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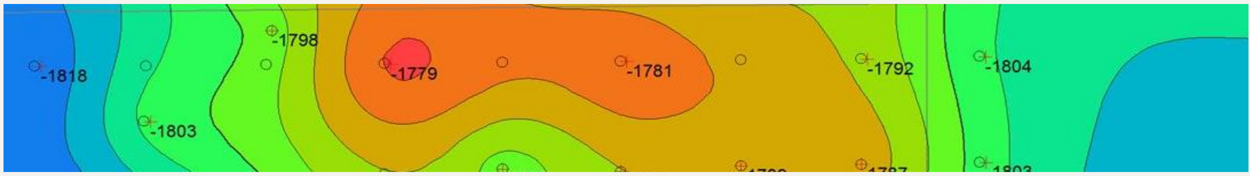

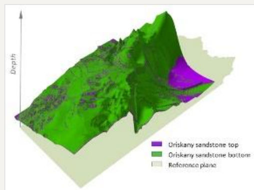

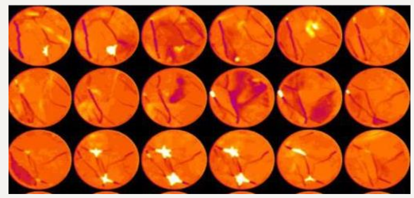


Intermountain West Energy Sustainability & Transitions Initiative: CO_2 Transport and Geologic Storage Modeling Results

October 31, 2022
DOE/NETL-2023/3817

Disclaimer

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ACRONYMS AND ABBREVIATIONS

%	Percent
#	Number
$	Dollars
2011$	Year 2011 dollars
2018$	Year 2018 dollars
2021$	Year 2021 dollars
3-D	Three dimensional
API	American Petroleum Institute
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CCUS	Carbon capture, utilization, and storage
cntrl	Control
CO_2	Carbon dioxide
DOE	Department of Energy
EIA	Energy Information Administration
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
ERR	Emergency and remedial response
FECM	Fossil Energy and Carbon Management
ft	Foot, feet
I-WEST	Intermountain West Energy Sustainability & Transitions
in	Inches
kt	kilotonnes
ktpa	kilotonnes per annum
kW	Kilowatt
LANL	Los Alamos National Laboratory
mD	Millidarcy
mi	Miles
mi^2	Square miles
Min	Minimum
MWhr	Megawatt-hour
NETL	National Energy Technology Laboratory
NPV	Net present value
O&M	Operation and maintenance
OOIP	Original oil-in-place
PISC	Post-injection site care
press.	Pressure
PROV	Province
STB	Stock tank barrel
tonne	Metric ton (1,000 kilograms)
uncert.	Uncertainty
U.S.	United States
USGS	8United States Geological Survey
WAG	Water alternating gas
yr	Year(s)

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1 PERFORMANCE AND COST MODELING OF CO_2 TRANSPORT, CO_2 SALINE STORAGE, AND CO_2-EOR

An analysis was performed for the Intermountain West Energy Sustainability & Transitions (I-WEST) initiative that utilized National Energy Technology Laboratory (NETL)-developed models for carbon dioxide (CO_2) transport, CO_2 saline storage, and CO_2-enhanced oil recovery (EOR) and Los Alamos National Laboratory (LANL)-developed models for CO_2 saline storage and CO_2 pipeline network buildout and optimization. NETL and LANL are national laboratories of the United States (U.S.) Department of Energy (DOE); NETL is part of the Office of Fossil Energy and Carbon Management (FECM), and LANL is part of the National Nuclear Security Administration Laboratories. These models were used to analyze various business cases given changes in technical and financial assumptions for the I-WEST region to see how these assumptions influence CO_2 transport and storage costs. Also, NETL-developed models were used to see the effect of changing oil prices on the viability of CO_2-EOR and the mass of CO_2 stored via CO_2-EOR. This supplementary documentation provides a detailed overview on the models, assumptions, and parameters used in the modeling and example results. It is important to note this document only focuses on the NETL-developed models and analysis approach. An Excel® spreadsheet, "IWEST_CO2 T&S Results_July 2022.xlsm," with results for all cases run from each NETL-developed model is publicly available on NETL's Energy Data eXchange site [1]. Sheets within the Excel® spreadsheet are organized by color to distinguish the result components: CO_2 transport (blue), CO_2 saline storage (green), and CO_2-EOR (orange).

2 CO_2 TRANSPORT PERFORMANCE AND COST MODELING

As previously mentioned, an NETL-developed model for CO_2 transport and LANL-developed model for CO_2 pipeline network buildout and optimization were used to analyze various business cases given changes in technical and financial assumptions for the I-WEST region to see how these assumptions influence CO_2 transport costs. For the purpose of this documentation, aspects of the NETL-developed model are just discussed.

2.1 CO2_T_COM APPLICATION AND OVERVIEW

The FECM/NETL CO_2 Transport Cost Model (CO2_T_COM) was used to depict the impact of CO_2 mass flow rate and pipeline distance on CO_2 transportation cost [2]. Various mass flow rates and pipeline distances were evaluated to illustrate this relationship for the transportation component in the "Pathways to CO_2 Utilization and Storage for the Intermountain West Region " section of the CO_2 storage and utilization chapter of the overall I-WEST report.

CO2_T_COM is a techno-economic model that calculates the revenues and costs (i.e., capital, operating, and financing) associated with transporting liquid CO_2 by pipeline. This Excel®-based model estimates costs for a single point-to-point pipeline, which may have pumps along the pipeline to boost the pressure. A key cost metric from this model is the first-year break-even price (in $/tonne) which is the minimum CO_2 price a pipeline operator can charge a CO_2 source for transporting its CO_2 and still have a viable project. This price is set in the first year of the project, and it escalates at the same rate as all costs to yield a nominal CO_2 price. The nominal CO_2 price is multiplied by the mass of CO_2 transported in a year to give the revenue in that year. The earnings before financing costs, in nominal dollars, are revenues minus capital costs, operating and maintenance (O&M) costs, and taxes. These nominal earnings are discounted by the weighted average cost of capital to give present value earnings that include financing costs. These present value earnings are summed to yield the net present value (NPV) for the project. When the NPV for the project is positive the project is viable, covering all costs including financing costs. The first-year break-even CO_2 price is determined by adjusting the CO_2 price until the NPV of the project is zero. At this price, the pipeline project is viable, but just barely (i.e., the project is breakeven).

The capital and O&M costs of the pipeline are driven by the nominal pipeline diameter and the number of pumps. CO2_T_COM divides the pipeline into equal length segments with a booster pump at the end of each segment except the last segment. Given a CO_2 mass flow rate, pipe segment length, and pressure drop across the pipe segment, CO2_T_COM calculates the minimum inner diameter needed for the pipe. The nominal pipe diameter is a standard pipe diameter that is equal to or greater than the minimum inner pipe diameter. A larger diameter pipeline can transport CO_2 a farther distance before a booster pump is needed, but the larger the diameter of the pipeline, the higher the capital costs of the pipe. CO2_T_COM has a macro that finds the combination of nominal pipeline diameter and number of booster pumps that gives the lowest overall first-year break-even price for CO_2. More detail on the CO2_T_COM can be found in the model's user's manual and overview presentation [3] [4].

2.2 Analytical Approach

As mentioned, CO2_T_COM was used to provide examples of CO_2 transportation cost based on the impact of CO_2 mass flow rate and pipeline distance. There are several key technical and financial inputs within CO2_T_COM, such as pipeline length, CO_2 mass flow rate, and debt and equity costs, for which the user can change to suit their project requirements; however, there are also default values for these inputs within the model. To provide examples of CO_2 transportation cost, certain parameters within CO2_T_COM were changed from their default values (i.e., those values already within the model on NETL's website) to obtain transportation costs for a dedicated pipeline, a single pipeline that transports CO_2 from an individual CO_2 source directly to a single storage site (i.e., site centroid), for various pipeline lengths and CO_2 mass flow rates. Table 1 highlights the modeling matrix used for these transportation cost examples with explanatory text.

All CO_2 prices, revenues and costs are initially calculated in 2011 dollars, the base year of CO2_T_COM. The model has two escalation rates. The first escalation rate escalates all CO_2 prices, revenues and costs from the base year to the first year of the pipeline project (i.e., when construction begins). The second escalation rate escalates all CO_2 prices, revenues and costs from the first year of the project onward. This second escalation rate can be non-zero for an analysis in nominal dollars or zero for an analysis in real or constant dollars.

Table 1. Modeling matrix with explanatory text for CO2_T_COM runs for the transportation cost examples

Parameter Name	Unit	Value	Note
Maximum mass flow rate of CO_2	Million tonnes/yr	0.1, 0.2, 0.3, 0.4, 0.5, 0.6, 0.7, 0.8, 0.9, 1.0, 1.5, 2.0, 2.5, 3.0, 3.5, 4.0, 4.5, 5.0	This value changed from the default values in the model with each mass flow rate run against each pipeline length
Capacity factor	%	85	Default value in the model
Length of pipeline	mi	10, 20, 30, 62, 100, 150, 200, 250, 300, 350, 400, 450, 500	This value changed from the default values in the model with each pipeline length run against each mass flow rate
Change in elevation	ft	0	Default value in the model
Project start year	yr	2018	Default value in the model
Duration of construction	yr	3	Default value in the model
Duration of operations	yr	30	Default value in the model

Parameter Name	Unit	Value	Note
Percent equity (remainder is debt)	%/yr	45	Default value in the model
Cost of equity	%/yr	10.77	This value was changed to the default value in the model for a real dollar analysis
Cost of debt	%/yr	3.91	This value was changed to the default value in the model for a real dollar analysis
Tax rate (effective)	%/yr	25.74	Default value in the model
Escalation rate from base year to project start year	%/yr	2.2	Default value in the model
Escalation rate from project start year and beyond	%/yr	0	This value was changed to the default value in the model for a real dollar analysis

To complete these transportation cost examples, all parameters in Table 1, except maximum mass flow rate of CO_2, capacity factor, length of pipeline, and change in elevation, were incorporated into the 'Main' sheet within the CO2_T_COM. The 'Cases' sheet was then utilized to define different cases with a case comprised of pipeline length, maximum CO_2 mass flow rate, capacity factor, average annual CO_2 mass flow rate (which is calculated as the product of the maximum CO_2 mass flow rate and capacity factor), and elevation change along the pipeline. The parameters featured in Table 1 for these items were incorporated in the 'Cases' sheet. A total of 234 cases were run using the "Process_Cases" macro within the 'Cases' sheet.

2.3 Results Summary

As mentioned above, the "Process_Cases" macro within the 'Cases' sheet in CO2_T_COM was used to derive results for 234 cases. Once the macro was complete, results were featured in the 'Cases' sheet, and the data was pared down to provide the results that would be of interest to the I-WEST initiative for all 234 cases. These results are featured in the 'CO2_T_COM Results' sheet within the Excel® spreadsheet file "IWEST_CO2 T&S Results_July 2022.xlsm" by mass flow rate and then pipeline distance (i.e., smallest to largest) [1]. User inputs (per values given in Table 1) and results in this sheet are provided in Table 2. Example technical and cost results from the 'CO2_T_COM Results' sheet for the 0.1 million tonnes/yr mass flow rate are found in Table 3.

Table 2. Description of columns within 'CO2_T_COM Results' sheet in "IWEST_CO2 T&S Results_July 2022.xlsm"

Model Data	Column	Item	Column	Item
Inputs	A	Case number (#) (determined by the user)	D	Capacity factor (%)
	B	Pipeline length (mi)	E	Average annual mass flow rate that is provided as an input but is a product of the maximum CO_2 mass flow rate and capacity factor (million tonnes/yr)
	C	Maximum CO_2 mass flow rate (million tonnes/yr)	F	Elevation difference (positive for increase along pipeline) (ft)
Results	G	Total mass of CO_2 transported (million tonnes)	W	Total capital costs (million 2018$) which is sum of columns S-V
	H	Minimum inside pipe diameter (in)	X	Fixed O&M pipe costs (million 2018$)
	I	Nominal pipe diameter (in)	Y	Fixed O&M pump costs (million 2018$)
	J	Actual outer pipe diameter (in)	Z	Other fixed O&M costs (million 2018$)
	K	Actual inner pipe diameter (in)	AA	Total fixed O&M costs (million 2018$) which is sum of columns X-Z
	L	Number of pumps (#)	AB	Variable O&M costs (million 2018$)
	M	Maximum required power of each pump (kW)	AC	Total O&M costs which is sum of columns AA and AB (million 2018$)
	N	First-year break-even CO_2 price in base year (2011$/tonne)	AD	Annual fixed O&M pipe costs (million 2018$/yr)
	O	First-year break-even CO_2 price in first year of project (2018$/tonne)	AE	Annual fixed O&M pump costs (million 2018$/yr)
	P	First-year break-even CO_2 price in first year of transport (2021$/tonne)	AF	Annual other fixed O&M costs (million 2018$/yr)
	Q	Net present value of free cash flow (million$)	AG	Annual fixed O&M costs (million 2018$/yr) which is sum of AD-AF
	R	Rate of return (%)	AH	Annual variable O&M costs (million 2018$/yr)
	S	Capital cost of pipeline (million 2018$)	AI	Annual pump energy usage (MWhr/yr)
	T	Capital cost of pumps (million 2018$)	AJ	Annual total O&M costs which is the sum of columns AG and AH (million 2018$/yr)
	U	Other capital costs (million 2018$)	AK	Revenue (million 2018$)
	V	Contingency (million 2018$)		

Table 3. Example technical and cost results for 0.1 million tonnes/yr mass flow rate from 'CO2_T_COM Results' sheet in "IWEST_CO2 T&S Results_July 2022.xlsm"

Maximum CO_2 Mass Flow Rate	Case Number	Pipeline Length	Nominal Pipe Diameter	Number of Pumps	First-year Break-even Price in First Year of Project	Total Capital Costs	Total O&M Costs	Revenue
million tonnes/yr	#	mi	in	#	2018$/tonne	million 2018$	million 2018$	million 2018$
0.1	1	10	4	0	13.81	9.98	8.40	35.22
	2	20	4	0	23.40	17.28	13.17	59.67
	3	30	4	0	33.98	24.58	17.93	84.10
	4	62	4	0	63.67	47.95	33.17	162.36
	5	100	4	0	100.09	75.70	51.27	255.23
	6	150	4	0	148.04	112.21	75.08	377.50
	7	200	4	0	195.97	148.72	98.89	499.72
	8	250	4	0	243.90	185.24	122.70	621.95
	9	300	4	0	291.85	221.75	146.51	744.22
	10	350	4	1	340.25	258.43	171.06	867.64
	11	400	4	1	388.18	294.94	194.87	989.86
	12	450	4	1	436.12	331.45	218.69	1,112.11
	13	500	4	1	484.05	367.96	242.50	1,234.33

3 CO_2 Saline Storage Performance and Cost Modeling

As previously mentioned, NETL- and LANL-developed models for CO_2 saline storage were used to analyze various business cases given changes in technical and financial assumptions for the I-WEST region to see how these assumptions influence CO_2 storage costs. For the purpose of this documentation, aspects of the NETL-developed model are just discussed.

3.1 CO2_S_COM Application and Overview

The FECM/NETL CO_2 Saline Storage Cost Model (CO2_S_COM) was used to evaluate the potential to store CO_2 in saline formations in the I-WEST region [5].

CO2_S_COM is a techno-economic model (Excel®-based) that has a database of geologic formations. It uses geologic data with user-specified injection rates and other design considerations to calculate technical quantities. These technical quantities are used to calculate capital costs and O&M costs. CO2_S_COM is a cash flow model that calculates technical requirements, revenues, and costs from the perspective of an organization operating a CO_2 saline storage project. The objective of the operator is to manage the storage site so that it is profitable. Thus, the operator will charge a CO_2 source a fee for injecting CO_2. This fee is a CO_2 price (in $/tonne of CO_2 injected) and provides the revenue to the operations to offset all costs including capital costs, O&M costs, taxes, costs of complying with regulations, interest and principal payments on debt, and the minimum desired internal rate of return on equity. More detail on the model can be found in the model's user's manual [6].

There have been updates to the CO2_S_COM and its user's manual since its original release in 2014. It is important to note that the analysis featured in the report was performed using a non-public version of the CO2_S_COM, which is planned to be released in the fall 2022 timeframe, so any discussion around the model pertains to this version. Citations reference the publicly available model. Because of the complexity of the model, technical and financial aspects of the model and, if applicable, how they were altered for the analysis will be discussed in tandem.

3.2 Analytical Approach

As mentioned, CO2_S_COM was used to estimate CO_2 storage costs in saline formations. There are several key technical and financial inputs within CO2_S_COM, such as the average annual rate of injection, storage project timelines, and debt and equity costs, for which the user can change to suit their project requirements; however, there are also default values for these inputs within the model. For the I-WEST analysis, certain parameters within CO2_S_COM were changed from their default values (i.e., those values already within the model) to obtain storage costs for four cases, which are explained in detail below, that provide different requirements for monitoring and timing of different aspects of the CO_2 injection process. Table 4 provides the modeling matrix used for this analysis with explanatory text.

