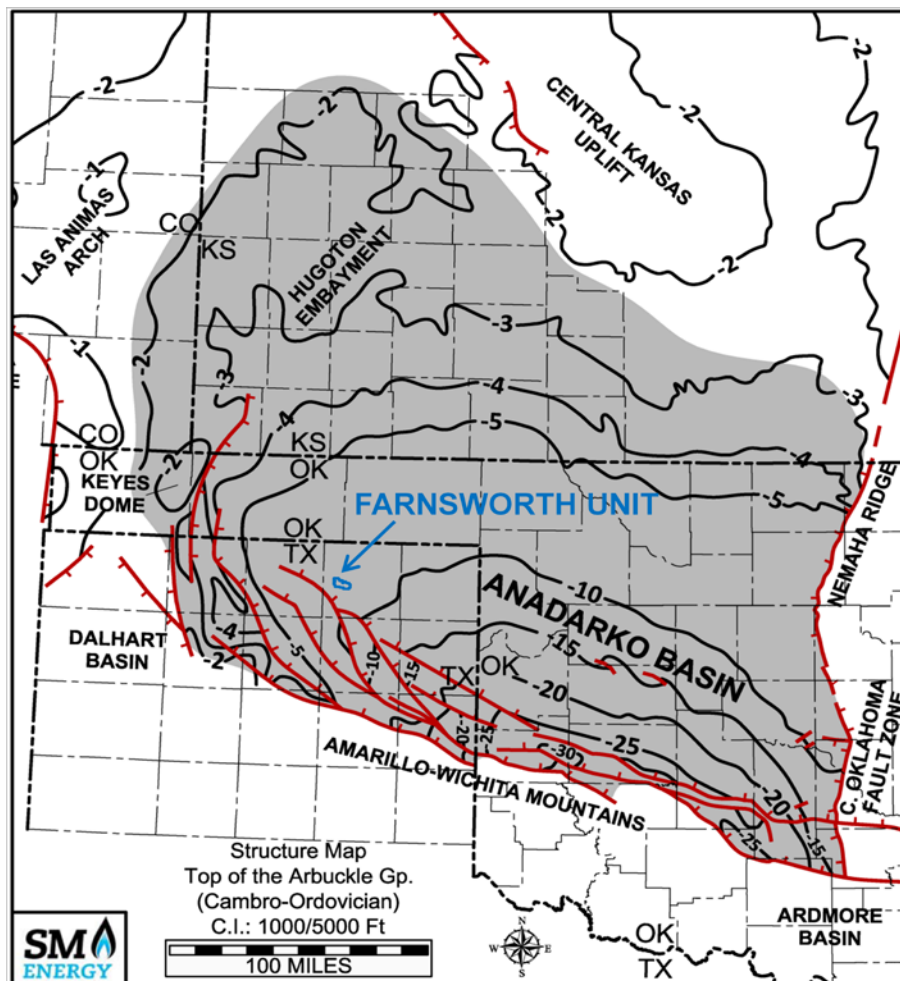


Figure 25: Location of the Farnsworth Unit within the Anadarko Basin (modified from Mitchell 2012)

The FWU reservoir consists of Upper and Lower units of the Buckhaults Sandstone of the Upper Morrow Formation. The Upper Morrow is an incised valley-fill sandstone that extends from Eastern Colorado and Western Kansas, through Oklahoma into the Texas Panhandle.

The Upper Morrow section of the FWU has five (5) sandstone members. The Buckhaults Sandstone is the most consistently developed and has been the most important petroleum producing reservoir in the field.

During the time of the Upper Morrow sand deposition, the FWU Area must have been comparatively flat. Wood fragments, brackish water fossils, black shales and large amounts of local pyrite and brackish connate waters indicate a stagnant, almost swampy environment (**Parker 1956**).

The Buckhaults Sandstone is divided into upper and lower units. The lower unit is most persistently developed across the field and is interpreted to be a braided stream deposit. The sand bodies of the upper unit are confined along the same boundaries as the lower unit, but are not as continuously developed. They are interpreted to be point-bar deposits of a meandering stream channel. These

two (2) units are generally in communication with each other, as significant shale breaks between them are encountered in only a few wells (**May 1987**).

The Upper Morrow reservoir in the FWU vary from siliceous coarse grained sandstones to gritty quartz conglomerates. The reservoir can grade vertically and laterally with great rapidity into finer or coarser sediments. Definite bedding planes are present. The matrix is composed almost entirely of kaolinitic material which contains shards of feldspar and quartz. Several of the cores observed contained phantom feldspar crystals which were entirely composed of kaolinitic material. This evidence coupled with the above mentioned shards indicate the derivation of the kaolinite to be from feldspars and the reservoir, as a whole, from original granitic type igneous rock (**Parker 1956**).

The Buckhaults sandstone is a coarse to very coarse-grained, arkose to arkosicwacke. Grain size distributions, sedimentary structure analysis, and sand-body geometry indicate that the Buckhaults was deposited in a fluvial-deltaic environment as distributary channel and distributary mouth bar sands. Depositional strike is northwest to southeast (**Munson 1994**).

The proposed source area for the Buckhaults sediments is the Amarillo-Wichita Uplift to the south. In addition the Cimarron Arch and/or Keyes Dome to the west-northwest may also have contributed sediment to the area. (**Munson 1994**).

"After deposition the Buckhaults sediments underwent a series of diagenetic alterations including: 1) dissolution of silica from volcanic quartz and detrital chert fragments; 2) alteration of detrital feldspar and formation of authigenic clays; 3) precipitation of calcite cement; and 4) development of authigenic pyrite. The dissolution of silica and alteration of feldspars served to enhance primary porosity while the authigenic clay formation and calcite cementation were deleterious to reservoir porosity and permeability." (**Munson 1994**).

The FWU reservoir has an average porosity of 15.4% (**Grigg 2012**). Horizontal permeability ranges from 20 to 3,200 mD (**May 1987**) and averages 45.2 mD (**Munson 1994**). Vertical permeability is approximately 20% of horizontal permeability (**May 1987**). Initial hydrostatic pressure was 15.19 MPa at 2,408 m depth (2203 psig at 7,900 ft depth). Initial reservoir temperature was approximately 75.6°C at 2,362 m depth (168°F at 7,750 ft depth) (**May 1987**). The current reservoir hydrostatic pressure is 24.13 to 31.72 MPa (MPa 3,500 to 4,600 psig).

Table 41 lists the stratigraphic nomenclature for the Texas Panhandle, which includes the FWU Site. **Figure 29** shows a 3D model of the FWU reservoir (including formations of Morrow, Atoka and Des Moines age) based on well logs. The reservoir and caprock structural geology is not complex. The reservoir top gently slopes from the northwest to the southeast across the FWU Site at 1.2% or 12 m/km (65 ft/mi). **Table 42** indicates the thickness and elevation of the formations in **Figure 26** at two points across the FWU Site. The Buckhaults Sandstone appears to be laterally continuous across the Site.

Table 41: Stratigraphic nomenclature for the Texas Panhandle (modified from Ball 1991)

System	Series	Unit	Comments
Quaternary	Pleistocene and recent	Alluvium	Sand , silt clay, and gravel of alluvial origin. Up to 30 m (100 ft) thick. yields small amounts of water. Forms areas of natural recharge locally (Alexander 1961).
Neogene (Tertiary)	Pliocene	Ogallala	Unconfined USDW aquifer. Unconsolidated and partially consolidated sediments of sand, silt, clay, gravel and caliche. Up to 213 m (700 ft) thick(Alexander 1961).
Permian	Guadalupe	Quartermaster Whitehorse Group	Salt, gypsum, anhydrite, red shale, and sandstone in the upper two-thirds; limestone, dolomite, and shale in the lower one-third. 1,158 m (3,800 ft) thick. Yields small amounts of water, generally saline (Alexander 1961 and USGS 2012a).
	Leonard	Blaine Cloreta Clearfork Group Wachita Wellington	
		Brown Dolomite	
		Chase Group Dolomite	
	Wolfcamp	Council Grove	
Pennsylvanian	Virgil	Virgilian	
		Hoover Sandstone	
		Heebner Shale	
		Douglas Group Sandstone	
		Tonkawa Sandstone	
	Missouri	Kansas City Group Limestone	244 m (800 ft) (Mitchell 2012)
		Cleveland Sandstone	15-30 m (50- 100 ft) thick (Hentz 2011); gas and oil present (Parker 1956)
	Des Moines	Marmaton Group Sandstone	73- 88 m (240- 290 ft) thick (Grigg 2012); gas and oil present (Parker 1956)
		Novi Limestone	155-183 m (510-600 ft) thick (Grigg 2012)
	Atoka	Thirteen Finger LS	49-79 m (160-260 ft) thick (Grigg 2012)
	Morrow	Morrow Shale	Primary seal or caprock; 24-29m (80- 95 ft thick (Grigg 2012)
		Morrow Buckhaults Sandstone and Pazourek Sandstone	Oil reservoir; 8-15 m (25-50 ft) thick (Grigg 2012)
		Morrow D Jones Sandstone and Squaw Belly Limestone	82-91 m (270- 300 ft) thick (Grigg 2012)
		Squaw Belly Limestone	99-116 m (325-380 ft) thick (Grigg 2012); gas and oil present (Parker 1956)
Mississippian	Chester	Chester Limestone	152 m (500 ft) thick (Mitchell 2012)
	Meramec	Ste. Genevieve Limestone St Louis Limestone Spergen Limestone Warsaw Limestone	396-427 m (1,300-1,400 ft) thick (Mitchell 2012)
		Osage Limestone Undifferentiated	
		Kinderhook Limestone Undifferentiated	
	Kinderhook		
Devonian	Upper	Woodford Shale (Chattanooga Shale)	0 ft thick (Mitchell 2012)
	Middle	Unconformity	0 m thick
	Lower	Unconformity	0 m thick
Silurian	Middle	Hunton Group Limestone	21-30 m (70-100 ft) thick (Mitchell 2012)
	Lower		
Ordovician	Upper	Silvan Shale	
	Upper Middle	Viola Limestone	76-81 m (250-265 ft) thick (Mitchell 2012)
	Lower Middle	Simpson Sandstone/Limestone/Shale Undifferentiated	23-27 m (75-90 ft) thick (Mitchell 2012)
		Unconformity	0 m thick
	Lower	Arbuckle Group Limestone/Dolomite (Ellenburger)	
Cambrian	Upper	Reagan Sandstone	
	Lower	Igneous and metasedimentary rocks	

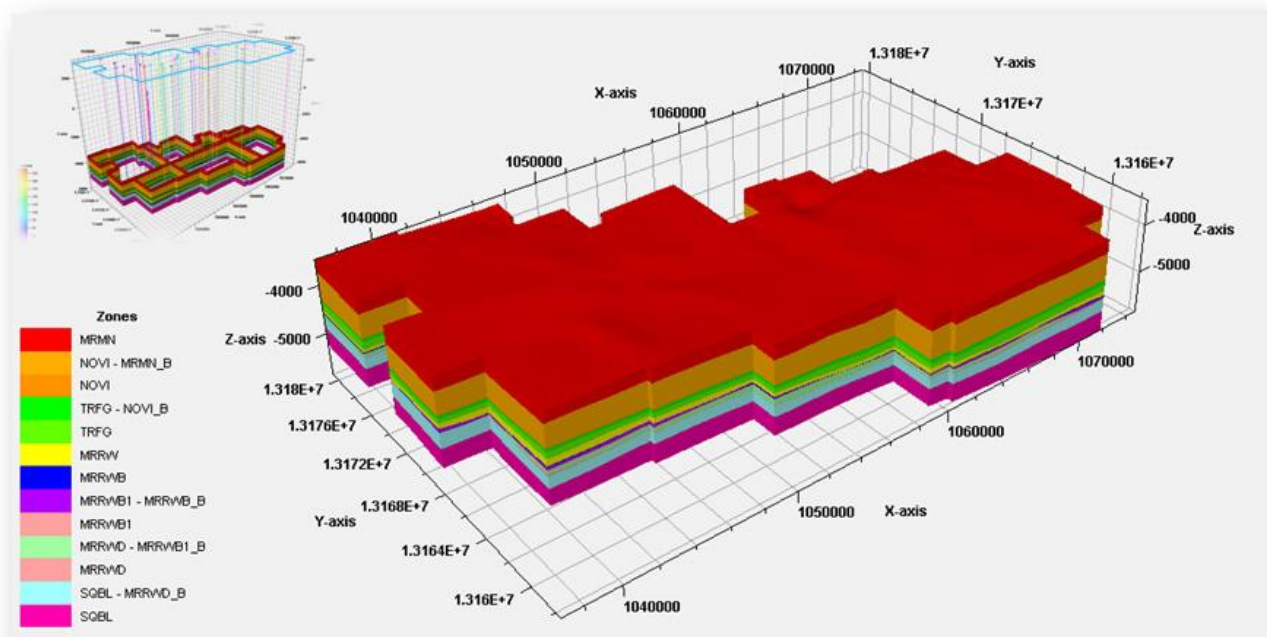


Figure 26: Geologic model of the Farnsworth Unit reservoir (Grigg 2012)

Table 42: Farnsworth Unit formation top elevations and thicknesses

Petrel Formation Code	Unit	Northwest corner of the Farnsworth Unit		Southeast corner of the Farnsworth Unit	
		Elevation of top	Thickness	Elevation of top	Thickness
MRMN	Marmaton Group Sandstone	-1067 m (-3500 ft)	73 m (240 ft)	-1219 m (-4000 ft)	88 m (290 ft)
NOVI	Novi Limestone	-1140 m (-3740 ft)	183 m (600 ft)	-1308 m (-4290 ft)	155 m (510 ft)
TRFG	Thirteen Finger Limestone	-1323 m (-4340 ft)	49 m (160 ft)	-1463 m (-4800 ft)	79 m (260 ft)
MRRW	Morrow Shale (<i>caprock</i>)	-1372 m (-4500 ft)	24 m (80 ft)	-1542 m (-5060 ft)	29 m (95 ft)
MRRWB and MRRWB1	Morrow Buckhaults Sandstone and Pazourek Sandstone (<i>oil reservoir</i>)	-1396 m (-4580 ft)	8 m (25 ft)	-1571 m (-5155 ft)	15 m (50 ft)
MRRWD and SQBL	Morrow D Jones Sandstone and Squaw Belly Limestone	-1404 m (-4605 ft)	91 m (300 ft)	-1586 m (-5205 ft)	82 m (270 ft)
SQBL	Squaw Belly Limestone	-1495 m (-4905 ft)	99 m (325 ft)	-1669 m (-5475 ft)	116 m (380 ft)

Surface elevation is 927 m (3,040 ft) above mean sea level in the northwest corner and 914 m (3,000 ft) in the southeast corner of the Farnsworth Unit.

The FWU reservoir is overlain by the Morrow Shale caprock or primary seal. The Morrow Shale appears to be laterally continuous and ranges from 24 to 29 m (80 to 95 ft) thick. The depth of the top of the Morrow Shale ranges from 1,966 to 2,134 m (6,540 to 7,000 ft) deep at the FWU Site.

The presence of an initial gas cap in the FWU reservoir indicated that the caprock provided an effective permeability barrier (**Parker 1956**). Gas and oil have been encountered in the Cleveland and Marmaton Formations above the FWU caprock and in the Squaw Belly Formation below the FWU reservoir.

Geological work suggests an east-west fault running across much of the west half of the FWU, along the southern edge of tracts 7, 8, 13 and 14. A pressure falloff test of well 13-3 conducted in 1986 showed some evidence of a barrier to flow. (**May 1987**).

There are multiple stacked seals and sinks above the Morrow Shale caprock. The seals include Permian salt, gypsum, anhydrite and red shale formations. The sinks include Pennsylvanian limestone, and sandstone formations and Permian dolomite formations.

The Ogallala aquifer is the main Underground Source of Drinking Water (USDW) at the FWU Site. Total water stored in the Ogallala within the FWU Site is estimated to be 518 Mm³ (420,000 acre-ft). The water quality ranges from 300 to 400 mg/L total dissolved solids (TDS). The Ogallala is the main source of fresh water for Ochiltree County. The main use for water at the FWU Site is irrigation of row crops. The Ogallala is unconfined on the top and is recharged from surface precipitation and irrigation water that penetrates through the soil. Annual recharge rate is approximately 12.5 mm (0.5 in). The saturated water level of the Ogallala aquifer is decreasing at a rate of 750 mm per year (30 inches per year) due to overuse.

The Ogallala consists of unconsolidated and partly consolidated sediments of Pliocene age. The bottom of the Ogallala is confined by nearly impermeable Permian red shale. The top of the Permian has low hills and wide valleys which contain deep, narrow stream channels. As the Ogallala was deposited on top of this irregular surface, the formation is very thin in some areas and very thick in others. Often this contrast occurs in relatively short distances (**Bell 1980**). Due to the presence of multiple stacked sinks and seals, there does not appear to be any hydrological connection between the Ogallala aquifer and the FWU reservoir.

The FWU Buckhaults Sandstone reservoir was discovered in October 1955 by Unocal. The Original Oil in Place (OOIP) was estimated to be 120 million Stock Tank Barrels (STB). This includes 64.93 million STB on the east side and 55.07 million STB on the west side. The original oil saturation was 0.69 and water saturation was 0.31 (**May 1987**).

Primary oil recovery (gas expansion drive), from 1956 through 1967, produced 5.67 million STB (10.3% of OOIP). Initial hydrostatic pressure averaged 15.19 MPa at 2,408 m depth (2,203 psig at 7,900 ft depth), (**May 1987**).

Secondary oil recovery (waterflooding), from 1968 to December 2010, produced 27.02 million STB (22.52% of OOIP). Starting hydrostatic pressure averaged 6.89 MPa (1,000 psig), (**May 1987**).

Tertiary oil recovery (CO₂-EOR) began in December 2010. Based on the chart in **Figure 27**, and estimated values in **Table 43**, CELLC appears to be projecting that up to 2.39 million tonnes (45.4 BSCF) of purchased CO₂ will be injected into the west side of the Farnsworth Unit and up to 7.8 million barrels of oil will be produced from 2011 through 2024 (**CELLC 2013 c**).

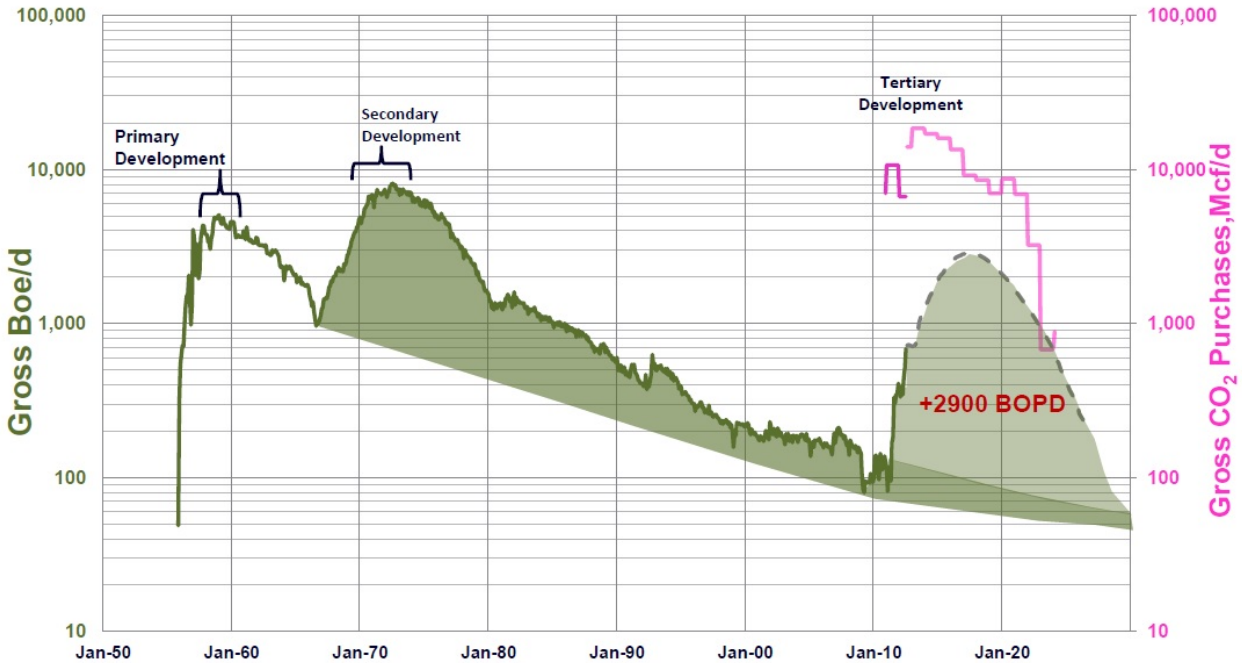


Figure 27: West Farnsworth Unit CO₂-EOR flood (CELLC 2013c)

Table 43: Projected West Farnsworth Unit CO₂ purchases and oil production (based on CELLC 2013c)

Year	Purchased CO ₂ injection				Oil production		
	(MMSCF/D)	(MMSCF/Y)	(t/y)	(HCPV/Y)	(STB/D)	(STB/Y)	(HCPV)
2010	0.0	0	0	0.0000	118	43,070	0.0008
2011	10.0	3,650	192,004	0.0244	209	76,285	0.0014
2012	8.8	3,212	168,964	0.0214	590	215,350	0.0039
2013	17.0	6,205	326,407	0.0414	1,023	373,395	0.0068
2014	16.0	5,840	307,207	0.0390	1,500	547,500	0.0099
2015	14.5	5,293	278,406	0.0353	2,200	803,000	0.0146
2016	13.0	4,745	249,605	0.0317	2,500	912,500	0.0166
2017	9.0	3,285	172,804	0.0219	2,900	1,058,500	0.0192
2018	8.5	3,103	163,204	0.0207	2,600	949,000	0.0172
2019	7.0	2,555	134,403	0.0171	2,400	876,000	0.0159
2020	9.0	3,285	172,804	0.0219	1,730	631,450	0.0115
2021	7.0	2,555	134,403	0.0171	1,300	474,500	0.0086
2022	3.1	1,132	59,521	0.0076	1,030	375,950	0.0068
2023	0.7	256	13,440	0.0017	800	292,000	0.0053
2024	0.9	329	17,280	0.0022	530	193,450	0.0035
Total		45,443	2,390,452	0.3034		7,821,950	0.1420

The projected 2.39 million tonnes of purchased CO₂ represents 0.3 Hydrocarbon Pore Volumes (HCPV) for the west side of the FWU. The projected EOR net CO₂ utilization is 5,842 SCF/STB. Southwest Partnership on Carbon Sequestration (SWP) has estimated that the FWU reservoir could store 10 million tonnes of CO₂. This represents a reservoir volume of 13.24 Mm³, which represents 0.582 HCPV or 0.4 total pore volume (SWP 2013).

There are 169 wells (**OGI 2013** and **RRC 2013**) that penetrate the FWU caprock (see **Figure 28**). These wells are categorized as:

- Active production wells: 23
- Active injection wells: 11
- Shut in wells: 53
- Plugged wells: 47
- Third-party wells (likely plugged): 35

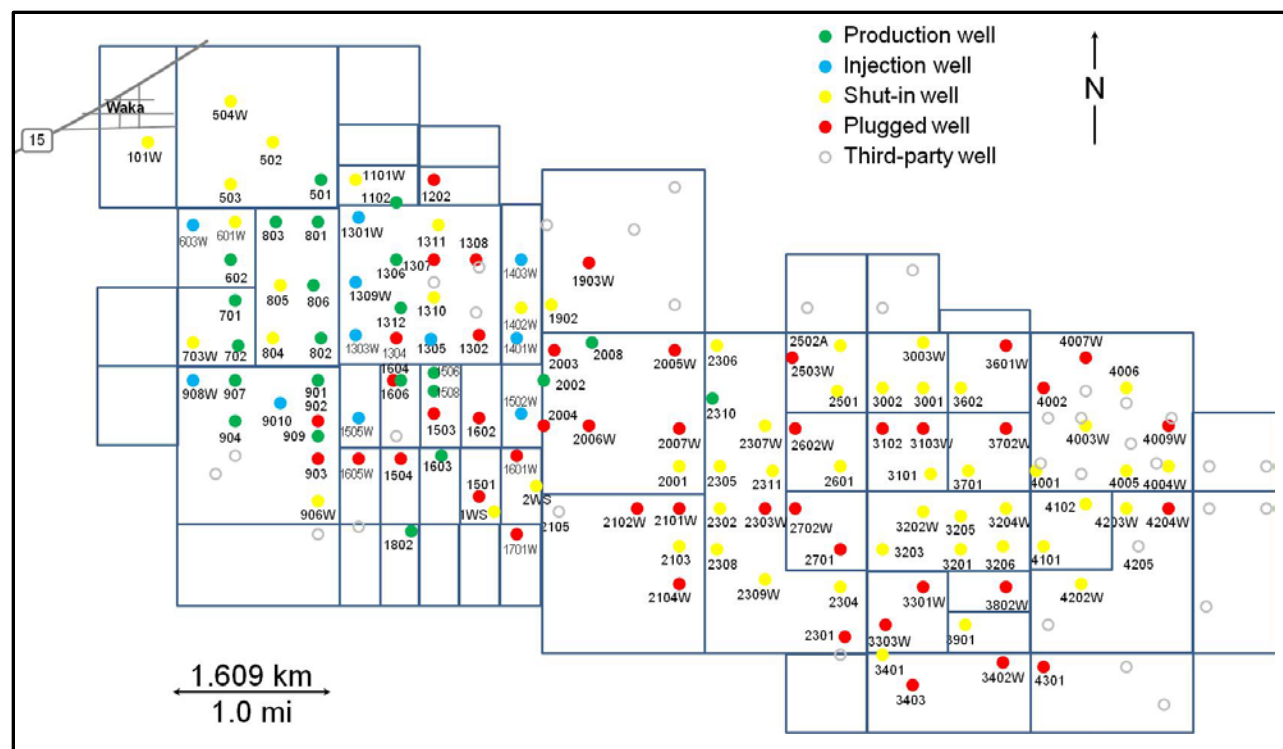


Figure 28: Locations of wells on the Farnsworth Unit Site

The FWU Site is sparsely populated as shown in **Figure 29**. The unincorporated community of Waka, Texas is located in the northwest corner of the Site. Outside of that area, there are approximately nine (9) houses and ten (10) industrial building sites scattered across the Site. **(USGS 2012 and Google Earth 2013)**. Buildings in the area typically do not have basements, but they may have storm cellars.

The FWU topography (see **Figure 30**) gently slopes from the northwest to the southeast at 0.3% or 3 m/km (15 ft/mi) from 930 m (3,050 ft) elevation to 900 m (2,950 ft) elevation. There are no significant topographic low areas that would allow CO₂, released to the atmosphere, to accumulate (**USGS 2012**).



Figure 29: Satellite map of the Farnsworth Unit (modified from Google Earth 2013)

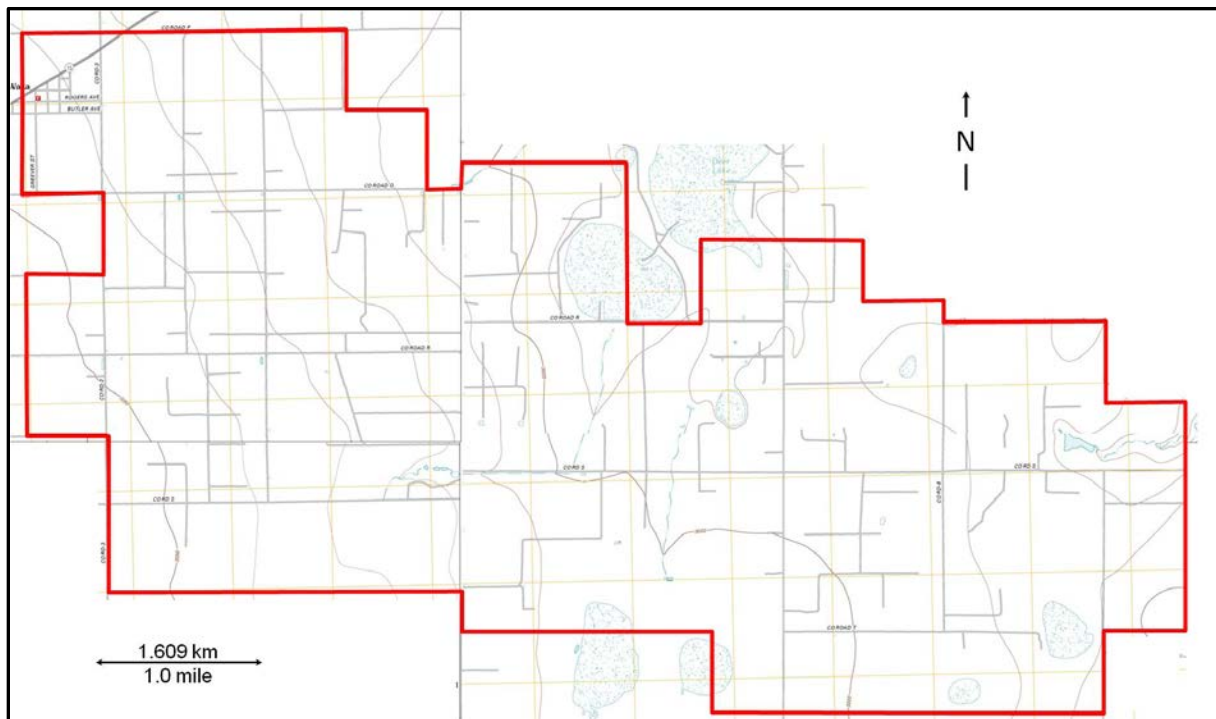


Figure 30: Surface topography of the Farnsworth Unit (modified from USGS 2012 b, c, d, & e)

Over 90% of the FWU Site is prime farmland covered with Sherm clay loam at least 2 m (80 in) thick. The main crops are sorghum, winter wheat and corn. Playa ponds (shallow ponds that fill up when it rains and evaporate when it is dry) cover 4% of the FWU Site. The bottoms of these ponds are covered with Ness clay, a somewhat impermeable soil that is typically over 2 m (80 in) thick.

The remaining 5% of the FWU Site is covered with other clay loams, similar to the Sherm clay loam. The soils at the site have low- to medium- wind and water erosion factors (**USDA 2013**).

The area is prone to tornados, hail and thunderstorms. The frequency of tornadoes is 2.3 times the national average.

The FWU Site has no:

- Sensitive receptors (schools, hospitals, prisons, care centers, churches)
- Threatened or endangered species critical habitats
- Wildlife preserves/bird sanctuaries
- National parks/monuments/forests
- Archaeological/historical/cultural sites
- Class I air quality areas
- Protected groundwater zones
- Wetlands/riparian areas
- Recreational/fishing areas
- Timberlands
- Tribal/Federal lands
- Military bases
- Heavy industrial sites/mines/quarries/tunnels
- Deep lakes/rivers/natural springs/reservoirs/dams
- Paleontology sites

3.6.2 Results

The deliverables developed to support this quantitative risk assessment are: a site-specific QFMEA model, prioritized list of risks and list of potential fatal risks. Over 400 risk areas were evaluated in the QFMEA model. The Farnsworth Unit QFMEA model is in **Appendix G**. The top ranking 25 risks, based on risk priority number, are listed in **Table 44**.

Table 44: Top 25 prioritized risk areas for the Farnsworth Unit Site

Line No.	Farnsworth Unit CO2-EOR subsurface, surface, technical and programmatic risk areas ranked by Risk Priority Number			Risk ranking			
	Index #	Risk area/FEP	Potential failure mode	Failure Probability (P = 1 to 5)	Failure Severity (S = 1 to 5)	Difficulty of Failure Detection (D = 1 to 5)	Risk Priority Number (RPN=P×S×D = 1 to 125)
1	08.03.00.	Price of oil (or other related commodities)	Oil price less than breakeven point. Arkalon ethanol plant shutdown due to low ethanol and high feedstock prices. Agrium fertilizer plant adversely impacted by low fertilizer prices.	4	4	3	48
2	08.08.00	Hedging or derivative positions	Actual oil production level below hedged production level. Counterparty default on hedging agreement obligations. Hedged price significantly below nonhedged price.	4	3	3	36
3	05.01.01.00.	Formation damage (CO2 leakage through damaged caprock near borehole)	CO2 leakage through damaged/fractured caprock near borehole. Low injectivity. Nonuniform injectivity	3	3	3	27
4	07.01.01.00.	Loss of containment	Migration of CO2 into overlying formations, soil, aquifers and/or atmosphere.	3	3	3	27
5	01.02.02.01.	Extreme weather event causing human injury/death	Tornado causing human injury/death.	3	4	2	24
6	16.01.00.	Accidents and unplanned events	Human injury/death. Facilities / equipment damage. CO2 release.	3	4	2	24
7	16.03.00.	Excavation/drilling	Pipeline damage. Human injury/death. CO2 release (HSE hazard).	3	4	2	24
8	21.08.10.	Pipeline rupture	Rapid release of CO2.	3	4	2	24
9	04.01.06.08.	Caprock fracture pressure	Caprock fracturing.	2	4	3	24
10	16.22.00.	Leaks and spills (oil spills)	Human injury. Environmental damage.	2	4	3	24
11	21.08.01.	Operator error in pipeline operation	Poor performance and/or failure of equipment/pipeline.	3	4	2	24
12	21.08.02.	Pipeline over pressuring	CO2 leak/rupture (HSE hazard).	3	4	2	24
13	03.02.03.06.	EOR oil reservoir heterogeneity	Non uniform flow of CO2/oil. Low sweep efficiency and low oil recovery.	4	3	2	24
14	03.02.03.07.	EOR hydrocarbon precipitation	Plugging of production wells and equipment.	4	3	2	24
15	16.27.00	Explosions and crashes (01.03.10.00.)	Damage to surface facilities. Multiple human injury/death.	2	5	2	20
16	21.02.03.	Pipeline failure history (for existing pipeline)	Pipeline leak	5	2	2	20
17	21.08.08.	Pipeline malfunctions	Pipeline flow interruption. Pipeline damage.	5	2	2	20
18	21.08.09.	Pipeline leak	Pipeline and property damage. Human injury/death.	5	2	2	20
19	03.02.03.05.	EOR viscosity relations	Flow stratification (fingering) in the reservoir. Decreased sweep efficiency and oil recovery.	3	3	2	18
20	03.02.03.13.	EOR injection and production well pattern and spacing	Early breakthrough of CO2. Low enhanced oil recovery.	3	3	2	18
21	04.01.05.00.	Reservoir exploitation	Pre-CO2 injection caprock or reservoir damage. Pre-existing CO2 in pore space (e.g. from EOR).	3	3	2	18
22	04.01.08.04.	Reservoir permeability and injectivity	Low sweep efficiency and low oil recovery.	3	3	2	18
23	03.02.13.05.	Desiccation of clay	Shrinking of clay particles in caprock leading to CO2 leakage.	2	3	3	18
24	03.03.01.01.	Fault valving and reactivation	CO2/brine leakage through a reactivated fault.	2	3	3	18
25	04.01.06.00.	Caprock or sealing formation	CO2 migration through caprock.	2	3	3	18

The top two (2) risk areas (price of oil and other related commodities, and hedging or derivative positions) are interrelated risks that impact project economics rather than human or environmental safety. The next two (2) risks (formation damage, and loss of containment) are subsurface risks that relate directly to CO₂ and H₂S migration through the caprock.

Risk 5, extreme weather event causing human injury/death, is specific to this Site and refers to the high level of tornado activity in the area and lack of shelter at the Site. The next three (3) risks (accidents and unplanned events, excavation/drilling, and pipeline rupture) are surface or near-surface risks that could lead to CO₂ (and H₂S) release. Risk 9, caprock fracture pressure is a subsurface risk tied to CO₂ containment. Risk 10, leaks and spills (oil spills), is a surface risk relevant to enhanced oil operations. Risk 11, EOR oil reservoir heterogeneity is a subsurface risk that impacts project economics rather than human or environmental safety. Risks 12 through 15, (explosions and crashes, pipeline failure history, pipeline malfunctions and pipeline leak) are all surface or near surface risks that may result in CO₂ release from a pipeline or surface facility.

There are thirty-eight (38) risk areas that potentially result in fatal injuries as listed in **Table 45**. Five (5) risk areas have an "unlikely" probability of fatalities occurring. Thirty-two (32) risk areas have an "extremely unlikely" probability, and one (1) risk area has an "incredible" probability.

The top five (5) risks are surface or near surface incidents that relate to on-site or off-site facilities. Risks 6 through 11 relate to accumulation of CO₂ and H₂S to hazardous levels in confined or unventilated areas. Risks 12 through 31 relate to typical industrial activities, not necessarily involving CO₂ sequestration. Risks 32 and 33 (CO₂ containing H₂S, and co-migration of other gases) would have ranked in the top four (4) risks, except it has a value of one (1) for difficulty of failure detection, as H₂S (in low concentrations) acts as an odorant for CO₂, making it easier to detect small or moderate leaks early. Risk 34, seismicity (natural earthquakes) is a natural hazard that could impact operations. Risks 35 through 37 relate to sudden, rapid, uncontrolled and/or violent release of CO₂ or hydrocarbon gases from a well, pipe or tank. Risk 38 is an "incredible" probability event of mass destruction due to a bolide (large meteorite) impact.

Table 45: Potentially fatal risk areas for the Farnsworth Unit Site

Line #	Farnsworth Unit CO ₂ -EOR subsurface, surface, technical and programmatic risk areas with potential fatalities			Risk ranking			
	Index #	Risk area/FEP	Potential failure mode	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk Priority Number (RPN=P×S×D = 1 to 125)
1	01.02.02.01.	Extreme weather event causing human injury/death	Tornado causing human injury/death.	3	4	2	24
2	16.01.00.	Accidents and unplanned events (02.01.09.00.)	Human injury/death. Facilities / equipment damage. CO ₂ release.	3	4	2	24
3	16.03.00.	Excavation/drilling	Pipeline damage. Human injury/death. CO ₂ release (HSE hazard).	3	4	2	24
4	21.08.10.	Pipeline rupture	Pipeline and property damage. Human injury/death.	3	4	2	24
5	16.27.00.	Explosions and crashes (01.03.10.00.)	Damage to surface facilities. Multiple human injury/death.	2	5	2	20
6	03.03.06.00.	CO ₂ release processes	CO ₂ release resulting in a fatality. (1) Blowout or rupture (rapid release of CO ₂). (2) Leak (moderate release of CO ₂). (3) CO ₂ diffusion through soil (slow release of CO ₂).	2	4	2	16
7	07.02.03.00.	CO ₂ release to the atmosphere	Accumulation of CO ₂ /H ₂ S in low surface areas with insufficient wind. Human injury/death.	2	4	2	16
8	07.04.01.00.	Health effects of CO ₂	Human injury/death due to accumulation of CO ₂ in unventilated low lying or confined areas.	2	4	2	16
9	07.04.01.01.	Elevated CO ₂ in air	Human injury/death due to accumulation of CO ₂ in unventilated low lying or confined areas.	2	4	2	16
10	06.03.06.00.	Buildings	Human injury/death due to migration of CO ₂ /H ₂ S into unventilated confined spaces occupied by humans.	2	4	2	16
11	07.04.02.00.	Toxicity of contaminants	Human injury/death due to accumulation of H ₂ S in unventilated low lying or confined areas	2	4	2	16
12	16.02.00.	Moving equipment	Facilities / equipment damage. Human injury/death. CO ₂ release (HSE hazard).	2	4	2	16
13	16.04.00.	Defective equipment	Human injury/death. Facilities / equipment damage. CO ₂ release (HSE hazard).	2	4	2	16
14	16.05.00.	Use of power tools	Human injury/death.	2	4	2	16
15	16.06.00.	Contact with rotating equipment	Human injury/death. Equipment damage.	2	4	2	16
16	16.07.00.	Working near pinch points	Human injury/death.	2	4	2	16
17	16.08.00.	Working in confined areas	Human injury/death.	2	4	2	16
18	16.09.00.	Working in high places	Human injury/death.	2	4	2	16
19	16.10.00.	Working in trench/ditch	Human injury/death.	2	4	2	16

Table 45: Potential fatal risk areas for the Farnsworth Unit Site (continued)

Line #	Farnsworth Unit CO2-EOR subsurface, surface, technical and programmatic risk areas with potential fatalities			Risk ranking			
	Index #	Risk area/FEP	Potential failure mode	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk Priority Number (RPN=PXSXD = 1 to 125)
20	16.11.00.	Working under a lifted load	Human injury/death.	2	4	2	16
21	16.17.00.	Exposure to hazardous materials	Human injury/death.	2	4	2	16
22	16.18.00.	Struck by object or flying debris	Human injury/death.	2	4	2	16
23	16.19.00.	Release of compressed gases or liquids	Human injury/death.	2	4	2	16
24	16.20.00.	Ignition of flammable gases or liquids	Human injury/death. Facilities / equipment damage.	2	4	2	16
25	16.21.00.	Trips, slips and falls	Human injury/death.	2	4	2	16
26	16.23.00.	Head bumping	Human injury/death.	2	4	2	16
27	16.24.00.	Overexertion from manual heavy lifting, pulling, or pushing	Human injury/death.	2	4	2	16
28	16.25.00.	On-road driving	Human injury/death. Vehicle / property damage.	2	4	2	16
29	16.26.00.	Off-road driving	Human injury/death. Vehicle /property damage.	2	4	2	16
30	16.28.00	Electric shock	Human injury/death	2	4	2	16
31	16.14.00.	Contact with hot surface, or exposure to heat or flame	Human injury/death.	2	4	2	16
32	02.01.03.01.	CO ₂ containing H ₂ S	Well/piping corrosion leading to leakage or rupture. Human injury/death.	3	4	1	12
33	03.03.07.00.	Co-migration of other gases	Human injury/death due to release of CO ₂ +H ₂ S and other gases into the atmosphere.	3	4	1	12
34	01.01.03.00.	Seismicity (Natural earthquakes)	Earthquake damage to borehole, equipment, pipeline, caprock, or reservoir.	2	4	1	8
35	04.02.03.00.	Hydrocarbons	Drilling through a methane gas pocket. Potential blowout and fire. Human injury/death.	2	4	1	8
36	05.02.03.00.	Blowouts	Human injury/death due to CO ₂ release through well blowout.	2	4	1	8
37	21.08.06.	Boiling liquid expanding vapor explosion (BLEVE)	Human injury/death due to boiling liquid expanding vapor explosion (BLEVE).	2	4	1	8
38	01.01.07.00.	Bolide impact (meteorite impact)	Bolide impact causing caprock failure, destruction of surface facilities, human injury/death.	1	5	1	5

4.0 CONCLUSIONS

4.1 Quantitative Failure Modes and Effects Analysis (QFMEA)

The primary objective of this project was successfully achieved by developing and applying a Quantitative Failure Modes and Effects Analysis (“QFMEA”) model. The QFMEA model is comprehensive and flexible. It can be applied to CO₂ capture, transportation, and sequestration/use in deep saline aquifers (DSA), enhanced oil recovery (EOR) operations or enhanced coal bed methane (ECBM) operations. The QFMEA model:

1. Identifies and characterizes the potential risks associated with CO₂ capture, transport, storage and use operations
2. Identifies the likely failure modes, causes, effects, and methods of detection
3. Lists possible risk prevention and risk mitigation steps
4. Estimates potential damage recovery costs, mitigation costs and cost savings resulting from mitigation
5. Ranks (prioritizes) risks according to the probability of failure, the severity of failure, the difficulty of early failure detection, and the potential for fatalities.

The QFMEA model generates the necessary information needed for effective project risk management. Diverse project information can be integrated into a concise, common format that allows comprehensive, quantitative analysis, by a cross-functional team of experts, to determine: What can possibly go wrong? How much will damage recovery cost? How can it be prevented or mitigated? What is the cost savings or benefit of prevention or mitigation? Which risks should be given highest priority for resolution?

The QFMEA model can be tailored to specific projects and is applicable to new projects, as well as, mature projects. The model can be revised and updated as new information becomes available. It accepts input from multiple sources, such as literature searches, site characterization, field data, computer simulations, analogues, process influence diagrams, probability density functions, financial analysis models, cost factors and heuristic best practices manuals, and converts the information into a standardized format in an Excel spreadsheet.

The efficacy of the QFMEA model was proven through completion of comprehensive, quantitative risk assessments at the following three sites:

1. SACROC Northern Platform CO₂-EOR Site in the Permian Basin, Scurry County, TX
2. Pump Canyon CO₂-ECBM Site in the San Juan Basin, San Juan County, NM
3. Farnsworth Unit CO₂-EOR Site in the Anadarko Basin, Ochiltree County, TX

4.2 SACROC Northern Platform CO₂-EOR Quantitative Risk Assessment

Carbon dioxide has been successfully injected at the SACROC Unit for over 40 years. The operation has been safe and profitable. There have been no reports of injuries, fatalities or environmental damage due to CO₂ injection at this Site. The quantitative risk assessment

demonstrated that the SACROC Northern Platform CO₂-EOR operation represents a “not significant” environmental risk due to nearly ideal subsurface and surface conditions, long-term operating experience and extent of technical knowledge of the formation and operations. The most costly potential risk areas (hedging, oil price, reservoir heterogeneity and scale buildup) are predicted to impact the project profitability rather than impact public health and safety or the environment. Most of the safety and environmental risks are controllable and can be mitigated with the existing operating procedures at the Site. In this regard, the SACROC Site represents an effective “good” benchmark for evaluating project risks associated with other CO₂-EOR and CO₂ sequestration sites.

With regard to subsurface conditions, the SACROC Northern Platform EOR reservoir is at an ideal depth (pressure and temperature) for maintaining CO₂ in supercritical and miscible condition. The integrity of the caprock (primary seal) has been demonstrated. There are multiple stacked seals and sinks overlying the caprock to provide additional security. There are no known faults penetrating the primary seal. Underground sources of drinking water in the Site area are limited to two (2) secondary USDW aquifers.

On the Site surface, there are no sensitive receptors (schools, hospitals, etc.) within 1.6 km of the Site. Population density within the Site area is less than 1 person per square kilometer. There are no population centers downwind from the Site for more than 40 km. There are no wetlands, timberlands, endangered/threatened species habitats, or national parks in the area. There are no significant surface waters except for a small creek. There is limited farming activity, but no significant industrial, commercial or mining activities in or near the Site area. The land is relatively flat, open and accessible.

Many of the risks associated with CO₂ sequestration in deep saline aquifers are mitigated in the SACROC Northern Platform CO₂-EOR operation. Reservoir over pressurization is mitigated by injecting CO₂ or water at constant pressure (rather than constant volume) and keeping fluid injection and production flow rates in balance.

The presence of hydrogen sulfide (H₂S) in the reservoir has both negative and positive consequences. On the negative side, H₂S is more toxic than CO₂, and needs to be monitored closely. However, at H₂S concentration of 1,000 ppm in the CO₂, the H₂S and CO₂ are approximately equal in toxicity levels. On the positive side, H₂S acts as an odorant for the CO₂ (similar to the odorant in natural gas). Therefore, CO₂ containing H₂S is easier to detect and trace for leakage. It is likely the co-existing relationship will provide a condition for earlier detection of small to moderate CO₂ leaks leading to faster remediation and thus minimize public health and safety risks.

The Site has been extensively characterized with seismic surveys, well logs, water studies and wellbore integrity studies. Although there are 639 deep wells penetrating the caprock in the Site, the operator has a preventative maintenance program for evaluating and reworking “at risk” wells.

4.3 San Juan Basin Pump Canyon CO₂-ECBM Site Quantitative Risk Assessment

A comprehensive, quantitative risk assessment was conducted on the San Juan Basin Pump Canyon CO₂-ECBM Site in San Juan County, NM. CO₂-ECBM is technically feasible at this Site but

not economically feasible at current market prices for CO₂ and natural gas. The price of CO₂ would have to be virtually free, or the price of natural gas would have to more than double to achieve an acceptable return on investment.

Decreased injectivity, caused by coal matrix swelling during CO₂ injection, is a significant technical problem which results in higher capital and operating costs. Coal plasticization could also become a significant problem under certain operating conditions.

As long as current CBM operations remain viable, it is unlikely that CO₂ sequestration would be considered in the Fruitland Formation. CO₂ sequestration requires increasing the coal seam pressure in order to allow the CO₂ to adsorb on the coal surface. CBM operation requires decreasing the coal seam pressure to allow methane to be desorbed from the coal.

It may be technically feasible to sequester CO₂ in Fruitland coal after CBM operations cease. However, the presence of natural CO₂ and methane in the Fruitland Formation and in all of the overlying formations and many of the underlying formations may complicate compliance with USEPA regulations for monitoring, verifying and accounting of stored CO₂. With multiple operators in the area producing methane from multiple formations, it may be difficult to assign liability for any CO₂ or methane gas leakage.

From a health, safety and environmental standpoint, methane gas seeps are a more probable risk than CO₂ leakage. Methane seeps have been observed in the San Juan River and Animas River areas dating back to the 1880s, before deep wells were drilled. No fatalities due to methane seeps have been reported. Slow release of either gas is unlikely to cause immediate human endangerment unless the gas accumulates in a low lying area or in an unventilated confined space. CO₂ is toxic or asphyxiating in concentrations greater than 4%. Methane is flammable or explosive in concentrations within the range of 5 to 15%.

CO₂ injected into the Fruitland coal in Section 32 is likely to stay in place. The coal has very little cleat pore space for free gases or water to exist. Ninety-nine (99) percent of the in-place CO₂ is adsorbed on the coal. The coal permeability decreases as reservoir pressure increases. The coal permeability also decreases due to coal matrix swelling associated with additional CO₂ adsorption. Hydrostatic pressure may gradually increase due to artesian effect after CBM operations cease. The Kirtland formation acts as a primary seal or caprock. As an additional safety precaution, CO₂ could be injected only in the basal coal zone. This would allow the middle and upper coal zones to act as secondary seals, fixing any escaped CO₂ in place.

Conversion of CBM wells to CO₂ injection wells could help improve the economics of CO₂ sequestration compared to drilling new injection wells. However, it may be a challenge to assure the integrity and operability of the converted wells because CBM wells in the area have open-hole cavity completions in the coal seams. These open cavities can be up to 5 m (16 ft) in diameter with fractures extending into the coal seams up to 61 m (200 ft) in length and would make it difficult to control the migration of injected CO₂.

Repressurization of the Fruitland Formation via CO₂ injection may be difficult due to limited injectivity. Extra precautions should be taken if CO₂ is injected near communities, fault zones, or environmentally sensitive areas.

4.4 Farnsworth Unit CO₂-EOR Site Quantitative Risk Assessment

This CQRA project team was originally to have access to a significant amount of field data through the Southwest Partnership on Carbon Sequestration (SWP) Phase III Project at the Farnsworth Unit Site. Unfortunately, the negotiations to develop the Phase III Project took longer than expected. Therefore, it was necessary to rely on data available in the public domain to prepare this risk assessment. The QFMEA model developed for this assessment represents a snapshot based on what is publicly known to date. As the SWP Phase III Project proceeds, the QFMEA model can be updated and revised by SWP as part of their ongoing risk management.

Based on available information, the Farnsworth Unit CO₂-EOR operation is technically and commercially feasible at current oil prices. The breakeven oil price is estimated to be less than \$60 per barrel.

The FWU reservoir is a secure storage site for CO₂. The caprock appears to be laterally continuous. There are multiple stacked seals and sinks separating the reservoir from the Ogallala aquifer. No significant structural features have been found that would indicate a potential pathway for CO₂ migration through the caprock other than leakage through existing wellbores. In this regard, there are 169 deep wells penetrating the FWU caprock.

There do not appear to be any sensitive environmental issues on the surface of the FWU Site. The Site is sparsely populated and covered with crop land and playa ponds. The land is relatively flat with no topographic low areas that would allow CO₂ to accumulate. All areas of the site are readily accessible by road.

The presence of pyrite (iron sulfide) in the reservoir indicates that H₂S is likely being generated, which will co-migrate with CO₂. Precautions should be taken to monitor and mitigate corrosion in wells and gas recycling equipment. Tight seals should be maintained and H₂S monitoring badges should be worn by on-site personnel. Although H₂S is more toxic than CO₂, it can serve as an odorant for the CO₂ (similar to the odorant in natural gas) and help improve early detection of small to medium CO₂ leaks. This would lead to faster remediation and thus minimize public health and safety risks.

The projected injection of 2.9 million tonnes of purchased CO₂ from 2011 through 2024 in the West side of the FWU represents 0.3 Hydrocarbon Pore Volume (HCPV). This is consistent with the current best practices for CO₂-EOR. The estimated CO₂ storage capacity of the total FWU reservoir of 10 million tonnes (0.582 HCV or 0.4 total pore volume) appears reasonable.

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Scurry county highlighted on Texas map

http://en.wikipedia.org/wiki/File:Map_of_Texas_highlighting_Scurry_County.svg

Scurry county shaded relief

<http://www.gis.ttu.edu/center/DataCatalog/Download.php?County=Scurry>

Scurry county showing SACROC Unit and Groundwater level

<http://www.beg.utexas.edu/gccc/sacroc/waterlevels.php>

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7.0 LIST OF ACRONYMS AND ABBREVIATIONS

3D: three dimensional
10-K: annual report
10-Q: quarterly report
ACEC: Area of Critical Environmental Concern
AMSL: above mean sea level
API: American Petroleum Institute
API°: American Petroleum Institute gravity
ARI: Advanced Resources International
As: arsenic
bbl: barrel
BCF: billion cubic feet
BLM: Bureau of Land Management
BMSL: below mean sea level
BOE: barrels of oil equivalent
BOPD: barrels of oil per day
BPD: barrels per day
BPSD: barrels per stream day
BSCFD: billion standard cubic feet per day
BTU: British thermal unit
BWPD: barrels of water per day
C: carbon
C: centigrade
C₁: methane CH₄ or hydrocarbon compounds with 1 carbon atom
C₂: ethane C₂H₆ or hydrocarbon compounds with 2 carbon atoms
C₃: propane C₃H₈ or hydrocarbon compounds with 3 carbon atoms
C₄: butane C₄H₁₀ or hydrocarbon compounds with 4 carbon atoms
C₅: pentane C₅H₁₂ or hydrocarbon compounds with 5 carbon atoms
C₆: hexane C₆H₁₄ or hydrocarbon compounds with 6 carbon atoms
C₇: heptane C₇H₁₆ or hydrocarbon compounds with 7 carbon atoms
Ca: calcium
Capex: capital expense
CBM: coal bed methane
CELLC: Chaparral Energy LLC
cf: cubic foot
CFR: Code of Federal Regulations
CH₄: methane
C_k: differential swelling factor
C_m: matrix compressibility
cm: centimeter
CMG: Computer Modeling Group
COGCC: Colorado Oil and Gas Commission
C_p: pore compressibility
cP: centipoise
CPM: computational pipeline monitoring (leak detection system)

CO₂: carbon dioxide
 CO₂-PENS: CO₂ Predicting Engineered Natural Systems
 CQRA: Comprehensive quantitative risk assessment
 D: day
 dBA: decibels A- weighted measurement
 DCF: distributable cash flow
 DOE: The United States Department of Energy
 DSA: deep saline aquifer
 E: east
 E&P: exploration and production
 E_a: areal displacement efficiency
 ECBM: enhanced coalbed methane
 E_d: microscopic displacement efficiency
 EFEP: external feature, event and/or process
 E_g: gravity efficiency
 EIA: Energy Information Agency
 E_v: vertical displacement efficiency
 EM: electro magnetic
 EOR: enhanced oil recovery
 EP-SJ: El Paso San Juan
 EPA: Environmental Protection Agency
 EPNG: El Paso Natural Gas (Burlington Resources)
 ERW: electric resistance welded
 ESP: electric submersible pump
 F: Fahrenheit
 FEP: feature, event and/or process
 FeS₂: iron sulfide
 FF: Faulkner & Flynn
 FM: farm-to-market (road)
 FMEA: failure modes and effects analysis
 FONSI: finding of no significant impact
 ft: feet
 FWU: Farnsworth Unit
 g: gram
 gal: gallon
 GEM: Generalized Equation-of State Model
 GOR: gas-oil ratio
 GPM: gallons per minute
 GPS: global positioning system
 GRE: glass reinforced epoxy
 Gt: giga tonne
 GT: gas turbine
 GW: groundwater
 h: hour
 H₂: hydrogen
 H₂O: water

H₂S: hydrogen sulfide
HC: hydrocarbon
HCCS: Headwaters Clean Carbon Services LLC
HCGOR: hydrocarbon gas oil ratio
HCO₃⁻: bicarbonate ion
HCPV: hydrocarbon pore volume
He: helium
HP: horsepower
HVA bit: high-volatile A bituminous coal
Hwy: highway
in: inch
INJ: injection or injected
InSAR: Interferometric Synthetic Aperture Radar
k: thousand
K: permeability
K: potassium
kg: kilogram
km: kilometers
KM: Kinder Morgan
KMP: Kinder Morgan Energy Partnership
Krg: relative permeability of gas
Kro: relative permeability of oil
Krw: relative permeability of water
kW: kilowatt
LACT: lease automated custody transfer
LANL: Los Alamos National Laboratory
lb: pound
LIDAR: light detection and ranging
LLC: Limited Liability Company
LP: Limited Partnership
m: meters
M: million or mega
M: magnitude (Richter magnitude scale) when referring to earthquakes
MAOP: maximum allowable operating pressure
MBPD: thousand barrels per day
MCF: thousand cubic feet
mD: millidarcies
Mg: magnesium
mg/L: milligrams per liter
mi: miles
mm: millimeter
MM: million
MMA: Marsh and McLennan Agency LLC
MMI: Modified Mercalli Intensity (earthquake scale)

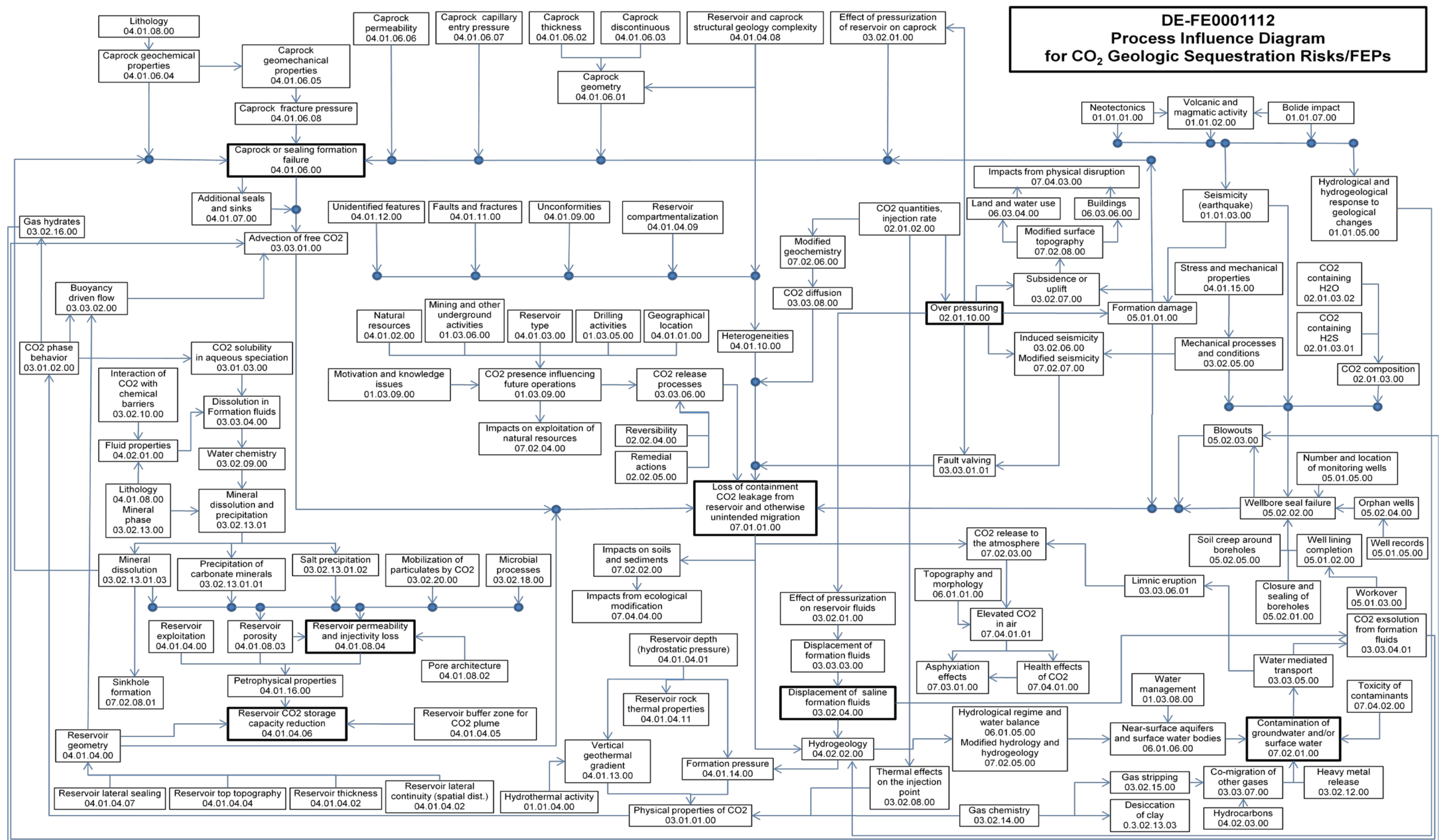
MMP: minimum miscibility pressure
MMSCFD: million standard cubic feet per day
Mn: manganese
MPa: mega pascal (million pascal)
mph: miles per hour
MS: Mississippi
MSCF: thousand standard cubic feet
Mt: mega tonne (million tonnes)
mW: milliwatt
MW: megawatt (million watts)
MWe: megawatt electrical
µg: microgram (one-millionth of a gram)
N: north
N₂: nitrogen
Na: sodium
NA: not applicable or not available
NCDC: National Climate Data Center
NE: northeast
NEIC: National Earthquake Information Center
NEPA: National Environmental Policy Act
NETL: National Energy Technology Laboratory
NGL: natural gas liquid
NM: New Mexico
Nm³: normal cubic meter
NMED: New Mexico Environmental Department
NMOCD: New Mexico Oil Conservation Division
NMT: New Mexico Tech
NO_x: nitrogen oxides
NW: northwest
O₂: oxygen
O&G: oil and gas
OCD: Oil Conservation Division of New Mexico
OGAP: Oil and Gas Accountability Project
OGIP: original gas in place
OOIP: original oil in place
Opex: operating expense
OSHA: Occupational Safety and Health Administration
OVHD: overhead
OWC: oil-water contact
P: pressure
P: probability
PAH: polycyclic aromatic hydrocarbon
pCi/L: picocuries per liter
PDE: preliminary determination of epicenters
PFC: perfluorocarbon
PFO: pressure fall off

PGA(g): peak ground acceleration (measured in gravity)
 pH: measure of the activity of the hydrogen ion
 PHMSA: Pipeline and Hazardous Materials Safety Administration
 PID: process influence diagram
 P_L: Langmuir pressure
 PM_{2.5}: particulate matter equal to or less than 2.5 microns
 PM₁₀: particulate matter equal to or less than 10 microns
 pp: pages
 ppm: parts per million
 PROD: production or produced
 psi: pounds per square inch
 psia: pounds per square inch atmospheric
 psig: pounds per square inch gauge
 PURCH: purchased
 PV: pore volume
 QFMEA: quantitative failure modes and effects analysis
 R: range (as in R08W)
 RB: reservoir barrel
 Rn: radon
 ROW: right-of-way
 ROZ: residual oil zone
 Rr: rural road
 S: severity
 S: south
 S: sulfur
 SACROC: Scurry Area Canyon Reef Operators Committee
 SAR: sodium adsorption ratio
 SCADA: system control and data acquisition
 SCF: standard cubic feet
 SDA: specially designated area
 SE: southeast
 SHPO: State Historic Preservation Office
 SJB: San Juan Basin
 SMLS: seamless
 SO_x: sulfur oxides
 ST: short ton (2000 lbs)
 ST: steam turbine
 STB: stock tank barrel
 SW: southwest
 SWP: Southwest Partnership on Carbon Sequestration
 t: tonne (metric ton)
 T: temperature
 T: township (as in T32N)
 TCF: trillion cubic feet
 TDS: total dissolved solids
 TX: Texas

UIC: underground injection control
US: United States
USBR: United States Bureau of Reclamation
USDW: underground source of drinking water
USEPA: United States Environmental Protection Agency
USGS: United States Geological Survey
UU: University of Utah
 V_L : Langmuir volume
Vol: volume
VSP: vertical seismic profiling
W: west
WAG: water alternating gas
WL: water level
WOR: water-oil ratio
WRCC: Western Regional Climate Center
WTI: Western Texas Intermediate
XRD: x-ray diffraction
y: year
 λ : Rock fabric number
 ρ : density
 Φ : porosity
#: number
#: pound
°: degree
' : minute

Appendix A

Process Influence Diagrams



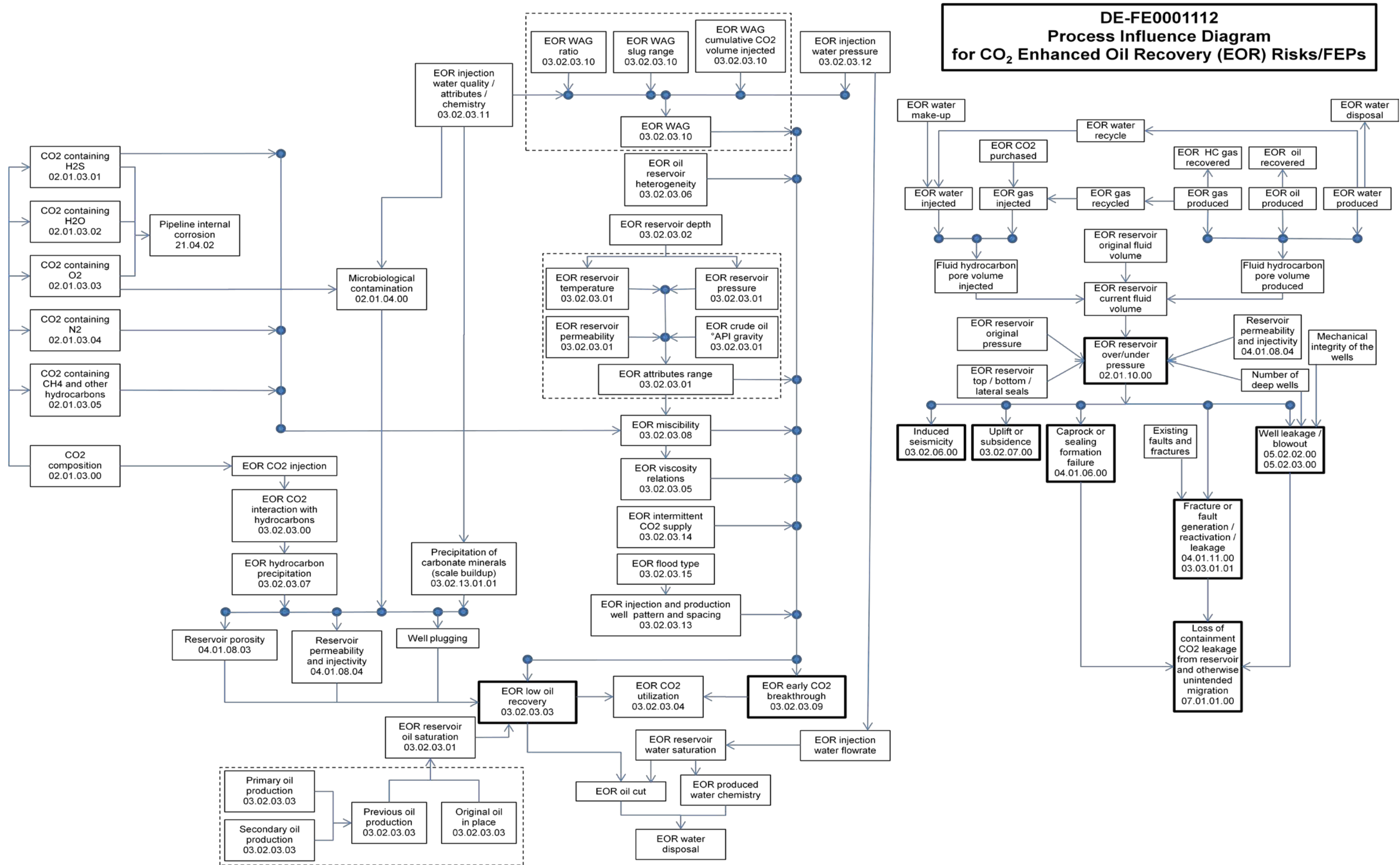
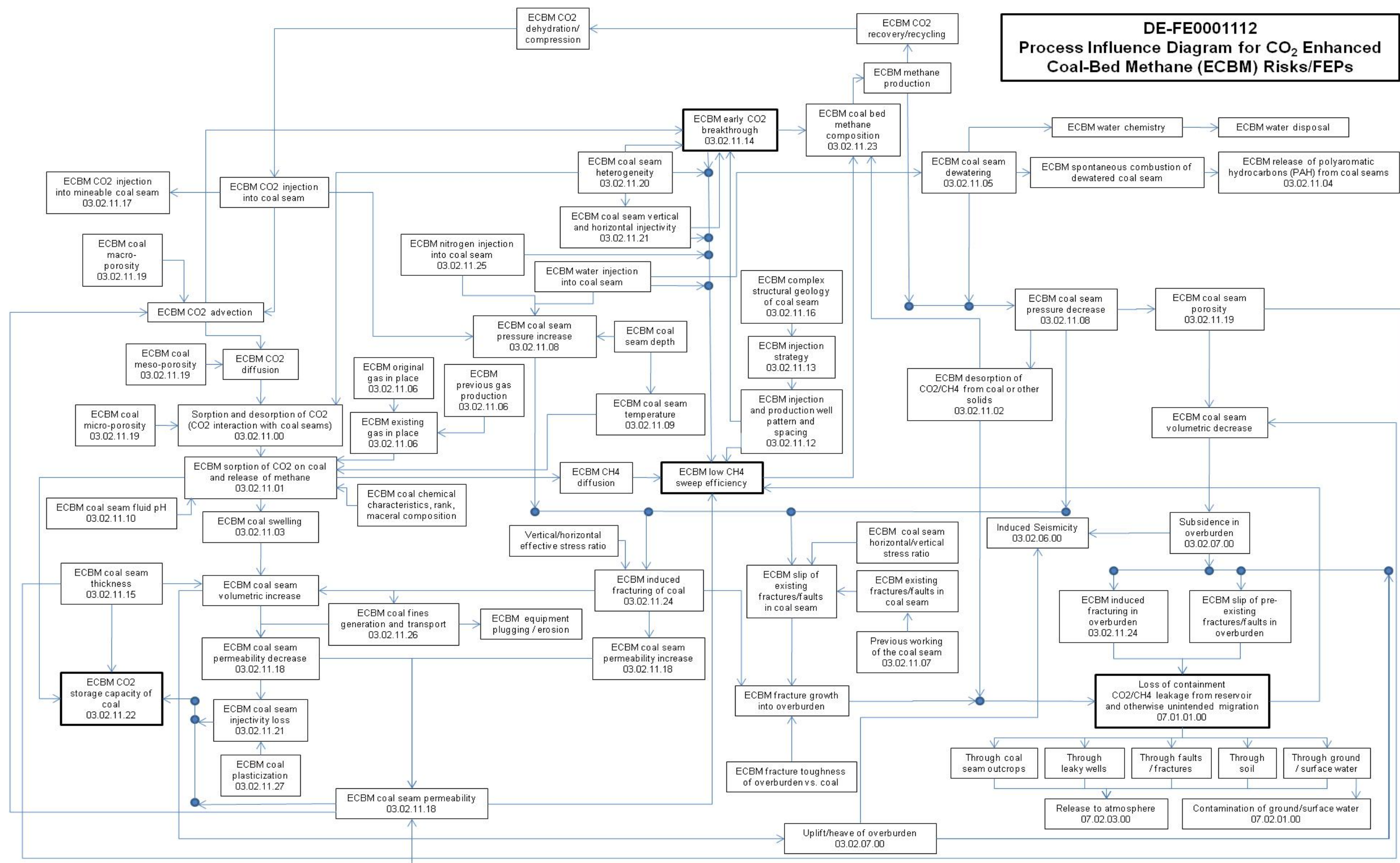


Figure A-2: Process influence diagram for CO₂-EOR risks/FEPs



Appendix B

Cost Factors and Formulas

Cost factors and formulas

PORE SPACE LEASING OR PURCHASE COSTS	UNITS	VALUE	REFERENCE
One-time, up-front fee to acquire option before CO ₂ injection	\$ per land owner	500	Gresham 2010
Annual lease fee for state-owned pore space	\$/year per acre	45 to 65	Gresham 2010
Annual lease fee for private pore space	\$/year per acre	2 to 10	Gresham 2010
Long-term lease up-front cost for state-owned pore space	\$/acre	400 to 600	Gresham 2010
Long-term lease up-front cost for private pore space	\$/acre	20 to 100	Gresham 2010
Purchase cost of pore space	\$/acre	60 to 2,000	Gresham 2010
LAND LEASING OR PURCHASE COSTS	UNITS	VALUE	REFERENCE
Leasing of public land (typical BLM rate)	\$/acre/year	10,000	RPSEA 2010
Purchase of private land (farmland)	\$/acre	20,000	RPSEA 2010
Purchase of private land (grassland)	\$/acre	1,000	Various sources
SITE CHARACTERIZATION AND PERMITTING COSTS	UNITS	VALUE	REFERENCE
Site Characterization for CO₂ Geologic Storage			
Average	\$/site	25,000,000	WorleyParsons 2009
Low	\$/site	15,000,000	WorleyParsons 2009
High	\$/site	150,000,000	WorleyParsons 2009
Permitting for CO₂ Geologic Storage			
Low	\$/site	5,000,000	WorleyParsons 2009
High	\$/site	10,000,000	WorleyParsons 2009
CO ₂ COMPRESSION COSTS	UNITS	VALUE	REFERENCE
Power to compress CO ₂ from 0.12 to 15.3 MPa	kWh/t	89 to 102	Various sources
Installed capital cost for CO ₂ compressors (5000 HP electric)	\$/HP	2000	Kinder Morgan 2009
Power to pump CO ₂ from 8 to 15 MPa	kWh/t	4	McCollum 2008
Installed capital cost for CO ₂ booster pumps (4000 HP electric)	\$/HP	2000	Kinder Morgan 2009
Annual fixed operation and maintenance costs (excludes power)	% of capital	4	McCollum 2008
Measurement station (500 MMCFD or 26,316 tonnes/day CO ₂)	\$/station	500,000	Kinder Morgan 2009
Conversion factor: 1 HP = 0.7457 kW			
PIPELINE INSTALLED CAPITAL COST, INCLUDING RIGHT-OF-WAY (ROW)	UNITS	VALUE	REFERENCE
Flat and dry terrain	\$/inch-dia/mi	50,000	Kinder Morgan 2009
Mountainous terrain	\$/inch-dia/mi	85,000	Kinder Morgan 2009
Marshy wetland area	\$/inch-dia/mi	100,000	Kinder Morgan 2009
River crossing	\$/inch-dia/mi	300,000	Kinder Morgan 2009
High population density area	\$/inch-dia/mi	100,000	Kinder Morgan 2009
Offshore at 150-200 ft (46-61 m) depth	\$/inch-dia/mi	700,000	Kinder Morgan 2009
REGIONAL MULTIPLIER FOR CAPITAL COST ADJUSTMENT	UNITS	VALUE	REFERENCE
Midwest (IL, MI, OH, KY)	Dimensionless	1.01	Unpublished
Northeast (PA)	Dimensionless	1.07	Unpublished
Central (CO, KS, MT, ND, WY)	Dimensionless	0.96	Unpublished
Southeast (AL, MS, SC, VA)	Dimensionless	0.89	Unpublished
Southwest (AR, TX)	Dimensionless	0.90	Unpublished
West (CA, AB, BC)	Dimensionless	1.19	Unpublished
United States average	Dimensionless	1.00	Unpublished
PIPELINE OPERATING AND MAINTENANCE (O&M) COSTS	UNITS	VALUE	REFERENCE
Materials costs (2011 dollars)	Diameter = D (inches) Length = L (miles)	Material cost (\$) = \$70,350 + \$2.01 x L x (330.5 x D ² + 686.7 x D + 26,960)	Grant 2013
Labor costs (2011 dollars)	Diameter = D (inches) Length = L (miles)	Labor cost (\$) = \$371,850 + \$2.01 x L x (343.2 x D ² + 2,074 x D + 170,013)	Grant 2013
Miscellaneous costs (2011 dollars)	Diameter = D (inches) Length = L (miles)	Misc. cost (\$) = \$147,250 + \$1.55 x L x (8,417 x D + 7,234)	Grant 2013
Right-of-way (ROW) costs (2011 dollars)	Diameter = D (inches) Length = L (miles)	ROW cost (\$) = \$51,200 + \$1.28 x L x (577 x D + 29,788)	Grant 2013
CO ₂ surge tank (2011 dollars)	\$	1,244,724	Grant 2013
Pipeline control system (2011 dollars)	\$	111,907	Grant 2013
PIPELINE OPERATING AND MAINTENANCE (O&M) COSTS	UNITS	VALUE	REFERENCE
Annual pipeline fixed O&M costs	\$/mile/year	8,632	Tarka 2010
Annual pipeline fixed O&M costs (2011 dollars)	\$/mile/year	8,454	Grant 2013
Annual pipeline fixed O&M costs	\$/mile/year	13,390	IEAGHG 2011

VERTICAL INJECTION WELL DRILLING AND COMPLETION COST	UNITS	VALUE	REFERENCE	\$/m	\$/ft
Well depth 500 ft (152 m)	\$/well	629,575	Unpublished	4142	1259
Well depth 1,000 ft (305 m)	\$/well	1,178,100	Unpublished	3863	1178
Well depth 2,000 ft (610 m)	\$/well	2,059,000	Unpublished	3375	1030
Well depth 3,000 ft (914 m)	\$/well	2,696,700	Unpublished	2950	899
Well depth 4,000 ft (1,219 m)	\$/well	3,145,200	Unpublished	2580	786
Well depth 5,000 ft (1,524 m)	\$/well	3,458,500	Unpublished	2269	692
Well depth 6,000 ft (1,829 m)	\$/well	3,690,600	Unpublished	2018	615
Well depth 7,000 ft (2,133 m)	\$/well	3,895,500	Unpublished	1826	557
Well depth 8,000 ft (2,438 m)	\$/well	4,127,200	Unpublished	1693	516
Well depth 9,000 ft (2,743 m)	\$/well	4,439,700	Unpublished	1619	493
Well depth 10,000 ft (3,048 m)	\$/well	4,887,000	Unpublished	1603	489
Well depth 15,000 ft (4,572 m)	\$/well	11,035,500	Unpublished	2414	736
Well depth 20,000 ft (6,096 m)	\$/well	28,654,000	Unpublished	4700	1433
Formula for well capex	\$/well	$\$/\text{well capex} = 3.17832 * 10^{-4} * (\text{m depth})^3 - 1.890143 * (\text{m depth})^2 + 4411.75 * (\text{m depth})$	Unpublished		
Well depth 6,700 ft (2,042 m) single injection	\$/well	1,200,000	Ricketson 2012	588	179
Well depth 6,700 ft (2,042 m) dual injection	\$/well	1,800,000	Ricketson 2012	881	269
PRODUCTION WELL DRILLING AND COMPLETION COST	UNITS	VALUE	REFERENCE	\$/m	\$/ft
Horizontal production well (6000 ft vertical + 7000 ft lateral)	\$/well	5,500,000	Whiting 2011 Whiting 2010	1388	423
Horizontal production well (6000 ft vertical + 4000 ft lateral)	\$/well	4,000,000	Whiting 2011 Whiting 2010	1312	400
Horizontal production well (8000 ft vertical + 5000 ft lateral)	\$/well	7,000,000	PetroHawk 2011	1767	538
Horizontal production well (6500 ft vertical + 4500 ft lateral)					
Vertical drilling, casing & cementing (6,500 ft)	\$/well	663,275	Hefley 2011	335	102
Horizontal drilling, casing & cementing (4,500 ft)	\$/well	1,214,850	Hefley 2011	886	270
Hydraulic fracturing (4,500 ft)	\$/well	2,500,000	Hefley 2011	1823	556
Drilling out plugs and cleanout	\$/well	200,000	Hefley 2011		
Well head components	\$/well	465,000	Hefley 2011		
Total	\$/well	5,043,125	Hefley 2011	1504	458
Permitting	\$/well	10,075	Hefley 2011		
Site preparation	\$/well	400,000	Hefley 2011		
Land acquisition cost	\$/640 acres	2,191,125	Hefley 2011		
Interim remediation of pad area and roads	\$/pad	615,500	Hefley 2011		
Gathering pipeline ROW, mtl's & install	\$/4,500 ft	472,000	Hefley 2011	344	105
Vertical production well depth 1804 ft (550 m)	\$/well	634,370	PSAC 2011	1153	352

PRODUCITON WELL ARTIFICIAL LIFT	UNITS	VALUE	REFERENCE		
Power to lift water with a rod pump	kVWh/(t of fluid)/(m of lift)	0.005	Calculated		
Power to lift water with an electric submersible pump	kVWh/(t of fluid)/(m of lift)	0.010	Calculated		
WATER PRODUCTION WELL CAPEX	UNITS	VALUE	REFERENCE		
Capex for water production well*	Formula		Modified from LBG-GUYTON 2003		
6 inch diameter well with 25 to 150 gpm production	\$ = \$/well	\$=14,000+136*GPM+120*FT			
8 inch diameter well with 150 to 300 gpm production	GPM = pump capacity in gpm of water	\$=20,000+130*GPM+280*FT			
10 inch diameter well with 300 to 500 gpm production	FT = well depth in ft	\$=30,000+126*GPM+360*FT			
12 inch diameter well with 500 to 800 gpm production		\$=40,000+120*GPM+450*FT			
16 inch diameter well with 800 to 2000 gpm production		\$=44,000+120*GPM+640*FT			
*Includes: cost of drilling and completion, well development testing, pump, motor controls, column pipe, installation and mobilization.					
MONITORING (OBSERVATION) WELL DRILING AND COMPLETION COST	UNITS	VALUE	REFERENCE	\$/m	\$/ft
Monitoring well (down to 9000 ft max.)	\$/ft	100-130	EPA 2010	328 - 427	100 - 130
HYDRAULIC FRACTURING / STIMULATION	UNITS	VALUE	REFERENCE		
Cost of hydraulic fracturing horizontal well (including sand, fuel, water, chemicals, perforating gun, plugs, services)	\$/ft perforated length	500 to 600	Hefley 2011		
Cost of hydraulic fracturing horizontal well	\$/300 ft stage	150,000	Hefley 2011		
Cost of hydraulic fracturing horizontal well	ft/stage	200 to 500	Hefley 2011		
Cost to clean out and perforating of first stage	\$/300 ft stage	35,000 to 50,000	Hefley 2011		
Fresh water consumption for fracking	gpm	3,150 to 4,200	Hefley 2011		
Fresh water consumption for fracking	gallons/300 ft stage	270,000	Hefley 2011		
Fresh water consumption for fracking	gallons/15 stages (4500 ft of perforated length)	4,000,000	Hefley 2011		
Fresh water consumption for fracking	gallons / horizontal well	3,000,000 to 8,000,000	Hefley 2011		
Pump capacity for fracking (12-18 pumps)	HP	25,000 to 30,000	Hefley 2011		
Diesel fuel for powering water pumps	Gallons diesel/300 ft stage	4,000	Hefley 2011		
Sand for fracking	t sand / 300 ft stage	250	Hefley 2011		
Fracking water pit	\$/pit	120,000	Hefley 2011		
Liner and fencing for fracking water pit	\$/pit	60,000 to 70,000	Hefley 2011		
Fresh water consumption for fracking vertical well in Marcellus shale	gallons per well	500,000 to 1,000,000	Hefley 2011		
INJECTION WELL OPERATION AND MAINTENANCE COSTS	UNITS	VALUE	REFERENCE		
Fixed operating & maintenance costs	\$/yr/well	11,566	Tarka 2010		
Variable costs	\$/y per tpd CO2	3,301	Tarka 2010		
Surface Maintenance	\$/yr per well	120,608	Tarka 2010		
Subsurface Maintenance	\$/yr per m-depth per well	23.23	Tarka 2010		
Wellbore maintenance costs for injection wells	\$/well/year plus Cents per MCF of CO2 injected	10,000-11,000 1.3	Ricketson 2012		

MVA TOOL COSTS	UNITS	VALUE	REFERENCE
3D seismic survey - minimum required to get useable data (20 folds)	\$/mi ² of subsurface area	200,000	Unpublished
3D seismic survey - good data (50-69 folds)	\$/mi ² of subsurface area	1,000,000 to 2,000,000	Unpublished
3D seismic survey - exceptional data (>70 folds)	\$/mi ² of subsurface area	>2,000,000	Unpublished
3D seismic survey cost formula	\$/mi ² of subsurface area	$\$/mi^2 = (4625.4 * \text{fold} - 22622) * (1.8942 * e^{(0.0195 * \text{fold})})$	
2D seismic data acquisition	\$/km	5,140 to 19,531	Unpublished
2D Seismic data processing	\$/km	1,677	Unpublished
Borehole gravity density survey for 4000 ft (1,219 m) well*	\$/survey	69,038	Unpublished
Brine total analysis suite	\$/sample	855	Unpublished
Brine trace element analysis	\$/sample	200	Unpublished
Coring*	\$/ft	232 to 366	Unpublished
Coring	\$/ft	500	PSAC 2011
CO2 monitor/alarm	\$/unit	300 to 1000	Various sources
CO2 surface flux monitoring system			
Capital cost	\$/station	70,000	
Annual maintenance cost	% of capex	5	Benson 2009
Interpretation cost	\$/y per station	10,000	
CO2, VOC, CH4, H2S multi-gas analyzer	\$/unit	1500 to 15000	Various sources
Cross-well seismic*	\$/event	440,900	Unpublished
Eddy covariance CO2/CH4/H2O (installed capital cost)	\$/station	99,300	Vendor estimate
Eddy covariance CO2/CH4/H2O (O&M cost)	\$/y per station	10,000	EPA 2010
Gamma ray survey	\$/ft	0.22	Unpublished
InSAR survey and analysis. One image per quarter for 72 to 365 km ² reservoir area at 2000 m depth (190 to 645 km ² surface area)	\$/quarter	50,000 to 75,000	Vendor estimate 2012
InSAR survey and analysis. Two images per quarter for 734 to 1467 km ² reservoir area at 2000 m depth (1170 to 2162 km ² surface area)	\$/quarter	100,000 to 150,000	Vendor estimate 2012
InSAR corner reflector capex (placed 1 per 1 to 1.2 km ² of surface area)	\$/corner reflector	3,485	Vendor estimate 2012
InSAR GPS station capex (placed 1 per 90 km ² of surface area)	\$/GPS station	20,000	Vendor estimate 2012
Light detection and ranging (LIDAR) mobilization cost for small projects	\$	3,500	Stennett 2008
Light detection and ranging (LIDAR) costs for large projects (>1000 square miles)	\$/acre	1.49	Stennett 2008
Light detection and ranging (LIDAR) costs for small projects (less than 1 square mile)	\$/acre	0.15	Stennett 2008
Light detection and ranging (LIDAR) costs based on large projects. Add 10-20% for QA/QC.	\$/square mile	80 to 200	Kansas 2011
Light detection and ranging (LIDAR) for 2 to 3 m postings. Includes flight, LIDAR collection, post processing, delivery. Excluding DEMs, DTMs, contours, special accuracy requirements and licensing restrictions.	\$/square mile	1000 to 2000	SUU 2011

MVA TOOL COSTS (CONTINUED)	UNITS	VALUE	REFERENCE
Microseismic buried array for continuous passive seismic monitoring			
Capex (6 stations/18 channels per square mile)	\$/square mile	120,000 to 125,000	Vendor estimate 2011
Opex	\$/y per square mile	10,000	
Total cost	\$/t CO2 injected	0.5	
Microseismic – array install and design	\$/well	620,524	Unpublished
Microseismic – field engineer	\$/day	1,390	Unpublished
Microseismic – rentals	\$/week	2,707	Unpublished
Microseismic – safety engineer	\$/day	1,070	Unpublished
Microseismic – service rig	\$/day	5,832	Unpublished
MRI logging	\$/ft	14.74	Unpublished
Mud logging	\$/day	1,275	Unpublished
Neutron survey – dual spaced	\$/ft	0.82	Unpublished
Point surveying and mapping	\$/well	2,718	Unpublished
Production log	\$/log	98,832	Unpublished
Pulsed neutron capture – field engineer	\$/day	1,390	Unpublished
Pulsed neutron capture - logging	\$/well	18,234	Unpublished
Pulsed neutron capture – safety engineer	\$/day	1,070	Unpublished
Reservoir saturation tool log	\$/run	60,514	Unpublished
Resistivity survey	\$/ft	1.39	Unpublished
Rotary sidewall cores	\$/20ft of core	1,783.65	Unpublished
Soil gas survey*	\$/event	70,000	Unpublished
Tiltmeter cost based on array of 100 tiltmeters for 10 km ² reservoir area (190 km ² surface area) plus 3 GPS stations. Manual data collection.			Vendor estimate 2012
Capex (100 tiltmeter array)	\$/100 tiltmeter array	390,000	
Capex (3 GPS stations)	\$/3 GPS stations)	60,000	
Opex including data analysis	\$/array per quarter	125,000 to 150,000	
Vertical seismic profiling (VSP) zero offset for well depth of approx. 3,500 ft - Costs represent those for a single well and survey only and are a wrap-up of mobilization, equipment installation, data acquisition, equipment removal, and data processing.	\$/well/survey	130,000 to 140,000	Unpublished 2009
VSP offset (well depth approx. 3,750 ft) - Costs represent those for a single well and survey only and are a wrap-up of mobilization, equipment installation, data acquisition, equipment removal, and data processing.	\$/well/survey	300,000 to 400,000	Unpublished 2011
VSP far offset (well depth approx. 3,500 ft) - Costs represent those for a single well and survey only and are a wrap-up of mobilization, equipment installation, data acquisition, equipment removal, and data processing.	\$/well/survey	180,000 to 190,000	Unpublished 2009
VSP multi offset (well depth approx. 4000 ft) - Costs represent those for a single well and survey only and are a wrap-up of mobilization, equipment installation, data acquisition, equipment removal, and data processing.	\$/well/survey	200,000 to 210,000	Unpublished 2009
VSP walkaway (well depth approx. 7,500 ft) - Costs represent those for a single well and survey only. The lower range cost (\$250K) is a wrap-up of mobilization, equipment installation, data acquisition, equipment removal, and data processing. The upper range cost (\$860K) includes the purchase and permanent installation of a geophone string into a dedicated monitoring well, data acquisition, and data processing.	\$/well/survey	250,000 to 860,000	Unpublished 2009 and 2010
Wireline log – deep and sidewall cores	\$/job	362,008	Unpublished
Wireline log – deep/intermediate depth	\$/job	58,383	Unpublished
XRMI survey (XRMI - extended range micro imager)	\$/ft	27.09	Unpublished
*This cost is likely project-specific and should not be considered a standard.			

EOR SURFACE FACILITIES CAPEX AND POWER USAGE	UNITS	VALUE	REFERENCE
Order-of-magnitude specific capital cost for EOR surface facilities - excluding wells	\$/tpd CO2	36,000	Unpublished
Breakdown of capital cost			
CO2 recycle compression facility (assuming CO2 recycle capacity is equal to CO2 makeup capacity)	% of total	33	Unpublished
CO2 trunk and lateral injection distribution system	% of total	45	Unpublished
Production gathering system, tankage and water disposal	% of total	22	Unpublished
Total	% of total	100	Unpublished
Power consumption for CO2 recycle compression	kWh/t CO2 recycled	85	Unpublished
Power consumption for water extraction at 167.73 kg/bbl (1055 kg/m3) using a rod pump	kWh/bbl brine per m of lift	0.00084	
	KWh/bbl brine per ft of lift	0.000256	
Power consumption for water extraction at 167.73 kg/bbl (1055 kg/m ³) using an electric submersible pump	kWh/bbl brine per m of lift	0.00168	Calculated
	KWh/bbl brine per ft of lift	0.000512	
Power consumption for water extraction at 158.83 kg/bbl (999 kg/m3) using a rod pump	kWh/bbl water per m of lift	0.000795	
	kWh/bbl water per ft of lift	0.000242	
Power consumption for water extraction at 158.83 kg/bbl (999 kg/m ³) using an electric submersible pump	kWh/bbl water per m of lift	0.00159	Calculated
	kWh/bbl water per ft of lift	0.000484	
Power consumption for crude oil extraction at 126.87 kg/bbl (798 kg/m ³) using a rod pump	kWh/bbl crude oil per m of lift using ESP	0.000635	Calculated
	kWh/bbl crude oil per ft of lift	0.000194	
Power consumption for crude oil extraction at 126.87 kg/bbl (798 kg/m ³) using an electric submersible pump	kWh/bbl crude oil per m of lift using ESP	0.00127	Calculated
	kWh/bbl crude oil per ft of lift	0.000387	
EOR SURFACE AND SUBSURFACE FACILITIES CAPEX	UNITS	VALUE	REFERENCE
Specific capital cost for EOR operation (surface and subsurface facilities)	\$/BOEPD	30,000 to 60,000	Unpublished
EOR COST BREAKDOWN	UNITS	VALUE	REFERENCE
Royalties and production tax	\$/bbl of oil	18	FOX 2011
Capital expense	\$/bbl of oil	10	FOX 2011
Operating expense	\$/bbl of oil	20	FOX 2011
CO2 expense	\$/bbl of oil	15	FOX 2011
Profit margin	\$/bbl of oil	22	FOX 2011
Oil price	\$/bbl of oil	85	FOX 2011
Only 20% rate of return before tax because CO2 costs are at start of the project.			

FEDERAL LEASE ROYALTIES FY2011	UNITS	VALUE	REFERENCE
Oil	% of sales value	13.27	BLM 2012
Natural gas	% of sales value	10.83	BLM 2012
Natural gas liquids	% of sales value	10.27	BLM 2012
TRIBAL LEASE ROYALTIES FY 2011	UNITS	VALUE	REFERENCE
Oil	% of sales value	17.25	BLM 2012
Natural gas	% of sales value	15.26	BLM 2012
CBM ROYALTY PAYMENT AND TAX RATES	UNITS	VALUE	REFERENCE
Federal lands	% of revenues	12.5	ARI 2006
State lands	% of revenues	16.7	ARI 2006
Private lands	% of revenues	15 to 20	ARI 2006
Wyoming severance and ad valorem taxes	% of revenues	12	ARI 2006
REMEDATION COSTS	UNITS	VALUE	REFERENCE
Locating existing leaky well(s) Field surveys	\$/survey	200,000	Kuuskraa 2008
Locating leak in a new well Includes 2 diagnostic logs (such as cement bond log, downhole wireline video camera or spinner survey) plus diagnostic and management charge	\$/well	300,000	Kuuskraa 2008
Locating leaky fault, fracture zone, spill point etc. 3D seismic survey	\$/mi2/survey	150,000	Kuuskraa 2008
Horizontal leak detection wells	\$/well	4,000,000	
Plugging abandoned or orphaned wells.	\$/m depth	34 to 66	Mitchell 2011
Plugging abandoned or orphaned wells Average	\$/well	100,000	Kuuskraa 2008
Range	\$/well	25,000 to 200,000	
Well remediation cost to fix leak			
Recementing of simple well bore leak	\$/well	50,000	Kuuskraa 2008
Repairing substantial section of well	\$/well	100,000	Kuuskraa 2008
Install & cement smaller diameter liner inside well casing	\$/well	100,000	Kuuskraa 2008
Injection well recompletion cost to fix leak	\$/well	100,000-300,000	Various sources
Mitigating caprock leak (Stop CO2 injection into reservoir and inject water into formation above caprock to form a pressure barrier) Cost of horizontal water injection wells Cost of water plant	\$/well \$/facility	4,000,000 2,000,000	Kuuskraa 2008
Mitigating caprock leak with chemical sealant injectant	\$/t sealant		
Mitigating caprock leak with cement injection	\$/t cement	110-120	Various sources
Decommissioning of injection site facilities and wells Based on percentage of original installed capital cost	% of CAPEX	15	IEAGHG 2011
Contain contaminated ground water with hydraulic barriers	\$ of CAPEX	1,000,000 per well + 2,000,000 per water facility	Modified from Kuuskraa 2008
Erosion control	\$/m length of Muscle Wall	163	Unpublished
Self-siphon tubes to control CO2 in deep lakes	\$/unit capex \$/y/unit opex	250,000 5,000	Modified from BBC News 201
Ventilator for confined space	\$/unit capex \$/y/unit opex	300 to 500 200	Various sources
Energy recovery ventilator for confined space	\$/unit capex \$/y/unit opex	1,000 to 5,000 100	Various sources
Surface facility winterization	% of CAPEX	10	Unpublished

OIL SPILL DAMAGE RECOVERY	UNITS	VALUE	REFERENCE
Chevron, Salt Lake City, UT June & Dec 2010			
Oil spilled	Barrels	1300	Stettler 2011
Damage recovery cost	\$	42,600,000	
Damage recovery cost per barrel	\$/barrel	32,769	
Enbridge, Kalamazoo River, MI, July 2010			
Oil spilled	Barrels	19,000	Klug 2011
Damage recovery cost	\$	700,000,000	
Damage recovery cost per barrel	\$/barrel	36,750	
ExxonMobil, Yellowstone River, MT, July 2011			
Oil spilled	Barrels	1509	AP 2012
Damage recovery cost	\$	135,000,000	
Damage recovery cost per barrel	\$/barrel	89,463	
BP, Gulf of Mexico, July-September 2010			
Oil spilled	Barrels	4,900,000 (includes 810,000 collected)	Wikipedia 2012
Damage recovery cost	\$	43,500,000,000	Knock 2011
Damage recovery cost per barrel	\$/barrel	8,878	
Statutory maximum fine for oil spills under the Clean Water Act	Accidental \$/barrel With gross negligence \$/barrel	1000 \$4,300	Herron 2013
COMPENSATION FOR HEALTH EFFECT DAMAGE	UNITS	VALUE	REFERENCE
Fatality	\$/fatality	1,500,000	OH&S 2011
Serious (irreversible) injury	\$/individual	1,500,000	OH&S 2011
Loss of Life	\$/fatality	2,200,000	Dolan 2010
Irreversible Effects	\$/individual	500,000	Dolan 2010
Adverse Effects	\$/individual	50,000	Dolan 2010
COMPENSATION FOR WILDLIFE KILL	UNITS	VALUE	REFERENCE
Endangered species	\$/each	10,000 to 100,000	Modified from Brown 1992
Threatened species	\$/each	4,000 to 10,000	Modified from NCAC 2002
Common species	\$/each	5 to 4,000	Modified from NCAC 2002
COMPENSATION FOR LIVESTOCK KILL	UNITS	VALUE	REFERENCE
Cattle	\$/ea	800 to 2,000	Various sources
Horses	\$/ea	500 to 5,000	Various sources
Sheep/hogs	\$/ea	100 to 200	Various sources
Poultry	\$/ea	1 to 10	Various sources
COMPENSATION FOR CROP AND TIMBER DAMAGE	UNITS	VALUE	REFERENCE
Low productivity soil	\$/acre per year	267 to 702	Purdue 2011
Average productivity soil	\$/acre per year	336 to 880	Purdue 2011
High productivity soil	\$/acre per year	406 to 1,058	Purdue 2011
Timberland damage	\$/acre per year	2,000 to 5,000	Various sources
Timberland reforestation	\$/acre per year	300 to 800	Various sources
LAND RECLAMATION	UNITS	VALUE	REFERENCE
Restoration for temporary or permanent impacts to sensitive habitat, wetlands, floodplains, forested areas, etc.	\$/acre	50,000	RPSEA 2010

WATER HANDLING AND STORAGE CAPITAL COSTS	UNITS	VALUE	REFERENCE
Water pipeline	\$/in-dia/linear foot	10	RPSEA 2010
Water transfer and distribution pump stations	\$/hp	2,000	RPSEA 2010
Steel water storage tank	\$/million gallons	50,000	RPSEA 2010
Concrete water storage tank	\$/million gallons	60,000	RPSEA 2010
Plastic water storage tank	\$/million gallons	120,000	RPSEA 2010
Water storage pond	\$/acre	40,000	RPSEA 2010
Buildings	\$/square foot	100	RPSEA 2010
Water facility for discharge to stream	\$/million gallons per day	590,000	RPSEA 2010
Water disposal well	\$/million gallons per day	1,000,000	RPSEA 2010
Water percolation pond	\$/acre	40,000	RPSEA 2010
WATER DISPOSAL COSTS (CAPEX+OPEX)	UNITS	VALUE	REFERENCE
Shallow well injection	\$/barrel	0.30 to 10.00	RPSEA 2009
Deep well salt water disposal	\$/barrel	0.40 to 0.60	Imperial Resources 2010
Evaporation	\$/barrel	0.40 to 3.95	RPSEA 2009
Land application	\$/barrel	0.30 to 26.25	RPSEA 2009
Thermal treatment	\$/barrel	10.50 to 105	RPSEA 2009
Cavern disposal	\$/barrel	0.30 to 10.00	RPSEA 2009
General water disposal cost range	\$/barrel \$/t	0.50 to 5.00 3 to 30	RPSEA 2009
REVERSE OSMOSIS DESALINATION	UNITS	VALUE	REFERENCE
Seawater (20,000 to 47,000 mg/l TDS) reverse osmosis - SWRO			
Capex	\$/bpd treated	125 to 295	RPSEA 2009
Opex	\$/barrel treated	0.08	
Membrane life	Years	3 to 7	
Power consumption	kWh/barrel	0.46 to 0.67	
Permeate recovery at 100 to 400 mg/l TDS	% of feed	30 to 60	
Brackish water (500 to 25,000 mg/l TDS) reverse osmosis - BWRO			
Capex	\$/bpd treated	35 to 170	RPSEA 2009
Opex	\$/barrel treated	0.03	
Membrane life	Years	3 to 7	
Power consumption	kWh/barrel	0.02 to 0.13	
Permeate recovery at 100 to 1500 mg/l TDS	% of feed	60 to 85	
SWRO production cost (capex + opex)	\$/m3	0.59 to 1.50	Modified from Younos 2005
BWRO production cost (capex + opex)	\$/m3	0.20 to 0.60	Modified from Younos 2005
SWRO cost delivered to consumer (30,000 to 35,000 ppm TDS feed)	\$/1000 gallons	3.00 to 8.00	AMTA 2007
BWRO cost delivered to consumer (1,000 to 5,000 ppm TDS feed)	\$/1000 gallons	1.50 to 3.00	AMTA 2007
SWRO+ ion exchange (10,000 to 85,000 ppm TDS feed)	\$/t	0.30 to 0.80	Aines 2010
OTHER WATER TREATMENT COSTS (CAPEX + OPEX)	UNITS	VALUE	REFERENCE
Ion exchange at 7500 bpd (220 gpm)	\$/barrel	0.08 to 0.11 (30% tied to capital)	RPSEA 2009
Ion exchange at 30,000 bpd (880 gpm)	\$/barrel	0.04 to 0.07 (20% tied to capital)	RPSEA 2009
Air stripping 1,714 bpd in a low profile tray stack	\$/barrel	0.08 to 0.09	FRTR 2002
Air stripping 17,142 bpd in a low profile tray stack	\$/barrel	0.02	FRTR 2002
Nanofiltration of brackish water (500 to 25,000 mg/l TDS)			
Capex	\$/bpd treated	35 to 170	RPSEA 2009
Opex	\$/barrel treated	0.03	
Membrane life	Years	3 to 7	
Power consumption	kWh/barrel	0.08	
Recovery	% of feed	75 to 90	
Replacement of potable water supply (\$3/kgal)	\$/t	0.8	Unpublished
PRODUCED WATER DISPOSAL COSTS	UNITS	VALUE	REFERENCE
Surface discharge			
Capex	\$/bpd treated	4.69	ARI 2006
Opex	\$/barrel treated	0.04	
Infiltration impoundment capital cost			
Capex	\$/bpd treated	65.31	ARI 2006
Opex	\$/barrel treated	0.10	
Shallow re-injection well			
Capex	\$/bpd treated	113.75	ARI 2006
Opex	\$/barrel treated	0.10	
Reverse osmosis with trucking and disposal of residual concentrate			
Capex	\$/bpd treated	225.94	ARI 2006
Opex	\$/barrel treated	0.31	

CHEMICALS AND INJECTION FLUIDS	UNITS	VALUE	REFERENCE
Xylene for control of asphaltene precipitation	\$/t xylene	1050 to 1125	ICIS 2011B
Methanol for control of gas hydrate buildup	\$/t methanol	420 to 430	ICIS 2011B
Chlorine gas for control of microbial growth	\$/t chlorine	310 to 340	ICIS 2011A
Caustic soda for control of pH	\$/t NaOH	500	RPSEA 2009
Hydrochloric acid for control of scaling	\$/t hydrochloric acid	99 to 132	ICIS 2011C
Hot water for control of paraffin precipitation	\$/t hot water	2 to 3	Calculated
Steam for control of paraffin precipitation	\$/t steam	14 to 19	Calculated
Fresh water for control of salt precipitation	\$/t water	0.5 to 1.0	Unpublished
Brine for control of pressure	\$/t brine	0.5	Unpublished
Liquid nitrogen for sweep	\$/t LN2	50 to 100	Various sources
LITIGATION COSTS	UNITS	VALUE	REFERENCE
Short-term litigation costs (during active months)	\$/month	75,000 to 150,000	Best professional judgment
Long-term litigation costs	\$/year	500,000	Best professional judgment
EARTHQUAKE DAMAGE	UNITS	VALUE	REFERENCE
Earthquake intensity in peak ground acceleration			
<0.092 gravity	% of total building and infrastructure replacement value	0	Modified from ATC 1985
0.092 to 0.18 gravity		0.5	
0.18 to 0.34 gravity		5	
0.34 to 0.65 gravity		20	
0.65 to 1.24 gravity		45	
>1.24 gravity		80 to 100	
PIPING COST	UNITS	VALUE	REFERENCE
2-inch polyethylene pipe	\$/ft not installed	2.4	ebay.com
2-inch polyethylene pipe	\$/ft installed	4.00-9.32	Tubbs 2008
3-inch polyethylene pipe	\$/ft installed	5.5	Banks 2006
4-inch polyethylene pipe	\$/ft installed	8.00-15.56	Tubbs 2008
6-inch polyethylene pipe	\$/ft installed	17	Banks 2006
6-inch polyethylene pipe	\$/ft installed	10.00-32.00	Tubbs 2008
2-inch steel pipe*	\$/ft installed excl. ROW	18.94	Calculated
3-inch steel pipe*	\$/ft installed excl. ROW	28.41	Calculated
4-inch steel pipe*	\$/ft installed excl. ROW	37.88	Calculated
6-inch steel pipe*	\$/ft installed excl. ROW	56.82	Calculated
8-inch steel pipe*	\$/ft installed excl. ROW	75.76	Calculated
*Based on \$50,000 per inch-mile.			
FRACTURE STIMULATION TREATMENTS IN THE FRUITLAND FORMATION OF THE SAN JUAN BASIN	UNITS	VALUE	REFERENCE
Crosslinked gelled sand fracking	\$/well	50,000-60,000	EPA 2004 Palmer 1993
Slick water sand fracking	\$/well	25,000- 35,000	EPA 2004 Palmer 1993
Foam fracking (gelled water)	\$/well	100,000-110,000	EPA 2004 Palmer 1993
Foam fracking (slick water)	\$/well	75,000-85,000	EPA 2004 Palmer 1993

Appendix C

Schedule of Insurable Risks and Estimated Minimum Requirements for a CO₂ Sequestration Facility

SCHEDULE OF INSURABLE RISKS AND ESTIMATED MINIMUM REQUIREMENTS FOR A CO2 SEQUESTRATION FACILITY											
Category	Insurable Risk	Type of Insurance or Risk Financing Instrument Needed	When Is Insurance Needed?	Normal Coverage Term	Probable Minimum Required Limits	Probable Minimum Deductible / Self Insured Retention	Premium Rating Basis	Probable Minimum Annual Premium Rate	Valuation of Premium Rating Basis	Insurable Perils (Causes of Loss)	Comments
Property Damage	Direct damage to buildings and equipment under construction or installation	Builders/Installation Risk	Prior to facility construction/ installation	12 months	Total values of buildings and equipment	\$5,000 to \$100,000	Total values of buildings and equipment	\$0.20 per \$100 of total values	Replacement cost	All risk type including mechanical breakdown, testing subject to exclusions	Common excluded perils (cause of loss) include war, nuclear, latent defect
	Net revenue loss, continuing/expediting expenses after direct damage to buildings and equipment under construction or installation	Property/Time Element (Business Interruption, Extra Expense)	Prior to facility construction/ installation	12 months	Total values of buildings and equipment	5 Days	Total values of buildings and equipment	\$0.25 per \$100 of total values	Actual loss sustained	All risk type including mechanical breakdown subject to exclusions	Common excluded perils (cause of loss) include war, nuclear, latent defect
	Direct damage to buildings and equipment	Property/Direct Damage	During operation and post-injection site care	12 months	Total values of buildings and equipment	\$50,000	Total values of buildings and equipment	\$0.15 per \$100 of total values	Replacement cost	All risk type including mechanical breakdown subject to exclusions	Common excluded perils (cause of loss) include war, nuclear, latent defect
	Net revenue loss, continuing/expediting expenses after direct damage to buildings and equipment due to insurable perils	Property/Time Element (Business Interruption, Extra Expense)	During operation and post-injection site care	12 months	Total values of buildings and equipment	5 Days	Total values of buildings and equipment	\$0.25 per \$100 of total values	Actual loss sustained	All risk type including mechanical breakdown subject to exclusions	Common excluded perils (cause of loss) include war, nuclear, latent defect
	Direct damage to buildings and equipment; net revenue loss, continuing/expediting expenses after direct damage to buildings and equipment due to earthquake and flood	Property/Time Element (Business Interruption, Extra Expense)	During operation and post-injection site care	12 months	Total values of buildings and equipment	2% to 10% of Insured Values per Location	Total values of buildings and equipment	\$0.03 per \$100 of total values	Actual loss sustained	Earthquake, flood	Insurers will only provide significantly reduced negotiated sublimits
	Direct damage to machinery and equipment in transit	Property/Direct Damage; Property/Time Element (Business Interruption, Extra Expense)	Prior to facility construction/ installation and/or during operation and post-injection site care	12 months	Total values of property in transit and estimated time element exposure	\$5,000- \$100,000	Total values of property in transit and estimated time element exposure	\$0.07 per \$100 of total values	Replacement cost	Transit	
	Net revenue loss, continuing/Expediting Expenses after direct damage to machinery and equipment in transit	Property/Direct Damage; Property/Time Element (Business Interruption, Extra Expense)	Prior to facility construction/ installation and/or during operation and post-injection site care	12 months	Total values of property in transit and estimated time element exposure	\$5,000 to \$100,000	Total values of property in transit and estimated time element exposure	\$0.07 per \$100 of total values	Replacement cost	Transit	
	Direct damage to underground pipeline(s) and/or pipelines off premise	Underground or Off-Premises Pipeline	Prior to facility construction/ installation and during operation	12 months	Total replacement value	\$50,000 to \$100,000	Mileage and diameter of pipe; # of pump stations		Replacement cost	Specified perils including, earthquake, flood, explosion	Common excluded perils (cause of loss) include war, nuclear, latent defect; depend; depending upon length of pipeline, the insurance may be included in facility property policy.
	Direct damage to mobile equipment	Equipment Floater	During operation and post-injection site care	12 months	Total values of mobile equipment	\$5,000 to \$100,000	Total values of mobile equipment	\$0.20 per \$100 of total values	Replacement cost	All risk type subject to exclusions	
Third-Party Liability	Sudden and accidental failure of well control	Control of Well Insurance	During operation and post-injection site care	12 months	\$3,000,000 to \$5,000,000	\$100,000 to \$250,000	Total well(s) depth in feet	\$0.15 to 0.20 per foot	Expense reimbursement	Loss of well control (not including seepage)	
	Bodily injury, property damage or personal injury to third-parties due to operations and/or completed operations	General Liability	Prior to facility construction/ installation and during operation and post-injection site care	12 months	\$1,000,000 to \$2,000,000	\$5,000	Volume of CO ₂ sequestered		N/A		
	Bodily injury, property damage to third-parties due to vehicle use	Business Auto Liability	Prior to facility construction/ installation and during operation and post-injection site care	12 months	\$1,000,000	\$0 to \$5,000	# of vehicles	\$350 to \$1,500 per insured vehicle	N/A		
	Direct damage to owned/rented vehicles	Business Auto Physical Damage	Prior to facility construction/ installation and during operation and post-injection site care	12 months	N/A	\$0	Per Vehicle	\$300 to \$500 per insured vehicle	Actual Cash Value		
	Injury to employees	Employers Liability	Prior to facility construction/ installation and during operation and post-injection site care	12 months	\$1,000,000	\$0		Included in Workers Compensation premium	N/A		Applies only in injured employee(s) are able to reject statutory Workers Compensation benefit
	Extraordinary third-party liability due to bodily injury and property damage associated with catastrophic non-environmental events	Umbrella Liability	Prior to facility construction/ installation and during operation and post-injection site care	12 months	\$25,000,000	N/A	Underlying liability premium costs	30-60% of underlying liability premium costs	N/A		Typically, provides excess liability insurance above General Liability, Business Auto Liability and Employers Liability
	Injury to employees	Workers Compensation	Prior to facility construction/ installation and during operation and post-injection site care	12 months	Statutory benefits	\$0	Payroll per state defined employee classification	\$7.50 per \$100 total payroll	N/A		
	Loss of carbon credits	Customized Insurance Product	During operation and post-injection site care	12 to 36 months	Customized/ negotiated	\$0 to \$1,000,000	Regulation and political climate	1-10% of desired limit	N/A	Customized/ negotiated peril definitions	
	Environmental	Injury to environment at CO ₂ sequestration facility and surrounding third-party land and assets	Environmental Liability	Prior to facility construction/ installation and during operation and post-injection site care	12 to 36 months	\$10,000,000	\$50,000	Variable rating which includes, but not limited to, existing environmental conditions, size of property, project revenue, limits required	At least \$100,000	N/A	All risk, subject to exclusions
Surety Bonds	Performance assurance for third-party building/installation contractors and/or third-party facility operators	Surety (Bond)	Prior to facility construction/ installation and during operation and post-injection site care	12 to 36 months	Contractual obligation	Deductible not referenced, but collateral may be required	Total value of contractual obligation	\$5 per \$1000 of contractual obligation	Contractual obligation	Third-party contractor's non-performance as required by contract	Surety company has right to provide performance before monetary remedy is made.
	Financial assurance obligation for closure/post closure	Closure/Post Closure Insurance or Surety (Bond) Alternative	Prior to facility construction/ installation and during operation and post-injection site care	12 months	Regulated remedy	Deductible not referenced, but collateral may be required	Total value of financial assurance required	2.0% to 4.5% per total financial assurance. Collateral required will affect percentage.	N/A	Claim made by a regulatory body for closure/post closure (partial or final closure)	Insurer typically pays claim directly to regulatory body, not to the insured

Appendix D

CO₂ Sequestration Financial Model

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
1	00.00.00.00.	ASSESSMENT BASIS	This category of FEPs determines the boundary conditions for any assessment, specifying the spatial and temporal domain of the system. The Assessment Basis determines what is being assessed and why, so that those FEPs that need to be considered in the analysis can be defined, and those which can be screened out as being outside the scope of the assessment can be identified.									
2	00.01.00.00.	Purpose of the assessment	The purpose of the assessment of geological CO2 sequestration.	The general purpose of an assessment of geological CO2 sequestration is to determine the performance of the sequestration system. In any specific case, however, the purpose of conducting an assessment may vary from simple calculations to test initial ideas for sequestration concepts, to support for an application for regulatory approval requiring detailed, site-specific performance assessment against relevant criteria. The level of complexity and comprehensiveness will vary according to the use to which it will be put. Additionally, the assessment endpoints of interest may not only vary in type, depending on the assessment purpose, but also in the level of rigor required for compliance demonstration.	Evaluate the CO2-EOR risks of the SACROC Northern Platform area							
3	00.02.00.00.	Endpoints of interest	The assessment endpoints of interest.	The structure and composition of an assessment will tend to reflect the endpoints that are required to be assessed. These in turn, will reflect the criteria that are adopted to judge the overall performance of the sequestration system. Thus, for example, an assessment may be constrained to considering the degree of containment within a geological feature, alternatively, it may need to address potential near-surface impacts. Invariably, a combination of endpoints will be required.	Comprehensive quantitative risk assessment							
4	00.03.00.00.	Spatial domain of interest	The spatial domain of interest in the assessment.	The spatial domain of interest will be dependent on the site context, which may vary from generic assessments to site specific assessments, the sequestration concept and the endpoints of interest. The spatial domain will contribute to determining the information requirements and modeling capabilities that may be required.	SACROC Northern Platform area							

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
1	00.00.00.00.	ASSESSMENT BASIS	0	0	0	0															
2	00.01.00.00.	Purpose of the assessment	0	0	0	0															
3	00.02.00.00.	Endpoints of interest	0	0	0	0															
4	00.03.00.00.	Spatial domain of interest	0	0	0	0															

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
5	00.04.00.00.	Timescales of interest	Timescale of interest for the assessment.	Timescales over which the assessment will be performed will constrain processes which must be considered in the assessment. In general terms, there are three timescales of interest for geological storage of carbon dioxide. Firstly, there is the timescale during construction and operation which has a lifetime in years or decades. Secondly there is a timescale over which isolation of carbon dioxide from the atmosphere is necessary to mitigate climate change. This timescale is likely to be in the order of a few hundred years at most. The third timescale of interest is potentially much longer and is that pertaining to the assessment of potential hazard to humans and the environment. This timescale could be in the order of thousands to tens of thousands of years.	Risk assessment: 1948 through end of CO2-EOR operations. Economic history: 2002-2011. Economic forecast: 2012-2021.							
6	00.05.00.00.	Sequestration assumptions	High level assumptions concerning the sequestration system(s) of relevance to the assessment. For example, the quantity and quality of CO2 sequestered, the method of injection and information concerning the assumed performance of the sequestration system.	Provides a background to the sequestration technique adopted. Note that more detailed consideration of the CO2 sequestration system is provided in subsequent FEP categories.	Reproduce historical performance from 1972 through 2002. Run three scenarios from 2009 through 2030 based on conventional CO2-EOR, best practices and high CO2 injection rates for enhanced oil recovery.							
7	00.06.00.00.	Future human action assumptions	The assumptions made in the assessment concerning general boundary conditions for assessing future human action and exposure.	For example, it can be expected that human technology and society will develop over the timescales of relevance for the assessment of CO2 sequestration systems, however, this development is unpredictable. Therefore it may be necessary to make some assumptions in order to constrain the range of future human actions that are considered, such as assuming that only present-day technologies, or technologies practiced in the past, will be considered.	Assume no change in human activity in the area.							
8	00.07.00.00.	Legal and regulatory framework	The legal and regulatory framework within which the assessment takes place.	In undertaking an assessment it is vital to consider the appropriate regulatory framework requirements. At one extreme these may be specific, prescriptive quantitative requirements, at the other they could be non-prescriptive or may not have been fully developed. The legal and regulatory framework can shape various aspects of an assessment, such as the required assessment endpoints, timescales of interest and assumptions concerning future human actions.	Assume no change in legal and regulatory framework.							
9	00.08.00.00.	Model and data issues	General methodological issues affecting the assessment modeling process and use of data	Examples of general model and data issues include the treatment of uncertainty; the availability, collection and method for handling site specific data; and the reduction/simplification of models and data.	Process-level modeling using CMG GEM using available published site data as of 2012 and filling in with assumptions where there are gaps.							

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
5	00.04.00.00.	Timescales of interest	0	0	0	0															1
6	00.05.00.00.	Sequestration assumptions	0	0	0	0															1
7	00.06.00.00.	Future human action assumptions	0	0	0	0															
8	00.07.00.00.	Legal and regulatory framework	0	0	0	0															
9	00.08.00.00.	Model and data issues	0	0	0	0															

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
10	00.09.00.00.	Public acceptance and information	The amount and type of information needed for public acceptance and to comply with industry best management practices.	Focus on health, safety and environmental risks as well as economic and lifestyle impact on the public at large.	Based on 64 years of operation, there is public acceptance.							
11	00.10.00.00	Financial viability	The minimum return on investment needed to justify the risks involved in undertaking the project.	Higher risks require higher rewards to justify undertaking a project. The risk assessment may give an indication of the minimum rate of return required to attract capital funding for the project.	Assume 20% internal rate of return.							
12	00.11.00.00	Adequate risk characterization	The level of detail and depth of risk characterization needed.	Characterization of risks can include identifying potential modes of failure, estimating probability of failure occurring and impact severity of failure and determining potential steps to prevent or mitigate failure.	Comprehensive quantitative risk assessment through QFMEA. Independent assessment based on information in the public domain.							
13	01.00.00.00.	EXTERNAL FACTORS	This category of FEPs describes natural or human factors that are outside the system domain. These FEPs are most important in determining scenarios for the future evolution of the system, and are often referred to as EFEPs (External FEPs). Three classes of FEPs are considered. Geological Factors and Climatic Factors are concerned with natural processes and events, whilst Future Human Actions is concerned with those human activities that can directly affect the sequestration system.	This category is divided into three classes: 1. Geological factors 2. Climate factors 3. Human action factors								
14	01.01.00.00.	Geological factors	Natural geological processes and events in the environment outside the system domain that are relevant to the evolution of the sequestration system.	Changes in the geological environment outside the system domain may directly affect the transport of carbon dioxide within the system.								
15	01.01.01.00.	Neotectonics	Neotectonics is the study of crustal movements that both occurred in the Earth's recent past and are continuing at the present day. These movements, which are driven directly or indirectly by global plate motions (tectonics), result in the vertical and horizontal warping, folding or faulting of the Earth's surface.	Neotectonic events have the potential to cause sudden changes in the physical properties of rocks due to stress changes and induced hydrogeological changes.	Stable regional area. Neotectonics not likely to impact site.		Damage to equipment (wells, pipeline, surface facilities). Caprock failure. Reservoir disruption.	Significant sudden crustal movement	Leakage of CO2 Shutdown of facility. Loss of business.	Geodetic monitoring (GPS, InSAR, LIDAR, strain, tilt, etc.). Monitoring passive seismic activity.	Avoid high risk sites (areas with active crustal movement). Fully characterize	Proper shutdown procedures in case of an earthquake. Emergency response procedures for dealing with CO2 leakage. Discontinue injection and decrease reservoir pressure.
16	01.01.02.00.	Volcanic and magmatic activity	Magma is molten, mobile rock material, generated below and within the Earth's crust, which gives rise to igneous rocks when solidified. A volcano is a vent or fissure in the Earth's surface through which molten or part-molten materials (lava) may flow, and ash and hot gases be expelled.	The high temperatures associated with volcanic and magmatic activity may result in permanent changes in the surrounding rocks, either directly, or through circulating high temperature fluids. This FEP is relevant to CO2 disposal in areas of potential magmatic activity, e.g. Japan. Besides bedrock damage, pressure and temperature changes due to heating, stress, or displacement could affect CO2 density and solubility, creating the risk of uncontrolled, rapid migration and escape of stored CO2. CO2STORE page 69)	No local volcanic activity.		Borehole damage. Pipeline failure. Reservoir disruption.	Volcanic eruption. Magmatic intrusion.	CO2 leakage (HSE hazard). Damage to boreholes, equipment, pipeline, caprock. Shutdown of facility. Loss of business.	Monitoring surface distortion with LIDAR and other remote geodetic measurements. Monitoring seismic activity. Monitoring change in bottom hole temperatures.	Proper site characterization and site selection avoiding areas with volcanic and magmatic activity.	Proper shutdown procedures in case of volcanic eruption. Emergency response procedures for dealing with CO2 leakage. Discontinue injection and decrease reservoir pressure.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
10	00.09.00.00.	Public acceptance and information	0	0	0	0															1
11	00.10.00.00	Financial viability	0	0	0	0															
12	00.11.00.00	Adequate risk characterization	0	0	0	0															1
13	01.00.00.00.	EXTERNAL FACTORS	0	0	0	0															
14	01.01.00.00.	Geological factors	0	0	0	0															
15	01.01.01.00.	Neotectonics	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
16	01.01.02.00.	Volcanic and magmatic activity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
17	01.01.03.00.	Seismicity (Natural earthquakes)	Events and processes related to naturally occurring seismic events and also the potential for seismic events. A seismic event is caused by rapid relative movements within the Earth's crust usually along existing faults. The accompanying release of energy may result in rock movement and/or rupture, e.g. earthquakes. Many people are convinced that we want to avoid seismically-active areas for CO2 storage. In reality there are very large natural gas fields associated with some of the planet's major fault zones (Indonesia, Malaysia and California). Earthquakes in these areas have never been associated with sudden emissions of significant quantities of natural gas or oil from deep reservoirs. (CCP 2009) Major earthquakes (magnitude 6 and above) occur primarily in strong, brittle basement rock at depths on the order of 10 km (6 miles) or more. Very small earthquakes occur at depths as shallow as 3 km (2 miles). Micro-seismicity consists of very tiny seismic events often responding to subsurface fluid flow and relative pressure changes. All parts of the Earth's crust are in continuous movement and generate micro-seismic events, and the analysis of micro-seismicity offers unique insights into subsurface properties (CCP 2009). 1. Earthquake induced fractures/faults 2. Natural micro-seismicity	Seismic events may result in changes in the physical properties of rocks due to stress changes and induced hydrogeological changes. Seismic events are most common in tectonically active or volcanically active regions at crustal plate margins. Seismic disturbances might cause caprock failure (Damen 2006). Earthquakes could disrupt drilling, well operation, and monitoring activities, and damage surface facilities including the CO2 source. An earthquake on a fault through the CO2 plume could create or close an open pathway. Earthquakes may cause public concern about the project even if not project related. Micro-seismicity may cause public concern about the project even if not project related, may add noise interfering with micro-seismic monitoring. Earthquake near Nakaoka, Japan CO2 injection site caused significant public concern causing project to be moved off shore, even though earthquake was not directly caused by CO2 injection.	There have been 45 earthquakes (2.5 to 4.6 magnitude and 5-10 km deep) recorded from 1977-2011 within 24 km of the SACROC Site. 32 of the earthquakes occurred between AUG 2010 and DEC 2011. Two occurred within the SACROC Site. Most activity was northeast of the SACROC Site (neic.usgs.gov 2012). USGS estimated probability of earthquake exceeding listed magnitude occurring within 50 km of SACROC within the next 50 years: 5.5 magnitude: 0.083% 6.0 magnitude: 0.038% 6.5 magnitude: 0.011% 7.0 magnitude: 0.001% (homefacts.com 2012)	Records for earthquakes below 2.5 magnitude not available.	Earthquake damage to borehole, equipment, pipeline, caprock, or reservoir.	Natural earthquake Magnitude ≥ 6.5 within 10 km	CO2 leakage (HSE hazard). Interruption of business. Natural micro-seismicity is unlikely to cause damage but may arouse public concern about the project.	Measuring the rate of slippage of landmarks along faults to predict earthquakes. Geodetic monitoring (GPS, InSAR, LIDAR, strain, tilt, etc.); Monitoring seismic activity to distinguish between natural and induced micro-seismicity. Monitoring well and pipeline pressures and equipment operation.	Proper site characterization and site selection avoiding areas with active fault zones and avoiding low lying tsunami zones. Baseline surveys for micro-seismicity prior to CO2 injection.	Proper shutdown procedures in case of an earthquake. Emergency response procedures for dealing with CO2 leakage. Discontinue injection and decrease reservoir pressure. Passive microseismic monitoring to confirm earthquake was natural rather than induced.
18	01.01.04.00.	Hydrothermal activity	Processes associated with high temperature groundwaters, and hydrothermal alteration of minerals in the rocks through which the high temperature groundwater flows. Hydrothermal activity may be directly associated with volcanic and magmatic activity. Hot springs, geysers and submarine hydrothermal vents provide evidence of hydrothermal activity.	Can result in the hydrothermal alteration of rocks or minerals by the reaction of hot water (and other fluids) with pre-existing rocks. Springs, geysers and submarine hydrothermal vents can provide pathways for CO2 to reach the surface.	No hydrothermal activity in the area (based on published bottomhole temperatures).		High bottom hole temperatures. Caprock failure. Mineralization and alteration of formation and wells. Alteration of formation fluid chemistry.	Hydrothermal activity	CO2 leakage (HSE hazard). Damage to boreholes and wells. Damage to monitoring equipment.	Existence of hot springs, geysers and hydrothermal vents. Higher than normal thermal gradient. Monitoring change in bottom hole temperatures. Monitoring change in reservoir fluid chemistry.	Proper site characterization and site selection avoiding areas of hydrothermal activity.	Decrease reservoir pressure. Extract CO2 or brine from reservoir and inject into another more secure reservoir.
19	01.01.05.00.	Hydrological and hydrogeological response to geological changes	Processes arising from large-scale geological changes and could include changes of fluid boundary conditions due to the effects of changes of fluid properties of geological units due to changes in rock stress or fault movements.	In and below low-permeability geological formations, hydrogeological conditions may evolve very slowly and often reflect past geological conditions, i.e. be in a state of disequilibrium	Reservoir closed on top, bottom and three sides. South side open to additional SACROC unit reservoir.		Reservoir disruption. Interaction between CO2/brine and near surface aquifers	Hydrological and hydrogeological response to geological changes.	Contamination of near surface drinking water.	Monitoring near surface water chemistry. Monitoring and modeling subsurface CO2 plume.	Proper site characterization and site selection, avoiding areas where hydrology or hydrogeology are in disequilibrium.	Decrease reservoir pressure. Extract CO2 or brine from reservoir and inject into another more secure reservoir.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) injuries: \$1.5M per injury	Minor (recover-able) injuries: \$0.05M per injury													
17	01.01.03.00.	Seismicity (Natural earthquakes)	2	4	1	8	PGA(g) 0.092-0.18 = 1/1000,000 fatality rate. PGA(g) 0.18-0.34 = 1/100,000 fatality rate. PGA(g) 0.34-0.65 = 1/10,000 fatality rate. PGA(g) 0.65-1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate. Not attributable to CO2-EOR.	PGA(g) 0.092-0.18 = 1/250,000 injury rate. PGA(g) 0.18-0.34 = 1/25,000 injury rate. PGA(g) 0.34-0.65 = 1/2,500 injury rate. PGA(g) 0.65-1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate. Not attributable to CO2-EOR.	PGA(g) 0.092-0.18 = 3/100,000 injury rate. PGA(g) 0.18-0.34 = 3/10,000 injury rate. PGA(g) 0.34-0.65 = 3/1,000 injury rate. PGA(g) 0.65-1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate. Not attributable to CO2-EOR.	PGA(g) >0.5 = damage to USDW aquifers. \$200/t CO2 released into USDW.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Not attributable to CO2-EOR.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	0 -15 days @ \$20,000/d revenue lost per pattern idled to assess and fix damage. Worst case: project shut down due to natural earthquake being mistaken as induced seismicity.	May require additional water curtains to isolate any new faults or injection of sealants to seal any new faults. Additional cost for continuous passive micro-seismic monitoring.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of total damages attributable to CO2-EOR.	Cost to locate and fix well leak \$0.3M per leak. + Cost to locate and fix fracture or fault leak: \$3M per leak. + Cost to replace contaminated USDW \$1M/y per leak until fixed. + Cost of lost CO2: \$0.5M per year per leak. Worst case: Project shutdown if natural earthquake mistaken for induced seismicity.	Cost to locate and fix well leak \$0.3M per leak. + Cost to locate and fix fracture or fault leak: \$3M per leak. + Cost to replace contaminated USDW \$1M per year per leak until fixed. + Cost of lost CO2: \$0.5M per year per leak.	Cost of continuous passive micro-seismic monitoring.: Capex: \$3.9M Opex: \$0.3M/y	Savings of \$1M/y per leak for USDW not contaminated + Savings of \$0.5M/y per leak of CO2 not lost.	Worst case: Saving of project value minus cost of continuous passive micro-seismicity monitoring.	1
18	01.01.04.00.	Hydrothermal activity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
19	01.01.05.00.	Hydrological and hydrogeological response to geological changes	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
20	01.01.06.00.	Large scale erosion (See 06.01.03.00)	Processes related to the large scale (geological) removal of rocks and sediments, with associated changes in topography and geological/hydrogeological conditions of the system.	Potential to modify the geological and hydrogeological environment.	Relatively flat topography except the northeast quadrant of the site which is full of drainage gullies (Brand quadrangle USGS topographic map 1979). Erosion due to storms likely to be very localized.							
21	01.01.07.00.	Bolide impact (meteorite impact)	An extraterrestrial body in the 1-10 km size range, which impacts the earth at high velocity, explodes upon impact, and creates a large crater.	A low probability, high consequence event that has the potential to substantially disrupt the CO2 storage system. Often screened out on the basis that the impact of the bolide will greatly exceed that of the disruption caused to the sequestration system.	Probability of a bolide impacting in Scurry County 4.6E-12 to 9.2E-12 per year (based on NASA estimates of 1 to 2 bolides per million years and Scurry County representing 4.6E-06 of the Earth's surface area).		Bolide impact causing caprock failure, destruction of surface facilities, human injury/death.	Bolide impact.	Catastrophic destruction. Release of CO2 may be one of the least effects.	NASA monitoring and modeling the trajectory of bolides in space.	Destruction of bolides in space before they have a chance to hit the earth.	Procedures to shutdown and evacuate site in cases of imminent danger.
22	01.02.00.00.	Climatic factors	Natural processes and events in the atmospheric environment that are relevant to the evolution of the sequestration system.	Changes in climate may directly affect the nature of any impacts that are incurred if carbon dioxide returns to the near-surface environment.								
23	01.02.01.00.	Global climate change (See 01.02.02.00.)	The process of global climate change due to natural and/or anthropogenic causes. The last two million years of the Quaternary have been characterized by glacial/interglacial cycling. According to the Milankovitch Theory, the Quaternary glacial/interglacial cycles are caused by long-term changes in seasonal and latitudinal distribution of incoming solar radiation which are due to the periodic variations of the Earth's orbit about the Sun (Milankovitch cycles). Evidence suggests that the Earth is presently in a period of global warming. The anthropogenic release of gases into the atmosphere may be increasing the rate of global warming by enhancing the natural greenhouse effect, a process by which long wave radiation emitted from the Earth is trapped in the atmosphere by greenhouse gases such as CO2.	Changes in the global climate are likely to impact the CO2 sequestration system in a number of ways. For example, through its affect on sea levels and the local and regional climate. Changes in ecology and human behavior in response to climate change will influence the relevant FEPs to be considered in the surface environment as an assessment extends into the future. Changes in air emission policies in response to global climate change will impact the feasibility of using CCS.	Drought, high temperatures and thunderstorms common in Scurry County.		Extreme weather events such as high wind and/or flooding damaging project facilities.	Significant and severe global climate change.	Business interruption (advance loss of profits), facilities damage.	Monitor trends in climate change that may have a detrimental effect on the project.	Proper site characterization and site selection avoiding low coastal areas or flood plains. Proper design consideration to accommodate extreme or changing weather patterns.	Maintain procedures for dealing with severe weather that may require an emergency shutdown.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) injuries: \$1.5M per injury	Minor (recover-able) injuries: \$0.05M per injury												
20	01.01.06.00.	Large scale erosion (See 06.01.03.00)	0	0	0	0															
21	01.01.07.00.	Bolide impact (meteorite impact)	1	5	1	5	PGA(g) 0.092-0.18 = 1/1000,000 fatality rate. PGA(g) 0.18-0.34 = 1/100,000 fatality rate. PGA(g) 0.34-0.65 = 1/10,000 fatality rate. PGA(g) 0.65-1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate. Not attributable to CO2-EOR.	PGA(g) 0.092-0.18 = 1/250,000 injury rate. PGA(g) 0.18-0.34 = 1/25,000 injury rate. PGA(g) 0.34-0.65 = 1/2,500 injury rate. PGA(g) 0.65-1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate. Not attributable to CO2-EOR.	PGA(g) 0.092-0.18 = 3/100,000 injury rate. PGA(g) 0.18-0.34 = 3/10,000 injury rate. PGA(g) 0.34-0.65 = 3/1,000 injury rate. PGA(g) 0.65-1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate. Not attributable to CO2-EOR.	PGA(g) >0.5 = damage to USDW aquifers. \$200/t CO2 released into USDW.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Not attributable to CO2-EOR.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	Shutdown of project	Shutdown of Project	up to 10% of total CO2 stored	10% of total damages	100% of project cost + cost to locate and fix leaks + cost of CO2 emitted + cost to replace contaminated USDW: >\$100M	100% of project cost + cost to locate and fix leaks + cost of CO2 emitted + cost to replace contaminated USDW: >\$100M	None	None	
22	01.02.00.00.	Climatic factors	0	0	0	0															
23	01.02.01.00.	Global climate change (See 01.02.02.00.)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
24	01.02.02.00.	Regional and local climate change (extreme weather events damaging facilities)	Processes related to the possible future changes, and evidence for past changes, of climate at a storage site. This is likely to occur in response to global climate change, but the changes will be specific to situation, and may include short term fluctuations. Climate is characterized by a range of factors including temperature, precipitation and pressure as well as other components of the climate system such as oceans, ice and snow, biota and the land surface. Climatic changes lasting only a few decades may be referred to as climatic fluctuations. These are unpredictable at the current state of knowledge although historical evidence indicates the degree of past fluctuations. 1. Warm climate effects (01.02.06.00) 2. Cold climate effects 3. Wet climate effects 4. Dry climate effects 5. Hydrological and hydrogeological response to climate change (01.02.07.00)	Changes in the regional and local climate could affect the CO2 sequestration system in a number of ways. For example, changes in groundwater recharge could affect regional hydrogeology and hence the transport of CO2 dissolved in groundwater. It may also alter the near-surface environment to which some of the disposed CO2 may migrate. Regions with a tropical climate may experience extreme weather patterns (monsoons, hurricanes) that could result in flooding, storm surges, high winds etc. with implications for erosion and hydrogeology. The high temperatures and humidity associated with tropical climates result in rapid biological degradation and soils are generally thin. In arid climates, total rainfall, erosion and recharge may be dominated by infrequent storm events. The hydrology and hydrogeology of a region is closely coupled to climate. Climate controls the amount of precipitation and evaporation, seasonal ice cover, and thus the soil water balance, extent of soil saturation, surface runoff groundwater recharge, sediment load and seasonality. Vegetation and human actions may modify these responses.	Local area susceptible to drought, high temperatures, tornados, lightning, thunderstorms and ice storms. Drought causing shrinkage of clay soil, resulting in road, rail and pipeline buckling. Thunderstorms may cause fast flooding. Estimated probability of occurrence at the SACROC Northern Platform Area: Tornado: 5.88E-03/y Thunderstorm wind: 3.8/y Hail: 8.9/y Flooding: 1.3/y Ice storm: 2E-01/y Blizzard: 1.6E-02/y Drought: 1.4/y Strong wind: 1.2E-01/y Dust storm: 1.2E-02/y Wildfire: 1E-02/y	Need historical data on weather damage to facilities.	Extreme weather events damaging project facilities.	Significant and severe regional or local climate change.	Business interruption (advance loss of profits), facilities damage. Monitoring extreme weather patterns.	Proper site characterization and site selection avoiding flood plains. Proper design consideration to accommodate extreme or changing weather patterns.	Maintain procedures for dealing with severe weather that may require an emergency shutdown.	
25	01.02.03.00.	Sea level change	Processes related to changes in sea level which may occur as a result of global (eustatic) change and/or regional geological change, e.g. isostatic movements. The component of sea-level change involving the interchange of water between land ice and the sea is referred to as eustatic change. As ice sheets melt so the ocean volume increases and sea levels rise. Sea level at a given location will also be affected by vertical movement of the land mass, e.g. depression and rebound due to glacial loading and unloading, referred to as isostatic change.	Sea level change may affect the sequestration system through its impact on the near surface environment and the regional or local hydrogeological regime.	Site not impacted by sea level change.		Flooding/erosion of pipeline right-of-way or injection site. Contamination of near surface drinking water with sea water.	Significant sea level change	Facilities flood damage. Business interruption (advanced loss of profits). Potential for project instead of sea level to be blamed for increased drinking water salinity.	Monitor trends in sea level change and analyze the potential impact on the project.	Proper site characterization and site selection avoiding low coastal areas or flood plains.	Installing barriers. Perform baseline surveys to determine source of water contamination.
26	01.02.04.00.	Periglacial effects	Related to the physical processes and associated landforms in cold but ice-sheet-free environments.	An important characteristic of periglacial environments is the seasonal change from winter freezing to summer thaw with large water movements and potential for erosion. Frozen sub-soils are referred to as permafrost. Melt water from seasonal thaw is unable to percolate downwards due to permafrost and saturates the surface materials. Permafrost layers may isolate the deep hydrogeological regime from surface hydrology, or flow may be focused at "taliks" (localized unfrozen zones, e.g. under lakes, large rivers or at regions of groundwater discharge).	No periglacial effects.		Erosion and frost heave. Permafrost forms local near-surface cap.	Periglacial effects	Damage to facilities. CO2 release (HSE hazard). Accumulation of migrating CO2 beneath permafrost zone and potential catastrophic release.	Monitoring weather forecasts for extreme conditions. Monitoring surface water movement and erosion patterns.	Proper site characterization and site selection avoiding permafrost areas.	Proper winterization of surface facilities. Erosion control barriers.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
24	01.02.02.00.	Regional and local climate change (extreme weather events damaging facilities)	3	2	1	6	None. Fatality rate: 1.5/1000 based on Katrina + flood Not attributable to CO2-EOR	Serious injury rate: 1.5/250 Not attributable to CO2-EOR	Minor injury rate: 4.5/100 Not attributable to CO2-EOR	Not attributable to CO2-EOR	Not attributable to CO2-EOR	Surface facilities damage <\$1M for most situations but \$10M+ if compressors are involved.	0-7 days @ \$20,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of total damages	Cost to repair surface facilities: <\$1M + Cost of business interruption	Cost of insurance deductable.	Cost of insurance coverage for weather and flood damage and business interruption: 0.28% of surface facilities value per year + 0.25% of revenue per year respectively.	Savings in cost to repair surface facilities + Savings in cost of business interruption - Cost of insurance - Cost of insurance deductable.	
25	01.02.03.00.	Sea level change	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
26	01.02.04.00.	Periglacial effects	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

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27	01.02.05.00.	Glacial and ice sheet effects	Processes related to the effects of glaciers and ice sheets within the region of a storage site. This is distinct from the effects of large ice masses on global and regional climate. The ice sheet and the permafrost beneath the ice sheet may constitute a barrier to groundwater flow and to heat loss. If the basal transmissivity of the till and bedrock below the ice is low, water pressures may rise to levels equaling the ice pressure inducing the formation of major conduits in the subglacial material. The central parts of the ice sheet are likely to be warm-based and could permit groundwater recharge to take place. Discharge of groundwater is likely to take place close to and beyond the frontal parts of the ice sheet. Excessive recharge at the margin of the ice sheet could provide direct recharge of oxidizing water to considerable depths in conductive fracture zones. If the permeability at and beyond the rim of the ice is low, the water pressures may again build up resulting in hydrofracturing of the ice or the rock mass. As the ice sheet advances, these induced fractures may increase their aperture and depth due to freezing of subglacial melt water.	Erosional processes (abrasion, over deepening) associated with glacial action, especially advancing glaciers and ice sheets, and with glacial melt waters beneath the ice mass and at the margins, can lead to morphological changes in the environment, e.g. U-shaped valleys, hanging valleys, fjords and drumlins. Depositional features associated with glaciers and ice sheets include moraines and eskers. The pressure of the ice mass on the landscape may result in significant hydrogeological effects and even depression of the regional crustal plate.	No glacial effects.		Erosion, deposition and hydrogeological effects having detrimental effect on CO2 geologic storage	Glaciers and ice sheet	Facilities damage and CO2 release (HSE hazard).	Monitor glacier and ice sheet movement. Analyze trends to project future movement.	Proper site characterization and site selection avoiding glaciers and ice sheets.	Permanently close facility and relocate project site.
28	01.02.06.00.	Warm climate effects (See 01.02.01.00.)										
29	01.02.07.00.	Hydrological and hydrogeological response to climate changes (See 01.02.01.00.)										
30	01.02.08.00.	Responses to climate change (See 01.02.01.00.)										
31	01.03.00.00.	Future human actions	Human activities that are relevant to the evolution of the sequestration system.	Human activities may directly interfere with the sequestered fluid resulting in immediate or delayed impacts.								
32	01.03.01.00.	Human influence on climate (See 01.02.01.00.)										

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
27	01.02.05.00.	Glacial and ice sheet effects	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
28	01.02.06.00.	Warm climate effects (See 01.02.01.00.)	0	0	0	0	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
29	01.02.07.00.	Hydrological and hydrogeological response to climate changes (See 01.02.01.00.)	0	0	0	0	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
30	01.02.08.00.	Responses to climate change (See 01.02.01.00.)	0	0	0	0	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
31	01.03.00.00.	Future human actions	0	0	0	0															
32	01.03.01.00.	Human influence on climate (See 01.02.01.00.)	0	0	0	0	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
33	01.03.02.00.	Motivation and knowledge issues (Future interference with or intrusion into the CO2 reservoir by third parties)	Events and processes related to the degree of knowledge of the existence, location and/or nature of the storage site. Also, reasons for deliberate interference with, or intrusion into, a CO2 storage site after closure with complete or incomplete knowledge. Knowledge of the sequestration site may be regained through post-closure airborne, geophysical or other surface-based non-intrusive investigation of a sequestration site. Such investigations might occur after information of the location of the sequestration system has been lost and therefore excludes monitoring of the disposal system, but includes activities such as prospecting for geological resources. The evidence of the sequestration, such as injection boreholes, may itself prompt investigation. 1. Inadvertent interference with or intrusion into the CO2 reservoir. 2. Deliberate interference with or intrusion into the CO2 reservoir. 3. Malicious intrusion and sabotage.	Some future human actions could directly impact upon performance of the storage system. The following could be distinguished: - inadvertent actions, which are actions taken without knowledge or awareness of the storage site, and - deliberate actions, which are actions that are taken with knowledge of the storage systems existence and location, e.g. deliberate attempts to retrieve any hydrocarbons (e.g., EOR and ECBM) associated with the CO2 Intermediate cases, of intrusion with incomplete knowledge, could also occur. Terrorist activities against pipelines and facilities.	Site registered and well defined. Inadvertent intrusion into the CO2 reservoir unlikely. Deliberate intrusion possible if recovery of oil in the residual oil zone is desired or recovery of CO2 for use in additional EOR.		Third-party penetration of the primary caprock.	Inadvertent or deliberate interference with or intrusion into the CO2 reservoir.	CO2 leakage.	Routine inspections and/or monitoring of the site for third-party subsurface activities.	Clearly mark the site with warning signs and register the site as a CO2 storage EOR site with the State.	Routine site inspection and monitoring. Supervising on site drilling activities. Procedures for stopping blowouts or leaks.
34	01.03.03.00.	Social and institutional developments	Events and processes related to changes in social patterns and degree of local government, planning and regulation. Potentially significant social and institutional developments include: 1. Changes in planning controls (zoning) 2. Environmental legislation; 3. Demographic change and urban development; 4. Changes in land use; 5. Loss of archives/records, loss/degradation of societal memory.	Social and institutional developments have the potential to affect motivation and knowledge issues, human use of the surface and sub-surface environments and the type of impacts that may be considered.	Unlikely to be affected by change in zoning, demographic change, change in land use or loss of records. Limited water resources in the area. Limited population. Could be affected by environmental legislation.		Change in zoning laws, land use, environmental legislation, demographics or loss of public records that would have significant detrimental effect on the project.	Radical social and institutional developments	Increased operating costs due to compliance with regulation changes or increased legal costs.	Monitor zoning, environmental legislation, and demographic trends.	Monitor zoning announcements, environmental legislation, and demographic changes. Taking appropriate legal action if necessary to protect the site . Clearly mark the site with warning signs and register the site as a CO2 storage site with the State. Keep backup documentation at off-site locations.	Routine site inspection and/or monitoring. Provide input/feedback to lawmakers.
35	01.03.04.00.	Technological developments	Events and processes related to future developments in human technology and changes in the capacity and motivation to implement technologies. This may include retrograde developments, e.g. loss of capacity to implement a technology. 1. New technology replacing the need for CO2 geologic sequestration 2. New low-cost desalination making saline aquifers more valuable 3. Lack of CO2 capture technology improvements making it too expensive 4. Robotic underground mining making deeper resources more mineable	Of interest are those technologies that might change the capacity of humans to intrude deliberately or otherwise into a storage site, to cause changes that would affect the movement of CO2 and associated contaminants, or that may otherwise affect the performance and safety of the sequestration system. Technological developments are likely but may not be predictable especially at longer times into the future.	Extremely unlikely to be negatively affected by technology development during the life of CO2-EOR operations. New technology could provided incentive to recover CO2 for more EOR or recover more residual oil below the water-oil contact.		CO2-EOR becoming infeasible due to a new technology development.	Technology development that would significantly expand cheap oil production or alternative fuel supplies.	Delay or shutdown of project. Increased costs. Business interruption (advanced loss of profits). Greater liability exposure.	Keep abreast of new technology developments and analyze impact on project economics.	Proactive approach in improving and optimizing CO2-EOR economics.	Take corrective action to address evolving competitive environment.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
33	01.03.02.00.	Motivation and knowledge issues (Future interference with or intrusion into the CO2 reservoir by third parties)	2	2	1	4	None	None	None	\$200/t CO2 released into USDW	\$0.1M to plug and abandon well.	Damage to caprock	0-7 days @ \$20,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 @ \$32.32/y per well leak	10% of damage costs	<\$0.5M	None	Registering site with the State and supervise third-party subsurface activities <\$0.1M	<\$0.4M	
34	01.03.03.00.	Social and institutional developments	2	3	1	6	None	None	None	None	None	None	None	Increased operating costs for compliance with new regulations or increased legal costs to protect the project: \$1-10M	None	10% of damage costs	<\$10M	None	Increased operating costs for compliance with new regulations or increased legal costs to protect the project: \$1-10M	None	
35	01.03.04.00.	Technological developments	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Monitor technology developments impacting cheap oil production or alternative fuel supplies. Part of ongoing costs.	None	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
36	01.03.05.00.	Drilling activities (third-party drilling through caprock)	Events related to any type of drilling activity in the vicinity of the CO2 sequestration system. These may be taken with or without knowledge of the disposal and may include activities such as: 1. Exploratory and/or exploitation drilling for natural resources; 2. Attempted recovery of residual hydrocarbon resources (e.g., EOR, ECBM, shale gas); 3. Drilling for water resources; 4. Drilling for site characterization or research; 5. Drilling for liquid waste or other fluids disposal; 6. Drilling for geothermal resources.	Has the potential to disrupt geological features that provide a barrier to CO2 migration and provide a relatively quick migration pathway to the near-surface.	Extremely unlikely. Operator controls rights to CO2 and oil. Area well characterized with over 639 deep wells within the Northern Platform area.	Need information on the potential for shale gas in Wolfcamp shale formations above reservoir.	1. Well CO2 blowout 2. Well CO2 leakage 3. Caprock failure	Drilling through caprock	Release of CO2 to upper formations, near surface aquifer, soil or atmosphere.	Routine inspections and/or monitoring of the site for drilling activity.	Clearly mark the site with warning signs and register the site as a CO2 storage site with the State.	Routine site inspection and monitoring. Supervising on site drilling activities. Procedures for stopping blowouts or leaks. Streamline requirements of lease co-use requirements as appropriate. Monitor well permit activity or institutional controls that prohibits any drilling activities in designated areas.
37	01.03.06.00.	Mining and other underground activities	Events related to any type of mining or excavation activity carried out in the vicinity of the storage site. These may be taken with or without knowledge of the site. Mining and other excavation activities include: 1. Resource mining or quarrying; 2. Excavation for industry, storage, disposal or military purposes; 3. Scientific or archaeological investigation; 4. Shaft construction, underground construction and tunneling; 5. Underground nuclear testing; 6. Malicious intrusion, sabotage or war; 7. Underground utilities and pipelines	Mining and other underground activities have the potential to disrupt the geosphere (storage reservoir, surrounding and overlying rock) and near-surface environment. They therefore have the potential to significantly affect the migration and distribution of sequestered CO2.	Mining not a factor in the area. Area well characterized. Several inactive mines and quarries (15-caliche pits, 1-gravel pit and 2-unidentified mines) in the Northern Platform area.	Need information on the potential for shale gas in Wolfcamp shale formations above reservoir.	Exposure of people to accumulated CO2 in confined underground spaces.	Mining and other underground activities.	CO2 leakage. Asphyxiation.	Routine inspections and/or monitoring of the site for mining and other underground activities.	Proper site characterization and site selection avoiding potential mining, industrial, military, archeological, geothermal, nuclear, waste disposal and transportation areas. Clearly mark the site with warning signs and register the site as a CO2 storage site with the State.	Routine site inspection and monitoring. Supervising on site drilling/excavation activities. Procedures for stopping blowouts or leaks.
38	01.03.07.00.	Human activities in the surface environment	Events and processes related to any type of human activities that may be carried out in the surface environment that can potentially affect the performance of the storage system, or leakage pathways, excepting those FEPs related to water management which are described elsewhere. Examples include: 1. Residential, industrial, and infrastructure construction; 2. Pollution of surface environment and groundwater. 3. Change in groundwater geochemistry not caused by project. 4. Human activities in the surface environment offsite (farming, harvesting, irrigation maintenance) in low areas with limited air circulation.	Human activities in the surface environment have the potential to affect CO2 release processes, should leakage occur. They may also determine the types of impact to be considered or activities that would increase risk exposures.	Very limited human activity in the site area. Population density estimated at 2.3 people per square mile. No significant population change expected.		Exposure of people to accumulated CO2 in low areas with limited air circulation. Contamination of groundwater by third parties not related to CO2.	Human activities in the surface environment .	Asphyxiation. Potential public concerns.	Routine inspections and/or monitoring of the site for human surface activities.	Clearly mark the site with warning signs and register the site as a CO2 storage site with the State.	Routine site inspection and monitoring. Supervising on site excavation activities. Procedures for stopping leaks.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
36	01.03.05.00.	Drilling activities (third-party drilling through caprock)	2	2	1	4	None	None	None	\$200/t CO2 released into USDW	\$0.1M to plug and abandon well.	Damage to caprock	0-7 days @ \$20,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$0.5M	None	Supervise third-party drilling activities <\$0.1M. Use BOP and packers for well control during deep drilling.	<\$0.4M	1
37	01.03.06.00.	Mining and other underground activities	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
38	01.03.07.00.	Human activities in the surface environment	2	2	1	4	None	None	None	None	Buildup of H2S/CO2 in confined spaces requiring ventilation.	None	0-15 days @ \$20,000/d revenue lost per pattern idled	None	5,000 to 10,000 t CO2 @ \$32.32/t CO2	10% of damage costs	<\$1M	None	Installation of H2S/CO2 monitors, alarms and ventilation in confined spaces <\$300k	<\$0.7M	1

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
39	01.03.08.00.	Water management	Events and processes related to groundwater and surface water management including water extraction, reservoirs, dams, and river management. Water is a valuable resource and water extraction and management schemes provide increased control over its distribution and availability through construction of dams, barrages, canals, pumping stations and pipelines. Groundwater and surface water may be extracted for human domestic use (e.g. drinking water, washing), agricultural uses (e.g. irrigation, animal consumption) and industrial uses. 1. Water extraction 2. Surface water reservoir construction 3. Dam construction 4. River management	Extraction and management of water may affect the movement of CO2 or associated contaminants to and in the surface environment.	No significant surface water or primary USDW aquifer in the area. Small creek runs through the site. Water in the Dockum secondary USDW aquifer has 1000 to 5000 ppm TDS. Limited use of groundwater locally for irrigation.		Contamination of ground/surface water with CO2/brine and migration of contaminated water.	Water management - extraction combined with CO2/brine leakage.	Extended water contamination.	Monitor CO2/salinity of ground/surface water.	Not applicable.	Monitor and model CO2 plume and brine movement. Monitor CO2 and salinity of ground/surface water. Stop CO2 injection, depressurize the reservoir. Locate and eliminate CO2/brine leaks. Segregate and treat contaminated water.
40	01.03.09.00.	CO2 presence influencing future operations	The presence of injected CO2 may hinder future extractive operations by obscuring seismic traces or by making the drilling process more difficult. Conversely, the presence of CO2 locally, might allow for more economic future enhanced oil recovery operations. This FEP assumes that future technical advances might identify useable resources in the vicinity of previous CO2 injection.	Drilling through a formation filled with supercritical CO2 might cause 'blowouts' or loss of CO2 along the wellbore. A CO2 'bubble' will change the velocity of seismic waves, distorting the 'image' of the underlying formations, and reducing confidence in the understanding of this structure.	Potential for shale gas or residual oil recovery (below the oil-water contact).	Impact of CO2 presence on potential recovery of shale gas or residual oil.	Well leakage. Distortion of seismic readings. CO2 leakage due to fracturing of Wolfcamp shale.	CO2 presence underground.	Release of CO2 to upper formations, near surface aquifer, soil or atmosphere.	Monitoring and modeling of CO2 plume.	Clearly mark the site with warning signs and register the site as a CO2 storage site with the State. Maintain blow out protectors and packers Use more than one method of monitoring CO2 plume movement.	Procedures/training for dealing with well blowouts. Seal well. Decrease reservoir pressure.
41	01.03.10.00.	Explosions and crashes (See 16.27.00.)										
42	02.00.00.00.	CO2 STORAGE	This category of FEPs specifies details of the sequestration concept under consideration. It is split into two classes for the pre- and post-closure periods.	This category is divided into two classes: 1. Pre-closure 2. Post-closure								
43	02.01.00.00.	Pre-closure	Details of the sequestration concept, the fluids injected, and factors for the design, construction, operation and decommissioning phases.	The details of the sequestration concept are fundamental to determining which FEPs in other categories need to be considered in a given assessment. Some details of sequestration operations may affect the post-closure performance.								
44	02.01.01.00.	Storage concept	Features related to the concept of storage, such as whether a closure exists (sequestration in an abandoned oil or gas field or coal seam) or whether isolation of CO2 is dependent upon slow diffusion rates through an extensive open structure (saline aquifer sequestration). 1. Deep saline aquifer CO2 storage - Sealed reservoir - Open reservoir 2. EOR CO2 storage 3. ECBM CO2 storage 4. Temporary CO2 storage and pumping facilities - Above ground - Underground (see Reversibility)	Different processes will be relevant to different storage concepts. For example, the rate of CO2 migration in an open aquifer will be relevant to safety assessment of saline aquifer storage, but less relevant to sequestration in a closed geological structure.	Mature (40 years) CO2-EOR storage with multiple stacked sinks and seals.		Loss of control of CO2 migration.	Improper storage concept.	Potential CO2 release (HSE hazard). Increased costs and loss of revenue.	Fully characterize and model the site early in the design phase. Continuously monitoring and modeling the site. Periodic evaluation of actual versus expected performance.	Fully characterize and model the site early in the design phase. Select the appropriate injection strategy for the site.	Continuously monitor and model the site. Make adjustments to CO2 injection strategy as necessary.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
39	01.03.08.00.	Water management	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
40	01.03.09.00.	CO2 presence influencing future operations	2	2	2	8	None	None	None	\$200/t CO2 released into USDW	\$0.1M to plug and abandon well.	Damage to caprock	0-7 days @ \$20,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$0.5M	\$0	Supervise third- party drilling activities <\$0.1M	<\$0.4M	1
41	01.03.10.00.	Explosions and crashes (See 16.27.00.)	0	0	0	0															
42	02.00.00.00.	CO2 STORAGE	0	0	0	0															
43	02.01.00.00.	Pre-closure	0	0	0	0															
44	02.01.01.00.	Storage concept	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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45	02.01.02.00.	CO2 quantities, injection rate	Features related to the amounts of CO2 injected and their rate of injection into the storage aquifer/reservoir.	High rates of CO2 injection could have adverse affects, such as formation fracturing. For fast injection rates, displacement of oil/water will not be efficient during enhanced oil recovery; instead one will recover CO2; premature breakthrough is undesirable from an economic perspective. Larger volumes of injected CO2 are likely to result in more frequent and more intense induced seismicity unless compensated for with simultaneous production of fluids.	Not an issue for CO2-EOR because fluids are injected and produced simultaneously, thus avoiding over pressuring. Project uses natural CO2. Injection rate is tied to optimizing EOR and based on constant pressure rather than constant volume.	Individual well injection and production data since 2002.	1. CO2 quantities, injection rate exceeding reservoir storage capacity. 2. Over pressuring. 3. Loss of injectivity	Large CO2 quantities. High CO2 injection rate. Mineralization in and near wellbore reduces injectivity. Reservoir conditions are different than expected (e.g., lower injection capacity or permeability; heterogeneities; reservoir compartmentalization).	High injection pressure causing fracture of reservoir/caprock causing CO2 leakage. Displacement of brine leading to resource contamination. Induced seismicity. Lower capacity than planned. Lower injectivity than planned. Inability to accept contracted CO2 from source and related business losses.	Monitoring CO2 injection rate and bottom hole pressure.	Fully characterize and model the site early in the design phase. Conduct injectivity tests and adjust injection plan appropriately. Avoid excess injection pressures. If injection pressure is unacceptably high, cut back on individual well injection rate and use additional injection wells.	Avoid excess injection pressures. If injection pressure is unacceptably high, cut back on individual well injection rate and use additional injection wells.
46	02.01.03.00.	CO2 composition	The composition and physical state (liquid, supercritical fluid etc.) of injected CO2, with contents of impurities etc. Temperature and pressure of injected fluid are also relevant. During CO2 storage operations, the principal injected gas is CO2 captured and concentrated from human activity sources. However, the gas that is injected into a reservoir may not be 100 % CO2, especially if there is some recycling of gas (in the case of enhanced oil recovery). Impurities can include: H2S, CH4, N2, NOx, SO2 and mercaptans. These may be present either intentionally or because it could be particularly difficult or superfluous to separate them from CO2. The CO2 stream may contain such things as: corrosives, noncondensable gases, oxidants, toxic impurities, flammable/combustible/pyrophoric constituents, odorous constituents, organics or particulates.	The presence of even small amounts of other gases has a strong effect on the phase behavior of CO2-dominated gases. High-pressure equations of state for CO2-dominated gas mixtures are required to take into account changes in critical pressures and temperatures caused by the presence of other gases. Impurities will reduce the critical temperature which, in turn, has effects on interfacial tension. Impurities may affect pore water chemistry (pH and redox conditions, for example) depending on the impurities involved. Special care is needed when considering corrosive gases, such as H2S.	CO2 currently coming from natural sources controlled by Kinder Morgan. McElmo dome 98.2% CO2.		Pipeline/well corrosion leading to leakage or rupture.	CO2 stream composition off spec.	CO2 release (HSE hazard). Downtime for repairs.	Monitoring composition of CO2 stream.	Maintain tight spec on CO2 stream composition Avoid upset operating conditions in CO2 supply dehydration.	Withhold purchase of CO2 until CO2 is on spec. Maintain injection HCPV with recycled CO2 and supplemental water. Select proper materials of construction for pipeline and well components and maintain tight seals and failsafe systems to prevent leakage. Monitor corrosion rate in piping and equipment.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
45	02.01.02.00.	CO2 quantities, injection rate	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
46	02.01.03.00.	CO2 composition	2	3	1	6	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	0-5 days @ \$20,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$3M	None	Cost of water to supplement CO2 injection <\$100k.	Up to \$2.9M	2

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
47	02.01.03.01.	CO2 containing H2S	High concentration of hydrogen sulfide (H2S) in the CO2 makes it a toxic waste which can lead to more stringent permitting and compliance requirements. It also increases the safety risks. The exposure threshold at which H2S is immediately dangerous to life or health, according to the National Institute of Occupational Safety and Health, is 100 ppm, compared to 40,000 ppm for CO2 (IPCC 2005) H2S should be kept below maximum concentration of 10 to 200 ppm in the CO2 for safety reasons.	Sufficient quantities of H2S + H2O in CO2 can cause corrosion or sulfide stress cracking (CCP 2009) and increase safety risks. H2S is strong smelling and requires additional sealing around the wellhead to capture fugitive emissions and minimize odors. On a positive side, H2S in CO2 can decrease minimum miscibility pressure (MMP) for enhanced oil recovery and makes small CO2 leaks easier to detect due to the smell.	H2S maintained less than 10 mg/l and total sulfur maintained below 35 mg/l in current purchased CO2. Recycled CO2 has 1000 mg/l of H2S.		Well/piping corrosion leading to leakage or rupture. Human injury/death.	High H2S content in CO2 stream in presence of water.	CO2 + H2S release. Liabilities.	Monitoring H2S content of purchased CO2 stream and recycled CO2 stream. Monitor H2S around injection wells and gas recycling facilities.	Maintain tight H2S specification on CO2 supply. Avoid contact with water. Avoid upset conditions with CO2 dehydration	Stop injection and fix or resolve leakage. Select proper materials of construction for pipeline, gas recycling facilities and well components and maintain tight seals and failsafe systems to prevent leakage. Monitor for H2S around injection wells and gas recycling facilities. Install alarms.
48	02.01.03.02.	CO2 containing H2O	In order to prevent corrosion in pipeline and wellhead systems, CO2 is normally dehydrated to less than 0.5 g/m³ (30 lb per MMCF) or less than 20 ppm. (WRI 2008)	If the water vapor is not removed prior to compression, the CO2 product will be very corrosive and the pipeline well head and borehole would have to be built with much more expensive materials than carbon steel.	Water maintained less than 25 lbs per MMCF in purchased CO2.		Pipeline/well corrosion leading to leakage or rupture.	High H2O content in CO2 stream.	CO2 release (HSE hazard).	Monitoring H2O content of purchased CO2 stream and recycled CO2 stream. Monitoring pipeline thickness.	Maintain tight H2O specification on CO2 stream. Avoid upset conditions with CO2 dehydration. Properly eliminate residual water from pipelines.	Monitor for water in CO2 streams and pipeline. Stop injection and fix or resolve leakage. Proper selection of materials of construction for pipeline, gas recycling facilities and well components.
49	02.01.03.03.	CO2 containing O2	EOR and deep saline applications can tolerate some oxygen (air) in the CO2, but ECBM can't. Oxygen in CO2 will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow. The preferred specification is less than 10 ppm oxygen. Oxygen in the 1-2% range or above could impact mineralogical reactions in the reservoir.	Oxygen in CO2 can cause pipeline corrosion, oxidize oil in EOR or oxidize coal and/or methane in ECBM. High oxygen content (5-10%) will not liquefy or dissolve in downhole storage of CO2, and therefore will result in undesirable back pressure and downhole gas pockets. Oxygen can contaminate or degrade CO2 capture and CO2 dehydration sorbents. Oxygen could cause subsurface microbial growth but is not expected to have a significant impact.	O2 maintained less than 10 ppm in purchased CO2.		Pipeline/well corrosion leading to leakage or rupture. Oxidation of oil in EOR. Oxidation of coal and/or methane in ECBM.	High O2 content in CO2 stream	CO2 leakage. Lower EOR yield. Lower ECBM yield.	Monitoring O2 content of purchased CO2 stream and recycled CO2 stream. Monitoring pipeline thickness.	Maintain tight O2 specification on CO2 supply. Avoid upset conditions and ingress in CO2 production system.	Monitor for O2 in CO2. Stop injection and fix or resolve leakage.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) injuries: \$1.5M per injury	Minor (recover-able) injuries: \$0.05M per injury												
47	02.01.03.01.	CO2 containing H2S	3	4	1	12	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	2 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	0-5 days @ \$20,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$3M	None	Monitor H2S in CO2 and around injection wells and recycle facilities. Maintain tight seals and failsafe systems <\$300k	Up to \$2.7M	1
48	02.01.03.02.	CO2 containing H2O	3	3	1	9	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	0-5 days @ \$20,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$3M	None	Monitor for H2O in CO2. Monitor pipeline corrosion. Monitor pipeline leakage <\$300k	Up to \$2.7M	1
49	02.01.03.03.	CO2 containing O2	2	3	1	6	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	0-5 days @ \$20,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$3M	None	Monitor for O2 in CO2. Monitor pipeline corrosion. Monitor pipeline leakage <\$300k	Up to \$2.7M	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
50	02.01.03.04.	CO2 containing N2	Nitrogen in CO2 will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow. Nitrogen is normally kept to less than 4% of volume in CO2.	Nitrogen is undesirable for EOR because it raises the minimum miscibility pressure (MMP) of the fluid and makes the injection process less efficient. Nitrogen is not a problem in ECBM as a minor component of CO2. It will lower the partial pressure of methane and allow more methane to be released and recovered. Minor amounts of nitrogen in CO2 can increase compression and transmission energy consumption and can result in two phase operation. Nitrogen (and argon) will not liquefy or dissolve in downhole storage of CO2, and therefore will result in undesirable back pressure and downhole gas pockets.	Nitrogen maintained less than 4%, McElmo CO2: 1.6% N2.		Two-phase flow in pipeline. Underground gas pockets detrimental to CO2 storage. Increased MMP detrimental to CO2 EOR.	High nitrogen content in CO2 stream.	Increased power for compression and transport of gas. Decreased CO2 storage capacity. Lower yield in EOR.	Monitoring N2 content of purchased CO2 stream and buildup in recycle CO2 stream	Control nitrogen content in CO2 supply. Avoid upset operating conditions and air ingress in CO2 production.	Monitor for N2 in CO2.
51	02.01.03.07.	CO2 containing CH4 and other hydrocarbons	Total hydrocarbons are normally kept to less than 5% of volume in CO2.	Methane and other hydrocarbons can be a combustion concern in the presence of oxygen. Methane can impact the maximum miscibility pressure (MMP) of CO2 and oil in EOR.	Total hydrocarbons maintained less than 5% in purchased CO2. McElmo CO2: 0.2% CH4. Hydrocarbons recovered from recycled CO2 stream.		Increased MMP detrimental to CO2 EOR.	High methane and/or other hydrocarbon content in CO2 stream.	Decrease in EOR yield.	Monitoring methane and other hydrocarbon content of purchased CO2 stream and recycled CO2 stream.	Control hydrocarbon content in CO2 stream. Avoid upset operating conditions in CO2 supply and CO2 capture.	Monitor for hydrocarbons in CO2. Select proper materials of construction for pipeline and well components and maintain tight seals and failsafe systems to prevent leakage.
52	02.01.03.08.	CO2 containing mercaptans	Mercaptans are organic compounds containing sulfur. Total sulfur in CO2 is normally kept to less than 35 mg/l. Methyl mercaptan is susceptible to photo oxidation in the atmosphere to hydrogen, sulfur dioxide, dimethyl disulfide and other polysulfide's. Therefore it has a relatively low half-life. Methyl mercaptan exhibits a toxicity similar to, but less than that of hydrogen sulfide. The OSHA permissible exposure level (PEL) is 10 mg/l.	Mercaptans and other malodorous sulfur compounds are strong smelling and toxic and require additional sealing around the wellhead to capture fugitive emissions and minimize odors. The strong odor of mercaptans suggests it is unlikely humans would willingly tolerate concentrations much above the odor threshold for any substantial period of time. However humans in occupational settings may rapidly succumb to extremely high levels of methyl mercaptan.	Total sulfur maintained less than 35 mg/l in purchased CO2.		Pipeline/well corrosion leading to leakage or rupture.	High mercaptans content in CO2 stream in presence of H2O.	CO2 + mercaptan release (HSE hazard).	Monitoring total sulfur content of CO2 stream.	Maintain tight sulfur specification on CO2 supply. Avoid contact with water. Avoid upset conditions with CO2 dehydration.	Select proper materials of construction for pipeline, gas recycling facilities and well components and maintain tight seals and failsafe systems to prevent leakage. Monitor for H2S around injection wells and gas recycling facilities. Install alarms.
53	02.01.03.09.	CO2 containing NOx, SOx	Traces of NOx and SOx may occur when CO2 is captured from a post-combustion operations. Although sulfur is present in most fossil fuels, the amount of SOx in the CO2 stream is expected to be very low because deep sulfur removal is required prior to post-combustion CO2 capture to prevent excessive sorbent degradation/loss. Pre-combustion and post-combustion are likely to produce <0.01 vol % SOx and <0.01 vol % NOx in the CO2 stream (IPCC 2005). Oxyfuel combustion may produce 0.5 vol % SOx and 0.01 vol % NOx in the CO2 stream (IPCC 2005).	NOx and SOx may increase corrosion in pipeline and wellhead systems if H2O is present. NOx and SO2 are polluting gases that are generated by the same power plants that generate massive amounts of CO2 and attract emission taxes in certain countries (e.g. Italy). Their injection, in smaller amounts, with CO2 could therefore help the economics of sequestration. Different sets of geochemical reactions are expected when these trace contaminants are present.	NOx and SOx not present in natural CO2.		Pipeline/well corrosion leading to leakage or rupture.	High NOx or SOx content in CO2 stream in presence of H2O.	CO2 release (HSE hazard).	Monitoring NOx, SOx and H2O content of CO2 stream.	Avoid upset operating conditions in CO2 supply capture and dehydration. Avoid NOx, SOx in contact with H2O and metal.	Require CO2 supplier to flare and vent gas until CO2 stream is on spec, Select proper materials of construction for pipeline and well components and maintain tight seals and failsafe systems to prevent leakage.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
50	02.01.03.04.	CO2 containing N2	2	1	1	2	None	None	None	None	None	Decreased EOR performance + increased compression cost.	None	None	None	None	None	None	Monitor for N2 in CO2. Part of ongoing costs.	None	
51	02.01.03.07.	CO2 containing CH4 and other hydrocarbons	2	1	1	2	None	None	None	None	None	None	None	Decreased EOR performance	None	None	None	None	Monitor for hydrocarbons in CO2. Part of ongoing costs.	None	
52	02.01.03.08.	CO2 containing mercaptans	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	Monitor H2S in CO2 and around injection wells and recycle facilities. Maintain tight seals and failsafe systems <\$300k	None	
53	02.01.03.09.	CO2 containing NOx, SOx	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
54	02.01.03.10.	CO2 containing particulates	CO2 is normally scrubbed clean of particulates prior to input into the pipeline. Particulates could carry over due to upset conditions.	Particulate matter can cause valve and instrumentation plugging or erosion of piping.	Particulates are filtered out of recycled CO2 and have not been an issue in purchased CO2.	No data available on particulates in produced CO2 at SACROC,	Plugging of valves and/or erosion of piping.	High concentration of particulates in CO2 stream.	Potential CO2 leakage. Higher maintenance costs and downtime.	Monitoring CO2 stream for particulates. Monitoring operating pressures.	Avoid upset operating conditions in CO2 production and recycling.	Filter recycled gas. Monitor pressure drops in gas recycling system.
55	02.01.03.11.	CO2 containing toxic volatile metals (mercury, lead, or cadmium)	Most CO2 capture systems are likely to include mercury capture either as an upstream unit or an integral part of the CO2 capture system. It is not expected that mercury, lead or cadmium ion complexes will follow the CO2 concentrate stream during regeneration, other than by physical entrainment as aerosols, which can be eliminated by an in-line mist eliminator stage.	Presence of toxic volatile metals in the CO2 stream could classify it as a hazardous waste.	Toxic volatile metals not present in purchased CO2.		Release of toxic metals into the subsurface or surface environment.	High concentration of toxic volatile metals in CO2 stream.	Water, atmosphere, or soil contamination	Monitoring CO2 stream composition.	Install volatile metal capture system upstream of CO2 capture. Avoid upset operating conditions in CO2 capture and dehydration.	Require CO2 supplier to flare and vent gas until CO2 stream is on spec.
56	02.01.03.12.	CO2 containing pyrophoric compounds	Pyrophoric compounds can spontaneously ignite when in contact with air. Iron sulfide is one of the most common pyrophoric compounds associated with the oil and gas industry.	Pyrophoric materials can cause fires or explosions when exposed to air.	Pyrophoric compounds not present in purchased CO2. Potential for iron sulfide being present in recycled CO2.	No data available on pyrophoric compounds in recycled CO2 at SACROC,	Spontaneous combustion in the presence of oxygen.	High concentration of pyrophoric compounds in CO2 stream in presence of air or oxygen.	Fire or explosion.	Monitoring CO2 stream composition.	Avoid operating conditions that would generate pyrophoric compounds.	Avoid contact with air or oxygen.
57	02.01.03.13	CO2 containing organic compounds	Trace amounts of organic compounds (derivatives or fragments of amine sorbents) could be carried over into the concentrated CO2 stream.	Organic compounds could feed microbial growth underground which can lead to plugging of wells and/or decreased permeability.	Glycol carryover from CO2 dehydration limit of ≤ 0.3 gal/MMCF. Potassium carbonate used instead of amine sorbents for CO2 recovery.		Enhanced microbial growth underground detrimental to injectivity but could enhance EOR.	High organic compound content in CO2 stream.	Decreased injectivity. Decreased or increased EOR yield.	Monitoring CO2 stream composition.	Maintain tight spec on organic compounds in CO2 stream. Avoid upset operating conditions in CO2 capture and dehydration.	Monitor glycol content in CO2 streams.
58	02.01.03.14	CO2 containing CO or H2	Traces of CO and H2 may occur when CO2 is captured from a pre-combustion operation such as those involving gasification..	CO and H2 are safety risks due to their combustibility in the presence of oxygen and potential for H2 embrittlement of metal components. CO2 combined with CO is more toxic than when CO2 or CO are separate. (Duncan 2012).	CO and H2 at very low levels in natural CO2.		Combustion in the presence of oxygen and an ignition source.	High CO or H2 content in CO2 stream.	Fire or explosion.	Monitoring CO and H2 content in CO2 stream.	Avoid contacting CO2 stream with oxygen.	Monitor CO2 streams for CO and H2. Select proper materials of construction for pipeline and well components and maintain tight seals and failsafe systems to prevent leakage.
59	02.01.04.00.	Microbiological contamination	Microbiological contamination of injected fluid. Contamination of supercritical CO2 is considered unlikely due to its being a very good solvent. However, other fluids (like water) may be injected into the storage site that may be contaminated with microbes. Microbes are known to populate geologic strata at least 2750 meters below the surface.	The introduction of microbes into the sequestration system may affect both the performance of the storage system and the endpoints considered. Microbial growth can lead to well plugging and/or decreased permeability.	Biocide added to injected water. Microbial growth and plugging has not been noted as a historical issue.	No data available on microbiological contamination at SACROC,	Microbial growth underground detrimental to DSA, EOR or ECBM	Microbiological contamination from CO2 stream or other injection fluids	Decreased injectivity. Decreased EOR or ECBM yield	Monitoring of injection fluids for microbes	Control CO2 supply and fluids to avoid microbial contamination	Use chemical treatment if necessary to control microbial contamination/growth

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
54	02.01.03.10.	CO2 containing particulates	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
55	02.01.03.11.	CO2 containing toxic volatile metals (mercury, lead, or cadmium)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
56	02.01.03.12.	CO2 containing pyrophoric compounds	2	2	1	4	None	None	None	None	None	Fire or explosion damage. <\$1M per incident typical but \$10M to \$20M if compressors are involved.	1-5 days @ \$20,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Fire damage <\$1 M	None	Monitor for iron sulfide buildup <\$0.1M	Up to \$0.9 M	
57	02.01.03.13	CO2 containing organic compounds	2	2	1	4	None	None	None	None	None	None	1-5 days @ \$20,000/d revenue lost per pattern idled	Increased injection cost due to decreased injectivity. Cost of chlorine for microbial control \$310-340/t Cl (\$0.03/t water treated @ 4 ppm Cl)	None	None	Increased injection cost + down time cost for control of microbial growth. <\$1M	None	Monitor glycol content in CO2 streams. Monitor injectivity.<\$100k	Up to \$0.9 M	
58	02.01.03.14	CO2 containing CO or H2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
59	02.01.04.00.	Microbiological contamination	1	1	1	1	None	None	None	None	None	None	1-5 days @ \$20,000/d revenue lost per pattern idled	Increased injection cost due to decreased injectivity Cost of chlorine for microbial control \$310-340/t Cl (\$0.03/t water treated @ 4 ppm Cl)	None	None	Cost per plugging event <\$0.1 M	None	Pretreat injected water with chlorine biocide: \$0.03/t water. Part of ongoing costs.	Savings of <\$0.1M/ per plugging event eliminated.	

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SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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60	02.01.05.00.	Schedule and planning (See 11.03.00.)										
61	02.01.06.00.	Pre-closure administrative control (See 11.06.00.)										
62	02.01.07.00.	Pre-closure monitoring of storage (See 23.08.00.)										
63	02.01.08.00.	Quality control (See 11.08.00.)										
64	02.01.09.00.	Accidents and unplanned events (See 16.01.00.)										
65	02.01.10.00.	Over pressuring	The CO2 injection process is greatly influenced by the target reservoir formation pore pressure. The formation pressure is considered over pressured if it is above the normal hydrostatic pressure for the given depth. Over pressuring may occur at any depth, naturally or artificially. Man-made overpressure may be accidental or deliberate. An example of deliberate overpressure is injecting gaseous CO2 in an aquifer at a faster rate than water can drain from the reservoir zone. In such a case the overpressure is caused by the injection activity (not natural processes). The maximum tolerable overpressure is calculated as a function of the desired storage volume and of a chosen safety factor below the critical fracturing gradient of the top seal rock. Deliberate overpressure induction is a mechanism for storing energy (associated with the pressure) for later extraction. An example of accidental overpressure is the depressurization of a storage reservoir where the CO2 is in liquid form, below but near the critical phase change pressure. The change of phase to gas creates a gas column that could exercise an unforeseen overpressure at the top of the gas column. 1. Deliberate over pressuring 2. Accidental over pressuring 3. Regional-scale over pressuring 4. Local-scale over pressuring 5. Caprock failure due to over pressuring 6. Caprock failure due to dilatant shear 7. Reactivating existing faults/fractures in caprock 8. Low injection pressure limit	Deliberate or accidental over pressuring during the operational phase will affect the initial geosphere conditions for a post-closure assessment. It has the potential to cause fractures in the sealing formation and hence provide migration pathways for the sequestered CO2. Induced fractures in the caprock can be created by over pressuring the reservoir. Fractures could be sealed in time by precipitation of newly formed minerals, but could also be re-opened as a consequence of new changes in stresses during storage of CO2.	Not an issue in CO2-EOR because CO2 and water are injected at constant pressure rather than constant volume, and oil, water and CO2 are produced simultaneously with CO2 and water injection. Data from 1948-2002 showed reservoir fluid volume varied within less than 1% of reservoir pore volume.	Need historical data on reservoir pressure at SACROC.	Fracturing caprock.	Deliberate over pressuring. Accidental over pressuring.	CO2/brine release (HSE hazard). Induced seismicity and/or uplift.. Fault activation or dilation	Monitoring CO2 injection pressure versus caprock fracture pressure. Alarm system if injection pressure exceeds 90% of fracture pressure.	Determine fracture pressure. Monitor CO2 injection pressure. Keep CO2 injection pressure below 90% of caprock fracture pressure.	Develop procedures for handling an over pressuring situation. Operator training. Monitor pressures in existing nearby wells.
66	02.02.00.00.	Post-closure	Details of post-closure activities associated with sequestration.	Human activities post-closure may affect the likelihood of specific impacts being incurred.								
67	02.02.01.00.	Post-closure administrative control (See 11.07.00.)										
68	02.02.02.00.	Post-closure monitoring of storage (See 23.09.00.)										
69	02.02.03.00.	Records and markers (long-term knowledge retention) (See 11.04.00.)										

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
60	02.01.05.00.	Schedule and planning (See 11.03.00.)	0	0	0	0															
61	02.01.06.00.	Pre-closure administrative control (See 11.06.00.)	0	0	0	0															
62	02.01.07.00.	Pre-closure monitoring of storage (See 23.08.00.)	0	0	0	0															
63	02.01.08.00.	Quality control (See 11.08.00.)	0	0	0	0															
64	02.01.09.00.	Accidents and unplanned events (See 16.01.00.)	0	0	0	0															
65	02.01.10.00.	Over pressuring	2	5	2	20	PGA(g) 0.092-0.18 = 1/1000,000 fatality rate. PGA(g) 0.18- 0.34 =1/100,000 fatality rate. PGA(g) 0.34- 0.65 = 1/10,000 fatality rate. PGA(g) 0.65- 1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate.	PGA(g) 0.092- 0.18 = 1/250,000 injury rate. PGA(g) 0.18- 0.34 = 1/25,000 injury rate. PGA(g) 0.34- 0.65 = 1/2,500 injury rate. PGA(g) 0.65- 1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate.	PGA(g) 0.092- 0.18 = 3/100,000 injury rate. PGA(g) 0.18- 0.34 = 3/10,000 injury rate. PGA(g) 0.34- 0.65 = 3/1,000 injury rate. PGA(g) 0.65- 1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate.	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18- 0.34 = 5% of total PGA(g) 0.34- 0.65 = 20% of total. PGA(g) 0.65- 1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Potential class action lawsuit for property damage, loss of property value, reimburseme nt for earthquake insurance and emotional distress.	PGA(g) 0.092- 0.18 = 0.5% of total. PGA(g) 0.18- 0.34 = 5% of total. PGA(g) 0.34- 0.65 = 20% of total. PGA(g) 0.65- 1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	Shutdown of project through court ordered injunctive relief likely if multiple events of PGA(g)>0.1 (>4 magnitude earthquake)	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	>\$100M	None	Maintain CO2 injection pressure at <90% of fracture pressure: Maintain balance between volume of fluids injected and produced. Part of on going costs. Continuous passive micro- seismic monitoring Capex: \$3.9M Opex: \$0.3M/y	>\$100M	1
66	02.02.00.00.	Post-closure	0	0	0	0															
67	02.02.01.00.	Post-closure administrative control (See 11.07.00.)	0	0	0	0															
68	02.02.02.00.	Post-closure monitoring of storage (See 23.09.00.)	0	0	0	0															
69	02.02.03.00.	Records and markers (long-term knowledge retention) (See 11.04.00.)	0	0	0	0															

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
70	02.02.04.00.	Reversibility	The degree to which the sequestered CO2 could be deliberately removed, if required. Either as an extreme remedial action, because the CO2 is required as a resource, or because its presence is impeding access to other geological resources.	The degree to which reversibility is considered in the design of a sequestration system may influence its long-term performance, by leaving viable boreholes in-situ after closure, for example.	Recoverable CO2 estimated at 67% of purchased CO2.		CO2 leakage from retained wells.	Retaining facilities for potential future extraction of CO2.	CO2 release (HSE hazard).	Routine inspection of retained wells for corrosion. Monitoring retained wells for CO2 leakage.	Proper selection of materials of construction for wells. Proper plugging of wells. Routine inspection of wells for corrosion. Risk management input into reversibility plan. Retain good records and models on CO2 injection.	Prepare procedures for extraction of CO2. Monitor wells for leaks over time from end of CO2-EOR to time of extracting CO2. Rework wells that leak.
71	02.02.05.00.	Remedial actions	Events and processes related to actions that might be taken following closure of a storage site to remedy problems that, either, are associated with its not performing to the standards required, result from disruption by some natural event or process, or result from inadvertent or deliberate damage by human actions.	The aim of possible future remedial actions will be to modify the performance and safety of the CO2 sequestration system.	Other than the potential for leaky wellbores, there is unlikely to be any disruption of the stored CO2.		CO2 leakage from wells.	Improper or lack of remedial action.	CO2 release (HSE hazard).	Routine inspection and monitoring of site.	Maintain good records and models of CO2 injection. Use appropriate materials of construction. Routine inspection and monitoring of site.	Prepare procedures for remediating CO2 leakage. Monitor for CO2 leakage. Remediate any CO2 leakage quickly.
72	03.00.00.00.	CO2 PROPERTIES, INTERACTIONS & TRANSPORTATION	This category of FEPs is concerned with those Features, Events and Processes that are relevant to the fate of the sequestered fluid. Carbon dioxides properties can vary greatly between conditions at depth and near surface, and a wide range of physical and chemical reactions can be important. The category is divided into three classes for the properties, interactions and transport of carbon dioxide.	This category is divided into three classes: 1. CO2 properties 2. CO2 interactions 3. CO2 transport These properties will have a significant impact on all of the risk calculations.								
73	03.01.00.00.	CO2 properties	The fundamental physical and chemical properties of carbon dioxide, taking into account impurities. 1. CO2 properties changed by pressure 2. CO2 properties changed by temperature 3. CO2 properties changed by impurities 4. CO2 properties changed by reservoir geochemistry (i.e. CO2 migrating from quartz into calcite cemented sand)	Carbon dioxides properties can vary greatly with pressure, temperature and impurities, and an understanding of these properties is essential before the fate of sequestered fluid can be assessed.								

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
70	02.02.04.00.	Reversibility	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil contaminatio n and/or vegetation kill	Covered under natural resource damage	None	None	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	Cost to locate and fix leaky wells: \$0.3M/well + Cost to replace contaminated USDW: \$1M/y per leak + Value of lost CO2: \$0.5M/y per leak	None	Cost to monitor wells for leaks over time and rework risky wells: \$0.1M/well reworked.	Up to \$3M	1
71	02.02.05.00.	Remedial actions	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil contaminatio n and/or vegetation kill	Covered under natural resource damage	None	None	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	Cost to locate and fix leaky wells: \$0.3M/well + Cost to replace contaminated USDW: \$1M/y per leak + Value of lost CO2: \$0.5M/y per leak	None	Cost to monitor wells for leaks over time and rework risky wells: \$0.1M/well reworked.	Up to \$3M	1
72	03.00.00.00.	CO2 PROPERTIES, INTERACTIONS & TRANSPORTATION	0	0	0	0															
73	03.01.00.00.	CO2 properties	0	0	0	0															

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
74	03.01.01.00.	Physical properties of CO2	Physical properties of CO2 including density, viscosity, interfacial tension and thermal conductivity and their dependence on pressure and temperature. 1. CO2 density 2. CO2 viscosity 3. CO2 interfacial tension 4. CO2 thermal conductivity	The physical properties of CO2 determine the way in which it will behave in the environment once injected. Calculation of overpressure at constant rate injection and of injectivity at constant pressure injection are impacted by the choices of properties.	CO2 is currently supercritical, miscible with oil, and close to the density of oil at reservoir conditions.		CO2 split into two phases.	CO2 physical properties	Early breakthrough of CO2 Higher CO2 recycling costs. Decreased CO2 storage capacity.	Characterize and model reservoir temperature, pressure, geochemistry and CO2 composition. Analyze impact of any changes on CO2 physical properties.	Take CO2 physical properties into account in modeling.	Take CO2 physical properties into account in modeling.
75	03.01.02.00.	CO2 phase behavior	FEPs related to the phase behavior (gas, liquid, supercritical fluid) of CO2. The presence of contaminants in the injected CO2 (e.g. N2) and gas and hydrocarbons (e.g., in EOR and ECBM operations) in the reservoir will affect the phase behavior and partition of CO2 between different physical states. CO2 mixing with other fluids and gases, leads to modified flow behavior that is not fully understood (CCP 2009)	CO2 phase behavior is a primary consideration for modeling CO2 migration. CO2 is expected to be in the supercritical state under most sequestration scenarios.	CO2 phase behavior taken into account in process-level modeling.		CO2 changing from supercritical to gas-liquid; this will happen at temperatures lower than 32°C (90°F) and pressures less than 7.4 MPa (1100 psia).	CO2 phase behavior	Decreased reservoir storage capacity. Accelerated CO2 migration	Plan for occurrences of low pressures or temperatures Characterize and model reservoir temperature, pressure, geochemistry and CO2 composition. Analyze impact of any changes on CO2 phase behavior.	Proper site selection avoiding shallow reservoirs that would not have sufficient pressure and temperature to keep CO2 supercritical. Take CO2 phase behavior into account in modeling.	Avoid sequestration in reservoirs at depths less than 800 m. Avoid under pressured and low temperature reservoirs. Take CO2 phase behavior into account in modeling.
76	03.01.03.00.	CO2 solubility and aqueous speciation (See 03.02.13.02. and 03.02.13.06.)	CO2 solubility is the amount of CO2 that can dissolve for given conditions in water. It can vary as a function of temperature, pressure and precise composition of the fluid (e.g. salinity, dissolved species/complexes, presence of hydrocarbons - e.g., EOR and ECBM). Changing temperature and pressure accompanying migration of CO2 can therefore influence CO2 solubility, potentially leading to gas exsolution. CO2 is present in the aqueous phase as: aqueous CO2; carbonic acid (H ₂ CO ₃); bicarbonate (HCO ₃ ⁻); and carbonate (CO ₃ ²⁻). Note that other dissolved ions (Na ⁺ , Mg ²⁺ , Ca ²⁺ , etc.) are also involved and provide an array of linked, reversible reactions.	CO2 solubility has an impact on the chemical composition of formation fluids, pressure distribution, 'sorption' processes, mineral-fluid reactions and the overall storage capacity of CO2. Dissolved CO2 may migrate in a different manner to 'free' supercritical CO2. CO2 solubility in water and its partition between aqueous, gaseous, and organic phases controls the efficiency of diffusive transport and successive mineral reactions. The aqueous speciation of dissolved CO2 will impact upon the mobility of sequestered CO2 and associated contaminants.	CO2 will dissolve in brine. Acidification of brine contributes to mineral dissolution in the limestone reservoir, increasing permeability. Produced brine prone to scaling at decreased pressure and temperature. Han estimated about 3% of free CO2 may dissolve in brine in the SACROC Northern Platform area (Han 2010).		Mineral dissolution. Mineral precipitation (scaling).	CO2 solubility and aqueous speciation.	Increased permeability and injectivity or weakening of formation structure Scaling and plugging in production wells and recycling system.	Characterize and model reservoir brine properties, CO2 solubility and aqueous speciation. Analyze impact of any changes on chemical composition of fluids, pressure distribution, sorption processes, mineral-fluid reactions, and overall storage capacity. Perform well tests frequently to detect any unusual behavior.	Take CO2 solubility and aqueous speciation into account in modeling.	Take CO2 solubility and aqueous speciation into account in modeling. Monitor for scale buildup in production and recycling systems. Treat with acids or scaling inhibitors as appropriate.
77	03.02.00.00.	CO2 interactions	Potential interactions of carbon dioxide with solid, liquid or gaseous media.	A wide range of physical and chemical reactions can be important, and an understanding of these interactions is essential for the assessment of potential impacts.								

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
74	03.01.01.00.	Physical properties of CO2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
75	03.01.02.00.	CO2 phase behavior	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
76	03.01.03.00.	CO2 solubility and aqueous speciation (See 03.02.13.02. and 03.02.13.06.)	0	0	0	0															
77	03.02.00.00.	CO2 interactions	0	0	0	0															

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
78	03.02.01.00.	Effects of pressurization of reservoir on caprock (See 02.01.10.00.)	A storage reservoir will experience enhanced pressure due to injection of CO2. This may exceed original 'natural' pressurization due to hydrocarbon emplacement (EOR or ECBM, for example), or clay mineral transformations during diagenesis.	Over pressuring of the reservoir may involve leakage of CO2 through the caprock due to fracturing or enhanced interactions with CO2.	Over pressurization of reservoir unlikely due to balanced fluid production and injection.							
79	03.02.02.00.	Effects of pressurization on reservoir fluids	Increased pressurization caused by the injection of supercritical CO2 will affect the behavior of other fluids within the reservoir.	The potential importance of increased pressurization to enhanced oil and gas recovery indicates that it can modify the mobility of other fluids in the receiving reservoir.	The platform reservoir is sealed on the top, bottom and east, west and north sides by impermeable or less permeable formations. Any pressure increase in the reservoir would push fluids towards the south which is an extension of the reservoir owned by Kinder Morgan. Water curtains are used to keep CO2/brine migration within patterns.		Displacement of CO2/brine	Effect of pressurization on reservoir fluids	CO2/brine release (HSE hazard). Adverse geochemical impact on freshwater resources.	Monitoring and modeling of CO2/brine movement.	Characterize, model and monitor reservoir CO2/brine movement. Adjust injection strategy as needed to control CO2/brine movement. Extract brine for pressure and plume control.	Use water curtains to keep CO2/brine migration within patterns.
80	03.02.03.00.	Interaction with hydrocarbons (See 0.3.02.03.01 through 03.02.03.15)	In EOR or ECBM sites, for example, hydrocarbons could be mobilized by CO2, by miscible displacement and transported to the near-surface. This is of particular relevance if enhanced oil recovery is an additional aim of the sequestration concept. Kolak and Burruss (2003) demonstrate that polyaromatic hydrocarbons (PAHs) can be mobilized by sequestration in deep coal beds. Sequestered CO2 can also precipitate asphaltenes from crude oil under certain conditions of composition, temperature and pressure. Such precipitation in the vicinity of injection wells can lead to loss of injectivity and even plugging of the wells.	Mobilized hydrocarbons may migrate to the near-surface environment. Precipitated asphaltenes can clog pores, reducing permeability and affecting fluid flow paths.	The original CO2-EOR flood from 1972-1999 was immiscible due to sub-MMP pressures. The current CO2-EOR flood is miscible.							
81	03.02.03.01.	EOR attribute range	Technical screening guidelines for CO2 flooding: recommended (current projects range) Crude oil gravity, °API: >22 (27 to 44) Crude oil viscosity, cp: <10 (0.3 to 6) Crude oil composition: High percent of C5 to C12 Reservoir oil saturation: >40% (15 to 70%) Type of formation: Relatively thin sandstone or carbonate unless dipping Permeability: Not critical if sufficient rates can be applied Depth/temperature: For miscible displacement, depth must be great enough to allow injection pressures greater than the minimum miscible pressure (MMP), which increase with temperature and for heavier oils (Meyer 2007). Oil formation volume factor (ratio real barrels/stock tank barrels): 1.2 to 1.4 Real barrels at subsurface conditions (at depth) Stock tank barrels at surface conditions	Operating outside the EOR attribute range could lead to low oil recovery. This could impact CO2 sequestration economics.	The SACROC EOR attributes fall within the range of recommended EOR attributes. Crude oil gravity: 39 to 45 °API Crude oil viscosity: 0.35 to 1 cP Reservoir initial oil saturation: 71.8% Limestone formation Permeability: 3.06x10-14 m² (19.4 to 31mD) Porosity: 7.11 to 9.84% Reservoir pressures above 15.86 MPa MMP. Formation volume factor: 1.472 RB/STB	Need to confirm MMP value.	Low enhanced oil recovery	Operating outside the EOR attribute range	Higher costs. Lower revenues.	Fully characterize EOR reservoir and compare site specific EOR attributes with recommended EOR attributes. Fully characterize EOR reservoirs for EOR attributes. Select EOR reservoirs that fall within the acceptable range of EOR attributes.	Monitor and model EOR performance. Identify irregularities. Determine root cause for irregularities. Adjust injection and production strategy if necessary.	

