Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

STRATEGIES FOR STORAGE PERMANENCE: WELL INTEGRITY AND LEGACY WELL EVALUATIONS

Plains CO_2 Reduction (PCOR) Partnership Initiative
Task 2 – Deliverable 5

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DOE Cooperative Agreement No. DE-FE0031838

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December 2021
March 2022 Approved

2022-EERC-03-10

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ACKNOWLEDGMENT

This material is based upon work supported by DOE NETL under Award No. DE-FE0031838 and NDIC under Contract Nos. FY20-XCI-226 and G-050-96.

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DEFINITIONS

Annulus/annular – the space between two concentric objects, such as between the wellbore and casing or between casing and tubing, where fluid can flow.

Area of review (AOR) – the region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity. The AOR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide (CO_2) stream and displaced fluids and is based on available site characterization, monitoring, and operational data as set forth in 40 Code of Federal Regulations (CFR) Subpart H – Criteria and Standards Applicable to Class VI Wells § 146.84 (Source: 40 CFR § 146.81[d]).

Caliper log tool – measures the variation in borehole diameter as it is withdrawn from the bottom of the hole, using two or more articulated arms that push against the borehole wall.

Casing/casing string – An assembled length of steel pipe configured to suit a specific wellbore. The sections of pipe are connected and lowered into a wellbore, then cemented in place. Casing is run to protect or isolate formations adjacent to the wellbore.

Cement bond log – Used to assess bond integrity between the cement-to-casing and cement-to-formation interface by measuring the loss of acoustic energy as acoustic waves are attenuated through the interactions at the cement interfaces and by the cement itself. The amount of attenuation relates to the fraction of the casing perimeter covered by cement.

Class VI wells – U.S. Environmental Protection Agency (EPA) permit classification of wells that are used to inject CO_2 into deep rock formations. This long-term underground storage is called geologic sequestration. Geologic sequestration refers to technologies to reduce CO_2 emissions to the atmosphere and mitigate climate change.

Confining zone – a geologic formation, group of formations, or part of a formation stratigraphically overlying and underlying the injection zone(s) that acts as barrier to fluid movement (Source: 40 CFR § 146.81[d]).

Geologic storage – the process of storing captured anthropogenic CO_2 deep underground for permanent storage. Also known as geologic sequestration.

Injection zone – a geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive CO_2 through a well or wells associated with a geologic sequestration project. Also known as sequestration zone.

Legacy well – wells in the AOR that are classified as historical wells, previously drilled, completed, produced, shut in (inactive or temporarily abandoned), and plugged and abandoned.

Microannulus – A small gap that can form between the casing or liner and the surrounding cement sheath. A microannulus can jeopardize the hydraulic efficiency of a primary cementing operation, allowing communication between zones if it is severe and connected.

Mechanical integrity test – a wellbore integrity test conducted on a well to ensure that both the external and internal mechanical components of the well function in a way that is protective of public health and the environment. The internal part has mechanical integrity if no leakage is noted in the packer, casing, or tubing. The external part has mechanical integrity if no movement of fluid is noted through the vertical channels that are adjacent to the well.

Orphan well – wells in the AOR that are classified as historical wells, previously drilled, completed, produced, shut in (inactive or temporarily abandoned), and plugged and abandoned, with no responsible party.

Primacy – EPA creates minimum regulations, and the Safe Drinking Water Act (SDWA) establishes a process for U.S. states to apply to EPA for the authority to regulate underground injection. This is known as primary enforcement authority, or “primacy.” When a state demonstrates to EPA that it has established an appropriate level of statutory authority and administrative regulations, EPA grants the state primacy.

Production casing – A casing string that is set across the reservoir interval and within which the primary completion components are installed.

Storage complex – A storage complex is a subsurface geologic system comprising a storage unit and primary and, possibly, secondary seal(s), extending laterally to the defined limits of the CO_2 storage operation or operations.

Surface casing – refers to the first string of casing that is set in a well and varies in length from a few hundred to a few thousand feet, with requirements to be set at depths to protect the deepest known USDW.

Top of cement – the height of cement in the annulus of the wellbore.

Underground source of drinking water – an aquifer or its portion 1) which supplies any public water system or 2) which contains a quantity of groundwater sufficient to supply a public water system and 3) currently supplies drinking water for human consumption or 4) contains fewer than 10,000 mg/L total dissolved solids and 5) which is not an exempted aquifer.

STRATEGIES FOR STORAGE PERMANENCE: WELL INTEGRITY AND LEGACY WELL EVALUATIONS

EXECUTIVE SUMMARY

Comprising ten states and four Canadian provinces, the Plains CO_2 Reduction (PCOR) Partnership Initiative (hereafter referred to as the PCOR Partnership) region is home to abundant and diverse sources of anthropogenic carbon dioxide (CO_2) (e.g., coal- and gas-fired power plants, gas-processing plants, ethanol plants), fitting geology for CO_2 geologic storage and utilization to enhance oil recovery, expanding CO_2 pipeline infrastructure, and robust energy and agriculture industries.

The 45Q tax credit and other incentive programs are generating significant interest in developing commercial carbon capture and storage (CCS) projects in the PCOR Partnership region. Site selection plays a vital role for project developers to be able to demonstrate storage permanence and ultimately satisfy the accounting requirements for the 45Q tax credit and other incentive programs.

