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Quantitative Risk Assessment of Leakage through Legacy Wells in Support of Permit Application for a Large-scale CO_2 Injection Project in Southwestern US

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Abstract

The US DOE funded San Juan Basin CarbonSAFE project is focused on developing an integrated CCS project located in the San Juan Basin, NM, USA. One of the primary requirements of the Class VI permit application that will have to submitted for the project is demonstrating that the proposed CO_2 injection operations will not lead to endangerment of underground sources of drinking waters (USDW) due to leakage through legacy (or existing) wells that may lie within a pressure dependent area of review (AoR). Using a CO_2 injection scenario, we demonstrate various steps associated with evaluation of endangerment of USDW. An area of review associated with the injection scenario was delineated using the results of numerical reservoir simulations and existing wells penetrating the target zone within the AoR were identified. The identified wells included plugged and abandoned wells as well as salt-water disposal wells. Not all the wells fell within the predicted boundary of CO_2 plume. A quantitative assessment was performed to evaluate the risks associated with CO_2 and brine leakage through the existing wells within the area of review. The leakage risk assessment was performed using the NRAP-open-IAM tool developed by US DOE's National Risk Assessment Partnership. The tool utilized predictions of pressures and saturations in the storage reservoir, characterization data on existing wells within the area of review, and information on regional groundwater aquifer. The NRAP-open-IAM calculations indicated no significant threat to regional groundwater due to leakage through the existing wells within the predicted area of review. Information on well status, well completions as well as plugging and abandonment was utilized in conjunction with the results of leakage risk assessment and reservoir simulations to evaluate the need for corrective actions. Our evaluation indicated that a phased approach for corrective actions could be utilized based on multiple factors including, status of the existing wells, their locations within the predicted pressure and saturation plume and no predicted endangerment of groundwater through leakage risk assessment. Results of this project will be a good reference for other projects that will need to address corrective actions for the legacy wells while developing CO_2 injection permit applications.

Keywords: UIC Class VI permit application; leakage risks; legacy wells; quantitative risk assessment; NRAP-open-IAM; corrective action plan

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1. Introduction

The US Department of Energy (US DOE) is facilitating accelerated deployment of commercial scale geologic CO_2 storage (GCS) projects through its CarbonSAFE (Carbon Storage Assurance Facility Enterprise) initiative. The overall goal of the CarbonSAFE initiative is to address key gaps in the commercial deployment of carbon capture and storage (CCS) technology. Currently, the initiative is in Phase-III with a focus on addressing issues associated with site characterization and permitting of large-scale projects. US DOE has funded five large-scale storage (50+ million tons cumulative storage) projects, including the San Juan Basin CarbonSAFE (SJB-CarbonSAFE) project led by New Mexico Institute of Mining & Technology (NMT). The primary objective of SJB-CarbonSAFE project is to perform comprehensive characterization of storge complex located in the San Juan Basin and to develop a permit application needed for deployment of a commercial scale integrated CCS project to be located within the basin.

1.1. SJB-CarbonSAFE project

The San Juan Basin is primarily located in the northwest New Mexico and extends into southwest Colorado (Fig. 1). The basin is a 26,000 square mile, bowl-shaped depression containing more than 14,000 feet of sedimentary rocks from the Paleozoic to Recent. It is one of the oldest oil and gas producing basins in the US with the first documented

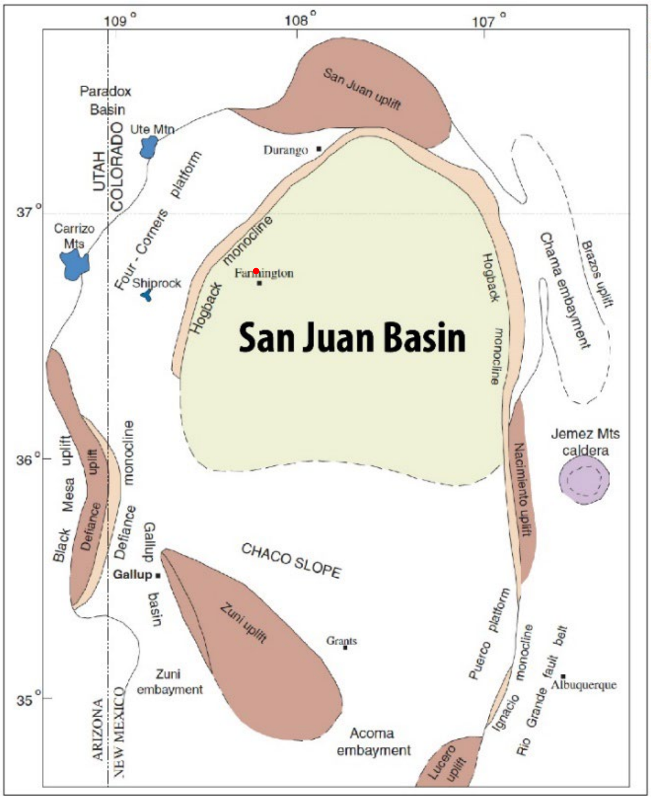

Fig. 1. Location of the San Juan Basin.