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
78	03.02.01.00.	Effects of pressurization of reservoir on caprock (See 02.01.10.00.)	0	0	0	0															1
79	03.02.02.00.	Effects of pressurization on reservoir fluids	2	1	2	4	None	None	None	None	None	None	None	None	None	None	None	None	Use water curtains to keep CO2/brine migration within patterns: \$0.50/t water	None	2
80	03.02.03.00.	Interaction with hydrocarbons (See 0.3.02.03.01 through 03.02.03.15)	0	0	0	0															
81	03.02.03.01.	EOR attribute range	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

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82	03.02.03.02.	EOR reservoir depth	Recommended depths of CO2 floods of typical Permian Basin oils CO2 Miscible Gravity, °API Depth >40 > 762 m (2500 ft) 32 to 39.3 > 853 m (2800 ft) 28 to 31.9 > 1006 m (3300 ft) 22 to 27.9 > 1219 m (4000 ft) <22 Fails CO2 screening CO2 Immiscible Gravity, °API Depth 13 to 21.9 > 549 m (1800 ft) <13 Fails CO2 screening (Meyer 2007)	Operating conditions outside miscible range could lead to low oil recovery. This could impact CO2 sequestration economics and result in more CO2 recycling.	Reservoir depth sufficient for miscible flooding. Depth to top of Canyon formation in the Platform area: 1675 to 1750 m (5500 to 5750 ft) API Gravity: 39 to 45		Insufficient pressure for MMP. Insufficient pressure range between MMP and fracture pressure.	Insufficient EOR reservoir depth.	Low EOR yields. Limited operating range.	Determine reservoir bottom hole pressure, minimum miscibility pressure and fracture pressure.	Fully characterize EOR reservoir. Select reservoir with sufficient depth to allow miscible flow and sufficient pressure operating range between minimum miscibility pressure(MMP) and fracture pressure.	Pressurize reservoir with water injection prior to CO2 injection. (This may not work because elevated pressure will dissipate over time and water injection may redistribute oil and clay).
83	03.02.03.03.	EOR oil recovery	Typical oil recovery by recovery mechanism as a function of Original Oil in Place (OOIP) Primary: 6 to 15% OOIP Secondary: 6 to 30% OOIP Miscible CO2 EOR: 8 to 20% OOIP Remaining: 8 to 35% OOIP (Meyer2007) Miscible CO2 EOR: 7-23% OOIP Immiscible CO2 EOR: 9 to 19% OOIP (Meyer 2007)	Prior oil production and methods could impact CO2 EOR results and amount of CO2 that can be sequestered.	SACROC CO2-EOR tertiary recoveries range from <4% to 10% of OOIP.		Low enhanced oil recovery.	Poor EOR performance.	Lower revenues. Higher operating costs per barrel of oil.	Monitor actual versus projected enhanced oil recovery.	Fully characterize the reservoir for EOR attributes. Select EOR reservoirs that fall within the acceptable range of EOR attributes. Model EOR operation and try to optimize oil recovery through reservoir engineering. Operate above the minimum miscibility pressure.	Monitor EOR actual versus projected performance. Identify the cause of any variation. Adjust CO2 EOR strategy to improve oil recovery if necessary. Optimize WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and utilization and increase oil recovery.
84	03.02.03.04.	EOR CO2 utilization	For field scale miscible CO2 EOR floods net (purchased) amount of CO2 required is estimated to be between 60 to 262 m ³ CO2/m ³ oil (2.5 to 11 MCF/STB) of incremental recovery with an average value of 143 to 167 m ³ /m ³ (6 to 7 MCF/STB). For immiscible floods, actual incremental oil recovery has been on the order of 119 to 286 m ³ /m ³ (5 to 12 MCF/STB) (Meyer 2007).	Increased CO2 demand per barrel of oil produced will impact EOR project economics. This could impact CO2 sequestration economics as well.	Net CO2 utilization averaged 8992 SCF purchased CO2/STB oil from 2000-2010. The value is decreasing over time and was 5,380 SCF purchased CO2/STB oil in 2011.		High CO2 consumption per barrel of oil recovered.	Poor EOR performance.	Increased operating costs. Higher CO2 recycling costs.	Monitor actual versus projected CO2 consumption per barrel of oil.	Fully characterize the reservoir for EOR attributes. Model EOR operation and try to optimize CO2 consumption per barrel of oil through reservoir engineering.	Monitor EOR actual versus projected performance. Identify the cause of any variation. Adjust CO2 EOR strategy to optimize CO2 usage if necessary. Optimize WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and utilization and increase oil recovery.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
82	03.02.03.02.	EOR reservoir depth	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
83	03.02.03.03.	EOR oil recovery	3	4	1	12	None	None	None	None	None	None	None	Decrease in EOR performance: \$25M/y	None	None	10% decrease in oil recovery (1,000 bpd): \$25M/y	None	Cost of WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and utilization and increase oil recovery: \$10M/y	Savings: \$15M/y	2
84	03.02.03.04.	EOR CO2 utilization	2	3	1	6	None	None	None	None	None	None	None	Increased CO2 purchases: \$5.8M/y	None	None	A 20% increase in CO2 purchases@ \$32.32/t CO2: \$5.8M/y	No increase in CO2 purchase: \$0M/y	Cost of WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and utilization: \$5.5M/y	Savings \$0.3M/y	2

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85	03.02.03.05.	EOR viscosity relations	Because the viscosity of CO2 at reservoir conditions is much lower than that of most oils, viscous instability will limit the sweep efficiency of the displacement and, therefore, oil recovery (Meyer 2007). Crude oil viscosity, cp: <10 (0.3 to 6)	Can lead to adverse hydrodynamic instabilities, such as fingering, which lead to vertical fluid stratification and reduced oil recovery (Meyer 2007). This could also result in more CO2 breakthrough and require more CO2 recycling.	Oil viscosity: 0.35 cP. CO2 viscosity: 0.0562 cP. Brine viscosity: 0.8 cP.		Flow stratification (fingering) in the reservoir. Decreased sweep efficiency and oil recovery.	EOR viscosity relations.	Reduced oil recovery. Higher CO2 recycling costs.	Determine EOR viscosities under reservoir conditions and input into reservoir model.	Fully characterize the reservoir. Model EOR operation and try to optimize CO2 flow through reservoir engineering.	Monitor EOR actual versus projected performance. Identify the cause of any variation. Use polymers or foaming agents to adjust CO2 viscosity.
86	03.02.03.06.	EOR oil reservoir heterogeneity	Oil reservoir rock is extremely heterogeneous, exhibiting zones of high permeability in close proximity to those of low permeability. These permeability differences may be innate, that is caused by differences in pore structure at the time of geological deposition, or a product of fractures, natural or man-made (Meyer 2007)	Can decrease efficiency of oil recovery and CO2 sequestration.	The SACROC reservoir is highly heterogeneous with a Dykstra-Parson coefficient of approximately 0.68.	Need historical data on heterogeneity impact on oil recovery.	Non uniform flow of CO2/oil. Low sweep efficiency and low oil recovery.	EOR reservoir heterogeneity.	Reduced oil recovery. Higher CO2 recycling costs.	Fully characterize reservoir for heterogeneity and input into model.	Take into account heterogeneity of oil reservoir in EOR modeling and reservoir engineering in order to optimize performance.	Monitor EOR actual versus projected performance. Identify the cause of any variation. Adjust CO2 EOR strategy to optimize CO2 usage if necessary. Optimize WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and utilization and increase oil recovery.
87	03.02.03.07.	EOR hydrocarbon precipitation	CO2 injection encourages precipitation of asphaltenes or paraffins.	Precipitation of asphaltenes can clog pores, reducing permeability and affecting fluid flow paths. It can also cause plugging of boreholes.	Hydrocarbon precipitation has occurred when temperatures got too low. (Rickerson 2012A).	Need historical data on hydrocarbon precipitation and control.	Pore space blockage and reduced permeability. Plugging of production wells and equipment.	EOR hydrocarbon precipitation.	Well plugging. Decreased injectivity or production. Delays for shutdown and cleanout.	Characterize site for asphalt or paraffin precipitation. Monitor changes in injection pressure.	Use Teflon coated tubulars and components. Monitor for asphaltene or paraffin precipitation. Inject hot water or steam every couple of months. Injection of some hydrocarbon gas along with CO2 can decrease the tendency for asphaltene or paraffin precipitation. Keep operating temperatures sufficiently high. Use staged decompression to avoid overcooling.	Circulate xylene, deasphalted oil, or enzymes to remove asphaltene buildup. Inject hot water or steam to remove paraffin buildup.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
85	03.02.03.05.	EOR viscosity relations	4	4	2	32	None	None	None	None	None	None	None	Decrease in EOR performance: \$12.6M/y	None	None	5% decrease in oil recovery (500 bpd): \$12.6M/y	No decrease in oil revenue: \$0M/y	Cost of polymers or foaming agents used to adjust CO2 viscosity: \$1.8M/y	Savings: \$10.8M/y	2	
86	03.02.03.06.	EOR oil reservoir heterogeneity	5	4	2	40	None	None	None	None	None	None	None	Decrease in EOR performance: \$25M/y	None	None	10% decrease in oil recovery (1,000 bpd): \$25M/y	None	Cost of WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and utilization and increase oil recovery: \$10M/y	Savings: \$15M/y	2	
87	03.02.03.07.	EOR hydrocarbon precipitation	4	4	2	32	None	None	None	None	None	None	5 days @ \$20,000/d revenue lost per pattern idled	Decrease in EOR performance: 16M/y	None	None	Oil revenue loss \$15M/y Cleanout cost: \$1M/y	Oil revenue loss: \$2.5M/y Cleanout cost: \$0.2M/y	Cost of Teflon coating, elevated operating temperatures and staged decompression: \$2M/y	Savings \$11.3M/y	1	

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88	03.02.03.08.	EOR miscibility	Flooding a reservoir with CO2 can occur either miscibly or immiscibly. Miscible CO2 displacement is only achieved under a specific combination of conditions, which are set by four variables: reservoir temperature, reservoir pressure, injected gas composition, and oil chemical composition (Meyer 2007). Miscible displacement is achieved at pressures above the minimum miscibility pressure (MMP). If the reservoir pressure is below the MMP, CO2 can still be injected, but the efficiency of the enhanced oil recovery process is adversely impacted. Typically this does not occur since, after primary depletion, water flooding operations commence which restore reservoir pressure to values above the MMP (Meyer 2007). 1. Miscible CO2 flooding 2. Immiscible CO2 flooding	Operating under miscible conditions results in significantly higher oil recovery than operating under immiscible conditions. Higher oil recovery improves economics of EOR and CO2 sequestration.	CO2 is miscible under SACROC reservoir conditions. Reservoir pressure is >20 MPa and MMP is estimated to be 15.86 MPa.	Confirm current reservoir pressure and MMP.	Decreased enhanced oil recovery.	Immiscible operation.	High operating costs, lower revenues.	Determine minimum miscibility pressure and compare with reservoir conditions.	Fully characterize the reservoir for EOR attributes. Maintain injection pressure above the minimum miscibility pressure (MMP) while not exceeding 90% of the fracture pressure.	Increase reservoir pressure with water injection if needed.
89	03.02.03.09.	EOR early CO2 breakthrough	Early breakthrough of CO2 results in production of significant amounts of CO2 and water along with oil. The alternating water and CO2 gas (WAG) approach is typically applied in CO2 EOR to minimize CO2 use (as it is purchased) and to avoid early breakthrough of CO2.	Breakthrough of CO2 increases operating costs due to the need to recycle the CO2 and can also result in lower oil recovery.	Highly heterogeneous permeability caused early breakthrough of CO2 which limited the performance and recovery efficiency. Prior CO2 injection (1972-1995) may have saturated high permeability zones leading to early CO2 breakthrough. WAG, selective perforation, polymer gels, foaming surfactants, sealants, and other techniques testing to mitigate early CO2 breakthrough. WAG and selective perforation (dual injection) currently used. (Ricketson 2012A)		High CO2 consumption per barrel of oil recovered.	Early CO2 breakthrough.	Increased operating costs. Higher CO2 recycling costs.	Monitor CO2/oil production.	Fully characterize and model the EOR reservoir. Optimize reservoir engineering.	Recycle CO2. Modifying well pattern/spacing. WAG.. Selective perforation. Polymer gels. Foaming surfactants. Sealants.
90	03.02.03.10.	EOR Water alternating gas (WAG)	WAG involves alternating injection of water and gas (CO2) to optimize EOR performance. WAG ratios range: 1:1 to 5:1 (0.5:1 to 4:1 per NETL 2009) Slug range: 0.1% to 2% of reservoir hydrocarbon pore volume (NETL 2009) Cumulative CO2 volume: 15 to 30% of hydrocarbon pore volume (NETL 2009)	WAG ratio may have a positive or negative impact on oil recovery.	WAG used at SACROC in 4 sequences. 1. 0% H2O/100% CO2 2. 50% H2O/50% CO2 3. 67% H2O/33% CO2 4. 100% H2O/0% CO2 Slug size: 0.25 to 0.4 HCPV		Low enhanced oil recovery.	Suboptimal water and CO2 gas (WAG) ratio.	Lower revenues. Higher operating costs per barrel of oil.	Monitor CO2/water/oil production and CO2/water injection.	Optimize WAG ratio through modeling and reservoir engineering	Evaluate WAG actual versus predicted performance based on modeling and make adjustments to the WAG ratio or well pattern/spacing as needed.
91	03.02.03.11.	EOR injection water quality / attributes / chemistry	Water quality can impact EOR performance. Injection of low salinity water into an EOR reservoir where the sandstone cement consists of anhydrite could cause the anhydrite to convert to gypsum and its volume would increase up to 1.5 times resulting in decreased pore space and permeability. Injection microbial contaminated water could result in well plugging or decreased permeability due to microbial growth. Injection of corrosive water could result in corrosion of equipment, piping and borehole liners. Injection of hard water could lead to scale buildup.	Lower oil recovery. Corrosion, scale buildup or microbe growth in system equipment. Decreased permeability near injection wells.	Corrosion in the producing wells and surface equipment due to recycling of CO2 has ranged from minimal to severe. Predictions of corrosivity based on CO2 and water cuts have not always proved accurate. Although a few failures have occurred, equipment selection and inhibitor applications have adequately controlled corrosion in CO2 removal and reinjection facilities. (Newton 1977). Injection water filtered and treated with biocides, oxygen scavengers, scale inhibitors and corrosion inhibitors. (Ricketson 2012A)	Need historical data on injection water quality and pre-treatment	Corrosion, scale buildup or microbe buildup.	Quality of EOR injected water.	Increased maintenance cost. Injection disruption.	Monitor injection water quality and injection pressure and flowrate. Use proper materials for tubing, equipment and piping prevent or minimize corrosion, erosion, scaling or microbe buildup.	Treat injection water to prevent corrosion, scaling or microbe buildup.	Monitor injection pressure and flowrate. Filter and treat water with chemicals to prevent corrosion, remove scale and control microbial buildup. Get proper clearance for injection of chemicals if necessary.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) injuries: \$0.05M per injury												
88	03.02.03.08.	EOR miscibility	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
89	03.02.03.09.	EOR early CO2 breakthrough	4	3	1	12	None	None	None	None	None	None	None	Increased CO2 recycling cost: \$3M/y	None	None	10% increase in CO2 recycling: \$3M/y	\$0M/y	Cost of WAG selective perforation and water curtains: \$2M/y	Savings: \$1M/y	2
90	03.02.03.10.	EOR Water alternating gas (WAG)	2	4	1	8	None	None	None	None	None	None	None	Decrease in EOR performance: \$12.5M/y	None	None	5% decrease in oil recovery (500 bpd): \$12.5M/y	\$0M/y	Cost of modifying WAG ratio: Part of ongoing costs.	Savings: \$12.5M/y	2
91	03.02.03.11.	EOR injection water quality / attributes / chemistry	2	4	1	8	None	None	None	None	None	None	5 days @ \$20,000/d revenue lost per pattern idled	Oil revenue loss \$15M/y Cleanout cost: \$1M/y	None	None	Oil revenue loss \$15M/y Cleanout cost: \$1M/y	Oil revenue loss: \$2.5M/y Cleanout cost: \$0.2M/y	Pretreatment of injected water at \$8M/y.	Savings: \$5.3M/y	1

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92	03.02.03.12.	EOR injection water pressure	Water is denser than CO2. When changing from CO2 injection to water injection, a pressure differential needs to be overcome. To do so, the water supply header operates at a pressure in excess of the CO2 supply header pressure. This allows water to be throttled into the well, its pressure declining to the appropriate value once the CO2 is displaced from the wellbores (Meyer 2007).	System should be designed to provide the proper water injection pressure.	CO2 is injected at around 2000 psi (surface) and water is injected slightly above that.		Unable to inject water at appropriate rate. Hydro fracturing.	Water pressure too low. Water pressure too high.	Poor oil recovery. Caprock damage and potential CO2 release.	Monitor water pressure and flowrate.	Calculate water pressure needed based on modeling. Install sufficient pumping capacity to meet water pressure and flowrate requirements. Injection pressure should not exceed 90% of fracture pressure.	Monitor water pressure and adjust pump pressure as needed. Change frequency or rate.
93	03.02.03.13.	EOR injection and production well pattern and spacing	The pattern is typically a 5-spot (one injection well in center surrounded by four production wells) or inverse 5-spot (one production well in center surrounded by four injection wells), or a variety of other patterns. Typically there are 0.5 to 4.0 production wells for every injection well. The spacing of injection and production wells refers to the area covered by the well pattern. It may be 8, 12, 16 or more hectares (20, 30, 40 or more acres).	Improper injection and production well spacing and pattern can lead to early CO2 breakthrough and/or low oil recovery.	Initially 160 acre injection-centered 9-spot was used. Back filled with 40 acre (20 to 60 acre) injection-centered 5-spot pattern. Improved sweep efficiency. The 40 acre pattern usually performed better than the 20 or 60 acre patterns. (Ricketsen 2012A).		Early breakthrough of CO2. Low enhanced oil recovery.	Improper injection and production well pattern and spacing..	Increased operating cost. Increased CO2 recycling costs. Lower revenues.	Monitor and model well performance.	Optimize well spacing and pattern based on modeling and reservoir engineering.	Monitor well performance versus model predictions. Adjust model and well spacing and pattern as needed to optimize oil recovery. Use injection water curtains to control CO2 flow within patterns.
94	03.02.03.14.	EOR intermittent CO2 supply	Intermittent CO2 supply can be caused by interruptions at the source, CO2 capture, compression, pipeline or wellhead.	Intermittent CO2 supply can negatively impact sweep efficiency of EOR and therefore make sequestration less attractive.	Intermittent CO2 supply was a problem in the initial tertiary flood. Only about 75% capacity achieved. Multiple sources for natural CO2 (McElmo Dome, Bravo Dome and Doe Canyon Deep), multiple pipelines and improved CO2 compressor availability have overcome those problems in current operations. As a mature CO2-EOR operation, SACROC has significantly cut back on purchased CO2 supply and is predominantly dependent on recycled CO2.	Need historical data on CO2 supply reliability, impact on oil recovery and mitigation steps.	Interruption in CO2 injection	Intermittent CO2 supply.	Decreased EOR performance.	Maintain daily, weekly and monthly nominations for CO2 supply and demand planning. Monitor CO2 input pressure and flowrate to pipeline.	Maintain daily, weekly and monthly nominations for CO2 supply and demand planning. Maintain CO2 production.	Use water injection as a backup for sweep if necessary. Flood only a limited section depending on the geology.
95	03.02.03.15.	EOR flood type	CO2 flooding types include gravity stable and conventional piston flooding. In gravity stable flooding, CO2 is injected in the top of a reservoir (dome) as a supercritical fluid or dense gas and builds an oil bank by mobilizing residual oil downward as the CO2 cap expands. It is important to maintain a relatively uniform front and avoid coning. In the conventional piston flooding, CO2 is injected into an oil reservoir and builds an oil bank by mobilizing residual oil horizontally as the CO2 plume expands. 1. Gravity stable CO2 flooding 2. Piston CO2 flooding	Flooding should be optimized to maintain a relatively uniform front and avoid coning or CO2 early breakthrough (profile control).	Conventional piston-type CO2-EOR flooding with water curtain used at SACROC.		Low enhanced oil recovery.	Improper EOR flood type.	Higher operating costs and lower revenues.	Fully characterize EOR reservoir and model flood type options to be evaluated.	Fully characterize and model EOR reservoir and select the optimum flood type.	Monitor well performance versus model predictions. Adjust model and flood type, well spacing and pattern as needed to optimize oil recovery.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
92	03.02.03.12.	EOR injection water pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
93	03.02.03.13.	EOR injection and production well pattern and spacing	3	4	2	24	None	None	None	None	None	None	None	Decrease in EOR performance: \$12.5M/y	None	None	5% decrease in oil recovery (500 bpd): \$12.5M/y	\$0M/y	Cost of modifying well spacing + or \$2.5M/y	Savings: \$10M/y to \$15M/y	2	
94	03.02.03.14.	EOR intermittent CO2 supply	2	3	1	6	None	None	None	None	None	None	None	Decrease in EOR performance: \$1-10M	None	None	20% decrease in oil recovery (2,000 bpd): \$138k/d x 15 days: \$2M	10% decrease in oil recovery (1,000 bpd): \$69k/d x 15 days: \$1M	Cost of additional water: \$1.8k/d x 15 days: \$0.03M	Savings: <\$1M	2	
95	03.02.03.15.	EOR flood type	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	

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96	03.02.04.00.	Displacement of saline formation fluids	Injection of CO2 into a geologic formation may result in displacement of saline formation fluids into potable water supplies. Limitations on the pressure in a formation (for seal integrity) will mean that existing fluids are displaced/replaced. Displaced fluids are highly likely to be saline. Because the pressure wave created by injection travels much further than the physical CO2 front, displacement of saline formation fluids can occur at locations outside the CO2 storage area. Inter-connection of aquifer systems may enable saline fluids to enter potable water formations. For significant storage to be possible, it is necessary for a significant amount of the native pore space fluid to be displaced from the reservoir over the injection period. This may occur either by production of fluids (oil or gas), by deliberate production of formation water, and/or by migration of fluids into adjacent formations, surface or oceans.	Displaced saline formation fluids may contaminate near-surface aquifers with subsequent impacts, such as contamination of potable water supplies.	The platform reservoir is sealed on the top, bottom, east, west and north sides. The only opening is the south side which opens up into the middle of the SACROC unit. There are no known faults or fracture zones penetrating the primary seal. CO2-EOR accommodates injected volume by simultaneous production of reservoir fluids. There are multiple-stacked seals and sinks above the SACROC reservoir. Only secondary USDW aquifers occur in the SACROC area.		Contamination of ground/surface water with CO2/brine.	Displacement of brine due to CO2 injection.	Liability for contamination of ground/surface water with CO2/brine. Damage to drinking water and/or irrigation water supply.	Monitor CO2/salinity of ground/surface water.	Fully characterize and model reservoir to understand likely displacement of brine. Take into account brine displacement in reservoir engineering. Extract brine for pressure and plume management.	Monitor near surface aquifers for increased salinity. Determine root cause for any increase in salinity. Use tracers if necessary. Extract brine for pressure and plume management.
97	03.02.05.00.	Change in mechanical processes and conditions	Features and processes related to the mechanical processes and conditions resulting from the injection of CO2 that affect the rock, boreholes and other engineered features, and the overall mechanical evolution with time. This includes the effects of hydraulic, mechanical and thermal loads imposed on the rock by the injected CO2. Injection of CO2 into a reservoir can cause (directly or indirectly) changes of the geomechanical properties of the reservoir rock. Direct changes can be due to change of reservoir pressure and temperature (PVT system). Indirect changes (of rock properties) might result from geochemical and mineralogical changes after storage of CO2.	Mechanical changes of the reservoir resulting from CO2 injection (such as generation of fractures, reactivation of fractures/faults, changes of bulk elastic properties and effective reservoir) could lead to subsidence/uplift (at surface), induced seismicity, changes in migration pathways, even burst/leakage of the seal. Examples of other relevant processes are: borehole lining collapse; rock volume changes, leading to cracking	Fractures exist from previous hydraulic fracturing operations. Natural faults and fractures occur in the reservoir but do not penetrate the primary seal. There are multiple stacked seals and sinks above the caprock. CO2 injection compensated for by simultaneous production of fluids. Reservoir fluid volume remains within 1% of original volume.		1. Fracturing caprock. 2. Reactivating a fault. 3. Induced seismicity. 4. Uplift/subsidence. 5. Borehole collapse.	Change in mechanical processes and conditions caused by CO2 injection.	1. CO2 release (HSE hazard). 2/3. Seismic damage to surface buildings and infrastructure. 4. Change in surface water flow impacting farmland. 5. Well damage.	Characterize the site and model geomechanics. Determine fracture pressure. Monitor injection pressure. Alarm system if injection pressure exceeds 90% of fracture pressure.	Determine fracture pressure. Operate below 90% of fracture pressure.	Operate below 90% of fracture pressure. Monitor injection pressure Maintain reservoir fluid volume close to original fluid volume. Continuous monitoring of passive micro-seismicity

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96	03.02.04.00.	Displacement of saline formation fluids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
97	03.02.05.00.	Change in mechanical processes and conditions	1	1	1	1	PGA(g) 0.092-0.18 = 1/1000,000 fatality rate. PGA(g) 0.18- 0.34 = 1/100,000 fatality rate. PGA(g) 0.34- 0.65 = 1/10,000 fatality rate. PGA(g) 0.65- 1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate.	PGA(g) 0.092- 0.18 = 1/250,000 injury rate. PGA(g) 0.18- 0.34 = 1/25,000 injury rate. PGA(g) 0.34- 0.65 = 1/2,500 injury rate. PGA(g) 0.65- 1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate.	PGA(g) 0.092- 0.18 = 3/100,000 injury rate. PGA(g) 0.18- 0.34 = 3/10,000 injury rate. PGA(g) 0.34- 0.65 = 3/1,000 injury rate. PGA(g) 0.65- 1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate.	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18- 0.34 = 5% of total PGA(g) 0.34- 0.65 = 20% of total. PGA(g) 0.65- 1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Potential class action lawsuit for property damage, loss of property value, reimburse- ment for earthquake insurance and emotional distress.	PGA(g) 0.092- 0.18 = 0.5% of total. PGA(g) 0.18- 0.34 = 5% of total. PGA(g) 0.34- 0.65 = 20% of total. PGA(g) 0.65- 1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	Shutdown of project through court ordered injunctive relief likely if multiple events of PGA(g)>0.1 (>4 magnitude earthquake)	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	None	None	Cost to maintain CO2 injection pressure below 90% of fracture pressure and maintain reservoir fluid volume close to original fluid volume: Part of ongoing costs.	None	2

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98	03.02.06.00.	Induced seismicity	Injection of CO2 may cause and trigger seismic events and earthquake hazards through processes such as reducing friction at existing faults. This may occur both in seismically active areas and in areas characterized by a low background seismicity (reactivation of ancient fault planes, changes in the orientation, fluid-pockets occurrence). This FEP includes micro seismicity. Induced macro-seismicity activity is a function of existing regional and local stresses, of porosity structure, and of imposed injection stresses. Induced macro-seismicity is less likely if the injection formation is dominated by intergranular and not fracture porosity. The problem of seismicity might be more serious when CO2 is injected into a reservoir in tectonically active regions with high density of active faults (Damen 2006). 1. Induced macro-seismicity 2. Induced micro-seismicity 3. Seismicity tied to activation of an existing structure (fault/fracture) 4. Seismicity tied to creation of a new structure (fault/fracture)	Seismicity can introduce sudden physical changes to the sequestration system and may expose any local population to earthquake hazards. Potential effects of reservoir-induced seismicity (RIS) are damage to the caprock and wells, which might cause CO2 leakage, and damage to building and infrastructure (Damen 2006). In a reservoir that is under high tectonic stresses, any significant reduction of pressure (pressure acting between individual rock particles) may trigger faults. This may lead to uplifting or down-faulting of the surface (Damen 2006).	Although the area Northeast of the Platform area has experienced earthquakes up to 4.6 magnitude, there does not appear to be any indication that it is tied to induced seismicity. The earthquake epicenters are 5 to 10 km below the surface, while the CO2 injection and oil production are 2 km below the surface and separated from lower formations by the somewhat impermeable Strawn formation. In addition the reservoir is sealed on the top, east, north and west sides. Thus pressure fronts would likely move south, away from seismic activity. CO2 injection is compensated for by simultaneous production of fluids from the reservoir. The volume of fluids in the reservoir is within 1% of original volume. CO2 injection pressures are maintained at <90% of fracture pressure.	Records for earthquakes below 2.5 magnitude not available.	Induced earthquake >4 magnitude.	Induced seismicity.	Public concern and potential class action lawsuits.	Characterize the site and model geomechanics. Determine fracture pressure. Monitor injection pressure. Alarm system if injection pressure exceeds 90% of fracture pressure. Maintain reservoir fluid volume near original fluid volume.	Determine fracture pressure. Operate below 90% of fracture pressure. Maintain reservoir fluid volume close to original volume.	Operate below 90% of fracture pressure. Monitor injection pressure and passive micro-seismicity.
99	03.02.07.00.	Subsidence or uplift	Injecting the CO2 may cause acidification of formation water, leading to mineral dissolution and subsidence. This is of particular relevance to shallow storage sites. Chemical compaction or dissolution of the reservoir rock will particularly be a matter of concern in carbonate rocks with high porosity (Damen 2006). Injection of large quantities of CO2 into a confined aquifer may increase pore pressure and lift the overlying rocks upwards. It is not envisaged that uplift will take place in a CO2 reservoir as long as the maximum storage pressure is kept below the geostatic pressure (Damen 2006). 1. Subsidence 2. Uplift	Deformation may affect geological processes and may result in impacts of concern at the surface. Dissolution of the reservoir rock (chemical compaction) can lead to the reservoir caving in under the weight of the overburden formation (Damen 2006) Vertical subsidence or uplift above large reservoirs could affect lake levels and shift streams in lowland areas with low topographic relief. Subsidence or uplift could damage buildings or farmland.	There have been no indications of subsidence or uplift in the area. This is not likely to be a problem because injected CO2 and water are compensated for by simultaneous oil, water and CO2 production. Fluid volume in the reservoir is within 1% of original volume.	Need historical data on subsidence or uplift.	1. Caprock collapse. 2. Change in surface elevation under buildings and infrastructure. 3. Change in lake level. 4. Change is stream/river pathway. 5. Infrastructure damage.	Subsidence due to mineral dissolution. Uplift due to increased pore pressure.	CO2 release (HSE hazard). Liability for damage to surface buildings and infrastructure. Liability for damage to farmland. Change in land use.	Characterize the site and model geomechanics and geochemistry. Determine fracture pressure. Monitor injection pressure. Alarm system if injection pressure exceeds 90% of fracture pressure. LIDAR surveys.	Select a deep rather than shallow reservoir. Characterize and model the geomechanical and geochemical reactions in the reservoir and caprock. Operate below 90% of fracture pressure. Volume increase from CO2 injection compensated for by water/oil production in EOR, coal seam dewatering in ECBM and brine extraction in DSA.	Monitor any mineral dissolution in critical formations Operate below 90% of fracture pressure. Monitor injection pressure, LIDAR and passive micro-seismicity. Mitigate uplift by extracting water from the reservoir.
100	03.02.08.00.	Thermal effects on the injection point	Temperature of the injected fluid could result in geological modification of the region around the point of injection due to thermal gradients. 1. Cooling due to CO2 changing from supercritical to gas phase. 2. Injected CO2 may be 25 to 50°C cooler than the in-situ temperature.	These thermal effects could influence the mobility of the injected CO2 and impurities.	Thermal effects have not been identified as an issue at SACROC, CO2 is injected at 37.8°C (100°F) and reservoir temperature is 54.4°C (130°F). Reservoir pressure and temperature are significantly above CO2 supercritical pressure and temperature.	Need historical data on thermal fracturing and control, bottom hole temperature, and injection temperature.	Scale buildup. Induced thermal fractures in reservoir and caprock; caprock failure.	Thermal effects on the injection point. Propagation of thermal stress fractures through reservoir and caprock.	Decreased porosity, permeability, injectivity; CO2 release (HSE hazard).	Monitor bottom hole temperatures and pressure.	Select site with reservoir pressure above the CO2 supercritical pressure.	Adjust CO2 injection temperature upward to partially compensate for any cooling effect.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
98	03.02.06.00.	Induced seismicity	2	2	1	4	PGA(g) 0.092-0.18 = 1/1000,000 fatality rate. PGA(g) 0.18- 0.34 =1/100,000 fatality rate. PGA(g) 0.34- 0.65 = 1/10,000 fatality rate. PGA(g) 0.65- 1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate.	PGA(g) 0.092- 0.18 = 1/250,000 injury rate. PGA(g) 0.18- 0.34 = 1/25,000 injury rate. PGA(g) 0.34- 0.65 = 1/2,500 injury rate. PGA(g) 0.65- 1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate.	PGA(g) 0.092- 0.18 = 3/100,000 injury rate. PGA(g) 0.18- 0.34 = 3/10,000 injury rate. PGA(g) 0.34- 0.65 = 3/1,000 injury rate. PGA(g) 0.65- 1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate.	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18- 0.34 = 5% of total PGA(g) 0.34- 0.65 = 20% of total. PGA(g) 0.65- 1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Potential class action lawsuit for property damage, loss of property value, reimburse- ment for earthquake insurance and emotional distress.	PGA(g) 0.092- 0.18 = 0.5% of total. PGA(g) 0.18- 0.34 = 5% of total. PGA(g) 0.34- 0.65 = 20% of total. PGA(g) 0.65- 1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	Shutdown of project through court ordered injunctive relief likely if multiple events of PGA(g)>0.1 (>4 magnitude earthquake)	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$1M for legal and public outreach costs to avoid shutdown.	None	Cost to maintain CO2 injection pressure below 90% of fracture pressure and maintain reservoir fluid volume close to original fluid volume: Part of ongoing costs.	None	2
99	03.02.07.00.	Subsidence or uplift	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
100	03.02.08.00.	Thermal effects on the injection point	2	1	3	6	None	None	None	None	None	None	None	None	None	None	None	Adjust CO2 injection temperature to compensate for cooling effect in the reservoir. Part of ongoing costs.	None	2	

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101	03.02.09.00.	Reservoir water chemistry	Water phase geochemistry of sequestered CO ₂ . This includes the solubility trapping of CO ₂ in water (H ₂ O) to form carbonic acid (H ₂ CO ₃). Subsequent ionic trapping of carbonic acid with hydroxide ions (OH ⁻) forms bicarbonate ions (HCO ₃ ⁻), which can react in turn with further hydroxide ions to form carbonate (CO ₃). 1. Formation of carbonic acid (H ₂ CO ₃) 2. Formation of bicarbonate ions (HCO ₃ ⁻) 3. Formation of carbonate (CO ₃)	Modification of the water phase geochemistry can disturb the equilibrium between the water and solid phase of the reservoir and result in further geochemical (for example, solid phase geochemistry) and physical changes with resulting implications for the long-term performance of the sequestration system.	Any acidification of the brine from CO ₂ dissolution is likely to be neutralized by the basicity of the Canyon limestone formation. Dissolution of the limestone takes place in the reservoir and scale buildup takes place in the producing and recycling systems.	Need historical data on produced water chemistry and treatment.	Scale buildup. Salt precipitation. Conversion of anhydrite to gypsum in rock formation.	Change in water chemistry.	Decreased or increased porosity, permeability, injectivity.	Monitor bottom hole water chemistry. Monitor injection pressure.	Take geochemistry into consideration in site characterization, modeling and reservoir engineering.	Monitor produced water chemistry. Monitor injection water chemistry. Adjust injection water chemistry to control scaling or salt precipitation. Use of Teflon coating to control scale buildup.
102	03.02.10.00.	Interaction of CO ₂ with chemical barriers	Chemical barriers (pH, Eh-pH, ion exchange) may exist in aquifers to retard the migration of CO ₂ from depth. The precipitation of CO ₂ bearing solids may result from such interactions. 1. pH barrier 2. Eh-pH barrier 3. Ion exchange barrier	Such barriers will affect the rate of migration of CO ₂ from depth.	The CO ₂ is held in place by impermeable shale barriers rather than chemical barriers. Carbonate reservoir helps neutralize pH of brine.		Migration of CO ₂ past chemical barrier.	Interaction of CO ₂ with chemical barriers.	CO ₂ release (HSE hazard).	Include geochemistry in site characterization and modeling. Monitor CO ₂ migration and interaction with chemical barrier.	Include geochemistry in site characterization and modeling. Monitor CO ₂ migration and interaction with chemical barrier.	Include geochemistry in site characterization and modeling. Monitor CO ₂ migration and interaction with chemical barrier. Consider possible chemical treatment. Obtain proper approval for use of chemicals if necessary.
103	03.02.11.00.	Sorption and desorption of CO ₂ (CO ₂ interaction with coal seams)	The sorption and desorption of CO ₂ on geological materials. Sorption onto coal and the displacement of methane (CH ₄) is the primary mechanism behind the enhanced coal bed methane recovery (ECBM) method for geological CO ₂ sequestration.	The rate of sorption and desorption of CO ₂ on geological materials affects its mobility and therefore the performance of the storage system.	Coal seams are not present in the area. The Wolfcamp shale has some organic material that could adsorb CO ₂ that diffuses into the shale, but this is likely insignificant.		1. Limited CO ₂ sorption and methane release on coal. 2. Desorption of CO ₂	ECBM sorption of CO ₂ on coal and release of methane.	Limited CO ₂ storage. Low ECBM yield. Higher costs. Lower revenues.	Monitor CO ₂ injection and CH ₄ +CO ₂ +H ₂ O production.	Characterize and model coal seam for CO ₂ sorption. Select sites that have appropriate coal quality and methane content. Design well pattern and spacing to allow sufficient time for coal to sorb on to the coal and methane to be released. Avoid decreasing pressure in the coal seam to the point that CO ₂ desorbs.	Monitor and model CO ₂ injection and methane + CO ₂ = water production. Compare actual performance versus model projections. Identify root cause of any deviation from projections. Take corrective action as needed.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
101	03.02.09.00.	Reservoir water chemistry	4	4	2	32	None	None	None	None	None	None	5 days @ \$20,000/d revenue lost per pattern idled	Oil revenue loss \$15M/y Cleanout cost: \$1M/y	None	None	Oil revenue loss \$15M/y Cleanout cost: \$1M/y	Oil revenue loss: \$2.5M/y Cleanout cost: \$0.2M/y	Pretreatment of injected water at \$4M/y.	Savings: \$9.3M/y	2
102	03.02.10.00.	Interaction of CO2 with chemical barriers	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
103	03.02.11.00.	Sorption and desorption of CO2 (CO2 interaction with coal seams)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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104	03.02.11.01.	ECBM sorption of CO2 on coal and release of methane	Based on the Langmuir isotherm, CO2 has higher affinity to coal and therefore displaces CH4 adsorbed on the coal. 2-3 moles CO2 adsorbed on coal for every mole of CH4 desorbed. CO2 adsorption: up to 41 Nm ³ /tonne coal (1400 scf/st coal) CH4 release: up to 13-15 Nm ³ /tonne coal (450-500 scf/st coal) at 22°C 72°F and 0-7 MPa (0-1000 psi)). The CO2/CH4 sorption ratio of coal varies depending on the rank of coal. Typical CO2/CH4 sorption ratios for various coals are as follows: Low volatile bituminous: 1:1 Medium volatile bituminous: 1.5:1 High volatile A bituminous: 3:1 High volatile bituminous: 6:1 Sub bituminous: 10:1 (Reeves 2003)	Adsorption of CO2 on coal can have a positive effect on CO2 sequestration.	Not applicable to this site		Limited CO2 sorption and methane release.	ECBM sorption of CO2 on coal and release of methane	Limited CO2 storage. Low ECBM yield. Higher costs. Lower revenues.	Monitor CO2 injection and CH4+CO2+H2O production.	Characterize and model coal seam for CO2 sorption. Select sites that have appropriate coal quality and methane content. Design well pattern and spacing to allow sufficient time for coal to sorb on to the coal and methane to be released.	Monitor and model CO2 injection and methane + CO2 = water production. Compare actual performance versus model projections. Identify root cause of any deviation from projections. Take corrective action as needed.
105	03.02.11.02.	ECBM desorption of CO2 from coal or other solids	CO2 desorption can occur with decreased pressure.	Release of CO2 could lead to leakage.	Not applicable to this site		Release of CO2	ECBM desorption of CO2 from coal or other solids	Decreased CO2 storage capacity Migration of CO2	Monitor CO2 injection and CH4+CO2+H2O production.	Avoid decreasing pressure in the coal seam to the point that CO2 desorbs.	Increase pressure in coal seam with nitrogen injection.
106	03.02.11.03.	ECBM coal swelling	The chemical reactions and physical processes that occur during CO2 injection into coal seams and their impact on the integrity of the coal seams are not well understood. One of the reactions is swelling of the coal matrix when injecting CO2. (Damen 2006) When CO2 is injected into a coal seam, the coal matrix swells causing the cleat permeability to decrease.	Coal seam swelling may cause a reduction in permeability and injectivity. Swelling might also induce stresses on the overlying and underlying rock strata in non ideal coal seams (thin, low permeability and highly faulted), that could cause faulting and possible migration pathways out of the coal seam (Damen 2006).	Not applicable to this site		Fracturing of caprock. Decrease in CO2 injectivity.	ECBM coal swelling.	CO2 and/or CH4 release (HSE hazard). Higher operating costs.	Monitoring CO2 injectivity.	Characterize and model coal seam for coal swelling. Select sites that have appropriate coal quality and methane content. Design well pattern and spacing to allow sufficient time for coal to sorb on to the coal and methane to be released.	If coal swelling occurs with CO2 injection, it can be countered somewhat by dewatering. Different completion methods could be attempted.
107	03.02.11.04.	ECBM release of polyaromatic hydrocarbons (PAH) from coal seams	Polyaromatic hydrocarbons are chemical compounds that consist of aromatic rings. They are found in oil, coal and tar deposits. They tend to be released as a by-product of coal fires.	Toxicity issues and operation issues with decreased permeability.	Not applicable to this site		Contamination of groundwater with PAH.	ECBM release of polyaromatic hydrocarbons (PAH) from coal seams.	HSE hazard of contaminated water.	Establish base line study of PAH in local groundwater. Monitor groundwater for increases in PAH.	Characterize and model the interaction of CO2, coal and polyaromatic hydrocarbons.	Monitor groundwater for increases in PAH. Determine toxicity level and root cause. Take remedial action necessary to eliminate PAH (i.e., insitu treatment using vegetation; stabilization with humic acid; or pump and treat methods).
108	03.02.11.05.	ECBM coal seam dewatering	As a coal seam is dewatered, its pressure decreases. Cleat permeability increases. Coal matrix shrinks, opening up cleat fractures. Assume that the coal cleats are originally 100% saturated with water. Recommendation for ECBM: Coal seams with low water saturation (Bachu 2008)	Coal dewatering produces large quantities of water that must be properly treated and disposed of. In some cases, this may be a limiting factor in obtaining environmental permits and take a significant toll on project economics.	Not applicable to this site		Inability to treat or dispose of ECBM produced water.	ECBM coal seam dewatering.	Project delay or shutdown. Business interruption. Advanced loss of profits.	Monitor permitting and compliance process for water disposal.	Obtain permit for water disposal to handle all disposal needs. Treat produced water if necessary to meet disposal requirements.	Have backup disposal option in place.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

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104	03.02.11.01.	ECBM sorption of CO2 on coal and release of methane	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
105	03.02.11.02.	ECBM desorption of CO2 from coal or other solids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
106	03.02.11.03.	ECBM coal swelling	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
107	03.02.11.04.	ECBM release of polyaromatic hydrocarbons (PAH) from coal seams	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
108	03.02.11.05.	ECBM coal seam dewatering	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

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109	03.02.11.06.	ECBM original gas in place	Original gas (methane) in place (OGIP) depends on the rank of coal. Free gas occurs within natural fractures. Dissolved gas occurs in water within the natural fractures. Adsorbed gas occurs within the coal matrix. Adsorbed gas typically represents over 95% of total. (Mansourine 2003) Coal bed methane may be formed by bacteria (biogenic methane) at depths less than 300 meters, or formed by heat and pressure transformation of coal organic matter (thermogenic methane) at greater depths in higher-rank coals. Thermogenic methane frequently contains trace amounts of H₂O, CO₂, N₂ and H₂S. Existing gas in place = original gas in place - previous gas production. Recommendation for ECBM: Methane-saturated seams should be preferred from a methane production perspective. From a storage perspective, under saturated coal seams can still be effective (Bachu 2008).	OGIP impacts the amount of methane available for ECBM recovery.	Not applicable to this site		Low methane yield.	ECBM original gas in place.	Higher costs. Lower revenues.	Characterize and model coal seam for original gas in place. Calculate existing gas in place.	Characterize and model coal seam for original gas in place. Calculate existing gas in place. Select site that has sufficient gas in place.	Compare actual with projected methane recovery. Identify any deviation from projected. Determine root cause and make appropriate adjustments.
110	03.02.11.07.	Previous working of the coal seam	Primary CBM takes out 20-60% of the original gas in place (OGIP). CO₂ ECBM can recover an additional 30%. Up to 80-90% of OGIP can be recovered with primary CBM plus CO₂ ECBM. Production stages of a coal bed methane well 1. Dewatering stage 2. Stable production stage 3. Decline stage (Mansourine 2003) 4. CO₂ injection stage	Wells selected for ECBM CO ₂ injection should be near depletion to optimize CBM and ECBM performance.	Not applicable to this site		Low methane yield.	Previous working of coal seam	Higher costs. Lower revenues.	Include previous working of coal seam in characterizing and modeling the ECBM coal seam if documentation exists.	Include previous working of coal seam in characterizing and modeling the ECBM CO ₂ injection that are near depletion to optimize CBM and ECBM performance.	Compare actual with projected methane recovery. Identify any deviation from projected. Determine root cause and make appropriate adjustments.
111	03.02.11.08.	ECBM coal seam pressure	Coal seam hydrostatic pressure increases with depth. CO₂, N₂ and water injection increase hydrostatic pressure. Dewatering and methane production decrease hydrostatic pressure. CO₂, CH₄, N₂ and H₂S adsorption capacity of coal increases with coal seam hydrostatic pressure.	Gas adsorption is pressure dependent. The pressure profile in the reservoir must be understood and the injection operation designed appropriately. Gas adsorption of coal increases with pressure. Gas desorption of coal increases as pressure decreases. As reservoir pressure decreases, the rate at which CH₄ desorbs increases. However, CO₂ adsorption decreases with decreased pressure. At supercritical pressures, CO₂ adsorption may be replaced by absorption as CO₂ diffuses in coal. CO₂ is a coal plasticizer, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure. The transition temperature may drop from ~400°C at 3MPa to <30°C at 5.5 MPa. Coal plasticization, or softening, destroys any permeability that would allow CO₂ injection. (Bachu 2006).	Not applicable to this site		Low CH ₄ desorption. Low CO ₂ sorption.	ECBM coal seam pressure.	Higher costs. Lower revenues.	Take pressure into account in characterizing and modeling ECBM coal seams. Monitor CO ₂ injection, bottom hole pressure, and CH ₄ +CO ₂ +H ₂ O production. Compare actual with projected (modeled) results.	Take coal seam pressure into account in characterizing and modeling ECBM coal seams. Inject CO ₂ at low pressure to increase CH ₄ recovery. Inject CO ₂ at high pressure to increase CO ₂ storage. Avoid exceeding 90% of fracture pressure.	Monitor CO ₂ injection, bottom hole pressure, and CH ₄ +CO ₂ +H ₂ O production. Compare actual with projected (modeled) results. Adjust coal seam pressure (by injecting or extracting water) to optimize CH ₄ recovery or CO ₂ storage. Avoid exceeding 90% of fracture pressure.

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109	03.02.11.06.	ECBM original gas in place	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
110	03.02.11.07.	Previous working of the coal seam	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
111	03.02.11.08.	ECBM coal seam pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
112	03.02.11.09.	ECBM coal seam temperature	Coal seam temperature increases with depth. CO2 adsorption is an exothermic reaction and will provide a heat source, at least during the active injection phase of the project. As temperature of the coal seam increases, the adsorption of CO2 decreases.	Impacts CO2 adsorption and methane release.	Not applicable to this site		Low CH4 desorption. Low CO2 sorption.	ECBM coal seam temperature.	Higher costs. Lower revenues.	Take coal seam temperature into account in characterizing and modeling ECBM coal seams. Monitor CO2 injection bottom hole temperature and CH4+CO2+H2O production. Compare actual with projected (modeled) results.	Take coal seam temperature into account in characterizing and modeling ECBM coal seams. Inject CO2 at high temperature to increase CH4 recovery. Inject CO2 at low temperature to increase CO2 storage.	Monitor CO2 injection bottom hole temperature and CH4+CO2+H2O production. Compare actual with projected (modeled) results. Adjust coal seam pressure to optimize CH4 recovery or CO2 storage. Avoid exceeding 90% of fracture pressure.
113	03.02.11.10.	ECBM coal seam fluid pH	The pH of aqueous solutions affects the surface of material it is in contact with. In the case of coal, at a high pH value, the carbonaceous surface assumes a net negative charge. At a low pH, the carbonaceous surface assumes a net positive charge. Theoretically, a pH of 9 would favor and a pH of 2 would disfavor the aqueous capture of CO2.	pH of water in the coal seam may impact CO2 adsorption.	Not applicable to this site		Low CH4 desorption. Low CO2 sorption.	ECBM coal seam fluid pH.	Higher costs. Lower revenues.	Determine optimum pH for CO2 adsorption and/or CH4 desorption. Include pH in characterization and modeling of ECBM coal seam. If possible, try to operate near the optimum pH range.	Determine optimum pH for CO2 adsorption and/or CH4 desorption. Include pH in characterization and modeling of ECBM coal seam. If possible, try to operate near the optimum pH range.	Monitor pH of coal seam fluids. Make adjustments to pH through CO2 and/or water injection.
114	03.02.11.12.	ECBM injection and production well pattern and spacing	The most common drilling pattern is a 5-spot (injection well in the center and production wells in the corners or inverse 5-spot (injection in the corners and production in the center). Drilling on 16, 65 or 233 hectare (40, 160 or 640 acre) spacing. When injecting CO2, it is important to allow sufficient time for displacement of the methane (locating production wells far away enough from the injection wells).	Impacts the sweep efficiency of ECBM and the effective sorption of CO2.	Not applicable to this site		Low CH4 desorption. Low CO2 sorption.	ECBM injection and production well pattern and spacing	Higher costs. Lower revenues.	Monitor and model well performance	Optimize well spacing and pattern based on modeling and reservoir engineering.	Monitor well performance versus model predictions. Adjust model and well spacing and pattern as needed to optimize CH4 recovery.
115	03.02.11.13.	ECBM injection strategy	Constant injection rate or variable injection rate "huff and puff" (alternating starting and stopping CO2 injection over time).	Impacts the sweep efficiency of ECBM and the effective sorption of CO2.	Not applicable to this site		Low CH4 desorption. Low CO2 sorption.	Improper ECBM injection strategy.	Higher costs. Lower revenues.	Monitor and model well performance. Compare actual with projected performance.	Fully characterize and model the ECBM coal seam. Select the optimum injection strategy.	Monitor and model well performance. Compare actual with projected performance. Modify injection strategy if necessary.
116	03.02.11.14.	ECBM early CO2 breakthrough	Early breakthrough of CO2 can be caused by high permeability areas in the coal seam or improper well pattern/spacing.	Impacts the sweep efficiency of ECBM and increases costs due to the need for excess CO2 recycling.	Not applicable to this site		Higher CO2 consumption.	ECBM early CO2 breakthrough.	Higher operating costs. Higher CO2 recycling costs.	Monitor CO2 injection and CH4+CO2+H2O production.	Fully characterize and model the ECBM coal seam. Optimize well pattern/spacing.	Recycle CO2. Consider modifying well pattern/spacing.
117	03.02.11.15.	ECBM coal seam thickness	For ECBM at least one coal seam should be at least 0.5 m (1.5 ft) thick. However, the thicker the seam, the more likely it could be mineable. Recommended for ECBM: Concentrated coal deposits (few, thick seams) are generally favored over stratigraphical dispersed beds comprising multiple, thin seams (Bachu 2008).	Seams less than 0.5 m (1.5 ft) thick can limit injectivity.	Not applicable to this site		Low injectivity.	Insufficient coal seam thickness.	Higher costs. Lower revenues.	Characterize the coal seam thickness to confirm it meets recommendation.	Characterize the coal seam thickness to confirm it meets recommendation. Avoid sites with thin coal seams.	Avoid sites with thin coal seams.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
112	03.02.11.09.	ECBM coal seam temperature	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
113	03.02.11.10.	ECBM coal seam fluid pH	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
114	03.02.11.12.	ECBM injection and production well pattern and spacing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
115	03.02.11.13.	ECBM injection strategy	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
116	03.02.11.14.	ECBM early CO2 breakthrough	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
117	03.02.11.15.	ECBM coal seam thickness	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
118	03.02.11.16.	ECBM complex structural geology of coal seam	Complex structural geology can make ECBM more difficult to model, less efficient to implement and more susceptible to leakage. Recommendation for ECBM: Simple structure. The reservoir should be minimally faulted and folded . The coal seams should be laterally continuous and vertically isolated from surrounding strata to prevent migration of excess CO2 and CH4 into adjacent aquifers and possibly to the surface (Bachu 2008).	Potential for CO2 leakage and lower methane yields.	Not applicable to this site		CO2 leakage through existing or reactivated fault. Uncontrolled CO2 migration.	ECBM complex structural geology of coal seam	CO2 release (HSE hazard).	Fully characterize and model the site early in the design phase. Continuously monitoring and modeling the site. Evaluation of actual versus expected performance.	Fully characterize and model the site. Avoid sites with complex structural geology.	Monitor and model CO2 movement well performance. Compare actual with projected performance. Take remedial action if CO2 migration goes out of control (inject water to redirect migration or extract CO2 and reinject elsewhere.
119	03.02.11.17.	ECBM CO2 injection into mineable coal seams	CO2 ECBM is normally applied to coal seams that are too thin or too deep to be mined.	CO2 ECBM in mineable coal seams will complicate the recovery of those coal reserves. However, removing methane decreases the explosion possibility for future mining.	Not applicable to this site		CO2 contamination of coal reserves.	ECBM CO2 injection into mineable coal seams.	Loss of monetized value of contaminated coal reserves.	Identify ownership of mineral rights.	Obtain mineral rights for selected coal seam including sufficient buffer to protect against infringement on third-party reserves.	Evaluate CO2 extraction options and safety measures to be taken if coal seam is to be mined in the future.
120	03.02.11.18.	ECBM coal seam permeability	The permeability of coal varies in two basic ways: 1. Phase relative permeability effects 2. Change in the effective stress within the seams (Mansourine 2003) Cleat permeability is primarily controlled by the prevailing horizontal stresses. ECBM wells that produce little water or gas may indicate low permeability. Recommended permeability for ECBM: 1 to 5 mD (Bachu 2008). Coal permeability decreases with depth, such that injectivity is not possible below about 914 m (3000 ft) without fracturing (NETL 2010).	Low permeability makes CO2 ECBM more difficult and more expensive.	Not applicable to this site		Low CO2 injectivity and CH4 extraction.	Low ECBM coal seam permeability.	High operating costs, lower revenues.	Characterize and model coal seam permeability. Monitor CO2 injectivity.	Characterize and model coal seam permeability. Select coal seams with acceptable permeability.	Monitor injectivity. Dewater coal seam to increase cleat permeability. Consider hydraulic fracturing.
121	03.02.11.19.	ECBM coal porosity	Micro-porosity: < 2 nm pore diameter impacts sorption Meso-porosity: >2 nm <50 nm pore diameter impacts diffusion Macro-porosity (fracture porosity): > 50 nm impacts Darcy flow Induced fractures: pipe flow (Mansourine 2003) Cleat porosity represents the initial water storage volume in the coal seam.	Coal bed porosity and permeability increases as reservoir pressure is lowered and gas production occurs.	Not applicable to this site		Low CO2 injectivity and CH4 extraction.	Low ECBM coal seam porosity.	High operating costs, lower revenues.	Characterize and model coal seam porosity. Monitor CO2 injectivity.	Characterize and model coal seam porosity. Select coal seams with acceptable porosity.	Monitor injectivity. Dewater coal seam to improve injectivity.
122	03.02.11.20.	ECBM coal seam heterogeneity	Permeability can vary by more than an order of magnitude in coal seams.	Heterogeneity in permeability can result in CO2 early breakthrough, limit CO2 storage capacity and limit methane recovery.	Not applicable to this site		Low CO2 injectivity and CH4 extraction.	ECBM coal seam heterogeneity.	High operating costs, lower revenues.	Fully characterize and model heterogeneity of the coal seam. Monitor and model well performance. Compare actual with projected performance.	Fully characterize and model heterogeneity of the coal seam. Optimize the CO2 injection strategy to accommodate the heterogeneity of the coal seam.	Monitor and model well performance. Compare actual with projected performance. Modify injection strategy if necessary.

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
118	03.02.11.16.	ECBM complex structural geology of coal seam	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
119	03.02.11.17.	ECBM CO2 injection into mineable coal seams	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
120	03.02.11.18.	ECBM coal seam permeability	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
121	03.02.11.19.	ECBM coal porosity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
122	03.02.11.20.	ECBM coal seam heterogeneity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
123	03.02.11.21.	ECBM coal seam vertical and horizontal injectivity	Vertical and horizontal injectivity in coal seams is largely determined by the cleat size and cleat angle.	Vertical and horizontal injectivity may determine whether to use vertical or horizontal type wells for CO2 injection.	Not applicable to this site		Low CO2 injectivity and CH4 extraction	ECBM coal seam vertical and horizontal injectivity	High operating costs, lower revenues.	Fully characterize and model the coal seam taking into account differences in vertical and horizontal injectivity. Monitor and model well performance. Compare actual with projected performance.	Fully characterize and model the coal seam taking into account differences in vertical and horizontal injectivity. Optimize the CO2 injection strategy by use of vertical or horizontal wells to accommodate the differences in vertical and horizontal injectivity.	Monitor and model well performance. Compare actual with projected performance. Modify injection strategy using vertical or horizontal CO2 injection if necessary.
124	03.02.11.22.	ECBM CO2 storage capacity of coal	Typical sorption of coal can be up to 41 Nm ³ /tonne (1400 scf/st) at 22°C and 0- 6.9MPa (0-1000 psi).	Depending on the objective of CO2 ECBM, the CO2 storage capacity can have a positive or negative impact. If the objective is to minimize CO2 consumption/cost it can be a negative. If the objective is to maximize CO2 sequestration, it is a positive.	Not applicable to this site		Low CO2 storage capacity.	ECBM CO2 storage capacity of coal	Cost of acquiring operating additional CO2 geologic storage capacity.	Determine the CO2 storage capacity of coal through core sample testing. Model CO2 sorption. Monitor actual versus projected results.	Characterize and model the coal seam to estimate storage capacity. Select coal seams with sufficient CO2 storage capacity.	Dewater the coal seam to enhance CO2 storage capacity.
125	03.02.11.23.	ECBM coal bed methane composition	Coal bed methane tends to be sweet (no H2S). It contains small amounts of CO2 and nitrogen.	Impacts gas treatment facilities on surface and value of coal bed methane.	Not applicable to this site		Contamination of coal bed methane with N2, CO2 or other stripped gases.	ECBM coal bed methane composition	Additional processing costs for cleaning coal bed methane.	Monitor coal bed methane composition.	Characterize and model the coal seam to estimate coal bed methane quality. Design gas treatment facility to handle expected range of composition.	Monitor coal bed methane quality. Adjust gas treatment and/or CO2 injection strategy to deal with changes in quality.
126	03.02.11.24.	ECBM induced fracturing of coal	Coal is an extremely stress-sensitive rock	Limits CO2 injection pressure.	Not applicable to this site		Fracturing caprock.	ECBM induced fracturing of coal.	Release of CO2 (HSE hazard).	Determine fracturing pressure of caprock and coal. Monitor injection pressure. Alarm if CO2 injection pressure. Alarm if injection pressure exceeds 80% of caprock fracturing pressure. Monitor CO2 content in upper formations, groundwater, soil and/or atmosphere.	Determine fracturing pressure of caprock and coal. Monitor CO2 injection pressure. Do not exceed 90% of caprock fracturing pressure.	Monitor CO2/CH4 content in upper formations, groundwater, soil and/or atmosphere. If leakage is detected, lower coal seam pressure by lowering CO2 injection pressure or dewatering. Try to locate and remediate leak.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
123	03.02.11.21.	ECBM coal seam vertical and horizontal injectivity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
124	03.02.11.22.	ECBM CO2 storage capacity of coal	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
125	03.02.11.23.	ECBM coal bed methane composition	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
126	03.02.11.24.	ECBM induced fracturing of coal	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
127	03.02.11.25.	ECBM nitrogen injection into coal seam	Nitrogen has a lower affinity to coal than CH4. Nitrogen injection lowers the partial pressure of CH4 which allows CH4 to diffuse through the coal matrix with greater ease, improving recovery of CBM at a faster rate.	Nitrogen is not a problem in ECBM as a minor component of CO2. It will lower the partial pressure of methane and allow more methane to be released and recovered. Some of the nitrogen injected with CO2 may end up in the coal bed methane, resulting in a lower value product.	Not applicable to this site		Nitrogen contamination of coal bed methane.	ECBM nitrogen injection into coal seam.	Coal bed methane off spec. Increased costs. Decreased revenue.	Monitoring gas compositions of injected gas and produced gas.	Keep nitrogen gas content of CO2 stream low. Characterize and model gas composition of injected and produced gases.	Monitoring gas compositions of injected gas and produced gas. Treat produced gas to remove nitrogen.	
128	03.02.11.26	ECBM coal fines generation and transport	Induced fracturing of coal seams can lead to fines generation. These fines can be mobilized by injected gases or fluids. Some types of medium- and low-volatile bituminous coals are weaker, and have a greater tendency of generating fines, than other coals.	Coal fines can: 1. Plug and reduce coal seam permeability 2. Plug and reduce fracture conductivity 3. Plug submersible pumps 4. Erode ECBM systems 5. Accumulate in ECBM separators 6. Require disposal (Palmer 2008)	Not applicable to this site		Loss if injectivity.	Coal fines generation and transport plugging pore spaces and fractures.	Diminished ECBM performance. Higher costs, lower revenues. Decreased CO2 storage capacity.	Monitoring injection pressure and flowrate.	Avoid induced fracturing of weak coals.	Put in additional injection wells.	
129	03.02.11.27	ECBM coal plasticization	CO2 is a coal plasticizer, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure. The transition temperature may drop from ~400°C at 3MPa to <30°C at 5.5 MPa. (Bachu 2006). Recommendation for ECBM: Avoid deep ECBM sites that have CO2 supercritical pressures and temperatures above 30°C (Bachu 2008).	Coal plasticization, or softening, destroys any permeability that would allow CO2 injection. (Bachu 2006).	Not applicable to this site		Loss of injectivity.	Plasticization of coal .	Shutdown of operation.	Monitoring injection pressure and rate. Monitoring bottom hole pressures and temperatures.	Avoid deep ECBM sites that have CO2 supercritical pressures and temperatures above 30°C.	Permanent facility closure. Relocate site.	
130	03.02.12.00.	Heavy metal release	Heavy metal ions may be dissolved in formation fluids or adsorbed on rock/mineral surfaces. Complexation may occur between CO2 and heavy metals dissolved in formation fluids. The influence of dissolved CO2 on pore water chemistry can also reduce the pH and change the equilibrium between sorption/desorption of metals, thereby resulting in significant release of these metals.	This process has the potential to release heavy metals, which may then migrate to the near-surface environment with resulting impacts of interest. These heavy metals will also change pore water chemistry, which could impact on carbonate complexation.	The reservoir is a carbonate and will neutralize the pH of the brine. Some of the overlying sinks are also carbonates that would mitigate water acidification if CO2 were to leak above the primary seal. Analyses of USDW water inside and outside SACROC showed no increased concentration of heavy metals inside the SACROC area. (Smyth 2012)	Need data on heavy metal content in produced water/brine.	Migration of heavy metals with CO2/brine into the near surface environment.	Heavy metal release.	Contamination of ground/surface water and/or soil.	Conduct baseline study of heavy metals in the reservoir and near surface environment. Monitor heavy metal content in produced brine, ground/surface water, and soil.	Characterize and model the reservoir for heavy metal content and release. Avoid sites where heavy metal concentration is unusually high and would have a significant impact on the near surface environment.	Conduct baseline survey of heavy metal content in the near surface environment. Monitor heavy metal content in produced brine. Monitor CO2 and salinity in near surface environment. If CO2/brine contamination is indicated, check for heavy metal content.	
131	03.02.13.00.	Mineral phase (See 03.02.13.01. through 03.02.13.06.)	Geochemistry of the mineral phase relevant to sequestered CO2, including ion exchange and mineral dissolution.	Geochemical reactions between sequestered CO2 and the mineral phase of the storage system will affect the evolution of the system and the sorption (and therefore mobility) of the CO2.	The reservoir is a limestone and susceptible to mineral dissolution and precipitation.								
132	03.02.13.01.	Mineral dissolution and precipitation (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	The dissolution of minerals (grains or cement) due to the addition of CO2 (an acid gas) to the geochemistry and precipitation. For example, the dissolution of albite and precipitation of calcite modeled for the Sleipner site by Gaus et al. (2003). 1. Mineral dissolution and precipitation in the reservoir 2. Mineral dissolution and precipitation in or near the borehole 3. Mineral dissolution and precipitation in the caprock 4. Mineral dissolution and precipitation in faults and fractures	CO2 reaction with the host rock will modify: the porosity and permeability of the reservoir; fluid flow (direction or velocity); mechanical properties (e.g. strength); and CO2 storage capacity.								Monitoring injectivity and bottomhole pressures.	

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
127	03.02.11.25.	ECBM nitrogen injection into coal seam	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
128	03.02.11.26	ECBM coal fines generation and transport	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
129	03.02.11.27	ECBM coal plasticization	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
130	03.02.12.00.	Heavy metal release	2	1	3	6	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
131	03.02.13.00.	Mineral phase (See 03.02.13.01. through 03.02.13.06.)	0	0	0	0															
132	03.02.13.01.	Mineral dissolution and precipitation (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	0	0	0	0															

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133	03.02.13.02.	Precipitation of carbonate minerals (scale buildup)	CO2 reacts with brine to form hard water which can lead to scaling in or near a production well. Calcium carbonate and magnesium carbonate can be formed when HCO_3^- reacts with Ca^{2+} or Mg^{2+} .	Scale buildup can cause reduced porosity and permeability in the reservoir, especially near the borehole.	Scale problems have occurred in isolated instances but thus far have not posed a general problem due to proper treating and handling techniques (acid wash and scale inhibitors).	Need historical data on scale buildup and control.	Pore plugging. Well and equipment plugging.	Precipitation of carbonate minerals (scale buildup).	Decreased injectivity, decreased production, higher operating costs. Down time for clean out.	Characterization and modeling taking into account mineral precipitation reactions, mineralogy, brine chemistry and CO2 interaction. Monitoring CO2/brine movement, brine chemistry and changes in injectivity.	Avoid injecting water with high concentration of scale forming ions. Periodically clean out production facilities with acid.	Periodically treat system with scale inhibiting chemicals.
134	03.02.13.03.	Salt precipitation	Dry CO2 can pick up moisture from high salinity brines in the reservoir. This increases the salinity of the brines. (CCP 2009)	Increased salinity of brines can lead to precipitation of salt in pore space, which can decrease reservoir permeability and impair injection rates of CO2. (CCP 2009) "Dry out" and "salt out" may cause reduced porosity and permeability in the reservoir, especially near the borehole.	Salt precipitation could be an issue in the reservoir due to the high salinity (59,000 ppm TDS) of the brine, but may be mitigated if low salinity water is injected in the WAG process.	Need historical data on salt precipitation on control.	Pore plugging.	Salt precipitation.	Decreased injectivity, higher operating costs. Interruption of operations.	Include brine salinity and potential for salt precipitation in characterization and modeling. Monitor brine salinity and well injectivity.	Control salinity of injected water.	Monitor salinity of brine. Use fresh water injection to help dissolve salt buildup.
135	03.02.13.04.	Ion exchange (mineral dissolution and precipitation) (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	The process of exchanging one ion in the liquid phase for another ion on a charged, solid substrate. Injected CO2 may perturb ion exchange equilibrium between relevant minerals (such as sheet silicates) and the pore fluid. Some cations may be released to the pore fluid and others fixed as a consequence.	Disturbance of the rock-pore fluid equilibrium may affect the capacity of the rock to store CO2.								Monitor and model ion exchange, mineralogy and common ions in brine. Control chemistry of injected water.
136	03.02.13.05.	Desiccation of clay	CO2 is likely to be dried to prevent corrosion during transport. Injection of dry CO2 will cause it to take up water from the pores of the host formation and overlying rocks. It has the potential to suck water out of an overlying clay. CO2 can also be adsorbed by clay.	If clay dehydrates, it will shrink and crack. This might aid CO2 migration upwards.	Not identified as a problem at SACROC. Wolfcamp shale consists of 62% illite and 3.4% other clay minerals.	Need historical data on clay desiccation and control.	Shrinking of clay particles in caprock leading to CO2 leakage.	Desiccation of clay.	CO2 release (HSE hazard).	Characterize clay content of caprock and reservoir. Model and observe impact of CO2 on clay desiccation. Monitor for CO2 leakage near wells.	Characterize caprock to evaluate clay content and potential for desiccation. Avoid CO2 injection in areas where clay desiccation would be a problem.	Inject water to hydrate clay.
137	03.02.13.06.	Mineral dissolution	The dissolution of minerals (grains or cement) due to the addition of CO2 (an acid gas) to the geochemistry. 1. Mineral dissolution in the reservoir 2. Mineral dissolution in or near the borehole 3. Mineral dissolution in the caprock 4. Mineral dissolution in faults and fractures	CO2 reaction with the host rock will increase: the porosity and permeability of the reservoir; increase fluid flow (direction or velocity); decrease mechanical properties (e.g. strength); and increase CO2 storage capacity.	Mineral dissolution occurs in the Canyon and Cisco limestone formations, but there is no evidence this has impacted the Wolfcamp shale (primary seal). No faults have been identified that penetrate the primary seal. Mineral dissolution increases injectivity in the reservoir but is insufficient to impact the structural strength of the primary seal.	Need historical data on mineral dissolution and control.	Weakening and fracture/collapse of caprock. Reactivation of fault. Subsidence. Channeling within the reservoir.	Mineral dissolution.	Decreased sweep efficiency due to channeling. Increased CO2 permeability and injectivity.	Characterization and modeling taking into account mineral dissolution reactions, mineralogy, brine chemistry and CO2 interaction. Monitoring CO2/brine movement, brine chemistry, core sample analysis, elevation change, micro-seismicity.	Characterization and modeling taking into account mineral dissolution reactions, mineralogy, brine chemistry and CO2 interaction. Avoid sites where mineral dissolution could weaken the integrity of the caprock.	Monitoring injectivity and bottomhole pressures. Selective perforation or use of gels or sealant.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
133	03.02.13.02.	Precipitation of carbonate minerals (scale buildup)	5	4	2	40	None	None	None	None	None	None	None	Oil revenue loss \$13.5M/y Cleanout cost: \$1M/y	None	None	\$14.5M/y	\$2.7M/y	Pretreat injected water. Periodically clean out production facilities with acid. Part of ongoing costs.	Savings: \$11.8M/y	22
134	03.02.13.03.	Salt precipitation	3	2	3	18	None	None	None	None	None	None	None	<\$1M/y	None	None	<\$1M/y	<\$0.5M/y	Periodically inject fresh water to control salt precipitation. \$0.50/t water injected. Part of ongoing costs.	N<\$0.5M/y	2
135	03.02.13.04.	Ion exchange (mineral dissolution and precipitation) (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	0	0	0	0															
136	03.02.13.05.	Desiccation of clay	2	3	3	18	None	None	None	\$200/t CO2/brine released into USDW	None	None	None	\$1M to \$3M to locate and fix leak	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage is undetected and unmitigated for 5 years: <\$6M	Assuming leakage detected early: <\$1M	Inject water to hydrate clay. \$0.50/t water injected.	Savings: Up to \$4M	2
137	03.02.13.06.	Mineral dissolution	2	3	2	12	None	None	None	\$200/t CO2/brine released into USDW	None	None	None	Loss of oil revenue: \$10M/y due to channeling of CO2.	None	None	<\$10M/y	<\$2M/y	Selective perforation or use of gels or sealant: <\$5M/y	<\$3M/y	2

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SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
138	03.02.14.00.	Gas chemistry (CO2 interacting with gases in the reservoir)	Gases such as CO2, methane and H2S, will occur naturally in the geosphere, either sorbed onto minerals, dissolved in formation fluids or as a free gas phase. Gas solubility will depend upon pressure, temperature and the salinity of the formation fluid. 1. CO2 interacting with free gases in the reservoir 2. CO2 interacting with gases sorbed onto minerals 3. CO2 interacting with gases dissolved in formation fluids 4. CO2 interacting with gaseous hydrocarbons in the reservoir	Gases naturally present in the geosphere could affect the behavior of CO2 injected into a storage reservoir and could accompany CO2 along potential migration paths.	Free gases were not originally present in the reservoir. However, after the reservoir pressure decreased below the bubble point, some hydrocarbon gases came out of solution from the oil. H2S was introduced into the reservoir by prior water and CO2 injection. H2S monitors and alarms have been installed near injection wells.	Need data on produced gas composition.	Corrosion of well production and recycle system components.	Gas chemistry (CO2 interacting with gases in the reservoir).	Release of CO2 and associated gases (HSE hazard). More complicated gas treatment and cleanup.	Characterize the reservoir for the presence of gases (particularly H2S). Monitor produced gas composition.	Monitor for H2S in the site area.	Monitor for H2S in the recycled CO2 and around injection wells and recycle facilities. Maintain tight seals and failsafe systems
139	03.02.15.00.	Gas stripping in overlying formations	CO2 migration through the reservoir and into the overlying barrier sequence could result in the CO2 stripping other gases entrained within the sediments. This could include: 1. Radon stripping 2. Methane (CH4) stripping, and 3. Hydrogen sulfide (H2S) stripping.	The presence of other gases in a leaking CO2 gas stream is important in deciding the level of CO2 leakage that can be tolerated and may constitute an important hazard.	H2S was introduced into the reservoir by prior water and CO2 injection. H2S acts as an odorant for early detection of CO2 and any stripped gases.	Need data on gas content in formations overlying primary seal.	Release of CO2 and stripped gases to ground/surface water and/or atmosphere.	Gas stripping	Water contamination. Atmospheric emissions.	Characterize site for the presence of gases in overlying formations. Monitor for H2S as an early detection of gas leakage or release.	Characterize site for the presence of gases that may be stripped and transported by CO2 (particularly H2S). Maintain integrity of the caprock seal.	Monitor H2S near wells or in confined spaces. Maintain tight seals and failsafe systems.
140	03.02.16.00.	Gas hydrates	Gas hydrates are 'ice-like' solids that form at low temperatures and high pressures. They are formed of 'cages' of water molecules surrounding a gas molecule. CO2 can form hydrates in the presence of water. The prevention of hydrate formation in the well during startup will need to be considered. It is likely that methanol spacers will need to be used. (CCP 2009) Hydrate potentially could form in the well when starting back up after a shut down. During the process of shutting down, measures should be taken to mitigate the formation of hydrates when starting back up. Often a methanol "cap" is pumped in the top of the tubulars. (CCP 2009) As a consequence of well control using a brine or similar fluid, there can be intermixing of the CO2 and the well control fluid that could result in hydrate formation or hydrate blocks. Using hydrate inhibited fluids or having operational practices that minimize the amount of CO2 inflow during workovers should be considered. (CCP 2009) There is a lack of experimental data and models for predicting the water solubility of CO2 at temperatures below 10°C. Moreover, there is a need to investigate hydrate formation conditions with CO2 near and below water saturated conditions in the presence of carbon steel surfaces. (DNV CO2PIPETRANS Phase 2) 1. Gas hydrates formed below deep water 2. Gas hydrates formed below permafrost 3. Gas hydrates formed in well during startup 4. Gas hydrates formed in pipeline	Cooling of the reservoir (e.g. by injecting cold CO2 or through adiabatic expansion) well below normal in-situ temperatures might stabilize gas hydrates. Their growth might seal fluid flow pathways (at least temporarily). If CO2 is injected below deep water or permafrost, then rising CO2 might hit the hydrate stability zone before escaping to the ocean or air, so hydrates could act as a secondary chemical barrier. Similarly, storage could be focused on actively forming CO2 hydrate as a stable, immobile phase to lock up the CO2 (Koide et al., 1997).	Produced CO2 is decompressed in multiple stages to prevent gas hydrate formation. Hydrate inhibitor may also be added.	Need historical data on gas hydrate formation and control.	Plugging of production wells or recycling system.	Gas hydrates.	Interruption of operations.	Determine conditions for formation of gas hydrates. Monitor for those conditions. Monitor for plugging of production wells and/or decreased injectivity.	Characterize the site for conditions which could lead to gas hydrate formation. Try to operate outside of the conditions leading to gas hydrate formation.	Monitor for conditions which could lead to gas hydrate formation and try to operate outside of those conditions. Remediate hydrates using methanol or other solvents. Obtain proper approvals if chemicals are injected.

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
138	03.02.14.00.	Gas chemistry (CO2 interacting with gases in the reservoir)	2	2	2	8	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	0-5 days @ \$20,000/d revenue lost per pattern idled	NA	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage is undetected and unmitigated for 1 year: <\$1M	Assuming leakage detected within a month: <\$0.1M	Monitor H2S in CO2 and around injection wells and recycle facilities. Maintain tight seals and failsafe systems <\$300k	Savings: <\$0.6M	2
139	03.02.15.00.	Gas stripping in overlying formations	2	2	2	8	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	0-5 days @ \$20,000/d revenue lost per pattern idled	NA	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage is undetected and unmitigated for 1 year: <\$1M	Assuming leakage detected within a month: <\$0.1M	Monitor H2S in CO2 and around injection wells and recycle facilities. Maintain tight seals and failsafe systems <\$300k	Savings: <\$0.6M	1
140	03.02.16.00.	Gas hydrates	3	2	2	12	None	None	None	None	None	Plugging of production wells or pore space <\$1M per incident.	1-5 days @ \$20,000/d revenue lost per pattern idled	Methanol cost for controlling hydrates \$420- \$30/t of methanol	None	None	Up to \$1 M per plugging incident.	None	Avoidance cost in site selection. Remediate hydrates using methanol or other hydrate inhibitors. \$420- 430/t methanol.	Up to \$1 M per plugging incident.	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
141	03.02.17.00.	Biogeochemistry	Features and processes related to the biological/biochemical processes that affect the CO ₂ , borehole seals and rock/pore fluid, and the overall biological/biochemical evolution with time. This includes the effects of biological/biochemical influences on the CO ₂ and engineered components by the surrounding geology. Microbes exist in the subsurface and are used in hydrocarbon operations to improve hydrocarbon recovery (e.g., in EOR and ECBM operations). Microbes can also catalyze geochemical reactions, including methanogenesis, but the latter reaction is thermodynamically unfavorable and is unlikely.	Examples of relevant processes are: - microbial growth; - microbial/biological mediated processes; and - microbial/biological effects of evolution of redox (Eh) and acidity/alkalinity (pH) , etc. This FEP has probably low relevance to the safety/fate of CO ₂ . However, CO ₂ releases may affect/impact microbe populations being used in independent hydrocarbon-recovery enhancement projects.	Microbes beneficial to improve hydrocarbon recovery. Microbial plugging of wellbores at SACROC has not been a problem because injected water is pretreated.	No microbe data available at SACROC,	Pore/well plugging. Generation of CH ₄ or H ₂ S gases.	Biochemistry.	Decreased injectivity and interruption of operations. Increased HSE risks for release of CO ₂ containing CH ₄ or H ₂ S. Corrosion of well, production and recycle system components.	Characterize the site for microbe types and microbial growth. Monitor for microbial growth and activity (pore plugging and generation of CH ₄ or H ₂ S).	Avoid injecting water containing microbes or nutrients that may stimulate microbial growth and activity.	Use chemical treatment if necessary to control microbial contamination/growth. Obtain proper approvals if chemicals are injected.
142	03.02.18.00.	Microbial processes	Microbes can metabolize CO ₂ , for example, methanogenic microbes use H ₂ to reduce CO ₂ to methane (CH ₄), a process called methanogenesis. These microbes need anaerobic conditions. Microbes can produce SO _x , NO _x , and CO under oxic conditions and H ₂ S and CH ₄ under anoxic conditions.	Methanogenesis, if it occurs, could affect the pressure distribution of CO ₂ . The fate and impact of the CH ₄ produced may be an endpoint of interest in itself.	Microbes beneficial to improve hydrocarbon recovery. Microbes have not been a problem at SACROC. Biocides are added to injected water. Any methane produced by microbes is recovered. H ₂ S is already present.	No microbe data available at SACROC,	Generation of CH ₄ or H ₂ S gases.	Microbial processes.	HSE risks for release of CO ₂ containing CH ₄ or H ₂ S. Corrosion of well, production and recycle system components.	Characterize the site for microbe types and microbial growth. Monitor for microbial growth and activity (pore plugging and generation of CH ₄ or H ₂ S).	Avoid injecting water containing microbes or nutrients that may stimulate microbial growth and activity.	Use chemical treatment if necessary to control microbial contamination/growth. Obtain proper approvals if chemicals are injected. Monitor H ₂ S in CO ₂ and around injection wells and recycle facilities. Maintain tight seals and failsafe systems.
143	03.02.19.00.	Biomass uptake of CO ₂	If sequestered CO ₂ migrates to the biosphere, it can be taken up by microbes, plants and algae (including phytoplankton).	This mechanism may provide a sink for CO ₂ that has migrated from the sequestration system.	There is little biomass on the surface of the project site except for some scattered crop lands.		NA	Biomass uptake of CO ₂ .	Positive effect on CO ₂ sequestration.	Characterize site for biomass content.	Maintain biomass on site that may collect leaked CO ₂ .	NA
144	03.02.20.00.	Mobilization of particulates by CO ₂	Insoluble particulates could be mobilized by CO ₂ via chemical hydrodynamic interaction with the reservoir rock.	Particulate mobilization could increase permeability at the point of mobilization, but it could also decrease permeability in reservoir locations where particulates are deposited or trapped.	Mobilization of particulates has not been reported as a problem at SACROC,	No data on mobilization of particulates by CO ₂ at SACROC.	Reservoir permeability decreased.	Deposition of mobilized particulates.	Decreased injectivity. Higher operating costs.	Monitor injectivity.	Characterize the site for conditions which could lead to mobilization of insoluble particulates.	Increase the number of injection wells. Hydrofracturing or acid stimulation to improve injectivity.
145	03.03.00.00.	CO ₂ transport	Transport processes that may affect sequestered carbon dioxide and associated impurities.	An understanding of those processes that could transport carbon dioxide, and associated impurities, within the geosphere, near-surface and surface environments is fundamental to the assessment of long-term performance and safety.								

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
141	03.02.17.00.	Biogeochemistry	2	1	3	6	None	None	None	None	None	None	1-5 days@ \$20,000/d revenue lost per pattern idled	Increased injection cost due to decreased injectivity Cost of chlorine for microbial control \$310- 340/t Cl (\$0.03/t water treated @ 4 ppm Cl)	None	None	\$0.1M/pattern decreased oil revenue per clean out	None	Pretreat injected water with chlorine biocide <\$0.03/t water	\$0.1M/pattern per clean out eliminated	2
142	03.02.18.00.	Microbial processes	2	1	3	6	None	None	None	None	None	None	1-5 days @ \$20,000/d revenue lost per pattern idled	Increased injection cost due to decreased injectivity Cost of chlorine for microbial control \$310- 340/t Cl (\$0.03/t water treated @ 4 ppm Cl)	None	None	\$0.1M/pattern decreased oil revenue per clean out	None	Pretreat injected water with chlorine biocide <\$0.03/t water	\$0.1M/pattern per clean out eliminated	1
143	03.02.19.00.	Biomass uptake of CO2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
144	03.02.20.00.	Mobilization of particulates by CO2	2	2	3	12	None	None	None	None	None	None	1-5 days @ \$20,000/d revenue lost per pattern idled	Cost of acid stimulation or fracture stimulation \$0.25M/well	None	None	Cost of acid stimulation or fracking: \$0.25M/well	None	Cost of acid stimulation or fracking: \$0.25M/well	None	2
145	03.03.00.00.	CO2 transport	0	0	0	0															

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146	03.03.01.00.	Advection of free CO2	Advection of free CO2 occurs in response to differences in pressure. The pressure difference may be due to differences in the pressure of injected CO2 and formation pressures. The rate and direction of advection is affected by the physical properties of the rock, such as porosity and permeability. Advection may also occur through fractures. Fracture flow will be episodic with high transport efficiencies. Resealing of fractures (for example by cementation) will reduce and ultimately block fluid flow. 1. Advection causing change in CO2 migration direction 2. Hydrodynamic gradients	Advective flow is a key transport process for migrating CO2, and associated contaminants, in the geosphere (reservoir, surrounding and overlying rock), near-surface and surface environments.	Advective flow of CO2 controlled by injection water curtains at SACROC to keep CO2 within patterns.		CO2 migration different than planned.	Advection of free CO2.	Decreased oil recovery	Monitor CO2 migration through seismic surveys and production wells.	Take into account advection of CO2 in site characterization and modeling and apply to CO2 injection strategy.	Monitor and model CO2 movement. Compare actual with projected. Take remedial action if CO2 migration goes out of control (inject water to form water curtains).
147	03.03.01.01.	Fault valving and reactivation	Fault valving is a process resulting from gradual build up of pore pressure due to fluid generation, causing the subsequent opening of a fault along with fluid escape towards surface. This mechanism has been recognized as causing earthquakes in many parts of the world, as a result of hydrocarbon generation (e.g., in EOR or ECBM operations) or infiltration of other fluids. 1. CO2 leakage through an existing open fault 2. CO2 leakage through a reactivated fault	Large releases of pore fluids may occur during fault valving episodes.	The reservoir is known to have many faults and fractures but there are no known faults penetrating the primary seal.		CO2/brine leakage through a reactivated fault.	Fault valving.	CO2 release (HSE hazard).	Characterize and model the site for existing faults. Monitor for CO2/H2S near fault. Monitor micro-seismicity.	Characterize and model the site for existing faults. Avoid or isolate areas with faults penetrating the caprock. Maintain CO2 injection pressure at <90% of fracture pressure.	Monitor CO2/H2S near fault. Monitor micro-seismicity or surface displacement (LiDAR). Inject sealants into fault. Use injection water curtains to keep CO2/H2S migration away from faults.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
146	03.03.01.00.	Advection of free CO2	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	None	None	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<4% decrease in oil revenue (400 bpd): <\$10M/y	None	Cost of injection water curtains to control CO2 migration within patterns: <\$1M/y	Savings: <\$9M/y	1
147	03.03.01.01.	Fault valving and reactivation	2	3	3	18	PGA(g) 0.092-0.18 = 1/1000,000 fatality rate. PGA(g) 0.18- 0.34 =1/100,000 fatality rate. PGA(g) 0.34- 0.65 = 1/10,000 fatality rate. PGA(g) 0.65- 1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate.	PGA(g) 0.092- 0.18 = 1/250,000 injury rate. PGA(g) 0.18- 0.34 = 1/25,000 injury rate. PGA(g) 0.34- 0.65 = 1/2,500 injury rate. PGA(g) 0.65- 1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate.	PGA(g) 0.092- 0.18 = 3/100,000 injury rate. PGA(g) 0.18- 0.34 = 3/10,000 injury rate. PGA(g) 0.34- 0.65 = 3/1,000 injury rate. PGA(g) 0.65- 1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate.	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18- 0.34 = 5% of total. PGA(g) 0.34- 0.65 = 20% of total. PGA(g) 0.65- 1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Potential class action lawsuit for property damage, loss of property value, reimburse- ment for earthquake insurance and emotional distress.	PGA(g) 0.092- 0.18 = 0.5% of total. PGA(g) 0.18- 0.34 = 5% of total. PGA(g) 0.34- 0.65 = 20% of total. PGA(g) 0.65- 1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	Shutdown of project through court ordered injunctive relief likely if multiple events of PGA(g)>0.1 (>4 magnitude earthquake)	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	Assuming leakage detected early and mitigated: \$1M for water remediation	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Savings: Up to \$3M	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
148	03.03.02.00.	Buoyancy-driven flow	Different relative densities of fluids in a geological system will result in buoyancy-driven flows as less dense fluids will have a tendency to flow upwards. The density of fluids will depend on its temperature and pressure. If a stream of CO2 begins to move upward, expansion of the volume and decrease in the density provides increasing energy to drive flow upward, which can result in gas lift, a strong process for moving fluid upward (NETL 2010). 1. CO2 exceeding reservoir spill point 2. Lateral CO2 flow across top of reservoir 3. CO2 buoyancy putting pressure on caprock	Carbon dioxide can be less dense than water, which may cause injected CO2 to flow upwards and accumulate above the water phase below the caprock of a reservoir. Water with dissolved CO2 is more dense than water, which can result in stratification of water bodies into which CO2 may leak, if conditions are suitable.	Buoyancy flow at SACROC is limited by discontinuous vertical permeability in the reservoir and the fact that the CO2 and oil have similar densities.		CO2 migration different than planned.	Buoyancy-driven flow.	Decreased oil recovery	Monitor CO2 migration through seismic surveys and production wells.	Take into account buoyancy-driven CO2 in site characterization and modeling and apply to CO2 injection strategy.	Monitor and model CO2 movement. Compare actual with projected. Take remedial action if CO2 migration goes out of control (selective perforation, polymer gel, sealants).
149	03.03.03.00.	Displacement of formation fluids	This depends on interfacial tension and capillary pressure. Capillary pressure is the pressure difference existing across the interface separating two immiscible fluids due to interfacial tension. The interfacial tension itself is caused by the imbalance in the molecular forces of attraction experienced by the molecules at the surface and is a function of temperature and pressure. At a given pressure, increased interfacial tension values between water and CO2 will make larger pores accessible to CO2 (this is only valid for water-wet systems). The change from a water-wet system to a CO2-wet system has an effect on capillary forces (i.e. displacement of water by enhanced pressure versus CO2 injection with less capillary pressure) and the displacement capacity (i.e. as a non-wetting fluid, CO2 will have less displacement capacity). If the injection velocity is high, effects of capillary forces are small.	Interfacial tension and capillary pressure determine the location of CO2 within the pore spaces of the reservoir and the displacement capacity of the reservoir.	The SACROC Northern Platform operates under miscible conditions and uses WAG to improve sweep efficiency.		Failure of CO2 to displace oil/brine in pores.	Interfacial tension and capillary pressure.	Decreased oil recovery.	Characterize and model site taking into account brine movement and replenishing. Monitor salinity of ground/surface water.	Characterize and model interfacial tension and capillary pressure for CO2, oil and brine. Maintain miscible conditions in the reservoir.	Maintain miscible conditions in the reservoir.
150	03.03.04.00.	CO2 dissolution in formation fluids	The process of dissolution of CO2 in formation fluids. The rate of dissolution depends on factors such as the interfacial area between the CO2 and the formation fluids and temperature.	Dissolution in formation fluids can be an important positive process in decreasing the free CO2 remaining in the reservoir.	Injected CO2 is dissolved in the residual oil and brine. Modeling by Ham indicated that up to 67% of injected CO2 may dissolve in residual oil, 3% may dissolve in brine and the balance may be freely mobile CO2 (Han 2010).		Not a negative risk	CO2 dissolution in formation fluids.	Positive effect on CO2 sequestration.	Characterize and model site taking into account dissolution of CO2 into brine.	NA	Using well patterns more amenable for dissolution will reduce risks.
151	03.03.04.01.	CO2 exsolution from formation fluids	Long-term risks might result from the gravitational sinking of dense CO2 saturated brines; if they come into contact with salt formations this could lead to a degassing of the formation water and the ascent of CO2 outside of the original closed storage structure. (CO2STORE, page 68) Exsolution can also occur under significant (large) changes in pressure or temperature. The risk of major changes in pressure or temperature in a deep reservoir is very low.	Displaced brine containing dissolved CO2 flows to the surface and releases CO2 to the atmosphere or ocean.	CO2 exsolution occurs as formation fluids are extracted and exposed to lower pressure. There is the potential for CO2 exsolution due to leaky wellbores.	What is the potential for CO2 exsolution as a result of leaky wellbores?	Displacement of CO2/brine plus exsolution of CO2 .	CO2 exsolution from formation fluids	CO2 release (HSE hazard).	Characterize and model site taking into account dissolution, brine movement and conditions required for CO2 exsolution.	Maintain integrity of caprock and wells.	Monitor CO2/H2S near wells. Isolate and rework leaky wells.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
148	03.03.02.00.	Buoyancy-driven flow	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Pore space infringement (\$500+/acre)	None	None	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<4% decrease in oil production (400 bpd); <\$10M/y	None	Cost of selective perforation, polymer gel or sealant. <\$4M/y	Savings: <\$6M/y	1
149	03.03.03.00.	Displacement of formation fluids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	Cost to maintain miscible conditions part of ongoing operation.	None	1
150	03.03.04.00.	CO2 dissolution in formation fluids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	Cost to maintain miscible conditions part of ongoing operation.	None	2
151	03.03.04.01.	CO2 exsolution from formation fluids	3	2	3	18	None	None	None	<5,000 t/y CO2/brine per leak @ \$200/t CO2/brine released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	None	None	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$1M per incident	None	Cost of monitoring for CO2/H2S near wells plus isolating and reworking leaky wells:<\$100k/inci dent	Up to \$0.9M per incident avoided.	2

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
152	03.03.05.00.	Water mediated transport	Processes related to the transport of CO2, and associated contaminants, in groundwater and surface water, including advection, dispersion and molecular diffusion. Advection is the process by which contaminants are transported by the bulk movement of the water in which they are dissolved. Advective groundwater flow can occur along connected porous regions, such as fractures and faults. Dispersion is the collective name for the consequences of a number of processes that cause 'spreading-out' of CO2, and associated contaminants, dissolved in water in all directions, superimposed on the bulk movement predicted by a simple advection model. It results in a spatially distributed contaminant plume. Diffusion is the process whereby chemical species move under the influence of a chemical potential gradient (usually a concentration gradient).	The transport of CO2, and associated contaminants, within groundwater is likely to be a key migration process and therefore an important consideration in determining performance and safety. CO2 dissolves in brine at CO2/brine interface and brine transports CO2 out of closure.	The SACROC area groundwater level is elevated and can flow in all directions away from the site. The SACROC Northern Platform reservoir is isolated from USDW aquifers by 5000 ft of multiple stacked seals and sinks and closed on three sides, top and bottom. However leaky wellbores could allow CO2 and contaminants to seep into overlying aquifers. There are very limited surface waters above the SACROC Northern Platform site (limited to a small creek and some small ponds).		Extensive ground/surface water contamination.	Water mediated transport.	Liability for contamination of ground/surface water with CO2/brine. Damage to drinking water and/or irrigation water supply.	Characterize and monitor ground/surface water for CO2 and salinity.	Maintain integrity of caprock and wells.	Monitor for pH/CO2/H2S in ground water and CO2/H2S near wells. Locate, isolate and rework leaky wells.
153	03.03.06.00.	CO2 release processes	Processes by which CO2 is lost from the sequestration system. Once in the near-surface, changes in pressure and temperature result in the potential for phase changes and degassing, with resulting changes in the transport properties of sequestered CO2. Examples of CO2 release processes include: 1. Surface blowouts (rapid release of CO2) 2. Undersea blowouts (rapid release of CO2) 3. CO2 geysers (such as Crystal Geyser in Utah) 4. Submarine gas release (Slow or moderate release of CO2) 5. Diffusion through soil (slow release of CO2) 6. CO2 released through mud volcano or mud flow. In fine-clastic unconsolidated rocks, suspensions could form and cause mud-volcanism and mud flows. (CO2STORE p.68) Mud diapir could be formed in unconsolidated (plastic, water-rich, under-compacted) reservoir and overburden strata possibly including the entire reservoir because of the buoyancy of store CO2. (CO2STORE, page 68)	The potential for CO2 to be lost from a sequestration system will determine the performance of that system. Rapid release of CO2 will tend to shoot CO2 into the atmosphere where it will quickly mix with air and diffuse. Slow release of CO2 will diffuse into soil gas. Moderate release of CO2 will tend to blanket the ground unless there is sufficient air circulation (wind). Thus moderate release of CO2 can be a greater safety risk than rapid or slow release.	The likely CO2 release processes at SACROC are: 1. Well blowout or leakage 2. Piping rupture or leakage 3. Equipment failure CO2-EOR operations released 0.3% of total CO2 handled in 2008. Key causes were: routine maintenance and power outages caused by storms. (Bradley 2009a) CO2 pipeline operations released 0.000035% of CO2 transported in 2008. (Bradley 2009a) CO2 supply operations released 0.004% of CO2 produced in 2008. Key cause was routine maintenance. (Bradley 2009a)		CO2 release resulting in a fatality. (1) Blowout or rupture (rapid release of CO2). (2) Leak (moderate release of CO2). (3) CO2 diffusion through soil (slow release of CO2).	CO2 release processes.	(1) Damage to surface facilities. Injury to humans or fauna. (2) Accumulation of CO2 in low surface areas or confined areas. Asphyxiation of humans or fauna. (3) Damage to flora, rodents and organisms in soil. (1-3) Loss of CO2 storage credits.	Monitor and model CO2 plume. Monitor for CO2 leaks. Monitor well/pipeline pressure, corrosion and excavation activity.	Maintain integrity of caprock, wells, piping and equipment. Maintain blow out preventers and packers in wells. Maintain block valves and computational pipeline monitoring (CPM) leak detection system for pipelines.	Monitor well, pipeline and equipment for pressure and corrosion Supervise excavation activity near pipeline. Monitor for H2S near wells and CO2 recycling facilities. Monitor for CO2/H2S and ventilate confined spaces. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/H2S leak.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
152	03.03.05.00.	Water mediated transport	2	2	3	12	None	None	None	<5,000 t/y CO2/brine per leak @ \$200/t CO2/brine released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	None	None	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$1M per incident	None	Cost of monitoring for CO2/H2S near wells plus locating, isolating and reworking leaky wells:<\$200k/inci dent	Up to \$0.8M per incident avoided.	1
153	03.03.06.00.	CO2 release processes	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2/brine per leak @ \$200/t CO2/brine released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	Damage from blowout: \$0.5M. Well abandonment and replacement: \$2M	0-10 days @ \$20,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Well blowout: <\$3M per event Pipeline rupture:<\$1M per event Compressor failure: \$2M per event Fatalities and/or injuries: \$3.1M	None	Mitigation costs for wells: \$15,000/active well per year Mitigation costs for pipelines: \$3,600/mi per year Mitigation costs for facilities: 1% of equipment capex per year	Up to \$2.5M per blowout prevented Up to \$500k/rupture prevented Up to \$1.8M per compressor failure. Up to \$3.1 M for fatalities and/or injuries prevented.	2

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
154	03.03.06.01.	Limnic eruption	The rapid turnover and degassing of CO2 from a surface water body. Due to the high solubility of CO2 in water, a lake can dissolve a volume of CO2 that, in gaseous form, is more than five times its volume. CO2 rich water is denser than pure water which can result in an unstable stratification. A drop in temperature will reduce the solubility of CO2 in water. If the water reaches its solubility limit as a result, bubbles will nucleate. As the bubbles rise and grow, a chain reaction occurs where a sudden ex-solution of CO2 can result in a rapid degassing of the water body with an eruption of rising, expanding bubbles. Limnic eruptions can be triggered by events such as landslides that disturb the unstable stratification.	Limnic eruption provides a release mechanism for CO2, migrating from a storage system to the atmosphere. Natural limnic eruption events can be catastrophic. On the 29th of August 1986, a massive limnic eruption from Lake Nyos in Cameroon resulted in 1800 deaths as the CO2 smothered local villages. The CO2, which is volcanic in origin, seeps through the lake bed sediments and builds up in the lower strata of the water column. The Lake Nyos sudden release involved an estimated 240,000 tonnes of CO2 (Damen 2006).	There are no surface water bodies at the site sufficient to generate a limnic eruption.		Massive release of CO2.	Limnic eruption.	Catastrophic asphyxiation.	Monitor CO2 content in the bottom of deep lakes above or near CO2 storage.	Avoid selecting CO2 sites below deep lakes. Ensure the integrity of the caprock. Agitate the lake water to prevent stratification and CO2 buildup.	Monitor buildup of CO2 in the bottom of deep lakes above or near CO2 site. Install siphon tubes to bring deep waters to the surface to allow gradual CO2 release and prevent stratification and CO2 buildup.
155	03.03.07.00.	Co-migration of other gases	Surface seepages of CO2 may contain significant amounts of other gases due to co-migration, such as hydrogen sulfide (H2S). This is especially the case where the CO2 reservoir is a reducing chemical environment. H2S is derived from the hydration of sulfide minerals (e.g. FeS) or from the chemical reduction of aqueous sulfate species. H2S is highly toxic and therefore potentially harmful to the biosphere. Even in low concentrations it is deleterious to long-term health (human/animal), in addition to being extremely unpleasant.	The co-migration of other gases to the surface environment may cause areas of leakage to become uninhabitable – at least temporarily. The detection of H2S provides a quick (non-analytical/aesthetic) test for CO2 escape and thus can be used as a "marker" gas.	Produced CO2 contains 1000 ppm (0.1%) H2S.		Human injury/death due to release of CO2+H2S and other gases into the atmosphere.	Co-migration of CO2 and other gases.	More severe HSE hazard than CO2 alone. Damage to well, production and recycling systems and potential release of gases to the atmosphere.	Detection of H2S odor in the atmosphere.	Maintain integrity of the caprock wells and recycling system. Use proper materials of construction. Maintain tight seals and failsafe systems.	Monitor for H2S near wells, recycling facilities and confined areas. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/H2S leak.
156	03.03.08.00.	Diffusion of CO2	Diffusion is the net movement of a constituent in response to a concentration gradient. Diffusion always results in mass transfer from the region of high concentration to regions of low concentration. Diffusion will occur in conjunction with flow, but it will also occur in the absence of flow, and it is the primary transport mechanism in the absence of flow (as through a highly impermeable rock).	Diffusion is a transport process by which CO2 can access portions of the reservoir that are not directly exposed to advective flow. It can also be a primary transport mechanism in highly impermeable rocks such as caprock.	Diffusion of CO2 is an extremely slow process and is unlikely to impact the surface environment. The SACROC Northern Platform area has 5000 ft of multiple stacked seals and sinks.		CO2 movement through caprock.	Diffusion of CO2.	Leakage of CO2 above caprock.	Monitoring for CO2 above caprock.	Select site with thick, impermeable caprock and multiple stacked seals.	Monitor fresh water aquifers above the caprock for CO2. Monitor and ventilate confined spaces above the reservoir.
157	04.00.00.00.	GEOSPHERE	This category of FEPs is concerned with the geology, hydrogeology and geochemistry of the geosphere. The category covers the reservoir, overburden and surrounding rock up to the near-surface which is considered in a separate FEP category. Taken together, the FEPs in this category describe what is known about the natural system prior to sequestration operations commencing. The category is divided into three classes: Geology, Fluids, and Geochemistry.	This category is divided into three classes: 1. Geology 2. Fluids 3. Geochemistry								
158	04.01.00.00.	Geology	Geological features of the geosphere, which comprises of the reservoir, overburden and surrounding rock prior to injection of CO2.	An understanding of the natural system into which the carbon dioxide is injected is essential for the assessment of long-term performance and safety.								

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) injuries: \$1.5M per injury	Minor (recover-able) injuries: \$0.05M per injury												
154	03.03.06.01.	Limnic eruption	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
155	03.03.07.00.	Co-migration of other gases	2	4	1	8	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	1-5 days @ \$20,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$4M	None	Monitor for H2S around injection wells and recycle facilities. Maintain tight seals and failsafe systems <\$300k	Up to \$3.7M	1
156	03.03.08.00.	Diffusion of CO2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
157	04.00.00.00.	GEOSPHERE	0	0	0	0															
158	04.01.00.00.	Geology	0	0	0	0															

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
159	04.01.01.00.	Geographical location	The geographic location of a CO2 storage reservoir will influence the type of impacts to consider, e.g. continental or sub-marine, in the vicinity of a volcano, or tectonic activity, etc. In addition, proximity to human populations will increase importance of any release to the surface. 1. Onshore reservoir 2. Offshore reservoir 3. Near volcanic or tectonic activity 4. In densely populated areas	Proximity to natural hazards will increase their importance in being considered in the assessment. Proximity to human populations place more emphasis on the significance of near-surface releases. The potential impact on human beings of a sudden release of CO2 from an onshore reservoir will be higher than from an onshore reservoir (Damen 2006) The potential impact on human beings of a sudden release of CO2 from an offshore reservoir will be lower than from an onshore reservoir (Damen 2006). However CO2 storage costs are likely to be higher for offshore reservoirs.	The SACROC Northern Platform site has very low population density. Other than weather, there are no known natural hazards other than earthquakes northeast of the site.		Selection of project site that would subject the project to significant natural hazards or liabilities.	Geographical location.	Failure of project to be permitted. Failure of project to be financed. Failure of project to proceed. CO2 leakage. HSE damage including loss of life.	Conduct risk assessment on site selection.	Maintain integrity of the caprock wells and recycling system. Use proper materials of construction. Maintain tight seals and failsafe systems. Protect surface facilities from severe weather.	Monitor for H2S near wells, recycling facilities and confined areas. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/H2S leak severe weather or earthquake.
160	04.01.02.00.	Natural resources	Natural resources within the geosphere including: solid mineralogical resources, such as coal or minerals, fluid and gaseous resources, such as hydrocarbons (EOR and ECBM) or water, and other resources such as geothermal or microbial resources. Deep aquifers with high porosity suitable for CO2 storage would also be potentially suitable for geothermal energy production. (CO2STORE, page 70) Rights to pore space normally stay with the owner of the surface land. However, this may vary from state to state. Although saline water has few uses currently, these resources are protected by mining law in some EU states. And in some countries and states, brines legally are classified as groundwater and protected by law. (CO2STORE page 70). Depths for known natural major CO2 fields range from 200 to 5,000 m (656 to 16404 ft). (CCP 2009) 1. Mineral resources 2. Coal seams 3. Oil resources 4. Natural gas resources 5. Underground drinking water sources 6. Geothermal resources 7. Pore space owned by others 8. Saline water 9. Natural CO2	The presence of natural resources may mean that future human exploitation of the system cannot be ignored in assessing long term performance since they may increase the possibility of future human intrusion. Owners of mineral rights could claim primacy over CO2 injection. Unmineable coal seams could become mineable with robotic mining systems. There may be adjacent oil properties owned by third-parties that could be contaminated by CO2 injection. Natural gas could be released when drilling and injecting CO2. CO2 mixed with natural gas would need to be captured and reinjected. Underground drinking water could be contaminated by CO2 or displaced brine. CO2 combined with water could lead to corrosion of geothermal systems. CO2 from adjacent injection projects could infringe the project's pore space. Increased demand for water and improvement in desalination technologies could convert deep saline aquifers into valuable natural resources which could lead to restrictions on CO2 injection into deep saline aquifers.	1. Mineral resources are limited to abandoned caliche and gravel pits. 2. No coal seams have been identified in the site area. 3. Oil resources are part of the SACROC unit. 4. Shale gas could exist in the Wolfcamp shale. 5. Underground water is limited to secondary USDW aquifers (Ogallala and Dockum formations). 6. No geothermal resources have been identified. 7. Pore space is controlled by Kinder Morgan 8. Saline water exists in Permian and Pennsylvanian formations. 9. Natural CO2 has not been found.	What is the potential for shale gas in Wolfcamp shale formations above reservoir?	Contamination of third-party natural resources with CO2 and/or brine.	Natural resources adjacent to the injection site.	Liability for decontamination of natural resources, business interruption and advanced loss of profits.	Conduct baseline survey of CO2 and salinity measurements in sensitive areas before injecting CO2. Monitor and model CO2 plume and brine movement. Monitor CO2 and salinity in sensitive areas.	Avoid fracturing the Wolfcamp shale. Evaluate the existence and feasibility of recovering shale gas from the Wolfcamp shale while maintaining the integrity of the seal.	Monitor for H2S near wells. Monitor for CO2/H2S in produced gas and water. Inject sealants to seal up fractures that may release CO2/H2S. Maintain mechanical integrity of wells, recycling systems and seals.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
159	04.01.01.00.	Geographical location	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
160	04.01.02.00.	Natural resources	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	None	1-15 days @ \$20,000/d revenue lost per pattern idled Cost to locate and fix leaky well: \$0.3M Cost to locate and fix leaky fault or fracture zone: \$3M	Cost to locate and fix leaky well: \$0.3M Cost to locate and fix leaky fault or fracture zone: \$3M	<10,000 t/y CO2 per leak @ \$32.32/t CO2 10% of damage costs	Up to \$4M	None	Avoid fracturing Wolfcamp shale.	Up to \$4M	1	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
161	04.01.03.00.	Reservoir type	The generic type of reservoir being considered for storage of CO2. Brownfield developments, for example in mature oil and gas fields, will offer the benefit of beginning with a well-characterized system and a significant amount of infrastructure. However, field redevelopments for CO2 storage will require a significant amount of work to assess the integrity and re-usability of existing well, flow lines and facilities. (CCP 2009) Greenfield developments, such as deep saline aquifers, require significant new infrastructure and additional initial characterization work and are associated with greater uncertainty. A steeper learning curve is to be expected and modifications to an initial development plan may occur as additional knowledge is gained during early development work. (CCP 2009) 1. Oil reservoir - EOR (such as the Weyburn project); 2. Gas reservoir (such as the Coal-Seq project); 3. Deep saline aquifer (such as at Sleipner); and 4. Coal seams - ECBM (such as the Coal-Seq and RECOPOL projects). 5. Brownfield site 6. Greenfield site	The generic reservoir type will provide a high-level indication of the geological characteristics of the storage location. It will also contribute towards the extent and type of historical exploitation of any geological resources. Development of brownfield sites can expect to include a significant number of well re-completions, abandonments and possibly re-abandonment of old wells, new drilling and upgrades to surface infrastructure. (CCP 2009) Greenfield sites require more time and money to develop sufficient site characterization data but are less likely to have leakage through existing wells due to the lack of existing wells.	The SACROC Northern Platform is a partially depleted oil reservoir incorporating CO2-EOR. The brownfield site is well characterized with 639 deep wells and 3D seismic surveys. The oil field has been operating since 1948.		NA	NA	NA	NA	Take into account the reservoir type and historical uses in characterizing, modeling and selecting a site.	NA
162	04.01.04.00.	Reservoir geometry	Geometry of the CO2 storage reservoir including the spatial distribution, depth and the topography of the top.	The geometry of the storage reservoir helps to determine the capacity of the geosphere. The geometry of the top is particularly important because supercritical CO2 is buoyant and will therefore migrate to the top of a reservoir. Once at the top of the reservoir, it will migrate according to the precise topography of the top. Local "highs" could produce small-scale traps within the overall aquifer; bigger structures would produce bigger traps. Spill points are determined by the lowest point that can retain the sequestered CO2.	The SACROC Northern Platform area is an elevated coral reef structure isolated by an impermeable shale formation on the top, east, north and west sides and a less permeable carbonate formation on the bottom. The geometry is well characterized through 639 wells and 3D seismic surveys.		Migration of CO2 outside of project site.	Improper reservoir geometry for CO2 storage.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Monitoring and modeling CO2 plume and brine migration.	Take into account reservoir geometry in characterizing, modeling.	NA
163	04.01.04.01.	Reservoir depth (Reservoir hydrostatic pressure)	The hydrostatic pressure varies with depth. It is desirable to store CO2 at depths greater than approximately 800-1000 m where the hydrostatic pressure will maintain CO2 in a supercritical (dense) phase. (CCP 2009). Excessive depth will result in excessive hydrostatic pressure, which will require higher CO2 injection pressure. 1. Insufficient reservoir depth 2. Insufficient hydrostatic pressure 3. Excessive reservoir depth 4. Excessive hydrostatic pressure	Insufficient reservoir depth may result in pressures that are too low for keeping CO2 in a supercritical state. Excessive depth will require higher CO2 injection pressure and increase cost of CO2 injection..	The reservoir is at a depth ranging from 1,951 to 2103 m (6400 to 6900 ft) below the surface and is sufficiently deep for CO2-EOR and sequestration, but not excessively deep.		Pressure too low to keep CO2 in supercritical state. Pressure too high.	Insufficient reservoir depth (hydrostatic pressure). Excess reservoir depth (hydrostatic pressure).	Potential for CO2 to revert to gas phase, decreasing CO2 storage capacity Excess operating costs to pressurize CO2.	Measurement of bottom hole pressure.	Take into account reservoir depth and hydrostatic pressure in characterizing, modeling.	NA

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
161	04.01.03.00.	Reservoir type	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
162	04.01.04.00.	Reservoir geometry	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
163	04.01.04.01.	Reservoir depth (Reservoir hydrostatic pressure)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
164	04.01.04.02.	Reservoir thickness	Normally, a formation thickness of around 20 m (66 ft) would be considered as a minimum requirement, but this varies with injection volume requirements. 1. Insufficient reservoir thickness	Insufficient reservoir thickness will result in an extended CO2 plume and limit the storage capacity of the reservoir	The Platform thickness ranges from more than 229 m (750 ft) in the center to 24 m (80 ft) at the periphery.		Insufficient CO2 storage capacity.	Insufficient reservoir thickness.	Business interruption. Added capital and operating costs.	Historical drilling records, drill core analyses, well logging and seismic surveys.	Take into account reservoir thickness in characterizing and modeling.	NA
165	04.01.04.03.	Reservoir lateral continuity (spatial distribution)	Lateral flow barriers can include unconformities or pinch-outs that erode the porous and permeable material and provide direct contact to a low permeability seal, faults and naturally over pressured zones. 1. Insufficient reservoir lateral continuity	Insufficient lateral continuity (or spatial distribution) of a reservoir will limit its CO2 storage capacity	The reservoir is restricted on the east, north and west sides by the Wolfcamp shale. The lateral formations drop off at the sides due to erosion. The south side is connected to the rest of the SACROC unit.		Insufficient CO2 storage capacity.	Insufficient reservoir lateral continuity (spatial distribution).	Business interruption. Added capital and operating costs.	Historical drilling records, drill core analyses, well logging and seismic surveys.	Take into account reservoir lateral continuity in characterizing and modeling.	NA
166	04.01.04.04.	Reservoir top topography	Reservoirs with dipping top topography (monocline) are susceptible to buoyancy-driven up dip CO2 migration. The migration up dip may enhance CO2/brine contact and CO2 dissolution in the brine. The preferred top topography is an anticline or dome structure to restrict the flow of injected CO2 on multiple sides. Spill point is the lowest point that can retain sequestered CO2. 1. Flat 2. Monocline 3. Dome 4. Anticline 5. Shallow spill points	Flat top topography of the reservoir may make it difficult to contain the CO2 plume Dipping top topography of the reservoir may make it difficult to trap buoyant CO2. Injected CO2 migrates up dip out of closure. Shallow spill point in a dome structure may limit the amount of CO2 that can be locally contained in a reservoir	The top of the Northern Platform reservoir is a very rugged dome type. The spill point is up to 204 m (670 ft).		Uncontrolled buoyant migration of CO2 beyond project area.	Reservoir top topography.	CO2 leakage (HSE hazard). Contamination of adjacent pore space, natural resources (including water).	Historical drilling records, drill core analyses, well logging and seismic surveys.	Take into account reservoir top topography in characterizing and modeling.	NA
167	04.01.04.05.	Reservoir buffer zone for CO2 plume	The buffer zone represents additional land owned or leased beyond the ultimate extent of the CO2 plume. 1. Insufficient buffer zone for CO2 plume	Insufficient buffer zone may result in CO2 plume infringing on third-party pore space.	A buffer zone is not needed because the Northern Platform reservoir is closed on the east, north and west sides and opens to the rest of the SACROC unit on the South side.		CO2 migration beyond project area.	Insufficient reservoir buffer zone.	CO2 leakage (HSE hazard). Contamination of adjacent pore space, natural resources (including water).	Historical drilling records, drill core analyses, well logging, seismic surveys and modeling to estimate ultimate extent of CO2 plume. CO2 monitoring to determine actual extent of CO2 plume.	NA	NA
168	04.01.04.06.	Reservoir CO2 storage capacity	Reservoir CO2 storage capacity is primarily determined by pore volume. 1. Insufficient reservoir storage capacity.	Insufficient reservoir storage capacity will require alternative storage site(s). Increased storage costs.	CO2 storage capacity is not a significant concern at SACROC because natural CO2 is being injected for EOR.		CO2 migrating out of project area. Limitation on CO2 injection.	Insufficient CO2 storage capacity.	CO2 leakage (HSE hazard). Contamination of adjacent pore space, natural resources (including water). Early shutdown of CO2 injection.	Historical drilling records, drill core analyses, well logging, seismic surveys and modeling to estimate ultimate extent of CO2 plume. CO2 monitoring to determine actual extent of CO2 plume.	Characterize and model CO2 storage capacity of the reservoir. Use a conservative estimate.	NA

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
164	04.01.04.02.	Reservoir thickness	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
165	04.01.04.03.	Reservoir lateral continuity (spatial distribution)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
166	04.01.04.04.	Reservoir top topography	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
167	04.01.04.05.	Reservoir buffer zone for CO2 plume	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	NA
168	04.01.04.06.	Reservoir CO2 storage capacity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
169	04.01.04.07.	Reservoir lateral sealing	Lateral flow barriers can include unconformities or pinch-outs that erode the porous and permeable material and provide direct contact to a low permeability seal, faults and naturally over pressured zones. 1. Open reservoir (lack of lateral sealing of reservoir) 2. Closed reservoir 3. Semi-closed reservoir	Potential for CO2 plume to infringe on third-party pore space or escape if lateral seal is lacking.	The Northern Platform reservoir is a semi-reservoir, closed on the east, north and west sides and opens to the rest of the SACROC unit on the south side.		CO2 migration beyond project area.	Lack of reservoir lateral sealing.	CO2 leakage (HSE hazard). Contamination of adjacent pore space, natural resources (including water).	Historical drilling records, drill core analyses, well logging, seismic surveys and modeling to estimate ultimate extent of CO2 plume. CO2 monitoring to determine actual extent of CO2 plume.	Take into account lateral sealing in characterizing and modeling. Select reservoir with lateral sealing.	Monitor and model CO2 plume and brine movement. Use injection water curtains to keep CO2 flow within patterns.
170	04.01.04.08.	Reservoir and caprock structural geology complexity	In tectonically complex areas, there are too many small structures to be identified, delineated and investigated individually. 1. Reservoir and caprock structural geology too complex	Complex structural geology may result in greater difficulty in modeling, monitoring and controlling CO2 storage.	Not an issue based on 40 years of CO2-EOR operation. Caprock has maintained its integrity. Reservoir engineering has successfully dealt with reservoir structural geology complexity. The SACROC unit reservoir is a north-south trending carbonate buildup with a slight dogleg to the west. The northern half of the SACROC unit is structurally highest, dips steeply to the west and east, and contains the thickest portion of the reservoir. Overlying the entire structure is a thick sequence of dark black organic-rich shale. This thick sequence forms both the seal and the source for the hydrocarbons trapped in this reservoir (Hawkins 1996). Complex geometry with compartmentalization caused by changes in depositional environments, erosion and possible faulting and karsting. Carbonate debris flows and Cisco aged, in-place flank bioherm mounds lend further complexity on the western and eastern margins of the platform (Reeves2008). The reservoir is well characterized with wells and seismic surveys.		Low oil recovery CO2/brine release	Complexity of reservoir and caprock structural geology	Low revenues and/or higher operating costs.	Characterization and modeling of reservoir and caprock structural geology. Comparison of model predictions with actual performance.	Characterization and modeling of reservoir and caprock structural geology to optimize reservoir engineering.	Monitor and model oil, water and CO2 production. Evaluate root cause for unexpected results. Mitigate problems with complex structural geology by adjusting well spacing, pattern type, selective perforation, water injection curtains, WAG
171	04.01.04.09.	Reservoir compartmentalization	A once continuous reservoir can become compartmentalized. CO2 migration restricted to an isolated part of the formation. Unexpected bottom hole pressure increase. Pressure transient analysis suggests hydraulically isolated wells.	Greater difficulty in modeling, monitoring and controlling CO2 storage.	Sufficient number of wells exist to overcome any problems with compartmentalization. Compartmentalization exists but a sufficient number of wells exist to overcome any problems with compartmentalization. Complex geometry with compartmentalization caused by changes in depositional environments, erosion and possible faulting and karsting. Production data from this area displays strong evidence of vertical migration pathways that bypass low permeability barriers. (Reeves2008).		Low oil recovery	Reservoir compartmentalization.	Low revenues and/or higher operating costs.	Characterization and modeling of reservoir for compartmentalization. Monitoring bottom hole pressure and CO2 plume.	Characterization and modeling of reservoir for compartmentalization to optimize reservoir engineering. Sufficient wells exist to overcome any problems with compartmentalization.	Monitor and model oil, water and CO2 production. Evaluate root cause for unexpected results. Mitigate problems with complex structural geology by adjusting well spacing, pattern type, selective perforation, water injection curtains, WAG.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
169	04.01.04.07.	Reservoir lateral sealing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
170	04.01.04.08.	Reservoir and caprock structural geology complexity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
171	04.01.04.09.	Reservoir compartmentalization	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
172	04.01.04.10.	Reservoir temperature (See 04.01.13.00.)										
173	04.01.04.11	Reservoir rock thermal properties	Rock thermal properties included: 1. Thermal conductivity 2. Heat capacity 3. Thermal expansion coefficient	These properties will dictate how fast the rock will change temperature in response to injected CO2 that is warmer or cooler than the reservoir, and they will also dictate whether fracture or pore permeability will increase or decrease as a result of temperature changes in the rock mass.	SACROC unit is operated well into CO2 supercritical conditions. CO2 injection temperature is 37.8°C and reservoir temperature is 54.4°C. CO2 injection temperature can be adjusted within limits if needed.	Data on rock thermal properties not available.	Slow increase or decrease in rock temperature and expansion or contraction when CO2 is injected. Fast increase or decrease in rock temperature and expansion or contraction when CO2 is injected; fracture of reservoir r and/or seal rock due to thermal shock.	Low thermal properties. High thermal properties. Migration of CO2 out of reservoir along induced thermal fractures.	Increase or decrease in rock temperature, injectivity and rock volume. Potential leakage through caprock into USDW aquifers or biosphere.	Measure thermal properties of reservoir rock samples and include the results in modeling. Monitor aquifer chemistry and atmospheric concentrations.	Characterization and modeling of reservoir rock thermal properties. Keep CO2 injection temperature and rate compatible with desired reservoir temperature.	Monitor reservoir temperature. Adjust CO2 injection temperature, rate or WAG to control rock temperature if necessary.
174	04.01.05.00.	Reservoir exploitation	Degree to which geological resources (such as oil and gas) have been exploited prior to the injection of CO2. 1. Existing boreholes 2. Oil previously removed 3. Gas previously removed 4. Existing mine workings (for ECBM) 5. In-situ gasification (for ECBM) 6. Natural gas storage 7. Compressed air storage 8. Radioactive waste storage 9. Hazardous waste disposal (Class 1 wells) 10. Water extracted	The extent of previous exploitation will help to determine the initial state of a storage reservoir. For example: - the existence and nature of boreholes; and - the presence of geological resources, such as oil and gas. Previous exploitation of the storage reservoir area will improve the amount of historical information available concerning the reservoir characteristics.	The Northern Platform has 639 deep wells penetrating the primary seal. Total oil production through 2002 was 594 million STB (874 million RB). Hydrocarbon gas production through 2002 was 637 BCF. Most of this was dissolved in the oil. Some areas of the reservoir show signs of hydraulic fracturing. Some areas are saturated with CO2 from tertiary operations between 1972 and 2002.		Pre-CO2 injection caprock or reservoir damage. Pre-existing CO2 in pore space (e.g. from EOR).	Reservoir previous exploitation.	1. Permitting delays or restrictions. Cleanup liability litigation. 2. CO2 leakage (HSE hazard). 3. Decreased reservoir capacity.	Survey historical records and documents on the site that may indicate potential problems or risks for CO2 storage. Conduct baseline survey for pre-CO2 injection site contamination and damage.	Take into account reservoir previous exploitation in characterizing and modeling.	Monitor and model CO2 and water injection and oil, water and CO2 production. Use selective perforation, avoid or seal fractures. Use injection water curtains.
175	04.01.06.00.	Caprock or sealing formation	The nature of the relatively impermeable layer of rock overlying the storage reservoir that forms a barrier to the upward migration of buoyant fluids, such as sequestered CO2.	The caprock or sealing formation plays a key roll in preventing the sequestered CO2 from migrating to the surface environment.	The caprock (Wolfcamp shale) is 10 to 100 m (30 to 328 ft) thick, laterally continuous, dark-black, organic-rich, low permeability shale. This is overlain by a 100m (328 ft) thick laterally-continuous Wolfcamp shale & sandstone. Above this is a 226 m (741 ft) Wolfcamp limestone mixed with shale. Above that is 1128 m (3,700 ft) of multiple layers of fine-clastics, evaporites and carbonates before reaching the secondary USDW aquifers.		CO2 migration through caprock.	Caprock or sealing formation lack of integrity	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock for sealing integrity. Monitor pressure in formations above the caprock.	Characterize and model caprock for sealing integrity. Avoid areas lacking sealing integrity. Maintain injection pressures below 90% of fracture pressure.	Monitor pressure in formations above the caprock. Monitor boreholes, permeable zones, faults, fracture zones, that penetrate the caprock, for CO2/H2S leakage. Isolate areas lacking sealing integrity with water curtains. Inject sealants into fractures.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
172	04.01.04.10.	Reservoir temperature (See 04.01.13.00.)	0	0	0	0															
173	04.01.04.11	Reservoir rock thermal properties	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
174	04.01.05.00.	Reservoir exploitation	3	3	2	18	None	None	None	None	None	None	None	None	None	None	<\$7M/y	None	<\$7M/y	None	1
175	04.01.06.00.	Caprock or sealing formation	2	3	3	18	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	None	None	None	Cost to locate and fix leak in fault, fracture zone or high permeability pathway in caprock	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for five years: Up to \$6M for water remediation	Assuming leakage detected early and mitigated: <\$1M for water remediation	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Savings: Up to \$2M	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
176	04.01.06.01.	Caprock geometry	Geometry of the caprock including the spatial distribution, depth and the topography of the bottom.	CO2 migration diverges from expected path. Significant CO2 volumes migrate off structure. Insufficient capacity for planned injection volume of CO2. Unexpected pressure increase during injection.	The Wolfcamp shale and secondary seals are laterally continuous over the Northern Platform area.		CO2 migration around caprock	Caprock geometry.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock geometry. Monitor pressure in formations above the caprock.	Characterize and model caprock geometry. Avoid sites where caprock geometry is not amenable for CO2 storage.	Monitor and model CO2 plume and brine migration. Remediate uncontrolled migration by injecting/extracting water, depressuring reservoir, relocating CO2 injection or extracting CO2 and reinjecting into a more secure reservoir. Select sites with multiple stacked seals and sinks.
177	04.01.06.02.	Caprock thickness	Greater thickness improves the strength and sealing capacity of the caprock. Preferred caprock thickness: > 100m Minimum caprock thickness: >20m	Insufficient caprock thickness could lead to caprock failure and/or release of CO2 from the reservoir.	The caprock (Wolfcamp shale) is 10 to 100 m (30 to 328 ft) thick, laterally continuous, dark-black, organic-rich, low permeability shale. This is overlain by a 100m (328 ft) thick laterally-continuous Wolfcamp shale & sandstone. Above this is a 226 m (741 ft) Wolfcamp limestone mixed with shale. Above that is 1128 m (3,700 ft) of multiple layers of fine-clastics, evaporites and carbonates before reaching the secondary USDW aquifers.		CO2 migration through caprock.	Thin caprock.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize the caprock thickness based on historical drilling records, drill core analyses, well logging, seismic surveys and modeling.	Include caprock thickness in characterization and modeling. Avoid sites with thin caprock, unless reinforced with multiple stacked secondary seals.	Monitor pressure in formations above the caprock. Identify and remediate leaks.
178	04.01.06.03.	Caprock discontinuous	Caprock discontinuities can be caused by unconformities or pinchouts.	CO2 escapes through gap in caprock into higher formation or aquifer	The caprock is laterally continuous over the Northern Platform.		CO2 upward migration through discontinuous portion of caprock.	Discontinuous caprock.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock for continuity based on historical drilling records, drill core analyses, well logging, seismic surveys.	Characterize and model caprock for continuity. Avoid sites with discontinuous caprock that might impact CO2 storage integrity.	Monitor pressure in formations above the caprock. Identify and remediate leaks.
179	04.01.06.04.	Caprock geochemical properties	CO2 chemical reaction with caprock can weaken the physical strength of the caprock. High permeability zones might exist or be formed by reaction of CO2 with the caprock, causing the caprock to dissolve. CO2 can dehydrate clay shales in the caprock, thereby increasing its permeability. (Damen 2006)	Unintended migration of CO2 by chemical reaction induced breaching of the caprock.	The Wolfcamp shale is very fine-grained, quartz-rich with clay-rich layers. The clay layers are rich in dark-brown organic material. X-ray diffraction results show the shale is predominantly illite (62%) and quartz (22%) with lesser amounts of feldspar (5.1%), carbonate (4.5%), pyrite (3.4%) and other clay minerals. Analysis of a core sample containing shale near a well bore showed that after 30 years of CO2 exposure, there was no obvious evidence for CO2 interaction (Carey 2005 and 2007, and WoldeGabriel 2006). There are multiple stacked seals and sinks above the caprock.		Geochemical failure of caprock.	Caprock geochemically reactive with CO2.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterization and modeling of caprock geochemical properties based on drill core analyses.	Characterization and modeling of caprock geochemical properties based on drill core analyses. Avoid sites with caprock that would be highly reactive with CO2.	Monitor pressure in formations above the caprock. Identify and remediate leaks.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
176	04.01.06.01.	Caprock geometry	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
177	04.01.06.02.	Caprock thickness	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
178	04.01.06.03.	Caprock discontinuous	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
179	04.01.06.04.	Caprock geochemical properties	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
180	04.01.06.05.	Caprock geomechanical properties	Low fracturing pressure	Could limit CO2 injection rate. Increased CO2 injection cost. In general, the mechanical behavior of shale will show more elastic change and is more resistant to elevated pressure than other brittle hard rock.	The caprock is a shale. There are multiple stacked seals and sinks located above the caprock.		Mechanical failure of caprock.	Caprock geomechanical weakness.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterization and modeling of caprock geomechanical properties based on drill core analyses.	Characterization and modeling of caprock geomechanical properties based on drill core analyses. Avoid sites with mechanically weak or over stressed caprock. Avoid injection pressures exceeding 90% of fracture pressure.	Monitor and model geomechanical stress in caprock. Monitor pressure in formations above the caprock. Identify and remediate leaks.	
181	04.01.06.06.	Caprock Permeability	The permeability of a caprock capable of retaining fluids through geologic time is approximately 0.001 to 0.00001 milli-darcies (mD). Mudstone caprock permeability is typically less than 0.001 mD.	Permeable zones in the caprock could form CO2 pathways of escape.	Vertical permeability negligible (<0.05mD). Horizontal permeability <1 mD wet or near 9mD in oven dried samples (Carey 2007) There are multiple stacked seals and sinks located above the caprock.		CO2 migration through high permeability zone in caprock.	Caprock high permeability zone.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock permeability.	Characterize and model caprock permeability. Avoid or isolate areas with high caprock permeability.	Monitor pressure in formations above the caprock. Isolate high permeability zones with injection water curtains and/or sealants.	
182	04.01.06.07.	Caprock capillary entry pressure	No rocks have zero porosity, but the sealing layer provides a seal because the pore throats are too small to permit CO2 to enter the water-filled pores. (CCP 2009)	If the CO2 injection pressure exceeds the capillary pressure of the caprock, CO2 can penetrate or pass through the caprock	Caprock capillary entry pressure not expected to have any significant impact on containment. There are multiple stacked seals and sinks located above the caprock.		CO2 migration through caprock.	Caprock capillary entry pressure exceeded.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock capillary entry pressure. Monitor CO2 injection pressure.	Characterize and model caprock capillary entry pressure. Avoid injection pressures exceeding caprock capillary entry pressure.	Monitor CO2 injection pressure. Monitor pressure in formations above the caprock.	
183	04.01.06.08.	Caprock fracture pressure	The critical pressure to avoid exceeding is the fracture pressure of the confining interval (caprock) above the reservoir, which is normally higher than the fracture pressure in the injection interval. (CCP 2009) Maximum injection pressure is typically at least 0.34 MPa (50 psi) below fracture pressure. EPA UIC Class VI regulations limit CO2 injection pressure to 90 percent of fracture pressure.	If the CO2 injection pressure exceeds the fracture pressure of the caprock, the caprock could fracture and allow CO2 to pass through the caprock.	Step-rate test conducted on well 27-4 in 1993 showed minor parting pressure at: BHP = 28.3 MPa (4,100 psia) and major parting pressure at BHP = 33 MPa (4,800 psia) Hawkins 1996. Current CO2 injection pressure estimated to be BHP = 29MPa (4,200 psia). There are multiple stacked seals and sinks above the caprock.	Caprock fracture pressure not available.	Caprock fracturing.	Caprock fracture pressure exceeded.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock fracture pressure. Monitor CO2 injection pressure and micro seismicity.	Avoid sites with fractured caprock. Keep injection pressure below 90% of caprock fracture pressure.	Monitor injection pressure. Monitor pressure in formations above the caprock. Passive micro-seismic monitoring. Isolate fractured area with injection water curtains and/or sealant.	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
180	04.01.06.05.	Caprock geomechanical properties	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
181	04.01.06.06.	Caprock Permeability	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
182	04.01.06.07.	Caprock capillary entry pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
183	04.01.06.08.	Caprock fracture pressure	2	4	3	24	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	None	None	None	Cost to locate and fix leak in fault, fracture zone or high permeability pathway in caprock	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	Assuming leakage detected early and mitigated: \$1M for water remediation	Monitor pressure in overlying formations. Continuous passive micro- seismic monitoring: Capex: \$3.9M Opex: \$0.3M/y Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	None	1	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
184	04.01.07.00.	Additional seals and sinks (secondary seals)	This concerns the concept of successive lithological, hydraulic and/or chemical barriers acting successively to prevent fluid escape to surface environments. From a geological point of view the permeability barrier is probably the most important, in comparison with other types of traps. However, it may be necessary to consider a sequence of traps in CO2 migration models in addition to the conventional low permeability barriers. For example, within the Weyburn sequestration project, the primary caprock is the Watrous formation, however, low permeability formations at higher stratigraphical layers provide potential additional seals, preventing upward migration of sequestered CO2. Stacked reservoirs consist of multiple alternating seals and reservoirs above the primary reservoir. The additional reservoirs can provide a back up for CO2 containment if the primary seal is broken. 1. Multiple stacked seals 2. Multiple stacked reservoirs	Without multiple stacked seals and sinks there is no fallback position if CO2 escapes through the primary seal.	Multiple stacked seals and sinks are present over the Northern Platform reservoir.	Need detailed stratigraphic column and lithology for formations above the caprock.	Failure of primary seal without backup seals and sinks.	Lack of additional seals and sinks	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model site, including primary and secondary seals and sinks. Monitor for CO2 and salinity in secondary sinks above the primary seal.	Take into consideration multiple-stacked seals and sinks in site characterization, modeling and selection.	Monitor pressure in formations above the caprock.. Isolate CO2 pathway with injection water curtains and/or sealants.
185	04.01.08.00.	Lithology	The systematic description of rocks in terms of their mineral assemblage and texture. The lithology of the geosphere (including both the reservoir and the caprock) determines the reservoir physical and transport properties (including porosity and permeability). It concerns the mineralogical composition, texture (grain size, sorting) and fabric (sedimentary structures, vertical and horizontal heterogeneities). Potential reservoir lithologies include sandstones and limestones. 1. Caprock lithology 2. Reservoir lithology	The physical and chemical and mineralogical properties of the reservoir rocks affect: the capacity to store CO2; fluid flow and CO2 migration; determine which water-rock reactions can take place; and influence the rock strength and elastic properties (such as compressibility, shear strength, Poisson's ratio etc).	The caprock (Wolfcamp shale) is very fine-grained, thin quartz-rich layers separating thick clay-rich layers. The clay layers are rich in dark-brown organic material. X-ray diffraction results show the shale is predominantly illite (62%) and quartz (22%) with lesser amounts of feldspar (5.1%), carbonate (4.5%), pyrite (3.4%) and other clay minerals (Carey 2007) The reservoir (Cisco and Canyon limestones) contain mostly calcite with minor ankerite and quartz (Carey 2007) There are multiple seals and sinks above the caprock with different lithologies.	Need detailed stratigraphic column and lithology for formations above the caprock.	Caprock failure. Uplift or subsidence. Loss of reservoir porosity, permeability, injectivity.	Lithology	1. Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Take into account lithology of caprock and reservoir in characterizing and modeling sites.	Take into account lithology of caprock and reservoir in characterizing and modeling sites.	Monitor and model CO2, H2S and brine migration, chemical reactions and changes in mechanical properties of rocks. Isolate CO2 pathway with injection water curtains and/or sealants.
186	04.01.08.01.	Lithification / diagenesis	The slow physical, chemical and/or biological processes by which unconsolidated sediments become sedimentary rock. These processes can result in changes to the original mineralogy.	The state of lithification/diagenesis contributes to determining the physical and chemical characteristics of sedimentary rock. For example, porosity usually decreases during diagenesis, except in rare cases such as dissolution of minerals and dolomitization. It is very unlikely that deep subsurface geologic formations are unconsolidated. Unconsolidated formations are young in geologic time and located at shallow depths.	Nonconsolidated sediments are not present at depth.		Decreased porosity and permeability.	Lithification / diagenesis.	Decreased CO2 storage capacity and injectivity.	Take into account lithification /diagenesis in site characterization and modeling. Monitor CO2 injectivity.	NA	NA

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
184	04.01.07.00.	Additional seals and sinks (secondary seals)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
185	04.01.08.00.	Lithology	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
186	04.01.08.01.	Lithification / diagenesis	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

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187	04.01.08.02.	Pore architecture (See 04.01.08.03. and 04.01.08.04.)	Structure and density of discrete voids within the rock (pores). 1. Reduced pore volume or distribution limiting CO2 injection	The pore architecture determines the porosity and permeability of the rock, which are key features when considering the mobility of fluids and gases within the rock. Rate of long-term pressure build-up greater than expected. Increases CO2 injection cost. Need for additional wells.	The reservoir porosity averages 9.8% and ranges from 4 to 20%. Karsting is present.. The reservoir permeability averages 10mD and ranges from 1 to 1760 mD (Dutton 2004). In EOR, pore architecture impacts sweep efficiency and oil recovery.							
188	04.01.08.03.	Reservoir porosity	Porosity values greater than 10% in carbonate formations or 15% in clastic formations are generally desirable. (CCP 2009). It is important to distinguish between total porosity and effective (flowing) porosity. Flowing porosity is what can be readily displaced by CO2 invasion. Total porosity minus flowing porosity is pore space that will likely remain occupied by residual pore fluids after CO2 invasion, although CO2 can diffuse into this pore space. 1. Total porosity 2. Effective (flowing) porosity	Low porosity makes CO2 injection more difficult and can limit the rate of injection into a reservoir.	The reservoir porosity averages 9.8% and ranges from 4 to 20% (Dutton 2004) In EOR, porosity impacts oil in place and oil recovery.		Low oil in place. Low oil recovery.	Low or irregular reservoir porosity.	Decreased oil revenues	Take into account reservoir porosity in site characterization and modeling. Monitor CO2 injectivity, sweep efficiency and oil recovery.	Take into account pore architecture in site characterization and modeling. Avoid reservoir areas with low porosity and low permeability.	Identify and avoid areas with low porosity.
189	04.01.08.04.	Reservoir permeability and injectivity	Permeability measures the ability of fluids to flow through a formation. High values indicate a well-connected pore space while low values indicate convoluted conduits that disconnect the pores. Porous rocks have a wide range in permeability between around 0.1 milli-Darcy (mD) for very tight rocks, to several darcies for very permeable formations. (CCP 2009) In general, the better the porosity, the better the permeability (and thus injectivity) - however, large variations in permeability mean the porosity and permeability variations need to be mapped in detail (CCP 2009) Ideally, CO2 storage requires high permeability (>100 mD) to ensure near well bore injectivities for quick access to pore space. However, this is not always possible and near wellbore permeabilities may need to be enhanced by artificially stimulating the wells to allow for improved injectivity. (CCP 2009) Injectivity is impacted by porosity and permeability. Low injectivity can be partially compensated for by greater injection pressure and/or more wells. Decreasing injectivity can result when initial injection rate meets expectations but overall pore space is limited. Bottom hole pressure gradually increases. 1. Insufficient reservoir injectivity	Low permeability makes CO2 injection more difficult and can limit the rate of injection into a reservoir. While high permeabilities are generally desirable, very high permeability pathways or conduits can enhance CO2 migration along concentrated pathways reducing the effective storage within the target formation. (CCP 2009) In moderate to low permeability, or poorly connected reservoirs, a higher well density will be needed to limit pressure evolution and allow for efficient injection. (CCP 2009) Uncertainty in permeability could lead to high numbers of wells needed. Low reservoir injectivity will limit the rate of CO2 injection and require increased bottom hole pressure and/or more injection wells.	The reservoir permeability averages 10mD and ranges from 1 to 1760 mD (Dutton 2004). Injectivity of CO2 and water increased gradually by as much as 50% after 1972 due to possible dissolution of carbonates on the walls of flow channels. In EOR, permeability impacts sweep efficiency and oil recovery.	Need historical data on injectivity.	Low sweep efficiency and low oil recovery.	Low reservoir permeability and injectivity	Decreased oil revenues	Take into account reservoir permeability in site characterization and modeling. Monitor CO2 injectivity, sweep efficiency and oil recovery.	Take into account pore architecture in site characterization and modeling. Avoid reservoir areas with low porosity and low permeability.	Monitor and model CO2 injectivity, sweep efficiency and oil recovery. Use injection water curtains, selective perforation, polymer gels, foaming agents or sealants to control CO2 flow. Use acid or hydraulic fracturing stimulation to improve injectivity.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
187	04.01.08.02.	Pore architecture (See 04.01.08.03. and 04.01.08.04.)	0	0	0	0															
188	04.01.08.03.	Reservoir porosity	3	4	2	24	None	None	None	None	None	None	None	10% decrease in oil recovery (1,000 bpd): \$25M/y	None	None	10% decrease in oil recovery (1,000 bpd): \$25M/y	10% decrease in oil recovery (1,000 bpd): \$25M/y	Avoid areas with low porosity.	None	2
189	04.01.08.04.	Reservoir permeability and injectivity	3	4	2	24	None	None	None	None	None	None	None	10% decrease in oil recovery (1,000 bpd): \$25M/y	None	None	10% decrease in oil recovery (1,000 bpd): \$25M/y	None	Cost of monitoring, modeling and mitigation steps to improve injectivity and CO2 flood uniformity: \$10M/y	\$15M/y	1

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
190	04.01.09.00.	Unconformities	Geological surfaces separating older from younger rocks and representing a gap in the geologic record. Such a surface might result from a hiatus in deposition of sediments, possibly in combination with erosion, or deformation such as faulting. An angular unconformity separates younger strata from eroded, dipping older strata. A disconformity represents a time of no deposition, possibly combined with erosion, and can be difficult to distinguish within a series of parallel strata. A nonconformity separates overlying strata from eroded, older igneous or metamorphic rocks. 1. Unconformities 2. Disconformities 3. Nonconformities	Unconformities can act both as potential seals or lateral migration pathways for fluids. For example, the impermeable barrier resulting from the widespread development of diagenic anhydritized carbonate associated with the unconformity between the Mississippian beds and overlying Triassic Watrous Formation in the vicinity of the Weyburn pool.	Unconformities exist between the Pennsylvanian and Permian formations at the top of the reservoir. Discontinuities exist on the east and west sides of the reservoir. The unconformities are below the caprock and the disconformities form lateral barriers.		Lateral migration of CO2/brine through an unconformity.	Presence of unconformities, disconformities, or nonconformities.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Monitor and model CO2 plume and brine migration. Monitor overlying formations, soils, and water for CO2, salinity, pH.	Take into account unconformities, disconformities and nonconformities in site characterization and modeling.	Monitor and model CO2 and brine migration. Monitor pressure in formation overlying the caprock. Use injection water curtains, selective perforation, or sealant to isolate unconformities, discontinuities or unconformities that may provide CO2 leakage pathways.
191	04.01.10.00.	Heterogeneities (See 03.02.03.06.)	Heterogeneities are variations in the rock properties of a geological formation. 1. Reservoir heterogeneity 2. High permeability layers in reservoir 3. Interstitial layers of shale or baffles in reservoir 4. Caprock heterogeneity (high permeability zones) 5. Heterogeneity of overlying aquifers (more difficult to monitor for CO2) 6. Heterogeneity of porosity 7> Heterogeneity of mineralogy 8. Heterogeneity of degree of fracturing 9. Heterogeneity of geochemistry	Heterogeneities can result in directional variations in permeability, which affects the mobility of fluids and gases in the rock. For example, experience from the Saline Aquifer CO2 Storage project (SACS) has shown that both stratigraphical and structural local permeability heterogeneities have the potential to profoundly affect CO2 distribution and migration (Chadwick et al., 2003). The image below shows seismic sections through the Sleipner injection site from Zweigel et al. (2001). The strong amplitudes are taken to be CO2 accumulations.	The Northern Platform reservoir (Cisco and Canyon formations) is highly heterogeneous. During deposition, extreme fluctuations in sea level induced rapid growth of the reef and sudden severe exposures. This resulted in lateral and vertical discontinuity of porosity and permeability with the presence of karsting, detrital flows, vuggy porosity, and micro-fractures. Natural fractures and karsted intervals can dominate zonal injection paths and exhibit very directional flow (Larkin 2008). Dykstra-Parsons coefficient: 0.68 (Dicharry 1973).	Need historical data on heterogeneity impact on oil recovery.						

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
190	04.01.09.00.	Unconformities	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
191	04.01.10.00.	Heterogeneities (See 03.02.03.06.)	0	0	0	0																

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Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
192	04.01.11.00.	Fractures and faults (CO2 leakage through new or existing fractures or faults)	Fractures are cracks or breaks in rock. Fractures along which displacement has occurred are called faults. Fractures and faults can occur over a wide range of scales. The presence of a fault does not imply a leakage problem. Most rocks are faulted and fractured in some way over geological time. The critical question for CO2 storage is whether there are any faults or fractures that could provide leakage pathways under present day geological conditions. In addition to the basic geometry of connected rocks and flow paths, this involves the study of geomechanics, stress fields and fracture behavior. Simply put many "faults: do not leak at all and many huge oil and gas fields that include faults prove the point. (CCP 2009)	Fractures can enhance conductivity, for example, by a conductive fracture connecting permeable regions together. They can also act as seals, by bringing a relatively permeable region into contact with low conductivity rock, for example. Movement on a fault that transverses a wellbore could damage or sever casing or tubing. CO2 might leak through open (no-sealing) faults, which extend into the caprock. CO2 might leak through natural fractures in the caprock.	Man-made fractures and natural fractures and faults exist in the Northern Platform reservoir, but the faults do not penetrate the caprock. There are multiple stacked seals and sinks above the caprock.	Need data on faults and fractures in reservoir.	1. Reactivation of a dormant fault. 2. CO2 leakage through a fault or fracture zone.	Existing or new fractures and faults.	1. Seismic activity. 2. Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Monitor pressure in formations near fault and fracture zones. Monitor passive seismicity and LiDAR displacement above fault.	Take into account local faults and fracture zones in site characterization and modeling. Keep injection pressure below 90% of caprock fracture pressure. Select sites with multiple stacked seals and sinks.	Monitor and model CO2 and brine migration and pressure near fault and fracture zones. Monitor pressure in formations above caprock. Isolate leaking faults or fracture zones with injection water curtains and/or sealants.	
193	04.01.12.00.	Undetected features	Natural or man-made features within the geological environment that may not be detected during site investigations. Examples of possible undetected features are fracture/fault zones, the presence of brines or old mine workings. Some physical features of the storage environment may remain undetected during site surveys and even during preliminary borehole drilling. The nature of the geological environment will indicate the likelihood that certain types of undetected features may be present and the site investigation may be able to place bounds on the maximum size or minimum proximity to such features. 1. Existing fracture/fault zones 2. Underground cavities/karsts (natural or man made) 3. Existing boreholes 4. Subsurface infrastructure (piping, underground utilities) 4. Gas chimneys 5. Shallow gas/drift gas (above bedrock) 6. Clustered small gas-related amplitude anomalies along fault planes	Undetected features could significantly affect the performance of a sequestration system. For example, local permeability heterogeneities with the potential to profoundly affect the distribution and migration of CO2 at Sleipner (within the Saline Aquifer CO2 Storage project, SACS) were only discovered after effectively being illuminated by the sequestered CO2 (Chadwick et al., 2003). Shallow gas (above bedrock) can cause drilling problems and impede monitoring.	The Northern Platform site has data from 639 boreholes penetrating down through the reservoir. Plus 3D seismic surveys. Therefore, the probability of any large undetected features is extremely unlikely.	Need data on faults and fractures in reservoir.	CO2 leakage through an undetected fracture/fault zone, borehole, gas chimney or other features.	Undetected features.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Conduct ground and 3D-seismic surveys to detect underground features. Take results into consideration in site characterization and modeling.	Conduct ground and 3D-seismic surveys to detect underground features. Take results into consideration in site characterization and modeling.	Monitor and model CO2 and brine migration. Monitor overlying formations for CO2/salinity/pH changes. Depressurize reservoir if leakage is detected. Extract CO2 from leaking reservoir and inject into sealed reservoir if necessary. Select sites with multiple stacked seals and sinks.	

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
192	04.01.11.00.	Fractures and faults (CO2 leakage through new or existing fractures or faults)	2	3	3	18	PGA(g) 0.092-0.18 = 1/1000,000 fatality rate. PGA(g) 0.18-0.34 = 1/100,000 fatality rate. PGA(g) 0.34-0.65 = 1/10,000 fatality rate. PGA(g) 0.65-1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate.	PGA(g) 0.092-0.18 = 1/250,000 injury rate. PGA(g) 0.18-0.34 = 1/25,000 injury rate. PGA(g) 0.34-0.65 = 1/2,500 injury rate. PGA(g) 0.65-1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate.	PGA(g) 0.092-0.18 = 3/100,000 injury rate. PGA(g) 0.18-0.34 = 3/10,000 injury rate. PGA(g) 0.34-0.65 = 3/1,000 injury rate. PGA(g) 0.65-1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate.	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Potential class action lawsuit for property damage, loss of property value, reimbursement for earthquake insurance and emotional distress.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	Shutdown of project through court ordered injunctive relief likely if multiple events of PGA(g)>0.1 (>4 magnitude earthquake)	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	Assuming leakage detected early and mitigated: <\$1M for water remediation	Continuous passive micro-seismic monitoring: Capex: \$3.9M Opex: \$0.3M/y Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Monitor pressure in overlying formations.	Savings: Up to \$2M	1
193	04.01.12.00.	Undetected features	2	3	3	18	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	None	None	None	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	Assuming leakage detected early and mitigated: <\$1M for water remediation	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Savings \$2M	1	

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
194	04.01.13.00.	Vertical geothermal gradient 04.01.04.10.	Temperature profile in the geosphere prior to the injection of CO₂. Temperature generally increases with depth, but the rate of increase varies significantly depending on the geothermal gradient. The critical temperature for CO₂ is 31.1°C. The average geothermal gradient is approximately 25°C per km. If the surface temperature is 10°C, the critical temperature will be reached at a depth of 840 m. However, a considerable variation in geothermal gradients and sub-surface temperatures can be expected at a depth of 1000 m. For example, in Europe temperatures at 1000 m range from 20 to 75°C, with local temperatures of more than 200°C in volcanic areas.	Relevant to temperature dependent physical/chemical/biological/hydraulic processes, such as CO₂ phase behavior. Temperature, coupled with pressure, will affect the phase behavior of CO₂ as well as the solubility of many other constituents present in the reservoir (including gases, liquids and solids.)	The vertical geothermal gradient is 0.019°C/m depth (0.01°F/ft depth). The temperature at 2042 m (6700 ft) is 54.4°C (130°F).		CO ₂ phase change from supercritical to gas underground.	High vertical geothermal gradient.	Decreased CO ₂ storage. Increase CO ₂ mobility.	Take into account vertical geothermal gradient in site characterization and modeling. Monitor bottom hole temperatures.	Take into account vertical geothermal gradient in site characterization, modeling and reservoir engineering.	Monitor and model bottom hole temperatures. Extract brine to increase CO₂ storage capacity and control CO₂ migration.
195	04.01.14.00.	Formation pressure	The pressure of fluids within the pores of a formation, normally hydrostatic pressure, or the pressure exerted by a column of water from the formations depth to the sea level prior to the injection of CO₂. The critical pressure of CO₂ is 7.38 MPa. The average underground hydrostatic pressure increases with depth by approximately 10.5 MPa per km for aquifers that are in open communication with surface water. Applying this average gradient, the critical pressure of CO₂ will be reached at a depth of around 690 m. However, aquifers or hydrocarbon reservoirs (e.g., EOR and ECBM) that are sealed off from the rest of the sub-surface may be under- or over pressured. 1. Hydrostatic pressure 2. Fracture pressure 3. Lithostatic pressure	Contributes towards determining the mobility of sequestered CO ₂ .	The initial reservoir pressure was 21.53 MPa at 2042 m depth (3122 psia at 6,700 ft depth). Reservoir pressure dropped to 11.38 MPa (1650 psia at the end of primary production. The reservoir has been repressurized above 19.65 MPa (2850 psi) as of 1977. Range of operation between MMP and initial fracture pressure. MMP: 15.85 MPa (2300 psi). Initial fracture pressure: 28.27 MPa (4100 psi).	Need historical data on reservoir pressure at SACROC.	1. CO₂ phase change from supercritical to gas underground. 2. Formation pressure below minimum miscible pressure (MMP) for enhanced oil recovery.	Low formation pressure.	1. Decreased CO₂ storage. Increased CO₂ mobility. 2. Low oil yield for CO₂ enhanced oil recovery (EOR)	Take into account formation pressure in site characterization and modeling. Monitor bottom hole pressure.	Measure bottom hole pressure. Take into account formation pressure in site characterization and modeling. Avoid sites where formation pressure is lower than CO₂ supercritical pressure or below MMP (for EOR sites).	Monitor bottom hole pressure. Increase formation pressure by injecting water before injecting CO₂. Do not exceed 90% of fracture pressure.
196	04.01.15.00.	Initial stress and mechanical properties	The stress condition and mechanical properties of the geosphere prior to injection of CO ₂ .	The initial stress state and mechanical properties are a baseline from which the potential effect of injecting supercritical CO ₂ can be assessed.	Fractures exist from previous hydraulic fracturing operations. Natural faults and fractures occur in the reservoir but do not penetrate the primary seal. Failure of multiple stacked seals are unlikely. CO₂ injection compensated for by simultaneous production of fluids. Reservoir fluid volume remains within 1% of original volume.	Need historical data on stress and mechanical properties.	1. Fracturing caprock. 2. Seismicity. 3. Uplift/subsidence. 4. Borehole collapse.	Initial stress and mechanical properties.	1. CO₂ release (HSE hazard). 2. Seismic damage to surface buildings and infrastructure. 3. Change in surface water flow impacting farmland. 4. Well damage.	Conduct baseline study of initial stress state and mechanical properties of the reservoir and caprock and include these in site characterization and modeling. Monitor changes in stress state and mechanical properties over time.	Conduct baseline study of initial stress state and mechanical properties of the reservoir and caprock and include these in site characterization, modeling and reservoir engineering. Avoid sites with high stress state or low mechanical properties.	Monitor changes in stress state and mechanical properties over time. Do not exceed 90% of fracture pressure. Maintain relative balance between volume of injected fluids and volume of produced fluids.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
194	04.01.13.00.	Vertical geothermal gradient 04.01.04.10.	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
195	04.01.14.00.	Formation pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
196	04.01.15.00.	Initial stress and mechanical properties	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

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197	04.01.16.00.	Petrophysical properties (See 03.02.03.01.; 04.01.08.03. and 04.01.08.04.)	Petrophysical properties of the geosphere prior to the injection of CO2. This includes features such as permeability, porosity, residual saturation, capillary pressure and wettability.	Petrophysical properties influence how injected CO2 will migrate in the geosphere. For example, permeability influences the direction and rate of CO2 movement, and porosity and residual saturation influence the dimensions of the CO2 plume.	Reservoir porosity averages 9.8% and ranges from 4 to 20% (Dutton 2004). Reservoir permeability averages 10mD and ranges from 1 to 1760 mD (Dutton 2004). Initial water saturation: 0.282 (Vest 1970) Initial oil saturation: 0.718 (vest 1970) Irreducible water saturation: 0.22 to 0.38 (Gonzalez 2008)							
198	04.02.00.00.	Fluids	Details of fluids in the geosphere, which comprises of the reservoir, overburden and surrounding rock prior to the injection of CO2. Water will generally be present, but other fluids, particularly hydrocarbons (e.g., EOR and ECBM), may be important, dependent on the sequestration concept.	Water and other fluids in the sequestration system will affect the transport and interactions of injected carbon dioxide.								
199	04.02.01.00.	Fluid properties (See 03.02.13.03)	Properties of the geosphere fluids prior to injection of CO2, including composition and geochemistry. The high salinity of deep aquifers is, generally, an indication of very low or insignificant throughput of meteoric waters. 1. Fluid chemical composition and geochemistry 2. High salinity fluid 3. Fluid density	The fluid properties and geochemistry of the geosphere will contribute towards determining how injected CO2 will behave in the geosphere. Very high salinity can lead to deposition of halite in pore spaces and cause decreased permeability and injectivity.	Brine salinity: 159,000 ppm TDS Brine density: 1100 kg/m3 Brine viscosity: 0.8 cP Solution of hydrocarbon gas in crude oil: 178m3/m3 (1000 SCF/STB) Crude oil density: 800 kg/m3 Crude oil viscosity: 0.38cP CO2 density: 800 kg/m3 CO2 viscosity: 0.0562 cP Oil and CO2 densities very similar at reservoir conditions. Brine density is significantly greater. CO2 viscosity is significantly lower than crude oil or brine.	Need historical data on produced water chemistry and treatment.						
200	04.02.02.00.	Hydrogeology	Natural formation water flow pathways (directions, velocities) in the geosphere will be important in determining the long-term migration paths for CO2. This depends on factors including: hydraulic heads, permeability and porosity distribution, the existence of fracture networks, connection between aquifers, position of the recharge and discharge areas. 1. Natural fluid flow pathways 2. Position of aquifer recharge and discharge areas 3. Connection between deep saline aquifer and shallow drinking water aquifer	This will affect the migration of dissolved CO2 in the reservoir and the geosphere (direction, timing), the position of the interface between supercritical CO2 and aquifer water (inclined interface). There may also be a possible effect on overlying aquifers used for drinking water.	The Northern Platform is closed on all but the south side. Therefore hydrogeology flow is restricted. Extensive fractures, karsts and other pathways exist that can lead to early breakthrough or fingering of CO2.		Migration of CO2/brine out of reservoir.	Hydrogeology.	CO2 contamination of groundwater aquifers	Monitoring near surface water chemistry.	Hydrogeology is not a factor in the Northern Platform reservoir.	NA

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197	04.01.16.00.	Petrophysical properties (See 03.02.03.01.; 04.01.08.03. and 04.01.08.04.)	0	0	0	0															
198	04.02.00.00.	Fluids	0	0	0	0															
199	04.02.01.00.	Fluid properties (See 03.02.13.03)	0	0	0	0															
200	04.02.02.00.	Hydrogeology	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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201	04.02.03.00.	Hydrocarbons	The presence and distribution of hydrocarbons, such as oil and/or gas (e.g., EOR and ECBM), within the storage system.	Hydrocarbons have potentially important implications for a storage system, by both influencing the likelihood of previous geological exploitation of the area, and by being an important component of the system with which sequestered CO2 can interact.	Northern Platform original oil in place was 1.227 billion STB. Production from 1948 through 2002 was 593,588,895 STB. Initial oil saturation was 0.72. Residual oil saturation in 2003 was 0.3483. Initial gas saturation was 0.00.		Drilling through a methane gas pocket. Potential blowout and fire. Human injury/death.	Presence of hydrocarbons.	Equipment damage. Methane release to atmosphere. Liabilities.	Monitor boreholes for pressure kicks.	Monitor and model hydrocarbon saturation, and production. Ensure blowout preventer and packers are working properly at all times.	Monitor for borehole pressure kicks. Train operators how to deal with pressure kicks and blowouts.. Ensure blowout preventer and packer are working properly at all times. Monitor hydrocarbon production.
202	05.00.00.00.	BOREHOLES	This category of FEPs is concerned with the way that activity by humans alters the natural system. Both boreholes used in the sequestration operations and those drilled for other purposes are relevant to the long-term performance of the system. The category is divided into two classes for the drilling process, and sealing and abandonment.	This category is divided into two classes: 1. Drilling and completion 2. Sealing and abandonment								
203	05.01.00.00.	Drilling and completion	FEPs relevant to the operation of boreholes drilled within the system domain.	Boreholes can potentially provide short circuits for carbon dioxide transport.								
204	05.01.01.00.	Formation damage (CO2 leakage through damaged caprock near borehole)	Alteration of the far-field or virgin characteristics of a formation, usually by exposure to drilling fluids. Fracturing associated with formation damage can increase porosity, whereas the water or solid particles in the drilling fluids, or both, can decrease the pore volume and effective permeability of the formation in the near-wellbore region. Some boreholes in the early 20th century may have been explosive fractured with nitroglycerin. Later boreholes may have been hydrofractured. 1. Explosive fracturing 2. Hydrofracturing A number of mechanisms can result in a decrease in porosity, including: 3. Solid particles from the drilling fluid physically plug or bridge across flow paths in the porous formation 4. Water from drilling causing clay minerals in the formation to swell 5. Chemical reactions between drilling fluid and the formation rock and fluids precipitating solids	Formation damage has a number of potential implications for assessing CO2 sequestration: - it can make information from affected boreholes non-representative of the true characteristics of the damaged formations; and - damaged regions themselves may provide flow paths for CO2 migration, particularly if damage results in fracturing. - decrease in near borehole porosity can result in unexpected increase in bottom hole pressure	Hydrofractures, dissolved pathways and eroded pathways exist from early operations. 639 wells penetrate the primary seal. Most of them are over 50 years old.	Need historical data on formation damage at SACROC,	CO2 leakage through damaged/fractured caprock near borehole. Low injectivity. Nonuniform injectivity	Formation damage.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Increased operating costs. Lower oil recovery.	Review and analyze well records, if any. Determine damage that may have been done by fracturing, erosion or plugging. Run fall-off tests on wells. Monitor and model injection and production fluid volumes.	Run fall off tests and characterize responses in overlying formations. Replug and seal at-risk wells. Pressurize wells with water prior to injecting CO2 to check for leaks.	Monitor for H2S near wells. Use water curtains to isolate damaged areas. Use sealants to fill in fractured areas. Use selective perforations to achieve more uniform CO2 injection and flow.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
201	04.02.03.00.	Hydrocarbons	2	4	1	8	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1-2 @ \$0.05 M per minor (recoverable) injury	None	None	Damage due to well blowout caused by drilling through hydrocarbon trap. Repair and damage recovery \$1.5M	1-10 days @ \$20,000/d revenue lost per pattern idled	None	Emissions tied to hydrocarbon release/flarin g	10% of damage costs	<\$3M per blowout. Fatalities and/or injuries: \$3.1M	None	Cost to maintain BOP and packers and emergency response plan for blowout fire and explosion are all part of ongoing operations.	Up to \$3M for every blowout prevented. Up to \$3.1M for fatalities and/or injuries prevented.	1
202	05.00.00.00.	BOREHOLES	0	0	0	0															
203	05.01.00.00.	Drilling and completion	0	0	0	0															
204	05.01.01.00.	Formation damage (CO2 leakage through damaged caprock near borehole)	3	3	3	27	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	None	None	None	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 1 year: \$1.2M for water remediation and CO2 loss per leaky well	Assuming leakage detected early and mitigated: <\$1M for water remediation	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	None	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
205	05.01.02.00.	Well lining and completion	At the time of drilling, boreholes are lined with a metal casing. Cement is pumped downhole inside the casing string, and it is pushed upward under and outside the casing lower end, between the casing and the rock wall. In multi-stage cement jobs, cement is squeezed between the casing and the rock wall through purpose made perforations. The cement could be pushed behind casing from the bottom hole to the surface, or to a predetermined depth. Curing of cement is the process of maintaining the proper temperature and moisture conditions to promote optimum cement hydration immediately after placement. Proper moisture conditions are critical because water is necessary for the hydration of cementitious materials. As cement hydrates, strength increases and permeability decreases. When hydration stops, strength gain ceases. Therefore, proper hydration of the cement is important in the fabrication of strong, durable concrete. Alteration of borehole linings will occur with time, depending on the natural fluid composition of the deep reservoir and the input of high concentrations of CO2 carrying natural H2S, which may accelerate corrosion.	Borehole lining and completion will contribute to determining the performance of a borehole both during its operational and post-closure phases. This is important from the perspective of CO2 sequestration, since boreholes may provide preferential short circuits to the surface with potential release of CO2 and contamination of upper aquifers.	639 wells exist that penetrate the primary seal. Most of them are over 50 years old. Cement linings have been tested for degradation and appear to be holding up well. Shut in wells are selectively evaluated and reworked as needed to mitigate leakage.		CO2 leakage through active well	Poor well lining completion.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Review and analyze well records. Determine if well lining and completion methods meet current requirements. Characterize with logging tools. Pressurize with water prior to injecting CO2 to check for leaks.	For new wells, use best available methods for completion. Use best cements and characterize using logging tools. For old wells characterize and recomple or plug and abandon. Pressurize with water prior to injecting CO2 to check for leaks.	Monitor for H2S near wells. Use water curtains to isolate damaged areas. Use sealants to seal fractured areas. Use selective perforations to achieve more uniform CO2 injection and flow.
206	05.01.03.00.	Workover	The process of performing major maintenance or remedial treatments on a borehole often associated with the re-use of existing boreholes. Workover techniques include flushing of the formation and the removal and replacement of the borehole lining. Well control procedures during workovers must provide for unique phase behavior of any CO2 being circulated out. (CCP 2009) EOR operations often re-complete old wells. Proper re-completion includes: Examining cement bond logs to evaluate bonding between the casing and adjoining formation. Use of squeeze cement if insufficient or inadequate bonding was detected. Wellbore drilling of plugged and abandoned wells to bottom of target formation. Run a casing mechanical integrity test. If pressure fall off was observed, the leaking section of casing should be identified and resealed by squeeze cementing or, in extreme cases, install a liner over the leaking section. 1. Improper modification or reuse of existing boreholes	Workover will result in modified borehole properties that may need consideration within an assessment.	Workovers are performed on up to 7-8% of injection wells per year. Operator has an upfront evaluation process used in decision to reuse existing wells or drill new wells.	Need historical data on workovers at SACROC,	CO2 and other gases (such as CH4 of H2S) leakage through borehole during workover.	Workover.	Leakage of CO2/H2S (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Monitor for H2S near borehole. Monitor borehole pressure. Monitor pressure in formations above caprock.	Install blow out preventers and packers in wells.	Monitor for H2S near borehole. Monitor borehole for pressure kicks. Maintain blow out preventer and packers in working order.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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									Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
205	05.01.02.00.	Well lining and completion	4	2	2	16	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Covered under natural resource damage	None	None	Cost to locate leak \$0.2M. Cost to fix leak \$0.1M.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 1 year: \$1.2M for water remediation and CO2 loss per leaky well	Assuming leakage detected early and mitigated: <\$1M for water remediation per leaky well	Cost to locate and fix leak:<\$300k.	Up to \$0.7M	1		
206	05.01.03.00.	Workover	4	2	2	16	None	None	None	None	None	None	None	<\$1M per event tied to a workover/well	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$1M per event tied to a workover/well	None	Install and maintain BOP and packers. <\$0.3M/well	Up to \$0.7M for every event prevented	1		

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
207	05.01.04.00.	Number and location of monitoring wells	Often, monitoring wells (observation wells or verification wells) are needed to monitor the physical conditions (pressure, temperature, etc.) of the storage reservoir, both inside and/or outside the area immediately affected by the storage operations, or above the storage reservoir. Monitoring wells could be "adopted", by using existing wells to host the appropriate instrumentation (piezometers, pressure gauges, thermometers, etc.), or they could be purpose drilled anew. Direct monitoring techniques usually require access from wellbores that penetrate the containment system into the storage reservoir (CCP 2009) Direct measurements can also be obtained from observation wells at shallower horizons above the expected seal. Wells of this type might provide direct and early indication of unexpected movement. (CCP 2009) General the concept is to minimize monitoring wells that penetrate the seal because they are, by default, potential leakage pathways. (CCP 2009) 1. Lack of or insufficient number of monitoring wells 2. Too many monitoring wells 3. Improperly located monitoring wells.	Observation or monitoring wells may provide an accidental leakage route for the stored CO2, particularly wells drilled inside the area of storage. There are unique tradeoffs associated with the number and location of monitoring wells.	As a CO2-EOR operation using natural CO2, there is no need for monitoring wells to verify storage. Production well performance gives a good indication of CO2 migration. 3D seismic surveys are also used effectively.		CO2/H2S leakage through monitoring wells.	Presence of monitoring wells penetrating the reservoir.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Monitor for H2S near wells.	NA	NA
208	05.01.05.00.	Well records	The drilling of boreholes for site investigation, resource exploitation and/or CO2 injection will result in many documents being generated in paper or digital form. Typical well records include location coordinates, depth, electric logs, mud logs, drilling parameter logs, composite log, testing reports (if applicable), coring report (if applicable), and a final report. Physical records from cutting samples, cores and fluid samples will also be documented. The principal tool to gain knowledge about the sequence of drilled rock formations is Borehole Logging. Common measures include hole diameter, natural gamma ray response, spontaneous electrical potential, rock resistivity, velocity of acoustic waves through rock, neutron susceptibility, etc. The documents originating at the time of drilling are often the most accurate records of the succession of events associated with the drilling of the well. The curation of such unique records is an invaluable tool to pass knowledge to future generations. 1. Lack of or incomplete records for existing wells 2. Retention/management of well records and data	Well records provide a key source of baseline information regarding the sequestration site. They provide information concerning the nature of the rocks drilled by the well and their petrophysical characteristics in terms of sealing potential and reservoir potential. Additionally, records from wells drilled over a period of time can give a picture of how the system is evolving either naturally, or as a result of the exploitation of geological resources. This baseline information is an important input both into the initial conditions relevant to the system to be assessed, as well as providing an indication of the likely importance of other FEPs. Incomplete well records equate to a potential gap in understanding of the storage system and may result in potentially important features being overlooked in the assessment process. Large amounts of data will be generated by the project. Data could be poorly communicated between groups, or be badly managed to the point that important data is lost, or used incorrectly.	A database of over 2000 wells exist for the SACROC unit. 639 of these wells are in the Northern Platform. Data includes location, depth, design, and injection/production history. Most of the wells do not have a full well log suite (RHOB, NPHI< GR and DT). Most are missing RHOB and/or DT logs (Gonzalez 2008).	Need well records.	Lack of well records. Loss of well records. Inaccurate well records.	Well records not maintained properly.	Failure to remain in compliance with regulations. Operator errors based on inaccurate well records.	Periodically audit well records for existing wells and maintain accurate records for new wells.	Characterize existing wells. Standardize documentation of well records. Take into account well record data in site characterization and modeling.	Conduct periodic audits of well record documentation to assure the records are thorough and accurate. Maintain digital backup of well records at more than one location.
209	05.02.00.00.	Borehole seals and abandonment	FEPs relevant to the closure of boreholes drilled within the system domain.	The way that boreholes are closed and sealed is directly relevant to the likelihood that they could act as short circuits for carbon dioxide transport.								

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
207	05.01.04.00.	Number and location of monitoring wells	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
208	05.01.05.00.	Well records	2	3	2	12	None	None	None	None	None	None	Interruption for non compliance @ \$20,000/d revenue lost per pattern idled.	None	None	Fines for non compliance	Up to \$3M per event.	None	Regularly audit well records and confirm accuracy: <\$100K.	Up to \$2.9M for every prevented event	1
209	05.02.00.00.	Borehole seals and abandonment	0	0	0	0															

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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210	05.02.01.00.	Closure and sealing of boreholes	Features related to the cessation of CO2 injection operations at a site and the sealing of injection and monitoring wells. When a borehole is drilled to the potential storage reservoir, it creates communication with possible overlying reservoirs and with the surface. Cementing and abandonment procedures are designed to permanently plug such communication channel. The cement plugs are commonly located across potential problem spots, to minimize leaking risks. Particular attention should be paid to the quality of the original cement job behind the casing string. If uncemented space is detected, known or suspected behind casing, depending on the lithology across such interval, it may be important to squeeze extra cement between the rock face and the casing to complement the final abandonment plugs inside the casing. Individual boreholes may be closed in sequence, but closure refers to final closure of the whole system, and may include removal of surface installations. The schedule and procedure for sealing and closure may need to be considered in the assessment. A typical well abandonment may include the following: - Remove tubing and packer - Permanently seal the formation with a fluid that reduces permeability - Place plugs of cement or other materials for isolation - Test the plugs - Place a cap on the casing at the surface	The intention of borehole sealing is to prevent human access to the sequestered CO2 and to prevent the borehole from providing a migration pathway for the CO2. Correct cementing and abandonment operations are essential to achieve restoration of pristine sealing above the designed storage reservoir formation.	Wells with problems are plugged and abandoned. Most wells are shut in. Out of over 2015 wells in the SACROC Unit, there are 450 active injection wells and 400 active production wells. That leaves over 1165 wells that are shut in or abandoned. Kinder Morgan has a very effective program for plugging and abandoning wells that has prevented CO2 leakage (Smyth 2012).	How many wells have been plugged and abandoned? What procedures are used for plugging and abandoning?	CO2 leakage through boreholes after closure.	Closure and sealing of boreholes.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Evaluate well materials and procedures for compatibility with CO2 and long-term conditions. Periodically monitor for H2S near closed wells.	Characterize abandoned wells. Replug high risk wells. Use closure plug materials that are compatible with CO2 and the expected long-term conditions.	Periodically monitor for H2S near abandoned wells. Replug leaky wells.
211	05.02.02.00.	Seal failure	Degradation of borehole linings (metal and cement) will occur with time, depending on the natural fluid composition of the deep reservoir and the input of high concentrations of CO2. Any H2S present may accelerate corrosion of metal linings. Cement will be attacked by high partial pressures of CO2, low pH and appreciable concentrations of sulfate, chloride, and magnesium ions in the formation fluids. Seal failure will occur once liners have degraded and corroded. Portland cement blended with 50% fly ash had a 30 year life in a field that produced 96% CO2 with water saturation of approximately 20%. (CCP 2009). Conventional Portland cement-fly ash systems can inhibit CO2 migration even after carbonation of the cement because permeability remains relatively low and capillary resistance is relatively high. (CCP 2009). The Basis of Design for new wells should emphasize barrier performance using fundamentals of wellbore preparation, mud removal and cement placement to provide tight interfaces that inhibit fluid migration. Material selection of cement and metallurgy are important, but should be considered secondary to the process of cement placement. (CCP 2009). The cement interfaces between the boreholes and the casing through the caprock are the key to well integrity and seal integrity. Good isolation requires tight cement interfaces with the formation and casing. (CCP 2009)	Seal failure may provide preferential short circuits to the surface with potential release of CO2 and associated contaminants to the surface or near-surface environment. The failure may provide a preferential pathway either through the borehole annulus or around the outside of the casing. Cement interfaces, not cement matrix are the most likely path for migration. (CCP 2009). 1. CO2 leakage at cement-casing interface 2. CO2 leakage through the cement matrix 3. CO2 leakage through pathways created by chemical dissolution of cement 4. CO2 leakage through fractures in cement 5. CO2 leakage through an open annular region due to inadequate cement placement 6. CO2 leakage at cement caprock interface 7. CO2 leakage through corroded or cracked casing 8. CO2 leakage through packer	From 1948 through present, there have been 9 reported well control problems in the SACROC unit. The last one was in 2009. None of these caused any injuries or deaths. The incident in 2009 involved release of CO2 containing H2S and required evacuation of 5-6 homes in the area. The well was leaking from the brandenhead or the casing annulus (RRC 2012). Reported site issues: poor cement around pipe, corrosive water zones, and use of old wells. Successful site practices: carbon steel casing, circulate cement to surface (2-stage, standard blends), coating for corrosive areas, and good upfront evaluation to reuse wells or drill new wells (Ricketson 2012).	Need historical record of wellbore failures at SACROC.	CO2 leakage through the borehole annulus or around the outside of the casing.	Borehole seal failure.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Evaluate well materials and procedures for compatibility with CO2 and long-term conditions. Periodically monitor for H2S near closed wells.	Complete new wells and recompleat old wells using CO2 resistant materials. Use proper completion procedures to ensure tight cement interfaces.	Periodically monitor for H2S near abandoned wells. Replug leaky wells.

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210	05.02.01.00.	Closure and sealing of boreholes	4	2	2	16	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Covered under natural resource damage	None	None	Cost to locate leak \$0.2M. Cost to fix leak \$0.1M.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation per leaky well	Assuming leakage detected early and mitigated: <\$1M for water remediation per leaky well	Periodically monitor for H2S near abandoned wells. Replug leaky wells: <\$300k per leaky well	Up to \$4.7M	1
211	05.02.02.00.	Seal failure	4	2	2	16	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Covered under natural resource damage	None	None	Periodically monitor for H2S near abandoned wells. Replug leaky wells: <\$300k per leaky well	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 1 year: \$1.2M for water remediation per leaky well	Assuming leakage detected early and mitigated: <\$1M for water remediation per leaky well	Periodically monitor for H2S near abandoned wells. Replug leaky wells: <\$300k per leaky well	Up to \$0.2M	1

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212	05.02.03.00.	Blowouts	Uncontrolled flow (CO₂, brine, oil, gas or mixture of these) from depth leading to gas and/or fluid erupting from a well or borehole to either the terrestrial or aquatic environments. Blowout is an ordinary drilling hazard, well understood and controlled by current technology. Assuming that ordinary blow-out risk controls are present, particular risks might include: (1) A monitoring or verification well drilled into a porous formation that has elevated pressure due to CO₂, or (2) A drilled formation with significant unexpected H₂S (MCSG 2009). The greatest danger for loss of well control is during workover operations. Estimates based on both oil and gas wells give a frequency of 3x10⁻⁴ blowouts per well per year (IEA GHG, 2003) (Damen 2006). 1. Blowout due to equipment failure (packer, blowout preventer, valve failure) 2. Blowout due to accident (truck backing over injection well) 3. Blowout due to human error (valve left open) 4. Blowout of CO₂ injection well 5. Blow out of production well 6. Blow out of monitoring well 7. Blowout of inactive plugged and abandoned well 8. Blowout during workover/remediation of existing well	A surface or undersea blowout would provide a rapid pathway for CO₂ to reach the surface. Apart from the CO₂ release, the potential consequences are casualties among operators and economic damage caused by explosion or fire when upcoming hydrocarbons are ignited or by parts of the well, which can be launched by the pressure release.(Damen 2006)	From 1948 through present, there have been no reported blowouts in the SACROC unit. (RRC 2012)	Need historical record of blowouts at SACROC (if any).	Human injury/death due to CO ₂ release through well blowout.	Blowouts.	Leakage of CO ₂ (HSE hazard) into the surface water or atmosphere.	Monitor for pressure kicks in wells.	Design, construct and operate wells properly to prevent blowouts. Make sure the blowout preventer, packer and valves are maintained in proper working order.	Monitor for pressure kicks. Monitor for H₂S near well. Have standard procedures in place and train operators to deal with blowouts.
213	05.02.04.00.	Orphan wells	CO₂ storage projects may be part of an Enhanced Oil Recovery (EOR) project or stand-alone deep saline aquifer projects. Either way, it is likely that the target geological structure has been the object of past exploration efforts, possibly involving drilling wells. The existence of old wells could be obvious if the wells are still active, but could be overlooked if the old (orphan) wells have been long cemented and abandoned. Technical details of such abandoned vintage wells may in fact not be readily available, or altogether lost. In such a case, the old cementing (sealing) job could be substandard. Some coal bed methane operations used open completion wells (no casing). It is possible to stabilize a hole without casing with gravel packing or sorted liners 1. Failure to identify and locate existing wells - active wells, abandoned wells, shallow wells that don't penetrate the caprock, deep wells that penetrate the caprock 2. Failure to test wells for mechanical integrity 3. Failure to remediate old wells 3. Failure of old well due to poor cementing, sealing, closing 4. Improper workover/recompletion of old well 5. Leakage of CO₂ or brine through old well to overlying formations, underground aquifers or surface. 6. Collapse of open borehole (non-cased, open-completion holes often used in CBM)	Old substandard plugged well could provide a potential CO₂ leakage route to the surface or to possible reservoirs above the designed CO₂ storage reservoir. There is little chance of detecting a substandard well abandonment before the beginning of CO₂ injection to the designed reservoir, particularly if the existence of an old well has been overlooked. If old abandoned wells are known in the area of the CO₂ injection operations, the risk is minimized by carefully check any potential CO₂ leak to the surface at the old well head location. If old wells are unknown and not suspected, it is good practice to run a baseline soil gas survey (if applicable) and successive soil gas surveys at intervals after the beginning of CO₂ injection. Open completion wells are more likely to leak than other wells and subject to collapsing.	Existing wells are inspected, tested and reworked, if necessary, on a selective basis as injection moves from one pattern to another.	Need data on orphan wells at SACROC.	CO ₂ leakage through old substandard wells.	Orphan wells.	Leakage of CO ₂ (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Review and analyze well records, if any. Determine if well plugging and completion methods meet current requirements. Characterize with logging tools. Pressurize with water prior to injecting CO ₂ to check for leaks.	Identify and analyze old wells using records, surveys and field testing. Replug at-risk wells.	Monitor for H₂S near wells. Replug leaky wells.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
212	05.02.03.00.	Blowouts	2	4	1	8	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	2 @ \$0.05 M per minor (recoverable) injury	None	None	Damage due to well blowout caused by CO2 formation kick Repair \$0.5M	1-10 days @ \$20,000/d revenue lost per pattern idled	Up to \$2 M per CO2 blowout.	5,000 to 10,000 t CO2 per blowout	10% of damage costs	Blowout: <\$3M per event. Fatalities and/or injuries: \$3.1M,	None	Monitor for pressure kicks. Maintain well control with BOP and packers. Part of ongoing operation costs.	Up to \$3M per CO2 blowout prevented. Up to \$3.1 M for fatalities and/or injuries prevented.	1
213	05.02.04.00.	Orphan wells	4	2	2	16	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Covered under natural resource damage	None	None	Periodically monitor for H2S near abandoned wells. Replug leaky wells: <\$300k per leaky well	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 1 year: Up to \$1M for water remediation per leaky well	Assuming leakage detected early and mitigated: <\$1M for water remediation per leaky well	Periodically monitor for H2S near abandoned wells. Replug leaky wells: <\$300k per leaky well	Up to \$10.7M	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
214	05.02.05.00.	Soil creep around boreholes	The slow downward gravitational movement of soil around boreholes.	This process results in changing properties of the soil around borehole casings after abandonment. It may either increase or decrease the degree of sealing and therefore the potential for the region immediately around the borehole to act as a migration pathway for CO2 and/or associated contaminants.	This has not been listed as a significant problem at SACROC.		CO2 leakage around the borehole.	Soil creep around boreholes	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Examine existing abandoned wells to get an idea of the problem. If there are wells with this problem, identify what was the difference between them and the wells without the problem.	Examine existing abandoned wells for soil creep. If there are wells with this problem, identify what was the difference between them and the wells without soil creep. Apply lessons learned to newly abandoned wells.	Monitor for soil creep. Fill in as needed.
215	05.02.07.00.	Borehole sand control (sand blocking)	Applies to unconsolidated reservoirs. Sand control may be necessary to maintain the structure of the reservoir around the wellbore. Migration of sand and fines into the near wellbore area may severely restrict production/injection. Sand blocking is a problem when the reservoir is unconsolidated and the wellbore is shut in for maintenance or upsets. (CCP 2009) Dehydration and deposition of gravel pack contents that cannot be displaced or removed from the well (CCP 2009) 1. Sand blocking 2. Dissolution of sand control resins 3. Dehydration and deposition of gravel pack contents	Operation delays. Maintenance costs.	This is not applicable at SACROC. The reservoir formations are consolidated carbonates.		Sand blocking.	Borehole sand control.	Loss of injectivity. Operating delays and higher maintenance costs.	Take into account any reservoir unconsolidated features in site characterization.	Characterize reservoir. Avoid sites with unconsolidated reservoirs.	Use appropriate design, operation and maintenance procedures for sand control.
216	05.02.08.00.	Wellbore fluids (causing corrosion or scale buildup)	Once the well is completed, impairment implications of the fluids or non-fluids left in the wellbore during startup will need to be considered. (CCP 2009) It is important to consider the displacement of any fluids into the reservoir during start up and the effect of injectivity resulting from the introduction of the fluids. (CCP 2009) Stimulation fluids should be carefully selected in terms of compatibility with the well materials, workover materials and reservoir. (CCP 2009) 1. Wellbore fluids 2. Startup fluids 3. Stimulation fluids	Fluids left in the wellbore for extended amounts of time could potentially corrode the tubulars, drop out precipitants, or cause bacterial growth. (CCP 2009) Startup fluids may impact injectivity due to precipitation of solids. Stimulation fluids may cause corrosion or precipitation of solids.	Brine is used as a packer fluid with corrosion inhibitor, biocides, scale inhibitor and oxygen scavenger.	Confirm composition of wellbore fluids at SACROC.	Corrosion of wellbore tubulars. Plugging of wellbore tubulars.	Wellbore fluids.	Operating delays and higher maintenance costs.	Monitor chemistry of wellbore fluids.	Monitor chemistry of wellbore fluids. Avoid leaving detrimental wellbore fluids in the well for long periods of time. Use corrosion resistant, Teflon coated tubulars.	Treat wellbore fluids prior to injection. Use corrosion inhibitor, biocides, scale inhibitor and oxygen scavenger.
217	06.00.00.00.	NEAR-SURFACE ENVIRONMENT	This category of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible environment. The environment could be terrestrial or aquatic, and human behavior in that environment needs to be described. The category is divided into three classes: Terrestrial Environment; Aquatic Environment; and Human Behavior.	This category is divided into three classes: 1. Terrestrial environment 2. Aquatic environment 3. Human behavior								
218	06.01.00.00.	Terrestrial environment	This class of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible terrestrial environment.	The near-surface environment is where most potential impacts would be incurred. The FEPs in this class are relevant if that environment is terrestrial.								

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
214	05.02.05.00.	Soil creep around boreholes	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
215	05.02.07.00.	Borehole sand control (sand blocking)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
216	05.02.08.00.	Wellbore fluids (causing corrosion or scale buildup)	2	2	2	8	None	None	None	None	None	Damage due to corrosion of well components. <\$1M per incident.	1-5 days @ \$20,000/d revenue lost per pattern idled	Repair costs of up to \$0.1M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Damage due to corrosion of well components. <\$1M per incident.	None	Use corrosion resistant materials of construction. Pretreat well fluids with corrosion inhibitors: <\$300k	Up to \$700k per incident prevented..	1
217	06.00.00.00.	NEAR-SURFACE ENVIRONMENT	0	0	0	0															
218	06.01.00.00.	Terrestrial environment	0	0	0	0															

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Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
219	06.01.01.00.	Topography and morphology	Features related to the relief and shape of the surface environment and its evolution. 1. Low surface areas (valleys, gullies, ditches) 2. Rugged terrain 3. Confined spaces (caves, canyons)	This FEP refers to local land form and land form changes with implications for the surface environment, e.g. plains, hills, valleys, and effects of river and glacial erosion thereon. In the long term, such changes may occur as a response to other geological changes. Leaked CO2 can accumulate in low surface areas and confined spaces. Rugged terrain may make it difficult to access the site, difficult to lay pipeline and difficult to monitor or conduct seismic studies.	The surface is relatively flat except in the northeast quadrant of the site which is covered with creek gullies. (Google Earth 2012).		Accumulation of CO2/H2S in low surface areas or confined spaces without sufficient ventilation.	Presence of low areas or confined spaces near the CO2 injection site.	Endangerment of flora, fauna and humans in low surface areas or confined spaces without sufficient ventilation if CO2 leakage occurs.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Monitor those areas for accumulation of CO2.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk.	Monitor low surface areas or confined spaces for CO2/H2S accumulation. Post warning signs.
220	06.01.02.00.	Soils and sediments impact on project	Features related to the physical and chemical characteristics of the soils and sediments and their evolution. Different soil and sediment types, e.g. characterized by mineralogy, particle-size distribution and organic content, will have different properties with respect to erosion/deposition, sorption etc.	Soil and sediment characteristics will influence the type of vegetation and land use. They will also determine relevant processes to consider should CO2 and/or associated contaminants migrate to the terrestrial surface environment.	The NW, SW and SE quadrants of the Northern Platform site have about 16 inches of Abilene clay loam underlain by 2 ft of calcareous heavy clay loam and 2 ft of caliche or chalk (Templin 1931). There are sporadic occurrences of Potter gravely loam in these quadrants. The NE quadrant of the site is rough, broken and stony land, with Spur loam along Ennis Creek, and sporadic occurrences of Miles loam, Potter gravely loam and Abilene loam. Vernon clay occurs in the northeast corner of the site (Map of Scurry County Soils 1931).		Accumulation of CO2 and/or H2S in soil and sediments.	Presence of soils and sediments near the CO2 injection site.	Flora damage. Conduct baseline study for CO2, CH4 and H2S in soils and sediments. Monitor soils and sediments for CO2 and/or H2S.	Take into account soils and sediments in site characterization. Select site with high integrity caprock.	Periodically monitor near surface for CO2 and/or H2S. Identify any irregularities. Determine root cause. Locate and plug leaks.	
221	06.01.03.00.	Erosion and deposition	FEPs related to all the erosional and depositional processes that operate in the surface environment, and their evolution with time. Relevant processes may include fluvial and glacial erosion and deposition, denudation, Aeolian erosion and deposition. These processes will be controlled by factors such as the climate, vegetation, topography and geomorphology.	Erosional and depositional processes will influence the way in which the surface environment has evolved and will evolve over the time-scale of interest.	Soils formed on an erosional surface characterized by rolling plains having ancient stream terraces associated with stream dissection. Erosion is shallow rather than deep (Map of general soils of Texas 2008).	Need historical data on erosion problems at SACROC.	Erosion or deposition around surface facilities, roads or pipelines.	Rain, flooding or high winds.	Damage to surface facilities roads or pipelines. Monitor and track erosion and deposition.	Proper site characterization and site selection avoiding areas with steep slopes >18%, unconsolidated sandy soil (e.g. sand dunes), or flood plains.	Install barriers for erosion control. Provide periodic erosion or deposition control maintenance.	

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
219	06.01.01.00.	Topography and morphology	2	2	2	8	None	None	None	None	None	None	1-15 days @ \$20,000/d revenue lost per pattern idled	Damage <\$1M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Damage <\$1M	None	Monitoring costs and cost to locate and fix leak <\$300k	Up to \$700k per incident prevented..	1
220	06.01.02.00.	Soils and sediments impact on project	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
221	06.01.03.00.	Erosion and deposition	3	2	1	6	None	None	None	Not attributable to CO2-EOR	Not attributable to CO2-EOR	Pipeline damage <\$1M based on 1986- 2011 DOT data	0-7 days @ \$20,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of total damages	<\$1M per incident	None	Periodic erosion control maintenance: \$0.1M to \$1M	Savings: <\$0.9 per pipeline rupture prevented	2

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222	06.01.04.00.	Atmosphere and meteorology (See 10.01.01)	FEPs related to the characteristics of the atmosphere, weather and climate, and their evolution with time. In case of CO2 leakage to the surface, the weather is a relevant factor determining the dispersion or the displacement of the gas: currents, evolution of the concentration of the gas, gas accumulations. Atmospheric characteristics include physical transport of gas, aerosols and dust in the atmosphere and chemical and photochemical reactions. Meteorology is characterized by atmospheric precipitation, temperature, pressure, wind speed and direction. The variability in meteorology should be included so that extremes such as drought, flooding, storms and snow melt are identified.	This information will determine the behavior of CO2 should it reach the atmosphere and is therefore an important factor when considering exposure of the local population and of the local environment. Meteorological characteristics also influence the near-surface hydrological regime with its subsequent consequences for CO2 migration.	The climate is subhumid, warm, and of a continental type. Average annual rainfall: 21 inches. Dry, mild winters. Summers warm with thunderstorms and hail. Prevailing wind is from south (175 to 180 degrees) away from Snyder, TX. Nearest down wind population center is Spur, TX (population 1,008) which is 66 km (41 miles) north. Mean wind speed is 18 km/h (11 mph). Potential for tornados, droughts, and floods.		Severe weather.	Atmospheric meteorology.	Damage to surface facilities roads and pipelines.	Monitor weather reports for severe weather.	Take into account atmosphere and meteorology in site characterization, design operation and atmospheric dispersion modeling for CO2/H2S leaks.	Maintain procedures for dealing with severe weather that may require an emergency shutdown.
223	06.01.05.00.	Hydrological regime and water balance	Processes related to near-surface hydrology at a catchment scale and also soil water balance, and their evolution with time. The hydrological regime is a description of the movement of water through the surface and near-surface environment. It includes the movement of materials associated with the water such as gas or particulates and extremes such as drought, flooding, storms and snow melt. 1. CO2 and associated contaminants leakage affecting the hydrological regime and water balance. 2. Displaced brine affecting the hydrological regime and water balance 3. Groundwater withdrawal causing change in CO2 or brine migration 4. ECBM water extraction impacting water level in shallow wells.	The hydrological regime and water balance will influence the way in which CO2 migrates should it reach the near-surface environment.	There is a mounding of groundwater over the SACROC unit. This may be due to the fact that the surface topography is a regional high in this area between the Brazos and Colorado Rivers and because of extensive pipelines which disturb the surface and enable enhanced recharging. The Darcy velocity of the groundwater away from the high levels above the SACROC unit is approximately 30-61 m (100-200 ft) per year. (Smyth 2012)		Dispersion of leaked CO2 and/or brine in near-surface aquifers or surface waters.	Hydrological regime and water balance near the CO2 injection site.	CO2/brine contamination of near surface waters.	Conduct baseline survey of near-surface water quality. Model hydrological regime to determine likely scenarios for CO2/brine dispersion. Monitor pressure in formations above the caprock. Monitor water level in shallow wells for significant changes that may be tied to ECBM water extraction.	Characterize the local hydrological regime and water balance and incorporate results into models.	Monitor pressure in formations above the caprock and/or highest secondary seal. Monitor near surface aquifers for changes in CO2/salinity/pH. Determine root cause for any changes. Use tracers if necessary. Locate, isolate and fix leak. Locate, isolate and remediate contaminated water.

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222	06.01.04.00.	Atmosphere and meteorology (See 10.01.01)	2	2	2	8	None	None	None	None	None	Surface facilities damage <\$1M for must situations but \$10M+ if compressors are involved.	0-7 days @ \$20,000/d revenue lost per pattern idled	<\$1M per event	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of total damages	<\$1M/event	Cost of insurance deductible.	Insurance coverage for weather and flood damage and business interruption 0.28% of surface facilities value per year + 0.25% of revenue per year	<\$1M per event minus insurance deductible minus cost of insurance	
223	06.01.05.00.	Hydrological regime and water balance	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Contamination of well water and build up of CO2 in well	None	1-15 days @ \$20,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: \$6M for water remediation	Assuming leakage detected early and mitigated: <\$1M for water remediation	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Savings Up to \$2M	1

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224	06.01.06.00.	Near-surface aquifers and surface water bodies	Features related to the physical and chemical characteristics of aquifers and water-bearing features and their evolution.	Shallow Aquifers Aquifers may yield significant amounts of water to wells or surface springs and may thus be a flow path for CO₂ to the surface environment. The presence of aquifers and other water-bearing features will be determined by the geological, hydrological and climatic factors. Shallow aquifers will be able to dissolve CO₂, reducing further upward migration. The amount of CO₂ that can dissolve will depend on factors such as the location of the water table, the chemical composition of pore waters, CO₂ flux rates, and hydrogeology. Surface Water Bodies Streams, rivers and lakes often act as boundaries of hydrogeological systems. They may represent a significant source of dilution for CO₂ and contaminants entering these systems, or act as reservoirs. In hot dry environments, where evaporation dominates, concentration or exsolution of gas is possible. Water with dissolved CO₂ is denser than pure water, which can result in stratification and the potential for limnic eruption.	There are intermittent creeks and a few small ponds in the site area. Ennis Creek flows from NW to SE and from W to E. The Ogallala and Dockum formations are shallow secondary USDW aquifers. The Ogallala is 49 ft thick in the east and 98 ft thick in the west of the Northern Platform area. The Dockum is 312 ft in the east and 384 ft in the west of the Northern Platform area. Water level is about 130 to 170 ft deep and goes down to the bottom of the Dockum 361 ft in the east and 492 ft in the west of the site. The USDW ground water above the SACROC unit contains 1000 ppm TDS and pH is around 7. Studies on pH, TDS, Na, K, Cl, As, Zn, Ca, HCO₃, delta 13C, F, nitrate, Se, Ag, Ba, Cd, Cr, Cu, Pb, Sb, Th, U, Al, Mn, sulfates, Fe, Hg and B₁ have not indicate any impact from CO₂ leakage (Smyth 2012)		Migration of CO ₂ /H ₂ S and/or brine into near-surface aquifers or surface waters.	Locating CO ₂ injection site near fresh water aquifers and surface water bodies. Leakage of CO ₂ /H ₂ S from reservoir through caprock and secondary seals to overlying aquifers and surface water bodies.	CO ₂ /brine contamination of near surface waters.	Conduct baseline survey of near-surface water quality. Monitor near surface aquifers for changes in salinity/pH.	Include near-surface aquifers and surface waters in site characterization. Avoid sites with sensitive groundwater areas. Maintain integrity of caprock and lateral seals.	Monitor near surface aquifers for changes in CO₂/salinity/pH. Determine root cause for any changes. Use tracers if necessary. Locate, isolate and fix leak. Locate isolate and remediate contaminated water.
225	06.01.07.00.	Terrestrial flora and fauna	Features and processes related to the characteristics of terrestrial and freshwater flora and fauna, and their evolution. Includes plants, animals, fungi, algae and microbes. Plants usually have a higher resistance against CO₂ than mammals, but persistent leaks could suppress respiration in the root zone. Tree kills associated with soil gas concentrations in the range of 20-30% have been observed at Mammoth Mountain, California, where volcanic out gassing of CO₂ (0.13 0.44 Mt/yr) has been occurring since at least 1990. The leakage rate (flux) varies between 25 and 7000 g CO₂/day/m². (Damen 2006). 1. Natural flora and fauna 2. Agricultural flora and fauna	Flora and fauna may be affected by concentrations of CO ₂ in the near-surface environment and may be indicators of CO ₂ leakage.	Vegetation is limited to mesquite grasslands and local crop lands such as cotton. There are several rare, endangered or threatened species in Scurry county, but no protected habitats in the Northern Platform site.		CO ₂ /H ₂ S migration into terrestrial areas containing flora and fauna.	Leakage of CO ₂ /H ₂ S through caprock and secondary seals to surface environment	Endangerment of flora, fauna in areas without sufficient ventilation.	Conduct baseline survey of flora, fauna and CO ₂ in the project area before CO ₂ injection. Monitor changes in flora, fauna and CO ₂ . Monitor potential leakage pathways (wellbores, faults) and receptors (aquifers).	Include flora and fauna in site characterization. Avoid sites with habitats for endangered or protected species.	Conduct baseline survey of flora, fauna and CO₂ in the project area before CO₂ injection. Monitor changes in flora, fauna and CO₂ content. Determine root cause for any changes. Locate, isolate and fix leak.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
224	06.01.06.00.	Near-surface aquifers and surface water bodies	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 per acre to remediate contaminated wetlands and surface waters	Covered under natural resource damage	None	1-15 days @ \$20,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5years: Up to \$6M for water remediation	Assuming leakage detected early and mitigated: <\$1M for water remediation	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Savings: Up to \$2M	1
225	06.01.07.00.	Terrestrial flora and fauna	2	1	2	4	None	None	None	Accumulatio n of CO2 in poorly ventilated low areas resulting in flora and fauna kill <\$100k	Included under natural resources.	None	1-15 days @ \$20,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$100k per event	None	Monitor for CO2/H2S near surface. Monitor pressure in formations above caprock and secondary seals: <\$200k Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	Savings: None to \$3M loss.	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
226	06.01.08.00.	Terrestrial ecological systems (See 06.01.07.00)	Features and processes related to interactions between terrestrial and freshwater populations of animals, plants, algae, fungi, microbes and their evolution. Characteristics of the ecological system include the vegetation regime, and natural cycles such as forest fires or flash floods that influence the development of the ecology. The plant, animal, algal, fungal and microbial populations occupying the surface environment are an intrinsic component of its ecology. Their behavior and population dynamics are regulated by the wide range of processes that define the ecological system. Human activities have significantly altered the natural ecology of most environments.	The ecology of the terrestrial near-surface environment determines the types of organisms present and their inter-dependencies. These can influence the types of impact of interest and can provide a mechanism for monitoring CO2 leakage.	This is a low value ecological system.		Migration of CO2/H2S and/or brine into the terrestrial ecological system.	Leakage of CO2/H2S through caprock and secondary seals to surface environment	Disruption of the terrestrial ecological system.	Conduct baseline survey of CO2 and salinity measurements in sensitive areas before injecting CO2. Monitor and model CO2 plume and brine movement. Monitor CO2 and salinity in sensitive areas. Monitor potential leakage pathways (wellbores, faults) and receptors (aquifers).	Take into account the ecological system in site characterization.	Conduct baseline survey before injecting CO2. Monitor surface CO2/H2S. Locate, isolate and fix leak.
227	06.02.00.00.	Aquatic environment	This class of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible aquatic environment (seas, lakes, rivers).	The near-surface environment is where most potential impacts would be incurred. The FEPs in this class are relevant if that environment is aquatic.								
228	06.02.01.00.	Coastal features	Features and processes related to the characteristics of coasts and the near shore, and their evolution. Coastal features include headlands, bays, beaches, spits, cliffs and estuaries.	The processes operating on these features, e.g. active erosion, deposition, longshore transport, may affect mechanisms for the migration of CO2, and associated contaminants, entering the surface environment.	Not applicable to this site		Migration of CO2 and/or brine into a coastal environment.	Leakage of CO2 through caprock to surface environment	Contamination of waters and endangerment of marine life.	Conduct baseline survey of coastal features, CO2, salinity and phi Monitor for changes. Monitor CO2 plume migration.	Take into account coastal features in site characterization. Avoid sensitive areas or habitats for endangered or protected species.	Conduct baseline survey of coastal features, CO2, salinity and phi Monitor for changes. Determine root cause of changes. Monitor CO2 plume migration. Adjust CO2 injection strategy if necessary.
229	06.02.02.00.	Local oceanography	Features and processes related to the characteristics of seas and oceans and their evolution. This includes the topography and morphology of the seabed; thermal stratification and salinity gradients; and marine currents.	The local oceanographic features and processes determine the potential for dilution or accumulation of CO2, and associated contaminants in the marine environment.	Not applicable to this site		Migration of CO2 into the ocean.	Leakage of CO2 through caprock to surface environment	Disruption of the seabed, CO2 accumulation, formation of gas hydrates..	Conduct baseline survey of local oceanographic conditions prior to injecting CO2. Monitor CO2 plume.	Include local oceanography in site characterization if applicable. Avoid sensitive areas or habitats for endangered or protected species.	Conduct baseline survey of local oceanographic conditions prior to injecting CO2. Monitor CO2 plume. Adjust CO2 injection strategy if necessary.
230	06.02.03.00.	Aquatic sediments	Features and processes associated with sediments in the aquatic environment. This includes both the physical and chemical characteristics of the sediments, along with sedimentation and resuspension processes.	Aquatic bed sediment characteristics will influence the ecology of the aquatic environment. They will also determine relevant processes to consider should CO2 and/or associated contaminants migrate to the aquatic environment.	Not applicable to this site		Migration of CO2 and/or brine into the aquatic environment.	Leakage of CO2 through caprock to surface environment	Disruption of aquatic sediments and related ecology.	Conduct baseline survey of local aquatic sediment conditions prior to injecting CO2. Monitor surface water for CO2/salinity/phi Monitor CO2 plume.	Take into account aquatic sediments in site characterization, if applicable. Avoid sensitive areas or habitats for endangered or protected species.	Conduct baseline survey of aquatic sediments, CO2, salinity and phi Monitor for changes. Determine root cause of changes. Adjust CO2 injection strategy if necessary.

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
226	06.01.08.00.	Terrestrial ecological systems (See 06.01.07.00)	2	1	2	4	None	None	None	Accumulatio n of CO2 in poorly ventilated low areas resulting in flora and fauna kill <\$100k	Included under natural resources.	None	1-15 days @ \$20,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$2M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$100k per event	None	Monitor for CO2/H2S near surface. Monitor pressure in formations above caprock and secondary seals: <\$200k Cost to locate and fix leak, \$0.3M for leaky well. \$2M for leaky fault, fracture zone or high permeability pathway.	Savings: None to \$3M loss.	1
227	06.02.00.00.	Aquatic environment	0	0	0	0															
228	06.02.01.00.	Coastal features	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
229	06.02.02.00.	Local oceanography	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
230	06.02.03.00.	Aquatic sediments	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

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231	06.02.04.00.	Aquatic flora and fauna	Features and processes related to the characteristics of aquatic flora and fauna, and their evolution. Includes plants, animals, fungi, algae and microbes.	Flora and fauna may be affected by concentrations of CO2 in the aquatic environment and may be indicators of CO2 leakage.	Not applicable to this site		CO2 migration into aquatic areas containing flora and fauna.	Leakage of CO2 through caprock to surface environment	Endangerment of aquatic flora and fauna.	Conduct baseline survey of aquatic flora, fauna and CO2/salinity/pH in the project area before CO2 injection. Monitor changes in flora, fauna and CO2/salinity/phi	Include aquatic flora and fauna in site characterization. Avoid sites with habitats for endangered or protected species.	Conduct baseline survey of aquatic flora, fauna and CO2/salinity/pH in the project area before CO2 injection. Monitor changes in aquatic flora, fauna and CO2/salinity/phi Determine root cause for any changes. Adjust CO2 injection strategy if necessary.
232	06.02.05.00.	Aquatic ecological systems	Features and processes related to interactions between populations of algae, animals, microbes and their evolution. Characteristics of the ecological system. The algal, animal and microbial populations occupying the aquatic environment are an intrinsic component of its ecology. Their behavior and population dynamics are regulated by the wide range of processes that define the ecological system.	The ecology of the aquatic environment determines the types of organisms present and their inter-dependencies. These can influence the types of impact of interest and can provide a mechanism for monitoring CO2 leakage.	Not applicable to this site		Migration of CO2 into an aquatic ecological system.	Leakage of CO2 through caprock to surface environment	Disruption of the aquatic ecological system.	Conduct baseline survey of aquatic ecological system for CO2/salinity/pH in the project area before CO2 injection. Monitor changes in CO2/salinity/pH.	Take into account the aquatic ecological system in site characterization. Avoid sites with sensitive areas or habitats for endangered or protected species.	Conduct baseline survey of aquatic ecological system for CO2/salinity/pH in the project area before CO2 injection. Monitor changes in CO2/salinity/phi Determine root cause for any changes. Adjust CO2 injection strategy if necessary.
233	06.03.00.00.	Human behavior	Details of the human behavior in the near-surface environment where impacts may be incurred.	Human behavior will affect the nature and magnitude of potential impacts to human beings.								
234	06.03.01.00.	Human characteristics	Features and processes related to characteristics, e.g. physiology, metabolism, of individual humans. This includes considerations of variability, in individual humans, of physiology and metabolism due to age and other variations. Physiology refers to body and organ form and function. Metabolism refers to the chemical and biochemical reactions which occur within an organism, or part of an organism, in connection with the production and use of energy. Children and infants, although similar to adults, often have characteristic differences, e.g. metabolism and respiratory rates, which may lead to different characteristics of exposure to CO2 or contaminants.	Human physiology and metabolism determine the effect of exposure to CO2 and associated contaminants.	The Northern Platform area has very low population density. There are no known sensitive receptors such as school, hospitals, prisons, care centers, or churches in the area.		Migration of CO2 into sensitive receptor areas (schools, hospitals, prisons, care centers).	Locating CO2 injection site near sensitive receptors. Leakage of CO2 through caprock to surface environment.	Endangerment of humans with greater vulnerability in areas of insufficient ventilation.	Conduct baseline survey of CO2 measurements in sensitive areas before injecting CO2. Monitor and model CO2 plume. Monitor CO2 concentration in sensitive areas.	Take into account sensitive receptor areas in site characterization. Avoid sensitive receptor areas in site selection.	Monitor surface CO2 concentration in/near sensitive receptor areas and install alarms if necessary. Maintain an emergency response plan. Train operators, and first responders and educate residents what to do in case of a CO2 leak.
235	06.03.02.00.	Diet and food processing	Features related to intake of food and water by individual humans and the compositions and origin of intake. This includes considerations of how diets, of individual humans, may vary with age and other variations (ingestion of soil by infants, for example). This FEP also includes processes related to the treatment of foodstuffs and water between origin and consumption. For example, once a crop is harvested it may be subject to a variety of storage, processing and preoperational activities prior to human or livestock consumption. Water sources may be treated prior to human or livestock consumption, e.g. chemical treatment and/or filtration.	The human diet provides a potentially important exposure pathway to contaminants released into the food chain as a result of the CO2 sequestration system. Food preparation processes may change the distribution and content of CO2 and/or associated contaminants in the product.	Crop land in the site area is limited and is primarily cotton, sorghum, wheat and other fodder crops.		Migration of CO2/brine containing heavy metals into agricultural areas and into the food processing chain.	Locating CO2 injection sites near agricultural land. Leakage of CO2 through caprock to surface environment	Contamination of food chain with heavy metals.	Characterize soils, water and crops in the site area. Conduct baseline survey for potential contaminants prior to CO2 injection. Monitor for changes in crops, agricultural products or soil and water chemistries.	Characterize soils, water and agricultural in the site area. Conduct baseline survey for potential contaminants prior to CO2 injection. Avoid sensitive groundwater areas and areas with high content of heavy metals that could be leached out by acidic water.	Monitor soils, water and agricultural products for contaminants. Maintain a contingency plan in case of contamination.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
231	06.02.04.00.	Aquatic flora and fauna	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
232	06.02.05.00.	Aquatic ecological systems	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
233	06.03.00.00.	Human behavior	0	0	0	0																
234	06.03.01.00.	Human characteristics	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
235	06.03.02.00.	Diet and food processing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
236	06.03.03.00.	Lifestyles	Features related to non-diet related behavior of individual humans, including time spent in various environments, pursuit of activities and uses of materials. This includes consideration of variability of the habits of individuals due to age and other factors. The human habits refer to the time spent in different environments in pursuit of different activities and other uses of materials. The diet and habits will be influenced by agricultural practices and human factors such as culture, religion, economics and technology.	Human habits will determine the exposure pathways of interest in an assessment. Camping, plowing, fishing, and swimming are examples of behavior that might give rise to extended close proximity exposure to CO2 and/or contaminants mobilized in an area of CO2 sequestration.	There is some limited farming activity in the Northern Platform area, but no recreational camping, fishing, or swimming activities likely.		Migration of CO2 into areas frequented by humans.	Locating CO2 injection sites near populated areas. Leakage of CO2 through caprock to surface environment	Endangerment of humans with in areas of insufficient ventilation.	Conduct baseline survey of CO2, salinity and pH measurements in sensitive areas before injecting CO2. Monitor and model CO2 plume and brine movement. Monitor CO2, salinity and pH in sensitive areas.	Take into account land use by humans in site characterization. Avoid popular recreational areas.	Monitor soils, water and agricultural products for contaminants. Maintain a contingency plan in case of contamination.
237	06.03.04.00.	Land and water use	FEPs related to land and water use by humans in the near-surface environment and the resulting implications for CO2 leakage and contaminant transport and exposure pathways. This includes consideration of: - the use of natural or semi-natural tracts of land and water such as forest, brush, rivers, lakes and the sea; - rural and agricultural land and water use (including freshwater and marine fisheries); - urban and industrial land and water use related to developments, including transport, and their effects on hydrology; and - leisure and other uses of environment.	These FEPs can influence the potential transport and exposure pathways for CO2 and its associated contaminants as well as the potential evolution of the system during the timescales of interest. Particular considerations are relevant for each type of land use addressed, for example: - special foodstuffs and resources may be gathered from natural land and water which may lead to significant modes of exposure to CO2 or contaminants; - an important set of processes are those related to agricultural practices, their effects on land form, hydrology and natural ecology, and also their impact in determining contaminant uptake through food chains and other exposure paths; - human populations are concentrated in urban areas in modern societies. Significant areas of land may be devoted to industrial activities. Water resources may be diverted over considerable distances to serve urban and/or industrial requirements; - significant areas of land, water, and coastal areas may be devoted to leisure activities. e.g. water bodies for recreational uses, mountains/wilderness areas for hiking and camping activities.	The Northern Platform area has been used for oil production for over 64 years. There is very little surface water. A minor amount of land is used for farming. Most of the water for city use (Snyder, TX) comes from reservoirs outside of the SACROC area. Injection water for WAG and water curtain control is mostly recycled produced water with some make-up water from outside the SACROC area.		Migration of CO2 into areas of heavy land use.	Locating CO2 injection sites near land and water used by humans.	Endangerment of humans within areas of insufficient ventilation.	Conduct baseline survey on land use and future planning. Monitor changes in zoning and land use.	Take into account current and future land use in site characterization. Avoid sites that are densely populated, sensitive receptor areas or subject to future urban sprawl or industrialization.	Monitor CO2, salinity and pH in sensitive areas. Install CO2, VOCS, CH4, H2S alarms and signs if necessary. Maintain a contingency plan. Train operators and first responders, and educate residents what to do in case of a CO2 leak.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
236	06.03.03.00.	Lifestyles	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
237	06.03.04.00.	Land and water use	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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238	06.03.05.00.	Community characteristics	Features related to characteristics, behavior and lifestyle of groups of humans that might be considered as target groups in an assessment. Relevant characteristics might be the size of a group and degree of self-sufficiency in food stuffs/diet. Associated with this is a consideration of the amount of resources required to meet the needs of the community.	This FEP involves a consideration of aggregated human behavior in order to consider their dependency on and interactions with their environment. It therefore provides input to a consideration of potential human interference with the CO2 storage system as well as input to considering potential exposure pathways.	There are no communities within the Northern Platform area.		Migration of CO2 into densely populated areas.	Locating CO2 injection site near densely populated areas. Leakage of CO2 through caprock to surface environment	Endangerment of humans in areas of insufficient ventilation.	Conduct baseline survey of CO2, salinity and pH measurements in sensitive areas before injecting CO2. Monitor and model CO2 plume and brine movement. Monitor CO2, salinity and pH in sensitive areas.	Take into account human population density and behavior in site characterization. Avoid areas of high population density.	Monitor CO2, salinity and pH in sensitive areas. Install CO2, VOCS, CH4, H2S alarms and signs if necessary. Maintain a contingency plan. Train operators and first responders, and educate residents what to do in case of a CO2 leak.
239	06.03.06.00.	Buildings	Features related to houses, or other structures or shelters, in which humans spend time. 1. Basements/cellars 2. Subterranean pathways	The structure or materials used in building construction be significant factors for determining potential exposure pathways to CO2 or contaminants. For example, given that CO2 is denser than air, it may accumulate in the basements/cellars of dwellings.	There are an estimated 28 residences within the Northern Platform area. In addition, there appear to be several small industrial structures such as warehouses, workshops or barns. Most buildings in the region do not have basements. Most of these are in the Southern half of the Northern Platform area.	How many buildings have basements or subterranean utility inlets (if any)?	Human injury/death due to migration of CO2/H2S into unventilated confined spaces occupied by humans.	Presence of buildings near EOR site. Leakage of CO2/H2S through caprock and secondary seals to surface environment.	Endangerment of humans in areas of insufficient ventilation.	Monitor CO2/H2S in inhabited confined spaces.	Take into account buildings in site characterization. Ventilate confined areas. Avoid densely populated areas.	Monitor CO2/H2S in sensitive confined areas. Install CO2, H2S alarms and signs if necessary. Maintain a contingency plan. Train operators and first responders, and educate residents what to do in case of a CO2/H2S leak.
240	07.00.00.00.	IMPACTS	This category of FEPs is concerned with any endpoint that could be of interest in an assessment of performance and safety. The classes of impact considered are: Impacts to Humans; Impacts to Flora and Fauna; and Impacts to the Physical Environment. Note that: - financial impacts are assumed to be implicitly considered within each of the impact FEPs; and - unless stated, the FEPs refer to both CO2 and mobilized contaminants (minerals, heavy metals, hydrocarbons (e.g., EOR and ECBM), gases).	This category is divided into four classes: 1. System performance 2. Impacts on the physical environment 3. Impacts on flora and fauna 4. Impacts on humans								
241	07.01.00.00.	System performance	Performance of the sequestration system from the perspective of its success at preventing sequestered CO2 from reaching the atmosphere.	The fate of sequestered CO2 is a fundamental endpoint for an assessment.								

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							Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury												
238	06.03.05.00.	Community characteristics	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
239	06.03.06.00.	Buildings	2	4	1	8	1 @ \$1.5M per fatality	Accumulation of CO2 in unventilated confined areas 1 @ \$1.5M per serious (irrecoverable) injury	Accumulation of CO2 in unventilated confined areas 1-2 @ \$0.05M per minor (recoverable) injury	None	None	None	1-15 days @ \$20,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Damage involving a fatality or multiple injuries: <\$5M	Assuming CO2/H2S detected early with alarm or smell: \$<200k	Monitor confined spaces for CO2/H2S. Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	Savings \$1.8 to \$4.5M.	1
240	07.00.00.00.	IMPACTS	0	0	0	0															
241	07.01.00.00.	System performance	0	0	0	0															

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242	07.01.01.00.	Loss of containment	Loss of sequestered CO2 from the intended storage reservoir. Loss includes both consideration of loss to other parts of the geosphere and to the near-surface and surface environments, such as loss to marine water and surface water bodies, where CO2 may result in stratification or pooling.	Loss of containment may be an endpoint of interest to the assessment. For example, the assessment context may dictate that near-surface or surface processes are outside the scope of the assessment.	The most likely potential for loss of CO2 containment would be through a wellbore leak or blowout or a pipeline leak or rupture. There are no faults penetrating the primary seal and there are enough secondary seals and sinks to prevent significant release of CO2 into an USDW or into the air.		Migration of CO2 into overlying formations, soil, aquifers and/or atmosphere.	Loss of containment.	Endangerment of humans and/or animals in low areas or confined areas with insufficient ventilation.	Monitor and model CO2 plume. Monitor overlying layers and/or near surface for CO2.	Ensure integrity of the caprock and lateral seals.	Monitor pressure in formations above the caprock. Monitor surface CO2/H2S near wells. Select sites with multiple stacked seals and sinks.
243	07.02.00.00.	Impacts on the physical environment	FEPs relevant to adverse impacts on the physical environment. Note that these may be endpoints of interest in themselves, but may also cause other impacts of interest.	Adverse impacts on the environment can be postulated as a result of sequestration operations, even if there are no associated impacts to humans or on flora and fauna.								
244	07.02.01.00.	Contamination of groundwater (and/or surface water)	The existence of water aquifers may be important if they are subject to CO2-induced chemical changes or CO2-induced saline intrusion. The migration of CO2 into an aquifer will result in the acidification of the water. Depending on the mineralogical composition of the aquifer and the chemical composition of the water, chemical reactions may occur which release heavy metals from the solid phase. The mechanisms which may cause this release include dissolution of metal oxides or oxyhydroxides, the reaction/diagenesis of clay minerals, and the desorption of metals that are adsorbed on clay surfaces or organic complexes. 1. CO2 contamination of underground drinking water sources 2. CO2 contamination of surface waters 3. Displaced brine contamination of groundwater. 4. EOR oil spill (see 16.22.00)	Contamination of groundwater resources may result in impacts on flora, fauna and/or humans if the water is abstracted or flows to the surface environment. These potential impacts are considered in the subsequent FEP classes, however, contamination of groundwater may be an endpoint of interest in itself. An increase in CO2 concentration might cause a decrease in pH to a level of 4-5, which might cause calcium dissolution, increase in the hardness of water and alteration of minerals from minerals from rocks and soils that could release elements such as heavy metals into the water supply. Foundations of buildings could be damaged by seepage of groundwater containing CO2 in shallow unconsolidated sediments and soils. This could be a problems if CO2 were to be stored (and leak) underneath, for example, historical city centers, other heritage objects, or archeological sites (CO2STORE) Surface water could be contaminated by CO2 leakage, which could affect aquatic ecosystems by decreasing pH, especially in stagnant or stratified waters (Damen 2006) Displaced brine may cause undesirable effects such as a rise of the water table (which could have negative impact on land quality and use) and an increase in salinity of sweet water reservoirs used for drinking water extraction and irrigation (Damen	There are no significant surface waters to contaminate. There are over 5,000 ft of multiple stacked seals and sinks that would minimize CO2 leakage into an USDW. Up to the mid-1970s, produced brine was disposed in unlined brine evaporation pits. This may have resulted in some brine seeping into the Ogallala or Dockum aquifers (Smyth 2012). With the absence of surface waters, any oil spills are likely to be localized.	Need to confirm the quality and quantity of USDW ground water in the SACROC Northern Platform area.	Increase of CO2, H2S, hydrocarbon, salinity, and/or heavy metal content, and decrease in pH of groundwater or surface water.	Contamination of groundwater (and/or surface water).	Endangerment of flora and fauna. Cost of water treatment to remove contaminants. Monitor for EOR oil spills.	Include near-surface aquifers and surface waters in site characterization. Avoid sites with sensitive groundwater areas. Maintain integrity of caprock and lateral seals.	Monitor near surface aquifers for changes in CO2/salinity/pH. Determine root cause for any changes. Use tracers if necessary. Locate, isolate and fix leak. Locate isolate and remediate contaminated water.	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
242	07.01.01.00.	Loss of containment	4	3	3	36	None	None	2 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	None	1-15 days @ \$20,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Damage assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	Assuming early detection and mitigation:<\$1 M with no fatalities or injuries.	Monitor surface CO2/H2S. Monitor pressures in formations above caprock: <\$300k. Locate, isolate and fix well leak.<\$300k. Locate, isolate and fix leaky fault, fracture zone or high permeability pathway: \$3M	Up to \$2M per leakage event detected and remediated early.	
243	07.02.00.00.	Impacts on the physical environment	0	0	0	0															
244	07.02.01.00.	Contamination of groundwater (and/or surface water)	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 per acre to remediate contaminat ed wetlands and surface waters	Covered under natural resource damage	None	1-15 days @ \$20,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: \$6M for water remediation	Assuming leakage detected early and mitigated: <\$1M for water remediation	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Savings : Up to \$2M	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
245	07.02.02.00.	Impacts on soils and sediments	Soils and sediments may have elevated concentrations of CO2, should it leak from the storage system, and/or other contaminants, such as heavy metals, hydrocarbons (e.g., EOR and ECBM) or even increased salinity resulting from CO2 sequestration. For example, natural CO2 leaking from a trapped reservoir near Mammoth Mountain, in California, has resulted in soil gas concentrations of 20 to 90%. 1. Contamination of soil 2. Contamination of sediments	Increased CO2 concentrations and/or contamination of soils and sediments with associated substances may be sufficient to modify the ecology and/or use of the impacted area by humans.	CO2 contamination of soil would likely be tied to wellbore leakage or pipeline leak. Impact on soil would be localized. Sediments limited to Ennis Creek.		CO2 / H2S / hydrocarbon / brine / heavy metal contamination of soils and sediments. EOR oil spill.	Leakage of CO2 through caprock to surface environment. EOR oil spill. Spill of industrial fluids or materials at drill or injection site.	Land use restrictions. Cost of soil/sediment cleanup	Monitor soils and sediments for CO2, H2S, hydrocarbon, salinity, pH and heavy metals. Monitor for EOR oil spills.	Take into account soils and sediments in site characterization. Select site with high integrity caprock.	Conduct baseline study for CO2, CH4 and H2S in soils and sediments. Periodically monitor near surface for CO2 and/or H2S. Identify any irregularities. Determine root cause. Locate and plug leaks.
246	07.02.03.00.	CO2 release to the atmosphere	Release of CO2 (or other contaminants, such as radon or methane, mobilized as a result of the sequestration) to the atmosphere from the storage system .	Release of sequestered CO2 or mobilized methane to the atmosphere will reduce the effectiveness of the storage system at preventing greenhouse gases from being emitted to the atmosphere. Atmospheric contamination could also lead to health impacts on humans and wildlife. Rapid release likely to effectively disperse the CO2 higher in the atmosphere. Moderate release likely to concentrated CO2 near the ground, representing the highest risk. Slow release likely to disperse CO2 in the soil and atmosphere.	Release of CO2/H2S into the atmosphere would likely be tied to wellbore leakage. The presence of H2S would be a factor in wellbore leakage/blowout or in any equipment failure involving recycled gas. CO2-EOR operations released 0.3% of total CO2 handled in 2008. Key causes were: routine maintenance and power outages caused by storms. (Bradley 2009a) CO2 pipeline operations released 0.000035% of CO2 transported in 2008. (Bradley 2009a) CO2 supply operations released 0.004% of CO2 produced in 2008. Key cause was routine maintenance. (Bradley 2009a)		Accumulation of CO2/H2S in low surface areas with insufficient wind. Human injury/death.	Release of CO2/H2S to the atmosphere	Endangerment of humans at high CO2/H2S levels.	Monitor CO2 and/or H2S content near surface with alarm system.	Characterize and model the site for CH4, H2S and any other gases that may accompany a CO2 release. Operate, maintain and seal wells properly. Avoid over pressuring the reservoir. Maintain the integrity of the caprock and lateral seal. Maintain blowout protector, packers and valves in operating condition.	Monitor for H2S near wells and CO2 recycling facilities. Install alarms and signs in low surface areas and high risk areas. Monitor for CO2/H2S and ventilate confined spaces. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/H2S leak.
247	07.02.04.00.	Impacts on exploitation of natural resources	The impact of CO2 sequestration on the exploitation of natural resources such as oil and gas. Enhanced oil recovery (EOR) and enhanced coal bed methane (ECBM) recovery projects involving the injection of CO2 are based on improved recovery of oil and methane respectively resulting from CO2 sequestration. However, CO2 sequestration may result in the contamination of geological resources (such as hydrocarbons and minerals) or inhibit their recovery or future exploitation. Note that the potential impact on groundwater resources is considered in Impacts on groundwater. 1. Contamination of mineral resources 2. Contamination of mineable coal seams 3. Contamination of oil resources 4. Contamination of natural gas resources 5. Contamination of geothermal resources 6. Contamination of pore space owned by others.	Impacts on the exploitation of natural resources can be positive (such as EOR and ECBM) and/or negative (such as inhibited recovery). These may result in other (for example, financial) impacts, or may be endpoints of interest in themselves.	Potential natural resources in the area that could be impacted by the presence of CO2 are limited to residual oil (below the oil-water contact) and shale gas in the Wolfcamp shale. Presence of CO2 will not hinder residual oil recovery. No geothermal resources in the area. No significant mineral or coal resources in the area. North Platform reservoir is isolated from third-party pore space.	Presence of shale gas in the Wolfcamp shale?	Presence of CO2 hindering recovery of shale gas	Presence of shale gas in Wolfcamp shale formation.	Preventing or limiting recovery of shale gas from the Wolfcamp formation.	Determine existence of shale gas in Wolfcamp formation. Determine if fracking can be used to recover shale gas in Wolfcamp formation while maintaining integrity of the caprock. Monitor CO2/H2S in produced gas and near surface.	Avoid exploiting the Wolfcamp shale.	Monitor fracking through passive seismic to identify location and size of fractures. Monitor CO2/H2S content in produced gas and near surface. Seal up fractures and plug well if CO2/H2S release confirms a loss of containment.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
245	07.02.02.00.	Impacts on soils and sediments	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
246	07.02.03.00.	CO2 release to the atmosphere	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	2 @ \$0.05 M per minor (recoverable) injury	None	None	Damage from blowout: \$0.5M.	1-5 days to stop and fix well	Well leakage: <\$1M Well blowout: <\$3M per event.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Well leakage: <\$1M Well blowout: <\$3M per event. Fatalities and/or injuries: \$3.1M	\$0	Monitor for H2S around injection wells and recycle facilities. Maintain tight seals and failsafe systems <\$300k	Savings: \$700k to \$2.5M Up to \$3.1 M for fatalities and/or injuries prevented.	1
247	07.02.04.00.	Impacts on exploitation of natural resources	2	1	2	4	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Potential decrease in monetized value of Wolfcamp shale gas. Damage \$0 because potential gas has no value.	None	None	None	None	None	None	None	Not drilling or fracturing for shale gas.	None	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
248	07.02.05.00.	Modified hydrology and hydrogeology	The injection of CO2 may result in modifications to both the deep hydrogeology and near-surface hydrology.	Changes in the deep hydrogeology or near-surface hydrology may affect aquifer abstraction or even surface hydrology for groundwater driven features. These impacts may be either positive or negative.	The Northern Platform reservoir is sealed on the top, east, north, west and bottom by less permeable formations. The reservoir is further protected by 5000 ft of multiple seals and sinks.		Damage to near surface aquifers.	Modified hydrology and hydrogeology as result of CO2 injection, migration, or leakage.	Contamination of water with CO2 and/or brine.	Conduct baseline survey of groundwater level and quality prior to CO2 injection. Monitor changes in CO2, salinity, phi Monitor water level in wells. Monitor CO2 plume and brine migration.	Take into account hydrology and hydrogeology in site characterization and modeling.	Monitor pressure in formations above the caprock and secondary seals. Monitor water level in wells. Identify irregularities. Determine root cause.
249	07.02.06.00.	Modified geochemistry	The injection of CO2 will modify the geochemistry of the sequestration system. This may be confined to the immediate vicinity of the storage location, or, through leakage from the reservoir, may affect other locations.	The extent of geochemical modifications may be an endpoint of interest, due to resulting changes to geological processes. For example, the acidification of the geochemical regime may cause minerals to be dissolved, with potential implications for the porosity and stability of the geological formations.	Modifications of the geochemistry of the sequestration system due to CO2 injection have been limited. The carbonate reservoir acts as a buffer on fluid pH. Studies indicate dolomite is dissolving and calcite is precipitating (Smyth 2012).	Need historical data on produced water chemistry.	1. Dissolution of minerals. 2. Precipitation of minerals.	Modified geochemistry due to CO2	1. Weakening of formation mechanical properties leading to fracture and/or subsidence. 2. Decreased injectivity .	Characterization and modeling of caprock and reservoir geochemical properties based on drill core analyses.	Take into account geochemistry in site characterization, modeling and reservoir engineering.	Monitor and model injectivity and production pressure. Use selective perforation and water curtains to deal with nonuniform CO2 flow. Use acid treatment to remove carbonate mineral precipitation.
250	07.02.07.00. (See 03.02.06.00)	Modified seismicity	Injection of supercritical CO2 into a geological formation may induce seismic events and processes.	Induced seismicity may be an endpoint of interest in itself, or it can result in other impacts, such as physical disruption of the surface environment.	Seismic records do not show any earthquakes that could be tied to injection of CO2 in the Northern Platform. The earthquakes that have occurred were outside the areas that would be impacted by pressure waves from CO2 injection. Modified seismicity is limited in CO2-EOR because fluids are simultaneously injected and produced.	Data not available on earthquakes less than magnitude of 2.5.	Induced earthquake >4 magnitude.	Modified seismicity due to injection of CO2.	Building and/or infrastructure damage. Liability costs.	Monitor passive seismic and surface displacement (LIDAR). Monitor injection pressure.	Determine fracture pressure. Operate below 90% of fracture pressure. Maintain reservoir fluid volume close to original volume.	Operate below 90% of fracture pressure. Monitor injection pressure and passive micro-seismicity.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
248	07.02.05.00.	Modified hydrology and hydrogeology	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
249	07.02.06.00.	Modified geochemistry	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
250	07.02.07.00. (See 03.02.06.00)	Modified seismicity	2	2	1	4	PGA(g) 0.092-0.18 = 1/1000,000 fatality rate. PGA(g) 0.18-0.34 = 1/100,000 fatality rate. PGA(g) 0.34-0.65 = 1/10,000 fatality rate. PGA(g) 0.65-1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate.	PGA(g) 0.092-0.18 = 1/250,000 injury rate. PGA(g) 0.18-0.34 = 1/25,000 injury rate. PGA(g) 0.34-0.65 = 1/2,500 injury rate. PGA(g) 0.65-1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate.	PGA(g) 0.092-0.18 = 3/100,000 injury rate. PGA(g) 0.18-0.34 = 3/10,000 injury rate. PGA(g) 0.34-0.65 = 3/1,000 injury rate. PGA(g) 0.65-1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate.	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Potential class action lawsuit for property damage, loss of property value, reimbursement for earthquake insurance and emotional distress.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	Shutdown of project through court ordered injunctive relief likely if multiple events of PGA(g)>0.1 (>4 magnitude earthquake)	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$1M for legal and public outreach costs to avoid shutdown.	None	Cost to maintain CO2 injection pressure below 90% of fracture pressure and maintain reservoir fluid volume close to original fluid volume: Part of ongoing costs.	None	1	

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251	07.02.08.00.	Modified surface topography	The gradual or sudden sinking (subsidence) or elevation (uplift) of the topography of the terrestrial surface or marine sea-bed.	Deformation of the terrestrial surface or sea-bed may be an endpoint of interest in itself, or may result in other impacts, such as damage to property.	The depth of the CO2-EOR operation is 1951 to 2103 m (6400 to 6900ft). The net change in fluid volume has been minimal. Modified surface topography is unlikely with CO2-EOR because fluids are simultaneously injected and produced..		Building and/or infrastructure damage. Change in drainage/water flow impacting agricultural land.	Subsidence or uplift.	Liability costs. Economic cost to project; damage to project structures and infrastructure.	Monitor passive micro-seismic and surface displacement (LiDAR). Monitor injection pressure. Monitor dissolution of minerals.	Take into account subsidence or uplift in site characterization and modeling. Avoid shallow injection sites or sites susceptible to significant dissolution of minerals or over pressuring.	Monitor continuous passive micro-seismic and surface displacement (LiDAR). Compare with model. Identify any irregularities and take corrective action if necessary. Extract brine to control pressure and provide more room for CO2 storage.
252	07.02.08.01.	Sinkhole formation	Addition of CO2 in a limestone or carbonate-rich aquifer could result in dissolution of the rock matrix and the enlargement of voids. If this process takes place at relatively shallow depth collapse may result in subsidence at the surface and sinkhole formation. For example, CO2 leakage around a borehole drilled to extract natural CO2 from a reservoir in Florina, Greece, resulted in subsidence around the borehole that filled up with water.	Large scale collapse structures may cause significant change to surface topography and possible CO2 migration paths. Sinkholes can provide locations where leaking CO2 can accumulate.	The depth of the CO2-EOR operation is 1951 to 2103 m (6400 to 6900ft). The net change in fluid volume has been minimal. Surface sinkhole because of the depth.		CO2 migration through sinkhole.	Sinkhole formation.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Building and/or infrastructure damage. Liability costs.	Monitor surface displacement (LiDAR). Monitor and model mineral dissolution.	Take into account limestone formations (susceptible to dissolution) in site characterization and modeling. Avoid shallow limestone formations that have the potential for sinkhole formation.	Monitor surface displacement (LiDAR). Compare with model. Identify any irregularities and cut back on CO2 injection if necessary.
253	07.03.00.00.	Impacts on flora and fauna	FEPs relevant to impacts on flora and fauna. 1. Natural flora and fauna 2. Agricultural flora and fauna	Impacts on flora and fauna can be postulated as a result of sequestration operations, even if there are no associated impacts to humans.								