CO2_S_COM was designed to mimic the costs anticipated for a CO_2 saline storage project including the activities and costs needed to comply with the Class VI injection well regulations for CO_2 injection wells and Subpart RR of the Greenhouse Gas Reporting Rule which is applicable to Class VI injection wells. At this time, very few projects have obtained Class VI injection well permits. The only Class VI permits that have been issued for projects that are injecting CO_2 are two permits for injection wells in Decatur Illinois that are part of a demonstration project sponsored by FECM/NETL [7, 8]. In the requests for proposals for the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) projects sponsored by FECM/NETL, a commercial-scale CO_2 saline storage operation is defined as one that injects at least 50 million tonnes of CO_2 over a 20-to 30-year time period [9]. Two Class VI injection well permits have been issued by the state of North Dakota (one for the CarbonSAFE project named Project Tundra) but neither project has begun injection [10]. Using the CarbonSAFE definition of a commercial-scale project, there are no commercial-scale CO_2 injection projects operating in the United States [7, 9].

Since commercial-scale CO_2 injection is just beginning in the United States, there is considerable uncertainty regarding the operation and regulatory requirements for these projects. To address this uncertainty, CO2_S_COM was used to evaluate four cases with different assumptions about the requirements for monitoring and timing of different aspects of the CO_2 injection process for each storage formation evaluated. These four cases are intended to provide a range of plausible assumptions and how changing assumptions can affect the cost of CO_2 saline storage.

- **Baseline Case:** In developing the Class VI regulations, the U.S. Environmental Protection Agency (EPA) performed a Pro Forma cost analysis that provided a number of assumptions for different aspects of a CO_2 saline storage project, and many of these assumptions are utilized in the Baseline Case [11] [12] [13]. The Baseline Case also includes several default assumptions in the Class VI regulations. The Pro Forma analysis does not represent regulatory requirements or even guidance, but it does provide a perspective on what could be required for a Class VI project. The assumptions used in the Baseline Case are similar to the baseline assumptions provided in earlier versions of CO2_S_COM that are discussed in NETL's CO_2 Transport and Storage: Quality Guidelines for Energy System Studies [14]. This scenario assumes fairly extensive site monitoring efforts along with 50 years of post-injection site care (PISC).
- **Enhanced Policy Case 1:** The Class VI regulations provide considerable flexibility and recently several states have applied for primacy. At least two states (North Dakota and Wyoming) have obtained primacy for overseeing Class VI injection well permits. These states have passed their own laws and regulations regarding Class VI injection wells. In addition, a number of organizations are proceeding with CO_2 injection projects including the CarbonSAFE projects funded in part by FECM/NETL. Two Class VI injection well permits have been approved in North Dakota, and this recent experience suggests that some of the assumptions in the EPA Pro Forma analysis can be modified. Enhanced Policy Case 1 provides operational assumptions that are more consistent with recent experience. Financial responsibility assumptions are assumed the same as the Baseline Case.
- **Enhanced Policy Case 2:** This case uses the same operational assumptions as Enhanced Policy Case 1 except PISC is reduced to 15 years instead of 50 years. Financial responsibility is still a trust fund, but payment period is 10 years rather than 3 years. The changes are believed to be more consistent with recent experience. Section 3.7

discusses the financial responsibility requirement of the Class VI injection well regulations in more detail.

- **Enhanced Policy Case 3:** Assumptions are the same as Enhanced Policy Case 2 except the financial responsibility instrument is self-insurance, instead of a trust fund, for corrective action, injection well plugging, and PISC and site closure.

To complete this analysis, all parameters in Table 4, except project start year, method chosen to determine monitoring well count, escalation rate from base year to project start year, and tax rate, were incorporated into the 'Cases' sheet within CO2_S_COM. The 'Cases' sheet was then utilized to define the four different cases. The project start year, method chosen to determine monitoring well count, escalation rate from base year to project start year, and tax rate from Table 4 were incorporated in the 'Key_Inputs' sheet. The four cases were run using the "Process_Cases" macro within the 'Cases' sheet for the storage formations in the I-WEST states and states near the I-WEST states.

Table 4. Modeling matrix with explanatory text for CO2_S_COM runs in this analysis

<table>
<tr><th colspan="2">Parameter Group/Name</th><th>Unit</th><th colspan="2">Baseline Case</th><th colspan="2">Enhanced Policy Case 1</th><th colspan="2">Enhanced Policy Case 2</th><th colspan="2">Enhanced Policy Case 3</th><th>Note</th></tr>
<tr><td rowspan="9">Operational</td><td>Project start year</td><td>yr</td><td colspan="2">2018</td><td colspan="2">2018</td><td colspan="2">2018</td><td colspan="2">2018</td><td>Default value in the model</td></tr>
<tr><td>Site screening duration</td><td>yr</td><td colspan="2">1</td><td colspan="2">1</td><td colspan="2">1</td><td colspan="2">1</td><td>Default value in the model; see Section 3.4 below for more information</td></tr>
<tr><td>Site selection & site characterization duration</td><td>yr</td><td colspan="2">3</td><td colspan="2">2</td><td colspan="2">2</td><td colspan="2">2</td><td>Default value changed in at least one case; see Section 3.4 below for more information</td></tr>
<tr><td>Number of sites pre-characterized</td><td>#</td><td colspan="2">4</td><td colspan="2">1</td><td colspan="2">1</td><td colspan="2">1</td><td>Default value changed in at least one case</td></tr>
<tr><td>Permitting & construction duration</td><td>yr</td><td colspan="2">2</td><td colspan="2">1</td><td colspan="2">1</td><td colspan="2">1</td><td>Default value changed in at least one case; see Section 3.4 for more information</td></tr>
<tr><td>Operations duration</td><td>yr</td><td colspan="2">30</td><td colspan="2">30</td><td colspan="2">30</td><td colspan="2">30</td><td>Default value in the model; see Section 3.4 below for more information</td></tr>
<tr><td>PISC & site closure duration</td><td>yr</td><td colspan="2">50</td><td colspan="2">50</td><td colspan="2">15</td><td colspan="2">15</td><td>Default value changed in at least one case; see Section 3.4 below for more information</td></tr>
<tr><td>CO_2 mass flow rate for injection project</td><td>million tonnes/yr</td><td colspan="2">4.3</td><td colspan="2">4.3</td><td colspan="2">4.3</td><td colspan="2">4.3</td><td>Default value in the model</td></tr>
<tr><td>Capacity factor</td><td>%</td><td colspan="2">85</td><td colspan="2">85</td><td colspan="2">85</td><td colspan="2">85</td><td>Default value in the model</td></tr>
<tr><td rowspan="3">Deep Monitoring Wells</td><td colspan="2">Method chosen to determine monitoring well count</td><td colspan="2">Spacing</td><td colspan="2">Spacing</td><td colspan="2">Spacing</td><td colspan="2">Spacing</td><td>Default value in the model</td></tr>
<tr><td colspan="2">Above seal monitoring well</td><td>CO_2 Plume Uncert. Area</td><td>Press. Front Area</td><td>CO_2 Plume Uncert. Area</td><td>Press. Front Area</td><td>CO_2 Plume Uncert. Area</td><td>Press. Front Area</td><td>CO_2 Plume Uncert. Area</td><td>Press. Front Area</td><td>See section 3.6 below for more information on these wells</td></tr>
<tr><td>Well spacing</td><td>mi^2/well</td><td>4</td><td>50</td><td>4</td><td>50</td><td>4</td><td>50</td><td>4</td><td>50</td><td>Default values in the model</td></tr>
</table>

Parameter Group/Name		Unit	Baseline Case		Enhanced Policy Case 1		Enhanced Policy Case 2		Enhanced Policy Case 3		Note
	Min wells - start	#	1	1	1	1	1	1	1	1	Default value in the model
	Min wells - end	#	2	2	2	2	2	2	2	2	Default value in the model
	Max # of wells cntrl*	#	9,999	0	0	0	0	0	0	0	Default value changed in at least one case for CO_2 Plume Uncert. Area
	Fixed well count	#	0	0	0	0	0	0	0	0	Default value in the model
	In reservoir monitoring well		CO_2 Plume Uncert. Area	Press. Front Area	CO_2 Plume Uncert. Area	Press. Front Area	CO_2 Plume Uncert. Area	Press. Front Area	CO_2 Plume Uncert. Area	Press. Front Area	See Section 3.6 below for more information on these wells
	Well spacing	mi^2/well	4	50	4	50	4	50	4	50	Default values in the model
	Min wells - start	#	1	1	1	1	1	1	1	1	Default value in the model
	Min wells - end	#	2	2	2	2	2	2	2	2	Default value in the model
	Max # of wells cntrl*	#	0	0	0	0	0	0	0	0	Default value in the model
	Fixed well count	#	0	0	0	0	0	0	0	0	Default value in the model
	Dual completed monitoring well		CO_2 Plume Uncert. Area	Press. Front Area	CO_2 Plume Uncert. Area	Press. Front Area	CO_2 Plume Uncert. Area	Press. Front Area	CO_2 Plume Uncert. Area	Press. Front Area	See Section 3.6 for more information on these wells
	Well spacing	mi^2/well	4	50	4	50	4	50	4	50	Default values in the model
	Min wells - start	#	2	1	2	1	2	1	2	1	Default values in the model
	Min wells - end	#	2	2	2	2	2	2	2	2	Default value in the model
	Max # of wells cntrl*	#	9,999	4	-1	0	-1	0	-1	0	Default value changed in at least one case
	Fixed well count	#	0	0	0	0	0	0	0	0	Default value in the model

Parameter Group/Name		Unit	Baseline Case	Enhanced Policy Case 1	Enhanced Policy Case 2	Enhanced Policy Case 3	Note
Surface Area and 3-D Seismic	Maximum surface area for CO_2 plume uncert. area for a project (project CO_2 injection rate is reduced to force CO_2 plume uncert. area to equal this value)	mi^2	1,000	1,000	1,000	1,000	Default value in the model
	3-D seismic cost	$/mi^2$	70,307	70,307	70,307	70,307	Default value in the model
Financial Variables	Escalation rate from base year to project start year	%/yr	1.3	1.3	1.3	1.3	Default value in the model
	Escalation rate from project start year and beyond	%/yr	0	0	0	0	This value was changed to the default value in the model for a real dollar analysis
	Percent equity (remainder is debt)	%	45	45	45	45	Default value in the model
	Minimum desired internal rate of return on equity (real)	%/yr	10.77	10.77	10.77	10.77	This value was changed to the default value in the model for a real dollar analysis
	Interest rate on debt (real)	%/yr	3.91	3.91	3.91	3.91	This value was changed to the default value in the model for a real dollar analysis
	Tax rate (effective)	%/yr	25.74	25.74	25.74	25.74	Default value in the model

Parameter Group/Name		Unit	Baseline Case	Enhanced Policy Case 1	Enhanced Policy Case 2	Enhanced Policy Case 3	Note
Financial Responsibility	Density of wells needing corrective action	well/mi^2	0.25	0.25	0.25	0.25	Default value in the model
	Financial responsibility instrument for corrective action, injection well plugging, and PISC & site closure		Trust fund	Trust fund	Trust fund	Self-insurance	Default value changed in at least one case; see Section 3.7 below for more information
	Project year when payments into trust fund begin	yr	5	3	3	3	Default value changed in at least one case
	Duration of payments into trust fund	yr	3	3	10	10	Default value changed in at least one case

*Note: -1 for "Max # of wells cntrl" indicates maximum number of monitoring wells equals number of injection wells

3.3 Geologic Data

CO2_S_COM has a geologic database with 314 potential storage formations. Each potential storage formation is characterized by the following geologic data: surface area, depth to the top of the formation, thickness, porosity and permeability of the formation, and salinity. The storage formations were defined to be big enough to accommodate many saline storage projects, but also small enough so that the geologic data is representative of the entire storage formation. The lithology and depositional history of the storage formation are also recorded. The temperature and pressure in the formation are noted if known. Of the 314 storage formations, 121 are in I-WEST states and 104 are in states near I-WEST states.

3.4 Design Considerations

This section discusses key design considerations for a CO_2 saline storage project. Table 4 summarizes the parameters used in this analysis, which are discussed below and referenced in this section. Important design variables are the average annual rate of CO_2 injection and the maximum daily rate of injection. In this analysis, as indicated in Table 4, it is assumed for all cases that the average annual rate of injection is 4.3 million tonnes which is the mass of CO_2 that could be captured from a typical supercritical coal-fired power plant operating at 85% capacity factor with 90% capture efficiency. Assuming the CO_2 storage site also operates at 85% capacity factor, the maximum rate of injection is 13,900 tonne/day which is 5.06 million tonnes/yr on an annualized basis. For all cases, the duration of injection is assumed to be 30 years, also indicated in Table 4.

CO2_S_COM assumes a CO_2 saline storage project is conducted in six stages:

- Stage 1 - Site Screening: The developer collects existing data and uses it to select one or more sites for pre-characterization. As indicated in Table 4, the duration of this stage was assumed to be 1 year for all cases.
- Stage 2 - Site Selection & Site Characterization: The developer pre-characterizes one or more sites with the pre-characterization involving installation of one stratigraphic test well and two lines of two-dimensional seismic on each site. One of the sites is selected for a full characterization which involves the installation of an additional stratigraphic test well and a full three-dimensional (3-D) seismic survey of the anticipated maximum extent of the CO_2 plume area with uncertainty (see discussion in Section 3.5 below). The injection design and permit documents are prepared by the end of this stage which includes the monitoring program, corrective action program, and emergency and remedial response (ERR) plan. The operator also obtains site access permissions and pore-space rights from landowners. As indicated in Table 4, the number of sites pre-characterized were assumed to be 4 for the Baseline Case and 1 for Enhanced Policy cases 1-3. The duration of this stage was assumed to be 3 years for the Baseline Case and 2 years for Enhanced Policy cases 1-3. When the Class VI regulations were implemented, it was thought that several sites might need to be pre-characterized. However, recent experience suggests that developers of CO_2 saline storage sites are comfortable that they can find suitable storage sites without extensive pre-

characterization. This notion is anticipated to reduce the time needed to complete this stage.

- Stage 3 - Permitting & Construction: The operator submits the Class VI permit application to the governing regulatory agency. After preliminary approval, the injection wells are installed, and the operator resubmits any permit documents that need to be updated with new data obtained from the injection wells. The stratigraphic test wells installed earlier may be converted to injection wells or deep monitoring wells. The operator also installs surface equipment (roads, buildings, CO_2 pipes from the source, high-grade meters to measure the mass of CO_2 coming onto the site, pipelines carrying CO_2 from the metering station to the injection wells). With the newly installed monitoring equipment, samples are collected to establish ambient or background conditions before injection begins. In this analysis, it is assumed that the two stratigraphic test wells are completed as deep monitoring wells. As indicated in Table 4, the duration of this stage was assumed to be 2 years for the Baseline Case and 1 year for Enhanced Policy cases 1-3. The initial Class VI permits took time to receive approval because the permitting process was new. As interest in CO_2 saline storage increases, the government agencies overseeing the permitting process are making efforts to reduce the time needed to obtain a permit. Hence the duration of this stage was reduced from 2 to 1 year for this analysis.
- Stage 4 – Operations: Injection of CO_2 begins and continues for as long as the operator has designed the project. At the end of operations, CO_2 injection stops, and the injection wells are plugged. During operations, the operator performs monitoring according to the monitoring program detailed in the Class VI permit and reports monitoring results to the governing regulatory authority. As discussed previously and indicated in Table 4, the duration of this stage was assumed to be 30 years.
- Stage 5 –PISC & Site Closure: After CO_2 injection stops, the Class VI regulations require the operator to continue monitoring for leaks until the CO_2 plume has stabilized and the pressures in the storage formation have subsided. PISC ends when the governing regulatory authority issues a finding of non-endangerment. At this time, all monitoring equipment is removed as well as other unneeded equipment and the site is closed. The duration of PISC is highly uncertain since PISC is far in the future and no commercial-scale CO_2 injection project has reached this stage. The default in the Class VI regulations is 50 years, but this value is negotiable. The Class VI permit for Project Tundra in North Dakota specifies a PISC period of 10 years [15, 16]. Other states are considering PISC periods of 15 years. Recent work by the FECM/NETL-sponsored National Risk Assessment Partnership, suggests that risks of leakage and induced seismicity are highest during operations and decline rapidly after injection ceases, so the 10-to 15-year PISC periods are consistent with this work [17]. In the I-WEST analysis, PISC was assumed to be 50 years for the Baseline Case and Enhanced Policy Case 1 and 15 years for Enhanced Policy cases 2 and 3, as indicated in Table 4.
- Stage 6 – Long-term Stewardship: In CO2_S_COM, it is assumed that after the site is closed, long-term responsibility for the site is turned over to the state and any future issues are addressed from a trust fund operated by the state. In CO2_S_COM, the trust

fund is financed by fees based on the mass of CO_2 injected that are collected by the state during injection of CO_2.

3.5 Key Technical Calculations

CO2_S_COM calculates several technical quantities that are used to calculate costs and often drive the cost of CO_2 saline storage for a project.