oil and gas producing wells drilled in 1911 and 1921, respectively. Since the discovery of oil and gas, over 42,000 wells have been drilled and over 300 oil and gas fields have been developed within the basin. To date >335 million barrels of oil and >54 TCF of natural gas has been produced from these fields. In addition to the oil and gas bearing formations, multiple deeper saline aquifers exist in the basin that can be potential GCS targets. The DOE funded

Southwest Regional Partnership has identified ~198 billion tons of initial CO_2 storage capacity in the basin including approximately 182 billion tons in the deeper saline aquifers.

The SJB-CarbonSAFE project is associated with an integrated CCS project the includes capturing CO_2 emissions from a source located in the vicinity of the San Juan Basin. The primary focus is developing a storage project that will inject all or part of the captured CO_2 in the suitable saline aquifers. Utilizing all data available from the past exploration, production and other characterization activities, the SJB-CarbonSAFE project team has identified three Jurassic sandstone formations as the reservoirs that have the best and safest potential to store large volumes of CO_2 - the Salt Wash Member of the Morrison Formation, the Bluff Sandstone, and the Entrada Sandstone (Fig. 2).

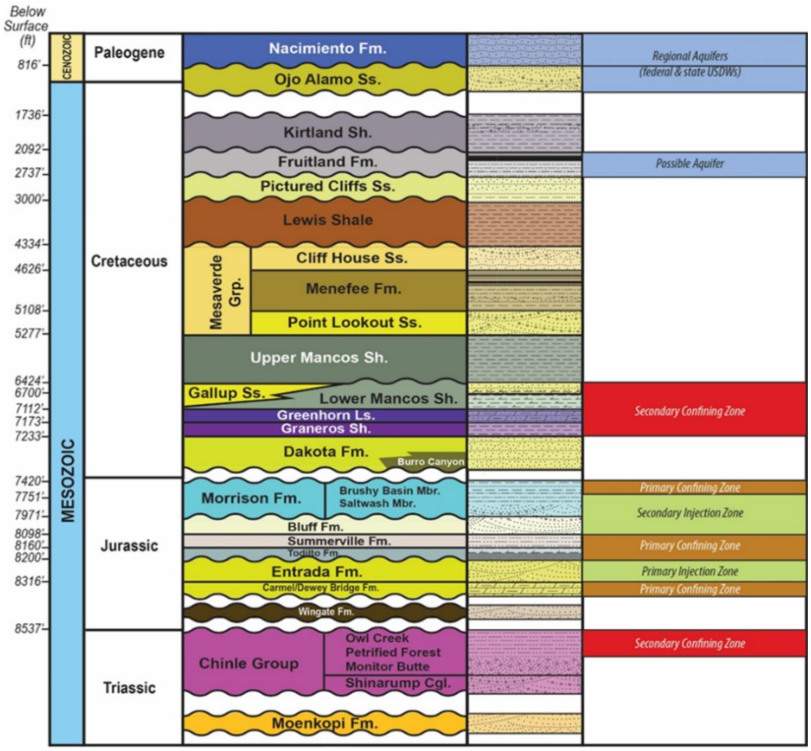

Fig. 2. Stratigraphy of San Juan Basin.

There are multiple, aerially extensive confining zones including, the Brushy Basin Member of the Morrison Formation, the Summerville Formation, the Todilto Formation, and the Carmel Formation, which will be the primary confining zones. In addition, multiple secondary confining zones also exists including, the Cretaceous Mancos Shale, Greenhorn Limestone and Graneros Shale (above) and the siltstones and shales of the Triassic Chinle Group (below). The SJB-CarbonSAFE project has performed further characterization and modeling necessary for putting together an application to receive the permit required for developing and operating a GCS project within the San Juan Basin.

1.2. GCS permit application

In US, the injection of CO_2 in the subsurface reservoirs for the purpose of long-term storage is regulated by the US Environmental Protection Agency (US-EPA) through its Underground Injection Control (UIC) program. The primary goal of the UIC program is to protect the underground sources of drinking water (USDW) from endangerment by ensuring safe injection of fluid in subsurface formations. US-EPA added a new class of injection wells, Class VI, for GCS as part of the UIC program and published related regulatory requirements in 2010. Under the regulations EPA has developed specific criteria for Class VI wells for site characterization, CO_2 injection well construction, CO_2 injection well operations, monitoring during as well as after injection, financial responsibility and reporting.