A key strategy for ensuring storage permanence is to understand project risks and likelihood of CO_2 escaping the storage reservoir along leakage pathways. A properly characterized storage complex will have the geologic characteristics necessary to contain the injected CO_2, leaving wellbore penetrations and the existence of transmissive faults or fractures as the only potential leakage pathways that need to be investigated to ensure site feasibility and reservoir integrity. The injection well(s) and monitoring well(s) associated with the storage operations need to be constructed and operated in a manner that ensures mechanical integrity. Legacy oil and gas wells within the storage project's area of review (AOR) are required to be evaluated for zonal isolation to ensure the well does not provide a leakage pathway and compromise reservoir integrity. An understanding of wellbore integrity in relation to CCS project development will assist CCS project operators in their project feasibility investigations. A knowledge of the relevant regulations, approaches to well evaluation, and remediation considerations and strategies for wellbores are essential to making informed decisions about project location selection and design.

Legacy wells within the AOR need to be identified, located, and evaluated to ensure integrity of the storage complex has not been compromised. A project risk assessment evaluates and ranks wells that are subject to remediation and/or monitoring. Evaluation of wells can be intensive and site-specific, and well records (well files) can have varying levels of available information. The threshold for selecting wells for remediation may vary by project or location. State or provincial regulations may dictate what remediation actions are necessary. In some cases, wells may be monitored instead of fully remediated. For example, a well that is outside of the expected CO_2 plume may simply be monitored during and after CO_2 injection. The risk assessment will weigh the benefits and risks associated with any wells identified as needing remediation.

STRATEGIES FOR STORAGE PERMANENCE: WELL INTEGRITY AND LEGACY WELL EVALUATIONS

INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership Initiative (hereafter referred to as the PCOR Partnership) is one of four Regional Carbon Sequestration Partnership (RCSP) projects operating under the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) Regional Initiative to Accelerate CCUS (carbon capture, utilization, and storage). The PCOR Partnership region encompasses ten U.S. states and four Canadian provinces in the upper Great Plains and northwestern regions of North America. The PCOR Partnership is led by the Energy & Environmental Research Center (EERC) with support from the University of Wyoming (UW) and the University of Alaska Fairbanks (UAF) and includes over 200 stakeholders from the public and private sectors. The goal of this joint government–industry effort is to identify and address regional capture, transport, use, and storage challenges facing commercial deployment of CCUS throughout the PCOR Partnership region.

The deployment of commercial CCUS projects in the PCOR Partnership region includes geologic storage of carbon dioxide (CO_2) in saline formations (dedicated storage) and utilization of CO_2 stored in association with enhanced oil recovery (CO_2 EOR and associated storage). Commercialization of CCUS has led to the expansion of existing CO_2 pipeline transportation networks and construction of new CO_2 pipelines, connecting areas of the PCOR Partnership region with major industrial CO_2 sources to geologic formations best-suited for permanent storage. Interest in developing commercial carbon capture and storage (CCS) projects in non-hydrocarbon-bearing geologic formations (i.e., dedicated storage in saline formations) has significantly increased with the business driver combination of the tax credit for carbon sequestration (26 U.S. Code § 45Q) and Low-Carbon Fuel Standard (LCFS) markets (Peck and others, 2021).

Developing dedicated storage projects is reliant on demonstrating the CO_2 will be permanently stored in order to receive tax credit and other incentives (e.g., California Air Resources Board [CARB] LCFS). The importance of selecting the right site to ensure storage permanence will influence the project developer's ability to demonstrate reservoir integrity and satisfy the accounting requirements for the 45Q tax credit and other incentive programs. When determining the feasibility of a dedicated storage site, project developers consider the local geologic setting (e.g., formation depth, porosity, permeability, and sealing formations above and below the storage reservoir), the location of known faults and/or fractures that may compromise reservoir integrity, and legacy wellbores in and around the storage project. Legacy wellbores are typically associated with oil and gas exploration and production and can include producing wells,

wells that previously produced oil and/or gas but have since been plugged and abandoned (i.e., cased-hole plugged), or exploration wells that were plugged and abandoned when oil and/or gas was not discovered (i.e., open-hole plugged).

As part of the regulatory permitting process, CCS operators are required to delineate an area of review (AOR) and evaluate the integrity of all wells that penetrate the storage reservoir or its upper seal within the AOR. The complexity of this evaluation is based on the number and era of wells inside the AOR. Legacy wells may present challenges to CCS projects, with the majority of these wells drilled under different regulatory standards than today. Regulations evolve over time with the advancement of technology, improvement of materials, and understanding of the subsurface. In addition, access to well records has also improved over time, but there is no regulated standard for well documentation and retention. Depending on when (i.e., era) and where (e.g., state) a legacy well was drilled, well records may be limited if available at all. Well data records typically provide comprehensive documentation of a well's history and include information such as current well status, drilling and completion, and plugging activities. A CCS project team of engineers, geologists, and operators will need to identify, locate, and assess all legacy wellbores within the AOR and ensure that the wells will not compromise containment of the stored CO_2. The evaluation is focused on proving isolation and integrity of the storage complex. If wells are deemed to be an unacceptable risk for compromising containment, the project team must develop mitigation procedures for corrective actions.

Wellbore integrity is the ability of a well to maintain isolation of geologic formations and prevent the vertical migration of fluids (Zhang and Bachu, 2011; Crow and others, 2010). Wells maintain geologic isolation through successful applications of cementing, casing strings, and plugs (abandonment). Wells should have multiple barriers to ensure integrity; if one barrier fails, the subsequent barriers provide reinforcement to maintain the overall integrity of the well. For example, multiple cement plugs can be placed at different depths for well abandonment, and cement is placed around the casing strings to prevent fluids in the wellbore from entering the surrounding formations.