- CO_2 plume area: To run the CO2_S_COM, the user specifies a maximum CO_2 injection rate, an average annual CO_2 injection rate, and duration of injection. As discussed in Section 3.3, the geologic database provides the depth to the top of the formation, thickness, porosity, and permeability. Temperature and pressure in the storage formation are in the database, if known. If not known, the temperature and pressure are calculated from gradient data and the depth. The model uses the temperature and pressure in the storage formation to calculate the density of CO_2 in the formation. The geologic database also provides the lithology and deposition history, and these are used to estimate storage coefficients per a study by the IEA Greenhouse Gas R&D Programme [18]. The storage coefficient depends on whether or not the CO_2 is injected into a formation with an enclosure at the seal. If the interface with the seal forms a dome or anticline, the CO_2 can migrate upward into the enclosure, forcing some brine out with the CO_2 being trapped. Alternatively, the interface between the storage formation and seal can be relatively flat and the CO_2 will tend to spread out across this interface, although this movement is very slow after injection stops. The storage coefficients for domes and anticlines are higher than for flatter structures. However, the occurrence and geometry (e.g., area, thickness) of domes and anticlines are poorly understood. For this analysis, storage coefficients for flatter structures were used. With the average annual CO_2 injection rate, duration of injection, density of CO_2, thickness, porosity, and storage coefficient, CO2_S_COM calculates the area of the CO_2 plume.
- CO_2 plume uncertainty area: The CO_2 plume area can be interpreted as a "best estimate" of the extent of the CO_2 plume at the end of injection. However, there is significant uncertainty in this estimate because there is much that is not known about the subsurface geology. The estimated CO_2 plume area may be too high or too low. Also, the positioning of the actual plume may be different from the estimate even if the estimated area encompassed by the plume turns out to be similar to the actual CO_2 plume area. To address these uncertainties, a CO_2 plume uncertainty area is calculated by multiplying the CO_2 plume area by a CO_2 plume uncertainty multiplier which was 1.75 for this analysis (default in the model). In CO2_S_COM, the CO_2 plume uncertainty area is used as the area where pore space rights and land use access need to be secured and paid for. It is worth noting that depending on the site geology and mass of CO_2 injected, the CO_2 plume area and CO_2 plume uncertainty area can be very large, covering tens to hundreds of square miles. So, CO_2 storage projects can have very large footprints.
- Pressure front area: The injection of CO_2 into a subsurface storage formation will increase the pressure in the formation. Pressure increases will propagate faster and further than the CO_2 plume. To account for the area with elevated pressure, CO2_S_COM calculates a pressure front area by multiplying the CO_2 plume uncertainty

area by a pressure front multiplier. The pressure front multiplier is site specific but can be quite large. A value of 10 was used in this analysis (default value in the model), which results in a very large pressure front area.

- Number of injection wells: CO2_S_COM calculates the number of injection wells needed in a two-step process. First, the model has several algorithms for calculating the maximum CO_2 injection rate that the storage formation can sustain, which is denoted q_{form} for this discussion. These algorithms all depend on the permeability, thickness, and the maximum pressure allowed in the formation. The Class VI injection well regulations restrict the highest pressure at the injection well to be less than 90% of the fracture pressure for the storage formation; so, the largest pressure increase is 90% of the fracture pressure minus the ambient pressure in the formation. For this analysis, the algorithm developed by Law and Bachu (default in the model) was used to estimate q_{form} [19]. Second, the model provides a limit on the maximum injection rate that the injection well can sustain based on fluid mechanics of CO_2 flowing in the well, which is denoted q_{w_mech} for this discussion. Based on discussions with reservoir engineers involved in CO_2 injection demonstration projects for NETL, a maximum value of 3,660 tonnes of CO_2 injected per day was used in this analysis. The maximum CO_2 mass flow rate in a well (denoted q_{well} in this discussion) is the lower of q_{form} and q_{w_mech}. The maximum rate of CO_2 injection for the CO_2 injection project (13,900 tonne/day for this analysis) is divided by q_{well}, and the result is rounded up to the nearest integer. This gives the number of active injection wells that must always be available to accommodate the design maximum flow rate of CO_2 for the CO_2 storage project. Since injection wells must be taken offline periodically for testing and maintenance, backup injection wells will be needed. CO2_S_COM multiplies the number of active wells by 1.1 (a 10% increase) and rounds this value up to the nearest integer to calculate the number of injection wells needed for the project. This results in at least one backup injection well being implemented for each CO_2 storage project.
- Maximum CO_2 storage capacity for the storage formation: CO2_S_COM determines the maximum storage capacity of the storage formation. The user needs to input the fraction of the storage formation that can be used for CO_2 storage projects. It is assumed that some parts of the storage formation, such as urbanized areas, will not be available for CO_2 storage. In this analysis, it was assumed that 80% of the storage formation can be used for storage (default in the model). CO2_S_COM calculates the pore space available for storage by multiplying the surface area of the formation by the thickness, porosity, storage coefficient, and fraction of the formation available for storage. This pore space is multiplied by the density of CO_2 in the formation to give the maximum storage capacity. If this maximum storage capacity is divided by the mass of CO_2 injected by each CO_2 storage project (129 million tonnes in this analysis), this result rounded down to the nearest integer gives the number of storage projects that could be implemented in the storage formation. It should be noted this is equivalent to packing the storage projects so close together that the CO_2 plume areas for each project just touch with no gaps between the plumes. This is not realistic, but it does define a maximum storage capacity.

- Effective storage capacity based on number of injection projects that can operate simultaneously: A more relevant measure of storage capacity is the capacity associated with injection projects that are operating simultaneously in the injection formation. At least two constraints will limit the number of injection projects:
  - First, the CO_2 plume uncertainty area is used to define the area where a CO_2 injection operation obtains pore space rights. In CO2_S_COM, it is assumed that the pore space cannot be used for two injection projects, at least not for two injection projects operating simultaneously. At best, the most CO_2 storage projects that can operate simultaneously is the maximum storage capacity estimated previously multiplied by the inverse of the CO_2 plume uncertainty multiplier, denoted f_{plun}. In this analysis, the CO_2 plume uncertainty multiplier was 1.75, so its inverse f_{plun}, is 0.57.
  - Second, a single injection project will cause pressures to be elevated over the pressure front area. Multiple injection projects that are simultaneously injecting CO_2 into the same storage formation will have to be spaced far enough apart that their pressure fronts do not significantly interfere with each other. In a study by Teletzke et al. [20], a geologic model was constructed of a basin using a reservoir simulation model. Multiple injection wells were installed on a grid in the basin and CO_2 was injected in each well. The model was used to estimate the fraction of a storage formation that could be used for simultaneous CO_2 injection. The formation was assumed to be homogeneous. The permeability of the formation was varied, additional model runs were executed, and the influence of pressure on the wells was investigated. Using the results of the simulations, a pressure interference factor (Equation 1) was developed that depended on permeability. This permeability-based pressure interference factor varies between 0 and 1 and expresses the fraction of a storage formation that can support wells simultaneously injecting CO_2 with minimal pressure management activities.

$$f_{press_{adj}} = 0.065 \cdot \left(\frac{0.8}{\left(1 + \left(\frac{10{,}000}{k^2}\right)\right)} \right)$$

Equation 1

Where:

f_{press_adj} = permeability-based pressure interference factor (dimensionless)

k = average permeability (mD)

Error! Reference source not found. illustrates how the pressure adjustment f actor varies with permeability. In this analysis, the pressure adjustment factor was calculated for each storage formation.

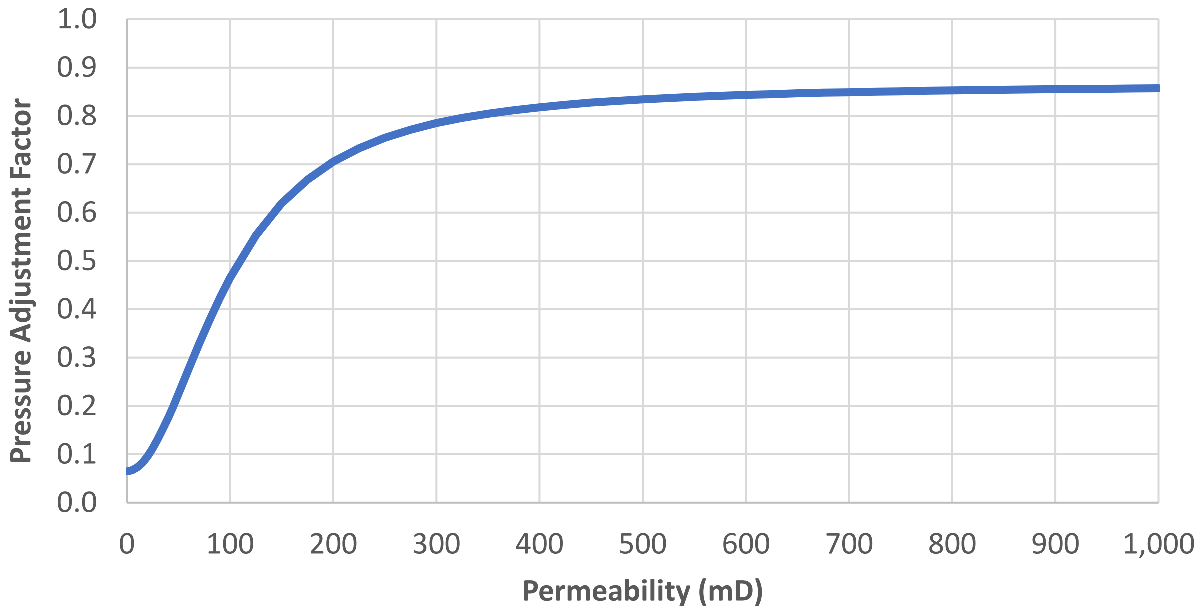

Figure 1. Pressure adjustment factor as a function of permeability

- In this analysis, a storage capacity reduction factor (f_{cap_reduc}) was calculated equal to the minimum of f_{plun} or f_{press_adj}. The maximum CO_2 storage capacity was multiplied by this storage capacity reduction factor to give the effective CO_2 storage capacity available for storage projects injecting simultaneously into the same storage formation. The effective CO_2 storage capacity was divided by the CO_2 injected by a single storage project (129 million tonnes in this analysis) and this result was rounded down to the nearest integer to give the number of CO_2 storage projects that can be implemented simultaneously in the storage formation. If this number was 0, it was set to 1, since it was assumed one CO_2 storage project could be implemented.

3.6 Monitoring Program

CO2_S_COM provides many technology options for costing out a monitoring program to satisfy the requirements of the Class VI regulations and Subpart RR requirements. In this analysis, the monitoring program was assumed to consist of the following technologies:

- Deep monitoring wells: Within CO2_S_COM, above seal, in reservoir, and dual completed monitoring wells can be modeled within the CO_2 uncertainty area and pressure front area using either a fixed well count or well spacing. Above seal wells are drilled just above the seal formation. Total depth is based on the top of a reservoir formation per the model's geologic database less 200 ft thickness for the seal formation. Providing direct sampling of the storage reservoir, in reservoir wells are drilled into and completed in the storage reservoir. In CO2_S_COM, these wells are drilled halfway through the storage reservoir. Dual completed wells are those completed in reservoir and above seal thus sampling both horizons. In their analysis, EPA recommended dual completing wells because it will reduce drilling costs [13]. For the analysis in this report, monitoring wells were dual completed. See Table 4 for the assumptions on monitoring wells used in the analysis.

- 3-D seismic surveys: CO2_S_COM provides costs for acquiring 3-D seismic data. The total cost of 3-D seismic is based on the $/mi^2 over which 3-D data is acquired plus a cost for processing field data which is represented as a percentage of the survey cost. For this analysis, a cost of $70,307/mi^2 was used for a survey and 10% was used as the processing fee; both are the defaults in the model. The survey cost is based on conversations with industry experts, but this cost can change based on application of different technology, improved technology, or better field logistics. During three of the CO_2 storage project stages, 3-D seismic data will be acquired. A user can determine the recurring period for this acquisition within CO2_S_COM which will determine the number of occurrences per stage. In this analysis, a 3-D seismic survey is performed once over the anticipated full extent of the CO_2 plume uncertainty area during site characterization to help characterize the geology. During operations and PISC, a 3-D seismic survey is performed every 5 years covering the area of the CO_2 plume uncertainty area at the time of the survey. These surveys are intended to help track the evolution of the CO_2 plume. Although the same recurrence period was used for PISC as for operations, it may not be necessary to acquire 3-D seismic data as frequently during PISC, so a lower number than 5 years may be more reasonable.
- Groundwater monitoring wells: The purpose of groundwater monitoring wells is to monitor the quality of groundwater that can serve as a source of drinking water. These wells also collect data to determine the flow of groundwater. These monitoring wells are used to collect evidence of leaks of CO_2 or brine into the groundwater. Within CO2_S_COM, the number of groundwater monitoring wells is tied to the number of injection wells. In this analysis, there is one groundwater monitoring well drilled per injection well, which is the default in the model.
- Vadose zone monitoring wells: The vadose zone is the area between the land surface and the water table. This well is used to sample soil gas in the vadose zone and the samples are analyzed for CO_2 concentrations in the soil gas. Elevated CO_2 concentrations could indicate a leak has occurred. Like the groundwater monitoring well, the number of vadose zone monitoring wells is tied to the number of injection wells within CO2_S_COM. In this analysis, there is one vadose zone well drilled per injection well, which is the default in the model.
- Eddy covariance monitoring: Eddy covariance towers provide near-surface atmospheric monitoring of CO_2 concentrations in ambient air. Within CO2_S_COM, a user can provide a one-time cost for an Eddy covariance tower, which is on a $/site basis, as well as the number of sites. This one-time cost occurs during the site selection and site characterization stage of the project, and the user has the ability to determine how often it occurs during that time. For this analysis, the Eddy covariance cost was $70,000/site and the number of sites was 5 (both are defaults in the model).

- Surface air monitoring around surface equipment: CO2_S_COM provides costs for equipment to monitor for CO_2 leaks around surface equipment, such as meters, joints, flanges, and well heads. For this analysis, it was assumed that CO_2 leakage detection would occur periodically during operations and cost $10,000 per year in base 2008 dollars.

3.7 Financial Responsibility

The Class VI injection well regulations require the saline storage operator to provide financial assurance or financial responsibility for covering the cost of four aspects of CO_2 saline storage:

- Corrective action: Wells that pose a threat to an underground source of drinking water or lack high-quality cement documentation are required to go through corrective action in order to prevent CO_2 leakage. The focus is typically on deep legacy wells that penetrate the cap rock into the storage formation and could provide a leakage pathway if the well was not correctly plugged and abandoned. Corrective action is part of the area of review plan submitted upon application for a Class VI permit. For the analysis, it was assumed that legacy wells occur at a rate of 0.25 well/mi^2 across the pressure front area (the default in the model) which means one well per 4 mi^2 will require corrective action. As far as financial responsibility, the model allows the user to select any of the options available (mentioned below) to cover costs. As mentioned in Table 4, a trust fund was used for the Baseline Case and Enhanced Policy cases 1-2 and self-insurance for Enhanced Policy Case 3.
- Injection well plugging: Once injection is complete, the injection wells will require plugging. EPA provides requirements on how to properly plug an injection well in order to protect underground sources of drinking water. CO2_S_COM allows the user to select any of the financial responsibility options available (mentioned below) to cover costs. As indicated in Table 4, a trust fund was used for the Baseline Case and Enhanced Policy cases 1-2 and self-insurance for Enhanced Policy Case 3.
- PISC and site closure: This aspect of a CO_2 storage project involves the tasks for monitoring the CO_2 plume after injection. The goal is to observe pressure decline in the injection formation and the movement of CO_2 to stabilize so that the regulatory agency can issue a finding of non-endangerment. The site can then be closed. In CO2_S_COM, the user can select trust fund, escrow account, or self-insurance as financial instruments to cover this aspect of financial responsibility. As indicated in Table 4, a trust fund was used for the Baseline Case and Enhanced Policy cases 1-2 and self-insurance for Enhanced Policy Case 3. As discussed in Section 3.4, the duration of PISC is 50 years for the Baseline Case and Enhanced Policy Case 1 and 15 years for Enhanced Policy cases 2 and 3.
- Emergency and remedial response (ERR): An owner or operator of a CO_2 storage project must provide an ERR Plan that discusses ways that underground sources of drinking water could be impacted by leaks from the CO_2 storage site and how such leaks would be addressed. The operator of the CO_2 storage project must also provide a mechanism for paying for costs arising from such leaks. Within CO2_S_COM, ERR is covered by an insurance policy with the premium paid on each tonne of CO_2 injected. This cost is

applied during all years of the operations stage. For this analysis, $0.75/tonne/yr was used which is the default in the model.

The Class VI injection well regulations provide several financial instruments that can be used to demonstrate financial responsibility. CO2_S_COM implements several of these financial instruments: letter of credit, trust fund, escrow account, insurance, and surety bond. For this analysis, the cost of corrective action, injection well plugging, and PISC and site closure are covered by either a trust fund or self-insurance depending on the case. As mentioned above, ERR is assumed to be covered by an insurance policy for all cases with the insurance policy funded by a payment to the insurance company during each year of CO_2 injection.

3.8 CASH FLOWS AND FIRST-YEAR BREAK-EVEN CO_2 PRICE

As noted above, CO2_S_COM is a cash flow model that calculates revenues and costs from the perspective of an organization operating a CO_2 saline storage project. The objective of the operator is to manage the storage site so that it is profitable.

All costs and revenues are provided in the base year of 2008. CO2 _S_COM provides two escalation rates. The first escalation rate is used to escalate costs and revenues to the first year of the project (not the first year of CO_2 injection). In this analysis, the first year of the project was assumed to be 2018, default in the model. This second escalation rate can be set to zero for a real or constant dollar analysis, which is what was done for this effort. For a real or constant dollar analysis the interest rate on debt and the minimum desired internal rate of return on equity must be selected to be consistent with an escalation rate of zero.

In CO2_S_COM, the user selects a price for CO_2 in the first year of the project. CO2_S_COM multiplies the mass of CO_2 injected each year by the CO_2 price to generate revenues in each year. Revenues are generated in real dollars in the base year, real dollars in the first year of the project, and escalated or nominal dollars.

CO2_S_COM calculates capital and O&M costs for almost 500 discrete items, and these are posted in the appropriate years in real base year dollars. These costs are summed to give cash flows of capital costs and O&M costs in real base year dollars. CO2_S_COM also provides cash flows in real dollars for the first year of the project and nominal dollars. The capital cost cash flows are totaled by different categories for tax purposes. For each category, the appropriate depreciation schedule is applied to depreciate the capital expenses. Depreciation is done with nominal cash flow dollars.