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
251	07.02.08.00.	Modified surface topography	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
252	07.02.08.01.	Sinkhole formation	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
253	07.03.00.00.	Impacts on flora and fauna	0	0	0	0															

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
254	07.03.01.00.	Asphyxiation effects	Asphyxiation effects of CO2 on terrestrial and aquatic fauna. Oxygen is an essential requirement for respiration in animals and is therefore needed to sustain life. High concentrations of CO2 in air or water will lead to suffocation of terrestrial and aquatic animals due to a lack of oxygen reaching the blood stream. If meteorological conditions do not disperse CO2 released to the atmosphere, it can gather close to the surface and remain in depressions, such as natural hollows. This property allows CO2 to reach high concentrations if released in sufficient quantities under particular atmospheric conditions. The 1986 Lake Nyos disaster in Cameroon provides a graphic example of the potential effects of high atmospheric concentrations of CO2. A large limnic eruption resulted in the death of wildlife and approximately 1800 people in the surrounding area and up to 27 km away. In a similar way to gaseous CO2 being denser than air, water containing high concentrations of dissolved CO2 is denser than pure water, a factor that contributes to the limnic eruption phenomenon observed at Lake Nyos. In addition to the possibility of dissolved CO2 causing asphyxiation in aquatic organisms, if gaseous CO2 forms a layer at the surface of water bodies, it can prevent the oxygenation of the water and lead to a reduction of the O2 concentration thereby contributing to asphyxiation of aquatic organisms.	Levels of CO2 from a sequestration project sufficient to cause asphyxiation of fauna would be an endpoint of concern in assessing the geological sequestration of CO2.	On-site (recycled and subsurface) CO2 contains 1000 ppm H2S. At 30,000 ppm CO2 and 30 ppm H2S, both are equally toxic. At concentrations less than this, H2S acts as an odorant for CO2 similar to odorants in natural gas. This provides an additional warning system where leaks may occur. H2S monitors are installed around injection wells.		Endangerment of animals.	Asphyxiation effects of CO2 when accumulated in low areas or confined spaces.	Liability costs.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Monitor those areas for accumulation of CO2/H2S	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Install CO2/H2S monitors and alarms. Maintain blowout preventers, packers, valves, pipelines and equipment in proper operating condition. Maintain caprock integrity.	Monitor at risk areas for CO2/H2S. Install alarms if necessary or ventilate areas where CO2 may accumulate. Post warning signs. Train operators and first responders and educate local residents how to identify and deal with CO2/H2S leaks. Train operators to handle blowouts and pipeline ruptures.
255	07.03.02.00.	Effects of CO2 on plants, algae, fungi and microorganisms	Plants, algae, fungi and microorganisms (in both terrestrial and aquatic environments) use energy in sunlight to photosynthesize carbohydrates from CO2 and water (H2O). Increasing concentrations of CO2 around the photosynthetic tissues, increases the rate of photosynthesis and therefore growth and productivity in terrestrial and aquatic plants and algae. However, the roots of most plants need oxygen to breakdown carbohydrates to provide energy for root growth and healthy metabolism, a process called aerobic respiration. High concentrations of CO2 in the soil reduces the availability of O2 and can cause roots and therefore plants to die. At Mammoth Mountain, in California, CO2 has accounted for up to 95% of the gas concentration in soil at the edge of Horseshoe Lake due to release from natural geological CO2 reservoirs caused by volcanic activity. These high soil concentrations have resulted in areas of forest being killed.	Concentrations of CO2 in the soil, atmosphere and/or water sufficient to impact on the growth of plants and algae would be an endpoint of interest in assessing the geological sequestration of CO2.	Vegetation is limited to mesquite grasslands and local crop lands such as cotton. There are several rare, endangered or threatened species in Scurry county, but no protected habitats in the Northern Platform site.		Endangerment of plants, algae, fungi and microorganisms.	Effects of CO2 on plants, algae, fungi and microorganisms	Liability costs.	Conduct baseline survey of species in soil, sediments and water. Monitor CO2 levels in soils, sediments and water.	Characterize the species found in soils, sediments and water on site. Avoid sites with habitats for endangered or protected species.	Conduct a baseline survey in the project area before CO2 injection. Monitor plants, algae fungi and microorganisms for unexplained dead zones. Determine root cause. Check CO2 content in the area. Locate and plug leaks, if any.

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Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
254	07.03.01.00.	Asphyxiation effects	2	2	2	8	None	None	None	Animal kill:<\$0.5M	Animal kill:<\$0.5M	None	None	Cost to locate and fix leaky well: <\$0.3M Cost to fix pipeline rupture: <\$1M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$1M per event	None	Monitor for CO2/H2S near surface. Monitor pressure in formations above caprock and secondary seals: <\$200k	<\$0.8M	1
255	07.03.02.00.	Effects of CO2 on plants, algae, fungi and microorganisms	2	2	2	8	None	None	None	\$50,000/acre soil contaminatio n and/or vegetation kill (likely to be very localized)	Up to \$1,000/acre for crop kill. Up to \$5,000 per acre for timber kill (likely to be very localized)	None	1-15 days @ \$20,000/d revenue lost per pattern idled	Cost to locate and fix leaky well: <\$0.3M Cost to fix pipeline rupture: <\$1M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$1M per event	None	Monitor for CO2/H2S near surface. Monitor pressure in formations above caprock and secondary seals: <\$200k	<\$0.8M	1

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256	07.03.03.00.	Ecotoxicology of contaminants	Ecotoxicology deals with the toxic effects of contaminants on the biosphere. Contaminants other than CO2 may be introduced to the biosphere as a result of geological CO2 sequestration due to: - impurities associated with the sequestration fluid, such as hydrogen sulfide (H2S), methane (CH4), nitrogen oxides (NOx) and mercaptans; - the mobilization of substances in the geological environment due to the sequestration of CO2, such as hydrocarbons (e.g., EOR and ECBM), brine, CH4 and heavy metals. These substances may have a toxic effect on organisms in the biosphere, including plants, animals, algae and fungi. 1. H2S release impact on the biosphere 2. Methane release impact on the biosphere 3. Heavy metal release impact on the biosphere 4. Mercaptans release impact on the biosphere 5. NOx release impact on the biosphere	The potential for contaminants associated with and/or mobilized by CO2 sequestration to have a toxic effect on organisms should they migrate to the biosphere will be of interest in an assessment of the geological sequestration of CO2. Methane leakage may affect shallow water quality and pose a lethal threat when accumulating in confined spaces such as basements/cellars. The global warming potential of methane is circa 23 times that of CO2 (Damen 2006)	On-site (recycled and subsurface) CO2 contains 1000 ppm H2S. At 30,000 ppm CO2 and 30 ppm H2S, both are equally toxic. At concentrations less than this, H2S acts as an odorant for CO2 similar to odorants in natural gas. This provides an additional warning system where leaks may occur. H2S monitors are installed around injection wells.		Endangerment of plants, animals, algae or fungi due to contamination of near surface environment with H2S, hydrocarbons, mercaptans, brine, heavy metals, oil.	Ecotoxicity of contaminants.	Liability costs.	Conduct baseline survey of contaminants in soil, sediments, water prior to CO2 injection. Monitor and model CO2 plume and brine migration. Monitor for contaminants in near-surface soil, sediments and water.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Install CO2/H2S monitors and alarms. Maintain blowout preventers, packers, valves, seals, pipelines and equipment in proper operating condition. Maintain caprock integrity.	Monitor at risk areas for CO2/H2S. Install alarms if necessary or ventilate areas where CO2 may accumulate. Post warning signs. Train operators and first responders and educate local residents how to identify and deal with CO2/H2S leaks. Train operators to handle blowouts and pipeline ruptures.
257	07.03.04.00.	Ecological effects	Geological sequestration of CO2 may have an impact on the biosphere at a community, population and/or ecological level, with subsequent implications for biodiversity. The potential impact of releases of CO2 and associated or mobilized contaminants into the biosphere may disrupt biological interactions sufficiently to modify the terrestrial or aquatic ecosystems affected. For example, the sudden release of natural CO2 due to the limnic eruption at Lake Nyos, Cameroon, resulted in the sudden death of wildlife, but was unlikely to affect the ecology in the longer term. However, the continued gradual release of natural CO2 into soil near Mammoth Mountain, California, has been sufficient to kill trees and damage the local ecosystem since 1996 until the present day.	The degree of potential ecological disruption resulting from geological CO2 sequestration may be an endpoint of interest, especially if the ecosystem affected is considered valuable and/or sensitive to perturbations.	The local ecological system is not considered valuable and/or sensitive to perturbations. Historically, CO2 releases have been localized from boreholes, pipelines or equipment failures.		Endangerment of flora, fauna, humans.	Disruption of the ecological system by CO2, brine and other contaminant migration.	Liability costs.	Characterize the on-site ecological system. Conduct baseline survey for CO2 and associated contaminants in the near-surface prior to CO2 injection. Monitor and model CO2 plume and brine migration. Monitor for CO2 and other contaminants in the near-surface.	Take into account the ecological system in site characterization.	Conduct baseline survey before injecting CO2. Monitor surface CO2/H2S. Locate, isolate and fix leak.

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
256	07.03.03.00.	Ecotoxicology of contaminants	2	2	2	8	None	None	None	\$50,000/acre to remediate disturbance of ecological system.	\$50,000/acre to remediate disturbance of ecological system.	None	1-15 days@ \$20,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for a long period. Damage to ecological system: <\$500k per event.	Assuming leakage detected early and mitigated. Damage to ecological system: <\$100k per event.	Monitor surface CO2/H2S. Locate, isolate and fix leak.<\$300k	Savings: \$100k	1
257	07.03.04.00.	Ecological effects	2	2	2	8	None	None	None	\$50,000/acre to remediate disturbance of ecological system.	\$50,000/acre to remediate disturbance of ecological system.	None	1-15 days@ \$20,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for a long period. Damage to ecological system: <\$500k per event.	Assuming leakage detected early and mitigated. Damage to ecological system: <\$100k per event.	Monitor surface CO2/H2S. Locate, isolate and fix leak.<\$300k	Savings: \$100k	1

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Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
258	07.03.05.00.	Modification of microbiological systems	Microbes will be present in the geosphere as well as in the terrestrial and/or marine environments above the CO2 storage reservoir. CO2 sequestration may disrupt microbial aerobic respiration but may enhance anaerobic respiration, with subsequent implications for the processes in which the microbes are involved. Microbes play an important roll in all terrestrial and aquatic ecosystems, including those associated with extreme environments, such as deep sea hydrothermal vents.	The potential impact of CO2 sequestration on aerobic and anaerobic microbial respiration in the geosphere, terrestrial and aquatic biosphere may be an endpoint of interest.	No noticeable impact on microbes have been observed over the past 40 years of CO2 injection.	No data available on microbes in the SACROC area.	Disruption of microbiological systems in terrestrial or aquatic environments by CO2/brine migration. Introduction and growth of microbiological systems underground through injection of contaminated water.	Modification of microbiological systems.	Disruption of lower food chain. Plugging of pores and wellbores. Microbial generation of CH4 or H2S. Note that microbe activity can have a positive impact on oil recovery.	Conduct baseline survey of terrestrial, aquatic and sub-surface microbiological systems prior to CO2 injection. Monitor growth/decline of microbiological systems during CO2 injection. Monitor and model CO2 plume and brine migration. Monitor for CH4 and H2S generation.	Characterize site for terrestrial, aquatic and sub-surface microbiological systems. Properly treat water prior to injection underground. Use of biocides to avoid sub-surface microbial growth. Avoid injection of oxygen and organics with CO2.	Use chemical treatment if necessary to control microbial contamination/growth. Obtain proper approvals if chemicals are injected. Monitor H2S in CO2 and around injection wells and recycle facilities. Maintain tight seals and failsafe systems.
259	07.04.00.00.	Impacts on humans	FEPs relevant to adverse impacts on people.	A range of possible impacts to human beings can be postulated as a result of sequestration operations.								
260	07.04.01.00.	Health effects of CO2	Elevated atmospheric concentrations of CO2 can result in both acute and chronic health effects in humans. If meteorological conditions do not disperse CO2 released to the atmosphere, it can gather close to the surface and remain in depressions, such as the basement of buildings or at the surface of lakes. This property allows CO2 to reach high concentrations if released in sufficient quantities under particular atmospheric conditions. The primary health effect of concern is asphyxiation. High concentrations of CO2 in air will lead to suffocation of humans due to a lack of oxygen reaching the blood stream. Asphyxiation can occur once atmospheric concentrations reach approximately 10% CO2. Other health effects include those directly associated with elevated concentrations of CO2 in the blood stream, such as acidosis and physiological responses to the elevated blood CO2. The 1986 Lake Nyos disaster in Cameroon provides a graphic example of the potential effects of high atmospheric concentrations of CO2. A large limnic eruption resulted in the death of approximately 1800 people in the surrounding area and up to 27 km away. (Note that this event resulted from natural volcanic activity rather than CO2 storage). Asphyxiation requires high CO2 concentration in occupied (usually confined) space, plus either poor ventilation or high release rate. 1. Health effects of gaseous release of CO2 2 Health effects of liquid/supercritical release of CO2	The potential for CO2 to be released to the atmosphere in sufficient quantities to cause health effects in humans will be an endpoint of interest in assessing the geological sequestration of CO2. CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).	On-site (recycled and subsurface) CO2 contains 1000 ppm H2S. At 30,000 ppm CO2 and 30 ppm H2S, both are equally toxic. At concentrations less than this, H2S acts as an odorant for CO2 similar to odorants in natural gas. This provides an additional warning system where leaks may occur. H2S monitors are installed around injection wells.		Human injury/death due to accumulation of CO2 in unventilated low lying or confined areas.	Headache, impairment, unconsciousness or asphyxiation. Liability costs. Negative view of project by stakeholders.	Monitor CO2 content in working/living areas.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Install CO2/H2S monitors and alarms. Maintain blowout preventers, packers, valves, pipelines and equipment in proper operating condition. Maintain caprock integrity.	Monitor at risk areas for CO2/H2S. Install alarms if necessary or ventilate areas where CO2 may accumulate. Post warning signs. Train operators and first responders and educate local residents how to identify and deal with CO2/H2S leaks. Train operators to handle blowouts and pipeline ruptures.	

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
258	07.03.05.00.	Modification of microbiological systems	2	1	3	6	None	None	None	None	None	None	1-5 days d@ \$20,000/d revenue lost per pattern idled	Increased injection cost due to decreased injectivity Cost of chlorine for microbial control \$310- 340/t Cl (\$0.03/t water treated @ 4 ppm Cl)	None	None	\$50k per clean out, assuming 5 days downtime.	Up to 84% fewer clean outs.	Pretreat injected water with chlorine biocide <\$0.03/t water	Savings of \$50k per cleanout avoided.	1
259	07.04.00.00.	Impacts on humans	0	0	0	0															
260	07.04.01.00.	Health effects of CO2	2	4	2	16	1 @ \$1.5M per fatality	Accumulation of CO2 in unventilated low lying or confined areas 1 @ \$1.5M per serious (irrecoverable) injury	Accumulation of CO2 in unventilated low lying or confined areas 2 @ \$0.05M per minor (recoverable) injury	Accumulatio n of CO2 in poorly ventilated low areas resulting in wildlife kill up to \$1M	Accumulatio n of CO2 in unventilated low lying areas resulting in livestock kill up to \$1M	None	1-15 days @ \$20,000/d revenue lost per pattern idled	Cost to locate and fix leaky well: <\$0.3M Cost to fix well blowout: <\$3M. Cost to fix pipeline rupture: <\$1M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Blowout:<\$3M per event. Fatalities and/or injuries: \$3.1M	<\$2M per event	Monitors and alarms for CO2/H2S: <\$300k	Up to \$2.8M per event prevented	1

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261	07.04.01.01.	Elevated CO2 in air	CO2 = 5000 ppm (0.5%): OSHA permissible exposure limit: Time weighted average concentration for 8-hour work day. American Conference of Governmental Industrial Hygienists (ACGIH) threshold limit value: Time weighted average concentration for normal 8-hour work day or 40-hour work week. CO2 = 30,000 ppm (3%): Breathing increases to twice normal rate and a person would experience impaired hearing, headache, and increased blood pressure (Shell). Occupational Safety & Health Administration (OSHA) short-term exposure level: Maximum concentration for 15-minute period (maximum of 4 periods per day with at least 60 minutes between exposure periods). CO2 = 40,000 ppm (4%): National Institute for Occupational Safety and Health (NIOSH) immediate danger to life and health: The maximum level to which a healthy individual can be exposed to a chemical for 30 minutes and escape without suffering irreversible health effects or impairing symptoms. CO2 = 50,000 ppm (5%): Breathing increases to approximately 4 times normal rate, symptoms of intoxication become evident and slight choking may be felt (Shell). CO2 = 75,000 ppm (7.5%): A sharp odor is noticeable. At this level a person would experience very labored breathing, headache, visual impairment, and ringing in the ears. Judgment may be impaired, followed within minutes by loss of consciousness(Shell). CO2 = 100,000 ppm (10%): Unconsciousness	CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).	On-site (recycled and subsurface) CO2 contains 1000 ppm H2S. At 30,000 ppm CO2 and 30 ppm H2S, both are equally toxic. At concentrations less than this, H2S acts as an odorant for CO2 similar to odorants in natural gas. This provides an additional warning system where leaks may occur. H2S monitors are installed around injection wells.		Human injury/death due to accumulation of CO2 in unventilated low lying or confined areas.	Elevated CO2 in air.	Headache, impairment, unconsciousness or asphyxiation. Liability costs.	Monitor CO2 content in working/living areas.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Install CO2/H2S monitors and alarms. Maintain blowout preventers, packers, valves, pipelines and equipment in proper operating condition. Maintain caprock integrity.	Monitor at risk areas for CO2/H2S. Install alarms if necessary or ventilate areas where CO2 may accumulate. Post warning signs. Train operators and first responders and educate local residents how to identify and deal with CO2/H2S leaks. Train operators to handle blowouts and pipeline ruptures.
262	07.04.02.00.	Toxicity of contaminants	Contaminants other than CO2 may be introduced to the biosphere as a result of geological CO2 sequestration due to: - impurities associated with the sequestration fluid, such as hydrogen sulfide (H2S), methane (CH4), nitrogen oxides (NOx) and mercaptans; - the mobilization of substances in the geological environment due to the sequestration of CO2, such as hydrocarbons (e.g., EOR and ECBM), CH4 and heavy metals. Such contaminants may be toxic to humans and could cause harm if exposure pathways exist. The toxicity will depend on: the form of exposure, e.g. ingestion or inhalation, leading to internal exposure or proximity to concentrations of contaminants leading to external exposure; the metabolism of the contaminant and physico-chemical form if inhaled or ingested, which will determine the extent to which the element/species may be taken up and retained in body tissues.	The potential for contaminants associated with an/or mobilized by CO2 sequestration to cause harm to humans is an endpoint of interest when assessing the geological sequestration of CO2. CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).	On-site (recycled and subsurface) CO2 contains 1000 ppm H2S. At 30,000 ppm CO2 and 30 ppm H2S, both are equally toxic. At concentrations less than this, H2S acts as an odorant for CO2 similar to odorants in natural gas. This provides an additional warning system where leaks may occur. H2S monitors are installed around injection wells.		Human injury/death due to accumulation of H2S in unventilated low lying or confined areas	Toxicity of contaminants.	Endangerment of human health. Liability costs.	Monitor contaminants in CO2 stream, reservoir fluids, production well.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Install CO2/H2S monitors and alarms. Maintain blowout preventers, packers, valves, seals, pipelines and equipment in proper operating condition. Maintain caprock integrity.	Monitor at risk areas for CO2/H2S. Install alarms if necessary or ventilate areas where CO2 may accumulate. Post warning signs. Train operators and first responders and educate local residents how to identify and deal with CO2/H2S leaks. Train operators to handle blowouts and pipeline ruptures.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
261	07.04.01.01.	Elevated CO2 in air	2	4	2	16	1 @ \$1.5M per fatality	Accumulation of CO2 in unventilated low lying or confined areas 1 @ \$1.5M per serious (irrecoverable) injury	Accumulation of CO2 in unventilated low lying or confined areas 2 @ \$0.05M per minor (recoverable) injury	Accumulatio n of CO2 in poorly ventilated low areas resulting in wildlife kill up to \$1M	Accumulatio n of CO2 in unventilated low lying areas resulting in livestock kill up to \$1M	None	1-15 days @ \$20,000/d revenue lost per pattern idled	Cost to locate and fix leaky well: <\$0.3M Cost to fix well blowout: <\$3M. Cost to fix pipeline rupture: <\$1M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Blowout:<\$3M per event. Fatalities and/or injuries: \$3.1M	<\$2M per event	Monitors and alarms for CO2/H2S: <\$300k	Up to \$2.8M per event prevented	1
262	07.04.02.00.	Toxicity of contaminants	2	4	2	16	1 @ \$1.5M per fatality	Accumulation of H2S in unventilated low lying or confined areas 1 @ \$1.5M per serious (irrecoverable) injury	Accumulation of H2S in unventilated low lying or confined areas 2 @ \$0.05M per minor (recoverable) injury	Accumulatio n of H2S in poorly ventilated low areas resulting in wildlife kill up to \$1M	Accumulatio n of H2S in unventilated low lying areas resulting in livestock kill up to \$1M	None	1-15 days until leakage is fixed	Cost to locate and fix leaky well: <\$0.3M Cost to fix well blowout: <\$3M. Cost to fix pipeline rupture: <\$1M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Blowout:<\$3M per event. Fatalities and/or injuries: \$3.1M	<\$2M per event	Monitors and alarms for CO2/H2S: <\$300k	Up to \$2.8M per event prevented	1

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263	07.04.03.00.	Impacts from physical disruption	Impacts on humans due to physical disruption of the environment caused by geological CO2 sequestration. For example, damage to buildings due to induced seismicity, damage to farmland due to subsidence or uplift.	Physical disruption of the environment caused by CO2 sequestration may have a detrimental impact on humans.	There have been no indications of subsidence, uplift or induced seismicity in the Northern Platform Area. CO2 injection is compensated for by simultaneous production of fluids from the reservoir. The volume of fluids in the reservoir is within 1% of original volume. CO2 injection pressures are maintained at <90% of fracture pressure.		Contamination of natural resources. Induced seismicity. Subsidence/uplift.	Physical disruption due to improper CO2 injection/leakage.	Loss of monetized value of contaminated resources. Damage to buildings and infrastructure. Damage to farmland. Liability costs.	Monitor and model CO2 plume and brine migration. Monitor overlying formations, soils, and water for CO2, salinity, phi Continuous passive micro-seismicity monitoring. Monitor and model surface displacement (LIDAR).	Determine fracture pressure. Operate below 90% of fracture pressure. Maintain reservoir fluid volume close to original volume. Avoid areas with high population density.	Operate below 90% of fracture pressure. Monitor injection pressure and passive micro-seismicity.
264	07.04.04.00.	Impacts from ecological modification (See 06.01.08.00)	Impacts on humans due to ecological modification. These may be negative (for example, reduced timber yields due to damage caused to trees by CO2 in the soil) or positive (for example, increased crop yields due to higher atmospheric CO2).	Ecological modification caused by CO2 sequestration may have a positive or negative impact on humans.	The local ecological system is not considered valuable and/or sensitive to perturbations. Historically, CO2 releases have been localized from boreholes, pipelines or equipment failures.		Timber kill. Agricultural crop and/or animal kill. Natural flora and/or fauna kill. Aquatic/marine life kill.	Ecological modification due to improper CO2 injection/leakage.	Loss of monetized value of resources. Liability costs.	Monitor and model CO2 plume and brine migration. Monitor overlying formations, soils, and water for CO2, salinity, phi Monitor and model passive seismicity. Monitor and model surface displacement (LIDAR).	Take into account the ecological system in site characterization.	Conduct baseline survey before injecting CO2. Monitor surface CO2/H2S. Locate, isolate and fix leak.
265	08.00.00	ECONOMIC RISKS										

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
263	07.04.03.00.	Impacts from physical disruption	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
264	07.04.04.00.	Impacts from ecological modification (See 06.01.08.00)	2	1	2	4	None	None	None	Accumulatio n of CO2 in poorly ventilated low areas resulting in flora and fauna kill <\$100k	Included under natural resources.	None	1-15 days @ \$20,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$100k per event	None	Monitor for CO2/H2S near surface. Monitor pressure in formations above caprock and secondary seals: <\$200k Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	Savings: None to \$3M loss.	1
265	08.00.00	ECONOMIC RISKS	0	0	0	0															

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266	08.01.00.	Cost escalation / inflation	Cost escalation/inflation may be higher than budgeted. Cost escalations are of particular concern because field-service costs (drilling, geophysics, etc.) and equipment may continue to increase as the price of oil stays high. Key cost items that may be effected by escalation/inflation include: 1. Steel cost 2. Other material cost 3. Equipment cost 4. Labor cost 5. Imported goods cost (due to currency exchange) 6. Financing/risk transfer costs 7. Assessment and permitting costs 8. Mitigation and closure costs	The risk of cost escalations is significant; cost increases may force a change in scope-of-work.	As a mature project, much of the capital infrastructure is already in place. Therefore the impact of cost escalation/inflation will be minimal.		Project becomes economically infeasible.	Cost escalation/inflation higher than budgeted.	Cost overruns. Project halted.	Monitor cost indexes. Track and project costs versus budget.	Use updated/current information on labor and material rates with escalation over the job period. Structure foreign contracts in US currency or buy domestically.	Allow for time sensitive information to be updated to expose any issues as soon as possible. Hedge currency exchange for foreign contracts.
267	08.02.00.	CO2 value/cost	Incentives for CO2 capture and storage are particularly important for CO2 sequestration in deep saline aquifers. In this case, the value or cost of CO2 may be determined by cap-and-trade, carbon tax or emission credits. In EOR and ECBM the value of CO2 may be tied to the price of oil or natural gas. However, the cost of CO2 capture and transport may be higher or lower than the assigned value. Value of emission credits provide incentive for CO2 sequestration, particularly in deep saline aquifers (DSA). CO2 purchase cost higher than budgeted. CO2 has traditionally been purchased for EOR and ECBM use. Economic arrangements among project participants could have negative project impacts under changed or unanticipated conditions. 1. Value of CO2 emissions credits lower than budgeted 2. CO2 purchase cost higher than budgeted	A low value for emission credits may be insufficient to cover the cost of CO2 capture and sequestration in deep saline aquifers.	The cost of CO2 is one of the biggest expenses for CO2-EOR, but Kinder Morgan owns large natural CO2 resources and pipeline, therefore CO2 costs can be controlled. Also, as a mature project, the amount of purchased CO2 required has decreased with increased recycled CO2 availability.		Project economically infeasible because of high CO2 transfer cost.	Lower value for emission credits than expected. Higher CO2 cost than expected.	Project halted.	Track actual CO2 costs versus budget.	For EOR projects CO2 transfer price to the WTI crude oil price.	None needed. KM CO2 owns the CO2 and benefits if price increases. Only 12% of SACROC injected CO2 is purchased. The balance comes from recycling produced CO2.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
266	08.01.00.	Cost escalation / inflation	2	2	1	4	None	None	None	None	None	None	None	As a mature project, escalation/inflation may have a net positive effect on earnings, excluding capital expansion. Assuming a capital expansion budget of \$30M/y for the Northern Platform area. A 5% escalation would result in a \$1.5M/y increase instead of a \$0.6M/y increase for a 2% escalation	None	None	<\$1M/y	<\$1M/y	Part of ongoing costs.	None	1
267	08.02.00.	CO2 value/cost	1	1	1	1	None	None	None	None	None	None	None	Any cost increase in CO2 would benefit KM CO2.	None	None	None	None	None	None	

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268	08.03.00.	Price of oil (or other related commodities)	The prices of related commodities can impact the value and/or availability of CO2. 1. Oil price - impacts EOR economics 2. Natural gas price - impacts ECBM economics 3. Fertilizer price - impacts CO2 supply from fertilizer plants 4. Ethanol price - impacts CO2 supply from ethanol plants 5. Cement price - impacts CO2 supply from cement plants	Low commodity prices can impact the viability of a CO2 capture and storage project.	Current or future distressed financial conditions of KM customers could have an adverse impact on KM in the event the customers are unable to pay for the products or services provided (Kinder Morgan 2012). The price of oil is up which has had a beneficial impact on project economics. Oil prices are more likely to remain high than decrease due to political unrest. With much of the capital in place, the project can weather occasional decreases in oil price.	Confirm the breakeven oil price for SACROC	Oil price less than breakeven point.	Low commodity prices.	Project halted.	Track related commodity markets. Analyze impact of market changes on CO2 supply.	Analyze trends in commodity prices. Plan for worst case scenarios.	Hedge oil prices.
269	08.04.00.	Project development costs	Project development costs that could be higher than expected or budgeted include: 1. Surface land and/or pore space access costs - purchase or lease 2. Water rights costs 3. Mineral rights costs - needed for EOR or ECBM 4. Pipeline right-of-way (ROW) costs 5. Site characterization costs 6. Permitting costs 7. Technology licensing costs 8. Engineering, procurement and construction (EPC) costs 9. Insurance costs 10. Project financing costs 11. Legal costs 12. Closure and post-closure costs	High project development costs can make the project economically infeasible. Project may be halted if some of the necessary requirements are unobtainable.	As a mature project much of the development costs have already been expended.		Project economically infeasible.	Project development costs higher than budgeted.	Project halted.	Track costs versus budget.	(Numbers below refer to numbers under Definitions) 1. Focus on EOR rather than DSA to avoid pore space issues. 3. Work out mineral rights leases early. 4. Use existing pipeline corridors. 5. Select brownfield site with existing characterization data.	(Numbers below refer to numbers under Definitions) 1. Have backups for site location. 4. Have backup for pipeline right of way. 6. Use public outreach effectively to keep permitting costs down. 9. Self insure. 10. Get equity financing.
270	08.05.00.	Project capital costs	Project capital costs that could be higher than budgeted include: 1. CO2 capture system 2. CO2 dehydration 3. CO2 compression 4. CO2 pipeline 5. Well head system 6. CO2 recycle system - for EOR 7. Oil tankage - for EOR 8. Natural gas processing system - for ECBM 9. Water tankage - for EOR or ECBM 10. Water treatment system - for EOR or ECBM 11. New well drilling and completion 12. Old well remediation/replugging 13. Old well workover 14. Site preparation 15. Access roads 16. Power supply system 17. Water supply system 18. Communications system 19. Monitoring system costs 20. Accidental loss	High project capital costs can make the project economically infeasible. Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.	As a mature project capital costs have already been expended. Annual capital budgets can be adjusted to suit market conditions.		Project becomes economically infeasible.	Project capital costs higher than budgeted.	Project halted.	Track costs versus budget.	Obtain hard quotes from manufacturers with time sensitive escalation and time period of validity defined. Use conservative estimates and escalations. Use experienced contractors.	Track actual vs. budgeted expenses. Prioritize expenses and cut low priority costs. Renegotiate scope of work. Obtain additional equity funding.

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268	08.03.00.	Price of oil (or other related commodities)	4	4	3	48	None	None	None	None	None	None	None	\$1/bbl WTI decrease revenues \$3.7M/y w/o hedging and \$0.6M/y w/ hedging	None	None	\$3.7-\$76MM	\$0.6-14.3M	\$2-31M	\$1.1-30.7M	
269	08.04.00.	Project development costs	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
270	08.05.00.	Project capital costs	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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271	08.06.00.	Operating and maintenance costs	Project operating and maintenance costs that could be higher than budgeted include: 1. CO2 capture operating costs 2. CO2 dehydration/compression operating costs 3. CO2 pipeline operating costs 4. Injection operating costs 5. Monitoring costs 6. Simulation modeling costs 7. Maintenance costs 8. Lease operating expenses 9. Management fees 10. Working capital 11. Severance and ad valorem tax 12. Investor reporting costs 13. Power cost 14. Make-up water cost 15. Water treatment/disposal cost 16. Labor cost 17. Security costs 18. Site close costs 19. Verification costs 20. Regulatory compliance costs 21. Insurance costs 22. Cost for losses 23. Post-closure costs for DSA 24. Accidental loss 25. Financial reserves for DSA EPA UIC Class VI wells	High operating and maintenance costs can impair project economic viability. Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.	As a mature project, operating costs have been well established and controlled.		Project becomes economically infeasible	Project operating and maintenance costs higher than budgeted.	Project halted.	Track costs versus budget.	Use historical O&M data and experienced cost estimators to prepare budgets.	Implement a Total Productive Maintenance (TPM) program.
272	08.07.00.	Project Financing	Factors which could impact project financing include: 1. Government project funding withdrawn for technical reasons. 2. Government project funding withdrawn for political reasons 3. Change in equity project funding 4. National/global economic downturn impact on project financing 5. Lack of economic incentives for CCS impact on project financing 6. Private financing	Lack of or loss of project financing could halt the project.	As a mature project, project financing has been completed. Substantial debt could adversely affect financial health and make KM more vulnerable to adverse economic conditions (Kinder Morgan 2012). Large amount of variable rate debt makes KM vulnerable to increases in interest rates (Kinder Morgan 2012). Expansion programs require access to new capital. Tightened capital markets or more expensive capital would impair ability to grow (Kinder Morgan 2012).		Project unable to complete financing	Project loses one or more sources of funding.	Project halted or delayed.	Monitor project financing negotiations.	Keep debt at a sustainable level.	Tie future capital investment to market conditions. Adjust scope of projects to improve economics for project financing. Secure additional equity and refinance high interest rate debt.

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271	08.06.00.	Operating and maintenance costs	3	3	1	9	None	None	None	None	None	None	None	Assume \$80M/y O&M cost for the Northern Platform excluding CO2 and capital expansion. A 10% increase in costs would cost \$8M/y	None	None	\$8M/y	\$4M/y	\$1M/y	\$3M/y	1
272	08.07.00.	Project Financing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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273	08.08.00	Hedging	Hedging may be used as a risk management tool to control the adverse impact of fluctuating commodity prices.	Hedging arrangements are used to reduce exposure to fluctuations in commodity prices (i.e., CO2, oil, natural gas). Hedging can create financial risks when: 1. Production is less than hedged amount. 2. The counterparty to the hedging contract defaults on its contract obligations 3. Change in the expected differential between the underlying price in the hedging agreement and the actual price received 4. Limitation of the benefit when commodity prices increase (Kinder Morgan 2012)	If KM does not achieve production volumes greater than, or equal to, their hedged volumes, they may suffer financial losses not offset by physical transactions (Kinder Morgan 2012). KM may be exposed to financial losses of the counterparty to the hedging contract defaults on its contract obligations, or when there is a change in the expected differential between the underlying price in the hedging agreement and the actual price received (Kinder Morgan 2012). Hedging may limit the benefit KM would otherwise received from increases in prices of oil (Kinder Morgan 2012).		Actual oil production level below hedged production level. Counterparty default on hedging agreement obligations. Hedged price significantly below nonhedged price.	Production problems. Over estimating amount to be hedged. Poor selection of hedging counterparty. Underestimating hedging price.	Loss of revenues.	Monitoring commodity prices, production rates, and financial health of hedging counterparty.	Avoid hedging. Improve price forecasting. Carefully select hedging counterparty.	Keep the portion of hedged product to a manageable level. Negotiate a reasonable margin between expected hedged and unhedged prices.
274	09.00.00.	PERMITTING RISKS										
275	09.01.00.	Permit compliance - obtain or maintain permits	Permitting and NEPA compliance are lengthy processes, and are subject to even more delays because of uncertainty associated with permitting sequestration (a relatively new issue for federal, state and local regulatory agencies).The procedures for permit compliance could cause delays. Potential permits required for a CCS project include: 1. National Environmental Policy Act (NEPA) - Environmental Assessment (EA) - Environmental Impact Statement (EIS) 2. Underground Injection Control (UIC) permit 3. CO2 storage permit 4. Drilling permit 5. Water discharge/disposal permit 6. Crossing permits for wetlands, federal land, tribal land, railroads, highways, roads 7. Construction general permit 8. Storm water discharge permit 9. Air quality construction permit 10. Seismic permit 11. Storage tank permit 12. Closure financial assurance 13. Post-closure financial assurance	Lack of permit could halt or restrict construction or operation; permit delay could have other impacts including increased costs.	The SACROC unit is a mature site and fully permitted. Permit requirements for UIC Class II wells are significantly less stringent than UIC Class VI wells. Kinder Morgan timely compliance record in 2011: 99.5% (Kean 2102).		Project cannot obtain or maintain new permits.	Project out of compliance with new regulations.	Project halted or delayed.	Track permitting processes and regulations. Compare actual versus plan. Ensure continuous compliance with permits.	Use experienced permitting manager / consultant. Ensure continuous compliance with permits.	Use experienced permitting manager / consultant. Ensure continuous compliance with permits.

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273	08.08.00	Hedging	5	4	3	60	None	None	None	None	None	None	None	Assume 85% of oil production is hedged, a \$10/bbl underestimated hedge price could result in a loss of \$1M in revenue.	None	None	\$31M	\$15M	\$1M/y	\$15M	1
274	09.00.00.	PERMITTING RISKS	0	0	0	0															
275	09.01.00.	Permit compliance - obtain or maintain permits	3	3	1	9	None	None	None	None	None	None	Business interruption or shutdown \$0.8M/day for Northern Platform area. A 5-day shutdown would cost \$4M in revenue.	Impacts profitability.	None	Assume fine of \$0.5M	\$4.5M	\$0M	\$0.5M	\$4M	1

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276	09.02.00.	Public outreach and education	Public acceptance support and trust is critical to obtaining environmental permits. Public outreach and education can be more difficult than expected. 1. Lack of public acceptance that CO2 emissions contribute to global warming 2. Lack of public acceptance that global warming is an eminent danger to society 3. Lack of public that carbon capture and storage (CCS) is safe 4. Poor public perception of CCS projects 5. Local community actions and reactions 6. Special interest groups or non-governmental organizations actions and reactions 7. Lack of political support for the project 8. Risk off-sets	Failure to get public acceptance for a project can lead to significant delays in, and costs for, permitting An unexpected situation arises that is not technically impacting but the appearance of unpreparedness spurs public concern.	Project already permitted. The SACROC unit has been in operation for over 60 years with public support. The Northern Platform area has very low population density.		Project unable to get new permits.	Lack of public support for project.	Project halted or delayed.	Track public opinion.	Maintain a comprehensive public outreach program.	Maintain a comprehensive public outreach program.
277	09.03.00.	Saline water extraction, treatment and disposal	Large amounts of saline water are pumped out of the ground for EOR and ECBM. EOR water production increases over time. In high water cut cases, water may represent 99% of the production volume and oil only 1% of the volume. ECBM employs water production to lower the over pressure in the coal seam, decrease swelling and increase permeability. Water may be extracted in a DSA operation to make room for injected CO2 and manage pressure. Extracted water is increasingly becoming a prominent issue, particularly deliberately extracting water to manage CO2 plume (e.g. extracting water to encourage plume migration and reinjecting the extracted water into a different part of the reservoir so that it is not extracted again). Some researchers believe CO2 can be injected into reservoirs without extracting water. This may be true in an open storage reservoir. But in a closed reservoir, injecting CO2 without extracting water will build up pressure in the reservoir and severely restrict the CO2 storage capacity. CO2 changes water composition and makes water more acidic (pH 4-5). Therefore EOR and ECBM production water may require more treatment before it can be disposed of. The acidic water may also include trace amounts of arsenic and other metals.	Saline water disposed could be one of the most critical issues in permitting. Treating the water will concentrate brine that will need to be reinjected.	Project already permitted. Produced water is injected back into the reservoir after being filtered and treated with biocide, oxygen scavenger, scaling inhibitor and corrosion inhibitor.		Project unable to get, or loses, permit to treat/dispose of extracted water. Water treatment/disposal costs significantly higher than expected.	Project out of compliance with regulations covering water treatment and disposal. Excessive extracted water volumes and/or poor water quality.	Project halted or delayed. Project return on investment (ROI) lower than expected.	Monitor water treatment/disposal regulations. Model extracted water volumes and quality.	Maintain balance between produced and injected water.	Comply with all State water disposal regulations. Evaluate alternative methods of treating and disposing of produced water.
278	09.04.00	Natural resources nearby	1. Mineral resources 2. Mineable coal seams 3. Oil reservoirs 4. Natural gas reservoirs 5. Underground drinking water sources 6. Surface waters - lakes, rivers, streams 7. Geothermal resources 8. Pores space owned by others 9. Deep saline aquifers 10. Microbial resources 11. Soil - farmland 12. Flora and fauna - endangered species and critical habitats	CO2 or brine fluid migration could contaminate others' natural resources and lead to permitting delays due to legal contest.	Project already permitted. The Northern Platform area is relatively barren with a small amount of farmland, insignificant surface water, and low population density. Potential resources are shale gas in the Wolfcamp shale and residual oil zone in the lowest Canyon formation.		Project unable to get permits. Permit compliance too expensive.	Project in conflict with or could negatively impact nearby natural resources.	Project halted or delayed. Project ROI negatively impacted.	Monitor site characterization and environmental impact statement work.	Avoid fracturing Wolfcamp shale (primary seal) for recovery of shale gas.	Control fracturing of Wolfcamp shale for recovery of shale gas to prevent leakage of CO2+H2S. Use continuous passive microseismic monitoring. Monitor overlying formations for CO2/H2S.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
276	09.02.00.	Public outreach and education	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
277	09.03.00.	Saline water extraction, treatment and disposal	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
278	09.04.00	Natural resources nearby	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
279	09.05.00.	Dense population nearby	Present and future urban sprawl. 1. Sensitive receptors (schools, hospitals, care centers, churches, prisons) in or near injection site 2. Dense population located downhill or downwind of injection site 3. Populated subsurface structures located nearby	Additional safety precaution measures are required to protect against CO2 leakage in dense population areas..	Project already permitted. Population density in the Northern Platform area is estimated at 2.3 residents per square mile. There are no sensitive receptors in the area.		Project unable to get new permits. Permit compliance more expensive than planned.	Existing or future population density near site.	Project halted or delayed.	Track existing and planned population density near the site.	Avoid selecting sites near densely populated areas. Use existing pipeline corridors.	Provide additional monitoring, pipeline integrity management program and emergency response plan for populated sites. Assess alternative site.
280	09.06.00.	Conflicts with use of surface	Conflicts with use of the surface may include 1. Agriculture 2. Fishing 3. National parks/monuments 4. Wetlands 5. Timberland 6. Recreational areas 7. Military areas 8. Heavy industry sites 9. Urban areas 10. Archeological sites 11. Tribal sacred ground 12. Endangered species critical habitats 13. Bird sanctuaries 14. Historical sites 15. Groundwater protection zones. 17. Change in land use (zoning change)	Some land uses may impact site selection and permitting. Others may require additional monitoring and modeling to provide added protection from CO2 leakage. Nearby heavy industry can interfere with seismic readings. Land use changes could restrict access to and use of land for CO2 sequestration	Project already permitted. The SACROC unit has been operated for over 60 years. There are no known current or potential conflicts with surface use. Possibility of increased costs to retain necessary land use (Kinder Morgan 2012).		Project unable to get new permits.	Project in conflict with use of surface.	Project halted or delayed.	Monitor site characterization and environmental impact statement work.	Use existing injection (i.e., EOR, CBM) sites and pipeline corridors. Avoid sensitive areas or habitats for endangered or protected species. Characterize sites for potential surface land use.	Design around sensitive areas. Monitor CO2 plume and brine migration. Assess alternative site.
281	09.07.00.	Conflicts with use of subsurface	Conflicts with use of the subsurface may include: 1. Natural gas storage 2. Compressed air storage 3. Geothermal plants 4. Radioactive waste disposal 5. Petroleum production 6. Coal mining 7. Health spas	Could impact site selection and permitting.	Project already permitted. Subsurface oil and gas rights are controlled by Kinder Morgan.		Project unable to get new permits.	Project in conflict with use of subsurface.	Project halted or delayed.	Monitor site characterization and environmental impact statement work.	Use existing injection (i.e., EOR, CBM) sites and pipeline corridors. Avoid sites with conflicting subsurface use. Characterize sites for potential conflicting subsurface use.	Design around conflicting areas. Monitor CO2 plume and brine migration. Assess alternative site.
282	09.08.00.	Permit denied or modified by government agency	A permit may be modified by government agency to require increase data access and approval by NGOs and/or public 1. Permit denied because the project is considered high risk to public 2. Permit denied because there is uncertainty over the safety of the project 3. Permit revoked due to owner failing to comply with regulations (action or inaction) 4. Permit delayed due to owner action or inaction	Causes delays leading to price escalation. Could halt the project.	Project already permitted. Permits could change if CO2 continues to be injected for sequestration after EOR is completed.		Project unable to get new, or loses permit. Permit compliance costs more expensive than expected.	Project out of compliance with permit regulations.	Project halted or delayed. Project ROI negatively impacted.	Track permitting processes and regulations. Compare actual versus plan.	Use experienced permitting manager / consultant. Comply with permit requirements.	Use experienced permitting manager / consultant Revise project and/or permit application to resolve uncertainties, high risks etc. Assess alternative site. Comply with permit requirements.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
279	09.05.00.	Dense population nearby	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
280	09.06.00.	Conflicts with use of surface	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
281	09.07.00.	Conflicts with use of subsurface	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
282	09.08.00.	Permit denied or modified by government agency	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

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283	09.09.00.	Pre-existing contaminated site	Site may have already been contaminated by non-CO2 storage related activities.	Pre-existing contamination of groundwater, surface water, and/or soil. Requires assessment to determine if proposed project would be impacted by or exacerbate existing condition. Or assume responsibility for remediation of pre-existing conditions.	Project already permitted. There are no known superfund or hazardous waste releases or brownfield sites or landfills registered with the EPA in the Northern Platform area. There are approximately 45 above ground storage tank sites in the area. Produced brine may have seeped into the soil from unlined brine evaporation pits prior to the mid-1970s (Smyth 2012).		Significant costs to remediate pre-existing contamination.	Pre-existing contaminated site.	Project halted or delayed. Increased capital costs. Complex or misleading monitoring data.	Comprehensive site characterization and environmental impact statement work for pre-existing contamination.	Characterize sites for pre-existing contamination to evaluate operational impacts and additional costs. Conduct baseline studies to define preinjection conditions. Use experienced permitting manager / consultant.	Use experienced permitting manager / consultant
284	10.00.00.	EXTERNAL RISKS										
285	10.01.00.	Natural disaster risks (01.02.02.00.)	1. Fire -wildfires, industrial fires 2. Flood - flood plain, dry wash areas, flash floods, tsunamis, debris flows 3. Earthquake - natural seismic activity, rock slides, mud slides 4. Winter storms - blizzards, ice storms, arctic cold 5. Hail storm 6. High winds - tornadoes, hurricanes, typhoons, cyclones 7. Heat wave 8. Drought 9. Heavy rain - monsoons, tropical storms, thunder storms 10. Lightning 11. Sand/dust storms 12. Avalanche 13. Electromagnetic disturbances - sunspots 14. Volcano 15. Corrosive atmospheres - high humidity, coastal sea breeze, industrial plant acid gas emissions	Natural disasters can delay, impair or shutdown a project.	Potential natural disasters in the Scurry county include (in order of occurrences): hail, thunderstorms (lightning), floods, strong winds, drought, waves, winter storms, earthquakes, dust storms, wildfires, heat waves, and tornados (USA.com 2012)/.		Project facilities damaged and/or personnel injured.	Natural disaster.	Project halted, delayed or impaired. Project ROI negatively impacted. Infrastructure damage.	Monitor site characterization for site-specific disaster risks. Monitor weather forecasts for severe weather conditions.	Select sites and pipeline corridors that are less likely to be exposed to natural disasters. Avoid flood plains. Include potential natural disasters in site characterization.	Implement emergency response plan covering all potential disasters. Comply with fire suppression codes. Ground surface equipment to protect from lightning. Cover sensitive equipment. Monitor severe weather reports. Integrate mitigative measures into facility design and operations. Implement effective storm management plans.
286	10.02.00.	Security risks	1. Theft 2. Vandalism - onsite equipment or offsite monitoring equipment 3. Employee sabotage 4. Civil unrest - riots, civil war, rebellion, insurrection, military or usurped power or confiscation 5. Terrorist activities 6. War - invasion, acts of foreign enemies, hostilities 7. Nationalization 8. Government sanctions, blockade, embargo 9. Labor disputes - strike, lockout 10. Damage to surface facilities by human activity 11. Hunting season - stray bullets	Risks to employees, public and equipment.	Terrorist attacks, or a threat of them, may adversely impact KM business (Kinder Morgan 2012). 24-hr surveillance and fencing around injector wells (Ricketson 2012).		Project facilities damaged and/or personnel harmed. Project security cost increased.	Security breach.	Project halted, delayed or impaired. Project ROI negatively impacted. Infrastructure or equipment damage	Monitor security alerts and level of civil / employee unrest.	Integrate appropriate security controls and systems to protect above ground facilities. Bury pipeline sufficiently deep. Do background checks and drug tests on all new employees. Supervise all crews during working hours.	Implement an emergency response plan and enhanced security procedures.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
283	09.09.00.	Pre-existing contaminated site	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
284	10.00.00.	EXTERNAL RISKS	0	0	0	0															
285	10.01.00.	Natural disaster risks (01.02.02.00.)	3	2	1	6	None	None	None	None	None	Surface facilities damage <\$1M for most situations but \$10M+ if compressors are involved.	0-7 days @ \$20,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of total damages	Cost to repair surface facilities <\$1M + Cost of business interruption	Cost of insurance deductible.	Insurance coverage for weather and flood damage and business interruption 0.28% of surface facilities value per year + 0.25% of revenue per year	Savings in cost to repair surface facilities + Savings in cost of business interruption + Cost of insurance	1
286	10.02.00.	Security risks	2	2	2	8	None	None	None	None	None	Surface facilities damage or pipeline. <\$1M per incident.	0-2 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	Cost to repair surface facilities <\$1M	\$0 Proper security program. On going cost.	<\$1M	1	

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287	10.03.00.	Competition	Other projects in the area may compete for the same CO2, labor, infrastructure, land, pore space, funding 1. Interaction with adjacent CO2 sequestration sites 2. Infringement of project's pore space by third-party injection of CO2, water or waste disposal	Could halt the project or increase costs. Potential decreased storage capacity.	KM CO2 owns the CO2 supply and controls right to operate the SACROC unit.		Project loss of CO2 supply. Project costs increased.	Competitor activity.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor competitor activities.	Secure CO2 supply with exclusive long-term agreement.	Identify backup CO2 supplies.
288	10.04.00.	CO2 supply	Changes in the operation of the CO2 source plant may impact CO2 properties and/or flow rate. Unanticipated change in demand for injected CO2 (flow rate, pressure, water content, etc.) due to either uncontrollable physical changes or operating decisions, will affect operations of the CO2 source facility and potentially impose stresses upon surface and down hole equipment and borehole. Changes may be gradual or sudden. Also includes changes arising from characterization data, e.g., limits placed by reservoir on injectivity, capacity, etc. CO2 sources and sinks need to coordinate supply and demand and scheduled outages to avoid constraint startup/shutdown of compression facilities and maintain consistent pipeline pressure. This is normally done through a nomination process at least one week in advance. Operators of CO2 storage projects may incorporate excess injection capacity (i.e. spare wells) to permit continued injection during planned or unplanned well downtime. (CCP 2009)	Interruption of CO2 supply could result in a Business Interruption / Advanced Loss of profit type exposure, or even result in the project becoming uneconomic to continue. Lack of adequate CO2 supply could halt or limit injection. Intermittent injection schedule could increase stress on surface and down hole mechanical elements, could affect EOR/ECBM sweep efficiency, and could increase concentrations of various contaminants in the injected gas. The timing of CO2 availability may not match up with the time when CO2 is needed for EOR or ECBM. 1. CO2 outside of design specification - flow rate, composition, pressure, temperature 2. Change in CO2 supply conditions 3. Change in CO2 demand conditions 4. CO2 supply interruptions due to source plant outage/failure 5. CO2 supply interruptions due to CO2 capture outage/failure 6. CO2 supply interruptions due to compressor outage/failure 7. CO2 supply interruptions due to pipeline outage 8. Disparity in timing CO2 supply/demand 9. CO2 interruption due to accident at the CO2 supplier	Multiple sources of high quality natural CO2 are controlled by Kinder Morgan and supplied the SACROC unit by two pipelines. Supply reliability is very high because of improved compressor reliability. Quality is consistently high (typical of natural CO2). Purchased CO2 represents less than 12% of total CO2 injected at SACROC. Operation could be maintained even with interruption of purchased CO2 supply.		Disruption of project operations. Project CO2 costs increased.	CO2 supply interruption. CO2 off-spec.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor CO2 supplier operations, CO2 flowrate and CO2 quality.	Maintain multiple sources of CO2.	Monitor CO2 quality. Require CO2 supplier to vent off-spec CO2. Cut back CO2 injection on some patterns or compensate with increased water injection.
289	10.05.00.	Water supply	1. Water supply design specifications - Flow rates - Composition - Pressure - Temperature 2. Water supply interruptions	Could impact water and gas (WAG) flooding	Water injection and production are close to being in balance. Make up water was originally supplied from Lake J B Thomas. Most injection water is now recycled produced water.		Disruption of project operations. Project water costs increased.	Water supply interruption. Water off-spec.	Project delayed or impaired. Project ROI negatively impacted.	Monitor water supply and quality.	Take water supply volume and quality into account in system design. Consider redundant pumps, wells and/or water storage tanks.	Monitor for leaks in water piping. Implement pre-incident contingency plan. Add pumps, filtration or water treatment to resolve water volume or quality issues.
290	10.06.00.	Power supply	1. Power surges 2. Power brown outs 3. Power interruptions (black outs)	Could shut operations down.	Over 50% of power is supplied from an onsite 100MW NGCC power plant. Reliability has been very high. Well instrumentation is solar powered.		Disruption of project operations. Equipment damage.	Power supply interruption. Power surge/brownout.	Project delayed or impaired. Project ROI negatively impacted. CO2 release (HSE hazard)	Monitor power supply.	Install generator/battery backup system for key components.	Install surge protection if it is an issue. Make sure valves turn to safe default position when power goes out.

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287	10.03.00.	Competition	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
288	10.04.00.	CO2 supply	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
289	10.05.00.	Water supply	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
290	10.06.00.	Power supply	2	2	1	4	None	None	None	None	None	None	Business interruption	Impacts profitability.	<100t CO2 @ \$32.32/t CO2	10% of damage cost	<\$1M	<\$0.1M	\$0.5M	\$0.4M	1	

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291	10.07.00.	Communication system	Communications could be interrupted. The SCADA system may be dependent on one or more of the following communications systems: 1. Phone line 2. Fiber optics 3. Satellite 4. Internet	Loss of communication system could impair operations especially if the SCADA link is disconnected.	Solar powered SCADA monitoring system in place (Rickerson 2012).		Disruption of project operations. Equipment damage.	Communication system interruption.	Project delayed or impaired. Project ROI negatively impacted.	Monitor communication system.	Install fiber optics and backup system.	System maintenance. Implement contingency plan. Make sure valves turn to safe default position when SCADA system shutdown.
292	10.08.00.	Road access	Road to injection site could be blocked by snow, accident, washout, wildfire, flooding	Lack of road access to sites could impair operations	Good road access is available throughout the site. Mostly flat land in warm climate. Access unlikely to be disrupted except by flash flooding.		Disruption of project operations.	Roads inaccessible	Project delayed or impaired. Project ROI negatively impacted. Personnel or supplies unable to reach or leave site.	Monitor road conditions.	Road maintenance procedures in place. Alternate routes.	Road maintenance in place. Alternate routes.
293	11.00.00.	PROJECT MANAGEMENT RISKS										
294	11.01.00.	Management team	The project may include some unfamiliar activities and workflows, may acquire and respond to a wide range of newly acquired data, and may experience changes in objectives. Operational conflicts, anticipated or not, could impact project values. Inexperienced managers tend to be over optimistic in taking risks and taking short cuts. for example: failing to avoid high risk sites. 1. Inexperienced management team 2. Inability to execute contracts among project partners in a timely manner 3. Lack of stakeholder coordination	An inexperienced management team has a higher potential for mistakes and poor judgment Inefficient interface management can result in delays and failure to achieve project goals.	Strong, experienced management team in place.		Poor, or lack of, management decisions having a negative impact on the project.	Inexperienced management team	Project delayed or impaired. Project ROI negatively impacted.	Monitor implementation of project management plan.	Hire or assemble an experienced management team.	Hire additional experienced project managers / consultants if necessary. Conduct independent operational reviews.
295	11.02.00.	Operator training	1. Under qualified operators 2. Untrained operators 3. Operator error	Inadequate operator training can result in low labor productivity and greater potential for human error.	Strong operator training program in place.		Operator error or over confidence resulting in poor performance and/or equipment/system failure.	Insufficient operator training.	Project halted, delayed or impaired. Facilities damaged and/or personnel injured. CO2 release (HSE hazard). Project ROI negatively impacted. Regulatory violations.	Monitor operator training and performance.	Implement a continuous operator training program.	Maintain an ongoing operator training program in the operation phase with particular emphasis on emergency response.

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291	10.07.00.	Communication system	2	2	1	4	None	None	None	None	None	None	Business interruption	Impacts profitability.	<100t CO2 @ \$32.32/t CO2	10% of damage cost	<\$1M	<\$0.1M	\$0.5M	\$0.4M	1
292	10.08.00.	Road access	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
293	11.00.00.	PROJECT MANAGEMENT RISKS	0	0	0	0															
294	11.01.00.	Management team	2	4	1	8	None	None	None	None	None	None	Project delay or interruption	Hedging loss: <\$100M. Impacts profitability.	None	10% of damage cost	Hedging loss: <\$100M	None	Part of ongoing cost	None	1
295	11.02.00.	Operator training	2	3	1	6	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	Equipment or system failure.	Project delay or interruption	<\$10M Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$10M	None	Part of ongoing cost	<\$10M	1

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296	11.03.00.	Execution strategy	Poor execution strategy can result from: 1. Insufficient funding 2. Insufficient resources 3. Unrealistic schedule 4. Schedule and planning conflicts (02.01.05.00) 5. Poor timing 6. Lack of risk management plan Scheduling and planning covers the sequence of events and activities occurring during all phases of the project.	Poor execution strategy can result in project delays and increased project costs.	Effective execution strategy in place. Project development decisions generally are based on subjective judgments and assumptions that, while they may be reasonable, are by their nature speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, the successful completion of a well does not ensure a profitable return on investment (Kinder Morgan 2012).		Project delays and schedule conflicts.	Lack of scheduling and planning	Increased project costs.	Track actual schedule versus plan.	Detailed scheduling and planning. Prepare a realistic schedule. Work with experienced team members to execute the project. Update and follow project management plan and risk management plan.	Prioritize and accelerate work load. Use quarterly meetings to review and fine tune execution strategy and resolve schedule conflicts.
297	11.04.00.	Record keeping (See 02.02.03.00.)	Large amounts of data will be generated by the project. Data could be poorly communicated between groups, or be badly managed to the point that important data is lost, or used incorrectly. Features related to the retention of records of the content and nature of a CO2 storage site after closure and also the placing of permanent markers at or near the site. 1. Poor data management 2. Loss of archives/records 3. Unable to accurately verify the amount of CO2 retained in storage	It is expected that records will be kept to allow future generations to recall the existence and nature of the storage reservoir/aquifer following closure. Insufficient record keeping could lead to noncompliance with regulations and failure to achieve project goals.	Record keeping is for EOR rather than CO2 sequestration.		Noncompliance with regulations. Inadvertent future intrusion into the CO2 reservoir by third-party.	Improper record retention and marking.	Potential fines, penalties or business interruption for noncompliance.	Data management. Routine site inspection.	Set up an electronic data management system with off-site backups. Proper documentation. Standardize data formats. Clearly mark site with warnings and register site as CO2 storage site with the State.	Maintain data system and standardized formats. Routine site inspection and/or monitoring. Prepare procedures for potential remedial action.
298	11.05.00.	Multi-party project	CCS projects may involve multiple participants for CO2 supply, CO2 transportation, EPC (engineering, procurement and construction), CO2 storage, computer simulation, MVA (monitoring, verification and accounting), carbon trading, and risk management. There are challenges and risks in coordinating the responsibilities and liabilities among multiple organizations involved in a project. In case of too deep involvement of partners in day to day operations, shareholders may assume joint and several liability for actions of the partnership. Disagreement among partners may lead to deadlock in unanimous decision making.	Lack of communication, coordination and cooperation among project participants can lead to project delays and failure to achieve project objectives.	SACROC is made up of several members with Kinder Morgan providing the lead.		Project negatively impacted by poor, or lack of, multi-party coordination/cooperation.	Multi-party project	Project delays. Project ROI negatively impacted. Unclear responsibilities for liabilities.	Monitor multi party coordination / cooperation.	Maintain secure website, weekly conference calls, cross-functional working groups and management team. Establish clear division of scope of work and responsibilities.	Maintain secure website, weekly conference calls, cross-functional working groups and management team. Maintain clear division of scope of work and responsibilities.
299	11.06.00	Pre-closure administrative control (02.01.06.00.)	Features related to measures to control events at or around the sequestration site during the design, construction, operation and decommissioning phases. The type of administrative control may vary depending on the stage in the storage system lifetime. (02.01.06.00.)	The pre-closure administrative control will influence the quantity and quality of information about the sequestration project that is available post-closure, therefore helping to determine societal memory. The better the amount and quality of information available, the lower the possibility of inadvertent intrusion.	Pre-closure administration control focused on CO2-EOR rather than CO2 sequestration.		Future inadvertent intrusion into CO2 storage reservoir.	Lack of pre-closure administrative control	Future CO2 release (HSE hazard). Inability to transfer long-term liability. Penalties for non-compliance with regulations	Routine inspection and monitoring of site. One-call center.	Clearly mark the site with warning signs and register the site as a CO2 storage site with the State. Data management. Keep backup documentation at off-site locations.	Data management.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
296	11.03.00.	Execution strategy	2	3	1	6	None	None	None	None	None	None	Project delay or interruption	<\$10M Impacts profitability.	None	10% of damage cost	<\$10M	None	Part of ongoing cost	<\$10M	1
297	11.04.00.	Record keeping (See 02.02.03.00.)	2	2	2	8	None	None	None	None	None	None	None	None	None	<\$1M for fines or penalties.	None	None	Part of ongoing costs.	<\$1M	1
298	11.05.00.	Multi-party project	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
299	11.06.00	Pre-closure administrative control (02.01.06.00.)	2	2	2	8	None	None	None	None	None	None	None	None	None	Fines or penalties <\$1M	<\$1M	None	Part of ongoing costs	<\$1M	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
300	11.07.00	Post-closure administrative control (02.02.01.00.)	Administrative control of the sequestration site after closure of the project. The administrative control of the post-closure site may differ from that of the pre-closure site with subsequent implications for the resources available for administrative control, the degree of access and availability of information etc.	There may be potential for loss of information in any transfer of administrative control. A lack of awareness about the details of a CO2 sequestration project could result in inadvertent disruption in the future.	Post closure CO2-EOR requirements not as rigorous as CO2 sequestration.		Inadvertent intrusion into the CO2 reservoir. Loss of documentation in transfer of long-term liability.	Lack of post-closure administrative control.	CO2 release (HSE hazard). Delay or prevention of transferring long-term liability.	Data management. Routine site inspection.	Proper documentation and data management. Use multiple backup sites for data storage. Clearly mark site with warnings and register site as CO2 storage site with the State.	Data management. Routine site inspection and/or monitoring.
301	11.08.00	Quality Control (See 02.01.08.00.)	Features related to quality control procedures and tests during the design, and operation of the storage system. It could be expected that a range of quality control measures would be applied during operation of the storage system and supply of CO2 to be sequestered. There may be specific regulations governing quality control procedures, objectives and criteria.	The degree of quality control during the design, construction, operation and decommissioning of a sequestration system can affect the post-closure performance by influencing the integrity of the engineered parts of the system (borehole seals, for example) and by influencing the quantity, quality and accuracy of records. Quality of equipment could have a big impact on the project.	Wells and pipelines are regularly tested for mechanical integrity. Product is regularly tested for quality.		Equipment failure. Insufficient or inaccurate information to ensure safe storage of CO2.	Poor quality control	CO2 release (HSE hazard).	Risk management overseeing quality control.	Risk management overseeing quality control.	Formal risk management protocols and plan overseeing quality control.
302	11.09.00	Monitoring	There are many market and business conditions that should be monitored by management in order to make informed business decisions. These may include: 1. Environmental conditions 2. Public health 3. Public opinion 4. Legislation and regulations 5. Economic conditions 6. Operations 7. Natural resources 8. Water supply 9. Transportation logistics 10. Construction schedule 11. Climate change and weather conditions 12. Security 13. Pipeline 14. CO2/brine movement 15. Operating permit requirements.	Effective decision making requires timely knowledge and understanding of all factors that may influence or be influenced by the decision.	Wells are monitored for flow rate, temperature and pressure; annulus pressure and H2S.		Poor, or lack of, management decisions having a negative impact on the project.	Lack of knowledge or understanding of key factors that may influence or be influenced by management decisions.	Project delayed or impaired. Project ROI negatively impacted.	Assessment of monitoring systems in place.	Establish effective monitoring systems for key factors.	Hire independent auditors. To check the checkers. Hire additional outside monitoring services for key factors.
303	12.00.00.	ENGINEERING RISKS										
304	12.01.00.	Technical design	Technical design errors can be caused by: 1. Insufficient data 2. Lack of data - typical of greenfield sites 3. Inaccurate data 4. Misinterpretation of data 5. Use of wrong standards - unit conversion 6. Specification errors 7. Undefined specifications 8. Ignoring data 9. Calculation and modeling errors 10. Failure to design for full range of operating conditions and climate conditions. 11. Failure to design for high operating availability 12. Failure to design for failsafe protection for compression, pipeline, injection well control systems to ensure no unintended release of CO2	Technical design errors can lead to poor performance or failure of equipment/systems and possible CO2 release.	Over 40 years of CO2 injection, SACROC operators have tested and improved materials of construction and operating procedures to overcome issues with equipment reliability, corrosion and reservoir heterogeneity.		Poor performance or failure of equipment / systems.	Technical design errors.	Project delayed or impaired. Facilities damaged and/or personnel harmed. CO2 release (HSE hazard). Project ROI negatively impacted.	Monitor technical design through periodic design reviews.	Conduct periodic design reviews with cross-functional team of experts.	Conduct periodic design reviews with cross-functional team of experts. Correct design errors.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
300	11.07.00	Post-closure administrative control (02.02.01.00.)	2	2	2	8	None	None	None	None	None	None	None	None	None	Fines or penalties <\$1M	<\$1M	None	Part of ongoing costs	<\$1M	1
301	11.08.00	Quality Control (See 02.01.08.00.)	2	2	2	8	None	None	None	None	None	<\$1M	None	None	None	None	<\$1M	None	Part of ongoing costs	<\$1M	1
302	11.09.00	Monitoring	2	2	1	4	None	None	None	None	None	None	None	<\$1M	None	None	<\$1M	None	Part of ongoing costs	<\$1M	1
303	12.00.00.	ENGINEERING RISKS	0	0	0	0															
304	12.01.00.	Technical design	2	3	2	12	None	None	None	None	None	None	None	None	None	None	<\$10M	None	Part of ongoing costs	<\$10M	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
305	12.02.00.	Modeling and simulation	Use of multiple static and dynamic models that are populated and run by different people using different assumptions and methods can result in errors.	Modeling and simulation errors can result in uncertainties, interpretive disagreements and poor operational choices.	Models have been upgraded over time to improve simulation history matches and predictions.		Uncertainties and poor operational choices.	Modeling and simulation errors.	Project delayed or impaired. Facilities/systems damaged and/or personnel harmed. CO2 release (HSE hazard). Project ROI negatively impacted.	Monitor modeling and simulation through periodic reviews or checks to confirm accuracy.	Standardize model(s) to be used. Review simulation model results for accuracy and completeness using a cross-functional team of experts.	Periodic review of simulation model results.
306	12.03.00.	Baseline studies	Baseline surveys are important for determining ambient or background conditions prior to CO2 injection. They include: 1. Soil baseline 2. Water (surface and groundwater) baseline 3. Atmosphere baseline 4. Seismic baseline 5. Aquatic environment baseline 6. Fauna baseline 7. Flora baseline 8. Land use 9. Natural resources 10. Population 11. Local/regional economic baseline 12. Formation chemical baseline 13. Injection site contamination 14. Coastal features 15. Local oceanography 16. Aquatic sediments 17. Location and condition of existing wells 18. Formation geophysical baseline	Without baseline surveys the project will be unable to quantify what impact the project has had on the environment.	It is assumed that baseline studies were not completed prior to CO2 injection except for reservoir properties and performance.	Only details available relate to reservoir properties and performance.	Uncertainties and poor operational choices	Insufficient, or lack of, baseline studies	Project open to wide range of environmental liabilities that may or may not have been caused by the project. Project delayed or impaired. Project ROI negatively impacted. Injectivity or capacity different than expected.	Monitor the performance and quality of baseline studies.	Complete baseline studies before CO2 injection.	Review results of baseline studies.
307	13.00.00.	PROCUREMENT RISKS										
308	13.01.00.	Procurement delays	Procurement delays may threaten project goals. Infrastructure components may include power block, compressors, gas processing equipment, pumps, valving, metering and monitoring equipment. 1. Procurement delays - equipment and infrastructure 2. Procurement delays - drilling services 3. Vendor supply chain disruptions 4. Material supply shortages 5. Changes in materials and equipment costs	Could delay completion of construction	As a mature project, procurement delays are not a significant issue.		Project schedule disruption(s).	Procurement delays.	Project delayed. Project costs increased and project ROI decreased.	Track equipment and material delivery schedules.	Establish lead times for historically long-lead time items (like compressors) and build it into the schedule.	Monitor delivery schedule after orders are placed. Implement supply chain contingency plan.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
305	12.02.00.	Modeling and simulation	2	3	2	12	None	None	None	None	None	None	None	<\$10M	None	None	<\$10M	None	Part of ongoing costs	<\$10M	
306	12.03.00.	Baseline studies	2	3	2	12	None	None	None	None	None	None	None	<\$10M	None	10% of damage cost	<\$10M	None	Part of ongoing costs	<\$10M	1
307	13.00.00.	PROCUREMENT RISKS	0	0	0	0															
308	13.01.00.	Procurement delays	2	2	2	8	None	None	None	None	None	None	None	None	None	None	<\$1M	None	Part of ongoing costs	<\$1M	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
309	13.02.00.	Vendor errors	1. Vendor engineering errors 2. Defective manufacturing	Potential poor performance or failure of equipment/systems. Potential CO2 leakage.	Mature project.	Details not available	Poor performance or failure of equipment/systems.	Vendor errors	Project delayed or impaired. Facilities damaged and/or personnel harmed. CO2 release (HSE hazard). Project ROI negatively impacted.	Monitor vendor engineering, manufacturing, quality control and performance testing.	Use qualified vendors. Review vendor engineering, design and quality control testing. Negotiate performance guarantees.	Inspect/test delivered product.
310	13.03.00.	Contracting	The ability of project partners to formulate and execute contracts with third parties (non-partners) in a timely manner (not causing delays) apart from their specific contents. 1. EPC contract omissions 2. EPC contract insufficient detail 3. EPC contract change orders	The principal risk is delay and its impact upon achieving goals including cost.	Mature project.		Project schedule disruption(s). Increased EPC costs.	EPC contract omissions, errors or change orders	Project delayed. Project ROI negatively impacted.	Monitor EPC contract administration.	Use experienced contract administrator. Implement procedure for preparing request for quote (RFQ), RFQ review and bid review. Get at least 3 competitive bids on large contracts. Establish change order procedures.	Use experienced contract administrator. Hire additional experienced project administrators/consultants as necessary.
311	13.04.00.	Transportation logistics	Project-related traffic in and out of site; its effects upon both injection well, monitoring and CO2 supply operations. 1. Site traffic impact on injection and monitoring 2. Limitations on size/height/weight shipments to site	Could cause interruptions and delays.	Mature project.		Project schedule disruption(s). Increased transportation costs.	Transportation size/weight constraints	Project delayed. Project ROI negatively impacted.	Monitor transportation logistics.	Survey potential transportation routes before placing orders. Identify major weight/size items, supply/destination routes, weight/size restrictions, and alternate transportation modes and routes.	Monitor transportation logistics after orders are placed. Consider resolving any transportation bottlenecks by improving infrastructure. Implement supply chain contingency plan.
312	14.00.00.	CONSTRUCTION RISKS										
313	14.01.00.	Cost overruns	Construction cost overruns can be due to 1. Change orders 2. Cost escalation 3. Unexpected problems 4. Rework 5. Poor management.	Increased costs	Mature project. Cost overruns on expansions could adversely affect business (Kinder Morgan 2012).		Construction cost overruns	1. Change orders 2. Cost escalation 3. Unexpected problems 4. Rework 5. Poor management.	Project halted, delayed or impaired. Project ROI negatively impacted.	Track actual construction costs versus budget.	Negotiate not-to-exceed EPC contracts. Prepare detailed budget. Have experienced experts review budgets for accuracy and completeness.	Use experienced project managers. Monitor actual versus budgeted expenses. Monitor quality of work. Address deviations from plan early. Prioritize expenses. Cut low priority expenses if necessary. Adjust scope of work if necessary to stay within budget.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
309	13.02.00.	Vendor errors	2	2	2	8	None	None	None	None	None	None	None	None	None	None	<\$1M	None	Part of ongoing costs	<\$1M	
310	13.03.00.	Contracting	2	2	2	8	None	None	None	None	None	None	None	None	None	None	<\$1M	None	Part of ongoing costs	<\$1M	1
311	13.04.00.	Transportation logistics	2	2	2	8	None	None	None	None	None	None	None	None	None	None	<\$1M	None	Part of ongoing costs	<\$1M	1
312	14.00.00.	CONSTRUCTION RISKS	0	0	0	0															
313	14.01.00.	Cost overruns	2	3	2	12	None	None	None	None	None	None	None	None	None	None	<\$10M	None	Part of ongoing costs	<\$10M	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
314	14.02.00.	Schedule delays	Construction schedule delays can be due to 1. Permitting delays 2. Bad weather 3. Labor issues 4. Procurement delays 5. Accidents 6. Poor planning/management 7. Funding delays	Startup delay and increased costs.	Mature project. Delays on expansions could adversely affect business (Kinder Morgan 2012).		Construction schedule delays.	1. Permitting delays 2. Bad weather 3. Labor issues 4. Procurement delays 5. Accidents 6. Poor planning/management 7. Funding delays	Project halted, delayed or impaired. Project ROI negatively impacted.	Track actual versus planned schedule.	Build in cushion in schedule to accommodate unexpected delays. Address procedure for resolving schedule delays in project management plan.	Monitor work in progress versus schedule . Adjust schedule to accommodate unexpected delays.
315	14.03.00.	Construction defects	Construction defects may be identified during or after construction. They may include 1. Improper installation 2. Wrong installation 3. Damage during installation 4. Defective welding 5. Omissions	Increased costs, project delays due to need for rework, and potential human injury and equipment/systems damage	Mature project.		Construction defects.	1. Improper installation 2. Wrong installation 3. Damage during installation 4. Defective welding 5. Omissions	Project halted, delayed or impaired. Facilities damaged and/or personnel harmed. CO2 release (HSE hazard). Project ROI negatively impacted.	Monitor construction quality through regular inspections and testing.	Use qualified contractors. Issue detailed contracts and drawings. Inspect work.	Inspect work. Require contractors to repair any defects.
316	15.00.00.	COMMISSIONING AND STARTUP RISKS										
317	15.01.00.	Major rework	Major rework may be required to correct poor performance or failure of equipment/systems due to improper design, manufacturing, construction or operation.	Project delays and added costs.	Mature project. Facility capability demonstrated.		Schedule disruption. Increased cost.	Major rework.	Project ROI negatively impacted.	Track commissioning and startup performance.	Use experienced contractors. Construction management supervision.	Periodic site visits by stakeholders to inspect the work through the construction phase. Conduct periodic independent construction reviews.
318	15.02.00.	Unable to achieve design capacity	Operating capacity may be limited due to improper design, manufacturing, construction or operation.	Loss of revenues and increased costs.	Mature project. Capacity demonstrated.		Increased operating costs.	Unable to achieve design capacity	Project ROI negatively impacted.	Track commissioning and startup performance.	Design review process including sign off on drawings by competent engineers.	Performance testing. Resolution of bottlenecks.
319	15.03.00.	Operator error or over confidence during commissioning and startup	Incorrect operation due to lack of operator training	Potential human injury, equipment damage, project delays, added costs.	Mature project. Experienced operators. Good operator training program.	Data not available	Poor performance and/or equipment/system failure.	Operator error or over confidence.	Project halted, delayed or impaired. Facilities damaged and/or personnel injured. CO2 release (HSE hazard). Project ROI negatively impacted.	Track operator training and performance.	Implement a continuous operator training program.	Maintain an ongoing operator training program in the operation phase with particular emphasis on emergency response. Conduct periodic independent operating reviews.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
314	14.02.00.	Schedule delays	2	3	2	12	None	None	None	None	None	None	None	None	None	None	<\$10M	None	Part of ongoing costs	<\$10M	2	
315	14.03.00.	Construction defects	2	3	2	12	None	None	None	None	None	None	None	None	None	None	<\$10M	None	Part of ongoing costs	<\$10M	1	
316	15.00.00.	COMMISSIONING AND STARTUP RISKS	0	0	0	0																
317	15.01.00.	Major rework	2	3	2	12	None	None	None	None	None	None	None	None	None	None	<\$10M	None	Part of ongoing costs	<\$10M	1	
318	15.02.00.	Unable to achieve design capacity	2	3	2	12	None	None	None	None	None	None	None	None	None	None	<\$10M	None	Part of ongoing costs	<\$10M		
319	15.03.00.	Operator error or over confidence during commissioning and startup	2	3	1	6	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	Equipment or system failure.	Project delay or interruption	<\$10M Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$10M	None	Part of ongoing cost	<\$10M	1	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
320	15.04.00.	Startup pressure	Facilities sometimes do not have sufficient pressures to re-start injection. In these cases, injection tubing should be loaded with sufficient fluids to allow for a re-start. (CCP 2009)	Insufficient startup pressure can result in operating delays.	Mature project. Startup pressure demonstrated. Not an issue.		Operating delays.	Insufficient startup pressure.	Project ROI negatively impacted.	Monitor and model bottom hole pressure and injection pressure.	Design compressors/pumps with sufficient pressure to handle the full range of injection pressure required.	Load tubing with fluids prior to stating injection.
321	16.00.00.	FIELD SAFETY RISKS										
322	16.01.00.	Accidents and unplanned events (02.01.09.00.)	Events related to accidents and unplanned events during site investigation, CO2 emplacement and closure which might have an impact on long-term performance or safety. Accidents are events that are outside the range of normal operations although the possibility that certain types of accident may occur should be anticipated in operational planning. Unplanned events include accidents but could also include deliberate deviations from operational plans, e.g. in response to an accident, unexpected geological events or unexpected aspects of CO2 quality and injection arising during operations. Project related accidents can be caused by human error or equipment/system failure/malfunction. Accidents may occur during construction, commissioning, operation, maintenance or closure. Non-project related accidents may include: rupture of train or truck transport vessel, train derailment, site or water supply contamination. 1. Project related accidents 2. Non-project related accidents	Potential for human injury and/or equipment damage Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue. Accidents and unplanned events may affect the post-closure performance of the sequestration system. One example may be the incomplete sealing of an injection borehole that may subsequently provide a pathway for CO2 migration.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year Total fatality rates based on BLS data 2006-2010 (fatalities/worker/year) O&G extraction: 1.12E-04 Drilling O&G wells: 4.85E-04 Support activities for O&G wells: 2.85E-04 O&G pipeline construction: 1.94E-04 Pipeline transportation: 6.96E-05 O&G industry: 2.61E-04 Total significant injury (injuries requiring days away from work) rates based on BLS data 2006-2010 data (incidents/worker/year): O&G extraction: 6.29E-03 Drilling O&G wells: 1.50E-02 Support activities for O&G wells: 1.13E-02 O&G pipeline construction: 7.43E-03 Pipeline transportation: 5.96E-03 O&G industry: 2.61E-04		Human injury/death. Facilities / equipment damage. CO2 release.	Accidents and unplanned events.	Business interruption (advanced loss of profits). Liability costs.	Comprehensive risk assessment. Routine risk and safety audits.	Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement an emergency response plan and risk management plan. Analyze project changes for new risks.	Maintain safety training and standard procedures. Document response to accidents and unplanned events. Emergency response and contingency planning . Risk management plan. Liability insurance. Conduct periodic response drills.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #					Risk Ranking		Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
							Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury												
320	15.04.00.	Startup pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
321	16.00.00.	FIELD SAFETY RISKS	0	0	0	0															
322	16.01.00.	Accidents and unplanned events (02.01.09.00.)	3	4	2	24	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	<\$5M	Project delay, or interruption	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$10M	None	Part of ongoing costs	<\$10M per accident or unplanned event avoided	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
323	16.02.00.	Moving equipment	Moving equipment risks may include: 1. Hitting other equipment 2. Hitting personnel 3. Hitting power lines	Potential for human injury and/or equipment damage	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250. Approximately 3% of fatalities in the O&G industries were tied to pedestrians struck by a vehicle or mobile equipment in 2008 (BLS 2010). Fatality rate tied to pedestrian hit by moving equipment (assuming 15% of transportation incidents) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 5.94E-06 Drilling O&G wells: 1.82E-05 Support activities for O&G wells: 2.1E-05 O&G pipeline construction: 1.08E-05 Pipeline transportation: 5.97E-06 O&G industry: 1.52E-05 Significant injury rate tied to pedestrian being hit by moving equipment in drilling O&G		Facilities / equipment damage. Human injury/death. CO2 release (HSE hazard).	Improper operation of moving equipment.	Business interruption. Liability costs.	Monitor moving equipment on site.	Design site layout to safely accommodate moving equipment. Maintain moving equipment in safe operating condition. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
324	16.03.00.	Excavation/drilling	The one-call system should be used to locate underground utilities and pipelines before excavating or drilling. Excavation/drilling could hit other subsurface hazards such as gas pockets or underground storage tanks.	Potential for equipment damage, release of gases or liquids, fire, explosion, and/or human injury.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year. Fatality rate for drilling O&G wells based on BLS 2006-2010 data: 4.85E-04 fatalities/worker/year. Significant injury (injury requiring days away from work) rate for drilling O&G wells based on BLS 2006-2010 data: 1.55E-03		Pipeline damage. Human injury/death. CO2 release (HSE hazard).	Excavation/drilling.	Business interruption. Pipeline repair costs. Liability costs.	Monitoring excavation/drilling activities and one-call center alerts.	Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
323	16.02.00.	Moving equipment	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	Project delay, interruption	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$10M	None	Part of ongoing costs	<\$10M	1
324	16.03.00.	Excavation/drilling	3	4	2	24	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	Pipeline damage <\$1M per incident.	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
325	16.04.00.	Defective equipment	Equipment should be properly maintained and regularly inspected. Equipment defects may include: 1. Exposed electric wiring 2. Leaky hoses 3. Loose connections 4. Frayed cables	Higher risk for equipment failure and human injury	Fatality rate tied to contact with equipment (assuming 45% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.04E-05 Drilling O&G wells: 8.01E-05 Support activities for O&G wells: 3.02E-05 O&G pipeline construction: 2.41E-05 Pipeline transportation: 0 O&G industry: 3.25E-05 Significant injury rate due to being caught in an object equipment or material in drilling O&G wells based on BLS 2007 data: 3.88E-03 incidents/worker/year		Human injury/death. Facilities / equipment damage. CO2 release (HSE hazard).	Defective equipment	Project delayed or impaired. Liability costs. Project ROI negatively impacted.	Monitor equipment condition and maintenance records.	Maintain equipment in safe condition. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain equipment in safe condition. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
326	16.05.00.	Use of power tools	Operators should be properly trained in the use of power tools.	Potential for human injury and/or equipment damage	Fatality rate tied to contact with equipment (assuming 45% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.04E-05 Drilling O&G wells: 8.01E-05 Support activities for O&G wells: 3.02E-05 O&G pipeline construction: 2.41E-05 Pipeline transportation: 0 O&G industry: 3.25E-05 Significant injury rate due to being caught in an object equipment or material in drilling O&G wells based on BLS 2007 data: 3.88E-03 incidents/worker/year		Human injury/death.	Improper use of power tools.	Liability costs. Equipment repair costs.	Monitor operator training and use of power tools.	Select appropriate power tools. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain power tools in safe condition. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
325	16.04.00.	Defective equipment	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	5,000 to 50,000 t @ \$200/tCO2 released into USDW \$50,000/acre of land contaminate d	None	<\$2M	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$5M	None	Part of ongoing cost	<\$5M	2
326	16.05.00.	Use of power tools	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
327	16.06.00.	Contact with rotating equipment	Proper safeguards should be used to prevent contact with rotating equipment	Higher risk for being injured	Fatality rate tied to contact with equipment (assuming 45% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.04E-05 Drilling O&G wells: 8.01E-05 Support activities for O&G wells: 3.02E-05 O&G pipeline construction: 2.41E-05 Pipeline transportation: 0 O&G industry: 3.25E-05 Significant injury rate due to being caught in an object equipment or material in drilling O&G wells based on BLS 2007 data: 3.88E-03 incidents/worker/year		Human injury/death. Equipment damage.	Contact with rotating equipment.	Liability costs. Equipment repair costs.	Monitor activity around rotating equipment.	Install safeguards around rotating equipment. Lockout equipment before performing maintenance. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
328	16.07.00.	Working near pinch points	Proper safeguards should be used to prevent contact with pinch points	Higher risk for being pinched	Fatality rate tied to contact with equipment (assuming 45% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.04E-05 Drilling O&G wells: 8.01E-05 Support activities for O&G wells: 3.02E-05 O&G pipeline construction: 2.41E-05 Pipeline transportation: 0 O&G industry: 3.25E-05 Significant injury rate due to being caught in an object equipment or material in drilling O&G wells based on BLS 2007 data: 3.88E-03 incidents/worker/year		Human injury/death.	Working near pinch points.	Liability costs. Equipment repair costs.	Monitor activity around pinch points.	Install safeguards in pinch-point areas. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
327	16.06.00.	Contact with rotating equipment	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1
328	16.07.00.	Working near pinch points	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
329	16.08.00.	Working in confined areas	Working in confined areas can represent high risk especially where CO2 is involved.	Higher risk of asphyxiation or being crushed.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year.		Human injury/death.	Working in confined areas.	Liability costs. Equipment repair costs.	Monitor activity in confined areas.	Provide protective equipment and safeguards for working in confined areas, including CO2 alarm and ventilation if appropriate. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
330	16.09.00.	Working in high places	Working in high places is a common industrial occurrence	Higher risk of injury due to falling	Fatality rates tied to falls based on BLS data 2006-2010 (fatalities/worker/year) O&G extraction: 0 Drilling O&G wells: 5.27E-05 Support activities for O&G wells: 4.14E-06 O&G pipeline construction: 0 Pipeline transportation: 0 O&G industry: 1.15E-05 Significant injury rate resulting from falls to a lower level in drilling O&G wells in 2007 based on BLS data: 9.7E-04 incidents/worker/year		Human injury/death.	Working in high places.	Liability costs. Equipment repair costs.	Monitor activity in high places.	Provide protective equipment and safeguards for working in high places. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
331	16.10.00.	Working in trench/ditch	Pipeline construction involves trenching which is subject to cave-ins. Sufficient shielding or cave-in protection devices should be used if people go into a trench	High risk of being crushed and/or asphyxiated	Trench/ditch work limited due to the mature nature of the project.		Human injury/death.	Working in trench/ditch.	Liability costs.	Monitor activity in trenches / ditches.	Provide cave-in protection devices. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Supervise trench/ditch work. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
329	16.08.00.	Working in confined areas	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2
330	16.09.00.	Working in high places	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1
331	16.10.00.	Working in trench/ditch	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
332	16.11.00.	Working under a lifted load	Working under a lifted load should be avoided	Higher risk for being crushed	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250. Fatality rate tied to struck by object (assuming 55% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.28E-05 Drilling O&G wells: 9.85E-05 Support activities for O&G wells: 3.7E-05 O&G pipeline construction: 2.95E-05 Pipeline transportation: 0 O&G industry: 3.97E-05 Significant injury rate due to being struck by an object or flying debris in drilling O&G wells based on BLS 2007 data: 5.93E-03		Human injury/death.	Working under a lifted load.	Liability costs.	Monitor activity under lifted loads.	Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Supervise load lifting. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
333	16.12.00.	Contact with venomous snakes or insects	Field operations and data collection can be in close proximity to venomous snakes and insects in some parts of the country.	Potential for human injury.	Rattlesnakes, bees, wasps, fire ants, scorpions, black widows, brown recluse spiders and ticks are present in the region.		Human injury/death.	Contact with venomous snakes or insects.	Liability costs.	Monitor presence of venomous snakes and insects.	Clear work areas of stuff that would attract venomous snakes or insects. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Keep work areas clear of venomous snakes or insects. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
334	16.13.00.	Contact with poisonous plants	Field operations and data collection can be in close proximity to poisonous plants such as poison ivy or poison oak in some parts of the country.	Potential of human rash/irritation	Poison ivy, poison oak and poison sumac are present in the region.		Human injury.	Contact with poisonous plants.	Liability costs.	Monitor presence of poisonous plants.	Clear work areas of poisonous plants. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Keep work areas clear of poisonous plants. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
332	16.11.00.	Working under a lifted load	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2
333	16.12.00.	Contact with venomous snakes or insects	2	1	1	2	None	0 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	None	<\$0.1M	None	Part of ongoing costs	<\$0.1M	1
334	16.13.00.	Contact with poisonous plants	2	1	1	2	None	0 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	None	None	None	<\$0.01M	None	Part of ongoing cost	<\$0.01M	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
335	16.14.00.	Contact with hot surface, or exposure to heat or flame	Overheated equipment, welding areas, heaters and open flames are present at industrial sites.	Contact with hot surface or flame can cause burn injuries. Exposure to prolonged high temperatures can cause heat exhaustion or dehydration.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year.	Data not available	Human injury/death.	Contact with hot surface or exposure to heat or flame.	Liability costs.	Monitor activity near hot surfaces or open flames.	Install safeguards around hot surfaces or flames. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
336	16.15.00.	Exposure to noise	Operation of heavy equipment, pumps and compressors can generate loud noise.	Prolonged exposure to loud noise can cause hearing damage.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year.	Data not available	Human injury.	Exposure to noise.	Liability costs.	Monitor noise levels.	Provide hearing protection equipment. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
337	16.16.00.	Exposure to dust	Dust is generated in pipeline construction and field operations.	Prolonged exposure to dust can cause respiratory health problems.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year.	Data not available	Human injury.	Exposure to dust.	Liability costs.	Monitor dust levels.	Provide dust masks. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
335	16.14.00.	Contact with hot surface, or exposure to heat or flame	2	4	1	8	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1
336	16.15.00.	Exposure to noise	2	1	1	2	None	0 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	None	None	None	<\$0.1M	None	Part of ongoing cost	<\$0.1M	1
337	16.16.00.	Exposure to dust	2	1	1	2	None	0 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	None	None	None	<\$0.1M	None	Part of ongoing cost	<\$0.1M	2

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
338	16.17.00.	Exposure to hazardous materials	Fluids, fuels and chemicals used in field operations may be classified as hazardous materials.	Prolonged exposure to hazardous materials are known to cause health problems.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker /y Fatality rates tied to exposure to harmful substances or environments based on BLS data 2006-2010 (fatalities/worker/year) O&G extraction: 8.2E-06 Drilling O&G wells: 6.85E-05 Support activities for O&G wells: 2.07E-05 O&G pipeline construction: 1.65E-05 Pipeline transportation: 0 O&G industry: 2.5E-05 Significant injury rate due to exposure to harmful substances in drilling O&G wells based on BLS 2007 data: 6.04E-04	Data not available	Human injury/death.	Exposure to hazardous materials.	Liability costs.	Monitor presence of hazardous materials.	Properly identify and isolate hazardous materials. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
339	16.18.00.	Struck by object or flying debris	Drilling can often generate flying debris	Flying debris can cause human injury and/or equipment damage.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250. Fatality rate tied to struck by object (assuming 55% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.28E-05 Drilling O&G wells: 9.85E-05 Support activities for O&G wells: 3.7E-05 O&G pipeline construction: 2.95E-05 Pipeline transportation: 0 O&G industry: 3.97E-05 Significant injury rate due to being struck by an object or flying debris in drilling O&G wells based on BLS 2007 data: 5.93E-03	Data not available	Human injury/death.	Exposure to flying debris.	Liability costs.	Monitor for flying debris.	Install safeguards in area susceptible to flying debris. Provide safety glasses. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
338	16.17.00.	Exposure to hazardous materials	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2
339	16.18.00.	Struck by object or flying debris	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
340	16.19.00.	Release of compressed gases or liquids	Compressed CO2 pipelines, pressurized water lines, compressed air tanks are at risk for rupture.	Release of compressed gases or liquids can cause human injury and/or equipment damage.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year.	Data not available	Human injury/death.	Release of compressed gases or liquids.	Liability costs. Facilities repair costs.	Monitor work in areas near compressed gases or liquids.	Identify and protect/secure compressed gas/liquid lines, valves or tanks. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
341	16.20.00.	Ignition of flammable gases or liquids	Acetylene tanks, natural gas lines, liquid fuel lines could be ignited.	Ignition of flammable gases or liquids can cause explosions, severe injuries and property damage.	Flammable gases and liquids present at CO2-EOR surface facilities. No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250. Fatality rate tied to fires and explosions based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.91E-05 Drilling O&G wells: 4.48E-05 Support activities for O&G wells: 4.24E-05 O&G pipeline construction: 8.26E-06 Pipeline transportation: 0 O&G industry: 3.46E-05	Data not available	Human injury/death. Facilities / equipment damage.	Ignition of flammable gases or liquids.	Liability costs. Facilities / equipment repair costs.	Monitor work in areas near flammable gases or liquids.	Identify and isolate flammable gases and liquids. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
342	16.21.00.	Trips, slips and falls	Trips, slips and falls are common at industrial sites.	Potential for human injury	Fatality rates tied to falls based on BLS data 2006-2010 (fatalities/worker/year): O&G extraction: 0 Drilling O&G wells: 5.27E-05 Support activities for O&G wells: 4.14E-06 O&G pipeline construction: 0 Pipeline transportation: 0 O&G industry: 1.15E-05 Significant injury rate resulting from fall on same level in drilling O&G wells in 2007 based on BLS data (injuries/worker/year): 1.7E-03. Significant injury rate resulting from slips and trips in drilling O&G wells in 2007 based on BLS data	Data not available	Human injury/death.	Trips, slips and falls.	Liability costs.	Monitor work areas for potential causes of trips, slips and falls.	Clear work areas of items that would cause trips, slips or falls. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Keep work areas clear. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
340	16.19.00.	Release of compressed gases or liquids	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2
341	16.20.00.	Ignition of flammable gases or liquids	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	<\$2M	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$5M	None	Part of ongoing costs	<\$5M	2
342	16.21.00.	Trips, slips and falls	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
343	16.22.00.	Leaks and spills (related to oil spills rather than CO ₂ , H ₂ S and CH ₄)	Leaks and spills of lubricants, fuels, chemicals or hazardous materials are common at industrial sites. If they are not promptly taken care of they can lead to more serious problems.	Potential for human injury, equipment damage, fire or environmental damage.	No fatalities or significant injuries in past 40 years in CO ₂ -EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year. Potential for oil leak or spill.	Data not available	Human injury. Environmental damage.	Leaks and spills. Oil spill.	Liability costs. Environmental remediation costs.	Monitor stored/piped liquids.	Keep gases, liquids, solids contained. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Clean up any leaks or spills immediately. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning. Maintain risk management plan. Maintain liability insurance.
344	16.23.00.	Head bumping	Industrial sites are prone to have low hanging or falling objects that could injury unprotected heads	Potential for human head injury	Fatality rates tied to striking an object or equipment (assuming 5% of Contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.16E-06 Drilling O&G wells: 8.95E-06 Support activities for O&G wells: 3.36E-06 O&G pipeline construction: 2.69E-06 Pipeline transportation: 0 O&G industry: 3.61E-06 Significant injury rate due to being struck against an object in drilling O&G wells based on BLS data in 2007: 6.04E-04 incidents/worker/year	Data not available	Human injury/death.	Head bumping.	Liability costs.	Monitor wearing of hard hats in required areas.	Provide hard hats. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Place warning signs in low hanging areas. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning. Maintain risk management plan. Maintain liability insurance.
345	16.24.00.	Overexertion from manual heavy lifting, pulling, or pushing	Improper lifting of pipes, ducts, bars, boxes, bags, machine parts. Pulling/pushing wrenches, hoses, machine parts or heavy loads.	Potential for human back injury. Overexertion represented 11.3% of injuries requiring days away from work in drilling oil and gas wells in 2007. The injury rate was 2E-03 per worker per year.	No fatalities likely, unless complicated by heart attack or heat stroke. Overexertion represented 11.3% of injuries requiring days away from work in drilling oil and gas wells in 2007. The injury rate was 2E-03 per worker per year.	Data not available	Human injury/death.	Manual heavy lifting or pulling.	Liability costs.	Monitor heavy lifting or pulling activities.	Provide appropriate equipment for lifting or pulling heavy loads. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning. Maintain risk management plan. Maintain liability insurance.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
343	16.22.00.	Leaks and spills (related to oil spills rather than CO2, H2S and CH4)	2	4	3	24	None	None	None	<2,000 barrels of oil @ \$0.03M - \$0.09M per barrel of oil released.	Covered under natural resource damage	Damage to pipeline or storage tank <\$1M per incident	Pipeline shutdown for up to 30 days	Impacts profitability.	None	10% of damage cost	<\$100M	None	Part of ongoing cost	<\$100M	2
344	16.23.00.	Head bumping	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2
345	16.24.00.	Overexertion from manual heavy lifting, pulling, or pushing	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
346	16.25.00.	On-road driving	Vehicle travel to and from the site is typically among the highest risks in similar projects.	Potential for human injury and/or equipment damage	Kinder Morgan had 0.7 recordable vehicle accidents per 1 million miles driven. Approximately 31% of O&G industry fatalities were tied to highway transportation events in 2008 (BLS 2010). Fatality rates tied to highway driving based on BLS data 2006-2010. Assuming highway driving accounts for 56% of the fatality rates tied to transportation events.(fatalities/worker/year) : O&G extraction: 2.21E-05 Drilling O&G wells: 6.27E-05 Support activities for O&G operations: 7.84E-05 O&G pipeline construction: 7.27E-05 Pipeline transportation (operation): 2.23E-05 O&G industry: 5.66E-05. Injury rate requiring days away from work in drilling O&G wells tied to highway driving (assuming 56% of transportation incidents) based	No split between on-road and off-road driving.	Human injury/death. Vehicle / property damage.	On-road driving.	Liability costs. Vehicle and property damage repair.	Monitor on-road driving activity and road conditions.	Maintain vehicles in safe operating condition. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
347	16.26.00.	Off-road driving	Field data collection often requires off-road driving, sometimes in rocky, muddy, or steep terrain. Some personnel may lack experience with safe driving under challenging conditions.	Potential for human injury and/or equipment damage	Kinder Morgan had 0.7 recordable vehicle accidents per 1 million miles driven. Less than 3% of O&G industry fatalities were tied to off-road driving in 2008. (inferred from BLS data).	No split between on-road and off-road driving.	Human injury/death. Vehicle /property damage.	Off-road driving.	Liability costs. Vehicle and property damage repair costs.	Monitor off-road driving activity and driving conditions.	Maintain vehicles in safe operating condition. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
346	16.25.00.	On-road driving	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$2M	None	Part of ongoing costs	<\$2M	2
347	16.26.00.	Off-road driving	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$2M	None	Part of ongoing costs	<\$2M	2

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
348	16.27.00	Explosions and crashes (01.03.10.00.)	Events related to deliberate or accidental explosions and crashes such as might have some impact on a closed storage site, e.g. underground nuclear testing, an aircraft crash on the site, acts of war, marine collisions or trawler damage to exposed seabed structures. 1. Accidental explosions and crashes 2. Deliberate explosions and crashes 3. Project related 4. Non-project related	Explosions and crashes are likely to be low probability events that could have a significant impact on the performance of the sequestration system by disrupting the expected evolution of the system. Likely to have greater impact on surface facilities rather than subsurface systems.	One fire in 2006 when a pipe nipple blow out. No fatalities or significant injuries in past 40 years with average work force of 250. Approximately 13% of O&G industry fatalities are tied to fires and explosions (BLS 2010). Approximately 4% of O&G industry fatalities were tied to aircraft (helicopter) crashes in 2008 (BLS 2010). Fatality rate tied to fires and explosions based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.91E-05 Drilling O&G wells: 4.48E-05 Support activities for O&G wells: 4.24E-05 O&G pipeline construction: 8.26E-06 Pipeline transportation: 0 O&G Industry: 3.46E-05.	Data not available	Damage to surface facilities. Multiple human injury/death.	Explosions or crashes.	Liability costs. Property damage repair costs. Potential CO2 release.	Almost impossible to pre-detect.	Proper site characterization and site selection avoiding areas near heavily traveled flight paths, rail lines or busy highways. Provide motor vehicle crash barriers around surface facilities. Keep surface facilities secured from public access.	Procedures to shutdown and evacuate site in cases of imminent danger. Emergency response procedures/training. Maintain liability insurance.
349	16.28.00	Electric shock	Contact with electric current associated with electric machines, tools, appliances, light fixtures, overhead power lines, underground cables, transformers, wiring, and lightning.	Potential for human injury	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250.	Data not available	Human injury/death	Contact with electric current	Liability costs.	Monitor human activity near electrical areas.	Maintain electrical equipment in good working condition. Identify and avoid areas with overhead power lines or underground cables. Shut off power and lock out before working on electrical equipment.	Train operators how to respond to electric shock incidents.
350	17.00.00.	LEGAL, LEGISLATION & REGULATION RISKS										
351	17.01.00.	CO2 legislation	Some outstanding CO2 legislation issue are as follows: 1. Cap and Trade or Carbon tax incentives for CCS 2. Certification process for tradable carbon credits 3. Pore space access and ownership 4. Certification for transfer of long-term stewardship/liability for closed CO2 sites from operator to competent legal authority 5. Eminent domain authority 6. Forced unitization for EOR or ECBM 7. Priority of mineral rights over pore space rights 8. Value of escaped CO2	Legislation can have a significant impact on CCS project economics. Lack of, or gaps in, CO2 legislation can create uncertainty for the project and make it more difficult to permit and finance the project. Concerns that enacted CO2 legislation could be repealed or changed also contribute to uncertainty for the project and make it more difficult to finance.	Most legislation risks not applicable to CO2-EOR in a unitized field unless CO2 injection continues after EOR stops.	Lack of	Project uncertainties. Project economically infeasible.	Lack of CO2 legislation. Insufficient or onerous CO2 legislation.	Project halted or delayed. Project ROI negatively impacted.	Monitor federal and state CO2 legislation activity.	Tie investment in CCS projects to passage of appropriate CO2 legislation. Implement public outreach program to educate stakeholders on the legislative needs of the project. Shift from DSA to EOR or ECBM if CO2 legislation does not get passed, is insufficient or too onerous for DSA.	Monitor CO2 legislation and analyze the impact of CO2 legislation on the project. Continue public outreach program. Comply with CO2 legislation.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
348	16.27.00	Explosions and crashes (01.03.10.00.)	2	5	2	20	>1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	<\$5M	Project delay, or interruption	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$10M	None	Part of ongoing costs	<\$10M	1
349	16.28.00	Electric shock	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$2M	None	Part of ongoing costs	<\$2M	2
350	17.00.00.	LEGAL, LEGISLATION & REGULATION RISKS	0	0	0	0															
351	17.01.00.	CO2 legislation	2	2	1	4	None	None	None	None	None	None	None	<\$1M additional costs	None	None	<\$1M	None	<\$1M legal fees or additional reporting costs.	None	

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
352	17.02.00.	CO2 regulations	Some outstanding CO2 regulation issue are as follows: 1. CO2 storage permitting and compliance requirements 2. Permitting and compliance for Class VI wells 3. Permitting and compliance for hybrid Class II and VI wells (wells used for both EOR and DSA) 4. Post-injection site care (monitoring) period - EPA proposing 50 years with some flexibility 5. Safety guidelines - DOE best practices guidelines 6. Monitoring protocols - DOE guidelines 7. Verification and accounting procedures 8. Classification of CO2 as a pollutant rather than a commodity 9. CO2 emission controls and reporting 10. CO2 site straddling two states having to deal with differing regulations.	Regulations can have a significant impact on CCS project economics. Lack of, or gaps in, CO2 regulations can create uncertainty for the project and make it more difficult to permit and finance the project. Classification of CO2 as a pollutant rather than a commodity could impact EOR/ECBM operations.	New regulations and oversight, as well as changes in regulations, by regulatory agencies could adversely impact income and operations (Kinder Morgan 2012) CO2-EOR falls under UIC Class II wells, which are significantly less demanding than UIC Class VI wells. CO2 reporting regulations include CO2-EOR. Increased regulatory requirements relating to integrity of pipelines will require additional money to be spent to comply with these requirements (Kinder Morgan 2012)		Project uncertainties. Project economically infeasible.	Lack of CO2 regulations. Insufficient or onerous CO2 regulations.	Project halted or delayed. Project ROI negatively impacted.	Monitor federal and state CO2 regulation activity.	Tie investment in CCS projects to passage of appropriate CO2 regulations. Implement public outreach program to educate stakeholders on the regulation needs of the project. Shift from DSA to EOR or ECBM if CO2 regulations do not get passed, are insufficient or to onerous for DSA. Relocate project to different State if State regulations are not conducive to DSA.	Monitor CO2 regulations and analyze the impact of CO2 regulations on the project. Continue public outreach program. Comply with CO2 regulations.
353	17.03.00.	CO2 liabilities	Responsibility for the injected CO2 and any associated liability, during and after active project phase, is currently an unresolved legal issue. Project participants could reduce their involvement if this issue remains unresolved, or is resolved in a manner that unacceptably increases their exposure. 1. CO2 ownership and custody 2. Tort-injury to a third-party (person or property) 3. Property-rights dispute 4. Trespass - contamination of third-party natural resources 5. Trespass - infringement on third-party pore space 6. Breach of duty - leakage sufficient to undermine the value of carbon credits 7. Frivolous lawsuits private or organizational based legal challenges 8. Surface ownership and associated liability 9. Assigning liability responsibility in a multi-party project	Liability for potential damages associated with sequestration or operational aspects could preclude the project from moving forward. Property-right disputes over surface rights, mineral rights or pore space could halt or restrict construction, CO2 injection or monitoring operations for CCS projects.	CO2 ownership well defined. Pore space infringement and contamination of third-party resources unlikely due to KM control. Carbon credits not applicable to natural CO2. KM does not have surface ownership. KM has overall control of SACROC unit. Environmental, health and safety laws and regulations could expose KM to significant costs and liabilities (Kinder Morgan 2012).		Project uncertainties. Increased legal costs.	CO2 legal disputes.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor legal activities.	Obtain liability insurance.	Keep effective records. Maintain liability insurance.
354	17.03.01.	Insurance	There are many kinds of insurance coverage. Some of those that pertain to CCS include: 1. Physical damage 2. Machinery breakdown 3. Business interruption (advanced loss of profit) 4. Environmental 5. Third-party liability 6. Worker's compensation 7. Transportation 8. Closure and post-closure financial assurance 9. Operator's extra expense (OEE)	Insurance coverage may not be available for CCS projects until there is a sufficient track record of performance (or failure) to determine the probability of failure occurring.	Operator has been able to obtain necessary insurance.	Details not available	Project uncertainties. Increased costs.	Inability to get affordable insurance coverage.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor availability and cost of insurance coverage for CCS projects.	Work with a competent insurance broker to prepare an estimated maximum loss analysis, prepare underwriting reports for the project, and source insurance coverage. Self insure.	Work with a competent insurance broker to prepare an estimated maximum loss analysis, prepare underwriting reports for the project, and source insurance coverage. Self insure.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
352	17.02.00.	CO2 regulations	2	2	1	4	None	None	None	None	None	None	None	<\$1M additional costs	None	None	<\$1M	None	<\$1M legal fees or additional reporting costs.	None	
353	17.03.00.	CO2 liabilities	2	2	1	4	None	None	None	None	None	None	None	None	None	<\$1M legal expenses	<\$1M	None	<\$1M legal fees or additional reporting costs.	None	1
354	17.03.01.	Insurance	1	3	1	3	None	None	None	None	None	None	None	<\$10M additional costs	None	None	<\$10M	None	Self insurance. <\$10M	None	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
355	17.03.02	Transfer of long-term liability stewardship	Public companies cannot take on long-term liability for 50 years or more. There is no guarantee companies will stay in business that long. Therefore, it is up to a government entity to take on responsibility. The federal government would be preferred because it would level the playing field among states and spread the risks over more projects. A sinking fund could be used to cover the costs of such a program.	Companies are unlikely to invest in deep saline aquifer (DSA) sequestration projects without some assurance that the long-term liability is transferable or manageable.	Not applicable. CO2-EOR using natural CO2 does not have the long-term liability stewardship required for CO2-DSA.		Project uncertainties. Increased costs.	Inability to transfer long-term liability stewardship for CO2 storage.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor federal and state legislation on transfer of long-term liability stewardship for CO2 storage	Encourage the federal government to allow transfer of long-term liability of stored CO2 and establish a sinking fund for long-term stewardship of CO2 storage sites.	Monitor CO2 legislation and take corrective action as necessary. Establish long term O&M fund.
356	18.00.00.	CO2 CAPTURE RISKS										
357	18.01.00.	CO2 capture system performance	Performance risks for CO2 capture systems could include: 1. Production below design capacity 2. Unable to meet product specification 3. Low CO2 recovery 4. Low thermal efficiency - greater heat losses than expected, low heat recovery 5. Excess solvent or sorbent consumption 6. Excess power consumption 7. Excess steam consumption 8. Excess cooling water circulation required 9. Excess maintenance 10. Low process availability 11. Low mechanical availability	Poor performance of the CO2 capture system can result in higher operating and maintenance costs, interruption of CO2 supply, and/or off spec CO2.	Not applicable. Natural CO2 production system working successfully for 30 years. CO2 system used in gas recovery plants (for recycling CO2) is operating successfully.		High cost of CO2 capture. Off-spec CO2 stream. Low reliability of CO2 supply.	Poor performance of CO2 capture system.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor CO2 capture system operating performance.	Select commercially proven, reliable CO2 capture technology. Conduct design reviews using a cross-functional team of experts. Require performance test and process guarantees.	Monitor plant and process performance. Implement a comprehensive maintenance program. Operate at, or close to, steady state conditions.
358	18.02.00.	CO2 capture system design	Design deficiencies for CO2 capture systems could include: 1. Scale-up errors 2. Equipment undersized/oversized for proper residence time 3. Equipment undersized/oversized for proper surface area 4. Excess velocities 5. Inadequate expansion joints 6. System bottlenecks 7. Inadequate instrumentation 8. Inadequate process controls and alarms 9. Inadequate computer simulation models 10. Wrong sorption model for the contacting device 11. Insufficient winterization 12. Wrong materials of construction 13. Lack of emergency flare/vent 14. Lack of surge capacity 15. Lack of redundancy -backup systems	Design deficiencies can result in poor performance, higher operating and maintenance costs, interruption of CO2 supply, and/or off-spec CO2.	Not applicable. Natural CO2 production system working successfully for 30 years.		High cost of CO2 capture. Poor performance or failure of equipment/system.	CO2 capture design deficiencies.	Project halted, delayed or impaired. Facilities/equipment damage and/or human injury/death. CO2 release (HSE hazard).	Monitor technical design of CO2 capture system through periodic design reviews.	Negotiate process performance guarantees. Conduct design reviews using a cross-functional team of experts.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.
359	18.03.00.	CO2 capture system scale up limitations	The limits on scale up of the CO2 capture system could include: 1. Equipment size limits - manufacturing, transport, or structural load limits 2. Heat transfer limits 3. Mass transfer limits 4. Diffusion limits 5. Surface area limits 6. Reaction kinetics limits	Limits in scale up of the CO2 capture system can lead to higher capital cost and higher operating costs.	Not applicable. Natural CO2 production system working successfully for 30 years.		High cost of CO2 capture. Poor performance or failure of equipment/system.	Improper scale up of CO2 capture system.	Project halted, delayed or impaired. Facilities/equipment damage and/or human injury/death. CO2 release (HSE hazard).	Monitor technical design of CO2 capture system through periodic design reviews.	Determine limiting factor(s) for scale up. Size unit trains appropriately. Conduct design reviews using a cross-functional team of experts. Require performance test and process guarantees.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
355	17.03.02	Transfer of long-term liability stewardship	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
356	18.00.00.	CO2 CAPTURE RISKS	0	0	0	0															
357	18.01.00.	CO2 capture system performance	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
358	18.02.00.	CO2 capture system design	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
359	18.03.00.	CO2 capture system scale up limitations	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
360	18.04.00.	CO2 capture system operations	System operating risks for CO2 capture systems could include: 1. Non-equilibrium or non-steady-state conditions 2. Exothermic reactions overheating the process 3. Endothermic reactions overcooling the process 4. Pressure/stress buildup 5. Non-uniform mass distribution/dispersion/mixing – dead zones, stratification 6. Non-uniform temperature distribution – hot/cold spots, stratification 7. Mass and energy imbalance 8. System imbalance 9. Pressure or temperature cycling 10. System upset – unexpected high flow rate/temperature, carryover of upstream contaminants 11. Off-spec or inconsistent feed and/or product 12. Abrasion/erosion 13. Corrosion 14. Fouling 15. Contactor plugging 16. CO2 escape/leakage to the atmosphere 17. Scale build up causing heat exchanger failure 18. Air leakage - nitrogen dilution 19. Equipment failure due to defects, plugging, wear 20. Control system failure 21. Material/weld failure - leaks 22. Operator error	Operation and maintenance problems can result in higher operating and maintenance costs, CO2 supply interruptions and off-spec CO2.	Not applicable. Natural CO2 production system working successfully for 30 years. CO2 system used in gas recovery plants operating successfully.		High cost of CO2 capture. Poor performance or failure of equipment/system.	Operating problems with CO2 capture system.	Project halted, delayed or impaired. Facilities/equipment damage and/or human injury/death. CO2 release (HSE hazard).	Monitor CO2 capture system operating performance.	Select commercially proven, reliable CO2 capture technology. Implement a comprehensive maintenance program. Maximize operating time at steady state operation. Require performance test and process guarantees.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.
361	18.05.00.	CO2 capture solvent or sorbent	Solvent or sorbent risks for CO2 capture could include: 1. Off-spec or inconsistent solvent or sorbent 2. Unexpected contamination (SOx, NOx, Cl, H2O, hydrocarbons, trace metals, chemical slip, particulate matter) 3. Gradual buildup of contaminants in circulating loads 4. Foaming 5. Chemical reactions with contaminants - precipitation of solids 6. Excess viscosities 7. Chemical degradation of solvent or sorbent 8. Thermal degradation of solvent or sorbent 10. Aging (deactivation) of solvent or sorbent 11. Hazardous material handling	Off spec or degraded solvent or sorbent can result in poor CO2 capture, higher operating costs, CO2 supply interruptions, and off-spec CO2.	Not applicable. Natural CO2 production system working successfully for 30 years. Potassium carbonate CO2 system used in gas recovery plants operating successfully.		High cost of CO2 capture. Poor performance or failure of equipment/system.	Solvent/sorbent performance.	Project halted, delayed or impaired. Facilities/equipment damage and/or human injury/death CO2 release (HSE hazard).	Monitor CO2 capture solvent/sorbent performance.	Select commercially proven, reliable solvent/sorbent. Avoid system upsets and contaminants.	Monitor solvent/sorbent composition, properties, performance and losses. Determine root cause of deviations from expected results and take corrective action to resolve the problem.
362	19.00.00.	CO2 DEHYDRATION RISKS										

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Line #							Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
							Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury													
Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)																	
360	18.04.00.	CO2 capture system operations	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
361	18.05.00.	CO2 capture solvent or sorbent	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
362	19.00.00.	CO2 DEHYDRATION RISKS	0	0	0	0																

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
363	19.01.00.	CO2 dehydration system performance	Performance risks for CO2 dehydration systems could include: 1. Production below design capacity 2. Unable to meet product specification 3. Excess glycol consumption 4. Carryover of glycol into downstream systems 5. Excess utility consumption 6. Excess maintenance 7. Low plant process and/or mechanical availability	Poor performance of the CO2 dehydration system can result in higher operating and maintenance costs, interruption of CO2 supply, off spec CO2, and corrosion of downstream systems.	Natural CO2 dehydration system working successfully for 30 years.		Off-spec CO2. Low reliability of CO2 supply.	Poor performance of CO2 dehydration system.	Project delayed or impaired. Facilities/equipment damage due to corrosion. CO2 release (HSE hazard).	Monitor CO2 dehydration system operating performance.	Select commercially proven, reliable dehydration technology. Require performance test and process guarantees. Implement a comprehensive maintenance program. Maximize operating time at steady state operation.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.
364	19.02.00.	CO2 dehydration system operation	Operating risks for CO2 dehydration systems could include: 1. Upset conditions 2. Foaming in the contactor 3. Fouling 4. Buildup of liquid contaminants in recycled glycol 5. Buildup of solid contaminants in recycled glycol 6. Contactor plugging due to fouling 7. Reboiler tube failure due to fouling 8. Heat exchanger failure due to fouling 9. Pump seal failure due to fouling 10. Corrosion - wrong materials of construction 11. Oxidation degradation of glycol 12. Thermal degradation of glycol Dehydration units are normally fairly reliable as long as they are maintained properly avoid process upsets and/or contamination.	Operating problems in the CO2 dehydration system can result in higher operating and maintenance costs, interruption of CO2 supply, off spec CO2, and corrosion of downstream systems.	Natural CO2 dehydration system working successfully for 30 years.		Off-spec CO2. Low reliability of CO2 supply.	Operating problems with CO2 dehydration system.	Project delayed or impaired. Facilities/equipment damage due to corrosion. CO2 release (HSE hazard).	Monitor CO2 dehydration system operating performance.	Select commercially proven, reliable dehydration technology. Implement a comprehensive maintenance program. Avoid process upsets and contaminants.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.
365	20.00.00.	CO2 COMPRESSION RISKS										
366	20.01.00.	CO2 compression system performance	Performance risks for CO2 compression systems could include: 1. Output below design capacity 2. Unable to meet pressure specification 3. Excess power consumption 4. Excess maintenance 5. Low mechanical availability	CO2 operating performance is critical to success of a CCS project.	CO2 compressor performance has steady improved in recent years. CO2 compressor availability has increased from 91.7% in 2008 to 97% in 2011.		Off-spec CO2 pressure / flowrate. CO2 supply interruption.	Poor performance of CO2 compressors.	Project delayed or impaired. Facilities / equipment damage Project ROI lower than expected.	Monitor CO2 compression system operating performance.	Assure proper design and installation. Require performance test and process guarantees. Implement a comprehensive maintenance program. Try to maximize steady-state operation. Avoid upset conditions.	Resolve maintenance, system upsets and contamination problems quickly.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
363	19.01.00.	CO2 dehydration system performance	2	2	1	4	None	None	None	None	None	None	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	None	None	<\$1M	None	Part of ongoing costs	<\$1M	
364	19.02.00.	CO2 dehydration system operation	2	2	1	4	None	None	None	None	None	None	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	None	None	<\$1M	None	Part of ongoing costs	<\$1M	
365	20.00.00.	CO2 COMPRESSION RISKS	0	0	0	0															
366	20.01.00.	CO2 compression system performance	2	3	1	6	None	None	None	None	None	None	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	None	None	<\$10M	None	Part of ongoing cost	<\$10M	2

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
367	20.02.00.	CO2 compression system EPC	Engineering, procurement and construction (EPC) risks for compression systems could include: 1. Procurement delays - Compressors are typically one of the longest lead items for equipment 2. High capital cost - compression systems are one of the major capital costs for CCS projects 3. Improper specification 4. Metallurgical defect 5. Manufacturing defect 6. Improper installation	Delays in project startup. Increased capital cost. Operating problems resulting from improper specification or installation.	Mature operation. CO2 compression system already installed.		Construction/start up delays. Poor performance or failure of CO2 compression system. Higher capital / operating costs.	CO2 compression system EPC delays/defects/costs.	Project delayed or impaired. Facilities / equipment damage Project ROI negatively impacted.	Monitor CO2 compression system engineering, manufacturing, installation and performance testing.	Select a qualified EPC contractor. Require performance test and process guarantees.	Inspect and test equipment. Require vendor / contractor to fix defects.
368	20.03.00.	Compressor type	1. Reciprocating compressors - lower capital, higher maintenance, may require spare capacity 2. Centrifugal compressors - higher capital, lower maintenance 3. Screw compressors (dry type)	Type of compressors selected can impact capital costs, operating costs and operating availability.	Mature operation. Reciprocating and centrifugal compressors used.		Poor performance of CO2 compressors. Higher operating and maintenance costs. Lower CO2 availability.	Improper selection of CO2 compressors	Project delayed or impaired. Project ROI negatively impacted.	Monitor CO2 compressor selection process and operating performance.	Select qualified engineering company and vendors. Proper selection of the compressor type for the specific application.	Proper installation, operation and maintenance.
369	20.04.00.	Compression system operation	Operating risks for CO2 compression systems: 1. Improper operation - Intermittent operation of the compressor - Operating above/below recommended limits - Upset conditions - Operating compressor with control valve closed - Fouling by dust or liquid droplets - Plugging relief valves during depressurization - Corrosion - due to water in CO2 stream 2. Improper maintenance - Vibration - Noise - Overheating - Leakage 3. Wear and failure - Rod drop due to ring wear on recip. comp. - Rod run out or rod deflection on recip. comp. - Valve failure on recip. comp. - Bearing wear/failure - Tip wear on cent. comp. - Impeller blade failure on cent. comp. - Shaft failure - Compressor catastrophic failure	Downtime, loss of revenue, increased maintenance costs.	CO2 compressor availability has increased from 91.7% in 2008 to 97% in 2011.		Off-spec CO2 pressure / flowrate. CO2 supply interruption.	CO2 compression system operating problems.	Project delayed or impaired. Project ROI negatively impacted. Facilities / equipment damage. CO2 release (HSE hazard).	Monitor CO2 compression system operating performance.	Assure proper design and installation. Require performance test and process guarantees. Implement a comprehensive maintenance program. Try to maximize steady state operation. Avoid upset conditions.	Proper installation, operation and maintenance. Resolve maintenance, system upsets and contamination problems quickly.
370	21.00.00.	CO2 PIPELINE RISKS										
371	21.01.00.	Pipeline routing risks										
372	21.01.01.	New versus existing right-of-way (ROW)	ROW issues include: 1. Single or multiple pipeline rights 2. Width of ROW 3. Rights for above ground facilities 4. Access to site for repair/modification and inspections 5. Payment for original and continued use of ROW 6. Damage awards for the property owner 7. Requirement for pipeline removal upon abandonment of the pipeline. 8. Eminent domain - used as a last resort to gain access to ROW	Developing a new ROW is significantly more riskier than using an existing utility ROW.	Pipeline already installed.		High cost for right-of-way	Inability to acquire right-of-way at an affordable cost.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor right-of-way negotiations.	Maximize use of existing pipeline corridors in laying out pipeline right-of-way.	Design around problem areas.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
367	20.02.00.	CO2 compression system EPC	1	1	1	1	None	None	None	None	None	None	None	None	Impacts profitability.	None	None	None	None	None	None	2
368	20.03.00.	Compressor type	1	1	1	1	None	None	None	None	None	None	None	None	Impacts profitability.	None	None	None	None	None	None	1
369	20.04.00.	Compression system operation	2	3	1	6	None	None	None	None	None	None	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	None	None	<\$10M	None	Part of ongoing cost	<\$10M	1	
370	21.00.00.	CO2 PIPELINE RISKS	0	0	0	0																
371	21.01.00.	Pipeline routing risks	0	0	0	0																
372	21.01.01.	New versus existing right- of-way (ROW)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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373	21.01.02.	Climate conditions	Weather conditions can impact pipeline surface facilities 1. Severe high or low temperatures 2. Significant winds (tornadoes) 3. Lightning - common cause of pipeline damage 4. Heavy rain fall - flooding 5. Severe winter storms	Delays in construction and damage to surface facilities.	Pipeline already installed.		Construction schedule disruption(s). Damage to surface facilities. Human injury/death.	Severe climate conditions.	Project delayed or impaired. Project ROI negatively impacted. Liability costs.	Monitor weather forecasts for severe conditions.	Design pipeline surface facilities for full range of climate conditions. Avoid flood plains and steep slopes that may be susceptible to weather damage.	Monitor for severe weather reports.
374	21.01.03.	Soil and terrain conditions	1. Thin soil - insufficient to bury pipeline to depth 2. Corrosive soil - high moisture, high electrical conductivity, high acidity, and high dissolved salts 3. Rocky soil - special care needed in backfilling to protect pipeline 4. Unstable land - subsidence - uplift - landslides - earthquake area - active fault zone - high erosion areas - flood plains, dry wash - permafrost - frost heaves - high water table (marshes, swamps, peat bogs) - moving sand dunes - underground mine/coal mine areas - steep slopes >18% (landslides or erosion) 5. Rugged terrain/topography - mountains, hills, canyons, gorges 6. Significant elevation increase or variation over length of pipeline 7. Low lying areas 8. Exposed granite bedrock	1. Need to add soil to achieve 1.2 -1.8 m (4-6ft) burial depth 2. Accelerated external corrosion 3. Need fine backfill to protect pipeline 4. Can lead to unintended movement or abnormal loading of a pipeline resulting in mechanical damage, leakage or rupture. 5. Significantly higher installation cost 6. Increased compression or pumping costs due to higher pressure drop across pipeline 7. Potential for leaked CO2 to accumulate in low lying areas if there is insufficient escape velocity or wind to disperse the leaked CO2 to the atmosphere. 8. Very high costs for blasting a pipeline trench	Pipeline already installed.		High pipeline construction costs.	Soil/terrain conditions make pipeline installation difficult	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor pipeline right-of-way selection and assessment.	Avoid steep slopes, rugged terrain, flood plains, low-lying areas, rocky areas and unstable land.	Bring in fine backfill for pipeline in rocky areas. Regularly inspect and repair unstable areas. Design around problem areas.

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373	21.01.02.	Climate conditions	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
374	21.01.03.	Soil and terrain conditions	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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375	21.01.04.	Populated areas	A high population area means an urbanized area, as defined by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1000 people per square mile. This is designated a high consequence area. (49 CFR Part 195.450) Other populated areas are also designated as high consequence areas. Non rural areas categorized as high risk. Rural areas categorized as low risk. (49 CFR Part 195 Appendix B) Pipeline right-of-way must be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly. No pipeline may be located within 15 m (50 feet) of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate or assemble, unless it is provided with at least 0.3 m (12 inches) of cover in addition to that prescribed in Section 195.238 (49 CFR Part 195.210). CO2-CRC recommends a 30 m (100 ft) wide easement restricting access to the buried pipeline, a distance of 100 m (330 ft) minimum distance from residential buildings and a 1,000 m (3,300 ft) consultation zone on either side of the pipeline for emergency notification. 1. High population density nearby 2. Sensitive receptors (schools, hospitals, nursing homes, prisons) nearby 3. Business/industry/mining nearby 4. Residences nearby	The greater the number of people, the greater the risk of exposure to CO2.	Pipelines already installed. Cortez pipeline pass within 30 km of Albuquerque, NM. Bravo pipeline passes near Hobbs, NM. Cortez, Bravo, Centerline and Central Basin pipelines form hub near Denver City, TX. Centerline and Canyon Reef Carriers pipelines pass near Snyder, TX.		Higher pipeline construction and operating costs.	Pipeline right-of-way through or near existing or future high population density areas.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor current and potential population density in area of pipeline right-of-way.	Avoid densely populated areas for pipeline routing.	Design around densely populated areas. Implement a pipeline integrity management program in high consequence areas. Follow 49 CFR Part 195 regulations.
376	21.01.05.	Land crossings	1. Navigable water ways - Army Corp of Engineers permitting 2. Protected areas - Wetlands, migratory water bird concentration, national parks, habitats for imperiled, threatened, endangered or protected species (aquatic and terrestrial), archeological sites. (49 CFR Part 195.6) 3. Federal land - could trigger the need for permits from the US Army Corp of Engineers, the US Fish and Wildlife, the US Department of the Interior Bureau of Land Management (BLM), the US Department of Agriculture, Forest Service, the US Department of Defense. Also will trigger the National Environmental Policy Act (NEPA) and require Environmental Assessment (EA) or Environmental Impact Statement (EIS) 4. Tribal land - would trigger NEPA (EA or EIS) and the need for a permit from the US Department of Interior Bureau of Indian Affairs (BIA) 5. Transportation corridors - Railroads, highways, roads, bridges, other rights of way could trigger the need for permits from railroad companies, state/county departments of transportation. 6. Drinking water resource areas - 7. Non navigable surface waters - lakes, rivers, streams 8. Existing utility/pipeline rights-of-way	Land crossing increase cost and the need for additional permits.	Pipelines already installed. Cortez: 4 major river crossings (Animas, San Juan, Rio Grande and Pecos rivers).		Inability to obtain rights-of-way or pipeline construction permit. Higher pipeline construction and operating costs.	Pipeline crossing transportation corridors and/or sensitive land areas.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor transportation corridor and land crossings..	Avoid sensitive or high consequence areas. Keep crossings to a minimum.	Use seamless pipe and 2 m burial depth in crossings. Implement pipeline integrity management program in areas of high consequence. Follow 49 CFR Part 195 regulations. Regularly inspect and repair unstable areas. Post warning signs along right-of-way.

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375	21.01.04.	Populated areas	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
376	21.01.05.	Land crossings	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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377	21.01.06.	Offshore pipeline	The difficulty of offshore construction is roughly proportional to the depth multiplied by the pipeline diameter. (IPCC 2005). Some of the risks include: 1. Sea currents 2. Uneven seabed 3. Biological growth on pipeline 4. Arctic conditions (ice gouging)	Offshore pipeline have significantly higher costs.	Not applicable. Onshore pipeline		Very high pipeline construction and operating costs.	Offshore pipeline.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor offshore pipeline design, construction and operation.	Work with a qualified engineering firm to properly design offshore pipeline.	Regularly inspect and repair unstable areas.
378	21.02.00.	Pipeline design risks										
379	21.02.01.	Pipeline diameter	1. Large diameter Large diameter pipelines will release more CO2 in a rupture and are thus classified as having greater severity in the case of a failure such as a rupture. 2. Insufficient diameter for capacity Increased pressure required may place too much stress on the pipeline and components. Limits future expansion. 3. Excess diameter for capacity Resulting decreased pressure may put the CO2 at risk of changing from supercritical to two-phases. No room for turnaround.	High risk: Pipeline diameter 0.46 m (18 in) and above. Medium risk: Pipeline diameter from 0.25-0.4 m (10 to 16 in). Low risk: Pipeline diameter 0.2 m (8 in) and below. (49 CFR Part 195 Appendix B.	Pipeline diameter: Cortez: 30 in Bravo: 20 in CRC: 16 in CB: 26 in and 16 in Centerline: 16 in		Poor pipeline performance.	Improper selection of pipeline diameter.	Increased operating and maintenance costs. Limits on flowrate of CO2. Project ROI negatively impacted.	Monitor selection of pipeline diameter.	Size pipeline to effectively handle planned CO2 capacity with option for future capacity expansion by adding booster station(s).	Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
380	21.02.02.	Pipeline length	The longer the pipeline, the greater the risks.	Long pipeline more expensive, more potential for failure.	Pipeline length: Cortez: 808 km (502 mi) Bravo: 351 km (218 mi) CRC: 225 km (140 mi) CB: 230 km (143 mi) Centerline: 182 km (113 mi) Total: 1,796 km (1,116 mi)		High pipeline construction and operating costs.	Long pipeline.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor selection of pipeline route.	Keep pipeline length to a minimum without causing right-of-way issues.	Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
381	21.02.03.	Pipeline failure history (for existing pipeline)	Pipeline failure history for time-dependent defects can indicate probability of future failures.	High risk: >3 leaks in last 10 years. Low risk: ≤3 leaks in last 10 years. (49 CFR Part 195 Appendix B)	33 incidents reported on KM CO2 pipelines from 2002 - July 2012 11 significant incidents over 10.5 years based on PHMSA KM CO2 pipeline data: 1 significant incident/year (approximately 9.4E-04 significant incidents/mile/year). No injuries or fatalities. CO2 release from 0 to 941 t per incident (PHMSA 2012)		Pipeline leak	Use of an existing pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review failure history of existing pipeline.	Avoid use of existing pipeline unless the piping specification meets the requirements and sufficient maintenance/performance records are available.	Conduct inline and spot testing to confirm pipeline integrity.
382	21.02.04.	Pipeline age (for existing pipeline)	Safety risk increases with the age of the pipeline depending on the pipeline's coating and corrosion condition, and steel quality, toughness, welding.	High risk: >25 years old Low risk: <25 years old (49 CFR Part 195 Appendix C)	Year pipeline installed: Cortez: 1984 Bravo: 1984 CRC: 1972 CB: 1985 Centerline: 2003 11 significant incidents over 10.5 years based on PHMSA KM CO2 pipeline data: 1 significant incident/year (approximately 9.4E-04 significant incidents/mile/year). No injuries or fatalities. CO2 release from 0 to 941 t per incident (PHMSA 2012)		Pipeline leak	Old pipeline.	CO2 leak/rupture. (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Regularly inspect and test existing pipeline.	Avoid use of old pipeline unless the piping specification meets the requirements and sufficient maintenance/performance records are available, and sufficient testing can be done to confirm pipeline integrity.	Conduct inline and spot testing to confirm pipeline integrity.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
377	21.01.06.	Offshore pipeline	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
378	21.02.00.	Pipeline design risks	0	0	0	0															
379	21.02.01.	Pipeline diameter	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
380	21.02.02.	Pipeline length	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
381	21.02.03.	Pipeline failure history (for existing pipeline)	5	2	2	20	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	None	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
382	21.02.04.	Pipeline age (for existing pipeline)	5	2	2	20	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	None	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1

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383	21.02.05.	Pipeline pressure	All pipeline components must be designed and tested for at least 125% of maximum operating pressure (MOP). If, within a pipeline system, two or more components are to be connected at a place where one will operate at a higher pressure than another, the system must be designed so that any component operating at the lower pressure will not be overstressed. (49 CFR Part 195.104) Pipelines should be designed with sufficient pressure to maintain CO2 as a supercritical fluid. 1. Operating pipeline in excess of maximum operating pressure (MOP). 2. Operating pipeline below the CO2 supercritical pressure (CSP). 3. Insufficient working range between MOP and CSP.	Components operating at excessive operating pressure will be overstressed and subject to failure. Operating the pipeline at or below the supercritical pressure of CO2 can lead to CO2 phase change in the pipeline. If the supercritical CO2 drops back into the liquid-vapor, two-phase region (which occurs below 6.9 MPa (1000 psig) at ambient temperature), there would be freeze-up issues and a much higher pressure drop in the pipeline.	Maximum allowable operating pressure (MAOP): Cortez: 2698 psi Bravo: 2303 psi CRC: 2025 psi CB: 2466 psi Centerline: 2160 psi Significant incident rate due to pipeline pressure surge based on PHMSA KM CO2 pipeline data 2002- July 2012: 1.12E-05 significant incidents/year.		CO2 leak/rupture (HSE hazard).	Over pressuring CO2 pipeline.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline operating pressure.	Operate pipeline at less than 80% of maximum design pressure.	Operate pipeline at less than 80% of maximum design pressure. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
384	21.02.06.	Pipeline external loads	Anticipated external loads (e.g.), earthquakes, vibration, thermal expansion, and contraction must be provided for in designing a pipeline system. (See ASME B31.4). The pipe and other components must be supported in such a way that the support does not cause excess localized stresses (49 CFR Part 195.110). The pipe at each railroad and highway crossing must be installed so as to adequately withstand the dynamic forces exerted by anticipated traffic loads (49 CFR Part 195.256).	Insufficient design for external loads could lead to cracking and CO2 leakage.	No incidents reported.		CO2 leak/rupture (HSE hazard).	Excess pipeline external loads.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review pipeline external load calculations and construction drawings.	Use qualified contractor(s) to engineer, procure and construct the pipeline. Have an experienced engineer check external load factors.	Reinforce pipeline at crossings if necessary. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
385	21.02.07.	Pipeline wall thickness	Thicker pipe is typically used for sensitive areas like crossings. Wall thickness for 0.3 -0.36 m (12-14 in) pipe is typically 9.5 mm (0.375 in) except in sensitive areas like crossings where 12.7 mm (0.5 inch) wall thickness used for road crossings (up to 0.3 m (1 ft) past road right of way) and 15.9 mm (0.625 in) thickness used for railroad crossings. (DGC)	Thicker walls give a better safety margin.	Estimated wall thickness: Cortez: 0.786 in Bravo: 0.524 in CRC: 0.419 in CB: 0.681 and 0.419 in Centerline: 0.419 in	Data not available	CO2 leak/rupture (HSE hazard).	Thin pipeline wall.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review pipeline wall calculations and monitor pipeline wall thickness over time.	Select pipeline wall thickness that meets or exceeds codes.	Monitor wall thickness over the life of the project. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
386	21.02.08.	Pipeline steel grade	X65 carbon steel is typically used for CO2 pipeline if CO2 is dry and has low impurities such as H2S.	Pipeline steel grade determines pipeline maximum operating pressure	Cortez: A106 Gr B carbon steel CB: X-70		CO2 leak/rupture (HSE hazard).	Improper pipeline steel grade.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review steel grade selection for pipeline.	Select pipeline steel grade that meets or exceeds codes.	Monitor steel corrosion over life of the pipeline. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
387	21.02.09.	Pipeline temperature	CO2 increases in temperature as it is compressed and decreases in temperature as it expands. CO2 entering a pipeline may in the range of 49°C (120°F) however, it will gradually conform to the ambient ground temperature which may be in the range of 10°C (50°F). Components of CO2 pipelines that are subject to low temperatures during normal operation because of rapid pressure reduction or during the initial fill of the line must be made of materials that are suitable for those low temperatures. (49 CFR Part 195.102)	Improper material selection for pipeline components that may experience extreme cold due to rapid pressure reduction may result in component failure and CO2 leakage.	Temperature not to exceed 120°F (Havens 2008)	Actual data not available.	Damage to pipeline internal coating. CO2 leak/rupture (HSE hazard).	Too high or too low pipeline temperature.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline temperature.	Design compressor interstage coolers to maintain CO2 temperature below maximum. Install pipeline sufficiently deep.	Monitor pipeline temperature.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
383	21.02.05.	Pipeline pressure	4	2	1	8	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
384	21.02.06.	Pipeline external loads	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
385	21.02.07.	Pipeline wall thickness	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
386	21.02.08.	Pipeline steel grade	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
387	21.02.09.	Pipeline temperature	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
388	21.02.10.	Piping type	Seamless pipe is typically used for sensitive areas like crossings or near residences; double submerged arc welded or electric resistance welded pipe is typically used for other areas. (DGC)	Proper piping selection is important in sensitive areas to prevent risk of CO2 leakage.	Cortez: seamless		CO2 leak/rupture (HSE hazard).	Improper piping selection.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review piping selection.	Use seamless pipe for road, rail and creek crossings. Use ERW pipe for other areas.	Use additional reinforcement if necessary.
389	21.02.11.	Pipeline coating	CO2 pipelines are typically coated with fusion bonded epoxy to prevent corrosion. In addition piping used at bored crossings is overcoated with an abrasion resistant coating to prevent damage to the epoxy coating during installation. (DGC) 1. External coating 2. Internal coating	Damage to pipeline coating during installation or due to third-party excavation can result in external corrosion.	External coating used. Significant incident rate due to external corrosion based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 9.5E-02 significant incidents/year.		Pipeline corrosion.	Lack of, insufficient, improper or damaged pipeline coating.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline coating condition and performance.	Coat pipeline with fusion bonded epoxy.	Avoid damaging coating during transport and installation.
390	21.02.12.	Pipeline cathodic protection	Cathodic protection on CO2 pipelines is maintained by rectifiers located at main-line valve stations every 32 km (20 miles) or less along the pipeline. Cathodic protection is measured in voltage at test posts located at 1.6 km (1 mi) intervals over the length of the pipeline. The rectifier output is adjusted to maintain voltage levels between 0.85 and 1.4 volts at each test station. (DGC)	Insufficient or lack of cathodic protection could lead to external corrosion and CO2 leakage.	Cathodic protection used. Significant incident rate due to external corrosion based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 9.5E-02 significant incidents/year.		Pipeline corrosion.	Lack of, insufficient, improper or damaged pipeline cathodic protection.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline cathodic protection condition and performance.	Install cathodic protection and voltage test posts at every mile along the pipeline.	Monitor cathodic protection voltage over the length of the pipeline and adjust rectifier output to maintain appropriate voltage level.
391	21.02.13.	Pipeline booster stations or pumping stations	Booster or pumping stations are typically needed every 80-320 km (50 to 200 mi) depending on end-use pressure (EERC). Adequate ventilation must be provided in pumping station buildings to prevent the accumulation of CO2 gas. Warning devices must be installed to warn of the presence of CO2 gas in the pumping building. Safety devices to prevent over pressuring of primary and auxiliary pumping equipment and a device for emergency shutdown of each pumping station should be included. If power is necessary to actuate the safety devices, an auxiliary power supply should be included. (49 CFR Part 195.262) Take into account noise levels.	Insufficient booster or pumping stations could lead to low pressure at the end of the pipeline.	Number of booster stations: Cortez: 3 Bravo: 1 CRC: 6 Sufficient capacity demonstrated.		Insufficient pipeline pressure.	Insufficient booster or pumping stations.	Cost of increasing or upgrading booster station.	Monitor pipeline pressure.	Size pipeline to effectively handle planned CO2 capacity with option for future capacity expansion by adding booster station(s).	Leave space for booster stations.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
388	21.02.10.	Piping type	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
389	21.02.11.	Pipeline coating	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
390	21.02.12.	Pipeline cathodic protection	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
391	21.02.13.	Pipeline booster stations or pumping stations	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1

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392	21.02.14.	Pipeline future expansion	If there is potential for future expansion, it is practical to install taps for future branches, leave room for booster stations and design the pipeline to allow for expansion at higher pressure without having to replace piping and components. Pipeline diameter and pressure should take into account potential for future expansion through addition of booster stations and increased operating pressure.	Lack of reserved locations for booster stations, insufficient pipeline diameter, and excess operating pressure may make future expansion of pipeline capacity more difficult and more expensive.	Existing pipeline capacity is sufficient for the needs of the SACROC Northern Platform area. Cortez pipeline expandable from 1 BCFD to 4 BCFD.		Insufficient pipeline diameter for expansion.	Lack of planning for future pipeline expansion.	Excess operating pressure. Excess costs for pipeline expansion.	Monitor plans for future pipeline expansion.	Size pipeline to effectively handle planned CO2 capacity with option for future capacity expansion by adding booster station(s).	Leave space for booster stations.
393	21.02.15.	Pipeline flow velocity	Reported pipeline velocity varies from 0.9 to 4.6 m/s (3 to 15 ft/s). (IPCC 2005)	Excessive flow capacity could cause erosion in pipeline components.	Flow velocities fall within the acceptable range. Calculated flow velocity at 9.65 MPa (1400 psia) and 38°C (100°F): Cortez: 2.65 m/s Bravo: 1.09 m/s CRC: 1.28 m/s CB: 3.20 m/s Centerline: 1.61 m/s		Erosion of pipeline.	Excess pipeline flow velocity.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline flow velocity and wall thickness.	Design pipeline to stay within the safe range of CO2 velocity.	Adjust capacity or pressure to keep within the safe velocity range. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
394	21.02.16.	Pipeline SCADA system	Supervisory control and data acquisition (SCADA) system should have sufficient instrumentation for the central control room to monitor and control flow along the entire pipeline. The system should have built in redundancies to prevent loss of operational capability if a component fails. 1. IT security for SCADA system to protect against cyber-terrorism	Loss of the SCADA system could shut the pipeline down or result in pipeline failure and CO2 release.	SCADA systems installed. Significant incident rate due to malfunction of control or relief equipment based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 3.8E-01 significant incidents/year. Assume less than 5% tied to the SCADA system: <1.9E-02 significant incidents per year		Shutdown or failure of pipeline equipment/system.	Loss of, or malfunction of, SCADA system.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor SCADA system performance.	Comply with all 49 CFR Part 195 requirements for SCADA system.	Maintain SCADA system in good working order. Integrate backup system for critical functions. Develop and implement business continuity plan.
395	21.02.17.	Pipeline CPM leak detection systems	Computational pipeline monitoring (CPM) leak detection system must comply with section 4.2 of API 1130. (49 CFR Part 195.134). CPM leak detection can be based on acoustics, measurement of chemical release, detecting pressure changes or small changes in mass balance.	Lack of a properly designed CPM leak detection system prevents the pipeline operator from rapid detection and response to CO2 leaks. Inaccurate modeling of CO2 dense phase can cause the computational leak detection system to malfunction.	CPM leak detection systems installed.		Failure to detect CO2 leak/rupture.	Loss of, or malfunction of, CPM leak detection system	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor CPM leak detection system performance.	Comply with all 49 CFR Part 195 requirements for computational pipeline monitoring and leak detection system.	Maintain the CPM leak detection system in good working order.

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
392	21.02.14.	Pipeline future expansion	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
393	21.02.15.	Pipeline flow velocity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
394	21.02.16.	Pipeline SCADA system	4	2	1	8	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
395	21.02.17.	Pipeline CPM leak detection systems	2	2	2	8	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
396	21.02.18.	Pipeline block valves or control valves	Main-line valves (block or control valves) are located on either side of water crossings and approximately every 32 km (20 mi) overland in order to allow for quick isolation and to minimize the impact of a leak. (DGC) Valves must be installed at each of the following locations: on the suction end and discharge end of a pump station, on each mainline at locations along the pipeline system that will minimize damage or pollution from CO2 discharge, on each lateral takeoff from the trunk line, on each side of a water crossing that is more than 30 m (100 ft) wide and on each side of a reservoir that is holding water for human consumption. (49 CFR Part 195.260) Each valve must be installed in a location that is accessible to authorized employees and that is protected from damage or tampering. (49 CFR Part 195.258)	The distance between main-line valves determines the amount of CO2 released in a rupture. Longer spacing means a larger volume of CO2 is likely to escape.	Block valves installed.		Inability to section off pipeline in an emergency.	Insufficient number of, improperly designed, improperly installed, or failure of block valve(s).	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor block valve specification, installation and operating condition.	Comply with all 49 CFR Part 195 requirements for block valves.	Maintain all block valves in good working order.
397	21.02.19.	Pipeline internal inspection devices	Pipelines must be designed and constructed to accommodate the passage of instrumented internal inspection devices (i.e. smart pig). 49 CFR Part 195.120) No operator may use a launcher or receiver that is not equipped with a relief device capable safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. (49 CFR Part 195.426)	Internal inspection devices are important tools for detecting corrosion or mechanical damage in pipelines before they fail.	Smart pigs used for internal inspections.		Poor performance or failure of internal inspection device.	Improperly designed internal inspection device system.	CO2 leak (HSE hazard). Pipeline damage. Damage repair costs.	Monitor internal inspection device specification, installation, and operating condition.	Comply with all 49 CFR Part 195 requirements for internal inspection devices.	Maintain internal inspection devices and system in good working order.
398	21.02.20.	Pipeline seals	Teflon or nylon have been used for seals to prevent swelling. (Meyer 2007).	Improper sealing materials may react with CO2 and cause CO2 leakage	Significant incident rate due to seal failure (excluding pumps) on PHMSA KM CO2 pipeline data from 2002- July 2012: 0 significant incidents/year		Seal failure.	Improper design of seals.	CO2 leak (HSE hazard).	Monitor seal specification, installation, and operating condition.	Select seal materials that have been successfully tested for use with CO2.	Maintain seals in good working order. Monitor for leaks.
399	21.02.21.	Pipeline winterization	Winterization (protection from severe cold/ice) may be needed for above ground facilities in cold climates.	Lack of winterization can cause CO2 pipeline instrumentation lines and valves to freeze up in severe cold/icy weather.	Not applicable for this project.		Freezing weather damage to surface equipment / facilities.	Lack of pipeline winterization.	CO2 leak (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline winterization status and severe weather forecasts.	Provide sufficient shelter/insulation for sensitive surface facilities.	Monitor severe weather conditions. Train operators how to maintain operation during severe winter weather.
400	21.02.22.	Pipeline burial depth	CO2 pipelines are typically buried a minimum of 1.2 m (4 ft) over the length of the pipeline, ≥1.5 m (5 ft) below roads, ≥3 m (10 ft) below railroads, ≥1.2 m (4 ft) below ditches and ≥3 m (10 ft) below water line on shores. (DGC). Minimum burial depth for pipeline is 0.9 m (36 in) for industrial commercial and residential areas, 1.2 m (48 in) for crossing of inland bodies of water, 0.9 m (36 in) for drainage ditches at public roads and railroads, 1.2 m (48 in) for deepwater port safety zones, 0.9 m (36 in) for offshore areas and 0.8 m (30 in) elsewhere. There are exceptions for rock excavation areas. (49 CFR Part 195.248)	Insufficient burial depth makes pipeline more susceptible to excavation damage, sabotage, climate damage etc.	Burial depth greater than 1 m.		Pipeline mechanical damage.	Insufficient burial depth.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline burial depth.	Bury pipeline to meet or exceed compliance with 40 CFR Part 195.	Regularly inspect and maintain burial depth of pipeline.

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Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
396	21.02.18.	Pipeline block valves or control valves	5	2	1	10	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
397	21.02.19.	Pipeline internal inspection devices	2	2	2	8	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
398	21.02.20.	Pipeline seals	3	2	2	12	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
399	21.02.21.	Pipeline winterization	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
400	21.02.22.	Pipeline burial depth	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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401	21.02.23	Pipeline bedding and foundation structures	Pipeline bedding and foundation structures are designed to hold a pipeline stable throughout its life. This is particularly important for offshore pipelines.	Improper design of pipeline bedding or foundation structures could result in pipeline shifting or buckling.	Significant incident rate due to pipeline bedding and foundation structures based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 0 significant incidents/year		Shifting of pipeline.	Improper pipeline bedding and foundation structures.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline bedding and foundation structures.	Comply with all 49 CFR Part 195 requirements for pipeline bedding and foundation structures.	Regularly inspect pipeline for signs of shifting or buckling.
402	21.03.00.	Pipeline defects										
403	21.03.01.	Pipeline material defects	During the manufacturing of steel, impurities can sometimes remain in the molten steel. These impurities can cause an incomplete bonding of the material in the steel plate or solid round billet used to produce pipe and other pipeline components. reduce the wall thickness of the pipe or pipeline component, and, if large enough, can reduce the pressure-carrying capacity of the pipe or component. Some pipeline material defects include: 1. Propagating cracks - very rapid propagating cracks can occur that "unzip" the pipeline along its length. 2. Laminations and inclusions - caused by oxides or impurities trapped in the steel 3. Blisters and scabs - raised spots on steel surface caused by expansion of trapped gases within the steel 4. Hard spots - created by localized cooling of the steel plate (ERW pipe) during rolling 5. Indentations - formed by the expanders or mandrels used to make seamless pipe 6. Transit fatigue - cracks formed when pipes are repeated flexed during transportation and handling 7. Cyclic fatigue - cracks caused by stress from repeated fluctuating operating pressure within the pipe 8. Elastomer and polymer - failure due to reaction with CO2	1. Propagating cracks can lead to pipeline rupture. 2. A lamination or inclusion can eventually lead to failure if they eventually grow to the inner or outer wall of the pipe or pipeline component through pressure cycles. 3. Blisters and scabs reduce the wall thickness of the pipe and, if large enough, can reduce the pressure-carrying capacity of the pipe or component. 4. Cracking can occur at hard spots that eventually grows in size over time. 5. Stress risers can occur at indentations if they are too deep, eventually leading to pipe failure. 6. Transit fatigue cracks are typically discovered during the hydrostatic pressure testing however, some can remain and grow during pipeline pressure cycles until a failure occurs. 7. Can lead to CO2 leakage. 8. Failure of elastomers and/or polymers could lead to CO2 leakage.	Significant incident rate due to material defects based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 0 significant incidents/year.		Pipeline mechanical failure.	Pipeline material defects.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline manufacturing and quality control testing.	Select a competent pipe manufacturer. Inspect and test pipe before burial. Proper design, manufacturing, installation and maintenance of the pipeline.	Use of crack arrestors to mitigate propagating cracks.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
401	21.02.23	Pipeline bedding and foundation structures	1	1	2	2	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
402	21.03.00.	Pipeline defects	0	0	0	0															
403	21.03.01.	Pipeline material defects	3	2	2	12	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
404	21.03.02.	Pipeline weld defects	Some pipeline weld defects include: 1. Pinholes - small, unwelded area extending through the entire thickness of the weld 2. Toe cracks - occur where the crown of the weld bead intersects the edge of the plate in pipe joined using the Double Submerged Arc Welding (DSAW) 3. Off seam welding - crack caused by the inside and outside welds of the DSAW process being offset 4. Undercutting - occurs when there is an inadvertent reduction in the wall thickness in the area of the weld 5. Incomplete fusion - occurs when there is a lack of complete fusion of the weld and the base metal 6. Porosity - occurs when one or more voids are created in the weld material from shrinkage of the material 7. Slag inclusions - exist when non-metallic material becomes trapped in the weld 8. Weld defects in older pipe - Burnt pipe edges - Incomplete fusion - Hook cracks - Cold welds - Weld metal cracks For more details, see PHMSA.	Weld defects can lead to CO2 leakage	Significant incident rate due to weld defects based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 9.5E-02 significant incidents/year.		Pipeline weld failure.	Pipeline weld defects.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline welding and quality control testing.	Comply with all 49 CFR Part 195 welding requirements. Use certified welders. Inspect and test welds prior to burial.	Replace welds that do not pass inspection and testing.
405	21.03.03.	Pipeline equipment defects	Equipment failures involve pumps, compressors, valves, meters, tanks, control/relief equipment and other components and devices on pipeline systems. (PHMSA). Can include broken couplings, stripped threads.	Equipment is often located on company property that is not accessible to the public. Equipment failure usually results in a CO2 release that is contained on public property typically not resulting in injury to the general public. (PHMSA)	Significant incident rate due to equipment defects based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 0 significant incidents/year.		Equipment failure. Damage to equipment / system.	Pipeline equipment defects.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor equipment operation and maintenance.	Proper selection, operation and maintenance of equipment.	Monitor for equipment vibration or performance changes. Determine root cause and repair.
406	21.04.00.	Pipeline corrosion	About 15% of gas pipeline failures in Europe are caused by corrosion (EGIG 2008)	Corrosion can lead to pipe failure and CO2 leakage.								
407	21.04.01.	External corrosion	Galvanic corrosion can take place when an unprotected metal pipeline comes in contact with water or soil. 1. External corrosion of buried pipe 2. External corrosion of surface pipe	Corrosion can lead to pipe failure and CO2 leakage.	Cathodic protection and external coating used. Significant incident rate due to external corrosion based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 9.5E-02 significant incidents/year.		Pipeline failure.	External corrosion of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline external corrosion.	Comply with all 49 CFR Part 195 pipeline corrosion protection requirements.	Regular inspections, testing, cleaning and maintenance of pipeline.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
404	21.03.02.	Pipeline weld defects	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
405	21.03.03.	Pipeline equipment defects	3	2	2	12	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
406	21.04.00.	Pipeline corrosion	0	0	0	0															
407	21.04.01.	External corrosion	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
408	21.04.02.	Internal corrosion	There is potential for rapid corrosion of steel pipeline if free water becomes present in the CO2 stream. There is currently insufficient data to adequately understand the effect of an accidental flow of high water content CO2 into a pipeline and also the influence the various CO2 impurities (O2, H2, SOx, NOx, H2S TEG, MEG and amines/NH3) will have on the corrosion rates. (DNV CO2PIPETRANS Phase 2). Corrosion rate of carbon steel in dry supercritical CO2 is low. For AISI 1080 values around 12.5 microns per year have been measured at 9-12 MPa (90-120 bar) and 160-180°C for 200 days. During 12 years, the corrosion rate in an operating pipeline amounted to 0.25-2.5 microns per year.	Corrosion can lead to pipe failure and CO2 leakage.	Dry CO2 and regular internal inspection with smart pigs used. Significant incident rate due to internal corrosion based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 0 significant incidents/year		Pipeline failure.	Internal corrosion of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline internal corrosion.	Comply with all 49 CFR Part 195 pipeline corrosion protection requirements. Use dry CO2.	Avoid free water in pipeline. Clean pipeline internals. Regularly inspect pipeline for corrosion. Use smart pigs. Repair any corrosion damage as needed.
409	21.04.03.	Microbial corrosion	Microbial corrosion is corrosion promoted by microorganisms such as chemoautotrophs which can produce hydrogen sulfide, sulfuric acids, other acids or ammonia. Some bacteria directly oxidize iron to iron oxide or iron hydroxide.	Hydrogen sulfide can cause corrosion and sulfide stress cracking.	Significant incident rate due to microbial corrosion based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 0 significant incidents/year		Pipeline failure.	Microbial corrosion of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline microbial corrosion.	Comply with all 49 CFR Part 195 pipeline corrosion protection requirements.	Regularly inspect pipeline for corrosion using smart pigs. Repair any corrosion damage as needed.
410	21.04.05.	Selective seam corrosion	Selective seam corrosion (SSC) is a form of corrosion that tends to affect pipe manufactured prior to 1970 using low-frequency electric resistance welding (LR-ERW) or electric flash welding (EFW) processes. SSC is a localized corrosion attack along the weld bond line of ERW and EFW pipe, that leads to the development of a wedge shaped groove that is often filled with corrosion products. (PHMSA)	Risk for older LF-ERW or EFW pipe, not HF-ERW, DSAW or seamless pipe. (PHMSA)	Not applicable to this project.		Pipeline failure.	Selective seam corrosion of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor for selective seam corrosion if pipe manufactured prior to 1970.	Use newly manufactured pipe for construction of pipeline.	Regularly inspect pipeline for corrosion using smart pigs. Repair any corrosion damage as needed.
411	21.0404.	Stress corrosion cracking	Stress corrosion cracking (SCC) is a form of corrosion that produces a marked loss of pipeline strength with little metal loss. The combined influence of pipeline stress due to its pressurized contents and a corrosive medium can occasionally result in the formation of interlinking crack clusters that can grow until the affected pipe fails. (PHMSA)	Stress corrosion cracking can result in pipe failure and CO2 leakage.	Significant incident rate due to stress corrosion cracking based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 0 significant incidents/year		Pipeline failure.	Stress corrosion cracking of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline stress corrosion cracking.	Maintain pipeline pressure at less than 80% of maximum design pressure. Avoid moisture in the CO2 stream.	Monitor for moisture in the CO2. Regularly inspect pipeline for corrosion using smart pigs.
412	21.05.00.	Pipeline mechanical damage	Mechanical damage consists of dents, gouges, cracks, punctures, stress risers or ruptures.	Mechanical damage of a pipeline can lead to immediate or eventual/accelerated CO2 leakage.								

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P>S>D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
408	21.04.02.	Internal corrosion	3	2	2	12	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
409	21.04.03.	Microbial corrosion	3	2	2	12	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
410	21.04.05.	Selective seam corrosion	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
411	21.0404.	Stress corrosion cracking	3	2	2	12	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
412	21.05.00.	Pipeline mechanical damage	0	0	0	0															

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
413	21.05.01.	Excavation damage	About 50% of pipeline failures in Europe and 33% in the US are caused by excavation damage. Excavation damage can include damage to the external coating of the pipe, or dents, scrapes, cuts, or punctures directly into the pipeline itself. The damage can be caused by any type of excavation, including digging, grading, trenching and boring, road and highway maintenance, general construction and farming activities. It normally occurs when excavators fail to call their local one-call system to mark where underground facilities are located prior to excavating. (PHMSA)	Excavation can lead to pipeline damage and CO2 leakage.	Significant incident rate due to third-party damage based on PHMSA CO2 pipeline data from 1986 - July 2012: 1.12E-05/mile/year. Assume 1,116 miles combined pipeline length: 1.25E-02 significant incidents/year.		Pipeline mechanical damage.	Excavation near pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor excavation activity near pipeline.	Comply with all 49 CFR Part 195 excavation safety requirements including deep burial of pipeline, proper marking of ROW, regular ROW inspections, supervision of third-party excavation, and one-call system.	Train emergency response team to rapidly address excavation damage. Educate local residents how to identify and report leaks or damage.
414	21.05.02.	Natural force damage	Natural force damage includes damage from landslide, flood, heavy rains, riverbed scouring and washouts, dike breaks, subsidence, earthquakes, high winds, tornadoes, hurricanes, lightning, frost heaves, and frozen instrumentation lines. (PHMSA)	Can lead to unintended movement or abnormal loading of a pipeline resulting in mechanical damage, leakage or rupture.	Significant incident rate due to natural force damage based on PHMSA CO2 pipeline data from 1986 - July 2012: 1.12E-05 significant incidents/mile/year. Assume 1,116 miles combined pipeline length: 1.25E-02 significant incidents/year.		Pipeline mechanical damage.	Natural forces.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor natural force incidents near pipeline.	Comply with all 49 CFR Part 195 inspection requirements.	Maintain ROW to make it visually accessible from the air and physically accessible on the ground. Repair any eroded or damaged areas. Educate local residents how to identify and report leaks or damage.
415	21.05.03.	Other outside force damage	Other outside force damage excludes excavation but include such things as vehicle accident (hitting above ground valve or booster station), electric arcing from nearby power lines, vandalism, sabotage, terrorist attack, theft, fires from other businesses or industries, etc. (PHMSA) Most susceptible to this particular type of damage are above ground pipeline facilities which are in close proximity to highways or large population and industrial centers.	Mechanical damage of a pipeline can lead to immediate or eventual/accelerated CO2 leakage.	Significant incident rate due to third-party damage based on PHMSA CO2 pipeline data from 1986 - July 2012: 1.12E-05/mile/year. Assume 1,116 miles combined pipeline length: 1.25E-02 significant incidents/year.		Pipeline mechanical damage.	Other outside forces.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor human activity near pipeline right-of-way.	Comply with all 49 CFR Part 195 security requirements. Fence in and secure surface facilities. Direct traffic patterns and speeds to prevent accidents.	Monitor site activity. Train operators to handle security issues and emergencies. Educate local residents how to identify and report leaks or damage.
416	21.05.04.	Mechanical damage requiring immediate repair	Metal loss greater than 80% of nominal wall thickness. Dent located on the pipeline (above 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser. Dent located on the pipeline (above 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter. (49 CFR Part 195.452)	Mechanical damage can require immediate repair to prevent CO2 leakage.	Not reported.	Data not available. Assume that immediate repairs are handled in a timely manner.	CO2 leak/rupture (HSE hazard).	Failure to repair significant mechanical damage immediately.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor reports of pipeline mechanical damage and response time.	Comply with all 49 CFR Part 195 for repair of mechanical damage to pipeline.	Train employees to repair mechanical damage in a timely manner.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
413	21.05.01.	Excavation damage	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
414	21.05.02.	Natural force damage	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
415	21.05.03.	Other outside force damage	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
416	21.05.04.	Mechanical damage requiring immediate repair	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
417	21.05.05.	Mechanical damage requiring evaluation and remediation within 60 days of discovery	Dent on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser. Dent located on the pipeline (above 4 and 8 o'clock positions) with a depth between 3% and 6% of the nominal pipe diameter. (49 CFR Part 195.452)	Mechanical damage can require timely evaluation and remediation to prevent CO2 leakage.	Not reported.	Data not available. Assume mechanical damage requiring evaluation and remediation within 60 days of discovery is handled in a timely manner.	CO2 leak/rupture (HSE hazard).	Failure to repair minor mechanical damage within a reasonable time frame.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor reports of pipeline mechanical damage and response time.	Comply with 49 FCR Part 195 repair of mechanical damage to pipeline.	Train employees to repair mechanical damage in a timely manner.
418	21.06.00.	Pipeline procurement risks										
419	21.06.01.	Used pipe or old pipe	Used pipe must comply with the same quality requirements as new pipe. Used pipe must not have any mechanical damage (buckles, cracks, gouges, dents) or corroded areas that threaten the integrity of the pipe. (49 CFR Part 195.114).	Use of defective used pipe could result in pipe failure and CO2 leakage.	All new pipe used.		Weak or off spec pipe.	Use of used or old pipe.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipe specification and procurement.	Use new pipe.	Inspect and test all pipe prior to its use.
420	21.06.02.	Pipeline valves	Each valve must be of sound engineering design, compatible with pipe and fittings, successfully hydrostatically tested, clearly marked for open and closed positions (except check valves), properly marked (nameplate) and properly sized. (49 CFR Part 195.116)	Defective or off-spec valves could result in valve failure and CO2 leakage. Wrong sized valves could lead to additional pressure stress or failure.	Significant incident rate due to malfunction of control or relief equipment based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 3.8E-01 significant incidents/year.		Valve failure.	Defective or off-spec valves.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor valve specification and procurement.	Comply with 49 CFR Part 195 valve requirements. Select competent valve manufacturers. Select the proper type and size of valve.	Inspect and test all valves prior to being used. Properly install, operate and maintain valves.
421	21.06.03.	Pipeline fittings	Fittings must be suitable for the intended service and be at least as strong as the pipe and other fittings in the pipeline system. There may not be any buckles, dents, cracks, gouges or other defects in the fittings that may reduce the strength of the fitting. (49 CFR Part 195.118)	Defective off-spec fittings could result in fitting failure and CO2 leakage.	Significant incident rate due to thread stripped broken pipe coupling based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 9.5E-02 significant incidents/year. Fitting failure rates: 4E-03/fitting/year for <1/4" hole. 1E-03/fitting/year for 1/4" hole to full rupture (Quest 2010).		Fitting failure.	Defective or off-spec fittings.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor fitting specification and procurement.	Comply with 49 CFR Part 195 fitting requirements. Select competent fitting manufacturers. Select the proper type and size of fittings.	Inspect and test all fittings prior to being used. Properly install, operate and maintain fittings.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
417	21.05.05.	Mechanical damage requiring evaluation and remediation within 60 days of discovery	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
418	21.06.00.	Pipeline procurement risks	0	0	0	0															
419	21.06.01.	Used pipe or old pipe	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
420	21.06.02.	Pipeline valves	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
421	21.06.03.	Pipeline fittings	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
422	21.06.04.	Other pipeline components	Other components such as fabricated branch connections, closures, flange connections, station piping, and fabricated assemblies must meet applicable requirements. (49 CFR Part 195.122-195.130) Materials for bolts and nuts should be same as flange. At least one full thread of bolt should be exposed beyond the nut. Gasket material should be compatible with CO2.	Defective or off-spec pipeline components could result in component failure and CO2 leakage.	Significant incident rate due to component failure based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 9.5E-02 significant incidents/year.		Component failure.	Defective or off-spec pipeline components.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor other pipeline component specification and procurement.	Comply with 49 CFR Part 195 requirements for other pipeline components. Select competent manufacturers. Select the proper type and size of components.	Inspect and test all components prior to being used. Properly install, operate and maintain components.
423	21.07.00.	Pipeline construction defects	About 16% of gas pipeline failures in Europe are caused by construction defect or material failure. (EGIG 2008)	Construction defects could result in pipeline failure and CO2 leakage.								
424	21.07.01.	Pipe installation	All pipeline installed in a ditch must be installed in a manner that minimizes the introduction of secondary stresses and the possibility of damage to the pipe. (49 CFR Part 195.246). This is of particular concern in rocky soil. When a ditch for a pipeline is backfilled, it must be done in a manner that provides firm support under the pipe, and prevents damage to the pipe and pipe coating from equipment or from the backfill material. (49 CFR Part 195.252) Pipeline coating can be damaged during installation by laying the pipeline on sharp rocks in the ditch, dropping rocks on it during backfill, rough contact with equipment or abrasion if installing pipe through a bored hole under a road or railroad crossing.	Pipe damage during installation could result in accelerated pipe failure and CO2 leakage	Significant incident rate due to equipment/material/weld failure based on PHMSA CO2 pipeline data from 1986 - July 2012: 1.34E-04/mile/yr. Assume 1,116 miles combined KM CO2 pipeline length and assume 15% tied to installation issues: 2.25E-02 significant incidents/year.		Pipeline failure.	Pipe mechanical damage during installation.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline installation and testing.	Install pipeline in compliance with 49 CFR Part 195. Inspect and test prior to being placed in service.	Repair or replace any pipe damaged during installation.
425	21.07.02.	Valve and other equipment installation	Valves and other equipment must be properly seated and installed.	Valves that are not properly seated or improperly installed could lead to system failure.	Significant incident rate due to malfunction of control or relief equipment (including valves) based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 3.8E-01 significant incidents/year. Assume 15% due to installation issues: 5.7E-02 significant incidents/year.		Valve failure.	Improper seating / installation of valves.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor valve installation and testing.	Install valves and other equipment in compliance with 49 CFR Part 195. Inspect and test prior to being placed in service.	Repair or replace any valves or other equipment damaged during installation.
426	21.07.03.	Pipe bending	Pipe must not have a wrinkle bend. A bend must not impair serviceability of the pipe. Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage. On pipe containing a longitudinal weld, the longitudinal weld must be as practicable to the neutral axis of the bend unless the bend is made with an internal bending mandrel or the pipe is 0.32 m (12.75 in) or less nominal outside diameter or has a diameter to wall thickness ratio less than 70. Each circumferential weld which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process. (49 CFR Part 195.212)	Pipe damage during bending could result in accelerated pipe failure and CO2 leakage	Significant incident rate due to pipe bending based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 0 significant incidents/year.		Pipeline failure.	Pipe mechanical damage during bending.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipe bending and testing.	Bend pipe in compliance with 49 CFR Part 195. Inspect and test prior to being placed in service.	Replace any pipe bends that do not pass inspection or testing.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
422	21.06.04.	Other pipeline components	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
423	21.07.00.	Pipeline construction defects	0	0	0	0															
424	21.07.01.	Pipe installation	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
425	21.07.02.	Valve and other equipment installation	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
426	21.07.03.	Pipe bending	3	2	2	12	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
427	21.07.04.	Pipe welding (See 21.03.02.)	Welding must be performed by a qualified welder in accordance with welding procedures qualified under Section 5 of API 1104 or Section IX of the SASME Boiler and Pressure Vessel Code. Each welding procedure must be recorded in detail, including the results of the qualifying tests. 49 CFR Part 195.214-195.234)	Improper welding procedures could result in CO2 leakage.	Significant incident rate due to weld defects based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 9.5E-02 significant incidents/year.		Pipeline weld failure.	Pipe welding defects.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline welding and quality control testing.	Comply with all 49 CFR Part 195 welding requirements. Use certified welders. Inspect and test welds prior to burial.	Replace welds that do not pass inspection and testing.
428	21.07.06	Pipeline underground clearance	Any pipe installed underground must have at least 0.3 m (12 in) of clearance between the outside of the pipe and the extremity of any other structure, except that for drainage tile. (49 CFR Part 195.250).	Insufficient clearance could cause mechanical damage under load.	Significant incident rate based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 0 significant incidents/year.		Pipeline mechanical damage.	Insufficient underground clearance.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline installation for proper underground clearance.	Lay pipeline in compliance with 49 CFR Part 195. Assure sufficient clearance between the pipeline and other subsurface structures.	Design around subsurface structures if necessary.
429	21.07.07.	Pipeline integrity inspection	No pipe or other component may be installed in a pipeline system unless it has been visually inspected at the site of installation to ensure that it is not damaged in a manner that could impair its strength or reduce its serviceability. (49 CFR Part 195.206)	Improper or lack of integrity inspection may fail to discover mechanical damage or defects before CO2 is fed to the pipeline.	Pipe visual inspection used.		Failure to discover defects before CO2 fed to pipeline.	Improper or lack of integrity inspection.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline integrity inspection.	Conduct pipeline integrity inspections as required in 49 CFR Part 195.	Repair any mechanical damage, defects or leaks.
430	21.07.08.	Protection for above ground components	Above ground components may be installed in areas under direct control of the operator but should be inaccessible to the public. (49 CFR 195.254)	Insufficient protection for above ground components could lead to vandalism, theft and equipment damage by third parties.	Above ground components have fencing, security and surveillance.		Equipment theft/damage	Insufficient protection for above ground components.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor security for above ground components.	Fence in, mark and secure surface facilities.	Monitor activity at surface facilities.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
427	21.07.04.	Pipe welding (See 21.03.02.)	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
428	21.07.06	Pipeline underground clearance	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
429	21.07.07.	Pipeline integrity inspection	1	2	1	2	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
430	21.07.08.	Protection for above ground components	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
431	21.07.09.	Construction records	A complete record must be maintained by the operator for the life of each pipeline facility of girth welds (total, number tested, rejected, disposition), pipe installed (amount, location cover, size), locations of pipeline crossings, utility crossings, overhead crossings, valves, and corrosion test stations. (49 CFR Part 195.266) 1. Lack of final as-built drawings 2. Pipeline location not properly documented 3. Valves and other equipment not properly marked	Incomplete or inaccurate construction records or as-built drawings could result in error or confusion during operation, maintenance or emergency response. Improper documentation of pipeline location can lead to confusion when marking a pipeline location prior to excavation. Failure to properly mark valves and other equipment could lead to improper opening or closing of valves or improper equipment operation and/or maintenance.	Assume that accurate records are maintained according to code.	Details not available	Project uncertainty. Operator error.	Incomplete or inaccurate construction records.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor updating and maintenance of construction records.	Maintain an up-to-date set of construction drawings throughout the operation of the pipeline. Properly mark the pipeline location. Properly mark valves and other equipment.	Reconstruct any drawings or records that are missing.
432	21.08.00.	Pipeline operation risks										
433	21.08.01.	Operator error in pipeline operation	Operator error can include: 1. Leaving the wrong valve open or closed 2. Not following proper procedures 3. Using improper equipment or techniques to affect a repair 4. Improperly assessing a situation or condition resulting in inappropriate actions or decisions	Potential for pipeline failure and CO2 leakage.	Significant incident rate due to operator error based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 9.5E-02	Details on other operator errors not available.	Poor performance and/or failure of equipment/pipeline.	Operator error.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor operator training and performance.	Implement standard procedures for safe operation. Train personnel prior to allowing them to work on the pipeline.	Ongoing operator training. Failsafe control system to prevent or mitigate operator errors.
434	21.08.02.	Pipeline over pressuring	Maximum operating pressure (MOP) is limited to 80% of pipeline design pressure. Isolating pipework or facilities with dense phase CO2 can result in doubling the pressure from 10 to 20 MPa (100 to 200 bar) as temperature raises from 25°C to 40°C.	Isolation of pipeline sections could lead to pipeline over pressuring. Operating the pipeline above maximum operating pressure (MOP) could place the pipeline at risk for failure.	Significant incident rate due to pressure surge based on PHMSA KM CO2 pipeline data from 2002 - July 2012: 9.5E-02		CO2 leak/rupture (HSE hazard).	Pipeline over pressuring.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor CO2 pipeline pressure.	Implement standard operating procedures for controlling pipeline pressure.	Alarm system if pipeline pressure exceeds 80% of maximum design pressure.
435	21.08.03.	Pipeline re-pressurization	Re-pressurizing a pipeline results in isenthalpic flash across the re-pressurizing valve causing low temperature in the pipeline, no solid CO2 formation if the CO2 is warm enough. (Anderson 2008).	Low temperature across the re-pressurizing valve	Procedures in place for re-pressurization.		Plugging / damage to pipeline valves.	Improper pipeline re-pressurization.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor CO2 pipeline re-pressurization.	Implement standard operating procedures for re-pressurizing the pipeline.	Alarm system and control safety limits. Failsafe control system to prevent or mitigate operator errors in pipeline repressurization.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
431	21.07.09.	Construction records	2	2	2	8	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
432	21.08.00.	Pipeline operation risks	0	0	0	0															
433	21.08.01.	Operator error in pipeline operation	4	2	2	16	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
434	21.08.02.	Pipeline over pressuring	4	2	1	8	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
435	21.08.03.	Pipeline re-pressurization	3	2	2	12	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
436	21.08.04.	Pipeline depressurization	Rapid depressurization on blowdown of a pipeline can lead to low temperatures (isentropic behavior) and possible solid CO2 formation at pressures below 5 bar. (Anderson 2008).	Rapid depressurization of facilities can lead to CO2 hydrate formation in vent system, possibly causing blockage and over pressurization. (Anderson 2008). Solidification of CO2 could lead to plugging of relief valves. Lowering depressurization rate of a compressor can lead to asphyxiation risk. (Anderson 2008).	Procedures in place for depressurization.		Plugging / damage to pipeline valves.	Improper pipeline depressurization.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor CO2 pipeline depressurization.	Implement standard operating procedures for depressuring the pipeline.	Alarm system and control safety limits. Failsafe control system to prevent or mitigate operator errors in pipeline depressurization.
437	21.08.05.	Pipeline flow modeling	There is a need for improved understanding of the effect contaminants (O2, H2, SOx, NOx, H2S TEG, MEG and amines/NH3) have on the phase diagram and behavior of a CCS CO2 stream. (DNV CO2PIPETRANS Phase 2) Nitrogen and oxygen in CO2 will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow.	Improper understanding of the impact of CO2 impurities on the phase diagrams could lead to inaccurate pipeline flow modeling. Inaccurate modeling can cause the computational leak detection system to malfunction.	Kinder Morgan has developed an improved flow model for CO2.		Operator error.	Inaccurate pipeline flow model.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review accuracy of pipeline flow model.	Select optimum pipeline flow model. Verify model accuracy. Sufficiently train modelers.	Monitor actual versus model results and determine the root cause of any discrepancies.
438	21.08.06.	Boiling liquid expanding vapor explosion (BLEVE)	Boiling liquid expanding vapor explosion (BLEVE) is a type of explosion that can occur when a vessel or pipeline containing a pressurized liquid is ruptured. Such explosions can be extremely hazardous. A BLEVE results from the rupture of a vessel containing a liquid substantially above its atmospheric boiling point. The substance is stored partly in liquid form, with a gaseous vapor above the liquid filling the remainder of the container. If the vessel is ruptured — for example, due to corrosion, or failure under pressure — the vapor portion may rapidly leak, lowering the pressure inside the container. This sudden drop in pressure inside the container causes violent boiling of the liquid, which rapidly liberates large amounts of vapor. The pressure of this vapor can be extremely high, causing a significant wave of overpressure (an explosion) which may completely destroy the storage vessel and project fragments over the surrounding area. (Wikipedia)	Supercritical CO2 can have significant density variations with changes in pressure and temperature. If a pipeline ruptures, this could lead to a boiling liquid expanding vapor explosion (Anderson 2008).	No incidents reported.		Human injury/death due to boiling liquid expanding vapor explosion (BLEVE).	Pipeline rupture.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Liability costs. Damage repair costs.	Monitor pipeline operating conditions.	Implement standard procedures for safe operation and maintenance of pipeline.	Monitor pipeline for unsafe operating conditions. Alarm system. Emergency response plan. Train employees and educate local residents what to do in the event of a pipeline rupture. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
436	21.08.04.	Pipeline depressurization	3	2	2	12	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
437	21.08.05.	Pipeline flow modeling	2	2	3	12	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
438	21.08.06.	Boiling liquid expanding vapor explosion (BLEVE)	2	5	1	10	>1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<\$0.5M	<\$0.5M	<\$2M per incident	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	<10,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$10M	None	Part of ongoing costs	<\$10M per incident prevented.	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
439	21.08.07.	Pipeline scheduled maintenance	Typical scheduled maintenance jobs and frequency: Aerial patrols 26 times per year. Population density survey every other year. ROW inspection 26 times per year. Emergency systems tested annually. Rectifier maintenance completed 6 times per year. Cathodic protection survey annually. Internal inspection of pipeline using an electronic tool, every 5 years or more frequently if necessary. Overpressure safety devices checked annually. Public awareness and damage prevention program reviewed annually. (DGC). Inspect each mainline valve twice a year 1. Pipeline cleaning	Failure to properly inspect and maintain the pipeline could lead to pipeline failure and CO2 leakage.	Scheduled maintenance procedures in place.		Pipeline corrosion.	Lack of, or improper, pipeline scheduled maintenance.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline scheduled maintenance.	Comply with 49 CFR Part 195 pipeline scheduled maintenance requirements. Maintain proper pipeline maintenance.	Review status and results of pipeline scheduled maintenance annually.
440	21.08.08.	Pipeline malfunctions	Some pipeline malfunctions could include: 1. Equipment malfunction or failure 2. Unintended valve closure or shutdown 3. Loss of communication (SCADA system) 4. Power outage 5. Pig stuck in pipeline causing a shutdown	Pipeline malfunctions could lead to unintended shutdown or CO2 leakage.	33 incidents reported on KM CO2 pipelines from 2002 - July 2012 11 significant incidents over 10.5 years. No injuries or fatalities. CO2 release from 0 to 941 t per incident (PHMSA 2012)		Pipeline flow interruption. Pipeline damage.	Pipeline malfunction.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline operating conditions.	Install alarm system for equipment / valve malfunction or failure. Install backup communication system for SCADA. Install backup power generator or batteries. Implement standard operating procedures for inline inspection system (pig system).	Train personnel to properly respond to pipeline malfunctions on a timely basis.
441	21.08.09.	Pipeline leak	Pipeline leaks can include: 1. Pinhole leak - small leak (visible due to dry ice forming on the surface) 2. Pipeline puncture small diameter leak 3. Pipeline puncture large diameter leak	CO2 leakage.	33 incidents reported on KM CO2 pipelines from 2002 - July 2012 9 incidents with leaks greater than 10 t of CO2. 3 incidents with leaks greater than 100 t of CO2 0 incidents with leaks greater than 1000 t of CO2 No injuries or fatalities. No pipeline ruptures. CO2 release from 0 to 941 t per incident (PHMSA 2012)		Pipeline and property damage. Human injury/death.	Pipeline leak.	Liability costs. Damage repair costs..	Monitor pipeline operating conditions.	Implement standard procedures for safe operation and maintenance of pipeline.	Install and maintain CPM leak detection system. Install and maintain crack arrestors to minimize propagating cracks. Install and maintain block valves to section off the pipeline in case of a rupture. Train personnel and educate local residents on how to identify and respond to a pipeline leak/rupture. Implement and maintain an emergency response plan.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
439	21.08.07.	Pipeline scheduled maintenance	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
440	21.08.08.	Pipeline malfunctions	5	2	2	20	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
441	21.08.09.	Pipeline leak	5	2	2	20	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
442	21.08.10.	Pipeline rupture	Pipeline ruptures consist of a circumferential or longitudinal propagation fracture	CO2 leakage.	No ruptures reported for CO2 pipeline based on PHMSA data from 1986 - July 2012. Significant incident rate due to pipeline rupture based on PHMSA CO2 pipeline data from 2002 - July 2012: 0 significant incidents/year. Estimated CO2 release due to rupture (tonnes of CO2) for various pipeline diameters based on 32km (20m) distance between block valves: Pipe Dia. CO2 release 406mm (16in): 1393 t CO2 508mm (20in): 3873 t CO2 660mm (26in): 6547 t CO2 762mm (30in): 9133 t CO2		Pipeline and property damage. Human injury/death.	Pipeline rupture.	Liability costs. Damage repair costs..	Monitor pipeline operating conditions.	Implement standard procedures for safe operation and maintenance of pipeline.	Install and maintain CPM leak detection system. Install and maintain crack arrestors to minimize propagating cracks. Install and maintain block valves to section off the pipeline in case of a rupture. Train personnel and educate local residents on how to identify and respond to a pipeline leak/rupture. Implement and maintain an emergency response plan.
443	21.08.11.	Pipeline safety measures	Pipeline safety measures can include: 1. Emergency response plan 2. Reverse 911 call system - emergency alert 3. One-call system - prior to drilling or excavating 4. Supervision of excavation near pipelines 5. Regular inspection and maintenance of pipeline and ROW 6. CO2 monitors and alarms at booster stations 7. Oxygen packs at booster stations 8. Fire fighting equipment at booster stations 9. Public emergency response plan 10. Fencing and barricades to protect above ground facilities 11. Markers for ROW, valves and equipment	Lack of pipeline safety measures could lead to human injury and/or pipeline damage.	Pipeline safety measures in place. SCADA system Automatic and manual valves Marked right-of-way (ROW) and pipeline location Visual inspections of ROW by air every 2 weeks Frequent visual inspection of ROW by vehicle in built up areas Internal inspections with smart pigs Cathodic protection External coating of pipe Fracture arrestors every 1000 ft Public awareness program - mailing One-call system Emergency response plan Pipeline burial depth at least 1 m		Noncompliance with regulations.	Lack of or inadequate pipeline safety measures.	Fines or penalties for noncompliance. Possible business interruption.	Monitor pipeline safety measures.	Comply with all safety measures required by 49 CFR Part 195.	Review safety measures regularly to ensure they are operational. Make adjustments if necessary to ensure safety.
444	21.09.05	Pipeline hydraulic testing	Except as otherwise provided in this section ... no operator may operate a pipeline unless it has been pressure tested ... without leakage, (49 CFR Part 195.300-195.310)	Improper or lack of hydraulic testing may fail to discover leaks before CO2 is fed to the pipeline.	Hydraulic testing conducted on pipelines.		Failure to discover leaks before CO2 fed to pipeline.	Improper or lack of hydraulic pipeline testing.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline hydraulic testing.	Conduct pipeline hydrostatic testing in compliance with 49 CFR Part 195.	Locate and repair any leaks. Do not place pipeline into service until it has successfully passed hydrostatic testing.
445	22.00.00.	CO2 ON-SITE FACILITIES RISKS										

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
442	21.08.10.	Pipeline rupture	3	4	2	24	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<\$0.5M	<\$0.5M	<\$1M per incident	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	<10,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$5M	None	Part of ongoing costs	<\$5M per incident prevented.	
443	21.08.11.	Pipeline safety measures	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	<\$1M for fines, penalties and legal fees	<\$1M	None	Part of ongoing costs	<\$1M	1
444	21.09.05	Pipeline hydraulic testing	1	2	1	2	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
445	22.00.00.	CO2 ON-SITE FACILITIES RISKS	0	0	0	0															

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
446	22.01.00.	On-site facilities for DSA	On-site facilities for deep saline aquifer (DSA) CO2 injection can include: 1. Injection CO2 distribution system trunk and laterals 2. Power supply 3. Injection and monitoring wells 4. Onsite CO2 pumping stations 5. Water treatment facilities.	Potential problems could include, blowout, equipment failure.	Not applicable to CO2-EOR.		Poor performance or failure of equipment /systems.	Defective / off-spec on-site facilities for DSA.	CO2 leak / blowout. Water leak/rupture. Facilities and property damage. Human injury/death. Liability costs. Damage repair costs. Environmental clean up costs. Project ROI negatively impacted.	Monitor specification, procurement, installation, operation and maintenance of on-site facilities.	Train operators and managers. Properly specify, engineer, manufacture and install equipment and other components. Implement appropriate procedures for safe operation and maintenance of on-site facilities. Comply with state and federal regulations.	Implement and maintain a risk management plan. Monitor for CO2 leaks.
447	22.02.00.	On-site facilities for EOR	On-site facilities for CO2 enhanced oil recovery (EOR) can include: 1. Recycle CO2 compression system and building 2. Injection CO2 distribution system trunk and laterals 3. Production gathering system 4. Oil, water and slop storage tanks 5. CO2 dehydration system 6. CO2 gas scrubber/knockout drum 7. Flare system 8. Circulation and transfer pumps 9. Instrument air system 10. Control room, motor control center and building 11. Power supply transformers, UPS, PLCs, cables 12. Injection, production, disposal and monitoring wells 13. Water treatment/disposal facilities 14. CO2 separation and hydrocarbon recovery.	Potential problems could include blowout, oil leaks/spills ignition/explosion, equipment failure, water quality, water disposal	Facilities in place. Power supply problems resolved by installing captive power plant. Reliability of compressors has improved. CO2 and hydrocarbon separation has achieved high availability. Corrosion problems have improved. Freeze up of piping has been resolved by staged decompression. One fire reported in 2006 when a pipe nipple blew out.	No details on oil spills.	Poor performance or failure of equipment /systems.	Defective / off-spec on-site facilities for EOR.	CO2 leak / blowout. Oil leak-spill / ignition / explosion. Methane leak / ignition / explosion. Water leak/rupture. Facilities and property damage. Human injury/death. Liability costs. Damage repair costs. Environmental clean up costs. Project ROI negatively impacted.	Monitor specification, procurement, installation, operation and maintenance of on-site facilities.	Train operators and managers. Properly specify, engineer, manufacture and install equipment and other components. Implement appropriate procedures for safe operation and maintenance of on-site facilities. Comply with state and federal regulations.	Implement and maintain a risk management plan. Monitor for CO2, CH4, oil or water leaks.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
446	22.01.00.	On-site facilities for DSA	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
447	22.02.00.	On-site facilities for EOR	4	2	1	8	None	None	None	None	None	<\$0.5M per incident	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
448	22.03.00.	On-site facilities for ECBM	On-site facilities for CO2 enhanced coal bed methane (ECBM) can include: 1. Recycle CO2 compression system and building 2. Injection CO2 distribution system trunk and laterals 3. Production gathering system 4. Water storage tanks 5. CO2 dehydration system 6. CO2 capture system - removal of CO2 from nat. gas 7. Flare system 8. Circulation and transfer pumps 9. Instrument air system 10. Control room, motor control center and building 11. Power supply transformers, UPS, PLCs, cables 12. Injection, production, disposal and monitoring wells 13. Water treatment/disposal facilities	Potential problems could include blowout, methane leaks ignition/explosion, equipment failure, water disposal.	Not applicable to CO2-EOR.		Poor performance or failure of equipment /systems.	Defective / off-spec on-site facilities for ECBM.	CO2 leak / blowout. Methane leak / ignition / explosion. Water leak/rupture. Facilities and property damage. Human injury/death. Liability costs. Damage repair costs. Environmental clean up costs. Project ROI negatively impacted.	Monitor specification, procurement, installation, operation and maintenance of on site facilities.	Train operators and managers. Properly specify, engineer, manufacture and install equipment and other components. Implement appropriate procedures for safe operation and maintenance of on-site facilities. Comply with state and federal regulations.	Implement and maintain a risk management plan. Monitor for CO2, CH4 or water leaks.
449	22.04.00.	Injection well components	CO2 injection well components generally include: 1. Wellhead and tree 2. Tubing and casing 3. Safety valve 4. Packer 5. Packer fluid 6. Elastomers 7. Perforations 8. Sand control - for unconsolidated reservoirs	Component failure could result in CO2 leakage.	Nine incidents of loss of well control from 1972-2011. 9 incidents/2000 wells/40 years = 1.125E-04 incidents/well/year. Assume 180 injection wells in Northern Platform area.		Failure of injection well components.	Defective /off spec injection well components.	CO2 leak / blowout. Facilities and property damage. Human injury/death. Liability costs. Damage repair costs. Project ROI negatively impacted.	Monitor specification, procurement, installation, operation and maintenance of injection well components.	Train operators and managers. Properly specify, engineer, manufacture and install equipment and other components. Implement appropriate procedures for safe operation and maintenance of on-site facilities. Comply with state and federal regulations.	Implement and maintain a risk management plan. Monitor for CO2 or water leaks.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
448	22.03.00.	On-site facilities for ECBM	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
449	22.04.00.	Injection well components	4	2	1	8	None	None	None	None	None	<\$0.5M per incident	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	

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450	22.05.00.	Injection well materials of construction	DSA CO2 injection well components are typically carbon steel. Typical materials of construction for EOR CO2 injection wells include: - Upstream metering & piping runs: 316 SS, Fiberglass - Christmas tree (trim): 316 SS, Nickel, Monel - Valve packing and seals: Teflon, Nylon - Wellhead (trim): 316 SS, Nickel, Monel - Tubing hanger: 316 SS, Incoloy - Tubing: fiberglass lined (GRE) carbon steel, internally plastic coated carbon steel, corrosion resistant alloys - Tubing joint seals: Seal ring (fiberglass lined), coated threads and collars (internally plastic coated) - On/off tool, profile nipple: Nickel plated wetted parts, 316 SS - Packers: Internally coated hardened rubber of 80-90 durometer strength (Buna-N), Nickel plated wetted parts - Cements and cement additives: API cements and/or acid resistant specialty cements and additives - Production liner 316 SS, Incoloy - Casing: carbon steel J-55 and K-55 grades; corrosion resistant alloy used in intervals where potential potable water aquifers exist or where H2S is present (Meyer 2007) - Elastomers - Teflon or nylon have been used to prevent swelling	Corrosion can occur when tubulars are exposed to wet CO2. Sufficient quantities of H2S in CO2 can cause corrosion or sulfide stress cracking. (CCP 2009) The reservoir fluid affects corrosivity near the wellbore and compaction resistance where formation dissolution has occurred. In significant dissolution cases, the well tubulars must be designed to resist column buckling in the injection interval. (CCP 2009) CO2 phase behavior can impact velocity. High velocity of injection can cause erosion to materials exposed to the CO2 stream (CCP 2009)	All of the listed materials of construction are used at SACROC (Meyer 2007) Tubing: 2 7/8 inch and 3 1/2 inch diameter, internal fiberglass lining, J55 carbon-steel tubing and nitrile gaskets used. Use 8rd connections with proper torque and seal lube. Tubing body leak rare (Ricketson 2012). Packer issues: leakage around elements and on/off tool leaks. Successful practices: use nitrile elements and XXL nickel-plated on/off tool. Use brine as packer fluid with corrosion inhibitor, CO2 and H2S protection and oxygen scavenger (Ricketson 2012). Casing issues: poor cement around pipe, corrosive water zones, and use of old wells. Successful practices: carbon steel casing, circulate cement to surface (2-stage, standard blends), coating for corrosive areas, and good upfront evaluation to reuse wells or drill new wells (Ricketson 2012).		Corrosion / failure of injection well components.	Defective / off-spec injection well materials of construction.	CO2 leak. Downtime and repair costs.	Monitor specification, procurement, installation, operation and maintenance of injection well components.	Determine the characteristics of brine to be handled in the injection wells. Select materials that will resist corrosion , and/or scale buildup.	Monitor corrosion and scale buildup in injection wells and take necessary corrective action such as pre-treating the injected water.
451	22.05.01.	Elastomer seals	Since supercritical CO2 is a solvent, many elastomers, plastics, rubber, or resins present in a well could be subject to chemical attack or dissolution. When designing a CO2 injector, material should be based on performance expectations. Elastomers, in particular, are a common part of well hardware used to seal different components. Elastomers must be made of material that is chemically compatible or inert to the injection fluid and must be of sufficient strength or adequately anchored to withstand the different pressure and explosive decompression that might exist across a seal. Since the physical and performance characteristics of many elastomer materials change with pressure and temperature, the elastomer must be able to perform reliably across the full range of differential pressures and temperatures expected through the design life of the well at the location of the seal within the well. (CCP 2009) Teflon or nylon have been used for seals to prevent swelling. (Meyer 2007).	Elastomer seal failure can result in CO2 leakage.	Swell resistant elastomer materials such as nitrile rubbers are used for packers and Teflon and nylon are used for seals (Meyer 2007).		Seal failure.	Defective / off-spec elastomer seals.	CO2 leak. Downtime and repair costs.	Monitor specification, procurement, installation, operation and maintenance of elastomer seals.	Select elastomers that have a successful track record in handling CO2.	Replace elastomer seals that fail. Determine root cause. Monitor development of improved elastomers.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
450	22.05.00.	Injection well materials of construction	3	2	1	6	None	None	None	None	None	<\$0.5M per incident	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
451	22.05.01.	Elastomer seals	3	2	1	6	None	None	None	None	None	<\$0.5M per incident	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	

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452	22.06.00.	Injection well safety precautions	Safety precautions for injection wells include: 1. Casing corrosion protection - Impressed and passive currents - Oxygen, biocide corrosion inhibiting chemicals 2. Gentle handling to prevent damage to tubing coatings 3. Casing leak detection testing 4. Fencing, monitoring and atmospheric dispersion monitoring if near populated areas 5. Automatic shutdown controls for unsafe conditions	Lack of safety precautions can lead to greater risk of CO2 leakage	All of the safety precautions are implemented at SACROC (Meyer 2007).		Wellbore failure.	Lack of injection well safety precautions.	CO2 leak. Downtime and repair costs.	Monitor injection well safety precautions.	Comply with all state and federal injection well safety measures.	Annual review of safety measures, rules and regulations to confirm the project is in compliance.
453	22.07.00.	Production well submersible pump	While normally very reliable, the submersible pump in an EOR or ECBM production well can fail.	Failure of the submersible pump can result in operating delays and maintenance costs.	Electric submersible pump failure has been a significant problem at SACROC but is improving. ESP failure rate per year and average production loss per failure (barrels of oil): 2011: 14% (120 bbls) 2010: 26% (240 bbls) 2009: 29% (360 bbls) 2008: 40% (720 bbls) 2007: 79% (1950 bbls) (Bradley 2012)		Submersible pump failure.	Defective /off-spec submersible pump	Downtime and repair costs.	Monitor specification, procurement, installation, operation and maintenance of submersible pump.	Properly select, install, operate and maintain submersible pumps.	Monitor submersible pumps for corrosion, hydrocarbon deposition or scale buildup and take necessary corrective action.
454	22.08.00.	Production well materials of construction	Production wells tend to be exposed to mixtures of CO2, brine, hydrocarbons (oil and/or gas) and stripped gases such as H2S. Production wells may also be exposed to hydrocarbon (asphaltene, paraffin or polyaromatic) deposition. Teflon coating has proven to help reduce hydrocarbon deposition. Scale buildup may also be a problem depending on brine chemistry.	The produced mixtures can be very corrosive. Hydrocarbon deposition or scale buildup may cause significant down time for cleaning out.	Surface casing: 23 lb/ft M-50 RG-3/ST&C or 24 lb/ft M-65LTC R3(ERW) Production casing: 15.50 and/or 17 lb/ft J-55 LT&C/SMLS Tubing: Glass reinforced epoxy lined carbon steel(Meyer 2007)		Corrosion / failure of production well components.	Defective / off-spec production well materials of construction.	CO2 leak. Downtime and repair costs.	Monitor specification, procurement, operation and maintenance of production well components.	Determine the characteristics of fluids to be handled by the production well. Select materials that will resist corrosion, hydrocarbon deposition and/or scale buildup.	Monitor corrosion, hydrocarbon deposition and scale buildup in production wells and take necessary corrective action.
455	23.00.00.	CO2 MONITORING RISKS										

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
452	22.06.00.	Injection well safety precautions	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
453	22.07.00.	Production well submersible pump	5	2	1	10	None	None	None	None	None	<\$0.2M per incident	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
454	22.08.00.	Production well materials of construction	3	2	1	6	None	None	None	None	None	<\$0.5M per incident	0-5 days @ \$20,000/d revenue lost per pattern idled	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
455	23.00.00.	CO2 MONITORING RISKS	0	0	0	0															

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Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
456	23.01.00.	Data acquisition activities at the well	Activities include logging, drill stem tests, coring, hydrophone installation, etc.	May include some activities and procedures that are less familiar. Some techniques could limit other MMV techniques.	Monitoring limited to that required for CO2-EOR rather than MMV. Monitoring flowrate, injection pressures, temperatures, annulus pressure and H2S at injection wells (Ricketson 2012).		Project uncertainty due to lack of subsurface data.	Ineffective data acquisition activities at the well	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor data acquisition activities at the well.	Work with an experienced monitoring engineer / consultant to prepare a monitoring plan that optimizes wellbore data acquisition. Implement standard procedures for good monitoring.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.
457	23.02.00.	Data acquisition activities away from the well	Many activities and procedures will be effectively new and newly trained for. Some monitoring techniques could present risk or barriers to the application or success of other techniques.	Off-site monitoring activities may incur risk of physical accidents and may make the project publicly prominent.	Monitoring limited to that required for CO2-EOR rather than MMV.		Project uncertainty due to lack of subsurface data.	Ineffective data acquisition activities away from the well	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor data acquisition activities away from the well.	Work with an experienced monitoring engineer / consultant to prepare a monitoring plan that optimizes non-wellbore data acquisition. Implement standard procedures for good monitoring.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.
458	23.03.00.	Data acquisition conflicts	Data acquisition may involve many techniques including logging, fluid sampling, coring, surface and downhole geophones, surface seismic, surface air measurements, groundwater sampling, and others.	Use of some monitoring techniques can preclude or limit the applicability of other techniques.	Monitoring limited to that required for CO2-EOR rather than MMV.		Project uncertainty due to subsurface data conflicts.	Data acquisition conflicts.	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor data acquisition conflicts.	Prepare a monitoring plan that avoids data acquisition conflicts.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.
459	23.04.00.	Seismic surveys	Vertical resolution of seismic imaging is inherently limited such that features less than 10 m thick can rarely be discerned. (CCP 2009) Subsurface CO2 is not seismically resolvable. Limited or absence of plume images via seismic. Seismic readings may be compromised by vibration from nearby heavy industrial facilities. 1. 2-D seismic survey 2. 3-D seismic survey 3. 4-D seismic survey 4. Vertical seismic profile (VSP) 5. Cross well seismic survey	Seismic techniques unable to pick up subsurface features or track CO2 plume.	Seismic surveys already successfully completed. 3D seismic used. Crosswell seismic used to fill resolution gap between surface seismic and wellbore-scale measurements (Reese 2008).		Seismic techniques unable to pickup subsurface features or track CO2 plume.	Seismic survey poor resolution.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor specification and implementation of seismic surveys.	Combine seismic survey methods to get better resolution.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
456	23.01.00.	Data acquisition activities at the well	2	1	1	2	None	None	None	None	None	None	Inability to verify compliance with regulations	<\$0.1M	None	10% of total damages	<\$0.1M	None	Part of ongoing costs.	<\$0.1M	1	
457	23.02.00.	Data acquisition activities away from the well	2	1	1	2	None	None	None	None	None	None	Inability to verify compliance with regulations	<\$0.1M	None	10% of total damages	<\$0.1M	None	Part of ongoing costs.	<\$0.1M	1	
458	23.03.00.	Data acquisition conflicts	2	1	1	2	None	None	None	None	None	None	None	<\$0.1M	None	None	<\$0.1M	None	Part of ongoing costs.	<\$0.1M		
459	23.04.00.	Seismic surveys	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
460	23.05.00.	Gravity surveys	As a notional rule of thumb, CO2 filled reservoirs with less than 10% porosity, thicknesses of less than 10 m and depths greater than 2,500 m will be very difficult to resolve even with the best gravity data and mathematical inversion techniques. (CCP 2009) Current available standard gravimeters are capable of making repeat measurements valid to about 5 micro-gals. Fixed seal-floor gravimeters are essentially capable of the same. (CCP 2009) Corrections for motion are required for gravity data acquired from moving vessels. A change of only 1 cm of elevation will yield a difference of 3 micro-gals. Studies of oil fields have found that fixed permanent surface gravity monuments (i.e. stations) are essential to maximize repeatability (CCP 2009)	Gravity surveys unable to detect CO2 movement	No gravity surveys reported.	Have any gravity surveys been conducted?	Gravity survey unable to detect CO2 plume.	Site-specific conditions fall outside the effective range of gravity separation.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor specification and implementation of gravity surveys.	Consider alternative geophysical techniques if site-specific conditions fall outside the range of gravity survey effectiveness.	Consider alternative geophysical techniques if site-specific conditions fall outside the range of gravity survey effectiveness.
461	23.06.00.	InSAR surveys	InSAR is the current state-of-the-art satellite platform radar based technique to measure vertical ground elevations and relative elevation changes with time. (CCP 2009) Validation studies have shown that uplifts of 1-3 mm can be reliably and repeatedly measured when sites make use of special corner reflectors for calibration purposes. (CCP 2009)	InSAR may be unable to accurately measure vertical ground elevations and relative elevation changes over time due to high seasonal vegetation growth.	No InSAR surveys reported.	Have any InSAR surveys been conducted?	InSAR unable to accurately measure vertical ground elevations and relative elevation changes over time.	InSAR readings compromised by high seasonal vegetation growth.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor specification and implementation of InSAR surveys.	Avoid areas with high vegetation growth.	Install base pillars to get more accurate readings. Use tiltmeters as an alternative or complement.
462	23.07.00.	Well Monitoring	Well monitoring for CO2 storage seeks confident validation that: - Cement integrity and bond is maintained - Pressure isolation barriers are maintained and functioning - Corrosion is being controlled - The CO2 injection profile is being maintained - Barriers after plug and abandonment provide confidence. (CCP 2009)	Unexpected well failure due to lack of well monitoring.	Monitoring limited to that required for CO2-EOR rather than MMV.		Failure to detect well leakage.	Insufficient well monitoring.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Review monitoring plan and comprehensiveness of well monitoring.	Work with an experienced monitoring engineer / consultant to prepare a monitoring plan. Determine which wells to monitor and what monitoring tools to use. Implement standard procedures for good monitoring.	Monitor wells. Identify any trends or discrepancies and determine root cause.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
460	23.05.00.	Gravity surveys	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
461	23.06.00.	InSAR surveys	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
462	23.07.00.	Well Monitoring	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Part of ongoing costs.	None	1

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
463	23.07.00.	General monitoring risks	1. Weather conditions prevent using a monitoring method or retrieving data at a critical point in time 2. Injection site terrain too rugged for surface monitoring 3. Monitoring equipment not properly calibrated 4. Inappropriate monitoring suggests a false alarm for issues that do not exist (CCP 2009) 5. Inappropriate monitoring suggests a false sense of security (CCP 2009) 6. Difficulty of geophysical techniques monitoring below salt caprocks (CCP 2009) 7. Ineffective monitoring 8. Insufficient monitoring 9. Lack or loss of monitoring records 10. Accidental damage or breakdown of custom-made equipment, sensors or tools - repair/replacement delays and irretrievable data loss. 11. Conflicting results from different monitoring techniques. 12. Difficulty of monitoring stacked injection plumes	Ineffective or lack of monitoring can result in missed data. This leads to inadequate engineering control, raising costs and leakage risks; yields insufficient documentation to establish CO2 storage credits, etc.	Monitoring limited to that required for CO2-EOR rather than MMV for sequestration.		Unable to track CO2 plume movement and CO2 leakage.	Ineffective, insufficient or lack of monitoring.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor specification and implementation of monitoring techniques.	Determine MVA requirements. Select reliable monitoring methods. Implement standard procedures for monitoring. Back up data logging.	Analyze monitoring data versus simulation data. Identify any discrepancies. Determine root cause of discrepancies.
464	23.08.00.	Pre-closure monitoring of storage (02.01.07.00.)	Processes related to any monitoring undertaken during the operational and closure phase. The extent and requirement for such monitoring activities may be determined by issues such as storage concept, geological setting, regulations, or public pressure. A number of monitoring techniques exist including seismic data, electrical resistance, soil gas and isotopic characteristics.	Monitoring during the operational phase contributes towards the amount and quality of information initially available after closure concerning the behavior and distribution of sequestered CO2.	Monitoring limited to that required for CO2-EOR (limited to EPA reporting costs) rather than MMV for sequestration.		Insufficient or inaccurate information to ensure safe storage of CO2.	Lack of pre-closure monitoring of storage.	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Risk management review of MVA plan.	Preparation and implementation of MVA plan.	Implementation of MVA plan.
465	23.09.00.	Post-closure monitoring of storage	FEPs related to any monitoring undertaken during the post-closure phase. This includes monitoring of parameters related to the long-term safety and performance. The extent and requirement for such monitoring activities may be determined by issues such as storage concept, geological setting, regulations, or public pressure. A number of monitoring techniques exist including seismic data, electrical resistance, soil gas and isotopic characteristics.	Post-closure monitoring will provide information regarding the performance of the sequestration project and may trigger post-closure remedial actions, if necessary.	Monitoring limited to that required for CO2-EOR (limited to EPA reporting costs) rather than MMV for sequestration.		Insufficient or inaccurate information to ensure safe storage of CO2.	Lack of post-closure monitoring of storage.	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Risk management review of post-closure MVA plan.	Preparation and implementation of post-closure MVA plan.	Implementation of post-closure MVA plan. Prepare procedures for potential remedial action.

SACROC NORTHERN PLATFORM CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Risk Ranking		Estimated Potential Damage Recovery Costs														Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)					
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)															
463	23.07.00.	General monitoring risks	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Part of ongoing costs.	None	
464	23.08.00.	Pre-closure monitoring of storage (02.01.07.00.)	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Part of ongoing costs.	None	1
465	23.09.00.	Post-closure monitoring of storage	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Part of ongoing costs.	None	1

Appendix E

SACROC Northern Platform Site QFMEA Model

Appendix F

Pump Canyon Site QFMEA Model

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
1	00.00.00.00.	ASSESSMENT BASIS	This category of FEPs determines the boundary conditions for any assessment, specifying the spatial and temporal domain of the system. The Assessment Basis determines what is being assessed and why, so that those FEPs that need to be considered in the analysis can be defined, and those which can be screened out as being outside the scope of the assessment can be identified.									
2	00.01.00.00.	Purpose of the assessment	The purpose of the assessment of geological CO2 sequestration.	The general purpose of an assessment of geological CO2 sequestration is to determine the performance of the sequestration system. In any specific case, however, the purpose of conducting an assessment may vary from simple calculations to test initial ideas for sequestration concepts, to support for an application for regulatory approval requiring detailed, site-specific performance assessment against relevant criteria. The level of complexity and comprehensiveness will vary according to the use to which it will be put. Additionally, the assessment endpoints of interest may not only vary in type, depending on the assessment purpose, but also in the level of rigor required for compliance demonstration.	Evaluate the CO2-ECBM risks of the San Juan Basin Pump Canyon site	No project planned at this time.						
3	00.02.00.00.	Endpoints of interest	The assessment endpoints of interest.	The structure and composition of an assessment will tend to reflect the endpoints that are required to be assessed. These in turn, will reflect the criteria that are adopted to judge the overall performance of the sequestration system. Thus, for example, an assessment may be constrained to considering the degree of containment within a geological feature, alternatively, it may need to address potential near-surface impacts. Invariably, a combination of endpoints will be required.	Comprehensive quantitative risk assessment	No project planned at this time.						
4	00.03.00.00.	Spatial domain of interest	The spatial domain of interest in the assessment.	The spatial domain of interest will be dependent on the site context, which may vary from generic assessments to site specific assessments, the sequestration concept and the endpoints of interest. The spatial domain will contribute to determining the information requirements and modeling capabilities that may be required.	San Juan Basin Pump Canyon Site. One-Section Area: Section 32 of T31N R8W Nine-Section Area: Sections 28, 29, 30, 31 and 33 of T31N R8W and Sections 4, 5 and 6 of T30N R8W. Sixteen-Township Area T29-32N, R07-10W	No project planned at this time.						

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
1	00.00.00.00.	ASSESSMENT BASIS	0	0	0	0															
2	00.01.00.00.	Purpose of the assessment	0	0	0	0															
3	00.02.00.00.	Endpoints of interest	0	0	0	0															
4	00.03.00.00.	Spatial domain of interest	0	0	0	0															

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
5	00.04.00.00.	Timescales of interest	Timescale of interest for the assessment.	Timescales over which the assessment will be performed will constrain processes which must be considered in the assessment. In general terms, there are three timescales of interest for geological storage of carbon dioxide. Firstly, there is the timescale during construction and operation which has a lifetime in years or decades, secondly there is a timescale over which isolation of carbon dioxide from the atmosphere is necessary to mitigate climate change. This timescale is likely to be in the order of a few hundred years at most. The third timescale of interest is potentially much longer and is that pertaining to the assessment of potential hazard to humans and the environment. This timescale could be in the order of thousands to tens of thousands of years.	Risk assessment CO2-ECBM operating data: 2008-2009 Pump Canyon CO2-ECBM test. 1995-2001 Allison CO2-ECBM test. QFMEA time frame: 2013-2022. CO2-ECBM financial model: 2013-2022.	No project planned at this time.							
6	00.05.00.00.	Sequestration assumptions	High level assumptions concerning the sequestration system(s) of relevance to the assessment. For example, the quantity and quality of CO2 sequestered, the method of injection and information concerning the assumed performance of the sequestration system.	Provides a background to the sequestration technique adopted. Note that more detailed consideration of the CO2 sequestration system is provided in subsequent FEP categories.	Reproduce historical performance from 2008-2009 CO2-ECBM test. Run scenario from 2013-2022 based on hypothetical commercial CO2-ECBM.	No project planned at this time.							
7	00.06.00.00.	Future human action assumptions	The assumptions made in the assessment concerning general boundary conditions for assessing future human action and exposure.	For example, it can be expected that human technology and society will develop over the timescales of relevance for the assessment of CO2 sequestration systems, however, this development is unpredictable. Therefore it may be necessary to make some assumptions in order to constrain the range of future human actions that are considered, such as assuming that only present-day technologies, or technologies practiced in the past, will be considered.	Assume no change in human activity in the area.	No project planned at this time.							
8	00.07.00.00.	Legal and regulatory framework	The legal and regulatory framework within which the assessment takes place.	In undertaking an assessment it is vital to consider the appropriate regulatory framework requirements. At one extreme these may be specific, prescriptive quantitative requirements, at the other they could be non-prescriptive or may not have been fully developed. The legal and regulatory framework can shape various aspects of an assessment, such as the required assessment endpoints, timescales of interest and assumptions concerning future human actions.	Assume no change in legal and regulatory framework.	No project planned at this time.							
9	00.08.00.00.	Model and data issues	General methodological issues affecting the assessment modeling process and use of data	Examples of general model and data issues include the treatment of uncertainty; the availability, collection and method for handling site specific data; and the reduction/simplification of models and data.	Process-level modeling using COMET3, CMG-GEM and excel spreadsheet based on available published Site data as of 2012 and filling in with assumptions where there are gaps.	No project planned at this time.							
10	00.09.00.00.	Public acceptance and information	The amount and type of information needed for public acceptance and to comply with industry best management practices.	Focus on health, safety and environmental risks as well as economic and lifestyle impact on the public at large.	Based on 35 years of CBM operation, there is public acceptance.	No project planned at this time.							