Wellbore integrity evaluations for a CCS project will target project injection well(s), monitoring well(s), and all legacy wells within the storage complex AOR. The injection well(s) are typically new or recently drilled under stringent well construction regulations. Monitoring wells may be new drills or qualifying existing wellbores that penetrate the zone of interest. These wells require drilling and completion techniques following the presiding ruling regulatory requirements for CO_2 storage and with the expectation that the wellbores will be exposed to CO_2. CO_2 injection wells require completion methods utilizing CO_2-resistant materials (e.g., proper casing/tubing/equipment material, cement composition, etc.), with monitoring programs in place to ensure continuous isolation of geologic formations, thus preventing the migration of fluids. Risk levels for a recent or newly drilled well are minimal, with regulations and controls in place.

Wellbore integrity assessments consider each well on an individual basis, evaluating the ability of each wellbore to maintain isolation to protect the deepest underground source of drinking water (USDW) and prevent migration pathways to the surface. The integrity of any individual legacy wellbore is determined by the thorough review of well records by the project review team and participating regulatory agencies. Wells that are identified as not having sufficient integrity will be subject to remediation, further evaluation, or monitoring. Communication between wellbores presents challenges that must be considered, i.e., if a pathway exists between multiple legacy wellbores, which could compromise the integrity of the CO_2 storage complex.

This report provides a review of wellbore integrity related to CCS project development, including regulatory requirements, legacy well risk assessments/evaluations, and well remediation strategies. For this report, CCS projects will refer to dedicated storage projects that target deep saline formations. Associated storage projects (i.e., CO_2 EOR) are not a consideration for this discussion, as oil companies have dealt with managing well integrity for decades.

REGULATORY ENVIRONMENT

This section presents the regulatory environment for wellbore integrity in the context of permitting and operating CCS projects. The protection of USDWs is addressed by regulatory agencies within their underground injection control (UIC) programs as mandated by the Safe Drinking Water Act (SDWA) in the United States and federal environmental regulations in Canada. The discussion covers the requirements for injection well integrity to ensure protection of USDWs. In addition, there are specific requirements regarding existing legacy wells that may be classified as producing, shut in, temporarily abandoned, orphaned, monitoring, or other classifications. These types of wells typically have specific bonding and abandonment requirements to ensure the wells maintain integrity.

In the context of a geologic storage project, wells that are located within the AOR must be evaluated for wellbore integrity. This requires identifying and locating all wells present in the AOR, evaluation of the well's condition and status, a rigorous risk assessment, and risk-ranking process that results in the determination of what mitigation, if any, is required for each well in the AOR.

The following subsections cover the jurisdictions within the PCOR Partnership region (e.g., federal, state, and provincial) and outline CO_2 injection well and legacy well integrity regulations for the geologic storage of CO_2 in the context of the protection of USDWs and prevention of fluid movement outside the injection zone. Each jurisdiction will have regulations unique to its geographic area, although all regulations will meet minimum requirements established by federal regulations.

United States

U.S. Environmental Protection Agency (EPA)

The permitting process to inject and permanently store CO_2 in saline formations requires project developers to delineate an AOR boundary and evaluate all wells that penetrate the storage reservoir or its upper seal within the AOR. EPA has classified six injection well types from Class Ithrough VI under the federal UIC program. The UIC program is designed to regulate the injection of fluids underground for the purpose of storage, mineral recovery, or disposal in a manner that protects USDWs. Injection activities for CO_2 EOR and associated storage are regulated under the

Class II UIC Program, and injection of CO_2 for dedicated storage falls under the Class VI UIC Program (https://www.epa.gov/uic/underground-injection-control-well-classes).

- Class I wells are used to inject hazardous and nonhazardous wastes into deep, isolated rock formations.

- Class II wells are used exclusively to inject fluids associated with oil and natural gas production, primarily for the disposal of wastewater (i.e., saltwater disposal) or the subsurface emplacement of fluids for enhanced oil and/or gas recovery.

- Class III wells are used to inject fluids to dissolve and extract minerals.

- Class IV wells are shallow wells used to inject hazardous or radioactive wastes into or above a geologic formation that contains a USDW. In 1984, EPA banned the use of Class IV injection wells.

- Class V wells are used to inject nonhazardous fluids underground. Most Class V wells are used to dispose of wastes into or above USDWs.

- Class VI wells are wells used for injection of CO_2 into underground subsurface rock formations for long-term storage, or geologic sequestration.

Regulatory considerations for wellbore integrity are encompassed by the standards set by EPA under 40 Code of Federal Regulations (CFR) Part 146 Subpart H – Criteria and Standards Applicable to Class VI Wells. The EPA UIC requirements under Class VI outline the standards designed to protect USDWs. Specifically, 40 CFR § 146.89 describes the requirements for CO_2 injection well integrity. An injection well is considered to have well integrity if:

1) "There is no significant leak in the casing, tubing, or packer.

2) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore."

To demonstrate well integrity in a CO_2 injection well, a list of tests and monitoring requirements can be found in 40 CFR § 146.84b, including tubing–casing annulus pressure; continuous monitoring of pressure, rate, and volume; and monitoring pressures in nearby wells.

EPA's guidance on wellbore integrity was developed through the work of the American Petroleum Institute (API). API published standards for cements in oil and gas wells in 1952 (U.S. Environmental Protection Agency Office of Air and Radiation, 2010), which helped dictate the level of construction that oil and gas wells had to meet, as previous standards failed to prevent fluid movement in the well. While these standards helped create safer operating and subsequent plugged and abandoned (P&A) oil and gas wells, wells improperly plugged and abandoned before these standards still exist.