Any owner/operator of a GCS project is required to submit a permit application for the construction and operation of a Class VI injection well. One of the requirements for the Class VI well owner/operator is to delineate an area of review (AoR) for the proposed injection well, which is the region surrounding the well where the regional USDWs may be endangered due to deeper injection activities. The AoR is required to be delineated using computer modeling. After delineating the AoR the owner/operator is required to identify all potential conduits for fluid movement out of the injection zone including natural features (such as faults/fractures) and artificial penetrations (i.e. wellbores) that lie within the AoR. The owner and operator are further required to evaluate whether these pathways could serve as conduits for fluid movement and perform corrective actions necessary to ensure no fluid movement.

Given the presence of legacy wells in the San Juan Basin, one of the critical aspects a GCS project focused in the basin will have to address is evaluation of endangerment of the regional USDW through legacy wells within the AoR. For the SJB-CarbonSAFE project we utilized the quantitative leakage risk assessment approach developed by US DOE's NRAP (National Risk Assessment Partnership) project as part of the evaluation of endangerment of USDW.

1.3. NRAP's leakage risk assessment approach

The NRAP approach is built around integrated assessment modeling [1,2] for quantifying leakage risks. The integrated assessment modeling approach is built on systems-modeling approach that takes into consideration key components of a GCS system including storage reservoir, leakage pathways (e.g. wells, faults) and receptors (e.g. shallow formations including groundwater, atmosphere). Models simulating CO_2 and brine flow through the various afore-mentioned components and resulting interactions are linked together in an integrated assessment model for simulating behavior of the entire GCS system. The component models are developed to provide higher computational efficiency than high-fidelity models such as reservoir simulators. The NRAP team has utilized various approaches to develop high computational efficiency models including reduced order approximations of high-fidelity models, lookup tables of high-fidelity model outputs or analytical/semi-analytical models. The outputs of integrated assessment model include leakage rates of CO_2 and brine as well as impacts such as changes in pH or TDS in groundwater. The integrated assessment model enables efficient computations of large number of simulations of the entire GCS system and probabilistic estimates of quantities of interest for quantification of leakage risks.

2. Leakage risk assessment

Our workflow for leakage risk assessment included i) development of a reservoir model and predictions of CO_2 storage reservoir behavior through reservoir simulations of CO_2 injection, ii) delineation of AoR, iii) identification of existing wells within the AoR, iv) development of site-specific integrated assessment model with NRAP-open-IAM and v) quantification of leakage risks.

2.1. Reservoir simulations and AoR delineation

The project team utilized characterization data for San Juan Basin to develop a static geologic model for the basin. The geologic model extended from the surface alluvium to the Pre-Cambrian basement at the bottom. The available petrophysical data was used to develop facies model and generate porosity and permeability distributions throughout the model domain. The static geologic model was used to develop a dynamic reservoir simulation model using the Eclipse reservoir simulator. The reservoir model domain covered an area of 3691.17 mi^2 (60.72 miles x 60.79 miles). Unlike the geologic model, the vertical extent of the reservoir model only extended from the top of Dakota sandstone to the bottom of Owl Creek formation (refer to Fig. 2). This setup included the Entrada formation (the primary target zone), the Todilto formation (low permeability confining zone above Entrada) and Carmel formation (low permeability confining zone below Entrada). The numerical grid consisted of 322 x 321 x 29 cells in the x, y and z directions respectively (2,886,660 cells). The rock-fluid properties as well as initial conditions were set up using available characterization data. The reservoir model domain covered a portion of the San Juan Basin. The primary storage reservoir (Entrada formation) extends throughout the basin and beyond the boundaries of the reservoir model. To account for its continuity, the storage reservoir side boundaries were assumed to be constant pressure open flow boundaries. The top and bottom boundaries were assumed to be no-flow boundaries.

Given that there are no hydrocarbons present in the Entrada formation, there have not been any historic production activities from it in the proximity of the area of inteest. On the other hand, the formation has been used for disposal of salt-water that is produced from the shallower hydrocarbon fields in the basin. We utilized the available data for injection rates and surface injection pressures for salt-water disposal wells to perform a history match of the dynamic reservoir model as well as to set up initial hydrostatic conditions prior to beginning of CO_2 injection.