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
5	00.04.00.00.	Timescales of interest	0	0	0	0															1
6	00.05.00.00.	Sequestration assumptions	0	0	0	0															1
7	00.06.00.00.	Future human action assumptions	0	0	0	0															
8	00.07.00.00.	Legal and regulatory framework	0	0	0	0															
9	00.08.00.00.	Model and data issues	0	0	0	0															
10	00.09.00.00.	Public acceptance and information	0	0	0	0															1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
11	00.10.00.00	Financial viability	The minimum return on investment needed to justify the risks involved in undertaking the project.	Higher risks require higher rewards to justify undertaking a project. The risk assessment may give an indication of the minimum rate of return required to attract capital funding for the project.	Assume 20% minimum internal rate of return required to justify a project.	No project planned at this time.							
12	00.11.00.00	Adequate risk characterization	The level of detail and depth of risk characterization needed.	Characterization of risks can include identifying potential modes of failure, estimating probability of failure occurring and impact severity of failure and determining potential steps to prevent or mitigate failure.	Comprehensive quantitative risk assessment through QFMEA. Independent assessment based on information in the public domain.	No project planned at this time.							
13	01.00.00.00.	EXTERNAL FACTORS	This category of FEPs describes natural or human factors that are outside the system domain. These FEPs are most important in determining scenarios for the future evolution of the system, and are often referred to as EFEPs (External FEPs). Three classes of FEPs are considered. Geological Factors and Climatic Factors are concerned with natural processes and events, whilst Future Human Actions is concerned with those human activities that can directly affect the sequestration system.	This category is divided into three classes: 1. Geological factors 2. Climate factors 3. Human action factors									
14	01.01.00.00.	Geological factors	Natural geological processes and events in the environment outside the system domain that are relevant to the evolution of the sequestration system.	Changes in the geological environment outside the system domain may directly affect the transport of carbon dioxide within the system.									
15	01.01.01.00.	Neotectonics	Neotectonics is the study of crustal movements that both occurred in the Earths recent past and are continuing at the present day. These movements, which are driven directly or indirectly by global plate motions (tectonics), result in the vertical and horizontal warping, folding or faulting of the Earths surface.	Neotectonic events have the potential to cause sudden changes in the physical properties of rocks due to stress changes and induced hydrogeological changes.	Stable regional area. Neotectonics not likely to impact site.		Damage to equipment (wells, pipeline, surface facilities). Caprock failure. Reservoir disruption.	Significant sudden crustal movement	Leakage of CO2 Shutdown of facility. Loss of business.	Geodetic monitoring (GPS, InSAR, LIDAR, strain, tilt, etc.). Monitoring passive seismic activity.	Avoid high risk sites (areas with active crustal movement). Fully characterize the site and regional geology	Proper shutdown procedures in case of an earthquake. Emergency response procedures for dealing with CO2 leakage. Discontinue injection and decrease reservoir pressure.	
16	01.01.02.00.	Volcanic and magmatic activity	Magma is molten, mobile rock material, generated below and within the Earth's crust, which gives rise to igneous rocks when solidified. A volcano is a vent or fissure in the Earth's surface through which molten or part-molten materials (lava) may flow, and ash and hot gases be expelled.	The high temperatures associated with volcanic and magmatic activity may result in permanent changes in the surrounding rocks, either directly, or through circulating high temperature fluids. This FEP is relevant to CO2 sequestration in areas of potential magmatic activity, e.g. Japan. Besides bedrock damage, pressure and temperature changes due to heating, stress, or displacement could affect CO2 density and solubility , creating the risk of uncontrolled, rapid migration and escape of stored CO2. CO2STORE page 69)	San Juan volcanic field, located in the N portion of the SJB (Oligocene batholiths) affect the temperature patterns and heat flow and groundwater movement in the basin (Clarkson 1987; Haerer 2009) The San Juan volcanic field is located 100 km NE of the CO2 injection Site. Volcanic activity took place between 23-33 million years ago. The Valles Caldera super volcano is located 145 km (90 mi) SE of the CO2 injection Site. Last eruption was 50,000-60,000 years ago. Elevation: 3,431 m. Numerous igneous dikes and sills penetrate the Fruitland Formation on the E side of the SJB (near Dulce) about 48 km (30 mi) E of the CO2 injection site.		Borehole damage. Pipeline failure. Caprock failure. Reservoir disruption.	Volcanic eruption. Magmatic intrusion.	CO2/CH4 leakage (HSE hazard). Damage to boreholes, equipment, pipeline, caprock. Shutdown of facility. Loss of business.	Monitoring surface distortion with LIDAR and other remote geodetic measurements. Monitoring seismic activity. Monitoring change in bottom hole temperatures.	Proper site characterization and site selection avoiding areas with volcanic and magmatic activity.	Proper shutdown procedures in case of volcanic eruption. Emergency response procedures for dealing with CO2 leakage. Discontinue injection and decrease reservoir pressure.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS/D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
11	00.10.00.00	Financial viability	0	0	0	0															
12	00.11.00.00	Adequate risk characterization	0	0	0	0															1
13	01.00.00.00.	EXTERNAL FACTORS	0	0	0	0															
14	01.01.00.00.	Geological factors	0	0	0	0															
15	01.01.01.00.	Neotectonics	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
16	01.01.02.00.	Volcanic and magmatic activity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
17	01.01.03.00.	Seismicity (Natural earthquakes)	Events and processes related to naturally occurring seismic events and also the potential for seismic events. A seismic event is caused by rapid relative movements within the Earth's crust usually along existing faults. The accompanying release of energy may result in rock movement and/or rupture, e.g. earthquakes. Many people are convinced that we want to avoid seismically-active areas for CO2 storage. In reality there are very large natural gas fields associated with some of the planet's major fault zones (Indonesia, Malaysia and California). Earthquakes in these areas have never been associated with sudden emissions of significant quantities of natural gas or oil from deep reservoirs. (CCP 2009) Major earthquakes (magnitude 6 and above) occur primarily in strong, brittle basement rock at depths on the order of 10 km (6 miles) or more. Very small earthquakes occur at depths as shallow as 3 km (2 miles). Micro-seismicity consists of very tiny seismic events often responding to subsurface fluid flow and relative pressure changes. All parts of the Earth's crust are in continuous movement and generate micro-seismic events, and the analysis of micro-seismicity offers unique insights into subsurface properties (CCP 2009). 1. Earthquake induced fractures/faults 2. Natural micro-seismicity	Seismic events may result in changes in the physical properties of rocks due to stress changes and induced hydrogeological changes. Seismic events are most common in tectonically active or volcanically active regions at crustal plate margins. Seismic disturbances might cause caprock failure (Damen 2006). Earthquakes could disrupt drilling, well operation, and monitoring activities, and damage surface facilities including the CO2 source. An earthquake on a fault through the CO2 plume could create or close an open pathway. Earthquakes may cause public concern about the project even if not project related. Micro-seismicity may cause public concern about the project even if not project related, may add noise interfering with micro-seismic monitoring. Earthquake near Nakaoka, Japan CO2 injection site caused significant public concern causing project to be moved off shore, even though earthquake was not directly caused by CO2 injection.	There have been 32 earthquakes measuring M 2.0-4.6 recorded from 1966-2012 within 161 km (100 mi) of the Pump Canyon Site (neic.usgs.gov 2012). Six earthquakes have been recorded within 80 km (50 mi) of the site. All of them occurred in 1966 (USA.com 2013). The location is near Dulce, NM, in an area where numerous igneous dikes and sills penetrate the Fruitland Formation. Probability of a M 6.5 or greater earthquake occurring within 50 km of the Site over the next 50 years is 3.1E-04 (or 6.2E-06 per year).	Records for earthquakes below 2.0 magnitude not available.	Damage to borehole, equipment, pipeline, caprock, or reservoir. Human injury/death.	Natural earthquake Magnitude ≥ 6.5 within 50 km	CO2/CH4 leakage (HSE hazard). Interruption of business. Natural micro-seismicity is unlikely to cause damage but may arouse public concern about the project.	Monitoring seismic activity. Monitoring well and pipeline pressures and equipment operation. Monitoring for near surface CO2/CH4.	Proper site characterization and site selection avoiding areas with active fault zones and avoiding low lying tsunami zones. Baseline surveys for micro-seismicity prior to CO2 injection.	Proper shutdown procedures in case of an earthquake. Emergency response procedures for dealing with CO2 leakage. Discontinue injection and decrease reservoir pressure. Passive microseismic monitoring to confirm earthquake was natural rather than induced.
18	01.01.04.00.	Hydrothermal activity	Processes associated with high temperature groundwaters, and hydrothermal alteration of minerals in the rocks through which the high temperature groundwater flows. Hydrothermal activity may be directly associated with volcanic and magmatic activity. Hot springs, geysers and submarine hydrothermal vents provide evidence of hydrothermal activity.	Can result in the hydrothermal alteration of rocks or minerals by the reaction of hot water (and other fluids) with pre-existing rocks. Springs, geysers and submarine hydrothermal vents can provide pathways for CO2 to reach the surface.	Geothermal gradients in the area are higher than normal due to a remnant of the San Juan volcanic field, but do not impact CBM or CO2-ECBM. Geothermal gradient: 40C°/km depth (22F°/1000ft depth).		High bottom hole temperatures. Caprock failure. Mineralization and alteration of formation and wells. Alteration of formation fluid chemistry.	Hydrothermal activity	CO2/CH4 leakage (HSE hazard). Damage to boreholes and wells. Damage to monitoring equipment.	Existence of hot springs, geysers and hydrothermal vents. Higher than normal thermal gradient. Monitoring change in bottom hole temperatures. Monitoring change in reservoir fluid chemistry.	Proper site characterization and site selection avoiding areas of significant hydrothermal activity.	Stop CO2 injection. Extract CO2 or brine from reservoir and inject into another more secure reservoir. Decrease CO2 injection temperature.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Human health & safety	Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)							
															Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury				
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS/D = 1 to 125)															
17	01.01.03.00.	Seismicity (Natural earthquakes)	2	4	1	8	PGA(g) 0.092-0.18 = 1/1,000,000 fatality rate. PGA(g) 0.18-0.34 = 1/100,000 fatality rate. PGA(g) 0.34-0.65 = 1/10,000 fatality rate. PGA(g) 0.65-1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate. Not attributable to CO2-ECBM.	PGA(g) 0.092-0.18 = 1/250,000 injury rate. PGA(g) 0.18-0.34 = 1/25,000 injury rate. PGA(g) 0.34-0.65 = 1/2,500 injury rate. PGA(g) 0.65-1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate. Not attributable to CO2-ECBM.	PGA(g) 0.092-0.18 = 3/100,000 injury rate. PGA(g) 0.18-0.34 = 3/10,000 injury rate. PGA(g) 0.34-0.65 = 3/1,000 injury rate. PGA(g) 0.65-1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate. Not attributable to CO2-ECBM.	PGA(g) >0.5 = damage to USDW aquifers. \$200/t CO2 released into USDW.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Not attributable to CO2-ECBM.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	15 days downtime to assess damage at110MCFD per well @ \$3.5/MCF = \$6k For 16 wells = \$92k. For 160 wells = \$924k	Cost of continuous passive micro-seismic monitoring.: Capex: \$3.6M Opex: \$0.3M/y for a 30 square mile area.	\$32.32/t CO2 (\$1.70/MCF) \$3.50/MCF CH4	10% of total damages attributable to CO2-ECBM.	Cost to locate and fix well leak \$0.3M per leak. + Cost to locate and fix fracture or fault leak: \$3M per leak. + Cost to replace contaminated USDW \$0.5M/y per leak until fixed. + Cost of lost CO2/CH4: \$0.2M per year per leak. Worst case: Project shutdown if natural earthquake mistaken for induced seismicity.	Cost to locate and fix well leak \$0.3M per leak. + Cost to locate and fix fracture or fault leak: \$3M per leak. + Cost to replace contaminated USDW \$0.5M per year per leak until fixed. + Cost of lost CO2/CH4: \$0.2M per year per leak.	Cost of continuous passive micro-seismic monitoring.: Capex: \$3.6M Opex: \$0.3M/y for a 30 square mile area.	Savings of \$0.5M/y per leak for USDW not contaminated + Savings of \$0.2M/y per leak of CO2 /CH4 not lost.	1
18	01.01.04.00.	Hydrothermal activity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	2	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
19	01.01.05.00.	Hydrological and hydrogeological response to geological changes	Processes arising from large-scale geological changes and could include changes of fluid boundary conditions due to the effects of changes of fluid properties of geological units due to changes in rock stress or fault movements.	In and below low-permeability geological formations, hydrogeological conditions may evolve very slowly and often reflect past geological conditions, i.e. be in a state of disequilibrium	Fruitland Formation fluids are recharged artesian-style from high elevation outcrops located 48 km (30 mi) N of the injection site. The SJB has an inferred structural hingeline consisting of a NW-trending fault zone located 10 km (6 mi) S of the CO2 injection site. Permeability decreases SW of the hingeline due to the pinchout of high-permeability stratigraphic units. This caused a backup of formation fluids resulting in overpressuring of the Fruitland Formation at the CO2 injection site. This area has been depressurized from 11.33 MPa (1,644 PSIA) to 0.69 MPa (100 PSIG) by CBM/dewatering operations. Approximately 99% of injected CO2 is adsorbed on coal and 1% remains as free gaseous CO2 in cleat pore space.		Reservoir disruption. Interaction between CO2/brine and near surface aquifers	Hydrological and hydrogeological response to geological changes.	Contamination of near surface drinking water.	Monitoring near surface water chemistry. Monitoring and modeling subsurface CO2 plume.	Proper site characterization and site selection, avoiding areas where hydrology or hydrogeology are in disequilibrium.	Monitor pressure in formations above the caprock and secondary seals. Monitor water level in wells. Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
20	01.01.06.00.	Large scale erosion (See 06.01.03.00)	Processes related to the large scale (geological) removal of rocks and sediments, with associated changes in topography and geological/hydrogeological conditions of the system.	Potential to modify the geological and hydrogeological environment.	Pump Canyon watershed area has medium wind and water erosion (BLM 2003).							
21	01.01.07.00.	Bolide impact (meteorite impact)	An extraterrestrial body in the 1-10 km size range, which impacts the earth at high velocity, explodes upon impact, and creates a large crater.	A low probability, high consequence event that has the potential to substantially disrupt the CO2 storage system. Often screened out on the basis that the impact of the bolide will greatly exceed that of the disruption caused to the sequestration system.	Probability of a bolide impacting in San Juan County is 2.8E-11 to 5.6E-11 per year (based on NASA estimates of 1 to 2 bolides per million years and San Juan County representing 2.8E-05 of the Earth's surface area).		Bolide impact causing caprock failure, destruction of surface facilities, human injury/death.	Bolide impact.	Catastrophic destruction. Release of CO2 may be one of the least effects.	NASA monitoring and modeling the trajectory of bolides in space.	Destruction of bolides in space before they have a chance to hit the earth.	Procedures to shutdown and evacuate site in cases of imminent danger.
22	01.02.00.00.	Climatic factors	Natural processes and events in the atmospheric environment that are relevant to the evolution of the sequestration system.	Changes in climate may directly affect the nature of any impacts that are incurred if carbon dioxide returns to the near-surface environment.								

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P x S x D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
19	01.01.05.00.	Hydrological and hydrogeological response to geological changes	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
20	01.01.06.00.	Large scale erosion (See 06.01.03.00)	0	0	0	0																
21	01.01.07.00.	Bolide impact (meteorite impact)	1	5	1	5	PGA(g) 0.092-0.18 = 1/1,000,000 fatality rate. PGA(g) 0.18-0.34 = 1/100,000 fatality rate. PGA(g) 0.34-0.65 = 1/10,000 fatality rate. PGA(g) 0.65-1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate. Not attributable to CO2-ECBM	PGA(g) 0.092-0.18 = 1/250,000 injury rate. PGA(g) 0.18-0.34 = 1/25,000 injury rate. PGA(g) 0.34-0.65 = 1/2,500 injury rate. PGA(g) 0.65-1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate. Not attributable to CO2-ECBM.	PGA(g) 0.092-0.18 = 3/100,000 injury rate. PGA(g) 0.18-0.34 = 3/10,000 injury rate. PGA(g) 0.34-0.65 = 3/1,000 injury rate. PGA(g) 0.65-1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate. Not attributable to CO2-ECBM.	PGA(g) >0.5 = damage to USDW aquifers. \$200/t CO2 released into USDW.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Not attributable to CO2-ECBM.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	Shutdown of project	Shutdown of Project	up to 10% of total CO2 stored	10% of total damages	100% of project cost + cost to locate and fix leaks + cost of CO2 emitted + cost to replace contaminated USDW: >\$100M	100% of project cost + cost to locate and fix leaks + cost of CO2 emitted + cost to replace contaminated USDW: >\$100M	None	None		
22	01.02.00.00.	Climatic factors	0	0	0	0																

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Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
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23	01.02.01.00.	Global climate change (See 01.02.02.00.)	The process of global climate change due to natural and/or anthropogenic causes. The last two million years of the Quaternary have been characterized by glacial/interglacial cycling. According to the Milankovitch Theory, the Quaternary glacial/interglacial cycles are caused by long-term changes in seasonal and latitudinal distribution of incoming solar radiation which are due to the periodic variations of the Earth's orbit about the Sun (Milankovitch cycles). Evidence suggests that the Earth is presently in a period of global warming. The anthropogenic release of gases into the atmosphere may be increasing the rate of global warming by enhancing the natural greenhouse effect, a process by which long wave radiation emitted from the Earth is trapped in the atmosphere by greenhouse gases such as CO2. 1. Natural global climate change 2. Human induced climate change (01.03.01.00) 3. Ecology or human behavior response to climate change (01.02.08.00)	Changes in the global climate are likely to impact the CO2 sequestration system in a number of ways. For example, through its affect on sea levels and the local and regional climate. Changes in ecology and human behavior in response to climate change will influence the relevant FEPs to be considered in the surface environment as an assessment extends into the future. Changes in air emission policies in response to global climate change will impact the feasibility of using CCS.	Local area susceptible to drought, lightning and thunderstorms. Thunderstorms may cause flash flooding. Estimated probability of occurrence within 50 miles of Navajo Dam from 1950-2010: Flooding: 1.1/y Thunderstorm wind: 0.65/y Hail: 0.58/y Wildfire: 0.27/y Drought: 0.05/y Tornado (F2 or above): 0.017/y (USA.com 2012)								
24	01.02.02.00.	Regional and local climate change (extreme weather events damaging facilities)	Processes related to the possible future changes, and evidence for past changes, of climate at a storage site. This is likely to occur in response to global climate change, but the changes will be specific to situation, and may include short term fluctuations. Climate is characterized by a range of factors including temperature, precipitation and pressure as well as other components of the climate system such as oceans, ice and snow, biota and the land surface. Climatic changes lasting only a few decades may be referred to as climatic fluctuations. These are unpredictable at the current state of knowledge although historical evidence indicates the degree of past fluctuations. 1. Warm climate effects (01.02.06.00) 2. Cold climate effects 3. Wet climate effects 4. Dry climate effects 5. Hydrological and hydrogeological response to climate change (01.02.07.00)	Changes in the regional and local climate could affect the CO2 sequestration system in a number of ways. For example, changes in groundwater recharge could affect regional hydrogeology and hence the transport of CO2 dissolved in groundwater. It may also alter the near-surface environment to which some of the disposed CO2 may migrate. Regions with a tropical climate may experience extreme weather patterns (monsoons, hurricanes) that could result in flooding, storm surges, high winds etc. with implications for erosion and hydrogeology. The high temperatures and humidity associated with tropical climates result in rapid biological degradation and soils are generally thin. In arid climates, total rainfall erosion and recharge may be dominated by infrequent storm events. The hydrology and hydrogeology of a region is closely coupled to climate. Climate controls the amount of precipitation and evaporation, seasonal ice cover, and thus the soil water balance, extent of soil saturation, surface runoff groundwater recharge, sediment load and seasonality. Vegetation and human actions may modify these responses.	Local area susceptible to drought, lightning and thunderstorms. Thunderstorms may cause flash flooding. Estimated probability of occurrence within 80 km (50 MI) of Navajo Dam from 1950-2010: Flooding: 1.1/y Thunderstorm wind: 0.65/y Hail: 0.58/y Wildfire: 0.27/y Drought: 0.05/y Tornado (F2 or above): 0.017/y (USA.com 2012)	Extreme weather events damaging project facilities.	Significant and severe regional or local climate change.	Business interruption (advance loss of profits), facilities damage.	Monitor trends in climate change that may have a detrimental effect on the project. Monitoring extreme weather patterns.	Proper site characterization and site selection avoiding flood plains. Proper design consideration to accommodate extreme or changing weather patterns.	Maintain procedures for dealing with severe weather that may require an emergency shutdown.		

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking			Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)		Savings with risk mitigation (\$)
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
23	01.02.01.00.	Global climate change (See 01.02.02.00.)	0	0	0	0															
24	01.02.02.00.	Regional and local climate change (extreme weather events damaging facilities)	3	2	1	6	Not attributable to CO2-ECBM	Not attributable to CO2-ECBM	Not attributable to CO2-ECBM	Not attributable to CO2-ECBM	Not attributable to CO2-ECBM	Surface facilities damage <\$1M for most situations.	Loss of revenue due to downtime to assess and fix damage at 43 to 110 MCFD per well @ \$3.5/MCF = \$150 to \$385/d per well	None	None	None	Cost to repair surface facilities: <\$1M + Cost of business interruption	Cost of insurance deductable.	Cost of insurance coverage for weather and flood damage and business interruption: 0.28% of surface facilities value per year + 0.25% of revenue per year respectively.	Savings in cost to repair surface facilities + Savings in cost of business interruption - Cost of insurance - Cost of insurance deductable.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
25	01.02.03.00.	Sea level change	Processes related to changes in sea level which may occur as a result of global (eustatic) change and/or regional geological change, e.g. isostatic movements. The component of sea-level change involving the interchange of water between land ice and the sea is referred to as eustatic change. As ice sheets melt so the ocean volume increases and sea levels rise. Sea level at a given location will also be affected by vertical movement of the land mass, e.g. depression and rebound due to glacial loading and unloading, referred to as isostatic change.	Sea level change may affect the sequestration system through its impact on the near surface environment and the regional or local hydrogeological regime.	Site not impacted by sea level change.		Flooding/erosion of pipeline right-of-way or injection site. Contamination of near surface drinking water with sea water.	Significant sea level change	Facilities flood damage. Business interruption (advanced loss of profits). Potential for project instead of sea level to be blamed for increased drinking water salinity.	Monitor trends in sea level change and analyze the potential impact on the project.	Proper site characterization and site selection avoiding low coastal areas or flood plains.	Installing barriers. Perform baseline surveys to determine source of water contamination.
26	01.02.04.00.	Periglacial effects	Related to the physical processes and associated landforms in cold but ice-sheet-free environments.	An important characteristic of periglacial environments is the seasonal change from winter freezing to summer thaw with large water movements and potential for erosion. Frozen sub-soils are referred to as permafrost. Melt water from seasonal thaw is unable to percolate downwards due to permafrost and saturates the surface materials. Permafrost layers may isolate the deep hydrogeological regime from surface hydrology, or flow may be focused at "taliks" (localized unfrozen zones, e.g. under lakes, large rivers or at regions of groundwater discharge).	No periglacial effects.		Erosion and frost heave. Permafrost forms local near-surface cap.	Periglacial effects	Damage to facilities. CO2 release (HSE hazard). Accumulation of migrating CO2 beneath permafrost zone and potential catastrophic release.	Monitoring weather forecasts for extreme conditions. Monitoring surface water movement and erosion patterns.	Proper site characterization and site selection avoiding permafrost areas.	Proper winterization of surface facilities. Erosion control barriers.
27	01.02.05.00.	Glacial and ice sheet effects	Processes related to the effects of glaciers and ice sheets within the region of a storage site. This is distinct from the effects of large ice masses on global and regional climate. The ice sheet and the permafrost beneath the ice sheet may constitute a barrier to groundwater flow and to heat loss. If the basal transmissivity of the till and bedrock below the ice is low, water pressures may rise to levels equaling the ice pressure inducing the formation of major conduits in the subglacial material. The central parts of the ice sheet are likely to be warm-based and could permit groundwater recharge to take place. Discharge of groundwater is likely to take place close to and beyond the frontal parts of the ice sheet. Excessive recharge at the margin of the ice sheet could provide direct recharge of oxidizing water to considerable depths in conductive fracture zones. If the permeability at and beyond the rim of the ice is low, the water pressures may again build up resulting in hydrofracturing of the ice or the rock mass. As the ice sheet advances, these induced fractures may increase their aperture and depth due to freezing of subglacial melt water.	Erosional processes (abrasion, over deepening) associated with glacial action, especially advancing glaciers and ice sheets, and with glacial melt waters beneath the ice mass and at the margins, can lead to morphological changes in the environment, e.g. U-shaped valleys, hanging valleys, fjords and drumlins. Depositional features associated with glaciers and ice sheets include moraines and eskers. The pressure of the ice mass on the landscape may result in significant hydrogeological effects and even depression of the regional crustal plate.	No glacial effects.		Erosion, deposition and hydrogeological effects having detrimental effect on CO2 geologic storage	Glaciers and ice sheet	Facilities damage and CO2 release (HSE hazard).	Monitor glacier and ice sheet movement. Analyze trends to project future movement.	Proper site characterization and site selection avoiding glaciers and ice sheets.	Permanently close facility and relocate project site.
28	01.02.06.00.	Warm climate effects (See 01.02.01.00.)										
29	01.02.07.00.	Hydrological and hydrogeological response to climate changes (See 01.02.01.00.)										
30	01.02.08.00.	Responses to climate change (See 01.02.01.00.)										
31	01.03.00.00.	Future human actions	Human activities that are relevant to the evolution of the sequestration system.	Human activities may directly interfere with the sequestered fluid resulting in immediate or delayed impacts.								

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
25	01.02.03.00.	Sea level change	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
26	01.02.04.00.	Periglacial effects	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
27	01.02.05.00.	Glacial and ice sheet effects	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
28	01.02.06.00.	Warm climate effects (See 01.02.01.00.)	0	0	0	0																
29	01.02.07.00.	Hydrological and hydrogeological response to climate changes (See 01.02.01.00.)	0	0	0	0																
30	01.02.08.00.	Responses to climate change (See 01.02.01.00.)	0	0	0	0																
31	01.03.00.00.	Future human actions	0	0	0	0																

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
32	01.03.01.00.	Human influence on climate (See 01.02.01.00.)										
33	01.03.02.00.	Motivation and knowledge issues (Future interference with or intrusion into the CO2 reservoir by third parties)	Events and processes related to the degree of knowledge of the existence, location and/or nature of the storage site. Also, reasons for deliberate interference with, or intrusion into, a CO2 storage site after closure with complete or incomplete knowledge. Knowledge of the sequestration site may be regained through post-closure airborne, geophysical or other surface-based non-intrusive investigation of a sequestration site. Such investigations might occur after information of the location of the sequestration system has been lost and therefore excludes monitoring of the disposal system, but includes activities such as prospecting for geological resources. The evidence of the sequestration, such as injection boreholes, may itself prompt investigation. 1. Inadvertent interference with or intrusion into the CO2 reservoir. 2. Deliberate interference with or intrusion into the CO2 reservoir. 3. Malicious intrusion and sabotage.	Some future human actions could directly impact upon performance of the storage system. The following could be distinguished: - inadvertent actions, which are actions taken without knowledge or awareness of the storage site, and - deliberate actions, which are actions that are taken with knowledge of the storage systems existence and location, e.g. deliberate attempts to retrieve any hydrocarbons (e.g., EOR and ECBM) associated with the CO2 - malicious intrusion and sabotage. Intermediate cases, of intrusion with incomplete knowledge, could also occur. Terrorist activities against pipelines and facilities.	Site registered and well defined as a CBM site. Inadvertent intrusion into the CO2 reservoir unlikely. Extensive ongoing CBM, tight sands and shale gas operations in the area. Over 99% of CO2 likely to be adsorbed on coal with less than 1% of free gaseous CO2 in the cleat pore space.		Third-party penetration of the primary caprock.	Inadvertent or deliberate interference with or intrusion into the CO2 reservoir.	CO2/CH4 leakage.	Routine inspections and/or monitoring of the Site for third-party subsurface activities.	Clearly mark the site with warning signs and register the site as a CO2 storage site with the State.	Routine site inspection and monitoring. Supervising on site drilling activities. Procedures for stopping leaks.
34	01.03.03.00.	Social and institutional developments	Events and processes related to changes in social patterns and degree of local government, planning and regulation. Potentially significant social and institutional developments include: 1. Changes in planning controls (zoning) 2. Environmental legislation; 3. Demographic change and urban development; 4. Changes in land use; 5. Loss of archives/records, loss/degradation of societal memory.	Social and institutional developments have the potential to affect motivation and knowledge issues, human use of the surface and sub-surface environments and the type of impacts that may be considered.	Unlikely to be affected by demographic change, change in land use or loss of records. Section 32 is owned by the State. Over 70% of the land in the Sixteen-Township Area is managed by the Federal government and 60% of the land is listed as Specially Designated Areas which may be subject to rule changes with respect to drilling and operations. Could be affected by new stricter environmental legislation.		Change in zoning laws, land use or environmental legislation that would have significant detrimental effect on the project.	Radical social and institutional developments	Increased operating costs due to compliance with regulation changes or increased legal costs to protect the project.	Monitor zoning, environmental legislation, and demographic trends.	Monitor zoning announcements, environmental legislation, and demographic changes. Taking appropriate legal action if necessary to protect the site . Clearly mark the site with warning signs and register the site as a CO2 storage site with the State. Keep backup documentation at off-site locations.	Routine site inspection and/or monitoring. Provide input/feedback to lawmakers.
35	01.03.04.00.	Technological developments	Events and processes related to future developments in human technology and changes in the capacity and motivation to implement technologies. This may include retrograde developments, e.g. loss of capacity to implement a technology. 1. New technology replacing the need for CO2 geologic sequestration 2. New low-cost desalination making saline aquifers more valuable 3. Lack of CO2 capture technology improvements making it too expensive 4. Robotic underground mining making deeper resources more mineable	Of interest are those technologies that might change the capacity of humans to intrude deliberately or otherwise into a storage site, to cause changes that would affect the movement of CO2 and associated contaminants, or that may otherwise affect the performance and safety of the sequestration system. Technological developments are likely but may not be predictable especially at longer times into the future.	CO2-ECBM feasibility has decreased due to successful use of hydraulic fracturing and horizontal drilling for shale gas, resulting in increased natural gas supply and decreased natural gas prices.Failure severity is limited because CO2-ECBM projects are not being pursued. Technology development is needed to overcoming coal matrix swelling) in order to make CO2-ECBM feasible.		CO2-ECBM becoming infeasible due to a new technology development or lack of new technology development.	Technology development.	Delay or shutdown of project. Increased costs. Business interruption (advanced loss of profits). Greater liability exposure.	Keep abreast of new technology developments and analyze impact on project economics.	Proactive approach in improving and optimizing CO2-ECBM economics.	Take corrective action to address evolving competitive environment.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
32	01.03.01.00.	Human influence on climate (See 01.02.01.00.)	0	0	0	0															
33	01.03.02.00.	Motivation and knowledge issues (Future interference with or intrusion into the CO2 reservoir by third parties)	4	2	1	8	None	None	None	\$200/t CO2 released into USDW	\$0.1M to plug and abandon well.	Damage to caprock	None	None	\$32.32/t CO2 emitted (\$1.70/MCF of CO2) \$3.50/MCF of CH4 emitted.	None	<\$0.5M	None	Registering site with the State and supervise third-party subsurface activities <\$0.1M	<\$0.4M	
34	01.03.03.00.	Social and institutional developments	4	3	1	12	None	None	None	None	None	None	None	Increased operating costs for compliance with new regulations or increased legal costs to protect the project: \$1M-\$10M	None	10% of damage costs	Increased operating costs for compliance with new regulations or increased legal costs to protect the project: \$1M-\$10M	None	Increased operating costs for compliance with new regulations or increased legal costs to protect the project: \$1M-\$10M	None	
35	01.03.04.00.	Technological developments	5	1	1	5	None	None	None	None	None	None	None	Monitor technology developments impacting cheap oil production or alternative fuel supplies. Part of ongoing costs.	None	None	None	None	Monitor technology developments impacting cheap oil production or alternative fuel supplies. Part of ongoing costs.	None	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
36	01.03.05.00.	Drilling activities (third-party drilling through caprock)	Events related to any type of drilling activity in the vicinity of the CO2 sequestration system. These may be taken with or without knowledge of the disposal and may include activities such as: 1. Exploratory and/or exploitation drilling for natural resources; 2. Attempted recovery of residual hydrocarbon resources (e.g., EOR, ECBM, shale gas); 3. Drilling for water resources; 4. Drilling for site characterization or research; 5. Drilling for liquid waste or other fluids disposal; 6. Drilling for geothermal resources.	Has the potential to disrupt geological features that provide a barrier to CO2 migration and provide a relatively quick migration pathway to the near-surface.	Site area used for CBM and tight sands gas production by multiple operators. There is potential for shale gas operations in the future. Over 99% of injected CO2 likely to be adsorbed on coal with less than 1% of free gaseous CO2 in the cleat pore space.		Well CO2/CH4 leakage	Drilling through caprock	Release of CO2/CH4 to upper formations, near surface aquifer, soil or atmosphere.	Routine inspections and/or monitoring of the site for drilling activity.	Clearly mark the site with warning signs and register the site as a CO2 storage site with the State.	Routine site inspection and monitoring. Supervising on site drilling activities. Procedures for controlling kicks or leaks. Streamline requirements of lease CO use requirements as appropriate. Monitor well permit activity or institutional controls that prohibits any drilling activities in designated areas.
37	01.03.06.00.	Mining and other underground activities	Events related to any type of mining or excavation activity carried out in the vicinity of the storage site. These may be taken with or without knowledge of the site. Mining and other excavation activities include: 1. Resource mining or quarrying; 2. Excavation for industry, storage, disposal or military purposes; 3. Scientific or archaeological investigation; 4. Shaft construction, underground construction and tunneling; 5. Underground nuclear testing; 6. Malicious intrusion, sabotage or war; 7. Underground utilities and pipelines	Mining and other underground activities have the potential to disrupt the geosphere (storage reservoir, surrounding and overlying rock) and near-surface environment. They therefore have the potential to significantly affect the migration and distribution of sequestered CO2.	Mining not a factor in the area. Coal seams located below the maximum mineable depth. Area well characterized. No mines listed in the area. There are 10 sand and gravel quarries on the W side of the Sixteen-Township Area (BLM 2003).		Exposure of people to accumulated CO2 in confined underground spaces.	Mining and other underground activities.	CO2 leakage. Asphyxiation.	Routine inspections and/or monitoring of the site for mining and other underground activities.	Proper site characterization and site selection avoiding potential mining, industrial, military, archaeological, geothermal, nuclear, waste disposal and transportation areas. Clearly mark the site with warning signs and register the site as a CO2 storage site with the State.	Routine site inspection and monitoring. Supervising on site drilling/excavation activities. Procedures for stopping blowouts or leaks.
38	01.03.07.00.	Human activities in the surface environment	Events and processes related to any type of human activities that may be carried out in the surface environment that can potentially affect the performance of the storage system, or leakage pathways, excepting those FEPs related to water management which are described elsewhere. Examples include: 1. Residential, industrial, and infrastructure construction leading to pipeline damage. 2. Third-party pollution of surface environment and groundwater. 3. Change in groundwater chemistry not caused by project. 4. Human activities in the surface environment offsite (farming, harvesting, irrigation maintenance) in low areas with limited air circulation.	Human activities in the surface environment have the potential to affect CO2 release processes, should leakage occur. They may also determine the types of impact to be considered or activities that would increase risk exposures.	Very limited human activity in Section 32. No residences. Only CBM and gas operations. Simon Canyon (on the E side of the Nine-Section Area, 2 km (1.2 mi) from the CO2 injection well) is an Area of Critical Environmental Concern (ACEC) and is used for hiking, backpacking, fishing, picnicking and wildlife watching (BLM 2012). Farming operations are located along the Animas River.		Damage to surface facilities or pipelines. Contamination of groundwater by third parties not related to CO2.	Human activities in the surface environment.	CO2/CH4 leakage. Potential public concerns.	Routine inspections and/or monitoring of the site for human surface activities.	Clearly mark the site with warning signs and register the site as a CO2 storage site with the State. Conduct baseline water quality studies before CO2 injection.	Routine site inspection and monitoring. Supervising on-site excavation activities. Secure surface facilities from third-party intruders. Maintain emergency procedures for stopping leaks. Install CO2/CH4 monitors/alarms in high-risk areas.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
36	01.03.05.00.	Drilling activities (third-party drilling through caprock)	2	2	1	4	None	None	None	\$200/t CO2 released into USDW	Potential gas kick during drilling. Cost of additional drilling rig time: \$1,950/hour. \$0.1M to plug and abandon well.	None	None	Supervise third-party drilling activities <\$0.1M. Use BOP and packers for well control during deep drilling.	\$32.32/t CO2 emitted (\$1.70/MCF of CO2) \$3.50/MCF of CH4 emitted..	None	<\$0.5M	None	Supervise third-party drilling activities <\$0.1M. Use BOP and packers for well control during deep drilling.	<\$0.4M	1
37	01.03.06.00.	Mining and other underground activities	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
38	01.03.07.00.	Human activities in the surface environment	2	2	2	8	None	None	None	None	None	Damage to surface facilities or pipelines: <\$1M	Downtime for repairs to damage.	Additional security and monitoring costs: <\$0.5M	\$32.32/t CO2 emitted (\$1.70/MCF of CO2) \$3.50/MCF of CH4 emitted.	None	<\$1M for owner property damages, business interruptions and emissions.	None	Monitor surface facilities and pipelines. Secure surface facilities. Installation of CO2/CH4 monitors, alarms in high-risk areas: <\$0.5M	<\$0.5M	1

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39	01.03.08.00.	Water management	Events and processes related to groundwater and surface water management including water extraction, reservoirs, dams, and river management. Water is a valuable resource and water extraction and management schemes provide increased control over its distribution and availability through construction of dams, barrages, canals, pumping stations and pipelines. Groundwater and surface water may be extracted for human domestic use (e.g. drinking water, washing), agricultural uses (e.g. irrigation, animal consumption) and industrial uses. 1. Water extraction 2. Surface water reservoir construction 3. Dam construction 4. River management	Extraction and management of water may affect the movement of CO2 or associated contaminants to and in the surface environment.	No significant surface water or primary USDW aquifer in Section 32. CBM operation s have extensively dewatered the Fruitland Formation. Small ephemeral creeks run through the Nine-Section Area. Quintana Spring is located 1.8 km (1.1 mi) NE of the CO2 injection Site. Minix Spring is located 4.3 km (2.7 mi) NW of the Site. Navajo Dam (built in 1962) is located 6.4 km (4 mi) SE of the site. Navajo Reservoir is located 4.8 km (3 mi) E of the Site. The San Juan River (classified as Quality Water for trout fishing) is located 4.8 km (3 mi) S of the Site. The Animas River is located 18 km (9 mi) NW of the Site. The Pump Canyon ephemeral wash area is located 3 km (2 mi) SW of the Site. There are 13 salt water disposal wells in the Sixteen-Township Area. The salt water is injected into the Morrison and Entrada Formations.		Contamination of ground/surface water with CO2/CH4/brine and migration of contaminated water. Public concern about lower water table levels, even though CO2-ECBM may not be the cause.	Water management - extraction combined with CO2/CH4/brine leakage. Water management - extraction	Extended water contamination. Potential lawsuits.	Monitor CO2/salinity of ground / surface water.	Not applicable.	Monitor and model CO2/CH4/ brine movement. Monitor CO2 and salinity of ground/surface water. Stop CO2 injection, depressurize the reservoir. Locate and eliminate CO2/CH4/brine leaks. Segregate and treat contaminated water.
40	01.03.09.00.	CO2 presence influencing future operations	The presence of injected CO2 may hinder future extractive operations by obscuring seismic traces or by making the drilling process more difficult. Conversely, the presence of CO2 locally, might allow for more economic future enhanced oil recovery operations. This FEP assumes that future technical advances might identify useable resources in the vicinity of previous CO2 injection.	Drilling through a formation filled with supercritical CO2 might cause 'blowouts' or loss of CO2 along the wellbore. A CO2 'bubble' will change the velocity of seismic waves, distorting the 'image' of the underlying formations, and reducing confidence in the understanding of this structure.	CO2 released from bicarbonate-rich Fruitland Formation fluids currently makes up 10-30% of the CBM produced in the area. Additional CO2 injection could increase CO2 content of the CBM if a breakthrough occurs. This CO2 must be removed from the CBM to meet natural gas specifications. Repressurizing the Fruitland Formation with CO2 could decrease methane desorption and CBM production. Thousands of gas wells penetrate the Kirkland and Fruitland Formations in the SJB. Over 99% of injected CO2 likely to be adsorbed on coal with less than 1% of free gaseous CO2 in the cleat pore space.		Well leakage. Distortion of seismic readings. CO2/CH4 leakage due to fracking.	CO2 presence underground.	Release of CO2 to upper formations, near surface aquifer, soil or atmosphere.	Monitoring and modeling of CO2 plume.	Clearly mark the site with warning signs and register the site as a CO2 storage site with the State. Maintain blow out protectors and packers Use more than one method of monitoring CO2 plume movement.	Procedures/training for dealing with well kicks. Seal well. Decrease reservoir pressure.
41	01.03.10.00.	Explosions and crashes (See 16.27.00.)										
42	02.00.00.00.	CO2 STORAGE	This category of FEPs specifies details of the sequestration concept under consideration. It is split into two classes for the pre- and post-closure periods.	This category is divided into two classes: 1. Pre-closure 2. Post-closure								
43	02.01.00.00.	Pre-closure	Details of the sequestration concept, the fluids injected, and factors for the design, construction, operation and decommissioning phases.	The details of the sequestration concept are fundamental to determining which FEPs in other categories need to be considered in a given assessment. Some details of sequestration operations may affect the post-closure performance.								

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39	01.03.08.00.	Water management	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
40	01.03.09.00.	CO2 presence influencing future operations	2	2	1	4	None	None	None	\$200/t CO2 released into USDW	Potential gas kick during drilling. Cost of additional drilling rig time: \$1,950/hour. \$0.1M to plug and abandon well.	None	None	None	\$32.32/t CO2 emitted (\$1.70/MCF of CO2) \$3.50/MCF of CH4 emitted.	None	<\$0.5M	None	Supervise third- party drilling activities <\$0.1M. Use BOP and packers for well control during deep drilling.	<\$0.4M	1
41	01.03.10.00.	Explosions and crashes (See 16.27.00.)	0	0	0	0															
42	02.00.00.00.	CO2 STORAGE	0	0	0	0															
43	02.01.00.00.	Pre-closure	0	0	0	0															

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
44	02.01.01.00.	Storage concept	Features related to the concept of storage, such as whether a closure exists (sequestration in an abandoned oil or gas field or coal seam) or whether isolation of CO2 is dependent upon slow diffusion rates through an extensive open structure (saline aquifer sequestration). 1. Deep saline aquifer CO2 storage - Sealed reservoir - Open reservoir 2. EOR CO2 storage 3. ECBM CO2 storage 4. Temporary CO2 storage and pumping facilities - Above ground - Underground (see Reversibility)	Different processes will be relevant to different storage concepts. For example, the rate of CO2 migration in an open aquifer will be relevant to safety assessment of saline aquifer storage, but less relevant to sequestration in a closed geological structure.	Pump Canyon Site Mature (35 year old) CBM operation. Small demo CO2-ECBM test in 2008-2009.		Loss of control of CO2 migration.	Improper storage concept.	Potential CO2 release (HSE hazard). Increased costs and loss of revenue.	Fully characterize and model the site early in the design phase. Continuously monitoring and modeling the site. Periodic evaluation of actual versus expected performance.	Fully characterize and model the site early in the design phase. Select the appropriate injection strategy for the site.	Continuously monitor and model the Site. Make adjustments to CO2 injection strategy as necessary.
45	02.01.02.00.	CO2 quantities, injection rate	Features related to the amounts of CO2 injected and their rate of injection into the storage aquifer/reservoir.	High rates of CO2 injection could have adverse effects, such as formation fracturing. For large injection rates, displacement of oil/water will not be efficient during enhanced oil recovery; instead one will recover CO2; premature breakthrough is undesirable from an economic perspective. Larger volumes of injected CO2 are likely to result in more frequent and more intense induced seismicity unless compensated for with simultaneous production of fluids.	Pump Canyon Site CO2 injection well was originally planned to inject 68,000 t of CO2 over a 1 year period, but was only able to inject 16,871 t of CO2. CO2 injection rate was disrupted by coal matrix swelling causing permeability to decrease, and injectivity to decrease from 200 to 13 t/d (3,800 to 250 MSCFD over the one-year period). CO2 injection for a single vertical well may be limited to 17,000 t in the first year and 5,000 t each year thereafter.	No project planned at this time. Quantity of CO2 to be injected cannot be confirmed. Assuming a range of 0.3 Mty to 3 Mty.	CO2 injection wells unable to keep up with planned injection rate	Large CO2 injection rate	High injection pressure. Large number of CO2 injection wells.	Monitoring CO2 injection rate and bottom hole pressure.	Fully characterize and model the site early in the design phase. Conduct injectivity tests and adjust injection plan appropriately. Maintain injection pressure at <90% of fracture pressure. If injection rate falls, add additional injection wells to handle source stream.	Avoid excess injection pressures. If injection pressure is unacceptably high, cut back on individual well injection rate and use additional injection wells. Use horizontal wells instead of vertical wells to boost injection rate per well. Use hydraulic stimulation to boost injectivity
46	02.01.03.00.	CO2 composition	The composition and physical state (liquid, supercritical fluid etc.) of injected CO2, with contents of impurities etc. Temperature and pressure of injected fluid are also relevant. During CO2 storage operations, the principal injected gas is CO2 captured and concentrated from human activity sources. However, the gas that is injected into a reservoir may not be 100 % CO2, especially if there is some recycling of gas (in the case of enhanced oil recovery). Impurities can include: H2S, CH4, N2, NOx, SO2 and mercaptans. These may be present either intentionally or because it could be particularly difficult or superfluous to separate them from CO2. The CO2 stream may contain such things as: corrosives, noncondensable gases, oxidants, toxic impurities, flammable/combustible/pyrophoric constituents, odorous constituents, organics or particulates.	The presence of even small amounts of other gases has a strong effect on the phase behavior of CO2-dominated gases. High-pressure equations of state for CO2-dominated gas mixtures are required to take into account changes in critical pressures and temperatures caused by the presence of other gases. Impurities will reduce the critical temperature which, in turn, has effects on interfacial tension. Impurities may affect pore water chemistry (pH and redox conditions, for example) depending on the impurities involved. Special care is needed when considering corrosive gases, such as H2S.	CO2 for Pump Canyon and Allison Unit tests came from McElmo dome. The natural CO2 contained 98.2% CO2, 1.5% N2.	No project planned at this time. Final source and quality of CO2 stream cannot be confirmed.	Pipeline/well corrosion leading to leakage or rupture.	CO2 stream composition off spec.	CO2 release (HSE hazard). Downtime for repairs.	Monitoring composition of CO2 stream.	Maintain tight spec on CO2 stream composition Avoid upset operating conditions in CO2 supply dehydration.	Withhold purchase of CO2 until CO2 is on spec. Maintain injection HCPV with recycled CO2 and supplemental water. Select proper materials of construction for pipeline and well components and maintain tight seals and failsafe systems to prevent leakage. Monitor corrosion rate in piping and equipment.

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
44	02.01.01.00.	Storage concept	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
45	02.01.02.00.	CO2 quantities, injection rate	5	5	2	50	None	None	None	None	None	None	None	Significant number of injection wells required for commercial operation. \$24M for 0.3 Mt/y CO2. \$240M for 3Mt/y CO2.	None	None	Significant number of injection wells required for commercial operation. \$12M to \$24M for 0.3 Mt/y CO2. \$120M to 240M for 3Mt/y CO2.	None	Cost of injection wells for commercial operation: \$12M to \$24M for 0.3 Mt/y CO2. \$120M to 240M for 3Mt/y CO2.	None	1
46	02.01.03.00.	CO2 composition	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

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47	02.01.03.01.	CO2 containing H2S	High concentration of hydrogen sulfide (H2S) in the CO2 makes it a toxic waste which can lead to more stringent permitting and compliance requirements. It also increases the safety risks. The exposure threshold at which H2S is immediately dangerous to life or health, according to the National Institute of Occupational Safety and Health, is 100 ppm, compared to 40,000 ppm for CO2 (IPCC 2005) H2S should be kept below maximum concentration of 10 to 200 ppm in the CO2 for safety reasons.	Sufficient quantities of H2S + H2O in CO2 can cause corrosion or sulfide stress cracking (CCP 2009) and increase safety risks. H2S is strong smelling and requires additional sealing around the wellhead to capture fugitive emissions and minimize odors. On a positive side, H2S in CO2 can decrease minimum miscibility pressure (MMP) for enhanced oil recovery and makes small CO2 leaks easier to detect due to the smell.	H2S maintained at less than 10 mg/l and total sulfur maintained below 35 mg/l in McElmo CO2. Produced CO2 from CBM operations has very low H2S content.	No project planned at this time. Final source and quality of CO2 stream cannot be confirmed.	Well/piping corrosion leading to leakage or rupture. Human injury/death.	High H2S content in CO2 stream in presence of water.	CO2 + H2S release. Liabilities.	Monitoring H2S content of purchased CO2 stream and recycled CO2 stream. Monitor H2S around injection wells and gas recycling facilities.	Maintain tight H2S specification on CO2 supply. Avoid contact with water. Avoid upset conditions with CO2 dehydration	Stop injection and fix or resolve leakage. Select proper materials of construction for pipeline, gas recycling facilities and well components and maintain tight seals and failsafe systems to prevent leakage. Monitor for H2S around injection wells and gas recycling facilities. Install alarms.
48	02.01.03.02.	CO2 containing H2O	In order to prevent corrosion in pipeline and wellhead systems, CO2 is normally dehydrated to less than 0.5 g/m³ (30 lb per MMCF) or less than 20 ppm. (WRI 2008)	If the water vapor is not removed prior to compression, the CO2 product will be very corrosive and the pipeline well head and borehole would have to be built with much more expensive materials than carbon steel.	Water maintained at less than 25 lbs per MMCF in McElmo CO2.	No project planned at this time. Final source and quality of CO2 stream cannot be confirmed.	Pipeline/well corrosion leading to leakage or rupture.	High H2O content in CO2 stream.	CO2 release (HSE hazard).	Monitoring H2O content of purchased CO2 stream and recycled CO2 stream. Monitoring pipeline thickness.	Maintain tight H2O specification on CO2 stream. Avoid upset conditions with CO2 dehydration. Properly eliminate residual water from pipelines.	Monitor for water in CO2 streams and pipeline. Stop injection and fix or resolve leakage. Proper selection of materials of construction for pipeline, gas recycling facilities and well components.
49	02.01.03.03.	CO2 containing O2	EOR and deep saline applications can tolerate some oxygen (air) in the CO2, but ECBM can't. Oxygen in CO2 will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow. The preferred specification is less than 10 ppm oxygen. Oxygen in the 1-2% range or above could impact mineralogical reactions in the reservoir.	Oxygen in CO2 can cause pipeline corrosion, oxidize oil in EOR or oxidize coal and/or methane in ECBM. High oxygen content (5-10%) will not liquify or dissolve in downhole storage of CO2, and therefore will result in undesirable back pressure and downhole gas pockets. Oxygen can contaminate or degrade CO2 capture and CO2 dehydration sorbents. Oxygen could cause subsurface microbial growth but is not expected to have a significant impact.	O2 maintained at less than 10 ppm in McElmo CO2.	No project planned at this time. Final source and quality of CO2 stream cannot be confirmed.	Pipeline/well corrosion leading to leakage or rupture. Oxidation of oil in EOR. Oxidation of coal and/or methane in ECBM. Potential spontaneous combustion of dewatered coal.	High O2 content in CO2 stream	CO2 leakage. Lower EOR yield. Lower ECBM yield.	Monitoring O2 content of purchased CO2 stream and recycled CO2 stream. Monitoring pipeline thickness.	Maintain tight O2 specification on CO2 supply. Avoid upset conditions and ingress in CO2 production system.	Monitor for O2 in CO2. Stop injection and fix or resolve leakage.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
47	02.01.03.01.	CO2 containing H2S	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
48	02.01.03.02.	CO2 containing H2O	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
49	02.01.03.03.	CO2 containing O2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

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Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
50	02.01.03.04.	CO2 containing N2	Nitrogen in CO2 will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow. Nitrogen is normally kept to less than 4% of volume in CO2.	Nitrogen is undesirable for EOR because it raises the minimum miscibility pressure (MMP) of the fluid and makes the injection process less efficient. Nitrogen is not a problem in ECBM as a minor component of CO2. It will lower the partial pressure of methane and allow more methane to be released and recovered. Minor amounts of nitrogen in CO2 can increase compression and transmission energy consumption and can result in two phase operation. Nitrogen (and argon) will not liquify or dissolve in downhole storage of CO2, and therefore will result in undesirable back pressure and downhole gas pockets. N2 in the CO2 supply for ECBM may partially mitigate permeability decrease due to coal matrix swelling associated with CO2 adsorption. Increased N2 content in the CBM stream may be an early indicator that CO2 breakthrough is imminent. However, N2 would need to be removed from the CBM if it causes the CBM to be out of spec for pipeline natural gas.	McElmo CO2 typically contains 1.6%N2.	No project planned at this time. Final source and quality of CO2 stream cannot be confirmed.	Two-phase flow in pipeline. Underground gas pockets detrimental to CO2 storage. Increased MMP detrimental to CO2 EOR.	High nitrogen content in CO2 stream.	Increased power for compression and transport of gas. Decreased CO2 storage capacity. Lower yield in EOR.	Monitoring N2 content of purchased CO2 stream and buildup in recycle CO2 stream	Control nitrogen content in CO2 supply. Avoid upset operating conditions and air ingress in CO2 production.	Monitor for N2 in CO2.
51	02.01.03.07.	CO2 containing CH4 and other hydrocarbons	Total hydrocarbons are normally kept to less than 5% of volume in CO2.	Methane and other hydrocarbons can be a combustion concern in the presence of oxygen. Methane can impact the maximum miscibility pressure (MMP) of CO2 and oil in EOR.	McElmo CO2 typically contains 0.2% CH4.	No project planned at this time. Final source and quality of CO2 stream cannot be confirmed.	Increased MMP detrimental to CO2 EOR.	High methane and/or other hydrocarbon content in CO2 stream.	Decrease in EOR yield.	Monitoring methane and other hydrocarbon content of purchased CO2 stream and recycled CO2 stream.	Control hydrocarbon content in CO2 stream. Avoid upset operating conditions in CO2 supply and CO2 capture.	Monitor for hydrocarbons in CO2. Select proper materials of construction for pipeline and well components and maintain tight seals and failsafe systems to prevent leakage.
52	02.01.03.08.	CO2 containing mercaptans	Mercaptans are organic compounds containing sulfur. Total sulfur in CO2 is normally kept to less than 35 mg/l. Methyl mercaptan is susceptible to photo oxidation in the atmosphere to hydrogen, sulfur dioxide, dimethyl disulfide and other polysulfide's. Therefore it has a relatively low half-life. Methyl mercaptan exhibits a toxicity similar to, but less than that of hydrogen sulfide. The OSHA permissible exposure level (PEL) is 10 mg/l.	Mercaptans and other malodorous sulfur compounds are strong smelling and toxic and require additional sealing around the wellhead to capture fugitive emissions and minimize odors. The strong odor of mercaptans suggests it is unlikely humans would willingly tolerate concentrations much above the odor threshold for any substantial period of time. However humans in occupational settings may rapidly succumb to extremely high levels of methyl mercaptan.	McElmo CO2 typically contains l<35 mg/l total sulfur. Mercaptan content is insignificant.	No project planned at this time. Final source and quality of CO2 stream cannot be confirmed.	Pipeline/well corrosion leading to leakage or rupture.	High mercaptans content in CO2 stream in presence of H2O.	CO2 + mercaptan release (HSE hazard).	Monitoring total sulfur content of CO2 stream.	Maintain tight sulfur specification on CO2 supply. Avoid contact with water. Avoid upset conditions with CO2 dehydration.	Select proper materials of construction for pipeline, gas recycling facilities and well components and maintain tight seals and failsafe systems to prevent leakage. Monitor for H2S around injection wells and gas recycling facilities. Install alarms.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
50	02.01.03.04.	CO2 containing N2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
51	02.01.03.07.	CO2 containing CH4 and other hydrocarbons	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
52	02.01.03.08.	CO2 containing mercaptans	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

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53	02.01.03.09.	CO2 containing NOx, SOx	Traces of NOx and SOx may occur when CO2 is captured from a post-combustion operations. Although sulfur is present in most fossil fuels, the amount of SOx in the CO2 stream is expected to be very low because deep sulfur removal is required prior to post-combustion CO2 capture to prevent excessive sorbent degradation/loss. Pre-combustion and post-combustion are likely to produce <0.01 vol % SOx and <0.01 vol % NOx in the CO2 stream (IPCC 2005). Oxyfuel combustion may produce 0.5 vol % SOx and 0.01 vol % NOx in the CO2 stream (IPCC 2005).	NOx and SOx may increase corrosion in pipeline and wellhead systems if H2O is present. NOx and SO2 are polluting gases that are generated by the same power plants that generate massive amounts of CO2 and attract emission taxes in certain countries (e.g. Italy). Their injection, in smaller amounts, with CO2 could therefore help the economics of sequestration. Different sets of geochemical reactions are expected when these trace contaminants are present.	NOx and SOx not present in McElmo natural CO2.	No project planned at this time. Final source and quality of CO2 stream cannot be confirmed.	Pipeline/well corrosion leading to leakage or rupture.	High NOx or SOx content in CO2 stream in presence of H2O.	CO2 release (HSE hazard).	Monitoring NOx, SOx and H2O content of CO2 stream.	Avoid upset operating conditions in CO2 supply capture and dehydration. Avoid NOx, SOx in contact with H2O and metal.	Require CO2 supplier to flare and vent gas until CO2 stream is on spec, Select proper materials of construction for pipeline and well components and maintain tight seals and failsafe systems to prevent leakage.	
54	02.01.03.10.	CO2 containing particulates	CO2 is normally scrubbed clean of particulates prior to input into the pipeline. Particulates could carry over due to upset conditions.	Particulate matter can cause valve and instrumentation plugging or erosion of piping.	Particulates have not been an issue in McElmo CO2.	No project planned at this time. Final source and quality of CO2 stream cannot be confirmed.	Plugging of valves and/or erosion of piping.	High concentration of particulates in CO2 stream.	Potential CO2 leakage. Higher maintenance costs and downtime.	Monitoring CO2 stream for particulates. Monitoring operating pressures.	Avoid upset operating conditions in CO2 production and recycling.	Filter recycled gas. Monitor pressure drops in gas recycling system.	
55	02.01.03.11.	CO2 containing toxic volatile metals (mercury, lead, or cadmium)	Most CO2 capture systems are likely to include mercury capture either as an upstream unit or an integral part of the CO2 capture system. It is not expected that mercury, lead or cadmium ion complexes will follow the CO2 concentrate stream during regeneration, other than by physical entrainment as aerosols, which can be eliminated by an in-line mist eliminator stage.	Presence of toxic volatile metals in the CO2 stream could classify it as a hazardous waste.	Toxic volatile metals are not present in McElmo natural CO2.	No project planned at this time. Final source and quality of CO2 stream cannot be confirmed.	Release of toxic metals into the subsurface or surface environment.	High concentration of toxic volatile metals in CO2 stream.	Water, atmosphere, or soil contamination	Monitoring CO2 stream composition.	Install volatile metal capture system upstream of CO2 capture. Avoid upset operating conditions in CO2 capture and dehydration.	Require CO2 supplier to flare and vent gas until CO2 stream is on spec.	
56	02.01.03.12.	CO2 containing pyrophoric compounds	Pyrophoric compounds can spontaneously ignite when in contact with air. Iron sulfide is one of the most common pyrophoric compounds associated with the oil and gas industry.	Pyrophoric materials can cause fires or explosions when exposed to air.	Pyrophoric compounds not present in McElmo CO2.	No project planned at this time. Final source and quality of CO2 stream cannot be confirmed.	Spontaneous combustion in the presence of oxygen.	High concentration of pyrophoric compounds in CO2 stream in presence of air or oxygen.	Fire or explosion.	Monitoring CO2 stream composition.	Avoid operating conditions that would generate pyrophoric compounds.	Avoid contact with air or oxygen.	
57	02.01.03.13	CO2 containing organic compounds	Trace amounts of organic compounds (derivatives or fragments of amine sorbents) could be carried over into the concentrated CO2 stream.	Organic compounds could feed microbial growth underground which can lead to plugging of wells and/or decreased permeability.	Glycol carryover from CO2 dehydration limit of ≤0.3 gal/MMCF.	No project planned at this time. Final source and quality of CO2 stream cannot be confirmed.	Enhanced microbial growth underground detrimental to injectivity but could enhance EOR. And ECBM	High organic compound content in CO2 stream.	Decreased injectivity. Decreased or increased EOR yield.	Monitoring CO2 stream composition.	Maintain tight spec on organic compounds in CO2 stream. Avoid upset operating conditions in CO2 capture and dehydration.	Monitor glycol content in CO2 streams.	
58	02.01.03.14	CO2 containing CO or H2	Traces of CO and H2 may occur when CO2 is captured from a pre-combustion operation such as those involving gasification..	CO and H2 are safety risks due to their combustibility in the presence of oxygen and potential for H2 embrittlement of metal components. CO2 combined with CO is more toxic than when CO2 or CO are separate. (Duncan 2012).	CO and H2 at very low levels in McElmo natural CO2.	No project planned at this time. Final source and quality of CO2 stream cannot be confirmed.	Combustion in the presence of oxygen and an ignition source.	High CO or H2 content in CO2 stream.	Fire or explosion.	Monitoring CO and H2 content in CO2 stream.	Avoid contacting CO2 stream with oxygen.	Monitor CO2 streams for Co and H2. Select proper materials of construction for pipeline and well components and maintain tight seals and failsafe systems to prevent leakage.	

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53	02.01.03.09.	CO2 containing NOx, SOx	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
54	02.01.03.10.	CO2 containing particulates	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
55	02.01.03.11.	CO2 containing toxic volatile metals (mercury, lead, or cadmium)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
56	02.01.03.12.	CO2 containing pyrophoric compounds	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
57	02.01.03.13	CO2 containing organic compounds	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
58	02.01.03.14	CO2 containing CO or H2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

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59	02.01.04.00.	Microbiological contamination	Microbiological contamination of injected fluid. Contamination of supercritical CO2 is considered unlikely due to its being a very good solvent. However, other fluids (like water) may be injected into the storage site that may be contaminated with microbes. Microbes are known to populate geologic strata to at least 2,750 m (9,000 ft) below the surface.	The introduction of microbes into the sequestration system may affect both the performance of the storage system and the endpoints considered. Microbial growth can lead to well plugging ,decreased permeability and corrosion.	No water is being injected into the Fruitland Formation. Produced water in late-stage wells comes out as water vapor and is condensed in the CBM gathering system as distilled water.It can be surface discharged (after filtering), evaporated or injected into the Morrison and Entrada Formations at greater than 2,400 m (8,000 ft) depth. Chemical treatment (biocide) can control microbial growth in disposal wells.	No project planned at this time. Average produced water assumed to be 0.1 BBL/d per CBM well based on production data from OCD 2013.	Plugging or corrosion of equipment. Decreased permeability.	Microbiological contamination from injected fluids	Increased operating and maintenance costs. Potential leakage.	Monitoring of injection fluids for microbes	Control CO2 supply and fluids to avoid microbial contamination	Use chemical treatment if necessary to control microbial contamination / growth.
60	02.01.05.00.	Schedule and planning (See 11.03.00.)										
61	02.01.06.00.	Pre-closure administrative control (See 11.06.00.)										
62	02.01.07.00.	Pre-closure monitoring of storage (See 23.08.00.)										
63	02.01.08.00.	Quality control (See 11.08.00.)										
64	02.01.09.00.	Accidents and unplanned events (See 16.01.00.)										
65	02.01.10.00.	Over pressuring	The CO2 injection process is greatly influenced by the target reservoir formation pore pressure. The formation pressure is considered over pressured if it is above the normal hydrostatic pressure for the given depth. Over pressuring may occur at any depth, naturally or artificially. Man-made overpressure may be accidental or deliberate. An example of deliberate overpressure is injecting gaseous CO2 in an aquifer at a faster rate than water can drain from the reservoir zone. In such a case the overpressure is caused by the injection activity (not natural processes). The maximum tolerable overpressure is calculated as a function of the desired storage volume and of a chosen safety factor below the critical fracturing gradient of the top seal rock. Deliberate overpressure induction is a mechanism for storing energy (associated with the pressure) for later extraction. An example of accidental overpressure is the depressurization of a storage reservoir where the CO2 is in liquid form, below but near the critical phase change pressure. The change of phase to gas creates a gas column that could exercise an unforeseen overpressure at the top of the gas column. 1. Deliberate over pressuring 2. Accidental over pressuring 3. Regional-scale over pressuring 4. Local-scale over pressuring 5. Caprock failure due to over pressuring 6. Caprock failure due to dilatant shear 7. Reactivating existing faults/fractures in caprock 8. Low injection pressure limit	Deliberate or accidental over pressuring during the operational phase will affect the initial geosphere conditions for a post-closure assessment. It has the potential to cause fractures in the sealing formation and hence provide migration pathways for the sequestered CO2. Induced fractures in the caprock can be created by over pressuring the reservoir. Fractures could be sealed in time by precipitation of newly formed minerals, but could also be re-opened as a consequence of new changes in stresses during storage of CO2.	Injection controls are usually installed to prevent injection pressure from exceeding 90% of fracture pressure. Reservoir overpressurization is unlikely as long as CBM producer wells are operating. During the CO2 injection test, wellhead injection pressure was limited to 7.58 MPa (1,100 PSIG). The permitted maximum was 7.83 MPa (1,135 PSIG). Bottomhole injection pressure reached 13.79-14.82 MPa (2,000-2,150 PSIA). This is close to 90% of the estimated fracture pressure. Original reservoir pressure (prior to CBM) was 11.33 MPa at 918 m depth (1,644 PSIA at 3,102 ft depth).	Fracturing or displacement of caprock. Leakage of CO2/CH4/brine through existing wells or faults.	Deliberate or accidental over pressuring.	Induced seismicity and/or uplift. CO2/CH4/brine release (HSE hazard).	Monitoring CO2 injection pressure versus caprock fracture pressure. Alarm system if injection pressure exceeds 90% of fracture pressure.	Determine fracture pressure. Monitor CO2 injection pressure. Install failsafe control system to prevent injection pressure from exceeding 90% of caprock fracture pressure.	Develop procedures for handling an over pressuring situation. Operator training. Monitor pressures in existing nearby wells.	
66	02.02.00.00.	Post-closure	Details of post-closure activities associated with sequestration.	Human activities post-closure may affect the likelihood of specific impacts being incurred.								
67	02.02.01.00.	Post-closure administrative control (See 11.07.00.)										
68	02.02.02.00.	Post-closure monitoring of storage (See 23.09.00.)										

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P x S x D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
59	02.01.04.00.	Microbiological contamination	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
60	02.01.05.00.	Schedule and planning (See 11.03.00.)	0	0	0	0																
61	02.01.06.00.	Pre-closure administrative control (See 11.06.00.)	0	0	0	0																
62	02.01.07.00.	Pre-closure monitoring of storage (See 23.08.00.)	0	0	0	0																
63	02.01.08.00.	Quality control (See 11.08.00.)	0	0	0	0																
64	02.01.09.00.	Accidents and unplanned events (See 16.01.00.)	0	0	0	0																
65	02.01.10.00.	Over pressuring	2	5	2	20	None	None	None	\$200/t CO2 released into USDW	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Potential class action lawsuit for property damage, loss of property value, reimbursement for earthquake insurance and emotional distress.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total.	PGA(g) >0.1 (>4 magnitude earthquake)	Shutdown of project through court ordered injunctive relief likely if multiple events of PGA(g)>0.1 (>4 magnitude earthquake)	Maintain CO2 injection pressure at <90% of fracture pressure: Maintain balance between volume of fluids injected and produced. Part of ongoing costs.	\$32.32/t CO2 emitted (\$1.70/MCF CO2 emitted) \$3.50/MCF CH4 emitted.	10% of damage costs	Shutdown of operations: >\$100M	None	Maintain CO2 injection pressure at <90% of fracture pressure: Maintain balance between volume of fluids injected and produced. Part of ongoing costs.	Savings: >\$100M	1
66	02.02.00.00.	Post-closure	0	0	0	0																
67	02.02.01.00.	Post-closure administrative control (See 11.07.00.)	0	0	0	0																
68	02.02.02.00.	Post-closure monitoring of storage (See 23.09.00.)	0	0	0	0																

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Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
69	02.02.03.00.	Records and markers (long-term knowledge retention) (See 11.04.00.)										
70	02.02.04.00.	Reversibility	The degree to which the sequestered CO2 could be deliberately removed, if required. Either as an extreme remedial action, because the CO2 is required as a resource, or because its presence is impeding access to other geological resources.	The degree to which reversibility is considered in the design of a sequestration system may influence its long-term performance, by leaving viable boreholes in-situ after closure, for example.	CO2 can desorb from coal with decreased reservoir pressure.Wells would ned to work under a vacuum. Extremely unlikely stored CO2 would be reproduced. Long-term retention of unplugged wells for potential reversibility would be a significant liability.		CO2/CH4 leakage from retained wells.	Retaining facilities for potential future extraction of CO2.	Cost to remediate leaky unplugged well(s).	Routine inspection of retained wells for corrosion. Monitoring retained wells for CO2 leakage.	Proper selection of materials of construction for wells. Proper plugging of wells. Routine inspection of wells for corrosion. Risk management input into reversibility plan. Retain good records and models on CO2 injection.	Prepare procedures for extraction of CO2. Monitor wells for leaks over time from end of CO2-ECBM to time of extracting CO2. Rework wells that leak.
71	02.02.05.00.	Remedial actions	Events and processes related to actions that might be taken following closure of a storage site to remedy problems that, either, are associated with its not performing to the standards required, result from disruption by some natural event or process, or result from inadvertent or deliberate damage by human actions.	The aim of possible future remedial actions will be to modify the performance and safety of the CO2 sequestration system.	Post closure there is potential for limited CO2/CH4 leakage through wellbores, faults or fracture zones. Most CO2 is likely to be adsorbed on the coal and will not desorb unless the reservoir is further depressurized or a pressure pulse occurs.		CO2/CH4 leakage from plugged wells.	Improper or lack of remedial action.	Cost to remediate leaky plugged well(s).	Routine inspection and monitoring of site.	Maintain good records and models of CO2 injection. Use appropriate materials of construction. Routine inspection and monitoring of site.	Prepare procedures for remediating CO2 leakage. Monitor for CO2 leakage. Remediate any CO2 leakage quickly.
72	03.00.00.00.	CO2 PROPERTIES, INTERACTIONS & TRANSPORTATION	This category of FEPs is concerned with those Features, Events and Processes that are relevant to the fate of the sequestered fluid. Carbon dioxides properties can vary greatly between conditions at depth and near surface, and a wide range of physical and chemical reactions can be important. The category is divided into three classes for the properties, interactions and transport of carbon dioxide.	This category is divided into three classes: 1. CO2 properties 2. CO2 interactions 3. CO2 transport These properties will have a significant impact on all of the risk calculations.								
73	03.01.00.00.	CO2 properties	The fundamental physical and chemical properties of carbon dioxide, taking into account impurities. 1. CO2 properties changed by pressure 2. CO2 properties changed by temperature 3. CO2 properties changed by impurities 4. CO2 properties changed by reservoir geochemistry (i.e. CO2 migrating from quartz into calcite cemented sand)	Carbon dioxides properties can vary greatly with pressure, temperature and impurities, and an understanding of these properties is essential before the fate of sequestered fluid can be assessed.								

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Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Risk severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
69	02.02.03.00.	Records and markers (long-term knowledge retention) (See 11.04.00.)	0	0	0	0															
70	02.02.04.00.	Reversibility	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
71	02.02.05.00.	Remedial actions	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil contamination and/or vegetation kill	Covered under natural resource damage	None	None	Cost to monitor wells for leaks over time and rework risky wells: \$77k /well reworked.	\$32.32/t CO2 emitted (\$1.70/MCF CO2 emitted) \$3.50/MCF CH4 emitted.	10% of damage cost	Cost to locate and fix leaky wells: \$0.3M/well + Cost to replace contaminated USDW: \$1M/y per leak + Value of lost CO2/CH4 per leak + Cost of land remediation.	None	Cost to monitor wells for leaks over time and rework risky wells: \$77k /well reworked.	Up to \$3M	1
72	03.00.00.00.	CO2 PROPERTIES, INTERACTIONS & TRANSPORTATION	0	0	0	0															
73	03.01.00.00.	CO2 properties	0	0	0	0															

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
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74	03.01.01.00.	Physical properties of CO2	Physical properties of CO2 including density, viscosity, interfacial tension and thermal conductivity and their dependence on pressure and temperature. 1. CO2 density 2. CO2 viscosity 3. CO2 interfacial tension 4. CO2 thermal conductivity	The physical properties of CO2 determine the way in which it will behave in the environment once injected. Calculation of overpressure at constant rate injection and of injectivity at constant pressure injection are impacted by the choices of properties.	The CO2 is injected as a supercritical fluid (800 kg/m3) but transforms into a gas (12 kg/m3) inside the reservoir, and is adsorbed on the coal (1,180 kg/m3). The expansion of CO2 from a supercritical fluid to a gas is endothermic and the adsorption of CO2 on coal is exothermic. Approximately 99% of the CO2 adsorbs on the coal, leaving approximately 1% of gaseous CO2 in the cleat pore space.		CO2 transforming from a supercritical fluid to a gas.	CO2 physical properties	Early breakthrough of CO2 Higher CO2 recycling costs. Decreased CO2 storage capacity.	Characterize and model reservoir temperature, pressure, geochemistry and CO2 composition. Analyze impact of any changes on CO2 physical properties.	Take CO2 physical properties into account in modeling.	Take CO2 physical properties into account in modeling.
75	03.01.02.00.	CO2 phase behavior	FEPs related to the phase behavior (gas, liquid, supercritical fluid) of CO2. The presence of contaminants in the injected CO2 (e.g. N2) and gas and hydrocarbons (e.g., in EOR and ECBM operations) in the reservoir will affect the phase behavior and partition of CO2 between different physical states. CO2 mixing with other fluids and gases, leads to modified flow behavior that is not fully understood (CCP 2009)	CO2 phase behavior is a primary consideration for modeling CO2 migration. CO2 is expected to be in the supercritical state under most sequestration scenarios, except ECBM. The supercritical point is 32°C (90°F) and 7.4 MPa (1100 psia).	The CO2 is injected as a supercritical fluid (800 kg/m3) but transforms into a gas (12 kg/m3) inside the reservoir, and is adsorbed on the coal (1,180 kg/m3). The expansion of CO2 from a supercritical fluid to a gas is endothermic and the adsorption of CO2 on coal is exothermic. Approximately 99% of the CO2 adsorbs on the coal, leaving approximately 1% of gaseous CO2 in the cleat pore space.		CO2 transforming from a supercritical fluid to a gas.	CO2 phase behavior	Decreased CO2 storage capacity. Accelerated CO2 migration	Characterize and model reservoir temperature, pressure, geochemistry and CO2 composition. Analyze impact of any changes on CO2 phase behavior.	Proper site selection avoiding shallow reservoirs that would not have sufficient pressure and temperature to keep CO2 supercritical. Take CO2 phase behavior into account in modeling.	Avoid sequestration in reservoirs at depths less than 800 m. Avoid under pressured and low temperature reservoirs. Take CO2 phase behavior into account in modeling.
76	03.01.03.00.	CO2 solubility and aqueous speciation (See 03.02.13.02. and 03.02.13.06.)	CO2 solubility is the amount of CO2 that can dissolve for given conditions in water. It can vary as a function of temperature, pressure and precise composition of the fluid (e.g. salinity, dissolved species/complexes, presence of hydrocarbons - e.g., EOR and ECBM). Changing temperature and pressure accompanying migration of CO2 can therefore influence CO2 solubility, potentially leading to gas exsolution. CO2 is present in the aqueous phase as: aqueous CO2; carbonic acid (H2CO3); bicarbonate (HCO3-); and carbonate (CO3-). Note that other dissolved ions (Na+, Mg++, Ca++, etc.) are also involved and provide an array of linked, reversible reactions.	CO2 solubility has an impact on the chemical composition of formation fluids, pressure distribution, 'sorption' processes, mineral-fluid reactions and the overall storage capacity of CO2. Dissolved CO2 may migrate in a different manner to 'free' supercritical CO2. CO2 solubility in water and its partition between aqueous, gaseous, and organic phases controls the efficiency of diffusive transport and successive mineral reactions. The aqueous speciation of dissolved CO2 will impact upon the mobility of sequestered CO2 and associated contaminants.	Due to the dewatering of the coal seams, low pressure, 0.52-0.69 MPa (75-100 PSIG), and the high concentration of bicarbonates in the formation fluid, the amount of injected CO2 dissolved into the formation fluids is likely to be very limited unless the reservoir pressure is increased.							
77	03.02.00.00.	CO2 interactions	Potential interactions of carbon dioxide with solid, liquid or gaseous media.	A wide range of physical and chemical reactions can be important, and an understanding of these interactions is essential for the assessment of potential impacts.								
78	03.02.01.00.	Effects of pressurization of reservoir on caprock (See 02.01.10.00.)	A storage reservoir will experience enhanced pressure due to injection of CO2. This may exceed original 'natural' pressurization due to hydrocarbon emplacement (EOR or ECBM, for example), or clay mineral transformations during diagenesis.	Over pressuring of the reservoir may involve leakage of CO2 through the caprock due to fracturing or enhanced interactions with CO2.	The reservoir pressure of 0.52-0.69 MPa (75-100 PSIG) is very low compared to the initial reservoir pressure of 11.33 MPa (1,644 PSIG). Increasing reservoir pressure would increase CO2 adsorption and decrease or stop CBM production.							
79	03.02.02.00.	Effects of pressurization on reservoir fluids	Increased pressurization caused by the injection of supercritical CO2 will affect the behavior of other fluids within the reservoir.	The potential importance of increased pressurization to enhanced oil and gas recovery indicates that it can modify the mobility of other fluids in the receiving reservoir.	As long as CBM operations continue, reservoir pressure is likely to remain low. Increasing reservoir pressure would decrease or stop CBM production. Approximately 99% of injected CO2 is adsorbed on the coal and approximately 1% is gaseous CO2 in the cleat pore space. The coal seams have been dewatered.		Displacement of brine	Effect of pressurization on reservoir fluids	CO2/CH4/brine release (HSE hazard). Adverse geochemical impact on freshwater resources.	Monitoring and modeling of CO2/CH4/brine movement.	Characterize, model and monitor reservoir CO2/CH4/brine movement. Adjust injection strategy as needed to control CO2/CH4/brine movement. Extract brine for pressure and plume control.	Use production wells to extract CO2/CH4/brine. Use water curtains to keep CO2/CH4/brine migration within patterns.

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
74	03.01.01.00.	Physical properties of CO2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
75	03.01.02.00.	CO2 phase behavior	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
76	03.01.03.00.	CO2 solubility and aqueous speciation (See 03.02.13.02. and 03.02.13.06.)	0	0	0	0															
77	03.02.00.00.	CO2 interactions	0	0	0	0															
78	03.02.01.00.	Effects of pressurization of reservoir on caprock (See 02.01.10.00.)	0	0	0	0															
79	03.02.02.00.	Effects of pressurization on reservoir fluids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

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80	03.02.03.00.	Interaction with hydrocarbons (See 0.3.02.03.01 through 03.02.03.15)	In EOR or ECBM sites, for example, hydrocarbons could be mobilized by CO2, by miscible displacement and transported to the near-surface. This is of particular relevance if enhanced oil recovery is an additional aim of the sequestration concept. Kolak and Burruss (2003) demonstrate that polyaromatic hydrocarbons (PAHs) can be mobilized by sequestration in deep coal beds. Sequestered CO2 can also precipitate asphaltenes from crude oil under certain conditions of composition, temperature and pressure. Such precipitation in the vicinity of injection wells can lead to loss of injectivity and even plugging of the wells.	Mobilized hydrocarbons may migrate to the near-surface environment. Precipitated asphaltenes can clog pores, reducing permeability and affecting fluid flow paths.	CO2 displaces CH4 adsorbed on coal.																											
81	03.02.03.01.	EOR attribute range	Technical screening guidelines for CO2 flooding: recommended (current projects range) Crude oil gravity, °API: >22 (27 to 44) Crude oil viscosity, cp: <10 (0.3 to 6) Crude oil composition: High percent of C6 to C12 Reservoir oil saturation: >40% (15 to 70%) Type of formation: Relatively thin sandstone or carbonate unless dipping Permeability: Not critical if sufficient rates can be applied Depth/temperature: For miscible displacement, depth must be great enough to allow injection pressures greater than the minimum miscible pressure (MMP), which increase with temperature and for heavier oils (Meyer 2007). Oil formation volume factor (ratio real barrels/stock tank barrels): 1.2 to 1.4 Real barrels at subsurface conditions (at depth) Stock tank barrels at surface conditions	Operating outside the EOR attribute range could lead to low oil recovery. This could impact CO2 sequestration economics.	Not applicable to this site.		Low enhanced oil recovery	Operating outside the EOR attribute range	Increased costs. Decreased revenues.	Fully characterize EOR reservoir and compare site specific EOR attributes with recommended EOR attributes.	Fully characterize EOR reservoirs for EOR attributes. Select EOR reservoirs that fall within the acceptable range of EOR attributes.	Monitor and model EOR performance. Identify irregularities. Determine root cause for irregularities. Adjust injection and production strategy if necessary.																				
82	03.02.03.02.	EOR reservoir depth	Recommended depths of CO2 floods of typical Permian Basin oils <table><tr><td>CO2 Miscible</td><td>Depth</td></tr><tr><td>Gravity, °API</td><td></td></tr><tr><td>>40</td><td>> 762 m (2500 ft)</td></tr><tr><td>32 to 39.3</td><td>> 853 m (2800 ft)</td></tr><tr><td>28 to 31.9</td><td>> 1006 m (3300 ft)</td></tr><tr><td>22 to 27.9</td><td>> 1219 m (4000 ft)</td></tr><tr><td><22</td><td>Fails CO2 screening</td></tr></table> CO2 Immiscible <table><tr><td>Gravity, °API</td><td>Depth</td></tr><tr><td>13 to 21.9</td><td>> 549 m (1800 ft)</td></tr><tr><td><13</td><td>Fails CO2 screening</td></tr></table> (Meyer 2007)	CO2 Miscible	Depth	Gravity, °API		>40	> 762 m (2500 ft)	32 to 39.3	> 853 m (2800 ft)	28 to 31.9	> 1006 m (3300 ft)	22 to 27.9	> 1219 m (4000 ft)	<22	Fails CO2 screening	Gravity, °API	Depth	13 to 21.9	> 549 m (1800 ft)	<13	Fails CO2 screening	Operating conditions outside miscible range could lead to low oil recovery. This could impact CO2 sequestration economics and result in more CO2 recycling.	Not applicable to this site.		Insufficient pressure for MMP. Insufficient pressure range between MMP and fracture pressure.	Insufficient EOR reservoir depth.	Low EOR yields. Limited operating range.	Determine reservoir bottom hole pressure, minimum miscibility pressure and fracture pressure.	Fully characterize EOR reservoir. Select reservoir with sufficient depth to allow miscible flow and sufficient pressure operating range between minimum miscibility pressure(MMP) and fracture pressure.	Pressurize reservoir with water injection prior to CO2 injection. (This may not work because elevated pressure will dissipate over time and water injection may redistribute oil and clay).
CO2 Miscible	Depth																															
Gravity, °API																																
>40	> 762 m (2500 ft)																															
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									Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
80	03.02.03.00.	Interaction with hydrocarbons (See 0.3.02.03.01 through 03.02.03.15)	0	0	0	0																	
81	03.02.03.01.	EOR attribute range	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2		
82	03.02.03.02.	EOR reservoir depth	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2		

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83	03.02.03.03.	EOR oil recovery	Typical oil recovery by recovery mechanism as a function of Original Oil in Place (OOIP) Primary: 6 to 15% OOIP Secondary: 6 to 30% OOIP Miscible CO2 EOR: 8 to 20% OOIP Remaining: 8 to 35% OOIP (Meyer2007) Miscible CO2 EOR: 7-23% OOIP Immiscible CO2 EOR: 9 to 19% OOIP (Meyer 2007)	Prior oil production and methods could impact CO2 EOR results and amount of CO2 that can be sequestered.	Not applicable to this site.		Low enhanced oil recovery.	Poor EOR performance.	Lower revenues. Higher operating costs per barrel of oil.	Monitor actual versus projected enhanced oil recovery.	Fully characterize the reservoir for EOR attributes. Select EOR reservoirs that fall within the acceptable range of EOR attributes. Model EOR operation and try to optimize oil recovery through reservoir engineering. Operate above the minimum miscibility pressure.	Monitor EOR actual versus projected performance. Identify the cause of any variation. Adjust CO2 EOR strategy to improve oil recovery if necessary. Optimize WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and increase oil recovery.
84	03.02.03.04.	EOR CO2 utilization	For field scale miscible CO2 EOR floods net (purchased) amount of CO2 required is estimated to be between 60 to 262 m³ CO2/m³ oil (2.5 to 11 MCF/STB) of incremental recovery with an average value of 143 to 167 m³/m³ (6 to 7 MCF/STB). For immiscible floods, actual incremental oil recovery has been on the order of 119 to 286 m³/m³ (5 to 12 MCF/STB) (Meyer 2007).	Increased CO2 demand per barrel of oil produced will impact EOR project economics. This could impact CO2 sequestration economics as well.	Not applicable to this site.		High CO2 consumption per barrel of oil recovered.	Poor EOR performance.	Increased operating costs. Higher CO2 recycling costs.	Monitor actual versus projected CO2 consumption per barrel of oil.	Fully characterize the reservoir for EOR attributes. Model EOR operation and try to optimize CO2 consumption per barrel of oil through reservoir engineering.	Monitor EOR actual versus projected performance. Identify the cause of any variation. Adjust CO2 EOR strategy to optimize CO2 usage if necessary. Optimize WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and utilization and increase oil recovery.
85	03.02.03.05.	EOR viscosity relations	Because the viscosity of CO2 at reservoir conditions is much lower than that of most oils, viscous instability will limit the sweep efficiency of the displacement and, therefore, oil recovery (Meyer 2007). Crude oil viscosity, cp: <10 (0.3 to 6)	Can lead to adverse hydrodynamic instabilities, such as fingering, which lead to vertical fluid stratification and reduced oil recovery (Meyer 2007). This could also result in more CO2 breakthrough and require more CO2 recycling.	Not applicable to this site.		Flow stratification (fingering) in the reservoir. Decreased sweep efficiency and oil recovery.	EOR viscosity relations.	Reduced oil recovery. Higher CO2 recycling costs.	Determine EOR viscosities under reservoir conditions and input into reservoir model.	Fully characterize the reservoir. Model EOR operation and try to optimize CO2 flow through reservoir engineering.	Monitor EOR actual versus projected performance. Identify the cause of any variation. Use polymers or foaming agents to adjust CO2 viscosity.
86	03.02.03.06.	EOR oil reservoir heterogeneity	Oil reservoir rock is extremely heterogeneous, exhibiting zones of high permeability in close proximity to those of low permeability. These permeability differences may be innate, that is caused by differences in pore structure at the time of geological deposition, or a product of fractures, natural or man-made (Meyer 2007)	Can decrease efficiency of oil recovery and CO2 sequestration.	Not applicable to this site.		Non uniform flow of CO2/oil. Low sweep efficiency and low oil recovery.	EOR reservoir heterogeneity.	Reduced oil recovery. Higher CO2 recycling costs.	Fully characterize reservoir for heterogeneity and input into model.	Fully characterize oil reservoir. Take into account heterogeneity of oil reservoir in EOR modeling and reservoir engineering in order to optimize performance.	Monitor EOR actual versus projected performance. Identify the cause of any variation. Adjust CO2 EOR strategy to optimize CO2 usage if necessary. Optimize WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and increase oil recovery.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
83	03.02.03.03.	EOR oil recovery	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
84	03.02.03.04.	EOR CO2 utilization	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
85	03.02.03.05.	EOR viscosity relations	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
86	03.02.03.06.	EOR oil reservoir heterogeneity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
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87	03.02.03.07.	EOR hydrocarbon precipitation	CO2 injection encourages precipitation of asphaltenes or paraffins.	Precipitation of asphaltenes can clog pores, reducing permeability and affecting fluid flow paths. It can also cause plugging of boreholes.	Not applicable to this site.		Pore space blockage and reduced permeability. Plugging of production wells and equipment.	EOR hydrocarbon precipitation.	Well plugging. Decreased injectivity or production. Delays for shutdown and cleanout.	Characterize site for asphalt or paraffin precipitation. Monitor changes in injection pressure.	Use Teflon coated tubulars and components. Monitor for asphaltene or paraffin precipitation. Inject hot water or steam every couple of months. Injection of some hydrocarbon gas along with CO2 can decrease the tendency for asphaltene or paraffin precipitation. Keep operating temperatures sufficiently high. Use staged decompression to avoid overcooling.	Circulate xylene, deasphalted oil, or enzymes to remove asphaltene buildup. Inject hot water or steam to remove paraffin buildup.
88	03.02.03.08.	EOR miscibility	Flooding a reservoir with CO2 can occur either miscibly or immiscibly. Miscible CO2 displacement is only achieved under a specific combination of conditions, which are set by four variables: reservoir temperature, reservoir pressure, injected gas composition, and oil chemical composition (Meyer 2007). Miscible displacement is achieved at pressures above the minimum miscibility pressure (MMP). If the reservoir pressure is below the MMP, CO2 can still be injected, but the efficiency of the enhanced oil recovery process is adversely impacted. Typically this does not occur since, after primary depletion, water flooding operations commence which restore reservoir pressure to values above the MMP(Meyer 2007). 1. Miscible CO2 flooding 2. Immiscible CO2 flooding	Operating under miscible conditions results in significantly higher oil recovery than operating under immiscible conditions. Higher oil recovery improves economics of EOR and CO2 sequestration.	Not applicable to this site.		Decreased enhanced oil recovery.	Immiscible operation.	High operating costs, lower revenues.	Determine minimum miscibility pressure and compare with reservoir conditions.	Fully characterize the reservoir for EOR attributes. Maintain injection pressure above the minimum miscibility pressure (MMP) while not exceeding 90% of the fracture pressure.	Increase reservoir pressure with water injection if needed.
89	03.02.03.09.	EOR early CO2 breakthrough	Early breakthrough of CO2 results in production of significant amounts of CO2 and water along with oil. The alternating water and CO2 gas (WAG) approach is typically applied in CO2 EOR to minimize CO2 use (as it is purchased) and to avoid early breakthrough of CO2.	Breakthrough of CO2 increases operating costs due to the need to recycle the CO2 and can also result in lower oil recovery.	Not applicable to this site.		High CO2 consumption per barrel of oil recovered.	Early CO2 breakthrough.	Increased operating costs. Higher CO2 recycling costs.	Monitor CO2/oil production.	Fully characterize and model the EOR reservoir. Optimize reservoir engineering.	Recycle CO2. Modifying well pattern/spacing. WAG.. Selective perforation. Polymer gels. Foaming surfactants. Sealants.
90	03.02.03.10.	EOR Water alternating gas (WAG)	WAG involves alternating injection of water and gas (CO2) to optimize EOR performance. WAG ratios range: 1:1 to 5:1 (0.5:1 to 4:1 per NETL 2009) Slug range: 0.1% to 2% of reservoir hydrocarbon pore volume (NETL 2009) Cumulative CO2 volume: 15 to 30% of hydrocarbon pore volume (NETL 2009)	WAG ratio may have a positive or negative impact on oil recovery.	Not applicable to this site.		Low enhanced oil recovery.	Suboptimal water and CO2 gas (WAG) ratio.	Lower revenues. Higher operating costs per barrel of oil.	Monitor CO2/water/oil production and CO2/water injection.	Optimize WAG ratio through modeling and reservoir engineering	Evaluate WAG actual versus predicted performance based on modeling and make adjustments to the WAG ratio or well pattern/spacing as needed.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
87	03.02.03.07.	EOR hydrocarbon precipitation	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
88	03.02.03.08.	EOR miscibility	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
89	03.02.03.09.	EOR early CO2 breakthrough	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
90	03.02.03.10.	EOR Water alternating gas (WAG)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

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91	03.02.03.11.	EOR injection water quality / attributes / chemistry	Water quality can impact EOR performance. Injection of low salinity water into an EOR reservoir where the sandstone cement consists of anhydrite could cause the anhydrite to convert to gypsum and its volume would increase up to 1.5 times resulting in decreased pore space and permeability. Injection microbial contaminated water could result in well plugging or decreased permeability due to microbial growth. Injection of corrosive water could result in corrosion of equipment, piping and borehole liners. Injection of hard water could lead to scale buildup.	Lower oil recovery. Corrosion, scale buildup or microbe growth in system equipment. Decreased permeability near injection wells.	Not applicable to this site.		Corrosion, scale buildup or microbe buildup.	Quality of EOR injected water.	Increased maintenance cost. Injection disruption.	Monitor injection water quality and injection pressure and flowrate. Use proper materials for tubing, equipment and piping prevent or minimize corrosion, erosion, scaling or microbe buildup.	Treat injection water to prevent corrosion, scaling or microbe buildup.	Monitor injection pressure and flowrate. Filter and treat water with chemicals to prevent corrosion, remove scale and control microbial buildup. Get proper clearance for injection of chemicals if necessary.
92	03.02.03.12.	EOR injection water pressure	Water is denser than CO2. When changing from CO2 injection to water injection, a pressure differential needs to be overcome. To do so, the water supply header operates at a pressure in excess of the CO2 supply header pressure. This allows water to be throttled into the well, its pressure declining to the appropriate value once the CO2 is displaced from the wellbores (Meyer 2007).	System should be designed to provide the proper water injection pressure.	Not applicable to this site.		Unable to inject water at appropriate rate. Hydro fracturing.	Water pressure too low. Water pressure too high.	Poor oil recovery. Caprock damage and potential CO2 release.	Monitor water pressure and flowrate.	Calculate water pressure needed based on modeling. Install sufficient pumping capacity to meet water pressure and flowrate requirements. Injection pressure should not exceed 90% of fracture pressure.	Monitor water pressure and adjust pump pressure as needed. Change frequency or rate.
93	03.02.03.13.	EOR injection and production well pattern and spacing	The pattern is typically a 5-spot (one injection well in center surrounded by four production wells) or inverse 5-spot (one production well in center surrounded by four injection wells), or a variety of other patterns. Typically there are 0.5 to 4.0 production wells for every injection well. The spacing of injection and production wells refers to the area covered by the well pattern. It may be 8, 12, 16 or more hectares (20, 30, 40 or more acres).	Improper injection and production well spacing and pattern can lead to early CO2 breakthrough and/or low oil recovery.	Not applicable to this site.		Early breakthrough of CO2. Low enhanced oil recovery.	Improper injection and production well pattern and spacing..	Increased operating cost. Increased CO2 recycling costs. Lower revenues.	Monitor and model well performance.	Optimize well spacing and pattern based on modeling and reservoir engineering.	Monitor well performance versus model predictions. Adjust model and well spacing and pattern as needed to optimize oil recovery. Use injection water curtains to control CO2 flow within patterns.
94	03.02.03.14.	EOR intermittent CO2 supply	Intermittent CO2 supply can be caused by interruptions at the source, CO2 capture, compression, pipeline or wellhead.	Intermittent CO2 supply can negatively impact sweep efficiency of EOR and therefore make sequestration less attractive.	Not applicable to this site.		Interruption in CO2 injection	Intermittent CO2 supply.	Decreased EOR performance.	Maintain daily, weekly and monthly nominations for CO2 supply and demand planning. Monitor CO2 input pressure and flowrate to pipeline.	Maintain daily, weekly and monthly nominations for CO2 supply and demand planning. Maintain CO2 production,	Use water injection as a backup for sweep if necessary. Flood only a limited section depending on the geology.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
91	03.02.03.11.	EOR injection water quality / attributes / chemistry	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
92	03.02.03.12.	EOR injection water pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
93	03.02.03.13.	EOR injection and production well pattern and spacing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
94	03.02.03.14.	EOR intermittent CO2 supply	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

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95	03.02.03.15.	EOR flood type	CO2 flooding types include gravity stable and conventional piston flooding. In gravity stable flooding, CO2 is injected in the top of a reservoir (dome) as a supercritical fluid or dense gas and builds an oil bank by mobilizing residual oil downward as the CO2 cap expands. It is important to maintain a relatively uniform front and avoid coning. In the conventional piston flooding, CO2 is injected into an oil reservoir and builds an oil bank by mobilizing residual oil horizontally as the CO2 plume expands. 1. Gravity stable CO2 flooding 2. Piston CO2 flooding	Flooding should be optimized to maintain a relatively uniform front and avoid coning or CO2 early breakthrough (profile control).	Not applicable to this site.		Low enhanced oil recovery.	Improper EOR flood type.	Higher operating costs and lower revenues.	Fully characterize EOR reservoir and model flood type options to be evaluated.	Fully characterize and model EOR reservoir and select the optimum flood type.	Monitor well performance versus model predictions. Adjust model and flood type, well spacing and pattern as needed to optimize oil recovery.
96	03.02.04.00.	Displacement of saline formation fluids	Injection of CO2 into a geologic formation may result in displacement of saline formation fluids into potable water supplies. Limitations on the pressure in a formation (for seal integrity) will mean that existing fluids are displaced/replaced. Displaced fluids are highly likely to be saline. Because the pressure wave created by injection travels much further than the physical CO2 front, displacement of saline formation fluids can occur at locations outside the CO2 storage area. Inter-connection of aquifer systems may enable saline fluids to enter potable water formations. For significant storage to be possible, it is necessary for a significant amount of the native pore space fluid to be displaced from the reservoir over the injection period. This may occur either by production of fluids (oil or gas), by deliberate production of formation water, and/or by migration of fluids into adjacent formations, surface or oceans.	Displaced saline formation fluids may contaminate near-surface aquifers with subsequent impacts, such as contamination of potable water supplies.	Most of the coal seams have been dewatered. Any remaining formation fluids are pumped out with producer wells.		Contamination of ground/surface water with CO2/brine.	Displacement of brine due to CO2 injection.	Liability for contamination of ground/surface water with CO2/brine. Damage to drinking water and/or irrigation water supply.	Monitor CO2/salinity of ground/surface water.	Fully characterize and model reservoir to understand likely displacement of brine. Take into account brine displacement in reservoir engineering. Extract brine for pressure and plume management.	Monitor near surface aquifers for increased salinity. Determine root cause for any increase in salinity. Use tracers if necessary. Extract brine for pressure and plume management.
97	03.02.05.00.	Change in mechanical processes and conditions	Features and processes related to the mechanical processes and conditions resulting from the injection of CO2 that affect the rock, boreholes and other engineered features, and the overall mechanical evolution with time. This includes the effects of hydraulic, mechanical and thermal loads imposed on the rock by the injected CO2. Injection of CO2 into a reservoir can cause (directly or indirectly) changes of the geomechanical properties of the reservoir rock. Direct changes can be due to change of reservoir pressure and temperature (PVT system). Indirect changes (of rock properties) might result from geochemical and mineralogical changes after storage of CO2.	Mechanical changes of the reservoir resulting from CO2 injection (such as generation of fractures, reactivation of fractures/faults, changes of bulk elastic properties and effective reservoir) could lead to subsidence/uplift (at surface), induced seismicity, changes in migration pathways, even burst/leakage of the seal. Examples of other relevant processes are: borehole lining collapse; rock volume changes, leading to cracking	CO2 injection into the coal seams may result in thermal cooling due to expansion of CO2 from a supercritical fluid to a gas. CO2 adsorption results in coal matrix swelling and decreased permeability and injectivity. The high pressure of CO2 injection and reservoir temperature falls into the range of coal plasticity.		Fracturing caprock. Reactivating a fault. Induced seismicity. Uplift / subsidence. Borehole collapse.	Change in mechanical processes and conditions caused by CO2 injection.	CO2 release (HSE hazard). Seismic damage to surface buildings and infrastructure. Change in surface water flow impacting farmland. Well damage.	Characterize the site and model geomechanics. Determine fracture pressure. Monitor injection pressure. Alarm system if injection pressure exceeds 90% of fracture pressure.	Determine fracture pressure. Operate below 90% of fracture pressure.	Operate below 90% of fracture pressure. Monitor injection pressure Maintain reservoir fluid volume close to original fluid volume. Continuous monitoring of passive micro-seismicity

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
95	03.02.03.15.	EOR flood type	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
96	03.02.04.00.	Displacement of saline formation fluids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
97	03.02.05.00.	Change in mechanical processes and conditions	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

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98	03.02.06.00.	Induced seismicity	Injection of CO2 may cause and trigger seismic events and earthquake hazards through processes such as reducing friction at existing faults. This may occur both in seismically active areas and in areas characterized by a low background seismicity (reactivation of ancient fault planes, changes in the orientation, fluid-pockets occurrence). This FEP includes micro seismicity. Induced macro-seismicity activity is a function of existing regional and local stresses, of porosity structure, and of imposed injection stresses. Induced macro-seismicity is less likely if the injection formation is dominated by intergranular and not fracture porosity. The problem of seismicity might be more serious when CO2 is injected into a reservoir in tectonically active regions with high density of active faults (Damen 2006). 1. Induced macro-seismicity 2. Induced micro-seismicity 3. Seismicity tied to activation of an existing structure (fault/fracture) 4. Seismicity tied to creation of a new structure (fault/fracture)	Seismicity can introduce sudden physical changes to the sequestration system and may expose any local population to earthquake hazards. Potential effects of reservoir-induced seismicity (RIS) are damage to the caprock and wells , which might cause CO2 leakage , and damage to building and infrastructure (Damen 2006). In a reservoir that is under high tectonic stresses, any significant reduction of pressure (pressure acting between individual rock particles) may trigger faults. This may lead to uplifting or down-faulting of the surface (Damen 2006).	Pump Canyon Site No induced seismicity was observed during the CO2 injection test and during CBM operation. Control system was installed to limit CO2 injection pressure to <90% of fracture pressure. Generation of an earthquake with >4 magnitude would be incredible for a low-ressure CO2-ECBM operation.		Induced earthquake >4 magnitude.	Induced seismicity.	Public concern and potential class action lawsuits.	Characterize the site and model geomechanics. Determine fracture pressure. Identify any existing faults. Monitor injection pressure. Alarm system if injection pressure exceeds 90% of fracture pressure.	Determine fracture pressure. Install failsafe control system to maintain CO2 injection at <90% of fracture pressure. Maintain reservoir fluid volume close to original fluid volume:	Operate below 90% of fracture pressure. Monitor injection pressure. Monitor passive micro-seismicity.	
99	03.02.07.00.	Subsidence or uplift	Injecting the CO2 may cause acidification of formation water, leading to mineral dissolution and subsidence. This is of particular relevance to shallow storage sites. Chemical compaction or dissolution of the reservoir rock will particularly be a matter of concern in carbonate rocks with high porosity (Damen 2006). Injection of large quantities of CO2 into a confined aquifer may increase pore pressure and lift the overlying rocks upwards. It is not envisaged that uplift will take place in a CO2 reservoir as long as the maximum storage pressure is kept below the geostatic pressure (Damen 2006). 1. Subsidence 2. Uplift	Deformation may affect geological processes and may result in impacts of concern at the surface. Dissolution of the reservoir rock (chemical compaction) can lead to the reservoir caving in under the weight of the overburden formation (Damen 2006) Vertical subsidence or uplift above large reservoirs could affect lake levels and shift streams in lowland areas with low topographic relief. Subsidence or uplift could damage buildings or farmland.	Parts of the surface in Section 32 subsided by as much as 2 cm (0.77 in) over a 14.5 month period (1 AUG 2008-17NOV 2009) while other parts of the surface uplifted by as much as 0.5 cm (0.21 in). Note that during this time, CBM was produced by multiple wells from the Fruitland Formation, conventional natural gas was produced from the deeper Mesaverde Group, and CO2 was injected for part of the time (30JUL2008-12AUG2009). Closer to the CO2 injection well, the subsidence was 1.7 cm (0.67 in) and the uplift was 0.1 cm (0.04 in). (ARI 2010).		Building and/or infrastructure damage. Change in drainage/water flow impacting agricultural land.	Subsidence or uplift.	Liability for damage to surface buildings and infrastructure Passive seismic monitoring. Surface displacement monitoring (LiDAR). Monitor bottomhole pressure.	Take into account subsidence or uplift in site characterization and modeling. Avoid shallow injection sites or sites susceptible to significant dissolution of minerals or mineral expansion. Maintain injection pressure below 90% of fracture pressure.	Monitor for significant cracks in building and infrastructure foundations. Monitor any mineral dissolution in critical formations based on produced water composition. Operate below 90% of fracture pressure. Monitor injection pressure, LiDAR and passive micro-seismicity.		
100	03.02.08.00.	Thermal effects on the injection point	Temperature of the injected fluid could result in geological modification of the region around the point of injection due to thermal gradients. 1. Cooling due to CO2 changing from supercritical to gas phase (endothermic). 2. Injected CO2 may be 25 to 50°C cooler than the in-situ temperature. 3. Heating due to CO2 adsorption on coal (exothermic).	These thermal effects could influence the mobility of the injected CO2 and impurities.	The CO2 was injected at 36°C (97°F) and 13.79 MPa (2000 PSIA). The reservoir temperature was estimated to be 52.2°C (126°F). The expansion of CO2 from a supercritical fluid to a gas is endothermic but the adsorption of CO2 on coal is exothermic. Approximately 99% of the injected CO2 is adsorbed on the coal and 1% remains as a gas in the cleat pore space.		Propagation of thermal stress fractures through reservoir and caprock. Scale buildup.	Thermal effects on the injection point.	CO2/CH4/brine release. Decreased porosity, permeability, injectivity.	Monitor bottom hole temperatures and pressure.	Select site with reservoir pressure above the CO2 supercritical pressure.	Increase CO2 injection temperature to partially compensate for any cooling effect or decrease CO2 injection temperature to compensate for any heating effect.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
98	03.02.06.00.	Induced seismicity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
99	03.02.07.00.	Subsidence or uplift	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
100	03.02.08.00.	Thermal effects on the injection point	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
101	03.02.09.00.	Reservoir water chemistry	Water phase geochemistry of sequestered CO₂. This includes the solubility trapping of CO₂ in water (H₂O) to form carbonic acid (H₂CO₃). Subsequent ionic trapping of carbonic acid with hydroxide ions (OH⁻) forms bicarbonate ions (HCO₃⁻), which can react in turn with further hydroxide ions to form carbonate (CO₃). 1. Formation of carbonic acid (H₂CO₃) 2. Formation of bicarbonate ions (HCO₃⁻) 3. Formation of carbonate (CO₃)	Modification of the water phase geochemistry can disturb the equilibrium between the water and solid phase of the reservoir and result in further geochemical (for example, solid phase geochemistry) and physical changes with resulting implications for the long-term performance of the sequestration system.	Pump Canyon Site There has been no conclusive indication of water chemistry change as a result of CO₂ breakthrough. The pH of the produced water stabilized at around 8.0 with variations ranging from 7.0 to 9.0. TDS: 12,699-19,739 mg/L Ca²⁺: 7.3-17.0 mg/L Mg²⁺: 19.0-23.0 mg/L K⁺: 18-55.5 ppm Na⁺: 4,169-5,784 mg/L F⁻: 16.4-39.0 mg/L Cl⁻: 2,390-3,212 mg/L HCO₃⁻: 5,870-10,534 mg/L CO₃²⁻: 150-509 mg/L Primary precipitates are Nahcolite (NaHCO₃): 1.54 kg/bbl evaporated and Salt (NaCl): 1.0 kg/bbl evaporated. Presence of H₂S showed a dramatic impact on produced water chemistry analysis. Fluctuation of H₂S in produced water was not fully understood.	Data on H ₂ S content of water not available. Assume coal seams are almost completely dewatered based on average 0.1 BBL/d water production per well (OCD 2013).	Scale buildup and salt precipitation.	Change in water chemistry.	Decreased permeability and injectivity. Plugging of CBM wells and equipment.	Monitor bottom hole water chemistry. Monitor well performance.	Take geochemistry into consideration in site characterization, modeling and reservoir engineering.	Monitor produced water chemistry and well performance. Routinely flush wells with hot water and acid. Use Teflon coating to control scale buildup.
102	03.02.10.00.	Interaction of CO ₂ with chemical barriers	Chemical barriers (pH, Eh-pH, ion exchange) may exist in aquifers to retard the migration of CO₂ from depth. The precipitation of CO₂ bearing solids may result from such interactions. 1. pH barrier 2. Eh-pH barrier 3. Ion exchange barrier	Such barriers will affect the rate of migration of CO ₂ from depth.	The primary chemical barrier is adsorption of CO₂ on coal. The coal is covered by a shale caprock which provides the ultimate seal. Pump Canyon Site Coal vitrinite reflectance: 0.8% Coal rank: high-volatile A bituminous CO₂ adsorption on coal under mixed - gas conditions: At 0.69 MPa: 2-2.6 kg/t coal At 11.33 MPa : 9-11.4 kg/ t coal		Migration of CO ₂ past chemical barrier.	Interaction of CO ₂ with chemical barriers.	CO ₂ release (HSE hazard).	Include geochemistry in site characterization and modeling. Monitor CO ₂ migration and interaction with chemical barrier.	Include geochemistry in site characterization and modeling. Monitor CO ₂ migration and interaction with chemical barrier.	Include geochemistry in site characterization and modeling. Monitor CO ₂ migration and interaction with chemical barrier. Monitor for CO ₂ leakage in overlying formations.
103	03.02.11.00.	Sorption and desorption of CO ₂ (CO ₂ interaction with coal seams) See 03.02.11.01 through 03.02.11.27.	The sorption and desorption of CO ₂ on geological materials. Adsorption onto coal and the displacement of methane (CH ₄) is the primary mechanism behind the enhanced coal bed methane recovery (ECBM) method for geological CO ₂ sequestration.	The rate of sorption and desorption of CO ₂ on geological materials affects its mobility and therefore the performance of the storage system.	Pump Canyon Site Coal vitrinite reflectance: 0.8% Coal rank: high-volatile A bituminous CO₂ adsorption on coal under mixed - gas conditions: At 0.69 MPa: 2-2.6 kg/t coal At 11.33 MPa : 9-11.4 kg/ t coal							

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking			Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)		Savings with risk mitigation (\$)
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
101	03.02.09.00.	Reservoir water chemistry	5	3	2	30	None	None	None	None	None	None	Revenue loss due to well downtime: 43-110 MCFD of CH4 @ \$3.50/MCF = \$150-385/D per well. Assuming 3 days to clean out a well: \$450-\$1,155 per cleanout per well.	Cleanout cost: \$5,000/well	None	None	Well cleanout every 6 months: \$5,000+\$800 = \$5,800 x 2=\$11,600/y per well. Cost for 16 production wells: \$186k/y Cost for 160 production wells: \$1.86M/y	Well cleanout every 24 months: \$5,800/2 = \$2,900/y per well. Cost for 16 production wells: \$46k/y Cost for 160 production wells: \$460k/y	Use Teflon coating to control buildup.	Savings: \$140k/y to \$1.4M/y minus cost of Teflon coating.	2
102	03.02.10.00.	Interaction of CO2 with chemical barriers	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
103	03.02.11.00.	Sorption and desorption of CO2 (CO2 interaction with coal seams) See 03.02.11.01 through 03.02.11.27.	0	0	0	0															

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
104	03.02.11.01.	ECBM adsorption of CO2 and desorption of methane	Based on the Langmuir isotherm, CO2 has higher affinity to coal and therefore displaces CH4 adsorbed on the coal. 2-3 moles CO2 adsorbed on coal for every mole of CH4 desorbed. CO2 adsorption: up to 41 Nm³/tonne coal (1400 scf/st coal) CH4 release: up to 13-15 Nm³/tonne coal (450-500 scf/st coal) at 22°C 72°F and 0-7 MPa (0-1000 psi). The CO2/CH4 sorption ratio of coal varies depending on the rank of coal. Typical CO2/CH4 sorption ratios for various coals are as follows: Low volatile bituminous: 1.1 Medium volatile bituminous: 1.5:1 High volatile A bituminous: 3:1 High volatile bituminous: 6:1 Sub bituminous: 10:1 (Reeves 2003)	Adsorption of CO2 on coal can have a positive effect on CO2 sequestration.	Pump Canyon Site Coal rank: high-volatile A bituminous Coal vitrinite reflectance: 0.8% Coal ash content: 22-35% Coal moisture content: 3.4% CO2/CH4 adsorption ratio: 3:1. CO2 adsorption on coal under mixed - gas conditions: At 0.69 MPa: 2-2.6 kg/t coal At 11.33 MPa : 9-11.4 kg/ t coal Allison Unit Site Coal type: high-volatile A bituminous Vitrinite reflectance: 1.1% CO2/CH4 adsorption ratio: 3:1. See Langmuir isotherm constants in 03.02.11.00. The adsorption time for CO2 was estimated at 1 day in the Pump Canyon model and 10 days in the Allison Unit model.		Decreased CH4 production. Increased CO2 storage. Increased CH4 production. Decreased CO2 storage.	High CO2/CH4 adsorption ratio Low CO2/CH4 adsorption ratio	Decreased revenues. Increased costs.	Monitor CO2 injection and CH4 + CO2 + H2O production.	Characterize and model coal seam for CO2 sorption. Select sites that have appropriate coal quality and methane content. Design well pattern and spacing to allow sufficient time for CO2 to adsorption and CH4 desorption.	Monitor and model CO2 injection and methane + CO2 + water production. Compare actual performance versus model projections. Identify root cause of any deviation from projections. Take corrective action as needed.
105	03.02.11.02.	ECBM desorption of CO2 from coal or other solids	CO2 desorption can occur with decreased pressure, increased temperature, pressure pulse, or seismic event.	Release of CO2 could lead to leakage.	Pump Canyon Site Coal zones are at relatively low pressure: 0.52-0.69 MPa (75-100 PSIG). As CBM production continues, pressure may decrease, allowing some CO2 to desorb from the coal. However, after CBM production stops, it is likely that the reservoir will gradually build up pressure, allowing the CO2 to remain adsorbed on the coal. Also decreased permeability associated with CO2 adsorption is likely to keep CO2 in place.		Significant increase in CO2 volume as CO2 transforms to a gas	ECBM desorption of CO2 from coal	Decreased CO2 storage capacity. Migration of CO2. CO2 breakthrough.	Monitor CO2 injection and CH4 + CO2 + H2O production.	Avoid decreasing pressure in the coal seam to the point that CO2 desorbs.	Increase pressure in coal seam with nitrogen or water injection.
106	03.02.11.03.	ECBM coal swelling	The chemical reactions and physical processes that occur during CO2 injection into coal seams and their impact on the integrity of the coal seams are not well understood. One of the reactions is swelling of the coal matrix when injecting CO2. (Damen 2006) When CO2 is injected into a coal seam, the coal matrix swells causing the cleat permeability to decrease.	Coal seam swelling may cause a reduction in permeability and injectivity. Swelling might also induce stresses on the overlying and underlying rock strata in non ideal coal seams (thin, low permeability and highly faulted), that could cause faulting and possible migration pathways out of the coal seam (Damen 2006).	Coal matrix swelling and permeability reduction (as a result of CO2 being adsorbed onto the coal while displacing methane and increasing pressure) occurred during CO2 injection at the Pump Canyon site, resulting in a dramatic decrease in injectivity. Single-well CO2 injection rate decreased from 200 to 13 t/d (3,800 to 250 MSCFD over a one-year period at constant injection pressure.		Decrease in CO2 injectivity.	ECBM coal swelling.	Higher operating costs.	Monitoring CO2 injectivity.	Characterize and model coal seam for coal swelling. Avoid sites that have coals with large matrix swelling due to CO2 adsorption.	Additional dewatering. Regular recompletion of injection wells with hydraulic fracturing. Periodic shut-in of injection well. Additional injection wells. Use horizontal wells (not practical with multiple thin seams).
107	03.02.11.04.	ECBM release of polyaromatic hydrocarbons (PAH) from coal seams	Polyaromatic hydrocarbons are chemical compounds that consist of aromatic rings. They are found in oil, coal and tar deposits. They tend to be released as a by-product of coal fires.	Toxicity issues and operation issues with decreased permeability.	Polyaromatic hydrocarbons were not reported during or after CO2 injection at the Pump Canyon Site.	No data indicating release of PAH is an issue with CBM or ECBM.	Contamination of groundwater with PAH.	ECBM release of polyaromatic hydrocarbons (PAH) from coal seams.	HSE hazard of contaminated water.	Establish base line study of PAH in local groundwater. Monitor groundwater for increases in PAH.	Characterize and model the interaction of CO2, coal and polyaromatic hydrocarbons.	Monitor groundwater for increases in PAH. Determine toxicity level and root cause. Take remedial action necessary to eliminate PAH (i.e., insitu treatment using vegetation; stabilization with humic acid; or pump and treat methods).

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
104	03.02.11.01.	ECBM adsorption of CO2 and desorption of methane	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
105	03.02.11.02.	ECBM desorption of CO2 from coal or other solids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
106	03.02.11.03.	ECBM coal swelling	5	5	2	50	None	None	None	None	None	None	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160,000. Depending on size of the operation, additional injection wells could cost: \$10M to >\$100M	None	None	None	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160,000. Depending on size of the operation, additional injection wells could cost: \$10M to >\$100M	None	2	
107	03.02.11.04.	ECBM release of polyaromatic hydrocarbons (PAH) from coal seams	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
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108	03.02.11.05.	ECBM coal seam dewatering	As a coal seam is dewatered, its pressure decreases. Cleat permeability increases. Coal matrix shrinks, opening up cleat fractures. Assume that the coal cleats are originally 100% saturated with water. Recommendation for ECBM: Coal seams with low water saturation (Bachu 2008)	Coal dewatering produces large quantities of water that must be properly treated and disposed of. In some cases, this may be a limiting factor in obtaining environmental permits and take a significant toll on project economics.	The Pump Canyon coal seams were dewatered prior to CO2 injection. Reservoir hydrostatic pressure declined from 11.33 MPa at 918 m depth (1,644 psi at 3,012 ft depth) to 0.51-0.69 MPa (75-100 psig) due to dewatering (ARI 2010). CBM wells in the Pump Canyon area are late-stage with low water production. At low pressure, the produced water comes out of the well as water vapor and condenses in the CBM gathering system as distilled water with some coal fines. The water can be surface discharged (after filtering) or evaporated.		Inability to treat or dispose of ECBM produced water.	ECBM coal seam dewatering.	Project delay or shutdown. Business interruption. Advanced loss of profits. Additional disposal costs.	Monitor permitting and compliance process for water disposal.	Obtain permit for water disposal to handle all disposal needs. Treat produced water if necessary to meet disposal requirements.	Have backup disposal option in place.	
109	03.02.11.06.	ECBM original gas in place (OGIP)	Original gas (methane) in place (OGIP) depends on the rank of coal. Free gas occurs within natural fractures. Dissolved gas occurs in water within the natural fractures. Adsorbed gas occurs within the coal matrix. Adsorbed gas typically represents over 95% of total. (Mansourine 2003) Coal bed methane may be formed by bacteria (biogenic methane) at depths less than 300 meters, or formed by heat and pressure transformation of coal organic matter (thermogenic methane) at greater depths in higher-rank coals. Thermogenic methane frequently contains trace amounts of H2O, CO2, N2 and H2S. Existing gas in place = original gas in place - previous gas production. Recommendation for ECBM: Methane-saturated seams should be preferred from a methane production perspective. From a storage perspective, under saturated coal seams can still be effective (Bachu 2008).	OGIP impacts the amount of methane available for ECBM recovery. From an economic viewpoint, ECBM of saturated coals is preferable to under saturated coals due to earlier gas production and a larger in-place gas resource (Seidle 2011). Unsaturated coals require more initial dewatering before methane production begins.	Section 32 OGIP: 0.779 Gm3 (27.512 BCF) consisting of 18% CO2 and 82% CH4. Nine-Section Area OGIP: 7 Gm3 (248 BCF) consisting of 18% CO2 and 82% CH4. Sixteen-Township Area OGIP: 256 Gm3 (9 TCF) San Juan Basin OGIP: 1.2-1.4 Tm3 (43-49 TCF.) Based on Fruitland coal seams thicker than 0.6 m (2 ft), and greater than 122 m (400ft) depth, and average coal ash content of 30% and 20%. (Ayers 1994).		Low methane yield.	Original gas in place significantly less than estimated.	Increased costs. Decreased revenues.	Characterize and model coal seam for original gas in place. Calculate existing gas in place.	Characterize and model coal seam for original gas in place. Calculate existing gas in place. Select site that has sufficient gas in place.	Compare actual with projected methane recovery. Identify any deviation from projected. Determine root cause and make appropriate adjustments.	
110	03.02.11.07.	Previous working of the coal seam	Primary CBM can recover 20-90% of the original gas in place (OGIP). CO2 ECBM can recover an additional 5-30%. Production stages of a coal bed methane well 1. Dewatering stage 2. Stable production stage 3. Decline stage (Mansourine 2003) 4. CO2 injection stage	Wells selected for ECBM CO2 injection should be near depletion to optimize CBM and ECBM performance.	Section 32 CBM production: began in 1992. Estimated OGIP: 27.512 BSCF (18% CO2, 82% CH4) Cumulative gas produced through DEC 2012: 22.333 BSCF or 81.2% of OGIP Cumulative gas injected: 0.319 BSCF or 1.2% of OGIP. Estimated remaining gas in place: 5.498 BSCF or 20% of OGIP (56% CO2, 44% CH4)		Lower methane recovery	CBM wells not fully depleted before starting CO2-ECBM.	Increased costs. Decreased revenues.	Calculate OGIP and remaining gas in place based on well production.	Select wells for CO2-ECBM that are near depletion to optimize CBM and ECBM performance.	Avoid repressuring the coal seam until CBM is nearly depleted.	

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
108	03.02.11.05.	ECBM coal seam dewatering	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
109	03.02.11.06.	ECBM original gas in place (OGIP)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
110	03.02.11.07.	Previous working of the coal seam	2	5	1	10	None	None	None	None	Typical CBM fairway well production: 2013-2022: 260MMCF@ \$3.50/MCF = \$0.91M revenue loss per well if coal seams are repressurized early.	None	None	Typical CBM fairway well production: 2013-2022: 260MMCF@ \$3.50/MCF = \$0.91M revenue loss per well if coal seams are repressurized early.	None	None	Revenue loss for a set of 16 CBM wells: \$15M Revenue loss for a set of 160 CBM wells: \$146M	None	Delay CO2 injection until CBM is nearly depleted (after 2021)	Savings could exceed \$100M.	2

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
111	03.02.11.08.	ECBM coal seam pressure	Coal seam hydrostatic pressure increases with depth. CO ₂ , N ₂ and water injection increase hydrostatic pressure. Dewatering and methane production decrease hydrostatic pressure. CO ₂ , CH ₄ , N ₂ and H ₂ S adsorption capacity of coal increases with coal seam hydrostatic pressure.	Gas adsorption is pressure dependent. The pressure profile in the reservoir must be understood and the injection operation designed appropriately. Gas adsorption of coal increases with pressure. Gas desorption of coal increases as pressure decreases. As reservoir pressure decreases, the rate at which CH ₄ desorbs increases. However, CO ₂ adsorption decreases with decreased pressure. At supercritical pressures, CO ₂ adsorption may be replaced by absorption as CO ₂ diffuses in coal. CO ₂ is a coal plasticizer, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure. The transition temperature may drop from 400°C at 3MPa to <30°C at 5.5 MPa. Coal plasticization, or softening, destroys any permeability that would allow CO ₂ injection. (Bachu 2006).	Pump Canyon Site: Initial coal seam pressure (before CBM operations) was 11.33 MPa (1644 PSIA). CO ₂ was injected at a bottomhole pressure of 13.79-14.82 MPa (2000-2150 PISA) and 32-38°C (90-100°F). At these conditions, the CO ₂ is supercritical with a density of 800 kg/m ³ , and the coal may be in a rubbery plastic state. This may have contributed to some of the permeability loss during injection. Coal seam pressure at start of and during CO ₂ injection was 0.52 to 0.69 MPa (75 -100 PSIG) at 52.2°C (126°F). At these conditions, the CO ₂ is in a gaseous phase and the coal is in a glassy, brittle state. Fracture pressure of coal seams estimated at 15.86-17.24 MPa (2,300-2,500 PSI) (Reeves 2003).		Negative: Decreased CH ₄ desorption. Positive: Increased CO ₂ adsorption Negative: Decreased CO ₂ adsorption. Positive: Increased CH ₄ desorption	Increased ECBM coal seam pressure. Decreased ECBM coal seam pressure	Increasing pressure could decrease or stop CBM production in nearby wells. High pressure could fracture the coal and/or caprock. (See 03.02.11.24)	Take pressure into account in characterizing and modeling ECBM coal seams. Monitor CO ₂ injection, bottomhole pressure, and CH ₄ +CO ₂ +H ₂ O production in nearby wells.	Take coal seam pressure into account in characterizing and modeling ECBM coal seams. Inject CO ₂ at low pressure to increase CH ₄ recovery. Inject CO ₂ at high pressure to increase CO ₂ storage. Avoid increasing coal seam pressure while CBM operations are ongoing. Avoid exceeding 90% of fracture pressure.	Avoid repressuring the coal seam until CBM is nearly depleted.
112	03.02.11.09.	ECBM coal seam temperature	Coal seam temperature increases with depth. CO ₂ adsorption is an exothermic reaction and will provide a heat source, at least during the active injection phase of the project. As temperature of the coal seam increases, the adsorption of CO ₂ decreases. The average isosteric heat of adsorption of CO ₂ on coal was calculated to be 20.3+1.1 kJ (4.85+0.26kcal) per mole of CO ₂ adsorbed (Schroeder 2002).	Impacts CO ₂ adsorption and methane release.	The coal seam temperature is 52.2°C (126°F). The thermal gradient is 38.3 °C/km of depth (21.3°F/1000 FT of depth), which is higher than normal due to residual heat from regional igneous intrusions.		Negative: Decreased CO ₂ adsorption. Potential for coal plasticization. (see 03.02.11.27) Positive: Increased CH ₄ desorption	High coal seam temperature.	Negative: Less CO ₂ storage capacity. Early CO ₂ breakthrough. Positive: More CH ₄ production.	Take coal seam temperature into account in characterizing and modeling ECBM coal seams. Monitor CO ₂ injection bottom hole temperature and CH ₄ +CO ₂ +H ₂ O production. Compare actual with projected (modeled) results.	Take coal seam temperature into account in characterizing and modeling ECBM coal seams. Inject CO ₂ at high temperature to increase CH ₄ recovery. Inject CO ₂ at low temperature to increase CO ₂ storage. Inject CO ₂ at near reservoir temperature to avoid stressing well equipment when operations are up and down.	Monitor CO ₂ injection bottom hole temperature and CH ₄ +CO ₂ +H ₂ O production. Compare actual with projected (modeled) results. Decrease CO ₂ injection temperature. Adjust coal seam pressure to optimize CH ₄ recovery or CO ₂ storage.
113	03.02.11.10.	ECBM coal seam fluid pH	The pH of aqueous solutions affects the surface of material it is in contact with. In the case of coal, at a high pH value, the carbonaceous surface assumes a net negative charge. At a low pH, the carbonaceous surface assumes a net positive charge. Theoretically, a pH of 9 would favor and a pH of 2 would disfavor the aqueous capture of CO ₂ (Schroeder 2002).	pH of water in the coal seam may impact CO ₂ adsorption.	There has been no conclusive indication of water chemistry change as a result of CO ₂ breakthrough (ARI 2010). The pH of the produced water in Section 32 stabilized at around 8.0 with variations ranging from 7.0 to 9.0. Theoretically, this is in the range of favoring CO ₂ adsorption. (ARI 2010).	Insufficient data on the impact of pH on CO ₂ adsorption and CH ₄ desorption.	Low CH ₄ desorption. Low CO ₂ adsorption.	Low pH coal seam fluid.	Increased costs. Decreased revenues.	Determine optimum pH for CO ₂ adsorption and/or CH ₄ desorption. Monitor pH of coal seam fluids.	Determine optimum pH for CO ₂ adsorption and/or CH ₄ desorption and operate within an acceptable range.	Monitor pH of coal seam fluids. Make adjustments to pH through CO ₂ and/or chemical treatment.
114	03.02.11.11.	ECBM coal seam depth	Shallow coal seams have low pressure and consequently low methane gas content, while deep coal seams often lack permeability (Seidle 2011). Typical recommended depth 300-1500 m (984-4,921 ft).	The CO ₂ -ECBM coal seams should be within the recommended depth for CO ₂ injection (Seidle 2011).	The coal seams in the Sixteen-Township Site range from 600 to 1,150 m (2,000 to 3,800 ft) depth.		Low pressure, low methane OGIP Low permeability, low injectivity	Shallow coal seams Deep coal seams	Decreased CBM production. Increased costs.	Characterize and model coal seam depth.	Avoid sites where coal seam depth are too shallow or too deep.	Hydraulic stimulation for deep seams.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
111	03.02.11.08.	ECBM coal seam pressure	2	5	1	10	None	None	None	None	Typical CBM fairway well production: 2013-2022: 260MMCF@ \$3.50/MCF = \$0.91M revenue loss per well if coal seams are repressurized early.	None	None	Typical CBM fairway well production: 2013-2022: 260MMCF@ \$3.50/MCF = \$0.91M revenue loss per well if coal seams are repressurized early.	None	None	Revenue loss for a set of 16 CBM wells: \$15M Revenue loss for a set of 160 CBM wells: \$146M	None	Delay CO2 injection until CBM is nearly depleted (after 2021)	Savings could exceed \$100M.	2
112	03.02.11.09.	ECBM coal seam temperature	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
113	03.02.11.10.	ECBM coal seam fluid pH	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
114	03.02.11.11.	ECBM coal seam depth	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
115	03.02.11.12.	ECBM injection and production well pattern and spacing	The most common drilling pattern is a 5-spot (injection well in the center and production wells in the corners) or inverse 5-spot (injection in the corners and production in the center). Drilling on 16, 65 or 233 hectare (40, 160 or 640 acre) spacing. When injecting CO2, it is important to allow sufficient time for displacement of the methane (locating production wells far away enough from the injection wells).	Impacts the sweep efficiency of ECBM and the effective adsorption of CO2.	New Mexico regulations limit well density in the Fruitland Formation to one well per 160 acres. Pump Canyon Site Injection-centered 4-spot pattern. Allison Unit Site Injection-centered 5-spot pattern.		Early CO2 breakthrough. Decreased sweep efficiency.	ECBM injection and production wells too close together. ECBM injection and production wells too far apart.	Decreased CO2 storage capacity. Increased CO2 handling. Decreased CH4 production.	Monitor and model well performance (CH4 + CO2 + H2O production)	Optimize well spacing and pattern based on modeling and reservoir engineering.	Monitor well performance versus model predictions. Adjust model and well spacing and pattern as needed to optimize CH4 recovery and/or CO2 storage.
116	03.02.11.13.	ECBM injection strategy	Constant injection rate or variable injection rate "huff and puff"(alternating CO2 injection and CBM production over time).	Impacts the sweep efficiency of ECBM and the effective desorption of CO2.	Pump Canyon Site 16,781 t (319 MMSCF) of CO2 were injected over one-year (30JUL2008-12AUG2009) at constant pressure (90% of fracture pressure) Original plan was to inject 68,000 t CO2 over 12 months.** 80% of injected CO2 went into the lower coal zone.** Injection was designed to keep CO2 migration within the 640-acre project area. (ARI 2010). Allison Unit Site 336,665 t (6.4 BCF) of CO2 were injected over 6 years using huff-and-puff and constant pressure. No benefit was identified with the huff-and-puff (Reeves 2003)		Low sweep efficiency.	Improper ECBM injection strategy.	Decreased CH4 desorption. Decreased CO2 adsorption. Early CO2 breakthrough. Increased costs. Decreased revenues.	Monitor CO2 injection and CH4 + CO2 + H2O production.	Fully characterize and model the ECBM coal seam . Select the optimum injection strategy.	Monitor and model well performance. Compare actual with projected performance. Modify injection strategy if necessary.
117	03.02.11.14.	ECBM early CO2 breakthrough	Early breakthrough of CO2 can be caused by high permeability areas in the coal seam or improper well pattern/spacing.	Impacts the sweep efficiency of ECBM and increases costs due to the need for excess CO2 recycling.	Pump Canyon Site CO2 sensors at 3 immediate CBM wells indicate that no CO2 breakthrough occurred at the site. However the steady increase of CO2 by 3% at FC State Com 1 might be a sign of breakthrough. Perfluorocarbon tracers injected with the CO2 stream showed up 6 months later at FC State Com 1 and 10 months later at EPNG Com A 300 (Breakthrough was expected to occur first at EPNG Com A 300 due to its alignment with the face cleats). Nitrogen began building up in FC State Com 1 and EPNG Com A 300 within 2-4 months after CO2 injection began. Allison Unit Site CO2 breakthrough occurred in central CBM well (#113) 4.5 years after start of CO2 injection (236,718 t (4.5 BCF) of CO2 injected. Breakthrough is defined as point in time where 10 vol. % CO2 increase in CBM is observed.		Increased CO2 production. Decreased CH4 production.	ECBM early CO2 breakthrough.	Increased operating costs due to CO2 recycling costs.	Monitor CO2 injection and CH4 + CO2 + H2O production.	Fully characterize and model the ECBM coal seam . Optimize well pattern/spacing.	Recycle CO2. Consider modifying well pattern/spacing. Shut in CBM wells that have over 50% CO2 content.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS/D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
115	03.02.11.12.	ECBM injection and production well pattern and spacing	2	2	1	4	None	None	None	None	None	None	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160,000	None	None	CH4 production 50MMCFY less than optimum: \$175k per year .	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160,000	Up to \$15k.	2	
116	03.02.11.13.	ECBM injection strategy	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
117	03.02.11.14.	ECBM early CO2 breakthrough	3	3	1	9	None	None	None	None	None	None	Revenue loss with shutting in CBM wells with high CO2 content:50-200MCFD of CH4 @ \$3.50/MCF = \$175-700/D per well. Cost of CO2 separation from produced CBM: \$5.70/t CO2 (\$0.30/MCF CO2) Cost of compressing produced CO2 : 120 kWh/t CO2 \$0.06/kWh = \$7.20/t CO2 Cost of CO2 recycling: CO2: \$11.90/t (\$0.63/MCF)	If CO2 is not recycled, up to 25% of the injected CO2 could be emitted. Cost of purchased natural CO2: \$32.32/t (\$1.70/MCF). For 0.3 Mt/y injected CO2: 0.075Mt/y CO2 emitted @ \$32.32/t = \$2.4 M/y. For 3 Mt/y injected CO2: 0.75 Mt/y CO2 emitted @ \$32.32/t = \$24M/y	None	Depending on the size of the operation, the cost of replacing produced CO2 and shutting in CBM wells with high-CO2 content: \$2.4-24M/y	None	Cost of recycling produced CO2: \$1-10M/y	Savings of \$1.4-14M/y	2		

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
118	03.02.11.15.	ECBM coal seam thickness	For ECBM at least one coal seam should be at least 0.5 m (1.5 ft) thick. However, the thicker the seam, the more likely it could be mineable. Recommended for ECBM: Concentrated coal deposits (few, thick seams) are generally favored over stratigraphical dispersed beds comprising multiple, thin seams (Bachu 2008).	A coal deposit with a few thick seams over a short stratigraphic interval is preferable to one with multiple thin seams over a large interval Seidle 2011). Seams less than 0.5 m (1.5 ft) thick can limit injectivity. Multiple thin seams not well suited for horizontal injection wells.	Pump Canyon Site Net thickness all coal zones in Section 32: 17-20 m (55-65 ft). Average net thickness of individual zones and coal beds: Upper zone:7 m (23 ft) Coal bed F: 2.7 m (9 ft) Coal bed E: 2.1 m (7 ft) Middle zone: 4.7 m (15.5 ft) Coal bed D: 1.2 m (4 ft) Coal bed C: 1.4 m (5 ft) Basal zone: 8.5 m (28 ft) Coal bed B: 3.4 m (11 ft) Coal bed A: 4.0 m (13 ft) Total all zones: 20.2 m (66.5 ft) Total all coal beds: 14.8 m (49 ft) Allison Unit Site Net thickness of all coal zones: 10.4-14.3 m (34-47 ft) Average net thickness of individual coal zones: Upper zone: 6.7 m (22 ft) Middle Zone: 3 m (10 ft) Basal Zone: 3.4 m (11 ft) Total: 13.1 m (43 ft)		Decreased injection rate.	Insufficient coal seam thickness.	Increased costs. Decreased revenues.	Characterize the coal seam thickness to confirm it meets recommendation.	Characterize the coal seam thickness to confirm it meets recommendation. Avoid sites with thin coal seams.	Avoid sites with thin coal seams.	
119	03.02.11.16.	ECBM complex structural geology of coal seams	Complex structural geology can make ECBM more difficult to model, less efficient to implement and more susceptible to leakage. Recommendation for ECBM: Simple structure. The coal seams should be minimally faulted and folded. The coal seams should be laterally continuous and vertically isolated from surrounding strata to prevent migration of excess CO2 and CH4 into adjacent aquifers and possibly to the surface (Bachu 2008).	Complex structural geology has a significantly greater negative impact on CO2-ECBM than on CBM. Potential for CO2/CH4 leakage, compartmentalization, and lower methane recovery.	An inferred structural hingeline is located in the southern portion of the Sixteen-Township Area. The hingeline consists of a NW-trending fault zone that acts as a flow barrier for the Fruitland Formation and may contribute to upward fluid flow and existing methane seeps in the area. The fault zone underlies Turley and Navajo Dam communities. The Fruitland Formation gently slopes toward the basin floor from the SW and NE. The coal seams are complex and laterally discontinuous due to pinchouts, local fault truncations, channel scour, and facies changes. The number of coal seams in a given area can range from 0 to 16.The coal seams in the Pump Canyon Site are vertically compartmentalized by tonsteins (shale partings). Increased fracture intensity and permeability occurs where coal seams are folded or differentially compacted.		Compartmentalization. Poor CO2 sweep efficiency. Decreased CH4 recovery. Leakage of CO2/CH4 into overlying formations if coal seams are repressurized.	Complex structural geology of coal seams	Decreased CO2 storage capacity. Decreased CH4 production. Surface release /buildup of CO2/CH4. Contamination of ground water. Pump house fires.	Fully characterize and model the site early in the design phase. Monitor and model well performance.	Fully characterize and model the site. Use high-resolution 3D seismic surveys to characterize complex or high-risk areas.. Avoid sites with complex structural geology in high-risk areas. Avoid repressurizing coal seams in high-risk areas.	Monitor and model CO2/CH4 movement and well performance. Monitor near surface for CO2/CH4 leaks. Install alarms in high-risk areas. Locate and mitigate leaks. Depressurize coal seams.	
120	03.02.11.17.	ECBM CO2 injection into mineable coal seams	CO2 ECBM is normally applied to coal seams that are too thin or too deep to be mined.	CO2 ECBM in mineable coal seams will complicate the recovery of those coal reserves. However, removing methane decreases the explosion possibility for future mining.	All of the coal seams at the Site are classified as unmineable due to depth and thickness.		CO2 contamination of coal reserves.	ECBM CO2 injection into mineable coal seams.	Loss of monetized value of contaminated coal reserves.	Identify ownership of mineral rights.	Obtain mineral rights for selected coal seam including sufficient buffer to protect against infringement on third-party reserves.	Evaluate CO2 extraction options and safety measures to be taken if coal seam is to be mined in the future.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSOD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
118	03.02.11.15.	ECBM coal seam thickness	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
119	03.02.11.16.	ECBM complex structural geology of coal seams	4	3	3	36	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$0.3M for leaky well or \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	\$4M to locate and fix leak and remediate.	\$3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high- risk areas \$150k.	Savings of \$0.85M	2
120	03.02.11.17.	ECBM CO2 injection into mineable coal seams	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
121	03.02.11.18.	ECBM coal seam permeability	The permeability of coal varies in two basic ways: 1. Phase relative permeability effects 2. Change in the effective stress within the seams (Mansourine 2003) Cleat permeability is primarily controlled by the prevailing horizontal stresses. ECBM wells that produce little water or gas may indicate low permeability. Recommended minimum absolute permeability for ECBM:: 1 to 3 mD (Seidle 2011). Coal permeability decreases with depth, such that injectivity is not possible below about 914 m (3000 ft) without fracturing (NETL 2010).	Sorption of CO2 on coal swells the coal matrix and thus decreases permeability (Seidle 2011). Low permeability makes CO2 ECBM more difficult and more expensive. Coal seams have minimal porosity and limited communication from one cleat to the next. CBM wells where the stimulations have been aligned to cross the maximum number of face cleats have consistently outperformed wells that ignore the lay of the coal stresses (Simpson 2008).	Pump Canyon Site Initial permeability: Upper coal zone: 146 mD* Middle coal zone: 146 mD* Lower coal zone: 582 mD* Upper and middle coal zones permeabilities were adjusted to 10 mD in the history-match model to achieve 80% of CO2 injection in lower coal zone (ARI 2010) Permeability at the injection well decreased to less than 1mD over one-year of CO2 injection. Permeability estimated at 104-388 mD based on pressure buildup tests on EPNG Com A 300 and 300S.(ARI 2008) Vertical permeability on Fruitland coal was two orders of magnitude less than face cleat permeability. Butt cleat permeability was one-half the face cleat permeability (Seidle 2011). Vertical permeability used for modeling was 0.0001 mD. Compared to 146 to 582 mD for horizontal permeability.		Decreased CO2 injectivity and decreased CH4 production.	Decreased coal seam permeability.	Decreased profitability.	Characterize and model coal seam permeability. Monitor CO2 injectivity.	Characterize and model coal seam permeability. Select coal seams with acceptable permeability properties.	Monitor injectivity. Dewater coal seam to increase cleat permeability. Add more vertical injection wells (new or converted). Consider hydraulic fracturing. Use horizontal injection wells (not feasible for multiple thin seams).
122	03.02.11.19.	ECBM coal porosity	Micro-porosity: < 2 nm pore diameter impacts sorption Meso-porosity: >2 nm <50 nm pore diameter impacts diffusion Macro-porosity (fracture porosity): > 50 nm impacts Darcy flow Induced fractures: pipe flow (Mansourine 2003) Cleat porosity represents the initial water storage volume in the coal seam.	Coal bed porosity and permeability increases as reservoir pressure is lowered and gas production occurs. Coal fracture or cleat porosity is not as critical for CO2 storage as it is in deep saline aquifers because the CO2 is mainly adsorbed on the coal matrix. Coal seams have minimal porosity and limited communication from one cleat to the next.	Pump Canyon Site Upper coal zone porosity: 1.4% Lower coal zone porosity: 2.3% (ARI 2010) Permeability relates to porosity as follows: $(k_i / k_0) = (\Phi_i / \Phi_0)^3$ k =permeability k₀ = initial permeability Φ= porosity Φ₀ = initial porosity		Increased dewatering required. Decreased dewatering required.	High coal seam porosity. Low coal seam porosity.	Decreased profitability.	Characterize and model coal seam porosity. Monitor well performance.	Characterize and model coal seam porosity.	Monitor well performance. Dewater coal seam to improve CO2 injectivity and CBM production.
123	03.02.11.20.	ECBM coal seam heterogeneity	Coal is inherently heterogeneous. Coal rock properties can show extreme heterogeneity. Permeability can vary by more than an order of magnitude in coal seams.	The target coal seam should be laterally continuous and vertically isolated from surrounding strata to insure CO2 containment in the coal and efficient lateral sweep. (Seidle 2011). Heterogeneity in permeability can result in CO2 early breakthrough, limit CO2 storage capacity and limit methane recovery.	Regional studies by Fassett 1979 and Wray 2000 reveal the presence of considerable heterogeneity within the Fruitland Formation and individual seams (pinchouts, local fault truncations, channel scour and facies changes). Detailed study by Ayers and Zellers 1994 conducted near the Site reveals considerable complexity in the Fruitland depositional systems. Fassett 1979 indicates that continuity of subsurface coals over distances of a mile is speculative, at best. Seismic surveys reveal significant discontinuity, whereas the coal intervals in well log cross sections often suggest continuity, which may, in fact, not be the case. Seismic interpretation also reveals the presence of local fold-like structures with wavelengths ranging from 1 -3.5 km accompanied by relief of 2-20 m (6-60 ft).		Compartmentalization. Poor sweep efficiency. Decreased CH4 recovery. Decreased CO2 storage capacity.	Coal seam heterogeneity.	Decreased profitability..	Fully characterize and model heterogeneity of the coal seam. Monitor and model well performance. Compare actual with projected performance.	Fully characterize and model heterogeneity of the coal seam. Optimize the CO2 injection strategy to accommodate the heterogeneity of the coal seam.	Monitor and model well performance. Compare actual with projected performance. Modify injection strategy if necessary. Add more injection wells. Monitor for CO2/CH4 in high-risk areas.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
121	03.02.11.18.	ECBM coal seam permeability	5	5	2	50	None	None	None	None	None	None	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160k. Depending on size of the operation, additional injection wells could cost: \$10M to >\$100M	None	None	None	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160k. Depending on size of the operation, additional injection wells could cost: \$10M to >\$100M	None	2
122	03.02.11.19.	ECBM coal porosity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
123	03.02.11.20.	ECBM coal seam heterogeneity	4	4	2	32	None	None	None	None	None	None	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160k. Depending on size of the operation, additional injection wells could cost: \$10M-\$100 M	None	None	None	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160k. Depending on size of the operation, additional injection wells could cost: \$10M-\$100 M	None	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
124	03.02.11.21.	ECBM coal sudden brittle failure	Sudden brittle failure can occur when coal seam pressures decrease below a critical value.	Sudden brittle failure can lead to a drop in permeability Sudden brittle failure is experienced in coal mining but has not been observed in CBM field operations.	Sudden brittle failure occurs when pressure decreases below 1.7-2 MPa (250-300 PSI) based on lab testing of SJB coal from Colorado. However, there did not appear to be a failure during CO2 injection (Koperna 2012). In the SJB fairway, coal friability has been measured at 0.1 MPa (15 psi) (Simpson 2010).	Insufficient field data to indicate that sudden brittle failure occurs during CBM or ECBM operations.	Sudden decreased permeability. Potential CBM production well damage.	Coal sudden brittle failure.	Decreased profitability.	Monitor injectivity / permeability for any sudden decrease or associated microseismic event.	Avoid coal seams that may be prone to sudden brittle failure.	Rework damaged CBM production wells. Add wells to mitigate permeability loss.
125	03.02.11.22.	ECBM CO2 storage capacity of coal	Typical CO2 adsorption of coal can be up to 81.13 kg/tonne (1400 scf/st) at 22°C and 0- 6.9MPa (0-1000 psi). Over 99% of the CO2 can end up adsorbed on the coal, with less than 1% remaining as free gas in the cleat porosity.	Depending on the objective of CO2 ECBM, the CO2 storage capacity can have a positive or negative impact. If the objective is to minimize CO2 consumption/cost it can be a negative. If the objective is to maximize CO2 sequestration, it is a positive.	Pump Canyon Section 32 CO2 storage capacity at current pressure of 0.69 MPa (100 PSIG) and 52.2°C (126°F): 38,343 t CO2/km2 (109,419 ST CO2/mi2) (Calculated based on multi-component Langmuir isotherms for ultimate free gas mixture of 50% CO2, 49.9% CH4, 1%N2). Assumes 40% storage efficiency. CO2 storage capacity at initial pressure of 11.33 MPa (1644 PSIA) and 52.2°C (126°F): 160,145 t CO2/km2 (457,006 ST CO2/mi2) (Calculated based on multi-component Langmuir isotherms for ultimate free gas mixture of 50% CO2, 49.9% CH4, 1%N2). Assumes 40% storage efficiency.	 High CO2/CH4 ratio Low CO2/CH4 ratio	 High CO2 storage capacity of coal Low CO2 storage capacity of coal	 Increased CH4 production costs. Increased CO2 storage costs.	 Determine the CO2 storage capacity of coal through core sample testing. Model CO2 adsorption. Monitor actual versus projected well performance.	 Characterize and model the coal seam to estimate storage capacity. Select coal seams with sufficient CO2 storage capacity.	 Repressurize the coal seam to enhance CO2 storage capacity after CBM has been depleted.	
126	03.02.11.23.	ECBM produced gas composition	Coal bed methane tends to be sweet (no H2S). It contains small amounts of CO2 and nitrogen.	Impacts gas treatment facilities on surface and value of coal bed methane. U.S. natural gas specification CO2:<2% vol/ % Inerts (N2): <4 vol. %	Pump Canyon Site Composition of coalbed methane produced in Section 32 CH4: 68.4-79.1% CO2: 19.4-29.5% N2: 0.032-2.02% Ethane: 0.53-2.90% Propane: 0.06-1.67% 1-Butane: 0.01-0.20% n-Butane: 0.01-0.16% 1-Pentane: 0.001-0.03% n-Pentane: 0.00-0.02% Hexane: 0.00-0.11% (ARI 2010) Note the high CO2 content comes from exsolution of CO2 from biogenic bicarbonate-rich brine.	 ECBM produced gas unable to meet natural gas specification.	 Excess CO2 (or N2) in ECBM produced gas	 Additional processing costs remove CO2 and/or N2 from produced gas.	 Monitor produced gas composition.	 Characterize and model the coal seam to estimate coal bed methane quality. Design gas treatment facility to handle expected range of composition.	 Monitor coal bed methane quality. Adjust gas treatment to deal with changes in quality. Recycle captured CO2.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
124	03.02.11.21.	ECBM coal sudden brittle failure	3	2	3	18	None	None	None	None	None	Cost of workover for damaged CBM production wells \$50k to \$100k per well.	15 days at 156MCFD @ \$3.5/MCF = \$8k	None	None	None	CBM production loss of 57 MMCFY @ \$3.5/MCF ≈\$0.2M/y per well.	Revenue loss due to down time of 15 days for reworking: \$8k	Cost to rework damaged CBM production wells \$50k to \$100k per well.	Savings of \$92k to \$142k per well.	2
125	03.02.11.22.	ECBM CO2 storage capacity of coal	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
126	03.02.11.23.	ECBM produced gas composition	5	4	1	20	None	None	None	None	None	None	Revenue loss with shutting in CBM wells with high CO2 content.50- 200MCFD of CH4 @ \$3.50/MCF ≈\$175-700/D per well.	Cost of CO2 separation from produced CBM: \$5.70/t CO2 (\$0.30/MCF CO2) Cost of compressing produced CO2 : 120 kWh/t CO2 \$0.06/kWh ≈\$7.20/t CO2 Cost of CO2 recycling: CO2: \$11.90/t (\$0.63/MCF)	If CO2 is not recycled, up to 25% of the injected CO2 could be emitted. Cost of purchased natural CO2: \$32.32/t (\$1.70/MCF). For 0.3 Mt/y injected CO2: 0.075Mt/y CO2 emitted @ \$32.32/t = \$2.4 M/y. For 3 Mt/y injected CO2: 0.75 Mt/y CO2 emitted @ \$32.32/t = \$24M/y	None	Depending on the size of the operation, the cost of replacing produced CO2 and shutting in CBM wells with high-CO2 content: \$2.4-24M/y	None	Cost of recycling produced CO2: \$1-10M/y	Savings of \$1.5- 15M/y	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
127	03.02.11.24.	ECBM induced fracturing of coal (hydraulic stimulation).	Coal is an extremely stress-sensitive rock. Coal is "self healing" so proppants used in hydraulic fracturing have limited effectiveness (Simpson 2010)	Low fracture pressure limits CO2 injection pressure. Hydraulic fracturing may be required to mitigate decreasing permeability of coal. Bigger carrier volumes should be used for hydraulic stimulation of coal to scour bigger channels that are less likely to heal and are more conductive (Simpson 2010).	Pump Canyon Site CO2 was injected at bottomhole pressures of 13.79-14.82 MPa (2,000-2,150 PSIA). (ARI 2010). This is slightly less than 90% of fracture pressure based on the fracture pressure estimated for the Allison Unit Site. Allison Unit Site Fracture pressure of coal seams estimated at 15.86-17.24 MPa (2,300-2,500 PSI) (Reeves 2003). SJB Fairway In the SJB fairway, coal friability has been measured at 0.1 MPa (15 psi) (Simpson 2010).		Fracturing caprock.	ECBM induced fracturing of coal.	Release of CO2/CH4 into overlying formations. Determine fracturing pressure of caprock and coal. Monitor injection pressure. Alarm if injection pressure nears 90% of fracturing pressure. Monitor CO2/CH4 content in upper formations, groundwater, soil and/or atmosphere.	Determine fracturing pressure of caprock and coal. Monitor CO2 injection pressure. Limit injection pressure to less than 90% of fracturing pressure.	Monitor CO2/CH4 content in upper formations, groundwater, and high-risk areas. If leakage is detected, lower coal seam pressure by lowering CO2 injection pressure and/or dewatering. Try to locate and remediate leak with sealant.	
128	03.02.11.25.	ECBM nitrogen injection into coal seam	Nitrogen has a lower affinity to coal than CH4. Nitrogen injection lowers the partial pressure of CH4 which allows CH4 to diffuse through the coal matrix with greater ease, improving recovery of CBM at a faster rate.	Nitrogen is not a problem in ECBM as a minor component of CO2. It will lower the partial pressure of methane and allow more methane to be released and recovered. Some of the nitrogen injected with CO2 may end up in the coal bed methane, resulting in a lower value product. The typical U.S. natural gas specification requires N2 content to be <4%.	Pump Canyon Site The CO2 stream contained approximately 1.5% nitrogen. The nitrogen began showing up in the producers within 2-4 months after injection began. Tiffany Site Langmuir isotherm constants Langmuir volume: 7.66.02 m3 N2/t coal (254-257 SCF/ST) dry-ash-free basis Langmuir pressure: 9.85 MPa (1,429 PSIA)		Nitrogen contamination of coal bed methane. Increased CH4 production	ECBM nitrogen injection into coal seam.	Increased cost of processing CBM to remove N2 to meet natural gas specification. Partially offset by increased CBM production. Monitor composition of injected and produced gases.	Keep nitrogen gas content of CO2 stream low. Monitor composition of injected and produced gases.	Monitoring gas compositions of injected gas and produced gas. Treat produced gas to remove nitrogen.	
129	03.02.11.26	ECBM coal fines generation and transport	Induced fracturing of coal seams can lead to fines generation. These fines can be mobilized by injected gases or fluids. Some types of medium- and low-volatile bituminous coals are weaker, and have a greater tendency of generating fines, than other coals.	Coal fines can: 1. Plug and reduce coal seam permeability 2. Plug and reduce fracture conductivity 3. Plug submersible pumps 4. Erode ECBM systems 5. Accumulate in ECBM separators 6. Require disposal (Palmer 2008)	Coal fines accumulate in the wellbore during production, and must be cleaned out periodically. This requires a workover, which costs about \$50,000 (Logan 1989). These operations may be needed less frequently as time goes on, especially as water production and formation pressure decrease (Bland 1992). CBM can contain coal fines which tend to build up in pipes where water vapor condenses. The lines must be periodically pigged and the recovered dirty water must be filtered.		Sealing of hydraulic fractures. Plugging open cavity perforations. Buildup in CBM gathering lines.	Coal fines generation and transport.	Increased maintenance. Decreased profitability. Monitor well performance and coal fines in produced gas and produced water. Monitor pressure drop in CBM gathering lines.	Stabilize open well cavities and clean them out thoroughly before inserting the perforated tube.	Periodic well workover to clean out fines. Periodic pigging of CBM gathering lines. Recavitate well. Hydrofracture stimulation. Scrub out/filter out fines in produced gas and/or produced water.	
130	03.02.11.27	ECBM coal plasticization	CO2 is a coal plasticizer, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure. The transition temperature may drop from ~400°C at 3MPa to <30°C at 5.5 MPa. (Bachu 2006). Recommendation for ECBM: Avoid deep ECBM sites that have CO2 supercritical pressures and temperatures above 30°C (Bachu 2008).	Coal plasticization, or softening, destroys any permeability that would allow CO2 injection. (Bachu 2006). CO2 adsorption is a very fast process, but CO2 absorption is a very slow process.	Pump Canyon Site CO2 was injected at a bottomhole pressure of 13.79-14.82 MPa (2,000-2,150 PISA) and 32-38°C (90-100°F). At these conditions, the CO2 is supercritical with a density of 800 kg/m3,	The absorption (diffusion) of CO2 in coal at supercritical conditions is not well understood.	Irreversible significant decreased permeability. Decreased CO2 adsorption.	Plasticization of coal .	Shutdown of operation. Monitoring CO2 injection pressure and rate. Monitoring bottom hole pressures and temperatures.	Avoid deep ECBM sites that have CO2 supercritical pressures and temperatures above 30°C.	Shutdown operations.	

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Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P x S x D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
127	03.02.11.24.	ECBM induced fracturing of coal (hydraulic stimulation).	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
128	03.02.11.25.	ECBM nitrogen injection into coal seam	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
129	03.02.11.26	ECBM coal fines generation and transport	5	2	2	20	None	None	None	None	None	Cost of workover for damaged CBM production wells \$50k to \$100k per well.	15 days at 43 to 110 MCFD @ \$3.5/MCF = \$2k-\$6k	None	None	None	CBM production loss of 15.5-40 MMCFY @ \$3.5/MCF = \$55k to \$140k/y per well.	Revenue loss due to down time of 15 days for reworking: \$2k to \$6k	Cost to rework damaged CBM production wells \$50k to \$100k per well.	Savings of \$3k to \$34k per well.	2
130	03.02.11.27	ECBM coal plasticization	3	5	2	30	None	None	None	None	None	None	Shutdown of operations due to irreversible drop in permeability	None	None	None	Depending on the size of the operation, not shutting down could result in losses of \$10M/y to \$100M/y plus loss of the capital investment of \$26M to \$260M.	Loss of investment: \$26M to \$260M. Plus shutdown costs: \$4M to \$39M.	Loss of investment: \$26M to \$260M. Plus shutdown costs: \$4M to \$39M.	Savings of \$6M to \$61M.	2

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131	03.02.11.28	ECBM cavitation (open hole cavity completion)	Open hole cavity completion has been used to stimulate CBM production. It consists of sculpting a cavity in the coal seam with pressure surges. The casing in a well is set just above the coal seam and the coal is drilled unbalanced with water, air or foam. A cavity is formed in the coal seam by allowing coal to fracture and collapse into the wellbore as water and gas move toward the wellbore. Coal cuttings are removed by displacing with air or foam. The cavity can be expanded by repeatedly shutting in the well to build up pressure and then rapidly opening the well causing water and gas to flow toward the well, fracturing the coal seam and expanding the cavity. Cavities can penetrate up to 100 m into the coal seam. After the hole is stabilized, a perforated liner is installed across the cavity. (Bland 1992)	Cavitation has worked only in a limited number of coal fields so far. (Simpson 2010). It is mostly used in the San Juan Basin. Cavitation in existing producer wells may complicate conversion of wells to CO2 injection.	Cavitation is widely used in the SJB. Coal fines brought to the surface during cavitaion are often burned in a pit. A typical cavitation may generate 100 t of coal fines. The burning can last 7 to 10 days (OGAP2004).		Collapse of cavitation opening. Failure of cavitation to improve CBM production. Complication of converting a well from a producer to an injector due to cavitation.	Improper cavitation.	Displacement or fracturing of the overlying formation. Poor CBM recovery. Increased costs associated with well conversion or well replacement. Air pollution associated with burning recovered cavitation fines and flaring of associated CBM gases. Noise associated with the cavitation process.	Take into account strength of overlying formation and coal properties in planning cavitation. Monitor cavitation process and well performance.	Avoid over extending the cavity beyond rock strength limits. Use proper cavitation procedures and make sure the cavity is stabilized. Use cavitation in appropriate coal fields. Properly cement the casing above the coal seam. Take into consideration the potential for future well conversion when planning cavitation.	Recavitate and stabilize the well. Perform cement bond log to confirm quality of the cement job above the coal seam. Plug and abandon well and replace with a new well.	
132	03.02.12.00.	Heavy metal release	Heavy metal ions may be dissolved in formation fluids or adsorbed on rock/mineral surfaces. Complexation may occur between CO2 and heavy metals dissolved in formation fluids. The influence of dissolved CO2 on pore water chemistry can also reduce the pH and change the equilibrium between sorption/desorption of metals, thereby resulting in significant release of these metals.	This process has the potential to release heavy metals, which may then migrate to the near-surface environment with resulting impacts of interest. These heavy metals will also change pore water chemistry, which could impact on carbonate complexation.	No dramatic change in water chemistry was observed from offset wells during the CO2 injection test period. The formation water was bicarbonate-rich prior to CO2 injection. Approximately 99% of the injected CO2 is adsorbed on the coal and approximately 1% is gaseous CO2 in the cleat pore space. The coal seams are largely dewatered.	Heavy metals were measured but not reported.	Migration of heavy metals with CO2/CH4/brine into the near surface environment.	Heavy metal release.	Contamination of ground/surface water and/or soil.	Conduct baseline study of heavy metals in the reservoir and near surface environment. Monitor heavy metal content in produced brine, ground/surface water, and soil.	Characterize and model the reservoir for heavy metal content and release. Avoid sites where heavy metal concentration is unusually high and would have a significant impact on the near surface environment.	Conduct baseline survey of heavy metal content in the near surface environment. Monitor heavy metal content in produced brine. Monitor CO2 , CH4 and salinity in near surface environment. If CO2/CH4/brine contamination is indicated, check for heavy metal content.	
133	03.02.13.00.	Mineral phase (See 03.02.13.01. through 03.02.13.06.)	Geochemistry of the mineral phase relevant to sequestered CO2, including ion exchange and mineral dissolution.	Geochemical reactions between sequestered CO2 and the mineral phase of the storage system will affect the evolution of the system and the sorption (and therefore mobility) of the CO2.	Mineralization in filled coal cleats include pyrite, calcite, siderite, and gypsum. Formation fluids are bicarbonate-rich and capable of precipitating out nahcolite (NaHCO3) and salt (NaCl).								
134	03.02.13.01.	Mineral dissolution and precipitation (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	The dissolution of minerals (grains or cement) due to the addition of CO2 (an acid gas) to the geochemistry and precipitation. For example, the dissolution of albite and precipitation of calcite modeled for the Sleipner site by Gaus et al. (2003). 1. Mineral dissolution and precipitation in the reservoir 2. Mineral dissolution and precipitation in or near the borehole 3. Mineral dissolution and precipitation in the caprock 4. Mineral dissolution and precipitation in faults and fractures	CO2 reaction with the host rock will modify the porosity and permeability of the reservoir; fluid flow (direction or velocity); mechanical properties (e.g. strength); and CO2 storage capacity.	Mineral dissolution and precipitation is likely to be minimal in the coal seams. Carbonates are not prevalent at this site. Some clastics contain feldspar grains that could be reactive with carbonic acid. The bicarbonate-rich produced water indicates that scaling could be a problem.								

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
131	03.02.11.28	ECBM cavitation (open hole cavity completion)	4	3	2	24	None	None	None	None	None	None	Downtime for recavitation or rework. Loss revenue of \$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Cost of recavitation and reworking wells. \$77k/incident per well. Cost of a replacement well \$762k per well	None	None	Revenue loss of \$150-385 per day of downtime per well. Cost of recavitation or reworking well \$77k/incident per well. Cost of a replacement well \$762k per well	None	Proper cavitation procedures. Part of ongoing costs.	Savings of \$150-\$385 per day of downtime eliminated per well. Savings of \$77k/ incident eliminated. Savings of \$762k per replacement well eliminated.	2
132	03.02.12.00.	Heavy metal release	2	1	3	6	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
133	03.02.13.00.	Mineral phase (See 03.02.13.01. through 03.02.13.06.)	0	0	0	0															
134	03.02.13.01.	Mineral dissolution and precipitation (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	0	0	0	0															

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135	03.02.13.02.	Precipitation of carbonate minerals (scale buildup)	CO2 reacts with brine to form hard water which can lead to scaling in or near a production well. Calcium carbonate and magnesium carbonate can be formed when HCO ₃ ⁻ reacts with Ca ²⁺ or Mg ²⁺ .	Scale buildup can cause reduced porosity and permeability in the reservoir, especially near the borehole.	The produced water contained 5,870 to 10,534 mg/L of HCO₃⁻ prior to CO2 injection. This is sufficiently high to cause scaling problems. Based on produced water chemistries, the probable precipitates are Nahcolite (NaHCO2): 1.54 kg/bbl evaporated and Salt (NaCl): 1.0 kg/bbl evaporated. Nahcolite is granite hard and barely soluble in strong acid. Scale and salt inhibiting chemicals have not worked well in CBM gas wells because the flow stream lacks the total energy needed to move the slurry and it becomes immobile sludge. (Simpson 2010).		Well and equipment plugging. Pore plugging.	Precipitation of carbonate minerals (scale buildup).	Decreased injectivity, decreased production, increased operating costs. Downtime for clean out.	Characterization and modeling taking into account mineral precipitation reactions, mineralogy, brine chemistry and CO2 interaction. Monitoring produced water chemistry and well performance.	Design the facility to support flushing piping/vessels with hot water and/or strong acid. Periodically clean out production facilities with strong acid.	Design the facility to support flushing piping/vessels with hot water and/or strong acid. Periodically clean out production facilities with strong acid. Use Teflon coating on internals.	
136	03.02.13.03.	Salt precipitation	Dry CO2 can pick up moisture from high salinity brines in the reservoir. This increases the salinity of the brines. (CCP 2009)	Increased salinity of brines can lead to precipitation of salt in pore space, which can decrease reservoir permeability and impair injection rates of CO2. (CCP 2009) "Dry out" and "salt out" may cause reduced porosity and permeability in the reservoir, especially near the borehole.	Na⁺ and Cl⁻ levels in the formation water are low compared to deep saline aquifers. Na⁺ content: 4,169-5,784 mg/L Cl⁻ content 2,521-3,212 mg/L Based on produced water chemistries, the probable precipitates are Nahcolite (NaHCO2): 1.54 kg/bbl evaporated and Salt (NaCl): 1.0 kg/bbl evaporated. Scale and salt inhibiting chemicals have not worked well in CBM gas wells because the flow stream lacks the total energy needed to move the slurry and it becomes immobile sludge. (Simpson 2010).		Well and equipment plugging. Pore plugging.	Salt precipitation.	Decreased injectivity, increased operating costs. Interruption of operations.	Include brine chemistry and potential for salt precipitation in characterizing and modeling. Monitor produced water chemistry and well injectivity.	Avoid high salinity reservoirs. Design the facility to support flushing piping/vessels with hot water. Periodically clean out production facilities with hot water.	Design the facility to support flushing piping/vessels with hot water and/or strong acid. Periodically clean out production facilities with strong acid. Use Teflon coating on internals.	
137	03.02.13.04.	Ion exchange (mineral dissolution and precipitation) (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	The process of exchanging one ion in the liquid phase for another ion on a charged, solid substrate. Injected CO2 may perturb ion exchange equilibrium between relevant minerals (such as sheet silicates) and the pore fluid. Some cations may be released to the pore fluid and others fixed as a consequence.	Disturbance of the rock-pore fluid equilibrium may affect the capacity of the rock to store CO2.	Mineralization in filled coal cleats include pyrite, calcite, siderite, and gypsum.								

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS/D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
135	03.02.13.02.	Precipitation of carbonate minerals (scale buildup)	5	3	2	30	None	None	None	None	None	None	Revenue loss due to well downtime: 43- 110 MCFD of CH4 @ \$3.50/MCF =\$150-385/D per well. Assuming 3 days to clean out a well: \$450- \$1,155 per cleanout per well.	Cleanout cost: \$5,000/well	None	None	Well cleanout every 6 months: \$5,000+\$800 = \$5,800 x 2=\$11,600/y per well. Cost for 16 production wells: \$186k/y Cost for 160 production wells: \$1.86M/y	Well cleanout every 24 months: \$5,800/2 = \$2,900/y per well. Cost for 16 production wells: \$46k/y Cost for 160 production wells: \$460k/y	Use Teflon coating to control buildup.	Savings: \$140k/y to \$1.4M/y minus cost of Teflon coating.	2	
136	03.02.13.03.	Salt precipitation	5	3	2	30	None	None	None	None	None	None	Revenue loss due to well downtime: 43- 110 MCFD of CH4 @ \$3.50/MCF =\$150-385/D per well. Assuming 3 days to clean out a well: \$450- \$1,155 per cleanout per well.	Cleanout cost: \$5,000/well	None	None	Well cleanout every 6 months: \$5,000+\$800 = \$5,800 x 2=\$11,600/y per well. Cost for 16 production wells: \$186k/y Cost for 160 production wells: \$1.86M/y	Well cleanout every 24 months: \$5,800/2 = \$2,900/y per well. Cost for 16 production wells: \$46k/y Cost for 160 production wells: \$460k/y	Use Teflon coating to control buildup.	Savings: \$140k/y to \$1.4M/y minus cost of Teflon coating.	2	
137	03.02.13.04.	Ion exchange (mineral dissolution and precipitation) (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	0	0	0	0																

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
138	03.02.13.05.	Desiccation of clay	CO2 is likely to be dried to prevent corrosion during transport. Injection of dry CO2 will cause it to take up water from the pores of the host formation and overlying rocks. It has the potential to suck water out of an overlying clay. CO2 can also be adsorbed by clay.	If clay dehydrates, it will shrink and crack. This might aid CO2 migration upwards.	Coal beds are separated by shale partings which contain clay. The Kirtland Lower Shale is argillaceous or silty argillaceous mudstone with clay matrix dominated by illite-smectite mixed-layered clays. The Kirtland Upper Shale is argillaceous or silty argillaceous mudstone with clay matrix dominated by smectite and illite or mica. The high content of expandable clays (smectite and illite) in the Kirtland Shales make them susceptible to desiccation or expansion. These clays have 15-40% expandability and represent 11-23% of the volume.		Shrinking of clay particles in caprock leading to CO2/CH4 leakage.	Desiccation of clay.	CO2/CH4 release.	Characterize clay content of caprock and reservoir. Model and observe impact of CO2 on clay desiccation. Monitor for CO2 leakage near wells.	Characterize caprock to evaluate clay content and potential for desiccation. Avoid repressurizing in areas where clay desiccation would be a problem.	Inject water to rehydrate clay.
139	03.02.13.06.	Mineral dissolution	The dissolution of minerals (grains or cement) due to the addition of CO2 (an acid gas) to the geochemistry. 1. Mineral dissolution in the reservoir 2. Mineral dissolution in or near the borehole 3. Mineral dissolution in the caprock 4. Mineral dissolution in faults and fractures	CO2 reaction with the host rock will increase: the porosity and permeability of the reservoir; increase fluid flow (direction or velocity); decrease mechanical properties (e.g. strength); and increase CO2 storage capacity.	Mineral dissolution is likely to be minimal in the coal seams. Carbonates are not prevalent at this site except as fillings in cleats and fractures, and faults. Some clastics contain feldspar grains that could react with carbonic acid. Caprock may be sensitive to carbonic acid due to the presence of iron-bearing chlorite (0-13%) in the caprock (Heath 2010)		Weakening and fracture/displacement of caprock. Reactivation of fault. Subsidence. Channeling within the reservoir.	Mineral dissolution.	CO2/CH4 leakage Decreased sweep efficiency due to channeling. Increase scale buildup in wells and equipment.	Characterization and modeling taking into account mineral dissolution reactions, mineralogy, brine chemistry and CO2 interaction. Monitoring CO2/CH4/brine movement, produced water, core sample analysis, elevation change, micro-seismicity.	Characterization and modeling taking into account mineral dissolution reactions, mineralogy, brine chemistry and CO2 interaction. Avoid sites where mineral dissolution could weaken the integrity of the caprock.	Monitoring well performance, bottomhole pressures and produced water chemistry. Use of gels or sealant to control unwanted CO2/CH4 flow.
140	03.02.14.00.	Gas chemistry (CO2 interacting with gases in the reservoir)	Gases such as CO2, methane and H2S, will occur naturally in the geosphere, either sorbed onto minerals, dissolved in formation fluids or as a free gas phase. Gas solubility will depend upon pressure, temperature and the salinity of the formation fluid. 1. CO2 interacting with free gases in the reservoir 2. CO2 interacting with gases sorbed onto minerals 3. CO2 interacting with gases dissolved in formation fluids 4. CO2 interacting with gaseous hydrocarbons in the reservoir	Gases naturally present in the geosphere could affect the behavior of CO2 injected into a storage reservoir and could accompany CO2 along potential migration paths. Corrosion from CO2 and associated gases has not been a problem in SJB. The main corrosion comes from microbiological induced corrosion (Simpson 2010).	The formation contains CH4, CO2, N2 and H2S. The CH4 may represent 43.94% of the gas adsorbed on coal and is displaced by CO2. The in-situ CO2 comes from biogenic-derived bicarbonate in the formation water. It may represent 56.01% of the adsorbed gas in the formation. N2 represents 0.05% of the adsorbed gas in the formation. H2S is dissolved in the formation water and is variable but minimal.		Corrosion of well production and recycle system components.	Gas chemistry (CO2 interacting with gases in the reservoir).	Release of CO2 and associated gases (HSE hazard). More complicated gas treatment and cleanup.	Characterize the reservoir for the presence of gases (particularly H2S). Monitor produced gas composition.	Use corrosion resistant materials of construction.	Monitor produced gas composition. Monitor piping and production equipment for corrosion and CO2/CH4 leakage.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
138	03.02.13.05.	Desiccation of clay	2	3	3	18	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$3M for leaky high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	Assuming leakage undetected or unmitigated for 5 years: <\$5.1M for water remediation, and locate and fix leak.	Assuming leakage detected early and mitigated <\$3.3M for water remediation and locate and fix leak	Monitor for CO2/CH4 in high- risk areas \$150k:	Savings of \$1.65M	2
139	03.02.13.06.	Mineral dissolution	2	3	3	18	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$3M for leaky high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	Assuming leakage undetected or unmitigated for 5 years: <\$5.1M for water remediation, and locate and fix leak.	Assuming leakage detected early and mitigated <\$3.3M for water remediation and locate and fix leak	Monitor for CO2/CH4 in high- risk areas \$150k:	Savings of \$1.65M	2
140	03.02.14.00.	Gas chemistry (CO2 interacting with gases in the reservoir)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
141	03.02.15.00.	Gas stripping in overlying formations	CO2 migration through the reservoir and into the overlying barrier sequence could result in the CO2 stripping other gases entrained within the sediments. This could include: 1. Radon stripping 2. Methane (CH4) stripping, and 3. Hydrogen sulfide (H2S) stripping.	The presence of other gases in a leaking CO2 gas stream is important in deciding the level of CO2 leakage that can be tolerated and may constitute an important hazard.	Radon gas indoor levels in San Juan County are higher than US average (1.3 pCi/L). EPA limit for indoor radon gas is 4.0 pCi/L. Indoor radon levels in San Juan County: 68% <2 pCi/L 20% from 2 to 3.9 pCi/L 12% > 4 pCi/L San Juan County is one of 8 counties in NM that have a predicted average indoor radon screening level greater than 4 pCi/L Pyrite in overlying formations could contribute to the presence of H2S gas.		Release of CO2/CH4 and stripped gases to ground/surface water and/or atmosphere.	Gas stripping	Water contamination. Atmospheric emissions.	Characterize site for the presence of gases in overlying formations. Monitor for H2S as an early detection of gas leakage or release.	Characterize site for the presence of gases that may be stripped and transported by CO2/CH4 (particularly H2S and radon). Maintain integrity of the caprock seal.	Monitor confined spaces in high-risk areas for CO2/CH4. If CO2/CH4 is detected, also check for radon and H2S.	
142	03.02.16.00.	Gas hydrates	Gas hydrates are 'ice-like' solids that form at low temperatures and high pressures. They are formed of 'cages' of water molecules surrounding a gas molecule. CO2 can form hydrates in the presence of water. The prevention of hydrate formation in the well during startup will need to be considered. It is likely that methanol spacers will need to be used. (CCP 2009) Hydrate potentially could form in the well when starting back up after a shut down. During the process of shutting down, measures should be taken to mitigate the formation of hydrates when starting back up. Often a methanol "cap" is pumped in the top of the tubulars. (CCP 2009) As a consequence of well control using a brine or similar fluid, there can be intermixing of the CO2 and the well control fluid that could result in hydrate formation or hydrate blocks. Using hydrate inhibited fluids or having operational practices that minimize the amount of CO2 inflow during workovers should be considered. (CCP 2009) There is a lack of experimental data and models for predicting the water solubility of CO2 at temperatures below 10°C. Moreover, there is a need to investigate hydrate formation conditions with CO2 near and below water saturated conditions in the presence of carbon steel surfaces. (DNV CO2PIPETRANS Phase 2) 1. Gas hydrates formed below deep water 2. Gas hydrates formed below permafrost 3. Gas hydrates formed in well during startup 4. Gas hydrates formed in pipeline	Cooling of the reservoir (e.g. by injecting cold CO2 or through adiabatic expansion) well below normal in-situ temperatures might stabilize gas hydrates. Their growth might seal fluid flow pathways (at least temporarily). If CO2 is injected below deep water or permafrost, then rising CO2 might hit the hydrate stability zone before escaping to the ocean or air, so hydrates could act as a secondary chemical barrier. Similarly, storage could be focused on actively forming CO2 hydrate as a stable, immobile phase to lock up the CO2 (Koide et al., 1997).	CO2 was injected at bottomhole pressures up to 14.82 MPa (2,150 PSIA) into a reservoir of 0.52-0.69 MPa (75-100 PSIG). (ARI 2010). Production system is low pressure.		Plugging of production wells or recycling system.	Gas hydrates.	Interruption of operations.	Determine conditions for formation of gas hydrates. Monitor for those conditions. Monitor for plugging of production wells and/or decreased injectivity.	Characterize the site for conditions which could lead to gas hydrate formation. Try to operate outside of the conditions leading to gas hydrate formation.	Monitor for conditions which could lead to gas hydrate formation and try to operate outside of those conditions. Remediate hydrates using methanol or other solvents. Obtain proper approvals if chemicals are injected.	
143	03.02.17.00.	Biogeochemistry	Features and processes related to the biological/biochemical processes that affect the CO2, borehole seals and rock/pore fluid, and the overall biological/biochemical evolution with time. This includes the effects of biological/biochemical influences on the CO2 and engineered components by the surrounding geology. Microbes exist in the subsurface and are used in hydrocarbon operations to improve hydrocarbon recovery (e.g., in EOR and ECBM operations). Microbes can also catalyze geochemical reactions, including methanogenesis, but the latter reaction is thermodynamically unfavorable and is unlikely.	Examples of relevant processes are: - microbial growth; - microbial/biological mediated processes; and - microbial/biological effects of evolution of redox (Eh) and acidity/alkalinity (pH) . etc. This FEP has probably low relevance to the safety/fate of CO2. However, CO2 releases may affect/impact microbe populations being used in independent hydrocarbon-recovery enhancement projects.	The water in the Fruitland Formation is evolved meteoric waters rich in biogenic HCO ₃ ⁻ . Methanogenic microbes may have contributed to part of the methane formation. Any CH4 or H2S generated by microbes is likely to be adsorbed on the coal or recovered in CBM production.		Plugging of CBM or water disposal wells. Plugging of pore spaces.	Biogeochemistry.	Decreased injectivity.	Characterize the site for microbe types and microbial growth. Monitor well performance.	Avoid injecting water containing microbes or nutrients that may stimulate microbial growth and activity. Treat water with biocides before injection. Get approval for subsurface chemical use.	Monitor well performance. Treat water with biocides before injection. Get approval for subsurface chemical use.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #		Risk Area/FEP		Risk Ranking			Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
					Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)		Savings with risk mitigation (\$)
									Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
141	03.02.15.00.	Gas stripping in overlying formations	2	3	3	18	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$3M for leaky high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	Assuming leakage undetected or unmitigated for 5 years: <\$5.1M for water remediation, and locate and fix leak.	Assuming leakage detected early and mitigated <\$3.3M for water remediation and locate and fix leak	Monitor for CO2/CH4 in high- risk areas \$150k:	Savings of \$1.65M	2		
142	03.02.16.00.	Gas hydrates	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1		
143	03.02.17.00.	Biogeochemistry	2	1	3	6	None	None	None	None	None	None	None	None	None	None	None	None	Pretreat injected water with chlorine biocide <\$0.03/t water	None	2		

PUMP CANYON CO₂-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
144	03.02.18.00.	Microbial processes	Microbes can metabolize CO₂, for example, methanogenic microbes use H₂ to reduce CO₂ to methane (CH₄), a process called methanogenesis. These microbes need anaerobic conditions. Microbes can produce SO_x, NO_x, and CO under oxic conditions and H₂S and CH₄ under anoxic conditions. Known methanogens become dormant at temperatures above approximately 65°C (150°F) with higher temperatures essentially sterilizing the reservoir. Thermophilic methanogens can thrive up to 100°C (212°F) but their role in biogenic coal gas generation is uncertain. (Seidle 2011). Microbes are known to populate deep geologic strata to depths of 2,743 m (9000 ft).	Methanogenesis, if it occurs, could affect the pressure distribution of CO ₂ . The fate and impact of the CH ₄ produced may be an endpoint of interest in itself.	The water in the Fruitland Formation is evolved meteoric waters rich in bacterially-derived HCO₃⁻. Methanogenic microbes may have contributed to part of the methane formation. The sorption affinity of H₂S on coal is greater than CO₂ on coal. Therefore any methanogenic H₂S generated in the coal seam will be adsorbed on the coal. Microbiological induced corrosion (MIC) in piping and equipment is the main microbial process of concern.		Microbiological induced corrosion (MIC)	Microbial processes.	Additional costs for corrosion mitigation.	Characterize the site for microbe types and microbial growth. Monitor produced gas composition.	Avoid injecting water containing microbes or nutrients that may stimulate microbial growth and activity. Remove any condensed water in piping and equipment. Use corrosion resistant pipe (non-stainless steel).	Monitor produced gas composition. Monitor corrosion in piping and equipment.
145	03.02.19.00.	Biomass uptake of CO ₂	If sequestered CO ₂ migrates to the biosphere, it can be taken up by microbes, plants and algae (including phytoplankton).	This mechanism may provide a sink for CO ₂ that has migrated from the sequestration system.	Very limited biomass in the area.		No failure mode. This is a positive FEP.	Biomass uptake of CO ₂ .	Positive effect on CO ₂ sequestration.	Characterize site for biomass content.	Maintain biomass on site that may collect leaked CO ₂ .	Add biomass to surface.
146	03.02.20.00.	Mobilization of particulates by CO ₂	Insoluble particulates could be mobilized by CO ₂ via chemical hydrodynamic interaction with the reservoir rock.	Particulate mobilization could increase permeability at the point of mobilization, but it could also decrease permeability in reservoir locations where particulates are deposited or trapped.	Coal fines accumulate in the wellbore during production, and must be cleaned out periodically. This requires a workover, which costs about \$50,000 (Logan 1989). These operations may be needed less frequently as time goes on, especially as water production and formation pressure decrease (Bland 1992).		Plugged well or production equipment.	Mobilization of particulates.	Decreased CBM production.	Monitor well performance and coal fines in produced gas and produced water.	Stabilize open well cavities and clean them out thoroughly before inserting the perforated tube.	Periodic well workover to clean out fines. Recavitate well. Hydrofracture stimulation. Scrub out fines in produced gas and/or produced water.
147	03.03.00.00.	CO ₂ transport	Transport processes that may affect sequestered carbon dioxide and associated impurities.	An understanding of those processes that could transport carbon dioxide, and associated impurities, within the geosphere, near-surface and surface environments is fundamental to the assessment of long-term performance and safety.	The free CO ₂ in the coal seam is in a gaseous phase.							
148	03.03.01.00.	Advection of free CO ₂	Advection of free CO₂ occurs in response to differences in pressure. The pressure difference may be due to differences in the pressure of injected CO₂ and formation pressures. The rate and direction of advection is affected by the physical properties of the rock, such as porosity and permeability. Advection may also occur through fractures. Fracture flow will be episodic with high transport efficiencies. Resealing of fractures (for example by cementation) will reduce and ultimately block fluid flow. 1. Advection causing change in CO₂ migration direction 2. Hydrodynamic gradients	Advective flow is a key transport process for migrating CO ₂ , and associated contaminants, in the geosphere (reservoir, surrounding and overlying rock), near-surface and surface environments.	Pump Canyon Site CO₂ was injected at bottomhole pressures up to 14.82 MPa (2,150 PSIA) into the coal seams that were pressurized at 0.52-0.69 MPa (75-100 PSIG). (ARI 2010). Approximately 99% of injected CO₂ is adsorbed on coal and approximately 1% remains as gaseous CO₂ in the cleat pore space.		CO ₂ migration different than planned.	Advection of free CO ₂ .	Decreased CBM recovery	Monitor CO ₂ migration through production wells.	Take into account advection of CO ₂ in site characterization and modeling and apply to CO ₂ injection strategy.	Monitor CO₂ content in production wells for early breakthrough. Shut in production well if CO₂ breakthrough is excessive.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
144	03.02.18.00.	Microbial processes	2	1	1	2	None	None	None	None	None	None	None	None	None	None	Corrosion repair <\$100k	None	Remove any condensed water in piping and equipment. Use corrosion resistant pipe. Part of ongoing costs.	None	1
145	03.02.19.00.	Biomass uptake of CO2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
146	03.02.20.00.	Mobilization of particulates by CO2	5	2	2	20	None	None	None	None	None	None	15 days at 43 to 110 MCFD @ \$3.5/MCF = \$2k- \$6k	Cost of workover for damaged CBM production wells \$50k to \$100k per well.	None	None	CBM production loss of 15.5-40 MMCFY @ \$3.5/MCF = \$55k to \$140k/y per well.	Revenue loss due to down time of 15 days for reworking: \$2k to \$6k	Cost to rework damaged CBM production wells \$50k to \$100k per well.	Savings of \$3k to \$34k per well.	2
147	03.03.00.00.	CO2 transport	0	0	0	0															
148	03.03.01.00.	Advection of free CO2	2	1	2	4	None	None	None	None	None	None	None	None	None	None	None	None	Monitor CO2 content in production wells for early breakthrough. Shut in production well if CO2 breakthrough is excessive. Part of ongoing costs.	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
149	03.03.01.01.	Fault valving and reactivation	Fault valving is a process resulting from gradual build up of pore pressure due to fluid generation, causing the subsequent opening of a fault along with fluid escape towards surface. This mechanism has been recognized as causing earthquakes in many parts of the world, as a result of hydrocarbon generation (e.g., in EOR or ECBM operations) or infiltration of other fluids. 1. CO2 leakage through an existing open fault 2. CO2 leakage through a reactivated fault	Large releases of pore fluids may occur during fault valving episodes.	Pump Canyon Site Post-stack processing of the 3D seismic suggests the presence of fracturing and minor faulting within the Kirtland Shale caprock, whereas indicators for extensive fracturing and faulting within the Fruitland sequence is much less apparent. However, interpreted faults and fracture zones, with limited vertical extent and major penetrative faults have not been observed at the site (ARI 2010) An inferred NW-striking structural hingeline is located 10 km (6 mi) S of the CO2 injection Site. This structural hingeline is interpreted to be a zone of complex, NW-trending, echelon normal faults, with net down drop to the NE of 21 m (70 ft) and zone width of 10-16 km (6 to 10 mi). That would put the edge of the fault zone within 2-5 km (1-3 mi) of the injection Site (under the communities of Navajo Dam and Turley). Fault valving or reactivation would require the Fruitland Formation to be repressurized.		CO2/CH4 leakage through a valving or reactivated fault.	Fault valving or reactivation.	CO2/CH4 release (HSE hazard).	Characterize and model the site for existing faults. Monitor for CO2/CH4 near fault. Monitor passive seismicity.	Characterize and model the site for existing faults. Avoid or isolate areas with faults penetrating the caprock. Avoid repressurizing the Fruitland Formation.	Monitor CO2/CH4 near fault. Monitor micro-seismicity or surface displacement (InSAR or LIDAR). Inject sealants into fault.
150	03.03.02.00.	Buoyancy-driven flow	Different relative densities of fluids in a geological system will result in buoyancy-driven flows as less dense fluids will have a tendency to flow upwards. The density of fluids will depend on its temperature and pressure. If a stream of CO2 begins to move upward, expansion of the volume and decrease in the density provides increasing energy to drive flow upward, which can result in gas lift, a strong process for moving fluid upward (NETL 2010). 1. CO2 exceeding reservoir spill point 2. Lateral CO2 flow across top of reservoir 3. CO2 buoyancy putting pressure on caprock	Carbon dioxide can be less dense than water, which may cause injected CO2 to flow upwards and accumulate above the water phase below the caprock of a reservoir. Water with dissolved CO2 is more dense than water, which can result in stratification of water bodies into which CO2 may leak, if conditions are suitable.	Free CO2 in the gas phase is very buoyant, but vertical compartmentalization within and between the coal seams limits buoyancy-driven flow. Approximately 99% of the injected CO2 is adsorbed on the coal and 1% remains in the gaseous phase in the cleat pore space. Primary concern is CH4 seeps rather than CO2 leakage. CO2 has a greater affinity to coal than does CH4. CH4 seeps have been reported in the area as early as 1880. CBM production lowered reservoir pressure but injection of CO2 could increase reservoir pressure, displace CH4 and increase CH4 seeps through existing vertical path ways.		Uncontrolled CO2/CH4 migration	Buoyancy-driven flow.	Decreased CBM recovery	Monitor CO2/CH4 migration through production wells. Select site with multiple stacked seals and sinks.	Take into account buoyancy-driven CO2/CH4 in site characterization and modeling and apply appropriate CO2 injection and CBM production strategy. Locate and seal leaks.	

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Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
149	03.03.01.01.	Fault valving and reactivation	4	3	3	36	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and/or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	\$4M to locate and fix leak and remediate.	\$3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high-risk areas \$150k.	Savings of \$0.85M	2
150	03.03.02.00.	Buoyancy-driven flow	2	3	3	18	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and/or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$3M for leaky fault.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	Assuming leakage undetected or unmitigated for 5 years: <\$5.1M to locate and fix leak and remediate.	Assuming leakage detected early and mitigated <\$3.3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high-risk areas \$150k.	Savings of \$1.65M	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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151	03.03.03.00.	Displacement of formation fluids	This depends on interfacial tension and capillary pressure. Capillary pressure is the pressure difference existing across the interface separating two immiscible fluids due to interfacial tension. The interfacial tension itself is caused by the imbalance in the molecular forces of attraction experienced by the molecules at the surface and is a function of temperature and pressure. At a given pressure, increased interfacial tension values between water and CO2 will make larger pores accessible to CO2 (this is only valid for water-wet systems). The change from a water-wet system to a CO2-wet system has an effect on capillary forces (i.e. displacement of water by enhanced pressure versus CO2 injection with less capillary pressure) and the displacement capacity (i.e. as a non-wetting fluid, CO2 will have less displacement capacity). If the injection velocity is high, effects of capillary forces are small.	Interfacial tension and capillary pressure determine the location of CO2 within the pore spaces of the reservoir and the displacement capacity of the reservoir.	The Pump Canyon Site CO2 effectively displace water in the micro-porosity of the coal and adsorb on the coal. Langmuir equations indicate that approximately 99% of the injected CO2 is adsorbed on the coal and 1% remains in the gaseous phase in the cleat pore space.		Failure of CO2 to displace water and CH4 from the coal surface.	Interfacial tension and capillary pressure.	Early breakthrough of CO2. Decreased CH4 recovery and decreased CO2 storage capacity.	Monitor produced gas composition.	Characterize and model interfacial tension and capillary pressure for CO2, and water. Avoid over injecting CO2 beyond the capacity of the coal to adsorb it.	Monitor produced gas composition. Shut in wells with excessive CO2 breakthrough.
152	03.03.04.00.	CO2 dissolution in formation fluids	The process of dissolution of CO2 in formation fluids. The rate of dissolution depends on factors such as the interfacial area between the CO2 and the formation fluids and temperature.	Dissolution in formation fluids can be an important positive process in decreasing the free CO2 remaining in the reservoir.	Pump Canyon Site Fruitland formation has been mostly dewatered at the Site. Formation fluids are rich in biogenic bicarbonate (HCO ₃ ⁻). Therefore, very little injected CO2 will be dissolved in the formation fluids.		Not a negative risk	CO2 dissolution in formation fluids.	Positive effect on CO2 sequestration.	Characterize and model site taking into account dissolution of CO2 into brine.	NA	Using well patterns more amenable for dissolution will reduce risks.
153	03.03.04.01.	CO2 exsolution from formation fluids	Long-term risks might result from the gravitational sinking of dense CO2 saturated brines; if they come into contact with salt formations this could lead to a degassing of the formation water and the ascent of CO2 outside of the original closed storage structure. (CO2STORE, page 68) Exsolution can also occur under significant (large) changes in pressure or temperature. The risk of major changes in pressure or temperature in a deep reservoir is very low.	Displaced brine containing dissolved CO2 flows to the surface and releases CO2 to the atmosphere or ocean.	Pump Canyon Site Fruitland formation has been mostly dewatered at the Site. Formation fluids are rich in biogenic bicarbonate. As reservoir pressures decrease, CO2 gas may be released from the formation fluids, but the amount will be minimal.		Increased CO2 content in CBM produced gas	CO2 exsolution from formation fluids	Increased cost for removal of CO2 from CBM.	Characterize and model site taking into account in-situ CO2 in formation fluids and adsorbed on coal. Monitor produced gas composition.	Maintain integrity of caprock and wells.	Monitor CO2/CH4 in high-risk areas. Isolate and rework leaky wells.
154	03.03.05.00.	Water mediated transport	Processes related to the transport of CO2, and associated contaminants, in groundwater and surface water, including advection, dispersion and molecular diffusion. Advection is the process by which contaminants are transported by the bulk movement of the water in which they are dissolved. Advective groundwater flow can occur along connected porous regions, such as fractures and faults. Dispersion is the collective name for the consequences of a number of processes that cause 'spreading-out' of CO2, and associated contaminants, dissolved in water in all directions, superimposed on the bulk movement predicted by a simple advection model. It results in a spatially distributed contaminant plume. Diffusion is the process whereby chemical species move under the influence of a chemical potential gradient (usually a concentration gradient).	The transport of CO2, and associated contaminants, within groundwater is likely to be a key migration process and therefore an important consideration in determining performance and safety. CO2 dissolves in brine at CO2/brine interface and brine transports CO2 out of closure.	Pump Canyon Site Fruitland formation has been mostly dewatered at the Site. Formation fluids are already rich in biogenic HCO ₃ ⁻ . Approximately 99% of injected CO2 is adsorbed on the coal and 1% remains as free gas in the cleat porosity. Water mediated transport is likely to be minimal.		Extensive ground/surface water contamination.	Water mediated transport.	Liability for contamination of ground/surface water with CO2/brine. Damage to drinking water and/or irrigation water supply.	Characterize and monitor ground/surface water for CO2 and salinity.	Maintain integrity of caprock and wells.	Monitor for CO2/CH4 in high-risk areas. Locate, isolate and rework leaky wells.

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									Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
151	03.03.03.00.	Displacement of formation fluids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	Shut in wells with excessive CO2 breakthrough. Monitor produced gas composition. Part of ongoing costs.	None	1		
152	03.03.04.00.	CO2 dissolution in formation fluids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2		
153	03.03.04.01.	CO2 exsolution from formation fluids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2		
154	03.03.05.00.	Water mediated transport	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1		

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
155	03.03.06.00.	CO2 release processes	Processes by which CO2 is lost from the sequestration system. Once in the near-surface, changes in pressure and temperature result in the potential for phase changes and degassing, with resulting changes in the transport properties of sequestered CO2. Examples of CO2 release processes include: 1. Surface blowouts (rapid release of CO2) 2. Undersea blowouts (rapid release of CO2) 3. CO2 geysers (such as Crystal Geyser in Utah) 4. Submarine gas release (Slow or moderate release of CO2) 5. Diffusion through soil (slow release of CO2) 6. CO2 released through mud volcano or mud flow. In fine-clastic unconsolidated rocks, suspensions could form and cause mud-volcanism and mud flows. (CO2STORE p.68) Mud diapir could be formed in unconsolidated (plastic, water-rich, under-compacted) reservoir and overburden strata possibly including the entire reservoir because of the buoyancy of store CO2. (CO2STORE, page 68)	The potential for CO2 to be lost from a sequestration system will determine the performance of that system. Rapid release of CO2 will tend to shoot CO2 into the atmosphere where it will quickly mix with air and diffuse. Slow release of CO2 will diffuse into soil gas. Moderate release of CO2 will tend to blanket the ground unless there is sufficient air circulation (wind). Thus moderate release of CO2 can be a greater safety risk than rapid or slow release.	CO2 has a higher adsorption affinity to coal than does CH4. CH4 is desorbed as CO2 is adsorbed on the coal. Approximately 99% of the injected CO2 is adsorbed on coal and 1% remains as free gas in the cleat pore space. CH4 is likely to be the main gas released. CH4 seeps have been reported in the areas since 1880. The typical release processes are leaky faults, fractures or wellbores, with CH4 slowly diffusing through the soil or water. Buildup in confined areas such as pump houses has caused fires. Rapid or medium release of CO2/CH4 is unlikely due to the low reservoir pressures of <0.69 MPa (<100 PSIG), 6% of initial pressure. This could change if the reservoir was significantly repressurized.		Human injury/death resulting from: Blowout or rupture (rapid release of CO2/CH4). Leak (moderate release of CO2/CH4). CO2/CH4 diffusion through soil (slow release of CO2/CH4).	CO2/CH4 release processes.	Injury to humans, fauna or flora. Damage to surface facilities. Liability costs.	Monitor for CO2/CH4 in high-risk areas, around wells and near faults or fractures.	Maintain integrity of caprock, wells, piping and equipment. Avoid repressurizing the reservoir. Ventilate confined areas. Monitor for CO2/CH4 in high-risk areas.	Monitor for CO2/CH4 in high-risk areas, around wells and near faults or fractures. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
156	03.03.06.01.	Limnic eruption	The rapid turnover and degassing of CO2 from a surface water body. Due to the high solubility of CO2 in water, a lake can dissolve a volume of CO2 that, in gaseous form, is more than five times its volume. CO2 rich water is denser than pure water which can result in an unstable stratification. A drop in temperature will reduce the solubility of CO2 in water. If the water reaches its solubility limit as a result, bubbles will nucleate. As the bubbles rise and grow, a chain reaction occurs where a sudden ex-solution of CO2 can result in a rapid degassing of the water body with an eruption of rising, expanding bubbles. Limnic eruptions can be triggered by events such as landslides that disturb the unstable stratification.	Limnic eruption provides a release mechanism for CO2, migrating from a storage system to the atmosphere. Natural limnic eruption events can be catastrophic. On the 29th of August 1986, a massive limnic eruption from Lake Nyos in Cameroon resulted in 1,800 deaths as the CO2 smothered local villages. The CO2, which is volcanic in origin, seeps through the lake bed sediments and builds up in the lower strata of the water column. The Lake Nyos sudden release involved an estimated 240,000 tonnes of CO2 (Damen 2006).	The nearest body of deep water is Navajo Reservoir, 8 km (5 mi) E of the Pump Canyon Site. At full capacity, the reservoir has a maximum depth of 118 m (388 ft) and a surface area of 63.15 km2 (15,600 acres). The reservoir water level nearest the CO2 site is at 1,859 m (6,100 ft) elevation and the deepest area is 1,768 m (5,800 ft) elevation. The reservoir is a river channel, therefore the bottom water is not as stagnant as Lake Nyos. Approximately 99% of the injected CO2 is adsorbed on the coal and 1% remains in the cleat pore space. Therefore the amount of free gaseous CO2 would be limited.		Massive release of CO2.	Limnic eruption.	Catastrophic asphyxiation.	Monitor CO2 content in the bottom of deep lakes above or near CO2 storage.	Avoid selecting CO2 sites below deep lakes. Ensure the integrity of the caprock. Agitate the lake water to prevent stratification and CO2 buildup.	Monitor buildup of CO2 in the bottom of deep lakes above or near CO2 site. Install siphon tubes to bring deep waters to the surface to allow gradual CO2 release and prevent stratification and CO2 buildup.
157	03.03.07.00.	Co-migration of other gases	Surface seepages of CO2 may contain significant amounts of other gases due to co-migration, such as hydrogen sulfide (H2S). This is especially the case where the CO2 reservoir is a reducing chemical environment. H2S is derived from the hydration of sulfide minerals (e.g. FeS) or from the chemical reduction of aqueous sulfate species. H2S is highly toxic and therefore potentially harmful to the biosphere. Even in low concentrations it is deleterious to long-term health (human/animal), in addition to being extremely unpleasant.	The co-migration of other gases to the surface environment may cause areas of leakage to become uninhabitable – at least temporarily. The detection of H2S provides a quick (non-analytical/aesthetic) test for CO2 escape and thus can be used as a “marker” gas.	The Fruitland and overlying formations contain CO2, methane and possibly small amounts of H2S. Presence of H2S has not been reported in the CBM gas composition, but it has been present in produced water and overlying formations. CH4 is present in Fruitland and overlying formations. Radon gas is also reported in San Juan county.		Build up of CO2/CH4/H2S/Rn and other gases into a confined area.	Co-migration of CO2 and other gases.	Injury to humans, fauna or flora. Damage to surface facilities.	Detection of H2S odor in the atmosphere or confined space. Monitor for CO2/CH4 in high-risk areas, around wells and near faults or fractures.	Maintain integrity of caprock, wells, piping and equipment. Avoid repressurizing the reservoir. Ventilate confined areas.	Monitor for CO2/CH4 in high-risk areas, around wells and near faults or fractures. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
155	03.03.06.00.	CO2 release processes	3	4	3	36	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and mitigate near surface leakage of CO2/CH4: \$3M	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	Assuming leakage undetected or unmitigated for 5 years: <\$6.8M to locate and fix leak and remediate.	Assuming leakage detected early and mitigated <\$3.3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high- risk areas \$150k:	Savings of \$3.35M	2
156	03.03.06.01.	Limnic eruption	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
157	03.03.07.00.	Co-migration of other gases	2	3	3	18	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	\$4M to locate and fix leak and remediate.	\$3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high- risk areas \$150k:	Savings of \$0.85M	2

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158	03.03.08.00.	Diffusion of CO2	Diffusion is the net movement of a constituent in response to a concentration gradient. Diffusion always results in mass transfer from the region of high concentration to regions of low concentration. Diffusion will occur in conjunction with flow, but it will also occur in the absence of flow, and it is the primary transport mechanism in the absence of flow (as through a highly impermeable rock).	Diffusion is a transport process by which CO2 can access portions of the reservoir that are not directly exposed to advective flow. It can also be a primary transport mechanism in highly impermeable rocks such as caprock.	The Kirtland Shale is 237.3 m (779 ft) thick, and has vertical permeability of 1E-06 mD or lower. CH4 already exists in the Kirtland Shale and overlying formations, suggesting there are scattered high permeability areas in the Kirtland Shale. The CO2 molecule is smaller than the CH4 molecule and more susceptible to diffusion. However, diffusion is a slow process (years), while CO2 adsorption on coal is a fast process (days).		CO2/CH4 movement through caprock.	Diffusion of CO2/CH4.	Leakage of CO2/CH4 above caprock.	Monitoring for CO2 above caprock.	Select site with thick, impermeable caprock and multiple stacked seals.	Monitor water aquifers above the caprock for CO2/CH4. Monitor and ventilate confined spaces above the reservoir.
159	04.00.00.00.	GEOSPHERE	This category of FEPs is concerned with the geology, hydrogeology and geochemistry of the geosphere. The category covers the reservoir, overburden and surrounding rock up to the near-surface which is considered in a separate FEP category. Taken together, the FEPs in this category describe what is known about the natural system prior to sequestration operations commencing. The category is divided into three classes: Geology, Fluids, and Geochemistry.	This category is divided into three classes: 1. Geology 2. Fluids 3. Geochemistry								
160	04.01.00.00.	Geology	Geological features of the geosphere, which comprises of the reservoir, overburden and surrounding rock prior to injection of CO2.	An understanding of the natural system into which the carbon dioxide is injected is essential for the assessment of long-term performance and safety.								
161	04.01.01.00.	Geographical location	The geographic location of a CO2 storage reservoir will influence the type of impacts to consider, e.g. continental or sub-marine, in the vicinity of a volcano, or tectonic activity, etc. In addition, proximity to human populations will increase importance of any release to the surface. 1. Onshore/ offshore reservoir 2. Fault zone 3. Volcanic or tectonic activity 4. Densely populated areas 5. Heavy industrial site/commercial site 6. Military base 7. Sensitive receptor (schools, hospitals, etc) 8. Threatened or endangered species critical habitat 9. National park/monument/forest 10. Historical/archaeological/cultural site 11. Protected groundwater zone 12. Wetlands/riparian area 13. Recreational area 14. Agricultural area/fishing area 15. Timberland 16. Wilderness area/wildlife preserve 17. Paleontology site 18. Navigable surface waters 19. Federal/private/tribal land ownership 20. Dam/reservoir	Proximity to natural hazards will increase their importance in being considered in the assessment. Proximity to human populations place more emphasis on the significance of near-surface releases. The potential impact on human beings of a sudden release of CO2 from an offshore reservoir will be lower than from an onshore reservoir (Damen 2006). However CO2 storage costs are likely to be higher for offshore reservoirs.	Sixteen Township Area Onshore reservoir Inferred hingeline fault zone Four communities in the area 6,201 deep wells (11 wells/mi2) Navajo dam and reservoir San Juan and Animas rivers Land is 70% federal/30% private Coal is 80% federal/20% private Reese Canyon habitat for threatened and endangered species Simon Canyon Areas of Critical Environmental Concern Negro Canyon scenic area Navajo Lake State Park Three recreational areas Eight archaeological sites Multiple riparian areas Multiple bald eagle habitats Wildlife area = 50% of area. Animas River agricultural area San Juan River special trout fishing water	No project planned at this time. Specific area and land ownership not available.	Siting the project in a high-risk area. Human injury/death.	Geographical location.	Failure of project to be permitted. Failure of project to be financed. Failure of project to proceed. CO2/CH4 leakage. HSE damage including loss of life.	Conduct detailed risk assessment on site selection. Monitor CO2/CH4 in high-risk areas.	Maintain integrity of the caprock, wells and surface facilities. Use proper materials of construction. Maintain tight seals and failsafe systems.	Monitor for CO2/CH4 in high-risk areas, around wells and near faults or fractures. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
158	03.03.08.00.	Diffusion of CO2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
159	04.00.00.00.	GEOSPHERE	0	0	0	0															
160	04.01.00.00.	Geology	0	0	0	0															
161	04.01.01.00.	Geographical location	3	4	3	36	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix leak: \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability zone.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	Assuming leakage undetected or unmitigated for 5 years: <\$6.8M to locate and fix leak and remediate.	Assuming leakage detected early and mitigated <\$3.3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high- risk areas \$150k:	Savings of \$3.35M	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
162	04.01.02.00.	Natural resources	Natural resources within the geosphere including: solid mineralogical resources, such as coal or minerals, fluid and gaseous resources, such as hydrocarbons (EOR and ECBM) or water, and other resources such as geothermal or microbial resources. Deep aquifers with high porosity suitable for CO2 storage would also be potentially suitable for geothermal energy production. (CO2STORE, page 70) Rights to pore space normally stay with the owner of the surface land. However, this may vary from state to state. Although saline water has few uses currently, these resources are protected by mining law in some EU states. And in some countries and states, brines legally are classified as groundwater and protected by law. (CO2STORE page 70). Depths for known natural major CO2 fields range from 200 to 5,000 m (656 to 16404 ft). (CCP 2009) 1. Mineral resources 2. Coal seams 3. Oil resources 4. Natural gas resources 5. Underground drinking water sources 6. Geothermal resources 7. Pore space owned by others 8. Saline water 9. Natural CO2	The presence of natural resources may mean that future human exploitation of the system cannot be ignored in assessing long-term performance since they may increase the possibility of future human intrusion. Owners of mineral rights could claim primacy over CO2 injection. Unmineable coal seams could become mineable with robotic mining systems. There may be adjacent oil properties owned by third-parties that could be contaminated by CO2 injection. Natural gas could be released when drilling and injecting CO2. CO2 mixed with natural gas would need to be captured and reinjected. Underground drinking water could be contaminated by CO2 or displaced brine. CO2 combined with water could lead to corrosion of geothermal systems. CO2 from adjacent injection projects could infringe the project's pore space. Increased demand for water and improvement in desalination technologies could convert deep saline aquifers into	Sixteen-Township Area 1. There are no mines, just 10 permitted quarries in the area. 2. Coal seams are unmineable and used for CBM. 3. Oil is not present in the site area 4. Conventional natural gas is produced from formations below the Fruitland Formation. 5. Marginal USDW aquifers in the area. 6. Geothermal resources are minimal. 7. Approximately 18% of the original gas in place may have been natural CO2. Fruitland formation fluids are rich in biogenic bicarbonate. The biggest concern would be a decreased third-party CBM production due to repressurizing the coal seams with CO2 injection.	No project planned at this time. Specific area, land and mineral rights ownership not available. Classification of USDW aquifers not clear in the area.	Decreased third-party CBM production due to repressurizing the coal seams with CO2 injection.	Natural resources adjacent to the injection site.	Liability for remediation, business interruption and advanced loss of profits.	Conduct detailed risk assessment on site selection. Monitor CO2/CH4 in high-risk areas.	Maintain integrity of the caprock, wells and surface facilities. Avoid repressurizing the coal seams until CBM operations have ended.	Monitor for CO2/CH4 in high-risk areas, around wells and near faults or fractures. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.	
163	04.01.03.00.	Reservoir type	The generic type of reservoir being considered for storage of CO2. Brownfield developments, for example in mature oil and gas fields, will offer the benefit of beginning with a well-characterized system and a significant amount of infrastructure. However, field redevelopments for CO2 storage will require a significant amount of work to assess the integrity and re-usability of existing well, flow lines and facilities. (CCP 2009) Greenfield developments, such as deep saline aquifers, require significant new infrastructure and additional initial characterization work and are associated with greater uncertainty. A steeper learning curve is to be expected and modifications to an initial development plan may occur as additional knowledge is gained during early development work. (CCP 2009) 1. Oil reservoir - EOR (such as the Weyburn project); 2. Gas reservoir (such as the Coal-Seq project); 3. Deep saline aquifer (such as at Sleipner); and 4. Coal seams - ECBM (such as the Coal-Seq and RECOPOOL projects). 5. Brownfield site 6. Greenfield site	The generic reservoir type will provide a high-level indication of the geological characteristics of the storage location. It will also contribute towards the extent and type of historical exploitation of any geological resources. Development of brownfield sites can expect to include a significant number of well re-completions, abandonments and possibly re-abandonment of old wells, new drilling and upgrades to surface infrastructure. (CCP 2009) Greenfield sites require more time and money to develop sufficient site characterization data but are less likely to have leakage through existing wells due to the lack of existing wells.	The Pump Canyon Site is a partially depleted CBM reservoir consisting of three coal zones subdivided into 6 coal beds (2 beds per zone separated by shale partings). The Nine-Section Area has 85 deep wells and 3D seismic surveys completed .		NA	NA	NA	NA	Take into account the reservoir type and historical uses in characterizing, modeling and selecting a site.	NA	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
162	04.01.02.00.	Natural resources	1	5	1	5	None	None	None	None	Typical CBM fairway well production: 2013-2022: 260MMCF@ \$3.50/MCF = \$0.91M revenue loss per well if coal seams are repressurized early.	None	None	Typical CBM fairway well production: 2013- 2022: 260MMCF@ \$3.50/MCF = \$0.91M revenue loss per well if coal seams are repressurized early.	None	None	Revenue loss for a set of 16 CBM wells: \$15M Revenue loss for a set of 160 CBM wells: \$146M	None	Delay CO2 injection until CBM is nearly depleted (after 2021)	Savings could exceed \$100M.	2
163	04.01.03.00.	Reservoir type	1	1	1	1	None	None	None	None		None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis																																	
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)																												
164	04.01.04.00.	Reservoir geometry	Geometry of the CO2 storage reservoir including the spatial distribution, depth and the topography of the top.	The geometry of the storage reservoir helps to determine the capacity of the geosphere. The geometry of the top is particularly important because supercritical CO2 is buoyant and will therefore migrate to the top of a reservoir. Once at the top of the reservoir, it will migrate according to the precise topography of the top. Local "highs" could produce small-scale traps within the overall aquifer, bigger structures would produce bigger traps. Spill points are determined by the lowest point that can retain the sequestered CO2.	Pump Canyon Site The Pump Canyon consists of 3 coal zones subdivided into 6 coal beds (2 beds per zone separated by shale partings). The coal beds are somewhat contorted. The top of the reservoir is dipping 0.93% or 0.53 degrees from the SW to the NE. The geometry is well characterized in the Nine-Section Area with 3D seismic surveys.	No project planned at this time. Specific area, land and mineral rights ownership not available.	Migration of CO2 outside of project site.	Improper reservoir geometry for CO2 storage.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Monitoring and modeling CO2/CH4 migration.	Take into account reservoir geometry in characterizing, modeling.	Monitor production well performance. Monitor for CO2/CH4 in high-risk areas.																												
165	04.01.04.01.	Reservoir depth (Reservoir hydrostatic pressure)	The hydrostatic pressure varies with depth. It is desirable to store CO2 at depths greater than approximately 800-1000 m where the hydrostatic pressure will maintain CO2 in a supercritical (dense) phase. (CCP 2009). Excessive depth will result in excessive hydrostatic pressure, which will require higher CO2 injection pressure. 1. Insufficient reservoir depth 2. Insufficient hydrostatic pressure 3. Excessive reservoir depth 4. Excessive hydrostatic pressure	Insufficient reservoir depth may result in pressures that are too low for keeping CO2 in a supercritical state. Excessive depth will require higher CO2 injection pressure and increase cost of CO2 injection..	The reservoir is at a depth ranging from 903 m (2,961 ft) at the top of the upper coal bed to 965 m (3,166 ft) at the bottom of the lowest coal bed. Initial hydrostatic pressure was 11.33 MPa at 918 m depth (1,644 PSIA at 3,012 ft depth). Hydrostatic pressure was only 0.69 MPa (100 psig) at the start of the CO2 injection test due to previous CBM dewatering. Note that CO2 was injected as a supercritical fluid (800kg/m3) but transformed to a gas (12kg/m3) inside the reservoir.		Low pressure, low methane OGIP Low permeability, low injectivity	Shallow coal seams Deep coal seams	Decreased CBM production. Increased costs.	Characterize and model coal seam depth.	Avoid sites where coal seam depth are too shallow or too deep.	Hydraulic stimulation for deep seams.																												
166	04.01.04.02.	Reservoir thickness	Normally, a formation thickness of around 20 m (66 ft) would be considered as a minimum requirement, but this varies with injection volume requirements. 1. Insufficient reservoir thickness	Insufficient reservoir thickness will result in an extended CO2 plume and limit the storage capacity of the reservoir	Nine-Section Area The six coal beds in the Fruitland Formation are distributed across 61 m (200 ft) of thickness. The net coal thickness varies from 14 to 20m (45-65ft). The thickness of the coal beds from top to bottom is as follows (in meters): <table><tr><td>Bed ID</td><td>Avg.</td><td>Max.</td><td>Min.</td></tr><tr><td>F</td><td>2.7</td><td>3.7</td><td>2.0</td></tr><tr><td>E</td><td>2.1</td><td>2.7</td><td>1.5</td></tr><tr><td>D</td><td>1.2</td><td>2.0</td><td>1.1</td></tr><tr><td>C</td><td>1.4</td><td>2.3</td><td>0.9</td></tr><tr><td>B</td><td>3.4</td><td>4.3</td><td>2.7</td></tr><tr><td>A</td><td>4.0</td><td>5.5</td><td>3.0</td></tr></table>	Bed ID	Avg.	Max.	Min.	F	2.7	3.7	2.0	E	2.1	2.7	1.5	D	1.2	2.0	1.1	C	1.4	2.3	0.9	B	3.4	4.3	2.7	A	4.0	5.5	3.0		Decreased injection rate.	Insufficient coal seam thickness.	Increased costs. Decreased revenues.	Characterize the coal seam thickness to confirm it meets recommendation.	Characterize the coal seam thickness to confirm it meets recommendation. Avoid sites with thin coal seams.	Avoid sites with thin coal seams.
Bed ID	Avg.	Max.	Min.																																					
F	2.7	3.7	2.0																																					
E	2.1	2.7	1.5																																					
D	1.2	2.0	1.1																																					
C	1.4	2.3	0.9																																					
B	3.4	4.3	2.7																																					
A	4.0	5.5	3.0																																					
167	04.01.04.03.	Reservoir lateral continuity (spatial distribution)	Lateral flow barriers can include unconformities or pinch-outs that erode the porous and permeable material and provide direct contact to a low permeability seal, faults and naturally over pressured zones. 1. Insufficient reservoir lateral continuity	Insufficient lateral continuity (or spatial distribution) of a reservoir will limit its CO2 storage capacity	Sixteen-Township Area The coal seams are complex and laterally discontinuous due to pinchouts, local fault truncations, channel scour, and facies changes. This may require additional injection wells to get proper coverage. The number of coal seams in a given area can range from 0 to 16.	Insufficient site data to confirm lateral continuity of the reservoir beyond the Nine-Section Area.	Compartmentalization. Poor sweep efficiency. Decreased CH4 recovery. Decreased CO2 storage capacity.	Lack of reservoir lateral continuity (spatial distribution).	Decreased profitability.	Historical drilling records, drill core analyses, well logging and seismic surveys. Monitor CBM well performance.	Take into account reservoir lateral continuity in characterizing, modeling and injection strategy. Avoid CO2 injection in coal seams lacking lateral continuity.	Monitor CBM well performance. Monitor for CO2/CH4 in high-risk areas. Add more injection wells.																												