If a trust fund is used to cover some or all financial responsibility costs, then CO2_S_COM calculates the payments needed into the trust fund and withdrawals from the trust funds in later years to pay for items covered by the trust fund. CO2_S_COM allows the user to select the year when payments into the trust fund begin (it should be before injection begins) and the duration of payments. The Class VI regulations have a default pay in period of 3 years, but this payment period is negotiable.

CO2_S_COM calculates the amount of debt needed in each year along with the interest payments and principal payments on debt. CO2_S_COM uses debt (if needed) to cover costs in all years through the end of operations but not during PISC and site closure. It is assumed that expenses incurred during PISC and site closure are paid either by withdrawals from the trust fund or from equity. CO2_S_COM uses a cash sweep to pay off the principal on debt.

CO2_S_COM calculates tax-based earnings as revenues plus withdrawals from the trust fund minus depreciated capital costs, O&M costs, interest on debt, and payments into the trust fund. Carry-over losses from previous years are also considered. The tax-basis earnings are used to calculate federal corporate income taxes as well as state and local taxes.

CO2_S_COM then calculates the net cash flow to owners (i.e., equity investors) in each year as revenues, withdrawals from the trust fund, and debt proceeds minus capital costs, O&M costs, interest payments on debt, principal payments on debt, payments into the trust fund, and taxes. The net cash flow to owners is calculated in nominal dollars.

The net cash flow to owners is discounted by the minimum desired internal rate of return on equity to give present value cash flow to owners. This present value cash flow is summed to give the NPV for the project. If NPV is greater than zero, then the price set for CO_2 in the first year of the project is high enough to cover all costs, including financing costs, and the saline storage project is viable. If NPV is less than zero, then the first-year CO_2 price is too low and will not generate sufficient revenues to cover costs. In this instance, the saline storage project is not viable. If NPV equals zero, then the first-year CO_2 price is sufficient to cover all costs, including financing costs, so the saline storage project is viable, but just barely. This first-year CO_2 price is an extremely useful benchmark and is called the first-year break-even CO_2 price in the CO2_S_COM since this is the CO_2 price where the saline storage project is breakeven. The first-year break-even CO_2 price is the lowest price the storage project operator can charge and still have a viable project. Because the first-year break-even CO_2 price is so useful, CO2_S_COM includes a macro that will determine this CO_2 price (rounded up to the nearest penny).

3.9 RESULTS SUMMARY

As mentioned above, the "Process_Cases" macro within the 'Cases' sheet in CO2_S_COM was used to derive results for four cases. Once the macro was complete, results were featured in the 'Cases' sheet, and the data was pared down to provide the results that would be of interest to the I-WEST initiative for all four cases. These results are featured in the Excel® spreadsheet file "IWEST_CO2 T&S Results_July 2022.xlsm" [1]. Each case has its own results sheet named appropriately: CO2_S_COM Baseline Case Results, CO2_S_COM EP Case 1 Results, CO2_S_COM EP Case 2 Results, and CO2_S_COM EP Case 3 Results. Within each of these cases sheets, columns A through L provide results for input into SimCCS [21], while columns O through AR provide context to the results in columns A through L as well as other data that may be of interest. Storage formations are divided into two groups, those within I-WEST states and those in the states near the I-WEST states. Within each group, the storage formations are sorted by state and then from low to high first-year break-even CO_2 price in 2018$/tonne. Table 5 provides a description on each column within the results sheets. Example technical and cost results from the 'CO2_S_COM Baseline Case Results' sheet is found in Table 6.

Table 5. Description of columns within each case-specific sheet in "IWEST_CO2 T&S Results.xlsm"

Data	Column	Item	Column	Item
SimCCS Inputs	A	Number of the storage formation in the geologic database used for this analysis (#)	G	Individual well injection rate (million tonnes/yr); not calculated in CO2_S_COM
	B	Name of the storage formation including the state where the storage formation is located	H	Injection fixed capital cost (million$); not calculated in CO2_S_COM
	C	Storage capacity for the storage formation; this is the realistic or effective storage capacity for the storage formation where multiple storage projects are operating simultaneously (million tonnes)	I	Injection fixed O&M cost (million $/yr); not calculated in CO2_S_COM
	D	Total unit cost which is the first-year break-even CO_2 price (2018$/tonne)	J	Injection variable O&M cost ($/tonne); not calculated in CO2_S_COM
	E	Site-wide fixed capital cost (million$); not calculated in CO2_S_COM	K	Longitude of the centroid of the storage formation (degrees)
	F	Site-wide fixed O&M cost ($/yr); not calculated in CO2_S_COM	L	Latitude of the centroid of the storage formation (degrees)

Context and Results	O	Number assigned to each storage formation in the original geologic database; this is also the number assigned to each storage formation in the shape files for all the storage formations (#) The geologic database used for this analysis has the storage formations in a different order from the order in the original geologic database in CO2_S_COM. The numbers assigned to storage formations in this analysis are different from the number assigned to the same storage formations in the original geologic database.	AD	CO_2 injected by each injection project which is 129 million tonnes for most storage formations (million tonnes)
	P	Name of the storage formation without the state appended	AE	Average annual rate of CO_2 injected by each active injection well (million tonnes/yr)
	Q	State where the storage formation is located	AF	Average annual rate of CO_2 injection for the injection project (4.3 million tonnes/yr for most storage formations)
	R	Indicates the I-WEST status of the storage formation with 1 indicating the storage formation is in an I-WEST state and 2 indicating the storage formation is in a state near I-WEST states (#)	AG	First-year break-even CO_2 price (2018$/tonne). These values are the same as those in Column D.
	S	Surface area of the storage formation (mi^2)	AH	Total real capital and O&M costs divided by the mass of CO_2 injected to provide a unit total cost. This column is the sum of the values in columns AI and AJ. (2018$/tonne)

Data	Column	Item	Column	Item
Context and Results	T	Depth to top of storage formation (ft)	AI	Total real capital costs divided by the mass of CO_2 injected to provide a unit capital cost (2018$/tonne)
	U	Thickness of storage formation (ft)	AJ	Total real O&M costs divided by the mass of CO_2 injected to provide a unit O&M cost (2018$/tonne)
	V	Porosity of storage formation (%)	AK	Fraction of storage formation available for storage projects, which is 80% for all storage formations (%)
	W	Permeability of storage formation (mD)	AL	Maximum number of injection projects in formation if CO_2 plume areas are packed with no gaps (#)
	X	Storage coefficient (%)	AM	Average rate of CO_2 injection into the formation if injection projects are packed together (million tonnes/yr)
	Y	Duration of injection which is 30 years for all storage formations	AN	Maximum storage capacity if injection projects are packed together (million tonnes)
	Z	CO_2 plume area (mi^2)	AO	Storage capacity reduction factor that includes pressure and other constraints that limit the number of simultaneously injecting projects (dimensionless)
	AA	CO_2 plume uncertainty area (mi^2)	AP	Maximum number of injection projects in formation that can inject simultaneously (#)
	AB	Number of active injection wells needed for each injection project (#)	AQ	Average rate of CO_2 injection per formation for CO_2 projects that can inject simultaneously (million tonnes/yr)
	AC	Total number of injection wells for each injection project (#). CO2_S_COM uses the maximum daily CO_2 injection rate to determine the number of active injection wells that are needed. CO2_S_COM assumes these wells will need to be taken offline periodically for maintenance and testing. As such, CO2_S_COM assumes at least one additional injection well is needed for each injection project so that the number of active injection wells will be available at all times barring an issue that causes multiple injection wells to go offline simultaneously	AR	CO_2 storage capacity of the storage formation based on the number of injection projects that can be operated simultaneously (million tonnes). These values are the same as those in Column C.

There are several important things to note about the results from columns A through L. The storage capacity is the maximum CO_2 that can be stored in the entire storage formation over the period of injection (30 years in this analysis). The storage formation can accommodate multiple CO_2 injection projects. When multiple CO_2 injection projects are operating, the pressure increase from one project can increase pressures at nearby CO_2 injection projects, but the pressures at each injection well are required to be less than 90% of the fracture pressure. Thus, there is a limit to the number of injection projects that can be operated simultaneously keeping the pressures within the required limits. CO2_S_COM estimates the number of CO_2 injection projects that can be implemented simultaneously while keeping the pressures at acceptable levels. This number of injection projects was used to calculate the storage capacity presented in Column C.

Table 6. Example technical and cost results for Baseline Case from 'CO2_S_COM Baseline Case Results' sheet in "IWEST_CO2 T&S Results_July 2022.xlsm"

Unique ID	Storage Formation Name and State	Storage Capacity	Total Unit Cost	CO_2 Plume Area	Total Real Costs per Tonne CO_2 Injected
#		million tonnes	2018$/tonne	mi^2	2018$/tonne
78	Morrison1_CO	258	10.47	37	6.97
84	Morrison8_CO	2,193	15.30	68	10.36
1	Arbuckle2_CO	1,935	16.84	84	11.44
39	Entrada8_CO	903	17.14	107	11.58
56	Hermosa1b_CO	129	17.77	68	12.08
94	Nugget1_CO	2,322	18.08	63	12.23
55	Hermosa1a_CO	129	18.31	72	12.23
33	Entrada1_CO	3,999	22.23	135	15.13
117	Weber2_CO	258	24.71	110	16.15
116	Weber1_CO	129	25.35	114	16.53

4 CO_2-EOR PERFORMANCE AND COST MODELING

As previously mentioned, NETL-developed models for CO_2-EOR were used to provide an estimate for the role EOR could play (in the near term, and overall) within the I-WEST states, as well as the surrounding region by demonstrating how much CO_2 storage capacity (and incremental low-carbon oil production) is technically and economically feasible at various fixed oil prices (i.e., "the size of the prize") as a function of break-even carbon management cost from a CO_2 source's perspective. The I-WEST states and the surrounding region are together referred to as the "I-WEST region" throughout the remainder of this overview document. This assessment also identified the geographic distribution of the CO_2-EOR capacities, which combined with near-term assessments can outline potential "first movers." The models and analysis approach utilized are discussed in this section.

4.1 CO_2 EOR EVALUATION SYSTEM APPLICATION AND OVERVIEW

The FECM/NETL Onshore CO_2 EOR Evaluation System (CO_2 EOR Evaluation System) was used to determine CO_2-EOR resource capacity and economic assessments. The CO_2 EOR Evaluation System consists of the FECM/NETL CO_2 Prophet Model (CO2_Prophet), FECM/NETL Onshore CO_2 EOR Cost Model (CO2_E_COM), and FECM/NETL Onshore CO_2 EOR Evaluation Tool (CO2_E_EvTool).

CO2_Prophet is a simplified oil reservoir CO_2-EOR simulation mathematical model that generates streamlines and stream tubes to simulate the flow of fluids in an oil reservoir through two Fortran programs, StrmtbFlow [22]and StrmtbGen [23]. More details on CO2_Prophet can be found in the model's three user's manuals [24] [25] [26]. CO2_E_COM is a Fortran program that incorporates oil field performance outputs from CO2_Prophet, capital costs, O&M costs, and financing costs along with user-specified financial parameters (e.g., minimum desired return on investment and oil price) to estimate revenues and costs of implementing CO_2-EOR at an oil field [27]. More information on CO2_E_COM can be found in the model's user's manual [28]. CO2_E_EvTool is a Python script that can be used to evaluate the application of CO_2-EOR on multiple oil fields by using two Excel® files, a master user input file and an oil field data file. It is important to note that CO2_E_EvTool and its user's manual are not publicly available but are planned to be released in the late fall or early winter 2022 timeframe.

Outputs from CO_2 EOR Evaluation System include cumulative values for CO_2 purchased, annual CO_2 injection rate, incremental oil produced, and number of oil fields where CO_2-EOR was implemented. CO_2 EOR Evaluation System also provides the first-year break-even CO_2 price for each oil field for a specified oil price. Unlike a CO_2 saline storage operation where a CO_2 saline storage operator must be paid to accept CO_2, CO_2-EOR operators will pay for CO_2 if the oil price is high enough and their oil fields are good candidates for CO_2-EOR. The first-year break-even CO_2 price is the highest price the oil field operator can pay for CO_2 that will just barely cover all costs, including financing costs, for their CO_2-EOR operation. The first-year break-even price for CO_2 for an oil field is calculated for a specific oil price; however, the CO_2 EOR Evaluation System will calculate the first-year break-even price of CO_2 for an oil field for a range of oil prices input by the user.

4.2 ANALYTICAL APPROACH

U.S. Geological Survey (USGS) oil and gas province and state combinations [29] and conventional oil fields from the U.S. Energy Information Administration's (EIA) wloil.txt dataset were used to identify oil field zones located in the I-WEST region. Exact locations of individual oilfields is considered proprietary information and are not provided in the wloil.txt dataset. I-WEST region oil fields were then assessed for miscible water alternating gas (WAG) CO_2-EOR technical and economic feasibility and economical CO_2 storage capacity via CO_2-EOR using the CO_2 EOR Evaluation System. Nine cases alternating oil prices, see below, were evaluated. Information on how the dataset and CO_2 EOR Evaluation System were applied are discussed in the following subsections.

1. **CO2 EOR Evaluation System 50oil:** Break-even CO_2 prices are calculated at a fixed $50/STB oil price scenario
2. **CO2 EOR Evaluation System 60oil:** Break-even CO_2 prices are calculated at a fixed $60/STB oil price scenario
3. **CO2 EOR Evaluation System 70oil:** Break-even CO_2 prices are calculated at a fixed $70/STB oil price scenario
4. **CO2 EOR Evaluation System 80oil:** Break-even CO_2 prices are calculated at a fixed $80/STB oil price scenario
5. **CO2 EOR Evaluation System 90oil:** Break-even CO_2 prices are calculated at a fixed $90/STB oil price scenario
6. **CO2 EOR Evaluation System 100oil:** Break-even CO_2 prices are calculated at a fixed $100/STB oil price scenario
7. **CO2 EOR Evaluation System 110oil:** Break-even CO_2 prices are calculated at a fixed $110/STB oil price scenario
8. **CO2 EOR Evaluation System 120oil:** Break-even CO_2 prices are calculated at a fixed $120/STB oil price scenario
9. **CO2 EOR Evaluation System 150oil:** Break-even CO_2 prices are calculated at a fixed $150/STB oil price scenario

Two economic scenarios based on oil and CO2 price are also discussed in the following subsections.

1. **Most Optimistic Economic Scenario:** Oil price is $150/STB, and EOR operators are paid $99/tonne of CO_2 to take CO_2
2. **Conventional Economic Scenario:** Oil price is $70/STB, and EOR operatrs pay $25/tonne of CO_2 to receive CO_2

The analysis was organized into two parts:

1. Assessment of overall miscible CO_2-EOR resource capacity in the I-WEST region and supply curve analysis of this capacity with respect to CO_2 cost and oil price economics:

Overall CO_2-EOR annual injection rate resource capacity assessment provides insight on the I-WEST region's EOR fields to provide near-term CO_2 storage as a way to reach I-WEST's decarbonization roadmap. Supply curves illustrate economic constraints on the CO_2 storage capacity and incremental oil production results and demonstrate the potential impact of initiatives to lower the cost of CO_2 capture and transport.

2. Trend analysis of CO_2-EOR resource capacity by state and geographic province: Trend analysis provided insight into where this injection rate capacity is geographically concentrated (i.e., highlighted regions that may be first-movers for CO_2-EOR on accounts of economy-of-scale created by concentrated resource capacity).