The history matched model was subsequently used to perform numerical simulations of CO_2 injection. The SJB-CarbonSAFE team has explored multiple injection scenarios that can be potentially utilized to inject all or part of captured CO_2. Here we discuss results associated with one of the scenarios – injection of 6.2 million tons CO_2 per year using 10 injection wells. For reservoir simulations the cumulative injection amount was distributed among the injection wells using a group injection rate control with the maximum injection rate for individual wells at 1.5 million tons/yr. The maximum pressure constraint at the bottom holes of the injection wells was set at 80% of the prevalent fracture pressure gradient derived lithostatic pressures. The total simulation time was 100 years, including a 30-year pre-injection period, a 20-year injection period and a 50-year post-injection period.

The predicted reservoir pressures at the end of the injection period were used to delineate an AoR. The critical pressure needed to delineate the AoR was estimated using the US-EPA recommended computational approach. The approach required the predicted value of average reservoir pressure at the end of injection (estimated from reservoir simulations results), the salinity of water in the storage reservoir (14,400 ppm for Entrada formation) and the depth of lowermost USDW (we used the average depth of the Fruitland formation which is shown in Fig. 2). Fig. 3 shows the boundary of the estimated AoR. The figure also shows the predicted boundary of the CO_2 saturation plume at the end of injection. The predicted AoR is significantly larger than the predicted CO_2 plume as seen in Fig. 3. Additionally, the figure also demonstrates that the spatial distribution of pressure and CO_2 saturation in the reservoir is influenced by the permeability and porosity heterogeneity.

2.2. Existing (legacy) wells within the AoR

Next, the delineated AoR was used to identify existing wells within the AoR boundary that penetrate the primary confining zone. While a large number of wells have been drilled in the San Juan Basin, only ~150 wells extend into the Entrada formation. Utilizing public records on the wells within San Juan Basin (available through State of New Mexico Oil Conservation Division), we identified five existing wells within the predicted AoR boundary that penetrate the Todilto formation, the primary confining zone. Locations of these wells are shown on Fig. 3. Two of the five existing wells lie within the predicted CO_2 plume boundary while three lie outside of that boundary. The locations of the existing wells and local stratigraphic details were subsequently used for leakage risk simulations.

2.3. Leakage risk simulations using NRAP-open-IAM

As mentioned earlier, we used NRAP's integrated assessment modeling (IAM) approach to quantify the leakage risks through the five existing wells the lie within the predicted AoR. We developed a site-specific integrated assessment model using the NRAP-open-IAM tool. The primary components in the site-specific NRAP-open-IAM based model included the primary storage reservoir, existing wells, the regional USDW and the atmosphere. Models utilized for each of these components are briefly discussed below.

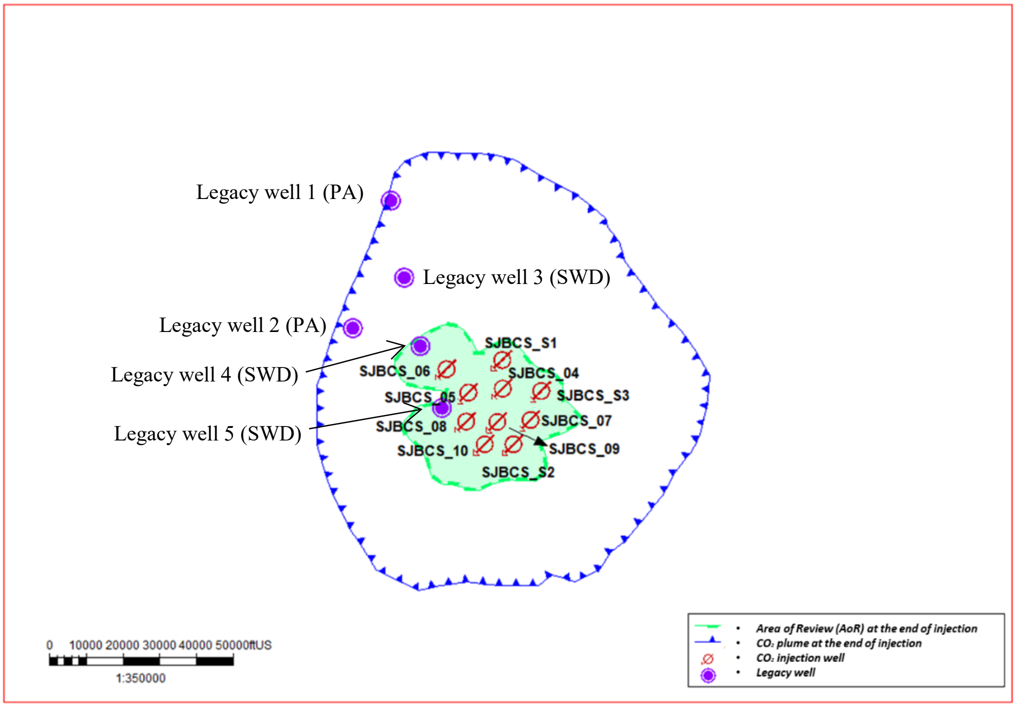

Fig. 3. Predicted AoR and CO_2 plume at the end of injection for one of the injection scenarios.

