Leakage risk assessment of the In Salah CO_2 storage project: Applying the Certification Framework in a dynamic context

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Abstract

The Certification Framework (CF) is a simple risk assessment approach for evaluating CO_2 and brine leakage risk at geologic carbon sequestration (GCS) sites. In the In Salah CO_2 storage project assessed here, five wells at Krechba produce natural gas from the Carboniferous C10.2 reservoir with 1.7–2% CO_2 that is delivered to the Krechba gas processing plant, which also receives high-CO_2 natural gas (~10% by mole fraction) from additional deeper gas reservoirs and fields to the south. The gas processing plant strips CO_2 from the natural gas that is then injected through three long horizontal wells into the water leg of the Carboniferous gas reservoir at a depth of approximately 1,800 m. This injection process has been going on successfully since 2004. The stored CO_2 has been monitored over the last five years by a Joint Industry Project (JIP) – a collaboration of BP, Sonatrach, and Statoil with co-funding from US DOE and EU DG Research. Over the years the JIP has carried out extensive analyses of the Krechba system including two risk assessment efforts, one before injection started, and one carried out by URS Corporation in September 2008. The long history of injection at Krechba, and the accompanying characterization, modeling, and performance data provide a unique opportunity to test and evaluate risk assessment approaches. We apply the CF to the In Salah CO_2 storage project at two different stages in the state of knowledge of the project: (1) at the pre-injection stage, using data available just prior to injection around mid-2004; and (2) after four years of injection (September 2008) to be comparable to the other risk assessments. The main risk drivers for the project are CO_2 leakage into potable groundwater and into the natural gas cap. Both well leakage and fault/fracture leakage are likely under some conditions, but overall the risk is low due to ongoing mitigation and monitoring activities. Results of the application of the CF during these different state-of-knowledge periods show that the assessment of likelihood of various leakage scenarios increased as more information became available, while assessment of impact stayed the same. Ongoing mitigation, modeling, and monitoring of the injection process is recommended.

Keywords: In Salah; risk assessment; leakage risk; carbon dioxide

1. Introduction

The Certification Framework (CF) is a simple risk assessment approach for evaluating CO_2 and brine leakage risk at geologic carbon sequestration (GCS) sites [1] (Oldenburg et al., 2009). The In Salah Gas project at Krechba in the Sahara Desert of Algeria is the world's largest on-shore saline-formation GCS project and has been injecting an average of 0.74 Mt CO_2/yr for over six years into the water-leg of the Carboniferous C10.2 Krechba sandstone gas reservoir with average permeability of 10 mD at a depth of 1,800 m. The history of injection at Krechba, and the accompanying characterization, modeling, and performance data, including novel satellite-based ground-surface deformation data, provide a unique opportunity to test and evaluate risk assessment approaches. Over the years the In Salah partners have carried out extensive analyses of the Krechba system including two risk assessment efforts, one internal by the JIP before injection started, and one commissioned by the JIP and carried out by URS Corporation in September 2008 using the RISQUE approach (e.g., [2] Bowden and Rigg, 2004). In this report, we describe an application of the Certification Framework (CF). One of the challenges addressed in this study is the time evolution of risk assessment and how updated information is incorporated into risk assessment studies. In this

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study, two main time periods are considered, namely pre-injection (pre-2004), and pre-September 2008, which was the time at which the RISQUE approach was carried out. Additional comments on leakage risk based on post-October 2008 information are also presented at the end.

2. Overview of the CF

The purpose of the CF is to provide a framework for project proponents, regulators, and the public to analyze the risks of geologic CO_2 storage in a simple and transparent way to certify startup and decommissioning of geologic CO_2 storage sites. The CF currently emphasizes leakage risk associated with subsurface processes and excludes compression, transportation, and injection-well leakage risks. The CF is designed to be simple by (1) using proxy concentrations or fluxes for quantifying impact rather than complicated exposure functions, (2) using a catalog of pre-computed CO_2 injection results, and (3) using a simple framework for calculating leakage risk. For transparency, the CF endeavors to be clear and precise in terminology in order to communicate to the full spectrum of stakeholders. Definitions used in the CF are as follows:

- *Effective Trapping* is the proposed overarching requirement for safety and effectiveness.
- *Storage Region* is the 3D volume of the subsurface intended to contain injected CO_2.
- *Leakage* is migration across the boundary of the Storage Region.
- *Compartment* is a region containing vulnerable entities (e.g., environment and resources).
- *Impact* is a consequence to a compartment, evaluated by proxy concentrations or fluxes.
- *Risk* is the product of probability and consequence (impact).
- *CO_2 Leakage Risk* is the probability that negative impacts will occur to compartments due to CO_2 migration.
- *Effective Trapping* implies that CO_2 Leakage Risk is below agreed-upon thresholds.

In the CF, impacts occur to compartments, while wells and faults are the potential leakage pathways. Figure 1 (left-hand side) shows how the CF conceptualizes the system into source, conduits (wells and faults), and compartments HMR, HS, USDW, NSE, and ECA, where

- ECA = Emission Credits and Atmosphere
- HS = Health and Safety
- NSE = Near-Surface Environment
- USDW = Underground Source of Drinking Water
- HMR = Hydrocarbon and Mineral Resource

Figure 1 (right-hand side) shows a flow chart of the general CF logic and inputs and outputs. We note that for this application to the In Salah CO_2 storage project, a much more qualitative approach was taken. The reasons for this were primarily related to time available for the study. Simply put, the large amount of information available required time to digest, and there was little time and budget remaining to carry out the kinds of modeling that produce quantitative risk numbers. Nevertheless, we assert that the CF approach is still valuable even when qualitative measures of likelihood, impact, and risk are produced because the CF points out the key areas of concern for the project as discussed below. Details of the CF methods and approaches can be found in [1] (Oldenburg et al., 2009).

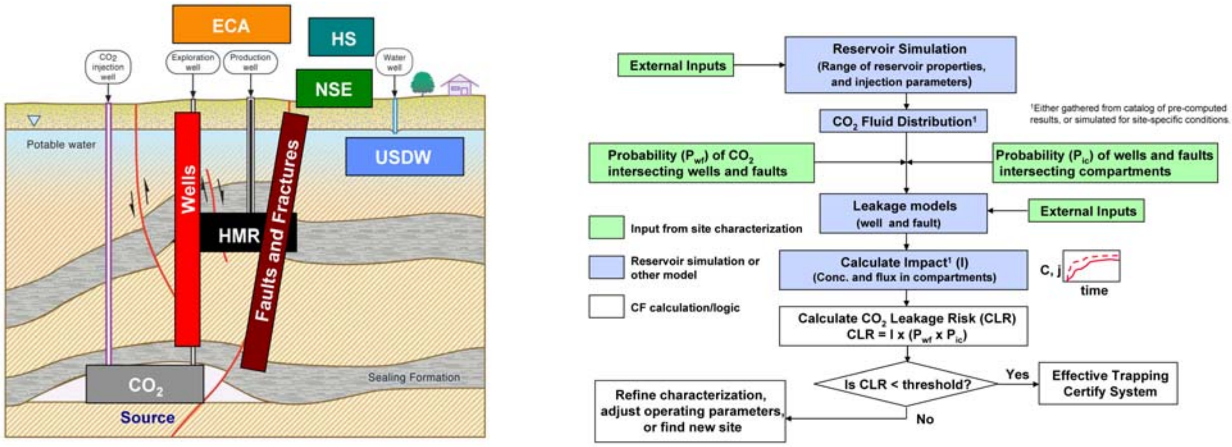

Figure 1. Generic schematic of compartments and conduits in the CF (left-hand side), and flow chart of the CF approach (right-hand side).