4.2.1 wloil.txt Dataset

In the contiguous United States, 2,874 conventional oil fields are identified by EIA's wloil.txt dataset, which is part of the Oil and Gas Supply Module within EIA's National Energy Modeling System [30]. This dataset was filtered to remove oil fields with the following criteria to obtain 1,581 oil fields within the I-WEST region:

- Flagged by EIA as tight (unconventional) oil fields
- Flagged by EIA as producing significant dissolved gas or condensate oil
- Flagged by EIA as already undergoing CO_2-EOR or any other form of tertiary EOR
- Oil fields outside the I-WEST region; Figure 2 shows the provinces that have oilfields that match the above criteria.**Error! Reference source not found.**

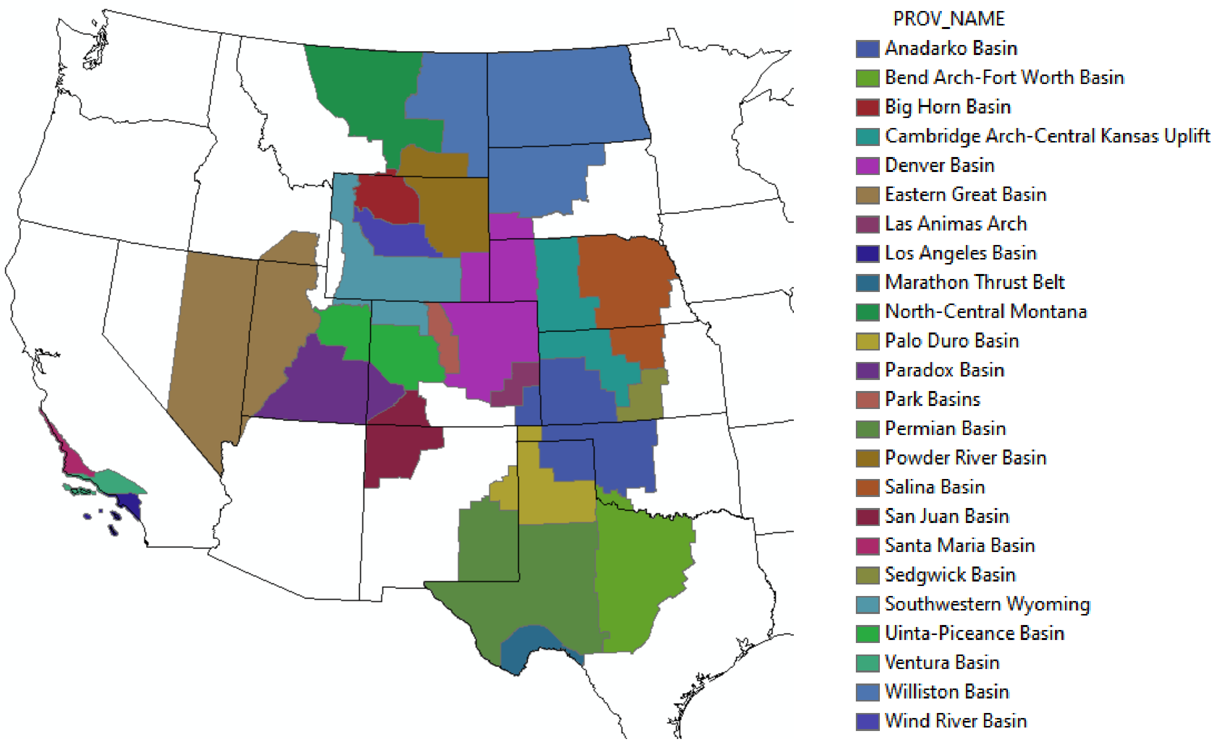

Figure 2. I-WEST region oil and gas provinces

Within the filtered oil field dataset, “shovel-ready” oil fields were also identified and flagged. “Shovel-ready” is defined as those oil fields that have current oil saturations (So_Cur) (per the last EIA wloil.txt 2014 update) that suggest the oil fields are near the end of secondary waterflooding and therefore likely ready to deploy CO_2-EOR in the near term. Oil fields were flagged as “shovel-ready” if their So_Cur was between 0.25 (25% of pore space) and 0.30 (30% of pore space), plus 15% of original oil-in-place (OOIP) (converted to fraction of pore space). Candidates for CO_2-EOR typically have So_Cur greater than 0.25 to 0.30 [31], so 0.25 was chosen as the lower bound for “shovel-ready” oil fields. CO_2-EOR can usually return 5-15% of additional OOIP [31], so So_Cur of 0.30 plus 15% of OOIP was chosen as the upper bound for “shovel-ready” oil fields. Oil fields with So_Cur greater than this upper bound would likely be undergoing profitable secondary waterflooding or primary oil production and not opt to deploy CO_2-EOR in the near-term. Based on the lower and upper So_Cur bounds, 447 oil fields in the filtered I-WEST region oil field dataset were flagged as “shovel-ready” (**Error! Reference source n ot found.**).

Table 7. Oil field count after filtering EIA’s wloil.txt dataset

I-WEST Region Oil and Gas Province Name	Oil Field Count		
	Entire wloil.txt Dataset	Filtered wloil.txt Dataset	"Shovel-Ready" CO_2-EOR
Anadarko Basin	220	216	43
Bend Arch-Ft. Worth Basin	211	210	63
Big Horn Basin	60	60	9
Cambridge Arch-Central Kansas	158	155	96

Central Montana	35	35	10
Denver Basin	69	59	20
Eastern Great Basin	5	5	0
Las Animas Arch	5	3	2
Los Angeles Basin	34	31	8
Marathon Thrust Belt	1	1	0
Montana Thrust Belt	1	0	0
Palo Duro Basin	3	1	1
Paradox Basin	17	15	3
Park Basins	1	1	1
Permian Basin	524	441	99
Powder River Basin	177	158	37
San Joaquin Basin	73	0	0
San Juan Basin	12	11	4
Santa Maria Basin	11	11	1
Sedgwick Basin/Salina Basin	18	18	11
Sonoma-Livermore	1	0	0
Southwestern Wyoming	23	18	8
Uinta-Piceance Basin	15	9	0
Ventura Basin	33	32	7
Williston Basin	72	69	17
Wind River Basin	25	19	6
Wyoming Thrust Belt	3	3	1
TOTAL	**2,874**	**1,581**	**447**

The filtered wloil.txt database was input into the CO_2 EOR Evaluation System to assess the magnitude of annual CO_2 injection rate available at various CO_2 and oil prices in the I-WEST region via CO_2-EOR.

4.2.2 CO_2 EOR Evaluation System

The three CO_2-EOR models within CO_2 EOR Evaluation System each played a key role in evaluating the filtered wloil.txt dataset. CO2_E_EvTool screened each oil field for CO_2-EOR candidacy to ensure they met five CO_2-EOR candidacy parameters per user-defined limits:

1. Field depth exceeds 2,600 ft ensuring CO_2 in the reservoir is supercritical
2. American Petroleum Institute (API) gravity exceeds 17.5 degrees API ensuring oil is suitable for miscible CO_2-EOR[a]
3. Duration of injection of CO_2 and water into a pattern is less than 60 years ensuring realistically economic CO_2-EOR projects
4. OOIP exceeds 5 million STB ensuring realistically economic CO_2-EOR projects
5. Reservoir pressure exceeds calculated minimum miscible pressure for the oil ensuring miscible CO_2-EOR

[a] The criteria for API gravity (17.5 degrees API), depth, and minimum miscibility pressure equation, using API gravity of the oil and reservoir temperature, are derived from Kuuskraa, et al. [33]

Each candidate oil field was run through CO2_Prophet by CO2_E_EvTool to generate CO_2-EOR technical and operational results and then those generated results were run through CO2_E_COM to obtain CO_2-EOR economics results. There are extensive critical, static, non-oil field specific inputs within both CO2_Prophet and CO2_E_COM for which the user can change to suit their project requirements; however, there are also default values for these inputs within the model. For the analysis, certain parameters within CO2_E_COM were changed from their default values (i.e., those values already within the model) to obtain costs for the nine aforementioned cases. Table 8 features select critical financial inputs within CO2_E_COM.

Table 8. Select CO2_E_COM key inputs for CO_2-EOR resource capacity assessment

Parameter Name	Unit	Value	Note
freqty	%	60	Fraction of financing using equity. Remainder is from debt.
eqtyrate	%	10.77	Minimum desired return on equity (after taxes)
debtrate	%	4.5	Annual interest rate on debt. Typically depends on escalation rate and perceived risk of the project taking the loan.
escrate	%	2.01	Escalation rate
fitrate	%	25.74	Effective tax rate, based on federal annual income tax rate of 21%; state tax rate (deducted from federal tax rate) of 6%
co2mon_stat	N/A	Technology 3&7	Monitoring equipment in injection and production wells; CO_2 leakage monitoring of above-ground equipment

Three key results from the CO_2 EOR Evaluation System for this analysis, discussed below, were used to generate CO_2 storage capacity and incremental oil production supply curves for the different oil prices as a function of CO_2 price.

1. CO2_purch: Total CO_2 purchased over the operational life of an oil field engaged in CO_2-EOR
2. Oil_prod: Total incremental oil produced over the operational life of an oil field engaged in CO_2-EOR
3. BE_CO2$: First-year break-even price of CO_2 for an economic CO_2-EOR project, for oil prices fixed at $50, $60, $70, $80, $90, $100, $110, $120, or $150/STB (in real 2018$)

Supply curves demonstrated how much CO_2 would be purchased over the lifetime of economical CO_2-EOR oil fields as oil price is held constant and CO_2 price changes. This analysis assumed a 30-year operating period for CO_2-EOR projects, to align with saline CO_2 storage capacity results, so annual injection rates can be estimated by dividing CO2_purch by 30 years. Heatmaps were generated that summed CO2_purch for technically feasible CO_2-EOR by state and for "shovel-ready" CO_2-EOR by state, which demonstrates the geographic concentration of potential CO_2 storage capacity as a result of CO_2-EOR.

4.3 Results Summary

This section provides information on the data within the spreadsheet file "IWEST_CO2 T&S Results_July 2022.xlsm" with example results and a high-level overview of results. More details on the two parts of the analysis (CO2-EOR resource capacity assessment and supply curve analysis and trend analysis of CO_2-EOR resource capacity) along with heatmaps are also provided.

4.3.1 Results Spreadsheet File

As previously mentioned, the CO_2 EOR Evaluation System was used to derive results for nine cases. Once the results were generated, they were pared down to provide the results that would be of interest to the I-IWEST initiative for all nine cases. These results are featured in the Excel® spreadsheet file "IWEST_CO2 T&S Results_July 2022.xlsm" [1]. Each case has its own results sheet named appropriately: CO2 EOR Eval Sys 50oil Results, CO2 EOR Eval Sys 60oil Results, CO2 EOR Eval Sys 70oil Results, CO2 EOR Eval Sys 80oil Results, CO2 EOR Eval Sys 90oil Results, CO2 EOR Eval Sys 100oil Results, CO2 EOR Eval Sys 110oil Results, CO2 EOR Eval Sys 120oil Results, and CO2 EOR Eval Sys 150oil Results. Within each of these cases sheets, columns A through L provide results for input into SimCCS [21], while columns O through AR provide context to the results in columns A through L as well as other data that may be of interest. Oil fields listed are technically feasible for miscible WAG CO_2-EOR and economically feasible at the listed oil and CO_2 prices provided. Results are sorted low to high by total unit cost (i.e., cost of CO_2 in $/tonne) with negative prices implying the CO_2-EOR operator pays the CO_2 source to receive CO_2 (business as usual). Positive total unit cost implies the CO_2 operator is paid by the CO_2 source to take the CO_2 (e.g., hypothetical emissions penalty). Some cells in the spreadsheet that convey "per tonne of CO_2 purchased" metrics are blank when no CO_2 was purchased because numbers cannot be divided by zero. Table 9 provides a description on each column within the results sheets. Example technical and cost results from the 'CO2 EOR Eval Sys 50oil Results' sheet is found in Table 10.

Table 9. Description of columns within each case-specific sheet in "IWEST_CO2 T&S Results_July 2022.xlsm"

Data	Column	Item	Column	Item
SimCCS Inputs	A	Unique ID of the oil field in CO_2 EOR Evaluation System	G	Individual well injection rate; not calculated in CO_2 EOR Evaluation System (million tonnes/yr)
	B	Name of the oil field; not given in database used for this analysis	H	Injection fixed capital cost; not calculated in CO_2 EOR Evaluation System (million$)
	C	Storage capacity for the storage formation/reservoir; this is the realistic or effective storage capacity where multiple storage projects are operating simultaneously (million tonnes)	I	Injection fixed O&M cost; not calculated in CO_2 EOR Evaluation System (million$/yr)
	D	Total unit cost, which is the CO_2 price paid, with negative prices paid by EOR operator and positive prices paid by CO_2 source (2018$/tonne)	J	Injection variable O&M cost; not calculated in CO_2 EOR Evaluation System ($/tonne)

Data	Column	Item	Column	Item
SimCCS Inputs	E	State-wide fixed capital cost; not calculated in CO_2 EOR Evaluation System (million $)	K	Longitude of the geographic centroid of the USGS oil and gas province – state combination (degrees)
	F	State-wide fixed O&M cost; not calculated in CO_2 EOR Evaluation System ($/yr)	L	Latitude of the geographic centroid of the USGS oil and gas province – state combination (degrees)

Context and Results	O	Brief description of the case which gives fixed first-year oil price that break-even CO_2 price is calculated at (2018$/STB)	AD	Injection duration as output from the CO_2 EOR Evaluation System (yr)
	P	Fixed first-year oil price that model is run (2018$/STB)	AE	Total number of active injection wells for each project (#)
	Q	Incremental oil production (i.e., additional oil produced as a result of CO_2-EOR operations) (million STB)	AF	Total number of active oil production wells for each project (#)
	R	Number of years CO_2-EOR operation can stay economically viable (yr)	AG	Purchased CO_2 injected per project; this is equivalent to the storage capacity in Column C (million tonnes)
	S	Indicates whether the field is “shovel-ready” or not with 1 indicating it is and 2 indicating it is not but will be in the future (#)	AH	Average rate of CO_2 injected divided by active injection well on economically viable timeframe (from Column R) basis (million tonnes/yr)
	T	Unique ID number of the oil field in the wloil.txt database (#)	AI	Average rate of CO_2 injection divided by CO_2-EOR project on economically viable timeframe (see Column R) basis (million tonnes/yr)
	U	State that the oil field is located in	AJ	First-year break-even CO_2 price; this is equivalent to total unit cost in Column D (2018$/tonne)
	V	Name of the USGS province including the state where the oil field is located	AK	Total of real capital and O&M costs divided by the mass of CO_2 purchased; this is the sum of values in columns AM and AN (2018$/tonne)
	W	Indicates the I-WEST status of the oil field with 1 indicating the oil field is in an I-WEST state and 2 indicating the oil field is in a state near I-WEST states (#)	AL	Total revenue divided by the mass of CO_2 purchased (2018$/tonne)
	X	Total estimated surface area of oil field (acres)	AM	Total of real capital costs divided by the mass of CO_2 purchased (2018$/tonne)
	Y	Depth to the top of the storage formation/reservoir within the oil field (ft)	AN	Total real O&M costs divided by the mass of CO_2 injected (2018$/tonne)
	Z	Thickness of the storage formation/reservoir within the oil field (ft)	AO	Total royalty costs divided by the mass of CO_2 injected (2018$/tonne)
	AA	Porosity of the storage formation/reservoir within the oil field (%)	AP	Total state taxes divided by the mass of CO_2 purchased (2018$/tonne)
	AB	Permeability of the storage formation/reservoir within the oil field (mD)	AQ	Total federal taxes divided by the mass of CO_2 purchased (2018$/tonne)

Data	Column	Item	Column	Item
Context and Results	AC	Dykstra-Parsons coefficient, a measure of permeability heterogeneity, with lower values being more homogenous and higher, more heterogeneous (dimensionless)	AR	Total after tax income divided by the mass of CO_2 purchased (2018$/tonne); this is Column AL minus the sum of columns AK, AO, AP, and AQ

Table 10. Example technical and cost results for $50/STB oil price in 'CO2 EOR Eval Sys 50oil Results' sheet in "IWEST_CO2 T&S Results_July 2022.xlsm"

Unique ID	Storage Capacity	Total Unit Cost	Incremental Oil Production	Surface Area of Oil Field	Total Real Costs per Tonne of CO_2 Purchased
#	million tonnes	2018$/tonne	million STB	acres	
DOOK6345700	3.8	-137.00	20.2	1,280	180.08
DONM6843700	38.4	-135.00	189.5	14,400	164.99
DOMT6750400	82.0	-113.00	435.1	85,090	160.47
DOCA6865400	24.6	-93.00	95.9	460	133.52
DOOK6337300	20.4	-87.00	83.5	12,144	135.63
DOTX6611300	2.2	-86.00	12.4	10,150	183.45
DOKS6463300	3.3	-83.00	12.6	600	125.45
DOTX6349000	93.5	-81.00	310.6	65,880	107.98
DOUT6841100	24.6	-81.00	82.4	1,600	107.56
DONM6584800	92.1	-78.00	341.8	32,000	118.92

4.3.2 Results High-Level Overview

As mentioned previously, the analysis was organized into two parts, 1) assessment of overall miscible CO_2-EOR resource capacity and supply curve analysis of this capacity with respect to CO_2 cost and oil price economics and 2) trend analysis of CO_2-EOR resource capacity by state and geographic province. Some key findings from these assessments included:

- The I-WEST region contains 1,581 oil fields; 1,268 are technically feasible, representing 8.0 billion tonnes of CO_2 storage capacity.
- Assuming EOR operators receive $70/STB of oil (2018$/STB), and the CO_2 price is $25/tonne of CO_2 ("Conventional Economic Scenario"), 258 oil fields are economically viable, representing 5.0 billion tonnes of CO_2 storage capacity, equivalent to a total annual injection rate capacity of 168 million tonnes/yr assuming a 30-year operations basis. Up to 15.1 billion STB of oil could be produced.
- The CO_2 storage capacity of the "Conventional Economic Scenario" CO_2 storage capacity is hosted by Texas (50%), Wyoming (10%), Kansas (10%), and New Mexico (9%) oil fields. The Permian Basin in Texas hosts 46% of the CO_2 storage capacity, followed by the New Mexico's Permian Basin (7%).
- Approximately 447 of the region's oil fields are likely near the end of secondary waterflooding and, therefore, have the potential to deploy CO_2-EOR in the near term (i.e., "shovel ready"); 389 are technically feasible, representing 1.1 billion tonnes of CO_2 storage capacity for these potential "first-mover" oil fields.

- Roughly 36 "shovel ready" oil fields are economically feasible at the "Conventional Economic Scenario" oil and CO_2 prices, representing 469 million tonnes of CO_2 storage capacity, equivalent to a total annual injection rate capacity of 15.6 million tonnes/yr assuming a 30-year operations basis. From these oil fields, 1.6 billion STB of incremental oil could be produced.
- Approximately 86% of CO_2 annual injection rate in the "shovel ready" oil fields for the "Conventional Economic Scenario" is concentrated in four provinces across four states: New Mexico's Permian Basin (31%; 4.9 million tonnes/yr) and San Juan Basin (10%; 1.5 million tonnes/yr); Kansas' Sedgwick/Salina Basin (16%; 2.5 million tonnes/yr) and Anadarko Basin (12%; 1.8 million tonnes/yr); Oklahoma's Anadarko Basin (9%; 1.3 million tonnes/yr), and Texas' Permian Basin (9%; 1.3 million tonnes/yr).