The purpose of the component model for primary storage reservoir is to predict changes in pressures and saturations in the reservoir resulting from CO_2 injection. For the SJB-CarbonSAFE model we directly utilized the predictions of Eclipse reservoir simulations using the lookup-table approach in NRAP-open-IAM.

The purpose of the component model for existing well is to predict CO_2 and brine leakage rates through the wells resulting from the changes in pressures and saturations in the primary storage reservoir. We utilized the cemented wellbore component model in NRAP-open-IAM. For each well the input data included location, depth to the storage reservoir, depth to the USDW and effective well cement permeability. Data on local stratigraphy was used to identify the depth to the USDW for each well. There are multiple permeable zones between the Entrada formation and the USDW. The well component model can be set up to include intermediate zones. Inclusion of intermediate zones can result in decreasing the ultimate mass of leaked CO_2 and brine into the USDW. For this study, we used a conservative approach by assuming no intermediate zones. The effective well cement permeability is one of the unknown parameters since no direct field measurements are available for any of the existing wells in San Juan Basin. Typical value of a good quality cement is around 1 μDarcy. For this study, we used a conservative approach by assuming wellbore cement permeability to be ~10 mili-Darcy, 4 orders of magnitude higher than permeability of a good cement.

The purpose of the component model for the USDW is to predict changes in the groundwater quality resulting from any CO_2 and brine that migrates from the primary target reservoir into the USDW through existing wells. We utilized the groundwater aquifer ROM in the NRAP-open-IAM for the USDW component model. We used site-specific characterization data to provide inputs required for the USDW component model. Given our primary focus was to assess impacts of leakage on USDW, we did not utilize a component model for the atmosphere but we did estimate the amount of CO_2 leaked to the atmosphere with NRAP-open-IAM.

Fig. 4 and Fig. 5 show the time-dependent reservoir pressures and saturations at the five existing wells in the AoR. The pressures at all well locations evolve in similar manner, gradual increase to a maximum value until the injection

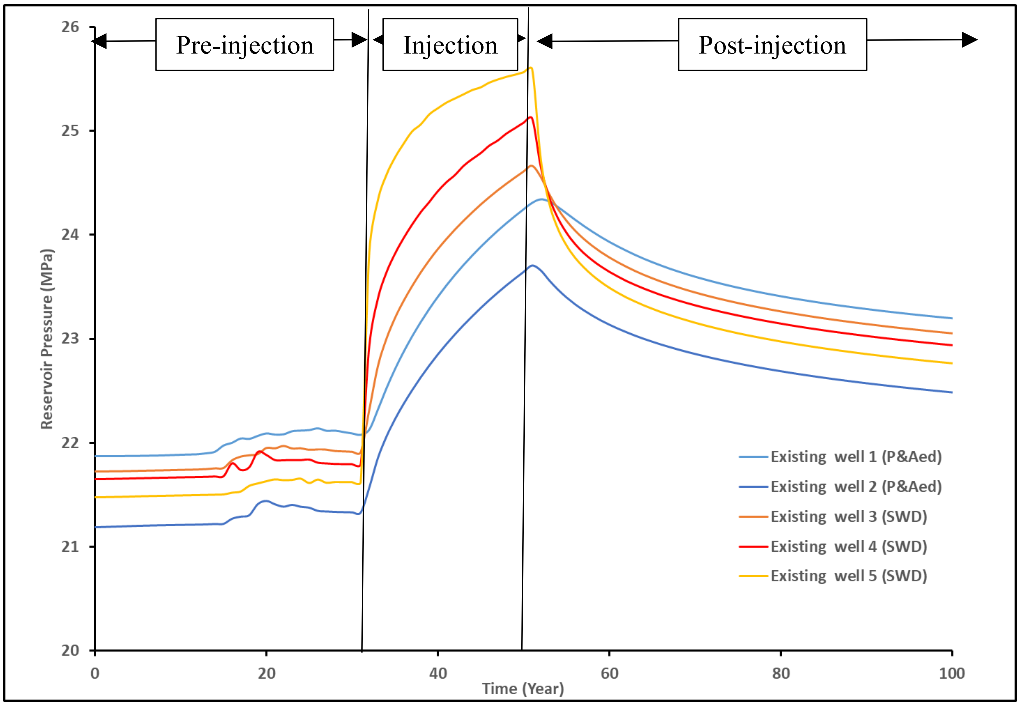

Fig. 4. Predicted reservoir pressures at the locations of five wells within the AoR.