3. CF Application to the In Salah CO_2 storage project

3.1. Overview of the In Salah CO_2 storage project

Since 2004, the In Salah CO_2 storage project in Algeria has been injecting CO_2 stripped from produced natural gas into the water leg of the Carboniferous C10.2 gas reservoir at Krechba for long-term storage (e.g., [3] Ringrose, et al., 2009; [4] Dodds, 2009). The gas reservoir structure is a 20 m-thick sandstone anticline at a depth of approximately 1,800 m with gas-cap footprint of dimension 20 km (NS) by 8 km (EW). Storage of 17 to 23 Mt of CO_2 was planned over the 30-year project duration.

3.2. Geology

The Krechba site is located in the Saharan Desert of Algeria approximately 200 km north of In Salah town. As such, the region is dry, hot, windy, and largely unvegetated and unpopulated. The geology of this Central Sahara region consists of a Precambrian craton on which km-thick Paleozoic sediments were deposited and then folded during the Hercynian orogeny creating a series of basins and ridges. Paleozoic formations younger than Viséan were either not deposited or were eroded from the Krechba area resulting in the Hercynian unconformity at a depth of approximately 900 m. Devonian and Carboniferous strata with a thickness of >2 km have been the focus of oil and gas exploration at the Krechba field. Laterally extensive sealing mudstones provide effective seals that have trapped natural gas in a closed anticline at Krechba. Relatively undisturbed sediments lie above the Carboniferous C20 (Viséan) mudstone across the Hercynian unconformity. Late Jurassic and/or early Cretaceous lagoonal environments may be responsible for the basal 2-5 m (7-16 ft) thick anhydrite observed at Krechba.

3.3. Hydrology

The Continental Intercalaire (CI) aquifer covers a large section of the Algerian Sahara and is hosted by the continental formations of the Lower Cretaceous (e.g., [5] Mansour et al., 2009). The aquifer is confined at Krechba and resides in multiple layers of mudstone, sands, and gravels creating a complex aquifer system. The net thickness of water-producing zones (upper and lower units) is ~400 m and the total thickness of the aquifer complex is ~500 m. The local water-table depth is approximately 150 m bgs within the Upper Cretaceous. Water quality is good with less than 1,000 mg/L TDS to a depth of more than 500 m. Figure 2 summarizes the water quality and hydrostratigraphy at Krechba.