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info		
			Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P x S x D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)		Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)
									Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
164	04.01.04.00.	Reservoir geometry	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
165	04.01.04.01.	Reservoir depth (Reservoir hydrostatic pressure)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
166	04.01.04.02.	Reservoir thickness	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
167	04.01.04.03.	Reservoir lateral continuity (spatial distribution)	4	4	2	32	None	None	None	None	None	None	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160k. Depending on size of the operation, additional injection wells could cost: \$10M- \$100 M	None	None	None	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160k. Depending on size of the operation, additional injection wells could cost: \$10M- \$100 M	None	2		

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
168	04.01.04.04.	Reservoir top topography	Reservoirs with dipping top topography (monocline) are susceptible to buoyancy-driven up dip CO2 migration. The migration up dip may enhance CO2/brine contact and CO2 dissolution in the brine. The preferred top topography is an anticline or dome structure to restrict the flow of injected CO2 on multiple sides. Spill point is the lowest point that can retain sequestered CO2. 1. Flat 2. Monocline 3. Dome 4. Anticline 5. Shallow spill points	Flat top topography of the reservoir may make it difficult to contain the CO2 plume Dipping top topography of the reservoir may make it difficult to trap buoyant CO2. Injected CO2 migrates up dip out of closure. Shallow spill point in a dome structure may limit the amount of CO2 that can be locally contained in a reservoir	Pump Canyon Nine-Section Area The tops of the coal zones are contorted monoclines with amplitude up to 10 m in elevation. The monoclines dips 0.93% or 0.53 degrees from the SW to the NE		Uncontrolled buoyant migration of CO2 beyond project area.	Reservoir top topography.	CO2 leakage (HSE hazard). Contamination of adjacent pore space, natural resources (including water).	Historical drilling records, drill core analyses, well logging and seismic surveys.	Take into account reservoir top topography in characterizing and modeling.	Monitor for CO2/CH4 in high-risk areas.
169	04.01.04.05.	Reservoir buffer zone for CO2 plume	The buffer zone represents additional land owned or leased beyond the ultimate extent of the CO2 plume. 1. Insufficient buffer zone for CO2 plume	Insufficient buffer zone may result in CO2 plume infringing on third-party pore space.	Pump Canyon Site No buffer zone was used in CO2 injection at the Pump Canyon site due to the limited volume injection. Approximately 99% of the injected CO2 is adsorbed on coal and 1% remains as gaseous CO2 in the cleat pore space.		CO2 migration beyond project area.	Insufficient reservoir buffer zone.	CO2 leakage (HSE hazard). Contamination of adjacent pore space, natural resources (including water).	Historical drilling records, drill core analyses, well logging, seismic surveys and modeling to estimate ultimate extent of CO2 plume. CO2 monitoring to determine actual extent of CO2 plume.	Include a buffer zone in project planning.	Purchased additional buffer zone if needed.
170	04.01.04.06.	Reservoir CO2 storage capacity	Reservoir CO2 storage capacity is primarily determined by pore volume. 1. Insufficient reservoir storage capacity.	Insufficient reservoir storage capacity will require alternative storage site(s). Increased storage costs.	Pump Canyon Section 32 CO2 storage capacity at current pressure of 0.69 MPa (100 PSIG) and 52.2°C (126°F): 38,343 t CO2/km2 (109,419 ST CO2/mi2) (Calculated based on multi-component Langmuir isotherms for ultimate free gas mixture of 50% CO2, 49.% CH4, 1%N2). Assumes 40% storage efficiency. CO2 storage capacity at initial pressure of 11.33 MPa (1644 PSIA) and 52.2°C (126°F): 160,145 t CO2/km2 (457,006 ST CO2/mi2) (Calculated based on multi-component Langmuir isotherms for ultimate free gas mixture of 50% CO2, 49.% CH4, 1%N2). Assumes 40% storage efficiency.		High CO2/CH4 ratio Low CO2/CH4 ratio	High CO2 storage capacity of coal Low CO2 storage capacity of coal	Increased CH4 production costs. Increased CO2 storage costs.	Determine the CO2 storage capacity of coal through core sample testing. Model CO2 adsorption. Monitor actual versus projected well performance.	Characterize and model the coal seam to estimate storage capacity. Select coal seams with sufficient CO2 storage capacity.	Repressurize the coal seam to enhance CO2 storage capacity after CBM has been depleted.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
168	04.01.04.04.	Reservoir top topography	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
169	04.01.04.05.	Reservoir buffer zone for CO2 plume	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	NA
170	04.01.04.06.	Reservoir CO2 storage capacity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
171	04.01.04.07.	Reservoir lateral sealing	Lateral flow barriers can include unconformities or pinch-outs that erode the porous and permeable material and provide direct contact to a low permeability seal, faults and naturally over pressured zones. 1. Open reservoir (lack of lateral sealing of reservoir) 2. Closed reservoir 3. Semi-closed reservoir	Potential for CO2 plume to infringe on third-party pore space or escape if lateral seal is lacking.	Pump Canyon Site Lateral sealing is not a significant issue with ECBM because approximately 99% of the injected CO2 is adsorbed on coal and 1% remains as gaseous CO2 in the cleat pore space. An inferred NW-striking structural hingeline is located 10 km (6 mi) S of the CO2 injection Site. This structural hingeline is interpreted to be a zone of complex, NW-trending, echelon normal faults, with net down drop to the NE of 21 m (70 ft) and zone width of 10-16 km (6 to 10 mi). That would put the edge of the fault zone within 2-5 km (1-3 mi) of the injection Site (under the communities of Navajo Dam and Turley).		CO2 migration beyond project area.	Lack of reservoir lateral sealing.	CO2 leakage (HSE hazard). Contamination of adjacent pore space, natural resources (including water)	Historical drilling records, drill core analyses, well logging, seismic surveys and modeling to estimate ultimate extent of CO2 plume. CO2 monitoring to determine actual extent of CO2 plume.	Take into account lateral sealing in characterizing and modeling. Select reservoir with lateral sealing.	Monitor and model CO2 plume and brine movement. Use injection water curtains to keep CO2 flow within patterns. Monitor for CO2/CH4 in high-risk areas.
172	04.01.04.08.	Reservoir and caprock structural geology complexity	In tectonically complex areas, there are too many small structures to be identified, delineated and investigated individually. 1. Reservoir and caprock structural geology too complex	Complex structural geology may result in greater difficulty in modeling, monitoring and controlling CO2 storage.	The reservoir is a monocline dipping 0.93% or 0.53° from SW to NE. It consists of three coal zones subdivided into 6 coal beds (2 beds per zone separated by shale partings). The coal beds are subject to pinchouts, channel scour, facies changes, local fault truncations, and moderate folding. The 237.3 m (779 ft) thick Kirtland Shale conformably overlies the Fruitland Formation and serves as the primary seal or caprock. The Kirtland Shale consists of upper and lower shale members separated by a middle sandstone member known as the Farmington Sandstone (Stone 1983). The Lower Shale is absent 27 km (17 mi) E of the CO2 injection site and the entire Kirtland Formation is missing 43 km (27 mi) E of the CO2 injection site (Heath 2010).		Compartmentalization. Poor CO2 sweep efficiency. Decreased CH4 recovery. Leakage of CO2/CH4 into overlying formations if coal seams are repressurized.	Complex structural geology of coal seams	Decreased CO2 storage capacity. Decreased CH4 production. Surface release /buildup of CO2/CH4. Contamination of ground water. Pump house fires.	Fully characterize and model the site early in the design phase. Monitor and model well performance. Avoid sites with complex structural geology in high-risk areas. Avoid repressurizing coal seams in high-risk areas.	Fully characterize and model the site. Use high-resolution 3D seismic surveys to characterize complex or high-risk areas.. Avoid sites with complex structural geology in high-risk areas. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.	Monitor and model CO2/CH4 movement and well performance. Monitor near surface for CO2/CH4 leaks. Install alarms in high-risk areas. Locate and mitigate leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
173	04.01.04.09.	Reservoir compartmentalization	A once continuous reservoir can become compartmentalized. CO2 migration restricted to an isolated part of the formation. Unexpected bottom hole pressure increase. Pressure transient analysis suggests hydraulically isolated wells.	Greater difficulty in modeling, monitoring and controlling CO2 storage.	The three coal zones in the Fruitland Formation are separated by interbedded clastics of shale, sandstone and siltstone averaging 13.7 m thick and ranging from 6.1 to 21.3 m thick. The coal beds within each zone are vertically compartmentalized by shale partings averaging 1.1 to 2.1 m thick and ranging from 0.6 to 10.4 m thick. The lower coal beds pinch out NE of the site.		Pore CO2 sweep efficiency. Decreased CBM recovery. Decreased CO2 storage	Reservoir compartmentalization.	Decreased profitability.	Characterization and modeling of reservoir for compartmentalization. Monitoring well performance.	Characterization and modeling of reservoir for compartmentalization to optimize reservoir engineering. Sufficient wells exist to overcome any problems with compartmentalization.	Monitor well performance. Add wells or convert wells if necessary.
174	04.01.04.10.	Reservoir temperature (See 04.01.13.00.)			The reservoir temperature is 52.2°C (126°F)							

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking			Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
171	04.01.04.07.	Reservoir lateral sealing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
172	04.01.04.08.	Reservoir and caprock structural geology complexity	4	3	3	36	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$0.3M for leaky well or \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	\$4M to locate and fix leak and remediate.	\$3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high- risk areas \$150k;	Savings of \$0.85M	2
173	04.01.04.09.	Reservoir compartmentalization	4	4	2	32	None	None	None	None	None	None	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160k. Depending on size of the operation, additional injection wells could cost: \$10M- \$100 M	None	None	None	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160k. Depending on size of the operation, additional injection wells could cost: \$10M- \$100 M	None	2
174	04.01.04.10.	Reservoir temperature (See 04.01.13.00.)	0	0	0	0															

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
175	04.01.04.11	Reservoir rock thermal properties	Rock thermal properties included: 1. Thermal conductivity 2. Heat capacity 3. Thermal expansion coefficient	These properties will dictate how fast the rock will change temperature in response to injected CO2 that is warmer or cooler than the reservoir, and they will also dictate whether fracture or pore permeability will increase or decrease as a result of temperature changes in the rock mass.	Thermal conductivity range of the Fruitland Formation: 2.01-2.13 W/mK (Haerer 2009).	Data on rock thermal properties not available.	Fracture of reservoir and/or seal rock due to thermal shock.	Slow increase or decrease in rock temperature and expansion or contraction when CO2 is injected. Fast increase or decrease in rock temperature and expansion or contraction when CO2 is injected.	Increase or decrease in rock temperature, injectivity and rock volume. Potential leakage through caprock into USDW aquifers or biosphere.	Measure thermal properties of reservoir rock samples and include the results in modeling. Monitor aquifer chemistry and atmospheric concentrations of CO2/CH4.	Characterization and modeling of reservoir rock thermal properties. Keep CO2 injection temperature and rate compatible with desired reservoir temperature.	Monitor reservoir temperature. Adjust CO2 injection temperature to control rock temperature if necessary.
176	04.01.05.00.	Reservoir exploitation	Degree to which geological resources (such as oil and gas) have been exploited prior to the injection of CO2. 1. Existing boreholes 2. Oil previously removed 3. Gas previously removed 4. Existing mine workings (for ECBM) 5. In-situ gasification (for ECBM) 6. Natural gas storage 7. Compressed air storage 8. Radioactive waste storage 9. Hazardous waste disposal (Class 1 wells) 10. Water extracted	The extent of previous exploitation will help to determine the initial state of a storage reservoir. For example: - the existence and nature of boreholes; and - the presence of geological resources, such as oil and gas. Previous exploitation of the storage reservoir area will improve the amount of historical information available concerning the reservoir characteristics.	The area is covered with a large number of deep wells used for CBM, conventional gas and tight gas production. Pump Canyon Section 32 Active wells: 10 Temp. abandoned wells: 1 Plugged wells: 2 Total wells: 13 Well density: 13 wells/mi2 Pump Canyon Nine-Section Area Active wells: 76 Temp. abandoned wells: 1 Plugged wells: 8 Total wells: 85 Well density: 9 wells/mi2 Pump Canyon Sixteen-Township Area: Active wells: 5,308 New wells planned: 71 Temp. abandoned wells: 25 Plugged wells: 797 Total wells: 6,201 Well density: 11 wells/ mi2		Pre-CO2 injection caprock or reservoir damage.	Reservoir previous exploitation.	CO2/CH4 leakage near existing wellbores..	Survey historical records and documents on the site that may indicate potential problems or risks for CO2 storage. Conduct baseline survey for pre-CO2 injection site contamination and damage.	Take into account reservoir previous exploitation in characterizing and modeling. Monitor , analyze and fix at risk wells before leakage becomes significant.	Monitor well performance. Monitor for CO2/CH4 in high-risk areas.
177	04.01.06.00.	Caprock or sealing formation	The nature of the relatively impermeable layer of rock overlying the storage reservoir that forms a barrier to the upward migration of buoyant fluids, such as sequestered CO2.	The caprock or sealing formation plays a key roll in preventing the sequestered CO2 from migrating to the surface environment.	The 237.3 m (779 ft) thick Kirtland Shale conformably overlies the Fruitland Formation and serves as the primary seal or caprock. The Kirtland Shale consists of upper and lower shale members separated by a middle sandstone member known as the Farmington Sandstone (Stone 1983).		CO2/CH4 migration through caprock.	Caprock or sealing formation lack of integrity	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock for sealing integrity. Track historical CH4 seeps. Monitor for CO2/CH4 in high-risk areas.	Characterize and model caprock for sealing integrity. Track historical CH4 seeps. Avoid injecting CO2 in areas lacking sealing integrity. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking			Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
175	04.01.04.11	Reservoir rock thermal properties	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
176	04.01.05.00.	Reservoir exploitation	4	3	2	24	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$0.3M for leaky well.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	Assuming leakage undetected or unmitigated for 5 years: <\$2.2M to locate and fix leak and remediate.	Assuming leakage detected early and mitigated <\$0.6M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high-risk areas \$150k:	Savings of \$1.45M	2
177	04.01.06.00.	Caprock or sealing formation	4	3	3	36	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	\$4M to locate and fix leak and remediate.	\$3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high-risk areas \$150k:	Savings of \$0.85M	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
178	04.01.06.01.	Caprock geometry	Geometry of the caprock including the spatial distribution, depth and the topography of the bottom.	CO2 migration diverges from expected path. Significant CO2 volumes migrate off structure. Insufficient capacity for planned injection volume of CO2. Unexpected pressure increase during injection.	The Kirtland Shale is 237.3 m (779 ft) thick. The top of the Kirtland Shale is 627m (2,056 ft) below the surface. The bottom topography of the Kirtland Shale dips 0.93% or 0.53* from the SW to the NE in Section 32.		CO2/CH4 migration around caprock	Caprock geometry.	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Monitor for CO2/CH4 in high-risk areas.	Characterize and model caprock geometry. Monitor pressure in formations above the caprock. Monitor for CO2/CH4 in high-risk areas.	Characterize and model caprock geometry. Avoid sites where caprock geometry is not amenable for CO2 storage. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.	
179	04.01.06.02.	Caprock thickness	Greater thickness improves the strength and sealing capacity of the caprock. Preferred caprock thickness:> 100m Minimum caprock thickness: >20m	Insufficient caprock thickness could lead to caprock failure and/or release of CO2 from the reservoir.	The Kirtland Shale is 237.3 m (779 ft) thick in Section 32. The Kirtland Formation is absent in the SE side of the San Juan Basin. It increases in depth from the SE to the NW.		CO2/CH4 migration through caprock.	Thin caprock.	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Monitor for CO2/CH4 in high-risk areas.	Characterize the caprock thickness based on historical drilling records, drill core analyses, well logging, seismic surveys and modeling. Monitor for CO2/CH4 in high-risk areas.	Include caprock thickness in characterization and modeling. Avoid sites with thin caprock, unless reinforced with multiple stacked secondary seals. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.	
180	04.01.06.03.	Caprock discontinuous	Caprock discontinuities can be caused by unconformities or pinchouts.	CO2 escapes through gap in caprock into higher formation or aquifer	The caprock is laterally continuous over the site area. The Lower Shale is absent 27 km (17 mi) E of the CO2 injection site and the entire Kirtland Formation disappears 43 km (27 mi) E of the CO2 injection site (Heath 2010).		CO2/CH4 upward migration through discontinuous portion of caprock.	Discontinuous caprock.	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Monitor for CO2/CH4 in high-risk areas.	Characterize and model caprock for continuity based on historical drilling records, drill core analyses, well logging, seismic surveys. Monitor for CO2/CH4 in high-risk areas.	Characterize and model caprock for continuity. Avoid sites with discontinuous caprock that might impact CO2 storage integrity. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
178	04.01.06.01.	Caprock geometry	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
179	04.01.06.02.	Caprock thickness	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
180	04.01.06.03.	Caprock discontinuous	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
181	04.01.06.04.	Caprock geochemical properties	CO2 chemical reaction with caprock can weaken the physical strength of the caprock. High permeability zones might exist or be formed by reaction of CO2 with the caprock, causing the caprock to dissolve. CO2 can dehydrate clay shales in the caprock, thereby increasing its permeability. (Damen 2006)	Unintended migration of CO2 by chemical reaction induced breaching of the caprock.	Pump Canyon Site Kirtland Upper Shale Argillaceous mudstones or sandy argillaceous mudstones. Clay matrix dominated by smectite and illite or mica. Kirtland Lower Shale Argillaceous or silty argillaceous mudstone. Clay matrix dominated by illite-smectite mixed-layered clays. Cement: dominated by quartz with some overgrowths replacing portions of the volcanic rock. Very little carbonate (0-3% at most). The risk of fresh water sensitivity is high due to large amounts of expandable clays. Smectite and mixed layer illite/smectite with 15-40% expandability are the predominant clay species. Total expandable clays of 11-23% were determined by XRD analysis. Expected sensitivity to acid-based fluids is high, due to the presence of significant amounts (0-13%) of iron-bearing chlorite.		Geochemical failure of caprock.	Caprock geochemically reactive with CO2.	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterization and modeling of caprock geochemical properties based on drill core analyses. Monitor for CO2/CH4 in high-risk areas.	Characterization and modeling of caprock geochemical properties based on drill core analyses. Avoid sites with caprock that would be highly reactive with CO2. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
182	04.01.06.05.	Caprock geomechanical properties	Low fracturing pressure	Could limit CO2 injection rate. Increased CO2 injection cost. In general, the mechanical behavior of shale will show more elastic change and is more resistant to elevated pressure than other brittle hard rock.	Pump canyon Site The Kirtland Shale has fracturing and minor faulting (ARI 2010). The fractures in core samples are probably pressure-release and dehydration features.(Koperna 2008).		Mechanical failure of caprock.	Caprock geomechanical weakness.	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterization and modeling of caprock geomechanical properties based on drill core analyses. Monitor for CO2/CH4 in high-risk areas.	Characterization and modeling of caprock geomechanical properties based on drill core analyses. Avoid sites with mechanically weak or over stressed caprock. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
183	04.01.06.06.	Caprock Permeability	The permeability of a caprock capable of retaining fluids through geologic time is approximately 0.001 to 0.00001 milli-darcies (mD). Mudstone caprock permeability is typically less than 0.001 mD.	Permeable zones in the caprock could form CO2 pathways of escape.	Vertical permeability of 4E-17 to 2E-15 m2 (4E-02 to 2 mD) (Kernodle 1996). Horizontal permeability of 7E-14 m2 (70 mD) (Kernodle 1996). Kirtland Upper Shale: 9.15E-05 mD (Heath 2010). Kirtland Lower Shale: 8.25E-05 mD (Heath 2010). Kirtland permeability ~1E-20 m2 (1E-06 mD) or lower. (Heath 2010).		CO2/CH4 migration through high permeability zone in caprock.	Caprock permeability.	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock permeability. Monitor for CO2/CH4 in high-risk areas.	Characterize and model caprock permeability. Avoid or isolate areas with high caprock permeability. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
181	04.01.06.04.	Caprock geochemical properties	2	3	3	18	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	\$4M to locate and fix leak and remediate.	\$3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high-risk areas \$150k:	Savings of \$0.85M	2	
182	04.01.06.05.	Caprock geomechanical properties	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
183	04.01.06.06.	Caprock Permeability	3	3	3	27	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	\$4M to locate and fix leak and remediate.	\$3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high-risk areas \$150k:	Savings of \$0.85M	2	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
184	04.01.06.07.	Caprock capillary entry pressure	No rocks have zero porosity, but the sealing layer provides a seal because the pore throats are too small to permit CO2 to enter the water-filled pores. (CCP 2009)	If the CO2 injection pressure exceeds the capillary pressure of the caprock, CO2 can penetrate or pass through the caprock	Kirtland Lower Shale capillary breakthrough pressure: 47-56 MPa (Heath 2011).		CO2 migration through caprock.	Caprock capillary entry pressure exceeded.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock capillary entry pressure. Monitor CO2 injection pressure. Monitor for CO2/CH4 in high-risk areas.	Characterize and model caprock capillary entry pressure. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
185	04.01.06.08.	Caprock fracture pressure	The critical pressure to avoid exceeding is the fracture pressure of the confining interval (caprock) above the reservoir, which is normally higher than the fracture pressure in the injection interval. (CCP 2009) Maximum injection pressure is typically at least 0.34 MPa (50 psi) below fracture pressure. EPA UIC Class VI regulations limit CO2 injection pressure to 90 percent of fracture pressure.	If the CO2 injection pressure exceeds the fracture pressure of the caprock, the caprock could fracture and allow CO2 to pass through the caprock.	Estimated caprock fracture pressure: 14.57 MPa at 864 m (2,114 PSIA at 2,835 FT). Calculated based on lithostatic pressure of 21.85 MPa (3,169 PSIA).		Caprock fracturing.	Caprock fracture pressure exceeded.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock fracture pressure. Monitor CO2 injection pressure and micro seismicity. Monitor for CO2/CH4 in high-risk areas.	Avoid sites with fractured caprock. Keep injection pressure below 90% of caprock fracture pressure.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak. Monitor pressure in formations above the caprock. Passive micro-seismic monitoring.
186	04.01.07.00.	Additional seals and sinks (secondary seals)	This concerns the concept of successive lithological, hydraulic and/or chemical barriers acting successively to prevent fluid escape to surface environments. From a geological point of view the permeability barrier is probably the most important, in comparison with other types of traps. However, it may be necessary to consider a sequence of traps in CO2 migration models in addition to the conventional low permeability barriers. For example, within the Weyburn sequestration project, the primary caprock is the Watrous formation, however, low permeability formations at higher stratigraphical layers provide potential additional seals, preventing upward migration of sequestered CO2. Stacked reservoirs consist of multiple alternating seals and reservoirs above the primary reservoir. The additional reservoirs can provide a back up for CO2 containment if the primary seal is broken. 1. Multiple stacked seals (caprocks) 2. Multiple stacked sinks (reservoirs)	Without multiple stacked seals and sinks there is no fallback position if CO2 escapes through the primary seal.	The coal beds act as seals as well as reservoirs due to the adsorption of CO2 and resulting matrix swelling decreasing permeability. The coal beds in the Fruitland Formation are separated and overlain by multiple shale partings. The Kirtland Shale includes an upper and lower shale separated by the Farmington sandstone. Although the Nacimiento Formation is classified as a potential aquifer, it has 74.3 m (244 ft) of shale and siltstone beds, representing 67% of its 110.6 m (363 ft) thickness.		Failure of primary seal without backup seals and sinks.	Lack of additional seals and sinks	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model site, including primary and secondary seals and sinks. Monitor for CO2/CH4 in high-risk areas.	Take into consideration multiple stacked seals and sinks in site characterization, modeling and selection.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P x S x D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
184	04.01.06.07.	Caprock capillary entry pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
185	04.01.06.08.	Caprock fracture pressure	2	3	3	18	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	\$4M to locate and fix leak and remediate.	\$3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high-risk areas \$150k.	Savings of \$0.85M	2
186	04.01.07.00.	Additional seals and sinks (secondary seals)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
187	04.01.08.00.	Lithology	The systematic description of rocks in terms of their mineral assemblage and texture. The lithology of the geosphere (including both the reservoir and the caprock) determines the reservoir physical and transport properties (including porosity and permeability). It concerns the mineralogical composition, texture (grain size, sorting) and fabric (sedimentary structures, vertical and horizontal heterogeneities). Potential reservoir lithologies include sandstones and limestones. 1. Caprock lithology 2. Reservoir lithology	The physical and chemical and mineralogical properties of the reservoir rocks affect: the capacity to store CO2; fluid flow and CO2 migration; determine which water-rock reactions can take place; and influence the rock strength and elastic properties (such as compressibility, shear strength, Poisson's ratio etc).	The reservoir is made up of high-volatile A bituminous coal seams separated by partings of siltstone and shale. The coal zones are separated by shale, sandstone and siltstone. (Weber 2012). Kirtland Upper Shale Argillaceous mudstones or sandy argillaceous mudstones. Clay matrix dominated by smectite and illite or mica (Heath 2010). Kirtland Lower Shale Argillaceous or silty argillaceous mudstone. Clay matrix dominated by illite-smectite mixed-layered clays (Heath 2010) Silt- to sand-sized grains are quartz, alkali feldspar, some plagioclase, and volcanic rock fragments (Heath 2010).		Caprock failure. Uplift or subsidence. Loss of reservoir porosity, permeability, injectivity.	Caprock lithology	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Take into account lithology of caprock and reservoir in characterizing and modeling sites.	Take into account lithology of caprock and reservoir in characterizing and modeling sites.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.	
188	04.01.08.01.	Lithification / diagenesis	The slow physical, chemical and/or biological processes by which unconsolidated sediments become sedimentary rock. These processes can result in changes to the original mineralogy.	The state of lithification/diagenesis contributes to determining the physical and chemical characteristics of sedimentary rock. For example, porosity usually decreases during diagenesis, except in rare cases such as dissolution of minerals and dolomitization. It is very unlikely that deep subsurface geologic formations are unconsolidated. Unconsolidated formations are young in geologic time and located at shallow depths.	Nonconsolidated sediments are not present at depth.		Decreased porosity and permeability.	Lithification / diagenesis.	Decreased CO2 storage capacity and injectivity.	Take into account lithification /diagenesis in site characterization and modeling. Monitor CO2 injectivity.	NA	NA	
189	04.01.08.02.	Pore architecture (See 04.01.08.03. and 04.01.08.04.)	Structure and density of discrete voids within the rock (pores). 1. Reduced pore volume or distribution limiting CO2 injection	The pore architecture determines the porosity and permeability of the rock, which are key features when considering the mobility of fluids and gases within the rock. Rate of long-term pressure build-up greater than expected. Increases CO2 injection cost. Need for additional wells.	The macro-pore structure of the coal beds consist of cleats. Face cleats are oriented N35E (almost precisely aligned in the direction of the EPNG COM A 300 well, SW of the injector). Butt cleats are oriented N55W. Tertiary cleats are oriented N-S. Primary cleat spacing: 2 to 8 cm. Primary cleat length: 2.5 cm to over 1 m. Primary cleat height: same as coal lithotype layer 1 cm to 10s of cm Secondary cleat spacing: 0.3 to 0.6 cm for high-volatile A bituminous. Secondary cleat length: <2cm Tertiary cleat spacing: 0.1-0.3 cm or less. Coalbed permeability may be 3 to 10 times greater in the face-cleat direction than in other directions. (ARI 2008).								

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
187	04.01.08.00.	Lithology	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
188	04.01.08.01.	Lithification / diagenesis	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
189	04.01.08.02.	Pore architecture (See 04.01.08.03. and 04.01.08.04.)	0	0	0	0															

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
190	04.01.08.03.	Reservoir porosity	Porosity values greater than 10% in carbonate formations or 15% in clastic formations are generally desirable. (CCP 2009). It is important to distinguish between total porosity and effective (flowing) porosity. Flowing porosity is what can be readily displaced by CO2 invasion. Total porosity minus flowing porosity is pore space that will likely remain occupied by residual pore fluids after CO2 invasion, although CO2 can diffuse into this pore space. 1. Total porosity 2. Effective (flowing) porosity	Low porosity makes CO2 injection more difficult and can limit the rate of injection into a reservoir. Porosities of coal seams can be more than an order of magnitude less than other reservoirs without affecting CO2 storage, because the CO2 is adsorbed on the coal surface and takes up significantly less space.	Pump Canyon Site Upper coal zone porosity: 1.4% Lower coal zone porosity: 2.3% (ARI 2010) Permeability relates to porosity as follows: $(k/k_i) = (\Phi/\Phi_i)^3$ k = permeability k_i = initial permeability Φ = porosity Φ_i = initial porosity		Increased dewatering required. Decreased dewatering required.	High coal seam porosity. Low coal seam porosity.	Decreased profitability.	Characterize and model coal seam porosity. Monitor well performance.	Characterize and model coal seam porosity.	Monitor well performance. Dewater coal seam to improve CO2 injectivity and CBM production.
191	04.01.08.04.	Reservoir permeability and injectivity	Permeability measures the ability of fluids to flow through a formation. High values indicate a well-connected pore space while low values indicate convoluted conduits that disconnect the pores. Porous rocks have a wide range in permeability between around 0.1 milli-Darcy (mD) for very tight rocks, to several darcies for very permeable formations. (CCP 2009) In general, the better the porosity, the better the permeability (and thus injectivity) - however, large variations in permeability mean the porosity and permeability variations need to be mapped in detail (CCP 2009) Ideally, CO2 storage requires high permeability (>100 mD) to ensure near well bore injectivities for quick access to pore space. However, this is not always possible and near wellbore permeabilities may need to be enhanced by artificially stimulating the wells to allow for improved injectivity. (CCP 2009) Injectivity is impacted by porosity and permeability. Low injectivity can be partially compensated for by greater injection pressure and/or more wells. Decreasing injectivity can result when initial injection rate meets expectations but overall pore space is limited. Bottom hole pressure gradually increases. 1. Insufficient reservoir injectivity 2. Decreasing reservoir injectivity	Low permeability makes CO2 injection more difficult and can limit the rate of injection into a reservoir. While high permeabilities are generally desirable, very high permeability pathways or conduits can enhance CO2 migration along concentrated pathways reducing the effective storage within the target formation. (CCP 2009) In moderate to low permeability, or poorly connected reservoirs, a higher well density will be needed to limit pressure evolution and allow for efficient injection. (CCP 2009) Uncertainty in permeability could lead to high numbers of wells needed. Low reservoir injectivity will limit the rate of CO2 injection and require increased bottom hole pressure and/or more injection wells.	Pump Canyon Site Initial permeability: Upper coal zone: 146 mD* Middle coal zone: 146 mD* Lower coal zone: 582 mD* Upper and middle coal zones permeabilities were adjusted to 10 mD in the history-match model to achieve 80% of CO2 injection in lower coal zone (ARI 2010) Permeability at the injection well decreased to less than 1mD over one-year of CO2 injection. Permeability estimated at 104-388 mD based on pressure buildup tests on EPNG Com A 300 and 300S.(ARI 2008) Vertical permeability on Fruitland coal was two orders of magnitude less than face cleat permeability. Butt cleat permeability was one-half the face cleat permeability (Seidle 2011). Vertical permeability used for modeling was 0.0001 mD. Compared to 146 to 582 mD for horizontal permeability.		Decreased CO2 injectivity and decreased CH4 production.	Decreased coal seam permeability.	Decreased profitability.	Characterize and model coal seam permeability. Monitor CO2 injectivity.	Characterize and model coal seam permeability. Select coal seams with acceptable permeability properties.	Monitor injectivity. Dewater coal seam to increase cleat permeability. Add more vertical injection wells (new or converted). Consider hydraulic fracturing. Use horizontal injection wells (not feasible for multiple thin seams).
192	04.01.09.00.	Unconformities	Geological surfaces separating older from younger rocks and representing a gap in the geologic record. Such a surface might result from a hiatus in deposition of sediments, possibly in combination with erosion, or deformation such as faulting. An angular unconformity separates younger strata from eroded, dipping older strata. A disconformity represents a time of no deposition, possibly combined with erosion, and can be difficult to distinguish within a series of parallel strata. A nonconformity separates overlying strata from eroded, older igneous or metamorphic rocks. 1. Unconformities 2. Disconformities 3. Nonconformities	Unconformities can act both as potential seals or lateral migration pathways for fluids. For example, the impermeable barrier resulting from the widespread development of diagenetic anhydritized carbonate associated with the unconformity between the Mississippian beds and overlying Triassic Watrous Formation in the vicinity of the Weyburn pool.	The Ojo Alamo Formation lies unconformably on the Kirtland Shale (Ayers 1994). The Kirtland Formation is absent 43 km (27 mi) E of the CO2 injection site.		Migration of CO2/CH4 through an unconformity.	Presence of unconformities	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Identify, characterize and model unconformities in the site area. Monitor for CO2/CH4 in high-risk areas.	Take into account unconformities, disconformities and nonconformities in site characterization and modeling. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
190	04.01.08.03.	Reservoir porosity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
191	04.01.08.04.	Reservoir permeability and injectivity	5	5	2	50	None	None	None	None	None	None	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160k. Depending on size of the operation, additional injection wells could cost: \$10M to >\$100M	None	None	None	None	Cost to add or relocate an injection well \$762k. Cost to convert an existing CBM well to a CO2 injection well: \$160k. Depending on size of the operation, additional injection wells could cost: \$10M to >\$100M	None	2
192	04.01.09.00.	Unconformities	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
193	04.01.10.00.	Heterogeneities (See 03.02.03.06.)	Heterogeneities are variations in the rock properties of a geological formation. 1. Reservoir heterogeneity 2. High permeability layers in reservoir 3. Interstitial layers of shale or baffles in reservoir 4. Caprock heterogeneity (high permeability zones) 5. Heterogeneity of overlying aquifers (more difficult to monitor for CO2) 6. Heterogeneity of porosity 7> Heterogeneity of mineralogy 8. Heterogeneity of degree of fracturing 9. Heterogeneity of geochemistry	Heterogeneities can result in directional variations in permeability, which affects the mobility of fluids and gases in the rock. For example, experience from the Saline Aquifer CO2 Storage project (SACS) has shown that both stratigraphical and structural local permeability heterogeneities have the potential to profoundly affect CO2 distribution and migration (Chadwick et al., 2003). The image below shows seismic sections through the Sleipner injection site from Zweigel et al. (2001). The strong amplitudes are taken to be CO2 accumulations.	Regional studies by Fassett 1979 and Wray 2000 reveal the presence of considerable heterogeneity within the Fruitland formation and individual seams (pinchouts, local fault truncations, channel scour and facies changes). Detailed study by Ayers and Zellers 1994 conducted near the demo site reveals considerable complexity in the Fruitland depositional systems. Fassett 1979 indicates that continuity of subsurface coals over distances of a mile is speculative, at best (ARI 2010).							
194	04.01.11.00.	Fractures and faults	Fractures are cracks or breaks in rock. Fractures along which displacement has occurred are called faults. Fractures and faults can occur over a wide range of scales. The presence of a fault does not imply a leakage problem. Most rocks are faulted and fractured in some way over geological time. The critical question for CO2 storage is whether there are any faults or fractures that could provide leakage pathways under present day geological conditions. In addition to the basic geometry of connected rocks and flow paths, this involves the study of geomechanics, stress fields and fracture behavior. Simply put many "faults: do not leak at all and many huge oil and gas fields that include faults prove the point. (CCP 2009)	Fractures can enhance conductivity, for example, by a conductive fracture connecting permeable regions together. They can also act as seals, by bringing a relatively permeable region into contact with low conductivity rock, for example. Movement on a fault that transverses a wellbore could damage or sever casing or tubing. CO2 might leak through open (no-sealing) faults, which extend into the caprock. CO2 might leak through natural fractures in the caprock.	Several studies have shown that northeast- and northwest-trending faults, fractures and foliations are present in the San Juan Basin (Tremain 1994). Increased fracture intensity, and therefore enhanced coalbed permeability may occur where coal seams are folded or differentially compacted (Ambrose 1994). Fracture swarms have been observed passing through the Pictured Cliffs Sandstone and the Fruitland coal (Tremain 1994). An inferred NW-striking structural hingeline is located 10 km (6 mi) S of the CO2 injection Site. This structural hingeline is interpreted to be a zone of complex, NW-trending, echelon normal faults, with net down drop to the NE of 21 m (70 ft) and zone width of 10-16 km (6 to 10 mi). That would put the edge of the fault zone within 2-5 km (1-3 mi) of the injection Site (under the communities of Navajo Dam and Turley).	Need data on faults and fractures in reservoir.	Reactivation of a dormant fault. CO2/CH4 leakage through a fault or fracture zone.	Existing or new fractures and faults.	CO2/CH4 release (HSE hazard). Monitor for CO2/CH4 near fault. Monitor passive seismicity.	Characterize and model the site for existing faults. Characterize and model the site for existing faults. Avoid or isolate areas with faults penetrating the caprock. Avoid repressurizing the Fruitland Formation.	Monitor for CO2/CH4 near fault and/or in high-risk areas. Monitor micro-seismicity or surface displacement (InSAR or LIDAR). Inject sealants into fault. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.	

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
193	04.01.10.00.	Heterogeneities (See 03.02.03.06.)	0	0	0	0															
194	04.01.11.00.	Fractures and faults	4	3	3	36	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	\$4M to locate and fix leak and remediate.	\$3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high-risk areas \$150k:	Savings of \$0.85M	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
195	04.01.12.00.	Undetected features	Natural or man-made features within the geological environment that may not be detected during site investigations. Examples of possible undetected features are fracture/fault zones, the presence of brines or old mine workings. Some physical features of the storage environment may remain undetected during site surveys and even during preliminary borehole drilling. The nature of the geological environment will indicate the likelihood that certain types of undetected features may be present and the site investigation may be able to place bounds on the maximum size or minimum proximity to such features. 1. Existing fracture/fault zones 2. Underground cavities/karsts (natural or man made) 3. Existing boreholes 4. Subsurface infrastructure (piping, underground utilities) 4. Gas chimneys 5. Shallow gas/drift gas (above bedrock) 6. Clustered small gas-related amplitude anomalies along fault planes	Undetected features could significantly affect the performance of a sequestration system. For example, local permeability heterogeneities with the potential to profoundly affect the distribution and migration of CO2 at Sleipner (within the Saline Aquifer CO2 Storage project, SACS) were only discovered after effectively being illuminated by the sequestered CO2 (Chadwick et al., 2003). Shallow gas (above bedrock) can cause drilling problems and impede monitoring.	Pump Canyon Site There is potential for undetected fractures, fracture swarms and faults with less than 0.6 m (2 ft) displacement within the Nine-Section Area, where a 3D seismic survey was conducted. The Sixteen-Township Area is likely to have significantly more fracture zones associated with folding and differential compaction. The inferred structural hingeline is not well defined.	3D seismic data for areas outside the Nine-Section Area is not available. CO2/CH4 leakage through an undetected fracture/fault zone, borehole, high permeability zone or other feature.	Undetected features.	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Conduct ground and 3D-seismic surveys to detect underground features. Monitor for CO2/CH4 in high-risk areas.	Select site with multiple stacked seals and sinks. Conduct ground and 3D-seismic surveys to detect underground features. Take results into consideration in site characterization and modeling. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.		
196	04.01.13.00.	Vertical geothermal gradient 04.01.04.10.	Temperature profile in the geosphere prior to the injection of CO2. Temperature generally increases with depth, but the rate of increase varies significantly depending on the geothermal gradient. The critical temperature for CO2 is 31.1°C. The average geothermal gradient is approximately 25°C per km. If the surface temperature is 10°C, the critical temperature will be reached at a depth of 840 m. However, a considerable variation in geothermal gradients and sub-surface temperatures can be expected at a depth of 1000 m. For example, in Europe temperatures at 1000 m range from 20 to 75°C, with local temperatures of more than 200°C in volcanic areas.	Relevant to temperature dependent physical/chemical/biological/hydraulic processes, such as CO2 phase behavior. Temperature, coupled with pressure, will affect the phase behavior of CO2 as well as the solubility of many other constituents present in the reservoir (including gases, liquids and solids.)	Pump Canyon Site Geothermal gradients in the area are higher than normal due to a remnant of the San Juan volcanic field, but do not impact CBM or CO2-ECBM. Geothermal gradient is 42.7°C per km of depth (23.6°F/1000FT of depth)..	High bottom hole temperatures. Caprock failure. Mineralization and alteration of formation and wells. Alteration of formation fluid chemistry.	High vertical geothermal gradient.	CO2/CH4 leakage (HSE hazard). Damage to boreholes and wells. Damage to monitoring equipment. Existence of hot springs, geysers and hydrothermal vents. Higher than normal thermal gradient. Monitoring change in bottom hole temperatures. Monitoring change in reservoir fluid chemistry.	Proper site characterization and site selection avoiding areas of significant hydrothermal activity.	Stop CO2 injection. Extract CO2 or brine from reservoir and inject into another more secure reservoir. Decrease CO2 injection temperature.		
197	04.01.14.00.	Formation pressure	The pressure of fluids within the pores of a formation, normally hydrostatic pressure, or the pressure exerted by a column of water from the formations depth to the sea level prior to the injection of CO2. The critical pressure of CO2 is 7.38 MPa. The average underground hydrostatic pressure increases with depth by approximately 10.5 MPa per km for aquifers that are in open communication with surface water. Applying this average gradient, the critical pressure of CO2 will be reached at a depth of around 690 m. However, aquifers or hydrocarbon reservoirs (e.g., EOR and ECBM) that are sealed off from the rest of the sub-surface may be under- or over pressured. 1. Hydrostatic pressure 2. Fracture pressure 3. Lithostatic pressure	Contributes towards determining the mobility of sequestered CO2.	Initial reservoir pressure prior to CBM operations was 11.33 MPa (1644 PSIA). Reservoir pressure at start of CO2 injection was 0.52 to 0.69 MPa (75-100 PSIG). (ARI 2010).	Positive Increased CH4 desorption from coal Negative Decreased CO2 adsorption on coal.	Low formation pressure.	Increased CH4 production. Decreased CO2 storage Take into account formation pressure in site characterization and modeling. Monitor bottom hole pressures.	Monitor bottom hole pressures and CBM well performance. Avoid repressurizing the reservoir before CBM operations have been completed.	Monitor CBM well performance. Install artificial lift, if needed, to boost wellhead pressure for CBM gathering system.		

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings					Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
195	04.01.12.00.	Undetected features	4	3	3	36	None	None	None	<1,000 t/yr CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$0.3M for leaky well or \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	\$4M to locate and fix leak and remediate.	\$3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high- risk areas \$150k:	Savings of \$0.85M	2	
196	04.01.13.00.	Vertical geothermal gradient 04.01.04.10.	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
197	04.01.14.00.	Formation pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
198	04.01.15.00.	Initial stress and mechanical properties	The stress condition and mechanical properties of the geosphere prior to injection of CO2.	The initial stress state and mechanical properties are a baseline from which the potential effect of injecting supercritical CO2 can be assessed.	Pump Canyon Site The reservoir went from being overpressured to being underpressured, due to dewatering and CBM production, prior to CO2 injection. Increased fracture intensity occurs where coal seams are folded, or differentially compacted. (Ambrose 1994)		Fracturing caprock. Seismicity. Uplift / subsidence. Borehole collapse.	Initial stress and mechanical properties.	CO2/CH4 release (HSE hazard). Damage to surface buildings and infrastructure. Well damage.	Conduct baseline study of initial stress state and mechanical properties of the reservoir and caprock and include these in site characterization and modeling. Monitor changes in stress state and mechanical properties over time.	Conduct baseline study of initial stress state and mechanical properties of the reservoir and caprock and include these in site characterization, modeling and reservoir engineering. Avoid repressurizing the reservoir. Monitor for CO2/CH4 in high-risk areas.	Monitor for CO2/CH4 in high-risk areas. Maintain injection pressures below 90% of fracture pressure. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
199	04.01.16.00.	Petrophysical properties (See 03.02.03.01.; 04.01.08.03. and 04.01.08.04.)	Petrophysical properties of the geosphere prior to the injection of CO2. This includes features such as permeability, porosity, residual saturation, capillary pressure and wettability.	Petrophysical properties influence how injected CO2 will migrate in the geosphere. For example, permeability influences the direction and rate of CO2 movement, and porosity and residual saturation influence the dimensions of the CO2 plume.	The coal beds are vertically compartmentalized by shale partings. Permeability is influenced by cleating							
200	04.02.00.00.	Fluids	Details of fluids in the geosphere, which comprises of the reservoir, overburden and surrounding rock prior to the injection of CO2. Water will generally be present, but other fluids, particularly hydrocarbons (e.g., EOR and ECBM), may be important, dependent on the sequestration concept.	Water and other fluids in the sequestration system will affect the transport and interactions of injected carbon dioxide.								
201	04.02.01.00.	Fluid properties (See 03.02.13.03)	Properties of the geosphere fluids prior to injection of CO2, including composition and geochemistry. The high salinity of deep aquifers is, generally, an indication of very low or insignificant throughput of meteoric waters. 1. Fluid chemical composition and geochemistry 2. High salinity fluid 3. Fluid density	The fluid properties and geochemistry of the geosphere will contribute towards determining how injected CO2 will behave in the geosphere. Very high salinity can lead to deposition of halite in pore spaces and cause decreased permeability and injectivity.	Brine total dissolved solids: 16,219 mg/L Brine density: 1000 kg/m3 Brine viscosity: 5.8E-04 Pa-s (0.58 cP) Assuming 52.2°C and 0.69MPa CO2 density: 12 kg/m3 CO2 viscosity: 1.64E-05 Pa-s (1.64E-02 cP)							
202	04.02.02.00.	Hydrogeology	Natural formation water flow pathways (directions, velocities) in the geosphere will be important in determining the long-term migration paths for CO2. This depends on factors including: hydraulic heads, permeability and porosity distribution, the existence of fracture networks, connection between aquifers, position of the recharge and discharge areas. 1. Natural fluid flow pathways 2. Position of aquifer recharge and discharge areas 3. Connection between deep saline aquifer and shallow drinking water aquifer	This will affect the migration of dissolved CO2 in the reservoir and the geosphere (direction, timing), the position of the interface between supercritical CO2 and aquifer water (inclined interface). There may also be a possible effect on overlying aquifers used for drinking water.	The Fruitland Formation has been mostly dewatered. Approximately 99% of the injected CO2 is adsorbed on the coal and 1% remains as gaseous CO2 in the cleat pore space. The formation fluids are rich in biogenic bicarbonate. The reservoir is vertically isolated by the Lewis Shale below and the Kirtland Shale above. There are also shale and siltstone layers within the Fruitland Formation itself. The Fruitland Formation and Upper Pictured Cliffs Sandstone are considered a single hydrologic unit because they have the same pressure.		Migration of CO2/CH4/brine out of reservoir.	Hydrogeology. CO2/CH4/brine contamination of groundwater aquifers	Monitor for CO2/CH4/brine in local wells and high-risk areas.	Monitor for CO2/CH4 in high-risk areas.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
198	04.01.15.00.	Initial stress and mechanical properties	2	3	3	18	None	None	None	<1,000 t/yr CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	Assuming leakage undetected or unmitigated for 5 years: <\$5.1M to locate and fix leak and remediate.	Assuming leakage detected early and mitigated <\$3.3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high-risk areas \$150k:	Savings of \$1.65M	2
199	04.01.16.00.	Petrophysical properties (See 03.02.03.01.; 04.01.08.03. and 04.01.08.04.)	0	0	0	0															
200	04.02.00.00.	Fluids	0	0	0	0															
201	04.02.01.00.	Fluid properties (See 03.02.13.03)	0	0	0	0															
202	04.02.02.00.	Hydrogeology	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
203	04.02.03.00.	Hydrocarbons	The presence and distribution of hydrocarbons, such as oil and/or gas (e.g., EOR and ECBM), within the storage system.	Hydrocarbons have potentially important implications for a storage system, by both influencing the likelihood of previous geological exploitation of the area, and by being an important component of the system with which sequestered CO2 can interact.	The Pump Canyon Site The Fruitland Formation is a partially depleted CBM reservoir with very-low oil saturation. The coalbed methane is dry (low in C2+ hydrocarbons) and is adsorbed on the coal and present in gaseous form in coal cleats. The reservoir also contains natural CO2..		CH4 seeps/leaks. Gas kicks during drilling.	Presence of hydrocarbons.	Surface release or buildup of CH4.	Monitor drilling for gas kicks. Monitor for CO2/CH4 in high-risk areas.	Monitor and model hydrocarbon saturation, and production. Maintain blow out preventers (BOP) and packers in drilling. Avoid repressuring the reservoir.	Monitor for gas kicks during drilling. Monitor for CO2/CH4 in high-risk areas. Locate and fix CH4 seeps/leaks Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
204	05.00.00.00.	BOREHOLES	This category of FEPs is concerned with the way that activity by humans alters the natural system. Both boreholes used in the sequestration operations and those drilled for other purposes are relevant to the long-term performance of the system. The category is divided into two classes for the drilling process, and sealing and abandonment.	This category is divided into two classes: 1. Drilling and completion 2. Sealing and abandonment	There are over 90 deep wells in a nine-section area.							
205	05.01.00.00.	Drilling and completion	FEPs relevant to the operation of boreholes drilled within the system domain.	Boreholes can potentially provide short circuits for carbon dioxide transport.								
206	05.01.01.00.	Formation damage (CO2 leakage through damaged caprock near borehole)	Alteration of the far-field or virgin characteristics of a formation, usually by exposure to drilling fluids. Fracturing associated with formation damage can increase porosity, whereas the water or solid particles in the drilling fluids, or both, can decrease the pore volume and effective permeability of the formation in the near-wellbore region. Some boreholes in the early 20th century may have been explosive fractured with nitroglycerin. Later boreholes may have been hydrofractured. 1. Explosive fracturing 2. Hydrofracturing A number of mechanisms can result in a decrease in porosity, including: 3. Solid particles from the drilling fluid physically plug or bridge across flow paths in the porous formation 4. Water from drilling causing clay minerals in the formation to swells 5. Chemical reactions between drilling fluid and the formation rock and fluids precipitating solids	Formation damage has a number of potential implications for assessing CO2 sequestration: - it can make information from affected boreholes non-representative of the true characteristics of the damaged formations; and - damaged regions themselves may provide flow paths for CO2 migration, particularly if damage results in fracturing. - decrease in near borehole porosity can result in unexpected increase in bottom hole pressure	Many CBM producer wells in the area have open cavity completions or were hydraulically stimulated to improve permeability.	Data on existing well stimulation not available for this study.	CO2/CH4 leakage through damaged / fractured caprock near borehole. Nonuniform injectivity	Formation damage.	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Increased cost of converting producer wells to injection wells or cost of adding new injection wells.	Analyze and test existing wells for formation damage. Monitor for CO2/CH4 near wells and in high-risk areas.	Proper completion and stimulation of wells. Analyze and test existing wells for formation damage. Recomplete or plug and replace at risk wells. Monitor for CO2/CH4 near wells and in high-risk areas.	Monitor for CO2/CH4 near well and in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
203	04.02.03.00.	Hydrocarbons	2	3	3	18	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	Assuming leakage undetected or unmitigated for 5 years: <\$5.1M to locate and fix leak and remediate.	Assuming leakage detected early and mitigated <\$3.3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high- risk areas \$150k.	Savings of \$1.65M	2	
204	05.00.00.00.	BOREHOLES	0	0	0	0																
205	05.01.00.00.	Drilling and completion	0	0	0	0																
206	05.01.01.00.	Formation damage (CO2 leakage through damaged caprock near borehole)	4	3	2	24	None	None	None	None	None	None	Downtime for rework. Loss revenue of \$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Cost of recompleting wells: \$77k/incident per well. Cost of a replacement well: \$762k per well	None	None	Revenue loss of \$150-385 per day of downtime per well. Cost of recompleting well \$77k/incident per well. Cost of a replacement well \$762k per well	None	Proper completion and stimulation procedures. Monitoring for CO2/CH4 near wells and in high- risk areas. Part of ongoing costs.	Savings of \$150- \$385 per day of downtime eliminated per well. Savings of \$77k/ recompletion eliminated. Savings of \$762k per replacement well eliminated.	2	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
207	05.01.02.00.	Well lining and completion	At the time of drilling, boreholes are lined with a metal casing. Cement is pumped downhole inside the casing string, and it is pushed upward under and outside the casing lower end, between the casing and the rock wall. In multi-stage cement jobs, cement is squeezed between the casing and the rock wall though purpose made perforations. The cement could be pushed behind casing from the bottom hole to the surface, or to a predetermined depth. Curing of cement is the process of maintaining the proper temperature and moisture conditions to promote optimum cement hydration immediately after placement. Proper moisture conditions are critical because water is necessary for the hydration of cementitious materials. As cement hydrates, strength increases and permeability decreases. When hydration stops, strength gain ceases. Therefore, proper hydration of the cement is important in the fabrication of strong, durable concrete. Alteration of borehole linings will occur with time, depending on the natural fluid composition of the deep reservoir and the input of high concentrations of CO2 carrying natural H2S, which may accelerate corrosion.	Borehole lining and completion will contribute to determining the performance of a borehole both during its operational and post-closure phases. This is important from the perspective of CO2 sequestration, since boreholes may provide preferential short circuits to the surface with potential release of CO2 and contamination of upper aquifers.	Prior to the late 1980s open hole completions were commonly used, but coal fines that accumulated during production eventually reduced gas rates, requiring expensive workovers to clean out the wellbore (Bland 1992). In the north-central part of the basin, where permeability and reservoir pressures were higher than average, open-hole cavity completions were used. This involves setting casing just above the coal and drilling it underbalanced with water, air or foam. A cavity is then created within the coal seam by allowing the coal to collapse or crumble into the wellbore. This allows the coal near the cavity to fracture, thus increasing permeability as water and gas within the cleat system move toward the wellbore, which is the area of lower pressure. the coal cuttings are removed from the resultant cavity by displacing with air or foam. A perforated lining is then run in the hole for control purposes (Bland 1992).	Data on producer well lining and completion not available for this study.	CO2/CH4 leakage through active well	Poor well lining and completion.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Review and analyze well records. Determine if well lining and completion methods meet current requirements. Characterize with logging tools. Monitor for CO2/CH4 near wells and in high-risk areas.	Use corrosion resistant casing. Use proper completion and stimulation procedures. Analyze and test existing wells for mechanical integrity. Rework, recement or plug and replace at risk wells. Monitor for CO2/CH4 near wells and in high-risk areas.	Monitor for CO2/CH4 near well and in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.	
208	05.01.03.00.	Workover	The process of performing major maintenance or remedial treatments on a borehole often associated with the re-use of existing boreholes. Workover techniques include flushing of the formation and the removal and replacement of the borehole lining. Well control procedures during workovers must provide for unique phase behavior of any CO2 being circulated out. (CCP 2009) EOR operations often re-complete old wells. Proper re-completion includes: Examining cement bond logs to evaluate bonding between the casing and adjoining formation. Use of squeeze cement if insufficient or inadequate bonding was detected. Wellbore drilling of plugged and abandoned wells to bottom of target formation. Run a casing mechanical integrity test. If pressure fall off was observed, the leaking section of casing should be identified and resealed by squeeze cementing or, in extreme cases, install a liner over the leaking section. 1. Improper modification or reuse of existing boreholes	Workover will result in modified borehole properties that may need consideration within an assessment.	Coal fines accumulate in the wellbore during production and must be cleaned out periodically. This requires a workover. These operations may be needed less frequently as time goes on, especially as water production and formation pressure decrease (Bland 1992).	Data on well workovers not available for this study.	CO2/CH4 leakage through borehole during workover.	Workover.	Release of CO2/CH4 (HSE hazard) into the atmosphere. Monitor for CO2/CH4 near borehole. Monitor borehole pressure.	Use of proper workover procedures Install blow out preventers and packers in wells and maintain them in working order. Monitor for CO2/CH4 near well and in high-risk areas.	Monitor for CO2/CH4 near wells and in high-risk areas. Maintain blow out preventer and packers in working order.	

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
207	05.01.02.00.	Well lining and completion	4	3	2	24	None	None	None	None	None	None	Downtime for rework. Loss revenue of \$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Cost of recompleting wells: \$77k/incident per well. Cost of a replacement well: \$762k per well	None	None	Revenue loss of \$150-385 per day of downtime per well. Cost of recompleting well \$77k/incident per well. Cost of a replacement well \$762k per well	None	Proper completion and stimulation procedures. Monitoring for CO2/CH4 near wells and in high-risk areas. Part of ongoing costs.	Savings of \$150-\$385 per day of downtime eliminated per well. Savings of \$77k/recompletion eliminated. Savings of \$762k per replacement well eliminated.	2
208	05.01.03.00.	Workover	3	2	2	12	None	None	None	None	None	None	None	Cost of workover \$50k-\$100k per well. Cost of a replacement well: \$762k per well	\$32,32/t CO2 emitted (\$1.70/MCF CO2 emitted) \$3.50/MCF CH4 emitted.	None	Cost of CO2/CH4 emitted: \$150/\$385/d Cost of workover \$50k-\$100k per well.	Cost of workover \$50k-\$100k per well.	Proper workover procedures including BOP and packers. Monitoring for CO2/CH4 near wells and in high-risk areas. Part of ongoing costs.	Savings of \$150-\$385 per day emissions prevented.	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
209	05.01.04.00.	Number and location of monitoring wells	Often, monitoring wells (observation wells or verification wells) are needed to monitor the physical conditions (pressure, temperature, etc.) of the storage reservoir, both inside and/or outside the area immediately affected by the storage operations, or above the storage reservoir. Monitoring wells could be “adopted”, by using existing wells to host the appropriate instrumentation (piezometers, pressure gauges, thermometers, etc.), or they could be purpose drilled anew. Direct monitoring techniques usually require access from wellbores that penetrate the containment system into the storage reservoir (CCP 2009) Direct measurements can also be obtained from observation wells at shallower horizons above the expected seal. Wells of this type might provide direct and early indication of unexpected movement. (CCP 2009) General the concept is to minimize monitoring wells that penetrate the seal because they are, by default, potential leakage pathways. (CCP 2009) 1. Lack of or insufficient number of monitoring wells 2. Too many monitoring wells 3. Improperly located monitoring wells.	Observation or monitoring wells may provide an accidental leakage route for the stored CO2, particularly wells drilled inside the area of storage. There are unique tradeoffs associated with the number and location of monitoring wells.	Producer wells were used as monitoring wells during the CO2 injection test.		CO2/CH4 leakage through monitoring wells.	Presence of monitoring wells penetrating the reservoir.	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Monitor for CO2/CH4 near wells.	Minimize number of monitoring wells. Assure integrity of monitoring wells.	Monitor for CO2/CH4 leaks. Locate and fix leaks.
210	05.01.05.00.	Well records	The drilling of boreholes for site investigation, resource exploitation and/or CO2 injection will result in many documents being generated in paper or digital form. Typical well records include location coordinates, depth, electric logs, mud logs, drilling parameter logs, composite log, testing reports (if applicable), coring report (if applicable), and a final report. Physical records from cutting samples, cores and fluid samples will also be documented. The principal tool to gain knowledge about the sequence of drilled rock formations is Borehole Logging. Common measures include hole diameter, natural gamma ray response, spontaneous electrical potential, rock resistivity, velocity of acoustic waves through rock, neutron susceptibility, etc. The documents originating at the time of drilling are often the most accurate records of the succession of events associated with the drilling of the well. The curation of such unique records is an invaluable tool to pass knowledge to future generations. 1. Lack of or incomplete records for existing wells 2. Retention/management of well records and data	Well records provide a key source of baseline information regarding the sequestration site. They provide information concerning the nature of the rocks drilled by the well and their petrophysical characteristics in terms of sealing potential and reservoir potential. Additionally, records from wells drilled over a period of time can give a picture of how the system is evolving either naturally, or as a result of the exploitation of geological resources. This baseline information is an important input both into the initial conditions relevant to the system to be assessed, as well as providing an indication of the likely importance of other FEPs. Incomplete well records equate to a potential gap in understanding of the storage system and may result in potentially important features being overlooked in the assessment process. Large amounts of data will be generated by the project. Data could be poorly communicated between groups, or be badly managed to the point that important data is lost, or used incorrectly.	The area is covered with a large number of deep wells used for CBM, conventional gas and tight gas production. Pump Canyon Section 32 Active wells: 10 Temp. abandoned wells: 1 Plugged wells: 2 Total wells: 13 Well density: 13 wells/mi2 Pump Canyon Nine-Section Area Active wells: 76 Temp. abandoned wells: 1 Plugged wells: 8 Total wells: 85 Well density: 9 wells/mi2 Pump Canyon Sixteen-Township Area: Active wells: 5,308 New wells planned: 71 Temp. abandoned wells: 25 Plugged wells: 797 Total wells: 6,201 Well density: 11 wells/ mi2	Lack of well records. Loss of well records. Inaccurate well records.	Well records not maintained properly.	Failure to remain in compliance with regulations. Operator errors based on inaccurate well records.	Periodically audit well records for existing wells and maintain accurate records for new wells.	Characterize existing wells. Standardize documentation of well records. Take into account well record data in site characterization and modeling.	Conduct periodic audits of well record documentation to assure the records are thorough and accurate. Maintain digital backup of well records at more than one location.	
211	05.02.00.00.	Borehole seals and abandonment	FEPs relevant to the closure of boreholes drilled within the system domain.	The way that boreholes are closed and sealed is directly relevant to the likelihood that they could act as short circuits for carbon dioxide transport.								

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			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
209	05.01.04.00.	Number and location of monitoring wells	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
210	05.01.05.00.	Well records	2	2	2	8	None	None	None	None	None	None	Interruption for non compliance @ \$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Regularly audit well records and confirm accuracy: <\$100k.	None	Fines for non compliance	<\$1M for noncompliance downtime, corrective action and fines.	None	Regularly audit well records and confirm accuracy: <\$100k.	Up to \$0.9M for every prevented event	1
211	05.02.00.00.	Borehole seals and abandonment	0	0	0	0															

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212	05.02.01.00.	Closure and sealing of boreholes	Features related to the cessation of CO2 injection operations at a site and the sealing of injection and monitoring wells. When a borehole is drilled to the potential storage reservoir, it creates communication with possible overlying reservoirs and with the surface. Cementing and abandonment procedures are designed to permanently plug such communication channel. The cement plugs are commonly located across potential problem spots, to minimize leaking risks. Particular attention should be paid to the quality of the original cement job behind the casing string. If uncemented space is detected, known or suspected behind casing, depending on the lithology across such interval, it may be important to squeeze extra cement between the rock face and the casing to complement the final abandonment plugs inside the casing. Individual boreholes may be closed in sequence, but closure refers to final closure of the whole system, and may include removal of surface installations. The schedule and procedure for sealing and closure may need to be considered in the assessment. A typical well abandonment may include the following: - Remove tubing and packer - Permanently seal the formation with a fluid that reduces permeability - Place plugs of cement or other materials for isolation - Test the plugs - Place a cap on the casing at the surface	The intention of borehole sealing is to prevent human access to the sequestered CO2 and to prevent the borehole from providing a migration pathway for the CO2. Correct cementing and abandonment operations are essential to achieve restoration of pristine sealing above the designed storage reservoir formation.	The area is covered with a large number of deep wells used for CBM, conventional gas and tight gas production. Pump Canyon Section 32 Active wells: 10 Temp. abandoned wells: 1 Plugged wells: 2 Total wells: 13 Well density: 13 wells/mi2 Pump Canyon Nine-Section Area Active wells: 76 Temp. abandoned wells: 1 Plugged wells: 8 Total wells: 85 Well density: 9 wells/mi2 Pump Canyon Sixteen-Township Area: Active wells: 5,308 New wells planned: 71 Temp. abandoned wells: 25 Plugged wells: 797 Total wells: 6,201 Well density: 11 wells/ mi2	Data on closure and sealing of boreholes not available for this study.	CO2/CH4 leakage through boreholes after closure.	Closure and sealing of boreholes.	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Evaluate well materials and procedures for compatibility with CO2 and long-term storage conditions.	Characterize abandoned wells. Replug high risk wells.	Recement/replug leaky wells.

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Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS/D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)		Savings with risk mitigation (\$)
							Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury												
212	05.02.01.00.	Closure and sealing of boreholes	4	3	2	24	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre for soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident.	None	None	Cost to locate leak \$0.2M. Cost to fix leak \$0.1M.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$1.6M per leaky well for water/land remediation, emissions and fines. Plus \$0.3M to locate and fix leak.	Assume leakage detected in 6 months. <\$150k per leaky well for water/land remediation, emissions, and fines. Plus \$0.3 M to locate and fix leak.	Use proper materials and procedures to cement and abandon wells. Periodically monitor wells for CO2/CH4. Part of ongoing costs.	Savings: <\$1.45M	1
213	05.02.02.00.	Seal failure	4	3	2	24	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre for soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident.	None	None	Cost to locate leak \$0.2M. Cost to fix leak \$0.1M.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$1.6M per leaky well for water/land remediation, emissions and fines. Plus \$0.3M to locate and fix leak.	Assume leakage detected in 6 months. <\$150k per leaky well for water/land remediation, emissions, and fines. Plus \$0.3 M to locate and fix leak.	Use proper materials and procedures to cement and abandon wells. Periodically monitor wells for CO2/CH4. Part of ongoing costs.	Savings: <\$1.45M	1

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
214	05.02.03.00.	Blowouts	Uncontrolled flow (CO2, brine, oil, gas or mixture of these) from depth leading to gas and/or fluid erupting from a well or borehole to either the terrestrial or aquatic environments. Blowout is an ordinary drilling hazard, well understood and controlled by current technology. Assuming that ordinary blow-out risk controls are present, particular risks might include: (1) A monitoring or verification well drilled into a porous formation that has elevated pressure due to CO2, or (2) A drilled formation with significant unexpected H2S (MCSG 2009). The greatest danger for loss of well control is during workover operations. Estimates based on both oil and gas wells give a frequency of 3x10⁻⁷ blowouts per well per year (IEA GHG, 2003) (Damen 2006). 1. Blowout due to equipment failure (packer, blowout preventer, valve failure) 2. Blowout due to accident (truck backing over injection well) 3. Blowout due to human error (valve left open) 4. Blowout of CO2 injection well 5. Blow out of production well 6. Blow out of monitoring well 7. Blowout of inactive plugged and abandoned well 8. Blowout during workover/remediation of existing well	A surface or undersea blowout would provide a rapid pathway for CO2 to reach the surface. Apart from the CO2 release, the potential consequences are casualties among operators and economic damage caused by explosion or fire when upcoming hydrocarbons are ignited or by parts of the well, which can be launched by the pressure release. (Damen 2006)	Prior to CBM development in the area, drillers experienced gas shows, kicks and sometimes blowouts in the Fruitland Formation (Bland 1992). Today blowouts are not expected because the reservoir is significantly depressurized. This could change if the reservoir is repressurized in order to store more CO2.	Data on blowouts not available for this study.	Human injury/death. Fire.	Blowouts.	Leakage of CO2/CH4 (HSE hazard) into the surface water or atmosphere. Damage to surface equipment. Liability costs.	Monitor for pressure kicks in wells.	Design, construct and operate wells properly to prevent blowouts. Make sure the blowout preventer, packer and valves are maintained in proper working order.	Monitor for pressure kicks. Monitor for CO2/CH4 near well. Have standard procedures in place and train operators to deal with blowouts. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
215	05.02.04.00.	Orphan wells	CO2 storage projects may be part of an Enhanced Oil Recovery (EOR) project or stand-alone deep saline aquifer projects. Either way, it is likely that the target geological structure has been the object of past exploration efforts, possibly involving drilling wells. The existence of old wells could be obvious if the wells are still active, but could be overlooked if the old (orphan) wells have been long cemented and abandoned. Technical details of such abandoned vintage wells may in fact not be readily available, or altogether lost. In such a case, the old cementing (sealing) job could be substandard. Some coal bed methane operations used open completion wells (no casing). It is possible to stabilize a hole without casing with gravel packing or sorted liners 1. Failure to identify and locate existing wells - active wells, abandoned wells, shallow wells that don't penetrate the caprock, deep wells that penetrate the caprock 2. Failure to test wells for mechanical integrity 3. Failure to remediate old wells 3. Failure of old well due to poor cementing, sealing, closing 4. Improper workover/recompletion of old well 5. Leakage of CO2 or brine through old well to overlying formations, underground aquifers or surface. 6. Collapse of open borehole (non-cased, open-completion holes often used in CBM)	Old substandard plugged well could provide a potential CO2 leakage route to the surface or to possible reservoirs above the designed CO2 storage reservoir. There is little chance of detecting a substandard well abandonment before the beginning of CO2 injection to the designed reservoir, particularly if the existence of an old well has been overlooked. If old abandoned wells are known in the area of the CO2 injection operations, the risk is minimized by carefully check any potential CO2 leak to the surface at the old well head location. If old wells are unknown and not suspected, it is good practice to run a baseline soil gas survey (if applicable) and successive soil gas surveys at intervals after the beginning of CO2 injection. Open completion wells are more likely to leak than other wells and subject to collapsing.	There are over 90 deep wells in the nine-section area. Wells over 50 yrs old: 17 Wells with log documents: 73 Plugged wells: 2 Shut in wells: 3 Temp. abandoned wells: 2 Active/pumping/flowing wells: 85 Active wells no data: 2 Active permit no data: 7 Cancelled: 1 Total: 102	Data on orphan wells not available for this study.	CO2/CH4 leakage through old substandard wells.	Orphan wells.	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Review and analyze well records, if any. Determine if well plugging and completion methods meet current requirements. Characterize with logging tools. Pressurize with water prior to injecting CO2 to check for leaks.	Identify and analyze old wells using records, surveys and field testing. Replug at-risk wells. Monitor for CO2/CH4 near wells.	Monitor for CO2/CH4 near wells. Replug leaky wells. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
214	05.02.03.00.	Blowouts	2	4	1	8	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	Damage due to well CO2/CH4 blowout Repair: <\$0.5M	\$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Monitor for pressure kicks. Maintain well control with BOP and packers. Part of ongoing operation costs.	<1000 t CO2 per blowout @ \$32.32/t of CO2 emitted. <20MMCF CH4 per blowout @ \$3.50/MCF	10% of damage costs	Blowout: <\$2M per event	None	Monitor for pressure kicks. Maintain well control with BOP and packers. Part of ongoing operation costs.	Up to \$2M per blowout prevented.	1
215	05.02.04.00.	Orphan wells	4	3	2	24	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre for soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident.	None	None	Cost to locate leak \$0.2M. Cost to fix leak \$0.1M.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$1.6M per leaky well for water/land remediation, emissions and fines. Plus \$0.3M to locate and fix leak.	Assume leakage detected in 6 months. <\$150k per leaky well for water/land remediation, emissions, and fines. Plus \$0.3 M to locate and fix leak.	Use proper materials and procedures to cement and abandon wells. Periodically monitor wells for CO2/CH4. Part of ongoing costs.	Savings: <\$1.45M	1

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216	05.02.05.00.	Soil creep around boreholes	The slow downward gravitational movement of soil around boreholes.	This process results in changing properties of the soil around borehole casings after abandonment. It may either increase or decrease the degree of sealing and therefore the potential for the region immediately around the borehole to act as a migration pathway for CO2 and/or associated contaminants.	This has not been listed as a significant problem in the site area.		CO2 leakage around the borehole.	Soil creep around boreholes	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Examine existing abandoned wells to get an idea of the problem. If there are wells with this problem, identify what was the difference between them and the wells without the problem.	Examine existing abandoned wells for soil creep. If there are wells with this problem, identify what was the difference between them and the wells without soil creep. Apply lessons learned to newly abandoned wells.	Monitor for soil creep. Fill in as needed.
217	05.02.07.00.	Borehole sand control (sand blocking)	Applies to unconsolidated reservoirs. Sand control may be necessary to maintain the structure of the reservoir around the wellbore. Migration of sand and fines into the near wellbore area may severely restrict production/injection. Sand blocking is a problem when the reservoir is unconsolidated and the wellbore is shut in for maintenance or upsets. (CCP 2009) Dehydration and deposition of gravel pack contents that cannot be displaced or removed from the well (CCP 2009) 1. Sand blocking 2. Dissolution of sand control resins 3. Dehydration and deposition of gravel pack contents	Operation delays. Maintenance costs.	Coal fines blocking (similar to sand blocking) is a problem with CBM wells. The problem decreases over time. Prior to the late 1980s open hole completions were commonly used, but coal fines that accumulated during production eventually reduced gas rates, requiring expensive workovers to clean out the wellbore (Bland 1992).		Sand blocking.	Borehole sand control.	Loss of injectivity. Operating delays and higher maintenance costs.	Take into account any reservoir unconsolidated features in site characterization.	Characterize reservoir. Avoid sites with unconsolidated reservoirs.	Use appropriate design, operation and maintenance procedures for sand control.
218	05.02.08.00.	Wellbore fluids (causing corrosion or scale buildup)	Once the well is completed, impairment implications of the fluids or non-fluids left in the wellbore during startup will need to be considered. (CCP 2009) It is important to consider the displacement of any fluids into the reservoir during start up and the effect of injectivity resulting from the introduction of the fluids. (CCP 2009) Stimulation fluids should be carefully selected in terms of compatibility with the well materials, workover materials and reservoir. (CCP 2009) 1. Wellbore fluids 2. Startup fluids 3. Stimulation fluids	Fluids left in the wellbore for extended amounts of time could potentially corrode the tubulars, drop out precipitants, or cause bacterial growth. (CCP 2009) Startup fluids may impact injectivity due to precipitation of solids. Stimulation fluids may cause corrosion or precipitation of solids.	Data on fluid chemistries not available.	Data on wellbore fluids not available for this study.	Corrosion of wellbore tubulars. Plugging of wellbore tubulars.	Wellbore fluids.	Increased maintenance costs.	Monitor chemistry of wellbore fluids, startup fluids and stimulation fluids for corrosion or scaling potential. Monitor well for corrosion and scale buildup.	Avoid leaving corrosive or scale-building fluids in the well for long periods of time. Use corrosion resistant and Teflon coated tubulars. Monitor well for corrosion and scale buildup.	Treat wellbore fluids with corrosion inhibitor, biocides, scale inhibitor and oxygen scavenger. Monitor for corrosion and scale buildup. Repair corroded areas. Periodically clean out well with strong acid to remove scale buildup.
219	06.00.00.00.	NEAR-SURFACE ENVIRONMENT	This category of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible environment. The environment could be terrestrial or aquatic, and human behavior in that environment needs to be described. The category is divided into three classes: Terrestrial Environment; Aquatic Environment; and Human Behavior.	This category is divided into three classes: 1. Terrestrial environment 2. Aquatic environment 3. Human behavior								
220	06.01.00.00.	Terrestrial environment	This class of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible terrestrial environment.	The near-surface environment is where most potential impacts would be incurred. The FEPs in this class are relevant if that environment is terrestrial.								

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
216	05.02.05.00.	Soil creep around boreholes	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
217	05.02.07.00.	Borehole sand control (sand blocking)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
218	05.02.08.00.	Wellbore fluids (causing corrosion or scale buildup)	2	1	2	4	None	None	None	None	None	corrosion damage to well components. <\$50k per incident per well. Scale damage to well components:<\$6k per incident per well.	\$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Corrosion repair costs: <\$50k per incident per well Cleanout repair costs: \$5k per incident per well	<3t/d CO2 per leak @ \$32.32/t CO2 <50MCF/d CH4 per leak @ \$3.50/MCF of CH4	10% of damage costs	Damage due to corrosion of well components. <\$100k per incident.	None	Use corrosion resistant materials of construction. Pretreat well fluids with corrosion inhibitors. Part of ongoing costs.	Savings <\$100k per incident prevented..	1
219	06.00.00.00.	NEAR-SURFACE ENVIRONMENT	0	0	0	0															
220	06.01.00.00.	Terrestrial environment	0	0	0	0															

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221	06.01.01.00.	Topography and morphology	Features related to the relief and shape of the surface environment and its evolution. 1. Low surface areas (valleys, gullies, ditches) 2. Rugged terrain 3. Confined spaces (caves, canyons)	This FEP refers to local land form and land form changes with implications for the surface environment, e.g. plains, hills, valleys, and effects of river and glacial erosion thereon. In the long term, such changes may occur as a response to other geological changes. Leaked CO2 can accumulate in low surface areas and confined spaces. Rugged terrain may make it difficult to access the site, difficult to lay pipeline and difficult to monitor or conduct seismic studies.	The Nine-Section Area is covered with mesas and canyons with elevation ranging from 1,816 m to 2,015 m (5,957 ft to 6,610 ft).		Human injury/death resulting from accumulation of CO2 in low surface areas or CO2/CH4 in confined spaces without sufficient ventilation.	Presence of low areas or confined spaces near the CO2 injection site.	Endangerment of flora, fauna and humans in low surface areas or confined spaces without sufficient ventilation if CO2/CH4 leakage occurs.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Monitor for CO2/CH4 in high-risk areas.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Monitor for CO2/CH4 in high-risk areas.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Post warning signs. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
222	06.01.02.00.	Soils and sediments impact on project	Features related to the physical and chemical characteristics of the soils and sediments and their evolution. Different soil and sediment types, e.g. characterized by mineralogy, particle-size distribution and organic content, will have different properties with respect to erosion/deposition, sorption etc.	Soil and sediment characteristics will influence the type of vegetation and land use. They will also determine relevant processes to consider should CO2 and/or associated contaminants migrate to the terrestrial surface environment.	The soil in the study area is sandy with moderate concentrations of silt and natural debris (Stone 1983). Travessilla-Rock outcrop-Weska: Very shallow to deep, nearly level to extremely steep, well drained soils that formed in alluvium, residuum, and eolian material, and rock outcrops; on uplands (Keetch 1980). Local CH4 seeps have killed flora.		Accumulation of CO2/CH4 in soil and sediments.	Presence of soils and sediments near the CO2 injection site.	Flora damage.	Conduct baseline study for CO2/CH4 in soils and sediments. Monitor soils and sediments for CO2/CH4. Monitor for CO2/CH4 in high-risk areas.	Take into account soils and sediments in site characterization. Maintain caprock and well integrity. Select site with multiple stacked seals and sinks. Monitor for CO2/CH4 in high-risk areas.	Conduct baseline study for CO2/CH4 in soils and sediments, including isotopes to determine gas source. Periodically monitor near surface for CO2/CH4. Identify any irregularities, such as vegetation dying out. Locate and fix leaks
223	06.01.03.00.	Erosion and deposition	FEPs related to all the erosional and depositional processes that operate in the surface environment, and their evolution with time. Relevant processes may include fluvial and glacial erosion and deposition, denudation, Aeolian erosion and deposition. These processes will be controlled by factors such as the climate, vegetation, topography and geomorphology.	Erosional and depositional processes will influence the way in which the surface environment has evolved and will evolve over the time-scale of interest.	Sixteen-Township Area susceptible to medium wind and water erosion and deposition.		Damage to surface facilities	Erosion and deposition.	Increased maintenance costs.	Monitor and track erosion and deposition. Monitor and track erosion and deposition.	Proper site characterization and site selection for surface facilities avoiding areas with steep slopes >18%, unconsolidated sandy soil (e.g. sand dunes), or flood plains. Monitor and track erosion and deposition.	Install barriers for erosion control. Provide periodic erosion or deposition control maintenance.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking			Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS/D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
221	06.01.01.00.	Topography and morphology	3	4	3	36	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$0.3M for leaky well or \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	Assuming leakage undetected or unmitigated for 5 years: <\$6.8M to locate and fix leak and remediate.	Assuming leakage detected early and mitigated <\$3.3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high- risk areas \$150k:	Savings of \$3.35M	1	
222	06.01.02.00.	Soils and sediments impact on project	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
223	06.01.03.00.	Erosion and deposition	2	1	1	2	None	None	None	None	None	None	None	None	None	None	Damage due to erosion or deposition: <\$100k	None	Periodic erosion control maintenance: <\$50k	Savings: <\$50k	2	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
224	06.01.04.00.	Atmosphere and meteorology	FEPs related to the characteristics of the atmosphere, weather and climate, and their evolution with time. In case of CO2 leakage to the surface, the weather is a relevant factor determining the dispersion or the displacement of the gas: currents, evolution of the concentration of the gas, gas accumulations. Atmospheric characteristics include physical transport of gas, aerosols and dust in the atmosphere and chemical and photochemical reactions. Meteorology is characterized by atmospheric precipitation, temperature, pressure, wind speed and direction. The variability in meteorology should be included so that extremes such as drought, flooding, storms and snow melt are identified.	This information will determine the behavior of CO2 should it reach the atmosphere and is therefore an important factor when considering exposure of the local population and of the local environment. Meteorological characteristics also influence the near-surface hydrological regime with its subsequent consequences for CO2 migration.	The amount of CO2 likely to be released into the atmosphere is minimal because the injected CO2 will be adsorbed on coal. CH4 released in small to moderate amounts into the atmosphere will be rapidly dispersed due to its light density compared to air. Large releases of CH4 could be ignited, leading to fire and/or explosion. Average max. temperature: 65.1°F Mean temperature: 51.8°F Average min. temperature: 38.4°F Extreme max. temperature: 104°F Extreme min. temperature: -16°F Average annual precipitation: 12.96 in Highest annual precipitation: 22.81 in Lowest annual precipitation: 5.85 in Average annual snow fall: 11.6 in (WRCC 2012) Wind direction: 36% from East 23% from West 16% from SW 8% from SE 7% from South 6% from NW 4% from NE (NMED 2008) Average wind speed in Navajo Dam, NM 1980-2010		Movement of CO2/CH4 atmospheric plume into populated areas. Lack of wind preventing dispersion of CO2/CH4 plume.	Atmospheric meteorology impact on released CO2/CH4	Endangerment of humans, fauna, or flora.	Monitor for CO2/CH4 in high-risk areas. Monitor weather conditions.	Take into account atmosphere and meteorology in dispersion modeling for CO2/CH4 leaks. Maintain caprock and well integrity. Monitor for CO2/CH4 in high-risk areas.	Monitor for CO2/CH4 in high risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
225	06.01.05.00.	Hydrological regime and water balance	Processes related to near-surface hydrology at a catchment scale and also soil water balance, and their evolution with time. The hydrological regime is a description of the movement of water through the surface and near-surface environment. It includes the movement of materials associated with the water such as gas or particulates and extremes such as drought, flooding, storms and snow melt. Groundwater withdrawal or movement causing change in CO2/CH4/brine migration	The hydrological regime and water balance will influence the way in which CO2 migrates should it reach the near-surface environment.	Sixteen-Township Area Recharging groundwater movement is from North to South. The north part of the SJB has higher elevation and outcropping of the Fruitland Formation. The water flows south to the San Juan River. CO2/CH4 released into groundwater could flow to existing natural springs or the San Juan or Animas Rivers. Distance from CO2 injection well Quintana Spring: 1.8 km (1.1 mi) NE Minix Spring: 4.3 km (2.7 mi) NW		Dispersion of leaked CO2/CH4/brine in near-surface aquifers or surface waters.	Hydrological regime and water balance impact on CO2/CH4 released into the groundwater.	CO2/brine contamination of near surface waters.	Conduct baseline survey of near-surface water quality. Model hydrological regime to determine likely scenarios for CO2/brine dispersion. Monitor pressure in formations above the caprock. Monitor water level in shallow wells for significant changes that may be tied to ECBM water extraction.	Characterize the local hydrological regime and water balance and incorporate results into models.	Monitor pressure in formations above the caprock and/or highest secondary seal. Monitor near surface aquifers for changes in CO2/salinity/pH. Determine root cause for any changes. Use tracers if necessary. Locate and fix leak. Locate, isolate and remediate contaminated water.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
224	06.01.04.00.	Atmosphere and meteorology	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
225	06.01.05.00.	Hydrological regime and water balance	2	3	3	18	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Potential pump house fire from CO2/CH4 leak: <\$50k per incident.	None	None	Cost to locate and fix leak: \$0.3M for leaky well.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$1.6M per leaky well for water/land remediation, emissions and fines. Plus \$0.3M to locate and fix leak.	Assume leakage detected in 6 months. <\$150k per leaky well for water/land remediation, emissions, and fines. Plus \$0.3 M to locate and fix leak.	Use proper materials and procedures to cement and abandon wells. Periodically monitor wells for CO2/CH4. Part of ongoing costs.	Savings: <\$1.45M	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
226	06.01.06.00.	Near-surface aquifers and surface water bodies	Features related to the physical and chemical characteristics of aquifers and water-bearing features and their evolution.	Shallow Aquifers Aquifers may yield significant amounts of water to wells or surface springs and may thus be a flow path for CO2 to the surface environment. The presence of aquifers and other water-bearing features will be determined by the geological, hydrological and climatic factors. Shallow aquifers will be able to dissolve CO2, reducing further upward migration. The amount of CO2 that can dissolve will depend on factors such as the location of the water table, the chemical composition of pore waters, CO2 flux rates, and hydrogeology. Surface Water Bodies Streams, rivers and lakes often act as boundaries of hydrogeological systems. They may represent a significant source of dilution for CO2 and contaminants entering these systems, or act as reservoirs. In hot dry environments, where evaporation dominates, concentration or exsolution of gas is possible. Water with dissolved CO2 is denser than pure water, which can result in stratification and the potential for limnic eruption.	Near surface aquifer: San Jose Formation: 0 to 495.6 m (0 to 1,626 ft) deep. Surface water distance from CO2 injection well Quintana Spring: 1.8 km (1.1 mi) NE Minix Spring: 4.3 km (2.7 mi) NW San Juan Rover: 5 km (3 mi) S Navajo Reservoir 8 km (5 mi) E A small intermittent stream flows N-S through Simon Canyon 3 km (1.9 mi) E. The primary gas release is likely to be CH4 rather than CO2.		Migration of CO2/CH4/brine into near-surface aquifers or surface waters.	Locating CO2 injection site near fresh water aquifers and surface water bodies. Leakage of CO2/H2S from reservoir through caprock and secondary seals to overlying aquifers and surface water bodies.	CO2/brine contamination of near surface waters.	Conduct baseline survey of near-surface water quality. Monitor near surface aquifers for changes in salinity/pH.	Include near-surface aquifers and surface waters in site characterization. Avoid sites with sensitive groundwater areas. Maintain integrity of caprock and lateral seals.	Monitor near surface aquifers for CO2/CH4. Locate and fix leak. Locate isolate and remediate contaminated water. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
227	06.01.07.00.	Terrestrial flora and fauna	Features and processes related to the characteristics of terrestrial and freshwater flora and fauna, and their evolution. Includes plants, animals, fungi, algae and microbes. Plants usually have a higher resistance against CO2 than mammals, but persistent leaks could suppress respiration in the root zone. Tree kills associated with soil gas concentrations in the range of 20-30% have been observed at Mammoth Mountain, California, where volcanic out gassing of CO2 (0.13-0.44 Mt/yr) has been occurring since at least 1990. The leakage rate (flux) varies between 25 and 7000 g CO2/day/m2. (Damen 2006). 1. Natural flora and fauna 2. Agricultural flora and fauna	Flora and fauna may be affected by concentrations of CO2 in the near-surface environment and may be indicators of CO2 leakage.	Flora is dominantly grasses and scattered pinyon and juniper. Scattered patches of ponderosa pine and Douglas fir are located in the high areas. Fauna consists of rangeland wildlife such as mule deer, coyote, porcupine, jackrabbit, cottontail, spotted ground squirrel, gray fox, skunk and weasel. Birds include turkey, sage grouse, bald eagle, oriole, pinion jay, cliff and violet green swallow, black-billed magpie, northern flicker, flycatcher, woodpecker, white-throated swift, canyon wren, mourning dove, turkey vulture, sharp-shinned hawk, American kestrel, northern harrier, golden eagle, great horned owl, prairie falcon, quail, and red-tailed hawk.		CO2/CH4 migration into terrestrial areas containing flora and fauna.	Presence of flora and fauna in the area.	Endangerment of flora, fauna in areas without sufficient ventilation. Monitor for changes in flora, fauna in the project area. Monitor for CO2/CH4 in high-risk areas.	Conduct baseline survey of flora, fauna and CO2/CH4 in the project area before CO2 injection. Include flora and fauna in site characterization. Avoid habitats for endangered or protected species. Monitor for CO2/CH4 in high-risk areas.	Conduct baseline survey of flora, fauna and CO2/CH4 in the project area before CO2 injection. Monitor for changes in flora and fauna in the project area and determine root cause. Monitor for CO2/CH4 in high-risk areas. Locate and fix leak.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
226	06.01.06.00.	Near-surface aquifers and surface water bodies	2	3	3	18	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Potential pump house fire from CO2/CH4 leak: <\$50k per incident.	None	None	Cost to locate and fix leak: \$0.3M for leaky well.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$1.6M per leaky well for water/land remediation, emissions and fines. Plus \$0.3M to locate and fix leak.	Assume leakage detected in 6 months. <\$150k per leaky well for water/land remediation, emissions, and fines. Plus \$0.3 M to locate and fix leak.	Use proper materials and procedures to cement and abandon wells. Periodically monitor wells for CO2/CH4. Part of ongoing costs.	Savings: <\$1.45M	1
227	06.01.07.00.	Terrestrial flora and fauna	2	2	2	8	None	None	None	Accumulation of CO2 in poorly ventilated low areas resulting in fauna kill <\$100k \$50k / acre for soil remediation and /or vegetation replanting due to CO2/CH4 release	Included under natural resources.	None	None	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Natural resource damage: <\$100k. Cost to locate and fix leaky well: \$300k.	Cost to locate and fix leaky well. \$300k.	Monitor for changes in flora and fauna. Monitor for CO2/CH4 in high-risk area. Cost: <\$100k	None	1

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Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
228	06.01.08.00.	Terrestrial ecological systems (See 06.01.07.00)	Features and processes related to interactions between terrestrial and freshwater populations of animals, plants, algae, fungi, microbes and their evolution. Characteristics of the ecological system include the vegetation regime, and natural cycles such as forest fires or flash floods that influence the development of the ecology. The plant, animal, algal, fungal and microbial populations occupying the surface environment are an intrinsic component of its ecology. Their behavior and population dynamics are regulated by the wide range of processes that define the ecological system. Human activities have significantly altered the natural ecology of most environments.	The ecology of the terrestrial near-surface environment determines the types of organisms present and their inter-dependencies. These can influence the types of impact of interest and can provide a mechanism for monitoring CO2 leakage.	Simon Canyon Area of Critical Environmental Concern is located on the E side of the nine-section site area, 2 km (1.2 mi) from the CO2 injection well.		Migration of CO2/CH4/brine into a terrestrial ecological system.	Presence of sensitive terrestrial ecological systems in the area.	Disruption of the terrestrial ecological system.	Conduct baseline survey of CO2/CH4 and salinity measurements in sensitive areas before injecting CO2. Monitor for changes in ecological systems in the project area. Monitor for CO2/CH4 in high-risk areas.	Take into account the ecological system in site characterization. Avoid sensitive ecological systems. Monitor for CO2/CH4 in high-risk areas.	Conduct baseline survey of ecological systems in the project area before injecting CO2. Monitor for changes in ecological systems in the project area and determine root cause. Monitor for CO2/CH4 in high-risk areas. Locate and fix leak.
229	06.02.00.00.	Aquatic environment	This class of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible aquatic environment (seas, lakes, rivers).	The near-surface environment is where most potential impacts would be incurred. The FEPs in this class are relevant if that environment is aquatic.								
230	06.02.01.00.	Coastal features	Features and processes related to the characteristics of coasts and the near shore, and their evolution. Coastal features include headlands, bays, beaches, spits, cliffs and estuaries.	The processes operating on these features, e.g. active erosion, deposition, longshore transport, may affect mechanisms for the migration of CO2, and associated contaminants, entering the surface environment.	Not applicable to this site		Migration of CO2 and/or brine into a coastal environment.	Leakage of CO2 through caprock to surface environment	Contamination of waters and endangerment of marine life.	Conduct baseline survey of coastal features, CO2, salinity and phi Monitor for changes. Monitor CO2 plume migration.	Take into account coastal features in site characterization. Avoid sensitive areas or habitats for endangered or protected species.	Conduct baseline survey of coastal features, CO2, salinity and phi Monitor for changes. Determine root cause of changes. Monitor CO2 plume migration. Adjust CO2 injection strategy if necessary.
231	06.02.02.00.	Local oceanography	Features and processes related to the characteristics of seas and oceans and their evolution. This includes the topography and morphology of the seabed; thermal stratification and salinity gradients; and marine currents.	The local oceanographic features and processes determine the potential for dilution or accumulation of CO2, or associated contaminants in the marine environment.	Not applicable to this site		Migration of CO2 into the ocean.	Leakage of CO2 through caprock to surface environment	Disruption of the seabed, CO2 accumulation, formation of gas hydrates..	Conduct baseline survey of local oceanographic conditions prior to injecting CO2. Monitor CO2 plume.	Include local oceanography in site characterization if applicable. Avoid sensitive areas or habitats for endangered or protected species.	Conduct baseline survey of local oceanographic conditions prior to injecting CO2. Monitor CO2 plume. Adjust CO2 injection strategy if necessary.
232	06.02.03.00.	Aquatic sediments	Features and processes associated with sediments in the aquatic environment. This includes both the physical and chemical characteristics of the sediments, along with sedimentation and resuspension processes.	Aquatic bed sediment characteristics will influence the ecology of the aquatic environment. They will also determine relevant processes to consider should CO2 and/or associated contaminants migrate to the aquatic environment.	Problems with silting in the San Juan River. Methane seeps have been reported in the rivers since 1850.		River silting.	Leakage of CO2/CH4 through aquatic sediments.	Disruption of aquatic ecological system.	Conduct baseline survey of local aquatic sediment conditions prior to injecting CO2. Monitor for CO2/CH4 bubbling through aquatic sediments.	Take into account aquatic sediments in site characterization, if applicable. Avoid sensitive areas or habitats for endangered or protected species. Monitor for CO2/CH4 in high-risk areas.	Monitor for significant changes in aquatic sediments. Determine root cause. Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
228	06.01.08.00.	Terrestrial ecological systems (See 06.01.07.00)	2	2	2	8	None	None	None	Accumulation of CO2 in poorly ventilated low areas resulting in fauna kill <\$100k \$50k / acre for soil remediation and /or vegetation replanting due to CO2/CH4 release	Included under natural resources.	None	None	Cost to locate and fix leak, \$0.3M for leaky well, \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Natural resource damage: <\$100k. Cost to locate and fix leaky well: \$300k.	Cost to locate and fix leaky well: \$300k.	Monitor for changes in flora and fauna. Monitor for CO2/CH4 in high- risk area. Cost: <\$100k	None	1	
229	06.02.00.00.	Aquatic environment	0	0	0	0																
230	06.02.01.00.	Coastal features	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
231	06.02.02.00.	Local oceanography	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
232	06.02.03.00.	Aquatic sediments	2	2	2	8	None	None	None	None	None	None	None	Monitor for CO2/CH4 in high- risk areas.	None	10% of total damage	Cost to locate and fix leaky well: \$300k.	None	Monitor for CO2/CH4 in high- risk areas.	None	2	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
233	06.02.04.00.	Aquatic flora and fauna	Features and processes related to the characteristics of aquatic flora and fauna, and their evolution. Includes plants, animals, fungi, algae and microbes.	Flora and fauna may be affected by concentrations of CO2 in the aquatic environment and may be indicators of CO2 leakage.	San Juan River listed as Quality Water for trout fishing) is located 4.8 km (3 mi) S of the site. Methane seeps have been reported in the rivers since 1850.		CO2/CH4 migration into aquatic areas containing flora and fauna.	Presence of aquatic flora and fauna in the area.	Endangerment of aquatic flora and fauna.	Conduct baseline survey of aquatic flora, fauna prior to CO2 injection. Monitor for changes in aquatic flora and fauna. Monitor for CO2/CH4 in the aquatic environment	Include aquatic flora and fauna in site characterization. Avoid sites with habitats for endangered or protected species. Monitor for CO2/CH4 in high-risk areas.	Monitor for significant changes in aquatic flora and fauna. Determine root cause. Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks.
234	06.02.05.00.	Aquatic ecological systems	Features and processes related to interactions between populations of algae, animals, microbes and their evolution. Characteristics of the ecological system. The algal, animal and microbial populations occupying the aquatic environment are an intrinsic component of its ecology. Their behavior and population dynamics are regulated by the wide range of processes that define the ecological system.	The ecology of the aquatic environment determines the types of organisms present and their inter-dependencies. These can influence the types of impact of interest and can provide a mechanism for monitoring CO2 leakage.	Simon Canyon Area of Critical Environmental Concern is located on the E side of the nine-section site area, less than 2 km (1.2 mi) from the CO2 injection well. The site has a local riparian ecological system. Pump Canyon on the W side of the injection site has a riparian ecological system. San Juan and Animas Rivers have several River Tracts with sensitive riparian ecological systems.		CO2/CH4 migration into aquatic ecological systems.	Presence of sensitive aquatic ecological systems.	Disruption of the aquatic ecological system.	Conduct baseline survey of aquatic ecological systems in the project area before CO2 injection. Monitor for changes in aquatic environmental systems. Monitor for CO2/CH4 in the aquatic environment.	Take into account aquatic ecological systems in site characterization. Avoid sites with sensitive areas or habitats for endangered or protected species. Monitor for CO2/CH4 in high-risk areas.	Conduct baseline survey of aquatic ecological systems in the project area before CO2 injection. Monitor for significant changes in the aquatic ecological systems. Determine root cause. Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks.
235	06.03.00.00.	Human behavior	Details of the human behavior in the near-surface environment where impacts may be incurred.	Human behavior will affect the nature and magnitude of potential impacts to human beings.								
236	06.03.01.00.	Human characteristics	Features and processes related to characteristics, e.g. physiology, metabolism, of individual humans. This includes considerations of variability, in individual humans, of physiology and metabolism due to age and other variations. Physiology refers to body and organ form and function. Metabolism refers to the chemical and biochemical reactions which occur within an organism, or part of an organism, in connection with the production and use of energy. Children and infants, although similar to adults, often have characteristic differences, e.g. metabolism and respiratory rates, which may lead to different characteristics of exposure to CO2 or contaminants.	Human physiology and metabolism determine the effect of exposure to CO2 and associated contaminants.	Section 32 has 0 population density. There are no known sensitive receptors such as school, hospitals, prisons, care centers, or churches in the area. Navajo Dam (population 281) is located 5.1 km (3.2 km) S of the CO2 injection site. Simon Canyon Area of Critical Environmental Concern is located on the E side of the nine-section site area, 2 km (1.2 mi) from the CO2 injection well.		Migration of CO2 into sensitive receptor areas (schools, hospitals, prisons, care centers).	Locating CO2 injection site near sensitive receptors. Leakage of CO2/CH4 through caprock to surface environment.	Endangerment of humans with greater vulnerability in areas of insufficient ventilation.	Conduct baseline survey of CO2/CH4 measurements in sensitive areas before injecting CO2. Monitor for CO2/CH4 in high-risk areas.	Take into account sensitive receptors in site characterization. Avoid sensitive receptor areas in site selection. Monitor for CO2/CH4 in high-risk areas	Monitor for CO2/CH4 in high-risk areas. Locate and fix CO2/CH4 leaks. Maintain an emergency response plan. Train operators, and first responders and educate residents what to do in case of a CO2/CH4 leak.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
233	06.02.04.00.	Aquatic flora and fauna	2	2	2	8	None	None	None	Potential fish kill: <\$100k	None	None	None	Monitor for changes in aquatic flora and fauna. Determine root cause. Monitor for CO2/CH4 in high- risk areas.	None	10% of total damage	Natural resource damage: <\$100k. Cost to locate and fix leaky well: \$300k.	None	Monitor for changes in aquatic flora and fauna. Determine root cause. Monitor for CO2/CH4 in high- risk areas.	None	1
234	06.02.05.00.	Aquatic ecological systems	2	2	2	8	None	None	None	Potential fish kill: <\$100k	None	None	None	Monitor for changes in aquatic flora and fauna. Determine root cause. Monitor for CO2/CH4 in high- risk areas.	None	10% of total damage	Natural resource damage: <\$100k. Cost to locate and fix leaky well: \$300k.	None	Monitor for changes in aquatic flora and fauna. Determine root cause. Monitor for CO2/CH4 in high- risk areas.	None	1
235	06.03.00.00.	Human behavior	0	0	0	0															
236	06.03.01.00.	Human characteristics	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
237	06.03.02.00.	Diet and food processing	Features related to intake of food and water by individual humans and the compositions and origin of intake. This includes considerations of how diets, of individual humans, may vary with age and other variations (ingestion of soil by infants, for example). This FEP also includes processes related to the treatment of foodstuffs and water between origin and consumption. For example, once a crop is harvested it may be subject to a variety of storage, processing and preoperational activities prior to human or livestock consumption. Water sources may be treated prior to human or livestock consumption, e.g. chemical treatment and/or filtration.	The human diet provides a potentially important exposure pathway to contaminants released into the food chain as a result of the CO2 sequestration system. Food preparation processes may change the distribution and content of CO2 and/or associated contaminants in the product.	Coal seams are mostly dewatered. Brine migration would be limited.. Formation Fluids have high pH due to biogenic carbonates. Approximately 99% of injected CO2 is adsorbed on coal and 1% remains as gaseous CO2 in cleat pore space. Agricultural activity is limited tom the Animas River valley. There are two important fishing areas nearby. San Juan River, is located 4.8 km (3 mi) S of the CO2 injection site. Navajo Lake State Park is located 8 km (5 mi) E and SE of the CO2 injection site.		Migration of CO2/CH4/brine containing heavy metals into agricultural areas and into the food processing chain.	Locating CO2 injection sites near agricultural land.	Contamination of food chain with heavy metals.	Characterize soils, water and crops in the site area. Conduct baseline survey for potential contaminants prior to CO2 injection. Monitor for significant changes in crops, agricultural products or soil and water chemistries. Monitor for CO2/CH4 in high-risk areas.	Characterize soils, water and agricultural products in the area. Conduct baseline survey for potential contaminants prior to CO2 injection. Avoid sensitive groundwater areas and areas with high content of heavy metals that could be leached out by acidic water. Maintain integrity of caprock and wells. Monitor for CO2/CH4 in high-risk areas.	Monitor soils, water and agricultural products for significant changes in contaminants. Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators, and first responders and educate residents what to do in case of a CO2/CH4 leak.
238	06.03.03.00.	Lifestyles	Features related to non-diet related behavior of individual humans, including time spent in various environments, pursuit of activities and uses of materials. This includes consideration of variability of the habits of individuals due to age and other factors. The human habits refer to the time spent in different environments in pursuit of different activities and other uses of materials. The diet and habits will be influenced by agricultural practices and human factors such as culture, religion, economics and technology.	Human habits will determine the exposure pathways of interest in an assessment. Camping, plowing, fishing, and swimming are examples of behavior that might give rise to extended close proximity exposure to CO2 and/or contaminants mobilized in an area of CO2 sequestration.	Camping and hiking available at Simon Canyon Area of Critical Environmental Concern, located on the E side of the Nine-Section Area, 2 km (1.2 mi) from the CO2 injection well. Fishing, boating and swimming available at Navajo Lake State Park 8 km (5 mi) E and SE of the CO2 injection site. Other recreation areas in the Sixteen-Township Area include: Alien Run biking, Navajo Lake Horse Trails, Rock Garden, San Juan River and Animas River.		Migration of CO2/CH4 into areas frequented by humans.	Locating CO2 injection sites near populated areas.	Endangerment of humans with in areas of insufficient ventilation.	Conduct baseline survey of CO2/CH4 in areas before injecting CO2. Monitor for CO2/CH4 in high-risk areas.	Take into account land use by humans in site characterization. Avoid popular recreation areas. Monitor for CO2/CH4 in high-risk areas.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators, and first responders and educate residents what to do in case of a CO2/CH4 leak.
239	06.03.04.00.	Land and water use	FEPs related to land and water use by humans in the near-surface environment and the resulting implications for CO2 leakage and contaminant transport and exposure pathways. This includes consideration of: - the use of natural or semi-natural tracts of land and water such as forest, brush, rivers, lakes and the sea; - rural and agricultural land and water use (including freshwater and marine fisheries); - urban and industrial land and water use related to developments, including transport, and their effects on hydrology; and - leisure and other uses of environment.	These FEPs can influence the potential transport and exposure pathways for CO2 and its associated contaminants as well as the potential evolution of the system during the timescales of interest. Particular considerations are relevant for each type of land use addressed, for example: - special foodstuffs and resources may be gathered from natural land and water which may lead to significant modes of exposure to CO2 or contaminants; - an important set of processes are those related to agricultural practices, their effects on land form, hydrology and natural ecology, and also their impact in determining contaminant uptake through food chains and other exposure paths; - human populations are concentrated in urban areas in modern societies. Significant areas of land may be devoted to industrial activities. Water resources may be diverted over considerable distances to serve urban and/or industrial requirements; - significant areas of land, water, and coastal areas may be devoted to leisure activities. e.g. water bodies for recreational uses, mountains/wilderness areas for hiking and camping activities.	Land use in Section 32 is limited to CBM production. The only surface water is a small spring (Quintana Spring). The land is not suitable for agricultural use, other than range grazing of cattle. Simon Canyon Area of Critical Environmental Concern is located on the E side of the nine-section site area, less than 2km (1.2 mi) from the CO2 injection well. This area is used for recreational activities.		Migration of CO2/CH4 into areas of significant land and water use.	Locating CO2 injection sites near land and water used by humans.	Endangerment of humans within areas of insufficient ventilation.	Conduct baseline survey on land use and future planning. Monitor changes in zoning and land use. Monitor for CO2/CH4 in high-risk areas.	Take into account current and future land use in site characterization. Avoid sites that are densely populated, sensitive receptor areas, or subject to future urban sprawl or industrialization. Maintain integrity of caprock and wells. Monitor for CO2/CH4 in high-risk areas.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators, and first responders and educate residents what to do in case of a CO2/CH4 leak.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
237	06.03.02.00.	Diet and food processing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
238	06.03.03.00.	Lifestyles	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
239	06.03.04.00.	Land and water use	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
240	06.03.05.00.	Community characteristics	Features related to characteristics, behavior and lifestyle of groups of humans that might be considered as target groups in an assessment. Relevant characteristics might be the size of a group and degree of self-sufficiency in food stuffs/diet. Associated with this is a consideration of the amount of resources required to meet the needs of the community.	This FEP involves a consideration of aggregated human behavior in order to consider their dependency on and interactions with their environment. It therefore provides input to a consideration of potential human interference with the CO2 storage system as well as input to considering potential exposure pathways.	The nearest communities are: Navajo Dam (population 281) located 5.1 km (3.2 km) S of CO2 injection site. Turley NM (pop. 443): 11 km (7 mi) SW. Blanco, NM (pop. 481): 18 km (11 mi) SW. Cedar Hill, NM (pop. 847): 19 km (12 mi) W. Aztec, NM (pop. 6,763): 26 km (16 mi) W. Bloomfield, NM (pop. 7,998): 29 km (18 mi) SW. Farmington, NM (pop. 45,256) 32 km (20 mi) SW.		Migration of CO2/CH4 into densely populated areas.	Locating CO2 injection site near densely populated areas.	Endangerment of humans in areas of insufficient ventilation.	Conduct baseline survey of CO2/CH4 in sensitive areas before injecting CO2. Monitor for CO2/CH4 in high-risk areas.	Take into account human population density and behavior in site characterization. Avoid areas of high population density. Maintain integrity of caprock and wells. Monitor for CO2/CH4 in high-risk areas.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators, and first responders and educate residents what to do in case of a CO2/CH4 leak.
241	06.03.06.00.	Buildings	Features related to houses, or other structures or shelters, in which humans spend time. 1. Basements/cellars 2. Subterranean pathways	The structure or materials used in building construction be significant factors for determining potential exposure pathways to CO2 or contaminants. For example, given that CO2 is denser than air, it may accumulate in the basements/cellars of dwellings.	Nine-Section Area There are only a few small utility buildings associated with CBM activities in the Nine-Section Area. Sixteen-Township Area Navajo Dam (population 281) located 5.1 km (3.2 km) S of the Pump Canyon CO2 injection Site. Turley NM (pop. 443): 11 km (7 mi) SW. Blanco, NM (pop. 481): 18 km (11 mi) SW. Cedar Hill, NM (pop. 847): 26km (16 mi) W.		Human injury/death resulting from migration of CO2/CH4 into unventilated confined spaces. Foundation cracking due to subsidence or uplift.	Presence of buildings in the CO2 injection area.	Endangerment of humans. Building damage Liability costs.	Monitor for CO2/CH4 in high-risk areas. Monitoring uplift/subsidence and significant cracking in foundations.	Take into account buildings in site characterization. Ventilate confined areas. Avoid injection CO2 in densely populated areas. Maintain integrity of caprock and wells. Monitor for CO2/CH4 in high-risk area.	Monitor for CO2/CH4 in high-risk areas. Ventilate confined areas. Locate and fix leaks. Maintain an emergency response plan. Train operators, and first responders and educate residents what to do in case of a CO2/CH4 leak.
242	07.00.00.00.	IMPACTS	This category of FEPs is concerned with any endpoint that could be of interest in an assessment of performance and safety. The classes of impact considered are: Impacts to Humans; Impacts to Flora and Fauna; and Impacts to the Physical Environment. Note that: - financial impacts are assumed to be implicitly considered within each of the impact FEPs; and - unless stated, the FEPs refer to both CO2 and mobilized contaminants (minerals, heavy metals, hydrocarbons (e.g., EOR and ECBM), gases).	This category is divided into four classes: 1. System performance 2. Impacts on the physical environment 3. Impacts on flora and fauna 4. Impacts on humans								
243	07.01.00.00.	System performance	Performance of the sequestration system from the perspective of its success at preventing sequestered CO2 from reaching the atmosphere.	The fate of sequestered CO2 is a fundamental endpoint for an assessment.								

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS/D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
240	06.03.05.00.	Community characteristics	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
241	06.03.06.00.	Buildings	3	4	3	36	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$0.3M for leaky well or \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	Assuming leakage undetected or unmitigated for 5 years: <\$6.8M to locate and fix leak and remediate.	Assuming leakage detected early and mitigated <\$3.3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high- risk areas \$150k:	Savings of \$3.35M	2	
242	07.00.00.00.	IMPACTS	0	0	0	0																
243	07.01.00.00.	System performance	0	0	0	0																

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
244	07.01.01.00.	Loss of containment	Loss of sequestered CO2 from the intended storage reservoir. Loss includes both consideration of loss to other parts of the geosphere and to the near-surface and surface environments, such as loss to marine water and surface water bodies, where CO2 may result in stratification or pooling.	Loss of containment may be an endpoint of interest to the assessment. For example, the assessment context may dictate that near-surface or surface processes are outside the scope of the assessment.	Methane seeps have occurred over the past 100 years in the San Juan River and Animas River areas suggesting that the Fruitland reservoir is not fully contained. Monitoring of the CO2 injection site, during and after injection, indicated no CO2 leakage from the Fruitland reservoir. However, CO2 injection was limited to 16,781 tonne and didn't reach the nearest production wells. Perfluorocarbon tracer (from CO2 injection) was detected in the soil near one of the production wells (ENPG A COM 300) from February to July of 2010. The operator determined that the cause was a leaky pipeline beneath the well pad. The pipeline was repaired and the tracer signal went away. There are over 90 existing deep wells in the nine-section area of the site. Sixteen wells are over 50 years old.		Migration of CO2/CH4 into overlying formations, soil, aquifers and/or atmosphere.	Loss of containment.	Endangerment of humans, fauna or flora in low areas or confined areas with insufficient ventilation.	Monitor for CO2/CH4 in high-risk areas.	Ensure integrity of the caprock, lateral seals and wells. Site project in areas with multiple stacked seals and sinks. Avoid injecting CO2 near sensitive high-risk areas. Monitor for CO2/CH4 in high-risk areas.	Monitor pressure in formations above the caprock. Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators, and first responders and educate residents what to do in case of a CO2/CH4 leak.	
245	07.02.00.00.	Impacts on the physical environment	FEPs relevant to adverse impacts on the physical environment. Note that these may be endpoints of interest in themselves, but may also cause other impacts of interest.	Adverse impacts on the environment can be postulated as a result of sequestration operations, even if there are no associated impacts to humans or on flora and fauna.									
246	07.02.01.00.	Contamination of groundwater (and/or surface water)	The existence of water aquifers may be important if they are subject to CO2-induced chemical changes or CO2-induced saline intrusion. The migration of CO2 into an aquifer will result in the acidification of the water. Depending on the mineralogical composition of the aquifer and the chemical composition of the water, chemical reactions may occur which release heavy metals from the solid phase. The mechanisms which may cause this release include dissolution of metal oxides or oxyhydroxides, the reaction/diagenesis of clay minerals, and the desorption of metals that are adsorbed on clay surfaces or organic complexes. 1. CO2 contamination of underground drinking water sources 2. CO2 contamination of surface waters 3. Displaced brine contamination of groundwater. 4. EOR oil spill (see 16.22.00)	Contamination of groundwater resources may result in impacts on flora, fauna and/or humans if the water is abstracted or flows to the surface environment. These potential impacts are considered in the subsequent FEP classes, however, contamination of groundwater may be an endpoint of interest in itself. An increase in CO2 concentration might cause a decrease in pH to a level of 4-5, which might cause calcium dissolution, increase in the hardness of water and alteration of minerals from minerals from rocks and soils that could release elements such as heavy metals into the water supply. Foundations of buildings could be damaged by seepage of groundwater containing CO2 in shallow unconsolidated sediments and soils. This could be a problems if CO2 were to be stored (and leak) underneath, for example, historical city centers, other heritage objects, or archeological sites (CO2STORE) Surface water could be contaminated by CO2 leakage, which could affect aquatic ecosystems by decreasing pH, especially in stagnant or stratified waters (Damen 2006) Displaced brine may cause undesirable effects such as a rise of the water table (which could have negative impact on land quality and use) and an increase in salinity of sweet water reservoirs used for drinking water extraction and irrigation (Damen	Shallow groundwater at this site already contained methane prior to CO2 injection began. Fruitland Formation fluid was high in biogenic bicarbonate prior to CO2 injection. Coal seams have been dewatered. Approximately 99% of injected CO2 adsorbed on coal and 1% remains as gaseous CO2 in cleat pore space.	Baseline USDW water quality at this site not available.	Increase of CO2, CH4, salinity, and/or heavy metal content, and decrease in pH of groundwater or surface water.	Contamination of groundwater (and/or surface water).	Endangerment of flora and fauna. Cost of water replacement or treatment to remove contaminants.	Conduct baseline survey on ground / surface water for CO2/CH4, salinity, pH and heavy metals prior to CO2 injection. Monitor for CO2/CH4 in high-risk areas.	Include near-surface aquifers and surface waters in site characterization. Avoid sites with sensitive groundwater areas. Maintain integrity of caprock and lateral seals. Monitor for CO2/CH4 in high-risk areas.	Monitor aquifers for significant changes in CO2/CH4/salinity/pH and heavy metals. Determine root cause for any changes. Use tracers if necessary. Locate and fix leak. Locate, isolate and remediate contaminated water. Monitor for CO2/CH4 in high-risk areas. Maintain an emergency response plan. Train operators, and first responders and educate residents what to do in case of a CO2/CH4 leak.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking			Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)		Savings with risk mitigation (\$)
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
244	07.01.01.00.	Loss of containment	4	3	3	36	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 / acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$0.3M for leaky well or \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	\$4M to locate and fix leak and remediate.	\$3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high- risk areas \$150k:	Savings of \$0.85M	2
245	07.02.00.00.	Impacts on the physical environment	0	0	0	0															
246	07.02.01.00.	Contamination of groundwater (and/or surface water)	2	3	3	18	None	None	None	<1,000 t/y CO2/brine per leak @ \$200/t CO2 released into USDW \$50,000 per acre to remediate contaminated wetlands and surface waters	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix CO2/CH4 leak: \$0.3M for leaky well or \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: <\$5.1M to locate and fix leak and remediate.	Assuming leakage detected early and mitigated <\$3.3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high- risk areas \$150k:	Savings of \$1.65M	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
247	07.02.02.00.	Impacts on soils and sediments	Soils and sediments may have elevated concentrations of CO ₂ , should it leak from the storage system, and/or other contaminants, such as heavy metals, hydrocarbons (e.g., EOR and ECBM) or even increased salinity resulting from CO ₂ sequestration. For example, natural CO ₂ leaking from a trapped reservoir near Mammoth Mountain, in California, has resulted in soil gas concentrations of 20 to 90%. 1. Contamination of soil 2. Contamination of sediments	Increased CO ₂ concentrations and/or contamination of soils and sediments with associated substances may be sufficient to modify the ecology and/or use of the impacted area by humans.	Local soil is of poor quality and rocky, therefore unlikely to be impacted by CO ₂ .		Accumulation of CO ₂ /CH ₄ / H ₂ S / brine in soil and sediments.	Release of CO ₂ /CH ₄ into soil or sediments	Land use restrictions. Cost of soil/sediment cleanup	Conduct baseline study for CO ₂ /CH ₄ in soils and sediments. Monitor for CO ₂ /CH ₄ in high-risk areas.	Take into account soils and sediments in site characterization. Maintain caprock and well integrity. Select site with multiple stacked seals and sinks. Monitor for CO ₂ /CH ₄ in high-risk areas.	Conduct baseline study for CO ₂ /CH ₄ in soils and sediments. Including isotopes to determine gas source. Periodically monitor near surface for CO ₂ /CH ₄ . Identify any irregularities, such as vegetation dying out. Locate and fix leaks.
248	07.02.03.00.	CO ₂ release to the atmosphere	Release of CO ₂ (or other contaminants, such as radon or methane, mobilized as a result of the sequestration) to the atmosphere from the storage system .	Release of sequestered CO ₂ or mobilized methane to the atmosphere will reduce the effectiveness of the storage system at preventing greenhouse gases from being emitted to the atmosphere. Atmospheric contamination could also lead to health impacts on humans and wildlife. Rapid release likely to effectively disperse the CO ₂ higher in the atmosphere. Moderate release likely to concentrated CO ₂ near the ground, representing the highest risk. Slow release likely to disperse CO ₂ in the soil and atmosphere.	The amount of CO ₂ likely to be released into the atmosphere is minimal because the injected CO ₂ will be adsorbed on coal. CH ₄ released in small to moderate amounts into the atmosphere will be rapidly dispersed due to its light density compared to air. Large releases of CH ₄ could be ignited, leading to fire and/or explosion. CBM produced in the area has high (20-30 volume %) CO ₂ content due to release of in-situ natural CO ₂ . The CO ₂ must be removed from the CBM in order to meet natural gas specifications. This CO ₂ is currently released to the atmosphere. Pump Canyon Site CO ₂ and tracer monitoring during and after CO ₂ injection showed no CO ₂ release from underground.		Human injury/death resulting from: Accumulation of CO ₂ in low surface areas with insufficient wind. Accumulation of CO ₂ /CH ₄ in unventilated confined spaces.	Release of CO ₂ /CH ₄ to the atmosphere	Endangerment of humans at high CO ₂ /CH ₄ levels. Potential fire or explosion.	Monitor for CO ₂ /CH ₄ in high-risk areas, around wells and near faults or fractures.	Maintain integrity of caprock, wells, piping and equipment. Avoid repressurizing the reservoir. Ventilate confined areas. Monitor for CO ₂ /CH ₄ in high-risk areas. Maintain blowout protector, packers and valves in operating condition.	Monitor for CO ₂ /CH ₄ in high-risk areas, around wells and near faults or fractures. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO ₂ /CH ₄ leak.
249	07.02.04.00.	Impacts on exploitation of natural resources	The impact of CO ₂ sequestration on the exploitation of natural resources such as oil and gas. Enhanced oil recovery (EOR) and enhanced coal bed methane (ECBM) recovery projects involving the injection of CO ₂ are based on improved recovery of oil and methane respectively resulting from CO ₂ sequestration. However, CO ₂ sequestration may result in the contamination of geological resources (such as hydrocarbons and minerals) or inhibit their recovery or future exploitation. Note that the potential impact on groundwater resources is considered in Impacts on groundwater. 1. Contamination of mineral resources 2. Contamination of mineable coal seams 3. Contamination of oil resources 4. Contamination of natural gas resources 5. Contamination of geothermal resources 6. Contamination of pore space owned by others.	Impacts on the exploitation of natural resources can be positive (such as EOR and ECBM) and/or negative (such as inhibited recovery). These may result in other (for example, financial) impacts, or may be endpoints of interest in themselves.	Approximately 65% of the original gas (CBM) in the Fruitland Formation at the site area has been recovered. Conventional natural gas and tight gas are also recovered from formations underlying the Fruitland Formation.	No project planned at this time. Specific area, land and mineral rights ownership not available. Classification of USDW aquifers not clear in the area.	Decreased third-party CBM production due to repressurizing the coal seams with CO ₂ injection.	Natural resources adjacent to the injection site.	Liability for remediation, business interruption and advanced loss of profits.	Conduct detailed risk assessment on site selection. Monitor CO ₂ /CH ₄ in high-risk areas.	Maintain integrity of the caprock, wells and surface facilities. Avoid repressurizing the coal seams until CBM operations have ended.	Monitor for CO ₂ /CH ₄ in high-risk areas, around wells and near faults or fractures. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO ₂ /CH ₄ leak.

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Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
247	07.02.02.00.	Impacts on soils and sediments	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
248	07.02.03.00.	CO2 release to the atmosphere	3	4	3	36	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<1,000 t/yr CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and mitigate near surface leakage of CO2/CH4: \$3M	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	Assuming leakage undetected or unmitigated for 5 years: <\$6.8M to locate and fix leak and remediate.	Assuming leakage detected early and mitigated <\$3.3M to locate and fix leak and remediate.	Monitor for CO2/CH4 in high- risk areas \$150k	Savings of \$3.35M	2
249	07.02.04.00.	Impacts on exploitation of natural resources	1	5	1	5	None	None	None	None	Typical CBM fairway well production: 2013-2022: 260MMCF@ \$3.50/MCF = \$0.91M revenue loss per well if coal seams are repressurized early.	None	None	Typical CBM fairway well production: 2013- 2022: 260MMCF@ \$3.50/MCF = \$0.91M revenue loss per well if coal seams are repressurized early.	None	None	Revenue loss for a set of 16 CBM wells: \$15M Revenue loss for a set of 160 CBM wells: \$146M	None	Delay CO2 injection until CBM is nearly depleted (after 2021)	Savings could exceed \$100M.	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
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250	07.02.05.00.	Modified hydrology and hydrogeology	The injection of CO2 may result in modifications to both the deep hydrogeology and near-surface hydrology.	Changes in the deep hydrogeology or near-surface hydrology may affect aquifer abstraction or even surface hydrology for groundwater driven features. These impacts may be either positive or negative.	Fruitland Formation fluids are recharged artesian-style from high elevation outcrops located 48 km (30 mi) N of the injection site. The SJB has an inferred structural hingeline consisting of a NW-trending fault zone located 10 km (6 mi) S of the CO2 injection site. Permeability decreases SW of the hingeline due to the pinchout of high-permeability stratigraphic units. This caused a backup of formation fluids resulting in overpressuring of the Fruitland Formation at the CO2 injection site. This area has been depressurized from 11.33 MPa (1,644 PSIA) to 0.69 MPa (100 PSIG) by CBM/dewatering operations. Approximately 99% of injected CO2 is adsorbed on coal and 1% remains as free gaseous CO2 in cleat pore space. CBM water production has depressurized the Fruitland Formation and slowed recharging via meteoric waters flowing from the north side of the basin where the Fruitland Formation outcrops at higher elevation.		Damage to near surface aquifers.	Modified hydrology and hydrogeology as result of CO2 injection, migration, or leakage.	Contamination of water with CO2/CH4/brine.	Conduct baseline survey of groundwater level and quality prior to CO2 injection. Monitor for significant changes in CO2, CH4, salinity, pH. Monitor water level in wells. Monitor for CO2/CH4 in high-risk areas..	Take into account hydrology and hydrogeology in site characterization and modeling. Maintain integrity of caprock and wells. Select site with multiple stacked sinks and seals. Monitor for CO2/CH4 in high-risk areas.	Monitor pressure in formations above the caprock and secondary seals. Monitor water level in wells. Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
251	07.02.06.00.	Modified geochemistry	The injection of CO2 will modify the geochemistry of the sequestration system. This may be confined to the immediate vicinity of the storage location, or, through leakage from the reservoir, may affect other locations.	The extent of geochemical modifications may be an endpoint of interest, due to resulting changes to geological processes. For example, the acidification of the geochemical regime may cause minerals to be dissolved, with potential implications for the porosity and stability of the geological formations.	There has been no conclusive indication of produced water chemistry change as a result of CO2 breakthrough at the site. The pH of the produced water stabilized at around 8.0 with variations ranging from 7.0 to 9.0. Presence of H2S showed a dramatic impact on produced water chemistry analysis. Fluctuation of H2S in produced water was not fully understood (ARI 2010).		1. Dissolution of minerals. 2. Precipitation of minerals.	Modified geochemistry due to CO2	1. Weakening of formation mechanical properties leading to fracture and/or subsidence. 2. Decreased injectivity .	Characterization and modeling of caprock and reservoir geochemical properties based on drill core analyses.	Take into account geochemistry in site characterization, modeling and reservoir engineering.	Monitor and model injectivity and production pressure. Use selective perforation and water curtains to deal with nonuniform CO2 flow. Use acid treatment to remove carbonate mineral precipitation.
252	07.02.07.00. (See 03.02.06.00)	Modified seismicity	Injection of supercritical CO2 into a geological formation may induce seismic events and processes.	Induced seismicity may be an endpoint of interest in itself, or it can result in other impacts, such as physical disruption of the surface environment.	No induced seismicity was observed during the CO2 injection test and during CBM operation.							

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
250	07.02.05.00.	Modified hydrology and hydrogeology	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
251	07.02.06.00.	Modified geochemistry	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
252	07.02.07.00. (See 03.02.06.00)	Modified seismicity	0	0	0	0															

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
253	07.02.08.00.	Modified surface topography	The gradual or sudden sinking (subsidence) or elevation (uplift) of the topography of the terrestrial surface or marine sea-bed.	Deformation of the terrestrial surface or sea-bed may be an endpoint of interest in itself, or may result in other impacts, such as damage to property.	Parts of the surface in Section 32 subsided by as much as 2 cm (0.77 in) over a 14.5 month period (1 AUG 2008-17NOV 2009) while other parts of the surface uplifted by as much as 0.5 cm (0.21 in). Note that during this time, CBM was produced by multiple wells from the Fruitland Formation, conventional natural gas was produced from the deeper Mesaverde Group, and CO2 was injected for part of the time (30JUL2008-12AUG2009). Closer to the CO2 injection well, the subsidence was 1.7 cm (0.67 in) and the uplift was 0.1 cm (0.04 in). (ARI 2010).		Building and/or infrastructure damage. Change in drainage/water flow impacting agricultural land.	Subsidence or uplift.	Liability for damage to surface buildings and infrastructure Surface displacement monitoring (InSAR or LIDAR). Monitor bottomhole pressure.	Monitor for significant cracks in building or infrastructure foundations. Passive seismic monitoring. Surface displacement monitoring (InSAR or LIDAR). Monitor bottomhole pressure.	Take into account subsidence or uplift in site characterization and modeling. Avoid shallow injection sites or sites susceptible to significant dissolution of minerals or mineral expansion. Maintain injection pressure below 90% of fracture pressure.	Monitor for significant cracks in building and infrastructure foundations. Monitor any mineral dissolution in critical formations based on produced water composition. Operate below 90% of fracture pressure. Monitor injection pressure. Monitor surface displacement with InSAR or LIDAR.
254	07.02.08.01.	Sinkhole formation	Addition of CO2 in a limestone or carbonate-rich aquifer could result in dissolution of the rock matrix and the enlargement of voids. If this process takes place at relatively shallow depth collapse may result in subsidence at the surface and sinkhole formation. For example, CO2 leakage around a borehole drilled to extract natural CO2 from a reservoir in Florina, Greece, resulted in subsidence around the borehole that filled up with water.	Large scale collapse structures may cause significant change to surface topography and possible CO2 migration paths. Sinkholes can provide locations where leaking CO2 can accumulate.	No sinkholes have been observed in the area. Sinkholes tend to be associated with carbonate formations. This area is mostly clastic formations.		Fracturing of overlying formation. CO2/CH4 migration through sinkhole. Surface subsidence.	Sinkhole formation.	Leakage of CO2/CH4 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Building and/or infrastructure damage.	Monitor surface displacement (InSAR or LIDAR). Monitor for significant cracks in building or infrastructure foundations. Monitor and model mineral dissolution. Monitor for CO2/CH4 in high-risk areas.	Take into account limestone formations (susceptible to dissolution) in site characterization and modeling. Avoid sites with shallow limestone formations that have the potential for sinkhole formation. Maintain caprock and well integrity.	Monitor for significant cracks in building and infrastructure foundations. Monitor any mineral dissolution in critical formations based on produced water composition. Monitor surface displacement (InSAR or LIDAR).
255	07.03.00.00.	Impacts on flora and fauna	FEPs relevant to impacts on flora and fauna. 1. Natural flora and fauna 2. Agricultural flora and fauna	Impacts on flora and fauna can be postulated as a result of sequestration operations, even if there are no associated impacts to humans.								

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
253	07.02.08.00.	Modified surface topography	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
254	07.02.08.01.	Sinkhole formation	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
255	07.03.00.00.	Impacts on flora and fauna	0	0	0	0															

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256	07.03.01.00.	Asphyxiation effects	Asphyxiation effects of CO2 on terrestrial and aquatic fauna. Oxygen is an essential requirement for respiration in animals and is therefore needed to sustain life. High concentrations of CO2 in air or water will lead to suffocation of terrestrial and aquatic animals due to a lack of oxygen reaching the blood stream. If meteorological conditions do not disperse CO2 released to the atmosphere, it can gather close to the surface and remain in depressions, such as natural hollows. This property allows CO2 to reach high concentrations if released in sufficient quantities under particular atmospheric conditions. The 1986 Lake Nyos disaster in Cameroon provides a graphic example of the potential effects of high atmospheric concentrations of CO2. A large limnic eruption resulted in the death of wildlife and approximately 1800 people in the surrounding area and up to 27 km away. In a similar way to gaseous CO2 being denser than air, water containing high concentrations of dissolved CO2 is denser than pure water, a factor that contributes to the limnic eruption phenomenon observed at Lake Nyos. In addition to the possibility of dissolved CO2 causing asphyxiation in aquatic organisms, if gaseous CO2 forms a layer at the surface of water bodies, it can prevent the oxygenation of the water and lead to a reduction of the O2 concentration thereby contributing to asphyxiation of aquatic organisms.	Levels of CO2 from a sequestration project sufficient to cause asphyxiation of fauna would be an endpoint of concern in assessing the geological sequestration of CO2.	Fauna consists of rangeland wildlife such as mule deer, elk, coyote, porcupine, jackrabbit, cottontail, spotted ground squirrel, gray fox, skunk and weasel. Birds include turkey, sage grouse, bald eagle, oriole, pinion jay, cliff and violet green swallow, black-billed magpie, northern flicker, flycatcher, woodpecker, white-throated swift, canyon wren, mourning dove, turkey vulture, sharp-shinned hawk, American kestrel, northern harrier, golden eagle, great horned owl, prairie falcon, quail, and red-tailed hawk. Sensitive habitat areas include Bald eagle habitats; Reese Canyon habitat for threatened and endangered species; riparian areas along Pump Canyon, Animas River, San Juan River; Simon Canyon; and Navajo Reservoir. Agricultural animals are located along the Animas River area.		Endangerment of fauna.	Asphyxiation effects of CO2 on fauna when CO2 accumulates in low areas or confined spaces.	Liability costs for fauna kills.	Conduct baseline survey of fauna species in the area. Monitor for unexplained fauna kills. Monitor for CO2/CH4 in high-risk areas.	Maintain integrity of caprock and wells. Avoid CO2 injection near habitats for endangered or protected species. Monitor for CO2/CH4 in high-risk areas. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
257	07.03.02.00.	Effects of CO2 on plants, algae, fungi and microorganisms	Plants, algae, fungi and microorganisms (in both terrestrial and aquatic environments) use energy in sunlight to photosynthesize carbohydrates from CO2 and water (H2O). Increasing concentrations of CO2 around the photosynthetic tissues, increases the rate of photosynthesis and therefore growth and productivity in terrestrial and aquatic plants and algae. However, the roots of most plants need oxygen to breakdown carbohydrates to provide energy for root growth and healthy metabolism, a process called aerobic respiration. High concentrations of CO2 in the soil reduces the availability of O2 and can cause roots and therefore plants to die. At Mammoth Mountain, in California, CO2 has accounted for up to 95% of the gas concentration in soil at the edge of Horseshoe Lake due to release from natural geological CO2 reservoirs caused by volcanic activity. These high soil concentrations have resulted in areas of forest being killed.	Concentrations of CO2 in the soil, atmosphere and/or water sufficient to impact on the growth of plants and algae would be an endpoint of interest in assessing the geological sequestration of CO2.	Vegetation is dominantly grasses and scattered pinyon and juniper in Section 32. Microorganisms form a quarter inch crust on sand in the area that helps prevent wind erosion. Algae and fungi are prevalent in riparian areas of Simon Canyon, San Juan River, Animas River, Pump Canyon and Navajo Reservoir.		Endangerment of plants, algae, fungi and microorganisms.	Effects of CO2 on plants, algae, fungi and microorganisms	Disruption of ecological systems. Liability costs for flora kills.	Conduct baseline survey of species in soil, sediments and water. Monitor CO2/CH4 levels in soils, sediments and water.	Maintain integrity of caprock and wells. Avoid CO2 injection near habitats for endangered or protected species. Monitor for CO2/CH4 in high-risk areas. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
256	07.03.01.00.	Asphyxiation effects	2	2	2	8	None	None	None	Animal kill:<\$0.5M	Animal kill:<\$0.5M	None	None	Cost to locate and fix leak: \$0.3M for leaky well or \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Damage recovery cost: <\$1M per event	None	Maintain integrity of caprock and wells. Part of ongoing costs. Monitor for CO2/CH4 in high risk area: <\$150k	Savings: <\$850k.	1
257	07.03.02.00.	Effects of CO2 on plants, algae, fungi and microorganisms	2	2	2	8	None	None	None	\$50,000/acre soil contamination and/or vegetation kill (likely to be very localized)	Up to \$1,000/acre for crop kill. Up to \$5,000 per acre for timber kill (likely to be very localized)	None	None	Cost to locate and fix leak: \$0.3M for leaky well or \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Damage recovery cost: <\$1M per event	None	Maintain integrity of caprock and wells. Part of ongoing costs. Monitor for CO2/CH4 in high risk area: <\$150k	Savings: <\$850k.	1

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Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
258	07.03.03.00.	Ecotoxicology of contaminants	Ecotoxicology deals with the toxic effects of contaminants on the biosphere. Contaminants other than CO2 may be introduced to the biosphere as a result of geological CO2 sequestration due to: - impurities associated with the sequestration fluid, such as hydrogen sulfide (H2S), methane (CH4), nitrogen oxides (NOx) and mercaptans; - the mobilization of substances in the geological environment due to the sequestration of CO2, such as hydrocarbons (e.g., EOR and ECBM), brine, CH4 and heavy metals. These substances may have a toxic effect on organisms in the biosphere, including plants, animals, algae and fungi. 1. H2S release impact on the biosphere 2. Methane release impact on the biosphere 3. Heavy metal release impact on the biosphere 4. Mercaptans release impact on the biosphere 5. NOx release impact on the biosphere	The potential for contaminants associated with and/or mobilized by CO2 sequestration to have a toxic effect on organisms should they migrate to the biosphere will be of interest in an assessment of the geological sequestration of CO2. Methane leakage may affect shallow water quality and pose a lethal threat when accumulating in confined spaces such as basements/cellars. The global warming potential of methane is circa 23 times that of CO2 (Damen 2006)	Hydrogen sulfide is at very low levels in the injected CO2 and produced CBM but was sporadically identified in produced water. Some H2S may have been released into the Fruitland and higher formations by sills that penetrate the formations on the E side of the SJB. Methane is present in formations below and above the Fruitland Formation. Methane seeps have been noted in the local region. Fruitland coal contains selenium and mercury. Radon gas is present in the area, probably from uranium decay in the Morrison Formation.	Lacking data on heavy metals in the area.	Endangerment of flora and fauna.	Ecotoxicity of contaminants.	Disruption of ecological systems. Liability costs for flora and/or fauna kills. Conduct baseline survey of contaminants in soil, sediments, water prior to CO2 injection. Monitor for CO2/CH4 in high-risk areas. Monitor for contaminants in near-surface soil, sediments and water.	Maintain integrity of caprock and wells. Avoid CO2 injection near habitats for endangered or protected species. Monitor for CO2/CH4 in high-risk areas. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.	
259	07.03.04.00.	Ecological effects	Geological sequestration of CO2 may have an impact on the biosphere at a community, population and/or ecological level, with subsequent implications for biodiversity. The potential impact of releases of CO2 and associated or mobilized contaminants into the biosphere may disrupt biological interactions sufficiently to modify the terrestrial or aquatic ecosystems affected. For example, the sudden release of natural CO2 due to the limnic eruption at Lake Nyos, Cameroon, resulted in the sudden death of wildlife, but was unlikely to affect the ecology in the longer term. However, the continued gradual release of natural CO2 into soil near Mammoth Mountain, California, has been sufficient to kill trees and damage the local ecosystem since 1996 until the present day.	The degree of potential ecological disruption resulting from geological CO2 sequestration may be an endpoint of interest, especially if the ecosystem affected is considered valuable and/or sensitive to perturbations.	Simon Canyon Area of Critical Environmental Concern is located on the E side of the nine-section site area, 2 km (1.2 mi) from the CO2 injection well. San Juan River trout fishing area is located 4.8 km (3 mi) S of the CO2 injection site.		Endangerment of flora and/or fauna.	Disruption of the ecological system by CO2, CH4, brine and other contaminant migration.	Liability costs. Characterize the on-site ecological systems. Conduct baseline survey for CO2/CH4 and associated contaminants in the near-surface prior to CO2 injection. Monitor for CO2/CH4 in high-risk areas.	Maintain integrity of caprock and wells. Avoid CO2 injection near habitats for endangered or protected species. Monitor for CO2/CH4 in high-risk areas. Avoid repressurizing the reservoir.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.	
260	07.03.05.00.	Modification of microbiological systems	Microbes will be present in the geosphere as well as in the terrestrial and/or marine environments above the CO2 storage reservoir. CO2 sequestration may disrupt microbial aerobic respiration but may enhance anaerobic respiration, with subsequent implications for the processes in which the microbes are involved. Microbes play an important roll in all terrestrial and aquatic ecosystems, including those associated with extreme environments, such as deep sea hydrothermal vents.	The potential impact of CO2 sequestration on aerobic and anaerobic microbial respiration in the geosphere, terrestrial and aquatic biosphere may be an endpoint of interest.	Microbiological systems played a key role in production of methane and bicarbonate-rich fluids in the Fruitland Formation. Microbe activity has decreased as regional formation temperatures due to cooling of magmatic intrusion NE of the injection site.	Lacking data on current microbiological systems	Endangerment of flora and/or fauna.	Modification of microbiological systems by CO2, CH4, brine or other contaminant migration. Disruption of lower food chain. Plugging of pores and wellbores. Microbial generation of CH4 or H2S. Note that microbe activity can have a positive impact on ECBM and EOR. Conduct baseline survey of terrestrial, aquatic and sub-surface microbiological systems prior to CO2 injection. Monitor for significant changes in microbiological systems during CO2 injection. Monitor for CO2/CH4 in high-risk areas.	Characterize site for terrestrial, aquatic and sub-surface microbiological systems. Properly treat water prior to injection underground. Use of biocides to avoid sub-surface microbial growth. Avoid injection of oxygen and organics with CO2. Monitor for CO2/CH4 in high risk areas.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.		
261	07.04.00.00.	Impacts on humans	FEPs relevant to adverse impacts on people.	A range of possible impacts to human beings can be postulated as a result of sequestration operations.								

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings					Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS-D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
258	07.03.03.00.	Ecotoxicology of contaminants	2	2	2	8	None	None	None	\$50,000/acre to remediate disturbance of ecological system.	\$50,000/acre to remediate disturbance of ecological system.	None	None	Cost to locate and fix leak: \$0.3M for leaky well or \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Damage recovery cost: <\$1M per event	None	Maintain integrity of caprock and wells. Part of ongoing costs. Monitor for CO2/CH4 in high risk area: <\$150k	Savings: <\$850k.	1	
259	07.03.04.00.	Ecological effects	2	2	2	8	None	None	None	\$50,000/acre to remediate disturbance of ecological system.	\$50,000/acre to remediate disturbance of ecological system.	None	Non	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Damage recovery cost: <\$1M per event	None	Maintain integrity of caprock and wells. Part of ongoing costs. Monitor for CO2/CH4 in high risk area: <\$150k	Savings: <\$850k.	1	
260	07.03.05.00.	Modification of microbiological systems	2	2	3	12	None	None	None	\$50,000/acre to remediate disturbance of ecological system.	\$50,000/acre to remediate disturbance of ecological system.	None	Non	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Damage recovery cost: <\$1M per event	None	Maintain integrity of caprock and wells. Part of ongoing costs. Monitor for CO2/CH4 in high risk area: <\$150k	Savings: <\$850k.	1	
261	07.04.00.00.	Impacts on humans	0	0	0	0																

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
262	07.04.01.00.	Health effects of CO2	Elevated atmospheric concentrations of CO2 can result in both acute and chronic health effects in humans. If meteorological conditions do not disperse CO2 released to the atmosphere, it can gather close to the surface and remain in depressions, such as the basement of buildings or at the surface of lakes. This property allows CO2 to reach high concentrations if released in sufficient quantities under particular atmospheric conditions. The primary health effect of concern is asphyxiation. High concentrations of CO2 in air will lead to suffocation of humans due to a lack of oxygen reaching the blood stream. Asphyxiation can occur once atmospheric concentrations reach approximately 10% CO2. Other health effects include those directly associated with elevated concentrations of CO2 in the blood stream, such as acidosis and physiological responses to the elevated blood CO2. The 1986 Lake Nyos disaster in Cameroon provides a graphic example of the potential effects of high atmospheric concentrations of CO2. A large limnic eruption resulted in the death of approximately 1800 people in the surrounding area and up to 27 km away. (Note that this event resulted from natural volcanic activity rather than CO2 storage). Asphyxiation requires high CO2 concentration in occupied (usually confined) space, plus either poor ventilation or high release rate. 1. Health effects of gaseous release of CO2 2 Health effects of liquid/supercritical release of CO2	The potential for CO2 to be released to the atmosphere in sufficient quantities to cause health effects in humans will be an endpoint of interest in assessing the geological sequestration of CO2. CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).	Communities in the Sixteen-Township Area: Navajo Dam (population 281) located 5.1 km (3.2 km) S of the CO2 injection Site. Turley NM (pop. 443): 11 km (7 mi) SW Blanco, NM (pop. 481): 18 km (11 mi) SW Cedar Hill, NM (pop. 847): 19 km (12 mi) W.		Human injury/death due to accumulation of CO2 in unventilated low lying or confined areas.	Health effects of CO2.	Liability costs. Negative view of project by stakeholders.	Monitor CO2/CH4 content in high-risk areas.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Ventilate confined spaces. Install CO2/CH4 monitors and alarms in high-risk areas. Maintain integrity of caprock, wells, surface facilities and pipelines. Avoid CO2 injection in densely populated areas.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
263	07.04.01.01.	Elevated CO2 in air	CO2 = 5000 ppm (0.5%): OSHA permissible exposure limit: Time weighted average concentration for 8-hour work day. American Conference of Governmental Industrial Hygienists (ACGIH) threshold limit value: Time weighted average concentration for normal 8-hour work day or 40-hour work week. CO2 = 30,000 ppm (3%): Breathing increases to twice normal rate and a person would experience impaired hearing, headache, and increased blood pressure (Shell). Occupational Safety & Health Administration (OSHA) short-term exposure level: Maximum concentration for 15-minute period (maximum of 4 periods per day with at least 60 minutes between exposure periods). CO2 = 40,000 ppm (4%): National Institute for Occupational Safety and Health (NIOSH) immediate danger to life and health: The maximum level to which a healthy individual can be exposed to a chemical for 30 minutes and escape without suffering irreversible health effects or impairing symptoms. CO2 = 50,000 ppm (5%): Breathing increases to approximately 4 times normal rate, symptoms of intoxication become evident and slight choking may be felt (Shell). CO2 = 75,000 ppm (7.5%): A sharp odor is noticeable. At this level a person would experience very labored breathing, headache, visual impairment, and dizziness to the eyes. Judgment may	CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).	Low to no population density in Section 32.		Human injury/death due to accumulation of CO2 in unventilated low lying or confined areas.	Health effects of CO2.	Liability costs. Negative view of project by stakeholders.	Monitor CO2/CH4 content in high-risk areas.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Ventilate confined spaces. Install CO2/CH4 monitors and alarms in high-risk areas. Maintain integrity of caprock, wells, surface facilities and pipelines. Avoid CO2 injection in densely populated areas.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.

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			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
262	07.04.01.00.	Health effects of CO2	2	4	2	16	1 @ \$1.5M per fatality	Accumulation of CO2 in unventilated low lying or confined areas 1 @ \$1.5M per serious (irrecoverable) injury	Accumulation of CO2 in unventilated low lying or confined areas 2 @ \$0.05M per minor (recoverable) injury	None	None	None	None	Cost to locate and fix leaky well: \$0.3M per incident Cost to locate and fix leaky fault, fracture zone or high permeability area: \$3M per incident	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Fatalities and/or injuries: \$3.5M	None	Monitoring and alarms for CO2/CH4 <\$300k	Savings of up to \$3.2M	1
263	07.04.01.01.	Elevated CO2 in air	2	4	2	16	1 @ \$1.5M per fatality	Accumulation of CO2 in unventilated low lying or confined areas 1 @ \$1.5M per serious (irrecoverable) injury	Accumulation of CO2 in unventilated low lying or confined areas 2 @ \$0.05M per minor (recoverable) injury	None	None	None	None	Cost to locate and fix leaky well: \$0.3M per incident Cost to locate and fix leaky fault, fracture zone or high permeability area: \$3M per incident	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Fatalities and/or injuries: \$3.5M	None	Monitoring and alarms for CO2/CH4 <\$300k	Savings of up to \$3.2M	1

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Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
264	07.04.02.00.	Toxicity of contaminants	Contaminants other than CO2 may be introduced to the biosphere as a result of geological CO2 sequestration due to: - impurities associated with the sequestration fluid, such as hydrogen sulfide (H2S), methane (CH4), nitrogen oxides (NOx) and mercaptans; - the mobilization of substances in the geological environment due to the sequestration of CO2, such as hydrocarbons (e.g., EOR and ECBM), CH4 and heavy metals. Such contaminants may be toxic to humans and could cause harm if exposure pathways exist. The toxicity will depend on: the form of exposure, e.g. ingestion or inhalation, leading to internal exposure or proximity to concentrations of contaminants leading to external exposure; the metabolism of the contaminant and physico-chemical form if inhaled or ingested, which will determine the extent to which the element/species may be taken up and retained in body tissues.	The potential for contaminants associated with an/or mobilized by CO2 sequestration to cause harm to humans is an endpoint of interest when assessing the geological sequestration of CO2. CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).	Low to no population density in Section 32.		Human injury/death due to accumulation of CO2/CH4 in confined spaces or low lying areas.	Toxicity of contaminants to humans.	Liability costs. Negative view of project by stakeholders.	Monitor CO2/CH4 content in high-risk areas.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Ventilate confined spaces. Install CO2/CH4 monitors and alarms in high-risk areas. Maintain integrity of caprock, wells, surface facilities and pipelines. Avoid CO2 injection in densely populated areas.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
265	07.04.03.00.	Impacts from physical disruption	Impacts on humans due to physical disruption of the environment caused by geological CO2 sequestration. For example, damage to buildings due to induced seismicity, damage to farmland due to subsidence or uplift.	Physical disruption of the environment caused by CO2 sequestration may have a detrimental impact on humans.	Low to no population density in Section 32. No significant buildings. No farmland. Only CBM and conventional natural gas production activities in Section 32. Potential disruption of recreational activities at Simon Canyon Area of Critical Environmental Concern, located on the E side of the nine-section site area, 2 km (1.2 mi) from the CO2 injection well.		Contamination of natural resources. Induced seismicity. Subsidence/uplift.	Physical disruption to humans due to improper CO2 injection or CO2/CH4 leakage.	Temporary emergency evacuation. Loss of monetized value of contaminated resources. Damage to buildings and infrastructure. Damage to farmland. Liability costs for damages.	Monitor for CO2/CH4 in high-risk areas Continuous passive micro-seismicity monitoring. Monitor surface displacement (InSAR or LIDAR).	Maintain integrity of caprock, wells, surface facilities and pipelines. Avoid injecting CO2 in areas with high population density. Monitor for CO2/CH4 in high-risk areas.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
266	07.04.04.00.	Impacts from ecological modification (See 06.01.08.00)	Impacts on humans due to ecological modification. These may be negative (for example, reduced timber yields due to damage caused to trees by CO2 in the soil) or positive (for example, increased crop yields due to higher atmospheric CO2).	Ecological modification caused by CO2 sequestration may have a positive or negative impact on humans.	The ecological systems in Section 32 are not considered valuable and/or sensitive to perturbations. Simon Canyon Area of Critical Environmental Concern is located on the E side of the Nine-Section Area, 2 km (1.2 mi) from the CO2 injection well.		Timber kill. Agricultural crop and/or animal kill. Natural flora and/or fauna kill. Aquatic/marine life kill.	Ecological modification due to CO2/CH4 leakage.	Loss of monetized value of resources. Liability costs.	Monitor for flora or fauna kills. Monitor for CO2/CH4 in high-risk areas. Continuous passive micro-seismicity monitoring. Monitor surface displacement (InSAR or LIDAR).	Take into account the ecological system in site characterization. Maintain integrity of caprock, wells, surface facilities and pipelines. Avoid injecting CO2 in areas with high population density. Monitor for CO2/CH4 in high-risk areas.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
267	08.00.00	ECONOMIC RISKS										

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Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
264	07.04.02.00.	Toxicity of contaminants	2	4	2	16	1 @ \$1.5M per fatality	Accumulation of CO2 in unventilated low lying or confined areas 1 @ \$1.5M per serious (irrecoverable) injury	Accumulation of CO2 in unventilated low lying or confined areas 2 @ \$0.05M per minor (recoverable) injury	None	None	None	None	Cost to locate and fix leaky well: \$0.3M per incident Cost to locate and fix leaky fault, fracture zone or high permeability area: \$3M per incident	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Fatalities and/or injuries: \$3.5M	None	Monitoring and alarms for CO2/CH4 <\$300k	Savings of up to \$3.2M	1	
265	07.04.03.00.	Impacts from physical disruption	2	3	2	12	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and/or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix leaky well: \$0.3M per incident Cost to locate and fix leaky fault, fracture zone or high permeability area: \$3M per incident	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: <\$5.1M to locate and fix leak and remediate.	None	Maintain integrity of caprock and wells. Part of ongoing costs. Monitor for CO2/CH4 in high risk area: <\$150k	Savings of <\$4.95M	1	
266	07.04.04.00.	Impacts from ecological modification (See 06.01.08.00)	2	3	2	12	None	None	None	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and/or vegetation replanting	Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	Cost to locate and fix leaky well: \$0.3M per incident Cost to locate and fix leaky fault, fracture zone or high permeability area: \$3M per incident	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: <\$5.1M to locate and fix leak and remediate.	None	Maintain integrity of caprock and wells. Part of ongoing costs. Monitor for CO2/CH4 in high risk area: <\$150k	Savings of <\$4.95M	1	
267	08.00.00	ECONOMIC RISKS	0	0	0	0																

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Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
268	08.01.00.	Cost escalation / inflation	Cost escalation/inflation may be higher than budgeted. Cost escalations are of particular concern because field-service costs (drilling, geophysics, etc.) and equipment may continue to increase as the price of oil stays high. Key cost items that may be effected by escalation/inflation include: 1. Steel cost 2. Other material cost 3. Equipment cost 4. Labor cost 5. Imported goods cost (due to currency exchange) 6. Financing/risk transfer costs 7. Assessment and permitting costs 8. Mitigation and closure costs	The risk of cost escalations is significant; cost increases may force a change in scope-of-work.	Capital costs have been holding relatively steady recently but could change with a future turnaround in the economy.	No project planned at this time.	Project becomes economically infeasible.	Cost escalation / inflation higher than budgeted.	Cost overruns. Project halted.	Monitor cost indexes. Track and project costs versus budget.	Use updated/current information on labor and material rates with escalation over the job period. Structure foreign contracts in US currency or buy domestically.	Allow for time sensitive information to be updated to expose any issues as soon as possible. Hedge currency exchange for foreign contracts.	
269	08.02.00.	CO2 value/cost	Incentives for CO2 capture and storage are particularly important for CO2 sequestration in deep saline aquifers. In this case, the value or cost of CO2 may be determined by cap-and-trade, carbon tax or emission credits. In EOR and ECBM the value of CO2 may be tied to the price of oil or natural gas. However, the cost of CO2 capture and transport may be higher or lower than the assigned value. Value of emission credits provide incentive for CO2 sequestration, particularly in deep saline aquifers (DSA). CO2 purchase cost higher than budgeted. CO2 has traditionally been purchased for EOR and ECBM use. Economic arrangements among project participants could have negative project impacts under changed or unanticipated conditions. 1. Value of CO2 emissions credits lower than budgeted 2. CO2 purchase cost higher than budgeted	A low value for emission credits may be insufficient to cover the cost of CO2 capture and sequestration in deep saline aquifers.	The cost of CO2 is one of the biggest expenses for CO2-ECBM, The Cortez pipeline, a major natural CO2 pipeline, is located 4.2 km (2.6 mi) from the site. Anthropogenic CO2 is limited in availability until changes in regulations or legislation provide greater incentives for capturing and storing CO2.	No project planned at this time.	Project economically infeasible because of high CO2 transfer cost.	Lower value for emission credits than expected. Higher CO2 capture cost than expected.	Project halted.	Track actual CO2 costs versus budget.	For ECBM projects, index CO2 transfer price to the natural gas price.	For ECBM projects, index CO2 transfer price to the natural gas price.	
270	08.03.00.	Price of natural gas (or other related commodities)	The prices of related commodities can impact the value and/or availability of CO2. 1. Oil price - impacts EOR economics 2. Natural gas price - impacts ECBM economics 3. Fertilizer price - impacts CO2 supply from fertilizer plants 4. Ethanol price - impacts CO2 supply from ethanol plants 5. Cement price - impacts CO2 supply from cement plants	Low commodity prices can impact the viability of a CO2 capture and storage project.	The current price of natural gas \$3.50/MCF is low due to the excess availability of shale gas in the US. Most references claim \$3/MCF to \$4/MCF as the breakeven price for dry shale gas production, which means that a profitable price range of \$4/MCF to \$6/MCF is forecast for natural gas in the foreseeable future	No project planned at this time.	Natural gas price less than breakeven point.	Low commodity prices.	Project halted.	Track related commodity markets. Analyze impact of market changes on CO2 supply.	Analyze trends in commodity prices. Plan for worst case scenarios.	Hedge product prices.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
268	08.01.00.	Cost escalation / inflation	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
269	08.02.00.	CO2 value/cost	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
270	08.03.00.	Price of natural gas (or other related commodities)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
271	08.04.00.	Project development costs	Project development costs that could be higher than expected or budgeted include: 1. Surface land and/or pore space access costs - purchase or lease 2. Water rights costs 3. Mineral rights costs - needed for EOR or ECBM 4. Pipeline right-of-way (ROW) costs 5. Site characterization costs 6. Permitting costs 7. Technology licensing costs 8. Engineering, procurement and construction (EPC) costs 9. Insurance costs 10. Project financing costs 11. Legal costs 12. Closure and post-closure costs	High project development costs can make the project economically infeasible. Project may be halted if some of the necessary requirements are unobtainable.	No project planned at this time.	No project planned at this time.	Project economically infeasible.	Project development costs higher than budgeted.	Project halted.	Track costs versus budget.	(Numbers below refer to numbers under Definitions) 1. Focus on EOR or ECBM rather than DSA to avoid pore space issues. 3. Work out mineral rights leases early. 4. Use existing pipeline corridors. 5. Select brownfield site with existing characterization data.	(Numbers below refer to numbers under Definitions) 1. Have backups for site location. 4. Have backup for pipeline right-of-way. 6. Use public outreach effectively to keep permitting costs down. 9. Self insure. 10. Get equity financing.
272	08.05.00.	Project capital costs	Project capital costs that could be higher than budgeted include: 1. CO2 capture system 2. CO2 dehydration 3. CO2 compression 4. CO2 pipeline 5. Well head system 6. CO2 recycle system - for EOR 7. Oil tankage - for EOR 8. Natural gas processing system - for ECBM 9. Water tankage - for EOR or ECBM 10. Water treatment system - for EOR or ECBM 11. New well drilling and completion 12. Old well remediation/replugging 13. Old well workover 14. Site preparation 15. Access roads 16. Power supply system 17. Water supply system 18. Communications system 19. Monitoring system costs 20. Accidental loss	High project capital costs can make the project economically infeasible. Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.	No project planned at this time.	No project planned at this time.	Project becomes economically infeasible.	Project capital costs higher than budgeted.	Project halted.	Track costs versus budget.	Obtain hard quotes from manufacturers with time sensitive escalation and time period of validity defined. Use conservative estimates and escalations. Use experienced contractors.	Track actual vs. budgeted expenses. Prioritize expenses and cut low priority costs. Renegotiate scope of work. Obtain additional equity funding.

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			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
271	08.04.00.	Project development costs	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
272	08.05.00.	Project capital costs	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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273	08.06.00.	Operating and maintenance costs	Project operating and maintenance costs that could be higher than budgeted include: 1. CO2 capture operating costs 2. CO2 dehydration/compression operating costs 3. CO2 pipeline operating costs 4. Injection operating costs 5. Monitoring costs 6. Simulation modeling costs 7. Maintenance costs 8. Lease operating expenses 9. Management fees 10. Working capital 11. Severance and ad valorem tax 12. Investor reporting costs 13. Power cost 14. Make-up water cost 15. Water treatment/disposal cost 16. Labor cost 17. Security costs 18. Site close costs 19. Verification costs 20. Regulatory compliance costs 21. Insurance costs 22. Cost for losses 23. Post-closure costs for DSA 24. Accidental loss 25 Financial reserves for DSA EPA UIC Class VI wells	High operating and maintenance costs can impair project economic viability. Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.	No project planned at this time.	No project planned at this time.	Project becomes economically infeasible	Project operating and maintenance costs higher than budgeted.	Decreased profitability. Project halted.	Track costs versus budget.	Use historical O&M data and experienced cost estimators to prepare budgets.	Implement a Total Productive Maintenance (TPM) program.
274	08.07.00.	Project Financing	Factors which could impact project financing include: 1. Government project funding withdrawn for technical reasons. 2. Government project funding withdrawn for political reasons 3. Change in equity project funding 4. National/global economic downturn impact on project financing 5. Lack of economic incentives for CCS impact on project financing 6. Private financing	Lack of or loss of project financing could halt the project.	No project planned at this time.	No project planned at this time.	Project unable to complete financing	Project loses one or more sources of funding.	Project halted or delayed.	Monitor project financing negotiations.	Keep debt at a sustainable level.	Tie future capital investment to market conditions. Adjust scope of project to improve economics for project financing. Secure additional equity and refinance high interest rate debt.
275	08.08.00	Hedging	Hedging may be used as a risk management tool to control the adverse impact of fluctuating commodity prices.	Hedging arrangements are used to reduce exposure to fluctuations in commodity prices (i.e., CO2, oil, natural gas). Hedging can create financial risks when: 1. Production is less than hedged amount. 2. The counterparty to the hedging contract defaults on its contract obligations 3. Change in the expected differential between the underlying price in the hedging agreement and the actual price received 4. Limitation of the benefit when commodity prices increase (Kinder Morgan 2012)	No project planned at this time. Hedging of natural gas prices may be required for project financing.	No project planned at this time.	Actual gas production level below hedged production level. Counterparty default on hedging agreement obligations. Hedged price significantly below nonhedged price.	Production problems. Over estimating amount to be hedged. Poor selection of hedging counterparty. Underestimating hedging price.	Decreased profitability.	Monitoring commodity prices, production rates, and financial health of hedging counterparty.	Avoid hedging. Improve price forecasting. Carefully select hedging counterparty.	Keep the portion of hedged product to a manageable level. Negotiate a reasonable margin between expected hedged and unhedged prices.
276	09.00.00.	PERMITTING RISKS										

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273	08.06.00.	Operating and maintenance costs	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
274	08.07.00.	Project Financing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
275	08.08.00	Hedging	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
276	09.00.00.	PERMITTING RISKS	0	0	0	0															

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277	09.01.00.	Permit compliance - obtain or maintain permits	Permitting and NEPA compliance are lengthy processes, and are subject to even more delays because of uncertainty associated with permitting sequestration (a relatively new issue for federal, state and local regulatory agencies).The procedures for permit compliance could cause delays. Potential permits required for a CCS project include: 1. National Environmental Policy Act (NEPA) - Environmental Assessment (EA) - Environmental Impact Statement (EIS) 2. Underground Injection Control (UIC) permit 3. CO2 storage permit 4. Drilling permit 5. Water discharge/disposal permit 6. Crossing permits for wetlands, federal land, tribal land, railroads, highways, roads 7. Construction general permit 8. Storm water discharge permit 9. Air quality construction permit 10. Seismic permit 11. Storage tank permit 12. Closure financial assurance 13. Post-closure financial assurance	Lack of permit could halt or restrict construction or operation; permit delay could have other impacts including increased costs.	No project planned at this time. Permitting could be an issue for new CO2 injection wells depending on whether the well is classified as UIC Class II (for EOR or ECBM) or Class VI (for CO2 Sequestration). Permitting requirements for Class VI wells may be too difficult to meet.	No project planned at this time.	Project cannot obtain or maintain new permits.	Project out of compliance with new regulations.	Project halted or delayed.	Track permitting processes and regulations. Compare actual versus plan.	Use experienced permitting manager / consultant. Ensure continuous compliance with permits.	Use experienced permitting manager / consultant. Ensure continuous compliance with permits.	
278	09.02.00.	Public outreach and education	Public acceptance support and trust is critical to obtaining environmental permits. Public outreach and education can be more difficult than expected. 1. Lack of public acceptance that CO2 emissions contribute to global warming 2. Lack of public acceptance that global warming is an eminent danger to society 3. Lack of public that carbon capture and storage (CCS) is safe 4. Poor public perception of CCS projects 5. Local community actions and reactions 6. Special interest groups or non-governmental organizations actions and reactions 7. Lack of political support for the project 8. Risk off-sets	Failure to get public acceptance for a project can lead to significant delays in, and costs for, permitting An unexpected situation arises that is not technically impacting but the appearance of unpreparedness spurs public concern.	No project planned at this time.	No project planned at this time.	Project unable to get new permits.	Lack of public support for project.	Project halted or delayed.	Track public opinion.	Maintain a comprehensive public outreach program.	Maintain a comprehensive public outreach program.	

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277	09.01.00.	Permit compliance - obtain or maintain permits	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
278	09.02.00.	Public outreach and education	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

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279	09.03.00.	Saline water extraction, treatment and disposal	Large amounts of saline water are pumped out of the ground for EOR and ECBM. EOR water production increases over time. In high water cut cases, water may represent 99% of the production volume and oil only 1% of the volume. ECBM employs water production to lower the over pressure in the coal seam, decrease swelling and increase permeability. Water may be extracted in a DSA operation to make room for injected CO2 and manage pressure. Extracted water is increasingly becoming a prominent issue, particularly deliberately extracting water to manage CO2 plume (e.g. extracting water to encourage plume migration and reinjecting the extracted water into a different part of the reservoir so that it is not extracted again). Some researchers believe CO2 can be injected into reservoirs without extracting water. This may be true in an open storage reservoir. But in a closed reservoir, injecting CO2 without extracting water will build up pressure in the reservoir and severely restrict the CO2 storage capacity. CO2 changes water composition and makes water more acidic (pH 4-5). Therefore EOR and ECBM production water may require more treatment before it can be disposed of. The acidic water may also include trace amounts of arsenic and other metals.	Saline water disposed could be one of the most critical issues in permitting. Treating the water will concentrate brine that will need to be reinjected.	Fruitland Formation is already dewatered in the site area. There are thirteen saline water disposal wells located within the Sixteen Township Area. Saline water is injected into the Morrison (Bluff Sandstone member) and Entrada Sandstone. CBM wells in the Pump Canyon area have been dewatered and operate at low pressure. Produced water comes out of the well as water vapor and is collected as it condenses in CBM gathering lines as distilled water. The condensed water may contain coal fines and should be filtered prior to surface discharge.	No project planned at this time.	Project unable to get, or loses, permit to treat/dispose of extracted water. Water treatment / disposal costs significantly higher than expected. Project out of compliance with regulations covering water treatment and disposal. Excessive extracted water volumes and/or poor water quality.	Project halted or delayed. Decreased profitability.	Monitor water treatment / disposal regulations. Model extracted water volumes and quality.	Maintain balance between produced and injected water.	Comply with all State water disposal regulations. Evaluate alternative methods of treating and disposing of produced water.	
280	09.04.00	Natural resources nearby	1. Mineral resources 2. Mineable coal seams 3. Oil reservoirs 4. Natural gas reservoirs 5. Underground drinking water sources 6. Surface waters - lakes, rivers, streams 7. Geothermal resources 8. Pores space owned by others 9. Deep saline aquifers 10. Microbial resources 11. Soil - farmland 12. Flora and fauna - endangered species and critical habitats	CO2 or brine fluid migration could contaminate others' natural resources and lead to permitting delays due to legal contest.	CBM operations are producing natural gas from the Fruitland Formation. Natural gas continues to be produced from the Mesaverde Group and other formations underlying the Fruitland Formation. Simon Canyon Area of Critical Environmental Concern is located on the E side of the Nine-Section Area. Approximately half of the Sixteen Township Area is listed as Special Designated Areas by the BLM.	No project planned at this time.	Project unable to get permits. Permit compliance too expensive. Project in conflict with or could negatively impact nearby natural resources.	Project halted or delayed. Decreased profitability.	Monitor site characterization and environmental impact statement work.	Avoid fracturing the caprock for recovery of shale gas.	Control fracturing of the caprock for recovery of shale gas to prevent leakage of CO2+CH4. Use continuous passive microseismic monitoring. Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.	

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279	09.03.00.	Saline water extraction, treatment and disposal	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
280	09.04.00	Natural resources nearby	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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281	09.05.00.	Dense population nearby	Present and future urban sprawl. 1. Sensitive receptors (schools, hospitals, care centers, churches, prisons) in or near injection site 2. Dense population located downhill or downwind of injection site 3. Populated subsurface structures located nearby	Additional safety precaution measures are required to protect against CO2 leakage in dense population areas..	Communities in the Sixteen-Township Area: Navajo Dam (population 281) is located 5 km (3 mi) S of the injection site. Turley (population 443) is located 11 km (7 mi) SW of the injection site. Blanco (population 388) is located 18 km (11 mi) SW of the CO2 injection site. Cedar Hill (population 847) is located 19 km (12 mi) NW of the injection site.	No project planned at this time.	Project unable to get new permits. Permit compliance more expensive than planned.	Existing or future population density near site.	Project halted or delayed. Decreased profitability.	Track existing and planned population density in the site area..	Avoid selecting sites near densely populated areas. Use existing pipeline corridors.	Monitor for CO2/CH4 in high-risk areas. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.
282	09.06.00.	Conflicts with use of surface	Conflicts with use of the surface may include 1. Agriculture 2. Fishing 3. National parks/monuments 4. Wetlands 5. Timberland 6. Recreational areas 7. Military areas 8. Heavy industry sites 9. Urban areas 10. Archeological sites 11. Tribal sacred ground 12. Threatened or endangered species critical habitats 13. Bird sanctuaries 14. Historical sites 15. Groundwater protection zones. 17. Change in land use (zoning change)	Some land uses may impact site selection and permitting. Others may require additional monitoring and modeling to provide added protection from CO2 leakage. Nearby heavy industry can interfere with seismic readings. Land use changes could restrict access to and use of land for CO2 sequestration	Sixteen Township Area Navajo dam and reservoir San Juan and Animas rivers Land is 70% federal/30% private Reese Canyon habitat for threatened and endangered species Simon Canyon Areas of Critical Environmental Concern Negro Canyon scenic area Navajo Lake State Park Three recreational areas Eight archaeological sites Multiple riparian areas Multiple bald eagle habitats Wildlife area s = 50% of area. Animas River agricultural area San Juan River "Quality Water" for trout fishing	No project planned at this time.	Project unable to get new permits.	Project in conflict with use of surface.	Project halted or delayed. Decreased profitability.	Monitor site characterization and environmental impact statement work.	Use existing injection (i.e., EOR, CBM) sites and pipeline corridors. Avoid sensitive areas or habitats for endangered or protected species. Characterize sites for potential surface land use.	Design around sensitive areas. Model and monitor CO2/CH4 migration.
283	09.07.00.	Conflicts with use of subsurface	Conflicts with use of the subsurface may include: 1. Natural gas storage 2. Compressed air storage 3. Geothermal plants 4. Radioactive waste disposal 5. Petroleum production 6. Coal mining 7 Health spas	Could impact site selection and permitting.	Multiple operators producing natural gas from Fruitland and other formations. May be difficult to unify the Fruitland Formation.	No project planned at this time.	Project unable to get new permits.	Project in conflict with use of subsurface.	Project halted or delayed. Decreased profitability.	Monitor site characterization and environmental impact statement work.	Use existing injection (i.e., EOR, CBM) sites and pipeline corridors. Avoid sites with conflicting subsurface use. Characterize sites for potential conflicting subsurface use.	Design around conflicting areas. Model and monitor CO2/CH4 migration
284	09.08.00.	Permit denied or modified by government agency	A permit may be modified by government agency to require increase data access and approval by NGOs and/or public 1. Permit denied because the project is considered high risk to public 2. Permit denied because there is uncertainty over the safety of the project 3. Permit revoked due to owner failing to comply with regulations (action or inaction) 4. Permit delayed due to owner action or inaction	Causes delays leading to price escalation. Could halt the project.	Permits could change if CO2 continues to be injected for sequestration after ECBM is completed.	No project planned at this time.	Project unable to get new permit, or loses permit. Permit compliance costs more expensive than expected.	Project out of compliance with permit regulations.	Project halted or delayed. Decreased profitability.	Track permitting processes and regulations. Compare actual versus plan.	Use experienced permitting manager / consultant. Comply with permit requirements.	Use experienced permitting manager / consultant Revise project and/or permit application to resolve uncertainties, high risks etc. Assess alternative site. Comply with permit requirements.

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281	09.05.00.	Dense population nearby	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
282	09.06.00.	Conflicts with use of surface	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
283	09.07.00.	Conflicts with use of subsurface	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
284	09.08.00.	Permit denied or modified by government agency	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

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285	09.09.00.	Pre-existing contaminated site	Site may have already been contaminated by non-CO2 storage related activities.	Pre-existing contamination of groundwater, surface water, and/or soil. Requires assessment to determine if proposed project would be impacted by or exacerbate existing condition. Or assume responsibility for remediation of pre-existing conditions.	There are no known superfund, hazardous waste releases, brownfield sites or landfills registered with the EPA in the Sixteen Township Area.	No project planned at this time.	Significant costs to remediate pre-existing contamination.	Pre-existing contaminated site.	Project halted or delayed. Increased capital costs. Complex or misleading monitoring data. Decreased profitability.	Comprehensive site characterization and environmental impact statement work for pre-existing contamination.	Characterize sites for pre-existing contamination to evaluate operational impacts and additional costs. Conduct baseline studies to define preinjection conditions. Use experienced permitting manager / consultant.	Use experienced permitting manager / consultant.
286	10.00.00.	EXTERNAL RISKS										
287	10.01.00.	Natural disaster risks (01.02.02.00.)	1. Fire -wildfires, industrial fires 2. Flood - flood plain, dry wash areas, flash floods, tsunami, debris flows 3. Earthquake - natural seismic activity, rock slides, mud slides 4. Winter storms - blizzards, ice storms, arctic cold 5. Hail storm 6. High winds - tornadoes, hurricanes, typhoons, cyclones 7. Heat wave 8. Drought 9. Heavy rain - monsoons, tropical storms, thunder storms 10. Lightning 11. Sand/dust storms 12. Avalanche 13. Electromagnetic disturbances - sunspots 14. Volcano 15. Corrosive atmospheres - high humidity, coastal sea breeze, industrial plant acid gas emissions	Natural disasters can delay, impair or shutdown a project.	Potential natural disasters in the Navajo Dam, NM area include (in order of occurrences from 1950-2010): Floods: 66 (1.1/y) Thunderstorm winds: 39 (0.65/y) Hail storms: 35 (0.58/y) Wildfires: 16 (0.27/y) Droughts: 3 (0.05/y) Tornadoes (F2 or above): 1 (0.017/y)	No project planned at this time.	Project facilities damaged and/or personnel injured.	Natural disaster.	Business interruption. Damage recovery. Decreased profitability.	Monitor site characterization for site-specific disaster risks. Monitor weather forecasts for severe weather conditions.	Select sites and pipeline corridors that are less likely to be exposed to natural disasters. Avoid flood plains. Include potential natural disasters in site characterization. Keep sites clear of dry vegetation.	Implement emergency response plan covering all potential disasters. Comply with fire suppression codes. Ground surface equipment to protect from lightning. Cover sensitive equipment. Monitor severe weather reports. Integrate mitigation measures into facility design and operations. Implement effective storm management plans.
288	10.02.00.	Security risks	1. Theft 2. Vandalism - onsite equipment or offsite monitoring equipment 3. Employee sabotage 4. Civil unrest - riots, civil war, rebellion, insurrection, military or usurped power or confiscation 5. Terrorist activities 6. War - invasion, acts of foreign enemies, hostilities 7. Nationalization 8. Government sanctions, blockade, embargo 9. Labor disputes - strike, lockout 10. Damage to surface facilities by human activity 11. Hunting season - stray bullets	Risks to employees, public and equipment.	No project planned at this time.	No project planned at this time.	Project facilities damaged and/or personnel harmed. Project security cost increased.	Security breach.	Business interruption. Damage recovery. Decreased profitability.	Monitor security alerts and level of civil / employee unrest.	Integrate appropriate security controls and systems to protect above ground facilities. Bury pipeline sufficiently deep. Do background checks and drug tests on all new employees. Supervise all crews during working hours.	Implement an emergency response plan and enhanced security procedures.
289	10.03.00.	Competition	Other projects in the area may compete for the same CO2, labor, infrastructure, land, pore space, funding 1. Interaction with adjacent CO2 sequestration sites 2. Infringement of project's pore space by third-party injection of CO2, water or waste disposal	Could halt the project or increase costs. Potential decreased storage capacity.	There are multiple operators producing natural gas from the Fruitland and other formations in the area.	No project planned at this time.	Project loss of CO2 supply. Project unable to obtain land access or mineral rights. Project costs increased.	Competitor activity.	Project halted, delayed or impaired. Decreased profitability.	Monitor competitor activities.	Secure CO2 supply with exclusive long-term agreement. Secure access to land and mineral rights with long-term agreement.	Identify backup CO2 supplies or alternative sites.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
285	09.09.00.	Pre-existing contaminated site	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
286	10.00.00.	EXTERNAL RISKS	0	0	0	0															
287	10.01.00.	Natural disaster risks (01.02.02.00.)	3	2	1	6	None	None	None	None	None	Surface facilities damage <\$0.5M for most situations .	\$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	None	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of total damages	Cost to repair surface facilities <\$0.5M + Cost of business interruption	Cost of insurance deductable.	Insurance coverage for weather, wildfire and flood damage and business interruption: 0.28% of surface facilities value per year + 0.25% of revenue per year	Savings: <\$0.3M	1
288	10.02.00.	Security risks	2	2	2	8	None	None	None	None	None	Surface facilities damage <\$0.5M for most situations .	\$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Proper security program. Ongoing cost.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of total damages	Cost to repair surface facilities <\$0.5M + Cost of business interruption	None	Proper security program. Ongoing cost.	Savings <\$0.5M	1
289	10.03.00.	Competition	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
290	10.04.00.	CO2 supply	Changes in the operation of the CO2 source plant may impact CO2 properties and/or flow rate. Unanticipated change in demand for injected CO2 (flow rate, pressure, water content, etc.) due to either uncontrollable physical changes or operating decisions, will affect operations of the CO2 source facility and potentially impose stresses upon surface and down hole equipment and borehole. Changes may be gradual or sudden. Also includes changes arising from characterization data, e.g., limits placed by reservoir on injectivity, capacity, etc. CO2 sources and sinks need to coordinate supply and demand and scheduled outages to avoid constraint startup/shutdown of compression facilities and maintain consistent pipeline pressure. This is normally done through a nomination process at least one week in advance. Operators of CO2 storage projects may incorporate excess injection capacity (i.e. spare wells) to permit continued injection during planned or unplanned well downtime. (CCP 2009)	Interruption of CO2 supply could result in a Business Interruption / Advanced Loss of profit type exposure, or even result in the project becoming uneconomic to continue. Lack of adequate CO2 supply could halt or limit injection. Intermittent injection schedule could increase stress on surface and down hole mechanical elements, could affect EOR/ECBM sweep efficiency, and could increase concentrations of various contaminants in the injected gas. The timing of CO2 availability may not match up with the time when CO2 is needed for EOR or ECBM. 1. CO2 outside of design specification - flow rate, composition, pressure, temperature 2. Change in CO2 supply conditions 3. Change in CO2 demand conditions 4. CO2 supply interruptions due to source plant outage/failure 5. CO2 supply interruptions due to CO2 capture outage/failure 6. CO2 supply interruptions due to compressor outage/failure 7. CO2 supply interruptions due to pipeline outage 8. Disparity in timing CO2 supply/demand 9. CO2 interruption due to accident at the CO2 supplier	A major natural CO2 pipeline is located 4.2 km (2.6 mi) from the site. Anthropogenic CO2 is limited in availability until changes in regulations or legislation provide greater incentives for capturing and storing CO2.	No project planned at this time.	Disruption of project operations. Project CO2 costs increased.	CO2 supply interruption. CO2 supply off-spec.	Project halted, delayed or impaired. Decreased profitability.	Monitor CO2 supplier operations, CO2 flowrate and CO2 quality.	Maintain multiple sources of CO2.	Monitor CO2 quality. Require CO2 supplier to vent off-spec CO2. Cut back CO2 injection on some patterns.
291	10.05.00.	Water supply	1. Water supply design specifications - Flow rates - Composition - Pressure - Temperature 2. Water supply interruptions	Could impact water and gas (WAG) flooding	Water is available from the Navajo reservoir, 8 km (5 mi) E of the CO2 injection site. Water mainly used for drilling, hydraulic stimulation or well cleanout.	No project planned at this time.	Disruption of project operations. Project water costs increased.	Water supply interruption. Water off-spec.	Project delayed or impaired. Decreased profitability.	Monitor water supply and quality.	Take water supply volume and quality into account in system design. Consider redundant pumps, wells and/or water storage tanks.	Monitor for leaks in water piping. Implement pre-incident contingency plan. Add pumps, filtration or water treatment to resolve water volume or quality issues.
292	10.06.00.	Power supply	1. Power surges 2. Power brown outs 3. Power interruptions (black outs)	Could shut operations down.	No project planned at this time.	No project planned at this time.	Disruption of project operations. Equipment damage.	Power supply interruption. Power surge/brownout.	Project delayed or impaired. Decreased profitability. CO2 release (HSE hazard)	Monitor power supply.	Install generator/battery backup system for key components.	Install surge protection if it is an issue. Make sure valves turn to safe default position when power goes out.
293	10.07.00.	Communication system	Communications could be interrupted. The SCADA system may be dependent on one or more of the following communications systems: 1. Phone line 2. Fiber optics 3. Satellite 4. Internet	Loss of communication system could impair operations especially if the SCADA link is disconnected.	No project planned at this time.	No project planned at this time.	Disruption of project operations. Equipment damage.	Communication system interruption.	Project delayed or impaired. Decreased profitability.	Monitor communication system.	Install fiber optics and backup system.	System maintenance. Implement contingency plan. Make sure valves turn to safe default position when SCADA system shutdown.
294	10.08.00.	Road access	Road to injection site could be blocked by snow, accident, washout, wildfire, flooding	Lack of road access to sites could impair operations	Good road access is available throughout the site.	No project planned at this time.	Disruption of project operations.	Roads inaccessible	Project delayed or impaired. Decreased profitability. Personnel/supplies unable to reach or leave site.	Monitor road conditions.	Road maintenance procedures in place. Alternate routes.	Road maintenance in place. Alternate routes.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
290	10.04.00.	CO2 supply	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
291	10.05.00.	Water supply	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
292	10.06.00.	Power supply	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
293	10.07.00.	Communication system	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
294	10.08.00.	Road access	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
295	11.00.00.	PROJECT MANAGEMENT RISKS										
296	11.01.00.	Management team	The project may include some unfamiliar activities and workflows, may acquire and respond to a wide range of newly acquired data, and may experience changes in objectives. Operational conflicts, anticipated or not, could impact project values. Inexperienced managers tend to be over optimistic in taking risks and taking short cuts. for example: failing to avoid high risk sites. 1. Inexperienced management team 2. Inability to execute contracts among project partners in a timely manner 3. Lack of stakeholder coordination	An inexperienced management team has a higher potential for mistakes and poor judgment Inefficient interface management can result in delays and failure to achieve project goals.	No project planned at this time.	No project planned at this time.	Poor, or lack of, management decisions having a negative impact on the project.	Inexperienced management team	Project delayed or impaired. Decreased profitability.	Monitor implementation of project management plan.	Hire or assemble an experienced management team.	Hire additional experienced project managers / consultants if necessary. Conduct independent operational reviews.
297	11.02.00.	Operator training	1. Under qualified operators 2. Untrained operators 3. Operator error	Inadequate operator training can result in low labor productivity and greater potential for human error.	No project planned at this time.	No project planned at this time.	Operator error or over confidence resulting in poor performance and/or equipment/system failure.	Insufficient operator training.	Project halted, delayed or impaired. Facilities damaged and/or personnel injured. CO2 release (HSE hazard). Decreased profitability. Regulatory violations.	Monitor operator training and performance.	Implement a continuous operator training program.	Maintain an ongoing operator training program in the operation phase with particular emphasis on emergency response.
298	11.03.00.	Execution strategy	Poor execution strategy can result from: 1. Insufficient funding 2. Insufficient resources 3. Unrealistic schedule 4. Schedule and planning conflicts (02.01.05.00) 5. Poor timing 6. Lack of risk management plan Scheduling and planning covers the sequence of events and activities occurring during all phases of the project.	Poor execution strategy can result in project delays and increased project costs.	No project planned at this time.	No project planned at this time.	Project delays and schedule conflicts.	Lack of scheduling and planning	Increased project costs.	Track actual schedule versus plan.	Detailed scheduling and planning. Prepare a realistic schedule. Work with experienced team members to execute the project. Update and follow project management plan and risk management plan.	Prioritize and accelerate work load. Use quarterly meetings to review and fine tune execution strategy and resolve schedule conflicts.
299	11.04.00.	Record keeping (See 02.02.03.00.)	Large amounts of data will be generated by the project. Data could be poorly communicated between groups, or be badly managed to the point that important data is lost, or used incorrectly. Features related to the retention of records of the content and nature of a CO2 storage site after closure and also the placing of permanent markers at or near the site. 1. Poor data management 2. Loss of archives/records 3. Unable to accurately verify the amount of CO2 retained in storage	It is expected that records will be kept to allow future generations to recall the existence and nature of the storage reservoir/aquifer following closure. Insufficient record keeping could lead to noncompliance with regulations and failure to achieve project goals.	No project planned at this time.	No project planned at this time.	Noncompliance with regulations. Inadvertent future intrusion into the CO2 reservoir by third-party.	Improper record retention and marking.	Potential fines, penalties or business interruption for noncompliance.	Data management. Routine site inspection.	Set up an electronic data management system with off-site backups. Proper documentation. Standardize data formats. Clearly mark site with warnings and register site as CO2 storage site with the State.	Maintain data system and standardized formats. Routine site inspection and/or monitoring. Prepare procedures for potential remedial action.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
295	11.00.00.	PROJECT MANAGEMENT RISKS	0	0	0	0															
296	11.01.00.	Management team	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
297	11.02.00.	Operator training	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
298	11.03.00.	Execution strategy	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
299	11.04.00.	Record keeping (See 02.02.03.00.)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
300	11.05.00.	Multi-party project	CCS projects may involve multiple participants for CO2 supply, CO2 transportation, EPC (engineering, procurement and construction), CO2 storage, computer simulation, MVA (monitoring, verification and accounting), carbon trading, and risk management. There are challenges and risks in coordinating the responsibilities and liabilities among multiple organizations involved in a project. In case of too deep involvement of partners in day to day operations, shareholders may assume joint and several liability for actions of the partnership. Disagreement among partners may lead to deadlock in unanimous decision making.	Lack of communication, coordination and cooperation among project participants can lead to project delays and failure to achieve project objectives.	No project planned at this time.	No project planned at this time.	Project negatively impacted by poor, or lack of, multi-party coordination/cooperation.	Multi-party project	Project delays. Decreased profitability. Unclear responsibilities for liabilities.	Monitor multi party coordination / cooperation.	Maintain secure website, weekly conference calls, cross-functional working groups and management team. Establish clear division of scope of work and responsibilities.	Maintain secure website, weekly conference calls, cross-functional working groups and management team. Maintain clear division of scope of work and responsibilities.
301	11.06.00	Pre-closure administrative control (02.01.06.00.)	Features related to measures to control events at or around the sequestration site during the design, construction, operation and decommissioning phases. The type of administrative control may vary depending on the stage in the storage system lifetime. (02.01.06.00.)	The pre-closure administrative control will influence the quantity and quality of information about the sequestration project that is available post-closure, therefore helping to determine societal memory. The better the amount and quality of information available, the lower the possibility of inadvertent intrusion.	No project planned at this time.	No project planned at this time.	Future inadvertent intrusion into CO2 storage reservoir.	Lack of pre-closure administrative control	Future CO2 release (HSE hazard). Inability to transfer long-term liability. Penalties for non-compliance with regulations	Routine inspection and monitoring of site. One-call center.	Clearly mark the site with warning signs and register the site as a CO2 storage site with the State. Data management. Keep backup documentation at off-site locations.	Data management.
302	11.07.00	Post-closure administrative control (02.02.01.00.)	Administrative control of the sequestration site after closure of the project. The administrative control of the post-closure site may differ from that of the pre-closure site with subsequent implications for the resources available for administrative control, the degree of access and availability of information etc.	There may be potential for loss of information in any transfer of administrative control. A lack of awareness about the details of a CO2 sequestration project could result in inadvertent disruption in the future.	No project planned at this time.	No project planned at this time.	Inadvertent intrusion into the CO2 reservoir. Loss of documentation in transfer of long-term liability.	Lack of post-closure administrative control.	CO2 release (HSE hazard). Delay or prevention of transferring long-term liability.	Data management. Routine site inspection.	Proper documentation and data management. Use multiple backup sites for data storage. Clearly mark site with warnings and register site as CO2 storage site with the State.	Data management. Routine site inspection and/or monitoring.
303	11.08.00	Quality Control (See 02.01.08.00.)	Features related to quality control procedures and tests during the design, and operation of the storage system. It could be expected that a range of quality control measures would be applied during operation of the storage system and supply of CO2 to be sequestered. There may be specific regulations governing quality control procedures, objectives and criteria.	The degree of quality control during the design, construction, operation and decommissioning of a sequestration system can affect the post-closure performance by influencing the integrity of the engineered parts of the system (borehole seals, for example) and by influencing the quantity, quality and accuracy of records. Quality of equipment could have a big impact on the project.	No project planned at this time.	No project planned at this time.	Equipment failure. Insufficient or inaccurate information to ensure safe storage of CO2.	Poor quality control	CO2 release (HSE hazard).	Risk management overseeing quality control.	Risk management overseeing quality control.	Formal risk management protocols and plan overseeing quality control.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
300	11.05.00.	Multi-party project	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
301	11.06.00	Pre-closure administrative control (02.01.06.00.)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
302	11.07.00	Post-closure administrative control (02.02.01.00.)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
303	11.08.00	Quality Control (See 02.01.08.00.)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
304	11.09.00	Monitoring	There are many market and business conditions that should be monitored by management in order to make informed business decisions. These may include: 1. Environmental conditions 2. Public health 3. Public opinion 4. Legislation and regulations 5. Economic conditions 6. Operations 7. Natural resources 8. Water supply 9. Transportation logistics 10. Construction schedule 11. Climate change and weather conditions 12. Security 13. Pipeline 14. CO2/brine movement 15. Operating permit requirements.	Effective decision making requires timely knowledge and understanding of all factors that may influence or be influenced by the decision.	No project planned at this time.	No project planned at this time.	Poor, or lack of, management decisions having a negative impact on the project.	Lack of knowledge or understanding of key factors that may influence or be influenced by management decisions.	Project delayed or impaired. Decreased profitability.	Assessment of monitoring systems in place.	Establish effective monitoring systems for key factors.	Hire independent auditors. To check the checkers. Hire additional outside monitoring services for key factors.
305	12.00.00.	ENGINEERING RISKS										
306	12.01.00.	Technical design	Technical design errors can be cause by: 1. Insufficient data 2. Lack of data - typical of greenfield sites 3. Inaccurate data 4. Misinterpretation of data 5. Use of wrong standards - unit conversion 6. Specification errors 7. Undefined specifications 8. Ignoring data 9. Calculation and modeling errors 10. Failure to design for full range of operating conditions and climate conditions. 11. Failure to design for high operating availability 12. Failure to design for failsafe protection for compression, pipeline, injection well control systems to ensure no unintended release of CO2	Technical design errors can lead to poor performance or failure of equipment/systems and possible CO2 release.	No project planned at this time.	No project planned at this time.	Poor performance or failure of equipment / systems.	Technical design errors.	Project delayed or impaired. Facilities damaged and/or personnel harmed. CO2 release (HSE hazard). Decreased profitability.	Monitor technical design through periodic design reviews.	Conduct periodic design reviews with cross-functional team of experts.	Conduct periodic design reviews with cross-functional team of experts. Correct design errors.
307	12.02.00.	Modeling and simulation	Use of multiple static and dynamic models that are populated and run by different people using different assumptions and methods can result in errors.	Modeling and simulation errors can result in uncertainties, interpretive disagreements and poor operational choices.	Simulation models for CO2-ECBM are not sufficiently developed.	No project planned at this time.	Uncertainties and poor operational choices.	Modeling and simulation errors.	Project delayed or impaired. Decreased profitability.	Monitor modeling and simulation through periodic reviews or checks to confirm accuracy.	Standardize model(s) to be used. Review simulation model results for accuracy and completeness using a cross-functional team of experts.	Periodic review of simulation model results. Compare modeling results with actual results.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
304	11.09.00	Monitoring	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
305	12.00.00	ENGINEERING RISKS	0	0	0	0															
306	12.01.00	Technical design	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
307	12.02.00	Modeling and simulation	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
308	12.03.00.	Baseline studies	Baseline surveys are important for determining ambient or background conditions prior to CO2 injection. They include: 1. Soil baseline 2. Water (surface and groundwater) baseline 3. Atmosphere baseline 4. Seismic baseline 5. Aquatic environment baseline 6. Fauna baseline 7. Flora baseline 8. Land use 9. Natural resources 10. Population 11. Local/regional economic baseline 12. Formation chemical baseline 13. Injection site contamination 14. Coastal features 15. Local oceanography 16. Aquatic sediments 17. Location and condition of existing wells 18. Formation geophysical baseline	Without baseline surveys the project will be unable to quantify what impact the project has had on the environment.	Pump Canyon Site The only baseline studies available relate to reservoir properties and performance.	No project planned at this time.	Uncertainties and poor operational choices	Insufficient, or lack of, baseline studies	Project open to wide range of environmental liabilities that may or may not have been caused by the project. Project delayed or impaired. Decreased profitability. Injectivity or capacity different than expected.	Monitor the performance and quality of baseline studies.	Complete baseline studies before CO2 injection.	Review results of baseline studies.
309	13.00.00.	PROCUREMENT RISKS										
310	13.01.00.	Procurement delays	Procurement delays may threaten project goals. Infrastructure components may include power block, compressors, gas processing equipment, pumps, valving, metering and monitoring equipment. 1. Procurement delays - equipment and infrastructure 2. Procurement delays - drilling services 3. Vendor supply chain disruptions 4. Material supply shortages 5. Changes in materials and equipment costs	Could delay completion of construction	No project planned at this time.	No project planned at this time.	Project schedule disruption(s).	Procurement delays.	Project delayed. Decreased profitability.	Track equipment and material delivery schedules.	Establish lead times for historically long-lead time items (like compressors) and build it into the schedule.	Monitor delivery schedule after orders are placed. Implement supply chain contingency plan.
311	13.02.00.	Vendor errors	1. Vendor engineering errors 2. Defective manufacturing	Potential poor performance or failure of equipment/systems. Potential CO2 leakage.	No project planned at this time.	No project planned at this time.	Poor performance or failure of equipment/systems.	Vendor errors	Project delayed or impaired. Facilities damaged and/or personnel harmed. CO2 release (HSE hazard). Decreased profitability.	Monitor vendor engineering, manufacturing, quality control and performance testing.	Use qualified vendors. Review vendor engineering, design and quality control testing. Negotiate performance guarantees.	Inspect/test delivered product.
312	13.03.00.	Contracting	The ability of project partners to formulate and execute contracts with third parties (non-partners) in a timely manner (not causing delays) apart from their specific contents. 1. EPC contract omissions 2. EPC contract insufficient detail 3. EPC contract change orders	The principal risk is delay and its impact upon achieving goals including cost.	No project planned at this time.	No project planned at this time.	Project schedule disruption(s). Increased EPC costs.	EPC contract omissions, errors or change orders	Project delayed. Decreased profitability.	Monitor EPC contract administration.	Use experienced contract administrator. Implement procedure for preparing request for quote (RFQ), RFQ review and bid review. Get at least 3 competitive bids on large contracts. Establish change order procedures.	Use experienced contract administrator. Hire additional experienced project administrators/consultants as necessary.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
308	12.03.00.	Baseline studies	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
309	13.00.00.	PROCUREMENT RISKS	0	0	0	0																
310	13.01.00.	Procurement delays	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
311	13.02.00.	Vendor errors	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
312	13.03.00.	Contracting	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
313	13.04.00.	Transportation logistics	Project-related traffic in and out of site; its effects upon both injection well, monitoring and CO2 supply operations. 1. Site traffic impact on injection and monitoring 2. Limitations on size/height/weight shipments to site	Could cause interruptions and delays.	No project planned at this time.	No project planned at this time.	Project schedule disruption(s). Increased transportation costs.	Transportation size/weight constraints	Project delayed. Decreased profitability.	Monitor transportation logistics.	Survey potential transportation routes before placing orders. Identify major weight/size items, supply/destination routes, weight/size restrictions, and alternate transportation modes and routes.	Monitor transportation logistics after orders are placed. Consider resolving any transportation bottlenecks by improving infrastructure. Implement supply chain contingency plan.
314	14.00.00.	CONSTRUCTION RISKS										
315	14.01.00.	Cost overruns	Construction cost overruns can be due to 1. Change orders 2. Cost escalation 3. Unexpected problems 4. Rework 5. Poor management.	Increased costs	No project planned at this time.	No project planned at this time.	Construction cost overruns	1. Change orders 2. Cost escalation 3. Unexpected problems 4. Rework 5. Poor management.	Project halted, delayed or impaired. Decreased profitability.	Track actual construction costs versus budget.	Negotiate not-to-exceed EPC contracts. Prepare detailed budget. Have experienced experts review budgets for accuracy and completeness.	Use experienced project managers. Monitor actual versus budgeted expenses. Monitor quality of work. Address deviations from plan early. Prioritize expenses. Cut low priority expenses if necessary. Adjust scope of work if necessary to stay within budget.
316	14.02.00.	Schedule delays	Construction schedule delays can be due to 1. Permitting delays 2. Bad weather 3. Labor issues 4. Procurement delays 5. Accidents 6. Poor planning/management 7. Funding delays	Startup delay and increased costs.	No project planned at this time.	No project planned at this time.	Construction schedule delays.	1. Permitting delays 2. Bad weather 3. Labor issues 4. Procurement delays 5. Accidents 6. Poor planning/management 7. Funding delays	Project halted, delayed or impaired. Decreased profitability.	Track actual versus planned schedule.	Build in cushion in schedule to accommodate unexpected delays. Address procedure for resolving schedule delays in project management plan.	Monitor work in progress versus schedule. Adjust schedule to accommodate unexpected delays.
317	14.03.00.	Construction defects	Construction defects may be identified during or after construction. They may include 1. Improper installation 2. Wrong installation 3. Damage during installation 4. Defective welding 5. Omissions	Increased costs, project delays due to need for rework, and potential human injury and equipment/systems damage	No project planned at this time.	No project planned at this time.	Construction defects.	1. Improper installation 2. Wrong installation 3. Damage during installation 4. Defective welding 5. Omissions	Project halted, delayed or impaired. Facilities damaged and/or personnel harmed. CO2 release (HSE hazard). Project ROI negatively impacted.	Monitor construction quality through regular inspections and testing.	Use qualified contractors. Issue detailed contracts and drawings. Inspect work.	Inspect work. Require contractors to repair any defects.
318	15.00.00.	COMMISSIONING AND STARTUP RISKS										
319	15.01.00.	Major rework	Major rework may be required to correct poor performance or failure of equipment/systems due to improper design, manufacturing, construction or operation.	Project delays and added costs.	No project planned at this time.	No project planned at this time.	Schedule disruption. Increased cost.	Major rework.	Decreased profitability.	Track commissioning and startup performance.	Use experienced contractors. Construction management supervision.	Periodic site visits by stakeholders to inspect the work through the construction phase. Conduct periodic independent construction reviews.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
313	13.04.00.	Transportation logistics	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
314	14.00.00.	CONSTRUCTION RISKS	0	0	0	0															
315	14.01.00.	Cost overruns	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
316	14.02.00.	Schedule delays	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
317	14.03.00.	Construction defects	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
318	15.00.00.	COMMISSIONING AND STARTUP RISKS	0	0	0	0															
319	15.01.00.	Major rework	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
320	15.02.00.	Unable to achieve design capacity	Operating capacity may be limited due to improper design, manufacturing, construction or operation.	Loss of revenues and increased costs.	No project planned at this time.	No project planned at this time.	Increased operating costs.	Unable to achieve design capacity	Decreased profitability.	Track commissioning and startup performance.	Design review process including sign off on drawings by competent engineers.	Performance testing. Resolution of bottlenecks.
321	15.03.00.	Operator error or over confidence during commissioning and startup	Incorrect operation due to lack of operator training	Potential human injury, equipment damage, project delays, added costs.	No project planned at this time.	No project planned at this time.	Poor performance and/or equipment/system failure.	Operator error or over confidence.	Project halted, delayed or impaired. Facilities damaged and/or personnel injured. CO2 release (HSE hazard). Decreased profitability. Regulatory violations.	Track operator training and performance.	Implement a continuous operator training program.	Maintain an ongoing operator training program in the operation phase with particular emphasis on emergency response. Conduct periodic independent operating reviews.
322	15.04.00.	Startup pressure	Facilities sometimes do not have sufficient pressures to re-start injection. In these cases, injection tubing should be loaded with sufficient fluids to allow for a re-start. (CCP 2009)	Insufficient startup pressure can result in operating delays.	No project planned at this time.	No project planned at this time.	Operating delays.	Insufficient startup pressure.	Decreased profitability.	Monitor and model bottom hole pressure and injection pressure.	Design compressors/pumps with sufficient pressure to handle the full range of injection pressure required.	Load tubing with fluids prior to stating injection.
323	16.00.00.	FIELD SAFETY RISKS										
324	16.01.00.	Accidents and unplanned events (02.01.09.00.)	Events related to accidents and unplanned events during site investigation, CO2 emplacement and closure which might have an impact on long-term performance or safety. Accidents are events that are outside the range of normal operations although the possibility that certain types of accident may occur should be anticipated in operational planning. Unplanned events include accidents but could also include deliberate deviations from operational plans, e.g. in response to an accident, unexpected geological events or unexpected aspects of CO2 quality and injection arising during operations. Project related accidents can be caused by human error or equipment/system failure/malfunction. Accidents may occur during construction, commissioning, operation, maintenance or closure. Non-project related accidents may include: rupture of train or truck transport vessel, train derailment, site or water supply contamination. 1. Project related accidents 2. Non-project related accidents	Potential for human injury and/or equipment damage Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue. Accidents and unplanned events may affect the post-closure performance of the sequestration system. One example may be the incomplete sealing of an injection borehole that may subsequently provide a pathway for CO2 migration.	Total fatality rates based on BLS data 2006-2010 (fatalities/worker/year) O&G extraction: 1.12E-04 Drilling O&G wells: 4.85E-04 Support activities for O&G wells: 2.85E-04 O&G pipeline construction: 1.94E-04 Pipeline transportation: 6.96E-05 O&G industry: 2.61E-04 Total significant injury (injuries requiring days away from work) rates based on BLS data 2006-2010 data (incidents/worker/year): O&G extraction: 6.29E-03 Drilling O&G wells: 1.50E-02 Support activities for O&G wells: 1.13E-02 O&G pipeline construction: 7.43E-03 Pipeline transportation: 5.96E-03 O&G industry: 1.02E-02	No project planned at this time.	Human injury/death. Facilities / equipment damage. CO2/CH4 release.	Accidents and unplanned events.	Business interruption. Liability costs.	Comprehensive risk assessment. Routine risk and safety audits.	Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement an emergency response plan and risk management plan. Analyze project changes for new risks.	Maintain safety training and standard procedures. Document response to accidents and unplanned events. Emergency response and contingency planning . Risk management plan. Liability insurance. Conduct periodic response drills.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS/D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
320	15.02.00.	Unable to achieve design capacity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
321	15.03.00.	Operator error or over confidence during commissioning and startup	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
322	15.04.00.	Startup pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
323	16.00.00.	FIELD SAFETY RISKS	0	0	0	0																
324	16.01.00.	Accidents and unplanned events (02.01.09.00.)	3	4	2	24	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<1,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	<\$5M	\$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Impacts profitability.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage cost	<\$10M per incident.	None	Maintain safety training and standard procedures. Part of ongoing costs	<\$10M per accident or unplanned event avoided	1	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
325	16.02.00.	Moving equipment	Moving equipment risks may include: 1. Hitting other equipment 2. Hitting personnel 3. Hitting power lines	Potential for human injury and/or equipment damage	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250. Approximately 3% of fatalities in the O&G industries were tied to pedestrians struck by a vehicle or mobile equipment in 2008 (BLS 2010). Fatality rate tied to pedestrian hit by moving equipment (assuming 15% of transportation incidents) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 5.94E-06 Drilling O&G wells: 1.82E-05 Support activities for O&G wells: 2.1E-05 O&G pipeline construction: 1.08E-05 Pipeline transportation: 5.97E-06 O&G industry: 1.52E-05 Significant injury rate tied to pedestrian being hit by moving equipment in drilling O&G wells based on BLS 2007 data: 5.49E-05.	No project planned at this time.	Facilities / equipment damage. Human injury/death. CO2/CH4 release (HSE hazard).	Improper operation of moving equipment.	Business interruption. Liability costs.	Monitor moving equipment on site.	Design site layout to safely accommodate moving equipment. Maintain moving equipment in safe operating condition. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
326	16.03.00.	Excavation/drilling	The one-call system should be used to locate underground utilities and pipelines before excavating or drilling. Excavation/drilling could hit other subsurface hazards such as gas pockets or underground storage tanks.	Potential for equipment damage, release of gases or liquids, fire, explosion, and/or human injury.	Fatality rate for drilling O&G wells based on BLS 2006-2010 data: 4.85E-04 fatalities/worker/year. Significant injury (injury requiring days away from work) rate for drilling O&G wells based on BLS 2006-2010 data: 1.5E-02 incidents/worker/year	No project planned at this time.	Pipeline damage. Human injury/death. CO2/CH4 release (HSE hazard).	Excavation/drilling.	Business interruption. Pipeline repair costs. Liability costs. Decreased profitability.	Monitoring excavation/drilling activities and one-call center alerts.	Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
327	16.04.00.	Defective equipment	Equipment should be properly maintained and regularly inspected. Equipment defects may include: 1. Exposed electric wiring 2. Leaky hoses 3. Loose connections 4. Frayed cables	Higher risk for equipment failure and human injury	Fatality rate tied to contact with equipment (assuming 45% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.04E-05 Drilling O&G wells: 8.01E-05 Support activities for O&G wells: 3.02E-05 O&G pipeline construction: 2.41E-05 Pipeline transportation: 0 O&G industry: 3.25E-05 Significant injury rate due to being caught in an object equipment or material in drilling O&G wells based on BLS 2007 data: 3.88E-03 incidents/worker/year	No project planned at this time.	Human injury/death. Facilities / equipment damage. CO2/CH4 release (HSE hazard).	Defective equipment	Project delayed or impaired. Liability costs. Decreased profitability.	Monitor equipment condition and maintenance records.	Maintain equipment in safe condition. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain equipment in safe condition. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info		
			Index #	Risk Area/FEP	Failure probability (P= 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)		Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)
									Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
325	16.02.00.	Moving equipment	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	\$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Impacts profitability.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage cost	<\$10M per incident.	None	Part of ongoing costs	<\$10M	1		
326	16.03.00.	Excavation/drilling	3	4	2	24	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	\$50,000/acre soil remediation and /or vegetation replanting	None	Pipeline damage <\$1M per incident.	\$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Impacts profitability.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided:<\$3M	2		
327	16.04.00.	Defective equipment	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<1,000 t CO2 @ \$200/t CO2 released into USDW \$50,000/acre of land contaminated	None	<\$2M	\$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Impacts profitability.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage cost	<\$5M per incident.	None	Part of ongoing cost	Savings per incident avoided:<\$5M	2		

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
328	16.05.00.	Use of power tools	Operators should be properly trained in the use of power tools.	Potential for human injury and/or equipment damage	Fatality rate tied to contact with equipment (assuming 45% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.04E-05 Drilling O&G wells: 8.01E-05 Support activities for O&G wells: 3.02E-05 O&G pipeline construction: 2.41E-05 Pipeline transportation: 0 O&G industry: 3.25E-05 Significant injury rate due to being caught in an object equipment or material in drilling O&G wells based on BLS 2007 data: 3.88E-03 incidents/worker/year	No project planned at this time.	Human injury/death.	Improper use of power tools.	Liability costs. Equipment repair costs.	Monitor operator training and use of power tools.	Select appropriate power tools. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain power tools in safe condition. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.	
329	16.06.00.	Contact with rotating equipment	Proper safeguards should be used to prevent contact with rotating equipment	Higher risk for being injured	Fatality rate tied to contact with equipment (assuming 45% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.04E-05 Drilling O&G wells: 8.01E-05 Support activities for O&G wells: 3.02E-05 O&G pipeline construction: 2.41E-05 Pipeline transportation: 0 O&G industry: 3.25E-05 Significant injury rate due to being caught in an object equipment or material in drilling O&G wells based on BLS 2007 data: 3.88E-03 incidents/worker/year	No project planned at this time.	Human injury/death. Equipment damage.	Contact with rotating equipment.	Liability costs. Equipment repair costs.	Monitor activity around rotating equipment.	Install safeguards around rotating equipment. Lockout equipment before performing maintenance. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.	
330	16.07.00.	Working near pinch points	Proper safeguards should be used to prevent contact with pinch points	Higher risk for being pinched	Fatality rate tied to contact with equipment (assuming 45% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.04E-05 Drilling O&G wells: 8.01E-05 Support activities for O&G wells: 3.02E-05 O&G pipeline construction: 2.41E-05 Pipeline transportation: 0 O&G industry: 3.25E-05 Significant injury rate due to being caught in an object equipment or material in drilling O&G wells based on BLS 2007 data: 3.88E-03 incidents/worker/year	No project planned at this time.	Human injury/death.	Working near pinch points.	Liability costs. Equipment repair costs.	Monitor activity around pinch points.	Install safeguards in pinch-point areas. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
328	16.05.00.	Use of power tools	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	1
329	16.06.00.	Contact with rotating equipment	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	1
330	16.07.00.	Working near pinch points	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
331	16.08.00.	Working in confined areas	Working in confined areas can represent high risk especially where CO2 is involved.	Higher risk of asphyxiation or being crushed.	Trench/ditch work limited due to the existence of pipeline infrastructure in the area.	No project planned at this time.	Human injury/death.	Working in confined areas.	Liability costs. Equipment repair costs.	Monitor activity in confined areas.	Provide protective equipment and safeguards for working in confined areas, including CO2 alarm and ventilation if appropriate. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
332	16.09.00.	Working in high places	Working in high places is a common industrial occurrence	Higher risk of injury due to falling	Fatality rates tied to falls based on BLS data 2006-2010 (fatalities/worker/year) O&G extraction: 0 Drilling O&G wells: 5.27E-05 Support activities for O&G wells: 4.14E-06 O&G pipeline construction: 0 Pipeline transportation: 0 O&G industry: 1.15E-05 Significant injury rate resulting from falls to a lower level in drilling O&G wells in 2007 based on BLS data: 9.7E-04 incidents/worker/year	No project planned at this time.	Human injury/death.	Working in high places.	Liability costs. Equipment repair costs.	Monitor activity in high places.	Provide protective equipment and safeguards for working in high places. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
333	16.10.00.	Working in trench/ditch	Pipeline construction involves trenching which is subject to cave-ins. Sufficient shielding or cave-in protection devices should be used if people go into a trench	High risk of being crushed and/or asphyxiated	Trench/ditch work limited due to the existence of pipeline infrastructure in the area.	No project planned at this time.	Human injury/death.	Working in trench/ditch.	Liability costs.	Monitor activity in trenches / ditches.	Provide cave-in protection devices. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Supervise trench/ditch work. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking			Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
331	16.08.00.	Working in confined areas	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	2
332	16.09.00.	Working in high places	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	\$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	1
333	16.10.00.	Working in trench/ditch	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
334	16.11.00.	Working under a lifted load	Working under a lifted load should be avoided	Higher risk for being crushed	Fatality rate tied to struck by object (assuming 55% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.28E-05 Drilling O&G wells: 9.85E-05 Support activities for O&G wells: 3.7E-05 O&G pipeline construction: 2.95E-05 Pipeline transportation: 0 O&G industry: 3.97E-05 Significant injury rate due to being struck by an object or flying debris in drilling O&G wells based on BLS 2007 data: 5.93E-03 incidents/worker/year	No project planned at this time.	Human injury/death.	Working under a lifted load.	Liability costs.	Monitor activity under lifted loads.	Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Supervise load lifting. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
335	16.12.00.	Contact with venomous snakes or insects	Field operations and data collection can be in close proximity to venomous snakes and insects in some parts of the country.	Potential for human injury.	Rattlesnakes, bees, wasps, fire ants, scorpions, black widows, brown recluse spiders and ticks are present in the region.	No project planned at this time.	Human injury/death.	Contact with venomous snakes or insects.	Liability costs.	Monitor presence of venomous snakes and insects.	Clear work areas of stuff that would attract venomous snakes or insects. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Keep work areas clear of venomous snakes or insects. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
336	16.13.00.	Contact with poisonous plants	Field operations and data collection can be in close proximity to poisonous plants such as poison ivy or poison oak in some parts of the country.	Potential of human rash/irritation	Poisonous plants not found in the site area.	No project planned at this time.	Human injury.	Contact with poisonous plants.	Liability costs.	Monitor presence of poisonous plants.	Clear work areas of poisonous plants. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Keep work areas clear of poisonous plants. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
334	16.11.00.	Working under a lifted load	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	2
335	16.12.00.	Contact with venomous snakes or insects	2	1	1	2	None	0 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	None	<\$0.1M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$0.1M	1
336	16.13.00.	Contact with poisonous plants	2	1	1	2	None	0 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	None	None	None	<\$0.01M	None	Part of ongoing cost	Savings per incident avoided: <\$0.1M	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
337	16.14.00.	Contact with hot surface, or exposure to heat or flame	Overheated equipment, welding areas, heaters and open flames are present at industrial sites.	Contact with hot surface or flame can cause burn injuries. Exposure to prolonged high temperatures can cause heat exhaustion or dehydration.	Data not available.	No project planned at this time.	Human injury/death.	Contact with hot surface or exposure to heat or flame.	Liability costs.	Monitor activity near hot surfaces or open flames.	Install safeguards around hot surfaces or flames. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.	
338	16.15.00.	Exposure to noise	Operation of heavy equipment, pumps and compressors can generate loud noise.	Prolonged exposure to loud noise can cause hearing damage.	Average noise levels associated with CBM (dBA at 15 m distance) Construction equipment: 85 Compressor station: 72 Pump jack: 67 Drilling rig: 86	No project planned at this time.	Human injury.	Exposure to noise.	Liability costs.	Monitor noise levels.	Provide hearing protection equipment. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.	
339	16.16.00.	Exposure to dust	Dust is generated in pipeline construction and field operations.	Prolonged exposure to dust can cause respiratory health problems.	Dust likely on site due to construction, traffic and wind.	No project planned at this time.	Human injury.	Exposure to dust.	Liability costs.	Monitor dust levels.	Provide dust masks. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Human health & safety	Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)							
															Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury				
Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)																
337	16.14.00.	Contact with hot surface, or exposure to heat or flame	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	1
338	16.15.00.	Exposure to noise	2	1	1	2	None	0 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	None	None	<\$0.1M per incident.	None	Part of ongoing cost	Savings per incident avoided: <\$0.1M	1	
339	16.16.00.	Exposure to dust	2	1	1	2	None	0 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	None	None	<\$0.1M per incident.	None	Part of ongoing cost	Savings per incident avoided: <\$0.1M	2	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
340	16.17.00.	Exposure to hazardous materials	Fluids, fuels and chemicals used in field operations may be classified as hazardous materials.	Prolonged exposure to hazardous materials are known to cause health problems.	Fatality rates tied to exposure to harmful substances or environments based on BLS data 2006-2010 (fatalities/worker/year) O&G extraction: 8.2E-06 Drilling O&G wells: 6.85E-05 Support activities for O&G wells: 2.07E-05 O&G pipeline construction: 1.65E-05 Pipeline transportation: 0 O&G industry: 2.5E-05 Significant injury rate due to exposure to harmful substances in drilling O&G wells based on BLS 2007 data: 6.04E-04 incidents/worker/year	No project planned at this time.	Human injury/death.	Exposure to hazardous materials.	Liability costs.	Monitor presence of hazardous materials.	Properly identify and isolate hazardous materials. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
341	16.18.00.	Struck by object or flying debris	Drilling can often generate flying debris	Flying debris can cause human injury and/or equipment damage.	Fatality rate tied to struck by object (assuming 55% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.28E-05 Drilling O&G wells: 9.85E-05 Support activities for O&G wells: 3.7E-05 O&G pipeline construction: 2.95E-05 Pipeline transportation: 0 O&G industry: 3.97E-05 Significant injury rate due to being struck by an object or flying debris in drilling O&G wells based on BLS 2007 data: 5.93E-03 incidents/worker/year	No project planned at this time.	Human injury/death.	Exposure to flying debris.	Liability costs.	Monitor for flying debris.	Install safeguards in area susceptible to flying debris. Provide safety glasses. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
342	16.19.00.	Release of compressed gases or liquids	Compressed CO2 pipelines, pressurized water lines, compressed air tanks are at risk for rupture.	Release of compressed gases or liquids can cause human injury and/or equipment damage.	Fatality and injury data not available.	No project planned at this time.	Human injury/death.	Release of compressed gases or liquids.	Liability costs. Facilities repair costs.	Monitor work in areas near compressed gases or liquids.	Identify and protect/secure compressed gas/liquid lines, valves or tanks. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
340	16.17.00.	Exposure to hazardous materials	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	2
341	16.18.00.	Struck by object or flying debris	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	1
342	16.19.00.	Release of compressed gases or liquids	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
343	16.20.00.	Ignition of flammable gases or liquids	Acetylene tanks, natural gas lines, liquid fuel lines could be ignited.	Ignition of flammable gases or liquids can cause explosions, severe injuries and property damage.	Flammable gases and liquids present at CO2-ECBM surface facilities. Fatality rate tied to fires and explosions based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.91E-05 Drilling O&G wells: 4.48E-05 Support activities for O&G wells: 4.24E-05 O&G pipeline construction: 8.26E-06 Pipeline transportation: 0 O&G industry: 3.46E-05	No project planned at this time.	Human injury/death. Facilities / equipment damage.	Ignition of flammable gases or liquids.	Liability costs. Facilities / equipment repair costs.	Monitor work in areas near flammable gases or liquids.	Identify and isolate flammable gases and liquids. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.	
344	16.21.00.	Trips, slips and falls	Trips, slips and falls are common at industrial sites.	Potential for human injury	Fatality rates tied to falls based on BLS data 2006-2010 (fatalities/worker/year): O&G extraction: 0 Drilling O&G wells: 5.27E-05 Support activities for O&G wells: 4.14E-06 O&G pipeline construction: 0 Pipeline transportation: 0 O&G industry: 1.15E-05 Significant injury rate resulting from fall on same level in drilling O&G wells in 2007 based on BLS data (injuries/worker/year): 1.7E-03. Significant injury rate resulting from slips and trips in drilling O&G wells in 2007 based on BLS data (incidents/worker/year): 2.38E-04.	No project planned at this time.	Human injury/death.	Trips, slips and falls.	Liability costs.	Monitor work areas for potential causes of trips, slips and falls.	Clear work areas of items that would cause trips, slips or falls. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Keep work areas clear. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.	
345	16.22.00.	Leaks and spills (related to oil spills rather than CO2, H2S and CH4)	Leaks and spills of lubricants, fuels, chemicals or hazardous materials are common at industrial sites. If they are not promptly taken care of they can lead to more serious problems.	Potential for human injury, equipment damage, fire or environmental damage.	This is a CO2-ECBM project, not involving oil pipelines or storage. Minimal storage of lubricants, fuels and chemicals.	No project planned at this time.	Human injury. Environmental damage.	Leaks and spills. Oil spill.	Liability costs. Environmental remediation costs.	Monitor stored/piped liquids.	Keep gases, liquids, solids contained. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Clean up any leaks or spills immediately. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
343	16.20.00.	Ignition of flammable gases or liquids	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	<\$2M	\$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Impacts profitability.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage cost	<\$5M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$5M	2
344	16.21.00.	Trips, slips and falls	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	1
345	16.22.00.	Leaks and spills (related to oil spills rather than CO2, H2S and CH4)	2	1	1	2	None	None	None	None	None	None	None	None	None	None	<\$0.1M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$0.1M	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
346	16.23.00.	Head bumping	Industrial sites are prone to have low hanging or falling objects that could injury unprotected heads	Potential for human head injury	Fatality rates tied to striking an object or equipment (assuming 5% of Contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.16E-06 Drilling O&G wells: 8.95E-06 Support activities for O&G wells: 3.36E-06 O&G pipeline construction: 2.69E-06 Pipeline transportation: 0 O&G industry: 3.61E-06 Significant injury rate due to being struck against an object in drilling O&G wells based on BLS data in 2007: 6.04E-04 incidents/worker/year	No project planned at this time.	Human injury/death.	Head bumping.	Liability costs.	Monitor wearing of hard hats in required areas.	Provide hard hats. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Place warning signs in low hanging areas. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
347	16.24.00.	Overexertion from manual heavy lifting, pulling, or pushing	Improper lifting of pipes, ducts, bars, boxes, bags, machine parts. Pulling/pushing wrenches, hoses, machine parts or heavy loads.	Potential for human back injury. Overexertion represented 11.3% of injuries requiring days away from work in drilling oil and gas wells in 2007. The injury rate was 2E-03 per worker per year.	Overexertion represented 11.3% of injuries requiring days away from work in drilling oil and gas wells in 2007. The injury rate was 2E-03 per worker per year . Fatalities possible when overexertion is complicated by heart attack or heat stroke.	No project planned at this time.	Human injury/death.	Manual heavy lifting or pulling.	Liability costs.	Monitor heavy lifting or pulling activities.	Provide appropriate equipment for lifting or pulling heavy loads. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
348	16.25.00.	On-road driving	Vehicle travel to and from the site is typically among the highest risks in similar projects.	Potential for human injury and/or equipment damage	Assuming highway driving accounts for 56% of the fatality rates tied to transportation events.(fatalities/worker/year): O&G extraction: 2.21E-05 Drilling O&G wells: 6.27E-05 Support activities for O&G operations: 7.84E-05 O&G pipeline construction: 7.27E-05 Pipeline transportation (operation): 2.23E-05 O&G industry: 5.66E-05. Injury rate requiring days away from work in drilling O&G wells tied to highway driving (assuming 56% of transportation incidents) based on BLS data for 2007 (incidents/worker/year): 2E-04	No project planned at this time.	Human injury/death. Vehicle / property damage.	On-road driving.	Liability costs. Vehicle and property damage repair.	Monitor on-road driving activity and road conditions.	Maintain vehicles in safe operating condition. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS/D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
346	16.23.00.	Head bumping	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	2
347	16.24.00.	Overexertion from manual heavy lifting, pulling, or pushing	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$3M	1
348	16.25.00.	On-road driving	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$2M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$2M	2

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
349	16.26.00.	Off-road driving	Field data collection often requires off-road driving, sometimes in rocky, muddy, or steep terrain. Some personnel may lack experience with safe driving under challenging conditions.	Potential for human injury and/or equipment damage	Less than 3% of O&G industry fatalities were tied to off-road driving in 2008. (inferred from BLS data).	No project planned at this time.	Human injury/death. Vehicle /property damage.	Off-road driving.	Liability costs. Vehicle and property damage repair costs.	Monitor off-road driving activity and driving conditions.	Maintain vehicles in safe operating condition. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
350	16.27.00	Explosions and crashes (01.03.10.00.)	Events related to deliberate or accidental explosions and crashes such as might have some impact on a closed storage site, e.g. underground nuclear testing, an aircraft crash on the site, acts of war, marine collisions or trawler damage to exposed seabed structures. 1. Accidental explosions and crashes 2. Deliberate explosions and crashes 3. Project related 4. Non-project related	Explosions and crashes are likely to be low probability events that could have a significant impact on the performance of the sequestration system by disrupting the expected evolution of the system. Likely to have greater impact on surface facilities rather than subsurface systems.	Approximately 13% of O&G industry fatalities are tied to fires and explosions (BLS 2010). Approximately 4% of O&G industry fatalities were tied to aircraft (helicopter) crashes in 2008 (BLS 2010). Fatality rate tied to fires and explosions based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.91E-05 Drilling O&G wells: 4.48E-05 Support activities for O&G wells: 4.24E-05 O&G pipeline construction: 8.26E-06 Pipeline transportation: 0 O&G Industry: 3.46E-05.	No project planned at this time.	Damage to surface facilities. Multiple human injury/death.	Explosions or crashes.	Liability costs. Property damage repair costs. Potential CO2 release.	Almost impossible to pre-detect.	Proper site characterization and site selection avoiding areas near heavily traveled flight paths, rail lines or busy highways. Provide motor vehicle crash barriers around surface facilities. Keep surface facilities secured from public access.	Procedures to shutdown and evacuate site in cases of imminent danger. Emergency response procedures/training. Maintain liability insurance.
351	16.28.00	Electric shock	Contact with electric current associated with electric machines, tools, appliances, light fixtures, overhead power lines, underground cables, transformers, wiring, and lightning.	Potential for human injury	No data available.	No project planned at this time.	Human injury/death	Contact with electric current	Liability costs.	Monitor human activity near electrical areas.	Maintain electrical equipment in good working condition. Identify and avoid areas with overhead power lines or underground cables. Shut off power and lock out before working on electrical equipment.	Train operators how to respond to electric shock incidents.
352	17.00.00.	LEGAL, LEGISLATION & REGULATION RISKS										

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Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)					
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)															
349	16.26.00.	Off-road driving	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$2M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$2M	2
350	16.27.00	Explosions and crashes (01.03.10.00.)	2	5	2	20	>1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	<\$5M	\$150-\$385/d of downtime per well based on 43 to 110 MCFD CH4 at \$3.5/MMBTU.	Impacts profitability.	<1,000 t/y CO2 per leak @ \$32.32/t CO2 <20MMCF/y CH4 @ \$3.50/MCF.	10% of damage cost	<\$10M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$10M	1
351	16.28.00	Electric shock	2	4	2	16	1 @ \$1.5M per fatality	0 @ \$1.5 M per serious (irrecoverable) injury	0 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$2M per incident.	None	Part of ongoing costs	Savings per incident avoided: <\$2M	2
352	17.00.00.	LEGAL, LEGISLATION & REGULATION RISKS	0	0	0	0															

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
353	17.01.00.	CO2 legislation	Some outstanding CO2 legislation issue are as follows: 1. Cap and Trade or Carbon tax incentives for CCS 2. Certification process for tradable carbon credits 3. Pore space access and ownership 4. Certification for transfer of long-term stewardship/liability for closed CO2 sites from operator to competent legal authority 5. Eminent domain authority 6. Forced unitization for EOR or ECBM 7. Priority of mineral rights over pore space rights 8. Value of escaped CO2	Legislation can have a significant impact on CCS project economics. Lack of, or gaps in, CO2 legislation can create uncertainty for the project and make it more difficult to permit and finance the project. Concerns that enacted CO2 legislation could be repealed or changed also contribute to uncertainty for the project and make it more difficult to finance.	Most legislation risks not applicable to CO2-ECBM in a unitized field unless CO2 injection continues after ECBM stops. CO2 legislation is likely to have a positive rather than negative impact on CO2-ECBM.	No project planned at this time.	Project uncertainties. Project economically infeasible.	Lack of CO2 legislation. Insufficient or onerous CO2 legislation.	Project halted or delayed. Decreased profitability.	Monitor federal and state CO2 legislation activity.	Tie investment in CCS projects to passage of appropriate CO2 legislation. Implement public outreach program to educate stakeholders on the legislative needs of the project. Shift from DSA to EOR or ECBM if CO2 legislation does not get passed, is insufficient or too onerous for DSA.	Monitor CO2 legislation and analyze the impact of CO2 legislation on the project. Continue public outreach program. Comply with CO2 legislation.
354	17.02.00.	CO2 regulations	Some outstanding CO2 regulation issue are as follows: 1. CO2 storage permitting and compliance requirements 2. Permitting and compliance for Class VI wells 3. Permitting and compliance for hybrid Class II and VI wells (wells used for both EOR and DSA) 4. Post-injection site care (monitoring) period - EPA proposing 50 years with some flexibility 5. Safety guidelines - DOE best practices guidelines 6. Monitoring protocols - DOE guidelines 7. Verification and accounting procedures 8. Classification of CO2 as a pollutant rather than a commodity 9. CO2 emission controls and reporting 10. CO2 site straddling two states having to deal with differing regulations.	Regulations can have a significant impact on CCS project economics. Lack of, or gaps in, CO2 regulations can create uncertainty for the project and make it more difficult to permit and finance the project. Classification of CO2 as a pollutant rather than a commodity could impact EOR/ECBM operations.	New regulations and oversight, as well as changes in regulations, by regulatory agencies could adversely impact income and operations. CO2-ECBM falls under UIC Class II wells, which are significantly less demanding than UIC Class VI wells. CO2 reporting regulations include CO2 ECBM. Increased regulatory requirements relating to integrity of pipelines or CO2 storage may require additional money to be spent to comply with these requirements.	No project planned at this time.	Project uncertainties. Project economically infeasible.	Lack of CO2 regulations. Insufficient or onerous CO2 regulations.	Project halted or delayed. Decreased profitability.	Monitor federal and state CO2 regulation activity.	Tie investment in CCS projects to passage of appropriate CO2 regulations. Implement public outreach program to educate stakeholders on the regulation needs of the project. Shift from DSA to EOR or ECBM if CO2 regulations do not get passed, are insufficient or too onerous for DSA. Relocate project to different State if State regulations are not conducive to DSA.	Monitor CO2 regulations and analyze the impact of CO2 regulations on the project. Continue public outreach program. Comply with CO2 regulations.
355	17.03.00.	CO2 liabilities	Responsibility for the injected CO2 and any associated liability, during and after active project phase, is currently an unresolved legal issue. Project participants could reduce their involvement if this issue remains unresolved, or is resolved in a manner that unacceptably increases their exposure. 1. CO2 ownership and custody 2. Tort-injury to a third-party (person or property) 3. Property-rights dispute 4. Trespass - contamination of third-party natural resources 5. Trespass - infringement on third-party pore space 6. Breach of duty - leakage sufficient to undermine the value of carbon credits 7. Frivolous lawsuits private or organizational based legal challenges 8. Surface ownership and associated liability 9. Assigning liability responsibility in a multi-party project	Liability for potential damages associated with sequestration or operational aspects could preclude the project from moving forward. Property-right disputes over surface rights, mineral rights or pore space could halt or restrict construction, CO2 injection or monitoring operations for CCS projects.	CO2 ownership not defined. Pore space infringement and contamination of third-party resources possible. Multiple operators producing gas from different formations on the same sites could create disputes over who is liable for a gas leak, subsidence or induced seismicity. Carbon credits not applicable to natural CO2. Environmental, health and safety laws and regulations could expose operator to significant costs and liabilities.	No project planned at this time.	Project uncertainties. Increased legal costs.	CO2 legal disputes.	Project halted, delayed or impaired. Decreased profitability.	Monitor legal activities.	Obtain liability insurance.	Keep effective records. Maintain liability insurance.