AOR delineation is a fundamental regulatory component of the UIC program to ensure protection of USDWs and is required for every injection well class, although the approach for how the AOR is delineated is well class-specific. AOR delineation for Well Classes I–V is either 1) a zone of endangering influence calculation or 2) a fixed radius not less than ¼ mile. This delineation is important because it draws a regulatory-defined boundary around the project area. Under the Class VI UIC Program, the AOR is defined as "the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids, and is based on available site characterization, monitoring, and operational data as set forth in § 146.84 (40 CFR 146.81[d])." AOR delineation under the Class VI UIC Program stands out from the other well classes with the requirement to use computational modeling and simulation to derive the AOR boundary.

40 CFR 146 Subpart H – Criteria and Standards Applicable to Class VI Wells, § 146.82(a)(4) requires the consideration of "a tabulation of all wells within the area of review which penetrate the injection or confining zone(s)." A CCS project team may encounter wells with deficient record retention. Deficient well records do not allow for a full evaluation of a well's condition, and these well records may be deficient for a variety of reasons including age of the well, absence of regulatory standards, or a transfer of wells between operators. More recent wells may be easier to evaluate, as more robust records are generally available.

An in-depth risk assessment performed by the CCS project team will identify any legacy wells that may compromise storage reservoir integrity. For CO_2 storage projects, EPA requires that the project operator demonstrate complete CO_2 containment in the injection zone for the protection of USDWs. Performing a risk assessment on each legacy well within the AOR will result in a risk ranking, and a corrective action plan is required to remediate wells that fail to maintain integrity of the storage formation.

The risk assessment of all wells within the AOR can be accomplished through review activities such as historical well record research and site reconnaissance. Assessment of legacy wells within the AOR should include, at a minimum, the necessary information to determine if remediation would be needed to minimize the risk of leakage pathways. The well information used in the assessment includes the following:

- Well total depth and measured depth
- Completion date
- Well abandonment date
- Openhole or cased-hole plugging
- Depth and thickness of cement plugs
- Drilling, casing, cementing, logging, and other well records (surface casing and intermediate casing string setting depth)
- Records of mechanical integrity tests (MITs) or cased-hole logs performed
- Well deviation

The assessment of wells within the AOR needs to be revisited every 5 years over the course of a CCS project, at the end of CO_2 injection, and prior to site closure. At the time of this writing, EPA maintains primary regulatory authority (primacy) for all Class VI injection well activities in every state except North Dakota and Wyoming.

North Dakota

To receive Class VI primacy, North Dakota-adopted rules that meet or exceed the stringency of the federal EPA UIC Class VI regulations in the protection of USDWs. North Dakota Century Code (NDCC) Chapter 38-22 identifies the North Dakota Industrial Commission's Department of Mineral Resources Oil and Gas Division (NDIC DMR) as the agency responsible for regulating geologic storage of CO_2 and Class VI injection well activities. The North Dakota law addresses permitting, pore space amalgamation, and long-term liability of a closed storage site. North Dakota statute also mandates a consultation period for the North Dakota Department of Environmental Quality (NDDEQ) to review all permits as part of the state's permit evaluation process. North Dakota Administrative Code (NDAC) Chapter 43-05-01 contains the regulations for geologic storage of CO_2. To ensure storage integrity and prevent potential migration pathways, the North Dakota Class VI application includes evaluations required for demonstrating well integrity of the CO_2 injection well(s), monitoring well(s), and existing wells located within the AOR. Specific regulations for wellbore integrity of the injection well can be found within NDAC § 43-05-01-11.1 Mechanical Integrity – Injection Wells as regulated by NDIC DMR. This section of the NDAC lays out guidelines similar to EPA's (40 CFR § 146.89 Mechanical Integrity). North Dakota regulations for AOR delineation (NDAC § 43-05-01-05.1) mirror the EPA Class VI requirements (40 CFR § 146.84), but North Dakota also has a default 1-mile AOR for the storage facility (NDAC § 43-05-01-05 1b[3]).

The North Dakota storage facility permit (SFP) is granted by project, allowing for single- or multiwell injection configurations for geologic storage of CO_2. Active permits and applications can be found on the NDIC DMR website. At the time of this writing, there have been three storage facility permit applications filed and approved by the state of North Dakota, including the approval of Red Trail Energy's geologic storage of CO_2 permit application in October 2021 (Case 28848-28850, Order 31453-31455). Minnkota Power Cooperative's geologic storage of CO_2 permit applications were approved January 2022 (Case 29029-29034, Order 31583-31588).

Wyoming

The Wyoming Department of Environmental Quality (Wyoming DEQ) developed rules regulating UIC Class VI injection wells under Chapter 24 of Wyoming's Water Quality Regulatory Program. These rules were first adopted in November 2010, prior to EPA officially issuing rules that established Class VI as a new well class under the UIC program in December 2010. As part of Wyoming's effort to meet the stringency of federal EPA Class VI requirements for primacy, Chapter 24 was revised in July 2016, with the application for primacy submitted in January 2018, and rules revised in January 2020. Wyoming DEQ received primacy approval on August 31, 2020. Wyoming DEQ recently went through one more round of rule revisions in coordination with EPA and announced that Chapter 24 was finalized on October 9, 2021.

The Wyoming Oil and Gas Conservation Commission (WOGCC) is the regulating agency responsible for permitting requests for unitization of pore space (WOGCC Rules, Chapter 3, § 43).

