

CO₂ Applications

Can enhanced oil recovery (EOR) contribute to CO₂ abatement as part of a climate-change-mitigation program?

EOR by use of CO₂ is an important technique for increasing oil recovery. Carbon capture and storage (CCS) will be an increasingly important technique for reducing atmospheric emissions of CO₂ as part of a climate-change-mitigation program. What role does EOR have in reducing CO₂ emissions to the atmosphere and in supporting climate-change mitigation?

It is clear that the two processes have very different objectives: EOR focuses on maximizing the amount of oil recovered, whereas CCS focuses on sequestration of CO₂ for the long term.

Most existing EOR projects use naturally occurring CO₂, produced from subsurface traps especially for EOR. Rather than mitigating emissions, these projects contribute to global CO₂ emissions. Clearly, this situation is not good for the climate.

Other emerging EOR projects and future projects could use anthropogenic CO₂ (i.e., CO₂ from industrial sources). When the CO₂ associated with the use of the EOR oil is taken into account along with the processing and emissions from CO₂ recycling, EOR is a significant producer of greenhouse gas and not a CO₂-abatement technique.

However, EOR oil does have a lower emissions intensity than non-EOR oil, assuming that the CO₂ is from anthropogenic sources. It would be much better, for example, to produce a barrel of EOR oil than a barrel of oil from oil sands.

EOR has an important role to play in energy security, but from a global-climate perspective, it is not a CO₂-abatement technique. **JPT**

**CO₂ Applications additional reading available
at OnePetro: www.onepetro.org**

SPE 116661 • "Optimizing Injection Intervals in Vertical and Horizontal Wells for CO₂ Sequestration" by Navanit Kumar, SPE, University of Texas at Austin, et al.

SPE 119747 • "Thermodynamic Criteria and Final Results of WAG CO₂ Injection in a Pilot Project in Croatia" by D. Novosel, INA-Naftaplina

SPE 114553 • "Produced CO₂ Storage Into Aquifer in an Offshore Field, Malaysia" by Dewanto Odeara Kartikasurja, SPE, Senenergy Ltd.



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Numerical Modeling of Pressure and Temperature Profiles Including Phase Transitions in Carbon Dioxide Wells

Geological storage of carbon dioxide (CO₂) usually is at conditions above the critical temperature and pressure; therefore, the CO₂ will exist as a single dense phase. However, conditions in the upper part of a CO₂ well with surface temperatures below the critical point of 31°C can lead to boiling and condensation in the well. The consequences of this are most apparent when the flow rate changes. Density profiles have been calculated for wells experiencing different thermal conditions to determine how bottomhole pressures are related to wellhead pressures.

Introduction

CO₂-injection wells are used in enhanced oil recovery (EOR). CO₂-production wells, from underground natural accumulations, provide a source of CO₂ for EOR and other industrial uses. Interest in CO₂ wells has intensified for geological storage as a means of reducing atmospheric greenhouse gases.

Accurate determination of downhole pressures is important if pressure is used to monitor the performance of a geological-storage reservoir. Reliable knowledge of bottomhole pressure helps prevent injection above pressures that can damage the formation. While

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bottomhole pressure can be measured with gauges, it is possible that, over a long period of time, downhole gauges may fail. Hence, calculating downhole pressure from wellhead pressure is desired. CO₂ has a critical pressure of 7.38 MPa and critical temperature of 31.0°C, so if the fluid is near the usual surface temperatures, conditions in the upper part of a well can cross the saturation line of CO₂, with boiling and condensation in the well if fluid pressures are in the vicinity of the critical pressure. Also, near the saturation line of CO₂, fluid properties display severely nonlinear behavior, challenging numerical simulation.

This phase-change issue usually is not of concern during injection of CO₂ for EOR because EOR normally involves continuous columns of liquid to the surface with the reservoir pressures required for minimum miscibility.

Conditions for phase change are more likely in circumstances not involving EOR, including CO₂ production from depleted CO₂ reservoirs, CO₂ injection into pressure-depleted gas reservoirs, and CO₂ storage at depths less than 2000 m.