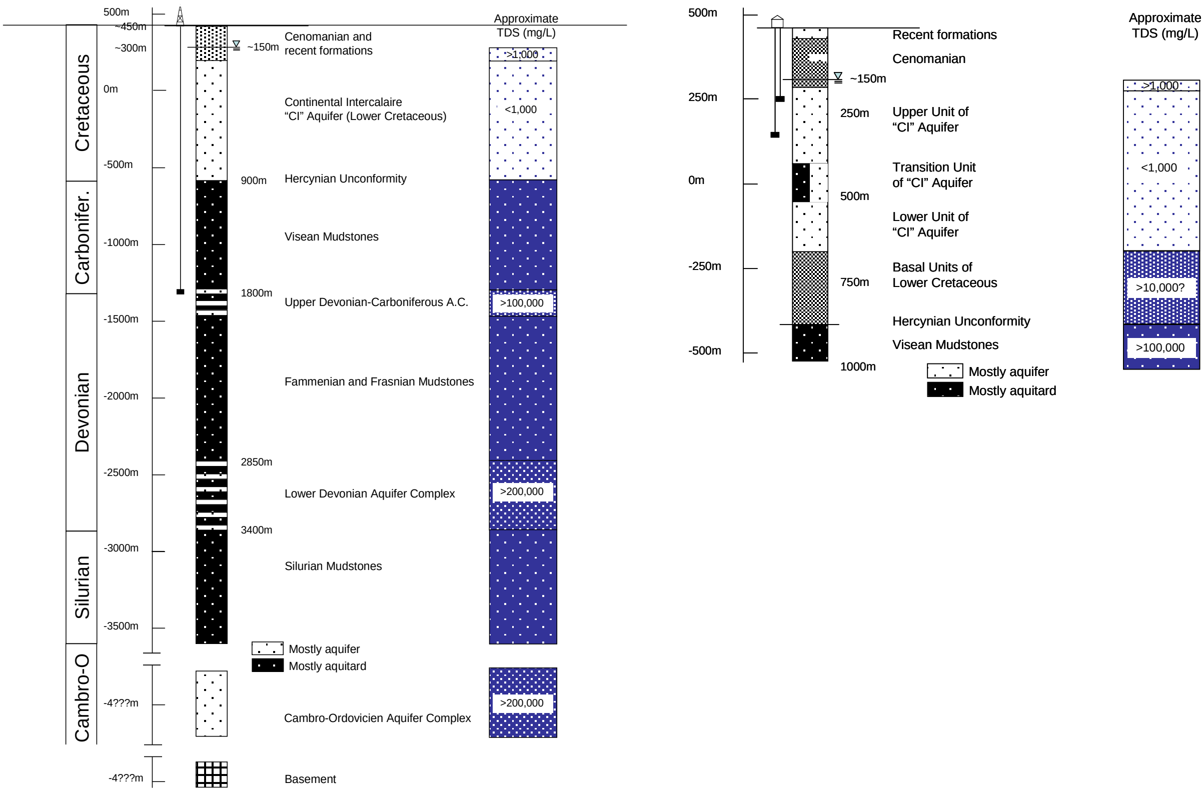

Figure 2. Generalized hydrostratigraphy and water quality in the Krechba area. (a) Whole section to the Cambrian; (b) section limited to Cretaceous strata.

3.4. Wells

Sixteen wells comprising appraisal (oldest), gas production, and CO_2 injection wells (newest) penetrate the C10.2 gas reservoir. The five Carboniferous gas production wells and three CO_2 injection wells have long horizontal sections within the C10.2 for enhanced production and injection, respectively. Figure 3 shows different views of the various wells.

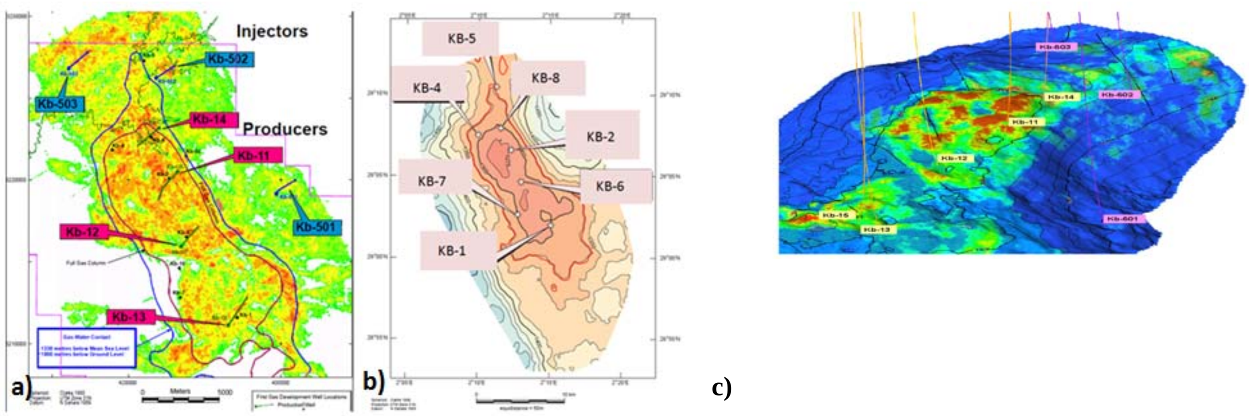

Figure 3. (a) Production and injection wells, (b) appraisal wells, and (c) three-dimensional structure contour of the C10.2 reservoir with color contours of porosity as interpreted by seismic data (Ringrose, pers. commun.) Kb-501, 502, and 503 are the CO_2 injection wells. Kb-11, 12, 13, 14, and 15 are gas production wells.

3.5. Faults and fractures

The conceptual geologic model of Krechba involves the broad two-way plunging anticline being influenced by underlying strike-slip faulting with a component of reverse displacement. These faults are reactivated and were formerly extensional faults. Predominantly east-west faults on the west limb and some subtler faults on the east limb are associated with these deeper faults. Drilling mud losses have occurred at various depths in the Viséan suggesting fractures are present.