However, the details of how WOGCC will work with Wyoming DEQ in the Class VI permitting process has yet to be clarified. Additionally, the Joint Minerals Committee plans to consider a carbon storage liability draft bill. This bill addresses the transfer of title and liability of a closed CO_2 storage site and is modeled after North Dakota's long-term liability law, which allows for the transfer of liability and title of the stored CO_2 to the state.

At the time of this writing, no Class VI permits have been filed in Wyoming. However, the UW School of Energy Resources is currently constructing two wells designed to Class VI standards. They are currently permitted as Class I wells, with plans to convert to Class VI wells.

Montana

The Montana Board of Oil and Gas Conservation (BOGC) has not applied for Class VI primacy but has begun establishing the groundwork for an application to EPA. Montana has drafted regulations addressing pore space and long-term liability. Implementation of these regulations is contingent on application and approval of primacy for CO_2 injection. Wellbore integrity policies could be adopted and modified from existing oil and gas policies under the Montana BOGC, the regulatory agency. Until Montana further develops carbon storage rules and gains primacy from EPA, Montana's Class VI wells will fall under federal jurisdiction and be governed by EPA Class VI regulations.

Nebraska

The Nebraska Geologic Storage of Carbon Dioxide Act (Legislative Bill 650), similar to North Dakota CO_2 storage law, was passed by the Nebraska Legislature and signed into law in May 2021. The Nebraska Oil and Gas Conservation Commission (NOGCC) has drafted regulatory language and plans to commence rulemaking in 2022. Until Nebraska applies for and receives Class VI primacy, Class VI injection wells will be regulated by EPA.

Canada

In Canada, the jurisdiction for regulating CCS projects lies primarily with the individual provinces, stemming from provincial jurisdiction over the direct ownership, management, and regulation of most natural resources. At the same time, the federal government holds jurisdiction over international and interprovincial issues, including transboundary pipelines, uranium and nuclear power, offshore areas, and federal lands. Responsibilities for environmental protection are shared between the federal and provincial governments. CO_2 storage regulation falls to the provinces, unless components of a project are transboundary in scope, projects occur in areas of federal jurisdiction, or the project has the potential to impact human and environmental receptors protected by federal environmental regulations.

British Columbia

There are two regulatory agencies in British Columbia (BC) that have roles in regulating CCS projects. The Ministry of Natural Gas Development is the agency developing regulatory policy framework for CCS. The BC Oil and Gas Commission is the agency that regulates oil and gas-processing facilities with capacity to capture CO_2 for storage (Lafarge Canada, 2021).

The BC Ministry of Natural Gas Development has been in the process of developing a regulatory framework for CCS for many years and has completed a draft policy. In 2014, the Ministry sought public input on the draft regulation. In 2015, they amended the Petroleum and Natural Gas Act and the Oil and Gas Activities Act to enable CCS. A second set of amendments is planned (Government of British Columbia, 2021). There are also proposals being prepared to look into regulations such as "site characterization details; CO_2 stream composition; a description of measures to prevent significant leakage, unintended migration, or other irregularities, as well as corrective measures and contingency plans in such an event," among other details that would help guide future carbon storage projects (Larken and others, 2019).

Project CO2MENT, is a CCS demonstration project currently in development in BC at Lafarge's Richmond cement plant (Scottish Carbon Capture and Storage, 2021; Lafarge Canada, 2021). It has completed Phase II, in which CO_2 is being captured from the flue gas. In Phase III, they will start demonstrating utilization of CO_2.

Alberta

In Alberta, there are also two regulatory agencies involved in CCS regulation. The environmental impacts of CCS projects are overseen by the Alberta Ministry of Environment and Parks (formerly known as the Ministry of Environment and Sustainable Resource Development) which monitors environmental resources such as land, water, and air quality. The agency is responsible for determining if CCS projects are required to go through an environmental impact assessment (EIA) process. Oil- and gas-related functions are administered by the Alberta Energy Regulator (formerly known as the Energy Resources Conservation Board), which treats CCS projects as acid gas disposal. It is the regulator responsible for granting approvals to drill wells and operate CO_2 injection projects (Larken and others, 2019; Wilson and others, 2017).

Alberta has a regulatory framework in place for regulations for storage, pore space ownership, and long-term liability. The framework includes the following pieces of legislation (Wilson and others, 2017; Larken and others, 2019):

- Carbon Capture and Storage Statutes Amendment Act (2010): legislation that addresses long-term liability and pore space ownership and allows provincial government to take on long-term liability for carbon sequestration. This act also mandates that CCS operators contribute to a postclosure stewardship fund that provides funding for future monitoring, maintenance, and remediation.

- Carbon Sequestration Tenure Regulation (2011): comprises rules regulating the process of obtaining tenure or lease rights for pore space.

- Environmental Protection and Enhancement Act: legislation that governs the EIA process.

One of Alberta's requirements for applications to store CO_2 is to demonstrate that the storage site has "suitable containment" properties to ensure that CO_2 will remain in the target formations. This includes a review of existing wells within the AOR that penetrate the storage complex. Regulations also require a monitoring, measurement, and verification (MMV) plan be submitted as part of the application. To develop the MMV plan, a risk assessment is completed to address the likelihood of potential risks. This risk assessment and MMV planning are an iterative process and should be regularly revisited and updated if the actual movement of the plume and pressure front are different from predictions. In 2013, the Alberta government funded a regulatory framework assessment (RFA) to evaluate current CCS regulations in the province, because of the long-term liability role of the government on site closure. Findings from this RFA recommended regulatory changes related to the technical, environmental, safety, and monitoring requirements for the safe deployment of CCS as well as other actions to increase the body of knowledge on CCS-related topics. The government of Alberta initiated development of a number of policy tools and regulatory requirements and processes to manage these liabilities (Sabin Center for Climate Change Law, 2021).