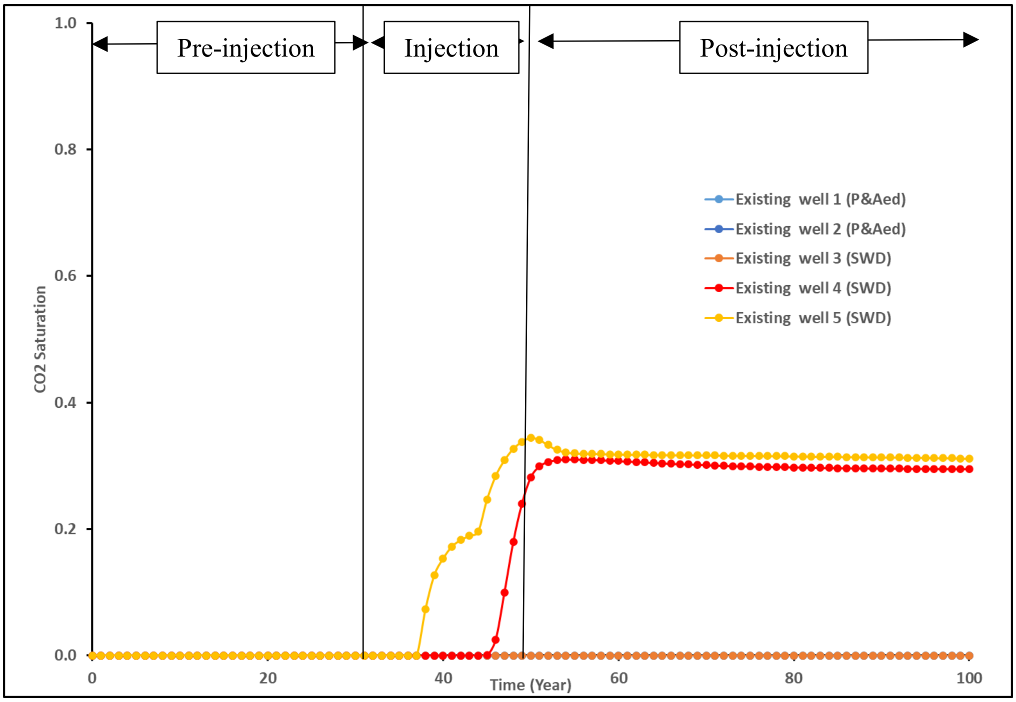

Fig. 5. Predicted reservoir CO_2 saturations at the locations of five wells within the AoR.

is stopped, followed by a steady decline during the post-injection period. The evolution of pressure at different well locations varies from well to well. The maximum pressure as well as the time at which the maximum is reached varies between the wells. Note the delay in the time at which the maximum pressure value is reached for 'Existing well 1' which is the farthest well from the injection well cluster compared to the other wells. Also, the maximum value is reached after the injection is stopped demonstrating that it takes time for the pressure front to travel through the reservoir. This is also manifested in the differences in the pressure decay behavior during the post-injection period. The evolution of CO_2 saturations near the existing wells is also a function of the separation between the wells and the injectors. The CO_2 plume does not reach three of the five wells. It takes ~7 years for the CO_2 plume to reach 'Existing well 5' (closest to the injectors) and ~15 years to reach 'Existing well 4'. Similarly, there is a difference in the maximum CO_2 saturation reached at these two wells. Note that unlike the decay in pressure, the CO_2 saturations remain constant and close to the maximum value during the post-injection period.

For all the existing wells the predicted CO_2 leak rates were zero. This is of note especially for the two existing wells within the CO_2 plume. This happens because the pressure at the bottom of the well is not sufficient to drive the CO_2 through the wellbore cement, even during the injection period. Extremely small amount of brine leakage was predicted for all the wells as seen in Fig. 6. The trends in the evolution of brine leakage rates were similar to those in the pressure demonstrating the brine leak is primarily driven by the pressure and it declines once pressure in the reservoir starts declining. The predicted maximum brine leakage rates ranged between 1.7×10^{-6} kg/s (0.05 tons/yr) to 3.6×10^{-6} kg/s (0.11 tons/yr). The lowest predicted leakage rate corresponded to the well closest to the boundary of the AoR. The maximum leakage rates were predicted at the end of the injection when the pressures in the reservoir were at their highest value. The IAM simulations also included predictions of impacts in the USDW due to brine leakage. The simulations results showed that none of the brine leakage led to any measurable impacts in the groundwater quality (in terms of changes in pH or TDS). The primary conclusion of the IAM simulations was that the risk to USDW due to leakage through the existing wells within AoR was extremely small to non-existent.