The mathematical treatment of wellbore flow has been described extensively. The full-length paper details the interpretation of flow by use of numerical methods. In the rock surrounding the well, phase change accompanying vertical migration of CO₂ during hypothetical leakage has been studied. Leakage usually involves smaller flow rates and closer thermal coupling to the surrounding rock compared with wellbore flow.

Basic Flow Equations

The authors made the following assumptions.

- The well's diameter is very small with respect to its length such that

pressure, temperature, and flow velocity are assumed to be constant over a cross-section. Hence, the flow is treated as 1D.

- The wellbore flow changes sufficiently slowly that it can be treated as quasisteady state, and changes in kinetic energy can be neglected (although in blowouts, this becomes important).

- The well is dry, without water being present.

- The coupled response from fluid movement in the reservoir is neglected.

See the full-length paper for the equations used.

Downhole conditions arising from the injection and production of CO₂ include the Joule-Thomson effect. Generally, the Joule-Thomson coefficient for CO₂ is positive for wellbore and reservoir conditions, so that the Joule-Thomson effect contributes to heating when fluid is compressed in the wellbore and to cooling when the fluid expands. For this work, pure CO₂ properties were calculated by use of a high-accuracy Span and Wagner equation of state along with other representations, and a multicomponent Peng-Robinson equation of state was used for mixtures of CO₂ with other gases.

Static Columns

The average geothermal gradient of the Earth is approximately 25°C/km. Given enough time, a static column of fluid in a well should reach thermal equilibrium with this gradient. With a fixed temperature profile, it becomes straightforward to calculate the density profile of a static fluid given a function that relates density to pressure and temperature. The final state of the well is independent of wellbore diameter and the thermal properties of the casing and surrounding formation. Rather than plot fluid properties as a function of depth, insight can be gained by plot-

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ting on a phase diagram. Phase properties can be expressed in combinations of pressure/volume/temperature or pressure/density/temperature.

Rather than an unstable two-phase condition, a relatively stable column with gas above liquid can be obtained when the fluid and surrounding casing and rock are no longer at the geothermal gradient as a consequence of boiling and condensation. To have a stable static column with gas above liquid at conditions near the saturation line, the thermal gradient in the fluid must follow the saturation line. The saturation line has a gradient of approximately 74°C/km at 20°C, and approximately 64°C/km near the critical temperature. Thus, over time, the casing and surrounding rock will approach these gradients above and below the gas/liquid boundary, with a much-reduced gradient at the boundary.

Producing Columns

Producing wells supply CO₂ for EOR and industrial uses and are a source for at least one CO₂-storage demonstration project. At very slow flow rates, the pressure and temperature profiles in a flowing column are close to those of a static column. An example is a well that is 2000 m deep. As the production rate increases, heat is retained in the produced fluid; thus, when the fluid reaches the surface, increased temperature is experienced at the wellhead. Warmer CO₂ is less dense, so the weight of the column reduces and, hence, pressure at the surface increases. At low flow velocities, the friction term in the flow equations is negligible, but as velocity increases, friction becomes more significant because it is proportional to the square of the velocity, with the other terms being linear with velocity. Thus, at very-high flow rates, the pressure drop caused by friction becomes appreciable and the pressure at the surface decreases. Accompanying this pressure drop is a temperature drop caused by the expansion of the CO₂. At extremely high rates, the flow approached adiabatic conditions and a blowout situation with severe cooling. The wellhead-pressure response is similar to the wellhead-temperature response.

Injection Columns

Injection wells are used for EOR and, more recently, for geological CO₂

storage. In the latter application, surface conditions are important because compression requires energy, and this energy requirement could add to greenhouse emissions that geological CO₂ storage is intended to reduce.

CO₂-injection columns are more constrained than producing columns. Rates are constrained by the requirement not to exceed the fracture pressure of the reservoir or the threshold pressure of the seal rock. Thus, surface conditions cannot be assigned arbitrarily. In one example, injection is at a rate of 3.5 kg/s in a well with 0.07-m radius that is 2000 m deep. The gradient of the injection well diverges from that of the static well such that while the fluid warms as it is injected, it increasingly falls below the temperature of the surrounding rock. This situation is contrasted with the injection column at the much slower rate of 0.086 kg/s. While the slow-rate injection column initially diverges from a static column, the gradient of the profile becomes the same as that of a static column because the fluid has more time to balance with the temperature of the surrounding rock. From these examples, it can be seen how injection columns can exist with phase conditions different from those of static columns.