4.3.3 CO_2-EOR Resource Capacity and Supply Curves and Trend Analysis of CO_2-EOR Resource Capacity

According to CO2_E_EvTool's screening criteria, 1,268 of 1,581 total conventional oil fields in the I-WEST region dataset were technically feasible for CO_2-EOR.

Figure 3, Figure 4, Figure 5, and Figure 6 show, respectively, the cost-supply curves for all 1,268 oil fields, by fixed oil price, for cumulative CO_2 purchased, cumulative annual injection rate (assuming a 30-year operations basis), cumulative incremental oil produced, and cumulative oil fields deployed, as a function of first-year break-even CO_2 price.

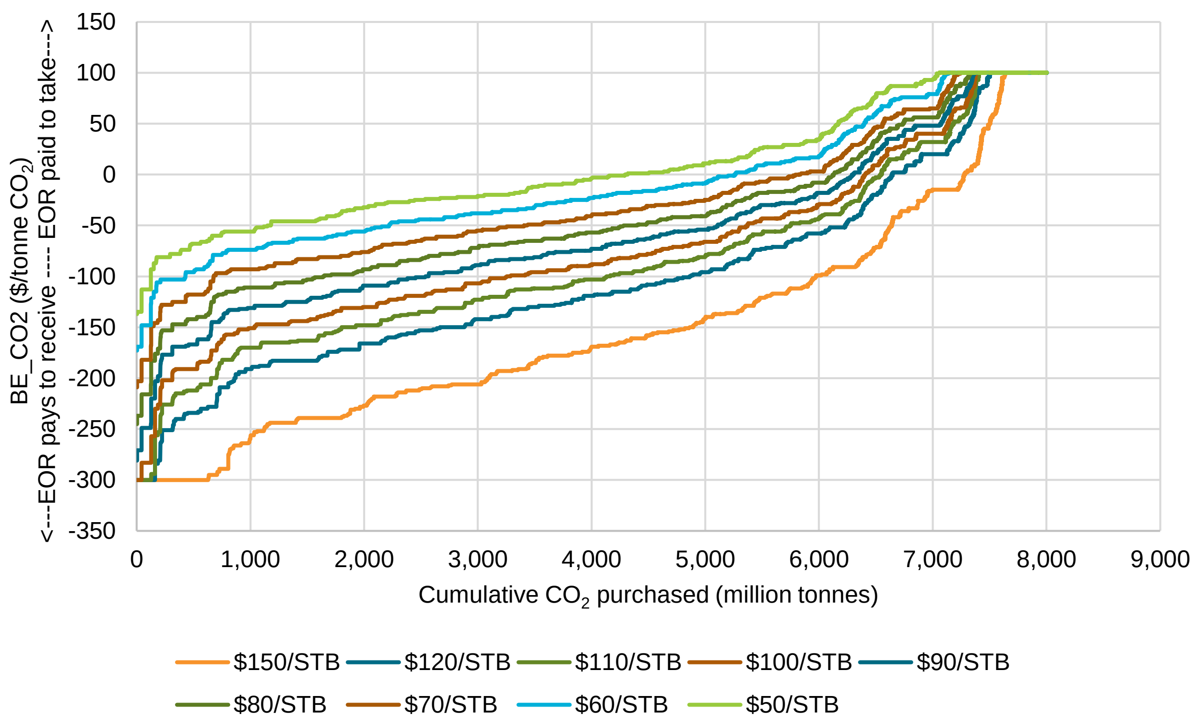

Figure 3. I-WEST region CO_2 purchased for CO_2-EOR as a function of CO_2 price by oil price

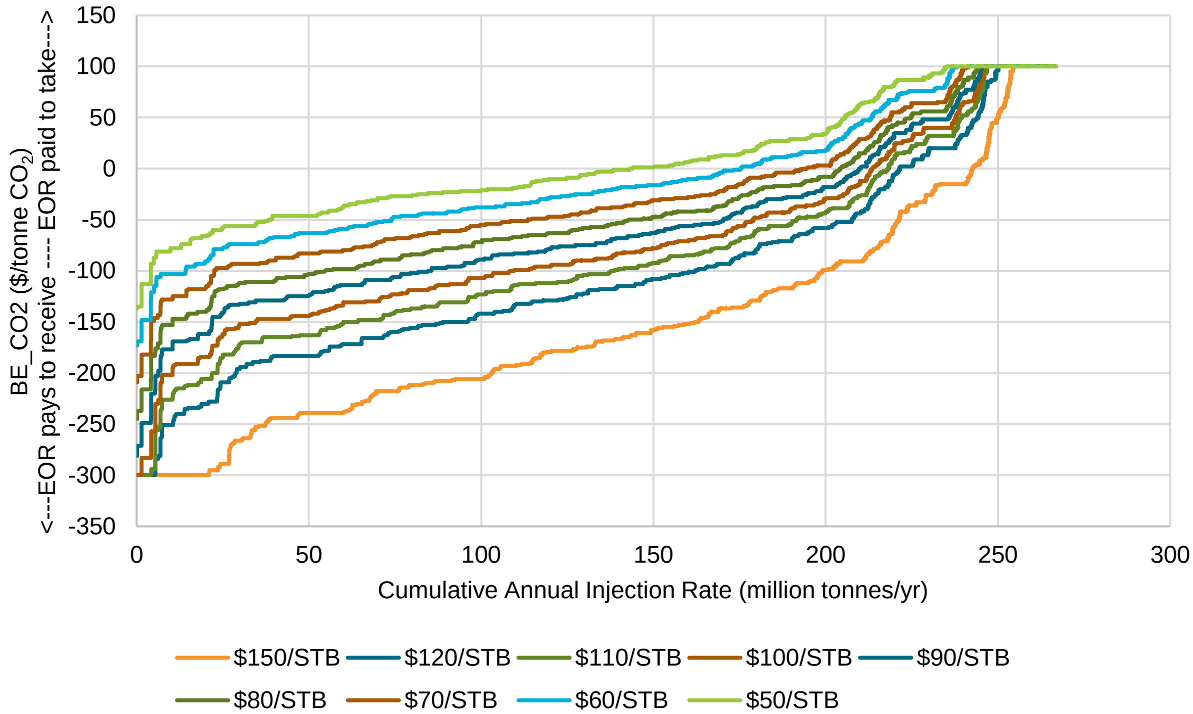

Figure 4. I-WEST region annual purchased CO_2 injection rate as a function of CO_2 price by oil price

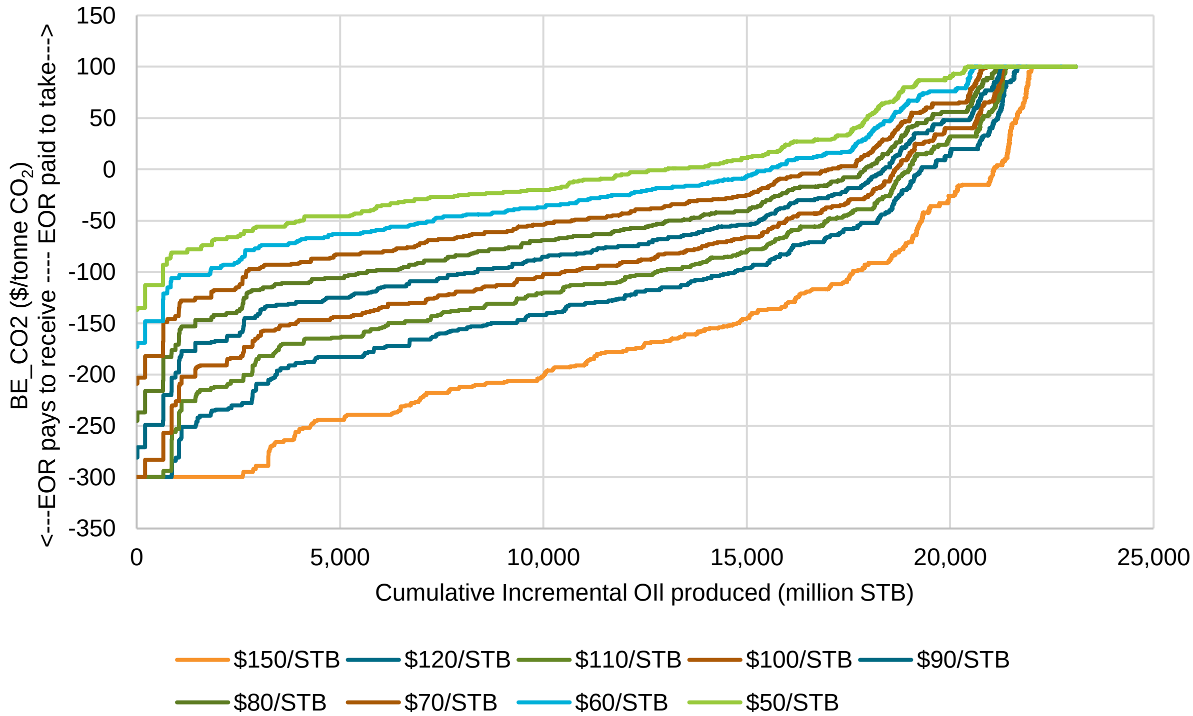

Figure 5. I-WEST region incremental oil production from CO_2-EOR as a function of CO_2 price by oil price

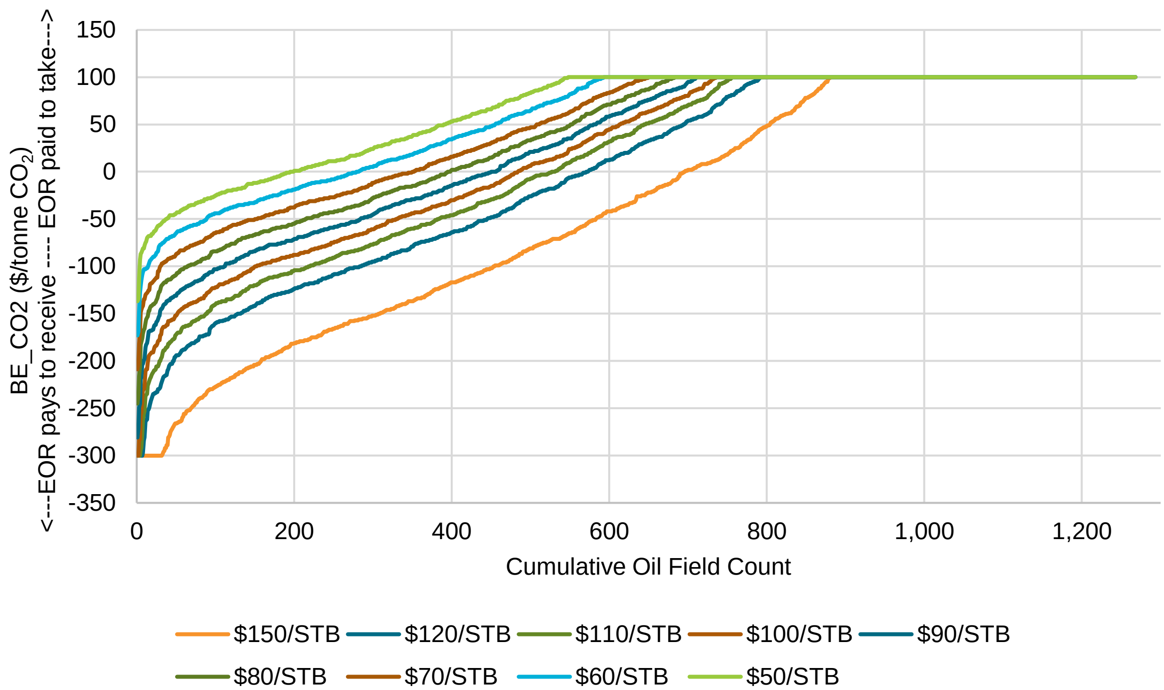

Figure 6. I-WEST region oil fields engaged in economical CO_2-EOR as a function of CO_2 price by oil price

Error! Reference source not found.Error! Reference source not found. highlights CO_2 EOR Ev aluation System results for different fixed oil price and break-even CO_2 price case that were extracted from ***Figure 3***, Figure 4, Figure 5, and Figure 6. This table (along with ***Figure 3***, Figure 4, Figure 5, and Figure 6) show that for CO_2-EOR, the I-WEST region has ample technically feasible CO_2 storage capacity (up to 7,994 million tonnes of CO_2).

Table 11. I-WEST region CO_2-EOR results for select break-even CO_2 prices by fixed oil price

CO_2 Price (Negative is Cost to EOR Operator)	Oil Price	Total CO_2 Purchased	Total Annual CO_2 Injection Rate (30-year Basis)	Total Incremental Oil Produced	Total Oil Fields Deployed
2018$/tonne CO_2	2018$/STB	million tonnes	million tonnes/yr	million STB	count
-25	50	2,535	84	8,162	101
-25	60	3,964	132	12,125	179
-25	70	5,039	168	15,074	258
-25	80	5,344	178	15,847	310
-25	90	5839	195	17,128	369
-25	100	6,174	206	18,039	418
-25	110	6,352	212	18,517	466
-25	120	6,447	215	18,776	503
-25	150	6,928	231	20,115	645
99	50	7,053	235	20,413	547
99	60	7,135	238	20,602	592
99	70	7,237	241	20,886	649
99	80	7,327	244	21,144	682
99	90	7,360	245	21,244	710

CO_2 Price (Negative is Cost to EOR Operator)	Oil Price	Total CO_2 Purchased	Total Annual CO_2 Injection Rate (30-year Basis)	Total Incremental Oil Produced	Total Oil Fields Deployed
2018$/tonne CO_2	2018$/STB	million tonnes	million tonnes/yr	million STB	count
99	100	7,374	246	21,287	735
99	110	7,402	247	21,355	755
99	120	7,498	250	21,637	791
99	150	7,632	254	22,000	880
100	50-150	7,994	266	23,075	1,268

At the "Most Optimistic Economic Scenario" ($150/STB oil, and EOR operator is paid $99/tonne CO_2 to take CO_2, presumably to avoid carbon emissions penalties or to receive carbon capture incentives), the I-WEST region could store 7,632 million tonnes of CO_2, equivalent to injecting 254 million tonnes/yr for 30 years, which would result in 22,000 million STB of incremental oil production, engaging 880 oil fields. At the "Conventional Economic Scenario" ($70/STB, and the EOR operator pays $25/tonne CO_2 to receive CO_2; i.e., $-25/t$CO_2$ cost to the CO_2 source) the I-WEST region could store 5,039 million tonnes of CO_2, equivalent to injecting 168 million tonnes/yr for 30 years, which would result in 15,074 million STB of incremental oil production, engaging 258 oil fields. The "Conventional Economic Scenario" was used to demonstrate how these results are broken out by state and province.

CO_2 EOR Evaluation System results for the "Conventional Economic Scenario" broken out by state are shown in Table 12. This table, along with Figure 7, demonstrate that 24% of the I-WEST region's total purchased CO_2 storage capacity resides within I-WEST's states. Texas provides half (50%) of the I-WEST region's purchased CO_2 storage capacity (2,512 million tonnes) at the $-25/tonne CO_2 and $70/STB "Conventional Economic Scenario." Figure 7 provides a heatmap that sums CO2_purch for technically feasible CO_2-EOR by state.

Table 12. "Conventional Economic Scenario" I-WEST region CO_2-EOR results, by state

State	CO_2 Price (Negative is Cost to EOR Operator)	Oil Price	Total CO_2 Purchased	Total Annual CO_2 Injection Rate (30-year Basis)	Total Incremental Oil Produced	Total Oil Fields Deployed
	2018$/tonne CO_2	2018$/STB	million tonnes	million tonnes/yr	million STB	count
CA	-25	70	337	11.2	1,056	14
CO	-25	70	7	0.2	25	3
KS	-25	70	513	17.1	1,781	25
MT	-25	70	177	5.9	768	8
ND	-25	70	324	10.8	991	11
NE	-25	70	78	2.6	251	9
NM	-25	70	449	15.0	1,431	20
OK	-25	70	70	2.3	252	20
TX	-25	70	2,512	83.7	6,981	109
UT	-25	70	84	2.78	236	12
WY	-25	70	489	16.3	1,302	27
Total			**5,039**	**168**	**15,074**	**258**

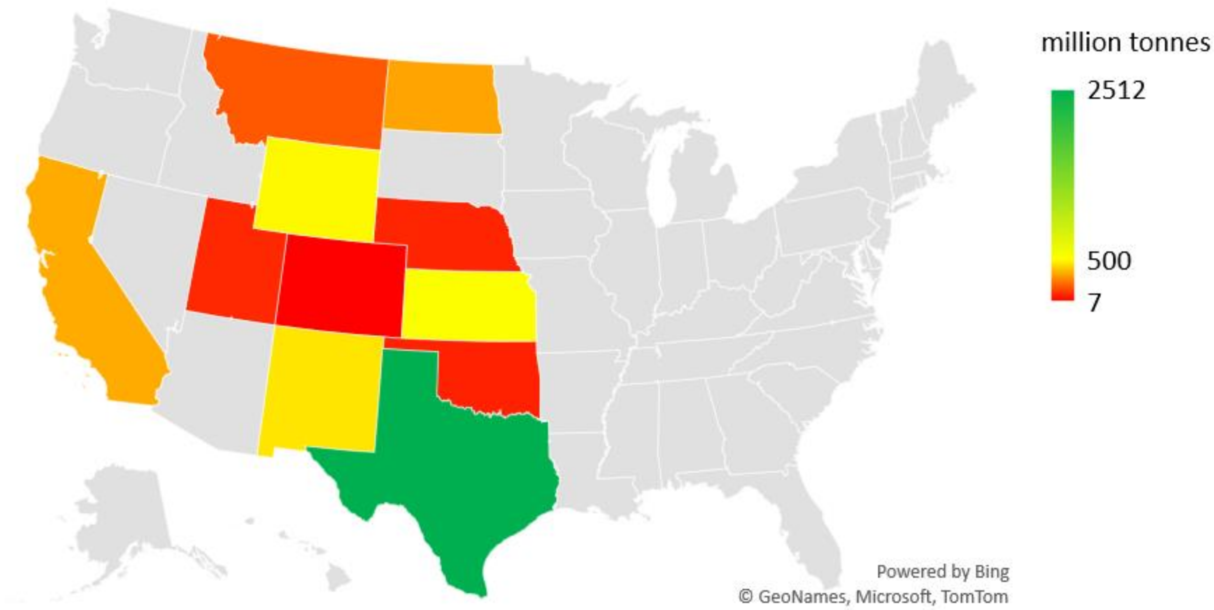

Figure 7. "Conventional Economic Scenario" I-WEST region total CO_2 storage capacity, by state

Table 13 shows CO_2 EOR Evaluation System results for the "Conventional Economic Scenario" broken out by province-state combination. This table demonstrates that the Permian Basin province in Texas contributes the most of any province-state combination to the I-WEST region's purchased CO_2 storage capacity (2,141 million tonnes; 43% of the region's total capacity) at the $-25/tonne CO_2 and $70/STB "Conventional Economic Scenario."