Alberta has two current CCS projects within the province: Quest and the Alberta carbon trunk line (Larken and others, 2019). Quest (Shell, 2021) is located near Edmonton, Alberta. It opened in late 2015 and has captured and stored over 5 million tonnes of CO_2. CO_2 is captured at the Shell Scotford Upgrader, which is a crude oil-processing facility. Storage is in a saline formation. The Alberta carbon trunk line is a 240-kilometer pipeline that collects CO_2 from industrial sources in Alberta and transports the CO_2 to oil fields to be used for EOR (Alberta Carbon Trunk Line, 2021). It was completed in 2020 and has captured and transported over 1 million tonnes of CO_2 for use in EOR fields.

Saskatchewan

The agencies in Saskatchewan involved in CCS regulation are the Saskatchewan Ministry of Energy and Resources, which is responsible for the regulation of the oil and gas industry and other natural resources, and the Saskatchewan Ministry of Environment, which is the agency responsible for conducting environmental assessments for proposed projects to determine if an EIA is necessary (Government of Saskatchewan, 2021; Larken and others, 2019).

Saskatchewan also has a regulatory framework in place for CCS project development. The major regulations include the following:

- Oil and Gas Conservation Act (OGCA): Amended in 2011 to expand powers to include oversight of CO_2 storage; long-term liability of CO_2 is also regulated under the OGCA.
- Crown Minerals Act: authorizes the leasing of pore space on Crown lands.
- Pipeline Act (2009 amendments): regulates CO_2 pipelines.

Unlike Alberta, which requires an MMV plan, Saskatchewan requires the CCS project's risk management plan to include monitoring of risk management to meet provincial requirements (Larken and others, 2019). The OGCA gives authority to the lieutenant governor in council to make regulations to ensure that wells are constructed, operated, and plugged in a manner that prevents contamination of water or air and to monitor non-oil-and-gas substances (e.g., CO_2) (Larken and others, 2019).

There are two current CCS projects in Saskatchewan. The Weyburn–Midale project is a CO_2 EOR project that began in 2000. The Boundary Dam Integrated CCS Demonstration Project is located at a coal-fired power plant that has six units. Unit 3 was retrofitted with CCS in 2013 and began capturing CO_2 in 2014, with the ability to capture 1 million tonnes of CO_2 per year. Captured CO_2 is transported via pipeline for use in EOR; CO_2 not used for EOR is transported to the Aquistore project to be injected and sequestered geologically (Power Technology, 2021; SaskPower, 2021).

Manitoba

Manitoba currently does not have any CCS regulatory framework in place or under development. Almost all electricity in Manitoba is from renewable energy sources, so the energy industry emits relatively few greenhouse gases, thus reducing the larger CO_2 capture targets for CCS. Approximately 97% of Manitoba's electricity is generated by hydroelectric, 3% is generated by wind, and less than 1% is generated by natural gas and coal.

WELL INTEGRITY RISK ASSESSMENT, RANKING, AND REMEDIATION

A full risk assessment performed by the CCS project team will assist in identifying potential project risks and whether wells identified as significant risks to the storage complex should be remediated or if continuous monitoring near the identified wells is an option. A risk ranking will identify and justify the immediate and sequential timing for well remediation, with the highest-risk-ranked wells remediated first followed by lower-ranked wells. Following International Organization for Standardization (ISO) 31000 Risk Management – Principals and Guidelines (2009), a risk register is developed by the technical experts performing the risk assessment. The process to determine the remediation and corrective action includes the risk analyses using a series of potential impact causes and effects scored (impact score) for each well, and from that total, each well is tabulated and sorted by impact score. The wells are risk-ranked to determine the timing of remediation and corrective action.

This register combines the comprehensive list of each potential risk factor identified, assigned risk probability, and assigned risk impact score. The register is then ranked from highest to lowest risk ranking to determine the timing of remediation or corrective action required for each wellbore. Some wells may require immediate remediation, some may need to be completed prior to start of CO_2 injection in order to obtain the proper permits (likely high- to medium-level risk wells closer to the injection site), and some remediation may occur after the start of CO_2 injection throughout the life of the project (likely lower-risk wells further from the injection site and/or fluid or pressure path). The project operator will develop corrective action plans for each wellbore identified as compromising the integrity of the storage complex. All remediation plans and timing of remediation decisions need to be justified and approved by the regulatory agency.

Tables 1 and 2 provide an example of risk assessment elements to be considered for the P&A and development wells (Patil and others, 2021). These risk elements can then be developed into a legacy well corrective action plan. The corrective action plan is provided to the respective governing body for review prior to, and then to be included in, the geologic storage permit application for approval. The execution of the plan provides assurance that the injected fluids will remain within the reservoir and that USDWs are protected. A detailed report on regulatory-driven risk assessment regarding the development of CCS projects will be developed under a future PCOR Partnership effort.