Adiabatic Flow

With adiabatic flow, there is no heat transfer between the fluid and the surrounding formation. High-velocity flow approaches adiabatic conditions. For steady-state adiabatic flow in a conduit, changes in potential energy over a vertical displacement balance the changes in specific enthalpy. The specific enthalpy of CO₂ is a function of pressure and temperature, which allows temperatures to be calculated for a given change in pressure and depth with changes at constant enthalpy. Note, however, that adiabatic changes are not isenthalpic. For upward fluid flow, the fluid gains potential energy at the expense of enthalpy, contributing to a drop in temperature.

Mixed Components

The consequence of CO₂ mixed with other fluids is that the critical point moves away from 31.0°C and 7.38 MPa. CO₂ mixed with nitrogen (critical temperature of -147°C) or methane (critical temperature of -83°C) leads to a reduction in the critical

temperature. With an appreciable fraction of nitrogen or methane, the critical temperature can be reduced such that two-phase conditions will not be encountered at the surface or in the wellbore under any realistic conditions. However, other components such as hydrogen sulfide (critical temperature of 100°C) used in acid-gas injection increase the critical temperature such that two-phase conditions are more likely to be encountered.

With mixed components, the composition of the gas phase at equilibrium can be different from that of the liquid phase. Hence, a static column with gas above liquid can have a different interpretation of composition at the wellhead than a flowing liquid. This situation could lead to possible misinterpretation of reservoir composition from sampling a static column at the wellhead.

Blowouts

Blowouts of CO₂ wells are particularly hazardous because of the tremendous expansion that can occur when containment is lost. Near the critical point, even small pressure drops can produce large volume increases, and CO₂ wells often operate with part of the well near the CO₂ critical point. Therefore, CO₂ wells are different from other wells, which can lead to behavior not expected by field personnel. With the rapid expansion of CO₂, correspondingly rapid cooling of the wellbore and fluid stream occurs. Cooling can reach the point at which solid dry-ice particles form, providing an additional hazard at the wellhead. After exiting the wellhead, the cold CO₂ condenses water from the atmosphere, creating a cloud of low visibility and water ice. After a blowout, the fluid accelerates until the pressure drop in the well matches the pressure drop between the reservoir and atmospheric pressure, limited by the sonic velocity. The sonic velocity is the maximum speed that fluids may attain.

Blowouts can be simulated with numerical-flow models. In a blowout simulation, temperatures drop very rapidly to the point at which solid CO₂ (dry ice) is formed (-78°C at atmospheric pressure). Even in the controlled release of CO₂ during a well test, dry ice can form downstream of the choke used to vent the CO₂. **JPT**

Gorgon Project: Subsurface Evaluation of Carbon Dioxide Disposal Under Barrow Island

The Gorgon Project is a major liquefied-natural-gas (LNG) development in northwestern Australia. The reservoir fluids of several fields contain carbon dioxide (CO₂), which will be extracted from the produced gas before liquefaction into LNG. The Gorgon joint-venture participants have proposed geological disposing of the produced reservoir CO₂ at the Barrow Island LNG plant. Key drivers are maximizing per-well injection of CO₂ and ensuring containment of CO₂ within the reservoir. Effective subsurface and economic evaluation enabled building a phased and flexible development plan for CO₂ disposal.

Introduction

The Gorgon and Io/Jansz gas fields will be developed initially as a subsea development with a tieback to Barrow Island, where the raw gas will undergo liquefaction for export. Production of gas also is considered for supply into the Australian domestic market.

The Gorgon gas field has 14% CO₂ in the reservoir-fluid composition. Reservoir CO₂ must be removed from the raw-gas stream before manufacture

of LNG because the liquefaction process occurs at process conditions at which CO₂ is solid. A large-volume of high-pressure CO₂ will be a byproduct from the necessary gas processing. Rather than emit the CO₂ to the atmosphere, it is proposed to dispose of the separated CO₂ into an unused saline aquifer, the Dupuy formation, more than 2000 m beneath Barrow Island. Over the life of the project, it is expected that more than 120 million tonnes of CO₂ will be injected into the Dupuy formation at rates of approximately 3.8 Mt/a.