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Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Risk priority number (PXS=D = 1 to 125) Difficulty of failure detection (D = 1 to 5)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
						Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
353	17.01.00.	CO2 legislation	3	2	1	6	None	None	None	None	None	None	None	<\$1M additional costs	None	None	<\$1M	None	<\$1M legal fees or additional reporting costs.	None	
354	17.02.00.	CO2 regulations	4	3	1	12	None	None	None	None	None	None	None	>\$1M additional costs	None	None	<\$1M	None	>\$1M legal fees or additional reporting costs.	None	
355	17.03.00.	CO2 liabilities	4	3	1	12	None	None	None	None	None	None	None	None	None	>\$1M legal expenses	<\$1M	None	>\$1M legal fees or additional reporting costs.	None	1

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356	17.03.01.	Insurance	There are many kinds of insurance coverage. Some of those that pertain to CCS include: 1. Physical damage 2. Machinery breakdown 3. Business interruption (advanced loss of profit) 4. Environmental 5. Third-party liability 6.Worker's compensation 7. Transportation 8.Closure and post-closure financial assurance 9. Operator's extra expense (OEE)	Insurance coverage may not be available for CCS projects until there is a sufficient track record of performance (or failure) to determine the probability of failure occurring.	No project planned at this time.	No project planned at this time.	Project uncertainties. Increased costs.	Inability to get affordable insurance coverage.	Project halted, delayed or impaired. Decreased profitability.	Monitor availability and cost of insurance coverage for CCS projects.	Work with a competent insurance broker to prepare an estimated maximum loss analysis, prepare underwriting reports for the project, and source insurance coverage. Self insure.	Work with a competent insurance broker to prepare an estimated maximum loss analysis, prepare underwriting reports for the project, and source insurance coverage. Self insure.
357	17.03.02	Transfer of long-term liability stewardship	Public companies cannot take on long-term liability for 50 years or more. There is no guarantee companies will stay in business that long. Therefore, it is up to a government entity to take on responsibility. The federal government would be preferred because it would level the playing field among states and spread the risks over more projects. A sinking fund could be used to cover the costs of such a program.	Companies are unlikely to invest in deep saline aquifer (DSA) sequestration projects without some assurance that the long-term liability is transferable or manageable.	No project planned at this time. CO2-ECBM using natural CO2 does not have the long-term liability stewardship required for CO2-DSA.	No project planned at this time.	Project uncertainties. Increased costs.	Inability to transfer long-term liability stewardship for CO2 storage.	Project halted, delayed or impaired. Decreased profitability.	Monitor federal and state legislation on transfer of long-term liability stewardship for CO2 storage	Encourage the federal government to allow transfer of long-term liability of stored CO2 and establish a sinking fund for long-term stewardship of CO2 storage sites.	Monitor CO2 legislation and take corrective action as necessary. Establish long term O&M fund.
358	18.00.00.	CO2 CAPTURE RISKS										
359	18.01.00.	CO2 capture system performance	Performance risks for CO2 capture systems could include: 1. Production below design capacity 2. Unable to meet product specification 3. Low CO2 recovery 4. Low thermal efficiency - greater heat losses than expected, low heat recovery 5. Excess solvent or sorbent consumption 6. Excess power consumption 7. Excess steam consumption 8. Excess cooling water circulation required 9. Excess maintenance 10. Low process availability 11. Low mechanical availability	Poor performance of the CO2 capture system can result in higher operating and maintenance costs, interruption of CO2 supply, and/or off spec CO2.	No project planned at this time.	No project planned at this time.	High cost of CO2 capture. Off-spec CO2 stream. Low reliability of CO2 supply.	Poor performance of CO2 capture system.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor CO2 capture system operating performance.	Select commercially proven, reliable CO2 capture technology. Conduct design reviews using a cross-functional team of experts. Require performance test and process guarantees.	Monitor plant and process performance. Implement a comprehensive maintenance program. Operate at, or close to, steady state conditions.
360	18.02.00.	CO2 capture system design	Design deficiencies for CO2 capture systems could include: 1. Scale-up errors 2. Equipment undersized/oversized for proper residence time 3. Equipment undersized/oversized for proper surface area 4. Excess velocities 5. Inadequate expansion joints 6. System bottlenecks 7. Inadequate instrumentation 8. Inadequate process controls and alarms 9. Inadequate computer simulation models 10. Wrong sorption model for the contacting devise 11. Insufficient winterization 12. Wrong materials of construction 13. Lack of emergency flare/vent 14. Lack of surge capacity 15. Lack of redundancy -backup systems	Design deficiencies can result in poor performance, higher operating and maintenance costs, interruption of CO2 supply, and/or off-spec CO2..	No project planned at this time.	No project planned at this time.	High cost of CO2 capture. Poor performance or failure of equipment/system	CO2 capture design deficiencies.	Project halted, delayed or impaired. Facilities/equipm ent damage and/or human injury/death. CO2 release (HSE hazard).	Monitor technical design of CO2 capture system through periodic design reviews.	Negotiate process performance guarantees. Conduct design reviews using a cross-functional team of experts.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.

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Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
356	17.03.01.	Insurance	2	3	1	6	None	None	None	None	None	None	None	<\$10M additional costs	None	None	<\$10M	None	Self insurance. <\$10M	None	1
357	17.03.02	Transfer of long-term liability stewardship	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
358	18.00.00.	CO2 CAPTURE RISKS	0	0	0	0															
359	18.01.00.	CO2 capture system performance	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
360	18.02.00.	CO2 capture system design	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
361	18.03.00.	CO2 capture system scale up limitations	The limits on scale up of the CO2 capture system could include: 1. Equipment size limits - manufacturing, transport, or structural load limits 2. Heat transfer limits 3. Mass transfer limits 4. Diffusion limits 5. Surface area limits 6. Reaction kinetics limits	Limits in scale up of the CO2 capture system can lead to higher capital cost and higher operating costs.	No project planned at this time.	No project planned at this time.	High cost of CO2 capture. Poor performance or failure of equipment/system.	Improper scale up of CO2 capture system.	Project halted, delayed or impaired. Facilities/equipment damage and/or human injury/death. CO2 release (HSE hazard).	Monitor technical design of CO2 capture system through periodic design reviews.	Determine limiting factor(s) for scale up. Size unit trains appropriately. Conduct design reviews using a cross-functional team of experts. Require performance test and process guarantees.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.
362	18.04.00.	CO2 capture system operations	System operating risks for CO2 capture systems could include: 1. Non-equilibrium or non-steady-state conditions 2. Exothermic reactions overheating the process 3. Endothermic reactions overcooling the process 4. Pressure/stress buildup 5. Non-uniform mass distribution/dispersion/mixing – dead zones, stratification 6. Non-uniform temperature distribution – hot/cold spots, stratification 7. Mass and energy imbalance 8. System imbalance 9. Pressure or temperature cycling 10. System upset – unexpected high flow rate/temperature, carryover of upstream contaminants 11. Off-spec or inconsistent feed and/or product 12. Abrasion/erosion 13. Corrosion 14. Fouling 15. Contactor plugging 16. CO2 escape/leakage to the atmosphere 17. Scale build up causing heat exchanger failure 18. Air leakage - nitrogen dilution 19. Equipment failure due to defects, plugging, wear 20. Control system failure 21. Material/weld failure - leaks 22. Operator error	Operation and maintenance problems can result in higher operating and maintenance costs, CO2 supply interruptions and off-spec CO2.	No project planned at this time.	No project planned at this time.	High cost of CO2 capture. Poor performance or failure of equipment/system.	Operating problems with CO2 capture system.	Project halted, delayed or impaired. Facilities/equipment damage and/or human injury/death. CO2 release (HSE hazard).	Monitor CO2 capture system operating performance.	Select commercially proven, reliable CO2 capture technology. Implement a comprehensive maintenance program. Maximize operating time at steady state operation. Require performance test and process guarantees.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.
363	18.05.00.	CO2 capture solvent or sorbent	Solvent or sorbent risks for CO2 capture could include: 1. Off-spec or inconsistent solvent or sorbent 2. Unexpected contamination (SOx, NOx, Cl, H2O, hydrocarbons, trace metals, chemical slip, particulate matter) 3. Gradual buildup of contaminants in circulating loads 4. Foaming 5. Chemical reactions with contaminants - precipitation of solids 6. Excess viscosities 7. Chemical degradation of solvent or sorbent 8. Thermal degradation of solvent or sorbent 9. Aging (deactivation) of solvent or sorbent 10. Hazardous material handling	Off spec or degraded solvent or sorbent can result in poor CO2 capture, higher operating costs, CO2 supply interruptions, and off-spec CO2.	No project planned at this time.	No project planned at this time.	High cost of CO2 capture. Poor performance or failure of equipment/system.	Solvent/sorbent performance.	Project halted, delayed or impaired. Facilities/equipment damage and/or human injury/death. CO2 release (HSE hazard).	Monitor CO2 capture solvent/sorbent performance.	Select commercially proven, reliable solvent/sorbent. Avoid system upsets and contaminants.	Monitor solvent/sorbent composition, properties, performance and losses. Determine root cause of deviations from expected results and take corrective action to resolve the problem.
364	19.00.00.	CO2 DEHYDRATION RISKS										

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									Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
361	18.03.00.	CO2 capture system scale up limitations	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None			
362	18.04.00.	CO2 capture system operations	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None			
363	18.05.00.	CO2 capture solvent or sorbent	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None			
364	19.00.00.	CO2 DEHYDRATION RISKS	0	0	0	0																	

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365	19.01.00.	CO2 dehydration system performance	Performance risks for CO2 dehydration systems could include: 1. Production below design capacity 2. Unable to meet product specification 3. Excess glycol consumption 4. Carryover of glycol into downstream systems 5. Excess utility consumption 6. Excess maintenance 7. Low plant process and/or mechanical availability	Poor performance of the CO2 dehydration system can result in higher operating and maintenance costs, interruption of CO2 supply, off spec CO2, and corrosion of downstream systems.	No project planned at this time.	No project planned at this time.	Off-spec CO2. Low reliability of CO2 supply.	Poor performance of CO2 dehydration system.	Project delayed or impaired. Facilities/equipment damage due to corrosion. CO2 release (HSE hazard).	Monitor CO2 dehydration system operating performance.	Select commercially proven, reliable dehydration technology. Require performance test and process guarantees. Implement a comprehensive maintenance program. Maximize operating time at steady state operation.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.
366	19.02.00.	CO2 dehydration system operation	Operating risks for CO2 dehydration systems could include: 1. Upset conditions 2. Foaming in the contactor 3. Fouling 4. Buildup of liquid contaminants in recycled glycol 5. Buildup of solid contaminants in recycled glycol 6. Contactor plugging due to fouling 7. Reboiler tube failure due to fouling 8. Heat exchanger failure due to fouling 9. Pump seal failure due to fouling 10. Corrosion - wrong materials of construction 11. Oxidation degradation of glycol 12. Thermal degradation of glycol Dehydration units are normally fairly reliable as long as they are maintained properly avoid process upsets and/or contamination.	Operating problems in the CO2 dehydration system can result in higher operating and maintenance costs, interruption of CO2 supply, off spec CO2, and corrosion of downstream systems.	No project planned at this time.	No project planned at this time.	Off-spec CO2. Low reliability of CO2 supply.	Operating problems with CO2 dehydration system.	Project delayed or impaired. Facilities/equipment damage due to corrosion. CO2 release (HSE hazard).	Monitor CO2 dehydration system operating performance.	Select commercially proven, reliable dehydration technology. Implement a comprehensive maintenance program. Avoid process upsets and contaminants.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.
367	20.00.00.	CO2 COMPRESSION RISKS										
368	20.01.00.	CO2 compression system performance	Performance risks for CO2 compression systems could include: 1. Output below design capacity 2. Unable to meet pressure specification 3. Excess power consumption 4. Excess maintenance 5. Low mechanical availability	CO2 operating performance is critical to success of a CCS project.	No project planned at this time.	No project planned at this time.	Off-spec CO2 pressure / flowrate. CO2 supply interruption.	Poor performance of CO2 compressors.	Project delayed or impaired. Facilities / equipment damage Project ROI lower than expected.	Monitor CO2 compression system operating performance.	Assure proper design and installation. Require performance test and process guarantees. Implement a comprehensive maintenance program. Try to maximize steady-state operation. Avoid upset conditions.	Resolve maintenance, system upsets and contamination problems quickly.

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Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
365	19.01.00.	CO2 dehydration system performance	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
366	19.02.00.	CO2 dehydration system operation	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
367	20.00.00.	CO2 COMPRESSION RISKS	0	0	0	0															
368	20.01.00.	CO2 compression system performance	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

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369	20.02.00.	CO2 compression system EPC	Engineering, procurement and construction (EPC) risks for compression systems could include: 1. Procurement delays - Compressors are typically one of the longest lead items for equipment 2. High capital cost - compression systems are one of the major capital costs for CCS projects 3. Improper specification 4. Metallurgical defect 5. Manufacturing defect 6. Improper installation	Delays in project startup. Increased capital cost. Operating problems resulting from improper specification or installation.	No project planned at this time.	No project planned at this time.	Construction/start up delays. Poor performance or failure of CO2 compression system. Higher capital / operating costs.	CO2 compression system EPC delays/defects/costs.	Project delayed or impaired. Facilities / equipment damage Project ROI negatively impacted.	Monitor CO2 compression system engineering, manufacturing, installation and performance testing.	Select a qualified EPC contractor. Require performance test and process guarantees.	Inspect and test equipment. Require vendor / contractor to fix defects.
370	20.03.00.	Compressor type	1. Reciprocating compressors - lower capital, higher maintenance, may require spare capacity 2. Centrifugal compressors - higher capital, lower maintenance 3. Screw compressors (dry type)	Type of compressors selected can impact capital costs, operating costs and operating availability.	No project planned at this time.	No project planned at this time.	Poor performance of CO2 compressors. Higher operating and maintenance costs. Lower CO2 availability.	Improper selection of CO2 compressors	Project delayed or impaired. Project ROI negatively impacted.	Monitor CO2 compressor selection process and operating performance.	Select qualified engineering company and vendors. Proper selection of the compressor type for the specific application.	Proper installation, operation and maintenance.
371	20.04.00.	Compression system operation	Operating risks for CO2 compression systems: 1. Improper operation - Intermittent operation of the compressor - Operating above/below recommended limits - Upset conditions - Operating compressor with control valve closed - Fouling by dust or liquid droplets - Plugging relief valves during depressurization - Corrosion - due to water in CO2 stream 2. Improper maintenance - Vibration - Noise - Overheating - Leakage 3. Wear and failure - Rod drop due to ring wear on recip. comp. - Rod run out or rod deflection on recip. comp. - Valve failure on recip. comp. - Bearing wear/failure - Tip wear on cent. comp. - Impeller blade failure on cent. comp. - Shaft failure - Compressor catastrophic failure	Downtime, loss of revenue, increased maintenance costs.	No project planned at this time.	No project planned at this time.	Off-spec CO2 pressure / flowrate. CO2 supply interruption.	CO2 compression system operating problems.	Project delayed or impaired. Project ROI negatively impacted. Facilities / equipment damage. CO2 release (HSE hazard).	Monitor CO2 compression system operating performance.	Assure proper design and installation. Require performance test and process guarantees. Implement a comprehensive maintenance program. Try to maximize steady-state operation. Avoid upset conditions.	Proper installation, operation and maintenance. Resolve maintenance, system upsets and contamination problems quickly.
372	21.00.00.	CO2 PIPELINE RISKS										
373	21.01.00.	Pipeline routing risks										
374	21.01.01.	New versus existing right-of-way (ROW)	ROW issues include: 1. Single or multiple pipeline rights 2. Width of ROW 3. Rights for above ground facilities 4. Access to site for repair/modification and inspections 5. Payment for original and continued use of ROW 6. Damage awards for the property owner 7. Requirement for pipeline removal upon abandonment of the pipeline. 8. Eminent domain - used as a last resort to gain access to ROW	Developing a new ROW is significantly more riskier than using an existing utility ROW.	No project planned at this time.	No project planned at this time.	High cost for right-of-way	Inability to acquire right-of-way at an affordable cost.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor right-of-way negotiations.	Maximize use of existing pipeline corridors in laying out pipeline right-of-way.	Design around problem areas.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
369	20.02.00.	CO2 compression system EPC	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
370	20.03.00.	Compressor type	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
371	20.04.00.	Compression system operation	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
372	21.00.00.	CO2 PIPELINE RISKS	0	0	0	0															
373	21.01.00.	Pipeline routing risks	0	0	0	0															
374	21.01.01.	New versus existing right- of-way (ROW)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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375	21.01.02.	Climate conditions	Weather conditions can impact pipeline surface facilities 1. Severe high or low temperatures 2. Significant winds (tornadoes) 3. Lightning - common cause of pipeline damage 4. Heavy rain fall - flooding 5. Severe winter storms	Delays in construction and damage to surface facilities.	No project planned at this time.	No project planned at this time.	Construction schedule disruption(s). Damage to surface facilities. Human injury/death.	Severe climate conditions.	Project delayed or impaired. Project ROI negatively impacted. Liability costs.	Monitor weather forecasts for severe conditions.	Design pipeline surface facilities for full range of climate conditions. Avoid flood plains and steep slopes that may be susceptible to weather damage.	Monitor for severe weather reports.
376	21.01.03.	Soil and terrain conditions	1. Thin soil - insufficient to bury pipeline to depth 2. Corrosive soil - high moisture, high electrical conductivity, high acidity, and high dissolved salts 3. Rocky soil - special care needed in backfilling to protect pipeline 4. Unstable land - subsidence - uplift - landslides - earthquake area - active fault zone - high erosion areas - flood plains, dry wash - permafrost - frost heaves - high water table (marshes, swamps, peat bogs) - moving sand dunes - underground mine/coal mine areas - steep slopes >18% (landslides or erosion) 5. Rugged terrain/topography - mountains, hills, canyons, gorges 6. Significant elevation increase or variation over length of pipeline 7. Low lying areas 8. Exposed granite bedrock	1. Need to add soil to achieve 1.2 -1.8 m (4-6ft) burial depth 2. Accelerated external corrosion 3. Need fine backfill to protect pipeline 4. Can lead to unintended movement or abnormal loading of a pipeline resulting in mechanical damage, leakage or rupture. 5. Significantly higher installation cost 6. Increased compression or pumping costs due to higher pressure drop across pipeline 7. Potential for leaked CO2 to accumulate in low lying areas if there is insufficient escape velocity or wind to disperse the leaked CO2 to the atmosphere. 8. Very high costs for blasting a pipeline trench	No project planned at this time.	No project planned at this time.	High pipeline construction costs.	Soil/terrain conditions make pipeline installation difficult	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor pipeline right-of-way selection and assessment.	Avoid steep slopes, rugged terrain, flood plains, low-lying areas, rocky areas and unstable land.	Bring in fine backfill for pipeline in rocky areas. Regularly inspect and repair unstable areas. Design around problem areas.
377	21.01.04.	Populated areas	A high population area means an urbanized area, as defined by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1000 people per square mile. This is designated a high consequence area. (49 CFR Part 195.450) Other populated areas are also designated as high consequence areas. Non rural areas categorized as high risk. Rural areas categorized as low risk. (49 CFR Part 195 Appendix B) Pipeline right-of-way must be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly. No pipeline may be located within 15 m (50 feet) of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate or assemble, unless it is provided with at least 0.3 m (12 inches) of cover in addition to that prescribed in Section 195.238 (49 CFR Part 195.210). CO2-CRC recommends a 30 m (100 ft) wide easement restricting access to the buried pipeline, a distance of 100 m (330 ft) minimum distance from residential buildings and a 1,000 m (3,300 ft) consultation zone on either side of the pipeline for emergency notification. 1. High population density nearby 2. Sensitive receptors (schools, hospitals, nursing homes, prisons) nearby 3. Business/industry/mining nearby 4. Residences nearby	The greater the number of people, the greater the risk of exposure to CO2.	No project planned at this time.	No project planned at this time.	Higher pipeline construction and operating costs.	Pipeline right-of-way through or near existing or future high population density areas.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor current and potential population density in area of pipeline right-of-way.	Avoid densely populated areas for pipeline routing.	Design around densely populated areas. Implement a pipeline integrity management program in high consequence areas. Follow 49 CFR Part 195 regulations.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
375	21.01.02.	Climate conditions	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
376	21.01.03.	Soil and terrain conditions	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
377	21.01.04.	Populated areas	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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378	21.01.05.	Land crossings	1. Navigable water ways - Army Corp of Engineers permitting 2. Protected areas - Wetlands, migratory water bird concentration, national parks, habitats for imperiled, threatened, endangered or protected species (aquatic and terrestrial), archeological sites. (49 CFR Part 195.6) 3. Federal land - could trigger the need for permits from the US Army Corp of Engineers, the US Fish and Wildlife, the US Department of the Interior Bureau of Land Management (BLM), the US Department of Agriculture, Forest Service, the US Department of Defense. Also will trigger the National Environmental Policy Act (NEPA) and require Environmental Assessment (EA) or Environmental Impact Statement (EIS) 4. Tribal land - would trigger NEPA (EA or EIS) and the need for a permit from the US Department of Interior Bureau of Indian Affairs (BIA) 5. Transportation corridors - Railroads, highways, roads, bridges, other rights of way could trigger the need for permits from railroad companies, state/county departments of transportation. 6. Drinking water resource areas - 7. Non navigable surface waters - lakes, rivers, streams 8. Existing utility/pipeline rights-of-way	Land crossing increase cost and the need for additional permits.	No project planned at this time.	No project planned at this time.	Inability to obtain rights-of-way or pipeline construction permit. Higher pipeline construction and operating costs.	Pipeline crossing transportation corridors and/or sensitive land areas.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor transportation corridor and land crossings..	Avoid sensitive or high consequence areas. Keep crossings to a minimum.	Use seamless pipe and 2 m burial depth in crossings. Implement pipeline integrity management program in areas of high consequence. Follow 49 CFR Part 195 regulations. Regularly inspect and repair unstable areas. Post warning signs along right-of-way.
379	21.01.06.	Offshore pipeline	The difficulty of offshore construction is roughly proportional to the depth multiplied by the pipeline diameter. (IPCC 2005). Some of the risks include: 1. Sea currents 2. Uneven seabed 3. Biological growth on pipeline 4. Arctic conditions (ice gouging)	Offshore pipeline have significantly higher costs.	No project planned at this time. No need for offshore pipeline.	No project planned at this time.	Very high pipeline construction and operating costs.	Offshore pipeline.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor offshore pipeline design, construction and operation.	Work with a qualified engineering firm to properly design offshore pipeline.	Regularly inspect and repair unstable areas.
380	21.02.00.	Pipeline design risks										
381	21.02.01.	Pipeline diameter	1. Large diameter Large diameter pipelines will release more CO2 in a rupture and are thus classified as having greater severity in the case of a failure such as a rupture. 2. Insufficient diameter for capacity Increased pressure required may place too much stress on the pipeline and components. Limits future expansion. 3. Excess diameter for capacity Resulting decreased pressure may put the CO2 at risk of changing from supercritical to two-phases. No room for turndown.	High risk: Pipeline diameter 0.46 m (18 in) and above. Medium risk: Pipeline diameter from 0.25-0.4 m (10 to 16 in). Low risk: Pipeline diameter 0.2 m (8 in) and below. (49 CFR Part 195 Appendix B.	No project planned at this time.	No project planned at this time.	Poor pipeline performance.	Improper selection of pipeline diameter.	Increased operating and maintenance costs. Limits on flowrate of CO2. Project ROI negatively impacted.	Monitor selection of pipeline diameter.	Size pipeline to effectively handle planned CO2 capacity with option for future capacity expansion by adding booster station(s).	Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
382	21.02.02.	Pipeline length	The longer the pipeline, the greater the risks.	Long pipeline more expensive, more potential for failure.	No project planned at this time.	No project planned at this time.	High pipeline construction and operating costs.	Long pipeline.	Project halted, delayed or impaired. Project ROI negatively impacted.	Monitor selection of pipeline route.	Keep pipeline length to a minimum without causing right-of-way issues.	Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info		
			Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)		Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)
									Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
378	21.01.05.	Land crossings	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1		
379	21.01.06.	Offshore pipeline	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1		
380	21.02.00.	Pipeline design risks	0	0	0	0																	
381	21.02.01.	Pipeline diameter	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1		
382	21.02.02.	Pipeline length	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1		

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
383	21.02.03.	Pipeline failure history (for existing pipeline)	Pipeline failure history for time-dependent defects can indicate probability of future failures.	High risk: >3 leaks in last 10 years. Low risk: ≤3 leaks in last 10 years. (49 CFR Part 195 Appendix B)	No project planned at this time.	No project planned at this time.	Pipeline leak	Use of an existing pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review failure history of existing pipeline.	Avoid use of existing pipeline unless the piping specification meets the requirements and sufficient maintenance/perform ance records are available.	Conduct inline and spot testing to confirm pipeline integrity.	
384	21.02.04.	Pipeline age (for existing pipeline)	Safety risk increases with the age of the pipeline depending on the pipeline's coating and corrosion condition, and steel quality, toughness, welding.	High risk: >25 years old Low risk: <25 years old (49 CFR Part 195 Appendix C)	No project planned at this time.	No project planned at this time.	Pipeline leak	Old pipeline.	CO2 leak/rupture. (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Regularly inspect and test existing pipeline.	Avoid use of old pipeline unless the piping specification meets the requirements and sufficient maintenance/performance records are available, and sufficient testing can be done to confirm pipeline integrity.	Conduct inline and spot testing to confirm pipeline integrity.	
385	21.02.05.	Pipeline pressure	All pipeline components must be designed and tested for at least 125% of maximum operating pressure (MOP). If, within a pipeline system, two or more components are to be connected at a place where one will operate at a higher pressure than another, the system must be designed so that any component operating at the lower pressure will not be overstressed. (49 CFR Part 195.104) Pipelines should be designed with sufficient pressure to maintain CO2 as a supercritical fluid. 1. Operating pipeline in excess of maximum operating pressure (MOP). 2. Operating pipeline below the CO2 supercritical pressure (CSP). 3. Insufficient working range between MOP and CSP.	Components operating at excessive operating pressure will be overstressed and subject to failure. Operating the pipeline at or below the supercritical pressure of CO2 can lead to CO2 phase change in the pipeline. If the supercritical CO2 drops back into the liquid-vapor, two-phase region (which occurs below 6.9 MPa (1000 psig) at ambient temperature), there would be freeze-up issues and a much higher pressure drop in the pipeline.	No project planned at this time.	No project planned at this time.	CO2 leak/rupture (HSE hazard).	Over pressuring CO2 pipeline.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline operating pressure.	Operate pipeline at less than 80% of maximum design pressure.	Operate pipeline at less than 80% of maximum design pressure. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.	
386	21.02.06.	Pipeline external loads	Anticipated external loads (e.g.), earthquakes, vibration, thermal expansion, and contraction must be provided for in designing a pipeline system. (See ASME B31.4). The pipe and other components must be supported in such a way that the support does not cause excess localized stresses (49 CFR Part 195.110). The pipe at each railroad and highway crossing must be installed so as to adequately withstand the dynamic forces exerted by anticipated traffic loads (49 CFR Part 195.256).	Insufficient design for external loads could lead to cracking and CO2 leakage.	No project planned at this time.	No project planned at this time.	CO2 leak/rupture (HSE hazard).	Excess pipeline external loads.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review pipeline external load calculations and construction drawings.	Use qualified contractor(s) to engineer, procure and construct the pipeline. Have an experienced engineer check external load factors.	Reinforce pipeline at crossings if necessary. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.	

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Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P x S x D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
383	21.02.03.	Pipeline failure history (for existing pipeline)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
384	21.02.04.	Pipeline age (for existing pipeline)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
385	21.02.05.	Pipeline pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
386	21.02.06.	Pipeline external loads	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
387	21.02.07.	Pipeline wall thickness	Thicker pipe is typically used for sensitive areas like crossings. Wall thickness for 0.3 -0.36 m (12-14 in) pipe is typically 9.5 mm (0.375 in) except in sensitive areas like crossings where 12.7 mm (0.5 inch) wall thickness used for road crossings (up to 0.3 m (1 ft) past road right of way) and 15.9 mm (0.625 in) thickness used for railroad crossings. (DGC)	Thicker walls give a better safety margin.	No project planned at this time	No project planned at this time.	CO2 leak/rupture (HSE hazard).	Thin pipeline wall.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review pipeline wall calculations and monitor pipeline wall thickness over time.	Select pipeline wall thickness that meets or exceeds codes.	Monitor wall thickness over the life of the project. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
388	21.02.08.	Pipeline steel grade	X65 carbon steel is typically used for CO2 pipeline if CO2 is dry and has low impurities such as H2S.	Pipeline steel grade determines pipeline maximum operating pressure	No project planned at this time.	No project planned at this time.	CO2 leak/rupture (HSE hazard).	Improper pipeline steel grade.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review steel grade selection for pipeline.	Select pipeline steel grade that meets or exceeds codes.	Monitor steel corrosion over life of the pipeline. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
389	21.02.09.	Pipeline temperature	CO2 increases in temperature as it is compressed and decreases in temperature as it expands. CO2 entering a pipeline may in the range of 49°C (120°F) however, it will gradually conform to the ambient ground temperature which may be in the range of 10°C (50°F). Components of CO2 pipelines that are subject to low temperatures during normal operation because of rapid pressure reduction or during the initial fill of the line must be made of materials that are suitable for those low temperatures. (49 CFR Part 195.102)	Improper material selection for pipeline components that may experience extreme cold due to rapid pressure reduction may result in component failure and CO2 leakage.	No project planned at this time.	No project planned at this time.	Damage to pipeline internal coating. CO2 leak/rupture (HSE hazard).	Too high or too low pipeline temperature.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline temperature.	Design compressor interstage coolers to maintain CO2 temperature below maximum. Install pipeline sufficiently deep.	Monitor pipeline temperature.
390	21.02.10.	Piping type	Seamless pipe is typically used for sensitive areas like crossings or near residences; double submerged arc welded or electric resistance welded pipe is typically used for other areas. (DGC)	Proper piping selection is important in sensitive areas to prevent risk of CO2 leakage.	No project planned at this time.	No project planned at this time.	CO2 leak/rupture (HSE hazard).	Improper piping selection.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review piping selection.	Use seamless pipe for road, rail and creek crossings. Use ERW pipe for other areas.	Use additional reinforcement if necessary.
391	21.02.11.	Pipeline coating	CO2 pipelines are typically coated with fusion bonded epoxy to prevent corrosion. In addition piping used at bored crossings is overcoated with an abrasion resistant coating to prevent damage to the epoxy coating during installation. (DGC) 1. External coating 2. Internal coating	Damage to pipeline coating during installation or due to third-party excavation can result in external corrosion.	No project planned at this time.	No project planned at this time.	Pipeline corrosion.	Lack of, insufficient, improper or damaged pipeline coating.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline coating condition and performance.	Coat pipeline with fusion bonded epoxy.	Avoid damaging coating during transport and installation.

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			Risk priority number (PXS=D = 1 to 125) Difficulty of failure detection (D = 1 to 5)	Failure severity (S = 1 to 5)	Failure probability (P = 1 to 5)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
						Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
387	21.02.07.	Pipeline wall thickness	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
388	21.02.08.	Pipeline steel grade	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
389	21.02.09.	Pipeline temperature	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
390	21.02.10.	Piping type	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
391	21.02.11.	Pipeline coating	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
392	21.02.12.	Pipeline cathodic protection	Cathodic protection on CO2 pipelines is maintained by rectifiers located at main-line valve stations every 32 km (20 miles) or less along the pipeline. Cathodic protection is measured in voltage at test posts located at 1.6 km (1 mi) intervals over the length of the pipeline. The rectifier output is adjusted to maintain voltage levels between 0.85 and 1.4 volts at each test station. (DGC)	Insufficient or lack of cathodic protection could lead to external corrosion and CO2 leakage.	No project planned at this time.	No project planned at this time.	Pipeline corrosion.	Lack of, insufficient, improper or damaged pipeline cathodic protection.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline cathodic protection condition and performance.	Install cathodic protection and voltage test posts at every mile along the pipeline.	Monitor cathodic protection voltage over the length of the pipeline and adjust rectifier output to maintain appropriate voltage level.
393	21.02.13.	Pipeline booster stations or pumping stations	Booster or pumping stations are typically needed every 80-320 km (50 to 200 mi) depending on end-use pressure (EERC). Adequate ventilation must be provided in pumping station buildings to prevent the accumulation of CO2 gas. Warning devices must be installed to warn of the presence of CO2 gas in the pumping building. Safety devices to prevent over pressuring of primary and auxiliary pumping equipment and a device for emergency shutdown of each pumping station should be included. If power is necessary to actuate the safety devices, an auxiliary power supply should be included. (49 CFR Part 195.262) Take into account noise levels.	Insufficient booster or pumping stations could lead to low pressure at the end of the pipeline.	No project planned at this time.	No project planned at this time.	Insufficient pipeline pressure.	Insufficient booster or pumping stations.	Cost of increasing or upgrading booster station.	Monitor pipeline pressure.	Size pipeline to effectively handle planned CO2 capacity with option for future capacity expansion by adding booster station(s).	Leave space for booster stations.
394	21.02.14.	Pipeline future expansion	If there is potential for future expansion, it is practical to install taps for future branches, leave room for booster stations and design the pipeline to allow for expansion at higher pressure without having to replace piping and components. Pipeline diameter and pressure should take into account potential for future expansion through addition of booster stations and increased operating pressure.	Lack of reserved locations for booster stations, insufficient pipeline diameter, and excess operating pressure may make future expansion of pipeline capacity more difficult and more expensive.	No project planned at this time.	No project planned at this time.	Insufficient pipeline diameter for expansion.	Lack of planning for future pipeline expansion.	Excess operating pressure. Excess costs for pipeline expansion.	Monitor plans for future pipeline expansion.	Size pipeline to effectively handle planned CO2 capacity with option for future capacity expansion by adding booster station(s).	Leave space for booster stations.
395	21.02.15.	Pipeline flow velocity	Reported pipeline velocity varies from 0.9 to 4.6 m/s (3 to 15 ft/s). (PCC 2005)	Excessive flow capacity could cause erosion in pipeline components.	No project planned at this time.	No project planned at this time.	Erosion of pipeline.	Excess pipeline flow velocity.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline flow velocity and wall thickness.	Design pipeline to stay within the safe range of CO2 velocity.	Adjust capacity or pressure to keep within the safe velocity range. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.

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Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
392	21.02.12.	Pipeline cathodic protection	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
393	21.02.13.	Pipeline booster stations or pumping stations	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
394	21.02.14.	Pipeline future expansion	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
395	21.02.15.	Pipeline flow velocity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
396	21.02.16.	Pipeline SCADA system	Supervisory control and data acquisition (SCADA) system should have sufficient instrumentation for the central control room to monitor and control flow along the entire pipeline. The system should have built in redundancies to prevent loss of operational capability if a component fails. 1. IT security for SCADA system to protect against cyber-terrorism	Loss of the SCADA system could shut the pipeline down or result in pipeline failure and CO2 release.	No project planned at this time.	No project planned at this time.	Shutdown or failure of pipeline equipment/system	Loss of, or malfunction of, SCADA system.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor SCADA system performance.	Comply with all 49 CFR Part 195 requirements for SCADA system.	Maintain SCADA system in good working order. Integrate backup system for critical functions. Develop and implement business continuity plan.
397	21.02.17.	Pipeline CPM leak detection systems	Computational pipeline monitoring (CPM) leak detection system must comply with section 4.2 of API 1130. (49 CFR Part 195.134). CPM leak detection can be based on acoustics, measurement of chemical release, detecting pressure changes or small changes in mass balance.	Lack of a properly designed CPM leak detection system prevents the pipeline operator from rapid detection and response to CO2 leaks. Inaccurate modeling of CO2 dense phase can cause the computational leak detection system to malfunction.	No project planned at this time.	No project planned at this time.	Failure to detect CO2 leak/rupture.	Loss of, or malfunction of, CPM leak detection system	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor CPM leak detection system performance.	Comply with all 49 CFR Part 195 requirements for computational pipeline monitoring and leak detection system.	Maintain the CPM leak detection system in good working order.
398	21.02.18.	Pipeline block valves or control valves	Main-line valves (block or control valves) are located on either side of water crossings and approximately every 32 km (20 mi) overland in order to allow for quick isolation and to minimize the impact of a leak. (DGC) Valves must be installed at each of the following locations: on the suction end and discharge end of a pump station, on each mainline at locations along the pipeline system that will minimize damage or pollution from CO2 discharge, on each lateral takeoff from the trunk line, on each side of a water crossing that is more than 30 m (100 ft) wide and on each side of a reservoir that is holding water for human consumption. (49 CFR Part 195.260) Each valve must be installed in a location that is accessible to authorized employees and that is protected from damage or tampering. (49 CFR Part 195.258)	The distance between main-line valves determines the amount of CO2 released in a rupture. Longer spacing means a larger volume of CO2 is likely to escape.	No project planned at this time.	No project planned at this time.	Inability to section off pipeline in an emergency.	Insufficient number of, improperly designed, improperly installed, or failure of block valve(s).	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor block valve specification installation and operating condition.	Comply with all 49 CFR Part 195 requirements for block valves.	Maintain all block valves in good working order.
399	21.02.19.	Pipeline internal inspection devices	Pipelines must be designed and constructed to accommodate the passage of instrumented internal inspection devices (i.e. smart pig). 49 CFR Part 195.120) No operator may use a launcher or receiver that is not equipped with a relief device capable safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. (49 CFR Part 195.426)	Internal inspection devices are important tools for detecting corrosion or mechanical damage in pipelines before they fail.	No project planned at this time.	No project planned at this time.	Poor performance or failure of internal inspection device.	Improperly designed internal inspection device system.	CO2 leak (HSE hazard). Pipeline damage. Damage repair costs.	Monitor internal inspection device specification, installation, and operating condition.	Comply with all 49 CFR Part 195 requirements for internal inspection devices.	Maintain internal inspection devices and system in good working order.
400	21.02.20.	Pipeline seals	Teflon or nylon have been used for seals to prevent swelling. (Meyer 2007).	Improper sealing materials may react with CO2 and cause CO2 leakage	No project planned at this time.	No project planned at this time.	Seal failure.	Improper design of seals.	CO2 leak (HSE hazard).	Monitor seal specification, installation, and operating condition.	Select seal materials that have been successfully tested for use with CO2.	Maintain seals in good working order. Monitor for leaks.

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396	21.02.16.	Pipeline SCADA system	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
397	21.02.17.	Pipeline CPM leak detection systems	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
398	21.02.18.	Pipeline block valves or control valves	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
399	21.02.19.	Pipeline internal inspection devices	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
400	21.02.20.	Pipeline seals	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

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401	21.02.21.	Pipeline winterization	Winterization (protection from severe cold/ice) may be needed for above ground facilities in cold climates.	Lack of winterization can cause CO2 pipeline instrumentation lines and valves to freeze up in severe cold/icy weather.	No project planned at this time.	No project planned at this time.	Freezing weather damage to surface equipment / facilities.	Lack of pipeline winterization.	CO2 leak (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline winterization status and severe weather forecasts.	Provide sufficient shelter/insulation for sensitive surface facilities.	Monitor severe weather conditions. Train operators how to maintain operation during severe winter weather.
402	21.02.22.	Pipeline burial depth	CO2 pipelines are typically buried a minimum of 1.2 m (4 ft) over the length of the pipeline, ≥1.5 m (5 ft) below roads, ≥3 m (10 ft) below railroads, ≥1.2 m (4 ft) below ditches and ≥3 m (10 ft) below water line on shores. (DGC). Minimum burial depth for pipeline is 0.9 m (36 in) for industrial commercial and residential areas, 1.2 m (48 in) for crossing of inland bodies of water, 0.9 m (36 in) for drainage ditches at public roads and railroads, 1.2 m (48 in) for deepwater port safety zones, 0.9 m (36 in) for offshore areas and 0.8 m (30 in) elsewhere. There are exceptions for rock excavation areas. (49 CFR Part 195.248)	Insufficient burial depth makes pipeline more susceptible to excavation damage, sabotage, climate damage etc.	No project planned at this time.	No project planned at this time.	Pipeline mechanical damage.	Insufficient burial depth.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline burial depth.	Bury pipeline to meet or exceed compliance with 40 CFR Part 195.	Regularly inspect and maintain burial depth of pipeline.
403	21.02.23	Pipeline bedding and foundation structures	Pipeline bedding and foundation structures are designed to hold a pipeline stable throughout its life. This is particularly important for offshore pipelines.	Improper design of pipeline bedding or foundation structures could result in pipeline shifting or buckling.	No project planned at this time.	No project planned at this time.	Shifting of pipeline.	Improper pipeline bedding and foundation structures.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline bedding and foundation structures.	Comply with all 49 CFR Part 195 requirements for pipeline bedding and foundation structures.	Regularly inspect pipeline for signs of shifting or buckling.
404	21.03.00.	Pipeline defects										

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
401	21.02.21.	Pipeline winterization	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
402	21.02.22.	Pipeline burial depth	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
403	21.02.23	Pipeline bedding and foundation structures	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
404	21.03.00.	Pipeline defects	0	0	0	0																

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
405	21.03.01.	Pipeline material defects	During the manufacturing of steel, impurities can sometimes remain in the molten steel. These impurities can cause an incomplete bonding of the material in the steel plate or solid round billet used to produce pipe and other pipeline components. reduce the wall thickness of the pipe or pipeline component, and, if large enough, can reduce the pressure-carrying capacity of the pipe or component. Some pipeline material defects include: 1. Propagating cracks - very rapid propagating cracks can occur that “unzip” the pipeline along its length. 2. Laminations and inclusions - caused by oxides or impurities trapped in the steel 3. Blisters and scabs - raised spots on steel surface caused by expansion of trapped gases within the steel 4. Hard spots - created by localized cooling of the steel plate (ERW pipe) during rolling 5. Indentations - formed by the expanders or mandrels used to make seamless pipe 6. Transit fatigue - cracks formed when pipes are repeated flexed during transportation and handling 7. Cyclic fatigue - cracks caused by stress from repeated fluctuating operating pressure within the pipe 8. Elastomer and polymer - failure due to reaction with CO2	1. Propagating cracks can lead to pipeline rupture. 2. A lamination or inclusion can eventually lead to failure if they eventually grow to the inner or outer wall of the pipe or pipeline component through pressure cycles. 3. Blisters and scabs reduce the wall thickness of the pipe and, if large enough, can reduce the pressure-carrying capacity of the pipe or component. 4. Cracking can occur at hard spots that eventually grows in size over time. 5. Stress risers can occur at indentations if they are too deep, eventually leading to pipe failure. 6. Transit fatigue cracks are typically discovered during the hydrostatic pressure testing however, some can remain and grow during pipeline pressure cycles until a failure occurs. 7. Can lead to CO2 leakage. 8. Failure of elastomers and/or polymers could lead to CO2 leakage.	No project planned at this time.	No project planned at this time.	Pipeline mechanical failure.	Pipeline material defects.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline manufacturing and quality control testing.	Select a competent pipe manufacturer. Inspect and test pipe before burial. Proper design, manufacturing, installation and maintenance of the pipeline.	Use of crack arrestors to mitigate propagating cracks.
406	21.03.02.	Pipeline weld defects	Some pipeline weld defects include: 1. Pinholes - small, unwelded area extending through the entire thickness of the weld 2. Toe cracks - occur where the crown of the weld bead intersects the edge of the plate in pipe joined using the Double Submerged Arc Welding (DSAW) 3. Off seam welding - crack caused by the inside and outside welds of the DSAW process being offset 4. Undercutting - occurs when there is an inadvertent reduction in the wall thickness in the area of the weld 5. Incomplete fusion - occurs when there is a lack of complete fusion of the weld and the base metal 6. Porosity - occurs when one ore more voids are created in the weld material from shrinkage of the material 7. Slag inclusions - exist when non-metallic material becomes trapped in the weld 8. Weld defects in older pipe - Burnt pipe edges - Incomplete fusion - Hook cracks - Cold welds - Weld metal cracks For more details, see PHMSA.	Weld defects can lead to CO2 leakage	No project planned at this time.	No project planned at this time.	Pipeline weld failure.	Pipeline weld defects.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline welding and quality control testing.	Comply with all 49 CFR Part 195 welding requirements. Use certified welders. Inspect and test welds prior to burial.	Replace welds that do not pass inspection and testing.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
405	21.03.01.	Pipeline material defects	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
406	21.03.02.	Pipeline weld defects	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
407	21.03.03.	Pipeline equipment defects	Equipment failures involve pumps, compressors, valves, meters, tanks, control/relief equipment and other components and devices on pipeline systems. (PHMSA). Can include broken couplings, stripped threads.	Equipment is often located on company property that is not accessible to the public. Equipment failure usually results in a CO2 release that is contained on public property, typically not resulting in injury to the general public. (PHMSA)	No project planned at this time.	No project planned at this time.	Equipment failure. Damage to equipment / system.	Pipeline equipment defects.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor equipment operation and maintenance.	Proper selection, operation and maintenance of equipment.	Monitor for equipment vibration or performance changes. Determine root cause and repair.
408	21.04.00.	Pipeline corrosion	About 15% of gas pipeline failures in Europe are caused by corrosion (EGIG 2008)	Corrosion can lead to pipe failure and CO2 leakage.								
409	21.04.01.	External corrosion	Galvanic corrosion can take place when an unprotected metal pipeline comes in contact with water or soil. 1. External corrosion of buried pipe 2. External corrosion of surface pipe	Corrosion can lead to pipe failure and CO2 leakage.	No project planned at this time.	No project planned at this time.	Pipeline failure.	External corrosion of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline external corrosion.	Comply with all 49 CFR Part 195 pipeline corrosion protection requirements.	Regular inspections, testing, cleaning and maintenance of pipeline.
410	21.04.02.	Internal corrosion	There is potential for rapid corrosion of steel pipeline if free water becomes present in the CO2 stream. There is currently insufficient data to adequately understand the effect of an accidental flow of high water content CO2 into a pipeline and also the influence the various CO2 impurities (O2, H2, SOx, NOx, H2S TEG, MEG and amines/NH3) will have on the corrosion rates. (DNV CO2PIPETRANS Phase 2). Corrosion rate of carbon steel in dry supercritical CO2 is low. For AISI 1080 values around 12.5 microns per year have been measured at 9-12 MPa (90-120 bar) and 160-180°C for 200 days. During 12 years, the corrosion rate in an operating pipeline amounted to 0.25-2.5 microns per year.	Corrosion can lead to pipe failure and CO2 leakage.	No project planned at this time.	No project planned at this time.	Pipeline failure.	Internal corrosion of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline internal corrosion.	Comply with all 49 CFR Part 195 pipeline corrosion protection requirements. Use dry CO2.	Avoid free water in pipeline. Clean pipeline internals. Regularly inspect pipeline for corrosion. Use smart pigs. Repair any corrosion damage as needed.
411	21.04.03.	Microbial corrosion	Microbial corrosion is corrosion promoted by microorganisms such as chemoautotrophs which can produce hydrogen sulfide, sulfuric acids, other acids or ammonia. Some bacteria directly oxidize iron to iron oxide or iron hydroxide.	Hydrogen sulfide can cause corrosion and sulfide stress cracking.	No project planned at this time.	No project planned at this time.	Pipeline failure.	Microbial corrosion of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline microbial corrosion.	Comply with all 49 CFR Part 195 pipeline corrosion protection requirements.	Regularly inspect pipeline for corrosion using smart pigs. Repair any corrosion damage as needed.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (OTHER) MODEL																						
Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings					Insurance ranking 1=needed info 2=helpful info
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
407	21.03.03.	Pipeline equipment defects	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
408	21.04.00.	Pipeline corrosion	0	0	0	0																
409	21.04.01.	External corrosion	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
410	21.04.02.	Internal corrosion	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
411	21.04.03.	Microbial corrosion	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
412	21.04.05.	Selective seam corrosion	Selective seam corrosion (SSC) is a form of corrosion that tends to affect pipe manufactured prior to 1970 using low-frequency electric resistance welding (LR-ERW) or electric flash welding (EFW) processes. SSC is a localized corrosion attack along the weld bond line of ERW and EFW pipe, that leads to the development of a wedge shaped groove that is often filled with corrosion products. (PHMSA)	Risk for older LF-ERW or EFW pipe, not HF-ERW, DSAW or seamless pipe. (PHMSA)	No project planned at this time.	No project planned at this time.	Pipeline failure.	Selective seam corrosion of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor for selective seam corrosion if pipe manufactured prior to 1970.	Use newly manufactured pipe for construction of pipeline.	Regularly inspect pipeline for corrosion using smart pigs. Repair any corrosion damage as needed.
413	21.0404.	Stress corrosion cracking	Stress corrosion cracking (SCC) is a form of corrosion that produces a marked loss of pipeline strength with little metal loss. The combined influence of pipeline stress due to its pressurized contents and a corrosive medium can occasionally result in the formation of interlinking crack clusters that can grow until the affected pipe fails. (PHMSA)	Stress corrosion cracking can result in pipe failure and CO2 leakage.	No project planned at this time.	No project planned at this time.	Pipeline failure.	Stress corrosion cracking of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline stress corrosion cracking.	Maintain pipeline pressure at less than 80% of maximum design pressure. Avoid moisture in the CO2 stream.	Monitor for moisture in the CO2. Regularly inspect pipeline for corrosion using smart pigs.
414	21.05.00.	Pipeline mechanical damage	Mechanical damage consists of dents, gouges, cracks, punctures, stress risers or ruptures.	Mechanical damage of a pipeline can lead to immediate or eventual/accelerated CO2 leakage.								
415	21.05.01.	Excavation damage	About 50% of pipeline failures in Europe and 33% in the US are caused by excavation damage. Excavation damage can include damage to the external coating of the pipe, or dents, scrapes, cuts, or punctures directly into the pipeline itself. The damage can be caused by any type of excavation, including digging, grading, trenching and boring, road and highway maintenance, general construction and farming activities. It normally occurs when excavators fail to call their local one-call system to mark where underground facilities are located prior to excavating. (PHMSA)	Excavation can lead to pipeline damage and CO2 leakage.	No project planned at this time.	No project planned at this time.	Pipeline mechanical damage.	Excavation near pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor excavation activity near pipeline.	Comply with all 49 CFR Part 195 excavation safety requirements including deep burial of pipeline, proper marking of ROW, regular ROW inspections, supervision of third-party excavation, and one-call system.	Train emergency response team to rapidly address excavation damage. Educate local residents how to identify and report leaks or damage.
416	21.05.02.	Natural force damage	Natural force damage includes damage from landslide, flood, heavy rains, riverbed scouring and washouts, dike breaks, subsidence, earthquakes, high winds, tornadoes, hurricanes, lightning, frost heaves, and frozen instrumentation lines. (PHMSA)	Can lead to unintended movement or abnormal loading of a pipeline resulting in mechanical damage, leakage or rupture.	No project planned at this time.	No project planned at this time.	Pipeline mechanical damage.	Natural forces.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor natural force incidents near pipeline.	Comply with all 49 CFR Part 195 inspection requirements.	Maintain ROW to make it visually accessible from the air and physically accessible on the ground. Repair any eroded or damaged areas. Educate local residents how to identify and report leaks or damage.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS/D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
412	21.04.05.	Selective seam corrosion	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
413	21.0404.	Stress corrosion cracking	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
414	21.05.00.	Pipeline mechanical damage	0	0	0	0																
415	21.05.01.	Excavation damage	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
416	21.05.02.	Natural force damage	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
417	21.05.03.	Other outside force damage	Other outside force damage excludes excavation but include such things as vehicle accident (hitting above ground valve or booster station), electric arcing from nearby power lines, vandalism, sabotage, terrorist attack, theft, fires from other businesses or industries, etc. (PHMSA) Most susceptible to this particular type of damage are above ground pipeline facilities which are in close proximity to highways or large population and industrial centers.	Mechanical damage of a pipeline can lead to immediate or eventual/accelerated CO2 leakage.	No project planned at this time.	No project planned at this time.	Pipeline mechanical damage.	Other outside forces.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor human activity near pipeline right-of-way.	Comply with all 49 CFR Part 195 security requirements. Fence in and secure surface facilities. Direct traffic patterns and speeds to prevent accidents.	Monitor site activity. Train operators to handle security issues and emergencies. Educate local residents how to identify and report leaks or damage.
418	21.05.04.	Mechanical damage requiring immediate repair	Metal loss greater than 80% of nominal wall thickness. Dent located on the pipeline (above 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser. Dent located on the pipeline (above 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter. (49 CFR Part 195.452)	Mechanical damage can require immediate repair to prevent CO2 leakage.	No project planned at this time.	No project planned at this time.	CO2 leak/rupture (HSE hazard).	Failure to repair significant mechanical damage immediately.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor reports of pipeline mechanical damage and response time.	Comply with all 49 CFR Part 195 for repair of mechanical damage to pipeline.	Train employees to repair mechanical damage in a timely manner.
419	21.05.05.	Mechanical damage requiring evaluation and remediation within 60 days of discovery	Dent on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser. Dent located on the pipeline (above 4 and 8 o'clock positions) with a depth between 3% and 6% of the nominal pipe diameter. (49 CFR Part 195.452)	Mechanical damage can require timely evaluation and remediation to prevent CO2 leakage.	No project planned at this time.	No project planned at this time.	CO2 leak/rupture (HSE hazard).	Failure to repair minor mechanical damage within a reasonable time frame.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor reports of pipeline mechanical damage and response time.	Comply with 49 FCR Part 195 repair of mechanical damage to pipeline.	Train employees to repair mechanical damage in a timely manner.
420	21.06.00.	Pipeline procurement risks										
421	21.06.01.	Used pipe or old pipe	Used pipe must comply with the same quality requirements as new pipe. Used pipe must not have any mechanical damage (buckles, cracks, gouges, dents) or corroded areas that threaten the integrity of the pipe. (49 CFR Part 195.114).	Use of defective used pipe could result in pipe failure and CO2 leakage.	No project planned at this time.	No project planned at this time.	Weak or off spec pipe.	Use of used or old pipe.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipe specification and procurement.	Use new pipe.	Inspect and test all pipe prior to its use.
422	21.06.02.	Pipeline valves	Each valve must be of sound engineering design, compatible with pipe and fittings, successfully hydrostatically tested, clearly marked for open and closed positions (except check valves), properly marked (nameplate) and properly sized. (49 CFR Part 195.116)	Defective or off-spec. valves could result in valve failure and CO2 leakage. Wrong sized valves could lead to additional pressure stress or failure.	No project planned at this time.	No project planned at this time.	Valve failure.	Defective or off-spec valves.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor valve specification and procurement.	Comply with 49 CFR Part 195 valve requirements. Select competent valve manufacturers. Select the proper type and size of valve.	Inspect and test all valves prior to being used. Properly install, operate and maintain valves.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable or incredible; Yellow/Orange = Headings or non-risk areas

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
417	21.05.03.	Other outside force damage	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
418	21.05.04.	Mechanical damage requiring immediate repair	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
419	21.05.05.	Mechanical damage requiring evaluation and remediation within 60 days of discovery	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
420	21.06.00.	Pipeline procurement risks	0	0	0	0																
421	21.06.01.	Used pipe or old pipe	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
422	21.06.02.	Pipeline valves	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
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423	21.06.03.	Pipeline fittings	Fittings must be suitable for the intended service and be at least as strong as the pipe and other fittings in the pipeline system. There may not be any buckles, dents, cracks, gouges or other defects in the fittings that may reduce the strength of the fitting. (49 CFR Part 195.118)	Defective off-spec fittings could result in fitting failure and CO2 leakage.	No project planned at this time.	No project planned at this time.	Fitting failure.	Defective or off-spec fittings.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor fitting specification and procurement.	Comply with 49 CFR Part 195 fitting requirements. Select competent fitting manufacturers. Select the proper type and size of fittings.	Inspect and test all fittings prior to being used. Properly install, operate and maintain fittings.
424	21.06.04.	Other pipeline components	Other components such as fabricated branch connections, closures, flange connections, station piping, and fabricated assemblies must meet applicable requirements. (49 CFR Part 195122-195.130) Materials for bolts and nuts should be same as flange. At least one full thread of bolt should be exposed beyond the nut. Gasket material should be compatible with CO2.	Defective or off-spec pipeline components could result in component failure and CO2 leakage.	No project planned at this time.	No project planned at this time.	Component failure.	Defective or off-spec pipeline components.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor other pipeline component specification and procurement.	Comply with 49 CFR Part 195 requirements for other pipeline components. Select competent manufacturers. Select the proper type and size of components.	Inspect and test all components prior to being used. Properly install, operate and maintain components.
425	21.07.00.	Pipeline construction defects	About 16% of gas pipeline failures in Europe are caused by construction defect or material failure. (EGIG 2008)	Construction defects could result in pipeline failure and CO2 leakage.								
426	21.07.01.	Pipe installation	All pipeline installed in a ditch must be installed in a manner that minimizes the introduction of secondary stresses and the possibility of damage to the pipe. (49 CFR Part 195.246). This is of particular concern in rocky soil. When a ditch for a pipeline is backfilled, it must be done in a manner that provides firm support under the pipe, and prevents damage to the pipe and pipe coating from equipment or from the backfill material. (49 CFR Part 195.252) Pipeline coating can be damaged during installation by laying the pipeline on sharp rocks in the ditch, dropping rocks on it during backfill, rough contact with equipment or abrasion if installing pipe through a bored hole under a road or railroad crossing.	Pipe damage during installation could result in accelerated pipe failure and CO2 leakage	No project planned at this time.	No project planned at this time.	Pipeline failure.	Pipe mechanical damage during installation.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline installation and testing.	Install pipeline in compliance with 49 CFR Part 195. Inspect and test prior to being placed in service.	Repair or replace any pipe damaged during installation.
427	21.07.02.	Valve and other equipment installation	Valves and other equipment must be properly seated and installed.	Valves that are not properly seated or improperly installed could lead to system failure.	No project planned at this time.	No project planned at this time.	Valve failure.	Improper seating / installation of valves.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor valve installation and testing.	Install valves and other equipment in compliance with 49 CFR Part 195. Inspect and test prior to being placed in service.	Repair or replace any valves or other equipment damaged during installation.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)					
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
423	21.06.03.	Pipeline fittings	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
424	21.06.04.	Other pipeline components	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
425	21.07.00.	Pipeline construction defects	0	0	0	0															
426	21.07.01.	Pipe installation	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
427	21.07.02.	Valve and other equipment installation	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
428	21.07.03.	Pipe bending	Pipe must not have a wrinkle bend. A bend must not impair serviceability of the pipe. Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage. On pipe containing a longitudinal weld, the longitudinal weld must be as practicable to the neutral axis of the bend unless the bend is made with an internal bending mandrel or the pipe is 0.32 m (12.75 in) or less nominal outside diameter or has a diameter to wall thickness ratio less than 70. Each circumferential weld which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process. (49 CFR Part 195.212)	Pipe damage during bending could result in accelerated pipe failure and CO2 leakage	No project planned at this time.	No project planned at this time.	Pipeline failure.	Pipe mechanical damage during bending.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipe bending and testing.	Bend pipe in compliance with 49 CFR Part 195. Inspect and test prior to being placed in service.	Replace any pipe bends that do not pass inspection or testing.
429	21.07.04.	Pipe welding (See 21.03.02.)	Welding must be performed by a qualified welder in accordance with welding procedures qualified under Section 5 of API 1104 or Section IX of the SASME Boiler and Pressure Vessel Code. Each welding procedure must be recorded in detail, including the results of the qualifying tests. 49 CFR Part 195.214-195.234)	Improper welding procedures could result in CO2 leakage.	No project planned at this time.	No project planned at this time.	Pipeline weld failure.	Pipe welding defects.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline welding and quality control testing.	Comply with all 49 CFR Part 195 welding requirements. Use certified welders. Inspect and test welds prior to burial.	Replace welds that do not pass inspection and testing.
430	21.07.06	Pipeline underground clearance	Any pipe installed underground must have at least 0.3 m (12 in) of clearance between the outside of the pipe and the extremity of any other structure, except that for drainage tile. (49 CFR Part 195.250).	Insufficient clearance could cause mechanical damage under load.	No project planned at this time.	No project planned at this time.	Pipeline mechanical damage.	Insufficient underground clearance.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline installation for proper underground clearance.	Lay pipeline in compliance with 49 CFR Part 195. Assure sufficient clearance between the pipeline and other subsurface structures.	Design around subsurface structures if necessary.
431	21.07.07.	Pipeline integrity inspection	No pipe or other component may be installed in a pipeline system unless it has been visually inspected at the site of installation to ensure that it is not damaged in a manner that could impair its strength or reduce its serviceability. (49 CFR Part 195.206)	Improper or lack of integrity inspection may fail to discover mechanical damage or defects before CO2 is fed to the pipeline.	No project planned at this time.	No project planned at this time.	Failure to discover defects before CO2 fed to pipeline.	Improper or lack of integrity inspection.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline integrity inspection.	Conduct pipeline integrity inspections as required in 49 CFR Part 195.	Repair any mechanical damage, defects or leaks.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
428	21.07.03.	Pipe bending	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
429	21.07.04.	Pipe welding (See 21.03.02.)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
430	21.07.06	Pipeline underground clearance	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
431	21.07.07.	Pipeline integrity inspection	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
432	21.07.08.	Protection for above ground components	Above ground components may be installed in areas under direct control of the operator but should be inaccessible to the public. (49 CFR 195.254)	Insufficient protection for above ground components could lead to vandalism, theft and equipment damage by third parties.	No project planned at this time.	No project planned at this time.	Equipment theft/damage	Insufficient protection for above ground components.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor security for above ground components.	Fence in, mark and secure surface facilities.	Monitor activity at surface facilities.
433	21.07.09.	Construction records	A complete record must be maintained by the operator for the life of each pipeline facility of girth welds (total, number tested, rejected, disposition), pipe installed (amount, location cover, size), locations of pipeline crossings, utility crossings, overhead crossings, valves, and corrosion test stations. (49 CFR Part 195.266) 1. Lack of final as-built drawings 2. Pipeline location not properly documented 3. Valves and other equipment not properly marked	Incomplete or inaccurate construction records or as-built drawings could result in error or confusion during operation, maintenance or emergency response. Improper documentation of pipeline location can lead to confusion when marking a pipeline location prior to excavation. Failure to properly mark valves and other equipment could lead to improper opening or closing of valves or improper equipment operation and/or maintenance.	No project planned at this time.	No project planned at this time.	Project uncertainty. Operator error.	Incomplete or inaccurate construction records.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor updating and maintenance of construction records.	Maintain an up-to-date set of construction drawings throughout the operation of the pipeline. Properly mark the pipeline location. Properly mark valves and other equipment.	Reconstruct any drawings or records that are missing.
434	21.08.00.	Pipeline operation risks										
435	21.08.01.	Operator error in pipeline operation	Operator error can include: 1. Leaving the wrong valve open or closed 2. Not following proper procedures 3. Using improper equipment or techniques to affect a repair 4. Improperly assessing a situation or condition resulting in inappropriate actions or decisions	Potential for pipeline failure and CO2 leakage.	No project planned at this time.	No project planned at this time.	Poor performance and/or failure of equipment/pipeline.	Operator error.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor operator training and performance.	Implement standard procedures for safe operation. Train personnel prior to allowing them to work on the pipeline.	Ongoing operator training. Failsafe control system to prevent or mitigate operator errors.
436	21.08.02.	Pipeline over pressuring	Maximum operating pressure (MOP) is limited to 80% of pipeline design pressure. Isolating pipework or facilities with dense phase CO2 can result in doubling the pressure from 10 to 20 MPa (100 to 200 bar) as temperature raises from 25°C to 40°C.	Isolation of pipeline sections could lead to pipeline over pressuring. Operating the pipeline above maximum operating pressure (MOP) could place the pipeline at risk for failure.	No project planned at this time.	No project planned at this time.	CO2 leak/rupture (HSE hazard).	Pipeline over pressuring.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor CO2 pipeline pressure.	Implement standard operating procedures for controlling pipeline pressure.	Alarm system if pipeline pressure exceeds 80% of maximum design pressure.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
432	21.07.08.	Protection for above ground components	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
433	21.07.09.	Construction records	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
434	21.08.00.	Pipeline operation risks	0	0	0	0															
435	21.08.01.	Operator error in pipeline operation	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
436	21.08.02.	Pipeline over pressuring	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
437	21.08.03.	Pipeline re-pressurization	Re-pressurizing a pipeline results in isenthalpic flash across the re-pressurizing valve causing low temperature in the pipeline, no solid CO2 formation if the CO2 is warm enough. (Anderson 2008).	Low temperature across the re-pressurizing valve	No project planned at this time.	No project planned at this time.	Plugging / damage to pipeline valves.	Improper pipeline re-pressurization.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor CO2 pipeline re-pressurization.	Implement standard operating procedures for re-pressuring the pipeline.	Alarm system and control safety limits. Failsafe control system to prevent or mitigate operator errors in pipeline repressurization.
438	21.08.04.	Pipeline depressurization	Rapid depressurization on blowdown of a pipeline can lead to low temperatures (isentropic behavior) and possible solid CO2 formation at pressures below 5 bar. (Anderson 2008).	Rapid depressurization of facilities can lead to CO2 hydrate formation in vent system, possibly causing blockage and over pressurization. (Anderson 2008). Solidification of CO2 could lead to plugging of relief valves. Lowering depressurization rate of a compressor can lead to asphyxiation risk. (Anderson 2008).	No project planned at this time.	No project planned at this time.	Plugging / damage to pipeline valves.	Improper pipeline depressurization.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor CO2 pipeline depressurization.	Implement standard operating procedures for depressuring the pipeline.	Alarm system and control safety limits. Failsafe control system to prevent or mitigate operator errors in pipeline depressurization.
439	21.08.05.	Pipeline flow modeling	There is a need for improved understanding of the effect contaminants (O2, H2, SOx, NOx, H2S TEG, MEG and amines/NH3) have on the phase diagram and behavior of a CCS CO2 stream. (DNV CO2PIPETRANS Phase 2) Nitrogen and oxygen in CO2 will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow.	Improper understanding of the impact of CO2 impurities on the phase diagrams could lead to inaccurate pipeline flow modeling. Inaccurate modeling can cause the computational leak detection system to malfunction.	No project planned at this time.	No project planned at this time.	Operator error.	Inaccurate pipeline flow model.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review accuracy of pipeline flow model.	Select optimum pipeline flow model. Verify model accuracy. Sufficiently train modelers.	Monitor actual versus model results and determine the root cause of any discrepancies.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
437	21.08.03.	Pipeline re- pressurization	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
438	21.08.04.	Pipeline depressurization	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
439	21.08.05.	Pipeline flow modeling	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
440	21.08.06.	Boiling liquid expanding vapor explosion (BLEVE)	Boiling liquid expanding vapor explosion (BLEVE) is a type of explosion that can occur when a vessel or pipeline containing a pressurized liquid is ruptured. Such explosions can be extremely hazardous. A BLEVE results from the rupture of a vessel containing a liquid substantially above its atmospheric boiling point. The substance is stored partly in liquid form, with a gaseous vapor above the liquid filling the remainder of the container. If the vessel is ruptured — for example, due to corrosion, or failure under pressure — the vapor portion may rapidly leak, lowering the pressure inside the container. This sudden drop in pressure inside the container causes violent boiling of the liquid, which rapidly liberates large amounts of vapor. The pressure of this vapor can be extremely high, causing a significant wave of overpressure (an explosion) which may completely destroy the storage vessel and project fragments over the surrounding area. (Wikipedia)	Supercritical CO2 can have significant density variations with changes in pressure and temperature. If a pipeline ruptures, this could lead to a boiling liquid expanding vapor explosion (Anderson 2008).	No project planned at this time.	No project planned at this time.	Human injury/death due to boiling liquid expanding vapor explosion (BLEVE).	Pipeline rupture.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Liability costs. Damage repair costs.	Monitor pipeline operating conditions.	Implement standard procedures for safe operation and maintenance of pipeline.	Monitor pipeline for unsafe operating conditions. Alarm system. Emergency response plan. Train employees and educate local residents what to do in the event of a pipeline rupture. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
441	21.08.07.	Pipeline scheduled maintenance	Typical scheduled maintenance jobs and frequency: Aerial patrols 26 times per year. Population density survey every other year. ROW inspection 26 times per year. Emergency systems tested annually. Rectifier maintenance completed 6 times per year. Cathodic protection survey annually. Internal inspection of pipeline using an electronic tool, every 5 years or more frequently if necessary. Overpressure safety devices checked annually. Public awareness and damage prevention program reviewed annually. (DGC). Inspect each mainline valve twice a year 1. Pipeline cleaning	Failure to properly inspect and maintain the pipeline could lead to pipeline failure and CO2 leakage.	No project planned at this time.	No project planned at this time.	Pipeline corrosion.	Lack of, or improper, pipeline scheduled maintenance.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline scheduled maintenance.	Comply with 49 CFR Part 195 pipeline scheduled maintenance requirements. Maintain proper pipeline maintenance.	Review status and results of pipeline scheduled maintenance annually.
442	21.08.08.	Pipeline malfunctions	Some pipeline malfunctions could include: 1. Equipment malfunction or failure 2. Unintended valve closure or shutdown 3. Loss of communication (SCADA system) 4. Power outage 5. Pig stuck in pipeline causing a shutdown	Pipeline malfunctions could lead to unintended shutdown or CO2 leakage.	No project planned at this time.	No project planned at this time.	Pipeline flow interruption. Pipeline damage.	Pipeline malfunction.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline operating conditions.	Install alarm system for equipment / valve malfunction or failure. Install backup communication system for SCADA. Install backup power generator or batteries. Implement standard operating procedures for inline inspection system (pig system).	Train personnel to properly respond to pipeline malfunctions on a timely basis.

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			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
440	21.08.06.	Boiling liquid expanding vapor explosion (BLEVE)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
441	21.08.07.	Pipeline scheduled maintenance	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
442	21.08.08.	Pipeline malfunctions	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
443	21.08.09.	Pipeline leak	Pipeline leaks can include: 1. Pinhole leak - small leak (visible due to dry ice forming on the surface) 2. Pipeline puncture small diameter leak 3. Pipeline puncture large diameter leak	CO2 leakage.	No project planned at this time.	No project planned at this time.	Pipeline and property damage. Human injury/death.	Pipeline leak.	Liability costs. Damage repair costs..	Monitor pipeline operating conditions.	Implement standard procedures for safe operation and maintenance of pipeline.	Install and maintain CPM leak detection system. Install and maintain crack arrestors to minimize propagating cracks. Install and maintain block valves to section off the pipeline in case of a rupture. Train personnel and educate local residents on how to identify and respond to a pipeline leak/rupture. Implement and maintain an emergency response plan.
444	21.08.10.	Pipeline rupture	Pipeline ruptures consist of a circumferential or longitudinal propagation fracture	CO2 leakage.	No project planned at this time.	No project planned at this time.	Pipeline and property damage. Human injury/death.	Pipeline rupture.	Liability costs. Damage repair costs..	Monitor pipeline operating conditions.	Implement standard procedures for safe operation and maintenance of pipeline.	Install and maintain CPM leak detection system. Install and maintain crack arrestors to minimize propagating cracks. Install and maintain block valves to section off the pipeline in case of a rupture. Train personnel and educate local residents on how to identify and respond to a pipeline leak/rupture. Implement and maintain an emergency response plan.
445	21.08.11.	Pipeline safety measures	Pipeline safety measures can include: 1. Emergency response plan 2. Reverse 911 call system - emergency alert 3. One-call system - prior to drilling or excavating 4. Supervision of excavation near pipelines 5. Regular inspection and maintenance of pipeline and ROW 6. CO2 monitors and alarms at booster stations 7. Oxygen packs at booster stations 8. Fire fighting equipment at booster stations 9. Public emergency response plan 10. Fencing and barricades to protect above ground facilities 11. Markers for ROW, valves and equipment	Lack of pipeline safety measures could lead to human injury and/or pipeline damage.	No project planned at this time.	No project planned at this time.	Noncompliance with regulations.	Lack of or inadequate pipeline safety measures.	Fines or penalties for noncompliance. Possible business interruption.	Monitor pipeline safety measures.	Comply with all safety measures required by 49 CFR Part 195.	Review safety measures regularly to ensure they are operational. Make adjustments if necessary to ensure safety.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
443	21.08.09.	Pipeline leak	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
444	21.08.10.	Pipeline rupture	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
445	21.08.11.	Pipeline safety measures	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
446	21.09.05	Pipeline hydraulic testing	Except as otherwise provided in this section ... no operator may operate a pipeline unless it has been pressure tested ... without leakage, (49 CFR Part 195.300-195.310)	Improper or lack of hydraulic testing may fail to discover leaks before CO2 is fed to the pipeline.	No project planned at this time.	No project planned at this time.	Failure to discover leaks before CO2 fed to pipeline.	Improper or lack of hydraulic pipeline testing.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline hydraulic testing.	Conduct pipeline hydrostatic testing in compliance with 49 CFR Part 195.	Locate and repair any leaks. Do not place pipeline into service until it has successfully passed hydrostatic testing.
447	22.00.00.	CO2 ON-SITE FACILITIES RISKS										
448	22.01.00.	On-site facilities for DSA	On-site facilities for deep saline aquifer (DSA) CO2 injection can include: 1. Injection CO2 distribution system trunk and laterals 2. Power supply 3. Injection and monitoring wells 4. Onsite CO2 pumping stations 5. Water treatment facilities.	Potential problems could include, blowout, equipment failure.	Not applicable to CO2-ECBM.		Poor performance or failure of equipment /systems.	Defective / off-spec on-site facilities for DSA.	CO2 leak / blowout. Water leak/rupture. Facilities and property damage. Human injury/death. Liability costs. Damage repair costs. Environmental clean up costs. Project ROI negatively impacted.	Monitor specification, procurement, installation, operation and maintenance of on-site facilities.	Train operators and managers. Properly specify, engineer, manufacture and install equipment and other components. Implement appropriate procedures for safe operation and maintenance of on-site facilities. Comply with state and federal regulations.	Implement and maintain a risk management plan. Monitor for CO2 leaks.

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Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
446	21.09.05	Pipeline hydraulic testing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
447	22.00.00.	CO2 ON-SITE FACILITIES RISKS	0	0	0	0															
448	22.01.00.	On-site facilities for DSA	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
449	22.02.00.	On-site facilities for EOR	On-site facilities for CO2 enhanced oil recovery (EOR) can include: 1. Recycle CO2 compression system and building 2. Injection CO2 distribution system trunk and laterals 3. Production gathering system 4. Oil, water and slop storage tanks 5. CO2 dehydration system 6. CO2 gas scrubber/knockout drum 7. Flare system 8. Circulation and transfer pumps 9. Instrument air system 10. Control room, motor control center and building 11. Power supply transformers, UPS, PLCs, cables 12. Injection, production, disposal and monitoring wells 13. Water treatment/disposal facilities 14. CO2 separation and hydrocarbon recovery.	Potential problems could include blowout, oil leaks/spills ignition/explosion, equipment failure, water quality, water disposal	Not applicable to CO2-ECBM.		Poor performance or failure of equipment /systems.	Defective / off-spec on-site facilities for EOR.	CO2 leak / blowout. Oil leak-spill / ignition / explosion. Methane leak / ignition / explosion. Water leak/rupture. Facilities and property damage. Human injury/death. Liability costs. Damage repair costs. Environmental clean up costs. Project ROI negatively impacted.	Monitor specification, procurement, installation, operation and maintenance of on-site facilities.	Train operators and managers. Properly specify, engineer, manufacture and install equipment and other components. Implement appropriate procedures for safe operation and maintenance of on-site facilities. Comply with state and federal regulations.	Implement and maintain a risk management plan. Monitor for CO2, CH4, oil or water leaks.
450	22.03.00.	On-site facilities for ECBM	On-site facilities for CO2 enhanced coal bed methane (ECBM) can include: 1. Recycle CO2 compression system 2. Injection CO2 distribution system trunk and laterals 3. CBM compression and gathering system 4. Water gathering and storage tanks 5. CO2 dehydration system 6. Gas processing - removal of CO2 from nat. gas 7. Flare system 8. Circulation and transfer pumps 9. Gas metering system 10. Control room, motor control center and building 11. Power supply transformers, UPS, PLCs, cables 12. Injection, production, disposal and monitoring wells 13. Water separation, treatment, storage, disposal facilities 14. Roads	Potential problems could include blowout, methane leaks ignition/explosion, equipment failure, water disposal.	Current low pressure of the Fruitland Formation would mitigate blowouts. The seams and dewatered and produced water comes out of the well in the form of water vapor and condenses in the CBM gathering system as distilled water containing coal fines. Methane leaks would be no more than typical CBM operations	No project planned at this time.	Poor performance or failure of equipment /systems. Land disturbance for roads, drilling pads, utilities, pipelines and production facilities. Water table decrease. Water discharge. Equipment noise. Decreased air quality due to compressor exhaust and dust generation. Non-native plant infestation. Road damage from heavy use. Wildlife habitat disruption.	Installation and operation of on-site facilities for ECBM.	CO2 leak / blowout. CH4 leak / ignition / explosion. Water leak. Lubricant, fuel, chemical leak Facilities and property damage. Liability costs. Damage repair costs. Environmental clean up costs. Decreased profitability. Visual impact of surface facilities.	Monitor specification, procurement, installation, operation and maintenance of on-site facilities.	Train operators and managers. Properly specify, engineer, manufacture and install equipment and other components. Implement appropriate procedures for safe operation and maintenance of on-site facilities. Comply with state and federal regulations. Use multiple wells per pad or dual completions or recompletions to minimize land disturbance. Follow existing utility corridors and roads for pipelines and electrical distribution. Use wireless transmission of well data to minimize site visits. Unitize operations. Avoid steep slopes and benches.	Monitor for CO2, CH4 in high risk areas. Locate and fix leaks. Use water for dust control. Control noise levels. Reclaim disturbed areas.

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			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
Line #	Index #	Risk Area/FEP	Failure probability (P= 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
449	22.02.00.	On-site facilities for EOR	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
450	22.03.00.	On-site facilities for ECBM	4	2	1	8	None	None	None	\$200/t CO2 or brine released into USDW. \$50,000 / acre for land remediation.	Road damage: \$1000/mi per year Rework shallow water wells: \$10k/well Potential pump house fire from CO2/CH4 leak: <\$50k per incident	None	None	None	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	<\$1M per incident	None	Part of ongoing costs.	Savings of <\$1M per incident avoided.	

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Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
451	22.04.00.	Injection well components	CO2 injection well components generally include: 1. Wellhead and tree 2. Tubing and casing 3. Safety valve 4. Packer 5. Packer fluid 6. Elastomers 7. Perforations 8. Sand control - for unconsolidated reservoirs	Component failure could result in CO2 leakage.	No project planned at this time.	No project planned at this time.	Failure of injection well components.	Defective / off spec injection well components.	CO2 leak. Facilities and property damage. Human injury/death. Liability costs. Damage repair costs. Decreased profitability.	Monitor specification, procurement, installation, operation and maintenance of injection well components.	Train operators and managers. Properly specify, engineer, manufacture and install equipment and other components. Implement appropriate procedures for safe operation and maintenance of on-site facilities. Comply with state and federal regulations.	Monitor for CO2/CH4 near wells. Locate and fix leaks. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/CH4 leak.	
452	22.05.00.	Injection well materials of construction	DSA CO2 injection well components are typically carbon steel. Typical materials of construction for EOR CO2 injection wells include: - Upstream metering & piping runs: 316 SS, Fiberglass - Christmas tree (trim): 316 SS, Nickel, Monel - Valve packing and seals: Teflon, Nylon - Wellhead (trim): 316 SS, Nickel, Monel - Tubing hanger: 316 SS, Incoloy - Tubing: fiberglass lined (GRE) carbon steel, internally plastic coated carbon steel, corrosion resistant alloys - Tubing joint seals: Seal ring (fiberglass lined), coated threads and collars (internally plastic coated) - On/off tool, profile nipple: Nickel plated wetted parts, 316 SS - Packers: Internally coated hardened rubber of 80-90 durometer strength (Buna-N), Nickel plated wetted parts - Cements and cement additives: API cements and/or acid resistant specialty cements and additives - Production liner 316 SS, Incoloy - Casing: carbon steel J-55 and K-55 grades; corrosion resistant alloy used in intervals where potential potable water aquifers exist or where H2S is present (Meyer 2007) Elastomers - Teflon or nylon have been used to prevent swelling	Corrosion can occur when tubulars are exposed to wet CO2. Sufficient quantities of H2S in CO2 can cause corrosion or sulfide stress cracking. (CCP 2009) The reservoir fluid affects corrosivity near the wellbore and compaction resistance where formation dissolution has occurred. In significant dissolution cases, the well tubulars must be designed to resist column buckling in the injection interval. (CCP 2009) CO2 phase behavior can impact velocity. High velocity of injection can cause erosion to materials exposed to the CO2 stream (CCP 2009)	No project planned at this time.	No project planned at this time.	Corrosion / failure of injection well components.	Defective / off-spec injection well materials of construction.	CO2 leak. Downtime and repair costs.	Monitor specification, procurement, installation, operation and maintenance of injection well components.	Determine the characteristics of brine to be handled in the injection wells. Select materials that will resist corrosion , and/or scale buildup.	Monitor corrosion and scale buildup in injection wells and take necessary corrective action such as pre-treating the injected water.	

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Risk Ranking		Estimated Potential Damage Recovery Costs													Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)					
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)																
451	22.04.00.	Injection well components	4	2	1	8	None	None	None	None	None	<\$0.2M per incident	\$288 to \$4,436/d of downtime per injection well.	Decreased profitability.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
452	22.05.00.	Injection well materials of construction	3	2	1	6	None	None	None	None	None	<\$0.5M per incident	\$288 to \$4,436/d of downtime per injection well.	Decreased profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1

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Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
453	22.05.01.	Elastomer seals	Since supercritical CO2 is a solvent, many elastomers, plastics, rubber, or resins present in a well could be subject to chemical attack or dissolution. When designing a CO2 injector, material should be based on performance expectations. Elastomers, in particular, are a common part of well hardware used to seal different components. Elastomers must be made of material that is chemically compatible or inert to the injection fluid and must be of sufficient strength or adequately anchored to withstand the different pressure and explosive decompression that might exist across a seal. Since the physical and performance characteristics of many elastomer materials change with pressure and temperature, the elastomer must be able to perform reliably across the full range of differential pressures and temperatures expected through the design life of the well at the location of the seal within the well. (CCP 2009) Teflon or nylon have been used for seals to prevent swelling. (Meyer 2007).	Elastomer seal failure can result in CO2 leakage.	No project planned at this time.	No project planned at this time.	Seal failure.	Defective / off-spec elastomer seals.	CO2 leak. Downtime and repair costs.	Monitor specification, procurement, installation, operation and maintenance of elastomer seals.	Select elastomers that have a successful track record in handling CO2.	Replace elastomer seals that fail. Determine root cause. Monitor development of improved elastomers.
454	22.06.00.	Injection well safety precautions	Safety precautions for injection wells include: 1. Casing corrosion protection - Impressed and passive currents - Oxygen, biocide corrosion inhibiting chemicals 2. Gentle handling to prevent damage to tubing coatings 3. Casing leak detection testing 4. Fencing, monitoring and atmospheric dispersion monitoring if near populated areas 5. Automatic shutdown controls for unsafe conditions	Lack of safety precautions can lead to greater risk of CO2 leakage	No project planned at this time.	No project planned at this time.	Wellbore failure.	Lack of injection well safety precautions.	CO2 leak. Downtime and repair costs.	Monitor injection well safety precautions.	Comply with all state and federal injection well safety measures.	Annual review of safety measures, rules and regulations to confirm the project is in compliance.
455	22.07.00.	Production well submersible pump	While normally very reliable, the submersible pump in an EOR or ECBM production well can fail.	Failure of the submersible pump can result in operating delays and maintenance costs.	Submersible pumps rarely used because the coal has been mostly dewatered.	No project planned at this time.	Submersible pump failure.	Defective /off-spec production well materials of construction.	Downtime and repair costs.	Monitor specification, procurement, installation, operation and maintenance of submersible pump.	Properly select, install, operate and maintain submersible pumps.	Monitor submersible pumps for corrosion or scale buildup or motor failure and take necessary corrective action.
456	22.08.00.	Production well materials of construction	Production wells tend to be exposed to mixtures of CO2, brine, hydrocarbons (oil and/or gas) and stripped gases such as H2S. Production wells may also be exposed to hydrocarbon (asphaltene, paraffin or polyaromatic) deposition. Teflon coating has proven to help reduce hydrocarbon deposition. Scale buildup may also be a problem depending on brine chemistry.	The produced mixtures can be very corrosive. Hydrocarbon deposition or scale buildup may cause significant down time for cleaning out.	No project planned at this time.	No project planned at this time.	Corrosion / failure of production well components.	Defective / off-spec production well materials of construction.	CO2/CH4 leak. Downtime and repair costs.	Monitor specification, procurement, installation, operation and maintenance of production well components.	Determine the characteristics of fluids to be handled by the production well. Select materials that will resist corrosion and/or scale buildup.	Monitor corrosion and scale buildup in production wells or take necessary corrective action.
457	23.00.00.	CO2 MONITORING RISKS										

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									Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
453	22.05.01.	Elastomer seals	3	2	1	6	None	None	None	None	None	<\$0.2M per incident	\$288 to \$4,436/d of downtime per injection well.	Decreased profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented			
454	22.06.00.	Injection well safety precautions	2	2	1	4	None	None	None	None	None	<\$0.2M per incident	\$288 to \$4,436/d of downtime per injection well.	Decreased profitability.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1		
455	22.07.00.	Production well submersible pump	2	2	1	4	None	None	None	None	None	<\$0.2M per incident	Revenue loss due to well downtime: 43- 110 MCFD of CH4 @ \$3.50/MCF = \$150-385/d per well.	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented			
456	22.08.00.	Production well materials of construction	3	2	1	6	None	None	None	None	None	<\$0.2M per incident	Revenue loss due to well downtime: 43- 110 MCFD of CH4 @ \$3.50/MCF = \$150-385/d per well.	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2. <20MMCF CH4 per leak at \$3.50/MCF	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented			
457	23.00.00.	CO2 MONITORING RISKS	0	0	0	0																	

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
458	23.01.00.	Data acquisition activities at the well	Activities include logging, drill stem tests, coring, hydrophone installation, etc.	May include some activities and procedures that are less familiar. Some techniques could limit other MMV techniques.	Monitoring requirements for CO2-ECBM different from monitoring requirements for deep saline aquifer sequestration..	No project planned at this time.	Project uncertainty due to lack of subsurface data.	Ineffective data acquisition activities at the well	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor data acquisition activities at the well.	Work with an experienced monitoring engineer / consultant to prepare a monitoring plan that optimizes wellbore data acquisition. Implement standard procedures for good monitoring.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.
459	23.02.00.	Data acquisition activities away from the well	Many activities and procedures will be effectively new and newly trained for. Some monitoring techniques could present risk or barriers to the application or success of other techniques.	Off-site monitoring activities may incur risk of physical accidents and may make the project publicly prominent.	Monitoring requirements for CO2-ECBM different from monitoring requirements for deep saline aquifer sequestration.	No project planned at this time.	Project uncertainty due to lack of subsurface data.	Ineffective data acquisition activities away from the well	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor data acquisition activities away from the well.	Work with an experienced monitoring engineer / consultant to prepare a monitoring plan that optimizes non-wellbore data acquisition. Implement standard procedures for good monitoring.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.
460	23.03.00.	Data acquisition conflicts	Data acquisition may involve many techniques including logging, fluid sampling, coring, surface and downhole geophones, surface seismic, surface air measurements, groundwater sampling, and others.	Use of some monitoring techniques can preclude or limit the applicability of other techniques.	Monitoring requirements for CO2-ECBM different from monitoring requirements for deep saline aquifer sequestration.	No project planned at this time.	Project uncertainty due to subsurface data conflicts.	Data acquisition conflicts.	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor data acquisition conflicts.	Prepare a monitoring plan that avoids data acquisition conflicts.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.
461	23.04.00.	Seismic surveys	Vertical resolution of seismic imaging is inherently limited such that features less than 10 m thick can rarely be discerned. (CCP 2009) Subsurface CO2 is not seismically resolvable. Limited or absence of plume images via seismic. Seismic readings may be compromised by vibration from nearby heavy industrial facilities. 1. 2-D seismic survey 2. 3-D seismic survey 3. 4-D seismic survey 4. Vertical seismic profile (VSP) 5. Cross well seismic survey	Seismic techniques unable to pick up subsurface features or track CO2 plume.	Monitoring requirements for CO2-ECBM different from monitoring requirements for deep saline aquifer sequestration. 3D seismic surveys completed on Nine-Section Area. Seismic surveys not able to pick up CO2 adsorbed on coal.	No project planned at this time.	Seismic techniques unable to pickup subsurface features or track CO2 plume.	Seismic survey poor resolution.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor specification and implementation of seismic surveys.	Combine seismic survey methods to get better resolution.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXS=D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
458	23.01.00.	Data acquisition activities at the well	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
459	23.02.00.	Data acquisition activities away from the well	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
460	23.03.00.	Data acquisition conflicts	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	None	None		
461	23.04.00.	Seismic surveys	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

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462	23.05.00.	Gravity surveys	As a notional rule of thumb, CO2 filled reservoirs with less than 10% porosity, thicknesses of less than 10 m and depths greater than 2,500 m will be very difficult to resolve even with the best gravity data and mathematical inversion techniques. (CCP 2009) Current available standard gravimeters are capable of making repeat measurements valid to about 5 micro-gals. Fixed seal-floor gravimeters are essentially capable of the same. (CCP 2009) Corrections for motion are required for gravity data acquired from moving vessels. A change of only 1 cm of elevation will yield a difference of 3 micro-gals. Studies of oil fields have found that fixed permanent surface gravity monuments (i.e. stations) are essential to maximize repeatability (CCP 2009)	Gravity surveys unable to detect CO2 movement	Monitoring requirements for CO2-ECBM different from monitoring requirements for deep saline aquifer sequestration. Gravity survey unable to detect CO2 adsorbed on coal.	No project planned at this time.	Gravity survey unable to detect CO2 plume.	Site-specific conditions fall outside the effective range of gravity separation.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor specification and implementation of gravity surveys.	Consider alternative geophysical techniques if site-specific conditions fall outside the range of gravity survey effectiveness.	Consider alternative geophysical techniques if site-specific conditions fall outside the range of gravity survey effectiveness.
463	23.06.00.	InSAR or LIDAR surveys	InSAR is the current state-of-the-art satellite platform radar based technique to measure vertical ground elevations and relative elevation changes with time. (CCP 2009) Validation studies have shown that uplifts of 1-3 mm can be reliably and repeatedly measured when sites make use of special corner reflectors for calibration purposes. (CCP 2009) Light detection and ranging (LIDAR) is an optical remote sensing technology that measures properties of scattered light to find range. Large amounts of data can be collected by plane. Optimal weather conditions are needed for operation. Data collection is not limited to daylight hours. LIDAR can penetrate vegetation canopy.	InSAR may be unable to accurately measure vertical ground elevations and relative elevation changes over time due to high seasonal vegetation growth.	Nine-Section Area InSAR was used to measure ground movement away from the immediate project area. Tiltmeters were used within the project area. Vegetation growth not a problem in this area.	No project planned at this time.	InSAR unable to accurately measure vertical ground elevations and relative elevation changes over time.	InSAR readings compromised by high seasonal vegetation growth.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor specification and implementation of InSAR surveys.	Avoid areas with high vegetation growth.	Install base pillars to get more accurate readings. Use tiltmeters as an alternative or complement. Use LIDAR to penetrate the vegetation canopy.
464	23.07.00.	Well Monitoring	Well monitoring for CO2 storage seeks confident validation that: - Cement integrity and bond is maintained - Pressure isolation barriers are maintained and functioning - Corrosion is being controlled - The CO2 injection profile is being maintained - Barriers after plug and abandonment provide confidence. (CCP 2009)	Unexpected well failure due to lack of well monitoring.	Monitoring requirements for CO2-ECBM different from monitoring requirements for deep saline aquifer sequestration. Unable to meet MMV requirements for CO2 sequestration. Monitoring flowrate, injection pressures, temperatures, annulus pressure and CO2 at injection wells.	No project planned at this time.	Failure to detect well leakage.	Insufficient well monitoring.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Review monitoring plan and comprehensiveness of well monitoring.	Work with an experienced monitoring engineer / consultant to prepare a monitoring plan. Determine which wells to monitor and what monitoring tools to use. Implement standard procedures for good monitoring.	Monitor for CO2/CH4 near wells. Locate and fix leaks.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking			Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info		
			Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)		Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)
									Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
462	23.05.00.	Gravity surveys	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None			
463	23.06.00.	InSAR or LIDAR surveys	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None			
464	23.07.00.	Well Monitoring	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Part of ongoing costs.	None	1		

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
465	23.07.00.	General monitoring risks	1. Weather conditions prevent using a monitoring method or retrieving data at a critical point in time 2. Injection site terrain too rugged for surface monitoring 3. Monitoring equipment not properly calibrated 4. Inappropriate monitoring suggests a false alarm for issues that do not exist (CCP 2009) 5. Inappropriate monitoring suggests a false sense of security (CCP 2009) 6. Difficulty of geophysical techniques monitoring below salt caprocks (CCP 2009) 7. Ineffective monitoring 8. Insufficient monitoring 9. Lack or loss of monitoring records 10. Accidental damage or breakdown of custom-made equipment, sensors or tools - repair/replacement delays and irretrievable data loss. 11. Conflicting results from different monitoring techniques. 12. Difficulty of monitoring stacked injection plumes	Ineffective or lack of monitoring can result in missed data. This leads to inadequate engineering control, raising costs and leakage risks; yields insufficient documentation to establish CO2 storage credits, etc.	Monitoring requirements for CO2-ECBM different from monitoring requirements for deep saline aquifer sequestration. Unable to meet MMV requirements for CO2 sequestration.	No project planned at this time.	Unable to track CO2 plume movement and CO2 leakage.	Ineffective, insufficient or lack of monitoring.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor specification and implementation of monitoring techniques.	Determine MVA requirements. Select reliable monitoring methods. Implement standard procedures for monitoring. Back up data logging.	Monitor for CO2/CH4 in high-risk areas. Analyze monitoring data versus simulation data. Identify any discrepancies. Determine root cause of discrepancies.
466	23.08.00.	Pre-closure monitoring of storage (02.01.07.00.)	Processes related to any monitoring undertaken during the operational and closure phase. The extent and requirement for such monitoring activities may be determined by issues such as storage concept, geological setting, regulations, or public pressure. A number of monitoring techniques exist including seismic data, electrical resistance, soil gas and isotopic characteristics.	Monitoring during the operational phase contributes towards the amount and quality of information initially available after closure concerning the behavior and distribution of sequestered CO2.	Monitoring requirements for CO2-ECBM different from monitoring requirements for deep saline aquifer sequestration. Unable to meet MMV requirements for CO2 sequestration.	No project planned at this time.	Insufficient or inaccurate information to ensure safe storage of CO2.	Lack of pre-closure monitoring of storage.	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Risk management review of MVA plan.	Preparation and implementation of MVA plan.	Implementation of MVA plan.
467	23.09.00.	Post-closure monitoring of storage	FEPs related to any monitoring undertaken during the post-closure phase. This includes monitoring of parameters related to the long-term safety and performance. The extent and requirement for such monitoring activities may be determined by issues such as storage concept, geological setting, regulations, or public pressure. A number of monitoring techniques exist including seismic data, electrical resistance, soil gas and isotopic characteristics.	Post-closure monitoring will provide information regarding the performance of the sequestration project and may trigger post-closure remedial actions, if necessary.	Monitoring requirements for CO2-ECBM different from monitoring requirements for deep saline aquifer sequestration. Unable to meet MMV requirements for CO2 sequestration.	No project planned at this time.	Insufficient or inaccurate information to ensure safe storage of CO2.	Lack of post-closure monitoring of storage.	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Risk management review of post-closure MVA plan.	Preparation and implementation of post-closure MVA plan.	Implementation of post-closure MVA plan. Prepare procedures for potential remedial action.

PUMP CANYON CO2-ECBM SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
465	23.07.00.	General monitoring risks	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Part of ongoing costs.	None	
466	23.08.00.	Pre-closure monitoring of storage (02.01.07.00.)	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Part of ongoing costs.	None	1
467	23.09.00.	Post-closure monitoring of storage	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Part of ongoing costs.	None	1

Appendix G

Farnsworth Unit Site QFMEA Model

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
1	00.00.00.00.	ASSESSMENT BASIS	This category of FEPs determines the boundary conditions for any assessment, specifying the spatial and temporal domain of the system. The Assessment Basis determines what is being assessed and why, so that those FEPs that need to be considered in the analysis can be defined, and those which can be screened out as being outside the scope of the assessment can be identified.									
2	00.01.00.00.	Purpose of the assessment	The purpose of the assessment of geological CO2 sequestration.	The general purpose of an assessment of geological CO2 sequestration is to determine the performance of the sequestration system. In any specific case, however, the purpose of conducting an assessment may vary from simple calculations to test initial ideas for sequestration concepts, to support for an application for regulatory approval requiring detailed, site-specific performance assessment against relevant criteria. The level of complexity and comprehensiveness will vary according to the use to which it will be put. Additionally, the assessment endpoints of interest may not only vary in type, depending on the assessment purpose, but also in the level of rigor required for compliance demonstration.	Identify and quantify the CO2-EOR risks of the Farnsworth Unit Site.							
3	00.02.00.00.	Endpoints of interest	The assessment endpoints of interest.	The structure and composition of an assessment will tend to reflect the endpoints that are required to be assessed. These in turn, will reflect the criteria that are adopted to judge the overall performance of the sequestration system. Thus, for example, an assessment may be constrained to considering the degree of containment within a geological feature, alternatively, it may need to address potential near-surface impacts. Invariably, a combination of endpoints will be required.	Comprehensive quantitative risk assessment							
4	00.03.00.00.	Spatial domain of interest	The spatial domain of interest in the assessment.	The spatial domain of interest will be dependent on the site context, which may vary from generic assessments to site specific assessments, the sequestration concept and the endpoints of interest. The spatial domain will contribute to determining the information requirements and modeling capabilities that may be required.	Farnsworth Unit Site 51.365 km ² 19.84 mi ² 12,698 acres (Grigg 2012)							

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
1	00.00.00.00.	ASSESSMENT BASIS	0	0	0	0															
2	00.01.00.00.	Purpose of the assessment	0	0	0	0															
3	00.02.00.00.	Endpoints of interest	0	0	0	0															
4	00.03.00.00.	Spatial domain of interest	0	0	0	0															

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
5	00.04.00.00.	Timescales of interest	Timescale of interest for the assessment.	Timescales over which the assessment will be performed will constrain processes which must be considered in the assessment. In general terms, there are three timescales of interest for geological storage of carbon dioxide. Firstly, there is the timescale during construction and operation which has a lifetime in years or decades, secondly there is a timescale over which isolation of carbon dioxide from the atmosphere is necessary to mitigate climate change. This timescale is likely to be in the order of a few hundred years at most. The third timescale of interest is potentially much longer and is that pertaining to the assessment of potential hazard to humans and the environment. This timescale could be in the order of thousands to tens of thousands of years.	Risks associated with CO2-EOR operation 2010 through 2012 (historical) 2013 through 2024 (projection)							
6	00.05.00.00.	Sequestration assumptions	High level assumptions concerning the sequestration system(s) of relevance to the assessment. For example, the quantity and quality of CO2 sequestered, the method of injection and information concerning the assumed performance of the sequestration system.	Provides a background to the sequestration technique adopted. Note that more detailed consideration of the CO2 sequestration system is provided in subsequent FEP categories.	It is assumed that CELLC is complying with all CO2-EOR and CO2 pipeline regulations and permits. Injection of 2.39 Mt (45.443 BSCF) of purchased CO2 into the West FWU from 2010 through 2024 as projected by CELLC (CELLC 2013c).							
7	00.06.00.00.	Future human action assumptions	The assumptions made in the assessment concerning general boundary conditions for assessing future human action and exposure.	For example, it can be expected that human technology and society will develop over the timescales of relevance for the assessment of CO2 sequestration systems, however, this development is unpredictable. Therefore it may be necessary to make some assumptions in order to constrain the range of future human actions that are considered, such as assuming that only present-day technologies, or technologies practiced in the past, will be considered.	Assume no change in human activity in the area.							
8	00.07.00.00.	Legal and regulatory framework	The legal and regulatory framework within which the assessment takes place.	In undertaking an assessment it is vital to consider the appropriate regulatory framework requirements. At one extreme these may be specific, prescriptive quantitative requirements, at the other they could be non-prescriptive or may not have been fully developed. The legal and regulatory framework can shape various aspects of an assessment, such as the required assessment endpoints, timescales of interest and assumptions concerning future human actions.	Assume no change in legal and regulatory framework.							

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
5	00.04.00.00.	Timescales of interest	0	0	0	0														1	
6	00.05.00.00.	Sequestration assumptions	0	0	0	0														1	
7	00.06.00.00.	Future human action assumptions	0	0	0	0															
8	00.07.00.00.	Legal and regulatory framework	0	0	0	0															

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
9	00.08.00.00.	Model and data issues	General methodological issues affecting the assessment modeling process and use of data	Examples of general model and data issues include the treatment of uncertainty; the availability, collection and method for handling site specific data; and the reduction/simplification of models and data.	A 3D geologic model has been developed by SWP as part of their Phase III project with CELLC.							
10	00.09.00.00.	Public acceptance and information	The amount and type of information needed for public acceptance and to comply with industry best management practices.	Focus on health, safety and environmental risks as well as economic and lifestyle impact on the public at large.	Based on 57 years of operation, there is public acceptance.							
11	00.10.00.00	Financial viability	The minimum return on investment needed to justify the risks involved in undertaking the project.	Higher risks require higher rewards to justify undertaking a project. The risk assessment may give an indication of the minimum rate of return required to attract capital funding for the project.	CELLC projecting 25 to 40% rate of return and a 2.5:1 to 3.5:1 return on investment for CO2-EOR operations (CELLC 2013c)							
12	00.11.00.00	Adequate risk characterization	The level of detail and depth of risk characterization needed.	Characterization of risks can include identifying potential modes of failure, estimating probability of failure occurring and impact severity of failure and determining potential steps to prevent or mitigate failure.	Comprehensive quantitative risk assessment through QFMEA. Independent assessment based on information in the public domain.							
13	01.00.00.00.	EXTERNAL FACTORS	This category of FEPs describes natural or human factors that are outside the system domain. These FEPs are most important in determining scenarios for the future evolution of the system, and are often referred to as EFEPs (External FEPs). Three classes of FEPs are considered. Geological Factors and Climatic Factors are concerned with natural processes and events, whilst Future Human Actions is concerned with those human activities that can directly affect the sequestration system.	This category is divided into three classes: 1. Geological factors 2. Climate factors 3. Human action factors								
14	01.01.00.00.	Geological factors	Natural geological processes and events in the environment outside the system domain that are relevant to the evolution of the sequestration system.	Changes in the geological environment outside the system domain may directly affect the transport of carbon dioxide within the system.								
15	01.01.01.00.	Neotectonics	Neotectonics is the study of crustal movements that both occurred in the Earth's recent past and are continuing at the present day. These movements, which are driven directly or indirectly by global plate motions (tectonics), result in the vertical and horizontal warping, folding or faulting of the Earth's surface.	Neotectonic events have the potential to cause sudden changes in the physical properties of rocks due to stress changes and induced hydrogeological changes.	Stable regional area. Neotectonics not likely to impact site.		Damage to equipment (wells, pipeline, surface facilities). Caprock failure. Reservoir disruption.	Significant sudden crustal movement	Leakage of CO2 Shutdown of facility. Loss of business.	Geodetic monitoring (GPS, InSAR, LIDAR, strain, tilt, etc.). Monitoring passive seismic activity.	Avoid high risk sites (areas with active crustal movement). Fully characterize	Proper shutdown procedures in case of an earthquake. Emergency response procedures for dealing with CO2 leakage. Discontinue injection and decrease reservoir pressure.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking		Estimated Potential Damage Recovery Costs												Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
9	00.08.00.00.	Model and data issues	0	0	0	0															
10	00.09.00.00.	Public acceptance and information	0	0	0	0															1
11	00.10.00.00	Financial viability	0	0	0	0															
12	00.11.00.00	Adequate risk characterization	0	0	0	0															1
13	01.00.00.00.	EXTERNAL FACTORS	0	0	0	0															
14	01.01.00.00.	Geological factors	0	0	0	0															
15	01.01.01.00.	Neotectonics	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
16	01.01.02.00.	Volcanic and magmatic activity	Magma is molten, mobile rock material, generated below and within the Earth's crust, which gives rise to igneous rocks when solidified. A volcano is a vent or fissure in the Earth's surface through which molten or part-molten materials (lava) may flow, and ash and hot gases be expelled.	The high temperatures associated with volcanic and magmatic activity may result in permanent changes in the surrounding rocks, either directly, or through circulating high temperature fluids. This FEP is relevant to CO2 disposal in areas of potential magmatic activity, e.g. Japan. Besides bedrock damage, pressure and temperature changes due to heating, stress, or displacement could affect CO2 density and solubility, creating the risk of uncontrolled, rapid migration and escape of stored CO2. CO2STORE page 69)	No local volcanic activity.		Borehole damage. Pipeline failure. Caprock failure. Reservoir disruption.	Volcanic eruption. Magmatic intrusion.	CO2 leakage (HSE hazard). Damage to boreholes, equipment, pipeline, caprock. Shutdown of facility. Loss of business.	Monitoring surface distortion with LIDAR and other remote geodetic measurements. Monitoring seismic activity. Monitoring change in bottom hole temperatures.	Proper site characterization and site selection avoiding areas with volcanic and magmatic activity.	Proper shutdown procedures in case of volcanic eruption. Emergency response procedures for dealing with CO2 leakage. Discontinue injection and decrease reservoir pressure.
17	01.01.03.00.	Seismicity (Natural earthquakes)	Events and processes related to naturally occurring seismic events and also the potential for seismic events. A seismic event is caused by rapid relative movements within the Earth's crust usually along existing faults. The accompanying release of energy may result in rock movement and/or rupture, e.g. earthquakes. Many people are convinced that we want to avoid seismically-active areas for CO2 storage. In reality there are very large natural gas fields associated with some of the planet's major fault zones (Indonesia, Malaysia and California). Earthquakes in these areas have never been associated with sudden emissions of significant quantities of natural gas or oil from deep reservoirs. (CCP 2009) Major earthquakes (magnitude 6 and above) occur primarily in strong, brittle basement rock at depths on the order of 10 km (6 miles) or more. Very small earthquakes occur at depths as shallow as 3 km (2 miles). Micro-seismicity consists of very tiny seismic events often responding to subsurface fluid flow and relative pressure changes. All parts of the Earth's crust are in continuous movement and generate micro-seismic events, and the analysis of micro-seismicity offers unique insights into subsurface properties(CCP 2009). 1. Earthquake induced fractures/faults 2. Natural micro-seismicity	Seismic events may result in changes in the physical properties of rocks due to stress changes and induced hydrogeological changes. Seismic events are most common in tectonically active or volcanically active regions at crustal plate margins. Seismic disturbances might cause caprock failure (Damen 2006). Earthquakes could disrupt drilling, well operation, and monitoring activities, and damage surface facilities including the CO2 source. An earthquake on a fault through the CO2 plume could create or close an open pathway. Earthquakes may cause public concern about the project even if not project related. Micro-seismicity may cause public concern about the project even if not project related, may add noise interfering with micro-seismic monitoring. Earthquake near Nakaoka, Japan CO2 injection site caused significant public concern causing project to be moved off shore, even though earthquake was not directly caused by CO2 injection.	There have been 4 earthquakes (2.8 to 4.8 magnitude and 5-24 km deep) recorded from 1966-2013 within 80 km of the Farnsworth Unit Site. (neic.usgs.gov 2013). USGS estimated probability of earthquake exceeding listed magnitude occurring within 50 km of Farnsworth Unit Site within the next 50 years: 5.5 magnitude: 0.221% 6.0 magnitude: 0.101% 6.5 magnitude: 0.029% 7.0 magnitude: 0.002% (homefacts.com 2013) Probability per year: 5.5 magnitude: 4E-05/y 6.0 magnitude: 2 E-05/y 6.5 magnitude: 6E-06/y 7.0 magnitude: 4E-07/y		Earthquake damage to borehole, equipment, pipeline, caprock, or reservoir.	Natural earthquake Magnitude ≥6.5 within 10 km	CO2 leakage (HSE hazard). Interruption of business. Natural micro-seismicity is unlikely to cause damage but may arouse public concern about the project.	Measuring the rate of slippage of landmarks along faults to predict earthquakes. Geodetic monitoring (GPS, InSAR, LIDAR, strain, tilt, etc.); Monitoring seismic activity to distinguish between natural and induced micro-seismicity. Monitoring well and pipeline pressures and equipment operation.	Proper site characterization and site selection avoiding areas with active fault zones and avoiding low lying tsunami zones. Baseline surveys for micro-seismicity prior to CO2 injection.	Proper shutdown procedures in case of an earthquake. Emergency response procedures for dealing with CO2 leakage. Discontinue injection and decrease reservoir pressure. Passive microseismic monitoring to confirm earthquake was natural rather than induced.
18	01.01.04.00.	Hydrothermal activity	Processes associated with high temperature groundwaters, and hydrothermal alteration of minerals in the rocks through which the high temperature groundwater flows. Hydrothermal activity may be directly associated with volcanic and magmatic activity. Hot springs, geysers and submarine hydrothermal vents provide evidence of hydrothermal activity.	Can result in the hydrothermal alteration of rocks or minerals by the reaction of hot water (and other fluids) with pre-existing rocks. Springs, geysers and submarine hydrothermal vents can provide pathways for CO2 to reach the surface.	No hydrothermal activity in the area (based on published bottomhole temperatures).		High bottom hole temperatures. Caprock failure. Mineralization and alteration of formation and wells. Alteration of formation fluid chemistry.	Hydrothermal activity	CO2 leakage (HSE hazard). Damage to boreholes and wells. Damage to monitoring equipment.	Existence of hot springs, geysers and hydrothermal vents. Higher than normal thermal gradient. Monitoring change in bottom hole temperatures. Monitoring change in reservoir fluid chemistry.	Proper site characterization and site selection avoiding areas of hydrothermal activity.	Decrease reservoir pressure. Extract CO2 or brine from reservoir and inject into another more secure reservoir.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
16	01.01.02.00.	Volcanic and magmatic activity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
17	01.01.03.00.	Seismicity (Natural earthquakes)	2	4	1	8	PGA(g) 0.092-0.18 = 1/1000,000 fatality rate. PGA(g) 0.18-0.34 =1/100,000 fatality rate. PGA(g) 0.34-0.65 = 1/10,000 fatality rate. PGA(g) 0.65-1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate. Not attributable to CO2-EOR.	PGA(g) 0.092-0.18 = 1/250,000 injury rate. PGA(g) 0.18-0.34 = 1/25,000 injury rate. PGA(g) 0.34-0.65 = 1/2,500 injury rate. PGA(g) 0.65-1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate. Not attributable to CO2-EOR.	PGA(g) 0.092-0.18 = 3/100,000 injury rate. PGA(g) 0.18-0.34 = 3/10,000 injury rate. PGA(g) 0.34-0.65 = 3/1,000 injury rate. PGA(g) 0.65-1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate. Not attributable to CO2-EOR.	PGA(g) >0.5 = damage to USDW aquifers. \$200/t CO2 released into USDW.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Not attributable to CO2-EOR.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	0 -15 days @ \$15,000/d revenue lost per pattern idled to assess and fix damage. Worst case: project shut down due to natural earthquake being mistaken as induced seismicity.	May require additional water curtains to isolate any new faults or injection of sealants to seal any new faults. Additional cost for continuous passive micro-seismic monitoring.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of total damages attributable to CO2-EOR.	Cost to locate and fix well leak \$0.3M per leak. + Cost to locate and fix fracture or fault leak: \$3M per leak. + Cost to replace contaminated USDW \$1M/y per leak until fixed. + Cost of lost CO2: \$0.5M per year per leak. Worst case: Project shutdown if natural earthquake mistaken for induced seismicity.	Cost to locate and fix well leak \$0.3M per leak. + Cost to locate and fix fracture or fault leak: \$3M per leak. + Cost to replace contaminated USDW \$1M/y per leak until fixed. + Cost of lost CO2: \$0.5M per year per leak. Cost of continuous passive micro-seismic monitoring.: Capex: \$2.4M Opex: \$0.2M/y	Savings of \$1M/y per leak for USDW not contaminated + Savings of \$0.5M/y per leak of CO2 not lost.	Worst case: Saving of project value minus cost of continuous passive micro-seismicity monitoring.	1
18	01.01.04.00.	Hydrothermal activity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	2	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
19	01.01.05.00.	Hydrological and hydrogeological response to geological changes	Processes arising from large-scale geological changes and could include changes of fluid boundary conditions due to the effects of changes of fluid properties of geological units due to changes in rock stress or fault movements.	In and below low-permeability geological formations, hydrogeological conditions may evolve very slowly and often reflect past geological conditions, i.e. be in a state of disequilibrium	Reservoir closed on top, open on bottom and laterally. Indications that up to a third of the water injected into the reservoir for secondary recovery may have flowed into underlying layers (May 1987)		Reservoir disruption. Interaction between CO2/brine and near surface aquifers	Hydrological and hydrogeological response to geological changes.	Contamination of near surface drinking water.	Monitoring near surface water chemistry. Monitoring and modeling subsurface CO2 plume.	Proper site characterization and site selection, avoiding areas where hydrology or hydrogeology are in disequilibrium.	Decrease reservoir pressure. Extract CO2 or brine from reservoir and inject into another more secure reservoir.
20	01.01.06.00.	Large scale erosion (See 06.01.03.00)	Processes related to the large scale (geological) removal of rocks and sediments, with associated changes in topography and geological/hydrogeological conditions of the system.	Potential to modify the geological and hydrogeological environment.	No large scale erosion. Flat topography across the site. Sherm clay loam and Ness clay have low-to-medium wind and water erosion.							
21	01.01.07.00.	Bolide impact (meteorite impact)	An extraterrestrial body in the 1-10 km size range, which impacts the earth at high velocity, explodes upon impact, and creates a large crater.	A low probability, high consequence event that has the potential to substantially disrupt the CO2 storage system. Often screened out on the basis that the impact of the bolide will greatly exceed that of the disruption caused to the sequestration system.	Probability of a bolide impacting in Ochiltee County 4.6E-12 to 9.2E-12 per year (based on NASA estimates of 1 to 2 bolides per million years and Ochiltee County representing 4.6E-06 of the Earth's surface area).		Bolide impact causing caprock failure, destruction of surface facilities, human injury/death.	Bolide impact.	Catastrophic destruction. Release of CO2 may be one of the least effects.	NASA monitoring and modeling the trajectory of bolides in space.	Destruction of bolides in space before they have a chance to hit the earth.	Procedures to shutdown and evacuate site in cases of imminent danger.
22	01.02.00.00.	Climatic factors	Natural processes and events in the atmospheric environment that are relevant to the evolution of the sequestration system.	Changes in climate may directly affect the nature of any impacts that are incurred if carbon dioxide returns to the near-surface environment.								

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
19	01.01.05.00.	Hydrological and hydrogeological response to geological changes	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
20	01.01.06.00.	Large scale erosion (See 06.01.03.00)	0	0	0	0																
21	01.01.07.00.	Bolide impact (meteorite impact)	1	5	1	5	PGA(g) 0.092-0.18 = 1/1000,000 fatality rate. PGA(g) 0.18-0.34 =1/100,000 fatality rate. PGA(g) 0.34-0.65 = 1/10,000 fatality rate. PGA(g) 0.65-1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate. Not attributable to CO2-EOR.	PGA(g) 0.092-0.18 = 1/250,000 injury rate. PGA(g) 0.18-0.34 = 1/25,000 injury rate. PGA(g) 0.34-0.65 = 1/2,500 injury rate. PGA(g) 0.65-1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate. Not attributable to CO2-EOR.	PGA(g) 0.092-0.18 = 3/100,000 injury rate. PGA(g) 0.18-0.34 = 3/10,000 injury rate. PGA(g) 0.34-0.65 = 3/1,000 injury rate. PGA(g) 0.65-1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate. Not attributable to CO2-EOR.	PGA(g) >0.5 = damage to USDW aquifers. \$200/t CO2 released into USDW.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Not attributable to CO2-EOR.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	Shutdown of project	Shutdown of Project	up to 10% of total CO2 stored	10% of total damages	100% of project cost + cost to locate and fix leaks + cost of CO2 emitted + cost to replace contaminated USDW: >\$100M	100% of project cost + cost to locate and fix leaks + cost of CO2 emitted + cost to replace contaminated USDW: >\$100M	None	None		
22	01.02.00.00.	Climatic factors	0	0	0	0																

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
23	01.02.01.00.	Global climate change	The process of global climate change due to natural and/or anthropogenic causes. The last two million years of the Quaternary have been characterized by glacial/interglacial cycling. According to the Milankovitch Theory, the Quaternary glacial/interglacial cycles are caused by long-term changes in seasonal and latitudinal distribution of incoming solar radiation which are due to the periodic variations of the Earth's orbit about the Sun (Milankovitch cycles). Evidence suggests that the Earth is presently in a period of global warming. The anthropogenic release of gases into the atmosphere may be increasing the rate of global warming by enhancing the natural greenhouse effect, a process by which long wave radiation emitted from the Earth is trapped in the atmosphere by greenhouse gases such as CO₂. 1. Natural global climate change 2. Human induced climate change (01.03.01.00) 3. Ecology or human behavior response to climate change (01.02.08.00)	Changes in the global climate are likely to impact the CO₂ sequestration system in a number of ways. For example, through its affect on sea levels and the local and regional climate. Changes in ecology and human behavior in response to climate change will influence the relevant FEPs to be considered in the surface environment as an assessment extends into the future. Changes in air emission policies in response to global climate change will impact the feasibility of using CCS.	Hail, tornadoes and thunderstorms common in Ochiltree County.		Extreme weather events such as high wind and/or flooding damaging project facilities.	Significant and severe global climate change.	Business interruption (advance loss of profits), facilities damage.	Monitor trends in climate change that may have a detrimental effect on the project.	Proper site characterization and site selection avoiding low coastal areas or flood plains. Proper design consideration to accommodate extreme or changing weather patterns.	Maintain procedures for dealing with severe weather that may require an emergency shutdown.
24	01.02.02.00.	Regional and local climate change (extreme weather events damaging facilities)	Processes related to the possible future changes, and evidence for past changes, of climate at a storage site. This is likely to occur in response to global climate change, but the changes will be specific to situation, and may include short term fluctuations. Climate is characterized by a range of factors including temperature, precipitation and pressure as well as other components of the climate system such as oceans, ice and snow, biota and the land surface. Climatic changes lasting only a few decades may be referred to as climatic fluctuations. These are unpredictable at the current state of knowledge although historical evidence indicates the degree of past fluctuations. 1. Warm climate effects (01.02.06.00) 2. Cold climate effects 3. Wet climate effects 4. Dry climate effects 5. Hydrological and hydrogeological response to climate change (01.02.07.00)	Changes in the regional and local climate could affect the CO₂ sequestration system in a number of ways. For example, changes in groundwater recharge could affect regional hydrogeology and hence the transport of CO₂ dissolved in groundwater. It may also alter the near-surface environment to which some of the disposed CO₂ may migrate. Regions with a tropical climate may experience extreme weather patterns (monsoons, hurricanes) that could result in flooding, storm surges, high winds etc. with implications for erosion and hydrogeology. The high temperatures and humidity associated with tropical climates result in rapid biological degradation and soils are generally thin. In arid climates, total rainfall, erosion and recharge may be dominated by infrequent storm events. The hydrology and hydrogeology of a region is closely coupled to climate. Climate controls the amount of precipitation and evaporation, seasonal ice cover, and thus the soil water balance, extent of soil saturation, surface runoff groundwater recharge, sediment load and seasonality. Vegetation and human actions may modify these responses.	Local area susceptible to drought, high temperatures, tornadoes, hail, lightning, thunderstorms and ice storms. Drought may shrinkage of clay soil, resulting in road, rail and pipeline buckling. Thunderstorms may cause fast flooding. Estimated probability of occurrence within 50km of the Farnsworth Unit Site: Hail: 32.4/y Thunderstorm winds: 11.15/y Floods: 1.3/y Tornadoes EF0-EF4: 6.5/y Tornadoes EF≥2: 1.4/y Strong winds: 0.82/y Heavy snows: 0.62/y Droughts: 0.27/y Wildfires: 0.23/y Winter storms: 0.2/y Ice storms: 0.131/y Blizzards: 0.05/y Tornado fatalities: 0.115/y Tornado injuries: 2.26/y (homefacts.com 2013)	Historical data on weather damage to facilities?	Tornado damaging project facilities.	Significant and severe regional or local climate change.	Business interruption (advance loss of profits), facilities damage.	Monitor trends in climate change that may have a detrimental effect on the project. Monitoring extreme weather patterns.	Proper site characterization and site selection avoiding flood plains. Proper design consideration to accommodate extreme or changing weather patterns.	Maintain procedures for dealing with severe weather that may require an emergency shutdown.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
23	01.02.01.00.	Global climate change	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
24	01.02.02.00.	Regional and local climate change (extreme weather events damaging facilities)	4	2	1	8	None. Fatality rate: 1.5/1000 based on Katrina + flood Not attributable to CO2-EOR	Serious injury rate: 1.5/250 Not attributable to CO2-EOR	Minor injury rate: 4.5/100 Not attributable to CO2-EOR	Not attributable to CO2-EOR	Not attributable to CO2-EOR	Surface facilities damage <\$1M for most situations but \$10M+ if compressors are involved.	0-7 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of total damages	Cost to repair surface facilities: <\$1M + Cost of business interruption	Cost of insurance deductable.	Cost of insurance coverage for weather and flood damage and business interruption: 0.28% of surface facilities value per year + 0.25% of revenue per year respectively.	Savings in cost to repair surface facilities + Savings in cost of business interruption - Cost of insurance - Cost of insurance deductable.	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
25	01.02.02.01.	Extreme weather event causing human injury/death	Extreme weather events such as tornadoes or hurricanes may cause human injury/death.	Site may not provide sufficient protection for operators against extreme weather events such as tornadoes	Tornado fatalities occurring within 50 km of the FWU Site: 0.115/y (homefacts.com 2013) Tornado fatalities occurring within the FWU Site: 7.58E-04/y (calculated)		Tornado causing human injury/death.	Significant and severe regional or local climate change.	Loss of life. Business interruption.	Monitoring extreme weather patterns.	Proper design consideration to accommodate extreme or changing weather patterns.	Maintain procedures for dealing with severe weather that may require an emergency shutdown.
26	01.02.03.00.	Sea level change	Processes related to changes in sea level which may occur as a result of global (eustatic) change and/or regional geological change, e.g. isostatic movements. The component of sea-level change involving the interchange of water between land ice and the sea is referred to as eustatic change. As ice sheets melt so the ocean volume increases and sea levels rise. Sea level at a given location will also be affected by vertical movement of the land mass, e.g. depression and rebound due to glacial loading and unloading, referred to as isostatic change.	Sea level change may affect the sequestration system through its impact on the near surface environment and the regional or local hydrogeological regime.	Site not impacted by sea level change.		Flooding/erosion of pipeline right-of-way or injection site. Contamination of near surface drinking water with sea water.	Significant sea level change	Facilities flood damage. Business interruption (advanced loss of profits). Potential for project instead of sea level to be blamed for increased drinking water salinity.	Monitor trends in sea level change and analyze the potential impact on the project.	Proper site characterization and site selection avoiding low coastal areas or flood plains.	Installing barriers. Perform baseline surveys to determine source of water contamination.
27	01.02.04.00.	Periglacial effects	Related to the physical processes and associated landforms in cold but ice-sheet-free environments.	An important characteristic of periglacial environments is the seasonal change from winter freezing to summer thaw with large water movements and potential for erosion. Frozen sub-soils are referred to as permafrost. Melt water from seasonal thaw is unable to percolate downwards due to permafrost and saturates the surface materials. Permafrost layers may isolate the deep hydrogeological regime from surface hydrology, or flow may be focused at "taliks" (localized unfrozen zones, e.g. under lakes, large rivers or at regions of groundwater discharge).	No periglacial effects.		Erosion and frost heave. Permafrost forms local near-surface cap.	Periglacial effects	Damage to facilities. CO2 release (HSE hazard). Accumulation of migrating CO2 beneath permafrost zone and potential catastrophic release.	Monitoring weather forecasts for extreme conditions. Monitoring surface water movement and erosion patterns.	Proper site characterization and site selection avoiding permafrost areas.	Proper winterization of surface facilities. Erosion control barriers.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)					
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)															
25	01.02.02.01.	Extreme weather event causing human injury/death	3	4	2	24	1 @ \$1.5M per fatality Not attributable to CO2-EOR	1 @ \$1.5 M per serious (irrecoverable) injury Not attributable to CO2-EOR	1 @ \$0.05 M per minor (recoverable) injury Not attributable to CO2-EOR	Not attributable to CO2-EOR	Not attributable to CO2-EOR	Surface facilities damage <\$1M for most situations but \$10M+ if compressors are involved.	0-7 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of total damages	Cost to repair surface facilities: <\$1M + Cost of business interruption	Cost of insurance deductible.	Cost of insurance coverage for weather and flood damage and business interruption: 0.28% of surface facilities value per year + 0.25% of revenue per year respectively.	Savings in cost to repair surface facilities + Savings in cost of business interruption - Cost of insurance - Cost of insurance deductible.	2
26	01.02.03.00.	Sea level change	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None		
27	01.02.04.00.	Periglacial effects	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None		

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
28	01.02.05.00.	Glacial and ice sheet effects	Processes related to the effects of glaciers and ice sheets within the region of a storage site. This is distinct from the effects of large ice masses on global and regional climate. The ice sheet and the permafrost beneath the ice sheet may constitute a barrier to groundwater flow and to heat loss. If the basal transmissivity of the till and bedrock below the ice is low, water pressures may rise to levels equaling the ice pressure inducing the formation of major conduits in the subglacial material. The central parts of the ice sheet are likely to be warm-based and could permit groundwater recharge to take place. Discharge of groundwater is likely to take place close to and beyond the frontal parts of the ice sheet. Excessive recharge at the margin of the ice sheet could provide direct recharge of oxidizing water to considerable depths in conductive fracture zones. If the permeability at and beyond the rim of the ice is low, the water pressures may again build up resulting in hydrofracturing of the ice or the rock mass. As the ice sheet advances, these induced fractures may increase their aperture and depth due to freezing of subglacial melt water.	Erosional processes (abrasion, over deepening) associated with glacial action, especially advancing glaciers and ice sheets, and with glacial melt waters beneath the ice mass and at the margins, can lead to morphological changes in the environment, e.g. U-shaped valleys, hanging valleys, fjords and drumlins. Depositional features associated with glaciers and ice sheets include moraines and eskers. The pressure of the ice mass on the landscape may result in significant hydrogeological effects and even depression of the regional crustal plate.	No glacial effects.		Erosion, deposition and hydrogeological effects having detrimental effect on CO2 geologic storage	Glaciers and ice sheet	Facilities damage and CO2 release (HSE hazard).	Monitor glacier and ice sheet movement. Analyze trends to project future movement.	Proper site characterization and site selection avoiding glaciers and ice sheets.	Permanently close facility and relocate project site.
29	01.02.06.00.	Warm climate effects (See 01.02.02.00.)										
30	01.02.07.00.	Hydrological and hydrogeological response to climate changes (See 01.02.02.00.)										
31	01.02.08.00.	Responses to climate change (See 01.02.01.00.)										
32	01.03.00.00.	Future human actions	Human activities that are relevant to the evolution of the sequestration system.	Human activities may directly interfere with the sequestered fluid resulting in immediate or delayed impacts.								
33	01.03.01.00.	Human influence on climate (See 01.02.01.00.)										

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
28	01.02.05.00.	Glacial and ice sheet effects	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
29	01.02.06.00.	Warm climate effects (See 01.02.02.00.)	0	0	0	0															
30	01.02.07.00.	Hydrological and hydrogeological response to climate changes (See 01.02.02.00.)	0	0	0	0															
31	01.02.08.00.	Responses to climate change (See 01.02.01.00.)	0	0	0	0															
32	01.03.00.00.	Future human actions	0	0	0	0															
33	01.03.01.00.	Human influence on climate (See 01.02.01.00.)	0	0	0	0															

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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34	01.03.02.00.	Motivation and knowledge issues (Future interference with or intrusion into the CO2 reservoir by third parties)	Events and processes related to the degree of knowledge of the existence, location and/or nature of the storage site. Also, reasons for deliberate interference with, or intrusion into, a CO2 storage site after closure with complete or incomplete knowledge. Knowledge of the sequestration site may be regained through post-closure airborne, geophysical or other surface-based non-intrusive investigation of a sequestration site. Such investigations might occur after information of the location of the sequestration system has been lost and therefore excludes monitoring of the disposal system, but includes activities such as prospecting for geological resources. The evidence of the sequestration, such as injection boreholes, may itself prompt investigation. 1. Inadvertent interference with or intrusion into the CO2 reservoir. 2. Deliberate interference with or intrusion into the CO2 reservoir. 3. Malicious intrusion and sabotage.	Some future human actions could directly impact upon performance of the storage system. The following could be distinguished: - inadvertent actions, which are actions taken without knowledge or awareness of the storage site, and - deliberate actions, which are actions that are taken with knowledge of the storage systems existence and location, e.g. deliberate attempts to retrieve any hydrocarbons (e.g., EOR and ECBM) associated with the CO2 - malicious intrusion and sabotage. Intermediate cases, of intrusion with incomplete knowledge, could also occur. Terrorist activities against pipelines and facilities.	Site registered and well defined. Inadvertent intrusion into the CO2 reservoir unlikely. Deliberate intrusion possible if recovery of tight oil or gas is pursued.	Presence of additional tight oil or gas above or below the FWU?	Third-party penetration of the primary caprock.	Inadvertent or deliberate interference with or intrusion into the CO2 reservoir.	CO2 leakage.	Routine inspections and/or monitoring of the site for third-party subsurface activities.	Clearly mark the site with warning signs and register the site as a CO2 storage EOR site with the State.	Routine site inspection and monitoring. Supervising on site drilling activities. Procedures for stopping blowouts or leaks.
35	01.03.03.00.	Social and institutional developments	Events and processes related to changes in social patterns and degree of local government, planning and regulation. Potentially significant social and institutional developments include: 1. Changes in planning controls (zoning) 2. Environmental legislation; 3. Demographic change and urban development; 4. Changes in land use; 5. Loss of archives/records, loss/degradation of societal memory.	Social and institutional developments have the potential to affect motivation and knowledge issues, human use of the surface and sub-surface environments and the type of impacts that may be considered.	Unlikely to be affected by change in zoning, demographic change, change in land use or loss of records. Limited water resources in the area. Limited population. Could be affected by environmental legislation.		Change in zoning laws, land use, environmental legislation, demographics or loss of public records that would have significant detrimental effect on the project.	Radical social and institutional developments	Increased operating costs due to compliance with regulation changes or increased legal costs.	Monitor zoning, environmental legislation, and demographic trends.	Monitor zoning announcements, environmental legislation, and demographic changes. Taking appropriate legal action if necessary to protect the site . Clearly mark the site with warning signs and register the site as a CO2 storage site with the State. Keep backup documentation at off-site locations.	Routine site inspection and/or monitoring. Provide input/feedback to lawmakers.
36	01.03.04.00.	Technological developments	Events and processes related to future developments in human technology and changes in the capacity and motivation to implement technologies. This may include retrograde developments, e.g. loss of capacity to implement a technology. 1. New technology replacing the need for CO2 geologic sequestration 2. New low-cost desalination making saline aquifers more valuable 3. Lack of CO2 capture technology improvements making it too expensive 4. Robotic underground mining making deeper resources more mineable	Of interest are those technologies that might change the capacity of humans to intrude deliberately or otherwise into a storage site, to cause changes that would affect the movement of CO2 and associated contaminants, or that may otherwise affect the performance and safety of the sequestration system. Technological developments are likely but may not be predictable especially at longer times into the future.	Extremely unlikely to be adversely affected by technology development during the life of CO2-EOR operations.		CO2-EOR becoming infeasible due to a new technology development.	Technology development that would significantly expand cheap oil production or alternative fuel supplies.	Delay or shutdown of project. Increased costs. Business interruption (advanced loss of profits). Greater liability exposure.	Keep abreast of new technology developments and analyze impact on project economics	Proactive approach in improving and optimizing CO2-EOR economics.	Take corrective action to address evolving competitive environment.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
34	01.03.02.00.	Motivation and knowledge issues (Future interference with or intrusion into the CO2 reservoir by third parties)	2	2	1	4	None	None	None	\$200/t CO2 released into USDW	\$0.1M to plug and abandon well.	Damage to caprock	0-7 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 @ \$32.32/y per well leak	10% of damage costs	<\$0.5M	None	Registering site with the State and supervise third-party subsurface activities <\$0.1M	<\$0.4M	
35	01.03.03.00.	Social and institutional developments	2	3	1	6	None	None	None	None	None	None	None	Increased operating costs for compliance with new regulations or increased legal costs to protect the project: \$1-10M	None	10% of damage costs	<\$10M	None	Increased operating costs for compliance with new regulations or increased legal costs to protect the project: \$1-10M	None	1
36	01.03.04.00.	Technological developments	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Monitor technology developments impacting cheap oil production or alternative fuel supplies. Part of ongoing costs.	None	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
37	01.03.05.00.	Drilling activities (third-party drilling through caprock)	Events related to any type of drilling activity in the vicinity of the CO2 sequestration system. These may be taken with or without knowledge of the disposal and may include activities such as: 1. Exploratory and/or exploitation drilling for natural resources; 2. Attempted recovery of residual hydrocarbon resources (e.g., EOR, ECBM, shale gas); 3. Drilling for water resources; 4. Drilling for site characterization or research; 5. Drilling for liquid waste or other fluids disposal; 6. Drilling for geothermal resources.	Has the potential to disrupt geological features that provide a barrier to CO2 migration and provide a relatively quick migration pathway to the near-surface.	Third-party drilling through the caprock is extremely unlikely . Operator controls rights to CO2 and oil. Site well characterized with approximately 130 deep wells.		1. Well CO2 blowout 2. Well CO2 leakage 3. Caprock failure	Drilling through caprock	Release of CO2 to upper formations, near surface aquifer, soil or atmosphere.	Routine inspections and/or monitoring of the site for drilling activity.	Clearly mark the site with warning signs and register the site as a CO2 storage site with the State.	Routine site inspection and monitoring. Supervising on site drilling activities. Procedures for stopping blowouts or leaks. Streamline requirements of lease co-use requirements as appropriate. Monitor well permit activity or institutional controls that prohibits any drilling activities in designated areas.
38	01.03.06.00.	Mining and other underground activities	Events related to any type of mining or excavation activity carried out in the vicinity of the storage site. These may be taken with or without knowledge of the site. Mining and other excavation activities include: 1. Resource mining or quarrying; 2. Excavation for industry, storage, disposal or military purposes; 3. Scientific or archaeological investigation; 4. Shaft construction, underground construction and tunneling; 5. Underground nuclear testing; 6. Malicious intrusion, sabotage or war; 7. Underground utilities and pipelines	Mining and other underground activities have the potential to disrupt the geosphere (storage reservoir, surrounding and overlying rock) and near-surface environment. They therefore have the potential to significantly affect the migration and distribution of sequestered CO2.	There are no mines or quarries in the Site area.		Exposure of people to accumulated CO2 in confined underground spaces.	Mining and other underground activities.	CO2 leakage. Asphyxiation.	Routine inspections and/or monitoring of the site for mining and other underground activities.	Proper site characterization and site selection avoiding potential mining, industrial, military, archeological, geothermal, nuclear, waste disposal and transportation areas. Clearly mark the site with warning signs and register the site as a CO2 storage site with the State.	Routine site inspection and monitoring. Supervising on site drilling/excavation activities. Procedures for stopping blowouts or leaks.
39	01.03.07.00.	Human activities in the surface environment	Events and processes related to any type of human activities that may be carried out in the surface environment that can potentially affect the performance of the storage system, or leakage pathways, excepting those FEPs related to water management which are described elsewhere. Examples include: 1. Residential, industrial, and infrastructure construction; 2. Pollution of surface environment and groundwater. 3. Change in groundwater geochemistry not caused by project. 4. Human activities in the surface environment offsite (farming, harvesting, irrigation maintenance) in low areas with limited air circulation.	Human activities in the surface environment have the potential to affect CO2 release processes, should leakage occur. They may also determine the types of impact to be considered or activities that would increase risk exposures.	The Site area is flat and covered with cropland. Groundwater is being consumed for irrigation faster than it can be recharged.		Exposure of people to accumulated CO2 in low areas with limited air circulation. Contamination of groundwater by third parties not related to CO2.	Human activities in the surface environment .	Asphyxiation. Potential public concerns.	Routine inspections and/or monitoring of the site for human surface activities.	Clearly mark the site with warning signs and register the site as a CO2 storage site with the State.	Routine site inspection and monitoring. Supervising on site excavation activities. Procedures for stopping leaks.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
37	01.03.05.00.	Drilling activities (third-party drilling through caprock)	2	2	1	4	None	None	None	\$200/t CO2 released into USDW	\$0.1M to plug and abandon well.	Damage to caprock	0-7 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$0.5M	None	Supervise third-party drilling activities <\$0.1M. Use BOP and packers for well control during deep drilling.	<\$0.4M	1
38	01.03.06.00.	Mining and other underground activities	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
39	01.03.07.00.	Human activities in the surface environment	2	2	1	4	None	None	None	None	Buildup of H2S/CO2 in confined spaces requiring ventilation.	None	0-15 days @ \$15,000/d revenue lost per pattern idled	None	5,000 to 10,000 t CO2 @ \$32.32/t CO2	10% of damage costs	<\$1M	None	Installation of H2S/CO2 monitors, alarms and ventilation in confined spaces <\$300k	<\$0.7M	1

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
40	01.03.08.00.	Water management	Events and processes related to groundwater and surface water management including water extraction, reservoirs, dams, and river management. Water is a valuable resource and water extraction and management schemes provide increased control over its distribution and availability through construction of dams, barrages, canals, pumping stations and pipelines. Groundwater and surface water may be extracted for human domestic use (e.g. drinking water, washing), agricultural uses (e.g. irrigation, animal consumption) and industrial uses. 1. Water extraction 2. Surface water reservoir construction 3. Dam construction 4. River management	Extraction and management of water may affect the movement of CO2 or associated contaminants to and in the surface environment.	The Ogallala Formation is the only USDW aquifer in the area and the main water source for the county. The water level in the Ogallala Formation is estimated to be decreasing at a rate of 0.76 m (2.5 ft) per year due to usage exceeding recharging (Bell 1980). There are approximately ten small playa ponds within the Site area. The southern tip of Deer Lake is also within the Site area. There is a small ephemeral creek drainage on the east edge of the Site that ultimately feeds into Wolf Creek. The Ogallala aquifer is effectively separated from the FWU reservoir by multiple stacked seals and sinks.		Contamination of ground/surface water with CO2/brine and migration of contaminated water.	Water management - extraction combined with CO2/brine leakage.	Extended water contamination.	Monitor CO2/salinity of ground/surface water.	Not applicable.	Monitor and model CO2 plume and brine movement. Monitor CO2 and salinity of ground/surface water. Stop CO2 injection, depressurize the reservoir. Locate and eliminate CO2/brine leaks. Segregate and treat contaminated water.
41	01.03.09.00.	CO2 presence influencing future operations	The presence of injected CO2 may hinder future extractive operations by obscuring seismic traces or by making the drilling process more difficult. Conversely, the presence of CO2 locally, might allow for more economic future enhanced oil recovery operations. This FEP assumes that future technical advances might identify useable resources in the vicinity of previous CO2 injection.	Drilling through a formation filled with supercritical CO2 might cause 'blowouts' or loss of CO2 along the wellbore. A CO2 'bubble' will change the velocity of seismic waves, distorting the 'image' of the underlying formations, and reducing confidence in the understanding of this structure.	Gas and oil have been found in the Cleveland and Marmaton Formations overlying the caprock.	Potential for oil and gas reserves above or below the reservoir?	Well leakage. Distortion of seismic readings. CO2 leakage due to fracking of overlying formations.	CO2 presence underground.	Release of CO2 to upper formations, near surface aquifer, soil or atmosphere.	Monitoring and modeling of CO2 plume.	Clearly mark the site with warning signs and register the site as a CO2 storage site with the State. Maintain blow out protectors and packers Use more than one method of monitoring CO2 plume movement.	Procedures/training for dealing with well blowouts. Seal well. Decrease reservoir pressure.
42	01.03.10.00.	Explosions and crashes (See 16.27.00.)										
43	02.00.00.00.	CO2 STORAGE	This category of FEPs specifies details of the sequestration concept under consideration. It is split into two classes for the pre- and post-closure periods.	This category is divided into two classes: 1. Pre-closure 2. Post-closure								
44	02.01.00.00.	Pre-closure	Details of the sequestration concept, the fluids injected, and factors for the design, construction, operation and decommissioning phases.	The details of the sequestration concept are fundamental to determining which FEPs in other categories need to be considered in a given assessment. Some details of sequestration operations may affect the post-closure performance.								

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
40	01.03.08.00.	Water management	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
41	01.03.09.00.	CO2 presence influencing future operations	2	2	2	8	None	None	None	\$200/t CO2 released into USDW	\$0.1M to plug and abandon well.	Damage to caprock	0-7 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$0.5M	\$0	Supervise third-party drilling activities <\$0.1M	<\$0.4M	1
42	01.03.10.00.	Explosions and crashes (See 16.27.00.)	0	0	0	0															
43	02.00.00.00.	CO2 STORAGE	0	0	0	0															
44	02.01.00.00.	Pre-closure	0	0	0	0															

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45	02.01.01.00.	Storage concept	Features related to the concept of storage, such as whether a closure exists (sequestration in an abandoned oil or gas field or coal seam) or whether isolation of CO2 is dependent upon slow diffusion rates through an extensive open structure (saline aquifer sequestration). 1. Deep saline aquifer CO2 storage - Sealed reservoir - Open reservoir 2. EOR CO2 storage 3. ECBM CO2 storage 4. Temporary CO2 storage and pumping facilities - Above ground - Underground (see Reversibility)	Different processes will be relevant to different storage concepts. For example, the rate of CO2 migration in an open aquifer will be relevant to safety assessment of saline aquifer storage, but less relevant to sequestration in a closed geological structure.	Mature (57 year old) partially depleted oil reservoir with 2.5-years of CO2-EOR. CO2-EOR storage with multiple stacked sinks and seals.		Loss of control of CO2 migration.	Improper storage concept.	Potential CO2 release (HSE hazard). Increased costs and loss of revenue.	Fully characterize and model the site early in the design phase. Continuously monitoring and modeling the site. Periodic evaluation of actual versus expected performance.	Fully characterize and model the site early in the design phase. Select the appropriate injection strategy for the site.	Continuously monitor and model the site. Make adjustments to CO2 injection strategy as necessary.
46	02.01.02.00.	CO2 quantities, injection rate	Features related to the amounts of CO2 injected and their rate of injection into the storage aquifer/reservoir.	High rates of CO2 injection could have adverse effects, such as formation fracturing. For fast injection rates, displacement of oil/water will not be efficient during enhanced oil recovery; instead one will recover CO2; premature breakthrough is undesirable from an economic perspective. Larger volumes of injected CO2 are likely to result in more frequent and more intense induced seismicity unless compensated for with simultaneous production of fluids.	Project uses anthropogenic CO2. Injection rate is tied to optimizing EOR and based on constant pressure rather than constant volume. CO2 injection rate in 2011 was 526 t/d (10 MMSCFD) of purchased anthropogenic CO2 plus 105.2 t/d (2MMSCFD) recycled CO2.	Individual well injection, production and pressure data?	1. CO2 quantities, injection rate exceeding reservoir storage capacity. 2. Over pressuring. 3. Loss of injectivity	Large CO2 quantities. High CO2 injection rate. Mineralization in and near wellbore reduces injectivity. Reservoir conditions are different than expected (e.g., lower injection capacity or permeability; heterogeneities; reservoir compartmentalization).	High injection pressure causing fracture of reservoir/caprock causing CO2 leakage. Displacement of brine leading to resource contamination. Induced seismicity. Lower capacity than planned. Lower injectivity than planned. Inability to accept contracted CO2 from source and related business losses.	Monitoring CO2 injection rate and bottom hole pressure.	Fully characterize and model the site early in the design phase. Conduct injectivity tests and adjust injection plan appropriately. Avoid excess injection pressures. If injection pressure is unacceptably high, cut back on individual well injection rate and use additional injection wells. If injection rate falls, add additional injection wells to handle source stream.	Avoid excess injection pressures. If injection pressure is unacceptably high, cut back on individual well injection rate and use additional injection wells.
47	02.01.03.00.	CO2 composition	The composition and physical state (liquid, supercritical fluid etc.) of injected CO2, with contents of impurities etc. Temperature and pressure of injected fluid are also relevant. During CO2 storage operations, the principal injected gas is CO2 captured and concentrated from human activity sources. However, the gas that is injected into a reservoir may not be 100 % CO2, especially if there is some recycling of gas (in the case of enhanced oil recovery). Impurities can include: H2S, CH4, N2, NOx, SO2 and mercaptans. These may be present either intentionally or because it could be particularly difficult or superfluous to separate them from CO2. The CO2 stream may contain such things as: corrosives, noncondensable gases, oxidants, toxic impurities, flammable/combustible/pyrophoric constituents, odorous constituents, organics or particulates.	The presence of even small amounts of other gases has a strong effect on the phase behavior of CO2-dominated gases. High-pressure equations of state for CO2-dominated gas mixtures are required to take into account changes in critical pressures and temperatures caused by the presence of other gases. Impurities will reduce the critical temperature which, in turn, has effects on interfacial tension. Impurities may affect pore water chemistry (pH and redox conditions, for example) depending on the impurities involved. Special care is needed when considering corrosive gases, such as H2S.	Anthropogenic CO2 currently coming from Arkalon Ethanol Plant in Liberal, KS with backup supply from the Agrium Fertilizer Plant in Borger, TX Ethanol plant CO2 stream: ≥97% CO2, ≤10% ppm H2S, ≤40 ppm S, ≤20% O2, ≤80 ppm N2, ≤30 lbs/MMCF H2O, ≤2,000 ppm organics, ≤120°F (Tracy 2012) Fertilizer plant CO2 stream: ≥95% CO2, ≤10 ppm S (Tracy 2012)		Pipeline/well corrosion leading to leakage or rupture.	CO2 stream composition off spec.	CO2 release (HSE hazard). Downtime for repairs.	Monitoring composition of CO2 stream.	Maintain tight spec on CO2 stream composition Avoid upset operating conditions in CO2 supply dehydration.	Withhold purchase of CO2 until CO2 is on spec. Maintain injection HCPV with recycled CO2 and supplemental water. Select proper materials of construction for pipeline and well components and maintain tight seals and failsafe systems to prevent leakage. Monitor corrosion rate in piping and equipment.

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FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
45	02.01.01.00.	Storage concept	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
46	02.01.02.00.	CO2 quantities, injection rate	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
47	02.01.03.00.	CO2 composition	2	3	1	6	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	0-5 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$3M	None	Cost of water to supplement CO2 injection <\$100k.	Up to \$2.9M	2

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
48	02.01.03.01.	CO2 containing H2S	High concentration of hydrogen sulfide (H2S) in the CO2 makes it a toxic waste which can lead to more stringent permitting and compliance requirements. It also increases the safety risks. The exposure threshold at which H2S is immediately dangerous to life or health, according to the National Institute of Occupational Safety and Health, is 100 ppm, compared to 40,000 ppm for CO2 (IPCC 2005) H2S should be kept below maximum concentration of 10 to 200 ppm in the CO2 for safety reasons.	Sufficient quantities of H2S + H2O in CO2 can cause corrosion or sulfide stress cracking (CCP 2009) and increase safety risks. H2S is strong smelling and requires additional sealing around the wellhead to capture fugitive emissions and minimize odors. On a positive side, H2S in CO2 can decrease minimum miscibility pressure (MMP) for enhanced oil recovery and makes small CO2 leaks easier to detect due to the smell.	H2S content of CO2 from ethanol plant: ≤10mg/L Total S content of CO2 from fertilizer plant: ≤10mg/L (Tracy 2012) FWU reservoir contains pyrite which adds H2S to the produced and recycled gas stream. Operators are required to wear H2S monitoring badges on site.	H2S content in produced and recycled gas stream?	Well/piping corrosion leading to leakage or rupture. Human injury/death.	High H2S content in CO2 stream in presence of water.	CO2 + H2S release. Liabilities.	Monitoring H2S content of purchased CO2 stream and recycled CO2 stream. Monitor H2S around injection wells and gas recycling facilities.	Maintain tight H2S specification on CO2 supply. Avoid contact with water. Avoid upset conditions with CO2 dehydration	Stop injection and fix or resolve leakage. Select proper materials of construction for pipeline, gas recycling facilities and well components and maintain tight seals and failsafe systems to prevent leakage. Monitor for H2S around injection wells and gas recycling facilities. Install alarms.
49	02.01.03.02.	CO2 containing H2O	In order to prevent corrosion in pipeline and wellhead systems, CO2 is normally dehydrated to less than 0.5 g/m ³ (30 lb per MMCF) or less than 20 ppm. (WRI 2008)	If the water vapor is not removed prior to compression, the CO2 product will be very corrosive and the pipeline well head and borehole would have to be built with much more expensive materials than carbon steel.	Water content of CO2 from ethanol plant: ≤30 lbs per MMCF (Tracy 2012).	Water content in recycled CO2? Water content in CO2 from the fertilizer plant?	Pipeline/well corrosion leading to leakage or rupture.	High H2O content in CO2 stream.	CO2 release (HSE hazard).	Monitoring H2O content of purchased CO2 stream and recycled CO2 stream. Monitoring pipeline thickness.	Maintain tight H2O specification on CO2 stream. Avoid upset conditions with CO2 dehydration. Properly eliminate residual water from pipelines.	Monitor for water in CO2 streams and pipeline. Stop injection and fix or resolve leakage. Proper selection of materials of construction for pipeline, gas recycling facilities and well components.
50	02.01.03.03.	CO2 containing O2	EOR and deep saline applications can tolerate some oxygen (air) in the CO2, but ECBM can't. Oxygen in CO2 will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow. The preferred specification is less than 10 ppm oxygen. Oxygen in the 1-2% range or above could impact mineralogical reactions in the reservoir.	Oxygen in CO2 can cause pipeline corrosion, oxidize oil in EOR or oxidize coal and/or methane in ECBM. High oxygen content (5-10%) will not liquefy or dissolve in downhole storage of CO2, and therefore will result in undesirable back pressure and downhole gas pockets. Oxygen can contaminate or degrade CO2 capture and CO2 dehydration sorbents. Oxygen could cause subsurface microbial growth but is not expected to have a significant impact.	Oxygen content of CO2 from the ethanol plant: ≤20 ppm (Tracy 2012).	Oxygen content in purchased and recycled CO2?	Pipeline/well corrosion leading to leakage or rupture. Oxidation of oil in EOR. Oxidation of coal and/or methane in ECBM.	High O2 content in CO2 stream	CO2 leakage. Lower EOR yield.	Monitoring O2 content of purchased CO2 stream and recycled CO2 stream. Monitoring pipeline thickness.	Maintain tight O2 specification on CO2 supply. Avoid upset conditions and ingress in CO2 production system.	Monitor for O2 in CO2. Stop injection and fix or resolve leakage.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Risk Area/FEP		Risk Ranking		Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info		
					Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)			
					Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury														
Index #			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)															
48	02.01.03.01.	CO2 containing H2S	3	4	1	12	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	0-5 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$3M	None	Monitor H2S in CO2 and around injection wells and recycle facilities. Maintain tight seals and failsafe systems <\$300k	Up to \$2.7M	1
49	02.01.03.02.	CO2 containing H2O	3	3	1	9	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	0-5 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$3M	None	Monitor for H2O in CO2. Monitor pipeline corrosion. Monitor pipeline leakage <\$300k	Up to \$2.7M	1
50	02.01.03.03.	CO2 containing O2	2	3	1	6	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	0-5 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$3M	None	Monitor for O2 in CO2. Monitor pipeline corrosion. Monitor pipeline leakage <\$300k	Up to \$2.7M	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
51	02.01.03.04.	CO2 containing N2	Nitrogen in CO2 will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow. Nitrogen is normally kept to less than 4% of volume in CO2.	Nitrogen is undesirable for EOR because it raises the minimum miscibility pressure (MMP) of the fluid and makes the injection process less efficient. Nitrogen is not a problem in ECBM as a minor component of CO2. It will lower the partial pressure of methane and allow more methane to be released and recovered. Minor amounts of nitrogen in CO2 can increase compression and transmission energy consumption and can result in two phase operation. Nitrogen (and argon) will not liquefy or dissolve in downhole storage of CO2, and therefore will result in undesirable back pressure and downhole gas pockets.	Nitrogen content in CO2 from the ethanol plant: ≤80 mg/L (Tracy 2012).	Nitrogen content in recycled CO2? Nitrogen content in CO2 from the fertilizer plant?	Two-phase flow in pipeline. Underground gas pockets detrimental to CO2 storage. Increased MMP detrimental to CO2 EOR.	High nitrogen content in CO2 stream.	Increased power for compression and transport of gas. Decreased CO2 storage capacity. Lower yield in EOR.	Monitoring N2 content of purchased CO2 stream and buildup in recycle CO2 stream	Control nitrogen content in CO2 supply. Avoid upset operating conditions and air ingress in CO2 production.	Monitor for N2 in CO2.
52	02.01.03.07.	CO2 containing CH4 and other hydrocarbons	Total hydrocarbons are normally kept to less than 5% of volume in CO2.	Methane and other hydrocarbons can be a combustion concern in the presence of oxygen. Methane can impact the maximum miscibility pressure (MMP) of CO2 and oil in EOR.	All hydrocarbons in produced gas are recycled with CO2.	Hydrocarbon content of purchased and recycled CO2?	Increased MMP detrimental to CO2 EOR.	High methane and/or other hydrocarbon content in CO2 stream.	Decrease in EOR yield.	Monitoring methane and other hydrocarbon content of purchased CO2 stream and recycled CO2 stream.	Control hydrocarbon content in CO2 stream. Avoid upset operating conditions in CO2 supply and CO2 capture.	Monitor for hydrocarbons in CO2. Select proper materials of construction for pipeline and well components and maintain tight seals and failsafe systems to prevent leakage.
53	02.01.03.08.	CO2 containing mercaptans	Mercaptans are organic compounds containing sulfur. Total sulfur in CO2 is normally kept to less than 35 mg/l. Methyl mercaptan is susceptible to photo oxidation in the atmosphere to hydrogen, sulfur dioxide, dimethyl disulfide and other polysulfide's. Therefore it has a relatively low half-life. Methyl mercaptan exhibits a toxicity similar to, but less than that of hydrogen sulfide. The OSHA permissible exposure level (PEL) is 10 mg/l.	Mercaptans and other malodorous sulfur compounds are strong smelling and toxic and require additional sealing around the wellhead to capture fugitive emissions and minimize odors. The strong odor of mercaptans suggests it is unlikely humans would willingly tolerate concentrations much above the odor threshold for any substantial period of time. However humans in occupational settings may rapidly succumb to extremely high levels of methyl mercaptan.	Total S content of CO2 from fertilizer plant: ≤10mg/L (Tracy 2012)	Mercaptans content of purchased and recycled CO2?	Pipeline/well corrosion leading to leakage or rupture.	High mercaptans content in CO2 stream in presence of H2O.	CO2 + mercaptan release (HSE hazard).	Monitoring total sulfur content of CO2 stream.	Maintain tight sulfur specification on CO2 supply. Avoid contact with water. Avoid upset conditions with CO2 dehydration.	Select proper materials of construction for pipeline, gas recycling facilities and well components and maintain tight seals and failsafe systems to prevent leakage. Monitor for H2S around injection wells and gas recycling facilities. Install alarms.
54	02.01.03.09.	CO2 containing NOx, SOx	Traces of NOx and SOx may occur when CO2 is captured from a post-combustion operations. Although sulfur is present in most fossil fuels, the amount of SOx in the CO2 stream is expected to be very low because deep sulfur removal is required prior to post-combustion CO2 capture to prevent excessive sorbent degradation/loss. Pre-combustion and post-combustion are likely to produce <0.01 vol % SOx and <0.01 vol % NOx in the CO2 stream (IPCC 2005). Oxyfuel combustion may produce 0.5 vol % SOx and 0.01 vol % NOx in the CO2 stream (IPCC 2005).	NOx and SOx may increase corrosion in pipeline and wellhead systems if H2O is present. NOx and SO2 are polluting gases that are generated by the same power plants that generate massive amounts of CO2 and attract emission taxes in certain countries (e.g. Italy). Their injection, in smaller amounts, with CO2 could therefore help the economics of sequestration. Different sets of geochemical reactions are expected when these trace contaminants are present.	NOx and SOx are not present in CO2 purchased from the ethanol and fertilizer plants because the CO2 is recovered in a reducing environment rather than an oxidizing environment.		Pipeline/well corrosion leading to leakage or rupture.	High NOx or SOx content in CO2 stream in presence of H2O.	CO2 release (HSE hazard).	Monitoring NOx, SOx and H2O content of CO2 stream.	Avoid upset operating conditions in CO2 supply capture and dehydration. Avoid NOx, SOx in contact with H2O and metal.	Require CO2 supplier to flare and vent gas until CO2 stream is on spec, Select proper materials of construction for pipeline and well components and maintain tight seals and failsafe systems to prevent leakage.

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FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
51	02.01.03.04.	CO2 containing N2	2	1	1	2	None	None	None	None	None	Decreased EOR performance + increased compression cost.	None	None	None	None	None	None	Monitor for N2 in CO2. Part of ongoing costs.	None	1
52	02.01.03.07.	CO2 containing CH4 and other hydrocarbons	2	1	1	2	None	None	None	None	None	None	None	Decreased EOR performance	None	None	None	None	Monitor for hydrocarbons in CO2. Part of ongoing costs.	None	2
53	02.01.03.08.	CO2 containing mercaptans	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	Monitor H2S in CO2 and around injection wells and recycle facilities. Maintain tight seals and failsafe systems <\$300k	None	1
54	02.01.03.09.	CO2 containing NOx, SOx	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
55	02.01.03.10.	CO2 containing particulates	CO2 is normally scrubbed clean of particulates prior to input into the pipeline. Particulates could carry over due to upset conditions.	Particulate matter can cause valve and instrumentation plugging or erosion of piping.	Particulates not present in purchased CO2.	Particulate content in recycled CO2?	Plugging of valves and/or erosion of piping.	High concentration of particulates in CO2 stream.	Potential CO2 leakage. Higher maintenance costs and downtime.	Monitoring CO2 stream for particulates. Monitoring operating pressures.	Avoid upset operating conditions in CO2 production and recycling.	Filter recycled gas. Monitor pressure drops in gas recycling system.
56	02.01.03.11.	CO2 containing toxic volatile metals (mercury, lead, or cadmium)	Most CO2 capture systems are likely to include mercury capture either as an upstream unit or an integral part of the CO2 capture system. It is not expected that mercury, lead or cadmium ion complexes will follow the CO2 concentrate stream during regeneration, other than by physical entrainment as aerosols, which can be eliminated by an in-line mist eliminator stage.	Presence of toxic volatile metals in the CO2 stream could classify it as a hazardous waste.	Toxic volatile metals not present in the purchased CO2.		Release of toxic metals into the subsurface or surface environment.	High concentration of toxic volatile metals in CO2 stream.	Water, atmosphere, or soil contamination	Monitoring CO2 stream composition.	Install volatile metal capture system upstream of CO2 capture. Avoid upset operating conditions in CO2 capture and dehydration.	Require CO2 supplier to flare and vent gas until CO2 stream is on spec.
57	02.01.03.12.	CO2 containing pyrophoric compounds	Pyrophoric compounds can spontaneously ignite when in contact with air. Iron sulfide is one of the most common pyrophoric compounds associated with the oil and gas industry.	Pyrophoric materials can cause fires or explosions when exposed to air.	Pyrophoric compounds not present in purchased CO2.	H2S content in recycled CO2 and presence of iron sulfide in recycle system?	Spontaneous combustion in the presence of oxygen.	High concentration of pyrophoric compounds in CO2 stream in presence of air or oxygen.	Fire or explosion.	Monitoring CO2 stream composition.	Avoid operating conditions that would generate pyrophoric compounds.	Avoid contact with air or oxygen.
58	02.01.03.13	CO2 containing organic compounds	Trace amounts of organic compounds (derivatives or fragments of amine sorbents) could be carried over into the concentrated CO2 stream.	Organic compounds could feed microbial growth underground which can lead to plugging of wells and/or decreased permeability.	Organics content in CO2 from the ethanol plant: ≤2000 mg/L (Tracy 2012).	Organics content of CO2 from the fertilizer plant? Organics content of recycled CO2?	Enhanced microbial growth underground detrimental to injectivity but could enhance EOR.	High organic compound content in CO2 stream.	Decreased injectivity. Decreased or increased EOR yield.	Monitoring CO2 stream composition.	Maintain tight spec on organic compounds in CO2 stream. Avoid upset operating conditions in CO2 capture and dehydration.	Monitor glycol content in CO2 streams.
59	02.01.03.14	CO2 containing CO or H2	Traces of CO and H2 may occur when CO2 is captured from a pre-combustion operation such as those involving gasification..	CO and H2 are safety risks due to their combustibility in the presence of oxygen and potential for H2 embrittlement of metal components. CO2 combined with CO is more toxic than when CO2 or CO are separate. (Duncan 2012).	CO and H2 contents well below ignition limits.	CO and H2 content in purchased and recycled CO2?	Combustion in the presence of oxygen and an ignition source.	High CO or H2 content in CO2 stream.	Fire or explosion.	Monitoring CO and H2 content in CO2 stream.	Avoid contacting CO2 stream with oxygen.	Monitor CO2 streams for CO and H2. Select proper materials of construction for pipeline and well components and maintain tight seals and failsafe systems to prevent leakage.
60	02.01.04.00.	Microbiological contamination	Microbiological contamination of injected fluid. Contamination of supercritical CO2 is considered unlikely due to its being a very good solvent. However, other fluids (like water) may be injected into the storage site that may be contaminated with microbes. Microbes are known to populate geologic strata to at least 2750 meters below the surface.	The introduction of microbes into the sequestration system may affect both the performance of the storage system and the endpoints considered. Microbial growth can lead to well plugging and/or decreased permeability.	Biocide normally added to injected water. Microbial growth and plugging has not been noted as a historical issue.	Data on microbiological contamination at FWU?	Microbial growth underground detrimental to DSA, EOR or ECBM	Microbiological contamination from CO2 stream or other injection fluids	Decreased injectivity. Decreased EOR or ECBM yield	Monitoring of injection fluids for microbes	Control CO2 supply and fluids to avoid microbial contamination	Use chemical treatment if necessary to control microbial contamination/growth
61	02.01.05.00.	Schedule and planning (See 11.03.00.)										
62	02.01.06.00.	Pre-closure administrative control (See 11.06.00.)										
63	02.01.07.00.	Pre-closure monitoring of storage (See 23.08.00.)										
64	02.01.08.00.	Quality control (See 11.08.00.)										

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Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
55	02.01.03.10.	CO2 containing particulates	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
56	02.01.03.11.	CO2 containing toxic volatile metals (mercury, lead, or cadmium)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
57	02.01.03.12.	CO2 containing pyrophoric compounds	2	2	1	4	None	None	None	None	None	Fire or explosion damage. <\$1M per incident typical.	1-5 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Fire damage <\$1 M	None	Monitor for iron sulfide buildup <\$0.1M	Up to \$0.9 M	1
58	02.01.03.13	CO2 containing organic compounds	2	2	1	4	None	None	None	None	None	1-5 days @ \$15,000/d revenue lost per pattern idled	Increased injection cost due to decreased injectivity. Cost of chlorine for microbial control \$310-340/t Cl (\$0.03/t water treated @ 4 ppm Cl)	None	None	Increased injection cost + down time cost for control of microbial growth. <\$1M	None	Monitor glycol content in CO2 streams. Monitor injectivity.<\$10k	Up to \$0.9 M	1	
59	02.01.03.14	CO2 containing CO or H2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
60	02.01.04.00.	Microbiological contamination	1	1	1	1	None	None	None	None	None	1-5 days @ \$15,000/d revenue lost per pattern idled	Increased injection cost due to decreased injectivity Cost of chlorine for microbial control \$310- 340/t Cl (\$0.03/t water treated @ 4 ppm Cl)	None	None	Cost per plugging event <\$0.1 M	None	Pretreat injected water with chlorine biocide: \$0.03/t water. Part of ongoing costs.	Savings of <\$0.1M/ per plugging event eliminated.		
61	02.01.05.00.	Schedule and planning (See 11.03.00.)	0	0	0	0															
62	02.01.06.00.	Pre-closure administrative control (See 11.06.00.)	0	0	0	0															
63	02.01.07.00.	Pre-closure monitoring of storage (See 23.08.00.)	0	0	0	0															
64	02.01.08.00.	Quality control (See 11.08.00.)	0	0	0	0															

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable, or incredible; Yellow/Orange = Headings or non-risk areas

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
65	02.01.09.00.	Accidents and unplanned events (See 16.01.00.)										
66	02.01.10.00.	Over pressuring	The CO2 injection process is greatly influenced by the target reservoir formation pore pressure. The formation pressure is considered over pressured if it is above the normal hydrostatic pressure for the given depth. Over pressuring may occur at any depth, naturally or artificially. Man-made overpressure may be accidental or deliberate. An example of deliberate overpressure is injecting gaseous CO2 in an aquifer at a faster rate than water can drain from the reservoir zone. In such a case the overpressure is caused by the injection activity (not natural processes). The maximum tolerable overpressure is calculated as a function of the desired storage volume and of a chosen safety factor below the critical fracturing gradient of the top seal rock. Deliberate overpressure induction is a mechanism for storing energy (associated with the pressure) for later extraction. An example of accidental overpressure is the depressurization of a storage reservoir where the CO2 is in liquid form, below but near the critical phase change pressure. The change of phase to gas creates a gas column that could exercise an unforeseen overpressure at the top of the gas column. 1. Deliberate over pressuring 2. Accidental over pressuring 3. Regional-scale over pressuring 4. Local-scale over pressuring 5. Caprock failure due to over pressuring 6. Caprock failure due to dilatant shear 7. Reactivating existing faults/fractures in caprock 8. Low injection pressure limit	Deliberate or accidental over pressuring during the operational phase will affect the initial geosphere conditions for a post-closure assessment. It has the potential to cause fractures in the sealing formation and hence provide migration pathways for the sequestered CO2. Induced fractures in the caprock can be created by over pressuring the reservoir. Fractures could be sealed in time by precipitation of newly formed minerals, but could also be re-opened as a consequence of new changes in stresses during storage of CO2.	CO2 and water are injected at constant pressure (below the fracture pressure) rather than constant volume, and oil, water and CO2 are produced simultaneously with CO2 and water injection. The volume* of purchased CO2 injected in 2012 was 7 times more than the volume* of oil produced. CO2 is injected in multiple wells rather than in a single well. Thus the localized stress associated with injection is dispersed. Reservoir pressure is currently 24.13 MPa (3,500 psi) in the west and far east FWU and 31.72 MPa (4,600 psi) in the middle. The minimum miscible pressure of the oil is 27.58+ MPa (4000+ psi). *Calculated at reservoir P&T.	Historical data on reservoir pressure? Reservoir and caprock fracture pressures? Bottomhole injection pressure? Annual CO2 and water injection rates? Annual oil, water, CO2 and other gas production rates?	Fracturing caprock.	Deliberate over pressuring. Accidental over pressuring.	CO2/brine release (HSE hazard). Induced seismicity and/or uplift.. Fault activation or dilation	Monitoring CO2 injection pressure versus caprock fracture pressure. Alarm system if injection pressure exceeds 90% of fracture pressure.	Determine fracture pressure. Monitor CO2 injection pressure. Keep CO2 injection pressure below 90% of caprock fracture pressure.	Develop procedures for handling an over pressuring situation. Operator training. Monitor pressures in existing nearby wells.
67	02.02.00.00.	Post-closure	Details of post-closure activities associated with sequestration.	Human activities post-closure may affect the likelihood of specific impacts being incurred.								
68	02.02.01.00.	Post-closure administrative control (See 11.07.00.)										
69	02.02.02.00.	Post-closure monitoring of storage (See 23.09.00.)										
70	02.02.03.00.	Records and markers (long-term knowledge retention) (See 11.04.00.)										
71	02.02.04.00.	Reversibility	The degree to which the sequestered CO2 could be deliberately removed, if required. Either as an extreme remedial action, because the CO2 is required as a resource, or because its presence is impeding access to other geological resources.	The degree to which reversibility is considered in the design of a sequestration system may influence its long-term performance, by leaving viable boreholes in-situ after closure, for example.	Recoverable CO2 estimated at 67% of purchased CO2 (based on SACROC).	Recoverable CO2 (% of purchased CO2)?	CO2 leakage from retained wells.	Retaining facilities for potential future extraction of CO2.	CO2 release (HSE hazard).	Routine inspection of retained wells for corrosion. Monitoring retained wells for CO2 leakage.	Proper selection of materials of construction for wells. Proper plugging of wells. Routine inspection of wells for corrosion. Risk management input into reversibility plan. Retain good records and models on CO2 injection.	Prepare procedures for extraction of CO2. Monitor wells for leaks over time from end of CO2-EOR to time of extracting CO2. Rework wells that leak.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Area/FEP		Risk Ranking		Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
							Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury												
65	02.01.09.00.	Accidents and unplanned events (See 16.01.00.)	0	0	0	0															
66	02.01.10.00.	Over pressuring	2	4	2	16	PGA(g) 0.092-0.18 = 1/1000,000 fatality rate. PGA(g) 0.18-0.34 = 1/100,000 fatality rate. PGA(g) 0.34-0.65 = 1/25,000 injury rate. PGA(g) 0.65-1.24 = 1/10,000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate.	PGA(g) 0.092-0.18 = 1/250,000 injury rate. PGA(g) 0.18-0.34 = 1/25,000 injury rate. PGA(g) 0.34-0.65 = 1/2,500 injury rate. PGA(g) 0.65-1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate.	PGA(g) 0.092-0.18 = 3/100,000 injury rate. PGA(g) 0.18-0.34 = 3/10,000 injury rate. PGA(g) 0.34-0.65 = 3/1,000 injury rate. PGA(g) 0.65-1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate.	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Potential class action lawsuit for property damage, loss of property value, reimbursement for earthquake insurance and emotional distress.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	Shutdown of project through court ordered injunctive relief likely if multiple events of PGA(g)>0.1 (>4 magnitude earthquake)	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Shutdown of project: \$45M/y	None	Maintain CO2 injection pressure at <90% of fracture pressure: Maintain balance between volume of fluids injected and produced. Part of on going costs. Continuous passive micro-seismic monitoring Capex: \$2.4M Opex: \$0.2M/y	\$45M/y savings by avoiding over pressuring.	1
67	02.02.00.00.	Post-closure	0	0	0	0															
68	02.02.01.00.	Post-closure administrative control (See 11.07.00.)	0	0	0	0															
69	02.02.02.00.	Post-closure monitoring of storage (See 23.09.00.)	0	0	0	0															
70	02.02.03.00.	Records and markers (long-term knowledge retention) (See 11.04.00.)	0	0	0	0															
71	02.02.04.00.	Reversibility	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil contamination and/or vegetation kill	Covered under natural resource damage	None	None	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	Cost to locate and fix leaky wells: \$0.3M/well + Cost to replace contaminated USDW: \$1M/y per leak + Value of lost CO2: \$0.5M/y per leak	None	Cost to monitor wells for leaks over time and rework risky wells: \$0.1M/well reworked.	Up to \$3M	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
72	02.02.05.00.	Remedial actions	Events and processes related to actions that might be taken following closure of a storage site to remedy problems that, either, are associated with its not performing to the standards required, result from disruption by some natural event or process, or result from inadvertent or deliberate damage by human actions.	The aim of possible future remedial actions will be to modify the performance and safety of the CO2 sequestration system.	Other than the potential for leaky wellbores, there is unlikely to be any disruption of the stored CO2.	Leakage incidents at Farnsworth Unit?	CO2 leakage from wells.	Improper or lack of remedial action.	CO2 release (HSE hazard).	Routine inspection and monitoring of site.	Maintain good records and models of CO2 injection. Use appropriate materials of construction. Routine inspection and monitoring of site.	Prepare procedures for remediating CO2 leakage. Monitor for CO2 leakage. Remediate any CO2 leakage quickly.
73	03.00.00.00.	CO2 PROPERTIES, INTERACTIONS & TRANSPORTATION	This category of FEPs is concerned with those Features, Events and Processes that are relevant to the fate of the sequestered fluid. Carbon dioxides properties can vary greatly between conditions at depth and near surface, and a wide range of physical and chemical reactions can be important. The category is divided into three classes for the properties, interactions and transport of carbon dioxide.	This category is divided into three classes: 1. CO2 properties 2. CO2 interactions 3. CO2 transport These properties will have a significant impact on all of the risk calculations.								
74	03.01.00.00.	CO2 properties	The fundamental physical and chemical properties of carbon dioxide, taking into account impurities. 1. CO2 properties changed by pressure 2. CO2 properties changed by temperature 3. CO2 properties changed by impurities 4. CO2 properties changed by reservoir geochemistry (i.e. CO2 migrating from quartz into calcite cemented sand)	Carbon dioxides properties can vary greatly with pressure, temperature and impurities, and an understanding of these properties is essential before the fate of sequestered fluid can be assessed.								
75	03.01.01.00.	Physical properties of CO2	Physical properties of CO2 including density, viscosity, interfacial tension and thermal conductivity and their dependence on pressure and temperature. 1. CO2 density 2. CO2 viscosity 3. CO2 interfacial tension 4. CO2 thermal conductivity	The physical properties of CO2 determine the way in which it will behave in the environment once injected. Calculation of overpressure at constant rate injection and of injectivity at constant pressure injection are impacted by the choices of properties.	CO2 is supercritical and miscible with oil at reservoir conditions. Reservoir pressure is currently 24.13 MPa (3,500 psi) in the west and far east FWU and 31.72 MPa (4,600 psi) in the middle. The minimum miscible pressure of the oil is 27.58+MPa (4000+ psi). Reservoir temperature is approximately 75.6° C (168° F).	CO2 split into two phases.	CO2 physical properties	Early breakthrough of CO2 Higher CO2 recycling costs. Decreased CO2 storage capacity.	Characterize and model reservoir temperature, pressure, geochemistry and CO2 composition. Analyze impact of any changes on CO2 physical properties.	Take CO2 physical properties into account in modeling.	Take CO2 physical properties into account in modeling.	
76	03.01.02.00.	CO2 phase behavior	FEPs related to the phase behavior (gas, liquid, supercritical fluid) of CO2. The presence of contaminants in the injected CO2 (e.g. N2) and gas and hydrocarbons (e.g., in EOR and ECBM operations) in the reservoir will affect the phase behavior and partition of CO2 between different physical states. CO2 mixing with other fluids and gases, leads to modified flow behavior that is not fully understood (CCP 2009)	CO2 phase behavior is a primary consideration for modeling CO2 migration. CO2 is expected to be in the supercritical state under most sequestration scenarios. CO2 often mixes with high ionic strength brines, modifying fluid behavior.	CO2 phase behavior taken into account in process-level modeling. Reservoir pressure is currently 24.13 MPa (3,500 psi) in the west and far east FWU and 31.72 MPa (4,600 psi) in the middle. The minimum miscible pressure of the oil is 27.58+MPa (4000+ psi). Reservoir temperature is approximately 75.6° C (168° F).	CO2 changing from supercritical to gas-liquid; this will happen at temperatures lower than 32°C (90°F) and pressures less than 7.4 MPa (1100 psia).	CO2 phase behavior	Decreased reservoir storage capacity. Accelerated CO2 migration	Plan for occurrences of low pressures or temperatures Characterize and model reservoir temperature, pressure, geochemistry and CO2 composition. Analyze impact of any changes on CO2 phase behavior.	Proper site selection avoiding shallow reservoirs that would not have sufficient pressure and temperature to keep CO2 supercritical. Take CO2 phase behavior into account in modeling.	Avoid sequestration in reservoirs at depths less than 800 m. Avoid under pressured and low temperature reservoirs. Take CO2 phase behavior into account in modeling.	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
72	02.02.05.00.	Remedial actions	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil contamination and/or vegetation kill	Covered under natural resource damage	None	None	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	Cost to locate and fix leaky wells: \$0.3M/well + Cost to replace contaminated USDW: \$1M/y per leak + Value of lost CO2: \$0.5M/y per leak	None	Cost to monitor wells for leaks over time and rework risky wells: \$0.1M/well reworked.	Up to \$3M	1
73	03.00.00.00.	CO2 PROPERTIES, INTERACTIONS & TRANSPORTATION	0	0	0	0															
74	03.01.00.00.	CO2 properties	0	0	0	0															
75	03.01.01.00.	Physical properties of CO2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
76	03.01.02.00.	CO2 phase behavior	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
77	03.01.03.00.	CO2 solubility and aqueous speciation (See 03.02.13.02. and 03.02.13.06.)	CO2 solubility is the amount of CO2 that can dissolve for given conditions in water. It can vary as a function of temperature, pressure and precise composition of the fluid (e.g. salinity, dissolved species/complexes, presence of hydrocarbons - e.g., EOR and ECBM). Changing temperature and pressure accompanying migration of CO2 can therefore influence CO2 solubility, potentially leading to gas exsolution. CO2 is present in the aqueous phase as: aqueous CO2; carbonic acid (H₂CO₃); bicarbonate (HCO₃⁻); and carbonate (CO₃²⁻). Note that other dissolved ions (Na⁺, Mg⁺⁺, Ca⁺⁺, etc.) are also involved and provide an array of linked, reversible reactions.	CO2 solubility has an impact on the chemical composition of formation fluids, pressure distribution, 'sorption' processes, mineral-fluid reactions and the overall storage capacity of CO2. Dissolved CO2 may migrate in a different manner to 'free' supercritical CO2. CO2 solubility in water and its partition between aqueous, gaseous, and organic phases controls the efficiency of diffusive transport and successive mineral reactions. The aqueous speciation of dissolved CO2 will impact upon the mobility of sequestered CO2 and associated contaminants.	CO2 will dissolve in brine. Acidification of brine may contribute to dissolution of carbonate and feldspar components of the sandstone in the reservoir, increasing permeability. Produced brine will be prone to scaling at decreased pressure and temperature. Dissolution of the calcite cement in the sandstone may provide some pH buffering for the formation fluids.	Produced water chemistry and pH before and after/during CO2 injection?	Mineral dissolution. Mineral precipitation (scaling).	CO2 solubility and aqueous speciation.	Increased permeability and injectivity or weakening of formation structure Scaling and plugging in production wells and recycling system.	Characterize and model reservoir brine properties, CO2 solubility and aqueous speciation. Analyze impact of any changes on chemical composition of fluids, pressure distribution, sorption processes, mineral fluid reactions, and overall storage capacity. Perform well tests frequently to detect any unusual behavior.	Take CO2 solubility and aqueous speciation into account in modeling.	Take CO2 solubility and aqueous speciation into account in modeling. Monitor for scale buildup in production and recycling systems. Treat with acids or scaling inhibitors as appropriate.
78	03.02.00.00.	CO2 interactions	Potential interactions of carbon dioxide with solid, liquid or gaseous media.	A wide range of physical and chemical reactions can be important, and an understanding of these interactions is essential for the assessment of potential impacts.								
79	03.02.01.00.	Effects of pressurization of reservoir on caprock (See 02.01.10.00.)	A storage reservoir will experience enhanced pressure due to injection of CO2. This may exceed original 'natural' pressurization due to hydrocarbon emplacement (EOR or ECBM, for example), or clay mineral transformations during diagenesis.	Over pressuring of the reservoir may involve leakage of CO2 through the caprock due to fracturing or enhanced interactions with CO2.								
80	03.02.02.00.	Effects of pressurization on reservoir fluids	Increased pressurization caused by the injection of supercritical CO2 will affect the behavior of other fluids within the reservoir.	The potential importance of increased pressurization to enhanced oil and gas recovery indicates that it can modify the mobility of other fluids in the receiving reservoir.	Minimum miscible pressure for CO2 and oil at FWU is 27.58+ MPa (4000+psi).	Lateral continuity and sealing of the reservoir?	Displacement of CO2/brine	Effect of pressurization on reservoir fluids	CO2/brine release (HSE hazard). Adverse geochemical impact on freshwater resources.	Monitoring and modeling of CO2/brine movement.	Characterize, model and monitor reservoir CO2/brine movement. Adjust injection strategy as needed to control CO2/brine movement. Extract brine for pressure and plume control.	Use water curtains to keep CO2/brine migration within patterns.
81	03.02.03.00.	Interaction with hydrocarbons (See 0.3.02.03.01 through 03.02.03.15)	In EOR or ECBM sites, for example, hydrocarbons could be mobilized by CO2, by miscible displacement and transported to the near-surface. This is of particular relevance if enhanced oil recovery is an additional aim of the sequestration concept. Kolak and Burruss (2003) demonstrate that polyaromatic hydrocarbons (PAHs) can be mobilized by sequestration in deep coal beds. Sequestered CO2 can also precipitate asphaltenes from crude oil under certain conditions of composition, temperature and pressure. Such precipitation in the vicinity of injection wells can lead to loss of injectivity and even plugging of the wells.									