3.6. Production and Injection Modeling

Reservoir modeling of gas production and CO_2 injection were carried out using CMG-GEM to predict the extent of CO_2 migration and pressure changes. Results showed CO_2 migration is very limited and mostly does not enter the gas cap as shown in Figure 4. Pressure change over the reservoir is also very small due to the compensating effects of pressure decline caused by natural gas production and pressure rise due to injection. The implication of small migration distance is that generally only the injection wells themselves are at risk of being potential CO_2 well leakage pathways, the well pair KB-5 and KB-502 being the exception.

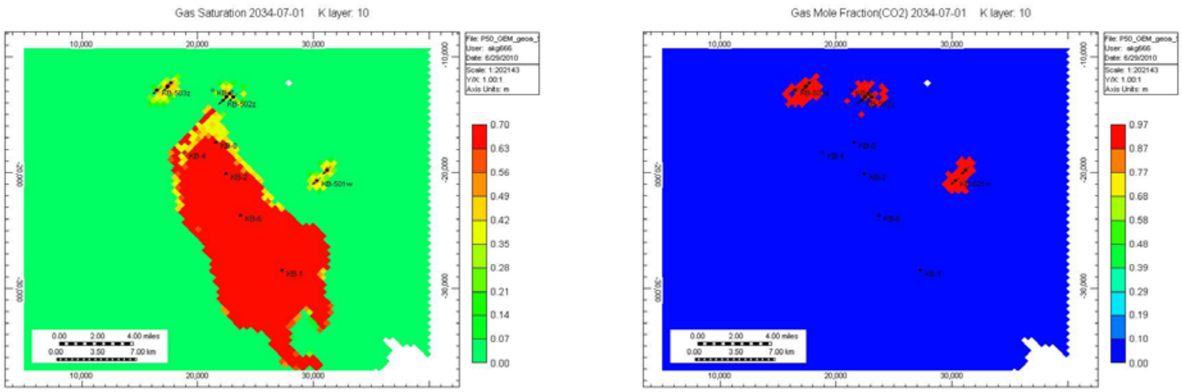

Figure 4. Gas saturation (left-hand side) and CO_2 mole fraction in the gas (right-hand side) after 30 years of natural gas production and CO_2 injection showing the limited extent of CO_2 migration and entry into the gas cap.

3.7. Storage Region Definition

For the purposes of this CF analysis, the lateral boundaries of the storage region will be defined in two different ways to honor the temporal aspects of the system relative to production of the natural gas resource in the C10.2 reservoir at Krechba. In particular, the storage region for the next 20 years requires two lateral boundaries: (1) a boundary defined by the edge of the gas cap, and (2) the lease boundary. After 20 years, the lateral boundary of the storage region will be the lease boundary all around the reservoir because the natural gas resource will be considered depleted. The bottom boundary is the D55 unit. As for the upper boundary, the top of the C20.7 unit is a natural choice for the effective cap rock because it is predominantly mudstone within which no mud loss events occurred. With these choices of boundaries for the storage region, the only CO_2 leakage fluxes that need to be considered are (1) upward to USDW or higher compartments through wells and faults, and (2) laterally for the next 20 years into the Krechba gas resource.

3.8. *Terminology for Likelihood, Impact, and Risk*

The CF project has defined terminology to describe approximate likelihoods as shown in Table 1. In the discussion below, likelihood terminology can be referenced to this table.

Table 1. Expectation terminology (modified from Hnottavange-Telleen, Schlumberger Carbon Services)

Occurrence expectation terminology	**If there were 100 projects like the In Salah JV,**
Improbable	…less than once in the 100 projects
Unlikely	…in 1 to 5 of the 100 projects
Somewhat likely	…in 6 to 10 of the 100 projects
Likely	…in 11 to 50 of the 100 projects
Very likely	… more than 50 times within the 100 projects

As for impact severity, we use the words negligible, low, medium, and high to describe impacts. Negligible means that it would be difficult to even detect or measure an impact. Low severity implies that the impacts are small, and should be acknowledged and possibly mitigated, but will not lead to a risk level warranting extensive or urgent mitigation. A moderate impact is one that could bring the risk level to one where risk mitigation should be carried out. High impacts will nearly always trigger risk mitigation, even when the likelihood is small.