Environmental Approvals

The CO₂-injection project was documented extensively, reviewed, and subjected to public comment as part of the Gorgon Project environmental-impact-assessment process for a 10-Mt/a LNG development. Following this process, the Western Australia (WA) Environmental Protection Authority found that the environmental risks associated with the CO₂-injection project were acceptable and recommended that CO₂ injection must proceed as an integral component of the Gorgon Project.

Dupuy Formation

Barrow Island is 56 km off the northwest coast of WA. The Barrow Island structure is a large north/south-trending doubly plunging anticline. The thickness of the Dingo claystone is unknown because it has not been penetrated fully in this area. However, it is likely between 4000 and 6000 m thick. The Dupuy formation, a member of the Dingo claystone, is a sandy and silty unit at the top of the Dingo interval. The Dupuy formation is 200 to 500 m thick beneath Barrow Island and comprises massive sandstones and highly bioturbated siltstones. The sandstones constitute the prime CO₂-disposal target. The Dingo claystone appears to

be present over the entire Barrow sub-basin; however, the Dupuy is a more localized depositional body confined to the eastern flank of the basin.

Subsurface Uncertainties

A subsurface-uncertainty assessment of a CO₂-disposal project in the Dupuy formation recommended acquiring new data that could confirm or narrow the range of subsurface uncertainty for key parameters that affect the project (e.g., injectivity and containment). To gather this information, the Gorgon CO₂-data well was drilled in 2006 and evaluated extensively.

The formation-permeability range was confirmed, with the Lower Dupuy showing better than expected reservoir quality. The sealing integrity of the basal Barrow Group shale was confirmed with mercury-injection capillary-pressure analysis, and the depositional-setting interpretation was refined. Geomechanical parameters, from extended leakoff tests in conjunction with the results of smaller-scale minifrac tests, now are supported by hard data and provide the framework for setting injection-pressure limits for the operational phase of the injection project.

Containment

Pressure and salinity differences between the Dupuy and overlying aquifers in the lower Barrow group show the existence of hydraulically separate aquifers and, hence, suggest at least one competent regional seal and a secondary seal or series of baffles above the Dupuy. These seals have maintained isolation of two major aquifers having salinity contrasts of at least 20,000 ppm NaCl equivalent over geological time.

Geomechanics

A comprehensive geomechanical model was developed on the basis of modified

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leakoff tests, minifrac data, image-log data from the Gorgon CO₂-data well, fault geometries mapped from seismics, and rock-mechanics data from core analysis. This geomechanical model was a significant component in evaluating the subsurface development of CO₂ disposal in the Dupuy. It affects well placement and well trajectories and improves understanding of containment at faults and of controlling injectivity into the Dupuy formation by use of reasonable operating pressures.

The placement and completions of injection wells use the inherent trapping mechanisms in saline formations. Dissolution and residual-gas trapping of the injected-CO₂ plume are maximized by enhancing reservoir contact with long migration pathways. To this end, the CO₂-injection wells will be down-dip from the structural high and wells will be completed beneath the Perforans shale to encourage lateral migration of the plume during injection.

Reservoir Modeling

For CO₂-disposal projects, reservoir models provide insight into the selection of appropriate sites, forecasts of injection rates, prediction of the movement of the CO₂ plume during and after injection, and an assessment of containment risks. The following steps were used to create a suitable reservoir model of the Dupuy.

- Create a suite of fine-scaled reservoir or static models that represents the uncertainty in reservoir volume, continuity, and permeability of the Dupuy formation accurately.
- Scale up the fine-scale reservoir models, preserving the flow and barrier/baffle characteristics of the original fine-scale representation, and allowing acceptable simulation run times.
- Simulate the scaled-up geological reservoir models, with knowledge of the subsurface behavior of injected CO₂, to determine injection rates and to understand the likely path and character of the resulting CO₂ plume.