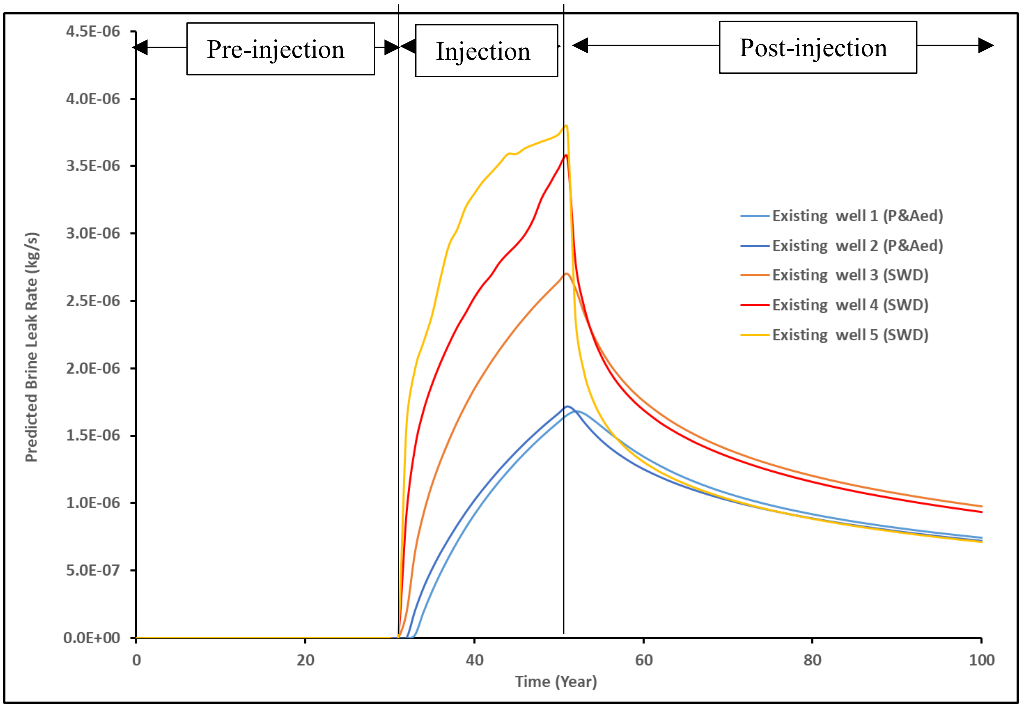

Fig. 6. Brine leakage rates predicted using NRAP-open-IAM for the five wells within the AoR.

3. Assessment of need for corrective action

In addition to quantifying leakage risks for the existing wells within the AoR, we also evaluated the need for corrective actions for the wells. This is one of the requirements of Class VI regulations. For this evaluation we gathered all publicly available information for the existing wells including well status, well design, data on drilling/completions, information on workovers and records related to plugging and abandonment. We should note that the information for the wells in the public domain is limited. Nonetheless, all available information was used to evaluate conditions of all the wells and to assess needs for corrective actions. The five existing wells consisted of two types of wells – plugged and abandoned (P&A'ed) wells and salt-water disposal wells.

3.1. Plugged and abandoned wells

Two of the five wells have been plugged and abandoned. Both were drilled to the Entrada formation, the primary target zone. One of the two wells was drilled in 1961 and abandoned in 1962. It was a hydrocarbon exploration well and was abandoned due to the absence of hydrocarbons. The second well was drilled in 2005 and used as a salt-water disposal well. It was plugged and abandoned in 2020 after water disposal operations were stopped. Records for the wells show that both wells are plugged at multiple locations including across the Fruitland formation, the regional USDW. There are no records of fluid leakage or related remediation workovers for either of these wells after their abandonment. As discussed in Section 2, both wells lie outside the CO_2 plume boundary. Additionally, the leakage risk simulations show that the brine leak rates for these wells are extremely small, even for a conservative scenario of high cement permeability. These results combined with the presence of multiple cement plugs, including across the USDW, ensure that the risk of fluid (bine) migration through these wells and endangerment of USDW is minimal to non-existent.

3.2. Salt-water disposal wells

Three of the five wells within the AoR are currently used as salt-water disposal wells to re-inject produced waters including into the Entrada formation. The three wells were drilled within the last 18 years and were completed with cement behind the casing over the entire length of the wells. Due to the regulatory requirements for salt-water disposal wells, the operators of these wells are required to perform annulus pressure monitoring and mechanical integrity tests every five years to ensure well integrity. To date none of the operators of these disposal wells has reported failed integrity tests.