Table 13. "Conventional Economic Scenario" I-WEST region CO_2-EOR results, by province-state

Province-State Combination	CO_2 Price (Negative is Cost to EOR Operator)	Oil Price	Total CO_2 Purchased	Total Annual CO_2 Injection Rate (30-year Basis)	Total Incremental Oil Produced	Total Oil Fields Deployed
	2018$/tonne CO_2	2018$/STB	million tonnes	million tonnes/yr	million STB	count
Anadarko Basin_CO	-25	70	1.9	0.06	8	1
Anadarko Basin_KS	-25	70	146.6	4.89	557	10
Anadarko Basin_OK	-25	70	69.2	2.31	249	18
Anadarko Basin_TX	-25	70	137.1	4.57	450	8
Bend Arch-Ft. Worth Basin_OK	-25	70	0.7	0.02	3	2
Bend Arch-Ft. Worth Basin_TX	-25	70	233.4	7.78	742	18
Big Horn Basin_MT	-25	70	7.5	0.25	14	1
Big Horn Basin_WY	-25	70	223.8	7.46	498	6
Cambridge Arch-Central Kansas_KS	-25	70	288.5	9.62	918	13
Cambridge Arch-Central Kansas_NE	-25	70	48.3	1.61	158	4
Central Montana_MT	-25	70	87.4	2.91	454	4
Denver Basin_CO	-25	70	4.7	0.16	16	1
Denver Basin_NE	-25	70	30.0	1.00	93	5
Denver Basin_WY	-25	70	3.8	0.13	14	1

Province-State Combination	CO_2 Price (Negative is Cost to EOR Operator)	Oil Price	Total CO_2 Purchased	Total Annual CO_2 Injection Rate (30-year Basis)	Total Incremental Oil Produced	Total Oil Fields Deployed
	2018$/tonne CO_2	2018$/STB	million tonnes	million tonnes/yr	million STB	count
Los Angeles Basin_CA	-25	70	118.9	3.96	381	8
Paradox Basin_UT	-25	70	14.9	0.50	50	6
Permian Basin_NM	-25	70	389.0	12.97	1,158	17
Permian Basin_TX	-25	70	2,141.2	71.37	5,789	83
Powder River Basin_WY	-25	70	221.7	7.39	694	14
San Juan Basin_NM	-25	70	60.3	2.01	273	3
Sedgwick Basin/Salina Basin_KS	-25	70	77.4	2.58	306	2
Southwestern Wyoming_CO	-25	70	0.3	0.01	1	1
Southwestern Wyoming_WY	-25	70	11.9	0.40	26	3
Uinta-Piceance Basin_UT	-25	70	59.4	1.98	159	4
Ventura Basin_CA	-25	70	218.1	7.27	676	6
Williston Basin_MT	-25	70	81.8	2.73	301	3
Williston Basin_ND	-25	70	324.2	10.81	991	11
Wind River Basin_WY	-25	70	25.2	0.84	63	2
Wyoming Thrust Belt_UT	-25	70	9.2	0.31	27	2
Wyoming Thrust Belt_WY	-25	70	2.8	0.09	8	1
Total			**5,039**	**168**	**15,074**	**258**

To get a sense of how much CO_2 storage capacity via CO_2-EOR would be available in the near term, “shovel ready” oil fields were flagged based on their reported current oil saturation. Of the 389 oil fields that would deploy at the “Conventional Economic Scenario”, 36 were flagged as “shovel ready”, that is, likely to deploy in the near term based on current oil saturation values in the oil field dataset (at its last update in 2014). Figure 8, Figure 9, Figure 10, and Figure 11, respectively, show the cost-supply curves for all 389 “shovel ready” oil fields, by fixed oil price, for cumulative CO_2 purchased, cumulative annual injection rate (assuming a 30-year operations basis), cumulative incremental oil produced, and cumulative oil fields deployed, as a function of first-year break-even CO_2 price.

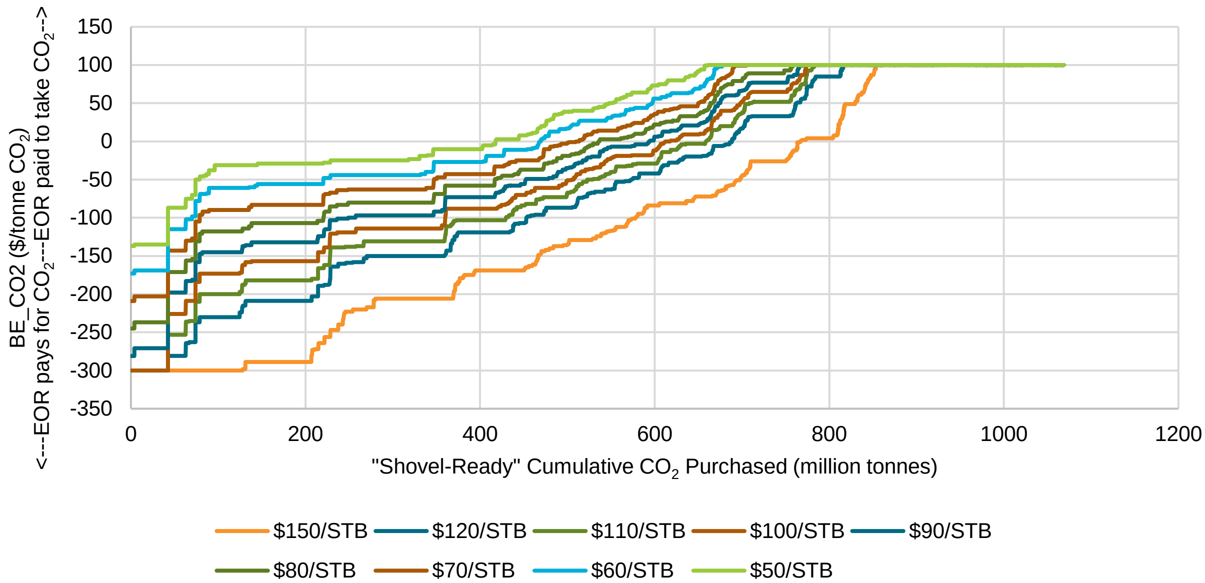

Figure 8. "Shovel-ready" I-WEST region CO_2 purchased for CO_2-EOR as a function of CO_2 price by oil price

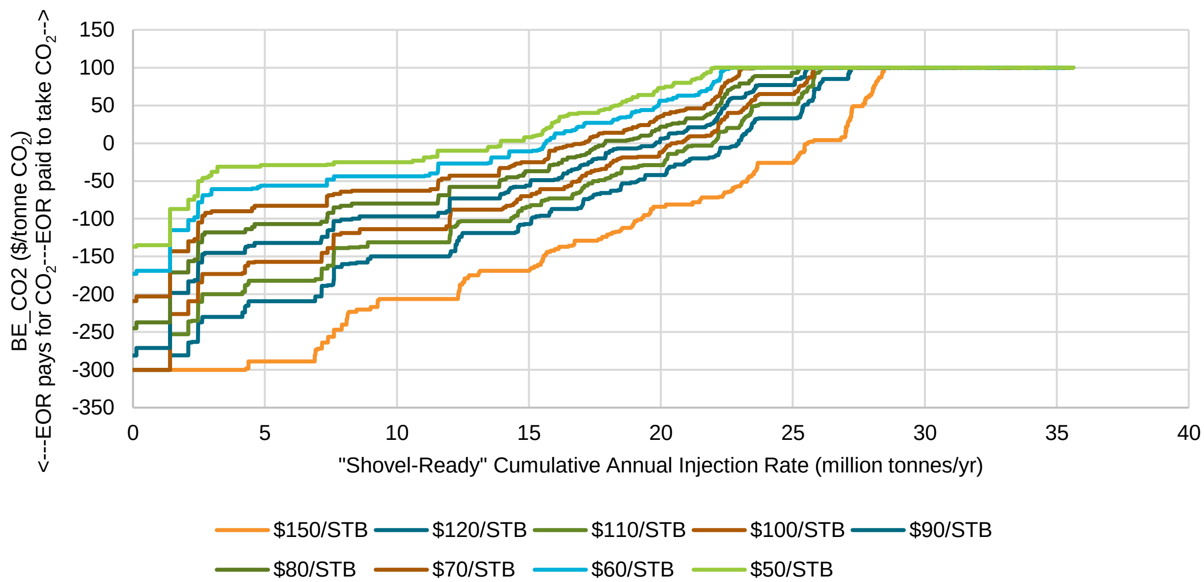

Figure 9. "Shovel-ready" I-WEST region annual purchased CO_2 injection rate as a function of CO_2 price by oil price

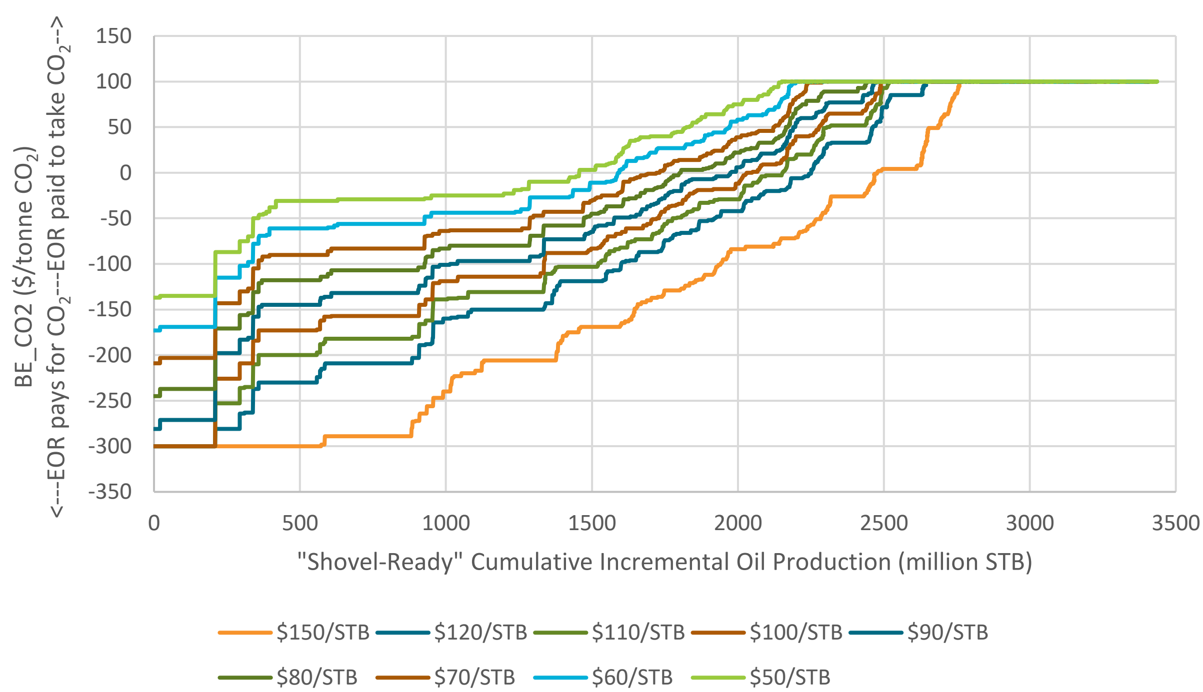

Figure 10. "Shovel-ready" I-WEST region incremental oil production from CO_2-EOR as a function of CO_2 price by oil price

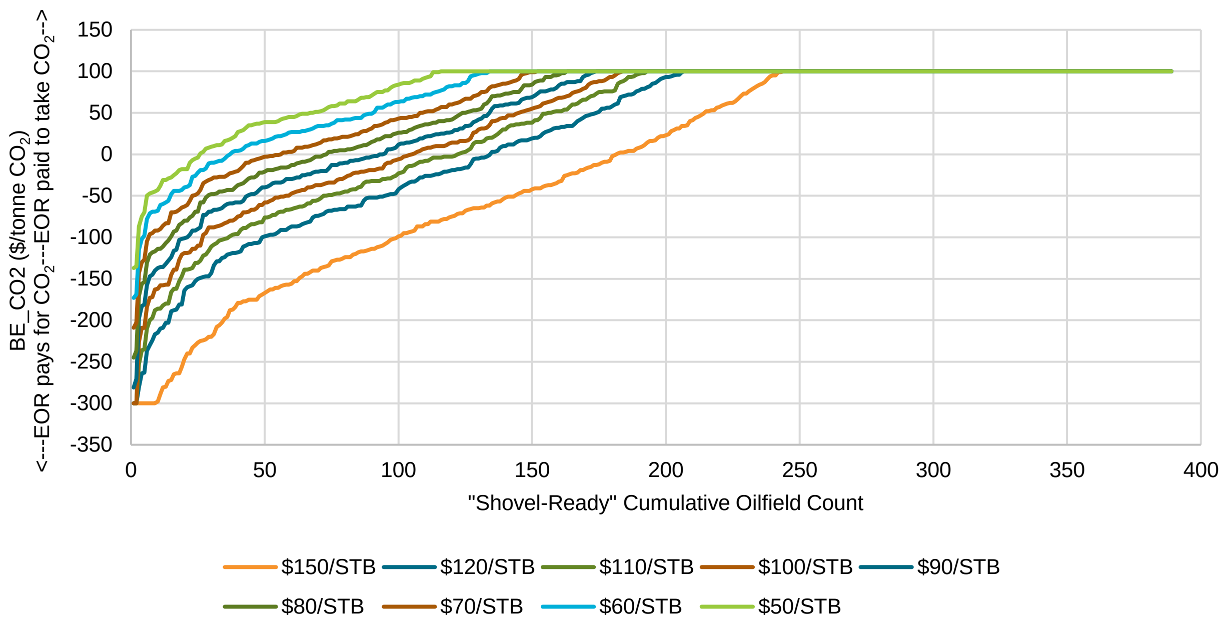

Figure 11. "Shovel-ready" I-WEST region oil fields engaged in economical CO_2-EOR as a function of CO_2 price by oil price

Table 14, generated from Figure 8, Figure 9, Figure 10, and Figure 11, shows the CO_2 EOR Evaluation System results for "shovel ready" oil fields for the "Conventional Economic Scenario" broken out by province-state combination. Table 14 shows that for the oil fields that might likely deploy CO_2-EOR in the near term, the I-WEST region could store 467 million tonnes of purchased CO_2, equivalent to 15.6 million tonnes/yr for 30 years. When accounting for "shovel readiness", Table 14 (along with Figure 12) demonstrates that 46% of the region's "shovel ready" purchased CO_2 storage capacity resides within I-WEST states and 86% of the region's total "shovel ready" purchased CO_2 storage capacity is concentrated in four provinces across four states: New Mexico's Permian Basin (31%; 145.8 million tonnes) and San Juan Basin (10%; 45.5 million tonnes); Kansas' Sedgewick Basin/Salina Basin (16%; 75.4 million tonnes) and Anadarko Basin (12%; 54.5 million tonnes); Oklahoma's Anadarko Basin (9%; 40.0 million tonnes), and Texas' Permian Basin (9%; 39.8 million tonnes). Figure 12 provides a heatmap that sums CO2_purch for technically feasible CO_2-EOR for "shovel-ready" CO_2-EOR by state.