Table 1. Well Integrity Risk Assessment Example Criteria for Existing P&A Wells (Patil and others, 2021)

No.	Scope	Potential Risk	Causes	Impact/Consequences
1	Exploration well in target CO_2 storage area	Mechanism of CO_2 leakage along the wellbores	– Cement plug failure due to thermal, hydro, mechanical (subsidence), chemical, changes – Cement in annulus degrades due to generation and propagation in cracks, microannulus, corrosion	– Operational and financial risk – CO_2 accumulation in the shallower zones within wellbore – CO_2 leakage to overburden or seabed
2	Number of cement plugs below surface plug, comparing plugging and abandonment procedures that were recorded based on industry standards	Existing P&A well unable to seal CO_2 storage reservoir	– Deviation from current stringent requirements to permanently seal wellbore	– CO_2 leaks into overburden and to seabed/marine environment – Could delay injection until resolved – Could be showstopper for project
3	Primary barrier – cement plug across permeable zones of different pressure regimes to be isolated	CO_2 leakage through deeper cement plug(s) set inside borehole Broken/stuck cement stringer Poor-quality plug	– Not enough cement above and below permeable zone (30 m above and below required) – Procedure not followed while setting plugs – Contaminated cement plug with brine	– Will lead to CO_2 accumulation above this barrier in place – Could be showstopper for project – Could delay injection because of remedial work
4	Secondary barrier – 15-m plug above/below cement retainer or 30 m with bridge plug	CO_2 leakage through secondary barrier cement plug(s) set inside borehole Broken/stuck cement stringer Poor-quality plug	– Insufficient cement plug-testing procedures – Insufficient cement above and below cement retainer – Contaminated cement plug with brine	– CO_2 accumulation in shallower zones within wellbore – Could be showstopper for project – Could delay injection because of remedial work
5	Shallow barrier – cement plug with cement retainer	CO_2 leakage through shallow barrier cement plug(s) set inside borehole to seal the annulus after casing cut and removal	– Insufficient cement above and below cement retainer – No cement retainer and only cement plugs may reduce seal capability	– CO_2 accumulation in shallower zones within wellbore – Could be showstopper for project – Could delay injection because of remedial work
6	Corrosion of wellbore construction material exposed to CO_2 storage reservoir, e.g., production casing/liner material	CO_2 leakage through microcracks, fissures, debonded area	– Long-term exposure to CO_2 or CO_2-saturated fluids anticipated to corrode carbon steel and degrade cement – Well thermal decomposition in water leg	– CO_2 leakage to overburden or seabed – CO_2 degradation of cement – Growth of preexisting cracks, microannulus, channels
7	Verification of barriers based on PETRONAS Procedures and Guidelines for Upstream Activities (PPGUA) 4.0, Volume 7, Section 9.6 (2020)	Failure of presence of barrier in the wellbore not tested up to standards	– Improper procedure setting barriers – Impurities at the casing–cement or casing–seal interface – Already damaged barrier	– Cement plug failure – CO_2 leaking in wellbore
8	Cap rock restoration CO_2 leakage through annular cement Annual cement data, cement bond log (CBL)/variable-density log (VDL)	Unable to evaluate cement behind casing	– No CBL data available and unable to run new CBL	– CO_2 leakage to overburden or seabed – CO_2 degradation of cement – Growth of preexisting cracks, microannulus, channels
9	Wellsite status (offshore/onshore) to access for reentry/mitigation purpose Reenter the well to remediate barriers and restore well integrity	Unable to access sub-mud line casing stump, excavation around stump, tie-back	– Guide base, wellhead retrieved, and casing cut a few meters below seabed – Top of well covered with sand or any other obstruction – Uncertainties in data on final well location	– Schedule impact – delay in job operations – If well is leaking, could be showstopper for project

Table 2. Well Integrity Risk Assessment Example Criteria for Recompleting/Development Wells (Patil and others, 2021)

No.	Scope	Potential Risk	Causes	Impact/Consequences
1	Well age	Wells in operations for >25 years	– Well deterioration – Casing/cement deterioration – Wellbore construction practices	– Compromised well integrity – Potential for loss of operating time due to unplanned shutdown – Cost impact/remedial workover jobs
2	Wellbore trajectory penetrating CO_2 storage and permeable zones below storage	CO_2 leakage risk from CO_2 storage reservoir up to surface Corrosion of casing–cement–formation composite structure	– Wellbore casing may contact corrosive reservoir fluids – Corrosion, casing–cement–formation composite structure may deteriorate	– Compromised well integrity – Potential for loss of operating time due to unplanned shutdown – Cost impact/remedial workover jobs
4	Well construction challenges /Nonproduction time	Losses Tight hole Lost hole/bottomhole assembly (BHA) Sidetrack due to wellbore stability	– Insufficient mud weight – Drilling experience and practices – Wellbore collapse/wellbore stability	– Nonproductive time incurred – Sidetrack – Extensive casing wear, reducing original casing strength
5	Wellhead	Unable to rig up on well Material not suitable for CO_2 injector	– Degraded, corrosion damage – Wellhead tilted	– Unable to enter and recomplete or P&A operations – Potential for loss of production/injection due to unplanned event – Cost impact/remedial workover jobs
6	Wellhead subsidence/uplift	Vertical movement >±5 cm	– Tectonic activities, reservoir compaction, mechanical failure, cement failure – Thermal effect – Casing/conductor corrosion – Fluid migration	– Damage to grating around wellhead, load transferred to weaker structure – Casings in compression, leading to casing collapse/cement failure and possible loss of pressure integrity
7	Wellhead material	Corrosion at wellhead, wellhead valves, and piping due to corrosive injection fluids	– Corrosion damage – Leaks	– Compromised well integrity – Potential for loss of production/injection due to unplanned shutdown – Cost impact/remedial workover jobs
8	Wellbore construction – casing material Conductor Surface casing Intermediate casing	Deformation Corrosion damage Leaks	– Mechanical problems encountered while drilling resulting in casing wear and reduced strength – Inadequate top of cement (TOC) across shallow permeable zones – Poor centralization and cemented casing – Casing deformation/cement shrinkage – Remaining casing strength	– Compromised well integrity – Potential for loss of production/injection due to unplanned shutdown – Cost impacts/remedial workover jobs

Continued . . .