In terms of risk terminology, we use the term de minimis to indicate a risk that is so low that for all practical purposes (e.g., as a target of mitigation), it can be ignored. A low risk implies a risk that should be acknowledged but does not warrant large expense or focus for mitigation. A moderate risk is one that should be mitigated to reduce the risk. A high risk clearly requires focused mitigation.

3.9. Leakage Risk Based on Pre-injection Information

3.9.1. Wells

Statistical data on well blowouts (defined as uncontrolled leakage from a well, no matter how small) from oil and gas operations in general can be used to estimate a likelihood of approximately 1% that a CO_2 injector well will blowout in the project lifetime [6] (Jordan and Benson, 2008). The non-operational wells are not expected to encounter CO_2 within many decades with the exception of KB-5 (which had a very small uncontrolled leakage amounting to less than one tonne of CO_2) and possibly KB-4 which are relatively close to injectors KB-502 and KB-503. Statistics for non-operational wells suggest that a blowout from such wells is improbable, however, impact severity is potentially high, so the integrity of these wells should be evaluated and checked at appropriate intervals. If necessary, full decommissioning should be carried out at an appropriate time. Depending on the abandonment procedure, well leakage of CO_2 would then become unlikely to improbable, rendering the well leakage risk low. The corresponding brine leakage risk is considered very low because of the small driving force for brine flow.

3.9.2. Faults and Fractures

With respect to leakage through faults and fractures, the static and post-closure periods are not a concern due to the record of gas accumulation and the long-term pressure decline expected in the system due to gas production. However, the injection period will produce overpressures that are of concern. In particular, the planned injection pressure window proposed is such that it will re-activate fractures in the C10.2, and possibly the overlying C10.3 to enhance injectivity, but that will not open fractures in the overlying C20. Based on this strategy and the reservoir depth, the upper limit of the injection pressure was variously set at 24 MPa or 29 MPa (3,500 psi or 4,200 psi). The former is equivalent to a gradient just above 1.3 SG (SG = specific gravity of water) and the latter to 1.45 SG given the reservoir depth. Given that injection may re-activate fractures up to the C10.3 and become filled with CO_2, fractures can be expected to extend relatively unattenuated to the base of the C20.1. By defining the upper storage region boundary at the C20.7, such upward migration is not considered leakage. However, further fracture propagation to the C20.7 and beyond cannot be ruled out. Therefore we assess fault/fracture leakage as improbable, but when combined with high potential impacts of such leakage on USDW, the results of fault/fracture leakage risk to USDW is considered low. The corresponding leakage of brine is considered de minimis through faults and fractures.

A summary of the pre-injection results is presented in Table 2. There is a tradeoff for wells in that some wells can provide valuable monitoring data-points, e.g., ground truth of CO_2 arrival, but such wells also represent a non-zero likelihood of well leakage. The project must balance the needs of a research project with the needs of an industrialscale storage project. We recommend that the integrity of wells be evaluated and checked at appropriate intervals. If necessary, full decommissioning should be carried out at an appropriate time. Modeling of coupled hydro-geomechanical effects should be continued to evaluate fracturing and faulting that could arise from high injection pressure

Table 2. CO_2 and brine leakage risk summary based on information known up to the time of injection (mid-2004).