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
77	03.01.03.00.	CO2 solubility and aqueous speciation (See 03.02.13.02. and 03.02.13.06.)	0	0	0	0															
78	03.02.00.00.	CO2 interactions	0	0	0	0															
79	03.02.01.00.	Effects of pressurization of reservoir on caprock (See 02.01.10.00.)	0	0	0	0															
80	03.02.02.00.	Effects of pressurization on reservoir fluids	2	1	2	4	None	None	None	None	None	None	None	None	None	None	None	None	Use water curtains to keep CO2/brine migration within patterns: \$0.50/t water	None	2
81	03.02.03.00.	Interaction with hydrocarbons (See 0.3.02.03.01 through 03.02.03.15)	0	0	0	0															

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
82	03.02.03.01.	EOR attribute range	Technical screening guidelines for CO2 flooding: recommended (current projects range) Crude oil gravity, °API: >22 (27 to 44) Crude oil viscosity, cp: <10 (0.3 to 6) Crude oil composition: High percent of C ₅ to C ₁₂ Reservoir oil saturation: >40% (15 to 70%) Type of formation: Relatively thin sandstone or carbonate unless dipping Permeability: Not critical if sufficient rates can be applied Depth/temperature: For miscible displacement, depth must be great enough to allow injection pressures greater than the minimum miscible pressure (MMP), which increase with temperature and for heavier oils (Meyer 2007). Oil formation volume factor (ratio reservoir barrels/stock tank barrels): 1.2 to 1.4 Reservoir barrels at subsurface conditions (at depth) Stock tank barrels at surface conditions	Operating outside the EOR attribute range could lead to low oil recovery. This could impact CO2 sequestration economics.	The FWU EOR attributes fall within the range of recommended EOR attributes. Crude oil gravity: 37.5 to 40°API Crude oil viscosity: 1.5 to 2.64 cP Reservoir initial oil saturation: 0.69 Sandstone formation Permeability: (45.2 mD) Porosity: 15.4% Reservoir pressures: 24.13 to 31.72 MPa (3,500 to 4,600 psi). Minimum miscible pressure: 27.58+ MPa (4000+ psi). Reservoir temperature: 75.6°C (168°F) Formation volume factor: 1.192 RB/STB		Low enhanced oil recovery	Operating outside the EOR attribute range	Higher costs. Lower revenues.	Fully characterize EOR reservoir and compare site specific EOR attributes with recommended EOR attributes.	Fully characterize EOR reservoirs for EOR attributes. Select EOR reservoirs that fall within the acceptable range of EOR attributes.	Monitor and model EOR performance. Identify irregularities. Determine root cause for irregularities. Adjust injection and production strategy if necessary.
83	03.02.03.02.	EOR reservoir depth	Recommended depths of CO2 floods of typical Permian Basin oils CO2 Miscible Gravity, °API Depth >40 > 762 m (2500 ft) 32 to 39.3 > 853 m (2800 ft) 28 to 31.9 > 1006 m (3300 ft) 22 to 27.9 > 1219 m (4000 ft) <22 Fails CO2 screening CO2 Immiscible Gravity, °API Depth 13 to 21.9 > 549 m (1800 ft) <13 Fails CO2 screening (Meyer 2007)	Operating conditions outside miscible range could lead to low oil recovery. This could impact CO2 sequestration economics and result in more CO2 recycling.	Reservoir depth of 2,362 m (7750 ft) is sufficient for miscible flooding based on oil with an API gravity of 37.5 to 40° API. Reservoir pressure is currently 24.13 MPa (3,500 psi) in the west and far east FWU and 31.72 MPa (4,600 psi) in the middle. The minimum miscible pressure of the oil is 27.58+MPa (4000+ psi). Reservoir temperature is approximately 75.6° C (168°F).		Insufficient pressure for MMP. Insufficient pressure range between MMP and fracture pressure.	Insufficient EOR reservoir depth.	Low EOR yields. Limited operating range.	Determine reservoir bottom hole pressure, minimum miscibility pressure and fracture pressure.	Fully characterize EOR reservoir. Select reservoir with sufficient depth to allow miscible flow and sufficient pressure operating range between minimum miscibility pressure(MMP) and fracture pressure.	Pressurize reservoir with water injection prior to CO2 injection. (This may not work because elevated pressure will dissipate over time and water injection may redistribute oil and clay).
84	03.02.03.03.	EOR oil recovery	Typical oil recovery by recovery mechanism as a function of Original Oil in Place (OOIP) Primary: 6 to 15% OOIP Secondary: 6 to 30% OOIP Miscible CO2 EOR: 8 to 20% OOIP Remaining: 8 to 35% OOIP (Meyer2007) Miscible CO2 EOR: 7-23% OOIP Immiscible CO2 EOR: 9 to 19% OOIP (Meyer 2007)	Prior oil production and methods could impact CO2 EOR results and amount of CO2 that can be sequestered.	FWU oil recovery: Primary: 12.18 MMSTB (10.15% of OOIP*) Secondary: 27.02 MMSTB (22.52% of OOIP*) Projected tertiary: 7.78 MMSTB (14.12% of OOIP**) *Based on 120 MMSTB OOIP. **All of the projected tertiary oil recovery is from the west FWU area, which had 55.07 STB of OOIP. Projected tertiary recovery based on total FWU is 6.48% of OOIP.	Projected FWU tertiary oil recovery?	Low enhanced oil recovery.	Poor EOR performance.	Lower revenues. Higher operating costs per barrel of oil.	Monitor actual versus projected enhanced oil recovery.	Fully characterize the reservoir for EOR attributes. Select EOR reservoirs that fall within the acceptable range of EOR attributes. Model EOR operation and try to optimize oil recovery through reservoir engineering. Operate above the minimum miscibility pressure.	Monitor EOR actual versus projected performance. Identify the cause of any variation. Adjust CO2 EOR strategy to improve oil recovery if necessary. Optimize WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and utilization and increase oil recovery.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
82	03.02.03.01.	EOR attribute range	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
83	03.02.03.02.	EOR reservoir depth	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
84	03.02.03.03.	EOR oil recovery	3	3	1	9	None	None	None	None	None	None	None	Decrease in EOR performance: \$<5M/y	None	None	10% decrease in oil recovery (<170 bpd): \$<5M/y	None	Cost of WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and utilization and increase oil recovery: \$4M/y	Savings: \$<1M/y	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
85	03.02.03.04.	EOR CO2 utilization	For field scale miscible CO2 EOR floods net (purchased) amount of CO2 required is estimated to be between 60 to 262 m ³ CO2/m ³ oil (2.5 to 11 MCF/STB) of incremental recovery with an average value of 143 to 167 m ³ /m ³ (6 to 7 MCF/STB). For immiscible floods, actual incremental oil recovery has been on the order of 119 to 286 m ³ /m ³ (5 to 12 MCF/STB) (Meyer 2007).	Increased CO2 demand per barrel of oil produced will impact EOR project economics. This could impact CO2 sequestration economics as well.	Projected CO2 EOR performance from 2011 through 2024: Purchased CO2: 1,266 Mm3 (44,713 MMSCF) Oil production: 1.237 Mm3 (7.78 MMSTB) Net EOR CO2 utilization: 1,023 m3 CO2/m3 oil (5,747 SCF/STB)		High CO2 consumption per barrel of oil recovered.	Poor EOR performance.	Increased operating costs. Higher CO2 recycling costs.	Monitor actual versus projected CO2 consumption per barrel of oil.	Fully characterize the reservoir for EOR attributes. Model EOR operation and try to optimize CO2 consumption per barrel of oil through reservoir engineering.	Monitor EOR actual versus projected performance. Identify the cause of any variation. Adjust CO2 EOR strategy to optimize CO2 usage if necessary. Optimize WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and utilization and increase oil recovery.
86	03.02.03.05.	EOR viscosity relations	Because the viscosity of CO2 at reservoir conditions is much lower than that of most oils, viscous instability will limit the sweep efficiency of the displacement and, therefore, oil recovery (Meyer 2007). Crude oil viscosity, cP: <10 (0.3 to 6)	Can lead to adverse hydrodynamic instabilities, such as fingering, which lead to vertical fluid stratification and reduced oil recovery (Meyer 2007). This could also result in more CO2 breakthrough and require more CO2 recycling.	Oil viscosity: 2.64 cP. CO2 viscosity: 0.0655 cP. Brine viscosity: 0.38 cP.		Flow stratification (fingering) in the reservoir. Decreased sweep efficiency and oil recovery.	EOR viscosity relations.	Reduced oil recovery. Higher CO2 recycling costs.	Determine EOR viscosities under reservoir conditions and input into reservoir model.	Fully characterize the reservoir. Model EOR operation and try to optimize CO2 flow through reservoir engineering.	Monitor EOR actual versus projected performance. Identify the cause of any variation. Use polymers or foaming agents to adjust CO2 viscosity.
87	03.02.03.06.	EOR oil reservoir heterogeneity	Oil reservoir rock is extremely heterogeneous, exhibiting zones of high permeability in close proximity to those of low permeability. These permeability differences may be innate, that is caused by differences in pore structure at the time of geological deposition, or a product of fractures, natural or man-made (Meyer 2007)	Can decrease efficiency of oil recovery and CO2 sequestration.	The FWU reservoir has a wide range of permeability (20 to 3220 mD). The reservoir can grade vertically and laterally with great rapidity into finer or coarser sediments. Definite bedding planes are present. The Upper Morrow section of the FWU has five sandstone members. The Buckhaults Sandstone is the most consistently developed and has been the most important producing reservoir in the field.	Heterogeneity of the FWU? FWU Dykstra-Parson coefficient?	Non uniform flow of CO2/oil. Low sweep efficiency and low oil recovery.	EOR reservoir heterogeneity.	Reduced oil recovery. Higher CO2 recycling costs.	Fully characterize reservoir for heterogeneity and input into model.	Fully characterize oil reservoir. Take into account heterogeneity of oil reservoir in EOR modeling and reservoir engineering in order to optimize performance.	Monitor EOR actual versus projected performance. Identify the cause of any variation. Adjust CO2 EOR strategy to optimize CO2 usage if necessary. Optimize WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and utilization and increase oil recovery.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking			Estimated Potential Damage Recovery Costs												Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)					
				Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
85	03.02.03.04.	EOR CO2 utilization	2	2	1	4	None	None	None	None	None	None	None	Increased CO2 purchases: \$1M/y	None	None	A 20% increase in CO2 purchases@ \$32.32/t CO2: \$1M/y	No increase in CO2 purchase: \$0M/y	Cost of WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and utilization: \$4M/y	None	2	
86	03.02.03.05.	EOR viscosity relations	3	3	2	18	None	None	None	None	None	None	None	5% decrease in oil recovery (85 bpd): \$2.2M/y	None	None	5% decrease in oil recovery (85 bpd): \$2.2M/y	No decrease in oil revenue: \$0M/y	Cost of polymers or foaming agents used to adjust CO2 viscosity: \$0.7M/y	Savings: \$1.5M/y	2	
87	03.02.03.06.	EOR oil reservoir heterogeneity	4	3	2	24	None	None	None	None	None	None	None	10% decrease in oil recovery (<170 bpd): <\$5M/y	None	None	10% decrease in oil recovery (<170 bpd): <\$5M/y	None	Cost of WAG, injected water curtains, selective perforation, use of polymer gels or sealants, and CO2 recycling to control CO2 migration and utilization and increase oil recovery: \$4M/y	Savings: <\$1M/y	2	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
88	03.02.03.07.	EOR hydrocarbon precipitation	CO2 injection encourages precipitation of asphaltenes or paraffins.	Precipitation of asphaltenes can clog pores, reducing permeability and affecting fluid flow paths. It can also cause plugging of boreholes.	Information not publicly available. Probability and severity based on experience with other CO2 EOR operations.	Incidents of hydrocarbon precipitation (frequency and magnitude)? Type of hydrocarbon precipitation (asphaltene or paraffin)? Method of mitigating hydrocarbon precipitation?	Plugging of production wells and equipment.	EOR hydrocarbon precipitation.	Well plugging. Decreased injectivity or production. Delays for shutdown and cleanout.	Characterize site for asphalt or paraffin precipitation. Monitor changes in injection pressure.	Use Teflon coated tubulars and components. Monitor for asphaltene or paraffin precipitation. Inject hot water or steam every couple of months. Injection of some hydrocarbon gas along with CO2 can decrease the tendency for asphaltene or paraffin precipitation. Keep operating temperatures sufficiently high. Use staged decompression to avoid overcooling.	Circulate xylene, deasphalted oil, or enzymes to remove asphaltene buildup. Inject hot water or steam to remove paraffin buildup.
89	03.02.03.08.	EOR miscibility	Flooding a reservoir with CO2 can occur either miscibly or immiscibly. Miscible CO2 displacement is only achieved under a specific combination of conditions, which are set by four variables: reservoir temperature, reservoir pressure, injected gas composition, and oil chemical composition (Meyer 2007). Miscible displacement is achieved at pressures above the minimum miscibility pressure (MMP). If the reservoir pressure is below the MMP, CO2 can still be injected, but the efficiency of the enhanced oil recovery process is adversely impacted. Typically this does not occur since, after primary depletion, water flooding operations commence which restore reservoir pressure to values above the MMP(Meyer 2007). 1. Miscible CO2 flooding 2. Immiscible CO2 flooding	Operating under miscible conditions results in significantly higher oil recovery than operating under immiscible conditions. Higher oil recovery improves economics of EOR and CO2 sequestration.	The CO2-EOR is operated under miscible conditions. Reservoir pressure is currently 24.13 MPa (3,500 psi) in the west and far east FWU and 31.72 MPa (4,600 psi) in the middle. The minimum miscible pressure of the oil is 27.58+MPa (4000+ psi). Reservoir temperature is approximately 75.6° C (168°F). Oil density: 802 kg/m3 (281 lb/bbl)* CO2 density: 755 kg/m3 (277 lb/bbl)* *At reservoir conditions.		Decreased enhanced oil recovery.	Immiscible operation.	High operating costs, lower revenues.	Determine minimum miscibility pressure and compare with reservoir conditions.	Fully characterize the reservoir for EOR attributes. Maintain injection pressure above the minimum miscibility pressure (MMP) while not exceeding 90% of the fracture pressure.	Increase reservoir pressure with water injection if needed.
90	03.02.03.09.	EOR early CO2 breakthrough	Early breakthrough of CO2 results in production of significant amounts of CO2 and water along with oil. The alternating water and CO2 gas (WAG) approach is typically applied in CO2 EOR to minimize CO2 use (as it is purchased) and to avoid early breakthrough of CO2.	Breakthrough of CO2 increases operating costs due to the need to recycle the CO2 and can also result in lower oil recovery.	Information not publicly available. Probability and severity based on experience with other CO2 EOR operations.	FWU CO2 breakthrough history?	High CO2 consumption per barrel of oil recovered.	Early CO2 breakthrough.	Increased operating costs. Higher CO2 recycling costs.	Monitor CO2/oil production.	Fully characterize and model the EOR reservoir. Optimize reservoir engineering.	Recycle CO2. Modifying well pattern/spacing. WAG.. Selective perforation. Polymer gels. Foaming surfactants. Sealants.
91	03.02.03.10.	EOR water alternating gas (WAG)	WAG involves alternating injection of water and gas (CO2) to optimize EOR performance. WAG ratios range: 1:1 to 5:1 (0.5:1 to 4:1 per NETL 2009) Slug range: 0.1% to 2% of reservoir hydrocarbon pore volume (NETL 2009) Cumulative CO2 volume: 15 to 30% of hydrocarbon pore volume (NETL 2009)	WAG ratio may have a positive or negative impact on oil recovery.	CELLC started with dry a WAG (1 water to 10 CO2) and is gradually moving toward a wet WAG (2 water to 1 CO2).	FWU WAG sequence and slug size?	Low enhanced oil recovery.	Suboptimal water and CO2 gas (WAG) ratio.	Lower revenues. Higher operating costs per barrel of oil.	Monitor CO2/water/oil production and CO2/water injection.	Optimize WAG ratio through modeling and reservoir engineering	Evaluate WAG actual versus predicted performance based on modeling and make adjustments to the WAG ratio or well pattern/spacing as needed.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking		Estimated Potential Damage Recovery Costs												Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
88	03.02.03.07.	EOR hydrocarbon precipitation	4	3	2	24	None	None	None	None	None	None	None	Clean out cost: \$1M/y	None	None	Clean out cost: \$1M/y	Clean out cost: \$1M/y	Cost of xylene or water/steam removal of hydrocarbon precipitates part of ongoing costs.	None	1
89	03.02.03.08.	EOR miscibility	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
90	03.02.03.09.	EOR early CO2 breakthrough	4	3	1	12	None	None	None	None	None	None	None	Increased CO2 recycling cost: \$1M/y	None	None	10% increase in CO2 recycling: \$1M/y	\$0M/y	Cost of WAG selective perforation and water curtains: \$0.5M/y	Savings: \$0.5M/y	2
91	03.02.03.10.	EOR water alternating gas (WAG)	2	3	1	6	None	None	None	None	None	None	None	Decrease in EOR performance: \$2.2M/y	None	None	5% decrease in oil recovery (85 bpd): \$2.2M/y	\$0M/y	Cost of modifying WAG ratio: Part of ongoing costs.	Savings: \$2.2M/y	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
92	03.02.03.11.	EOR injection water quality / attributes / chemistry	Water quality can impact EOR performance. Injection of low salinity water into an EOR reservoir where the sandstone cement consists of anhydrite could cause the anhydrite to convert to gypsum and its volume would increase up to 1.5 times resulting in decreased pore space and permeability. Injection microbial contaminated water could result in well plugging or decreased permeability due to microbial growth. Injection of corrosive water could result in corrosion of equipment, piping and borehole liners. Injection of hard water could lead to scale buildup.	Lower oil recovery. Corrosion, scale buildup or microbe growth in system equipment. Decreased permeability near injection wells.	Produced water is used for injection water. The produced water has 4,000 mg/L TDS. It is likely filtered and pretreated with corrosion inhibitors and biocides before reinjection. Sufficient produced water is generated to meet injection water demand. Excess produced water is reinjected in a disposal well located on site.	FWU injection water source, quantity, quality and pre-treatment?	Corrosion, scale buildup or microbe buildup.	Quality of EOR injected water.	Increased maintenance cost. Injection disruption.	Monitor injection water quality and injection pressure and flowrate. Use proper materials for tubing, equipment and piping prevent or minimize corrosion, erosion, scaling or microbe buildup.	Treat injection water to prevent corrosion, scaling or microbe buildup.	Monitor injection pressure and flowrate. Filter and treat water with chemicals to prevent corrosion, remove scale and control microbial buildup. Get proper clearance for injection of chemicals if necessary.
93	03.02.03.12.	EOR injection water pressure	Water is denser than CO2. When changing from CO2 injection to water injection, a pressure differential needs to be overcome. To do so, the water supply header operates at a pressure in excess of the CO2 supply header pressure. This allows water to be throttled into the well, its pressure declining to the appropriate value once the CO2 is displaced from the wellbores (Meyer 2007).	System should be designed to provide the proper water injection pressure.	Water injection system already installed and operating successfully. During secondary oil recovery, water was injected at near fracture pressure (estimated at approximately 45.78 MPa or 6,640 psi). Current regulations require injection to be less than 90% of fracture pressure: <41.2 MPa (<6,000 psi).	Confirm FWU injection water pressure?	Unable to inject water at appropriate rate. Hydro fracturing.	Water pressure too low. Water pressure too high.	Poor oil recovery. Caprock damage and potential CO2 release.	Monitor water pressure and flowrate.	Calculate water pressure needed based on modeling. Install sufficient pumping capacity to meet water pressure and flowrate requirements. Injection pressure should not exceed 90% of fracture pressure.	Monitor water pressure and adjust pump pressure as needed. Change frequency or rate.
94	03.02.03.13.	EOR injection and production well pattern and spacing	The pattern is typically a 5-spot (one injection well in center surrounded by four production wells) or inverse 5-spot (one production well in center surrounded by four injection wells), or a variety of other patterns. Typically there are 0.5 to 4.0 production wells for every injection well. The spacing of injection and production wells refers to the area covered by the well pattern. It may be 8, 12, 16 or more hectares (20, 30, 40 or more acres).	Improper injection and production well spacing and pattern can lead to early CO2 breakthrough and/or low oil recovery.	The well spacing at FWU is 80 acres.	Well pattern used at FWU?	Early breakthrough of CO2. Low enhanced oil recovery.	Improper injection and production well pattern and spacing..	Increased operating cost. Increased CO2 recycling costs. Lower revenues.	Monitor and model well performance.	Optimize well spacing and pattern based on modeling and reservoir engineering.	Monitor well performance versus model predictions. Adjust model and well spacing and pattern as needed to optimize oil recovery. Use injection water curtains to control CO2 flow within patterns.
95	03.02.03.14.	EOR intermittent CO2 supply	Intermittent CO2 supply can be caused by interruptions at the source, CO2 capture, compression, pipeline or wellhead.	Intermittent CO2 supply can negatively impact sweep efficiency of EOR and therefore make sequestration less attractive.	CELLC acquired long-term contracts for CO2 from multiple suppliers. CELLC owns the CO2 compression and pipeline facilities. Two pipelines are connected by a spur line across the FWU allowing backup in case one supplier goes down. Future plans call for connection of the Coffeyville and Enid pipelines with the Liberal and Borger pipelines to give additional backup CO2 supply.	Reliability of CO2 supplies?	Interruption in CO2 injection	Intermittent CO2 supply.	Decreased EOR performance.	Maintain daily, weekly and monthly nominations for CO2 supply and demand planning. Monitor CO2 input pressure and flowrate to pipeline.	Maintain daily, weekly and monthly nominations for CO2 supply and demand planning. Maintain CO2 production,	Use water injection as a backup for sweep if necessary. Flood only a limited section depending on the geology.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) injuries: \$1.5M per injury	Minor (recover-able) injuries: \$0.05M per injury												
92	03.02.03.11.	EOR injection water quality / attributes / chemistry	2	2	1	4	None	None	None	None	None	None	None	Clean out costs \$0.3M/y	None	None	Clean out costs \$0.3M/y	Clean out costs \$0.3M/y	Pretreatment of injected water part of ongoing cost.	None	1
93	03.02.03.12.	EOR injection water pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
94	03.02.03.13.	EOR injection and production well pattern and spacing	3	3	2	18	None	None	None	None	None	None	None	Decrease in EOR performance: \$2.2M/y	None	None	5% decrease in oil recovery (85 bpd): \$2.2M/y	\$0M/y	Cost of modifying well spacing + or - \$1.8M	Savings: \$0.4M/y	2
95	03.02.03.14.	EOR intermittent CO2 supply	2	2	1	4	None	None	None	None	None	None	None	Decrease in EOR performance: \$<1M	None	None	20% decrease in oil recovery (340 bpd): \$52.2k/d x 15 days: \$0.4M	10% decrease in oil recovery (170 bpd): \$26k/d x 15 days: \$0.2M	Cost of additional water: \$0.5k/d x 15 days: \$0.01M	Savings: \$0.19M	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
96	03.02.03.15.	EOR flood type	CO2 flooding types include gravity stable and conventional piston flooding. In gravity stable flooding, CO2 is injected in the top of a reservoir (dome) as a supercritical fluid or dense gas and builds an oil bank by mobilizing residual oil downward as the CO2 cap expands. It is important to maintain a relatively uniform front and avoid coning. In the conventional piston flooding, CO2 is injected into an oil reservoir and builds an oil bank by mobilizing residual oil horizontally as the CO2 plume expands. 1. Gravity stable CO2 flooding 2. Piston CO2 flooding	Flooding should be optimized to maintain a relatively uniform front and avoid coning or CO2 early breakthrough (profile control).	Conventional piston-type CO2-EOR flooding.		Low enhanced oil recovery.	Improper EOR flood type.	Higher operating costs and lower revenues.	Fully characterize EOR reservoir and model flood type options to be evaluated.	Fully characterize and model EOR reservoir and select the optimum flood type.	Monitor well performance versus model predictions. Adjust model and flood type, well spacing and pattern as needed to optimize oil recovery.
97	03.02.04.00.	Displacement of saline formation fluids	Injection of CO2 into a geologic formation may result in displacement of saline formation fluids into potable water supplies. Limitations on the pressure in a formation (for seal integrity) will mean that existing fluids are displaced/replaced. Displaced fluids are highly likely to be saline. Because the pressure wave created by injection travels much further than the physical CO2 front, displacement of saline formation fluids can occur at locations outside the CO2 storage area. Inter-connection of aquifer systems may enable saline fluids to enter potable water formations. For significant storage to be possible, it is necessary for a significant amount of the native pore space fluid to be displaced from the reservoir over the injection period. This may occur either by production of fluids (oil or gas), by deliberate production of formation water, and/or by migration of fluids into adjacent formations, surface or oceans.	Displaced saline formation fluids may contaminate near-surface aquifers with subsequent impacts, such as contamination of potable water supplies.	In CO2-EOR operation, displaced formation fluids are likely to be pumped out of the formation with produced oil. Excess produced water can be reinjected in a deep disposal well.	Lateral continuity and sealing of the reservoir?	Contamination of ground/surface water with CO2/brine.	Displacement of brine due to CO2 injection.	Liability for contamination of ground/surface water with CO2/brine. Damage to drinking water and/or irrigation water supply.	Monitor CO2/salinity of ground/surface water.	Fully characterize and model reservoir to understand likely displacement of brine. Take into account brine displacement in reservoir engineering. Extract brine for pressure and plume management.	Monitor near surface aquifers for increased salinity. Determine root cause for any increase in salinity. Use tracers if necessary. Extract brine for pressure and plume management.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
96	03.02.03.15.	EOR flood type	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
97	03.02.04.00.	Displacement of saline formation fluids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
98	03.02.05.00.	Change in mechanical processes and conditions	Features and processes related to the mechanical processes and conditions resulting from the injection of CO2 that affect the rock, boreholes and other engineered features, and the overall mechanical evolution with time. This includes the effects of hydraulic, mechanical and thermal loads imposed on the rock by the injected CO2. Injection of CO2 into a reservoir can cause (directly or indirectly) changes of the geomechanical properties of the reservoir rock. Direct changes can be due to change of reservoir pressure and temperature (PVT system). Indirect changes (of rock properties) might result from geochemical and mineralogical changes after storage of CO2.	Mechanical changes of the reservoir resulting from CO2 injection (such as generation of fractures, reactivation of fractures/faults, changes of bulk elastic properties and effective reservoir) could lead to subsidence/uplift (at surface), induced seismicity, changes in migration pathways, even burst/leakage of the seal. Examples of other relevant processes are: borehole lining collapse; rock volume changes, leading to cracking	There are multiple stacked sinks and seals above the reservoir. CO2 injection is partially compensated for by simultaneous production of fluids.	Existing fractures from previous hydraulic fracturing operations? Natural faults and fractures penetrating the primary seal?	1. Fracturing caprock. 2. Reactivating a fault. 3. Induced seismicity. 4. Uplift/subsidence. 5. Borehole collapse.	Change in mechanical processes and conditions caused by CO2 injection.	1. CO2 release (HSE hazard). 2/3. Seismic damage to surface buildings and infrastructure. 4. Change in surface water flow impacting farmland. 5. Well damage.	Characterize the site and model geomechanics. Determine fracture pressure. Monitor injection pressure. Alarm system if injection pressure exceeds 90% of fracture pressure.	Determine fracture pressure. Operate below 90% of fracture pressure.	Operate below 90% of fracture pressure. Monitor injection pressure Maintain reservoir fluid volume close to original fluid volume. Continuous monitoring of passive micro-seismicity
99	03.02.06.00.	Induced seismicity	Injection of CO2 may cause and trigger seismic events and earthquake hazards through processes such as reducing friction at existing faults. This may occur both in seismically active areas and in areas characterized by a low background seismicity (reactivation of ancient fault planes, changes in the orientation, fluid-pockets occurrence). This FEP includes micro seismicity. Induced macro-seismicity activity is a function of existing regional and local stresses, of porosity structure, and of imposed injection stresses. Induced macro-seismicity is less likely if the injection formation is dominated by intergranular and not fracture porosity. The problem of seismicity might be more serious when CO2 is injected into a reservoir in tectonically active regions with high density of active faults (Damen 2006). 1. Induced macro-seismicity 2. Induced micro-seismicity 3. Seismicity tied to activation of an existing structure (fault/fracture) 4. Seismicity tied to creation of a new structure (fault/fracture)	Seismicity can introduce sudden physical changes to the sequestration system and may expose any local population to earthquake hazards. Potential effects of reservoir-induced seismicity (RIS) are damage to the caprock and wells , which might cause CO2 leakage , and damage to building and infrastructure (Damen 2006). In a reservoir that is under high tectonic stresses, any significant reduction of pressure (pressure acting between individual rock particles) may trigger faults. This may lead to uplifting or down-faulting of the surface (Damen 2006).	CO2 injection is partially compensated for by simultaneous production of fluids from the reservoir. CO2 injection pressures are maintained at <90% of fracture pressure. CO2 is injected through multiple wells, which allows more dispersion of induced stress than a single well.	Any reports of induced seismicity in the area?	Induced earthquake >4 magnitude.	Induced seismicity.	Public concern and potential class action lawsuits.	Characterize the site and model geomechanics. Determine fracture pressure. Monitor injection pressure. Alarm system if injection pressure exceeds 90% of fracture pressure. Maintain reservoir fluid volume near original fluid volume.	Determine fracture pressure. Operate below 90% of fracture pressure. Maintain reservoir fluid volume close to original volume.	Operate below 90% of fracture pressure. Monitor injection pressure and passive micro-seismicity.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking					Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Human health & safety	Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)								
															Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury					
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)																
98	03.02.05.00.	Change in mechanical processes and conditions	1	1	1	1	PGA(g) 0.092-0.18 = 1/1000,000 fatality rate. PGA(g) 0.18-0.34 = 1/100,000 fatality rate. PGA(g) 0.34-0.65 = 1/10,000 fatality rate. PGA(g) 0.65-1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate.	PGA(g) 0.092-0.18 = 1/250,000 injury rate. PGA(g) 0.18-0.34 = 1/25,000 injury rate. PGA(g) 0.34-0.65 = 1/2,500 injury rate. PGA(g) 0.65-1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate.	PGA(g) 0.092-0.18 = 3/100,000 injury rate. PGA(g) 0.18-0.34 = 3/10,000 injury rate. PGA(g) 0.34-0.65 = 3/1,000 injury rate. PGA(g) 0.65-1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate.	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Potential class action lawsuit for property damage, loss of property value, reimbursement for earthquake insurance and emotional distress.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	Shutdown of project through court ordered injunctive relief likely if multiple events of PGA(g)>0.1 (>4 magnitude earthquake)	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	None	None	Cost to maintain CO2 injection pressure below 90% of fracture pressure and maintain reservoir fluid volume close to original fluid volume: Part of ongoing costs.	None	2	
99	03.02.06.00.	Induced seismicity	2	2	1	4	PGA(g) 0.092-0.18 = 1/1000,000 fatality rate. PGA(g) 0.18-0.34 = 1/100,000 fatality rate. PGA(g) 0.34-0.65 = 1/10,000 fatality rate. PGA(g) 0.65-1.24 = 1/1000 fatality rate. PGA(g) >1.24 = 1/100 to 1/5 fatality rate.	PGA(g) 0.092-0.18 = 1/250,000 injury rate. PGA(g) 0.18-0.34 = 1/25,000 injury rate. PGA(g) 0.34-0.65 = 1/2,500 injury rate. PGA(g) 0.65-1.24 = 1/250 injury rate. PGA(g) >1.24 = 1/25 to 2/5 injury rate.	PGA(g) 0.092-0.18 = 3/100,000 injury rate. PGA(g) 0.18-0.34 = 3/10,000 injury rate. PGA(g) 0.34-0.65 = 3/1,000 injury rate. PGA(g) 0.65-1.24 = 3/100 injury rate. PGA(g) >1.24 = 3/10 to 2/5 injury rate.	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) 0.65-1.24 = 45% of total. PGA(g) >1.24 = 80% to 100% of total. Potential class action lawsuit for property damage, loss of property value, reimbursement for earthquake insurance and emotional distress.	PGA(g) 0.092-0.18 = 0.5% of total. PGA(g) 0.18-0.34 = 5% of total. PGA(g) 0.34-0.65 = 20% of total. PGA(g) >1.24 = 80% to 100% of total. PGA(g) >0.5 = damage to caprock, wells and pipeline.	Shutdown of project through court ordered injunctive relief likely if multiple events of PGA(g)>0.1 (>4 magnitude earthquake)	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$1M for legal and public outreach costs to avoid shutdown.	None	Cost to maintain CO2 injection pressure below 90% of fracture pressure and maintain reservoir fluid volume close to original fluid volume: Part of ongoing costs.	None	2	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
100	03.02.07.00.	Subsidence or uplift	Injecting the CO2 may cause acidification of formation water, leading to mineral dissolution and subsidence. This is of particular relevance to shallow storage sites. Chemical compaction or dissolution of the reservoir rock will particularly be a matter of concern in carbonate rocks with high porosity (Damen 2006). Injection of large quantities of CO2 into a confined aquifer may increase pore pressure and lift the overlying rocks upwards. It is not envisaged that uplift will take place in a CO2 reservoir as long as the maximum storage pressure is kept below the geostatic pressure (Damen 2006). 1. Subsidence 2. Uplift	Deformation may affect geological processes and may result in impacts of concern at the surface. Dissolution of the reservoir rock (chemical compaction) can lead to the reservoir caving in under the weight of the overburden formation (Damen 2006) Vertical subsidence or uplift above large reservoirs could affect lake levels and shift streams in lowland areas with low topographic relief. Subsidence or uplift could damage buildings or farmland.	There have been no indications of subsidence or uplift in the area. CO2 and water injection are partially compensated for by simultaneous oil, water and CO2 production.	Any reported incidents of subsidence or uplift?	1. Caprock collapse. 2. Significant change in surface elevation under buildings and infrastructure. 3. Significant change in lake level. 4. Significant change in stream/river pathway. 5. Infrastructure damage.	Subsidence due to mineral dissolution. Uplift due to increased pore pressure.	CO2 release (HSE hazard). Liability for damage to surface buildings and infrastructure. Liability for damage to farmland. Change in land use.	Characterize the site and model geomechanics and geochemistry. Determine fracture pressure. Monitor injection pressure. Alarm system if injection pressure exceeds 90% of fracture pressure. LIDAR surveys.	Select a deep rather than shallow reservoir. Characterize and model the geomechanical and geochemical reactions in the reservoir and caprock. Operate below 90% of fracture pressure. Volume increase from CO2 injection compensated for by water/oil production in EOR, coal seam dewatering in ECBM and brine extraction in DSA.	Monitor any mineral dissolution in critical formations Operate below 90% of fracture pressure. Monitor injection pressure, LIDAR and passive micro-seismicity. Mitigate uplift by extracting water from the reservoir.
101	03.02.08.00.	Thermal effects on the injection point	Temperature of the injected fluid could result in geological modification of the region around the point of injection due to thermal gradients. 1. Cooling due to CO2 changing from supercritical to gas phase. 2. Injected CO2 may be 25 to 50°C cooler than the in-situ temperature.	These thermal effects could influence the mobility of the injected CO2 and impurities.	Reservoir conditions are significantly above CO2 supercritical pressure and temperature.	CO2 bottomhole injection temperature and pressure?	Scale buildup. Induced thermal fractures in reservoir and caprock; caprock failure.	Thermal effects on the injection point. Propagation of thermal stress fractures through reservoir and caprock.	Decreased porosity, permeability, injectivity; CO2 release (HSE hazard).	Monitor bottom hole temperatures and pressure.	Select site with reservoir pressure above the CO2 supercritical pressure.	Adjust CO2 injection temperature upward to partially compensate for any cooling effect.
102	03.02.09.00.	Reservoir water chemistry	Water phase geochemistry of sequestered CO2. This includes the solubility trapping of CO2 in water (H2O) to form carbonic acid (H2CO3). Subsequent ionic trapping of carbonic acid with hydroxide ions (OH-) forms bicarbonate ions (HCO3-), which can react in turn with further hydroxide ions to form carbonate (CO3). 1. Formation of carbonic acid (H2CO3) 2. Formation of bicarbonate ions (HCO3-) 3. Formation of carbonate (CO3)	Modification of the water phase geochemistry can disturb the equilibrium between the water and solid phase of the reservoir and result in further geochemical (for example, solid phase geochemistry) and physical changes with resulting implications for the long-term performance of the sequestration system.	Any acidification of the brine from CO2 dissolution may cause dissolution of carbonate and feldspar minerals in the sandstone. The dissolved minerals may precipitate out in the produced water system at lower pressure and temperature. Produced water currently has 4,000 total dissolved solids.	Produced water chemistry and pH before and after/during CO2 injection?	Scale buildup. Salt precipitation. Conversion of anhydrite to gypsum in rock formation.	Change in water chemistry.	Decreased or increased porosity, permeability, injectivity.	Monitor bottom hole water chemistry. Monitor injection pressure.	Take geochemistry into consideration in site characterization, modeling and reservoir engineering.	Monitor produced water chemistry. Monitor injection water chemistry. Adjust injection water chemistry to control scaling or salt precipitation. Use of Teflon coating to control scale buildup.
103	03.02.10.00.	Interaction of CO2 with chemical barriers	Chemical barriers (pH, Eh-pH, ion exchange) may exist in aquifers to retard the migration of CO2 from depth. The precipitation of CO2 bearing solids may result from such interactions. 1. pH barrier 2. Eh-pH barrier 3. Ion exchange barrier	Such barriers will affect the rate of migration of CO2 from depth.	The CO2 is held in place by an impermeable shale barrier rather than chemical barriers. Carbonate formations located above the reservoir and caprock may neutralize any acidic water that migrates through the caprock.	Primary caprock and lateral seal characteristics (formation, thickness, continuity, lithology, permeability)?	Migration of CO2 past chemical barrier.	Interaction of CO2 with chemical barriers.	CO2 release (HSE hazard).	Include geochemistry in site characterization and modeling. Monitor CO2 migration and interaction with chemical barrier.	Include geochemistry in site characterization and modeling. Monitor CO2 migration and interaction with chemical barrier.	Include geochemistry in site characterization and modeling. Monitor CO2 migration and interaction with chemical barrier. Consider possible chemical treatment. Obtain proper approval for use of chemicals if necessary.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)						
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																	
Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)																	
100	03.02.07.00.	Subsidence or uplift	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
101	03.02.08.00.	Thermal effects on the injection point	2	1	3	6	None	None	None	None	None	None	None	None	None	None	None	None	Adjust CO2 injection temperature to compensate for cooling effect in the reservoir: Part of ongoing costs.	None	2	
102	03.02.09.00.	Reservoir water chemistry	3	2	2	12	None	None	None	None	None	None	None	Clean out cost: \$0.3M/y	None	None	Clean out cost: \$0.3M/y	Clean out costs \$0.3M/y	Part of ongoing costs	None	2	
103	03.02.10.00.	Interaction of CO2 with chemical barriers	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
104	03.02.11.00.	Sorption and desorption of CO2 (CO2 interaction with coal seams)	The sorption and desorption of CO2 on geological materials. Sorption onto coal and the displacement of methane (CH4) is the primary mechanism behind the enhanced coal bed methane recovery (ECBM) method for geological CO2 sequestration.	The rate of sorption and desorption of CO2 on geological materials affects its mobility and therefore the performance of the storage system.	Not applicable to this site.	Presence of coal in formations overlying the reservoir (depth, thickness, continuity, type/rank)?	1. Limited CO2 sorption and methane release on coal. 2. Desorption of CO2	ECBM sorption of CO2 on coal and release of methane.	Limited CO2 storage. Low ECBM yield. Higher costs. Lower revenues.	Monitor CO2 injection and CH4+CO2+H2O production.	Characterize and model coal seam for CO2 sorption. Select sites that have appropriate coal quality and methane content. Design well pattern and spacing to allow sufficient time for coal to sorb on to the coal and methane to be released. Avoid decreasing pressure in the coal seam to the point that CO2 desorbs.	Monitor and model CO2 injection and methane + CO2 = water production. Compare actual performance versus model projections. Identify root cause of any deviation from projections. Take corrective action as needed.
105	03.02.11.01.	ECBM sorption of CO2 on coal and release of methane	Based on the Langmuir isotherm, CO2 has higher affinity to coal and therefore displaces CH4 adsorbed on the coal. 2-3 moles CO2 adsorbed on coal for every mole of CH4 desorbed. CO2 adsorption: up to 41 Nm ³ /tonne coal (1400 scf/st coal) CH4 release: up to 13-15 Nm ³ /tonne coal (450-500 scf/st coal) at 22°C 72°F and 0-7 MPa (0-1000 psi)). The CO2/CH4 sorption ratio of coal varies depending on the rank of coal. Typical CO2/CH4 sorption ratios for various coals are as follows: Low volatile bituminous: 1.1 Medium volatile bituminous: 1.5:1 High volatile A bituminous: 3:1 High volatile bituminous: 6:1 Sub bituminous: 10:1 (Reeves 2003)	Adsorption of CO2 on coal can have a positive effect on CO2 sequestration.	Not applicable to this site		Limited CO2 sorption and methane release.	ECBM sorption of CO2 on coal and release of methane	Limited CO2 storage. Low ECBM yield. Higher costs. Lower revenues.	Monitor CO2 injection and CH4+CO2+H2O production.	Characterize and model coal seam for CO2 sorption. Select sites that have appropriate coal quality and methane content. Design well pattern and spacing to allow sufficient time for coal to sorb on to the coal and methane to be released.	Monitor and model CO2 injection and methane + CO2 = water production. Compare actual performance versus model projections. Identify root cause of any deviation from projections. Take corrective action as needed.
106	03.02.11.02.	ECBM desorption of CO2 from coal or other solids	CO2 desorption can occur with decreased pressure.	Release of CO2 could lead to leakage.	Not applicable to this site		Release of CO2	ECBM desorption of CO2 from coal or other solids	Decreased CO2 storage capacity Migration of CO2	Monitor CO2 injection and CH4+CO2+H2O production.	Avoid decreasing pressure in the coal seam to the point that CO2 desorbs.	Increase pressure in coal seam with nitrogen injection.
107	03.02.11.03.	ECBM coal swelling	The chemical reactions and physical processes that occur during CO2 injection into coal seams and their impact on the integrity of the coal seams are not well understood. One of the reactions is swelling of the coal matrix when injecting CO2. (Damen 2006) When CO2 is injected into a coal seam, the coal matrix swells causing the cleat permeability to decrease.	Coal seam swelling may cause a reduction in permeability and injectivity. Swelling might also induce stresses on the overlying and underlying rock strata in non ideal coal seams (thin, low permeability and highly faulted), that could cause faulting and possible migration pathways out of the coal seam (Damen 2006).	Not applicable to this site		Fracturing of caprock. Decrease in CO2 injectivity.	ECBM coal swelling.	CO2 and/or CH4 release (HSE hazard). Higher operating costs.	Monitoring CO2 injectivity.	Characterize and model coal seam for coal swelling. Select sites that have appropriate coal quality and methane content. Design well pattern and spacing to allow sufficient time for coal to sorb on to the coal and methane to be released.	If coal swelling occurs with CO2 injection, it can be countered somewhat by dewatering. Different completion methods could be attempted.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
104	03.02.11.00.	Sorption and desorption of CO2 (CO2 interaction with coal seams)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
105	03.02.11.01.	ECBM sorption of CO2 on coal and release of methane	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
106	03.02.11.02.	ECBM desorption of CO2 from coal or other solids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
107	03.02.11.03.	ECBM coal swelling	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
108	03.02.11.04.	ECBM release of polyaromatic hydrocarbons (PAH) from coal seams	Polyaromatic hydrocarbons are chemical compounds that consist of aromatic rings. They are found in oil, coal and tar deposits. They tend to be released as a by-product of coal fires.	Toxicity issues and operation issues with decreased permeability.	Not applicable to this site		Contamination of groundwater with PAH.	ECBM release of polyaromatic hydrocarbons (PAH) from coal seams.	HSE hazard of contaminated water.	Establish base line study of PAH in local groundwater. Monitor groundwater for increases in PAH.	Characterize and model the interaction of CO ₂ , coal and polyaromatic hydrocarbons.	Monitor groundwater for increases in PAH. Determine toxicity level and root cause. Take remedial action necessary to eliminate PAH (i.e., in situ treatment using vegetation; stabilization with humic acid; or pump and treat methods).
109	03.02.11.05.	ECBM coal seam dewatering	As a coal seam is dewatered, its pressure decreases. Cleat permeability increases. Coal matrix shrinks, opening up cleat fractures. Assume that the coal cleats are originally 100% saturated with water. Recommendation for ECBM: Coal seams with low water saturation (Bachu 2008)	Coal dewatering produces large quantities of water that must be properly treated and disposed of. In some cases, this may be a limiting factor in obtaining environmental permits and take a significant toll on project economics.	Not applicable to this site		Inability to treat or dispose of ECBM produced water.	ECBM coal seam dewatering.	Project delay or shutdown. Business interruption. Advanced loss of profits.	Monitor permitting and compliance process for water disposal.	Obtain permit for water disposal to handle all disposal needs. Treat produced water if necessary to meet disposal requirements.	Have backup disposal option in place.
110	03.02.11.06.	ECBM original gas in place	Original gas (methane) in place (OGIP) depends on the rank of coal. Free gas occurs within natural fractures. Dissolved gas occurs in water within the natural fractures. Adsorbed gas occurs within the coal matrix. Adsorbed gas typically represents over 95% of total. (Mansourine 2003) Coal bed methane may be formed by bacteria (biogenic methane) at depths less than 300 meters, or formed by heat and pressure transformation of coal organic matter (thermogenic methane) at greater depths in higher-rank coals. Thermogenic methane frequently contains trace amounts of H ₂ O, CO ₂ , N ₂ and H ₂ S. Existing gas in place = original gas in place - previous gas production. Recommendation for ECBM: Methane-saturated seams should be preferred from a methane production perspective. From a storage perspective, under saturated coal seams can still be effective (Bachu 2008).	OGIP impacts the amount of methane available for ECBM recovery.	Not applicable to this site		Low methane yield.	ECBM original gas in place.	Higher costs. Lower revenues.	Characterize and model coal seam for original gas in place. Calculate existing gas in place.	Characterize and model coal seam for original gas in place. Calculate existing gas in place. Select site that has sufficient gas in place.	Compare actual with projected methane recovery. Identify any deviation from projected. Determine root cause and make appropriate adjustments.
111	03.02.11.07.	Previous working of the coal seam	Primary CBM takes out 20-60% of the original gas in place (OGIP). CO ₂ ECBM can recover an additional 30%. Up to 80-90% of OGIP can be recovered with primary CBM plus CO ₂ ECBM. Production stages of a coal bed methane well 1. Dewatering stage 2. Stable production stage 3. Decline stage (Mansourine 2003) 4. CO ₂ injection stage	Wells selected for ECBM CO ₂ injection should be near depletion to optimize CBM and ECBM performance.	Not applicable to this site		Low methane yield.	Previous working of coal seam	Higher costs. Lower revenues.	Include previous working of coal seam in characterizing and modeling the ECBM coal seam if documentation exists.	Include previous working of coal seam in characterizing and modeling the ECBM coal seam if documentation exists. Select wells for ECBM CO ₂ injection that are near depletion to optimize CBM and ECBM performance.	Compare actual with projected methane recovery. Identify any deviation from projected. Determine root cause and make appropriate adjustments.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
108	03.02.11.04.	ECBM release of polyaromatic hydrocarbons (PAH) from coal seams	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
109	03.02.11.05.	ECBM coal seam dewatering	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
110	03.02.11.06.	ECBM original gas in place	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
111	03.02.11.07.	Previous working of the coal seam	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
112	03.02.11.08.	ECBM coal seam pressure	Coal seam hydrostatic pressure increases with depth. CO2, N2 and water injection increase hydrostatic pressure. Dewatering and methane production decrease hydrostatic pressure. CO2, CH4, N2 and H2S adsorption capacity of coal increases with coal seam hydrostatic pressure.	Gas adsorption is pressure dependent. The pressure profile in the reservoir must be understood and the injection operation designed appropriately. Gas adsorption of coal increases with pressure. Gas desorption of coal increases as pressure decreases. As reservoir pressure decreases, the rate at which CH4 desorbs increases. However, CO2 adsorption decreases with decreased pressure. At supercritical pressures, CO2 adsorption may be replaced by absorption as CO2 diffuses in coal. CO2 is a coal plasticizer, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure. The transition temperature may drop from ~400°C at 3MPa to <30°C at 5.5 MPa. Coal plasticization, or softening, destroys any permeability that would allow CO2 injection. (Bachu 2006).	Not applicable to this site		Low CH4 desorption. Low CO2 sorption.	ECBM coal seam pressure.	Higher costs. Lower revenues.	Take pressure into account in characterizing and modeling ECBM coal seams. Monitor CO2 injection, bottom hole pressure, and CH4+CO2+H2O production. Compare actual with projected (modeled) results.	Take coal seam pressure into account in characterizing and modeling ECBM coal seams. Inject CO2 at low pressure to increase CH4 recovery. Inject CO2 at high pressure to increase CO2 storage. Avoid exceeding 90% of fracture pressure.	Monitor CO2 injection, bottom hole pressure, and CH4+CO2+H2O production. Compare actual with projected (modeled) results. Adjust coal seam pressure (by injecting or extracting water) to optimize CH4 recovery or CO2 storage. Avoid exceeding 90% of fracture pressure.
113	03.02.11.09.	ECBM coal seam temperature	Coal seam temperature increases with depth. CO2 adsorption is an exothermic reaction and will provide a heat source, at least during the active injection phase of the project. As temperature of the coal seam increases, the adsorption of CO2 decreases.	Impacts CO2 adsorption and methane release.	Not applicable to this site		Low CH4 desorption. Low CO2 sorption.	ECBM coal seam temperature.	Higher costs. Lower revenues.	Take coal seam temperature into account in characterizing and modeling ECBM coal seams. Monitor CO2 injection bottom hole temperature and CH4+CO2+H2O production. Compare actual with projected (modeled) results.	Take coal seam temperature into account in characterizing and modeling ECBM coal seams. Inject CO2 at high temperature to increase CH4 recovery. Inject CO2 at low temperature to increase CO2 storage.	Monitor CO2 injection bottom hole temperature and CH4+CO2+H2O production. Compare actual with projected (modeled) results. Adjust coal seam pressure to optimize CH4 recovery or CO2 storage. Avoid exceeding 90% of fracture pressure.
114	03.02.11.10.	ECBM coal seam fluid pH	The pH of aqueous solutions affects the surface of material it is in contact with. In the case of coal, at a high pH value, the carbonaceous surface assumes a net negative charge. At a low pH, the carbonaceous surface assumes a net positive charge. Theoretically, a pH of 9 would favor and a pH of 2 would disfavor the aqueous capture of CO2.	pH of water in the coal seam may impact CO2 adsorption.	Not applicable to this site		Low CH4 desorption. Low CO2 sorption.	ECBM coal seam fluid pH.	Higher costs. Lower revenues.	Determine optimum pH for CO2 adsorption and/or CH4 desorption. Include pH in characterizing and modeling of ECBM coal seam. If possible, try to operate near the optimum pH range.	Determine optimum pH for CO2 adsorption and/or CH4 desorption. Include pH in characterizing and modeling of ECBM coal seam. If possible, try to operate near the optimum pH range.	Monitor pH of coal seam fluids. Make adjustments to pH through CO2 and/or water injection.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
112	03.02.11.08.	ECBM coal seam pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
113	03.02.11.09.	ECBM coal seam temperature	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
114	03.02.11.10.	ECBM coal seam fluid pH	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
115	03.02.11.12.	ECBM injection and production well pattern and spacing	The most common drilling pattern is a 5-spot (injection well in the center and production wells in the corners or inverse 5-spot (injection in the corners and production in the center). Drilling on 16, 65 or 233 hectare (40, 160 or 640 acre) spacing. When injecting CO2, it is important to allow sufficient time for displacement of the methane (locating production wells far away enough from the injection wells).	Impacts the sweep efficiency of ECBM and the effective sorption of CO2.	Not applicable to this site		Low CH4 desorption. Low CO2 sorption.	ECBM injection and production well pattern and spacing	Higher costs. Lower revenues.	Monitor and model well performance	Optimize well spacing and pattern based on modeling and reservoir engineering.	Monitor well performance versus model predictions. Adjust model and well spacing and pattern as needed to optimize CH4 recovery.
116	03.02.11.13.	ECBM injection strategy	Constant injection rate or variable injection rate "huff and puff" (alternating starting and stopping CO2 injection over time).	Impacts the sweep efficiency of ECBM and the effective sorption of CO2.	Not applicable to this site		Low CH4 desorption. Low CO2 sorption.	Improper ECBM injection strategy.	Higher costs. Lower revenues.	Monitor and model well performance. Compare actual with projected performance.	Fully characterize and model the ECBM coal seam . Select the optimum injection strategy.	Monitor and model well performance. Compare actual with projected performance. Modify injection strategy if necessary.
117	03.02.11.14.	ECBM early CO2 breakthrough	Early breakthrough of CO2 can be caused by high permeability areas in the coal seam or improper well pattern/spacing.	Impacts the sweep efficiency of ECBM and increases costs due to the need for excess CO2 recycling.	Not applicable to this site		Higher CO2 consumption.	ECBM early CO2 breakthrough.	Higher operating costs. Higher CO2 recycling costs.	Monitor CO2 injection and CH4+CO2+H2O production.	Fully characterize and model the ECBM coal seam . Optimize well pattern/spacing.	Recycle CO2. Consider modifying well pattern/spacing.
118	03.02.11.15.	ECBM coal seam thickness	For ECBM at least one coal seam should be at least 0.5 m (1.5 ft) thick. However, the thicker the seam, the more likely it could be mineable. Recommended for ECBM: Concentrated coal deposits (few, thick seams) are generally favored over stratigraphical dispersed beds comprising multiple, thin seams (Bachu 2008).	Seams less than 0.5 m (1.5 ft) thick can limit injectivity.	Not applicable to this site		Low injectivity.	Insufficient coal seam thickness.	Higher costs. Lower revenues.	Characterize the coal seam thickness to confirm it meets recommendation.	Characterize the coal seam thickness to confirm it meets recommendation. Avoid sites with thin coal seams.	Avoid sites with thin coal seams.
119	03.02.11.16.	ECBM complex structural geology of coal seam	Complex structural geology can make ECBM more difficult to model, less efficient to implement and more susceptible to leakage. Recommendation for ECBM: Simple structure. The reservoir should be minimally faulted and folded . The coal seams should be laterally continuous and vertically isolated from surrounding strata to prevent migration of excess CO2 and CH4 into adjacent aquifers and possibly to the surface (Bachu 2008).	Potential for CO2 leakage and lower methane yields.	Not applicable to this site		CO2 leakage through existing or reactivated fault. Uncontrolled CO2 migration.	ECBM complex structural geology of coal seam	CO2 release (HSE hazard).	Fully characterize and model the site early in the design phase. Continuously monitoring and modeling the site. Evaluation of actual versus expected performance.	Fully characterize and model the site. Avoid sites with complex structural geology.	Monitor and model CO2 movement well performance. Compare actual with projected performance. Take remedial action if CO2 migration goes out of control (inject water to redirect migration or extract CO2 and reinject elsewhere.
120	03.02.11.17.	ECBM CO2 injection into mineable coal seams	CO2 ECBM is normally applied to coal seams that are too thin or too deep to be mined.	CO2 ECBM in mineable coal seams will complicate the recovery of those coal reserves. However, removing methane decreases the explosion possibility for future mining.	Not applicable to this site		CO2 contamination of coal reserves.	ECBM CO2 injection into mineable coal seams.	Loss of monetized value of contaminated coal reserves.	Identify ownership of mineral rights.	Obtain mineral rights for selected coal seam including sufficient buffer to protect against infringement on third-party reserves.	Evaluate CO2 extraction options and safety measures to be taken if coal seam is to be mined in the future.

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
115	03.02.11.12.	ECBM injection and production well pattern and spacing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
116	03.02.11.13.	ECBM injection strategy	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
117	03.02.11.14.	ECBM early CO2 breakthrough	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
118	03.02.11.15.	ECBM coal seam thickness	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
119	03.02.11.16.	ECBM complex structural geology of coal seam	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
120	03.02.11.17.	ECBM CO2 injection into mineable coal seams	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	

FARNSWORTH UNIT CO₂-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
121	03.02.11.18.	ECBM coal seam permeability	The permeability of coal varies in two basic ways: 1. Phase relative permeability effects 2. Change in the effective stress within the seams (Mansourine 2003) Cleat permeability is primarily controlled by the prevailing horizontal stresses. ECBM wells that produce little water or gas may indicate low permeability. Recommended permeability for ECBM: 1 to 5 mD (Bachu 2008). Coal permeability decreases with depth, such that injectivity is not possible below about 914 m (3000 ft) without fracturing (NETL 2010).	Low permeability makes CO ₂ ECBM more difficult and more expensive.	Not applicable to this site		Low CO ₂ injectivity and CH ₄ extraction.	Low ECBM coal seam permeability.	High operating costs, lower revenues.	Characterize and model coal seam permeability. Monitor CO ₂ injectivity.	Characterize and model coal seam permeability. Select coal seams with acceptable permeability.	Monitor injectivity. Dewater coal seam to increase cleat permeability. Consider hydraulic fracturing.
122	03.02.11.19.	ECBM coal porosity	Micro-porosity: < 2 nm pore diameter impacts sorption Meso-porosity: >2 nm <50 nm pore diameter impacts diffusion Macro-porosity (fracture porosity): > 50 nm impacts Darcy flow Induced fractures: pipe flow (Mansourine 2003) Cleat porosity represents the initial water storage volume in the coal seam.	Coal bed porosity and permeability increases as reservoir pressure is lowered and gas production occurs.	Not applicable to this site		Low CO ₂ injectivity and CH ₄ extraction.	Low ECBM coal seam porosity.	High operating costs, lower revenues.	Characterize and model coal seam porosity. Monitor CO ₂ injectivity.	Characterize and model coal seam porosity. Select coal seams with acceptable porosity.	Monitor injectivity. Dewater coal seam to improve injectivity.
123	03.02.11.20.	ECBM coal seam heterogeneity	Permeability can vary by more than an order of magnitude in coal seams.	Heterogeneity in permeability can result in CO ₂ early breakthrough, limit CO ₂ storage capacity and limit methane recovery.	Not applicable to this site		Low CO ₂ injectivity and CH ₄ extraction.	ECBM coal seam heterogeneity.	High operating costs, lower revenues.	Fully characterize and model heterogeneity of the coal seam. Monitor and model well performance. Compare actual with projected performance.	Fully characterize and model heterogeneity of the coal seam. Optimize the CO ₂ injection strategy to accommodate the heterogeneity of the coal seam.	Monitor and model well performance. Compare actual with projected performance. Modify injection strategy if necessary.
124	03.02.11.21.	ECBM coal seam vertical and horizontal injectivity	Vertical and horizontal injectivity in coal seams is largely determined by the cleat size and cleat angle.	Vertical and horizontal injectivity may determine whether to use vertical or horizontal type wells for CO ₂ injection.	Not applicable to this site		Low CO ₂ injectivity and CH ₄ extraction	ECBM coal seam vertical and horizontal injectivity	High operating costs, lower revenues.	Fully characterize and model the coal seam taking into account differences in vertical and horizontal injectivity. Monitor and model well performance. Compare actual with projected performance.	Fully characterize and model the coal seam taking into account differences in vertical and horizontal injectivity. Optimize the CO ₂ injection strategy by use of vertical or horizontal wells to accommodate the differences in vertical and horizontal injectivity.	Monitor and model well performance. Compare actual with projected performance. Modify injection strategy using vertical or horizontal CO ₂ injection if necessary.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
121	03.02.11.18.	ECBM coal seam permeability	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
122	03.02.11.19.	ECBM coal porosity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
123	03.02.11.20.	ECBM coal seam heterogeneity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
124	03.02.11.21.	ECBM coal seam vertical and horizontal injectivity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

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125	03.02.11.22.	ECBM CO2 storage capacity of coal	Typical sorption of coal can be up to 41 Nm ³ /tonne (1400 scf/st) at 22°C and 0- 6.9MPa (0-1000 psi).	Depending on the objective of CO2 ECBM, the CO2 storage capacity can have a positive or negative impact. If the objective is to minimize CO2 consumption/cost it can be a negative. If the objective is to maximize CO2 sequestration, it is a positive.	Not applicable to this site		Low CO2 storage capacity.	ECBM CO2 storage capacity of coal	Cost of acquiring operating additional CO2 geologic storage capacity.	Determine the CO2 storage capacity of coal through core sample testing. Model CO2 sorption. Monitor actual versus projected results.	Characterize and model the coal seam to estimate storage capacity. Select coal seams with sufficient CO2 storage capacity.	Dewater the coal seam to enhance CO2 storage capacity.
126	03.02.11.23.	ECBM coal bed methane composition	Coal bed methane tends to be sweet (no H2S). It contains small amounts of CO2 and nitrogen.	Impacts gas treatment facilities on surface and value of coal bed methane.	Not applicable to this site		Contamination of coal bed methane with N2, CO2 or other stripped gases.	ECBM coal bed methane composition	Additional processing costs for cleaning coal bed methane.	Monitor coal bed methane composition.	Characterize and model the coal seam to estimate coal bed methane quality. Design gas treatment facility to handle expected range of composition.	Monitor coal bed methane quality. Adjust gas treatment and/or CO2 injection strategy to deal with changes in quality.
127	03.02.11.24.	ECBM induced fracturing of coal	Coal is an extremely stress-sensitive rock	Limits CO2 injection pressure.	Not applicable to this site		Fracturing caprock.	ECBM induced fracturing of coal.	Release of CO2 (HSE hazard).	Determine fracturing pressure of caprock and coal. Monitor injection pressure. Alarm if CO2 injection pressure exceeds 80% of caprock fracturing pressure. Monitor CO2 content in upper formations, groundwater, soil and/or atmosphere.	Determine fracturing pressure of caprock and coal. Monitor CO2 injection pressure. Do not exceed 90% of caprock fracturing pressure.	Monitor CO2/CH4 content in upper formations, groundwater, soil and/or atmosphere. If leakage is detected, lower coal seam pressure by lowering CO2 injection pressure or dewatering. Try to locate and remediate leak.
128	03.02.11.25.	ECBM nitrogen injection into coal seam	Nitrogen has a lower affinity to coal than CH4. Nitrogen injection lowers the partial pressure of CH4 which allows CH4 to diffuse through the coal matrix with greater ease, improving recovery of CBM at a faster rate.	Nitrogen is not a problem in ECBM as a minor component of CO2. It will lower the partial pressure of methane and allow more methane to be released and recovered. Some of the nitrogen injected with CO2 may end up in the coal bed methane, resulting in a lower value product.	Not applicable to this site		Nitrogen contamination of coal bed methane.	ECBM nitrogen injection into coal seam.	Coal bed methane off spec. Increased costs. Decreased revenue.	Monitoring gas compositions of injected gas and produced gas.	Keep nitrogen gas content of CO2 stream low. Characterize and model gas composition of injected and produced gases.	Monitoring gas compositions of injected gas and produced gas. Treat produced gas to remove nitrogen.
129	03.02.11.26	ECBM coal fines generation and transport	Induced fracturing of coal seams can lead to fines generation. These fines can be mobilized by injected gases or fluids. Some types of medium- and low-volatile bituminous coals are weaker, and have a greater tendency of generating fines, than other coals.	Coal fines can: 1. Plug and reduce coal seam permeability 2. Plug and reduce fracture conductivity 3. Plug submersible pumps 4. Erode ECBM systems 5. Accumulate in ECBM separators 6. Require disposal (Palmer 2008)	Not applicable to this site		Loss if injectivity.	Coal fines generation and transport plugging pore spaces and fractures.	Diminished ECBM performance. Higher costs, lower revenues. Decreased CO2 storage capacity.	Monitoring injection pressure and flowrate.	Avoid induced fracturing of weak coals.	Put in additional injection wells.

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			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)						
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																	
125	03.02.11.22.	ECBM CO2 storage capacity of coal	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
126	03.02.11.23.	ECBM coal bed methane composition	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
127	03.02.11.24.	ECBM induced fracturing of coal	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
128	03.02.11.25.	ECBM nitrogen injection into coal seam	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
129	03.02.11.26	ECBM coal fines generation and transport	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
130	03.02.11.27	ECBM coal plasticization	CO2 is a coal plasticizer, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure. The transition temperature may drop from ~400°C at 3MPa to <30°C at 5.5 MPa. (Bachu 2006). Recommendation for ECBM: Avoid deep ECBM sites that have CO2 supercritical pressures and temperatures above 30°C (Bachu 2008).	Coal plasticization, or softening, destroys any permeability that would allow CO2 injection. (Bachu 2006).	Not applicable to this site		Loss of injectivity.	Plasticization of coal .	Shutdown of operation.	Monitoring injection pressure and rate. Monitoring bottom hole pressures and temperatures.	Avoid deep ECBM sites that have CO2 supercritical pressures and temperatures above 30°C.	Permanent facility closure. Relocate site.
131	03.02.12.00.	Heavy metal release	Heavy metal ions may be dissolved in formation fluids or adsorbed on rock/mineral surfaces. Complexation may occur between CO2 and heavy metals dissolved in formation fluids. The influence of dissolved CO2 on pore water chemistry can also reduce the pH and change the equilibrium between sorption/desorption of metals, thereby resulting in significant release of these metals.	This process has the potential to release heavy metals, which may then migrate to the near-surface environment with resulting impacts of interest. These heavy metals will also change pore water chemistry, which could impact on carbonate complexation.	Heavy metals may be associated with the pyrite in the reservoir. If the pyrite comes in contact with oxygen, it can acidify the formation fluid and release heavy metals. This may have a greater impact than CO2 acidification. Carbonate formations located above the caprock may buffer any acidic water that migrates through the caprock. This may decrease the potential for heavy metal release.	Heavy metal content in produced water/brine before and after/during CO2 injection? Presence of heavy metals in the reservoir and overlying formations?	Migration of heavy metals with CO2/brine into the near surface environment.	Heavy metal release.	Contamination of ground/surface water and/or soil.	Conduct baseline study of heavy metals in the reservoir and near surface environment. Monitor heavy metal content in produced brine, ground/surface water, and soil.	Characterize and model the reservoir for heavy metal content and release. Avoid sites where heavy metal concentration is unusually high and would have a significant impact on the near surface environment.	Conduct baseline survey of heavy metal content in the near surface environment. Monitor heavy metal content in produced brine. Monitor CO2 and salinity in near surface environment. If CO2/brine contamination is indicated, check for heavy metal content.
132	03.02.13.00.	Mineral phase (See 03.02.13.01. through 03.02.13.06.)	Geochemistry of the mineral phase relevant to sequestered CO2, including ion exchange and mineral dissolution.	Geochemical reactions between sequestered CO2 and the mineral phase of the storage system will affect the evolution of the system and the sorption (and therefore mobility) of the CO2.								
133	03.02.13.01.	Mineral dissolution and precipitation (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	The dissolution of minerals (grains or cement) due to the addition of CO2 (an acid gas) to the geochemistry and precipitation. For example, the dissolution of albite and precipitation of calcite modeled for the Steipner site by Gaus et al. (2003). 1. Mineral dissolution and precipitation in the reservoir 2. Mineral dissolution and precipitation in or near the borehole 3. Mineral dissolution and precipitation in the caprock 4. Mineral dissolution and precipitation in faults and fractures	CO2 reaction with the host rock will modify: the porosity and permeability of the reservoir; fluid flow (direction or velocity); mechanical properties (e.g. strength); and CO2 storage capacity.								
134	03.02.13.02.	Precipitation of carbonate minerals (scale buildup)	CO2 reacts with brine to form hard water which can lead to scaling in or near a production well. Calcium carbonate and magnesium carbonate can be formed when HCO ₃ ⁻ reacts with Ca ²⁺ or Mg ²⁺ .	Scale buildup can cause reduced porosity and permeability in the reservoir, especially near the borehole.	The produced water contains 4,000 mg/L of TDS.	Produced water chemistry and pH before and after/during CO2 injection? Incidents of scale buildup (frequency, magnitude, mineral type, method of control)?	Pore plugging. Well and equipment plugging.	Precipitation of carbonate minerals (scale buildup).	Decreased injectivity, decreased production, higher operating costs. Down time for clean out.	Characterization and modeling taking into account mineral precipitation reactions, mineralogy, brine chemistry and CO2 interaction. Monitoring CO2/brine movement, brine chemistry and changes in injectivity.	Avoid injecting water with high concentration of scale forming ions. Periodically clean out production facilities with acid.	Periodically treat system with scale inhibiting chemicals.

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Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
130	03.02.11.27	ECBM coal plasticization	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
131	03.02.12.00.	Heavy metal release	2	1	3	6	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
132	03.02.13.00.	Mineral phase (See 03.02.13.01. through 03.02.13.06.)	0	0	0	0															
133	03.02.13.01.	Mineral dissolution and precipitation (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	0	0	0	0															
134	03.02.13.02.	Precipitation of carbonate minerals (scale buildup)	3	2	2	12	None	None	None	None	None	None	None	Clean out costs \$0.3M/y	None	None	Clean out costs \$0.3M/y	Clean out costs \$0.3M/y	Pretreat injected water. Periodically clean out production facilities with acid. Part of ongoing costs.	None	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
135	03.02.13.03.	Salt precipitation	Dry CO2 can pick up moisture from high salinity brines in the reservoir. This increases the salinity of the brines. (CCP 2009)	Increased salinity of brines can lead to precipitation of salt in pore space, which can decrease reservoir permeability and impair injection rates of CO2. (CCP 2009) "Dry out" and "salt out" may cause reduced porosity and permeability in the reservoir, especially near the borehole.	The produced water contains 4,000 mg/L of TDS.	Produced water chemistry and pH before and after/during CO2 injection? Incidents of salt precipitation (frequency, magnitude, type, method of control)?	Pore plugging.	Salt precipitation.	Decreased injectivity, higher operating costs. Interruption of operations.	Include brine salinity and potential for salt precipitation in characterization and modeling. Monitor brine salinity and well injectivity.	Control salinity of injected water.	Monitor salinity of brine. Use fresh water injection to help dissolve salt buildup.
136	03.02.13.04.	Ion exchange (mineral dissolution and precipitation) (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	The process of exchanging one ion in the liquid phase for another ion on a charged, solid substrate. Injected CO2 may perturb ion exchange equilibrium between relevant minerals (such as sheet silicates) and the pore fluid. Some cations may be released to the pore fluid and others fixed as a consequence.	Disturbance of the rock-pore fluid equilibrium may affect the capacity of the rock to store CO2.								
137	03.02.13.05.	Desiccation of clay	CO2 is likely to be dried to prevent corrosion during transport. Injection of dry CO2 will cause it to take up water from the pores of the host formation and overlying rocks. It has the potential to suck water out of an overlying clay. CO2 can also be adsorbed by clay.	If clay dehydrates, it will shrink and crack. This might aid CO2 migration upwards.	The Buckhaults Sandstone contains approximately 25% kaolinite.	Expandable clay content in reservoir and caprock? Incidents of clay desiccation (frequency, magnitude, method of control)?	Shrinking of clay particles in caprock leading to CO2 leakage.	Desiccation of clay.	CO2 release (HSE hazard).	Characterize clay content of caprock and reservoir. Model and observe impact of CO2 on clay desiccation. Monitor for CO2 leakage near wells.	Characterize caprock to evaluate clay content and potential for desiccation. Avoid CO2 injection in areas where clay desiccation would be a problem.	Inject water to hydrate clay.
138	03.02.13.06.	Mineral dissolution	The dissolution of minerals (grains or cement) due to the addition of CO2 (an acid gas) to the geochemistry. 1. Mineral dissolution in the reservoir 2. Mineral dissolution in or near the borehole 3. Mineral dissolution in the caprock 4. Mineral dissolution in faults and fractures	CO2 reaction with the host rock will increase: the porosity and permeability of the reservoir; increase fluid flow (direction or velocity); decrease mechanical properties (e.g. strength); and increase CO2 storage capacity.	The reservoir is a sandstone with kaolinite, feldspar and calcite content susceptible to mineral dissolution and precipitation. Mineral dissolution may increase injectivity in the reservoir but is insufficient to impact the structural strength of the primary seal.	Produced water chemistry and pH before and after/during CO2 injection? Mineralogy of the caprock? Incidents of mineral dissolution in the reservoir or caprock (frequency, magnitude, type, method of control)?	Weakening and fracture/collapse of caprock. Reactivation of fault. Subsidence. Channeling within the reservoir.	Mineral dissolution.	Decreased sweep efficiency due to channeling. Increased CO2 permeability and injectivity.	Characterization and modeling taking into account mineral dissociation reactions, mineralogy, brine chemistry and CO2 interaction. Monitoring CO2/brine movement, brine chemistry, core sample analysis, elevation change, micro-seismicity.	Characterization and modeling taking into account mineral dissociation reactions, mineralogy, brine chemistry and CO2 interaction. Avoid sites where mineral dissolution could weaken the integrity of the caprock.	Monitoring injectivity and bottomhole pressures. Selective perforation or use of gels or sealant.
139	03.02.14.00.	Gas chemistry (CO2 interacting with gases in the reservoir)	Gases such as CO2, methane and H2S, will occur naturally in the geosphere, either sorbed onto minerals, dissolved in formation fluids or as a free gas phase. Gas solubility will depend upon pressure, temperature and the salinity of the formation fluid. 1. CO2 interacting with free gases in the reservoir 2. CO2 interacting with gases sorbed onto minerals 3. CO2 interacting with gases dissolved in formation fluids 4. CO2 interacting with gaseous hydrocarbons in the reservoir	Gases naturally present in the geosphere could affect the behavior of CO2 injected into a storage reservoir and could accompany CO2 along potential migration paths.	Current produced gas contains over 80% CO2. H2S is present in the produced gas.	Composition of produced gases before and after/during CO2 injection?	Corrosion of well production and recycle system components.	Gas chemistry (CO2 interacting with gases in the reservoir).	Release of CO2 and associated gases. More complicated gas treatment and cleanup.	Characterize the reservoir for the presence of gases (particularly H2S). Monitor produced gas composition.	Monitor for H2S in the site area.	Monitor for H2S in the recycled CO2 and around injection wells and recycle facilities. Maintain tight seals and failsafe systems

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Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
135	03.02.13.03.	Salt precipitation	1	1	2	2	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
136	03.02.13.04.	Ion exchange (mineral dissolution and precipitation) (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	0	0	0	0															
137	03.02.13.05.	Desiccation of clay	2	3	3	18	None	None	None	\$200/t CO2/brine released into USDW	None	None	None	\$1M to \$3M to locate and fix leak	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage is undetected and unmitigated for 5 years: <\$6M	Assuming leakage detected early: <\$1M	Inject water to hydrate clay. \$0.50/t water injected.	Savings: Up to \$4M	2
138	03.02.13.06.	Mineral dissolution	2	3	2	12	None	None	None	\$200/t CO2/brine released into USDW	None	None	None	Loss of oil revenue: \$5M/y due to channeling of CO2.	None	None	<\$5M/y	<\$2M/y	Selective perforation or use of gels or sealant: <\$3M/y	None	2
139	03.02.14.00.	Gas chemistry (CO2 interacting with gases in the reservoir)	2	2	2	8	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	0-5 days @ \$15,000/d revenue lost per pattern idled	NA	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage is undetected and unmitigated for 1 year: <\$1M	Assuming leakage detected within a month: <\$0.1M	Monitor H2S in CO2 and around injection wells and recycle facilities. Maintain tight seals and failsafe systems <\$300k	Savings: <\$0.6M	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
140	03.02.15.00.	Gas stripping in overlying formations	CO2 migration through the reservoir and into the overlying barrier sequence could result in the CO2 stripping other gases entrained within the sediments. This could include: 1. Radon stripping 2. Methane (CH4) stripping, and 3. Hydrogen sulfide (H2S) stripping.	The presence of other gases in a leaking CO2 gas stream is important in deciding the level of CO2 leakage that can be tolerated and may constitute an important hazard. H2S acts as an odorant for early detection of CO2 and any stripped gases.	There are multiple stacked seals and sinks above the caprock. The seals include Permian salt, gypsum, anhydrite and red shale formations.	Presence and composition of free gases in formations overlying the reservoir? Presence of H2S or iron sulfide in the reservoir and overlying formations?	Release of CO2 and stripped gases to ground/surface water and/or atmosphere.	Gas stripping	Water contamination. Atmospheric emissions.	Characterize site for the presence of gases in overlying formations. Monitor for H2S as an early detection of gas leakage or release.	Characterize site for the presence of gases that may be stripped and transported by CO2 (particularly H2S). Maintain integrity of the caprock seal.	Monitor H2S near wells or in confined spaces. Maintain tight seals and failsafe systems.
141	03.02.16.00.	Gas hydrates	Gas hydrates are 'ice-like' solids that form at low temperatures and high pressures. They are formed of 'cages' of water molecules surrounding a gas molecule. CO2 can form hydrates in the presence of water. The prevention of hydrate formation in the well during startup will need to be considered. It is likely that methanol spacers will need to be used. (CCP 2009) Hydrate potentially could form in the well when starting back up after a shut down. During the process of shutting down, measures should be taken to mitigate the formation of hydrates when starting back up. Often a methanol "cap" is pumped in the top of the tubulars. (CCP 2009) As a consequence of well control using a brine or similar fluid, there can be intermixing of the CO2 and the well control fluid that could result in hydrate formation or hydrate blocks. Using hydrate inhibited fluids or having operational practices that minimize the amount of CO2 inflow during workovers should be considered. (CCP 2009) There is a lack of experimental data and models for predicting the water solubility of CO2 at temperatures below 10°C. Moreover, there is a need to investigate hydrate formation conditions with CO2 near and below water saturated conditions in the presence of carbon steel surfaces. (DNV CO2PIPETRANS Phase 2) 1. Gas hydrates formed below deep water 2. Gas hydrates formed below permafrost 3. Gas hydrates formed in well during startup 4. Gas hydrates formed in pipeline	Cooling of the reservoir (e.g. by injecting cold CO2 or through adiabatic expansion) well below normal in-situ temperatures might stabilize gas hydrates. Their growth might seal fluid flow pathways (at least temporarily). If CO2 is injected below deep water or permafrost, then rising CO2 might hit the hydrate stability zone before escaping to the ocean or air, so hydrates could act as a secondary chemical barrier. Similarly, storage could be focused on actively forming CO2 hydrate as a stable, immobile phase to lock up the CO2 (Koide et al., 1997).	Assumed produced CO2 is decompressed in multiple stages to prevent gas hydrate formation. Hydrate inhibitor may also be added.	Incidents of gas hydrate formation on site (frequency, magnitude)? Steps taken to prevent gas hydrates forming during decompression of produced CO2 (like staged CO2 decompression or use of a hydrate inhibitor)?	Plugging of production wells or recycling system.	Gas hydrates.	Interruption of operations.	Determine conditions for formation of gas hydrates. Monitor for those conditions. Monitor for plugging of production wells and/or decreased injectivity.	Characterize the site for conditions which could lead to gas hydrate formation. Try to operate outside of the conditions leading to gas hydrate formation.	Monitor for conditions which could lead to gas hydrate formation and try to operate outside of those conditions. Remediate hydrates using methanol or other solvents. Obtain proper approvals if chemicals are injected.
142	03.02.17.00.	Biogeochemistry	Features and processes related to the biological/biochemical processes that affect the CO2, borehole seals and rock/pore fluid, and the overall biological/biochemical evolution with time. This includes the effects of biological/biochemical influences on the CO2 and engineered components by the surrounding geology. Microbes exist in the subsurface and are used in hydrocarbon operations to improve hydrocarbon recovery (e.g., in EOR and ECBM operations). Microbes can also catalyze geochemical reactions, including methanogenesis, but the latter reaction is thermodynamically unfavorable and is unlikely.	Examples of relevant processes are: - microbial growth; - microbial/biological mediated processes; and - microbial/biological effects of evolution of redox (Eh) and acidity/alkalinity (pH) , etc. This FEP has probably low relevance to the safety/fate of CO2. However, CO2 releases may affect/impact microbe populations being used in independent hydrocarbon-recovery enhancement projects.	Microbes may be beneficial to improve hydrocarbon recovery.	Incidents of microbe buildup and plugging (frequency, magnitude, and mitigation method)?	Pore/well plugging. Generation of CH4 or H2S gases.	Biochemistry.	Decreased injectivity and interruption of operations. Increased HSE risks for release of CO2 containing CH4 or H2S. Corrosion of well, production and recycle system components.	Characterize the site for microbe types and microbial growth. Monitor for microbial growth and activity (pore plugging and generation of CH4 or H2S).	Avoid injecting water containing microbes or nutrients that may stimulate microbial growth and activity.	Use chemical treatment if necessary to control microbial contamination/growth. Obtain proper approvals if chemicals are injected.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking		Estimated Potential Damage Recovery Costs												Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
					Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)			
					Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury														
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)															
140	03.02.15.00.	Gas stripping in overlying formations	2	2	2	8	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	0-5 days @ \$15,000/d revenue lost per pattern idled	NA	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage is undetected and unmitigated for 1 year: <\$1M	Assuming leakage detected within a month: <\$0.1M	Monitor H2S in CO2 and around injection wells and recycle facilities. Maintain tight seals and failsafe systems <\$300k	Savings: <\$0.6M	1
141	03.02.16.00.	Gas hydrates	3	2	2	12	None	None	None	None	None	Plugging of production wells or pore space <\$1M per incident.	1-5 days @ \$15,000/d revenue lost per pattern idled	Methanol cost for controlling hydrates \$420-\$30/t of methanol	None	None	Up to \$1 M per plugging incident.	None	Avoidance cost in site selection. Remediate hydrates using methanol or other hydrate inhibitors. \$420-430/t methanol.	Up to \$1 M per plugging incident.	1
142	03.02.17.00.	Biogeochemistry	2	1	3	6	None	None	None	None	None	None	1-5 days@ \$15,000/d revenue lost per pattern idled	Increased injection cost due to decreased injectivity Cost of chlorine for microbial control \$310-340/t Cl (\$0.03/t water treated @ 4 ppm Cl)	None	None	Clean out costs <\$100k/y	Clean out costs <\$100k/y	Pretreat injected water with chlorine biocide part of ongoing costs.	None	2

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
143	03.02.18.00.	Microbial processes	Microbes can metabolize CO2, for example, methanogenic microbes use H2 to reduce CO2 to methane (CH4), a process called methanogenesis. These microbes need anaerobic conditions. Microbes can produce SOx, NOx, and CO under oxic conditions and H2S and CH4 under anoxic conditions.	Methanogenesis, if it occurs, could affect the pressure distribution of CO2. The fate and impact of the CH4 produced may be an endpoint of interest in itself.	Microbes beneficial to improve hydrocarbon recovery.	Incidents of microbe methane or H2S production (frequency, magnitude, and mitigation method)?	Generation of CH4 or H2S gases.	Microbial processes.	HSE risks for release of CO2 containing CH4 or H2S. Corrosion of well, production and recycle system components.	Characterize the site for microbe types and microbial growth. Monitor for microbial growth and activity (pore plugging and generation of CH4 or H2S).	Avoid injecting water containing microbes or nutrients that may stimulate microbial growth and activity.	Use chemical treatment if necessary to control microbial contamination/growth. Obtain proper approvals if chemicals are injected. Monitor H2S in CO2 and around injection wells and recycle facilities. Maintain tight seals and failsafe systems.
144	03.02.19.00.	Biomass uptake of CO2	If sequestered CO2 migrates to the biosphere, it can be taken up by microbes, plants and algae (including phytoplankton).	This mechanism may provide a sink for CO2 that has migrated from the sequestration system.	Over 80% of the FWU Site is covered with croplands that can take up some CO2.		Positive impact. No failure mode.	Biomass uptake of CO2.	Positive effect on CO2 sequestration.	Characterize site for biomass content.	Maintain biomass on site that may collect leaked CO2.	None
145	03.02.20.00.	Mobilization of particulates by CO2	Insoluble particulates could be mobilized by CO2 via chemical hydrodynamic interaction with the reservoir rock.	Particulate mobilization could increase permeability at the point of mobilization, but it could also decrease permeability in reservoir locations where particulates are deposited or trapped.	Mobilization of particulates has not been reported as a problem.	Incidents of particulates mobilized by CO2 injection (frequency, magnitude, mitigating method)?	Reservoir permeability decreased.	Deposition of mobilized particulates.	Decreased injectivity. Higher operating costs.	Monitor injectivity.	Characterize the site for conditions which could lead to mobilization of insoluble particulates.	Increase the number of injection wells. Hydrofracturing or acid stimulation to improve injectivity.
146	03.03.00.00.	CO2 transport	Transport processes that may affect sequestered carbon dioxide and associated impurities.	An understanding of those processes that could transport carbon dioxide, and associated impurities, within the geosphere, near-surface and surface environments is fundamental to the assessment of long-term performance and safety.								
147	03.03.01.00.	Advection of free CO2	Advection of free CO2 occurs in response to differences in pressure. The pressure difference may be due to differences in the pressure of injected CO2 and formation pressures. The rate and direction of advection is affected by the physical properties of the rock, such as porosity and permeability. Advection may also occur through fractures. Fracture flow will be episodic with high transport efficiencies. Resealing of fractures (for example by cementation) will reduce and ultimately block fluid flow. 1. Advection causing change in CO2 migration direction 2. Hydrodynamic gradients	Advective flow is a key transport process for migrating CO2, and associated contaminants, in the geosphere (reservoir, surrounding and overlying rock), near-surface and surface environments.	Assumed best practices are used to control advection of CO2, including water curtains and polymer additives to adjust viscosity.	Verify method(s) of controlling advection of free CO2? Reservoir pressure, permeability and porosity data?	CO2 migration different than planned.	Advection of free CO2.	Decreased oil recovery	Monitor CO2 migration through seismic surveys and production wells.	Take into account advection of CO2 in site characterization and modeling and apply to CO2 injection strategy.	Monitor and model CO2 movement. Compare actual with projected. Take remedial action if CO2 migration goes out of control (inject water to form water curtains).

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)					
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
Index #			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)															
143	03.02.18.00.	Microbial processes	2	1	3	6	None	None	None	None	None	None	1-5 days @ \$15,000/d revenue lost per pattern idled	Increased injection cost due to decreased injectivity Cost of chlorine for microbial control \$310-340/t Cl (\$0.03/t water treated @ 4 ppm Cl)	None	None	Clean out costs <\$100k/y	Clean out costs <\$100k/y	Pretreat injected water with chlorine biocide part of ongoing costs.	None	1
144	03.02.19.00.	Biomass uptake of CO2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
145	03.02.20.00.	Mobilization of particulates by CO2	2	2	3	12	None	None	None	None	None	None	1-5 days @ \$15,000/d revenue lost per pattern idled	Cost of acid stimulation or fracture stimulation \$0.25M/well	None	None	Cost of acid stimulation or fracking: \$0.25M/well	None	Cost of acid stimulation or fracking: \$0.25M/well	None	2
146	03.03.00.00.	CO2 transport	0	0	0	0															
147	03.03.01.00.	Advection of free CO2	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	None	None	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<4% decrease in oil revenue (68 bpd): <\$1.7M/y	None	Cost of injection water curtains to control CO2 migration within patterns: <\$1M/y	Savings: <\$0.7M/y	1

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
148	03.03.01.01.	Fault valving and reactivation	Fault valving is a process resulting from gradual build up of pore pressure due to fluid generation, causing the subsequent opening of a fault along with fluid escape towards surface. This mechanism has been recognized as causing earthquakes in many parts of the world, as a result of hydrocarbon generation (e.g., in EOR or ECBM operations) or infiltration of other fluids. 1. CO2 leakage through an existing open fault 2. CO2 leakage through a reactivated fault	Large releases of pore fluids may occur during fault valving episodes.	Faulting peaked in the early Pennsylvanian and died out by the end of the Permian. Geological work suggests an east-west fault running across much of the west half of the FWU, along the southern edge of tracts 7, 8, 13 and 14. A pressure falloff test of well 13-3 conducted in 1986 showed some evidence of a barrier to flow. (May 1987)	Presence of faults penetrating the caprock? Incidents of fault valving or reactivation at FWU?	CO2/brine leakage through a reactivated fault.	Fault valving.	CO2 release	Characterize and model the site for existing faults. Monitor for CO2/H2S near fault. Monitor micro-seismicity.	Characterize and model the site for existing faults. Avoid or isolate areas with faults penetrating the caprock. Maintain CO2 injection pressure at <90% of fracture pressure.	Monitor CO2/H2S near fault. Monitor micro-seismicity or surface displacement (LiDAR). Inject sealants into fault. Use injection water curtains to keep CO2/H2S migration away from faults.
149	03.03.02.00.	Buoyancy-driven flow	Different relative densities of fluids in a geological system will result in buoyancy-driven flows as less dense fluids will have a tendency to flow upwards. The density of fluids will depend on its temperature and pressure. If a stream of CO2 begins to move upward, expansion of the volume and decrease in the density provides increasing energy to drive flow upward, which can result in gas lift, a strong process for moving fluid upward (NETL 2010). 1. CO2 exceeding reservoir spill point 2. Lateral CO2 flow across top of reservoir 3. CO2 buoyancy putting pressure on caprock	Carbon dioxide can be less dense than water, which may cause injected CO2 to flow upwards and accumulate above the water phase below the caprock of a reservoir. Water with dissolved CO2 is more dense than water, which can result in stratification of water bodies into which CO2 may leak, if conditions are suitable.	Density at reservoir conditions: CO2: 755 kg/m3 Oil: 802 kg/m3 Water: 990 kg/m3 Reservoir does not have a spill point. Reservoir top is almost flat. Reservoir is not very thick.		CO2 migration different than planned.	Buoyancy-driven flow.	Decreased oil recovery	Monitor CO2 migration through seismic surveys and production wells.	Take into account buoyancy-driven CO2 in site characterization and modeling and apply to CO2 injection strategy.	Monitor and model CO2 movement. Compare actual with projected. Take remedial action if CO2 migration goes out of control (selective perforation, polymer gel, sealants).
150	03.03.03.00.	Displacement of formation fluids	This depends on interfacial tension and capillary pressure. Capillary pressure is the pressure difference existing across the interface separating two immiscible fluids due to interfacial tension. The interfacial tension itself is caused by the imbalance in the molecular forces of attraction experienced by the molecules at the surface and is a function of temperature and pressure. At a given pressure, increased interfacial tension values between water and CO2 will make larger pores accessible to CO2 (this is only valid for water-wet systems). The change from a water-wet system to a CO2-wet system has an effect on capillary forces (i.e. displacement of water by enhanced pressure versus CO2 injection with less capillary pressure) and the displacement capacity (i.e. as a non-wetting fluid, CO2 will have less displacement capacity). If the injection velocity is high, effects of capillary forces are small.	Interfacial tension and capillary pressure determine the location of CO2 within the pore spaces of the reservoir and the displacement capacity of the reservoir.	In CO2-EOR operation, displaced formation fluids are likely to be pumped out of the formation with produced oil. Any excess produced water can be reinjected in an on-site deep disposal well.	Lateral continuity and sealing of the reservoir?	Failure of CO2 to displace oil/brine in pores.	Interfacial tension and capillary pressure.	Decreased oil recovery.	Characterize and model site taking into account brine movement and replenishing. Monitor salinity of ground/surface water.	Characterize and model interfacial tension and capillary pressure for CO2, oil and brine. Maintain miscible conditions in the reservoir.	Maintain miscible conditions in the reservoir.
151	03.03.04.00.	CO2 dissolution in formation fluids	The process of dissolution of CO2 in formation fluids. The rate of dissolution depends on factors such as the interfacial area between the CO2 and the formation fluids and temperature.	Dissolution in formation fluids can be an important positive process in decreasing the free CO2 remaining in the reservoir.	Any acidification of the brine from CO2 dissolution may cause dissolution of carbonate and feldspar minerals in the sandstone. The dissolved minerals may precipitate out in the produced water system at lower pressure and temperature.	Produced water chemistry and pH before and after/during CO2 injection? Rate of dissolution of CO2 in formation fluids?	Not a negative risk	CO2 dissolution in formation fluids.	Positive effect on CO2 sequestration.	Characterize and model site taking into account dissolution of CO2 into brine.	NA	Using well patterns more amenable for dissolution will reduce risks.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable, or incredible; Yellow/Orange = Headings or non-risk areas

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							Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury												
148	03.03.01.01.	Fault valving and reactivation	2	3	3	18	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Potential class action lawsuit for property damage, loss of property value, reimbursement for earthquake insurance and emotional distress.	None	Shutdown of project through court ordered injunctive relief likely if multiple events of PGA(g)>0.1 (>4 magnitude earthquake)	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	Assuming leakage detected early and mitigated: <\$1M for water remediation	Monitor pressure in overlying formations. Continuous passive micro-seismic monitoring: Capex: \$3.9M Opex: \$0.3M/y Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Savings: Up to \$2M	1
149	03.03.02.00.	Buoyancy-driven flow	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Pore space infringement (\$500+/acre)	None	None	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<4% decrease in oil production (116 bpd): <\$3M/y	None	Cost of selective perforation, polymer gel or sealant. <\$2M/y	Savings: <\$1M/y	1
150	03.03.03.00.	Displacement of formation fluids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	Cost to maintain miscible conditions part of ongoing operation.	None	1
151	03.03.04.00.	CO2 dissolution in formation fluids	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	Cost to maintain miscible conditions part of ongoing operation.	None	2

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152	03.03.04.01.	CO2 exsolution from formation fluids	Long-term risks might result from the gravitational sinking of dense CO2 saturated brines; if they come into contact with salt formations this could lead to a degassing of the formation water and the ascent of CO2 outside of the original closed storage structure. (CO2STORE, page 68) Exsolution can also occur under significant (large) changes in pressure or temperature. The risk of major changes in pressure or temperature in a deep reservoir is very low.	Displaced brine containing dissolved CO2 flows to the surface and releases CO2 to the atmosphere or ocean.	In CO2-EOR, CO2 exsolution occurs as formation fluids are extracted and exposed to lower pressure. At FWU the produced gases are reinjected.	Incidents of CO2 exsolution as a result of leaky wellbores (frequency, magnitude, and mitigation method)?	Displacement of CO2/brine plus exsolution of CO2 .	CO2 exsolution from formation fluids	CO2 release (HSE hazard).	Characterize and model site taking into account dissolution, brine movement and conditions required for CO2 exsolution.	Maintain integrity of caprock and wells.	Monitor CO2/H2S near wells. Isolate and rework leaky wells.
153	03.03.05.00.	Water mediated transport	Processes related to the transport of CO2, and associated contaminants, in groundwater and surface water, including advection, dispersion and molecular diffusion. Advection is the process by which contaminants are transported by the bulk movement of the water in which they are dissolved. Advective groundwater flow can occur along connected porous regions, such as fractures and faults. Dispersion is the collective name for the consequences of a number of processes that cause 'spreading-out' of CO2, and associated contaminants, dissolved in water in all directions, superimposed on the bulk movement predicted by a simple advection model. It results in a spatially distributed contaminant plume. Diffusion is the process whereby chemical species move under the influence of a chemical potential gradient (usually a concentration gradient).	The transport of CO2, and associated contaminants, within groundwater is likely to be a key migration process and therefore an important consideration in determining performance and safety. CO2 dissolves in brine at CO2/brine interface and brine transports CO2 out of closure.	Site surface waters are limited to ten small playa ponds, the southern tip of Deer lake, and an ephemeral creek on the east edge of the site. USDW groundwaters are limited to the Ogallala aquifer. Surface and groundwaters are separated from the reservoir by several thousand feet of stacked Permian seals consisting of salt, gypsum, anhydrite, and red shale formations.	Flowrate and direction of water in the Ogallala aquifer?	Extensive ground/surface water contamination.	Water mediated transport.	Liability for contamination of ground/surface water with CO2/brine. Damage to drinking water and/or irrigation water supply.	Characterize and monitor ground/surface water for CO2 and salinity.	Maintain integrity of caprock and wells.	Monitor for pH/CO2/H2S in ground water and CO2/H2S near wells. Locate, isolate and rework leaky wells.
154	03.03.06.00.	CO2 release processes	Processes by which CO2 is lost from the sequestration system. Once in the near-surface, changes in pressure and temperature result in the potential for phase changes and degassing, with resulting changes in the transport properties of sequestered CO2. Examples of CO2 release processes include: 1. Surface blowouts (rapid release of CO2) 2. Undersea blowouts (rapid release of CO2) 3. CO2 geysers (such as Crystal Geyser in Utah) 4. Submarine gas release (Slow or moderate release of CO2) 5. Diffusion through soil (slow release of CO2) 6. CO2 released through mud volcano or mud flow. In fine-clastic unconsolidated rocks, suspensions could form and cause mud-volcanism and mud flows. (CO2STORE p.68) Mud diapir could be formed in unconsolidated (plastic, water-rich, under-compacted) reservoir and overburden strata possibly including the entire reservoir because of the buoyancy of store CO2. (CO2STORE, page 68)	The potential for CO2 to be lost from a sequestration system will determine the performance of that system. Rapid release of CO2 will tend to shoot CO2 into the atmosphere where it will quickly mix with air and diffuse. Slow release of CO2 will diffuse into soil gas. Moderate release of CO2 will tend to blanket the ground unless there is sufficient air circulation (wind). Thus moderate release of CO2 can be a greater safety risk than rapid or slow release.	The likely CO2 release processes at FWU are: 1. Well blowout or leakage 2. Piping rupture or leakage 3. Equipment failure CO2-EOR operations typically may release 0.3% of total CO2 handled due to routine maintenance and power outages caused by storms (Bradley 2009a). CO2 pipeline operations typically may release 0.00035% of CO2 transported (Bradley 2009a).	Percentage of CO2 released in FWU CO2-EOR operations, CO2-pipeline transport and CO2-supply?	CO2 release resulting in a fatality. (1) Blowout or rupture (rapid release of CO2) (2) Leak (moderate release of CO2). (3) CO2 diffusion through soil (slow release of CO2).	CO2 release processes.	(1) Damage to surface facilities. Injury to humans or fauna. (2) Accumulation of CO2 in low surface areas or confined areas. Asphyxiation of humans or fauna. (3) Damage to flora, rodents and organisms in soil. (1-3) Loss of CO2 storage credits.	Monitor and model CO2 plume. Monitor for CO2 leaks. Monitor well/pipeline pressure, corrosion and excavation activity.	Maintain integrity of caprock, wells, piping and equipment. Maintain blow out preventers and packers in wells. Maintain block valves and computational pipeline monitoring (CPM) leak detection system for pipelines.	Monitor well, pipeline and equipment for pressure and corrosion Supervise excavation activity near pipeline. Monitor for H2S near wells and CO2 recycling facilities. Monitor for CO2/H2S and ventilate confined spaces. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/H2S leak.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
152	03.03.04.01.	CO2 exsolution from formation fluids	3	2	3	18	None	None	None	<5,000 t/y CO2/brine per leak @ \$200/t CO2/brine released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	None	None	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$1M per incident	None	Cost of monitoring for CO2/H2S near wells plus isolating and reworking leaky wells:<\$100k/inci dent	Up to \$0.9M per incident avoided.	2
153	03.03.05.00.	Water mediated transport	2	2	3	12	None	None	None	<5,000 t/y CO2/brine per leak @ \$200/t CO2/brine released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	None	None	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$1M per incident	None	Cost of monitoring for CO2/H2S near wells plus locating, isolating and reworking leaky wells:<\$200k/inci dent	Up to \$0.8M per incident avoided.	1
154	03.03.06.00.	CO2 release processes	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2/brine per leak @ \$200/t CO2/brine released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	Damage from blowout: \$0.5M. Well abandonment and replacement: \$2M	0-10 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Well blowout: <\$3M per event Pipeline rupture:<\$1M per event Compressor failure: \$2M per event Fatalities and/or injuries: \$3.1M	None	Mitigation costs for wells: \$15,000/active well per year Mitigation costs for pipelines: \$3,600/mi per year Mitigation costs for facilities: 1% of equipment capex per year	Up to \$2.5M per blowout prevented Up to \$500k/rupture prevented Up to \$1.8M per compressor failure prevented. Up to \$3.1 M for fatalities and/or injuries prevented.	2

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155	03.03.06.01.	Limnic eruption	The rapid turnover and degassing of CO₂ from a surface water body. Due to the high solubility of CO₂ in water, a lake can dissolve a volume of CO₂ that, in gaseous form, is more than five times its volume. CO₂ rich water is denser than pure water which can result in an unstable stratification. A drop in temperature will reduce the solubility of CO₂ in water. If the water reaches its solubility limit as a result, bubbles will nucleate. As the bubbles rise and grow, a chain reaction occurs where a sudden ex-solution of CO₂ can result in a rapid degassing of the water body with an eruption of rising, expanding bubbles. Limnic eruptions can be triggered by events such as landslides that disturb the unstable stratification.	Limnic eruption provides a release mechanism for CO₂, migrating from a storage system to the atmosphere. Natural limnic eruption events can be catastrophic. On the 29th of August 1986, a massive limnic eruption from Lake Nyos in Cameroon resulted in 1800 deaths as the CO₂ smothered local villages. The CO₂, which is volcanic in origin, seeps through the lake bed sediments and builds up in the lower strata of the water column. The Lake Nyos sudden release involved an estimated 240,000 tonnes of CO₂ (Damen 2006).	There are no surface water bodies at the site sufficiently large or deep to generate a limnic eruption.		Massive release of CO ₂ .	Limnic eruption.	Catastrophic asphyxiation.	Monitor CO ₂ content in the bottom of deep lakes above or near CO ₂ storage.	Avoid selecting CO ₂ sites below deep lakes. Ensure the integrity of the caprock. Agitate the lake water to prevent stratification and CO ₂ buildup.	Monitor buildup of CO ₂ in the bottom of deep lakes above or near CO ₂ site. Install siphon tubes to bring deep waters to the surface to allow gradual CO ₂ release and prevent stratification and CO ₂ buildup.
156	03.03.07.00.	Co-migration of other gases	Surface seepages of CO₂ may contain significant amounts of other gases due to co-migration, such as hydrogen sulfide (H₂S). This is especially the case where the CO₂ reservoir is a reducing chemical environment. H₂S is derived from the hydration of sulfide minerals (e.g. FeS₂) or from the chemical reduction of aqueous sulfate species. H₂S is highly toxic and therefore potentially harmful to the biosphere. Even in low concentrations it is deleterious to long-term health (human/animal), in addition to being extremely unpleasant.	The co-migration of other gases to the surface environment may cause areas of leakage to become uninhabitable – at least temporarily. The detection of H₂S provides a quick (non-analytical/aesthetic) test for CO₂ escape and thus can be used as a "marker" gas.	Most of the hydrocarbon gases have been depleted from the reservoir. The produced gas contains over 80% CO ₂ and has a small amount of H ₂ S.	Composition of produced gases before and after/during CO ₂ injection?	Human injury/death due to release of CO ₂ +H ₂ S and other gases into the atmosphere.	Co-migration of CO ₂ and other gases.	More severe HSE hazard than CO ₂ alone. Damage to well, production and recycling systems and potential release of gases to the atmosphere.	Detection of H ₂ S odor in the atmosphere.	Maintain integrity of the caprock wells and recycling system. Use proper materials of construction. Maintain tight seals and failsafe systems.	Monitor for H₂S near wells, recycling facilities and confined areas. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO₂/H₂S leak.
157	03.03.08.00.	Diffusion of CO ₂	Diffusion is the net movement of a constituent in response to a concentration gradient. Diffusion always results in mass transfer from the region of high concentration to regions of low concentration. Diffusion will occur in conjunction with flow, but it will also occur in the absence of flow, and it is the primary transport mechanism in the absence of flow (as through a highly impermeable rock).	Diffusion is a transport process by which CO₂ can access portions of the reservoir that are not directly exposed to advective flow. It can also be a primary transport mechanism in highly impermeable rocks such as caprock.	Diffusion of CO ₂ is an extremely slow process and is unlikely to impact the surface environment. The reservoir and caprock is overlain by limestone sinks and several thousand feet of Permian seals consisting of salt, gypsum, anhydrite and red shale formations.	Number, thickness and vertical permeability of seals overlying the FWU reservoir?	CO ₂ movement through caprock.	Diffusion of CO ₂ .	Leakage of CO ₂ above caprock.	Monitoring for CO ₂ above caprock.	Select site with thick, impermeable caprock and multiple stacked seals.	Monitor fresh water aquifers above the caprock for CO₂. Monitor and ventilate confined spaces above the reservoir.
158	04.00.00.00.	GEOSPHERE	This category of FEPs is concerned with the geology, hydrogeology and geochemistry of the geosphere. The category covers the reservoir, overburden and surrounding rock up to the near-surface which is considered in a separate FEP category. Taken together, the FEPs in this category describe what is known about the natural system prior to sequestration operations commencing. The category is divided into three classes: Geology, Fluids, and Geochemistry.	This category is divided into three classes: 1. Geology 2. Fluids 3. Geochemistry								
159	04.01.00.00.	Geology	Geological features of the geosphere, which comprises of the reservoir, overburden and surrounding rock prior to injection of CO₂.	An understanding of the natural system into which the carbon dioxide is injected is essential for the assessment of long-term performance and safety.								

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155	03.03.06.01.	Limnic eruption	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
156	03.03.07.00.	Co-migration of other gases	3	4	1	12	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	Covered under natural resource damage	Damage due to corrosion of compressor, pipeline and well components <\$1M per incident.	1-5 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$4M	None	Monitor for H2S around injection wells and recycle facilities. Maintain tight seals and failsafe systems <\$300k	Up to \$3.7M	1
157	03.03.08.00.	Diffusion of CO2	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
158	04.00.00.00.	GEOSPHERE	0	0	0	0															
159	04.01.00.00.	Geology	0	0	0	0															

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Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
160	04.01.01.00.	Geographical location	The geographic location of a CO2 storage reservoir will influence the type of impacts to consider, e.g. continental or sub-marine, in the vicinity of a volcano, or tectonic activity, etc. In addition, proximity to human populations will increase importance of any release to the surface. 1. Onshore reservoir 2. Offshore reservoir 3. Near volcanic or tectonic activity 4. In densely populated areas	Proximity to natural hazards will increase their importance in being considered in the assessment. Proximity to human populations place more emphasis on the significance of near-surface releases. The potential impact on human beings of a sudden release of CO2 from an onshore reservoir will be higher than from an onshore reservoir (Damen 2006) The potential impact on human beings of a sudden release of CO2 from an offshore reservoir will be lower than from an onshore reservoir (Damen 2006). However CO2 storage costs are likely to be higher for offshore reservoirs.	The FWU Site is over 80% cropland and has very low population density. Other than weather, there are no known natural hazards.		Selection of project site that would subject the project to significant natural hazards or liabilities.	Geographical location.	Failure of project to be permitted. Failure of project to be financed. Failure of project to proceed. CO2 leakage. HSE damage including loss of life.	Conduct risk assessment on site selection.	Maintain integrity of the caprock wells and recycling system. Use proper materials of construction. Maintain tight seals and failsafe systems. Protect surface facilities from severe weather.	Monitor for H2S near wells, recycling facilities and confined areas. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/H2S leak severe weather or earthquake.
161	04.01.02.00.	Natural resources	Natural resources within the geosphere including: solid mineralogical resources, such as coal or minerals, fluid and gaseous resources, such as hydrocarbons (EOR and ECBM) or water, and other resources such as geothermal or microbial resources. Deep aquifers with high porosity suitable for CO2 storage would also be potentially suitable for geothermal energy production. (CO2STORE, page 70) Rights to pore space normally stay with the owner of the surface land. However, this may vary from state to state. Although saline water has few uses currently, these resources are protected by mining law in some EU states. And in some countries and states, brines legally are classified as groundwater and protected by law. (CO2STORE page 70). Depths for known natural major CO2 fields range from 200 to 5,000 m (656 to 16404 ft). (CCP 2009) 1. Mineral resources 2. Coal seams 3. Oil resources 4. Natural gas resources 5. Underground drinking water sources 6. Geothermal resources 7. Pore space owned by others 8. Saline water 9. Natural CO2	The presence of natural resources may mean that future human exploitation of the system cannot be ignored in assessing long-term performance since they may increase the possibility of future human intrusion. Owners of mineral rights could claim primacy over CO2 injection. Unmineable coal seams could become mineable with robotic mining systems. There may be adjacent oil properties owned by third-parties that could be contaminated by CO2 injection. Natural gas could be released when drilling and injecting CO2. CO2 mixed with natural gas would need to be captured and reinjected. Underground drinking water could be contaminated by CO2 or displaced brine. CO2 combined with water could lead to corrosion of geothermal systems. CO2 from adjacent injection projects could infringe the project's pore space. Increased demand for water and improvement in desalination technologies could convert deep saline aquifers into valuable natural resources which could lead to restrictions on CO2 injection into deep saline aquifers.	1. No mineral resources have been identified in the FWU area. 2. No mineable coal seams have been identified in the site area. 3. Oil and gas resources have been found in the Cleveland and Marmaton formations (above the Upper Morrow reservoir). 4. USDW is limited to the Ogallala aquifer. 5. No geothermal resources have been identified. 6. The FWU produced water has a salinity of 4,000 mg/L TDS which falls into the category of USDW, but it is an exception to the rule because it is an oil reservoir. 7. Natural CO2 has not been found.	Presence of gas and oil resources above and below the FWU reservoir (formation, magnitude, recoverability)?	Contamination of third-party natural resources with CO2 and/or brine.	Natural resources adjacent to the injection site.	Liability for decontamination of natural resources, business interruption and advanced loss of profits. Monitor and model CO2 plume and brine movement. Monitor CO2 and salinity in sensitive areas.	Conduct baseline survey of CO2 and salinity measurements in sensitive areas before injecting CO2. Monitor and model recovering shale gas Morrow Shale while maintaining the integrity of the seal.	Avoid fracturing the Morrow Shale. Evaluate the existence and feasibility of recovering shale gas Morrow Shale while maintaining the integrity of the seal. Inject sealants to seal up fractures that may release CO2/H2S. Maintain mechanical integrity of wells, recycling systems and seals.	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
160	04.01.01.00.	Geographical location	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
161	04.01.02.00.	Natural resources	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	None	1-15 days @ \$15,000/d revenue lost per pattern idled Cost to locate and fix leaky well: \$0.3M Cost to locate and fix leaky fault or fracture zone: \$3M	Cost to locate and fix leaky well: \$0.3M Cost to locate and fix leaky fault or fracture zone: \$3M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Up to \$4M	None	Avoid fracturing Morrow Shale.	Up to \$4M	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
162	04.01.03.00.	Reservoir type	The generic type of reservoir being considered for storage of CO2. Brownfield developments, for example in mature oil and gas fields, will offer the benefit of beginning with a well-characterized system and a significant amount of infrastructure. However, field redevelopments for CO2 storage will require a significant amount of work to assess the integrity and re-usability of existing well, flow lines and facilities. (CCP 2009) Greenfield developments, such as deep saline aquifers, require significant new infrastructure and additional initial characterization work and are associated with greater uncertainty. A steeper learning curve is to be expected and modifications to an initial development plan may occur as additional knowledge is gained during early development work. (CCP 2009) 1. Oil reservoir - EOR (such as the Weyburn project); 2. Gas reservoir (such as the Coal-Seq project); 3. Deep saline aquifer (such as at Sleipner); and 4. Coal seams - ECBM (such as the Coal-Seq and RECOPOL projects). 5. Brownfield site 6. Greenfield site	The generic reservoir type will provide a high-level indication of the geological characteristics of the storage location. It will also contribute towards the extent and type of historical exploitation of any geological resources. Development of brownfield sites can expect to include a significant number of well re-completions, abandonments and possibly re-abandonment of old wells, new drilling and upgrades to surface infrastructure. (CCP 2009) Greenfield sites require more time and money to develop sufficient site characterization data but are less likely to have leakage through existing wells due to the lack of existing wells.	The FWU is a partially depleted oil reservoir incorporating CO2-EOR. The brownfield site is well characterized with over 130 deep wells and 3D seismic surveys. The oil field has been producing since 1956.		NA	NA	NA	NA	Take into account the reservoir type and historical uses in characterizing, modeling and selecting a site.	NA
163	04.01.04.00.	Reservoir geometry	Geometry of the CO2 storage reservoir including the spatial distribution, depth and the topography of the top.	The geometry of the storage reservoir helps to determine the capacity of the geosphere. The geometry of the top is particularly important because supercritical CO2 is buoyant and will therefore migrate to the top of a reservoir. Once at the top of the reservoir, it will migrate according to the precise topography of the top. Local "high" could produce small-scale traps within the overall aquifer; bigger structures would produce bigger traps. Spill points are determined by the lowest point that can retain the sequestered CO2.	The reservoir top gently slopes from the northwest to the southeast corner of the FWU at 1.2% or 12 m/km (65 ft/mile)	Map of the top of the reservoir?	Migration of CO2 outside of project site.	Improper reservoir geometry for CO2 storage.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Monitoring and modeling CO2 plume and brine migration.	Take into account reservoir geometry in characterizing, modeling.	NA
164	04.01.04.01.	Reservoir depth (Reservoir hydrostatic pressure)	The hydrostatic pressure varies with depth. It is desirable to store CO2 at depths greater than approximately 800-1000 m where the hydrostatic pressure will maintain CO2 in a supercritical (dense) phase. (CCP 2009). Excessive depth will result in excessive hydrostatic pressure, which will require higher CO2 injection pressure. 1. Insufficient reservoir depth 2. Insufficient hydrostatic pressure 3. Excessive reservoir depth 4. Excessive hydrostatic pressure	Insufficient reservoir depth may result in pressures that are too low for keeping CO2 in a supercritical state. Excessive depth will require higher CO2 injection pressure and increase cost of CO2 injection..	Average depth at FWU to the top of the Buckhaults Sandstone: 2,362 m (7,750 ft) Range of depth at FWU to the top of the Buckhaults Sandstone: 2,323 to 2,486 m (7,620 to 8,155 ft) (Grigg 2012). This is sufficiently deep for CO2-EOR and sequestration, but not excessively deep.		Pressure too low to keep CO2 in supercritical state. Pressure too high.	Insufficient reservoir depth (hydrostatic pressure). Excess reservoir depth (hydrostatic pressure).	Potential for CO2 to revert to gas phase, decreasing CO2 storage capacity Excess operating costs to pressurize CO2.	Measurement of bottom hole pressure.	Take into account reservoir depth and hydrostatic pressure in characterizing, modeling.	NA

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
162	04.01.03.00.	Reservoir type	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
163	04.01.04.00.	Reservoir geometry	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
164	04.01.04.01.	Reservoir depth (Reservoir hydrostatic pressure)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
165	04.01.04.02.	Reservoir thickness	Normally, a formation thickness of around 20 m (66 ft) would be considered as a minimum requirement, but this varies with injection volume requirements. 1. Insufficient reservoir thickness	Insufficient reservoir thickness will result in an extended CO2 plume and limit the storage capacity of the reservoir	The reservoir thickness ranges from 3 to 16 m (10 to 55 ft) with an average thickness of 6.66 m (22.5 ft) net pay.		Insufficient CO2 storage capacity.	Insufficient reservoir thickness.	Business interruption. Added capital and operating costs.	Historical drilling records, drill core analyses, well logging and seismic surveys.	Take into account reservoir thickness in characterizing and modeling.	NA
166	04.01.04.03.	Reservoir lateral continuity (spatial distribution)	Lateral flow barriers can include unconformities or pinch-outs that erode the porous and permeable material and provide direct contact to a low permeability seal, faults and naturally over pressured zones. 1. Insufficient reservoir lateral continuity	Insufficient lateral continuity (or spatial distribution) of a reservoir will limit its CO2 storage capacity	Based on the isopach map in Grigg 2012, the FWU reservoir appears to be relatively continuous within the FWU site, except for a small area in the very center. The reservoir thins out before it reaches the borders of the FWU site except in the Northeast and Southeast corners.	Verify reservoir lateral continuity and seals?	Insufficient CO2 storage capacity.	Insufficient reservoir lateral continuity (spatial distribution).	Business interruption. Added capital and operating costs.	Historical drilling records, drill core analyses, well logging and seismic surveys.	Take into account reservoir lateral continuity in characterizing and modeling.	NA
167	04.01.04.04.	Reservoir top topography	Reservoirs with dipping top topography (monocline) are susceptible to buoyancy-driven up dip CO2 migration. The migration up dip may enhance CO2/brine contact and CO2 dissolution in the brine. The preferred top topography is an anticline or dome structure to restrict the flow of injected CO2 on multiple sides. Spill point is the lowest point that can retain sequestered CO2. 1. Flat 2. Monocline 3. Dome 4. Anticline 5. Shallow spill points	Flat top topography of the reservoir may make it difficult to contain the CO2 plume Dipping top topography of the reservoir may make it difficult to trap buoyant CO2. Injected CO2 migrates up dip out of closure. Shallow spill point in a dome structure may limit the amount of CO2 that can be locally contained in a reservoir	The reservoir top gently slopes from the northwest to the southeast corner of the FWU at 1.2% or 12 m/km (65 ft/mile)	Map of the top of the reservoir?	Uncontrolled buoyant migration of CO2 beyond project area.	Reservoir top topography.	CO2 leakage (HSE hazard). Contamination of adjacent pore space, natural resources (including water).	Historical drilling records, drill core analyses, well logging and seismic surveys.	Take into account reservoir top topography in characterizing and modeling.	NA
168	04.01.04.05.	Reservoir buffer zone for CO2 plume	The buffer zone represents additional land owned or leased beyond the ultimate extent of the CO2 plume. 1. Insufficient buffer zone for CO2 plume	Insufficient buffer zone may result in CO2 plume infringing on third-party pore space.	The FWU reservoir thins out near the borders of the FWU site based on the isopach map in Grigg 2012.	Existing buffer zone around the reservoir?	CO2 migration beyond project area.	Insufficient reservoir buffer zone.	CO2 leakage (HSE hazard). Contamination of adjacent pore space, natural resources (including water).	Historical drilling records, drill core analyses, well logging, seismic surveys and modeling to estimate ultimate extent of CO2 plume. CO2 monitoring to determine actual extent of CO2 plume.	NA	NA
169	04.01.04.06.	Reservoir CO2 storage capacity	Reservoir CO2 storage capacity is primarily determined by pore volume. Insufficient reservoir storage capacity.	Insufficient reservoir storage capacity will require alternative storage site(s). Increased storage costs.	A conservative estimate of the CO2 storage capacity of the Morrow within the FWU exceeds 10 million tonnes (based only on rough estimates of formation volume and porosity). As the SWP gains possession of production data and other reservoir data, more accurate estimates of capacity will be made (SWP 2013). 10 Mt of CO2 = 13.24 Mm3 at reservoir conditions = 0.582 HCPV = 0.40 total pore volume in the FWU.	Reservoir CO2 storage capacity?	CO2 migrating out of project area. Limitation on CO2 injection.	Insufficient CO2 storage capacity.	CO2 leakage (HSE hazard). Contamination of adjacent pore space, natural resources (including water). Early shutdown of CO2 injection.	Historical drilling records, drill core analyses, well logging, seismic surveys and modeling to estimate ultimate extent of CO2 plume. CO2 monitoring to determine actual extent of CO2 plume.	Characterize and model CO2 storage capacity of the reservoir. Use a conservative estimate.	NA

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
165	04.01.04.02.	Reservoir thickness	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
166	04.01.04.03.	Reservoir lateral continuity (spatial distribution)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
167	04.01.04.04.	Reservoir top topography	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
168	04.01.04.05.	Reservoir buffer zone for CO2 plume	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	NA
169	04.01.04.06.	Reservoir CO2 storage capacity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
170	04.01.04.07.	Reservoir lateral sealing	Lateral flow barriers can include unconformities or pinch-outs that erode the porous and permeable material and provide direct contact to a low permeability seal, faults and naturally over pressured zones. 1. Open reservoir (lack of lateral sealing of reservoir) 2. Closed reservoir 3. Semi-closed reservoir	Potential for CO2 plume to infringe on third-party pore space or escape if lateral seal is lacking.	The FWU reservoir thins out near the borders of the FWU site based on the isopach map in Grigg 2012.	Reservoir lateral continuity and seals?	CO2 migration beyond project area.	Lack of reservoir lateral sealing.	CO2 leakage (HSE hazard). Contamination of adjacent pore space, natural resources (including water).	Historical drilling records, drill core analyses, well logging, seismic surveys and modeling to estimate ultimate extent of CO2 plume. CO2 monitoring to determine actual extent of CO2 plume.	Take into account lateral sealing in characterizing and modeling. Select reservoir with lateral sealing.	Monitor and model CO2 plume and brine movement. Use injection water curtains to keep CO2 flow within patterns.
171	04.01.04.08.	Reservoir and caprock structural geology complexity	In tectonically complex areas, there are too many small structures to be identified, delineated and investigated individually. Reservoir and caprock structural geology too complex	Complex structural geology may result in greater difficulty in modeling, monitoring and controlling CO2 storage.	The reservoir and caprock structural geology is not complex. The reservoir top and caprock bottom gently slope from the northwest to the southeast corner of the FWU at 1.2% or 12 m/km (65 ft/mile). They are laterally continuous across the FWU Site.		Low oil recovery CO2/brine release	Complexity of reservoir and caprock structural geology	Low revenues and/or higher operating costs.	Characterization and modeling of reservoir and caprock structural geology. Comparison of model predictions with actual performance.	Characterization and modeling of reservoir and caprock structural geology to optimize reservoir engineering.	Monitor and model oil, water and CO2 production. Evaluate root cause for unexpected results. Mitigate problems with complex structural geology by adjusting well spacing, pattern type, selective perforation, water injection curtains, WAG
172	04.01.04.09.	Reservoir compartmentalization	A once continuous reservoir can become compartmentalized. CO2 migration restricted to an isolated part of the formation. Unexpected bottom hole pressure increase. Pressure transient analysis suggests hydraulically isolated wells.	Greater difficulty in modeling, monitoring and controlling CO2 storage.	Geological work suggests an east-west fault running across much of the West half of the FWU, along the Southern edge of tracts 7, 8, 13 and 14. A pressure falloff test of well 13-3 conducted in 1986 showed some evidence of a barrier to flow. (May 1987).	Presence of compartmentalization at FWU?	Low oil recovery	Reservoir compartmentalization.	Low revenues and/or higher operating costs.	Characterization and modeling of reservoir for compartmentalization. Monitoring bottom hole pressure and CO2 plume.	Characterization and modeling of reservoir for compartmentalization to optimize reservoir engineering. Sufficient wells exist to overcome any problems with compartmentalization.	Monitor and model oil, water and CO2 production. Evaluate root cause for unexpected results. Mitigate problems with complex structural geology by adjusting well spacing, pattern type, selective perforation, water injection curtains, WAG.
173	04.01.04.10.	Reservoir temperature (See 04.01.13.00.)										
174	04.01.04.11	Reservoir rock thermal properties	Rock thermal properties included: 1. Thermal conductivity 2. Heat capacity 3. Thermal expansion coefficient	These properties will dictate how fast the rock will change temperature in response to injected CO2 that is warmer or cooler than the reservoir, and they will also dictate whether fracture or pore permeability will increase or decrease as a result of temperature changes in the rock mass.	Prock thermal properties for the FWU are not publicly available. Information may become available after characterization wells are drilled and cores analyzed as part of the SWP project.	Reservoir rock thermal properties at FWU?	Slow increase or decrease in rock temperature and expansion or contraction when CO2 is injected. Fast increase or decrease in rock temperature and expansion or contraction when CO2 is injected; fracture of reservoir r and/or seal rock due to thermal shock.	Low thermal properties. High thermal properties. Migration of CO2 out of reservoir along induced thermal fractures.	Increase or decrease in rock temperature, injectivity and rock volume. Potential leakage through caprock into USDW aquifers or biosphere.	Measure thermal properties of reservoir rock samples and include the results in modeling. Monitor aquifer chemistry and atmospheric concentrations.	Characterization and modeling of reservoir rock thermal properties. Keep CO2 injection temperature and rate compatible with desired reservoir temperature.	Monitor reservoir temperature. Adjust CO2 injection temperature, rate or WAG to control rock temperature if necessary.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
170	04.01.04.07.	Reservoir lateral sealing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
171	04.01.04.08.	Reservoir and caprock structural geology complexity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
172	04.01.04.09.	Reservoir compartmentalization	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
173	04.01.04.10.	Reservoir temperature (See 04.01.13.00.)	0	0	0	0															
174	04.01.04.11	Reservoir rock thermal properties	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
175	04.01.05.00.	Reservoir exploitation	Degree to which geological resources (such as oil and gas) have been exploited prior to the injection of CO2. 1. Existing boreholes 2. Oil previously removed 3. Gas previously removed 4. Existing mine workings (for ECBM) 5. In-situ gasification (for ECBM) 6. Natural gas storage 7. Compressed air storage 8. Radioactive waste storage 9. Hazardous waste disposal (Class 1 wells) 10. Water extracted	The extent of previous exploitation will help to determine the initial state of a storage reservoir. For example: - the existence and nature of boreholes; and - the presence of geological resources, such as oil and gas. Previous exploitation of the storage reservoir area will improve the amount of historical information available concerning the reservoir characteristics.	The FWU has 169 deep wells penetrating the caprock. Primary oil production began in 1956. Secondary waterflooding began in 1968. CO2 flooding began at the end of 2010. Gas and oil have been reported in the Cleveland and Marmaton formations, located above the caprock at the FWU.		Pre-CO2 injection caprock or reservoir damage. Pre-existing CO2 in pore space (e.g. from EOR).	Reservoir previous exploitation.	1. Permitting delays or restrictions. Cleanup liability litigation. 2. CO2 leakage (HSE hazard). 3. Decreased reservoir capacity.	Survey historical records and documents on the site that may indicate potential problems or risks for CO2 storage. Conduct baseline survey for pre-CO2 injection site contamination and damage.	Take into account reservoir previous exploitation in characterizing and modeling.	Monitor and model CO2 and water injection and oil, water and CO2 production. Use selective perforation, avoid or seal fractures. Use injection water curtains.
176	04.01.06.00.	Caprock or sealing formation	The nature of the relatively impermeable layer of rock overlying the storage reservoir that forms a barrier to the upward migration of buoyant fluids, such as sequestered CO2.	The caprock or sealing formation plays a key roll in preventing the sequestered CO2 from migrating to the surface environment.	The Morrow Shale acts as a caprock over the reservoir. It is laterally continuous across the FWU site. The presence of an initial gas cap in the FWU reservoir indicate that the caprock provides an effective permeability barrier (Parker 1956)	Caprock description and properties?	CO2 migration through caprock.	Caprock or sealing formation lack of integrity	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock for sealing integrity. Monitor pressure in formations above the caprock.	Characterize and model caprock for sealing integrity. Avoid areas lacking sealing integrity. Maintain injection pressures below 90% of fracture pressure.	Monitor pressure in formations above the caprock. Monitor boreholes, permeable zones, faults, fracture zones, that penetrate the caprock, for CO2/H2S leakage. Isolate areas lacking sealing integrity with water curtains. Inject sealants into fractures.
177	04.01.06.01.	Caprock geometry	Geometry of the caprock including the spatial distribution, depth and the topography of the bottom.	CO2 migration diverges from expected path. Significant CO2 volumes migrate off structure. Insufficient capacity for planned injection volume of CO2. Unexpected pressure increase during injection.	The Morrow Shale Formation is a monocline that gently slopes from the northwest to the southeast at 1.2% or 12m/km (65 ft/mi).		CO2 migration around caprock	Caprock geometry.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock geometry. Monitor pressure in formations above the caprock.	Characterize and model caprock geometry. Avoid sites where caprock geometry is not amenable for CO2 storage.	Monitor and model CO2 plume and brine migration. Remediate uncontrolled migration by injecting/extracting water, depressuring reservoir, relocating CO2 injection or extracting CO2 and reinjecting into a more secure reservoir. Select sites with multiple stacked seals and sinks.
178	04.01.06.02.	Caprock thickness	Greater thickness improves the strength and sealing capacity of the caprock. Preferred caprock thickness:> 100m Minimum caprock thickness: >20m	Insufficient caprock thickness could lead to caprock failure and/or release of CO2 from the reservoir.	the Morrow Shale Formation is 24 m (80 ft) thick in the northwest corner of the FWU and 29 m (95 ft) thick in the southeast corner.		CO2 migration through caprock.	Thin caprock.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize the caprock thickness based on historical drilling records, drill core analyses, well logging, seismic surveys and modeling.	Include caprock thickness in characterization and modeling. Avoid sites with thin caprock, unless reinforced with multiple stacked secondary seals.	Monitor pressure in formations above the caprock. Identify and remediate leaks.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Risk Ranking		Estimated Potential Damage Recovery Costs														Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)					
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)																
175	04.01.05.00.	Reservoir exploitation	3	3	2	18	None	None	None	None	None	None	None	None	None	None	<\$3M/y	None	<\$3M/y	None	1
176	04.01.06.00.	Caprock or sealing formation	2	3	3	18	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	None	None	None	Cost to locate and fix leak in fault, fracture zone or high permeability pathway in caprock	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for five years: Up to \$5M for water remediation	Assuming leakage detected early and mitigated: <\$1M for water remediation	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Savings: Up to \$1M	1
177	04.01.06.01.	Caprock geometry	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
178	04.01.06.02.	Caprock thickness	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
179	04.01.06.03.	Caprock discontinuous	Caprock discontinuities can be caused by unconformities or pinchouts.	CO2 escapes through gap in caprock into higher formation or aquifer	The caprock appears to be laterally continuous across the entire FWU Site.	Caprock lateral continuity?	CO2 upward migration through discontinuous portion of caprock.	Discontinuous caprock.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock for continuity based on historical drilling records, drill core analyses, well logging, seismic surveys.	Characterize and model caprock for continuity. Avoid sites with discontinuous caprock that might impact CO2 storage integrity.	Monitor pressure in formations above the caprock. Identify and remediate leaks.
180	04.01.06.04.	Caprock geochemical properties	CO2 chemical reaction with caprock can weaken the physical strength of the caprock. High permeability zones might exist or be formed by reaction of CO2 with the caprock, causing the caprock to dissolve. CO2 can dehydrate clay shales in the caprock, thereby increasing its permeability. (Damen 2006)	Unintended migration of CO2 by chemical reaction induced breaching of the caprock.	Information not publicly available. Probability and severity based on typical shale caprock. Information may become available after characterization wells are drilled and cores analyzed as part of the SWP project.	Caprock geochemical properties?	Geochemical failure of caprock.	Caprock geochemically reactive with CO2.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterization and modeling of caprock geochemical properties based on drill core analyses.	Characterization and modeling of caprock geochemical properties based on drill core analyses. Avoid sites with caprock that would be highly reactive with CO2.	Monitor pressure in formations above the caprock. Identify and remediate leaks.
181	04.01.06.05.	Caprock geomechanical properties	Low fracturing pressure	Could limit CO2 injection rate. Increased CO2 injection cost. In general, the mechanical behavior of shale will show more elastic change and is more resistant to elevated pressure than other brittle hard rock.	Fracture pressure estimated to be approximately 45.78 MPa (6,640 psi).	Caprock geomechanical properties? Caprock fracture pressure?	Mechanical failure of caprock.	Caprock geomechanical weakness.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterization and modeling of caprock geomechanical properties based on drill core analyses.	Characterization and modeling of caprock geomechanical properties based on drill core analyses. Avoid sites with mechanically weak or over stressed caprock. Avoid injection pressures exceeding 90% of fracture pressure.	Monitor and model geomechanical stress in caprock. Monitor pressure in formations above the caprock. Identify and remediate leaks.
182	04.01.06.06.	Caprock permeability	The permeability of a caprock capable of retaining fluids through geologic time is approximately 0.001 to 0.00001 milli-darcies (mD). Mudstone caprock permeability is typically less than 0.001 mD.	Permeable zones in the caprock could form CO2 pathways of escape.	The presence of an initial gas cap in the FWU reservoir indicate that the caprock provides an effective permeability barrier (Parker 1956)	Caprock permeability (vertical and horizontal, average and range)?	CO2 migration through high permeability zone in caprock.	Caprock high permeability zone.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock permeability.	Characterize and model caprock permeability. Avoid or isolate areas with high caprock permeability.	Monitor pressure in formations above the caprock. Isolate high permeability zones with injection water curtains and/or sealants.
183	04.01.06.07.	Caprock capillary entry pressure	No rocks have zero porosity, but the sealing layer provides a seal because the pore throats are too small to permit CO2 to enter the water-filled pores. (CCP 2009)	If the CO2 injection pressure exceeds the capillary pressure of the caprock, CO2 can penetrate or pass through the caprock	Caprock capillary entry pressure not expected to have any significant impact on containment. There are multiple stacked seals and sinks located above the caprock.	Caprock capillary entry pressure?	CO2 migration through caprock.	Caprock capillary entry pressure exceeded.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock capillary entry pressure. Monitor CO2 injection pressure.	Characterize and model caprock capillary entry pressure. Avoid injection pressures exceeding caprock capillary entry pressure.	Monitor CO2 injection pressure. Monitor pressure in formations above the caprock.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
179	04.01.06.03.	Caprock discontinuous	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
180	04.01.06.04.	Caprock geochemical properties	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
181	04.01.06.05.	Caprock geomechanical properties	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
182	04.01.06.06.	Caprock permeability	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
183	04.01.06.07.	Caprock capillary entry pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
184	04.01.06.08.	Caprock fracture pressure	The critical pressure to avoid exceeding is the fracture pressure of the confining interval (caprock) above the reservoir, which is normally higher than the fracture pressure in the injection interval. (CCP 2009) Maximum injection pressure is typically at least 0.34 MPa (50 psi) below fracture pressure. EPA UIC Class VI regulations limit CO₂ injection pressure to 90 percent of fracture pressure.	If the CO ₂ injection pressure exceeds the fracture pressure of the caprock, the caprock could fracture and allow CO ₂ to pass through the caprock.	Fracture pressure estimated to be approximately 45.78 MPa (6,640 psi).	Caprock fracture pressure?	Caprock fracturing.	Caprock fracture pressure exceeded.	Leakage of CO ₂ (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model caprock fracture pressure. Monitor CO ₂ injection pressure and micro seismicity.	Avoid sites with fractured caprock. Keep injection pressure below 90% of caprock fracture pressure.	Monitor injection pressure. Monitor pressure in formations above the caprock. Passive micro-seismic monitoring. Isolate fractured area with injection water curtains and/or sealant.
185	04.01.07.00.	Additional seals and sinks (secondary seals)	This concerns the concept of successive lithological, hydraulic and/or chemical barriers acting successively to prevent fluid escape to surface environments. From a geological point of view the permeability barrier is probably the most important, in comparison with other types of traps. However, it may be necessary to consider a sequence of traps in CO₂ migration models in addition to the conventional low permeability barriers. For example, within the Weyburn sequestration project, the primary caprock is the Watrous formation, however, low permeability formations at higher stratigraphical layers provide potential additional seals, preventing upward migration of sequestered CO₂. Stacked reservoirs consist of multiple alternating seals and reservoirs above the primary reservoir. The additional reservoirs can provide a back up for CO₂ containment if the primary seal is broken. 1. Multiple stacked seals 2. Multiple stacked reservoirs	Without multiple stacked seals and sinks there is no fallback position if CO ₂ escapes through the primary seal.	There are multiple stacked sinks and seals above the caprock. Several limestone and sandstone sinks are directly above the caprock. These are overlain by several salt, gypsum, anhydrite and red shale seals.	Detailed stratigraphic column, lithology, depths and thicknesses for formations above the caprock?	Failure of primary seal without backup seals and sinks.	Lack of additional seals and sinks	Leakage of CO ₂ (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Characterize and model site, including primary and secondary seals and sinks. Monitor for CO ₂ and salinity in secondary sinks above the primary seal.	Take into consideration multiple-stacked seals and sinks in site characterization, modeling and selection.	Monitor pressure in formations above the caprock. Isolate CO ₂ pathway with injection water curtains and/or sealants.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
184	04.01.06.08.	Caprock fracture pressure	2	4	3	24	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	None	None	None	Cost to locate and fix leak in fault, fracture zone or high permeability pathway in caprock	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	Assuming leakage detected early and mitigated: \$1M for water remediation	Monitor pressure in overlying formations. Continuous passive micro- seismic monitoring: Capex: \$3.9M Opex: \$0.3M/y Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	None	1
185	04.01.07.00.	Additional seals and sinks (secondary seals)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
186	04.01.08.00.	Lithology	The systematic description of rocks in terms of their mineral assemblage and texture. The lithology of the geosphere (including both the reservoir and the caprock) determines the reservoir physical and transport properties (including porosity and permeability). It concerns the mineralogical composition, texture (grain size, sorting) and fabric (sedimentary structures, vertical and horizontal heterogeneities). Potential reservoir lithologies include sandstones and limestones. 1. Caprock lithology 2. Reservoir lithology	The physical and chemical and mineralogical properties of the reservoir rocks affect: the capacity to store CO2; fluid flow and CO2 migration; determine which water-rock reactions can take place; and influence the rock strength and elastic properties (such as compressibility, shear strength, Poisson's ratio etc).	The upper Morrow reservoir in the FWU vary from siliceous coarse grained sandstones to gritty quartz conglomerates. The reservoir can grade vertically and laterally with great rapidity into finer or coarser sediments. Definite bedding planes are present. The matrix is composed almost entirely of kaolinitic material which contains shards of feldspar and quartz. Several of the cores observed contained phantom feldspar crystals which were entirely composed of kaolinitic material. This evidence coupled with the above mentioned shards indicate the derivation of the kaolinite to be from feldspars and the reservoir, as a whole, from original granitic type igneous rock (Parker 1956). The Buckhaults sandstone is a coarse to very coarse-grained, arkose to arkosicwacke. Grain size distributions, sedimentary structure analysis, and sand-body geometry indicate that the Buckhaults was deposited in a fluvial-deltaic environment as distributary channel and distributary mouth bar sands. Depositional strike is northwest to southeast. The proposed source area for the	Detailed stratigraphic column and lithology for formations above the reservoir? Information may become available after characterization wells are drilled and cores analyzed as part of the SWP project.	Caprock failure. Uplift or subsidence. Loss of reservoir porosity, permeability, injectivity.	Lithology	1. Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Take into account lithology of caprock and reservoir in characterizing and modeling sites.	Take into account lithology of caprock and reservoir in characterizing and modeling sites.	Monitor and model CO2, H2S and brine migration, chemical reactions and changes in mechanical properties of rocks. Isolate CO2 pathway with injection water curtains and/or sealants.	
187	04.01.08.01.	Lithification / diagenesis	The slow physical, chemical and/or biological processes by which unconsolidated sediments become sedimentary rock. These processes can result in changes to the original mineralogy.	The state of lithification/diagenesis contributes to determining the physical and chemical characteristics of sedimentary rock. For example, porosity usually decreases during diagenesis, except in rare cases such as dissolution of minerals and dolomitization. It is very unlikely that deep subsurface geologic formations are unconsolidated. Unconsolidated formations are young in geologic time and located at shallow depths.	Nonconsolidated and partially consolidated sediments are present in the Ogallala Formation.		Decreased porosity and permeability.	Lithification / diagenesis.	Decreased CO2 storage capacity and injectivity.	Take into account lithification /diagenesis in site characterization and modeling. Monitor CO2 injectivity.	NA	NA	
188	04.01.08.02.	Pore architecture (See 04.01.08.03. and 04.01.08.04.)	Structure and density of discrete voids within the rock (pores). 1. Reduced pore volume or distribution limiting CO2 injection	The pore architecture determines the porosity and permeability of the rock, which are key features when considering the mobility of fluids and gases within the rock. Rate of long-term pressure build-up greater than expected. Increases CO2 injection cost. Need for additional wells. In EOR, pore architecture impacts sweep efficiency and oil recovery.	The reservoir porosity averages approximately 15.4% (Grigg 2012) West FWU reservoir porosity averages 14% (May 1987). West FWU reservoir horizontal permeability ranges from 20 to 3220 mD. Vertical permeability is approximately 20% of horizontal permeability (May 1987). Core data showed no strong relationship between permeability and porosity (May 2013).								

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
186	04.01.08.00.	Lithology	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
187	04.01.08.01.	Lithification / diagenesis	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
188	04.01.08.02.	Pore architecture (See 04.01.08.03. and 04.01.08.04.)	0	0	0	0															

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
189	04.01.08.03.	Reservoir porosity	Porosity values greater than 10% in carbonate formations or 15% in clastic formations are generally desirable. (CCP 2009). It is important to distinguish between total porosity and effective (flowing) porosity. Flowing porosity is what can be readily displaced by CO2 invasion. Total porosity minus flowing porosity is pore space that will likely remain occupied by residual pore fluids after CO2 invasion, although CO2 can diffuse into this pore space. 1. Total porosity 2. Effective (flowing) porosity	Low porosity makes CO2 injection more difficult and can limit the rate of injection into a reservoir. In EOR, porosity impacts oil in place and oil recovery.	The reservoir porosity averages 15.4% (Grigg 2012). West FWU reservoir porosity averages 14% (May 1987). FWU average porosity of 14.53% (Munson 1994)		Low oil in place. Low oil recovery.	Low or irregular reservoir porosity.	Decreased oil revenues	Take into account reservoir porosity in site characterization and modeling. Monitor CO2 injectivity, sweep efficiency and oil recovery.	Take into account pore architecture in site characterization and modeling. Avoid reservoir areas with low porosity and low permeability.	Identify and avoid areas with low porosity.
190	04.01.08.04.	Reservoir permeability and injectivity	Permeability measures the ability of fluids to flow through a formation. High values indicate a well-connected pore space while low values indicate convoluted conduits that disconnect the pores. Porous rocks have a wide range in permeability between around 0.1 milli-Darcy (mD) for very tight rocks, to several darcies for very permeable formations. (CCP 2009) In general, the better the porosity, the better the permeability (and thus injectivity) - however, large variations in permeability mean the porosity and permeability variations need to be mapped in detail (CCP 2009) Ideally, CO2 storage requires high permeability (>100 mD) to ensure near well bore injectivities for quick access to pore space. However, this is not always possible and near wellbore permeabilities may need to be enhanced by artificially stimulating the wells to allow for improved injectivity. (CCP 2009) Injectivity is impacted by porosity and permeability. Low injectivity can be partially compensated for by greater injection pressure and/or more wells. Decreasing injectivity can result when initial injection rate meets expectations but overall pore space is limited. Bottom hole pressure gradually increases. 1. Insufficient reservoir injectivity	Low permeability makes CO2 injection more difficult and can limit the rate of injection into a reservoir. While high permeabilities are generally desirable, very high permeability pathways or conduits can enhance CO2 migration along concentrated pathways reducing the effective storage within the target formation. (CCP 2009) In moderate to low permeability, or poorly connected reservoirs, a higher well density will be needed to limit pressure evolution and allow for efficient injection. (CCP 2009) Uncertainty in permeability could lead to high numbers of wells needed. Low reservoir injectivity will limit the rate of CO2 injection and require increased bottom hole pressure and/or more injection wells. In EOR, permeability impacts sweep efficiency and oil recovery.	West FWU reservoir horizontal permeability ranges from 20 to 3220 mD. Vertical permeability is approximately 20% of horizontal permeability (May 1987). FWU average permeability: 45.2 mD (Munson 1994)	Reservoir injectivity?	Low sweep efficiency and low oil recovery.	Low reservoir permeability and injectivity	Decreased oil revenues	Take into account reservoir permeability in site characterization and modeling. Monitor CO2 injectivity, sweep efficiency and oil recovery.	Take into account pore architecture in site characterization and modeling. Avoid reservoir areas with low porosity and low permeability.	Monitor and model CO2 injectivity, sweep efficiency and oil recovery. Use injection water curtains, selective perforation, polymer gels, foaming agents or sealants to control CO2 flow. Use acid or hydraulic fracturing stimulation to improve injectivity.
191	04.01.09.00.	Unconformities	Geological surfaces separating older from younger rocks and representing a gap in the geologic record. Such a surface might result from a hiatus in deposition of sediments, possibly in combination with erosion, or deformation such as faulting. An angular unconformity separates younger strata from eroded, dipping older strata. A disconformity represents a time of no deposition, possibly combined with erosion, and can be difficult to distinguish within a series of parallel strata. A nonconformity separates overlying strata from eroded, older igneous or metamorphic rocks. 1. Unconformities 2. Disconformities 3. Nonconformities	Unconformities can act both as potential seals or lateral migration pathways for fluids. For example, the impermeable barrier resulting from the widespread development of diagenic anhydritized carbonate associated with the unconformity between the Mississippian beds and overlying Triassic Watrous Formation in the vicinity of the Weyburn pool.	Unconformities occur at the bottom of the Ogallala Formation, bottom of the Chattanooga Shale Formation and bottom of the Simpson Formation.	Presence of unconformities, disconformities and nonconformities at FWU?	Lateral migration of CO2/brine through an unconformity.	Presence of unconformities, disconformities, or nonconformities.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Monitor and model CO2 plume and brine migration. Monitor overlying formations, soils, and water for CO2, salinity, pH.	Take into account unconformities, disconformities and nonconformities in site characterization and modeling.	Monitor and model CO2 and brine migration. Monitor pressure in formation overlying the caprock. Use injection water curtains, selective perforation, or sealant to isolate unconformities, discontinuities or unconformities that may provide CO2 leakage pathways.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
189	04.01.08.03.	Reservoir porosity	2	3	2	12	None	None	None	None	None	None	None	10% decrease in oil recovery (170 bpd): <\$5M/y	None	None	10% decrease in oil recovery (170 bpd): <\$5M/y	10% decrease in oil recovery (170 bpd): <\$5M/y	Avoid areas with low porosity.	None	2
190	04.01.08.04.	Reservoir permeability and injectivity	3	3	2	18	None	None	None	None	None	None	None	10% decrease in oil recovery (170 bpd): <\$5M/y	None	None	10% decrease in oil recovery (170 bpd): <\$5M/y	None	Cost of monitoring, modeling and mitigation steps to improve injectivity and CO2 flood uniformity: \$1M/y	\$4M/y	1
191	04.01.09.00.	Unconformities	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
192	04.01.10.00.	Heterogeneities (See 03.02.03.06.)	Heterogeneities are variations in the rock properties of a geological formation. 1. Reservoir heterogeneity 2. High permeability layers in reservoir 3. Interstitial layers of shale or baffles in reservoir 4. Caprock heterogeneity (high permeability zones) 5. Heterogeneity of overlying aquifers (more difficult to monitor for CO2) 6. Heterogeneity of porosity 7> Heterogeneity of mineralogy 8. Heterogeneity of degree of fracturing 9. Heterogeneity of geochemistry	Heterogeneities can result in directional variations in permeability, which affects the mobility of fluids and gases in the rock. For example, experience from the Saline Aquifer CO2 Storage project (SACS) has shown that both stratigraphical and structural local permeability heterogeneities have the potential to profoundly affect CO2 distribution and migration (Chadwick et al., 2003). The image below shows seismic sections through the Sleipner injection site from Zweigel et al. (2001). The strong amplitudes are taken to be CO2 accumulations.								
193	04.01.11.00.	Fractures and faults (CO2 leakage through new or existing fractures or faults)	Fractures are cracks or breaks in rock. Fractures along which displacement has occurred are called faults. Fractures and faults can occur over a wide range of scales. The presence of a fault does not imply a leakage problem. Most rocks are faulted and fractured in some way over geological time. The critical question for CO2 storage is whether there are any faults or fractures that could provide leakage pathways under present day geological conditions. In addition to the basic geometry of connected rocks and flow paths, this involves the study of geomechanics, stress fields and fracture behavior. Simply put many "faults: do not leak at all and many huge oil and gas fields that include faults prove the point. (CCP 2009)	Fractures can enhance conductivity, for example, by a conductive fracture connecting permeable regions together. They can also act as seals, by bringing a relatively permeable region into contact with low conductivity rock, for example. Movement on a fault that transverses a wellbore could damage or sever casing or tubing. CO2 might leak through open (no-sealing) faults, which extend into the caprock. CO2 might leak through natural fractures in the caprock.	Geological work suggests an east-west fault running across much of the west half of the FWU, along the southern edge of tracts 7, 8, 13 and 14. A pressure falloff test of well 13-3 conducted in 1986 showed some evidence of a barrier to flow. (May 1987)	Existing fractures and faults penetrating the caprock?	CO2 leakage through a fault or fracture zone.	Existing or new fractures and faults.	Leakage of CO2 into upper formations, aquifers, soil, surface water, or atmosphere. Take into account local faults and fracture zones in site characterization and modeling. Monitor pressure in formations near fault and fracture zones. Monitor passive seismicity and LiDAR displacement above fault.	Take into account local faults and fracture zones in site characterization, modeling and reservoir engineering. Keep injection pressure below 90% of caprock fracture pressure. Select sites with multiple stacked seals and sinks.	Monitor and model CO2 and brine migration and pressure near fault and fracture zones. Monitor pressure in formations above caprock. Isolate leaking faults or fracture zones with injection water curtains and/or sealants.	
194	04.01.12.00.	Undetected features	Natural or man-made features within the geological environment that may not be detected during site investigations. Examples of possible undetected features are fracture/fault zones, the presence of brines or old mine workings. Some physical features of the storage environment may remain undetected during site surveys and even during preliminary borehole drilling. The nature of the geological environment will indicate the likelihood that certain types of undetected features may be present and the site investigation may be able to place bounds on the maximum size or minimum proximity to such features. 1. Existing fracture/fault zones 2. Underground cavities/karsts (natural or man made) 3. Existing boreholes 4. Subsurface infrastructure (piping, underground utilities) 4. Gas chimneys 5. Shallow gas/drift gas (above bedrock) 6. Clustered small gas-related amplitude anomalies along fault planes	Undetected features could significantly affect the performance of a sequestration system. For example, local permeability heterogeneities with the potential to profoundly affect the distribution and migration of CO2 at Sleipner (within the Saline Aquifer CO2 Storage project, SACS) were only discovered after effectively being illuminated by the sequestered CO2 (Chadwick et al., 2003). Shallow gas (above bedrock) can cause drilling problems and impede monitoring.	The FWU Site has over 130 deep wells penetrating through the caprock. A 3D seismic survey has been completed. The probability of any large undetected features such as faults is extremely unlikely. Faults with limited displacement and fractures may be undetected.	Potential for undetected features at FWU?	CO2 leakage through an undetected fracture/fault zone, borehole, gas chimney or other features.	Undetected features.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Conduct ground and 3D-seismic surveys to detect underground features. Take results into consideration in site characterization and modeling.	Conduct ground and 3D seismic surveys to detect underground features. Take results into consideration in site characterization and modeling.	Monitor and model CO2 and brine migration. Monitor overlying formations for CO2/salinity/pH changes. Depressurize reservoir if leakage is detected. Extract CO2 from leaking reservoir and inject into sealed reservoir if necessary. Select sites with multiple stacked seals and sinks.	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
192	04.01.10.00.	Heterogeneities (See 03.02.03.06.)	0	0	0	0															
193	04.01.11.00.	Fractures and faults (CO2 leakage through new or existing fractures or faults)	2	3	3	18	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Potential class action lawsuit for property damage, loss of property value, reimbursement for earthquake insurance and emotional distress.	None	Shutdown of project through court ordered injunctive relief likely if multiple events of PGA(g)>0.1 (>4 magnitude earthquake)	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	Assuming leakage detected early and mitigated: <\$1M for water remediation	Monitor pressure in overlying formations. Continuous passive micro-seismic monitoring: Capex: \$3.9M Opex: \$0.3M/y Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Savings: Up to \$2M	1
194	04.01.12.00.	Undetected features	2	3	3	18	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	None	None	None	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	Assuming leakage detected early and mitigated: <\$1M for water remediation	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Savings \$2M	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
195	04.01.13.00.	Vertical geothermal gradient 04.01.04.10.	Temperature profile in the geosphere prior to the injection of CO₂. Temperature generally increases with depth, but the rate of increase varies significantly depending on the geothermal gradient. The critical temperature for CO₂ is 31.1°C. The average geothermal gradient is approximately 25°C per km. If the surface temperature is 10°C, the critical temperature will be reached at a depth of 840 m. However, a considerable variation in geothermal gradients and sub-surface temperatures can be expected at a depth of 1000 m. For example, in Europe temperatures at 1000 m range from 20 to 75°C, with local temperatures of more than 200°C in volcanic areas.	Relevant to temperature dependent physical/chemical/biological/hydraulic processes, such as CO ₂ phase behavior. Temperature, coupled with pressure, will affect the phase behavior of CO ₂ as well as the solubility of many other constituents present in the reservoir (including gases, liquids and solids.)	The vertical geothermal gradient is 0.032°C/m depth (0.022°F/ft depth). The temperature at 2362 m (7750 ft) is 75.6°C (168°F).		CO ₂ phase change from supercritical to gas underground.	High vertical geothermal gradient.	Decreased CO ₂ storage. Increase CO ₂ mobility.	Take into account vertical geothermal gradient in site characterization and modeling. Monitor bottom hole temperatures.	Take into account vertical geothermal gradient in site characterization, modeling and reservoir engineering.	Monitor and model bottom hole temperatures. Extract brine to increase CO ₂ storage capacity and control CO ₂ migration.
196	04.01.14.00.	Formation pressure	The pressure of fluids within the pores of a formation, normally hydrostatic pressure, or the pressure exerted by a column of water from the formations depth to the sea level prior to the injection of CO₂. The critical pressure of CO₂ is 7.38 MPa. The average underground hydrostatic pressure increases with depth by approximately 10.5 MPa per km for aquifers that are in open communication with surface water. Applying this average gradient, the critical pressure of CO₂ will be reached at a depth of around 690 m. However, aquifers or hydrocarbon reservoirs (e.g., EOR and ECBM) that are sealed off from the rest of the sub-surface may be under- or over pressured. 1. Hydrostatic pressure 2. Fracture pressure 3. Lithostatic pressure	Contributes towards determining the mobility of sequestered CO ₂ .	The initial reservoir hydrostatic pressure was 15.19 MPa at 2,393 m depth (2203 psia at 7,850 ft depth). Reservoir hydrostatic pressure is currently 24.13 MPa (3,500 psi) on the west and east sides and 31.72 MPa (4,600 psi) in the center of the FWU reservoir. Minimum miscible pressure (MMP) is approximately 27.58 MPa (4,000+ psi). Lithostatic pressure at 2,322 m (7,600 ft) depth is approximately 57.23 MPa (8,300 psi). Fracture pressure at 2,332 m (7,650 ft) depth is estimated to be about 45.78 MPa (6,640 psi) assuming fracture pressure is roughly 80% of lithostatic pressure.	Change in reservoir hydrostatic pressure over time?	1. CO ₂ phase change from supercritical to gas underground. 2. Formation pressure below minimum miscible pressure (MMP) for enhanced oil recovery.	Low formation pressure.	1. Decreased CO ₂ storage. Increased CO ₂ mobility. 2. Low oil yield for CO ₂ enhanced oil recovery (EOR)	Take into account formation pressure in site characterization and modeling. Monitor bottom hole pressure.	Measure bottom hole pressure. Take into account formation pressure in site characterization and modeling. Avoid sites where formation pressure is lower than CO ₂ supercritical pressure or below MMP (for EOR sites).	Monitor bottom hole pressure. Increase formation pressure by injecting water before injecting CO ₂ . Do not exceed 90% of fracture pressure.
197	04.01.15.00.	Initial stress and mechanical properties	The stress condition and mechanical properties of the geosphere prior to injection of CO ₂ .	The initial stress state and mechanical properties are a baseline from which the potential effect of injecting supercritical CO ₂ can be assessed.	Information on stress and mechanical properties not publicly available. Information may become available after characterization wells are drilled and cores analyzed as part of the SWP project.	Reservoir and caprock stress and mechanical properties?	1. Fracturing caprock. 2. Seismicity. 3. Uplift/subsidence. 4. Borehole collapse.	Initial stress and mechanical properties.	1. CO ₂ release (HSE hazard). 2. Seismic damage to surface buildings and infrastructure. 3. Change in surface water flow impacting farmland. 4. Well damage.	Conduct baseline study of initial stress state and mechanical properties of the reservoir and caprock and include these in site characterization and modeling. Monitor changes in stress state and mechanical properties over time.	Conduct baseline study of initial stress state and mechanical properties of the reservoir and caprock and include these in site characterization, modeling and reservoir engineering. Avoid sites with high stress state or low mechanical properties.	Monitor changes in stress state and mechanical properties over time. Do not exceed 90% of fracture pressure. Maintain relative balance between volume of injected fluids and volume of produced fluids.
198	04.01.16.00.	Petrophysical properties (See 03.02.03.01.; 04.01.08.03. and 04.01.08.04.)	Petrophysical properties of the geosphere prior to the injection of CO ₂ . This includes features such as permeability, porosity, residual saturation, capillary pressure and wettability.	Petrophysical properties influence how injected CO ₂ will migrate in the geosphere. For example, permeability influences the direction and rate of CO ₂ movement, and porosity and residual saturation influence the dimensions of the CO ₂ plume.								

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
195	04.01.13.00.	Vertical geothermal gradient 04.01.04.10.	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
196	04.01.14.00.	Formation pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
197	04.01.15.00.	Initial stress and mechanical properties	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
198	04.01.16.00.	Petrophysical properties (See 03.02.03.01.; 04.01.08.03. and 04.01.08.04.)	0	0	0	0															

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199	04.02.00.00.	Fluids	Details of fluids in the geosphere, which comprises of the reservoir, overburden and surrounding rock prior to the injection of CO2. Water will generally be present, but other fluids, particularly hydrocarbons (e.g., EOR and ECBM), may be important, dependent on the sequestration concept.	Water and other fluids in the sequestration system will affect the transport and interactions of injected carbon dioxide.								
200	04.02.01.00.	Fluid properties (See 03.02.13.03)	Properties of the geosphere fluids prior to injection of CO2, including composition and geochemistry. The high salinity of deep aquifers is, generally, an indication of very low or insignificant throughput of meteoric waters. 1. Fluid chemical composition and geochemistry 2. High salinity fluid 3. Fluid density	The fluid properties and geochemistry of the geosphere will contribute towards determining how injected CO2 will behave in the geosphere. Very high salinity can lead to deposition of halite in pore spaces and cause decreased permeability and injectivity.								
201	04.02.02.00.	Hydrogeology	Natural formation water flow pathways (directions, velocities) in the geosphere will be important in determining the long-term migration paths for CO2. This depends on factors including: hydraulic heads, permeability and porosity distribution, the existence of fracture networks, connection between aquifers, position of the recharge and discharge areas. 1. Natural fluid flow pathways 2. Position of aquifer recharge and discharge areas 3. Connection between deep saline aquifer and shallow drinking water aquifer	This will affect the migration of dissolved CO2 in the reservoir and the geosphere (direction, timing), the position of the interface between supercritical CO2 and aquifer water (inclined interface). There may also be a possible effect on overlying aquifers used for drinking water.	The Ogallala aquifer is unconfined and is recharged from surface precipitation and some irrigation water that penetrates through the soil. Historical recharge rate is 12.5 mm (0.5 in) per year. Recharge rate is insufficient to cover withdrawal rate for irrigation. Water saturation thickness in the Ogallala aquifer was projected to drop 0.8 m (2.7 ft) per year from 1980-2020 (Bell 1980). The Ogallala aquifer is underlain by red shale and other Permian seal formations. There does not appear to be any natural connection between the Ogallala aquifer and the FWU reservoir.	Natural fluid flow pathways? Reservoir recharge and discharge (location and rate)?	Migration of CO2/brine out of reservoir.	Hydrogeology.	CO2 contamination of groundwater aquifers	Monitoring near surface water chemistry.	Hydrogeology is not a factor in the Northern Platform reservoir.	NA
202	04.02.03.00.	Hydrocarbons	The presence and distribution of hydrocarbons, such as oil and/or gas (e.g., EOR and ECBM), within the storage system.	Hydrocarbons have potentially important implications for a storage system, by both influencing the likelihood of previous geological exploitation of the area, and by being an important component of the system with which sequestered CO2 can interact.	FWU original oil in place was 120 million STB. FWU remaining oil in place: 80 million STB. Initial oil saturation: 0.69 (May 1987). FWU current oil saturation: 0.46 An initial gas cap was present in the FWU (Parker 1956) Hydrocarbon gas has been depleted. Produced gas currently contains more than 80% CO2 and is completely reinjected along with purchased CO2. Hydrocarbons are present in the Cleveland and Marmaton Formations located above the FWU caprock.		Drilling through a methane gas pocket. Potential blowout and fire. Human injury/death.	Presence of hydrocarbons.	Equipment damage. Methane release to atmosphere. Liabilities.	Monitor boreholes for pressure kicks.	Monitor and model hydrocarbon saturation and production. Ensure blowout preventer and packers are working properly at all times.	Monitor for borehole pressure kicks. Train operators how to deal with pressure kicks and blowouts.. Ensure blowout preventer and packer are working properly at all times. Monitor hydrocarbon production.

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199	04.02.00.00.	Fluids	0	0	0	0															
200	04.02.01.00.	Fluid properties (See 03.02.13.03)	0	0	0	0															
201	04.02.02.00.	Hydrogeology	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
202	04.02.03.00.	Hydrocarbons	2	4	1	8	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	Damage due to well blowout caused by drilling through hydrocarbon trap. Repair and damage recovery \$1.5M	1-10 days @ \$15,000/d revenue lost per pattern idled	None	Emissions tied to hydrocarbon release/flare g	10% of damage costs	<\$3M per blowout. Fatalities and/or injuries: \$3.1M	None	Cost to maintain BOP and packers and emergency response plan for blowout fire and explosion are all part of ongoing operations.	Up to \$3M for every blowout prevented. Up to \$3.1M for fatalities and/or injuries prevented.	1

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203	05.00.00.00.	BOREHOLES	This category of FEPs is concerned with the way that activity by humans alters the natural system. Both boreholes used in the sequestration operations and those drilled for other purposes are relevant to the long-term performance of the system. The category is divided into two classes for the drilling process, and sealing and abandonment.	This category is divided into two classes: 1. Drilling and completion 2. Sealing and abandonment								
204	05.01.00.00.	Drilling and completion	FEPs relevant to the operation of boreholes drilled within the system domain.	Boreholes can potentially provide short circuits for carbon dioxide transport.								
205	05.01.01.00.	Formation damage (CO2 leakage through damaged caprock near borehole)	Alteration of the far-field or virgin characteristics of a formation, usually by exposure to drilling fluids. Fracturing associated with formation damage can increase porosity, whereas the water or solid particles in the drilling fluids, or both, can decrease the pore volume and effective permeability of the formation in the near-wellbore region. Some boreholes in the early 20th century may have been explosive fractured with nitroglycerin. Later boreholes may have been hydrofractured. - Explosive fracturing - Hydrofracturing A number of mechanisms can result in a decrease in porosity, including: - Solid particles from the drilling fluid physically plug or bridge across flow paths in the porous formation - Water from drilling causing clay minerals in the formation to swell - Chemical reactions between drilling fluid and the formation rock and fluids precipitating solids	Formation damage has a number of potential implications for assessing CO2 sequestration: - it can make information from affected boreholes non-representative of the true characteristics of the damaged formations; and - damaged regions themselves may provide flow paths for CO2 migration, particularly if damage results in fracturing. - decrease in near borehole porosity can result in unexpected increase in bottom hole pressure	Up to 169 deep wells may penetrate the FWU caprock. Production wells: 23 Injection wells: 11 Shut-in wells: 53 Plugged wells: 47 Third-party wells: 35	Information on formation damage at FWU?	CO2 leakage through damaged/fractured caprock near borehole. Low injectivity. Nonuniform injectivity	Formation damage.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Increased operating costs. Lower oil recovery.	Review and analyze well records, if any. Determine damage that may have been done by fracking, erosion or plugging. Run fall-off tests on wells. Monitor and model injection and production fluid volumes.	Run fall off tests and characterize responses in overlying formations. Replug and seal at-risk wells. Pressurize wells with water prior to injecting CO2 to check for leaks.	Monitor for H2S near wells. Use water curtains to isolate damaged areas. Use sealants to fill in fractured areas. Use selective perforations to achieve more uniform CO2 injection and flow.
206	05.01.02.00.	Well lining and completion	At the time of drilling, boreholes are lined with a metal casing. Cement is pumped downhole inside the casing string, and it is pushed upward under and outside the casing lower end, between the casing and the rock wall. In multi-stage cement jobs, cement is squeezed between the casing and the rock wall through purpose made perforations. The cement could be pushed behind casing from the bottom hole to the surface, or to a predetermined depth. Curing of cement is the process of maintaining the proper temperature and moisture conditions to promote optimum cement hydration immediately after placement. Proper moisture conditions are critical because water is necessary for the hydration of cementitious materials. As cement hydrates, strength increases and permeability decreases. When hydration stops, strength gain ceases. Therefore, proper hydration of the cement is important in the fabrication of strong, durable concrete. Alteration of borehole linings will occur with time, depending on the natural fluid composition of the deep reservoir and the input of high concentrations of CO2 carrying natural H2S, which may accelerate corrosion.	Borehole lining and completion will contribute to determining the performance of a borehole both during its operational and post-closure phases. This is important from the perspective of CO2 sequestration, since boreholes may provide preferential short circuits to the surface with potential release of CO2 and contamination of upper aquifers.	Up to 169 deep wells may penetrate the FWU caprock. Production wells: 23 Injection wells: 11 Shut-in wells: 53 Plugged wells: 47 Third-party wells: 35	Well records on lining and completion procedures used? Inspection procedure for wells? Incidents of active well leakage (type, frequency, magnitude, methods of mitigation)?	CO2 leakage through active well	Poor well lining completion.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Review and analyze well records. Determine if well lining and completion methods meet current requirements. Characterize with logging tools. Pressurize with water prior to injecting CO2 to check for leaks.	For new wells, use best available methods for completion. Use best cements and characterize using logging tools. For old wells characterize and recompleat or plug and abandon. Pressurize with water prior to injecting CO2 to check for leaks.	Monitor for H2S near wells. Use water curtains to isolate damaged areas. Use sealants to seal fractured areas. Use selective perforations to achieve more uniform CO2 injection and flow.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking		Estimated Potential Damage Recovery Costs												Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
203	05.00.00.00.	BOREHOLES	0	0	0	0															
204	05.01.00.00.	Drilling and completion	0	0	0	0															
205	05.01.01.00.	Formation damage (CO2 leakage through damaged caprock near borehole)	3	3	3	27	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	None	None	None	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 1 year: \$1.2M for water remediation and CO2 loss per leaky well	Assuming leakage detected early and mitigated: <\$0.1M for water remediation	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	None	1
206	05.01.02.00.	Well lining and completion	3	2	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Covered under natural resource damage	None	None	Cost to locate leak \$0.2M. Cost to fix leak \$0.1M.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 6 months: \$0.6M for water remediation and CO2 loss per leaky well	Assuming leakage detected early and mitigated: <\$0.1M for water remediation per leaky well	Cost to locate and fix leak:<\$300k.	Up to \$0.2M	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
207	05.01.03.00.	Workover	The process of performing major maintenance or remedial treatments on a borehole often associated with the re-use of existing boreholes. Workover techniques include flushing of the formation and the removal and replacement of the borehole lining. Well control procedures during workovers must provide for unique phase behavior of any CO2 being circulated out. (CCP 2009) EOR operations often re-complete old wells. Proper re-completion includes: Examining cement bond logs to evaluate bonding between the casing and adjoining formation. Use of squeeze cement if insufficient or inadequate bonding was detected. Wellbore drilling of plugged and abandoned wells to bottom of target formation. Run a casing mechanical integrity test. If pressure fall off was observed, the leaking section of casing should be identified and resealed by squeeze cementing or, in extreme cases, install a liner over the leaking section. 1. Improper modification or reuse of existing boreholes	Workover will result in modified borehole properties that may need consideration within an assessment.	Operators wear H2S monitors on site. Assume best practices are used to monitor for H2S and CO2.	Workover schedule for injection and production wells? Evaluation process used to decide if existing wells should be reused or new wells drilled?	CO2 and other gases (such as CH4 or H2S) leakage through borehole during workover.	Workover.	Leakage of CO2/H2S into the atmosphere.	Monitor for H2S near borehole. Monitor borehole pressure. Monitor pressure in formations above caprock.	Install blow out preventers and packers in wells.	Monitor for H2S near borehole. Monitor borehole for pressure kicks. Maintain blow out preventer and packers in working order.
208	05.01.04.00.	Number and location of monitoring wells	Often, monitoring wells (observation wells or verification wells) are needed to monitor the physical conditions (pressure, temperature, etc.) of the storage reservoir, both inside and/or outside the area immediately affected by the storage operations, or above the storage reservoir. Monitoring wells could be "adopted", by using existing wells to host the appropriate instrumentation (piezometers, pressure gauges, thermometers, etc.), or they could be purpose drilled anew. Direct monitoring techniques usually require access from wellbores that penetrate the containment system into the storage reservoir (CCP 2009) Direct measurements can also be obtained from observation wells at shallower horizons above the expected seal. Wells of this type might provide direct and early indication of unexpected movement. (CCP 2009) General the concept is to minimize monitoring wells that penetrate the seal because they are, by default, potential leakage pathways. (CCP 2009) 1. Lack of or insufficient number of monitoring wells 2. Too many monitoring wells 3. Improperly located monitoring wells.	Observation or monitoring wells may provide an accidental leakage route for the stored CO2, particularly wells drilled inside the area of storage. There are unique tradeoffs associated with the number and location of monitoring wells.	Monitoring wells are normally not used for CO2-EOR operation. However the SWP project will include monitoring techniques that may require some monitoring wells.	Number, type and use of planned monitoring wells?	CO2/H2S leakage through monitoring wells.	Presence of monitoring wells penetrating the reservoir.	Leakage of CO2 into upper formations, aquifers, soil, surface water, or atmosphere.	Monitor for H2S near wells.	NA	NA

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P= 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
207	05.01.03.00.	Workover	4	2	2	16	None	None	None	None	None	None	None	<\$1M per event tied to a workover/well	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$1M per event tied to a workover/well	None	Install and maintain BOP and packers. <\$0.3M/well	Up to \$0.7M for every event prevented	1
208	05.01.04.00.	Number and location of monitoring wells	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
209	05.01.05.00.	Well records	The drilling of boreholes for site investigation, resource exploitation and/or CO2 injection will result in many documents being generated in paper or digital form. Typical well records include location co-ordinates, depth, electric logs, mud logs, drilling parameter logs, composite log, testing reports (if applicable), coring report (if applicable), and a final report. Physical records from cutting samples, cores and fluid samples will also be documented. The principal tool to gain knowledge about the sequence of drilled rock formations is Borehole Logging. Common measures include hole diameter, natural gamma ray response, spontaneous electrical potential, rock resistivity, velocity of acoustic waves through rock, neutron susceptibility, etc. The documents originating at the time of drilling are often the most accurate records of the succession of events associated with the drilling of the well. The curation of such unique records is an invaluable tool to pass knowledge to future generations. 1. Lack of or incomplete records for existing wells 2. Retention/management of well records and data	Well records provide a key source of baseline information regarding the sequestration site. They provide information concerning the nature of the rocks drilled by the well and their petrophysical characteristics in terms of sealing potential and reservoir potential. Additionally, records from wells drilled over a period of time can give a picture of how the system is evolving either naturally, or as a result of the exploitation of geological resources. This baseline information is an important input both into the initial conditions relevant to the system to be assessed, as well as providing an indication of the likely importance of other FEPs. Incomplete well records equate to a potential gap in understanding of the storage system and may result in potentially important features being overlooked in the assessment process. Large amounts of data will be generated by the project. Data could be poorly communicated between groups, or be badly managed to the point that important data is lost, or used incorrectly.	Up to 169 deep wells may penetrate the FWU caprock. Production wells: 23 Injection wells: 11 Shut-in wells: 53 Plugged wells: 47 Third-party wells: 35	Availability and accuracy of well records?	Lack of well records. Loss of well records. Inaccurate well records.	Well records not maintained properly.	Failure to remain in compliance with regulations. Operator errors based on inaccurate well records.	Periodically audit well records for existing wells and maintain accurate records for new wells.	Characterize existing wells. Standardize documentation of well records. Take into account well record data in site characterization and modeling.	Conduct periodic audits of well record documentation to assure the records are thorough and accurate. Maintain digital backup of well records at more than one location.	
210	05.02.00.00.	Borehole seals and abandonment	FEPs relevant to the closure of boreholes drilled within the system domain.	The way that boreholes are closed and sealed is directly relevant to the likelihood that they could act as short circuits for carbon dioxide transport.									

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
209	05.01.05.00.	Well records	2	3	2	12	None	None	None	None	None	None	Interruption for non compliance @ \$15,000/d revenue lost per pattern idled.	None	None	Fines for non compliance	Up to \$3M per event.	None	Regularly audit well records and confirm accuracy: ≤\$100K.	Up to \$2.9M for every prevented event	1
210	05.02.00.00.	Borehole seals and abandonment	0	0	0	0															

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
211	05.02.01.00.	Closure and sealing of boreholes	Features related to the cessation of CO2 injection operations at a site and the sealing of injection and monitoring wells. When a borehole is drilled to the potential storage reservoir, it creates communication with possible overlying reservoirs and with the surface. Cementing and abandonment procedures are designed to permanently plug such communication channel. The cement plugs are commonly located across potential problem spots, to minimize leaking risks. Particular attention should be paid to the quality of the original cement job behind the casing string. If uncemented space is detected, known or suspected behind casing, depending on the lithology across such interval, it may be important to squeeze extra cement between the rock face and the casing to complement the final abandonment plugs inside the casing. Individual boreholes may be closed in sequence, but closure refers to final closure of the whole system, and may include removal of surface installations. The schedule and procedure for sealing and closure may need to be considered in the assessment. A typical well abandonment may include the following: - Remove tubing and packer - Permanently seal the formation with a fluid that reduces permeability - Place plugs of cement or other materials for isolation - Test the plugs - Place a cap on the casing at the surface	The intention of borehole sealing is to prevent human access to the sequestered CO2 and to prevent the borehole from providing a migration pathway for the CO2. Correct cementing and abandonment operations are essential to achieve restoration of pristine sealing above the designed storage reservoir formation.	Up to 169 deep wells may penetrate the FWU caprock. Production wells: 23 Injection wells: 11 Shut-in wells: 53 Plugged wells: 47 Third-party wells: 35	Procedures used for plugging and abandoning wells?	CO2 leakage through boreholes after closure.	Closure and sealing of boreholes.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Evaluate well materials and procedures for compatibility with CO2 and long-term conditions. Periodically monitor for H2S near closed wells.	Characterize abandoned wells. Replug high risk wells. Use closure plug materials that are compatible with CO2 and the expected long-term conditions.	Periodically monitor for H2S near abandoned wells. Replug leaky wells.
212	05.02.02.00.	Seal failure	Degradation of borehole linings (metal and cement) will occur with time, depending on the natural fluid composition of the deep reservoir and the input of high concentrations of CO2. Any H2S present may accelerate corrosion of metal linings. Cement will be attacked by high partial pressures of CO2, low pH and appreciable concentrations of sulfate, chloride, and magnesium ions in the formation fluids. Seal failure will occur once liners have degraded and corroded. Portland cement blended with 50% fly ash had a 30 year life in a field that produced 96% CO2 with water saturation of approximately 20%. (CCP 2009). Conventional Portland cement-fly ash systems can inhibit CO2 migration even after carbonation of the cement because permeability remains relatively low and capillary resistance is relatively high. (CCP 2009). The Basis of Design for new wells should emphasize barrier performance using fundamentals of wellbore preparation, mud removal and cement placement to provide tight interfaces that inhibit fluid migration. Material selection of cement and metallurgy are important, but should be considered secondary to the process of cement placement. (CCP 2009). The cement interfaces between the boreholes and the casing through the caprock are the key to well integrity and seal integrity. Good isolation requires tight cement interfaces with the formation and casing. (CCP 2009)	Seal failure may provide preferential short circuits to the surface with potential release of CO2 and associated contaminants to the surface or near-surface environment. The failure may provide a preferential pathway either through the borehole annulus or around the outside of the casing. Cement interfaces, not cement matrix are the most likely path for migration. (CCP 2009). 1. CO2 leakage at cement-casing interface 2. CO2 leakage through the cement matrix 3. CO2 leakage through pathways created by chemical dissolution of cement 4. CO2 leakage through fractures in cement 5. CO2 leakage through an open annular region due to inadequate cement placement 6. CO2 leakage at cement caprock interface 7. CO2 leakage through corroded or cracked casing 8. CO2 leakage through packer	Up to 169 deep wells may penetrate the FWU caprock. Production wells: 23 Injection wells: 11 Shut-in wells: 53 Plugged wells: 47 Third-party wells: 35	Wellbore seal failure incidents (frequency, cause and magnitude)? Procedures for evaluating and monitoring wellbore seals?	CO2 leakage through the borehole annulus or around the outside of the casing.	Borehole seal failure.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Evaluate well materials and procedures for compatibility with CO2 and long-term conditions. Periodically monitor for H2S near closed wells.	Complete new wells and recompleting old wells using CO2 resistant materials. Use proper completion procedures to ensure tight cement interfaces.	Periodically monitor for H2S near abandoned wells. Replug leaky wells.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
211	05.02.01.00.	Closure and sealing of boreholes	4	2	2	16	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Covered under natural resource damage	None	None	Cost to locate leak \$0.2M. Cost to fix leak \$0.1M.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 1 years: Up to \$1M for water remediation per leaky well	Assuming leakage detected early and mitigated: <\$0.2M for water remediation per leaky well	Periodically monitor for H2S near abandoned wells. Replug leaky wells: <\$300k per leaky well	Up to \$0.5M	1
212	05.02.02.00.	Seal failure	4	2	2	16	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Covered under natural resource damage	None	None	Periodically monitor for H2S near abandoned wells. Replug leaky wells: <\$300k per leaky well	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 1 year: \$1.2M for water remediation per leaky well	Assuming leakage detected early and mitigated: <\$1M for water remediation per leaky well	Periodically monitor for H2S near abandoned wells. Replug leaky wells: <\$300k per leaky well	Up to \$0.2M	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
213	05.02.03.00.	Blowouts	Uncontrolled flow (CO2, brine, oil, gas or mixture of these) from depth leading to gas and/or fluid erupting from a well or borehole to either the terrestrial or aquatic environments. Blowout is an ordinary drilling hazard, well understood and controlled by current technology. Assuming that ordinary blow-out risk controls are present, particular risks might include: (1) A monitoring or verification well drilled into a porous formation that has elevated pressure due to CO2, or (2) A drilled formation with significant unexpected H2S (MCSG 2009). The greatest danger for loss of well control is during workover operations. Estimates based on both oil and gas wells give a frequency of 3x10⁻⁴ blowouts per well per year (IEA GHG, 2003) (Damen 2006). 1. Blowout due to equipment failure (packer, blowout preventer, valve failure) 2. Blowout due to accident (truck backing over injection well) 3. Blowout due to human error (valve left open) 4. Blowout of CO2 injection well 5. Blow out of production well 6. Blow out of monitoring well 7. Blowout of inactive plugged and abandoned well 8. Blowout during workover/remediation of existing well	A surface or undersea blowout would provide a rapid pathway for CO2 to reach the surface. Apart from the CO2 release, the potential consequences are casualties among operators and economic damage caused by explosion or fire when upcoming hydrocarbons are ignited or by parts of the well, which can be launched by the pressure release.(Damen 2006)	No well blowouts have been reported by the Texas RRC for the FWU.		Human injury/death due to CO2 release through well blowout.	Blowouts.	Leakage of CO2 into the atmosphere.	Monitor for pressure kicks in wells.	Design, construct and operate wells properly to prevent blowouts. Make sure the blowout preventer, packer and valves are maintained in proper working order.	Monitor for pressure kicks. Monitor for H2S near well. Have standard procedures in place and train operators to deal with blowouts.
214	05.02.04.00.	Orphan wells	CO2 storage projects may be part of an Enhanced Oil Recovery (EOR) project or stand-alone deep saline aquifer projects. Either way, it is likely that the target geological structure has been the object of past exploration efforts, possibly involving drilling wells. The existence of old wells could be obvious if the wells are still active, but could be overlooked if the old (orphan) wells have been long cemented and abandoned. Technical details of such abandoned vintage wells may in fact not be readily available, or altogether lost. In such a case, the old cementing (sealing) job could be substandard. Some coal bed methane operations used open completion wells (no casing). It is possible to stabilize a hole without casing with gravel packing or sorted liners 1. Failure to identify and locate existing wells - active wells, abandoned wells, shallow wells that don't penetrate the caprock, deep wells that penetrate the caprock 2. Failure to test wells for mechanical integrity 3. Failure to remediate old wells 3. Failure of old well due to poor cementing, sealing, closing 4. Improper workover/recompletion of old well 5. Leakage of CO2 or brine through old well to overlying formations, underground aquifers or surface. 6. Collapse of open borehole (non-cased, open-completion holes often used in CBM)	Old substandard plugged well could provide a potential CO2 leakage route to the surface or to possible reservoirs above the designed CO2 storage reservoir. There is little chance of detecting a substandard well abandonment before the beginning of CO2 injection to the designed reservoir, particularly if the existence of an old well has been overlooked. If old abandoned wells are known in the area of the CO2 injection operations, the risk is minimized by carefully check any potential CO2 leak to the surface at the old well head location. If old wells are unknown and not suspected, it is good practice to run a baseline soil gas survey (if applicable) and successive soil gas surveys at intervals after the beginning of CO2 injection. Open completion wells are more likely to leak than other wells and subject to collapsing.	Up to 169 deep wells may penetrate the FWU caprock. Production wells: 23 Injection wells: 11 Shut-in wells: 53 Plugged wells: 47 Third-party wells: 35	Procedures for inspecting and monitoring orphan wells?	CO2 leakage through old substandard wells.	Orphan wells.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Review and analyze well records, if any. Determine if well plugging and completion methods meet current requirements. Characterize with logging tools. Pressurize with water prior to injecting CO2 to check for leaks.	Identify and analyze old wells using records, surveys and field testing. Replug at-risk wells.	Monitor for H2S near wells. Replug leaky wells.

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
213	05.02.03.00.	Blowouts	2	4	1	8	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	Damage due to well blowout caused by CO2 formation kick Repair \$0.5M	1-10 days @ \$15,000/d revenue lost per pattern idled	Up to \$2 M per CO2 blowout.	5,000 to 10,000 t CO2 per blowout	10% of damage costs	Blowout: <\$3M per event. Fatalities and/or injuries: \$3.1M,	None	Monitor for pressure kicks. Maintain well control with BOP and packers. Part of ongoing operation costs.	Up to \$3M per CO2 blowout prevented. Up to \$3.1 M for fatalities and/or injuries prevented.	1
214	05.02.04.00.	Orphan wells	4	2	2	16	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Covered under natural resource damage	None	None	Periodically monitor for H2S near abandoned wells. Replug leaky wells: <\$300k per leaky well	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 1 year: Up to \$1M for water remediation per leaky well	Assuming leakage detected early and mitigated: <\$0.2M for water remediation per leaky well	Periodically monitor for H2S near abandoned wells. Replug leaky wells: <\$300k per leaky well	Up to \$0.5M	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
215	05.02.05.00.	Soil creep around boreholes	The slow downward gravitational movement of soil around boreholes.	This process results in changing properties of the soil around borehole casings after abandonment. It may either increase or decrease the degree of sealing and therefore the potential for the region immediately around the borehole to act as a migration pathway for CO2 and/or associated contaminants.	This has not been listed as a significant problem.	Incidents of soil creep around boreholes?	CO2 leakage around the borehole.	Soil creep around boreholes	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere.	Examine existing abandoned wells to get an idea of the problem. If there are wells with this problem, identify what was the difference between them and the wells without the problem.	Examine existing abandoned wells for soil creep. If there are wells with this problem, identify what was the difference between them and the wells without soil creep. Apply lessons learned to newly abandoned wells.	Monitor for soil creep. Fill in as needed.
216	05.02.07.00.	Borehole sand control (sand blocking)	Applies to unconsolidated reservoirs. Sand control may be necessary to maintain the structure of the reservoir around the wellbore. Migration of sand and fines into the near wellbore area may severely restrict production/injection. Sand blocking is a problem when the reservoir is unconsolidated and the wellbore is shut in for maintenance or upsets. (CCP 2009) Dehydration and deposition of gravel pack contents that cannot be displaced or removed from the well (CCP 2009) 1. Sand blocking 2. Dissolution of sand control resins 3. Dehydration and deposition of gravel pack contents	Operation delays. Maintenance costs.	This is not applicable at FWU. The reservoir formation is consolidated sandstone.		Sand blocking.	Borehole sand control.	Loss of injectivity. Operating delays and higher maintenance costs.	Take into account any reservoir unconsolidated features in site characterization.	Characterize reservoir. Avoid sites with unconsolidated reservoirs.	Use appropriate design, operation and maintenance procedures for sand control.
217	05.02.08.00.	Wellbore fluids (causing corrosion or scale buildup)	Once the well is completed, impairment implications of the fluids or non-fluids left in the wellbore during startup will need to be considered. (CCP 2009) It is important to consider the displacement of any fluids into the reservoir during start up and the effect of injectivity resulting from the introduction of the fluids. (CCP 2009) Stimulation fluids should be carefully selected in terms of compatibility with the well materials, workover materials and reservoir. (CCP 2009) 1. Wellbore fluids 2. Startup fluids 3. Stimulation fluids	Fluids left in the wellbore for extended amounts of time could potentially corrode the tubulars, drop out precipitants, or cause bacterial growth. (CCP 2009) Startup fluids may impact injectivity due to precipitation of solids. Stimulation fluids may cause corrosion or precipitation of solids.	Assume use of best practices and compliance with regulations and permits.	Composition of wellbore fluids used at FWU? Wellbore fluid additives (corrosion inhibitors, biocides, scale inhibitors and oxygen scavengers) used at FWU? Incidents of well corrosion or scale buildup (type, frequency, magnitude, and method of mitigating)?	Corrosion of wellbore tubulars. Plugging of wellbore tubulars.	Wellbore fluids.	Operating delays and higher maintenance costs.	Monitor chemistry of wellbore fluids.	Monitor chemistry of wellbore fluids. Avoid leaving detrimental wellbore fluids in the well for long periods of time. Use corrosion resistant, Teflon coated tubulars.	Treat wellbore fluids prior to injection. Use corrosion inhibitor, biocides, scale inhibitor and oxygen scavenger.
218	06.00.00.00.	NEAR-SURFACE ENVIRONMENT	This category of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible environment. The environment could be terrestrial or aquatic, and human behavior in that environment needs to be described. The category is divided into three classes: Terrestrial Environment; Aquatic Environment; and Human Behavior.	This category is divided into three classes: 1. Terrestrial environment 2. Aquatic environment 3. Human behavior								
219	06.01.00.00.	Terrestrial environment	This class of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible terrestrial environment.	The near-surface environment is where most potential impacts would be incurred. The FEPs in this class are relevant if that environment is terrestrial.								

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable, or incredible; Yellow/Orange = Headings or non-risk areas

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
215	05.02.05.00.	Soil creep around boreholes	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
216	05.02.07.00.	Borehole sand control (sand blocking)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
217	05.02.08.00.	Wellbore fluids (causing corrosion or scale buildup)	2	2	2	8	None	None	None	None	None	Damage due to corrosion of well components. <\$1M per incident.	1-5 days @ \$15,000/d revenue lost per pattern idled	Repair costs of up to \$0.1M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Damage due to corrosion of well components. <\$1M per incident.	None	Use corrosion resistant materials of construction. Pretreat well fluids with corrosion inhibitors: <\$300k	Up to \$700k per incident prevented..	1
218	06.00.00.00.	NEAR-SURFACE ENVIRONMENT	0	0	0	0															
219	06.01.00.00.	Terrestrial environment	0	0	0	0															

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable, or incredible; Yellow/Orange = Headings or non-risk areas

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
220	06.01.01.00.	Topography and morphology	Features related to the relief and shape of the surface environment and its evolution. 1. Low surface areas (valleys, gullies, ditches) 2. Rugged terrain 3. Confined spaces (caves, canyons)	This FEP refers to local land form and land form changes with implications for the surface environment, e.g. plains, hills, valleys, and effects of river and glacial erosion thereon. In the long term, such changes may occur as a response to other geological changes. Leaked CO2 can accumulate in low surface areas and confined spaces. Rugged terrain may make it difficult to access the site, difficult to lay pipeline and difficult to monitor or conduct seismic studies.	FWU land is relatively flat and slopes approximately 0.26% (14 ft per mile) from 930 m (3050 ft) elevation in the southwest corner to 900 m (2950 ft) in the east drainage area of the FWU site. There are no caves, canyons or other confining features.		Accumulation of CO2/H2S in low surface areas or confined spaces without sufficient ventilation.	Presence of low areas or confined spaces near the CO2 injection site.	Endangerment of flora, fauna and humans in low surface areas or confined spaces without sufficient ventilation if CO2 leakage occurs.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Monitor those areas for accumulation of CO2.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk.	Monitor low surface areas or confined spaces for CO2/H2S accumulation. Post warning signs.
221	06.01.02.00.	Soils and sediments impact on project	Features related to the physical and chemical characteristics of the soils and sediments and their evolution. Different soil and sediment types, e.g. characterized by mineralogy, particle-size distribution and organic content, will have different properties with respect to erosion/deposition, sorption etc.	Soil and sediment characteristics will influence the type of vegetation and land use. They will also determine relevant processes to consider should CO2 and/or associated contaminants migrate to the terrestrial surface environment.	FWU Site soils and sediments: 91.2% Sherm clay loam (prime farmland). 4.1% Ness clay (located on the bottom of playa ponds). 4.7% Other clay loams. Soils and sediments are greater than 2 m (80 in) thick.		Accumulation of CO2 and/or H2S in soil and sediments.	Presence of soils and sediments near the CO2 injection site.	Flora damage.	Conduct baseline study for CO2, CH4 and H2S in soils and sediments. Monitor soils and sediments for CO2 and/or H2S.	Take into account soils and sediments in site characterization. Select site with high integrity caprock.	Conduct baseline study for CO2, CH4 and H2S in soils and sediments. Periodically monitor near surface for CO2 and/or H2S. Identify any irregularities. Determine root cause. Locate and plug leaks.
222	06.01.03.00.	Erosion and deposition	FEPs related to all the erosional and depositional processes that operate in the surface environment, and their evolution with time. Relevant processes may include fluvial and glacial erosion and deposition, denudation, Aeolian erosion and deposition. These processes will be controlled by factors such as the climate, vegetation, topography and geomorphology.	Erosional and depositional processes will influence the way in which the surface environment has evolved and will evolve over the time-scale of interest.	<u>Sherm clay loam</u> Water erosion K Factor : 0.32 (medium-low) Wind erodibility index: 38 t/acre/y (low) Wind erodibility group: 7 (low) <u>Ness clay</u> Water erosion K Factor: 0.28 (medium-low) Wind erodibility index: 86 t/acre/y (medium-high) Wind erodibility group: 4 (medium)		Erosion or deposition around surface facilities, roads or pipelines.	Rain, flooding or high winds.	Damage to surface facilities roads or pipelines.	Monitor and track erosion and deposition.	Proper site characterization and site selection avoiding areas with steep slopes >18%, unconsolidated sandy soil (e.g. sand dunes), or flood plains.	Install barriers for erosion control. Provide periodic erosion or deposition control maintenance.
223	06.01.04.00.	Atmosphere and meteorology (See 10.01.01)	FEPs related to the characteristics of the atmosphere, weather and climate, and their evolution with time. In case of CO2 leakage to the surface, the weather is a relevant factor determining the dispersion or the displacement of the gas: currents, evolution of the concentration of the gas, gas accumulations. Atmospheric characteristics include physical transport of gas, aerosols and dust in the atmosphere and chemical and photochemical reactions. Meteorology is characterized by atmospheric precipitation, temperature, pressure, wind speed and direction. The variability in meteorology should be included so that extremes such as drought, flooding, storms and snow melt are identified.	This information will determine the behavior of CO2 should it reach the atmosphere and is therefore an important factor when considering exposure of the local population and of the local environment. Meteorological characteristics also influence the near-surface hydrological regime with its subsequent consequences for CO2 migration.	Average annual data 1980-2010 Average annual temp.: 13.5°C (56.3°F) Average annual precipitation: 0.5 m (19.56 in) Average annual days with >0.1 in precipitation: 36.2 days Average annual snow fall: 0.32 m (12.6 in). Average annual days with >1 in snow: 8.01 Average annual humidity: 78.36% Average annual wind speed: 27.4 km/h (17.02 mph). Wind direction is predominantly from the southwest. Dry, mild winters. Summers warm with thunderstorms and hail. Potential for tornados and droughts.		Severe weather.	Atmospheric meteorology.	Damage to surface facilities roads and pipelines.	Monitor weather reports for severe weather.	Take into account atmosphere and meteorology in site characterization, design operation and atmospheric dispersion modeling for CO2/H2S leaks.	Maintain procedures for dealing with severe weather that may require an emergency shutdown.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking		Estimated Potential Damage Recovery Costs												Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
					Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)			
					Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury														
Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)																
220	06.01.01.00.	Topography and morphology	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
221	06.01.02.00.	Soils and sediments impact on project	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
222	06.01.03.00.	Erosion and deposition	2	2	1	4	None	None	None	Not attributable to CO2-EOR	Not attributable to CO2-EOR	Pipeline damage <\$1M based on 1986-2011 DOT data	0-7 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of total damages	<\$1M per incident	None	Periodic erosion control maintenance: \$0.1M to \$1M	Savings: <\$0.9 per pipeline rupture prevented	2
223	06.01.04.00.	Atmosphere and meteorology (See 10.01.01)	4	2	1	8	None	None	None	None	None	Surface facilities damage <\$1M for most situations but \$10M+ if compressors are involved.	0-7 days @ \$15,000/d revenue lost per pattern idled	<\$1M per event	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of total damages	<\$1M/event	Cost of insurance deductible.	Insurance coverage for weather and flood damage and business interruption 0.28% of surface facilities value per year + 0.25% of revenue per year	<\$1M per event minus insurance deductible minus cost of insurance	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
224	06.01.05.00.	Hydrological regime and water balance	Processes related to near-surface hydrology at a catchment scale and also soil water balance, and their evolution with time. The hydrological regime is a description of the movement of water through the surface and near-surface environment. It includes the movement of materials associated with the water such as gas or particulates and extremes such as drought, flooding, storms and snow melt. 1. CO2 and associated contaminants leakage affecting the hydrological regime and water balance. 2. Displaced brine affecting the hydrological regime and water balance 3. Groundwater withdrawal causing change in CO2 or brine migration 4. ECBM water extraction impacting water level in shallow wells.	The hydrological regime and water balance will influence the way in which CO2 migrates should it reach the near-surface environment.	The majority of the surface at the FWU site is permeable farmland. The recharge rate of the Ogallala aquifer is 12.5 mm (0.5 in) per year, which is insufficient to cover withdrawal rate for irrigation. Water saturation thickness in the Ogallala aquifer was projected to drop 0.8 m (2.7 ft) per year from 1980-2020 (Bell 1980). Total water stored in the Ogallala aquifer within the FWU Site is estimated to be 420,000 acre-ft. Produced water is reinjected into the reservoir or into a deep disposal well on site.	Produced water quantity and quality? WAG ratio and slug size?	Dispersion of leaked CO2 and/or brine in near-surface aquifers or surface waters.	Hydrological regime and water balance near the CO2 injection site.	CO2/brine contamination of near surface waters.	Conduct baseline survey of near-surface water quality. Model hydrological regime to determine likely scenarios for CO2/brine dispersion. Monitor pressure in formations above the caprock. Monitor water level in shallow wells for significant changes that may be tied to ECBM water extraction.	Characterize the local hydrological regime and water balance and incorporate results into models.	Monitor pressure in formations above the caprock and/or highest secondary seal. Monitor near surface aquifers for changes in CO2/salinity/pH. Determine root cause for any changes. Use tracers if necessary. Locate, isolate and fix leak. Locate, isolate and remediate contaminated water.
225	06.01.06.00.	Near-surface aquifers and surface water bodies	Features related to the physical and chemical characteristics of aquifers and water-bearing features and their evolution.	Shallow Aquifers Aquifers may yield significant amounts of water to wells or surface springs and may thus be a flow path for CO2 to the surface environment. The presence of aquifers and other water-bearing features will be determined by the geological, hydrological and climatic factors. Shallow aquifers will be able to dissolve CO2, reducing further upward migration. The amount of CO2 that can dissolve will depend on factors such as the location of the water table, the chemical composition of pore waters, CO2 flux rates, and hydrogeology. Surface Water Bodies Streams, rivers and lakes often act as boundaries of hydrogeological systems. They may represent a significant source of dilution for CO2 and contaminants entering these systems, or act as reservoirs. In hot dry environments, where evaporation dominates, concentration or exsolution of gas is possible. Water with dissolved CO2 is denser than pure water, which can result	There are approximately 9 playa ponds within the FWU Site. The southern tip of Deer Lake is located on the northcentral side of the FWU Site. An ephemeral creek that ultimately drains into Wolf Creek is located on the east edge of the FWU site. The Ogallala USDW aquifer lies below the surface of the Site.		Migration of CO2/H2S and/or brine into near-surface aquifers or surface waters.	Locating CO2 injection site near fresh water aquifers and surface water bodies. Leakage of CO2/H2S from reservoir through caprock and secondary seals to overlying aquifers and surface water bodies.	CO2/brine contamination of near surface waters.	Conduct baseline survey of near-surface water quality. Monitor near surface aquifers for changes in salinity/pH.	Include near-surface aquifers and surface waters in site characterization. Avoid sites with sensitive groundwater areas. Maintain integrity of caprock and lateral seals.	Monitor near surface aquifers for changes in CO2/salinity/pH. Determine root cause for any changes. Use tracers if necessary. Locate, isolate and fix leak. Locate isolate and remediate contaminated water.

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Line #	Index #	Risk Area/FEP	Risk Ranking		Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info		
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)		Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
224	06.01.05.00.	Hydrological regime and water balance	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW	Contaminatio n of well water and build up of CO2 in well	None	1-15 days @ \$15,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: \$6M for water remediation	Assuming leakage detected early and mitigated: <\$1M for water remediation	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Savings Up to \$2M	1
225	06.01.06.00.	Near-surface aquifers and surface water bodies	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 per acre to remediate contaminated wetlands and surface waters	Covered under natural resource damage	None	1-15 days @ \$15,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5years: Up to \$6M for water remediation	Assuming leakage detected early and mitigated: <\$1M for water remediation	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Savings: Up to \$2M	1

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
226	06.01.07.00.	Terrestrial flora and fauna	Features and processes related to the characteristics of terrestrial and freshwater flora and fauna, and their evolution. Includes plants, animals, fungi, algae and microbes. Plants usually have a higher resistance against CO2 than mammals, but persistent leaks could suppress respiration in the root zone. Tree kills associated with soil gas concentrations in the range of 20-30% have been observed at Mammoth Mountain, California, where volcanic out gassing of CO2 (0.13-0.44 Mt/yr) has been occurring since at least 1990. The leakage rate (flux) varies between 25 and 7000 g CO2/day/m2. (Damen 2006). 1. Natural flora and fauna 2. Agricultural flora and fauna	Flora and fauna may be affected by concentrations of CO2 in the near-surface environment and may be indicators of CO2 leakage.	Vegetation is limited to local crop lands (corn, sorghum, wheat and alfalfa). There are few trees and minimal fauna.		CO2/H2S migration into terrestrial areas containing flora and fauna.	Leakage of CO2 /H2S through caprock and secondary seals to surface environment	Endangerment of flora, fauna in areas without sufficient ventilation.	Conduct baseline survey of flora, fauna and CO2 in the project area before CO2 injection. Monitor changes in flora, fauna and CO2. Monitor potential leakage pathways (wellbores, faults) and receptors (aquifers).	Include flora and fauna in site characterization. Avoid sites with habitats for endangered or protected species.	Conduct baseline survey of flora, fauna and CO2 in the project area before CO2 injection. Monitor changes in flora, fauna and CO2 content. Determine root cause for any changes. Locate, isolate and fix leak.
227	06.01.08.00.	Terrestrial ecological systems (See 06.01.07.00)	Features and processes related to interactions between terrestrial and freshwater populations of animals, plants, algae, fungi, microbes and their evolution. Characteristics of the ecological system include the vegetation regime, and natural cycles such as forest fires or flash floods that influence the development of the ecology. The plant, animal, algal, fungal and microbial populations occupying the surface environment are an intrinsic component of its ecology. Their behavior and population dynamics are regulated by the wide range of processes that define the ecological system. Human activities have significantly altered the natural ecology of most environments.	The ecology of the terrestrial near-surface environment determines the types of organisms present and their inter-dependencies. These can influence the types of impact of interest and can provide a mechanism for monitoring CO2 leakage.	Ecological systems typical of prime farmland and playa ponds.		Migration of CO2/H2S and/or brine into the terrestrial ecological system.	Leakage of CO2/H2S through caprock and secondary seals to surface environment	Disruption of the terrestrial ecological system.	Conduct baseline survey of CO2 and salinity measurements in sensitive areas before injecting CO2. Monitor and model CO2 plume and brine movement. Monitor CO2 and salinity in sensitive areas. Monitor potential leakage pathways (wellbores, faults) and receptors (aquifers).	Take into account the ecological system in site characterization.	Conduct baseline survey before injecting CO2. Monitor surface CO2/H2S. Locate, isolate and fix leak.
228	06.02.00.00.	Aquatic environment	This class of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible aquatic environment (seas, lakes, rivers).	The near-surface environment is where most potential impacts would be incurred. The FEPs in this class are relevant if that environment is aquatic.								
229	06.02.01.00.	Coastal features	Features and processes related to the characteristics of coasts and the near shore, and their evolution. Coastal features include headlands, bays, beaches, spits, cliffs and estuaries.	The processes operating on these features, e.g. active erosion, deposition, longshore transport, may affect mechanisms for the migration of CO2, and associated contaminants, entering the surface environment.	Not applicable to this site.		Migration of CO2 and/or brine into a coastal environment.	Leakage of CO2 through caprock to surface environment	Contamination of waters and endangerment of marine life.	Conduct baseline survey of coastal features, CO2, salinity and phi Monitor for changes. Monitor CO2 plume migration.	Take into account coastal features in site characterization. Avoid sensitive areas or habitats for endangered or protected species.	Conduct baseline survey of coastal features, CO2, salinity and phi Monitor for changes. Determine root cause of changes. Monitor CO2 plume migration. Adjust CO2 injection strategy if necessary.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking		Estimated Potential Damage Recovery Costs												Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
226	06.01.07.00.	Terrestrial flora and fauna	2	1	2	4	None	None	None	None	Included under natural resources.	None	1-15 days @ \$15,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$100k per event	None	Monitor for CO2/H2S near surface. Monitor pressure in formations above caprock and secondary seals: <\$200k Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	Savings: None to \$3M loss.	1
227	06.01.08.00.	Terrestrial ecological systems (See 06.01.07.00)	2	1	2	4	None	None	None	None	Included under natural resources.	None	1-15 days @ \$15,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$2M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$100k per event	None	Monitor for CO2/H2S near surface. Monitor pressure in formations above caprock and secondary seals: <\$200k Cost to locate and fix leak, \$0.3M for leaky well. \$2M for leaky fault, fracture zone or high permeability pathway.	Savings: None to \$3M loss.	1
228	06.02.00.00.	Aquatic environment	0	0	0	0															
229	06.02.01.00.	Coastal features	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
230	06.02.02.00.	Local oceanography	Features and processes related to the characteristics of seas and oceans and their evolution. This includes the topography and morphology of the seabed; thermal stratification and salinity gradients; and marine currents.	The local oceanographic features and processes determine the potential for dilution or accumulation of CO2, or associated contaminants in the marine environment.	Not applicable to this site.		Migration of CO2 into the ocean.	Leakage of CO2 through caprock to surface environment	Disruption of the seabed, CO2 accumulation, formation of gas hydrates..	Conduct baseline survey of local oceanographic conditions prior to injecting CO2. Monitor CO2 plume.	Include local oceanography in site characterization if applicable. Avoid sensitive areas or habitats for endangered or protected species.	Conduct baseline survey of local oceanographic conditions prior to injecting CO2. Monitor CO2 plume. Adjust CO2 injection strategy if necessary.
231	06.02.03.00.	Aquatic sediments	Features and processes associated with sediments in the aquatic environment. This includes both the physical and chemical characteristics of the sediments, along with sedimentation and resuspension processes.	Aquatic bed sediment characteristics will influence the ecology of the aquatic environment. They will also determine relevant processes to consider should CO2 and/or associated contaminants migrate to the aquatic environment.	Not applicable to this site.		Migration of CO2 and/or brine into the aquatic environment.	Leakage of CO2 through caprock to surface environment	Disruption of aquatic sediments and related ecology.	Conduct baseline survey of local aquatic sediment conditions prior to injecting CO2. Monitor surface water for CO2/salinity/phi Monitor CO2 plume.	Take into account aquatic sediments in site characterization, if applicable. Avoid sensitive areas or habitats for endangered or protected species.	Conduct baseline survey of local aquatic sediments, CO2, salinity and phi Monitor for changes. Determine root cause of changes. Adjust CO2 injection strategy if necessary.
232	06.02.04.00.	Aquatic flora and fauna	Features and processes related to the characteristics of aquatic flora and fauna, and their evolution. Includes plants, animals, fungi, algae and microbes.	Flora and fauna may be affected by concentrations of CO2 in the aquatic environment and may be indicators of CO2 leakage.	Not applicable to this site.		CO2 migration into aquatic areas containing flora and fauna.	Leakage of CO2 through caprock to surface environment	Endangerment of aquatic flora and fauna.	Conduct baseline survey of aquatic flora, fauna and CO2/salinity/pH in the project area before CO2 injection. Monitor changes in flora, fauna and CO2/salinity/phi	Include aquatic flora and fauna in site characterization. Avoid sites with habitats for endangered or protected species.	Conduct baseline survey of aquatic flora, fauna and CO2/salinity/pH in the project area before CO2 injection. Monitor changes in aquatic flora, fauna and CO2/salinity/phi Determine root cause for any changes. Adjust CO2 injection strategy if necessary.
233	06.02.05.00.	Aquatic ecological systems	Features and processes related to interactions between populations of algae, animals, microbes and their evolution. Characteristics of the ecological system. The algal, animal and microbial populations occupying the aquatic environment are an intrinsic component of its ecology. Their behavior and population dynamics are regulated by the wide range of processes that define the ecological system.	The ecology of the aquatic environment determines the types of organisms present and their inter-dependencies. These can influence the types of impact of interest and can provide a mechanism for monitoring CO2 leakage.	Not applicable to this site.		Migration of CO2 into an aquatic ecological system.	Leakage of CO2 through caprock to surface environment	Disruption of the aquatic ecological system.	Conduct baseline survey of aquatic ecological system for CO2/salinity/pH in the project area before CO2 injection. Monitor changes in CO2/salinity/phi	Take into account the aquatic ecological system in site characterization. Avoid sites with sensitive areas or habitats for endangered or protected species.	Conduct baseline survey of aquatic ecological system for CO2/salinity/pH in the project area before CO2 injection. Monitor changes in CO2/salinity/phi Determine root cause for any changes. Adjust CO2 injection strategy if necessary.
234	06.03.00.00.	Human behavior	Details of the human behavior in the near-surface environment where impacts may be incurred.	Human behavior will affect the nature and magnitude of potential impacts to human beings.								

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)		
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
230	06.02.02.00.	Local oceanography	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
231	06.02.03.00.	Aquatic sediments	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
232	06.02.04.00.	Aquatic flora and fauna	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
233	06.02.05.00.	Aquatic ecological systems	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
234	06.03.00.00.	Human behavior	0	0	0	0																

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
235	06.03.01.00.	Human characteristics	Features and processes related to characteristics, e.g. physiology, metabolism, of individual humans. This includes considerations of variability, in individual humans, of physiology and metabolism due to age and other variations. Physiology refers to body and organ form and function. Metabolism refers to the chemical and biochemical reactions which occur within an organism, or part of an organism, in connection with the production and use of energy. Children and infants, although similar to adults, often have characteristic differences, e.g. metabolism and respiratory rates, which may lead to different characteristics of exposure to CO2 or contaminants.	Human physiology and metabolism determine the effect of exposure to CO2 and associated contaminants.	The FWU Site has sparse population. There are no known sensitive receptors such as school, hospitals, prisons, care centers, or churches in the area. Nearest down-wind population centers are: Waka, TX (population 69) located in the northwest corner of the FWU Site. Farnsworth, TX (population 106) located 5.5 km (3.4 miles) north of the FWU Site. Perryton, TX (population 8,802) located 17 km (10.6 mi) northeast of the FWU Site.		Migration of CO2 into sensitive receptor areas (schools, hospitals, prisons, care centers).	Locating CO2 injection site near sensitive receptors. Leakage of CO2 through caprock to surface environment.	Endangerment of humans with greater vulnerability in areas of insufficient ventilation.	Conduct baseline survey of CO2 measurements in sensitive areas before injecting CO2. Monitor and model CO2 plume. Monitor CO2 concentration in sensitive areas.	Take into account sensitive receptor areas in site characterization. Avoid sensitive receptor areas in site selection.	Monitor surface CO2 concentration in/hear sensitive receptor areas and install alarms if necessary. Maintain an emergency response plan. Train operators, and first responders and educate residents what to do in case of a CO2 leak.
236	06.03.02.00.	Diet and food processing	Features related to intake of food and water by individual humans and the compositions and origin of intake. This includes considerations of how diets, of individual humans, may vary with age and other variations (ingestion of soil by infants, for example). This FEP also includes processes related to the treatment of foodstuffs and water between origin and consumption. For example, once a crop is harvested it may be subject to a variety of storage, processing and preoperational activities prior to human or livestock consumption. Water sources may be treated prior to human or livestock consumption, e.g. chemical treatment and/or filtration.	The human diet provides a potentially important exposure pathway to contaminants released into the food chain as a result of the CO2 sequestration system. Food preparation processes may change the distribution and content of CO2 and/or associated contaminants in the product.	Crops grown within the FWU Site are primarily corn, sorghum, and winter wheat.		Migration of CO2/brine containing heavy metals into agricultural areas and into the food processing chain.	Locating CO2 injection sites near agricultural land. Leakage of CO2 through caprock to surface environment	Contamination of food chain with heavy metals.	Characterize soils, water and crops in the site area. Conduct baseline survey for potential contaminants prior to CO2 injection. Monitor for changes in crops, agricultural products or soil and water chemistries.	Characterize soils, water and agricultural in the site area. Conduct baseline survey for potential contaminants prior to CO2 injection. Avoid sensitive groundwater areas and areas with high content of heavy metals that could be leached out by acidic water.	Monitor soils, water and agricultural products for contaminants. Maintain a contingency plan in case of contamination.
237	06.03.03.00.	Lifestyles	Features related to non-diet related behavior of individual humans, including time spent in various environments, pursuit of activities and uses of materials. This includes consideration of variability of the habits of individuals due to age and other factors. The human habits refer to the time spent in different environments in pursuit of different activities and other uses of materials. The diet and habits will be influenced by agricultural practices and human factors such as culture, religion, economics and technology.	Human habits will determine the exposure pathways of interest in an assessment. Camping, plowing, fishing, and swimming are examples of behavior that might give rise to extended close proximity exposure to CO2 and/or contaminants mobilized in an area of CO2 sequestration.	The FWU Site is primarily used for oil production and farming. Population density is very low.		Migration of CO2 into areas frequented by humans.	Locating CO2 injection sites near populated areas. Leakage of CO2 through caprock to surface environment	Endangerment of humans with in areas of insufficient ventilation.	Conduct baseline survey of CO2, salinity and pH measurements in sensitive areas before injecting CO2. Monitor and model CO2 plume and brine movement. Monitor CO2, salinity and pH in sensitive areas.	Take into account land use by humans in site characterization. Avoid popular recreational areas.	Monitor soils, water and agricultural products for contaminants. Maintain a contingency plan in case of contamination.

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Line #	Risk Ranking		Estimated Potential Damage Recovery Costs														Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)					
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)																
235	06.03.01.00.	Human characteristics	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
236	06.03.02.00.	Diet and food processing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
237	06.03.03.00.	Lifestyles	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
238	06.03.04.00.	Land and water use	FEPs related to land and water use by humans in the near-surface environment and the resulting implications for CO2 leakage and contaminant transport and exposure pathways. This includes consideration of: - the use of natural or semi-natural tracts of land and water such as forest, brush, rivers, lakes and the sea, - rural and agricultural land and water use (including freshwater and marine fisheries); - urban and industrial land and water use related to developments, including transport, and their effects on hydrology; and - leisure and other uses of environment.	These FEPs can influence the potential transport and exposure pathways for CO2 and its associated contaminants as well as the potential evolution of the system during the timescales of interest. Particular considerations are relevant for each type of land use addressed, for example: - special foodstuffs and resources may be gathered from natural land and water which may lead to significant modes of exposure to CO2 or contaminants; - an important set of processes are those related to agricultural practices, their effects on land form, hydrology and natural ecology, and also their impact in determining contaminant uptake through food chains and other exposure paths; - human populations are concentrated in urban areas in modern societies. Significant areas of land may be devoted to industrial activities. Water resources may be diverted over considerable distances to serve urban and/or industrial requirements; - significant areas of land, water, and coastal areas may be devoted to leisure activities. e.g. water bodies for recreational uses, mountains/wilderness areas for hiking and camping activities.	The FWU Site is primarily used for oil production and farming. Population density is very low. Groundwater is used mainly for irrigation.		Migration of CO2 into areas of heavy land use.	Locating CO2 injection sites near land and water used by humans.	Endangerment of humans within areas of insufficient ventilation.	Conduct baseline survey on land use and future planning. Monitor changes in zoning and land use.	Take into account current and future land use in site characterization. Avoid sites that are densely populated, sensitive receptor areas or subject to future urban sprawl or industrialization.	Monitor CO2, salinity and pH in sensitive areas. Install CO2, VOCs, CH4, H2S alarms and signs if necessary. Maintain a contingency plan. Train operators and first responders, and educate residents what to do in case of a CO2 leak.	
239	06.03.05.00.	Community characteristics	Features related to characteristics, behavior and lifestyle of groups of humans that might be considered as target groups in an assessment. Relevant characteristics might be the size of a group and degree of self-sufficiency in food stuffs/diet. Associated with this is a consideration of the amount of resources required to meet the needs of the community.	This FEP involves a consideration of aggregated human behavior in order to consider their dependency on and interactions with their environment. It therefore provides input to a consideration of potential human interference with the CO2 storage system as well as input to considering potential exposure pathways.	Nearest population centers are: Waka, TX (population 69) located in the northwest corner of the FWU Site. Farnsworth, TX (population 106) located 5.5 km (3.4 miles) north of the FWU Site. Perryton, TX (population 8,802) located 17 km (10.6 mi) northeast of the FWU Site.		Migration of CO2 into densely populated areas.	Locating CO2 injection site near densely populated areas. Leakage of CO2 through caprock to surface environment	Endangerment of humans in areas of insufficient ventilation.	Conduct baseline survey of CO2, salinity and pH measurements in sensitive areas before injecting CO2. Monitor and model CO2 plume and brine movement. Monitor CO2, salinity and pH in sensitive areas.	Take into account human population density and behavior in site characterization. Avoid areas of high population density.	Monitor CO2, salinity and pH in sensitive areas. Install CO2, VOCs, CH4, H2S alarms and signs if necessary. Maintain a contingency plan. Train operators and first responders, and educate residents what to do in case of a CO2 leak.	
240	06.03.06.00.	Buildings	Features related to houses, or other structures or shelters, in which humans spend time. 1. Basements/cellars 2. Subterranean pathways	The structure or materials used in building construction be significant factors for determining potential exposure pathways to CO2 or contaminants. For example, given that CO2 is denser than air, it may accumulate in the basements/cellars of dwellings.	There are an estimated 40 residential units within the Waka, TX zip code (79093) which includes most of the W FWU Site. Outside of the northwest corner there are approximately 9 houses scattered within the FWU Site. In addition, there are at least 10 sites with industrial structures such as warehouses, workshops or barns. Most buildings in the region do not have basements.		Human injury/death due to migration of CO2/H2S into unventilated confined spaces occupied by humans.	Presence of buildings near EOR site. Leakage of CO2/H2S through caprock and secondary seals to surface environment.	Endangerment of humans in areas of insufficient ventilation.	Monitor CO2/H2S in inhabited confined spaces.	Take into account buildings in site characterization. Ventilate confined areas. Avoid densely populated areas.	Monitor CO2/H2S in sensitive confined areas. Install CO2, H2S alarms and signs if necessary. Maintain a contingency plan. Train operators and first responders, and educate residents what to do in case of a CO2/H2S leak.	

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	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
238	06.03.04.00.	Land and water use	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
239	06.03.05.00.	Community characteristics	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
240	06.03.06.00.	Buildings	2	4	2	16	1 @ \$1.5M per fatality	Accumulation of CO2 in unventilated confined areas 1 @ \$1.5M per serious (irrecoverable) injury	Accumulation of CO2 in unventilated confined areas 1 @ \$0.05M per minor (recoverable) injury	None	None	None	1-15 days @ \$15,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Damage involving a fatality or multiple injuries: <\$5M	Assuming CO2/H2S detected early with alarm or smell: <\$200k	Monitor confined spaces for CO2/H2S. Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	Savings \$1.8 to \$4.5M.	1

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
241	07.00.00.00.	IMPACTS	This category of FEPs is concerned with any endpoint that could be of interest in an assessment of performance and safety. The classes of impact considered are: Impacts to Humans; Impacts to Flora and Fauna; and Impacts to the Physical Environment. Note that: - financial impacts are assumed to be implicitly considered within each of the impact FEPs; and - unless stated, the FEPs refer to both CO2 and mobilized contaminants (minerals, heavy metals, hydrocarbons (e.g., EOR and ECBM), gases).	This category is divided into four classes: 1. System performance 2. Impacts on the physical environment 3. Impacts on flora and fauna 4. Impacts on humans								
242	07.01.00.00.	System performance	Performance of the sequestration system from the perspective of its success at preventing sequestered CO2 from reaching the atmosphere.	The fate of sequestered CO2 is a fundamental endpoint for an assessment.								
243	07.01.01.00.	Loss of containment	Loss of sequestered CO2 from the intended storage reservoir. Loss includes both consideration of loss to other parts of the geosphere and to the near-surface and surface environments, such as loss to marine water and surface water bodies, where CO2 may result in stratification or pooling.	Loss of containment may be an endpoint of interest to the assessment. For example, the assessment context may dictate that near-surface or surface processes are outside the scope of the assessment.	The most likely potential for loss of CO2 containment would be a wellbore leak or blowout. There are no known faults penetrating the primary seal and there are enough secondary seals and sinks to prevent significant release of CO2 into the USDW or into the air.		Migration of CO2 into overlying formations, soil, aquifers and/or atmosphere.	Loss of containment.	Endangerment of humans and/or animals in low areas or confined areas with insufficient ventilation.	Monitor and model CO2 plume. Monitor overlying layers and/or near surface for CO2.	Ensure integrity of the caprock and lateral seals.	Monitor pressure in formations above the caprock. Monitor surface CO2/H2S near wells. Select sites with multiple stacked seals and sinks.
244	07.02.00.00.	Impacts on the physical environment	FEPs relevant to adverse impacts on the physical environment. Note that these may be endpoints of interest in themselves, but may also cause other impacts of interest.	Adverse impacts on the environment can be postulated as a result of sequestration operations, even if there are no associated impacts to humans or on flora and fauna.								

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
241	07.00.00.00.	IMPACTS	0	0	0	0															
242	07.01.00.00.	System performance	0	0	0	0															
243	07.01.01.00.	Loss of containment	3	3	3	27	None	None	2 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	None	1-15 days @ \$15,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Damage assuming leakage undetected or unmitigated for 5 years: Up to \$6M for water remediation	Assuming early detection and mitigation:<\$1 M with no fatalities or injuries.	Monitor surface CO2/H2S. Monitor pressures in formations above caprock: <\$300k. Locate, isolate and fix well leak.<\$300k. Locate, isolate and fix leaky fault, fracture zone or high permeability pathway: \$3M	Up to \$2M per leakage event detected and remediated early.	2
244	07.02.00.00.	Impacts on the physical environment	0	0	0	0															

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
245	07.02.01.00.	Contamination of groundwater (and/or surface water)	The existence of water aquifers may be important if they are subject to CO2-induced chemical changes or CO2-induced saline intrusion. The migration of CO2 into an aquifer will result in the acidification of the water. Depending on the mineralogical composition of the aquifer and the chemical composition of the water, chemical reactions may occur which release heavy metals from the solid phase. The mechanisms which may cause this release include dissolution of metal oxides or oxyhydroxides, the reaction/diagenesis of clay minerals, and the desorption of metals that are adsorbed on clay surfaces or organic complexes. 1. CO2 contamination of underground drinking water sources 2. CO2 contamination of surface waters 3. Displaced brine contamination of groundwater. 4. EOR oil spill (see 16.22.00)	Contamination of groundwater resources may result in impacts on flora, fauna and/or humans if the water is abstracted or flows to the surface environment. These potential impacts are considered in the subsequent FEP classes, however, contamination of groundwater may be an endpoint of interest in itself. An increase in CO2 concentration might cause a decrease in pH to a level of 4-5, which might cause calcium dissolution, increase in the hardness of water and alteration of minerals from minerals from rocks and soils that could release elements such as heavy metals into the water supply. Foundations of buildings could be damaged by seepage of groundwater containing CO2 in shallow unconsolidated sediments and soils. This could be a problems if CO2 were to be stored (and leak) underneath, for example, historical city centers, other heritage objects, or archeological sites (CO2STORE) Surface water could be contaminated by CO2 leakage, which could affect aquatic ecosystems by decreasing pH, especially in stagnant or stratified waters (Damen 2006) Displaced brine may cause undesirable effects such as a rise of the water table (which could have negative impact on land quality and use) and an increase in salinity of sweet water reservoirs used for drinking water extraction and irrigation (Damen	Total water stored in the Ogallala USDW aquifer at the FWU Site is estimated to be 420,000 acre-ft. Ogallala water contains 300 to 400 mg/L total dissolved solids. The Ogallala aquifer is separated from the FWU Upper Morrow reservoir by up to 2,134 m (7000 ft) of multiple seals and sinks that would minimize CO2 leakage into the aquifer. Approximately 4% of the FWU surface area is covered with small playa ponds. The bottom of these ponds is relatively impermeable Ness clay which is typically greater than 2 m (80 in) thick). Contamination of surface waters or near surface USDW is most likely to come from well leakage or oil spills.		Increase of CO2, H2S, hydrocarbon, salinity, and/or heavy metal content, and decrease in pH of groundwater or surface water.	Contamination of groundwater (and/or surface water).	Endangerment of flora and fauna. Cost of water treatment to remove contaminants.	Monitor ground/surface water for CO2, H2S, hydrocarbons, salinity, pH and heavy metals. Monitor for EOR oil spills.	Include near-surface aquifers and surface waters in site characterization. Avoid sites with sensitive groundwater areas. Maintain integrity of caprock and lateral seals.	Monitor near surface aquifers for changes in CO2/salinity/pH. Determine root cause for any changes. Use tracers if necessary. Locate, isolate and fix leak. Locate isolate and remediate contaminated water.
246	07.02.02.00.	Impacts on soils and sediments	Soils and sediments may have elevated concentrations of CO2, should it leak from the storage system, and/or other contaminants, such as heavy metals, hydrocarbons (e.g., EOR and ECBM) or even increased salinity resulting from CO2 sequestration. For example, natural CO2 leaking from a trapped reservoir near Mammoth Mountain, in California, has resulted in soil gas concentrations of 20 to 90%. 1. Contamination of soil 2. Contamination of sediments	Increased CO2 concentrations and/or contamination of soils and sediments with associated substances may be sufficient to modify the ecology and/or use of the impacted area by humans.	CO2 contamination of soil would likely be tied to wellbore leakage or pipeline leak. Impact on soil would be localized. Sediments are limited to relatively impermeable Ness clay on playa pond bottoms.		CO2 / H2S / hydrocarbon / brine / heavy metal contamination of soils and sediments. EOR oil spill.	Leakage of CO2 through caprock to surface environment. EOR oil spill. Spill of industrial fluids or materials at drill or injection site.	Land use restrictions. Cost of soil/sediment cleanup	Monitor soils and sediments for CO2, H2S, hydrocarbon, salinity, pH and heavy metals. Monitor for EOR oil spills.	Take into account soils and sediments in site characterization. Select site with high integrity caprock.	Conduct baseline study for CO2, CH4 and H2S in soils and sediments. Periodically monitor near surface for CO2 and/or H2S. Identify any irregularities. Determine root cause. Locate and plug leaks.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
245	07.02.01.00.	Contamination of groundwater (and/or surface water)	2	3	2	12	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000 per acre to remediate contaminated wetlands and surface waters	Covered under natural resource damage	None	1-15 days @ \$15,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for 5 years: \$6M for water remediation	Assuming leakage detected early and mitigated: <\$1M for water remediation	Monitor overlying formations. Isolate leaking areas with water curtains. Inject sealants into fractures. \$3M	Savings : Up to \$2M	1
246	07.02.02.00.	Impacts on soils and sediments	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
247	07.02.03.00.	CO2 release to the atmosphere	Release of CO2 (or other contaminants, such as radon or methane, mobilized as a result of the sequestration) to the atmosphere from the storage system .	Release of sequestered CO2 or mobilized methane to the atmosphere will reduce the effectiveness of the storage system at preventing greenhouse gases from being emitted to the atmosphere. Atmospheric contamination could also lead to health impacts on humans and wildlife. Rapid release likely to effectively disperse the CO2 higher in the atmosphere. Moderate release likely to concentrated CO2 near the ground, representing the highest risk. Slow release likely to disperse CO2 in the soil and atmosphere.	Release of CO2 into the atmosphere would likely be tied to wellbore leakage. The presence of H2S would be a factor in wellbore leakage/blowout or in any equipment failure involving recycled gas. Typical CO2-EOR operations (SACROC) release 0.3% of total CO2 handled. Key causes include: routine maintenance and power outages caused by storms. (Bradley 2009a) Typical CO2 pipeline operations (Kinder-Morgan) release 0.000035% of CO2 transported. (Bradley 2009a). Operators are required to wear H2S monitoring badges on site.	Content of H2S in produced and/or recycled CO2? Monitoring system for CO2 at FWU?	Accumulation of CO2/H2S in low surface areas with insufficient wind. Human injury/death.	Release of CO2/H2S to the atmosphere	Endangerment of humans at high CO2/H2S levels.	Monitor CO2 and/or H2S content near surface with alarm system.	Characterize and model the site for CH4, H2S and any other gases that may accompany a CO2 release. Operate, maintain and seal wells properly. Avoid over pressuring the reservoir. Maintain the integrity of the caprock and lateral seal. Maintain blowout protector, packers and valves in operating condition.	Monitor for H2S near wells and CO2 recycling facilities. Install alarms and signs in low surface areas and high risk areas. Monitor for CO2/H2S and ventilate confined spaces. Maintain an emergency response plan. Train operators and educate residents what to do in case of a CO2/H2S leak.	
248	07.02.04.00.	Impacts on exploitation of natural resources	The impact of CO2 sequestration on the exploitation of natural resources such as oil and gas. Enhanced oil recovery (EOR) and enhanced coal bed methane (ECBM) recovery projects involving the injection of CO2 are based on improved recovery of oil and methane respectively resulting from CO2 sequestration. However, CO2 sequestration may result in the contamination of geological resources (such as hydrocarbons and minerals) or inhibit their recovery or future exploitation. Note that the potential impact on groundwater resources is considered in Impacts on groundwater. 1. Contamination of mineral resources 2. Contamination of mineable coal seams 3. Contamination of oil resources 4. Contamination of natural gas resources 5. Contamination of geothermal resources 6. Contamination of pore space owned by others.	Impacts on the exploitation of natural resources can be positive (such as EOR and ECBM) and/or negative (such as inhibited recovery). These may result in other (for example, financial) impacts, or may be endpoints of interest in themselves.	No significant mineral, coal or geothermal resources in the area. Gas and oil are present in the Cleveland and Marmaton Formations above the FWU caprock.	Presence of gas or oil resources in formations above or below the FWU Upper Morrow reservoir?	Presence of CO2 hindering recovery of shale gas	Presence gas and oil in overlying or underlying formations.	Preventing or limiting fracking of the Morrow Shale formation.	Determine existence of gas or oil in overlying formations. Monitor CO2/H2S in produced gas and near surface.	Avoid fracking the Morrow shale.	Monitor fracking through passive seismic to identify location and size of fractures. Monitor CO2/H2S content in produced gas and near surface. Seal up fractures and plug well if CO2/H2S release confirms a loss of containment.	
249	07.02.05.00.	Modified hydrology and hydrogeology	The injection of CO2 may result in modifications to both the deep hydrogeology and near-surface hydrology.	Changes in the deep hydrogeology or near-surface hydrology may affect aquifer abstraction or even surface hydrology for groundwater driven features. These impacts may be either positive or negative.	The FWU reservoir is sealed on the top by a relatively impermeable caprock. The reservoir is further protected by up to 2,134 m (7000 ft) of multiple seals and sinks.	Details on seals and sinks above the FWU reservoir?	Damage to near surface aquifers.	Modified hydrology and hydrogeology as result of CO2 injection, migration, or leakage.	Contamination of water with CO2 and/or brine.	Conduct baseline survey of groundwater level and quality prior to CO2 injection. Monitor changes in CO2, salinity, phi Monitor water level in wells. Monitor CO2 plume and brine migration.	Take into account hydrology and hydrogeology in site characterization and modeling.	Monitor pressure in formations above the caprock and secondary seals. Monitor water level in wells. Identify irregularities. Determine root cause.	

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable, or incredible; Yellow/Orange = Headings or non-risk areas

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
247	07.02.03.00.	CO2 release to the atmosphere	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	Damage from blowout: \$0.5M.	1-5 days to stop and fix well	Well leakage: <\$1M Well blowout: <\$3M per event.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Well leakage: <\$1M Well blowout: <\$3M per event. Fatalities and/or injuries: \$3.1M	\$0	Monitor for H2S around injection wells and recycle facilities. Maintain tight seals and failsafe systems <\$300k	Savings: \$700k to \$2.5M Up to \$3.1 M for fatalities and/or injuries prevented.	1
248	07.02.04.00.	Impacts on exploitation of natural resources	2	1	2	4	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	None	None	None	None	None	None	None	Not drilling or fracturing for shale gas.	None	1
249	07.02.05.00.	Modified hydrology and hydrogeology	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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250	07.02.06.00.	Modified geochemistry	The injection of CO2 will modify the geochemistry of the sequestration system. This may be confined to the immediate vicinity of the storage location, or, through leakage from the reservoir, may affect other locations.	The extent of geochemical modifications may be an endpoint of interest, due to resulting changes to geological processes. For example, the acidification of the geochemical regime may cause minerals to be dissolved, with potential implications for the porosity and stability of the geological formations.	Information is not publicly available. Information will become available based on produced water sample analyses as part of the SWP project. The FWU formation water has 4,000 mg/L TDS.	Composition of produced water before and after/during CO2 injection? Details on seals and sinks above the FWU reservoir?	1. Dissolution of minerals. 2. Precipitation of minerals.	Modified geochemistry due to CO2	1. Weakening of formation mechanical properties leading to fracture and/or subsidence. 2. Decreased injectivity .	Characterization and modeling of caprock and reservoir geochemical properties based on drill core analyses.	Take into account geochemistry in site characterization, modeling and reservoir engineering.	Monitor and model injectivity and production pressure. Use selective perforation and water curtains to deal with nonuniform CO2 flow. Use acid treatment to remove carbonate mineral precipitation.
251	07.02.07.00.	Modified seismicity (See 03.02.06.00)	Injection of supercritical CO2 into a geological formation may induce seismic events and processes.	Induced seismicity may be an endpoint of interest in itself, or it can result in other impacts, such as physical disruption of the surface environment.								
252	07.02.08.00.	Modified surface topography	The gradual or sudden sinking (subsidence) or elevation (uplift) of the topography of the terrestrial surface or marine sea-bed.	Deformation of the terrestrial surface or sea-bed may be an endpoint of interest in itself, or may result in other impacts, such as damage to property.	The depth of the CO2-EOR operation is 2,362 m (7750 ft). The volume of CO2 to be injected at FWU is relatively low (up to 326,000 t/y). Injection is dispersed through approximately 11 injection wells. The injected volume is partially compensated for by simultaneous production of oil. Therefore the impact on surface topography is likely to be minimal.	Changes in surface elevation at the FWU site?	Building and/or infrastructure damage. Change in drainage/water flow impacting agricultural land.	Subsidence or uplift.	Liability costs. Economic cost to project; damage to project structures and infrastructure.	Monitor passive micro-seismic and surface displacement (LiDAR). Monitor injection pressure. Monitor dissolution of minerals.	Take into account subsidence or uplift in site characterization and modeling. Avoid shallow injection sites or sites susceptible to significant dissolution of minerals or over pressuring.	Monitor continuous passive micro-seismic and surface displacement (LiDAR). Compare with model. Identify any irregularities and take corrective action if necessary. Extract brine to control pressure and provide more room for CO2 storage.
253	07.02.08.01.	Sinkhole formation	Addition of CO2 in a limestone or carbonate-rich aquifer could result in dissolution of the rock matrix and the enlargement of voids. If this process takes place at relatively shallow depth collapse may result in subsidence at the surface and sinkhole formation. For example, CO2 leakage around a borehole drilled to extract natural CO2 from a reservoir in Florina, Greece, resulted in subsidence around the borehole that filled up with water.	Large scale collapse structures may cause significant change to surface topography and possible CO2 migration paths. Sinkholes can provide locations where leaking CO2 can accumulate.	The depth of the CO2-EOR operation is 2,362 m (7750 ft). The Upper Morrow reservoir is a sandstone with minor carbonate content.		CO2 migration through sinkhole.	Sinkhole formation.	Leakage of CO2 (HSE hazard) into upper formations, aquifers, soil, surface water, or atmosphere. Building and/or infrastructure damage. Liability costs.	Monitor surface displacement (LiDAR). Monitor and model mineral dissolution.	Take into account limestone formations (susceptible to dissolution) in site characterization and modeling. Avoid shallow limestone formations that have the potential for sinkhole formation.	Monitor surface displacement (LiDAR). Compare with model. Identify any irregularities and cut back on CO2 injection if necessary.
254	07.03.00.00.	Impacts on flora and fauna	FEPs relevant to impacts on flora and fauna. 1. Natural flora and fauna 2. Agricultural flora and fauna	Impacts on flora and fauna can be postulated as a result of sequestration operations, even if there are no associated impacts to humans.								

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
250	07.02.06.00.	Modified geochemistry	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
251	07.02.07.00.	Modified seismicity (See 03.02.06.00)	0	0	0	0															
252	07.02.08.00.	Modified surface topography	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
253	07.02.08.01.	Sinkhole formation	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
254	07.03.00.00.	Impacts on flora and fauna	0	0	0	0															

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255	07.03.01.00.	Asphyxiation effects	Asphyxiation effects of CO2 on terrestrial and aquatic fauna. Oxygen is an essential requirement for respiration in animals and is therefore needed to sustain life. High concentrations of CO2 in air or water will lead to suffocation of terrestrial and aquatic animals due to a lack of oxygen reaching the blood stream. If meteorological conditions do not disperse CO2 released to the atmosphere, it can gather close to the surface and remain in depressions, such as natural hollows. This property allows CO2 to reach high concentrations if released in sufficient quantities under particular atmospheric conditions. The 1986 Lake Nyos disaster in Cameroon provides a graphic example of the potential effects of high atmospheric concentrations of CO2. A large limnic eruption resulted in the death of wildlife and approximately 1800 people in the surrounding area and up to 27 km away. In a similar way to gaseous CO2 being denser than air, water containing high concentrations of dissolved CO2 is denser than pure water, a factor that contributes to the limnic eruption phenomenon observed at Lake Nyos. In addition to the possibility of dissolved CO2 causing asphyxiation in aquatic organisms, if gaseous CO2 forms a layer at the surface of water bodies, it can prevent the oxygenation of the water and lead to a reduction of the O2 concentration thereby contributing to asphyxiation of aquatic organisms.	Levels of CO2 from a sequestration project sufficient to cause asphyxiation of fauna would be an endpoint of concern in assessing the geological sequestration of CO2.	Presence of terrestrial and aquatic fauna is minimal at the FWU Site.		Endangerment of animals.	Asphyxiation effects of CO2 when accumulated in low areas or confined spaces.	Liability costs.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Install CO2/H2S monitors and alarms. Identify areas that may be at risk. Monitor those areas for accumulation of CO2/H2S	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Install CO2/H2S monitors and alarms. Maintain blowout preventers, packers, valves, pipelines and equipment in proper operating condition. Maintain caprock integrity.	Monitor at risk areas for CO2/H2S. Install alarms if necessary or ventilate areas where CO2 may accumulate. Post warning signs. Train operators and first responders and educate local residents how to identify and deal with CO2/H2S leaks. Train operators to handle blowouts and pipeline ruptures.
256	07.03.02.00.	Effects of CO2 on plants, algae, fungi and microorganisms	Plants, algae, fungi and microorganisms (in both terrestrial and aquatic environments) use energy in sunlight to photosynthesize carbohydrates from CO2 and water (H2O). Increasing concentrations of CO2 around the photosynthetic tissues, increases the rate of photosynthesis and therefore growth and productivity in terrestrial and aquatic plants and algae. However, the roots of most plants need oxygen to breakdown carbohydrates to provide energy for root growth and healthy metabolism, a process called aerobic respiration. High concentrations of CO2 in the soil reduces the availability of O2 and can cause roots and therefore plants to die. At Mammoth Mountain, in California, CO2 has accounted for up to 95% of the gas concentration in soil at the edge of Horseshoe Lake due to release from natural geological CO2 reservoirs caused by volcanic activity. These high soil concentrations have resulted in areas of forest being killed.	Concentrations of CO2 in the soil, atmosphere and/or water sufficient to impact on the growth of plants and algae would be an endpoint of interest in assessing the geological sequestration of CO2.	Vegetation is primarily crops such as corn, sorghum, wheat and alfalfa.		Endangerment of plants, algae, fungi and microorganisms.	Effects of CO2 on plants, algae, fungi and microorganisms	Liability costs.	Conduct baseline survey of species in soil, sediments and water. Monitor CO2 levels in soils, sediments and water.	Characterize the species found in soils, sediments and water on site. Avoid sites with habitats for endangered or protected species.	Conduct a baseline survey in the project area before CO2 injection. Monitor plants, algae fungi and microorganisms for unexplained dead zones. Determine root cause. Check CO2 content in the area. Locate and plug leaks, if any.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
255	07.03.01.00.	Asphyxiation effects	2	2	2	8	None	None	None	Animal kill:<\$0.1M	Animal kill:<\$0.1M	None	None	Cost to locate and fix leaky well: \$<0.3M Cost to fix pipeline rupture: <\$1M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$1M per event	None	Monitor for CO2/H2S near surface. Monitor pressure in formations above caprock and secondary seals: <\$200k	<\$0.8M	1
256	07.03.02.00.	Effects of CO2 on plants, algae, fungi and microorganisms	2	2	2	8	None	None	None	\$50,000/acre soil contamination and/or vegetation kill (likely to be very localized)	Up to \$1,000/acre for crop kill. (likely to be very localized)	None	1-15 days @ \$15,000/d revenue lost per pattern idled	Cost to locate and fix leaky well: \$<0.3M Cost to fix pipeline rupture: <\$1M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$1M per event	None	Monitor for CO2/H2S near surface. Monitor pressure in formations above caprock and secondary seals: <\$200k	<\$0.8M	1

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
257	07.03.03.00.	Ecotoxicology of contaminants	Ecotoxicology deals with the toxic effects of contaminants on the biosphere. Contaminants other than CO2 may be introduced to the biosphere as a result of geological CO2 sequestration due to: - impurities associated with the sequestration fluid, such as hydrogen sulfide (H2S), methane (CH4), nitrogen oxides (NOx) and mercaptans; - the mobilization of substances in the geological environment due to the sequestration of CO2, such as hydrocarbons (e.g., EOR and ECBM), brine, CH4 and heavy metals. These substances may have a toxic effect on organisms in the biosphere, including plants, animals, algae and fungi. 1. H2S release impact on the biosphere 2. Methane release impact on the biosphere 3. Heavy metal release impact on the biosphere 4. Mercaptans release impact on the biosphere 5. NOx release impact on the biosphere	The potential for contaminants associated with and/or mobilized by CO2 sequestration to have a toxic effect on organisms should they migrate to the biosphere will be of interest in an assessment of the geological sequestration of CO2. Methane leakage may affect shallow water quality and pose a lethal threat when accumulating in confined spaces such as basements/cellars. The global warming potential of methane is circa 23 times that of CO2 (Damen 2006)		Content of H2S and CH4 in produced and/or recycled CO2?	Endangerment of plants, animals, algae or fungi due to contamination of near surface environment with H2S, hydrocarbons, mercaptans, brine, heavy metals, oil.	Ecotoxicity of contaminants.	Liability costs.	Conduct baseline survey of contaminants in soil, sediments, water prior to CO2 injection. Monitor and model CO2 plume and brine migration. Monitor for contaminants in near-surface soil, sediments and water.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Install CO2/H2S monitors and alarms. Maintain blowout preventers, packers, valves, seals, pipelines and equipment in proper operating condition. Maintain caprock integrity.	Monitor at risk areas for CO2/H2S. Install alarms if necessary or ventilate areas where CO2 may accumulate. Post warning signs. Train operators and first responders and educate local residents how to identify and deal with CO2/H2S leaks. Train operators to handle blowouts and pipeline ruptures.
258	07.03.04.00.	Ecological effects	Geological sequestration of CO2 may have an impact on the biosphere at a community, population and/or ecological level, with subsequent implications for biodiversity. The potential impact of releases of CO2 and associated or mobilized contaminants into the biosphere may disrupt biological interactions sufficiently to modify the terrestrial or aquatic ecosystems affected. For example, the sudden release of natural CO2 due to the limnic eruption at Lake Nyos, Cameroon, resulted in the sudden death of wildlife, but was unlikely to affect the ecology in the longer term. However, the continued gradual release of natural CO2 into soil near Mammoth Mountain, California, has been sufficient to kill trees and damage the local ecosystem since 1996 until the present day.	The degree of potential ecological disruption resulting from geological CO2 sequestration may be an endpoint of interest, especially if the ecosystem affected is considered valuable and/or sensitive to perturbations.	The local ecological system is not considered to be sensitive to perturbations. Historically, CO2 releases from boreholes, pipelines or equipment failures have been very localized.		Endangerment of flora, fauna, humans.	Disruption of the ecological system by CO2, brine and other contaminant migration.	Liability costs.	Characterize the on-site ecological system. Conduct baseline survey for CO2 and associated contaminants in the near-surface prior to CO2 injection. Monitor and model CO2 plume and brine migration. Monitor for CO2 and other contaminants in the near-surface.	Take into account the ecological system in site characterization.	Conduct baseline survey before injecting CO2. Monitor surface CO2/H2S. Locate, isolate and fix leak.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
257	07.03.03.00.	Ecotoxicology of contaminants	2	2	2	8	None	None	None	\$50,000/acre to remediate disturbance of ecological system.	\$50,000/acre to remediate disturbance of ecological system.	None	1-15 days@ \$15,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for a long period. Damage to ecological system: <\$500k per event.	Assuming leakage detected early and mitigated. Damage to ecological system: <\$100k per event.	Monitor surface CO2/H2S. Locate, isolate and fix leak.<\$300k	Savings: \$100k	1
258	07.03.04.00.	Ecological effects	2	2	2	8	None	None	None	\$50,000/acre to remediate disturbance of ecological system.	\$50,000/acre to remediate disturbance of ecological system.	None	1-15 days@ \$15,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Assuming leakage undetected or unmitigated for a long period. Damage to ecological system: <\$500k per event.	Assuming leakage detected early and mitigated. Damage to ecological system: <\$100k per event.	Monitor surface CO2/H2S. Locate, isolate and fix leak.<\$300k	Savings: \$100k	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
259	07.03.05.00.	Modification of microbiological systems	Microbes will be present in the geosphere as well as in the terrestrial and/or marine environments above the CO2 storage reservoir. CO2 sequestration may disrupt microbial aerobic respiration but may enhance anaerobic respiration, with subsequent implications for the processes in which the microbes are involved. Microbes play an important role in all terrestrial and aquatic ecosystems, including those associated with extreme environments, such as deep sea hydrothermal vents.	The potential impact of CO2 sequestration on aerobic and anaerobic microbial respiration in the geosphere, terrestrial and aquatic biosphere may be an endpoint of interest.		Data on microbe populations at FWU site?	Disruption of microbiological systems in terrestrial or aquatic environments by CO2/brine migration. Introduction and growth of microbiological systems underground through injection of contaminated water.	Modification of microbiological systems.	Disruption of lower food chain. Plugging of pores and wellbores. Microbial generation of CH4 or H2S. Note that microbe activity can have a positive impact on oil recovery.	Conduct baseline survey of terrestrial, aquatic and sub-surface microbiological systems prior to CO2 injection. Monitor growth/decline of microbiological systems during CO2 injection. Monitor and model CO2 plume and brine migration. Monitor for CH4 and H2S generation.	Characterize site for terrestrial, aquatic and sub-surface microbiological systems. Properly treat water prior to injection underground. Use of biocides to avoid sub-surface microbial growth. Avoid injection of oxygen and organics with CO2.	Use chemical treatment if necessary to control microbial contamination/growth. Obtain proper approvals if chemicals are injected. Monitor H2S in CO2 and around injection wells and recycle facilities. Maintain tight seals and failsafe systems.
260	07.04.00.00.	Impacts on humans	FEPs relevant to adverse impacts on people.	A range of possible impacts to human beings can be postulated as a result of sequestration operations.								
261	07.04.01.00.	Health effects of CO2	Elevated atmospheric concentrations of CO2 can result in both acute and chronic health effects in humans. If meteorological conditions do not disperse CO2 released to the atmosphere, it can gather close to the surface and remain in depressions, such as the basement of buildings or at the surface of lakes. This property allows CO2 to reach high concentrations if released in sufficient quantities under particular atmospheric conditions. The primary health effect of concern is asphyxiation. High concentrations of CO2 in air will lead to suffocation of humans due to a lack of oxygen reaching the blood stream. Asphyxiation can occur once atmospheric concentrations reach approximately 10% CO2. Other health effects include those directly associated with elevated concentrations of CO2 in the blood stream, such as acidosis and physiological responses to the elevated blood CO2. The 1986 Lake Nyos disaster in Cameroon provides a graphic example of the potential effects of high atmospheric concentrations of CO2. A large limnic eruption resulted in the death of approximately 1800 people in the surrounding area and up to 27 km away. (Note that this event resulted from natural volcanic activity rather than CO2 storage). Asphyxiation requires high CO2 concentration in occupied (usually confined) space, plus either poor ventilation or high release rate. 1. Health effects of gaseous release of CO2 2 Health effects of liquid/supercritical release of CO2	The potential for CO2 to be released to the atmosphere in sufficient quantities to cause health effects in humans will be an endpoint of interest in assessing the geological sequestration of CO2. CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).	Potential health effects of CO2 are partially mitigated at FWU by: 1. Low population density except in Waka, TX in the northwest corner of the Site. 2. Limited topographic low areas for CO2 to accumulate in. 3. No basements associated with local structures for CO2 to accumulate in. CO2 could accumulate in unventilated buildings.	Concentration of H2S and CH4 in produced and recycled CO2? Use of CO2 and H2S monitors on site? Ventilation of buildings on-site?	Human injury/death due to accumulation of CO2 in unventilated low lying or confined areas.	Health effects of CO2.	Headache, impairment, unconsciousness or asphyxiation. Liability costs. Negative view of project by stakeholders.	Monitor CO2 content in working/living areas.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Install CO2/H2S monitors and alarms. Maintain blowout preventers, packers, valves, pipelines and equipment in proper operating condition. Maintain caprock integrity.	Monitor at risk areas for CO2/H2S. Install alarms if necessary or ventilate areas where CO2 may accumulate. Post warning signs. Train operators and first responders and educate local residents how to identify and deal with CO2/H2S leaks. Train operators to handle blowouts and pipeline ruptures.