Reservoir Simulation and Development Planning

Dynamic modeling of CO₂ injection into the Dupuy formation was used to gauge the effects of development decisions. These decisions included the number of injection wells, placement of injection wells, and the need for water production to create reservoir void-

age and pressure relief. The aim of the reservoir-simulation modeling studies was to determine the optimum development that ensures containment of the injected CO₂ while maximizing per-well injectivity (thus limiting capital expenditure). Geosequestration projects are unique because they consider the issue of containment: Either containment is maintained, or it fails. Simple focus on delivering the most capital-efficient project in terms of lowest well count is not sufficient; care must be taken to assure stakeholders that the injected CO₂ will remain in the target formation and that the risk of leakage from the reservoir is minimized.

Development Concept. Development planning for CO₂ injection was a fully integrated effort by the subsurface team. The placement of bottomhole locations was driven by geological factors and performance of wells under dynamic conditions—likely presence of sand, likely CO₂-migration pathways, location of containment risks (e.g., faults and old exploration wells). The plan includes three drill centers, eight injection wells, four water-production wells to reduce formation pressure, and four reservoir-surveillance wells to monitor plume movement away from the injectors. Injection wells will be completed in the Lower Dupuy and the Upper Massive Sand up to the Perforans siltstone. Completion under the Perforans siltstone provides some early migration benefits.

The migration of CO₂ through to the top seal of the formation, the Basal Barrow Group shale, is hampered by the very-low-permeability siltstones of the Upper Dupuy. The long period of migration in the simulation models (up to 8,000 years) allows trapping mechanisms in saline formations to have a significant effect in permanently trapping CO₂ in a dissolved or residual state without relying on the top seal as the only source of containment.

Reservoir Surveillance

Demonstrating the integrity of a CO₂-injection project by monitoring the behavior of injected CO₂ will be integral to gaining stakeholder support for the subsurface injection of CO₂. An operations-management plan will maximize the volume of CO₂ injected while ensuring safe injection operations. Reservoir simulation combined

with reservoir surveillance will focus on identifying conditions outlined in the operations-management plan that will trigger mitigation strategies to ensure responsible plume management. The primary mitigation zone is the injection reservoir itself and the zone directly overlying the injection reservoir. Thus, the monitoring plan must focus on acquiring data in this zone. If a mitigation strategy is implemented, then ongoing reservoir-simulation and reservoir-surveillance data will be used to predict and monitor the success of that particular mitigation option.

Monitoring Technologies. A combination of time-lapse seismic and well data from both injection and dedicated observation wells will be used to monitor CO₂ injection into the Dupuy formation. The objective is to provide a picture of the fluid-front movement through the host reservoir to compare with reservoir-simulation predictions.

Long-Term Responsibilities. While the concept of site closure can be applied to the decommissioning and rehabilitation associated with the surface facilities and wells used for CO₂ injection, the ability to demonstrate that the site is safe from CO₂ leakage may require additional time. It is proposed that day-to-day involvement with the site continue after the cessation of injection operations into a post-injection phase. The post-injection phase would end once agreement was reached with government that the closure criteria for the site had been met.

The duration of the post-injection phase will depend on the migration of the CO₂ in the reservoir and the information obtained about the ability to monitor and predict CO₂ behavior. The additional monitoring undertaken during the post-injection phase primarily will be to confirm the understanding developed during the operational phase. Site closure should occur once government is satisfied to a high degree of certainty of the following.

- Future land-use objectives defined at the time of project approval have been met.
- Residual risks of leakage and resulting liabilities are acceptably low.
- Ongoing costs associated with the site are acceptably low or are otherwise appropriately managed.

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Regulatory Framework to Accommodate Geological Storage of CO₂ in Alberta

A variety of methods has been proposed to reduce the effects of carbon dioxide (CO₂) emissions. One method is CO₂ capture and storage (CCS) in geological formations. Despite exceptional CCS potential in the Province of Alberta, Canada, legal and regulatory issues must be resolved to allow implementation. Without changes, there will not be enough certainty to enable the industry to make appropriate decisions that encourage investment.