The numerical reservoir simulations performed for this study accounted for water injection (set at current injection rates) through these disposal wells over the entire simulation duration. The process of injection of salt-water leads to increased pressure within the vicinity of disposal wells, which acts as a barrier limiting flow of fluids towards them. Leakage risks simulations showed that the predicted CO_2 leakage rates for all three wells is zero even for the two wells that lie within the predicted CO_2 plume boundary. The predicted bine leakage rates computed using conservative values of wellbore cement permeability are also extremely small. In addition, the integrity tests for these wells have not shown any loss of well integrity which can be used to infer that the well cement permeability may be significantly lower than the conservative values we used for leakage risk simulations. This indicates that the potential for endangerment of the regional USDW due to brine migration through these salt-water disposal wells will be extremely low to non-existent.

3.3. Evaluation of need for corrective actions

The discussions above indicate that for the injection scenario used in this study the existing wells within the AoR will not pose any endangerment to USDW. Three of the existing wells are salt-water disposal wells and by regulations their operators are required to ensure their integrity. Any loss of their integrity during CO_2 injection operations will be detected during their continued operations or at the time of their periodic integrity testing. The two P&A'ed wells lie outside predicted CO_2 plume boundary and are closer to the AoR boundary. Additionally, the leakage risk simulations results on Fig. 6 indicate that any potential brine leakage through these wells will be small and will even be delayed given their separations from the injection wells.

Our study results indicate that the existing wells that lie within the predicted AoR may not require any corrective actions prior to the start of the injection. A phased approach could be used to identify the need for the corrective actions and to implement them. As seen from Fig. 4, the injected CO_2 plume is predicted to intersect the closest salt-water disposal well approximately 7 years after the injection starts. This predicted delayed arrival could be used to justify delaying the assessment of the need for performing corrective actions for these wells. Monitoring data (collected during the operation of CO_2 storage project) coupled with predictions with updated reservoir models and data on salt-water injection well performance can be used to determine loss of integrity and the need to perform corrective actions for these wells as well as the timing for implementing the corrective actions. Similarly, any corrective actions for the three wells outside the CO_2 plume boundary could be delayed to a later date and their need could be further assessed after the commencement of injection operations by utilizing the monitoring data and predictions of updated reservoir models.

4. Conclusions

This study was aimed at demonstrating how quantitative leakage risk assessment can be used as part of the permit application process for UIC Class VI injection wells. Delineation of AoR using numerical reservoir modeling and identification of the needs for corrective actions for existing wells with the AoR is one of the requirements of Class VI permit application. As part of an integrated CCS project focused on the San Juan Basin where multiple wells have been drilled for hydrocarbon exploration and production, we have performed an assessment for leakage risks through existing wells and used the results for evaluating the needs for corrective actions. To quantify the leakage risks we utilized results of numerical reservoir simulations of CO_2 injection and NRAP-open-IAM, the integrated assessment modeling tool developed by the NRAP project.

While thousands of wells have been drilled in the San Juan Basin, very few reach the deeper formations which have been identified as potential CO_2 storage targets. This may also be the case for other basins suggesting that it is possible that even in basins with large number of wells only a limited number of wells may need to be assessed for corrective actions. The injection scenario used in our study resulted in identification of a large AoR but we identified only five existing wells that penetrate the Entrada formation within the predicted AoR. The leakage risks simulations showed that there will be no CO_2 leakage through the five wells and the brine leakage will be extremely small. The leakage risk simulations also showed that the predicted brine leakage will not result in any negative impacts in the regional USDW.

It is possible that deeper saline formations in the basins with ongoing hydrocarbon production operations are used for salt-water disposal and the disposal wells may lie within the vicinity of a GCS operation. Numerical modeling performed as part of our study showed that the CO_2 injection and water disposal operations could take place simultaneously in the same formations without having detrimental impacts on each other. The water disposal wells are required to maintain integrity to ensure that they can prevent fluid migration to USDW and are required to perform periodic testing. This testing and assurance of integrity would be of benefit for a GCS project.

Through a combined assessment of wells with publicly available data, quantitative leakage risk simulations and reservoir simulations, we demonstrated that a phased approach could be justified for determining the needs for corrective actions existing wells within the predicted AoR and implementing the actions. The phased approach could potentially result in significant cost savings to would be GCS site operators.

Finally, one of the goals of this paper is to demonstrate how a quantitative leakage risk assessment could be utilized as part of a Class VI permit application process. We hope the steps we utilized can be used as a guide by projects who need to evaluate whether existing wells within their predicted AoR can lead to endangerment of USDW and develop a corrective action plan.

Acknowledgements

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