Scenario	Pathway	Likelihood	Impact	Risk	Notes
Downward CO_2 leakage	Wells	Improbable	HMR (negligible)	De minimis	Wellbore integrity assumed excellent for the injection wells.
	Fractures/Faults	Improbable	HMR (negligible)	De minimis	Pressure dissipation and lower density of CO_2 reduce driving force.
Downward brine leakage	Wells	Improbable	HMR (negligible)	De minimis	Wellbore integrity assumed excellent for the injection wells.
	Fractures/Faults	Improbable	HMR (negligible)	De minimis	Pressure dissipation reduces downward driving force.
Upward CO_2 leakage	Wells	Unlikely-improbable	USDW (high)	Low	Depends on mitigation and/or abandonment
	Fractures/Faults	Improbable	USDW (high)	Low	Fracture flow very likely near reservoir, but not above C20.7
Upward brine leakage	Wells	Improbable	USDW (low)	Low	Small driving force.
	Fractures/Faults	Improbable	USDW (negligible)	De minimis	Small driving force.
CO_2 leakage into gas cap		Very likely	HMR (low)	Low	Risk low for 20 years, then drops to de minimis for the following 10 years.
CO_2 leakage across lease boundary		Improbable	Negligible	De minimis	

3.10. Leakage Risk Based on Information Prior to September 2008

Cement bond log (CBL) surveys of wells at Krechba have been carried out by various operators during the exploration and appraisal phase, results from which were made known in 2006 (after start-up of injection). CBL results revealed that several intervals in several appraisal wells have very bad cement bonds. Modeling of leakage fluxes up injection wells with good cement bonds produced fluxes of CO_2 too small to have measurable impact. Other injection wells with bad cement bonds provide a higher probability of subsurface blowout.

KB-5 experienced a minor wellhead leak of CO_2 in 2007, following the arrival of CO_2 from KB-502 much faster than expected [3] (Ringrose et.al., 2009). The flow rate of gas through this opening was small and the well is located in an unpopulated desert, so the consequence of this uncontrolled wellhead leak was negligible. We understand that KB-5 has now been fully decommissioned, but the occurrence of KB-5 well leakage raised the expected probability of well leakage to likely from improbable-unlikely as observations revealed faster CO_2 transport than was modeled, cement bonds may be bad, and the scenario of unauthorized wellhead modifications occurred. While ECA impacts are still low from such events, USDW impacts may be high resulting in an assessment that such leakage risk is moderate.

Modeling of the bottom hole pressure for KB-501 using the methods of [7] Pan et al. (2009) for a variety of well head pressures and injection rates suggests that injection pressures may be above the 24 MPa (3,500 psi) injection pressure threshold established to limit upward fracturing into the C20. The modeled injection pressures put the system at high likelihood of leakage from the storage region potentially resulting in impact to USDW. For this reason, CO_2 leakage risk through faults and fractures increased to moderate for the pre-September 2008 period relative to the pre-injection knowledge base. As a result, CO_2 injection rates have been reduced to reduce this risk.

3.11. Post-October 2008 Leakage Risk Update.

Additional information became available on the CI, and new water wells were constructed, but neither of these developments played any role in changing earlier assessments. Recent analysis of InSAR data suggest some pressurization may have occurred at the base of the Viséan but still within the storage region, a topic of ongoing research using approaches such as those of [8] Rutqvist et al. (2009) and [9] Iding and Ringrose (2010).

3.12. Overall Recommendations

Given the occurrence of faster-than-expected flow of CO_2 from KB-502 to KB-5 along the preferred orientation of faults, we note the potential for accelerated transport of CO_2 from KB-503 to KB-4, and recommend that the integrity of legacy wells KB-2, 4 and 8 should be evaluated and checked at appropriate intervals. If necessary, full decommissioning of these wells should be carried out at an appropriate time.

Work should be undertaken to determine if PSInSAR data inversion can discriminate brine pressurization in the base of the Viséan alone from upward movement of CO_2 via numerous fractures in addition to such pressurization.

Continued injection at the pressures maintained to date creates a significant opportunity for leakage out of the storage region that would propagate upward toward to USDW. Modeling of such an occurrence should be undertaken to determine the flow rates that might occur if such an event occurred.

A more prudent course of action would be to limit the pressures in all three injection wells to the lower end of the fracture gradient range for the base of the Viséan (we understand that this is now implemented). There should be a discussion of the appropriate safety factor to apply based on fracture gradient measurement accuracy and spatial variability, and then the upper pressure should be set based on dividing the difference of the fracture pressure and the original reservoir fluid pressure by this safety factor.

Acknowledgments

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