Introduction

The Canadian federal government has announced a national objective to reduce emissions nationally by 20% from current levels by 2020, and by 60 to 70% by 2050. Various target levels have been defined for greenhouse-gas (GHG) emissions in Alberta. Alberta is the first province in Canada to introduce legislation to reduce GHG-emission intensity from large industrial sources. Large companies in Alberta emitting more than 100 000 t/a of GHGs will have to reduce their annual emissions intensity by 12%, or they will be charged USD 15/t (all costs are in 2005 dollars) above the 12% target. Alberta claims that it wants to cut its projected GHG emissions in half, by 200 Mt, by 2050.

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CCS

CCS is a process for reducing GHG emissions into the atmosphere by first extracting CO₂ from gas streams typically emitted during electricity production, fuel processing, and other industrial process. Once captured and compressed, the CO₂ would be transported by pipeline or tanker to a storage site, often to be injected into an underground storage site (or geological formation).

Potential sites for geological storage of CO₂ include enhanced oil recovery by use of CO₂, CO₂ storage (CS) in depleted oil and gas reservoirs, replacement of methane by CO₂ in deep coalbeds, injection of CO₂ in deep saline aquifers, and CS in salt caverns. Among these options, saline aquifers possess the highest potential for CS in Alberta. Preliminary estimates indicate that the capacity of the Alberta basin to sequester CO₂ dissolved in the formation waters at depths greater than 1000 m is on the order of 4000 Gt of CO₂.

Challenges and Deployment

High capital costs and regulatory issues are the main challenges to CCS. Although all the components of CCS technology (i.e., capture, transport, and storage) are available and being demonstrated, they are not fully integrated in commercial-scale facilities. The current cost of CCS is USD 65 to 85/t of CO₂. This cost is predicted to reduce to USD 20 to 30/t of CO₂ after the technology is fully commercialized, which is expected to occur along with technology advancement after 2020. Financial and regulatory support is needed to make this happen. The industry requires policy and regulatory certainty to assess financial risks of carrying on with investment.

The regulatory framework should provide requirements for conducting the CCS operation in a manner that protects public safety and public interest. The regulatory regime may include a combination of prescriptive and performance-based requirements to minimize the risks of CCS activities. Examples of prescriptive requirements are well completion and abandonment, while maintaining aquifer pressure is an example of performance-based requirements. For CCS, the main risks are related to storage and containment of CO₂. Therefore, the regulatory framework detailed in the full-length paper focuses on the assessment and management of the risks associated only with CO₂ storage. Legal issues, such as the ownership of the pore space and long-term stewardship of CCS project, are not addressed in this work. This regulatory framework is based on current provincial regulations for management of acid-gas disposal. Basically, it includes the following stages: planning and design, operation, closure, and post-closure.

Alberta Applicable Regulations

Most of Alberta's regulation experience has developed from the permitting and oversight of sour-gas-disposal projects. Sour-hydrocarbon reservoirs in Alberta produce significant volumes of hydrogen sulfide (H₂S) and CO₂. Since 1990, oil- and gas-production wells in Alberta have been converted to acid-gas-disposal wells to reduce the emissions of H₂S to the atmosphere. Through this process, the produced H₂S and CO₂, with minor traces of hydrocarbons, are injected into deep geological formations. These acid-gas-injection activities represent a commercial-scale analog to geological storage of CO₂. Disposal

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of CO₂-rich acid-gas streams in these projects is regulated by the directives of the Alberta Energy Resources Conservation Board (AERCB).

Regulatory-Framework Modification

Current regulations of Alberta in the oil and gas sector provide the basis for regulating geological storage of CO₂ but did not anticipate the need for storage of large volumes of CO₂. Moreover, current regulations do not consider the long-term fate of the stored gas, which is crucial for the CS.

Project Planning and Design Stage.

In selecting of the CS target site, the geological formation(s) must be shown to have the appropriate long-term containment capability along with sufficient capacity and injectivity. Containment capability depends on the integrity of the seal, which depends on the thickness, permeability, and lateral continuity. Presence of conductive faults or leakage pathways (e.g., fractures and penetrating abandoned wells) can reduce the confinement of the seal. The site should not be prone to significant tectonic activity or earthquakes or be in proximity to active volcanism. These properties will be necessary to minimize the potential of an accidental release as a result of natural occurrences. In Alberta, the tectonic activity declines from the Rocky Mountains toward the Canadian shield. Therefore, the safety of CS is higher toward the east.