Table 14. "Conventional Economic Scenario" "Shovel ready" I-WEST region CO_2-EOR results, by province-state

Province-State Combination	CO_2 Price (Negative is Cost to EOR Operator)	Oil Price	Total CO_2 Purchased	Total Annual CO_2 Injection Rate (30-year basis)	Total Incremental Oil Produced	Total Oil Fields Deployed
	2018$/tonne$CO_2$	2018$/STB	million tonnes	million tonnes/yr	million STB	count
Anadarko Basin_KS	-25	70	54.5	1.82	236	3
Anadarko Basin_OK	-25	70	40.0	1.33	156	6
Anadarko Basin_TX	-25	70	1.1	0.04	4	1
Bend Arch-Ft. Worth Basin_TX	-25	70	0.5	0.02	1	1
Cambridge Arch-Central Kansas_KS	-25	70	11.7	0.39	41	5

Cambridge Arch-Central Kansas_NE	-25	70	5.6	0.19	20	1
Denver Basin_NE	-25	70	0.3	0.01	1	1
Los Angeles Basin_CA	-25	70	12.7	0.42	36	1
Permian Basin_NM	-25	70	145.8	4.86	384	2
Permian Basin_TX	-25	70	39.8	1.33	97.0	7
Powder River Basin_WY	-25	70	3.0	0.10	8	1
San Juan Basin_NM	-25	70	45.5	1.52	218	2
Sedgwick Basin/Salina Basin_KS	-25	70	75.4	2.51	297	1
Southwestern Wyoming_WY	-25	70	10.9	0.36	22	1
Ventura Basin_CA	-25	70	9.0	0.30	34	1
Williston Basin_MT	-25	70	3.0	0.10	9	1
Wyoming Thrust Belt_UT	-25	70	8.1	0.27	23	1
Total			**467**	**15.56**	**1,587**	**36**

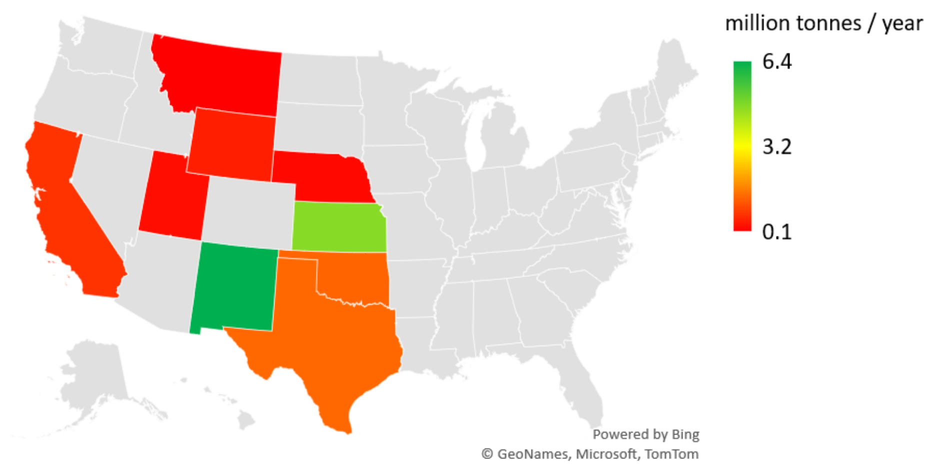

Figure 12. "Conventional Economic Scenario" I-WEST region "shovel-ready" annual CO_2 injection rate capacity, by state

Geologic parameters that impact CO_2-EOR economics, based on unpublished nationwide trend analyses, include reservoir size, measured as acre-feet of porosity, and reservoir homogeneity with respect to permeability (measured as Dykstra-Parsons coefficient [DPCoef]). Oil fields with relatively large acre-feet of pay generally have higher CO_2 storage capacity and can produce more incremental oil, improving CO_2-EOR project economics. Permeability homogeneity, (a lower DPCoef), too, generally correlates with improved CO_2-EOR economics, as homogenous permeability improves sweep efficiency (i.e., the amount of oil produced relative to the amount of oil that could possibly be produced from miscible CO_2-EOR; a proxy for conformance). Figure 13 shows "shovel ready" oil field average acre-feet of porosity and average DPCoef per oil field by state, sized by average CO_2 purchased per oil field, and demonstrates that New Mexico and Kansas have, on average, the largest oil fields with the second and third-most reservoir permeability homogeneity. Figure 14 shows the same results by province-state combination, and highlights that New Mexico's Permian Basin and San Juan Basin, and Kansas' Sedgwick/Salina Basin and Anadarko Basin have on average the largest oil fields and on average oil fields with among the more homogenous permeabilities.

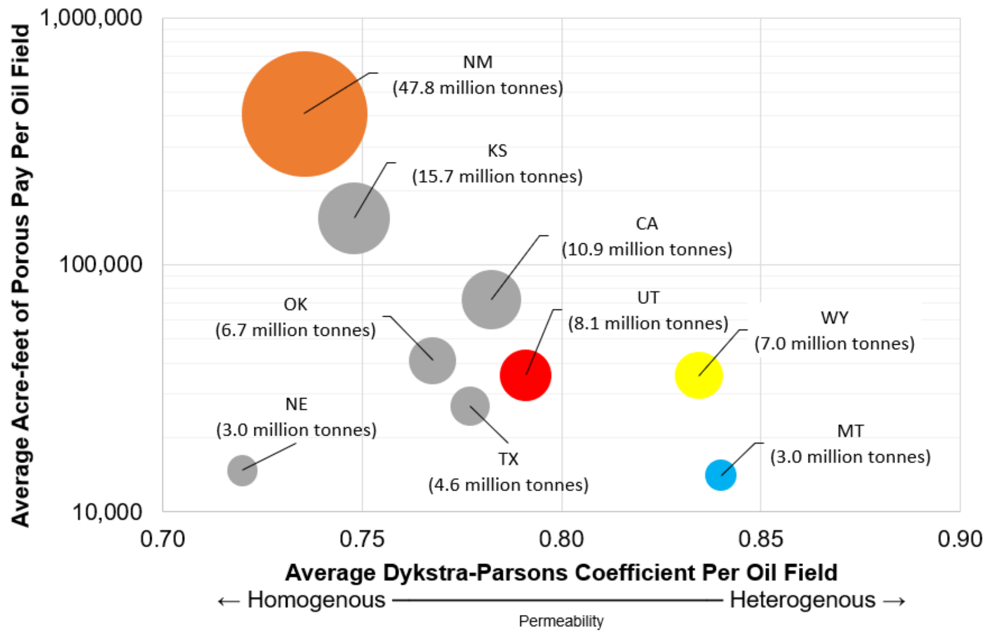

Figure 13. "Conventional Economic Scenario" average "shovel ready" oil field reservoir quality, by state, sized by state's average purchased CO_2 per field

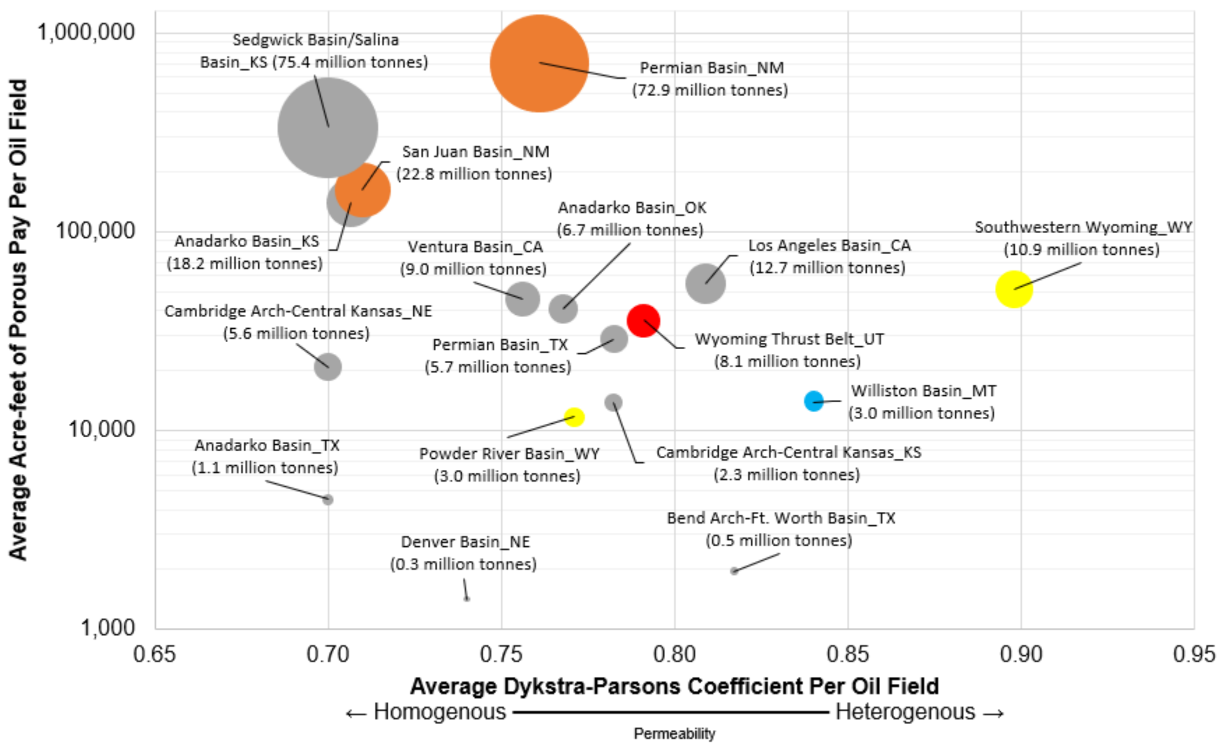

Figure 14. "Conventional Economic Scenario" average "shovel ready" oil field reservoir quality, by province-state combination, sized by average purchased CO_2 per field

4.4 Recommended Future Analyses

Several aspects of CO_2-EOR could be incorporated into future analyses including:

- Non-uniform rates of CO_2 purchase by EOR operators: This analysis reported CO_2-EOR annual injection rates assuming uniform injection over 30 years of CO_2-EOR operations to make CO_2-EOR results comparable with CO_2 saline storage results that assume 30 operating years. However, annual CO_2 purchase rate and annual CO_2 injection rate ramp up and then down over the life of a CO_2-EOR project as a result of both the EOR field operations expanding and then the reservoir filling up with CO_2, as well as produced CO_2 being recycled and reinjected. Figure 15 compares CO2_Prophet CO_2 mass flow rate outputs from a typical oil field in the dataset with the 30-year basis results (linear dashed lines) implied from the reported results.
- Oil field-specific duration of CO_2-EOR operations: The duration of economic CO_2-EOR operations also varies from oil field to oil field. Individual oil fields in the dataset are at $-25/tonne CO_2 and $70/STB oil and average 27 years of economic operation (the median is 18 years). Note that the particular oil field shown in Figure 15 operates for 18 years and has peak annual CO_2 purchase rates in operating years 7 and 8.
- Impact of state-specific and federal incentives and/or deterrents associated with CO_2-EOR operations: This analysis did not explicitly account for the impact of state and federal incentives, like the federal subsection 45Q carbon oxide sequestration tax credit (45Q). Future studies could account for and model the financial impact of such incentives; 45Q could reduce the cost of CO_2 incurred by CO_2-EOR projects, improving project economics, especially those with higher CO_2 utilization factors.
- Oil field-specific "cradle-to-grave" life cycle analysis of CO_2-EOR operations: This analysis did not assess potential CO_2 storage capacity in oil fields after CO_2-EOR operations cease. Regardless of the economic and regulatory obstacles of converting an oil field to a dedicated permanent CO_2 storage project, future analyses could be performed to estimate the amount of additional CO_2 that could be safely injected based on oil field-specific geologic data that assesses reservoir containment (for example, fracture gradient(s) of reservoir and caprock).
- Updated oil field dataset: The publicly-available wloil.txt dataset is outdated (it was last updated in 2014). More recent data, if available, would likely improve the accuracy of the injection rate and storage capacity estimates and trends derived by this analysis, especially by updating the "shovel-ready" list of oil fields.
- Potential use of CO_2-EOR oil fields for additional CO_2 storage capacity after tertiary oil recovery operations cease: While CO_2-EOR is a tool in U.S. decarbonization efforts, not all CO_2-EOR projects are themselves net zero, or net negative with respect to gate-to-gate carbon emissions. This study did not explicitly filter results to estimate how much incremental oil production from CO_2-EOR is estimated to be net zero or net negative. Incremental oil from CO_2-EOR is estimated to have a net life cycle CO_2 emission factor of 0.438 tonnes of CO_2 equivalent per barrel of oil produced when accounting for

upstream, gate-to-gate (assuming Ryan-Holmes gas processing), and downstream emissions, as well as displacement credit of U.S. grid electricity [32]. At the "Conventional Economic Scenario" of $-25/tonne CO_2 and $70/STB oil, only 18 oil fields could combine to inject 14.4 million tonnes/yr of freshly purchased CO_2 over a 30-year lifespan, store 433 million tonnes of CO_2, and produce 917 million STB of incremental "net negative" oil. Of these 18 oil fields, only 2 are "shovel ready", which could inject a combined 1.24 million tonnes/yr of CO_2 annually, store a total of 37.2 million tonnes of purchased CO_2, and produce 77.0 million STB of incremental "net negative" oil.

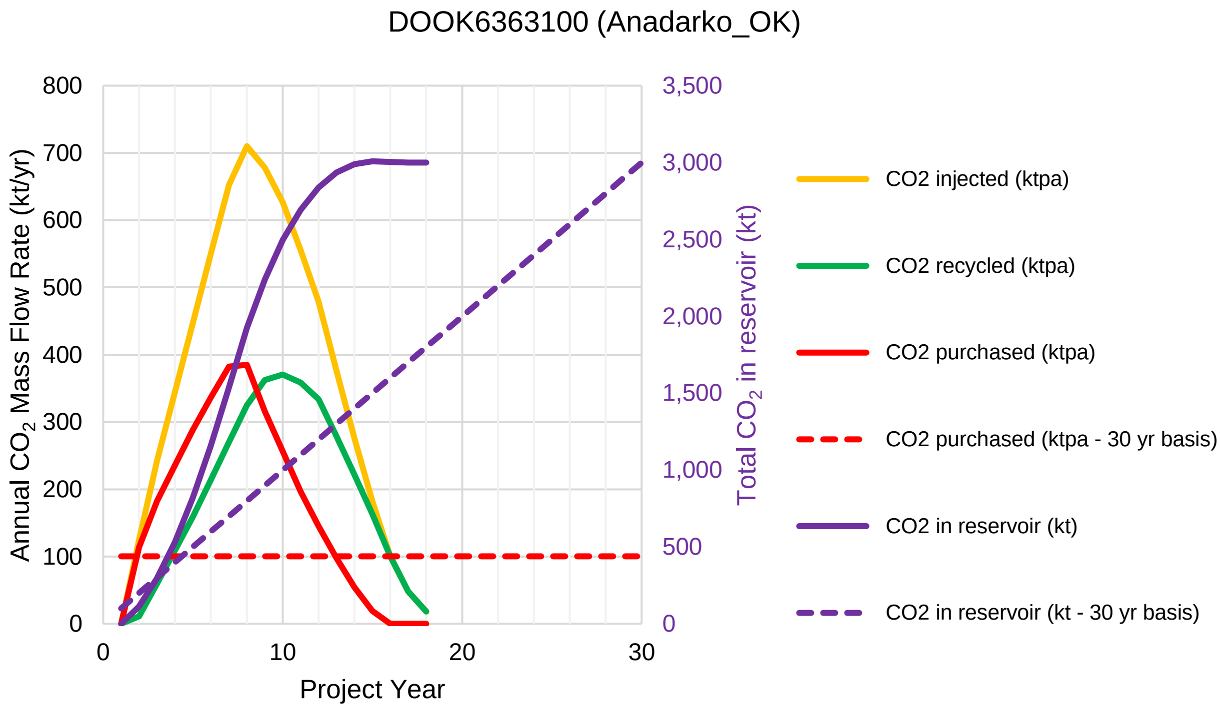

Figure 15. Example of oil field CO_2 mass flow rates output from CO2_Prophet compared with 30-year basis results

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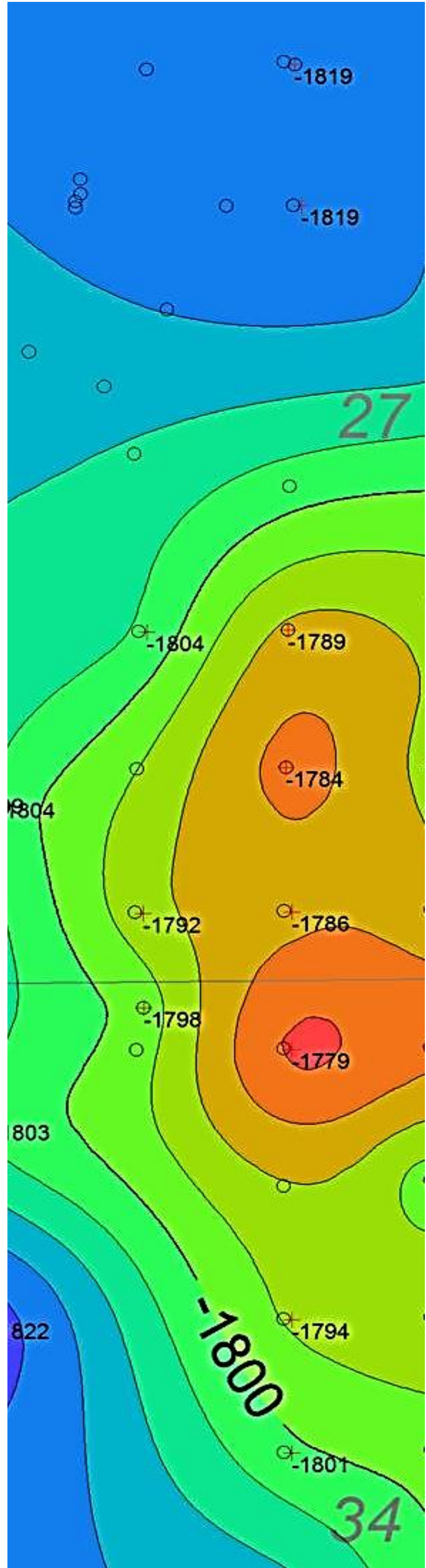

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