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Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
259	07.03.05.00.	Modification of microbiological systems	2	1	3	6	None	None	None	None	None	None	None	None	None	None	Clean out cost <\$100k/y	Clean out cost <\$100k/y	Pretreat injected water with chlorine biocide part of ongoing costs.	None	1
260	07.04.00.00.	Impacts on humans	0	0	0	0															
261	07.04.01.00.	Health effects of CO2	2	4	2	16	1 @ \$1.5M per fatality	Accumulation of CO2 in unventilated low lying or confined areas 1 @ \$1.5M per serious (irrecoverable) injury	Accumulation of CO2 in unventilated low lying or confined areas 1 @ \$0.05M per minor (recoverable) injury	Accumulation of CO2 in poorly ventilated low areas resulting in wildlife kill up to \$1M	Accumulation of CO2 in unventilated low lying areas resulting in livestock kill up to \$1M	None	1-15 days @ \$15,000/d revenue lost per pattern idled	Cost to locate and fix leaky well: \$<0.3M Cost to fix well blowout: <\$3M. Cost to fix pipeline rupture: <\$1M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Blowout:<\$3M per event. Fatalities and/or injuries: \$3.1M	<\$2M per event	Monitors and alarms for CO2/H2S: <\$300k	Up to \$2.8M per event prevented	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
262	07.04.01.01.	Elevated CO2 in air	CO2 = 5000 ppm (0.5%): OSHA permissible exposure limit: Time weighted average concentration for 8-hour work day. American Conference of Governmental Industrial Hygienists (ACGIH) threshold limit value: Time weighted average concentration for normal 8-hour work day or 40-hour work week. CO2 = 30,000 ppm (3%): Breathing increases to twice normal rate and a person would experience impaired hearing, headache, and increased blood pressure (Shell). Occupational Safety & Health Administration (OSHA) short-term exposure level: Maximum concentration for 15-minute period (maximum of 4 periods per day with at least 60 minutes between exposure periods). CO2 = 40,000 ppm (4%): National Institute for Occupational Safety and Health (NIOSH) immediate danger to life and health: The maximum level to which a healthy individual can be exposed to a chemical for 30 minutes and escape without suffering irreversible health effects or impairing symptoms. CO2 = 50,000 ppm (5%): Breathing increases to approximately 4 times normal rate, symptoms of intoxication become evident and slight choking may be felt (Shell). CO2 = 75,000 ppm (7.5%): A sharp odor is noticeable. At this level a person would experience very labored breathing, headache, visual impairment, and ringing in the ears. Judgment may be impaired, followed within minutes by loss of consciousness(Shell). CO2 = 100,000 ppm (10%): Unconsciousness	CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).	Potential health effects of CO2 are partially mitigated at FWU by: 1. Low population density except in Waka, TX in the northwest corner of the Site. 2. Limited topographic low areas for CO2 to accumulate in. 3. No basements associated with local structures for CO2 to accumulate in. CO2 could accumulate in unventilated buildings.	Use of CO2 and H2S monitors? Use of building ventilation?	Human injury/death due to accumulation of CO2 in unventilated low lying or confined areas.	Elevated CO2 in air.	Headache, impairment, unconsciousness or asphyxiation. Liability costs.	Monitor CO2 content in working/living areas.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Install CO2/H2S monitors and alarms. Maintain blowout preventers, packers, valves, pipelines and equipment in proper operating condition. Maintain caprock integrity.	Monitor at risk areas for CO2/H2S. Install alarms if necessary or ventilate areas where CO2 may accumulate. Post warning signs. Train operators and first responders and educate local residents how to identify and deal with CO2/H2S leaks. Train operators to handle blowouts and pipeline ruptures.
263	07.04.02.00.	Toxicity of contaminants	Contaminants other than CO2 may be introduced to the biosphere as a result of geological CO2 sequestration due to: - impurities associated with the sequestration fluid, such as hydrogen sulfide (H2S), methane (CH4), nitrogen oxides (NOx) and mercaptans; - the mobilization of substances in the geological environment due to the sequestration of CO2, such as hydrocarbons (e.g., EOR and ECBM), CH4 and heavy metals. Such contaminants may be toxic to humans and could cause harm if exposure pathways exist. The toxicity will depend on: the form of exposure, e.g. ingestion or inhalation, leading to internal exposure or proximity to concentrations of contaminants leading to external exposure; the metabolism of the contaminant and physico-chemical form if inhaled or ingested, which will determine the extent to which the element/species	The potential for contaminants associated with an/or mobilized by CO2 sequestration to cause harm to humans is an endpoint of interest when assessing the geological sequestration of CO2. CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).	H2S is present in the produced and recycled gas. Operators are required to wear H2S monitoring badges.	Concentration of H2S and CH4 in produced and recycled gas?	Human injury/death due to accumulation of H2S in unventilated low lying or confined areas	Toxicity of contaminants.	Endangerment of human health. Liability costs.	Monitor contaminants in CO2 stream, reservoir fluids, production well.	Take into account low surface areas and confined spaces in site characterization and modeling. Identify areas that may be at risk. Install CO2/H2S monitors and alarms. Maintain blowout preventers, packers, valves, seals, pipelines and equipment in proper operating condition. Maintain caprock integrity.	Monitor at risk areas for CO2/H2S. Install alarms if necessary or ventilate areas where CO2 may accumulate. Post warning signs. Train operators and first responders and educate local residents how to identify and deal with CO2/H2S leaks. Train operators to handle blowouts and pipeline ruptures.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking			Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)		Savings with risk mitigation (\$)
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
262	07.04.01.01.	Elevated CO2 in air	2	4	2	16	1 @ \$1.5M per fatality	Accumulation of CO2 in unventilated low lying or confined areas 1 @ \$1.5M per serious (irrecoverable) injury	Accumulation of CO2 in unventilated low lying or confined areas 1 @ \$0.05M per minor (recoverable) injury	Accumulation of CO2 in poorly ventilated low areas resulting in wildlife kill up to \$1M	Accumulation of CO2 in unventilated low lying areas resulting in livestock kill up to \$1M	None	1-15 days @ \$15,000/d revenue lost per pattern idled	Cost to locate and fix leaky well: \$<0.3M Cost to fix well blowout: <\$3M. Cost to fix pipeline rupture: <\$1M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Blowout:<\$3M per event. Fatalities and/or injuries: \$3.1M	<\$2M per event	Monitors and alarms for CO2/H2S: <\$300k	Up to \$2.8M per event prevented	1
263	07.04.02.00.	Toxicity of contaminants	2	4	2	16	1 @ \$1.5M per fatality	Accumulation of H2S in unventilated low lying or confined areas 1 @ \$1.5M per serious (irrecoverable) injury	Accumulation of H2S in unventilated low lying or confined areas 1 @ \$0.05M per minor (recoverable) injury	Accumulation of H2S in poorly ventilated low areas resulting in wildlife kill up to \$1M	Accumulation of H2S in unventilated low lying areas resulting in livestock kill up to \$1M	None	1-15 days until leakage is fixed	Cost to locate and fix leaky well: \$<0.3M Cost to fix well blowout: <\$3M. Cost to fix pipeline rupture: <\$1M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	Blowout:<\$3M per event. Fatalities and/or injuries: \$3.1M	<\$2M per event	Monitors and alarms for CO2/H2S: <\$300k	Up to \$2.8M per event prevented	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
264	07.04.03.00.	Impacts from physical disruption	Impacts on humans due to physical disruption of the environment caused by geological CO2 sequestration. For example, damage to buildings due to induced seismicity, damage to farmland due to subsidence or uplift.	Physical disruption of the environment caused by CO2 sequestration may have a detrimental impact on humans.	The volume of CO2 injected at FWU is relatively low (up to 326,000 t/y). Injection is dispersed through approximately 11 injection wells. The injected volume is partially compensated for by simultaneous production of oil. The amount of physical disruption on the surface is likely to be minimal.	Changes in surface elevation or microseismicity at the FWU Site?	Contamination of natural resources. Induced seismicity. Subsidence/uplift.	Physical disruption due to improper CO2 injection/leakage.	Loss of monetized value of contaminated resources. Damage to buildings and infrastructure. Damage to farmland. Liability costs.	Monitor and model CO2 plume and brine migration. Monitor overlying formations, soils, and water for CO2, salinity, phi Continuous passive micro-seismicity monitoring. Monitor and model surface displacement (LiDAR).	Determine fracture pressure. Operate below 90% of fracture pressure. Maintain reservoir fluid volume close to original volume. Avoid areas with high population density.	Operate below 90% of fracture pressure. Monitor injection pressure and passive micro-seismicity.
265	07.04.04.00.	Impacts from ecological modification (See 06.01.08.00)	Impacts on humans due to ecological modification. These may be negative (for example, reduced timber yields due to damage caused to trees by CO2 in the soil) or positive (for example, increased crop yields due to higher atmospheric CO2).	Ecological modification caused by CO2 sequestration may have a positive or negative impact on humans.	The local ecological system is not considered sensitive to perturbations. Historically, CO2 releases from boreholes, pipelines or equipment failures have been very localized.		Timber kill. Agricultural crop and/or animal kill. Natural flora and/or fauna kill. Aquatic/marine life kill.	Ecological modification due to improper CO2 injection/leakage.	Loss of monetized value of resources. Liability costs.	Monitor and model CO2 plume and brine migration. Monitor overlying formations, soils, and water for CO2, salinity, phi Monitor and model passive seismicity. Monitor and model surface displacement (LiDAR).	Take into account the ecological system in site characterization.	Conduct baseline survey before injecting CO2. Monitor surface CO2/H2S. Locate, isolate and fix leak.
266	08.00.00	ECONOMIC RISKS										
267	08.01.00.	Cost escalation / inflation	Cost escalation/inflation may be higher than budgeted. Cost escalations are of particular concern because field-service costs (drilling, geophysics, etc.) and equipment may continue to increase as the price of oil stays high. Key cost items that may be effected by escalation/inflation include: 1. Steel cost 2. Other material cost 3. Equipment cost 4. Labor cost 5. Imported goods cost (due to currency exchange) 6. Financing/risk transfer costs 7. Assessment and permitting costs 8. Mitigation and closure costs	The risk of cost escalations is significant; cost increases may force a change in scope-of-work.	As an existing CO2-EOR project, much of the capital infrastructure is already in place. Therefore the impact of cost escalation/inflation will be minimal.		Project becomes economically infeasible.	Cost escalation/inflation higher than budgeted.	Cost overruns. Project halted.	Monitor cost indexes. Track and project costs versus budget.	Use updated/current information on labor and material rates with escalation over the job period. Structure foreign contracts in US currency or buy domestically.	Allow for time sensitive information to be updated to expose any issues as soon as possible. Hedge currency exchange for foreign contracts.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
264	07.04.03.00.	Impacts from physical disruption	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
265	07.04.04.00.	Impacts from ecological modification (See 06.01.08.00)	2	1	2	4	None	None	None	Accumulation of CO2 in poorly ventilated low areas resulting in flora and fauna kill <\$100k	Included under natural resources.	None	1-15 days @ \$15,000/d revenue lost per pattern idled	Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage costs	<\$100k per event	None	Monitor for CO2/H2S near surface. Monitor pressure in formations above caprock and secondary seals: <\$200k Cost to locate and fix leak, \$0.3M for leaky well. \$3M for leaky fault, fracture zone or high permeability pathway.	Savings: None to \$3M loss.	1
266	08.00.00	ECONOMIC RISKS	0	0	0	0															
267	08.01.00.	Cost escalation / inflation	2	2	1	4	None	None	None	None	None	None	None	10% increase in capital expenditures: \$1M/y	None	None	10% increase in capital expenditures: \$1M/y	\$1M/y	Part of ongoing costs.	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
268	08.02.00.	CO2 value/cost	Incentives for CO2 capture and storage are particularly important for CO2 sequestration in deep saline aquifers. In this case, the value or cost of CO2 may be determined by cap-and-trade, carbon tax or emission credits. In EOR and ECBM the value of CO2 may be tied to the price of oil or natural gas. However, the cost of CO2 capture and transport may be higher or lower than the assigned value. Value of emission credits provide incentive for CO2 sequestration, particularly in deep saline aquifers (DSA). CO2 purchase cost higher than budgeted. CO2 has traditionally been purchased for EOR and ECBM use. Economic arrangements among project participants could have negative project impacts under changed or unanticipated conditions. 1. Value of CO2 emissions credits lower than budgeted 2. CO2 purchase cost higher than budgeted	A low value for emission credits may be insufficient to cover the cost of CO2 capture and sequestration in deep saline aquifers.	The cost of CO2 is one of the biggest expenses for CO2-EOR, but CELLC has secured long-term contracts from multiple CO2 suppliers and owns the compression and pipeline infrastructure. Therefore CO2 costs can be controlled.	CO2 pricing structure?	Project economically infeasible because of high CO2 transfer cost.	Lower value for emission credits than expected. Higher CO2 cost than expected.	Project halted.	Track actual CO2 costs versus budget.	For EOR projects CO2 transfer price to the WTI crude oil price.	CELLC has multiple long-term supply contracts for CO2 and owns the CO2 processing, compression and pipeline infrastructure.
269	08.03.00.	Price of oil (or other related commodities)	The prices of related commodities can impact the value and/or availability of CO2. 1. Oil price - impacts EOR economics 2. Natural gas price - impacts ECBM economics 3. Fertilizer price - impacts CO2 supply from fertilizer plants 4. Ethanol price - impacts CO2 supply from ethanol plants 5. Cement price - impacts CO2 supply from cement plants	Low commodity prices can impact the viability of a CO2 capture and storage project. An economic downturn can cause capital constraints and significant energy price volatility leading to: 1. Business failures of vendors, suppliers or customers. 2. Failure of hedging counterparties to fulfill delivery or purchase obligations 3. Decreased consumption of commodities 4. Increased cost of capital and increased difficulty accessing capital.	The price of oil is up which has had a beneficial impact on project economics. Low oil prices could negatively affect cash flow, capital expenditures, raising of capital, and repayment of debt. Low oil prices may also require a write-down of capitalized costs which could have a material adverse effect on CELLC's financial condition. Arkalon ethanol plant may be adversely impacted by high feedstock prices and low ethanol prices.	CELLC breakeven price for oil?	Oil price less than breakeven point. Arkalon ethanol plant shutdown due to low ethanol and high feedstock prices. Agrium fertilizer plant adversely impacted by low fertilizer prices.	Low commodity prices due to a recession.	Project halted. Significant loss of revenue and cash flow.	Track related commodity markets. Analyze impact of market changes on CO2 supply.	Analyze trends in commodity prices. Plan for worst case scenarios. Hedge oil prices.	Control costs. Shut in wells until prices recover. Shift to backup CO2 supplier.
270	08.04.00.	Project development costs	Project development costs that could be higher than expected or budgeted include: 1. Surface land and/or pore space access costs - purchase or lease 2. Water rights costs 3. Mineral rights costs - needed for EOR or ECBM 4. Pipeline right-of-way (ROW) costs 5. Site characterization costs 6. Permitting costs 7. Technology licensing costs 8. Engineering, procurement and construction (EPC) costs 9. Insurance costs 10. Project financing costs 11. Legal costs 12. Closure and post-closure costs	High project development costs can make the project economically infeasible. Project may be halted if some of the necessary requirements are unobtainable.	As an existing CO2-EOR project, much of the development costs have already been expended. The FWU was acquired in NOV 2009. CO2 compression and pipeline facilities have been installed. Proved undeveloped reserves comprise 55% of the total FWU proved reserves. CELLC plans \$120.7 million in capital expenditures to fully develop the FWU from 2013 through 2024. Full development may take longer and require higher levels of capital than currently anticipated.		Project economically infeasible.	Project development costs higher than budgeted.	Project halted.	Track costs versus budget.	(Numbers below refer to numbers under Definitions) 1. Focus on EOR rather than DSA to avoid pore space issues. 3. Work out mineral rights leases early. 4. Use existing pipeline corridors. 5. Select brownfield site with existing characterization data.	(Numbers below refer to numbers under Definitions) 1. Have backups for site location. 4. Have backup for pipeline right of way. 6. Use public outreach effectively to keep permitting costs down. 9. Self insure. 10. Get equity financing.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P= 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
268	08.02.00.	CO2 value/cost	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
269	08.03.00.	Price of oil (or other related commodities)	4	4	3	48	None	None	None	None	None	None	None	\$40/bbl WTI decrease, decreases revenue \$20M/y	None	None	\$20M/y	\$20M/y	None	None	
270	08.04.00.	Project development costs	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
271	08.05.00.	Project capital costs	Project capital costs that could be higher than budgeted include: 1. CO2 capture system 2. CO2 dehydration 3. CO2 compression 4. CO2 pipeline 5. Well head system 6. CO2 recycle system - for EOR 7. Oil tankage - for EOR 8. Natural gas processing system - for ECBM 9. Water tankage - for EOR or ECBM 10. Water treatment system - for EOR or ECBM 11. New well drilling and completion 12. Old well remediation/replugging 13. Old well workover 14. Site preparation 15. Access roads 16. Power supply system 17. Water supply system 18. Communications system 19. Monitoring system costs 20. Accidental loss	High project capital costs can make the project economically infeasible. Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.	As an existing CO2-EOR project much of the capital costs have already been expended. Annual capital budgets can be adjusted to suit market conditions. Proved undeveloped reserves comprise 55% of the total FWU proved reserves. CELLC plans \$120.7 million in capital expenditures to fully develop the FWU from 2013 through 2024. Full development may take longer and require higher levels of capital than currently anticipated. FWU capital expenditures by year: 2010: \$4.6M 2011: \$23.9M (\$10.5M for infrastructure & pipelines; \$6.4M for drilling; \$7M for enhancements & CO2 purchase) 2012: \$21.6M 2013: \$23.6M budgeted.		Project becomes economically infeasible.	Project capital costs higher than budgeted.	Project halted.	Track costs versus budget.	Obtain hard quotes from manufacturers with time sensitive escalation and time period of validity defined. Use conservative estimates and escalations. Use experienced contractors.	Track actual vs. budgeted expenses. Prioritize expenses and cut low priority costs. Renegotiate scope of work. Obtain additional equity funding.	
272	08.06.00.	Operating and maintenance costs	Project operating and maintenance costs that could be higher than budgeted include: 1. CO2 capture operating costs 2. CO2 dehydration/compression operating costs 3. CO2 pipeline operating costs 4. Injection operating costs 5. Monitoring costs 6. Simulation modeling costs 7. Maintenance costs 8. Lease operating expenses 9. Management fees 10. Working capital 11. Severance and ad valorem tax 12. Investor reporting costs 13. Power cost 14. Make-up water cost 15. Water treatment/disposal cost 16. Labor cost 17. Security costs 18. Site close costs 19. Verification costs 20. Regulatory compliance costs 21. Insurance costs 22. Cost for losses 23. Post-closure costs for DSA 24. Accidental loss 25 Financial reserves for DSA EPA UIC Class VI wells	High operating and maintenance costs can impair project economic viability. Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.	As an existing CO2-EOR project, operating costs have been well established and controlled. CELLC average lease operating expense: 2010: \$13.18/BOE 2011: \$14.03/BOE 3Q2012:\$14.69/BOE.		Project becomes economically infeasible	Project operating and maintenance costs higher than budgeted.	Project halted.	Track costs versus budget.	Use historical O&M data and experienced cost estimators to prepare budgets.	Implement a Total Productive Maintenance (TPM) program.	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P= 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
271	08.05.00.	Project capital costs	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
272	08.06.00.	Operating and maintenance costs	3	3	1	9	None	None	None	None	None	None	None	A 10% increase in O&M costs: \$3M/y	None	None	A 10% increase in O&M costs: \$3M/y	\$1M/y	\$1M/y	\$1M/y	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
273	08.07.00.	Project Financing	Factors which could impact project financing include: 1. Government project funding withdrawn for technical reasons. 2. Government project funding withdrawn for political reasons 3. Change in equity project funding 4. National/global economic downturn impact on project financing 5. Lack of economic incentives for CCS impact on project financing 6. Private financing	Lack of or loss of project financing could halt the project or delay expansions. High level of indebtedness can lead to: 1. Restrictions on business operation due to terms of the debt agreements 2. Use of substantial portion of cash flow to pay interest on outstanding debt 3. Competitive disadvantage compared to competitors with proportionally less debt 4. Impairment of additional financing for working capital, capital expenditures, debt servicing, restructuring, acquisitions, or general corporate purposes 5. Limited flexibility in planning for, or reacting to, changes in the business and industry 6. Vulnerability to economic downturns and adverse business developments 7. Vulnerability to interest rate increases.	CELLC transformed from high-debt, low-liquidity company to a financially stable company with approximately \$425 million in liquidity at year end 2010. CELLC net debt/EBITDA ratio: 3.8 in 3Q2012. As of 1APR2013, CELLC long-term indebtedness, including current maturities, was \$1.3 billion and the borrowing base under their senior secured revolving credit facility was \$500 million. (CELLC 10-K 2013) Expansion programs require access to new capital. Tightened capital markets or more expensive capital would impair ability to grow. Existing financial covenants may restrict the extent of new financing allowed.		Project unable to complete financing	Project loses one or more sources of funding.	Project halted or delayed.	Monitor project financing negotiations.	Keep debt at a sustainable level.	Tie future capital investment to market conditions. Adjust scope of projects to improve economics for project financing. Secure additional equity and refinance high interest rate debt.
274	08.08.00	Hedging or derivative positions	Hedging or derivative positions may be used as a risk management tool to control the adverse impact of fluctuating commodity prices.	Hedging arrangements are used to reduce exposure to fluctuations in commodity prices (i.e., CO2, oil, natural gas). Hedging can create financial risks when: 1. Production is less than hedged amount. 2. The counterparty to the hedging contract defaults on its contract obligations 3. Change in the expected differential between the underlying price in the hedging agreement and the actual price received 4. Limitation of the benefit when commodity prices increase Under certain circumstances, or if hedges are deemed ineffective, discontinued, or terminated for any reason, substantial financial losses may be incurred in closing out a company's position.	CELLC enters into derivative positions, some of which had previously been designated as cash flow hedges for accounting purposes. These derivative products include fixed-price swaps, collars, and basis swaps with financial institutions or other similar transactions. As of December 31, 2012, CELLC entered into swaps and three way collars for 1.02 million barrels of crude and 5.03 million barrels of natural gas liquids production for 2013 through 2014. These swaps had average monthly prices ranging from \$96.65 to \$96.87 per barrel of oil, and the three way collars had a weighted average \$111.33/bbl call price, \$98/bbl put price and \$77.37/bbl additional put price. (CELLC 10-K 2013). CELLC may have increased costs or reduced liquidity in the OTC derivatives market due to current or future regulations.		Actual oil production level below hedged production level. Counterparty default on hedging agreement obligations. Hedged price significantly below nonhedged price.	Production problems. Over estimating amount to be hedged. Poor selection of hedging counterparty. Underestimating hedging price.	Loss of revenues.	Monitoring commodity prices, production rates, and financial health of hedging counterparty.	Avoid hedging. Improve price forecasting. Carefully select hedging counterparty.	Keep the portion of hedged product to a manageable level. Negotiate a reasonable margin between expected hedged and unhedged prices.
275	09.00.00.	PERMITTING RISKS										

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
273	08.07.00.	Project Financing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
274	08.08.00	Hedging or derivative positions	4	3	3	36	None	None	None	None	None	None	None	Assume 85% of oil production is hedged, a \$20/bbl underestimated hedge price could result in a loss of \$10M in revenue.	None	None	\$10M	\$10M	None	None	1
275	09.00.00.	PERMITTING RISKS	0	0	0	0															

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
276	09.01.00.	Permit compliance - obtain or maintain permits	Permitting and NEPA compliance are lengthy processes, and are subject to even more delays because of uncertainty associated with permitting sequestration (a relatively new issue for federal, state and local regulatory agencies).The procedures for permit compliance could cause delays. Potential permits required for a CCS project include: 1. National Environmental Policy Act (NEPA) - Environmental Assessment (EA) - Environmental Impact Statement (EIS) 2. Underground Injection Control (UIC) permit 3. CO2 storage permit 4. Drilling permit 5. Water discharge/disposal permit 6. Crossing permits for wetlands, federal land, tribal land, railroads, highways, roads 7. Construction general permit 8. Storm water discharge permit 9. Air quality construction permit 10. Seismic permit 11. Storage tank permit 12. Closure financial assurance 13. Post-closure financial assurance	Lack of permit could halt or restrict construction or operation; permit delay could have other impacts including increased costs.	FWU is an existing CO2-EOR site and fully permitted. Permit requirements for UIC Class II wells are significantly less stringent than UIC Class VI wells. Typical Class II wells are permitted in about 5 months after application submission, assuming cementing is performed properly.		Project cannot obtain or maintain new permits.	Project out of compliance with new regulations.	Project halted or delayed.	Track permitting processes and regulations. Compare actual versus plan.	Use experienced permitting manager / consultant. Ensure continuous compliance with permits.	Use experienced permitting manager / consultant. Ensure continuous compliance with permits.
277	09.02.00.	Public outreach and education	Public acceptance support and trust is critical to obtaining environmental permits. Public outreach and education can be more difficult than expected. 1. Lack of public acceptance that CO2 emissions contribute to global warming 2. Lack of public acceptance that global warming is an eminent danger to society 3. Lack of public that carbon capture and storage (CCS) is safe 4. Poor public perception of CCS projects 5. Local community actions and reactions 6. Special interest groups or non-governmental organizations actions and reactions 7. Lack of political support for the project 8. Risk off-sets	Failure to get public acceptance for a project can lead to significant delays in, and costs for, permitting An unexpected situation arises that is not technically impacting but the appearance of unpreparedness spurs public concern.	Project already permitted. A CO2-EOR project is less controversial than a CO2-DSA project. Oil has been produced successfully at the FWU for 57 years.		Project unable to get new permits.	Lack of public support for project.	Project halted or delayed.	Track public opinion.	Maintain a comprehensive public outreach program.	Maintain a comprehensive public outreach program.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
276	09.01.00.	Permit compliance - obtain or maintain permits	3	3	1	9	None	None	None	None	None	None	Business interruption or shutdown \$0.8M/day for Northern Platform area. A 5-day shutdown would cost \$4M in revenue.	Impacts profitability.	None	Assume fine of \$0.5M	\$4.5M	\$0M	\$0.5M	\$4M	1
277	09.02.00.	Public outreach and education	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
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278	09.03.00.	Saline water extraction, treatment and disposal	Large amounts of saline water are pumped out of the ground for EOR and ECBM. EOR water production increases over time. In high water cut cases, water may represent 99% of the production volume and oil only 1% of the volume. ECBM employs water production to lower the over pressure in the coal seam, decrease swelling and increase permeability. Water may be extracted in a DSA operation to make room for injected CO2 and manage pressure. Extracted water is increasingly becoming a prominent issue, particularly deliberately extracting water to manage CO2 plume (e.g. extracting water to encourage plume migration and reinjecting the extracted water into a different part of the reservoir so that it is not extracted again). Some researchers believe CO2 can be injected into reservoirs without extracting water. This may be true in an open storage reservoir. But in a closed reservoir, injecting CO2 without extracting water will build up pressure in the reservoir and severely restrict the CO2 storage capacity. CO2 changes water composition and makes water more acidic (pH 4-5). Therefore EOR and ECBM production water may require more treatment before it can be disposed of. The acidic water may also include trace amounts of arsenic and other metals.	Saline water disposed could be one of the most critical issues in permitting. Treating the water will concentrate brine that will need to be reinjected.	Project already permitted. Produced water has 4,000 mg/L total dissolved solids. Some produced water is reinjected into the FWU reservoir as part of the WAG process. Excess produced water is injected into an existing deep disposal well located on site.	Produced water rate, treatment, disposal well API#, disposal formation, injection rate and injection pressure?	Project unable to get, or loses, permit to treat/dispose of extracted water. Water treatment/disposal costs significantly higher than expected.	Project out of compliance with regulations covering water treatment and disposal. Excessive extracted water volumes and/or poor water quality.	Project halted or delayed. Project profitability negatively impacted.	Monitor water treatment/disposal regulations. Model extracted water volumes and quality.	Maintain balance between produced and injected water.	Comply with all State water disposal regulations. Evaluate alternative methods of treating and disposing of produced water.
279	09.04.00	Natural resources nearby	1. Mineral resources 2. Mineable coal seams 3. Oil reservoirs 4. Natural gas reservoirs 5. Underground drinking water sources 6. Surface waters - lakes, rivers, streams 7. Geothermal resources 8. Pores space owned by others 9. Deep saline aquifers 10. Microbial resources 11. Soil - farmland 12. Flora and fauna - endangered species and critical habitats	CO2 or brine fluid migration could contaminate others' natural resources and lead to permitting delays due to legal contest.	Project already permitted. 1. No mineral resources have been identified in the Site area. 2. No coal seams have been identified in the Site area. 3. Oil resources are part of the FWU. 4. USDW is limited to the Ogallala aquifer (although the FWU reservoir water would qualify as USDW if it were not an oil reservoir). 5. No geothermal resources have been identified. 6. Saline water exists in Permian and Pennsylvanian formations. 7. Natural CO2 has not been found.	Presence of recoverable gas or oil above or below the FWU reservoir (formation, magnitude)?	Project unable to get permits. Permit compliance too expensive.	Project in conflict with or could negatively impact nearby natural resources.	Project halted or delayed. Project profitability negatively impacted.	Monitor site characterization and environmental impact statement work.	Avoid fracking the Morrow Shale (primary seal) Control Fracking of Morrow Shale for recovery of shale gas to prevent leakage of CO2+H2S. Use continuous passive microseismic monitoring. Monitor overlying formations for CO2/H2S.	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
278	09.03.00.	Saline water extraction, treatment and disposal	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
279	09.04.00	Natural resources nearby	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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280	09.05.00.	Dense population nearby	Present and future urban sprawl. 1. Sensitive receptors (schools, hospitals, care centers, churches, prisons) in or near injection site 2. Dense population located downhill or downwind of injection site 3. Populated subsurface structures located nearby	Additional safety precaution measures are required to protect against CO2 leakage in dense population areas..	Project already permitted. The FWU Site has sparse population. There are no known sensitive receptors such as school, hospitals, prisons, care centers, or churches in the area. Outside of the northwest corner of the FWU, there are 9 residences and 10 industrial building sites scattered around the FWU Site. Nearest down-wind population centers are: Waka, TX (population 69) located in the northwest corner of the FWU Site. Farnsworth, TX (population 106) located 5.5 km (3.4 miles) north of the FWU Site. Perryton, TX (population 8,802) located 17 km (10.6 mi) northeast of the FWU Site.		Project unable to get new permits. Permit compliance more expensive than planned.	Existing or future population density near site.	Project halted or delayed.	Track existing and planned population density near the site.	Avoid selecting sites near densely populated areas. Use existing pipeline corridors.	Provide additional monitoring, pipeline integrity management program and emergency response plan for populated sites. Assess alternative site.
281	09.06.00.	Conflicts with use of surface	Conflicts with use of the surface may include 1. Agriculture 2. Fishing 3. National parks/monuments 4. Wetlands 5. Timberland 6. Recreational areas 7. Military areas 8. Heavy industry sites 9. Urban areas 10. Archeological sites 11. Tribal sacred ground 12. Endangered species critical habitats 13. Bird sanctuaries 14. Historical sites 15. Groundwater protection zones. 17. Change in land use (zoning change)	Some land uses may impact site selection and permitting. Others may require additional monitoring and modeling to provide added protection from CO2 leakage. Nearby heavy industry can interfere with seismic readings. Land use changes could restrict access to and use of land for CO2 sequestration	Project already permitted. The FWU Site is mostly farmland. Oil has been produced on the Site for 57 years. There are no known surface conflicts.		Project unable to get new permits.	Project in conflict with use of surface.	Project halted or delayed.	Monitor site characterization and environmental impact statement work.	Use existing injection (i.e., EOR, CBM) sites and pipeline corridors. Avoid sensitive areas or habitats for endangered or protected species. Characterize sites for potential surface land use.	Design around sensitive areas. Monitor CO2 plume and brine migration. Assess alternative site.
282	09.07.00.	Conflicts with use of subsurface	Conflicts with use of the subsurface may include: 1. Natural gas storage 2. Compressed air storage 3. Geothermal plants 4. Radioactive waste disposal 5. Petroleum production 6. Coal mining 7. Health spas	Could impact site selection and permitting.	Project already permitted. FWU subsurface oil and gas rights are controlled by CELLCC. The FWU Site is mostly farmland. Oil has been produced on the Site for 57 years. There are no known subsurface conflicts.		Project unable to get new permits.	Project in conflict with use of subsurface.	Project halted or delayed.	Monitor site characterization and environmental impact statement work.	Use existing injection (i.e., EOR, CBM) sites and pipeline corridors. Avoid sites with conflicting subsurface use. Characterize sites for potential conflicting subsurface use.	Design around conflicting areas. Monitor CO2 plume and brine migration. Assess alternative site.
283	09.08.00.	Permit denied or modified by government agency	A permit may be modified by government agency to require increase data access and approval by NGOs and/or public 1. Permit denied because the project is considered high risk to public 2. Permit denied because there is uncertainty over the safety of the project 3. Permit revoked due to owner failing to comply with regulations (action or inaction) 4. Permit delayed due to owner action or inaction	Causes delays leading to price escalation. Could halt the project.	Project already permitted. Permits could change if CO2 continues to be injected for sequestration after EOR is completed.		Project unable to get new, or loses permit. Permit compliance costs more expensive than expected.	Project out of compliance with permit regulations.	Project halted or delayed. Project profitability negatively impacted.	Track permitting processes and regulations. Compare actual versus plan.	Use experienced permitting manager / consultant. Comply with permit requirements.	Use experienced permitting manager / consultant Revise project and/or permit application to resolve uncertainties, high risks etc. Assess alternative site. Comply with permit requirements.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable, or incredible; Yellow/Orange = Headings or non-risk areas

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking		Estimated Potential Damage Recovery Costs												Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
280	09.05.00.	Dense population nearby	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
281	09.06.00.	Conflicts with use of surface	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
282	09.07.00.	Conflicts with use of subsurface	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
283	09.08.00.	Permit denied or modified by government agency	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
284	09.09.00.	Pre-existing contaminated site	Site may have already been contaminated by non-CO2 storage related activities.	Pre-existing contamination of groundwater, surface water, and/or soil. Requires assessment to determine if proposed project would be impacted by or exacerbate existing condition. Or assume responsibility for remediation of pre-existing conditions.	Project already permitted. There are no known superfund or hazardous waste releases or brownfield sites or landfills registered with the EPA in the FWU Site.	Incidents of site contamination?	Significant costs to remediate pre-existing contamination.	Pre-existing contaminated site.	Project halted or delayed. Increased capital costs. Complex or misleading monitoring data.	Comprehensive site characterization and environmental impact statement work for pre-existing contamination.	Characterize sites for pre-existing contamination to evaluate operational impacts and additional costs. Conduct baseline studies to define preinjection conditions. Use experienced permitting manager / consultant.	Use experienced permitting manager / consultant
285	10.00.00.	EXTERNAL RISKS										
286	10.01.00.	Natural disaster risks	1. Fire -wildfires, industrial fires 2. Flood - flood plain, dry wash areas, flash floods, tsunamis, debris flows 3. Earthquake - natural seismic activity, rock slides, mud slides 4. Winter storms - blizzards, ice storms, arctic cold 5. Hail storm 6. High winds - tornadoes, hurricanes, typhoons, cyclones 7. Heat wave 8. Drought 9. Heavy rain - monsoons, tropical storms, thunder storms 10. Lightning 11. Sand/dust storms 12. Avalanche 13. Electromagnetic disturbances - sunspots 14. Volcano 15. Corrosive atmospheres - high humidity, coastal sea breeze, industrial plant acid gas emissions	Natural disasters can delay, impair or shutdown a project.	Potential natural disasters in within 50 km of Waka, TX include (in order of occurrences): hail, thunderstorm winds (and lightning), tornadoes, floods, strong winds, heavy snows, wildfires, droughts, winter storms, (homefacts.com 2013)		Project facilities damaged and/or personnel injured.	Natural disaster.	Project halted, delayed or impaired. Project profitability negatively impacted. Infrastructure damage.	Monitor site characterization for site-specific disaster risks. Monitor weather forecasts for severe weather conditions.	Select sites and pipeline corridors that are less likely to be exposed to natural disasters. Avoid flood plains. Include potential natural disasters in site characterization.	Implement emergency response plan covering all potential disasters. Comply with fire suppression codes. Ground surface equipment to protect from lightning. Cover sensitive equipment. Monitor severe weather reports. Integrate mitigative measures into facility design and operations. Implement effective storm management plans.
287	10.02.00.	Security risks	1. Theft 2. Vandalism - onsite equipment or offsite monitoring equipment 3. Employee sabotage 4. Civil unrest - riots, civil war, rebellion, insurrection, military or usurped power or confiscation 5. Terrorist activities 6. War - invasion, acts of foreign enemies, hostilities 7. Nationalization 8. Government sanctions, blockade, embargo 9. Labor disputes - strike, lockout 10. Damage to surface facilities by human activity 11. Hunting season - stray bullets	Risks to employees, public and equipment.	Terrorist attacks are very unlikely due to sparse population density and low priority targets. Low crime rate in the area. Violent crime rate 17% of national average. Property crime rate 40% of national average.	24-hour surveillance and fencing around injector wells?	Project facilities damaged and/or personnel harmed. Project security cost increased.	Security breach.	Project halted, delayed or impaired. Project profitability negatively impacted. Infrastructure or equipment damage	Monitor security alerts and level of civil / employee unrest.	Integrate appropriate security controls and systems to protect above ground facilities. Bury pipeline sufficiently deep. Do background checks and drug tests on all new employees. Supervise all crews during working hours.	Implement an emergency response plan and enhanced security procedures.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
284	09.09.00.	Pre-existing contaminated site	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
285	10.00.00.	EXTERNAL RISKS	0	0	0	0															
286	10.01.00.	Natural disaster risks	3	2	1	6	None	None	None	None	None	Surface facilities damage <\$1M for most situations.	0-7 days @ \$15,000/d revenue lost per pattern idled	None	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of total damages	Cost to repair surface facilities <\$1M + Cost of business interruption	Cost of insurance deductible.	Insurance coverage for weather and flood damage and business interruption 0.28% of surface facilities value per year + 0.25% of revenue per year	Savings in cost to repair surface facilities + Savings in cost of business interruption - Cost of insurance	1
287	10.02.00.	Security risks	2	2	2	8	None	None	None	None	None	Surface facilities damage or pipeline. <\$1M per incident.	0-2 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	Cost to repair surface facilities <\$1M	\$0	Proper security program. On going cost.	<\$1M	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
288	10.03.00.	Competition	Other projects in the area may compete for the same CO2, labor, infrastructure, land, pore space, funding 1. Interaction with adjacent CO2 sequestration sites 2. Infringement of project's pore space by third-party injection of CO2, water or waste disposal	Could halt the project or increase costs. Potential decreased storage capacity.	CELLC has acquired long-term contracts for CO2, owns the CO2 compression and pipeline facilities. Competition is mainly for personnel. This requires additional costs for maintaining the existing experienced management and technical staff.		Loss of key management or technical staff.	Competitor activity.	Project performance and profitability negatively impacted.	Monitor competitor activities and compensation packages.	Maintain competitive compensation packages and effective working conditions.	Identify backups for key management and technical staff. Maintain a strong recruiting program.
289	10.04.00.	CO2 supply	Changes in the operation of the CO2 source plant may impact CO2 properties and/or flow rate. Unanticipated change in demand for injected CO2 (flow rate, pressure, water content, etc.) due to either uncontrollable physical changes or operating decisions, will affect operations of the CO2 source facility and potentially impose stresses upon surface and down hole equipment and borehole. Changes may be gradual or sudden. Also includes changes arising from characterization data, e.g., limits placed by reservoir on injectivity, capacity, etc. CO2 sources and sinks need to coordinate supply and demand and scheduled outages to avoid constraint startup/shutdown of compression facilities and maintain consistent pipeline pressure. This is normally done through a nomination process at least one week in advance. Operators of CO2 storage projects may incorporate excess injection capacity (i.e. spare wells) to permit continued injection during planned or unplanned well downtime. (CCP 2009)	Interruption of CO2 supply could result in a Business Interruption / Advanced Loss of profit type exposure, or even result in the project becoming uneconomic to continue. Lack of adequate CO2 supply could halt or limit injection. Intermittent injection schedule could increase stress on surface and down hole mechanical elements, could affect EOR/ECBM sweep efficiency, and could increase concentrations of various contaminants in the injected gas. The timing of CO2 availability may not match up with the time when CO2 is needed for EOR or ECBM. 1. CO2 outside of design specification - flow rate, composition, pressure, temperature 2. Change in CO2 supply conditions 3. Change in CO2 demand conditions 4. CO2 supply interruptions due to source plant outage/failure 5. CO2 supply interruptions due to CO2 capture outage/failure 6. CO2 supply interruptions due to compressor outage/failure 7. CO2 supply interruptions due to pipeline outage 8. Disparity in timing CO2 supply/demand 9. CO2 interruption due to accident at the CO2 supplier	Multiple sources of high quality anthropogenic CO2 are controlled by CELLC through long-term contracts and ownership of compression and pipeline facilities. Arkalon Ethanol Plant, Liberal KS (up to 15MMCF/D) is the main supply for the FWU with backup from Agrium Fertilizer Plant, Borger, TX (up to 20MCFD).		Disruption of project operations. Project CO2 costs increased.	CO2 supply interruption. CO2 off-spec.	Project halted, delayed or impaired. Project profitability negatively impacted.	Monitor CO2 supplier operations, CO2 flowrate and CO2 quality.	Maintain multiple sources of CO2.	Monitor CO2 quality. Require CO2 supplier to vent off-spec CO2. Cut back CO2 injection on some patterns or compensate with increased water injection.
290	10.05.00.	Water supply	1. Water supply design specifications - Flow rates - Composition - Pressure - Temperature 2. Water supply interruptions	Could impact water and gas (WAG) flooding	Produced water of sufficient to meet all of the needs for WAG water injection. Excess produced water is injected into a deep disposal well located on site.	Produced water rate, treatment and disposal? Water injection rate and treatment?	Disruption of project operations. Project water costs increased.	Water supply interruption. Water off-spec.	Project delayed or impaired. Project profitability negatively impacted.	Monitor water supply and quality.	Take water supply volume and quality into account in system design. Consider redundant pumps, wells and/or water storage tanks.	Monitor for leaks in water piping. Implement pre-incident contingency plan. Add pumps, filtration or water treatment to resolve water volume or quality issues.
291	10.06.00.	Power supply	1. Power surges 2. Power brown outs 3. Power interruptions (black outs)	Could shut operations down.	It is assumed that power is purchased off the grid to meet on site needs.	Power source of supply and demand at FWU?	Disruption of project operations. Equipment damage.	Power supply interruption. Power surge/brownout.	Project delayed or impaired. Project profitability negatively impacted. CO2 release (HSE hazard)	Monitor power supply.	Install generator/battery backup system for key components.	Install surge protection if it is an issue. Make sure valves turn to safe default position when power goes out.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
288	10.03.00.	Competition	4	2	1	8	None	None	None	None	None	None	None	Increased costs to maintain or replace key personnel: \$1M/y	None	None	None	Increased costs to maintain or replace key personnel: \$1M/y	None	None	
289	10.04.00.	CO2 supply	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2
290	10.05.00.	Water supply	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
291	10.06.00.	Power supply	2	2	1	4	None	None	None	None	None	None	Business interruption	Impacts profitability.	<100t CO2 @ \$32.32/t CO2	10% of damage cost	<\$1M	<\$0.1M	\$0.5M	\$0.4M	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
292	10.07.00.	Communication system	Communications could be interrupted. The SCADA system may be dependent on one or more of the following communications systems: 1. Phone line 2. Fiber optics 3. Satellite 4. Internet	Loss of communication system could impair operations especially if the SCADA link is disconnected.		Operation, monitoring and emergency communication system used at FWU?	Disruption of project operations. Equipment damage.	Communication system interruption.	Project delayed or impaired. Project profitability negatively impacted. CO2 release (HSE hazard)	Monitor communication system.	Install fiber optics and backup system.	System maintenance. Implement contingency plan. Make sure valves turn to safe default position when SCADA system shutdown.
293	10.08.00.	Road access	Road to injection site could be blocked by snow, accident, washout, wildfire, flooding	Lack of road access to sites could impair operations	Good road access is available throughout the Site. The site is mostly flat land in a warm climate. Access unlikely to be disrupted.		Disruption of project operations.	Roads inaccessible	Project delayed or impaired. Project profitability negatively impacted. Personnel/supplies unable to reach or leave site.	Monitor road conditions.	Road maintenance procedures in place. Alternate routes.	Road maintenance in place. Alternate routes.
294	11.00.00.	PROJECT MANAGEMENT RISKS										
295	11.01.00.	Management team	The project may include some unfamiliar activities and workflows, may acquire and respond to a wide range of newly acquired data, and may experience changes in objectives. Operational conflicts, anticipated or not, could impact project values. Inexperienced managers tend to be over optimistic in taking risks and taking short cuts, for example: failing to avoid high risk sites. 1. Inexperienced management team 2. Inability to execute contracts among project partners in a timely manner 3. Lack of stakeholder coordination	An inexperienced management team has a higher potential for mistakes and poor judgment Inefficient interface management can result in delays and failure to achieve project goals.	Experienced management team in place. The unexpected loss of services of one or more of these key individuals could have a detrimental effect on CELLC's business.		Poor, or lack of, management decisions having a negative impact on the project.	Inexperienced management team	Project delayed or impaired. Project profitability negatively impacted.	Monitor implementation of project management plan.	Hire or assemble an experienced management team.	Hire additional experienced project managers / consultants if necessary. Conduct independent operational reviews.
296	11.02.00.	Operator training	1. Under qualified operators 2. Untrained operators 3. Operator error	Inadequate operator training can result in low labor productivity and greater potential for human error.	Competition for oil and gas technical professionals remains strong. CELLC is likely to continue experiencing increased costs to attract and retain these professionals. Assume CELLC has an effective operator training program in place.	Verify operator training program in place?	Operator error or over confidence resulting in poor performance and/or equipment/system failure.	Insufficient operator training.	Project halted, delayed or impaired. Facilities damaged and/or personnel injured. CO2 release (HSE hazard). Project profitability negatively impacted. Regulatory violations.	Monitor operator training and performance.	Implement a continuous operator training program.	Maintain an ongoing operator training program in the operation phase with particular emphasis on emergency response.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
292	10.07.00.	Communication system	2	2	1	4	None	None	None	None	None	None	Business interruption	Impacts profitability.	<100t CO2 @ \$32.32/t CO2	10% of damage cost	<\$1M	<\$0.1M	\$0.5M	\$0.4M	1
293	10.08.00.	Road access	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
294	11.00.00.	PROJECT MANAGEMENT RISKS	0	0	0	0															
295	11.01.00.	Management team	3	3	1	9	None	None	None	None	None	None	Project delay or interruption	Hedging loss or operational error <\$10M. Impacts profitability.	None	10% of damage cost	Hedging loss or operational error <\$10M	None	Part of ongoing cost	None	1
296	11.02.00.	Operator training	3	3	1	9	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	Equipment or system failure.	Project delay or interruption	Operational error: <\$10M	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	Operational error: <\$10M	None	Part of ongoing cost	<\$10M	1

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297	11.03.00.	Execution strategy	Poor execution strategy can result from: 1. Insufficient funding 2. Insufficient resources 3. Unrealistic schedule 4. Schedule and planning conflicts (02.01.05.00) 5. Poor timing 6. Lack of risk management plan Scheduling and planning covers the sequence of events and activities occurring during all phases of the project.	Poor execution strategy can result in project delays and increased project costs. Project development decisions generally are based on subjective judgments and assumptions that, while they may be reasonable, are by their nature speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, the successful completion of a well does not ensure a profitable return on investment.	An effective execution strategy is in place.		Project delays and schedule conflicts.	Lack of scheduling and planning	Increased project costs.	Track actual schedule versus plan.	Detailed scheduling and planning. Prepare a realistic schedule. Work with experienced team members to execute the project. Update and follow project management plan and risk management plan.	Prioritize and accelerate work load. Use quarterly meetings to review and fine tune execution strategy and resolve schedule conflicts.	
298	11.04.00.	Record keeping (See 02.02.03.00.)	Large amounts of data will be generated by the project. Data could be poorly communicated between groups, or be badly managed to the point that important data is lost, or used incorrectly. Features related to the retention of records of the content and nature of a CO2 storage site after closure and also the placing of permanent markers at or near the site. 1. Poor data management 2. Loss of archives/records 3. Unable to accurately verify the amount of CO2 retained in storage	It is expected that records will be kept to allow future generations to recall the existence and nature of the storage reservoir/aquifer following closure. Insufficient record keeping could lead to noncompliance with regulations and failure to achieve project goals.	Record keeping for CO2 storage being established as part of the SWP/CELLC FWU Project.		Noncompliance with regulations. Inadvertent future intrusion into the CO2 reservoir by third-party.	Improper record retention and marking.	Potential fines, penalties or business interruption for noncompliance.	Data management. Routine site inspection.	Set up an electronic data management system with off-site backups. Proper documentation. Standardize data formats. Clearly mark site with warnings and register site as CO2 storage site with the State.	Maintain data system and standardized formats. Routine site inspection and/or monitoring. Prepare procedures for potential remedial action.	
299	11.05.00.	Multi-party project	CCS projects may involve multiple participants for CO2 supply, CO2 transportation, EPC (engineering, procurement and construction), CO2 storage, computer simulation, MVA (monitoring, verification and accounting), carbon trading, and risk management. There are challenges and risks in coordinating the responsibilities and liabilities among multiple organizations involved in a project. In case of too deep involvement of partners in day to day operations, shareholders may assume joint and several liability for actions of the partnership. Disagreement among partners may lead to deadlock in unanimous decision making.	Lack of communication, coordination and cooperation among project participants can lead to project delays and failure to achieve project objectives.	CELLC acquired 99% working interest in the FWU in NOV2009. The SWP/CELLC FWU Project is a multi-party project that will require communication, coordination and cooperation, but the scope of this project is limited.		SWP project negatively impacted by poor, or lack of, multi-party coordination/cooperation.	Multi-party project	Project delays. Project profitability negatively impacted. Unclear responsibilities for liabilities.	Monitor multi party coordination / cooperation.	Maintain secure website, weekly conference calls, cross-functional working groups and management team. Establish clear division of scope of work and responsibilities.	Maintain secure website, weekly conference calls, cross-functional working groups and management team. Maintain clear division of scope of work and responsibilities.	
300	11.06.00	Pre-closure administrative control	Features related to measures to control events at or around the sequestration site during the design, construction, operation and decommissioning phases. The type of administrative control may vary depending on the stage in the storage system lifetime. (02.01.06.00.)	The pre-closure administrative control will influence the quantity and quality of information about the sequestration project that is available post-closure, therefore helping to determine societal memory. The better the amount and quality of information available, the lower the possibility of inadvertent intrusion.	Pre-closure administration control is being developed through the SWP/CELLC FWU Project. Pre-closure CO2-EOR requirements not as rigorous as CO2 sequestration. CELLC will be responsible for all applicable laws and regulations regarding decommissioning, abandonment and reclamation of facilities at the end of their economic life, the cost of which may be substantial. In the future CELLC may establish a reserve fund to cover decommissioning, abandonment and reclamation costs (CELLC 2013a)		Future inadvertent intrusion into CO2 storage reservoir.	Lack of pre-closure administrative control	Future CO2 release (HSE hazard). Inability to transfer long-term liability. Penalties for non-compliance with regulations	Routine inspection and monitoring of site. One-call center.	Clearly mark the site with warning signs and register the site as a CO2 storage site with the State. Data management. Keep backup documentation at off-site locations.	Data management.	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
297	11.03.00.	Execution strategy	3	3	1	9	None	None	None	None	None	None	Project delay or interruption	Strategic error: <\$10M	None	10% of damage cost	Strategic error: <\$10M	None	Part of ongoing cost	<\$10M	1
298	11.04.00.	Record keeping (See 02.02.03.00.)	2	2	2	8	None	None	None	None	None	None	None	None	None	<\$1M for fines or penalties.	<\$1M for fines or penalties.	None	Part of ongoing costs.	<\$1M	1
299	11.05.00.	Multi-party project	4	2	1	8	None	None	None	None	None	None	None	Increased project costs \$3M.	None	None	Increased project costs \$3M	None	Effective management cooperation: \$0.5M	\$2.5M	1
300	11.06.00	Pre-closure administrative control	2	2	2	8	None	None	None	None	None	None	None	None	None	Fines or penalties <\$1M	<\$1M	None	Part of ongoing costs	<\$1M	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
301	11.07.00	Post-closure administrative control	Administrative control of the sequestration site after closure of the project. The administrative control of the post-closure site may differ from that of the pre-closure site with subsequent implications for the resources available for administrative control, the degree of access and availability of information etc.	There may be potential for loss of information in any transfer of administrative control. A lack of awareness about the details of a CO2 sequestration project could result in inadvertent disruption in the future.	Post closure CO2-EOR requirements not as rigorous as CO2 sequestration. CELLC will be responsible for all applicable laws and regulations regarding decommissioning, abandonment and reclamation of facilities at the end of their economic life, the cost of which may be substantial. In the future CELLC may establish a reserve fund to cover decommissioning, abandonment and reclamation costs.	Cost of post closure administrative control?	Inadvertent intrusion into the CO2 reservoir. Loss of documentation in transfer of long-term liability.	Lack of post-closure administrative control.	CO2 release (HSE hazard). Delay or prevention of transferring long-term liability.	Data management. Routine site inspection.	Proper documentation and data management. Use multiple backup sites for data storage. Clearly mark site with warnings and register site as CO2 storage site with the State.	Data management. Routine site inspection and/or monitoring.
302	11.08.00	Quality Control (See 02.01.08.00.)	Features related to quality control procedures and tests during the design, and operation of the storage system. It could be expected that a range of quality control measures would be applied during operation of the storage system and supply of CO2 to be sequestered. There may be specific regulations governing quality control procedures, objectives and criteria.	The degree of quality control during the design, construction, operation and decommissioning of a sequestration system can affect the post-closure performance by influencing the integrity of the engineered parts of the system (borehole seals, for example) and by influencing the quantity, quality and accuracy of records. Quality of equipment could have a big impact on the project.	Regulations and permits require wells and pipelinese to be regularly tested for mechanical integrity. Product is required to be regularly tested for quality. Assume that CELLC operates in compliance with regulations and permits.	Copy of quality control plan?	Equipment failure. Insufficient or inaccurate information to ensure safe storage of CO2.	Poor quality control	CO2 release (HSE hazard).	Risk management overseeing quality control.	Risk management overseeing quality control.	Formal risk management protocols and plan overseeing quality control.
303	11.09.00	Monitoring	There are many market and business conditions that should be monitored by management in order to make informed business decisions. These may include: 1. Environmental conditions 2. Public health 3. Public opinion 4. Legislation and regulations 5. Economic conditions 6. Operations 7. Natural resources 8. Water supply 9. Transportation logistics 10. Construction schedule 11. Climate change and weather conditions 12. Security 13. Pipeline 14. CO2/brine movement 15. Operating permit requirements.	Effective decision making requires timely knowledge and understanding of all factors that may influence or be influenced by the decision.	The SWP/CELLC FUW Project will establish monitoring of CO2 movement in the FWU reservoir	Copy of the monitoring plan?	Poor, or lack of, management decisions having a negative impact on the project.	Lack of knowledge or understanding of key factors that may influence or be influenced by management decisions.	Project delayed or impaired. Project profitability negatively impacted.	Assessment of monitoring systems in place.	Establish effective monitoring systems for key factors.	Hire independent auditors. To check the checkers. Hire additional outside monitoring services for key factors.
304	12.00.00.	ENGINEERING RISKS										

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
301	11.07.00	Post-closure administrative control	2	2	2	8	None	None	None	None	None	None	None	None	None	Fines or penalties <\$1M	<\$1M	None	Part of ongoing costs	<\$1M	1
302	11.08.00	Quality Control (See 02.01.08.00.)	2	2	2	8	None	None	None	None	None	<\$1M	None	None	None	None	<\$1M	None	Part of ongoing costs	<\$1M	1
303	11.09.00	Monitoring	2	2	1	4	None	None	None	None	None	None	None	<\$1M	None	None	<\$1M	None	Part of ongoing costs	<\$1M	1
304	12.00.00.	ENGINEERING RISKS	0	0	0	0															

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
305	12.01.00.	Technical design	Technical design errors can be caused by: 1. Insufficient data 2. Lack of data - typical of greenfield sites 3. Inaccurate data 4. Misinterpretation of data 5. Use of wrong standards - unit conversion 6. Specification errors 7. Undefined specifications 8. Ignoring data 9. Calculation and modeling errors 10. Failure to design for full range of operating conditions and climate conditions. 11. Failure to design for high operating availability 12. Failure to design for failsafe protection for compression, pipeline, injection well control systems to ensure no unintended release of CO2	Technical design errors can lead to poor performance or failure of equipment/systems and possible CO2 release.	The FWU is a partially depleted oil reservoir incorporating CO2-EOR. The brownfield site is well characterized with 169 deep wells and 3D seismic surveys. The oil field has been operating since 1956. CO2-EOR operation began in DEC2010.	FWU technical design issues identified to date?	Poor performance or failure of equipment / systems.	Technical design errors.	Project delayed or impaired. Facilities damaged and/or personnel harmed. CO2 release (HSE hazard). Project profitability negatively impacted.	Monitor technical design through periodic design reviews.	Conduct periodic design reviews with cross-functional team of experts.	Conduct periodic design reviews with cross-functional team of experts. Correct design errors.
306	12.02.00.	Modeling and simulation	Use of multiple static and dynamic models that are populated and run by different people using different assumptions and methods can result in errors.	Modeling and simulation errors can result in uncertainties, interpretive disagreements and poor operational choices. Multiphase flow relative permeabilities are quite uncertain and control mobility of CO2 in models.	CELLC and SWP have developed simulation models for the FWU.	CO2-EOR modeling completed at FWU to date? Modeling history match achieved to date? Relative permeabilities used in models?	Uncertainties and poor operational choices.	Modeling and simulation errors.	Project delayed or impaired. Facilities/systems damaged and/or personnel harmed. CO2 release (HSE hazard). Project profitability negatively impacted.	Monitor modeling and simulation through periodic reviews or checks to confirm accuracy.	Standardize model(s) to be used. Review simulation model results for accuracy and completeness using a cross-functional team of experts.	Periodic review of simulation model results.
307	12.03.00.	Baseline studies	Baseline surveys are important for determining ambient or background conditions prior to CO2 injection. They include: 1. Soil baseline 2. Water (surface and groundwater) baseline 3. Atmosphere baseline 4. Seismic baseline 5. Aquatic environment baseline 6. Fauna baseline 7. Flora baseline 8. Land use 9. Natural resources 10. Population 11. Local/regional economic baseline 12. Formation chemical baseline 13. Injection site contamination 14. Coastal features 15. Local oceanography 16. Aquatic sediments 17. Location and condition of existing wells 18. Formation geophysical baseline	Without baseline surveys the project will be unable to quantify what impact the project has had on the environment.	It is assumed that baseline studies were not completed prior to CO2 injection except for reservoir properties and performance. CELLC acquired 99% working interest in the FWU in NOV2009. CO2 injection began in DEC2010. SWP will perform some soil and water baseline studies as part of the SWP/CELLC FWU Project.	Baseline studies completed before CO2 injection began?	Uncertainties and poor operational choices	Insufficient, or lack of, baseline studies	Project open to wide range of environmental liabilities that may or may not have been caused by the project. Project delayed or impaired. Project profitability negatively impacted. Injectivity or capacity different than expected.	Monitor the performance and quality of baseline studies.	Complete baseline studies before CO2 injection.	Review results of baseline studies.
308	13.00.00.	PROCUREMENT RISKS										

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
305	12.01.00.	Technical design	2	3	2	12	None	None	None	None	None	None	None	None	None	None	Design error <\$3M	None	Part of ongoing costs	<\$3M	1
306	12.02.00.	Modeling and simulation	2	3	2	12	None	None	None	None	None	None	None	<\$2M	None	None	Modeling error: <\$2M	None	Part of ongoing costs	<\$2M	1
307	12.03.00.	Baseline studies	2	3	2	12	None	None	None	None	None	None	None	<\$5M	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1
308	13.00.00.	PROCUREMENT RISKS	0	0	0	0															

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
309	13.01.00.	Procurement delays	Procurement delays may threaten project goals. Infrastructure components may include power block, compressors, gas processing equipment, pumps, valving, metering and monitoring equipment. 1. Procurement delays - equipment and infrastructure 2. Procurement delays - drilling services 3. Vendor supply chain disruptions 4. Material supply shortages 5. Changes in materials and equipment costs	Could delay completion of construction	As a mature project, procurement delays are not as significant an issue as they would be for a new project.	Incidents of procurement delays (type, frequency, magnitude, methods of mitigating)?	Project schedule disruption(s).	Procurement delays.	Project delayed. Project costs increased and project profitability decreased.	Track equipment and material delivery schedules.	Establish lead times for historically long-lead time items (like compressors) and build it into the schedule.	Monitor delivery schedule after orders are placed. Implement supply chain contingency plan.
310	13.02.00.	Vendor errors	1. Vendor engineering errors 2. Defective manufacturing	Potential poor performance or failure of equipment/systems. Potential CO2 leakage.	Mature project.	Incidents of vendor errors (type, frequency, magnitude, methods of mitigating)?	Poor performance or failure of equipment/systems.	Vendor errors	Project delayed or impaired. Facilities damaged and/or personnel harmed. CO2 release (HSE hazard). Project profitability negatively impacted.	Monitor vendor engineering, manufacturing, quality control and performance testing.	Use qualified vendors. Review vendor engineering, design and quality control testing. Negotiate performance guarantees.	Inspect/test delivered product.
311	13.03.00.	Contracting	The ability of project partners to formulate and execute contracts with third parties (non-partners) in a timely manner (not causing delays) apart from their specific contents. 1. EPC contract omissions 2. EPC contract insufficient detail 3. EPC contract change orders	The principal risk is delay and its impact upon achieving goals including cost.	Mature project.	Incidents of contractor errors (type, frequency, magnitude, methods of mitigating)?	Project schedule disruption(s). Increased EPC costs.	EPC contract omissions, errors or change orders	Project delayed. Project profitability negatively impacted.	Monitor EPC contract administration.	Use experienced contract administrator. Implement procedure for preparing request for quote (RFQ), RFQ review and bid review. Get at least 3 competitive bids on large contracts. Establish change order procedures.	Use experienced contract administrator. Hire additional experienced project administrators/consultants as necessary.
312	13.04.00.	Transportation logistics	Project-related traffic in and out of site; its effects upon both injection well, monitoring and CO2 supply operations. 1. Site traffic impact on injection and monitoring 2. Limitations on size/height/weight shipments to site	Could cause interruptions and delays.	Mature project.	Incidents of transportation problems (type, frequency, magnitude, methods of mitigating)?	Project schedule disruption(s). Increased transportation costs.	Transportation size/weight constraints	Project delayed. Project profitability negatively impacted.	Monitor transportation logistics.	Survey potential transportation routes before placing orders. Identify major weight/size items, supply/destination routes, weight/size restrictions, and alternate transportation modes and routes.	Monitor transportation logistics after orders are placed. Consider resolving any transportation bottlenecks by improving infrastructure. Implement supply chain contingency plan.
313	14.00.00.	CONSTRUCTION RISKS										

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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			Index #	Risk Area/FEP	Failure probability (P= 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)		Savings with risk mitigation (\$)
									Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
309	13.01.00.	Procurement delays	2	2	2	8	None	None	None	None	None	None	None	None	None	None	None	<\$1M	None	Part of ongoing costs	<\$1M	1	
310	13.02.00.	Vendor errors	2	2	2	8	None	None	None	None	None	None	None	None	None	None	None	<\$1M	None	Part of ongoing costs	<\$1M		
311	13.03.00.	Contracting	2	2	2	8	None	None	None	None	None	None	None	None	None	None	None	<\$1M	None	Part of ongoing costs	<\$1M	1	
312	13.04.00.	Transportation logistics	2	2	2	8	None	None	None	None	None	None	None	None	None	None	None	<\$1M	None	Part of ongoing costs	<\$1M	1	
313	14.00.00.	CONSTRUCTION RISKS	0	0	0	0																	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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314	14.01.00.	Cost overruns	Construction cost overruns can be due to 1. Change orders 2. Cost escalation 3. Unexpected problems 4. Rework 5. Poor management.	Increased costs	Mature project. Cost overruns on capital expenditures could adversely affect business.		Construction cost overruns	1. Change orders 2. Cost escalation 3. Unexpected problems 4. Rework 5. Poor management.	Project halted, delayed or impaired. Project profitability negatively impacted.	Track actual construction costs versus budget.	Negotiate not-to-exceed EPC contracts. Prepare detailed budget. Have experienced experts review budgets for accuracy and completeness.	Use experienced project managers. Monitor actual versus budgeted expenses. Monitor quality of work. Address deviations from plan early. Prioritize expenses. Cut low priority expenses if necessary. Adjust scope of work if necessary to stay within budget.
315	14.02.00.	Schedule delays	Construction schedule delays can be due to 1. Permitting delays 2. Bad weather 3. Labor issues 4. Procurement delays 5. Accidents 6. Poor planning/management 7. Funding delays	Startup delay and increased costs.	Mature project. Delays on capital expenditures could adversely affect business.		Construction schedule delays	1. Permitting delays 2. Bad weather 3. Labor issues 4. Procurement delays 5. Accidents 6. Poor planning/management 7. Funding delays	Project halted, delayed or impaired. Project profitability negatively impacted.	Track actual versus planned schedule.	Build in cushion in schedule to accommodate unexpected delays. Address procedure for resolving schedule delays in project management plan.	Monitor work in progress versus schedule. Adjust schedule to accommodate unexpected delays.
316	14.03.00.	Construction defects	Construction defects may be identified during or after construction. They may include 1. Improper installation 2. Wrong installation 3. Damage during installation 4. Defective welding 5. Omissions	Increased costs, project delays due to need for rework, and potential human injury and equipment/systems damage	Mature project.	Incidents of construction defects (type, frequency, magnitude, methods of mitigating)?	Construction defects.	1. Improper installation 2. Wrong installation 3. Damage during installation 4. Defective welding 5. Omissions	Project halted, delayed or impaired. Facilities damaged and/or personnel harmed. CO2 release (HSE hazard). Project profitability negatively impacted.	Monitor construction quality through regular inspections and testing.	Use qualified contractors. Issue detailed contracts and drawings. Inspect work.	Inspect work. Require contractors to repair any defects.
317	15.00.00.	COMMISSIONING AND STARTUP RISKS										
318	15.01.00.	Major rework	Major rework may be required to correct poor performance or failure of equipment/systems due to improper design, manufacturing, construction or operation.	Project delays and added costs.	Mature project. Facility capability demonstrated. Some rework being done on CO2 processing/compression facilities.	Incidents of major rework (type, frequency, magnitude, methods of mitigating)?	Schedule disruption. Increased cost.	Major rework.	Project profitability negatively impacted.	Track commissioning and startup performance.	Use experienced contractors. Construction management supervision.	Periodic site visits by stakeholders to inspect the work through the construction phase. Conduct periodic independent construction reviews.
319	15.02.00.	Unable to achieve design capacity	Operating capacity may be limited due to improper design, manufacturing, construction or operation.	Loss of revenues and increased costs.	Mature project. Capacity demonstrated.		Increased operating costs.	Unable to achieve design capacity	Project profitability negatively impacted.	Track commissioning and startup performance.	Design review process including sign off on drawings by competent engineers.	Performance testing. Resolution of bottlenecks.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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314	14.01.00.	Cost overruns	2	3	2	12	None	None	None	None	None	None	None	None	None	None	<\$2M	None	Part of ongoing costs	<\$2M		
315	14.02.00.	Schedule delays	2	3	2	12	None	None	None	None	None	None	None	None	None	None	<\$2M	None	Part of ongoing costs	<\$2M	2	
316	14.03.00.	Construction defects	2	3	2	12	None	None	None	None	None	None	None	None	None	None	<\$3M	None	Part of ongoing costs	<\$3M	1	
317	15.00.00.	COMMISSIONING AND STARTUP RISKS	0	0	0	0																
318	15.01.00.	Major rework	2	3	2	12	None	None	None	None	None	None	None	None	None	None	<\$3M	None	Part of ongoing costs	<\$3M	1	
319	15.02.00.	Unable to achieve design capacity	2	3	2	12	None	None	None	None	None	None	None	None	None	None	<\$3M	None	Part of ongoing costs	<\$3M		

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
320	15.03.00.	Operator error or over confidence during commissioning and startup	Incorrect operation due to lack of operator training	Potential human injury, equipment damage, project delays, added costs.	Mature project. Experienced operators.	Operator training program in place? Incidents of operator error (type, frequency, magnitude, methods of mitigating them)?	Poor performance and/or equipment/system failure.	Operator error or over confidence.	Project halted, delayed or impaired. Facilities damaged and/or personnel injured. CO2 release (HSE hazard). Project profitability negatively impacted.	Track operator training and performance.	Implement a continuous operator training program.	Maintain an ongoing operator training program in the operation phase with particular emphasis on emergency response. Conduct periodic independent operating reviews.
321	15.04.00.	Startup pressure	Facilities sometimes do not have sufficient pressures to re-start injection. In these cases, injection tubing should be loaded with sufficient fluids to allow for a re-start. (CCP 2009)	Insufficient startup pressure can result in operating delays.	Mature project. Startup pressure demonstrated. Not an issue.		Operating delays.	Insufficient startup pressure.	Project profitability negatively impacted.	Monitor and model bottom hole pressure and injection pressure.	Design compressors/pumps with sufficient pressure to handle the full range of injection pressure required.	Load tubing with fluids prior to starting injection.
322	16.00.00.	FIELD SAFETY RISKS										
323	16.01.00.	Accidents and unplanned events	Events related to accidents and unplanned events during site investigation, CO2 emplacement and closure which might have an impact on long-term performance or safety. Accidents are events that are outside the range of normal operations although the possibility that certain types of accident may occur should be anticipated in operational planning. Unplanned events include accidents but could also include deliberate deviations from operational plans, e.g. in response to an accident, unexpected geological events or unexpected aspects of CO2 quality and injection arising during operations. Project related accidents can be caused by human error or equipment/system failure/malfunction. Accidents may occur during construction, commissioning, operation, maintenance or closure. Non-project related accidents may include: rupture of train or truck transport vessel, train derailment, site or water supply contamination. 1. Project related accidents 2. Non-project related accidents	Potential for human injury and/or equipment damage Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue. Accidents and unplanned events may affect the post-closure performance of the sequestration system. One example may be the incomplete sealing of an injection borehole that may subsequently provide a pathway for CO2 migration.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year Total fatality rates based on BLS data 2006-2010 (fatalities/worker/year) O&G extraction: 1.12E-04 Drilling O&G wells: 4.85E-04 Support activities for O&G wells: 2.85E-04 O&G pipeline construction: 1.94E-04 Pipeline transportation: 6.96E-05 O&G industry: 2.61E-04 Total significant injury (injuries requiring days away from work) rates based on BLS data 2006-2010 data (incidents/worker/year): O&G extraction: 6.29E-03 Drilling O&G wells: 1.50E-02 Support activities for O&G wells: 1.13E-02 O&G pipeline construction: 7.43E-03 Pipeline transportation: 5.96E-03 O&G industry: 1.02E-02	Number of employees and contractors on FWU Site? Incidents of injury due to accidents and unplanned events at FWU?	Human injury/death. Facilities / equipment damage. CO2 release.	Accidents and unplanned events.	Business interruption (advanced loss of profits). Liability costs.	Comprehensive risk assessment. Routine risk and safety audits.	Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement an emergency response plan and risk management plan. Analyze project changes for new risks.	Maintain safety training and standard procedures. Document response to accidents and unplanned events. Emergency response and contingency planning . Risk management plan. Liability insurance. Conduct periodic response drills.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
320	15.03.00.	Operator error or over confidence during commissioning and startup	2	3	1	6	None	None	None	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	Equipment or system failure.	Project delay or interruption	<\$10M Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$2M	None	Part of ongoing cost	<\$2M	1
321	15.04.00.	Startup pressure	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
322	16.00.00.	FIELD SAFETY RISKS	0	0	0	0															
323	16.01.00.	Accidents and unplanned events	3	4	2	24	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	<\$5M	Project delay, or interruption	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$5M	None	Part of ongoing costs	<\$5M per accident or unplanned event avoided	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
324	16.02.00.	Moving equipment	Moving equipment risks may include: 1. Hitting other equipment 2. Hitting personnel 3. Hitting power lines	Potential for human injury and/or equipment damage	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250. Approximately 3% of fatalities in the O&G industries were tied to pedestrians struck by a vehicle or mobile equipment in 2008 (BLS 2010). Fatality rate tied to pedestrian hit by moving equipment (assuming 15% of transportation incidents) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 5.94E-06 Drilling O&G wells: 1.82E-05 Support activities for O&G wells: 2.1E-05 O&G pipeline construction: 1.08E-05 Pipeline transportation: 5.97E-06 O&G industry: 1.52E-05 Significant injury rate tied to pedestrian being hit by moving equipment in drilling O&G wells based on BLS 2007 data: 5.49E-05.	No. of employees and contractors on FWU Site? Incidents of injury due to moving equipment at FWU?	Facilities / equipment damage. Human injury/death. CO2 release (HSE hazard).	Improper operation of moving equipment.	Business interruption. Liability costs.	Monitor moving equipment on site.	Design site layout to safely accommodate moving equipment. Maintain moving equipment in safe operating condition. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
325	16.03.00.	Excavation/drilling	The one-call system should be used to locate underground utilities and pipelines before excavating or drilling. Excavation/drilling could hit other subsurface hazards such as gas pockets or underground storage tanks.	Potential for equipment damage, release of gases or liquids, fire, explosion, and/or human injury.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year. Fatality rate for drilling O&G wells based on BLS 2006-2010 data: 4.85E-04 fatalities/worker/year. Significant injury (injury requiring days away from work) rate for drilling O&G wells based on BLS 2006-2010 data: 1.55E-03	Number of employees and contractors on FWU Site? Incidents of injury due to excavation / drilling at FWU?	Pipeline damage. Human injury/death. CO2 release (HSE hazard).	Excavation/drilling.	Business interruption. Pipeline repair costs. Liability costs.	Monitoring excavation/drilling activities and one-call center alerts.	Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking		Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)		Savings with risk mitigation (\$)
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
324	16.02.00.	Moving equipment	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	Project delay, interruption	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$5M	None	Part of ongoing costs	<\$5M	1
325	16.03.00.	Excavation/drilling	3	4	2	24	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	Pipeline damage <\$1M per incident.	0-5 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
326	16.04.00.	Defective equipment	Equipment should be properly maintained and regularly inspected. Equipment defects may include: 1. Exposed electric wiring 2. Leaky hoses 3. Loose connections 4. Frayed cables	Higher risk for equipment failure and human injury	Fatality rate tied to contact with equipment (assuming 45% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.04E-05 Drilling O&G wells: 8.01E-05 Support activities for O&G wells: 3.02E-05 O&G pipeline construction: 2.41E-05 Pipeline transportation: 0 O&G industry: 3.25E-05 Significant injury rate due to being caught in an object equipment or material in drilling O&G wells based on BLS 2007 data: 3.88E-03 incidents/worker/year	Number of employees and contractors on FWU Site? Incidents of injury due to defective equipment at FWU?	Human injury/death. Facilities / equipment damage. CO2 release (HSE hazard).	Defective equipment	Project delayed or impaired. Liability costs. Project profitability negatively impacted.	Monitor equipment condition and maintenance records.	Maintain equipment in safe condition. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain equipment in safe condition. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
327	16.05.00.	Use of power tools	Operators should be properly trained in the use of power tools.	Potential for human injury and/or equipment damage	Fatality rate tied to contact with equipment (assuming 45% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.04E-05 Drilling O&G wells: 8.01E-05 Support activities for O&G wells: 3.02E-05 O&G pipeline construction: 2.41E-05 Pipeline transportation: 0 O&G industry: 3.25E-05 Significant injury rate due to being caught in an object equipment or material in drilling O&G wells based on BLS 2007 data: 3.88E-03 incidents/worker/year	Number of employees and contractors on FWU Site? Incidents of injury due to use of power tools at FWU?	Human injury/death.	Improper use of power tools.	Liability costs. Equipment repair costs.	Monitor operator training and use of power tools.	Select appropriate power tools. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain power tools in safe condition. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
328	16.06.00.	Contact with rotating equipment	Proper safeguards should be used to prevent contact with rotating equipment	Higher risk for being injured	Fatality rate tied to contact with equipment (assuming 45% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.04E-05 Drilling O&G wells: 8.01E-05 Support activities for O&G wells: 3.02E-05 O&G pipeline construction: 2.41E-05 Pipeline transportation: 0 O&G industry: 3.25E-05 Significant injury rate due to being caught in an object equipment or material in drilling O&G wells based on BLS 2007 data: 3.88E-03 incidents/worker/year	Number of employees and contractors on FWU Site? Incidents of injury due to contact with rotating equipment at FWU?	Human injury/death. Equipment damage.	Contact with rotating equipment.	Liability costs. Equipment repair costs.	Monitor activity around rotating equipment.	Install safeguards around rotating equipment. Lockout equipment before performing maintenance. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable, or incredible; Yellow/Orange = Headings or non-risk areas

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking		Estimated Potential Damage Recovery Costs												Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
326	16.04.00.	Defective equipment	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	5,000 to 50,000 t @ \$200/tCO2 released into USDW \$50,000/acre of land contaminated	None	<\$2M	0-5 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$5M	None	Part of ongoing cost	<\$5M	2
327	16.05.00.	Use of power tools	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1
328	16.06.00.	Contact with rotating equipment	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
329	16.07.00.	Working near pinch points	Proper safeguards should be used to prevent contact with pinch points	Higher risk for being pinched	Fatality rate tied to contact with equipment (assuming 45% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.04E-05 Drilling O&G wells: 8.01E-05 Support activities for O&G wells: 3.02E-05 O&G pipeline construction: 2.41E-05 Pipeline transportation: 0 O&G industry: 3.25E-05 Significant injury rate due to being caught in an object equipment or material in drilling O&G wells based on BLS 2007 data: 3.88E-03 incidents/worker/year	Number of employees and contractors on FWU Site? Incidents of injury due to working near pinch points at FWU?	Human injury/death.	Working near pinch points.	Liability costs. Equipment repair costs.	Monitor activity around pinch points.	Install safeguards in pinch-point areas. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
330	16.08.00.	Working in confined areas	Working in confined areas can represent high risk especially where CO2 is involved.	Higher risk of asphyxiation or being crushed.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year.	Number of employees and contractors on FWU Site? Incidents of injury due to working in confined areas at FWU?	Human injury/death.	Working in confined areas.	Liability costs. Equipment repair costs.	Monitor activity in confined areas.	Provide protective equipment and safeguards for working in confined areas, including CO2 alarm and ventilation if appropriate. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
331	16.09.00.	Working in high places	Working in high places is a common industrial occurrence	Higher risk of injury due to falling	Fatality rates tied to falls based on BLS data 2006-2010 (fatalities/worker/year) O&G extraction: 0 Drilling O&G wells: 5.27E-05 Support activities for O&G wells: 4.14E-06 O&G pipeline construction: 0 Pipeline transportation: 0 O&G industry: 1.15E-05 Significant injury rate resulting from falls to a lower level in drilling O&G wells in 2007 based on BLS data: 9.7E-04 incidents/worker/year	Number of employees and contractors on FWU Site? Incidents of injury due to working in high places at FWU?	Human injury/death.	Working in high places.	Liability costs. Equipment repair costs.	Monitor activity in high places.	Provide protective equipment and safeguards for working in high places. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
329	16.07.00.	Working near pinch points	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2
330	16.08.00.	Working in confined areas	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2
331	16.09.00.	Working in high places	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
332	16.10.00.	Working in trench/ditch	Pipeline construction involves trenching which is subject to cave-ins. Sufficient shielding or cave-in protection devices should be used if people go into a trench	High risk of being crushed and/or asphyxiated	Trench/ditch work limited due to the mature nature of the project.	Number of employees and contractors on FWU Site? Incidents of injury due to working in a trench?	Human injury/death.	Working in trench/ditch.	Liability costs.	Monitor activity in trenches / ditches.	Provide cave-in protection devices. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Supervise trench/ditch work. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
333	16.11.00.	Working under a lifted load	Working under a lifted load should be avoided	Higher risk for being crushed	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250. Fatality rate tied to struck by object (assuming 55% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.28E-05 Drilling O&G wells: 9.85E-05 Support activities for O&G wells: 3.7E-05 O&G pipeline construction: 2.95E-05 Pipeline transportation: 0 O&G industry: 3.97E-05 Significant injury rate due to being struck by an object or flying debris in drilling O&G wells based on BLS 2007 data: 5.93E-03 incidents/worker/year	Number of employees and contractors on FWU Site? Incidents of injury due to working under a lifted load at FWU?	Human injury/death.	Working under a lifted load.	Liability costs.	Monitor activity under lifted loads.	Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Supervise load lifting. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
334	16.12.00.	Contact with venomous snakes or insects	Field operations and data collection can be in close proximity to venomous snakes and insects in some parts of the country.	Potential for human injury.	Rattlesnakes, bees, wasps, fire ants, scorpions, black widows, brown recluse spiders and ticks are present in the region.	Number of employees and contractors on FWU Site? Incidents of injury due to contact with venomous snakes or insects at FWU?	Human injury/death.	Contact with venomous snakes or insects.	Liability costs.	Monitor presence of venomous snakes and insects.	Clear work areas of stuff that would attract venomous snakes or insects. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Keep work areas clear of venomous snakes or insects. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
332	16.10.00.	Working in trench/ditch	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2
333	16.11.00.	Working under a lifted load	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2
334	16.12.00.	Contact with venomous snakes or insects	2	1	1	2	None	0 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	None	<\$0.1M	None	Part of ongoing costs	<\$0.1M	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
335	16.13.00.	Contact with poisonous plants	Field operations and data collection can be in close proximity to poisonous plants such as poison ivy or poison oak in some parts of the country.	Potential of human rash/irritation	Poison ivy, poison oak and poison sumac are present in the region.	Number of employees and contractors on FWU Site? Incidents of injury due to contact with poisonous plants at FWU?	Human injury.	Contact with poisonous plants.	Liability costs.	Monitor presence of poisonous plants.	Clear work areas of poisonous plants. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Keep work areas clear of poisonous plants. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
336	16.14.00.	Contact with hot surface, or exposure to heat or flame	Overheated equipment, welding areas, heaters and open flames are present at industrial sites.	Contact with hot surface or flame can cause burn injuries. Exposure to prolonged high temperatures can cause heat exhaustion or dehydration.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year.	Number of employees and contractors on FWU Site? Incidents of injury due to contact with a hot surface or exposure to heat at FWU?	Human injury/death.	Contact with hot surface or exposure to heat or flame.	Liability costs.	Monitor activity near hot surfaces or open flames.	Install safeguards around hot surfaces or flames. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
337	16.15.00.	Exposure to noise	Operation of heavy equipment, pumps and compressors can generate loud noise.	Prolonged exposure to loud noise can cause hearing damage.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year.	No. of employees and contractors on FWU Site? Incidents of injury due to exposure to noise at FWU?	Human injury.	Exposure to noise.	Liability costs.	Monitor noise levels.	Provide hearing protection equipment. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
335	16.13.00.	Contact with poisonous plants	2	1	1	2	None	0 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	None	None	None	<\$0.01M	None	Part of ongoing cost	<\$0.01M	1
336	16.14.00.	Contact with hot surface, or exposure to heat or flame	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.5M	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1
337	16.15.00.	Exposure to noise	2	1	1	2	None	0 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	None	None	None	<\$0.1M	None	Part of ongoing cost	<\$0.1M	1

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
338	16.16.00.	Exposure to dust	Dust is generated in pipeline construction and field operations.	Prolonged exposure to dust can cause respiratory health problems.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year.	Number of employees and contractors on FWU Site? Incidents of injury due to exposure to dust at FWU?	Human injury.	Exposure to dust.	Liability costs.	Monitor dust levels.	Provide dust masks. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
339	16.17.00.	Exposure to hazardous materials	Fluids, fuels and chemicals used in field operations may be classified as hazardous materials.	Prolonged exposure to hazardous materials are known to cause health problems.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker /y Fatality rates tied to exposure to harmful substances or environments based on BLS data 2006-2010 (fatalities/worker/year) O&G extraction: 8.2E-06 Drilling O&G wells: 6.85E-05 Support activities for O&G wells: 2.07E-05 O&G pipeline construction: 1.65E-05 Pipeline transportation: 0 O&G industry: 2.5E-05 Significant injury rate due to exposure to harmful substances in drilling O&G wells based on BLS 2007 data: 6.04E-04	Number. of employees and contractors on FWU Site? Incidents of injury due to exposure to hazardous materials at FWU?	Human injury/death.	Exposure to hazardous materials.	Liability costs.	Monitor presence of hazardous materials.	Properly identify and isolate hazardous materials. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
338	16.16.00.	Exposure to dust	2	1	1	2	None	0 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	None	None	None	<\$0.1M	None	Part of ongoing cost	<\$0.1M	2
339	16.17.00.	Exposure to hazardous materials	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
340	16.18.00.	Struck by object or flying debris	Drilling can often generate flying debris	Flying debris can cause human injury and/or equipment damage.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250. Fatality rate tied to struck by object (assuming 55% of contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.28E-05 Drilling O&G wells: 9.85E-05 Support activities for O&G wells: 3.7E-05 O&G pipeline construction: 2.95E-05 Pipeline transportation: 0 O&G industry: 3.97E-05 Significant injury rate due to being struck by an object or flying debris in drilling O&G wells based on BLS 2007 data: 5.93E-03 incidents/worker/year	No. of employees and contractors on FWU Site?	Human injury/death.	Exposure to flying debris.	Liability costs.	Monitor for flying debris.	Install safeguards in area susceptible to flying debris. Provide safety glasses. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
341	16.19.00.	Release of compressed gases or liquids	Compressed CO2 pipelines, pressurized water lines, compressed air tanks are at risk for rupture.	Release of compressed gases or liquids can cause human injury and/or equipment damage.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year.	Number of employees and contractors on FWU Site? Incidents of injury due to release compressed gases or liquids at FWU?	Human injury/death.	Release of compressed gases or liquids.	Liability costs. Facilities repair costs.	Monitor work in areas near compressed gases or liquids.	Identify and protect/secure compressed gas/liquid lines, valves or tanks. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

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Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
340	16.18.00.	Struck by object or flying debris	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1
341	16.19.00.	Release of compressed gases or liquids	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
342	16.20.00.	Ignition of flammable gases or liquids	Acetylene tanks, natural gas lines, liquid fuel lines could be ignited.	Ignition of flammable gases or liquids can cause explosions, severe injuries and property damage.	Flammable gases and liquids present at CO2-EOR surface facilities. No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250. Fatality rate tied to fires and explosions based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.91E-05 Drilling O&G wells: 4.48E-05 Support activities for O&G wells: 4.24E-05 O&G pipeline construction: 8.26E-06 Pipeline transportation: 0 O&G industry: 3.46E-05	Number of employees and contractors on FWU Site? Incidents of injury due to fires at FWU?	Human injury/death. Facilities / equipment damage.	Ignition of flammable gases or liquids.	Liability costs. Facilities / equipment repair costs.	Monitor work in areas near flammable gases or liquids.	Identify and isolate flammable gases and liquids. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
343	16.21.00.	Trips, slips and falls	Trips, slips and falls are common at industrial sites.	Potential for human injury	Fatality rates tied to falls based on BLS data 2006-2010 (fatalities/worker/year): O&G extraction: 0 Drilling O&G wells: 5.27E-05 Support activities for O&G wells: 4.14E-06 O&G pipeline construction: 0 Pipeline transportation: 0 O&G industry: 1.15E-05 Significant injury rate resulting from fall on same level in drilling O&G wells in 2007 based on BLS data (injuries/worker/year): 1.7E-03. Significant injury rate resulting from slips and trips in drilling O&G wells in 2007 based on BLS data (incidents/worker/year): 2.38E-04.	Number of employees and contractors on FWU Site? Incidents of injury due to trips, slips and falls at FWU?	Human injury/death.	Trips, slips and falls.	Liability costs.	Monitor work areas for potential causes of trips, slips and falls.	Clear work areas of items that would cause trips, slips or falls. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Keep work areas clear. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
344	16.22.00.	Leaks and spills (oil spills)	Leaks and spills of lubricants, fuels, chemicals or hazardous materials are common at industrial sites. If they are not promptly taken care of they can lead to more serious problems.	Potential for human injury, equipment damage, fire or environmental damage.	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250: <1E-04 incidents/worker/year. Potential for oil leak or spill.	Number of employees and contractors on FWU Site? Incidents of oil spills at FWU?	Human injury. Environmental damage.	Leaks and spills. Oil spill.	Liability costs. Environmental remediation costs.	Monitor stored/piped liquids.	Keep gases, liquids, solids contained. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Clean up any leaks or spills immediately. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
342	16.20.00.	Ignition of flammable gases or liquids	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	<\$2M	0-5 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$5M	None	Part of ongoing costs	<\$5M	2
343	16.21.00.	Trips, slips and falls	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1
344	16.22.00.	Leaks and spills (oil spills)	2	4	3	24	None	None	1 @ \$0.05 M per minor (recoverable) injury	<250 barrels of oil @ \$0.03M - \$0.09M per barrel of oil released.	Covered under natural resource damage	Damage to pipeline or storage tank <\$1M per incident	Pipeline shutdown for up to 30 days	Impacts profitability.	None	10% of damage cost	\$7.5M to \$22.5M	None	Part of ongoing cost	\$7.5M to \$22.5M savings for prevention of oil spill.	2

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345	16.23.00.	Head bumping	Industrial sites are prone to have low hanging or falling objects that could injury unprotected heads	Potential for human head injury	Fatality rates tied to striking an object or equipment (assuming 5% of Contact with objects or equipment) based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.16E-06 Drilling O&G wells: 8.95E-06 Support activities for O&G wells: 3.36E-06 O&G pipeline construction: 2.69E-06 Pipeline transportation: 0 O&G industry: 3.61E-06 Significant injury rate due to being struck against an object in drilling O&G wells based on BLS data in 2007: 6.04E-04 incidents/worker/year	No. of employees and contractors on FWU Site? Incidents of injury due to head bumping at FWU?	Human injury/death.	Head bumping.	Liability costs.	Monitor wearing of hard hats in required areas.	Provide hard hats. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Place warning signs in low hanging areas. Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
346	16.24.00.	Overexertion from manual heavy lifting, pulling, or pushing	Improper lifting of pipes, ducts, bars, boxes, bags, machine parts. Pulling/pushing wrenches, hoses, machine parts or heavy loads.	Potential for human back injury. Overexertion represented 11.3% of injuries requiring days away from work in drilling oil and gas wells in 2007. The injury rate was 2E-03 per worker per year.	No fatalities likely, unless complicated by heart attack or heat stroke. Overexertion represented 11.3% of injuries requiring days away from work in drilling oil and gas wells in 2007. The injury rate was 2E-03 per worker per year.	Number of employees and contractors on FWU Site? Incidents of injury due to overexertion at FWU?	Human injury/death.	Manual heavy lifting or pulling.	Liability costs.	Monitor heavy lifting or pulling activities.	Provide appropriate equipment for lifting or pulling heavy loads. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
345	16.23.00.	Head bumping	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	2
346	16.24.00.	Overexertion from manual heavy lifting, pulling, or pushing	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M	1

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347	16.25.00.	On-road driving	Vehicle travel to and from the site is typically among the highest risks in similar projects.	Potential for human injury and/or equipment damage	Approximately 31% of O&G industry fatalities were tied to highway transportation events in 2008 (BLS 2010). Fatality rates tied to highway driving based on BLS data 2006-2010. Assuming highway driving accounts for 56% of the fatality rates tied to transportation events.(fatalities/worker/year) : O&G extraction: 2.21E-05 Drilling O&G wells: 6.27E-05 Support activities for O&G operations: 7.84E-05 O&G pipeline construction: 7.27E-05 Pipeline transportation (operation): 2.23E-05 O&G industry: 5.66E-05. Injury rate requiring days away from work in drilling O&G wells tied to highway driving (assuming 56% of transportation incidents) based on BLS data for 2007 (incidents/worker/year): 2E-04	Number of employees and contractors on FWU Site? Incidents of injury due to on-road driving at FWU?.	Human injury/death. Vehicle / property damage.	On-road driving.	Liability costs. Vehicle and property damage repair.	Monitor on-road driving activity and road conditions.	Maintain vehicles in safe operating condition. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.
348	16.26.00.	Off-road driving	Field data collection often requires off-road driving, sometimes in rocky, muddy, or steep terrain. Some personnel may lack experience with safe driving under challenging conditions.	Potential for human injury and/or equipment damage	Less than 3% of O&G industry fatalities were tied to off-road driving in 2008. (inferred from BLS data).	Number of employees and contractors on FWU Site? Incidents of injury due to off-road driving at FWU?.	Human injury/death. Vehicle /property damage.	Off-road driving.	Liability costs. Vehicle and property damage repair costs.	Monitor off-road driving activity and driving conditions.	Maintain vehicles in safe operating condition. Implement safety training and standard procedures for operators. Conduct regular safety audits during construction and operation. Implement emergency response plan and risk management plan.	Maintain safety training and standard procedures. Document response to safety incidents. Maintain emergency response planning . Maintain risk management plan. Maintain liability insurance.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
347	16.25.00.	On-road driving	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$2M	None	Part of ongoing costs	<\$2M	2
348	16.26.00.	Off-road driving	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$2M	None	Part of ongoing costs	<\$2M	2

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
349	16.27.00	Explosions and crashes (01.03.10.00.)	Events related to deliberate or accidental explosions and crashes such as might have some impact on a closed storage site, e.g. underground nuclear testing, an aircraft crash on the site, acts of war, marine collisions or trawler damage to exposed seabed structures. 1. Accidental explosions and crashes 2. Deliberate explosions and crashes 3. Project related 4. Non-project related	Explosions and crashes are likely to be low probability events that could have a significant impact on the performance of the sequestration system by disrupting the expected evolution of the system. Likely to have greater impact on surface facilities rather than subsurface systems.	One fire in 2006 when a pipe nipple blow out. No fatalities or significant injuries in past 40 years with average work force of 250. Approximately 13% of O&G industry fatalities are tied to fires and explosions (BLS 2010). Approximately 4% of O&G industry fatalities were tied to aircraft (helicopter) crashes in 2008 (BLS 2010). Fatality rate tied to fires and explosions based on BLS 2006-2010 data (fatalities/worker/year): O&G extraction: 1.91E-05 Drilling O&G wells: 4.48E-05 Support activities for O&G wells: 4.24E-05 O&G pipeline construction: 8.26E-06 Pipeline transportation: 0 O&G Industry: 3.46E-05.	Number of employees and contractors on FWU Site? Incidents of injury due to explosions or crashes at FWU?	Damage to surface facilities. Multiple human injury/death.	Explosions or crashes.	Liability costs. Property damage repair costs. Potential CO2 release.	Almost impossible to pre-detect.	Proper site characterization and site selection avoiding areas near heavily traveled flight paths, rail lines or busy highways. Provide motor vehicle crash barriers around surface facilities. Keep surface facilities secured from public access.	Procedures to shutdown and evacuate site in cases of imminent danger. Emergency response procedures/training. Maintain liability insurance.
350	16.28.00	Electric shock	Contact with electric current associated with electric machines, tools, appliances, light fixtures, overhead power lines, underground cables, transformers, wiring, and lightning.	Potential for human injury	No fatalities or significant injuries in past 40 years in CO2-EOR industry (Duncan 2009). Assume average work force of >250.	Number of employees and contractors on FWU Site? Incidents of injury due to electric shock at FWU?	Human injury/death	Contact with electric current	Liability costs.	Monitor human activity near electrical areas.	Maintain electrical equipment in good working condition. Identify and avoid areas with overhead power lines or underground cables. Shut off power and lock out before working on electrical equipment.	Train operators how to respond to electric shock incidents.
351	17.00.00.	LEGAL, LEGISLATION & REGULATION RISKS										
352	17.01.00.	CO2 legislation	Some outstanding CO2 legislation issue are as follows: 1. Cap and Trade or Carbon tax incentives for CCS 2. Certification process for tradable carbon credits 3. Pore space access and ownership 4. Certification for transfer of long-term stewardship/liability for closed CO2 sites from operator to competent legal authority 5. Eminent domain authority 6. Forced unitization for EOR or ECBM 7. Priority of mineral rights over pore space rights 8. Value of escaped CO2 9. Elimination of current tax deductions for oil and gas	Legislation can have a significant impact on CCS project economics. Lack of, or gaps in, CO2 legislation can create uncertainty for the project and make it more difficult to permit and finance the project. Concerns that enacted CO2 legislation could be repealed or changed also contribute to uncertainty for the project and make it more difficult to finance. Elimination of certain oil and gas tax deductions could make it more costly to develop EOR and ECBM projects and negatively affect the financial conditions and results of operations.	Most CO2 legislation risks not applicable to CO2-EOR in a unitized field unless CO2 injection continues after EOR stops. Elimination of certain tax deductions for oil and gas could negatively affect profitability.		Project uncertainties. Project economically infeasible. Loss of tax credits.	Lack of CO2 legislation. Insufficient or onerous CO2 legislation.	Project halted or delayed. Project profitability negatively impacted.	Monitor federal and state CO2 legislation activity.	Tie investment in CCS projects to passage of appropriate CO2 legislation. Implement public outreach program to educate stakeholders on the legislative needs of the project. Shift from DSA to EOR or ECBM if CO2 legislation does not get passed, is insufficient or too onerous for DSA.	Monitor CO2 legislation and analyze the impact of CO2 legislation on the project. Continue public outreach program. Comply with CO2 legislation.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
349	16.27.00	Explosions and crashes (01.03.10.00.)	2	5	2	20	>1 @ \$1.5M per fatality	>1 @ \$1.5 M per serious (irrecoverable) injury	>1 @ \$0.05 M per minor (recoverable) injury	<5,000 t/y CO2 per leak @ \$200/t CO2 released into USDW \$50,000/acre soil remediation and /or vegetation replanting	None	<\$5M	Project delay, or interruption	Impacts profitability.	<10,000 t/y CO2 per leak @ \$32.32/t CO2	10% of damage cost	<\$5M	None	Part of ongoing costs	<\$5M	1
350	16.28.00	Electric shock	2	4	2	16	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	None	None	Impacts profitability.	None	10% of damage cost	<\$2M	None	Part of ongoing costs	<\$2M	2
351	17.00.00.	LEGAL, LEGISLATION & REGULATION RISKS	0	0	0	0															
352	17.01.00.	CO2 legislation	2	3	1	6	None	None	None	None	None	None	None	\$3M/y additional costs due to elimination of tax credits	None	None	\$3M/y additional costs due to elimination of tax credits	None	None	None	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
353	17.02.00.	CO2 regulations	Some outstanding CO2 regulation issues are as follows: 1. CO2 storage permitting and compliance requirements 2. Permitting and compliance for Class VI wells 3. Permitting and compliance for hybrid Class II and VI wells (wells used for both EOR and DSA) 4. Post-injection site care (monitoring) period - EPA proposing 50 years with some flexibility 5. Safety guidelines - DOE best practices guidelines 6. Monitoring and operational reporting requirements 7. Verification and accounting procedures 8. Classification of CO2 as a pollutant rather than a commodity 9. CO2 emission controls and reporting 10. CO2 site straddling two states having to deal with differing regulations 11. Land use restrictions 12. Drilling bonds and other financial responsibility requirements 13. Spacing of wells 14. Reporting on emissions of greenhouse gases 15. Permitting of emissions of greenhouse gases and other regulated air pollutants 16. Utilization and pooling of properties 17. Well stimulation processes 18. Produced water disposal 19. Taxation 20. Habitat and endangered species protection, reclamation and remediation, and other environmental protection 21. CO2 pipeline requirements	Regulations can have a significant impact on CCS project economics. Lack of, or gaps in, CO2 regulations can create uncertainty for the project and make it more difficult to permit and finance the project.	New regulations and oversight, as well as changes in regulations, by regulatory agencies could adversely impact profitability through delay or curtailment of operations and increased cost of operations.		Project uncertainties. Increased CO2 reporting costs and liabilities.	Lack of CO2 regulations. Insufficient or onerous CO2 regulations.	Project halted or delayed. Project profitability negatively impacted.	Monitor federal and state CO2 regulation activity.	Tie investment in CCS projects to passage of appropriate CO2 regulations. Implement public outreach program to educate stakeholders on the regulation needs of the project. Shift from DSA to EOR or ECBM if CO2 regulations do not get passed, are insufficient or too onerous for DSA. Relocate project to different State if State regulations are not conducive to DSA.	Monitor CO2 regulations and analyze the impact of CO2 regulations on the project. Continue public outreach program. Comply with CO2 regulations.
354	17.03.00.	CO2 liabilities	Responsibility for the injected CO2 and any associated liability, during and after active project phase, is currently an unresolved legal issue. Project participants could reduce their involvement if this issue remains unresolved, or is resolved in a manner that unacceptably increases their exposure. 1. CO2 ownership and custody 2. Tort-injury to a third-party (person or property) 3. Property-rights dispute 4. Trespass - contamination of third-party natural resources 5. Trespass - infringement on third-party pore space 6. Breach of duty - leakage sufficient to undermine the value of carbon credits 7. Frivolous lawsuits private or organizational based legal challenges 8. Surface ownership and associated liability 9. Assigning liability responsibility in a multi-party project	Liability for potential damages associated with sequestration or operational aspects could preclude the project from moving forward. Property-right disputes over surface rights, mineral rights or pore space could halt or restrict construction, CO2 injection or monitoring operations for CCS projects. Under environmental, health and safety laws and regulations the owner/operator could be liable for: 1. Personal injuries 2. Property and natural resource damages 3. Oil spills and releases or discharges of hazardous materials 4. Well reclamation costs 5. Remediation and clean-up costs and other government sanctions and fines. 6. Other environmental damages 7. Additional reporting permitting or other issues arising from emissions of greenhouse gases and other regulated air pollutants.	CO2 ownership well defined. Pore space infringement and contamination of third-party resources unlikely due to CELLC control of the FWU. CELLC does not have surface ownership. Environmental, health and safety laws and regulations could expose CELLC to significant costs and liabilities. CELLC believe they have established appropriate cash reserves for known environmental liabilities, including clean up costs, but could be required to set aside additional reserves in the future due to uncertainties, incur material clean up costs, other liabilities, and/or expend significant sums to defend themselves against litigation related to legacy environmental issues, which could have an adverse effect on operating results.	Existing environmental liabilities at FWU?	Project uncertainties. Increased legal costs.	CO2 legal disputes.	Project halted, delayed or impaired. Project profitability negatively impacted.	Monitor legal activities.	Obtain liability insurance.	Keep effective records. Maintain liability insurance.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
353	17.02.00.	CO2 regulations	2	2	1	4	None	None	None	None	None	None	None	<\$1M additional costs	None	None	<\$1M	None	<\$1M legal fees or additional reporting costs.	None	
354	17.03.00.	CO2 liabilities	2	2	1	4	None	None	None	None	None	None	None	None	None	<\$1M legal expenses	<\$1M	None	<\$1M legal fees or additional reporting costs.	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
355	17.03.01.	Insurance	There are many kinds of insurance coverage. Some of those that pertain to CCS include: 1. Physical damage 2. Machinery breakdown 3. Business interruption (advanced loss of profit) 4. Environmental 5. Third-party liability 6. Worker's compensation 7. Transportation 8. Closure and post-closure financial assurance 9. Operator's extra expense (OEE)	Insurance coverage may not be available for CCS projects until there is a sufficient track record of performance (or failure) to determine the probability of failure occurring.	CELLC maintains insurance against some, but not all of the following risks: 1. injury or loss of life 2. severe damage to or destruction of property, natural resources and equipment 3. Pollution or other environmental damage 4. clean-up responsibilities 5. regulatory investigations and administrative, civil and criminal penalties 6. injunctions or other proceedings that suspend, limit or prohibit operations. Insurance may not be adequate to cover any or all resulting losses or liabilities. Moreover, CELLC may not be able to obtain any such insurance on commercially reasonable terms. The occurrence of, or failure by CELLC to obtain or maintain adequate insurance coverage, for any of the events listed above, could have a material adverse effect on CELLC's financial condition and results of operations, as well as their growth, exploration, and employee recruitment activities. (CELLC 2013a)		Project uncertainties. Increased costs.	Inability to get affordable insurance coverage.	Project halted, delayed or impaired. Project profitability negatively impacted.	Monitor availability and cost of insurance coverage for CCS projects.	Work with a competent insurance broker to prepare an estimated maximum loss analysis, prepare underwriting reports for the project, and source insurance coverage. Self insure.	Work with a competent insurance broker to prepare an estimated maximum loss analysis, prepare underwriting reports for the project, and source insurance coverage. Self insure.
356	17.03.02	Transfer of long-term liability stewardship	Public companies cannot take on long-term liability for 50 years or more. There is no guarantee companies will stay in business that long. Therefore, it is up to a government entity to take on responsibility. The federal government would be preferred because it would level the playing field among states and spread the risks over more projects. A sinking fund could be used to cover the costs of such a program.	Companies are unlikely to invest in deep saline aquifer (DSA) sequestration projects without some assurance that the long-term liability is transferable or manageable.	Not applicable. CO2-EOR does not have the long-term liability stewardship required for CO2-DSA.		Project uncertainties. Increased costs.	Inability to transfer long-term liability stewardship for CO2 storage.	Project halted, delayed or impaired. Project profitability negatively impacted.	Monitor federal and state legislation on transfer of long-term liability stewardship for CO2 storage	Encourage the federal government to allow transfer of long-term liability of stored CO2 and establish a sinking fund for long-term stewardship of CO2 storage sites.	Monitor CO2 legislation and take corrective action as necessary. Establish long term O&M fund.
357	18.00.00.	CO2 CAPTURE RISKS										
358	18.01.00.	CO2 capture system performance	Performance risks for CO2 capture systems could include: 1. Production below design capacity 2. Unable to meet product specification 3. Low CO2 recovery 4. Low thermal efficiency - greater heat losses than expected, low heat recovery 5. Excess solvent or sorbent consumption 6. Excess power consumption 7. Excess steam consumption 8. Excess cooling water circulation required 9. Excess maintenance 10. Low process availability 11. Low mechanical availability	Poor performance of the CO2 capture system can result in higher operating and maintenance costs, interruption of CO2 supply, and/or off spec CO2.	A CO2 capture system is not required for the Arkalon ethanol plant. The Agrium fertilizer plant may use an amine or PSD CO2 capture system.	Operating performance of the CO2 systems at Arkalon and Agrium?	High cost of CO2 capture. Off-spec CO2 stream. Low reliability of CO2 supply.	Poor performance of CO2 capture system.	Project halted, delayed or impaired. Project profitability negatively impacted.	Monitor CO2 capture system operating performance.	Select commercially proven, reliable CO2 capture technology. Conduct design reviews using a cross-functional team of experts. Require performance test and process guarantees.	Monitor plant and process performance. Implement a comprehensive maintenance program. Operate at, or close to, steady state conditions.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
355	17.03.01.	Insurance	2	3	1	6	None	None	None	None	None	None	None	<\$10M additional costs	None	None	<\$10M	None	Self insurance. <\$10M	None	1
356	17.03.02	Transfer of long-term liability stewardship	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
357	18.00.00.	CO2 CAPTURE RISKS	0	0	0	0															
358	18.01.00.	CO2 capture system performance	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
359	18.02.00.	CO2 capture system design	Design deficiencies for CO2 capture systems could include: 1. Scale-up errors 2. Equipment undersized/oversized for proper residence time 3. Equipment undersized/oversized for proper surface area 4. Excess velocities 5. Inadequate expansion joints 6. System bottlenecks 7. Inadequate instrumentation 8. Inadequate process controls and alarms 9. Inadequate computer simulation models 10. Wrong sorption model for the contacting devise 11. Insufficient winterization 12. Wrong materials of construction 13. Lack of emergency flare/vent 14. Lack of surge capacity 15. Lack of redundancy -backup systems	Design deficiencies can result in poor performance, higher operating and maintenance costs, interruption of CO2 supply, and/or off-spec CO2..	Arkalon ethanol plant (110,000 gpy ethanol capacity), located in Liberal, KS, is capable of supplying (631-789 t/d (12-15 MMSCF/D) of CO2. Operation began in 2009. CO2 processing, compression and pipeline facilities are owned by CELLC. CELLC made modifications to the Arkalon CO2 facility in 2012. Ethanol plants typically have high reliability. High purity CO2 is produced as a by-product of fermentation. Therefore a complicated CO2 capture system is not required. CO2 processing may involve removing oxygen from the CO2 stream. The Agrium fertilizer plant (0.5 Mt/y of ammonia/urea), located in Borger, TX, is capable of supplying 842-1052 t/d (16-20 MMSCF/D) of CO2. Operation began in 2001. High purity CO2 is produced as a by-product of hydrogen production, used for ammonia and urea production, using a typical amine absorption or pressure swing adsorption unit.	Arkalon CO2 system design basis? Borger CO2 system design basis?	High cost of CO2 capture. Poor performance or failure of equipment/system.	CO2 capture design deficiencies.	Project halted, delayed or impaired. Facilities/equipment damage and/or human injury/death. CO2 release (HSE hazard).	Monitor technical design of CO2 capture system through periodic design reviews.	Negotiate process performance guarantees. Conduct design reviews using a cross-functional team of experts.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.
360	18.03.00.	CO2 capture system scale up limitations	The limits on scale up of the CO2 capture system could include: 1. Equipment size limits - manufacturing, transport, or structural load limits 2. Heat transfer limits 3. Mass transfer limits 4. Diffusion limits 5. Surface area limits 6. Reaction kinetics limits	Limits in scale up of the CO2 capture system can lead to higher capital cost and higher operating costs.	Scale up limitations are not an issue. The capacity of the CO2 systems at Arkalon and Agrium are relatively small (0.2-0.3 Mt/y and 0.3 to 0.375 Mt/y of CO2 respectively) compared to power plant CO2 systems (3-16 Mt/y of CO2).		High cost of CO2 capture. Poor performance or failure of equipment/system.	Improper scale up of CO2 capture system.	Project halted, delayed or impaired. Facilities/equipment damage and/or human injury/death. CO2 release (HSE hazard).	Monitor technical design of CO2 capture system through periodic design reviews.	Determine limiting factor(s) for scale up. Size unit trains appropriately. Conduct design reviews using a cross-functional team of experts. Require performance test and process guarantees.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking		Estimated Potential Damage Recovery Costs												Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
359	18.02.00.	CO2 capture system design	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
360	18.03.00.	CO2 capture system scale up limitations	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
361	18.04.00.	CO2 capture system operations	System operating risks for CO2 capture systems could include: 1. Non-equilibrium or non-steady-state conditions 2. Exothermic reactions overheating the process 3. Endothermic reactions overcooling the process 4. Pressure/stress buildup 5. Non-uniform mass distribution/dispersion/mixing – dead zones, stratification 6. Non-uniform temperature distribution – hot/cold spots, stratification 7. Mass and energy imbalance 8. System imbalance 9. Pressure or temperature cycling 10. System upset – unexpected high flow rate/temperature, carryover of upstream contaminants 11. Off-spec or inconsistent feed and/or product 12. Abrasion/erosion 13. Corrosion 14. Fouling 15. Contactor plugging 16. CO2 escape/leakage to the atmosphere 17. Scale build up causing heat exchanger failure 18. Air leakage - nitrogen dilution 19. Equipment failure due to defects, plugging, wear 20. Control system failure 21. Material/weld failure - leaks 22. Operator error	Operation and maintenance problems can result in higher operating and maintenance costs, CO2 supply interruptions and off-spec CO2.	The Arkalon CO2 system has been operating since 2009. The Agrium CO2 system has been operating since 2001.	Operating performance of the Arkalon and Agrium CO2 systems?	High cost of CO2 capture. Poor performance or failure of equipment/system.	Operating problems with CO2 capture system.	Project halted, delayed or impaired. Facilities/equipment damage and/or human injury/death. CO2 release (HSE hazard).	Monitor CO2 capture system operating performance.	Select commercially proven, reliable CO2 capture technology. Implement a comprehensive maintenance program. Maximize operating time at steady state operation. Require performance test and process guarantees.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.
362	18.05.00.	CO2 capture solvent or sorbent	Solvent or sorbent risks for CO2 capture could include: 1. Off-spec or inconsistent solvent or sorbent 2. Unexpected contamination (SOx, NOx, Cl, H2O, hydrocarbons, trace metals, chemical slip, particulate matter) 3. Gradual buildup of contaminants in circulating loads 4. Foaming 5. Chemical reactions with contaminants - precipitation of solids 6. Excess viscosities 7. Chemical degradation of solvent or sorbent 8. Thermal degradation of solvent or sorbent 10. Aging (deactivation) of solvent or sorbent 11. Hazardous material handling	Off spec or degraded solvent or sorbent can result in poor CO2 capture, higher operating costs, CO2 supply interruptions, and off-spec CO2.	Solvents and sorbents are not used in the Arkalon CO2 recovery system. The Agrium CO2 recovery system may have an amine absorption step or a pressure swing adsorption unit.	Solvent or sorbent used at the Agrium plant to recover CO2?	High cost of CO2 capture. Poor performance or failure of equipment/system.	Solvent/sorbent performance.	Project halted, delayed or impaired. Facilities/equipment damage and/or human injury/death CO2 release (HSE hazard).	Monitor CO2 capture solvent/sorbent performance.	Select commercially proven, reliable solvent/sorbent. Avoid system upsets and contaminants.	Monitor solvent/sorbent composition, properties, performance and losses. Determine root cause of deviations from expected results and take corrective action to resolve the problem.
363	19.00.00.	CO2 DEHYDRATION RISKS										

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
361	18.04.00.	CO2 capture system operations	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
362	18.05.00.	CO2 capture solvent or sorbent	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
363	19.00.00.	CO2 DEHYDRATION RISKS	0	0	0	0															

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
364	19.01.00.	CO2 dehydration system performance	Performance risks for CO2 dehydration systems could include: 1. Production below design capacity 2. Unable to meet product specification 3. Excess glycol consumption 4. Carryover of glycol into downstream systems 5. Excess utility consumption 6. Excess maintenance 7. Low plant process and/or mechanical availability	Poor performance of the CO2 dehydration system can result in higher operating and maintenance costs, interruption of CO2 supply, off spec CO2, and corrosion of downstream systems.	Agrium fertilizer plant can provide backup CO2 if needed.	Design basis for Arkalon and Agrium CO2 dehydration units?	Off-spec CO2. Low reliability of CO2 supply.	Poor performance of CO2 dehydration system.	Project delayed or impaired. Facilities/equipment damage due to corrosion. CO2 release (HSE hazard).	Monitor CO2 dehydration system operating performance. Maintain backup CO2 supplier.	Select commercially proven, reliable dehydration technology. Require performance test and process guarantees. Implement a comprehensive maintenance program. Maximize operating time at steady state operation.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.
365	19.02.00.	CO2 dehydration system operation	Operating risks for CO2 dehydration systems could include: 1. Upset conditions 2. Foaming in the contactor 3. Fouling 4. Buildup of liquid contaminants in recycled glycol 5. Buildup of solid contaminants in recycled glycol 6. Contactor plugging due to fouling 7. Reboiler tube failure due to fouling 8. Heat exchanger failure due to fouling 9. Pump seal failure due to fouling 10. Corrosion - wrong materials of construction 11. Oxidation degradation of glycol 12. Thermal degradation of glycol Dehydration units are normally fairly reliable as long as they are maintained properly avoid process upsets and/or contamination.	Operating problems in the CO2 dehydration system can result in higher operating and maintenance costs, interruption of CO2 supply, off spec CO2, and corrosion of downstream systems.	The CO2 dehydration has been in operation since 2009. Agrium fertilizer plant can provide backup CO2 if needed.	Operating performance of the Arkalon and Agrium CO2 dehydration units?	Off-spec CO2. Low reliability of CO2 supply.	Operating problems with CO2 dehydration system.	Project delayed or impaired. Facilities/equipment damage due to corrosion. CO2 release (HSE hazard).	Monitor CO2 dehydration system operating performance. Maintain backup CO2 supplier.	Select commercially proven, reliable dehydration technology. Implement a comprehensive maintenance program. Avoid process upsets and contaminants.	Monitor plant and process performance and identify bottlenecks. Take corrective action as needed.
366	20.00.00.	CO2 COMPRESSION RISKS										
367	20.01.00.	CO2 compression system performance	Performance risks for CO2 compression systems could include: 1. Output below design capacity 2. Unable to meet pressure specification 3. Excess power consumption 4. Excess maintenance 5. Low mechanical availability	CO2 operating performance is critical to success of a CCS project.	Agrium fertilizer plant can provide backup CO2 if needed.	Design basis for Arkalon and Agrium CO2 compression systems?	Off-spec CO2 pressure / flowrate. CO2 supply interruption.	Poor performance of CO2 compressors.	Project delayed or impaired. Facilities / equipment damage Project profitability lower than expected.	Monitor CO2 compression system operating performance.	Assure proper design and installation. Require performance test and process guarantees. Implement a comprehensive maintenance program. Try to maximize steady-state operation. Avoid upset conditions.	Resolve maintenance, system upsets and contamination problems quickly.

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	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
364	19.01.00.	CO2 dehydration system performance	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
365	19.02.00.	CO2 dehydration system operation	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
366	20.00.00.	CO2 COMPRESSION RISKS	0	0	0	0															
367	20.01.00.	CO2 compression system performance	2	3	1	6	None	None	None	None	None	None	0-5 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	None	None	<\$5M	None	Part of ongoing cost	<\$5M	2

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368	20.02.00.	CO2 compression system EPC	Engineering, procurement and construction (EPC) risks for compression systems could include: 1. Procurement delays - Compressors are typically one of the longest lead items for equipment 2. High capital cost - compression systems are one of the major capital costs for CCS projects 3. Improper specification 4. Metallurgical defect 5. Manufacturing defect 6. Improper installation	Delays in project startup. Increased capital cost. Operating problems resulting from improper specification or installation.	CO2 compressors installed and operating since 2009 at Arkalon and 2001 at Agrium.		Construction/startup delays. Poor performance or failure of CO2 compression system. Higher capital / operating costs.	CO2 compression system EPC delays/defects/costs.	Project delayed or impaired. Facilities / equipment damage Project profitability negatively impacted.	Monitor CO2 compression system engineering, manufacturing, installation and performance testing.	Select a qualified EPC contractor. Require performance test and process guarantees.	Inspect and test equipment. Require vendor / contractor to fix defects.
369	20.03.00.	Compressor type	1. Reciprocating compressors - lower capital, higher maintenance, may require spare capacity 2. Centrifugal compressors - higher capital, lower maintenance 3. Screw compressors (dry type)	Type of compressors selected can impact capital costs, operating costs and operating availability.	CO2 compressors installed and operating since 2009 at Arkalon and 2001 at Agrium.	Type of compressors installed at Arkalon and Agrium?	Poor performance of CO2 compressors. Higher operating and maintenance costs. Lower CO2 availability.	Improper selection of CO2 compressors	Project delayed or impaired. Project profitability negatively impacted.	Monitor CO2 compressor selection process and operating performance.	Select qualified engineering company and vendors. Proper selection of the compressor type for the specific application.	Proper installation, operation and maintenance.
370	20.04.00.	Compression system operation	Operating risks for CO2 compression systems: 1. Improper operation - Intermittent operation of the compressor - Operating above/below recommended limits - Upset conditions - Operating compressor with control valve closed - Fouling by dust or liquid droplets - Plugging relief valves during depressurization - Corrosion - due to water in CO2 stream 2. Improper maintenance - Vibration - Noise - Overheating - Leakage 3. Wear and failure - Rod drop due to ring wear on recip. comp. - Rod run out or rod deflection on recip. comp. - Valve failure on recip. comp. - Bearing wear/failure - Tip wear on cent. comp. - Impeller blade failure on cent. comp. - Shaft failure - Compressor catastrophic failure	Downtime, loss of revenue, increased maintenance costs.	CO2 compressors installed and operating since 2009 at Arkalon and 2001 at Agrium. Agrium fertilizer plant can provide backup CO2 if needed.	Operating performance of CO2 compressors at Arkalon and Agrium?	Off-spec CO2 pressure / flowrate. CO2 supply interruption.	CO2 compression system operating problems.	Project delayed or impaired. Project profitability negatively impacted. Facilities / equipment damage. CO2 release (HSE hazard).	Monitor CO2 compression system operating performance.	Assure proper design and installation. Require performance test and process guarantees. Implement a comprehensive maintenance program. Try to maximize steady-state operation. Avoid upset conditions.	Proper installation, operation and maintenance. Resolve maintenance, system upsets and contamination problems quickly.
371	21.00.00.	CO2 PIPELINE RISKS										
372	21.01.00.	Pipeline routing risks										
373	21.01.01.	New versus existing right-of-way (ROW)	ROW issues include: 1. Single or multiple pipeline rights 2. Width of ROW 3. Rights for above ground facilities 4. Access to site for repair/modification and inspections 5. Payment for original and continued use of ROW 6. Damage awards for the property owner 7. Requirement for pipeline removal upon abandonment of the pipeline. 8. Eminent domain - used as a last resort to gain access to ROW	Developing a new ROW is significantly more riskier than using an existing utility ROW.	Pipelines already installed.		High cost for right-of-way	Inability to acquire right-of-way at an affordable cost.	Project halted, delayed or impaired. Project profitability negatively impacted.	Monitor right-of-way negotiations.	Maximize use of existing pipeline corridors in laying out pipeline right-of-way.	Design around problem areas.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable, or incredible; Yellow/Orange = Headings or non-risk areas

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury													
368	20.02.00.	CO2 compression system EPC	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	2	
369	20.03.00.	Compressor type	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
370	20.04.00.	Compression system operation	2	3	1	6	None	None	None	None	None	None	0-5 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	None	None	<\$5M	None	Part of ongoing cost	<\$5M	1	
371	21.00.00.	CO2 PIPELINE RISKS	0	0	0	0																
372	21.01.00.	Pipeline routing risks	0	0	0	0																
373	21.01.01.	New versus existing right-of- way (ROW)	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

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374	21.01.02.	Climate conditions	Weather conditions can impact pipeline surface facilities 1. Severe high or low temperatures 2. Significant winds (tornadoes) 3. Lightning - common cause of pipeline damage 4. Heavy rain fall - flooding 5. Severe winter storms	Delays in construction and damage to surface facilities.	Pipelines already installed. Severe weather could cause pipeline damage.		Construction schedule disruption(s). Damage to surface facilities. Human injury/death.	Severe climate conditions.	Project delayed or impaired. Project profitability negatively impacted. Liability costs.	Monitor weather forecasts for severe conditions.	Design pipeline surface facilities for full range of climate conditions. Avoid flood plains and steep slopes that may be susceptible to weather damage.	Monitor for severe weather reports.
375	21.01.03.	Soil and terrain conditions	1. Thin soil - insufficient to bury pipeline to depth 2. Corrosive soil - high moisture, high electrical conductivity, high acidity, and high dissolved salts 3. Rocky soil - special care needed in backfilling to protect pipeline 4. Unstable land - subsidence - uplift - landslides - earthquake area - active fault zone - high erosion areas - flood plains, dry wash - permafrost - frost heaves - high water table (marshes, swamps, peat bogs) - moving sand dunes - underground mine/coal mine areas - steep slopes >18% (landslides or erosion) 5. Rugged terrain/topography - mountains, hills, canyons, gorges 6. Significant elevation increase or variation over length of pipeline 7. Low lying areas 8. Exposed granite bedrock	1. Need to add soil to achieve 1.2 -1.8 m (4-6ft) burial depth 2. Accelerated external corrosion 3. Need fine backfill to protect pipeline 4. Can lead to unintended movement or abnormal loading of a pipeline resulting in mechanical damage, leakage or rupture. 5. Significantly higher installation cost 6. Increased compression or pumping costs due to higher pressure drop across pipeline 7. Potential for leaked CO2 to accumulate in low lying areas if there is insufficient escape velocity or wind to disperse the leaked CO2 to the atmosphere. 8. Very high costs for blasting a pipeline trench	Pipelines already installed. Terrain in the area is relatively flat. Soil is typically over 2 m (80 in.) thick.		High pipeline construction costs.	Soil/terrain conditions make pipeline installation difficult	Project halted, delayed or impaired. Project profitability negatively impacted.	Monitor pipeline right-of-way selection and assessment.	Avoid steep slopes, rugged terrain, flood plains, low-lying areas, rocky areas and unstable land.	Bring in fine backfill for pipeline in rocky areas. Regularly inspect and repair unstable areas. Design around problem areas.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
374	21.01.02.	Climate conditions	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
375	21.01.03.	Soil and terrain conditions	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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376	21.01.04.	Populated areas	A high population area means an urbanized area, as defined by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1000 people per square mile. This is designated a high consequence area. (49 CFR Part 195.450) Other populated areas are also designated as high consequence areas. Non rural areas categorized as high risk. Rural areas categorized as low risk. (49 CFR Part 195 Appendix B) Pipeline right-of-way must be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly. No pipeline may be located within 15 m (50 feet) of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate or assemble, unless it is provided with at least 0.3 m (12 inches) of cover in addition to that prescribed in Section 195.238 (49 CFR Part 195.210). CO2-CRC recommends a 30 m (100 ft) wide easement restricting access to the buried pipeline, a distance of 100 m (330 ft) minimum distance from residential buildings and a 1,000 m (3,300 ft) consultation zone on either side of the pipeline for emergency notification. 1. High population density nearby 2. Sensitive receptors (schools, hospitals, nursing homes, prisons) nearby 3. Business/industry/mining nearby 4. Residences nearby	The greater the number of people, the greater the risk of exposure to CO2.	Pipelines already installed. The Liberal, KS pipeline right-of-way passes near Perryton, TX (population 8,802) which is 17 km (10.6 mi) northeast of the FWU Site.	Population density along right-of-way for the Liberal, KS and Borger, TX pipelines?	Higher pipeline construction and operating costs.	Pipeline right-of-way through or near existing or future high population density areas.	Project halted, delayed or impaired. Project profitability negatively impacted.	Monitor current and potential population density in area of pipeline right-of-way.	Avoid densely populated areas for pipeline routing.	Design around densely populated areas. Implement a pipeline integrity management program in high consequence areas. Follow 49 CFR Part 195 regulations.
377	21.01.05.	Land crossings	1. Navigable water ways - Army Corp of Engineers permitting 2. Protected areas - Wetlands, migratory water bird concentration, national parks, habitats for imperiled, threatened, endangered or protected species (aquatic and terrestrial), archeological sites. (49 CFR Part 195.6) 3. Federal land - could trigger the need for permits from the US Army Corp of Engineers, the US Fish and Wildlife, the US Department of the Interior Bureau of Land Management (BLM), the US Department of Agriculture, Forest Service, the US Department of Defense. Also will trigger the National Environmental Policy Act (NEPA) and require Environmental Assessment (EA) or Environmental Impact Statement (EIS) 4. Tribal land - would trigger NEPA (EA or EIS) and the need for a permit from the US Department of Interior Bureau of Indian Affairs (BIA) 5. Transportation corridors - Railroads, highways, roads, bridges, other rights of way could trigger the need for permits from railroad companies, state/county departments of transportation. 6. Drinking water resource areas - 7. Non navigable surface waters - lakes, rivers, streams 8. Existing utility/pipeline rights-of-way	Land crossing increase cost and the need for additional permits.	Pipeline already installed.		Inability to obtain rights-of-way or pipeline construction permit. Higher pipeline construction and operating costs.	Pipeline crossing transportation corridors and/or sensitive land areas.	Project halted, delayed or impaired. Project profitability negatively impacted.	Monitor transportation corridor and land crossings..	Avoid sensitive or high consequence areas. Keep crossings to a minimum.	Use seamless pipe and 2 m burial depth in crossings. Implement pipeline integrity management program in areas of high consequence. Follow 49 CFR Part 195 regulations. Regularly inspect and repair unstable areas. Post warning signs along right-of-way.

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
376	21.01.04.	Populated areas	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
377	21.01.05.	Land crossings	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

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378	21.01.06.	Offshore pipeline	The difficulty of offshore construction is roughly proportional to the depth multiplied by the pipeline diameter. (IPCC 2005). Some of the risks include: 1. Sea currents 2. Uneven seabed 3. Biological growth on pipeline 4. Arctic conditions (ice gouging)	Offshore pipeline have significantly higher costs.	Not applicable. Onshore pipelines.		Very high pipeline construction and operating costs.	Offshore pipeline.	Project halted, delayed or impaired. Project profitability negatively impacted.	Monitor offshore pipeline design, construction and operation.	Work with a qualified engineering firm to properly design offshore pipeline.	Regularly inspect and repair unstable areas.	
379	21.02.00.	Pipeline design risks											
380	21.02.01.	Pipeline diameter	1. Large diameter Large diameter pipelines will release more CO2 in a rupture and are thus classified as having greater severity in the case of a failure such as a rupture. 2. Insufficient diameter for capacity Increased pressure required may place too much stress on the pipeline and components. Limits future expansion. 3. Excess diameter for capacity Resulting decreased pressure may put the CO2 at risk of changing from supercritical to two-phases. No room for turndown.	High risk: Pipeline diameter 0.46 m (18 in) and above. Medium risk: Pipeline diameter from 0.25-0.4 m (10 to 16 in). Low risk: Pipeline diameter 0.2 m (8 in) and below. (49 CFR Part 195 Appendix B.	Pipeline diameters: Liberal, KS pipeline: 102 mm (4 in assumed) Borger, TX pipeline: 102 mm (4 in) Coffeyville, KS pipeline: 203 mm (8 in)	Liberal, KS pipeline diameter?	Poor pipeline performance.	Improper selection of pipeline diameter.	Increased operating and maintenance costs. Limits on flowrate of CO2. Project profitability negatively impacted.	Monitor selection of pipeline diameter.	Size pipeline to effectively handle planned CO2 capacity with option for future capacity expansion by adding booster station(s).	Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.	
381	21.02.02.	Pipeline length	The longer the pipeline, the greater the risks.	Long pipeline more expensive, more potential for failure.	Pipeline length: Liberal, KS 153 km (95 mi)* Borger, TX: 138 km (86 mi)* FWU spur: 23 km (14 mi)* Total: 314 km (195 mi) *Connected		High pipeline construction and operating costs.	Long pipeline.	Project halted, delayed or impaired. Project profitability negatively impacted.	Monitor selection of pipeline route.	Keep pipeline length to a minimum without causing right-of-way issues.	Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.	
382	21.02.03.	Pipeline failure history (for existing pipeline)	Pipeline failure history for time-dependent defects can indicate probability of future failures.	High risk: >3 leaks in last 10 years. Low risk: ≤3 leaks in last 10 years. (49 CFR Part 195 Appendix B)	Five incidents have been reported on CELLCO CO2 pipelines from 2006 - 2013. One of them was significant (> 5 bbl of CO2 release). No injuries or fatalities. Property damage from \$3,500 to \$139,000 per incident. CO2 release from 0 to 108 t (0 to 850 bbl) per incident (PHMSA 2013)		Pipeline leak	Use of an existing pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review failure history of existing pipeline.	Avoid use of existing pipeline unless the piping specification meets the requirements and sufficient maintenance/performance records are available.	Conduct inline and spot testing to confirm pipeline integrity.	
383	21.02.04.	Pipeline age (for existing pipeline)	Safety risk increases with the age of the pipeline depending on the pipeline's coating and corrosion condition, and steel quality, toughness, welding.	High risk: >25 years old Low risk: <25 years old (49 CFR Part 195 Appendix C)	Year pipeline installed: Liberal, KS: 2009 Borger, TX: 2001 FWU spur: 2010		Pipeline leak	Old pipeline.	CO2 leak/rupture. (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Regularly inspect and test existing pipeline.	Avoid use of old pipeline unless the piping specification meets the requirements and sufficient maintenance/performance records are available, and sufficient testing can be done to confirm pipeline integrity.	Conduct inline and spot testing to confirm pipeline integrity.	

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									Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
378	21.01.06.	Offshore pipeline	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
379	21.02.00.	Pipeline design risks	0	0	0	0																	
380	21.02.01.	Pipeline diameter	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
381	21.02.02.	Pipeline length	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1	
382	21.02.03.	Pipeline failure history (for existing pipeline)	5	2	2	20	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	None	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1		
383	21.02.04.	Pipeline age (for existing pipeline)	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	None	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1		

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384	21.02.05.	Pipeline pressure	All pipeline components must be designed and tested for at least 125% of maximum operating pressure (MOP). If, within a pipeline system, two or more components are to be connected at a place where one will operate at a higher pressure than another, the system must be designed so that any component operating at the lower pressure will not be overstressed. (49 CFR Part 195.104) Pipelines should be designed with sufficient pressure to maintain CO2 as a supercritical fluid. 1. Operating pipeline in excess of maximum operating pressure (MOP). 2. Operating pipeline below the CO2 supercritical pressure (CSP). 3. Insufficient working range between MOP and CSP.	Components operating at excessive operating pressure will be overstressed and subject to failure. Operating the pipeline at or below the supercritical pressure of CO2 can lead to CO2 phase change in the pipeline. If the supercritical CO2 drops back into the liquid-vapor, two-phase region (which occurs below 6.9 MPa (1000 psig) at ambient temperature), there would be freeze-up issues and a much higher pressure drop in the pipeline.	Assume pipeline is designed and operated in compliance with all regulations, codes and permits.	Verify pipeline maximum allowable operating pressure?	CO2 leak/rupture (HSE hazard).	Over pressuring CO2 pipeline.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline operating pressure.	Operate pipeline at less than 80% of maximum design pressure.	Operate pipeline at less than 80% of maximum design pressure. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
385	21.02.06.	Pipeline external loads	Anticipated external loads (e.g., earthquakes, vibration, thermal expansion, and contraction must be provided for in designing a pipeline system. (See ASME B31.4). The pipe and other components must be supported in such a way that the support does not cause excess localized stresses (49 CFR Part 195.110). The pipe at each railroad and highway crossing must be installed so as to adequately withstand the dynamic forces exerted by anticipated traffic loads (49 CFR Part 195.256).	Insufficient design for external loads could lead to cracking and CO2 leakage.	No incidents reported due to external loads.		CO2 leak/rupture (HSE hazard).	Excess pipeline external loads.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review pipeline external load calculations and construction drawings.	Use qualified contractor(s) to engineer, procure and construct the pipeline. Have an experienced engineer check external load factors.	Reinforce pipeline at crossings if necessary. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
386	21.02.07.	Pipeline wall thickness	Thicker pipe is typically used for sensitive areas like crossings. Wall thickness for 0.3 -0.36 m (12-14 in) pipe is typically 9.5 mm (0.375 in) except in sensitive areas like crossings where 12.7 mm (0.5 inch) wall thickness used for road crossings (up to 0.3 m (1 ft) past road right of way) and 15.9 mm (0.625 in) thickness used for railroad crossings. (DGC)	Thicker walls give a better safety margin.	Assume pipeline is designed and operated in compliance with all regulations, codes and permits.	Verify pipeline wall thicknesses?	CO2 leak/rupture (HSE hazard).	Thin pipeline wall.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review pipeline wall calculations and monitor pipeline wall thickness over time.	Select pipeline wall thickness that meets or exceeds codes.	Monitor wall thickness over the life of the project. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
387	21.02.08.	Pipeline steel grade	X65 carbon steel is typically used for CO2 pipeline if CO2 is dry and has low impurities such as H2S.	Pipeline steel grade determines pipeline maximum operating pressure	Assume pipeline is designed and operated in compliance with all regulations, codes and permits.	Verify pipeline steel grades?	CO2 leak/rupture (HSE hazard).	Improper pipeline steel grade.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review steel grade selection for pipeline.	Select pipeline steel grade that meets or exceeds codes.	Monitor steel corrosion over life of the pipeline. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
384	21.02.05.	Pipeline pressure	4	2	1	8	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
385	21.02.06.	Pipeline external loads	2	2	1	4	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
386	21.02.07.	Pipeline wall thickness	2	2	1	4	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
387	21.02.08.	Pipeline steel grade	2	2	1	4	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
388	21.02.09.	Pipeline temperature	CO2 increases in temperature as it is compressed and decreases in temperature as it expands. CO2 entering a pipeline may be in the range of 49°C (120°F) however, it will gradually conform to the ambient ground temperature which may be in the range of 10°C (50°F). Components of CO2 pipelines that are subject to low temperatures during normal operation because of rapid pressure reduction or during the initial fill of the line must be made of materials that are suitable for those low temperatures. (49 CFR Part 195.102)	Improper material selection for pipeline components that may experience extreme cold due to rapid pressure reduction may result in component failure and CO2 leakage.	Assume pipeline is designed and operated in compliance with all regulations, codes and permits.	Verify pipeline maximum operating temperatures?	Damage to pipeline internal coating. CO2 leak/rupture (HSE hazard).	Too high or too low pipeline temperature.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline temperature.	Design compressor interstage coolers to maintain CO2 temperature below maximum. Install pipeline sufficiently deep.	Monitor pipeline temperature.
389	21.02.10.	Piping type	Seamless pipe is typically used for sensitive areas like crossings or near residences; double submerged arc welded or electric resistance welded pipe is typically used for other areas. (DGC)	Proper piping selection is important in sensitive areas to prevent risk of CO2 leakage.	Assume pipeline is designed and operated in compliance with all regulations, codes and permits.	Verify piping types?	CO2 leak/rupture (HSE hazard).	Improper piping selection.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Review piping selection.	Use seamless pipe for road, rail and creek crossings. Use ERW pipe for other areas.	Use additional reinforcement if necessary.
390	21.02.11.	Pipeline coating	CO2 pipelines are typically coated with fusion bonded epoxy to prevent corrosion. In addition piping used at bored crossings is overcoated with an abrasion resistant coating to prevent damage to the epoxy coating during installation. (DGC) 1. External coating 2. Internal coating	Damage to pipeline coating during installation or due to third-party excavation can result in external corrosion.	Assume pipeline is designed and operated in compliance with all regulations, codes and permits.	Verify type of pipeline coating?	Pipeline corrosion.	Lack of, insufficient, improper or damaged pipeline coating.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline coating condition and performance.	Coat pipeline with fusion bonded epoxy.	Avoid damaging coating during transport and installation.
391	21.02.12.	Pipeline cathodic protection	Cathodic protection on CO2 pipelines is maintained by rectifiers located at main-line valve stations every 32 km (20 miles) or less along the pipeline. Cathodic protection is measured in voltage at test posts located at 1.6 km (1 mi) intervals over the length of the pipeline. The rectifier output is adjusted to maintain voltage levels between 0.85 and 1.4 volts at each test station. (DGC)	Insufficient or lack of cathodic protection could lead to external corrosion and CO2 leakage.	Assume pipeline is designed and operated in compliance with all regulations, codes and permits.		Pipeline corrosion.	Lack of, insufficient, improper or damaged pipeline cathodic protection.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline cathodic protection condition and performance.	Install cathodic protection and voltage test posts at every mile along the pipeline.	Monitor cathodic protection voltage over the length of the pipeline and adjust rectifier output to maintain appropriate voltage level.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
388	21.02.09.	Pipeline temperature	2	2	1	4	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
389	21.02.10.	Piping type	2	2	1	4	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
390	21.02.11.	Pipeline coating	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
391	21.02.12.	Pipeline cathodic protection	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
392	21.02.13.	Pipeline booster stations or pumping stations	Booster or pumping stations are typically needed every 80-320 km (50 to 200 mi) depending on end-use pressure (EERC). Adequate ventilation must be provided in pumping station buildings to prevent the accumulation of CO2 gas. Warning devices must be installed to warn of the presence of CO2 gas in the pumping building. Safety devices to prevent over pressuring of primary and auxiliary pumping equipment and a device for emergency shutdown of each pumping station should be included. If power is necessary to actuate the safety devices, an auxiliary power supply should be included. (49 CFR Part 195.262) Take into account noise levels.	Insufficient booster or pumping stations could lead to low pressure at the end of the pipeline.	Assume pipeline is designed and operated in compliance with all regulations, codes and permits.	Number of pipeline booster stations or pumping stations?	Insufficient pipeline pressure.	Insufficient booster or pumping stations.	Cost of increasing or upgrading booster station.	Monitor pipeline pressure.	Size pipeline to effectively handle planned CO2 capacity with option for future capacity expansion by adding booster station(s).	Leave space for booster stations.
393	21.02.14.	Pipeline future expansion	If there is potential for future expansion, it is practical to install taps for future branches, leave room for booster stations and design the pipeline to allow for expansion at higher pressure without having to replace piping and components. Pipeline diameter and pressure should take into account potential for future expansion through addition of booster stations and increased operating pressure.	Lack of reserved locations for booster stations, insufficient pipeline diameter, and excess operating pressure may make future expansion of pipeline capacity more difficult and more expensive.	The Liberal, KS and Borger, TX pipeline system may eventually be connected to the Coffeyville, KS and Enid, OK pipelines to allow efficient and reliable distribution of CO2.	Other pipeline expansion plans?	Insufficient pipeline diameter for expansion.	Lack of planning for future pipeline expansion.	Excess operating pressure. Excess costs for pipeline expansion.	Monitor plans for future pipeline expansion.	Size pipeline to effectively handle planned CO2 capacity with option for future capacity expansion by adding booster station(s).	Leave space for booster stations.
394	21.02.15.	Pipeline flow velocity	Reported pipeline velocity varies from 0.9 to 4.6 m/s (3 to 15 ft/s). (IPCC 2005)	Excessive flow capacity could cause erosion in pipeline components.	Estimated pipeline flow velocities Liberal, KS: 1.1 to 1.4 m/s Borger, TX: 1.49 to 86 m/s FWU spur: 0.9 to 1.4 m/s	Verify pipeline flow velocities?	Erosion of pipeline.	Excess pipeline flow velocity.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline flow velocity and wall thickness.	Design pipeline to stay within the safe range of CO2 velocity.	Adjust capacity or pressure to keep within the safe velocity range. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.
395	21.02.16.	Pipeline SCADA system	Supervisory control and data acquisition (SCADA) system should have sufficient instrumentation for the central control room to monitor and control flow along the entire pipeline. The system should have built in redundancies to prevent loss of operational capability if a component fails. 1. IT security for SCADA system to protect against cyber-terrorism	Loss of the SCADA system could shut the pipeline down or result in pipeline failure and CO2 release.	SCADA systems installed.	Any operating issues with SCADA system?	Shutdown or failure of pipeline equipment/system.	Loss of, or malfunction of, SCADA system.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor SCADA system performance.	Comply with all 49 CFR Part 195 requirements for SCADA system.	Maintain SCADA system in good working order. Integrate backup system for critical functions. Develop and implement business continuity plan.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)					
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)															
392	21.02.13.	Pipeline booster stations or pumping stations	2	2	1	4	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
393	21.02.14.	Pipeline future expansion	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
394	21.02.15.	Pipeline flow velocity	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
395	21.02.16.	Pipeline SCADA system	4	2	1	8	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
396	21.02.17.	Pipeline CPM leak detection systems	Computational pipeline monitoring (CPM) leak detection system must comply with section 4.2 of API 1130. (49 CFR Part 195.134). CPM leak detection can be based on acoustics, measurement of chemical release, detecting pressure changes or small changes in mass balance.	Lack of a properly designed CPM leak detection system prevents the pipeline operator from rapid detection and response to CO2 leaks. Inaccurate modeling of CO2 dense phase can cause the computational leak detection system to malfunction.	CPM leak detection systems installed.	Any operating issues with CPM leak detection system?	Failure to detect CO2 leak/rupture.	Loss of, or malfunction of, CPM leak detection system	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor CPM leak detection system performance.	Comply with all 49 CFR Part 195 requirements for computational pipeline monitoring and leak detection system.	Maintain the CPM leak detection system in good working order.
397	21.02.18.	Pipeline block valves or control valves	Main-line valves (block or control valves) are located on either side of water crossings and approximately every 32 km (20 mi) overland in order to allow for quick isolation and to minimize the impact of a leak. (DGC) Valves must be installed at each of the following locations: on the suction end and discharge end of a pump station, on each mainline at locations along the pipeline system that will minimize damage or pollution from CO2 discharge, on each lateral takeoff from the trunk line, on each side of a water crossing that is more than 30 m (100 ft) wide and on each side of a reservoir that is holding water for human consumption. (49 CFR Part 195.260) Each valve must be installed in a location that is accessible to authorized employees and that is protected from damage or tampering. (49 CFR Part 195.258)	The distance between main-line valves determines the amount of CO2 released in a rupture. Longer spacing means a larger volume of CO2 is likely to escape.	Block valves installed.	Spacing between block valves?	Inability to section off pipeline in an emergency.	Insufficient number of, improperly designed, improperly installed, or failure of block valve(s).	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor block valve specification, installation and operating condition.	Comply with all 49 CFR Part 195 requirements for block valves.	Maintain all block valves in good working order.
398	21.02.19.	Pipeline internal inspection devices	Pipelines must be designed and constructed to accommodate the passage of instrumented internal inspection devices (i.e. smart pig). 49 CFR Part 195.120) No operator may use a launcher or receiver that is not equipped with a relief device capable safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. (49 CFR Part 195.426)	Internal inspection devices are important tools for detecting corrosion or mechanical damage in pipelines before they fail.	Smart pig systems installed.	Smart pigs used for internal inspection?	Poor performance or failure of internal inspection device.	Improperly designed internal inspection device system.	CO2 leak (HSE hazard). Pipeline damage. Damage repair costs.	Monitor internal inspection device specification, installation, and operating condition.	Comply with all 49 CFR Part 195 requirements for internal inspection devices.	Maintain internal inspection devices and system in good working order.
399	21.02.20.	Pipeline seals	Teflon or nylon have been used for seals to prevent swelling. (Meyer 2007).	Improper sealing materials may react with CO2 and cause CO2 leakage		Type of pipeline seals used? Incidents of seal leakage?	Seal failure.	Improper design of seals.	CO2 leak (HSE hazard).	Monitor seal specification, installation, and operating condition.	Select seal materials that have been successfully tested for use with CO2.	Maintain seals in good working order. Monitor for leaks.
400	21.02.21.	Pipeline winterization	Winterization (protection from severe cold/ice) may be needed for above ground facilities in cold climates.	Lack of winterization can cause CO2 pipeline instrumentation lines and valves to freeze up in severe cold/icy weather.	Assume surface equipment protected from winter storms.	Verify pipeline winterization?	Freezing weather damage to surface equipment / facilities.	Lack of pipeline winterization.	CO2 leak (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline winterization status and severe weather forecasts.	Provide sufficient shelter/insulation for sensitive surface facilities.	Monitor severe weather conditions. Train operators how to maintain operation during severe winter weather.

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			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
396	21.02.17.	Pipeline CPM leak detection systems	2	2	2	8	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
397	21.02.18.	Pipeline block valves or control valves	5	2	1	10	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
398	21.02.19.	Pipeline internal inspection devices	2	2	2	8	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
399	21.02.20.	Pipeline seals	3	2	2	12	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
400	21.02.21.	Pipeline winterization	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
401	21.02.22.	Pipeline burial depth	CO2 pipelines are typically buried a minimum of 1.2 m (4 ft) over the length of the pipeline, ≥1.5 m (5 ft) below roads, ≥3 m (10 ft) below railroads, ≥1.2 m (4 ft) below ditches and ≥3 m (10 ft) below water line on shores. (DGC). Minimum burial depth for pipeline is 0.9 m (36 in) for industrial commercial and residential areas, 1.2 m (48 in) for crossing of inland bodies of water, 0.9 m (36 in) for drainage ditches at public roads and railroads, 1.2 m (48 in) for deepwater port safety zones, 0.9 m (36 in) for offshore areas and 0.8 m (30 in) elsewhere. There are exceptions for rock excavation areas. (49 CFR Part 195.248)	Insufficient burial depth makes pipeline more susceptible to excavation damage, sabotage, climate damage etc.	Assume pipeline is designed and operated in compliance with all regulations, codes and permits.	Verify burial depth of pipelines?	Pipeline mechanical damage.	Insufficient burial depth.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline burial depth.	Bury pipeline to meet or exceed compliance with 40 CFR Part 195.	Regularly inspect and maintain burial depth of pipeline.
402	21.02.23	Pipeline bedding and foundation structures	Pipeline bedding and foundation structures are designed to hold a pipeline stable throughout its life. This is particularly important for offshore pipelines.	Improper design of pipeline bedding or foundation structures could result in pipeline shifting or buckling.	Assume pipeline is designed and operated in compliance with all regulations, codes and permits.	Verify pipeline bedding and foundation structures?	Shifting of pipeline.	Improper pipeline bedding and foundation structures.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline bedding and foundation structures.	Comply with all 49 CFR Part 195 requirements for pipeline bedding and foundation structures.	Regularly inspect pipeline for signs of shifting or buckling.
403	21.03.00.	Pipeline defects										
404	21.03.01.	Pipeline material defects	During the manufacturing of steel, impurities can sometimes remain in the molten steel. These impurities can cause an incomplete bonding of the material in the steel plate or solid round billet used to produce pipe and other pipeline components. reduce the wall thickness of the pipe or pipeline component, and, if large enough, can reduce the pressure-carrying capacity of the pipe or component. Some pipeline material defects include: 1. Propagating cracks - very rapid propagating cracks can occur that "unzip" the pipeline along its length. 2. Laminations and inclusions - caused by oxides or impurities trapped in the steel 3. Blisters and scabs - raised spots on steel surface caused by expansion of trapped gases within the steel 4. Hard spots - created by localized cooling of the steel plate (ERW pipe) during rolling 5. Indentations - formed by the expanders or mandrels used to make seamless pipe 6. Transit fatigue - cracks formed when pipes are repeated flexed during transportation and handling 7. Cyclic fatigue - cracks caused by stress from repeated fluctuating operating pressure within the pipe 8. Elastomer and polymer - failure due to reaction with CO2	1. Propagating cracks can lead to pipeline rupture. 2. A lamination or inclusion can eventually lead to failure if they eventually grow to the inner or outer wall of the pipe or pipeline component through pressure cycles. 3. Blisters and scabs reduce the wall thickness of the pipe and, if large enough, can reduce the pressure-carrying capacity of the pipe or component. 4. Cracking can occur at hard spots that eventually grows in size over time. 5. Stress risers can occur at indentations if they are too deep, eventually leading to pipe failure. 6. Transit fatigue cracks are typically discovered during the hydrostatic pressure testing however, some can remain and grow during pipeline pressure cycles until a failure occurs. 7. Can lead to CO2 leakage. 8. Failure of elastomers and/or polymers could lead to CO2 leakage.	Two CELLCO CO2 pipeline incidents caused by material/weld failure from 2006 to 2013. Neither was significant. Neither resulted in CO2 release. (PHMSA 2013)		Pipeline mechanical failure.	Pipeline material defects.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline manufacturing and quality control testing.	Select a competent pipe manufacturer. Inspect and test pipe before burial. Proper design, manufacturing, installation and maintenance of the pipeline.	Use of crack arrestors to mitigate propagating cracks.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
401	21.02.22.	Pipeline burial depth	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
402	21.02.23	Pipeline bedding and foundation structures	1	1	2	2	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
403	21.03.00.	Pipeline defects	0	0	0	0															
404	21.03.01.	Pipeline material defects	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
405	21.03.02.	Pipeline weld defects	Some pipeline weld defects include: 1. Pinholes - small, unwelded area extending through the entire thickness of the weld 2. Toe cracks - occur where the crown of the weld bead intersects the edge of the plate in pipe joined using the Double Submerged Arc Welding (DSAW) 3. Off seam welding - crack caused by the inside and outside welds of the DSAW process being offset 4. Undercutting - occurs when there is an inadvertent reduction in the wall thickness in the area of the weld 5. Incomplete fusion - occurs when there is a lack of complete fusion of the weld and the base metal 6. Porosity - occurs when one or more voids are created in the weld material from shrinkage of the material 7. Slag inclusions - exist when non-metallic material becomes trapped in the weld 8. Weld defects in older pipe - Burnt pipe edges - Incomplete fusion - Hook cracks - Cold welds - Weld metal cracks For more details, see PHMSA.	Weld defects can lead to CO2 leakage	Two CELLCO CO2 pipeline incidents caused by material/weld failure from 2006 to 2013. Neither was significant. Neither resulted in CO2 release. (PHMSA 2013)		Pipeline weld failure.	Pipeline weld defects.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline welding and quality control testing.	Comply with all 49 CFR Part 195 welding requirements. Use certified welders. Inspect and test welds prior to burial.	Replace welds that do not pass inspection and testing.
406	21.03.03.	Pipeline equipment defects	Equipment failures involve pumps, compressors, valves, meters, tanks, control/relief equipment and other components and devices on pipeline systems. (PHMSA). Can include broken couplings, stripped threads.	Equipment is often located on company property that is not accessible to the public. Equipment failure usually results in a CO2 release that is contained on public property, typically not resulting in injury to the general public. (PHMSA)	No CELLCO CO2 pipeline incidents were caused by equipment defects from 2006 to 2013 (PHMSA 2013).		Equipment failure. Damage to equipment / system.	Pipeline equipment defects.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor equipment operation and maintenance.	Proper selection, operation and maintenance of equipment.	Monitor for equipment vibration or performance changes. Determine root cause and repair.
407	21.04.00.	Pipeline corrosion	About 15% of gas pipeline failures in Europe are caused by corrosion (EGIG 2008)	Corrosion can lead to pipe failure and CO2 leakage.								
408	21.04.01.	External corrosion	Galvanic corrosion can take place when an unprotected metal pipeline comes in contact with water or soil. 1. External corrosion of buried pipe 2. External corrosion of surface pipe	Corrosion can lead to pipe failure and CO2 leakage.	Cathodic protection and external coating used. Two CELLCO CO2 pipeline incidents were caused by external corrosion from 2006 to 2013. One was significant with 108 t of CO2 released. (PHMSA 2013)		Pipeline failure.	External corrosion of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline external corrosion.	Comply with all 49 CFR Part 195 pipeline corrosion protection requirements.	Regular inspections, testing, cleaning and maintenance of pipeline.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
405	21.03.02.	Pipeline weld defects	3	2	2	12	None	None	None	None	None	<\$0.5M per incident	None	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	
406	21.03.03.	Pipeline equipment defects	3	2	2	12	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
407	21.04.00.	Pipeline corrosion	0	0	0	0															
408	21.04.01.	External corrosion	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
409	21.04.02.	Internal corrosion	There is potential for rapid corrosion of steel pipeline if free water becomes present in the CO2 stream. There is currently insufficient data to adequately understand the effect of an accidental flow of high water content CO2 into a pipeline and also the influence the various CO2 impurities (O2, H2, SOx, NOx, H2S TEG, MEG and amines/NH3) will have on the corrosion rates. (DNV CO2PIPETRANS Phase 2). Corrosion rate of carbon steel in dry supercritical CO2 is low. For AISI 1080 values around 12.5 microns per year have been measured at 9-12 MPa (90-120 bar) and 160-180°C for 200 days. During 12 years, the corrosion rate in an operating pipeline amounted to 0.25-2.5 microns per year.	Corrosion can lead to pipe failure and CO2 leakage.	No CELLCO CO2 pipeline incidents were caused by internal corrosion from 2006 to 2013 (PHMSA 2013).		Pipeline failure.	Internal corrosion of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline internal corrosion.	Comply with all 49 CFR Part 195 pipeline corrosion protection requirements. Use dry CO2.	Avoid free water in pipeline. Clean pipeline internals. Regularly inspect pipeline for corrosion. Use smart pigs. Repair any corrosion damage as needed.
410	21.04.03.	Microbial corrosion	Microbial corrosion is corrosion promoted by microorganisms such as chemoautotrophs which can produce hydrogen sulfide, sulfuric acids, other acids or ammonia. Some bacteria directly oxidize iron to iron oxide or iron hydroxide.	Hydrogen sulfide can cause corrosion and sulfide stress cracking.	Two CELLCO CO2 pipeline incidents were caused by external corrosion (which may, or may not, have involved microbial corrosion) from 2006 to 2013. One was significant with 108 t of CO2 released. (PHMSA 2013)	Incidents of microbial corrosion?	Pipeline failure.	Microbial corrosion of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline microbial corrosion.	Comply with all 49 CFR Part 195 pipeline corrosion protection requirements.	Regularly inspect pipeline for corrosion using smart pigs. Repair any corrosion damage as needed.
411	21.04.05.	Selective seam corrosion	Selective seam corrosion (SSC) is a form of corrosion that tends to affect pipe manufactured prior to 1970 using low-frequency electric resistance welding (LR-ERW) or electric flash welding (EFW) processes. SSC is a localized corrosion attack along the weld bond line of ERW and EFW pipe, that leads to the development of a wedge shaped groove that is often filled with corrosion products. (PHMSA)	Risk for older LF-ERW or EFW pipe, not HF-ERW, DSAW or seamless pipe. (PHMSA)	Assume new pipe was used and pipeline is designed and operated in compliance with all regulations, codes and permits.		Pipeline failure.	Selective seam corrosion of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor for selective seam corrosion if pipe manufactured prior to 1970.	Use newly manufactured pipe for construction of pipeline.	Regularly inspect pipeline for corrosion using smart pigs. Repair any corrosion damage as needed.
412	21.04.04.	Stress corrosion cracking	Stress corrosion cracking (SCC) is a form of corrosion that produces a marked loss of pipeline strength with little metal loss. The combined influence of pipeline stress due to its pressurized contents and a corrosive medium can occasionally result in the formation of interlinking crack clusters that can grow until the affected pipe fails. (PHMSA)	Stress corrosion cracking can result in pipe failure and CO2 leakage.	No CELLCO CO2 pipeline incidents were caused by stress corrosion cracking from 2006 to 2013 (PHMSA 2013).		Pipeline failure.	Stress corrosion cracking of pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline stress corrosion cracking.	Maintain pipeline pressure at less than 80% of maximum design pressure. Avoid moisture in the CO2 stream.	Monitor for moisture in the CO2. Regularly inspect pipeline for corrosion using smart pigs.
413	21.05.00.	Pipeline mechanical damage	Mechanical damage consists of dents, gouges, cracks, punctures, stress risers or ruptures.	Mechanical damage of a pipeline can lead to immediate or eventual/accelerated CO2 leakage.								

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable, or incredible; Yellow/Orange = Headings or non-risk areas

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking		Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)		Savings with risk mitigation (\$)
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
409	21.04.02.	Internal corrosion	3	2	2	12	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
410	21.04.03.	Microbial corrosion	3	2	2	12	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
411	21.04.05.	Selective seam corrosion	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
412	21.04.04.	Stress corrosion cracking	3	2	2	12	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
413	21.05.00.	Pipeline mechanical damage	0	0	0	0															

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable, or incredible; Yellow/Orange = Headings or non-risk areas

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
414	21.05.01.	Excavation damage	About 50% of pipeline failures in Europe and 33% in the US are caused by excavation damage. Excavation damage can include damage to the external coating of the pipe, or dents, scrapes, cuts, or punctures directly into the pipeline itself. The damage can be caused by any type of excavation, including digging, grading, trenching and boring, road and highway maintenance, general construction and farming activities. It normally occurs when excavators fail to call their local one-call system to mark where underground facilities are located prior to excavating. (PHMSA)	Excavation can lead to pipeline damage and CO2 leakage.	No CELLCO CO2 pipeline incidents were caused by excavation damage from 2006 to 2013 (PHMSA 2013).		Pipeline mechanical damage.	Excavation near pipeline.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor excavation activity near pipeline.	Comply with all 49 CFR Part 195 excavation safety requirements including deep burial of pipeline, proper marking of ROW, regular ROW inspections, supervision of third-party excavation, and one-call system.	Train emergency response team to rapidly address excavation damage. Educate local residents how to identify and report leaks or damage.
415	21.05.02.	Natural force damage	Natural force damage includes damage from landslide, flood, heavy rains, riverbed scouring and washouts, dike breaks, subsidence, earthquakes, high winds, tornadoes, hurricanes, lightning, frost heaves, and frozen instrumentation lines. (PHMSA)	Can lead to unintended movement or abnormal loading of a pipeline resulting in mechanical damage, leakage or rupture.	No CELLCO CO2 pipeline incidents were caused by natural force damage from 2006 to 2013 (PHMSA 2013).		Pipeline mechanical damage.	Natural forces.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor natural force incidents near pipeline.	Comply with all 49 CFR Part 195 inspection requirements.	Maintain ROW to make it visually accessible from the air and physically accessible on the ground. Repair any eroded or damaged areas. Educate local residents how to identify and report leaks or damage.
416	21.05.03.	Other outside force damage	Other outside force damage excludes excavation but include such things as vehicle accident (hitting above ground valve or booster station), electric arcing from nearby power lines, vandalism, sabotage, terrorist attack, theft, fires from other businesses or industries, etc. (PHMSA) Most susceptible to this particular type of damage are above ground pipeline facilities which are in close proximity to highways or large population and industrial centers.	Mechanical damage of a pipeline can lead to immediate or eventual/accelerated CO2 leakage.	No CELLCO CO2 pipeline incidents were caused by other outside force damage from 2006 to 2013 (PHMSA 2013).		Pipeline mechanical damage.	Other outside forces.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor human activity near pipeline right-of-way.	Comply with all 49 CFR Part 195 security requirements. Fence in and secure surface facilities. Direct traffic patterns and speeds to prevent accidents.	Monitor site activity. Train operators to handle security issues and emergencies. Educate local residents how to identify and report leaks or damage.
417	21.05.04.	Mechanical damage requiring immediate repair	Metal loss greater than 80% of nominal wall thickness. Dent located on the pipeline (above 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser. Dent located on the pipeline (above 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter. (49 CFR Part 195.452)	Mechanical damage can require immediate repair to prevent CO2 leakage.	None reported.	Incidents of mechanical damage requiring immediate repair?	CO2 leak/rupture (HSE hazard).	Failure to repair significant mechanical damage immediately.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor reports of pipeline mechanical damage and response time.	Comply with all 49 CFR Part 195 for repair of mechanical damage to pipeline.	Train employees to repair mechanical damage in a timely manner.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
414	21.05.01.	Excavation damage	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
415	21.05.02.	Natural force damage	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
416	21.05.03.	Other outside force damage	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
417	21.05.04.	Mechanical damage requiring immediate repair	2	2	1	4	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
418	21.05.05.	Mechanical damage requiring evaluation and remediation within 60 days of discovery	Dent on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser. Dent located on the pipeline (above 4 and 8 o'clock positions) with a depth between 3% and 6% of the nominal pipe diameter. (49 CFR Part 195.452)	Mechanical damage can require timely evaluation and remediation to prevent CO2 leakage.	None reported.	Incidents of mechanical damage requiring evaluation and remediation within 60 days of discovery?	CO2 leak/rupture (HSE hazard).	Failure to repair minor mechanical damage within a reasonable time frame.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor reports of pipeline mechanical damage and response time.	Comply with 49 CFR Part 195 repair of mechanical damage to pipeline.	Train employees to repair mechanical damage in a timely manner.
419	21.06.00.	Pipeline procurement risks										
420	21.06.01.	Used pipe or old pipe	Used pipe must comply with the same quality requirements as new pipe. Used pipe must not have any mechanical damage (buckles, cracks, gouges, dents) or corroded areas that threaten the integrity of the pipe. (49 CFR Part 195.114).	Use of defective used pipe could result in pipe failure and CO2 leakage.	Assume new pipe was used and pipeline is designed and operated in compliance with all regulations, codes and permits.		Weak or off spec pipe.	Use of used or old pipe.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipe specification and procurement.	Use new pipe.	Inspect and test all pipe prior to its use.
421	21.06.02.	Pipeline valves	Each valve must be of sound engineering design, compatible with pipe and fittings, successfully hydrostatically tested, clearly marked for open and closed positions (except check valves), properly marked (nameplate) and properly sized. (49 CFR Part 195.116)	Defective or off-spec valves could result in valve failure and CO2 leakage. Wrong sized valves could lead to additional pressure stress or failure.	No CELLCO2 pipeline incidents were caused by valve failure from 2006 to 2013 (PHMSA 2013).		Valve failure.	Defective or off-spec valves.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor valve specification and procurement.	Comply with 49 CFR Part 195 valve requirements. Select competent valve manufacturers. Select the proper type and size of valve.	Inspect and test all valves prior to being used. Properly install, operate and maintain valves.
422	21.06.03.	Pipeline fittings	Fittings must be suitable for the intended service and be at least as strong as the pipe and other fittings in the pipeline system. There may not be any buckles, dents, cracks, gouges or other defects in the fittings that may reduce the strength of the fitting. (49 CFR Part 195.118)	Defective off-spec fittings could result in fitting failure and CO2 leakage.	No CELLCO2 pipeline incidents were caused by fitting failure from 2006 to 2013 (PHMSA 2013).		Fitting failure.	Defective or off-spec fittings.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor fitting specification and procurement.	Comply with 49 CFR Part 195 fitting requirements. Select competent fitting manufacturers. Select the proper type and size of fittings.	Inspect and test all fittings prior to being used. Properly install, operate and maintain fittings.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)					
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)															
418	21.05.05.	Mechanical damage requiring evaluation and remediation within 60 days of discovery	2	2	1	4	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
419	21.06.00.	Pipeline procurement risks	0	0	0	0															
420	21.06.01.	Used pipe or old pipe	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
421	21.06.02.	Pipeline valves	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
422	21.06.03.	Pipeline fittings	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
423	21.06.04.	Other pipeline components	Other components such as fabricated branch connections, closures, flange connections, station piping, and fabricated assemblies must meet applicable requirements. (49 CFR Part 195122-195.130) Materials for bolts and nuts should be same as flange. At least one full thread of bolt should be exposed beyond the nut. Gasket material should be compatible with CO2.	Defective or off-spec pipeline components could result in component failure and CO2 leakage.	No CELLCO CO2 pipeline incidents were caused by failure of other pipeline components from 2006 to 2013 (PHMSA 2013).		Component failure.	Defective or off-spec pipeline components.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor other pipeline component specification and procurement.	Comply with 49 CFR Part 195 requirements for other pipeline components. Select competent manufacturers. Select the proper type and size of components.	Inspect and test all components prior to being used. Properly install, operate and maintain components.
424	21.07.00.	Pipeline construction defects	About 16% of gas pipeline failures in Europe are caused by construction defect or material failure. (EGIG 2008)	Construction defects could result in pipeline failure and CO2 leakage.								
425	21.07.01.	Pipe installation	All pipeline installed in a ditch must be installed in a manner that minimizes the introduction of secondary stresses and the possibility of damage to the pipe. (49 CFR Part 195.246). This is of particular concern in rocky soil. When a ditch for a pipeline is backfilled, it must be done in a manner that provides firm support under the pipe, and prevents damage to the pipe and pipe coating from equipment or from the backfill material. (49 CFR Part 195.252) Pipeline coating can be damaged during installation by laying the pipeline on sharp rocks in the ditch, dropping rocks on it during backfill, rough contact with equipment or abrasion if installing pipe through a bored hole under a road or railroad crossing.	Pipe damage during installation could result in accelerated pipe failure and CO2 leakage Significant incident rate due to equipment/material/weld failure based on PHMSA CO2 pipeline data from 1986 - July 2012: 1.34E-04/mile/yr.	No CELLCO CO2 pipeline incidents were caused by pipeline installation defects from 2006 to 2013 (PHMSA 2013).		Pipeline failure.	Pipe mechanical damage during installation.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline installation and testing.	Install pipeline in compliance with 49 CFR Part 195. Inspect and test prior to being placed in service.	Repair or replace any pipe damaged during installation.
426	21.07.02.	Valve and other equipment installation	Valves and other equipment must be properly seated and installed.	Valves that are not properly seated or improperly installed could lead to system failure.	No CELLCO CO2 pipeline incidents were caused by valve and other equipment installation defects from 2006 to 2013 (PHMSA 2013).		Valve failure.	Improper seating / installation of valves.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor valve installation and testing.	Install valves and other equipment in compliance with 49 CFR Part 195. Inspect and test prior to being placed in service.	Repair or replace any valves or other equipment damaged during installation.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
423	21.06.04.	Other pipeline components	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
424	21.07.00.	Pipeline construction defects	0	0	0	0															
425	21.07.01.	Pipe installation	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
426	21.07.02.	Valve and other equipment installation	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
427	21.07.03.	Pipe bending	Pipe must not have a wrinkle bend. A bend must not impair serviceability of the pipe. Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage. On pipe containing a longitudinal weld, the longitudinal weld must be as practicable to the neutral axis of the bend unless the bend is made with an internal bending mandrel or the pipe is 0.32 m (12.75 in) or less nominal outside diameter or has a diameter to wall thickness ratio less than 70. Each circumferential weld which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process. (49 CFR Part 195.212)	Pipe damage during bending could result in accelerated pipe failure and CO2 leakage	No CELLCO CO2 pipeline incidents were caused by pipeline bending defects from 2006 to 2013 (PHMSA 2013).		Pipeline failure.	Pipe mechanical damage during bending.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipe bending and testing.	Bend pipe in compliance with 49 CFR Part 195. Inspect and test prior to being placed in service.	Replace any pipe bends that do not pass inspection or testing.
428	21.07.04.	Pipe welding (See 21.03.02.)	Welding must be performed by a qualified welder in accordance with welding procedures qualified under Section 5 of API 1104 or Section IX of the SASME Boiler and Pressure Vessel Code. Each welding procedure must be recorded in detail, including the results of the qualifying tests. 49 CFR Part 195.214-195.234)	Improper welding procedures could result in CO2 leakage.	Two CELLCO CO2 pipeline incidents were caused by material/weld failure from 2006 to 2013. Neither was significant. Neither resulted in CO2 release. (PHMSA 2013)		Pipeline weld failure.	Pipe welding defects.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline welding and quality control testing.	Comply with all 49 CFR Part 195 welding requirements. Use certified welders. Inspect and test welds prior to burial.	Replace welds that do not pass inspection and testing.
429	21.07.06	Pipeline underground clearance	Any pipe installed underground must have at least 0.3 m (12 in) of clearance between the outside of the pipe and the extremity of any other structure, except that for drainage tile. (49 CFR Part 195.250).	Insufficient clearance could cause mechanical damage under load.	No CELLCO CO2 pipeline incidents were caused by pipeline underground clearance from 2006 to 2013 (PHMSA 2013). Assume pipeline installed in compliance with all regulations, codes and permits.		Pipeline mechanical damage.	Insufficient underground clearance.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline installation for proper underground clearance.	Lay pipeline in compliance with 49 CFR Part 195. Assure sufficient clearance between the pipeline and other subsurface structures.	Design around subsurface structures if necessary.
430	21.07.07.	Pipeline integrity inspection	No pipe or other component may be installed in a pipeline system unless it has been visually inspected at the site of installation to ensure that it is not damaged in a manner that could impair its strength or reduce its serviceability. (49 CFR Part 195.206)	Improper or lack of integrity inspection may fail to discover mechanical damage or defects before CO2 is fed to the pipeline.	Assume pipeline installed in compliance with all regulations, codes and permits.	Verify integrity inspection took place?	Failure to discover defects before CO2 fed to pipeline.	Improper or lack of integrity inspection.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline integrity inspection.	Conduct pipeline integrity inspections as required in 49 CFR Part 195.	Repair any mechanical damage, defects or leaks.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index # Risk Area/FEP		Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
427	21.07.03.	Pipe bending	3	2	2	12	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
428	21.07.04.	Pipe welding (See 21.03.02.)	4	2	2	16	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
429	21.07.06	Pipeline underground clearance	2	2	1	4	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
430	21.07.07.	Pipeline integrity inspection	1	2	1	2	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
431	21.07.08.	Protection for above ground components	Above ground components may be installed in areas under direct control of the operator but should be inaccessible to the public. (49 CFR 195.254)	Insufficient protection for above ground components could lead to vandalism, theft and equipment damage by third parties.	Assume pipeline installed in compliance with all regulations, codes and permits.	Verify protection for above ground components?	Equipment theft/damage	Insufficient protection for above ground components.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor security for above ground components.	Fence in, mark and secure surface facilities.	Monitor activity at surface facilities.
432	21.07.09.	Construction records	A complete record must be maintained by the operator for the life of each pipeline facility of girth welds (total, number tested, rejected, disposition), pipe installed (amount, location cover, size), locations of pipeline crossings, utility crossings, overhead crossings, valves, and corrosion test stations. (49 CFR Part 195.266) 1. Lack of final as-built drawings 2. Pipeline location not properly documented 3. Valves and other equipment not properly marked	Incomplete or inaccurate construction records or as-built drawings could result in error or confusion during operation, maintenance or emergency response. Improper documentation of pipeline location can lead to confusion when marking a pipeline location prior to excavation. Failure to properly mark valves and other equipment could lead to improper opening or closing of valves or improper equipment operation and/or maintenance.	Assume that accurate records are maintained according to code.	Verify accurate pipeline construction records maintained?	Project uncertainty. Operator error.	Incomplete or inaccurate construction records.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor updating and maintenance of construction records.	Maintain an up-to-date set of construction drawings throughout the operation of the pipeline. Properly mark the pipeline location. Properly mark valves and other equipment.	Reconstruct any drawings or records that are missing.
433	21.08.00.	Pipeline operation risks										
434	21.08.01.	Operator error in pipeline operation	Operator error can include: 1. Leaving the wrong valve open or closed 2. Not following proper procedures 3. Using improper equipment or techniques to affect a repair 4. Improperly assessing a situation or condition resulting in inappropriate actions or decisions	Potential for pipeline failure and CO2 leakage.	No CELLCO CO2 pipeline incidents were caused by operator error from 2006 to 2013 (PHMSA 2013).		Poor performance and/or failure of equipment/pipeline.	Operator error.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor operator training and performance.	Implement standard procedures for safe operation. Train personnel prior to allowing them to work on the pipeline.	Ongoing operator training. Failsafe control system to prevent or mitigate operator errors.
435	21.08.02.	Pipeline over pressuring	Maximum operating pressure (MOP) is limited to 80% of pipeline design pressure. Isolating pipework or facilities with dense phase CO2 can result in doubling the pressure from 10 to 20 MPa (100 to 200 bar) as temperature raises from 25°C to 40°C.	Isolation of pipeline sections could lead to pipeline over pressuring. Operating the pipeline above maximum operating pressure (MOP) could place the pipeline at risk for failure.	No CELLCO CO2 pipeline incidents were caused by pipeline over pressuring from 2006 to 2013 (PHMSA 2013).	Procedures in place to prevent overpressuring?	CO2 leak/rupture (HSE hazard).	Pipeline over pressuring.	Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor CO2 pipeline pressure.	Implement standard operating procedures for controlling pipeline pressure.	Alarm system if pipeline pressure exceeds 80% of maximum design pressure.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking		Estimated Potential Damage Recovery Costs											Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info	
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)		Savings with risk mitigation (\$)
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
431	21.07.08.	Protection for above ground components	2	2	1	4	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
432	21.07.09.	Construction records	3	2	2	12	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
433	21.08.00.	Pipeline operation risks	0	0	0	0															
434	21.08.01.	Operator error in pipeline operation	3	4	2	24	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2	10% of damage cost	<\$25M per incident	None	Part of ongoing costs	<\$2.5M per incident prevented	
435	21.08.02.	Pipeline over pressuring	3	4	2	24	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2	10% of damage cost	<\$2.5M per incident	None	Part of ongoing costs	<\$2.5M per incident prevented	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
436	21.08.03.	Pipeline re-pressurization	Re-pressurizing a pipeline results in isenthalpic flash across the re-pressurizing valve causing low temperature in the pipeline, no solid CO2 formation if the CO2 is warm enough. (Anderson 2008).	Low temperature across the re-pressurizing valve	No CELLCO CO2 pipeline incidents were caused by pipeline re-pressurizing from 2006 to 2013 (PHMSA 2013).	Procedures in place for re-pressurization?	Plugging / damage to pipeline valves.	Improper pipeline re-pressurization.	CO2 leak Pipeline and property damage. Liability costs. Damage repair costs.	Monitor CO2 pipeline re-pressurization.	Implement standard operating procedures for re-pressurizing the pipeline.	Alarm system and control safety limits. Failsafe control system to prevent or mitigate operator errors in pipeline repressurization.
437	21.08.04.	Pipeline depressurization	Rapid depressurization on blowdown of a pipeline can lead to low temperatures (isentropic behavior) and possible solid CO2 formation at pressures below 5 bar. (Anderson 2008).	Rapid depressurization of facilities can lead to CO2 hydrate formation in vent system, possibly causing blockage and over pressurization. (Anderson 2008). Solidification of CO2 could lead to plugging of relief valves. Lowering depressurization rate of a compressor can lead to asphyxiation risk. (Anderson 2008).	No CELLCO CO2 pipeline incidents were caused by pipeline depressurizing from 2006 to 2013 (PHMSA 2013)	Procedures in place for depressurization?	Plugging / damage to pipeline valves.	Improper pipeline depressurization.	CO2 leak Pipeline and property damage. Liability costs. Damage repair costs.	Monitor CO2 pipeline depressurization.	Implement standard operating procedures for depressurizing the pipeline.	Alarm system and control safety limits. Failsafe control system to prevent or mitigate operator errors in pipeline depressurization.
438	21.08.05.	Pipeline flow modeling	There is a need for improved understanding of the effect contaminants (O2, H2, SOx, NOx, H2S TEG, MEG and amines/NH3) have on the phase diagram and behavior of a CCS CO2 stream. (DNV CO2PIPETRANS Phase 2) Nitrogen and oxygen in CO2 will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow.	Improper understanding of the impact of CO2 impurities on the phase diagrams could lead to inaccurate pipeline flow modeling. Inaccurate modeling can cause the computational leak detection system to malfunction.	Information not publicly available. Assume pipeline is designed and operated in compliance with all regulations, codes and permits.	Operating issues with pipeline flow modeling?	Operator error.	Inaccurate pipeline flow model.	CO2 leak Pipeline and property damage. Liability costs. Damage repair costs.	Review accuracy of pipeline flow model.	Select optimum pipeline flow model. Verify model accuracy. Sufficiently train modelers.	Monitor actual versus model results and determine the root cause of any discrepancies.
439	21.08.06.	Boiling liquid expanding vapor explosion (BLEVE)	Boiling liquid expanding vapor explosion (BLEVE) is a type of explosion that can occur when a vessel or pipeline containing a pressurized liquid is ruptured. Such explosions can be extremely hazardous. A BLEVE results from the rupture of a vessel containing a liquid substantially above its atmospheric boiling point. The substance is stored partly in liquid form, with a gaseous vapor above the liquid filling the remainder of the container. If the vessel is ruptured — for example, due to corrosion, or failure under pressure — the vapor portion may rapidly leak, lowering the pressure inside the container. This sudden drop in pressure inside the container causes violent boiling of the liquid, which rapidly liberates large amounts of vapor. The pressure of this vapor can be extremely high, causing a significant wave of overpressure (an explosion) which may completely destroy the storage vessel and project fragments over the surrounding area. (Wikipedia)	Supercritical CO2 can have significant density variations with changes in pressure and temperature. If a pipeline ruptures, this could lead to a boiling liquid expanding vapor explosion (Anderson 2008).	No CELLCO CO2 pipeline incidents were caused by boiling liquid expanding vapor explosion from 2006 to 2013 (PHMSA 2013)		Human injury/death due to boiling liquid expanding vapor explosion (BLEVE).	Pipeline rupture.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline operating conditions.	Implement standard procedures for safe operation and maintenance of pipeline.	Monitor pipeline for unsafe operating conditions. Alarm system. Emergency response plan. Train employees and educate local residents what to do in the event of a pipeline rupture. Install block valves to separate sections of pipeline and minimize CO2 release in case of rupture.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)					
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)															
436	21.08.03.	Pipeline re-pressurization	3	2	2	12	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
437	21.08.04.	Pipeline depressurization	3	2	2	12	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
438	21.08.05.	Pipeline flow modeling	2	2	3	12	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
439	21.08.06.	Boiling liquid expanding vapor explosion (BLEVE)	2	4	1	8	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	<\$0.5M	<\$0.5M	<\$1M per incident	0-5 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$3M	None	Part of ongoing costs	<\$3M per incident prevented.	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
440	21.08.07.	Pipeline scheduled maintenance	Typical scheduled maintenance jobs and frequency: Aerial patrols 26 times per year. Population density survey every other year. ROW inspection 26 times per year. Emergency systems tested annually. Rectifier maintenance completed 6 times per year. Cathodic protection survey annually, Internal inspection of pipeline using an electronic tool, every 5 years or more frequently if necessary. Overpressure safety devices checked annually. Public awareness and damage prevention program reviewed annually. (DGC). Inspect each mainline valve twice a year 1. Pipeline cleaning	Failure to properly inspect and maintain the pipeline could lead to pipeline failure and CO2 leakage.	Assume pipeline is designed, operated, and maintained in compliance with all regulations, codes and permits.	Pipeline scheduled maintenance procedures in place?	Pipeline corrosion.	Lack of, or improper, pipeline scheduled maintenance.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline scheduled maintenance.	Comply with 49 CFR Part 195 pipeline scheduled maintenance requirements. Maintain proper pipeline maintenance.	Review status and results of pipeline scheduled maintenance annually.
441	21.08.08.	Pipeline malfunctions	Some pipeline malfunctions could include: 1. Equipment malfunction or failure 2. Unintended valve closure or shutdown 3. Loss of communication (SCADA system) 4. Power outage 5. Pig stuck in pipeline causing a shutdown	Pipeline malfunctions could lead to unintended shutdown or CO2 leakage.	One CELLCO CO2 pipeline incident was caused by miscellaneous cause from 2006 to 2013. It was not significant. Approximately 0.25 t of CO2 was released. (PHMSA 2013) Assume pipeline is designed and operated in compliance with all regulations, codes and permits.		Pipeline flow interruption. Pipeline damage.	Pipeline malfunction.	CO2 leak. Pipeline and property damage. Liability costs. Damage repair costs.	Monitor pipeline operating conditions.	Install alarm system for equipment / valve malfunction or failure. Install backup communication system for SCADA. Install backup power generator or batteries. Implement standard operating procedures for inline inspection system (pig system).	Train personnel to properly respond to pipeline malfunctions on a timely basis.
442	21.08.09.	Pipeline leak	Pipeline leaks can include: 1. Pinhole leak - small leak (visible due to dry ice forming on the surface) 2. Pipeline puncture small diameter leak 3. Pipeline puncture large diameter leak	CO2 leakage.	One CELLCO CO2 pipeline incident resulted in a significant CO2 leak of 108 t (850 bbl) from 2006 to 2013. It was caused by external corrosion. (PHMSA 2013)		Pipeline and property damage. Human injury/death.	Pipeline leak.	Liability costs. Damage repair costs..	Monitor pipeline operating conditions.	Implement standard procedures for safe operation and maintenance of pipeline.	Install and maintain CPM leak detection system. Install and maintain crack arrestors to minimize propagating cracks. Install and maintain block valves to section off the pipeline in case of a rupture. Train personnel and educate local residents on how to identify and respond to a pipeline leak/rupture. Implement and maintain an emergency response plan.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)					
			Fatalities: \$1.5M per fatality	Serious (irrecoverable) Injuries: \$1.5M per injury	Minor (recoverable) Injuries: \$0.05M per injury																
Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)																
440	21.08.07.	Pipeline scheduled maintenance	2	2	1	4	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
441	21.08.08.	Pipeline malfunctions	5	2	2	20	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
442	21.08.09.	Pipeline leak	5	2	2	20	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
443	21.08.10.	Pipeline rupture	Pipeline ruptures consist of a circumferential or longitudinal propagation fracture	CO2 leakage.	No CELLCO CO2 pipeline ruptures were reported from 2006 to 2013.		Rapid release of CO2.	Pipeline rupture.	Liability costs. Human injury/death. Damage repair costs..	Monitor pipeline operating conditions.	Implement standard procedures for safe operation and maintenance of pipeline.	Install and maintain CPM leak detection system. Install and maintain crack arrestors to minimize propagating cracks. Install and maintain block valves to section off the pipeline in case of a rupture. Train personnel and educate local residents on how to identify and respond to a pipeline leak/rupture. Implement and maintain an emergency response plan.
444	21.08.11.	Pipeline safety measures	Pipeline safety measures can include: 1. Emergency response plan 2. Reverse 911 call system - emergency alert 3. One-call system - prior to drilling or excavating 4. Supervision of excavation near pipelines 5. Regular inspection and maintenance of pipeline and ROW 6. CO2 monitors and alarms at booster stations 7. Oxygen packs at booster stations 8. Fire fighting equipment at booster stations 9. Public emergency response plan 10. Fencing and barricades to protect above ground facilities 11. Markers for ROW, valves and equipment	Lack of pipeline safety measures could lead to human injury and/or pipeline damage.	Assume pipeline is designed, operated, and maintained in compliance with all regulations, codes and permits.	Verify pipeline safety measures in place (Such as SCADA system Automatic and manual valves Marked right-of-way (ROW) and pipeline location Visual inspections of ROW by air every 2 weeks Frequent visual inspection of ROW by vehicle in built up areas Internal inspections with smart pigs Cathodic protection External coating of pipe Fracture arrestors every 1000 ft Public awareness program - mailing One-call system Emergency response plan Pipeline burial depth at least 1 m)?	Noncompliance with regulations.	Lack of or inadequate pipeline safety measures.	Fines or penalties for noncompliance. Possible business interruption.	Monitor pipeline safety measures.	Comply with all safety measures required by 49 CFR Part 195.	Review safety measures regularly to ensure they are operational. Make adjustments if necessary to ensure safety.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
	Index #	Risk Area/FEP	Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
443	21.08.10.	Pipeline rupture	3	4	2	24	1 @ \$1.5M per fatality	1 @ \$1.5 M per serious (irrecoverable) injury	1 @ \$0.05 M per minor (recoverable) injury	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$2.5M per incident	None	Part of ongoing costs	<\$2.5M per incident prevented	
444	21.08.11.	Pipeline safety measures	2	2	1	4	None	None	None	None	None	<\$0.15M per incident	None	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis					
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
445	21.09.05	Pipeline hydraulic testing	Except as otherwise provided in this section ... no operator may operate a pipeline unless it has been pressure tested ... without leakage, (49 CFR Part 195.300-195.310)	Improper or lack of hydraulic testing may fail to discover leaks before CO2 is fed to the pipeline.	Assume pipeline installed in compliance with all regulations, codes and permits.	Verify hydraulic testing completed?	Failure to discover leaks before CO2 fed to pipeline.	Improper or lack of hydraulic pipeline testing.	CO2 leak/rupture (HSE hazard). Pipeline and property damage. Human injury/death. Liability costs. Damage repair costs.	Monitor pipeline hydraulic testing.	Conduct pipeline hydrostatic testing in compliance with 49 CFR Part 195.	Locate and repair any leaks. Do not place pipeline into service until it has successfully passed hydrostatic testing.
446	22.00.00.	CO2 ON-SITE FACILITIES RISKS										
447	22.01.00.	On-site facilities for DSA	On-site facilities for deep saline aquifer (DSA) CO2 injection can include: 1. Injection CO2 distribution system trunk and laterals 2. Power supply 3. Injection and monitoring wells 4. Onsite CO2 pumping stations 5. Water treatment facilities.	Potential problems could include, blowout, equipment failure.	Not applicable to CO2-EOR.		Poor performance or failure of equipment /systems.	Defective / off-spec on-site facilities for DSA.	CO2 leak / blowout. Water leak/rupture. Facilities and property damage. Human injury/death. Liability costs. Damage repair costs. Environmental clean up costs. Project profitability negatively impacted.	Monitor specification, procurement, installation, operation and maintenance of on site facilities.	Train operators and managers. Properly specify, engineer, manufacture and install equipment and other components. Implement appropriate procedures for safe operation and maintenance of on-site facilities. Comply with state and federal regulations.	Implement and maintain a risk management plan. Monitor for CO2 leaks.
448	22.02.00.	On-site facilities for EOR	On-site facilities for CO2 enhanced oil recovery (EOR) can include: 1. Recycle CO2 compression system and building 2. Injection CO2 distribution system trunk and laterals 3. Production gathering system 4. Oil, water and slop storage tanks 5. CO2 dehydration system 6. CO2 gas scrubber/knockout drum 7. Flare system 8. Circulation and transfer pumps 9. Instrument air system 10. Control room, motor control center and building 11. Power supply transformers, UPS, PLCs, cables 12. Injection, production, disposal and monitoring wells 13. Water treatment/disposal facilities 14. CO2 separation and hydrocarbon recovery.	Potential problems could include blowout, oil leaks/spills ignition/explosion, equipment failure, water quality, water disposal	CO2-EOR facilities in place. No fatalities reported. Assume facilities designed, installed, operated and maintained in compliance with all regulations, codes and permits.	Operational performance of FWU on-site CO2-EOR facilities?	Poor performance or failure of equipment /systems.	Defective / off-spec on-site facilities for EOR.	CO2 leak Oil leak-spill Water leak Facilities and property damage. Liability costs. Damage repair costs. Environmental clean up costs. Project profitability negatively impacted.	Monitor specification, procurement, installation, operation and maintenance of on site facilities.	Train operators and managers. Properly specify, engineer, manufacture and install equipment and other components. Implement appropriate procedures for safe operation and maintenance of on-site facilities. Comply with state and federal regulations.	Implement and maintain a risk management plan. Monitor for CO2, CH4, oil or water leaks.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = redundant, not applicable, or incredible; Yellow/Orange = Headings or non-risk areas

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
445	21.09.05	Pipeline hydraulic testing	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
446	22.00.00.	CO2 ON-SITE FACILITIES RISKS	0	0	0	0															
447	22.01.00.	On-site facilities for DSA	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
448	22.02.00.	On-site facilities for EOR	4	2	1	8	None	None	None	None	None	<\$0.15M per incident	0-5 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Subsurface, Surface, Technical and Programmatic Risk Areas							Failure Modes and Effects Analysis						
Line #	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)	
449	22.03.00.	On-site facilities for ECBM	On-site facilities for CO2 enhanced coal bed methane (ECBM) can include: 1. Recycle CO2 compression system and building 2. Injection CO2 distribution system trunk and laterals 3. Production gathering system 4. Water storage tanks 5. CO2 dehydration system 6. CO2 capture system - removal of CO2 from nat. gas 7. Flare system 8. Circulation and transfer pumps 9. Instrument air system 10. Control room, motor control center and building 11. Power supply transformers, UPS, PLCs, cables 12. Injection, production, disposal and monitoring wells 13. Water treatment/disposal facilities	Potential problems could include blowout, methane leaks ignition/explosion, equipment failure, water disposal.	Not applicable to CO2-EOR.		Poor performance or failure of equipment /systems.	Defective / off-spec on-site facilities for ECBM.	CO2 leak / blowout. Methane leak / ignition / explosion. Water leak/rupture. Facilities and property damage. Human injury/death. Liability costs. Damage repair costs. Environmental clean up costs. Project profitability negatively impacted.	Monitor specification, procurement, installation, operation and maintenance of on-site facilities.	Train operators and managers. Properly specify, engineer, manufacture and install equipment and other components. Implement appropriate procedures for safe operation and maintenance of on-site facilities. Comply with state and federal regulations.	Implement and maintain a risk management plan. Monitor for CO2, CH4 or water leaks.	
450	22.04.00.	Injection well components	CO2 injection well components generally include: 1. Wellhead and tree 2. Tubing and casing 3. Safety valve 4. Packer 5. Packer fluid 6. Elastomers 7. Perforations 8. Sand control - for unconsolidated reservoirs	Component failure could result in CO2 leakage.	Assume injection wells designed, operated and maintained in compliance with all regulations, codes and permits.	Injection well design? Injection well operating performance? Incidents of injection well leakage (type, frequency, magnitude, methods of mitigating)?	Failure of injection well components.	Defective /off spec injection well components.	CO2 leak / blowout. Facilities and property damage. Human injury/death. Liability costs. Damage repair costs. Project profitability negatively impacted.	Monitor specification, procurement, installation, operation and maintenance of injection well components.	Train operators and managers. Properly specify, engineer, manufacture and install equipment and other components. Implement appropriate procedures for safe operation and maintenance of on-site facilities. Comply with state and federal regulations.	Implement and maintain a risk management plan. Monitor for CO2 or water leaks.	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #	Index #	Risk Area/FEP	Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (P×S×D = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
449	22.03.00.	On-site facilities for ECBM	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None		
450	22.04.00.	Injection well components	4	2	1	8	None	None	None	None	None	<\$0.15M per incident	0-5 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
451	22.05.00.	Injection well materials of construction	DSA CO2 injection well components are typically carbon steel. Typical materials of construction for EOR CO2 injection wells include: - Upstream metering & piping runs: 316 SS, Fiberglass - Christmas tree (trim): 316 SS, Nickel, Monel - Valve packing and seals: Teflon, Nylon - Wellhead (trim): 316 SS, Nickel, Monel - Tubing hanger: 316 SS, Incoloy - Tubing: fiberglass lined (GRE) carbon steel, internally plastic coated carbon steel, corrosion resistant alloys - Tubing joint seals: Seal ring (fiberglass lined), coated threads and collars (internally plastic coated) - On/off tool, profile nipple: Nickel plated wetted parts, 316 SS - Packers: Internally coated hardened rubber of 80-90 durometer strength (Buna-N), Nickel plated wetted parts - Cements and cement additives: API cements and/or acid resistant specialty cements and additives - Production liner 316 SS, Incoloy - Casing: carbon steel J-55 and K-55 grades; corrosion resistant alloy used in intervals where potential potable water aquifers exist or where H2S is present (Meyer 2007) - Elastomers - Teflon or nylon have been used to prevent swelling	Corrosion can occur when tubulars are exposed to wet CO2. Sufficient quantities of H2S in CO2 can cause corrosion or sulfide stress cracking. (CCP 2009) The reservoir fluid affects corrosivity near the wellbore and compaction resistance where formation dissolution has occurred. In significant dissolution cases, the well tubulars must be designed to resist column buckling in the injection interval. (CCP 2009) CO2 phase behavior can impact velocity. High velocity of injection can cause erosion to materials exposed to the CO2 stream (CCP 2009)	Assume injection wells designed, operated and maintained in compliance with all regulations, codes and permits.	Injection well design? Injection well operating performance? Incidents of injection well leakage (type, frequency, magnitude, methods of mitigating)?	Corrosion / failure of injection well components.	Defective / off-spec injection well materials of construction.	CO2 leak. Downtime and repair costs.	Monitor specification, procurement, installation, operation and maintenance of injection well components.	Determine the characteristics of brine to be handled in the injection wells. Select materials that will resist corrosion, and/or scale buildup.	Monitor corrosion and scale buildup in injection wells and take necessary corrective action such as pre-treating the injected water.
452	22.05.01.	Elastomer seals	Since supercritical CO2 is a solvent, many elastomers, plastics, rubber, or resins present in a well could be subject to chemical attack or dissolution. When designing a CO2 injector, material should be based on performance expectations. Elastomers, in particular, are a common part of well hardware used to seal different components. Elastomers must be made of material that is chemically compatible or inert to the injection fluid and must be of sufficient strength or adequately anchored to withstand the different pressure and explosive decompression that might exist across a seal. Since the physical and performance characteristics of many elastomer materials change with pressure and temperature, the elastomer must be able to perform reliably across the full range of differential pressures and temperatures expected through the design life of the well at the location of the seal within the well. (CCP 2009) Teflon or nylon have been used for seals to prevent swelling. (Meyer 2007).	Elastomer seal failure can result in CO2 leakage.	Assume elastomer seals designed, installed, operated and maintained in compliance with all regulations, codes and permits.	Type of elastomer seals used? Incidents of elastomer seal failure or leakage?	Seal failure.	Defective / off-spec elastomer seals.	CO2 leak. Downtime and repair costs.	Monitor specification, procurement, installation, operation and maintenance of elastomer seals.	Select elastomers that have a successful track record in handling CO2	Replace elastomer seals that fail. Determine root cause. Monitor development of improved elastomers.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

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							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
451	22.05.00.	Injection well materials of construction	3	2	1	6	None	None	None	None	None	<\$0.15M per incident	0-5 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	1
452	22.05.01.	Elastomer seals	3	2	1	6	None	None	None	None	None	<\$0.5M per incident	0-5 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2.	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
453	22.06.00.	Injection well safety precautions	Safety precautions for injection wells include: 1. Casing corrosion protection - Impressed and passive currents - Oxygen, biocide corrosion inhibiting chemicals 2. Gentle handling to prevent damage to tubing coatings 3. Casing leak detection testing 4. Fencing, monitoring and atmospheric dispersion monitoring if near populated areas 5. Automatic shutdown controls for unsafe conditions	Lack of safety precautions can lead to greater risk of CO2 leakage	Assume injection wells designed, operated and maintained in compliance with all regulations, codes and permits.	Injection well safety precautions implemented at FWU?	Wellbore failure.	Lack of injection well safety precautions.	CO2 leak. Downtime and repair costs.	Monitor injection well safety precautions.	Comply with all state and federal injection well safety measures.	Annual review of safety measures, rules and regulations to confirm the project is in compliance.
454	22.07.00.	Production well submersible pump	While normally very reliable, the submersible pump in an EOR or ECBM production well can fail.	Failure of the submersible pump can result in operating delays and maintenance costs.	Assume submersible pumps designed, operated and maintained in compliance with all regulations, codes, permits and best practices.	Production well submersible pump specification, operating performance, and failure rate?	Submersible pump failure.	Defective /off-spec submersible pump	Downtime and repair costs.	Monitor specification, procurement, installation, operation and maintenance of submersible pump.	Properly select, install, operate and maintain submersible pumps.	Monitor submersible pumps for corrosion, hydrocarbon deposition or scale buildup and take necessary corrective action.
455	22.08.00.	Production well materials of construction	Production wells tend to be exposed to mixtures of CO2, brine, hydrocarbons (oil and/or gas) and stripped gases such as H2S. Production wells may also be exposed to hydrocarbon (asphaltene, paraffin or polyaromatic) deposition. Teflon coating has proven to help reduce hydrocarbon deposition. Scale buildup may also be a problem depending on brine chemistry.	The produced mixtures can be very corrosive. Hydrocarbon deposition or scale buildup may cause significant down time for cleaning out.	Assume production wells designed, operated and maintained in compliance with all regulations, codes and permits.	Production well materials of construction, specification, operating performance, and failure rate?	Corrosion / failure of production well components.	Defective / off-spec production well materials of construction.	CO2 leak. Downtime and repair costs.	Monitor specification, procurement, installation, operation and maintenance of production well components.	Determine the characteristics of fluids to be handled by the production well. Select materials that will resist corrosion, hydrocarbon deposition and/or scale buildup.	Monitor corrosion, hydrocarbon deposition and scale buildup in production wells and take necessary corrective action.
456	23.00.00.	CO2 MONITORING RISKS										
457	23.01.00.	Data acquisition activities at the well	Activities include logging, drill stem tests, coring, hydrophone installation, etc.	May include some activities and procedures that are less familiar. Some techniques could limit other MMV techniques.	CO2-EOR operators are required to monitor flowrates, injection pressures, temperatures and annulus pressures. SWP will monitor downhole pressure and temperature, sample and analyze produced oil, gas and water, and track introduced or natural tracers. Three characterization wells will be completed.	Any data acquisition issues?	Project uncertainty due to lack of subsurface data.	Ineffective data acquisition activities at the well	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor data acquisition activities at the well.	Work with an experienced monitoring engineer / consultant to prepare a monitoring plan that optimizes wellbore data acquisition. Implement standard procedures for good monitoring.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.

FARNSWORTH UNIT CO2-EOR SITE QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA) MODEL

Line #			Risk Ranking				Estimated Potential Damage Recovery Costs										Risk Prevention/Mitigation Cost Savings				Insurance ranking 1=needed info 2=helpful info
			Failure probability (P = 1 to 5)	Failure severity (S = 1 to 5)	Difficulty of failure detection (D = 1 to 5)	Risk priority number (PXSxD = 1 to 125)	Human health & safety			Natural resource damage (\$)	Third-party property damage (\$)	Owner property damage (\$)	Owner business interruption (\$)	Owner economics (\$)	CO2 emissions (tonnes and \$)	Fines & legal expense: (\$) 10% of total damage	Damage recovery cost w/o prevention and mitigation (\$)	Damage recovery cost w/ prevention and mitigation (\$)	Cost of prevention and/or mitigation (\$)	Savings with risk mitigation (\$)	
							Fatalities: \$1.5M per fatality	Serious (irrecover- able) Injuries: \$1.5M per injury	Minor (recover-able) Injuries: \$0.05M per injury												
453	22.06.00.	Injection well safety precautions	2	2	1	4	None	None	None	None	None	<\$0.5M per incident	0-5 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	<1,000t CO2 per leak at \$32.32/t CO2	10% of damage cost	<\$1M per incident	None	Part of ongoing costs	<\$1M per incident prevented	1
454	22.07.00.	Production well submersible pump	5	2	1	10	None	None	None	None	None	<\$0.2M per incident	0-5 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
455	22.08.00.	Production well materials of construction	3	2	1	6	None	None	None	None	None	<\$0.15M per incident	0-5 days @ \$15,000/d revenue lost per pattern idled	Impacts profitability.	<500t CO2 per leak at \$32.32/t CO2	10% of damage cost	<\$0.5M per incident	None	Part of ongoing costs	<\$0.5M per incident prevented	
456	23.00.00.	CO2 MONITORING RISKS	0	0	0	0															
457	23.01.00.	Data acquisition activities at the well	2	1	1	2	None	None	None	None	None	None	Inability to verify compliance with regulations	<\$0.1M	None	10% of total damages	<\$0.1M	None	Part of ongoing costs.	<\$0.1M	1

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Line #	Subsurface, Surface, Technical and Programmatic Risk Areas						Failure Modes and Effects Analysis					
	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
458	23.02.00.	Data acquisition activities away from the well	Many activities and procedures will be effectively new and newly trained for. Some monitoring techniques could present risk or barriers to the application or success of other techniques.	Off-site monitoring activities may incur risk of physical accidents and may make the project publicly prominent.	SWP will monitor groundwater chemistry and soil gas. They will also conduct passive seismic, vertical seismic profiling and cross-well tomography. A 3D seismic survey has been completed to augment legacy 2D seismic survey data.	Any data acquisition issues?	Project uncertainty due to lack of subsurface data.	Ineffective data acquisition activities away from the well	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor data acquisition activities away from the well.	Work with an experienced monitoring engineer / consultant to prepare a monitoring plan that optimizes non-wellbore data acquisition. Implement standard procedures for good monitoring.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.
459	23.03.00.	Data acquisition conflicts	Data acquisition may involve many techniques including logging, fluid sampling, coring, surface and downhole geophones, surface seismic, surface air measurements, groundwater sampling, and others.	Use of some monitoring techniques can preclude or limit the applicability of other techniques.	SWP and CELLC will coordinate seismic activities to avoid conflicts. Downhole monitoring will be coordinated to avoid conflicts with production and injection.	Any data acquisition issues?	Project uncertainty due to subsurface data conflicts.	Data acquisition conflicts.	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor data acquisition conflicts.	Prepare a monitoring plan that avoids data acquisition conflicts.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.
460	23.04.00.	Seismic surveys	Vertical resolution of seismic imaging is inherently limited such that features less than 10 m thick can rarely be discerned. (CCP 2009) Subsurface CO2 is not seismically resolvable. Limited or absence of plume images via seismic. Seismic readings may be compromised by vibration from nearby heavy industrial facilities. 1. 2-D seismic survey 2. 3-D seismic survey 3. 4-D seismic survey 4. Vertical seismic profile (VSP) 5. Cross well seismic survey	Seismic techniques unable to pick up subsurface features or track CO2 plume.	Legacy 2D seismic data available. 3D seismic survey completed in JAN 2013. Multiple 3D vertical seismic profiling (VSP) planned to monitor CO2 plumes. Cross-well tomography will be used to provide more detail.		Seismic techniques unable to pickup subsurface features or track CO2 plume.	Seismic survey poor resolution.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor specification and implementation of seismic surveys.	Combine seismic survey methods to get better resolution.	Compare monitoring data with simulation data. Identify discrepancies and determine root cause.
461	23.05.00.	Gravity surveys	As a notional rule of thumb, CO2 filled reservoirs with less than 10% porosity, thicknesses of less than 10 m and depths greater than 2,500 m will be very difficult to resolve even with the best gravity data and mathematical inversion techniques. (CCP 2009) Current available standard gravimeters are capable of making repeat measurements valid to about 5 micro-gals. Fixed seal-floor gravimeters are essentially capable of the same. (CCP 2009) Corrections for motion are required for gravity data acquired from moving vessels. A change of only 1 cm of elevation will yield a difference of 3 micro-gals. Studies of oil fields have found that fixed permanent surface gravity monuments (i.e. stations) are essential to maximize repeatability (CCP 2009)	Gravity surveys unable to detect CO2 movement	No gravity surveys reported.	Have any gravity surveys been conducted?	Gravity survey unable to detect CO2 plume.	Site-specific conditions fall outside the effective range of gravity separation.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor specification and implementation of gravity surveys.	Consider alternative geophysical techniques if site-specific conditions fall outside the range of gravity survey effectiveness.	Consider alternative geophysical techniques if site-specific conditions fall outside the range of gravity survey effectiveness.

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458	23.02.00.	Data acquisition activities away from the well	2	1	1	2	None	None	None	None	None	None	Inability to verify compliance with regulations	<\$0.1M	None	10% of total damages	<\$0.1M	None	Part of ongoing costs.	<\$0.1M	1
459	23.03.00.	Data acquisition conflicts	2	1	1	2	None	None	None	None	None	None	None	<\$0.1M	None	None	<\$0.1M	None	Part of ongoing costs.	<\$0.1M	
460	23.04.00.	Seismic surveys	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	1
461	23.05.00.	Gravity surveys	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	

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	Index #	Risk Area/FEP	Description	Relevance	Site specific information	Information gaps or uncertainties	Potential failure mode	Cause of Failure	Potential failure effect	Method of detecting failure early	Risk prevention steps (actions taken to reduce probability of failure)	Risk mitigation steps (actions taken to reduce severity of failure effect or improve early detection of failure)
462	23.06.00.	InSAR surveys	InSAR is the current state-of-the-art satellite platform radar based technique to measure vertical ground elevations and relative elevation changes with time. (CCP 2009) Validation studies have shown that uplifts of 1-3 mm can be reliably and repeatedly measured when sites make use of special corner reflectors for calibration purposes. (CCP 2009)	InSAR may be unable to accurately measure vertical ground elevations and relative elevation changes over time due to high seasonal vegetation growth.	No InSAR surveys reported.	Have any InSAR surveys been conducted?	InSAR unable to accurately measure vertical ground elevations and relative elevation changes over time.	InSAR readings compromised by high seasonal vegetation growth.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor specification and implementation of InSAR surveys.	Avoid areas with high vegetation growth.	Install base pillars to get more accurate readings. Use tiltmeters as an alternative or compliment.
463	23.07.00.	Well monitoring	Well monitoring for CO2 storage seeks confident validation that: - Cement integrity and bond is maintained - Pressure isolation barriers are maintained and functioning - Corrosion is being controlled - The CO2 injection profile is being maintained - Barriers after plug and abandonment provide confidence. (CCP 2009)	Unexpected well failure due to lack of well monitoring.	CO2-EOR operators are required to monitor well flowrates, injection pressures, temperatures and annulus pressures.	Any data acquisition issues?	Failure to detect well leakage.	Insufficient well monitoring.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Review monitoring plan and comprehensiveness of well monitoring.	Work with an experienced monitoring engineer / consultant to prepare a monitoring plan. Determine which wells to monitor and what monitoring tools to use. Implement standard procedures for good monitoring.	Monitor wells. Identify any trends or discrepancies and determine root cause.
464	23.07.00.	General monitoring risks	1. Weather conditions prevent using a monitoring method or retrieving data at a critical point in time 2. Injection site terrain too rugged for surface monitoring 3. Monitoring equipment not properly calibrated 4. Inappropriate monitoring suggests a false alarm for issues that do not exist (CCP 2009) 5. Inappropriate monitoring suggests a false sense of security (CCP 2009) 6. Difficulty of geophysical techniques monitoring below salt caprocks (CCP 2009) 7. Ineffective monitoring 8. Insufficient monitoring 9. Lack or loss of monitoring records 10. Accidental damage or breakdown of custom-made equipment, sensors or tools - repair/replacement delays and irretrievable data loss. 11. Conflicting results from different monitoring techniques. 12. Difficulty of monitoring stacked injection plumes	Ineffective or lack of monitoring can result in missed data. This leads to inadequate engineering control, raising costs and leakage risks; yields insufficient documentation to establish CO2 storage credits, etc.	Problems may exist with getting accurate seismic readings due to presence of salt, gypsum and anhydrite deposits above the reservoir.	Any general monitoring issues?	Unable to track CO2 plume movement and CO2 leakage.	Ineffective, insufficient or lack of monitoring.	Project uncertainty. Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Monitor specification and implementation of monitoring techniques.	Determine MVA requirements. Select reliable monitoring methods. Implement standard procedures for monitoring. Back up data logging.	Analyze monitoring data versus simulation data. Identify any discrepancies. Determine root cause of discrepancies.
465	23.08.00.	Pre-closure monitoring of storage	Processes related to any monitoring undertaken during the operational and closure phase. The extent and requirement for such monitoring activities may be determined by issues such as storage concept, geological setting, regulations, or public pressure. A number of monitoring techniques exist including seismic data, electrical resistance, soil gas and isotopic characteristics.	Monitoring during the operational phase contributes towards the amount and quality of information initially available after closure concerning the behavior and distribution of sequestered CO2.	CELLC monitoring limited to that required for CO2-EOR. SWP will perform additional monitoring to verify successful storage of anthropogenic CO2 from the Arkalan ethanol plant.	Copy of the proposed monitoring plan?	Insufficient or inaccurate information to ensure safe storage of CO2.	Lack of pre-closure monitoring of storage.	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Risk management review of MVA plan.	Preparation and implementation of MVA plan.	Implementation of MVA plan.

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462	23.06.00.	InSAR surveys	1	1	1	1	None	None	None	None	None	None	None	None	None	None	None	None	None	None	
463	23.07.00.	Well monitoring	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Part of ongoing costs.	None	1
464	23.07.00.	General monitoring risks	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Part of ongoing costs.	None	
465	23.08.00.	Pre-closure monitoring of storage	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Part of ongoing costs.	None	1

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466	23.09.00.	Post-closure monitoring of storage	FEPs related to any monitoring undertaken during the post-closure phase. This includes monitoring of parameters related to the long-term safety and performance. The extent and requirement for such monitoring activities may be determined by issues such as storage concept, geological setting, regulations, or public pressure. A number of monitoring techniques exist including seismic data, electrical resistance, soil gas and isotopic characteristics.	Post-closure monitoring will provide information regarding the performance of the sequestration project and may trigger post-closure remedial actions, if necessary.	Post-closure monitoring limited to that required for CO2-EOR rather than MMV CO2 sequestration.	Copy of the proposed post-closure monitoring plan?	Insufficient or inaccurate information to ensure safe storage of CO2.	Lack of post-closure monitoring of storage.	Inability to transfer long-term liability. Penalties for non-compliance with regulations. Liabilities for uncontrolled CO2 migration.	Risk management review of post-closure MVA plan.	Preparation and implementation of post-closure MVA plan.	Implementation of post-closure MVA plan. Prepare procedures for potential remedial action.

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466	23.09.00.	Post-closure monitoring of storage	2	1	1	2	None	None	None	None	None	None	None	None	None	None	None	None	Part of ongoing costs.	None	1