The storage capacity depends on both the bulk pore volume of the formation and the depth. As the depth increases, the reservoir volume required for storage of a unit mass of CO₂ decreases. In reservoirs with typical pressure and temperature profiles, and all else being equal, greater depths mean higher storage capacity. Moreover, risk of leakage is reduced in deeper formations. Current studies in Alberta show that injectivity is the main limiting factor. The injectivity depends on the permeability of the aquifer and on the well design.

Once a site is selected on the basis of regional screening and simple modeling tools, the selected site must be characterized intensively to ensure meeting the criteria. Prescriptive regulations can be adapted to ensure that

the minimum data for reservoir characterization are acquired. 3D-seismic data, pumping tests for evaluating storage formations and seals, and cement-integrity logs should be among these data. The caprock should be characterized, and its integrity should be assessed. Characterization should consider the uncertainty in caprock and reservoir parameters. It should provide the likely scenario, confidence limits, and extreme scenarios. Once the aquifer is characterized, available simulation software could be used to assess short-term and long-term aspects of the CO₂ storage.

The main pathways for leakage of CO₂ are the target-formation-penetrating wells (active or abandoned). The number of abandoned wells penetrating the aquifer and the quality of abandonment are important parameters in site selection. Degradation of the cement plugs by injected CO₂ can cause leakage over the long term. Current abandonment regulations require revision to consider this issue. The regulatory framework should provide standards for designing injection wells. Corrosion-resistant casing/tubing and CO₂-resistant packers and cement should be considered in designing the injection wells.

Standards on well perforation and wellhead pressure are needed. Currently, the wellhead pressure is limited to 90% of the formation fracture pressure. More research is required to determine whether the caprock fails at a pressure below or higher than this pressure.

Operation Stage. Formation pressures will be highest during the active injection phase, thus the driving forces that could cause leakage will be greatest during this time. Standards for monitoring and verification of injected CO₂ at this stage are crucial to any regulatory framework. Typically, the operator is required to collect vital data on containment, reactivity of CO₂ with its surroundings, leakage, and long-term storage. The reservoir model will be updated (history matched) by use of these data. This update is necessary to predict lateral and vertical migration of CO₂, offering potential revisions for operation or starting preventive remediation. Monitoring plans should be developed to provide

data on injection rate and pressure, injected volume, composition of the injectant, spatial distribution of the CO₂ plume, reservoir pressure, well integrity, and leakage.

To ensure safe storage, the detection limit must be calibrated to the formation characteristics. If the required detection limit is too low, the cost of implementing the monitoring program would be unnecessarily high, thus discouraging widespread implementation of CCS.

Many studies have identified possible approaches for monitoring that would satisfy the needs of safe storage. The monitoring challenge is not to find methods that will work but to find cost-effective approaches that are fit-for-purpose.

Closure/Post-Closure Stages. The closure stage is the stage at which injection (10 to 50 years) has ceased. The regulatory framework should provide requirements for safe abandonment of the wells. The current AERCB Directive 20 can be used for well abandonment. If the well is not required for monitoring, the wellbore may be plugged in such a way that minimizes the risk of any leakage. This approach might include cementing all the casings in the abandoned wellbore (or use of some other plugging compound that would be more flexible and last longer than current cements).

Post-closure stage starts after certification of site closure. Monitoring of safe storage should be continued over this phase. As with the operation stage, the monitoring system should be site-specific. CO₂ storage is expected to become increasingly safe over time as injection pressures decrease post-operation by different trapping mechanisms, including capillary trapping, dissolution, and mineralization.

Conclusions

Acid-gas-disposal activities in Alberta are managed by AERCB directives that can be adapted to handle the CS projects. The regulatory regime should be able to handle the assessment and management of the risks associated with the CS projects through phases of planning and design, operation, closure, and post-closure. Guidelines of existing regulations should be modified to accommodate CS operations. **JPT**

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