Table 2. Well Integrity Risk Assessment Example Criteria for Recompleting/Development Wells (Patil and others, 2021) (continued)

No.	Scope	Potential Risk	Causes	Impact/Consequences
9	Wellbore construction – casing material Production/liner casing	Deformation Corrosion damage Leaks	– Non-corrosion-resistant alloy (CRA) material exposure to CO_2 – Degrade cement behind production casing – Poor cemented casing	– Compromised well integrity – Potential for loss of production/injection due to unplanned shutdown – Cost impact/remedial workover jobs
10	Cementing	Sustained casing pressure Ineffective mud removal during cementing, causing channel Sustained casing pressures CCP, SCP, higher than threshold, production casing pressure (PCP) lower than threshold)	– Poor mud removal/channels in cemented annulus – Inadequate cement across shallow permeable zones – Inadequately engineered cement slurry design not considering long-term stresses and mechanical properties of set cement – Poor centralization or no centralization – Inadequate cement volume/excess volume of cemented casing – Poor wellbore condition due to excessive borehole breakout or washout – Microannulus/cement shrinkage – Cyclic wellbore pressures and temperatures or cement degradation in corrosive environment	– Compromised well integrity – Potential for loss of production/injection due to unplanned shutdown – Cost impact/remedial workover jobs – Microannulus behind casing – Flow behind casing – Casing and cement corrosion
11	Cement material	Non-CO_2-resistant/Class G/Class H cement will deteriorate relatively earlier than geopolymer/slag flex cement	– Casing in contact with formation due to insufficient centralization – Poor mud properties used – high pore volume (PV) and yield point (YP) – Inadequate or no pipe movement – Low pumping/displacement rates – Hole enlargement – Poor spacer train design	– Inadequate isolation of overlying formations – Gas channels and high annulus pressure during drilling and production – Potential well integrity
13	Conductor casing pressure (CCP) and surface/intermediate casing pressure (ICP)	Casing annulus pressure, casing leak operator's general limits are as follows: Sustained casing pressure (SCP) and another casing – minimum between maximum allowable working pressure (MAWP) and 300 psi PCP – minimum between MAWP and 500 psi	– Loss of zonal isolation by cement outside casing (poor cementing) – Inadequate cement height outside prod. casing – Temperature change – Seabed subsidence, unstable/unconsolidated formation	– Well intervention required if annulus pressure increases often after bleeding

Continued . . .

Table 2. Well Integrity Risk Assessment Example Criteria for Recompleting/Development Wells (Patil and others, 2021) (continued)

No.	Scope	Potential Risk	Causes	Impact/Consequences
15	PCP	Casing annulus pressure; casing leak operator's general limits are as follows: SCP and another casing – minimum between MAWP and 300 psi PCP – minimum between MAWP and 500 psi	– Tubing leak/tubing hanger leak, packer/seal assemble leak – Production casing leak – SCSSV control line leak into annulus – Temperature expansion due to change in production/injection	– Well intervention required if annulus pressure increases often after bleeding
16	SCP	Unable to bleed off pressure or long time to bleed off during rig entry, unable to proceed with rig entry because of A and B annulus pressure above 100 psi	– Poor previous casing cement bond behind casing – Unable to isolate source of pressure – Trapped pressure inside casings	– Unable to reenter well because rig unable to approach platform – Hydrocarbon in annulus to surface – Unable to bleed down surface pressure below 100 psi for rig entry – Prolong shutdown, cost impact
17	Completion and completion string production tubing, tubing hanger, surface-controlled subsurface safety valve (SCSSV), packers/gauges/perforated casing/liner, cased hole completion	Non-CRA materials, damages, leaks, degraded cement behind perforation/casing getting corroded	– Acidic condition due to corrosive formation fluid and carbon steel reacting due to corrosive environment – Carbonation/corrosion of Class G cement	– Well intervention required to replace upper completion frequently – Cracks/microchannels in cement – Cost impact/additional time

WELLBORE EVALUATION

Regulators and CCS project operators need to address legacy wells within a designated AOR. Regulating bodies have mandated rules addressing the adequacy of existing abandoned wells and the construction of injection and monitoring wells in such a manner that prevents the migration of CO_2 or associated fluids to protect USDWs. EPA created a flow diagram to assist with the review of wellbores in an AOR (Figure 1). Legacy wells within the AOR must be identified and located prior to assessment for risk. Depending on the specific area, simply locating all legacy wells, especially older wells from several decades ago, can present a significant risk to the CCS project. Well records may be nonexistent, and abandoned wells likely have had wellheads removed and casing cut off several feet below the surface. A CCS project team should have a good understanding of the oil development history of the project area to understand the likelihood of abandoned wells that are not in state databases. If there is the potential for these abandoned wells in the area, the CCS project team must develop a plan for addressing this issue. Once all legacy wells are identified and located in the AOR, a thorough process for well evaluation is essential.

Several factors could increase the potential risk of legacy wells such as poor cement jobs, casing corrosion, or well maintenance activities (e.g., acid jobs). An additional risk is a lack of available information (e.g., missing or incomplete well records) about individual wells, creating uncertainty in the condition of the existing well. Thoroughly researching the history of a wellbore can be intensive, as multiple resources for well data may need to be evaluated including the regulatory agency database and historic well files. Gathering and evaluating information on operational history, including relevant operations addressing a wellbore's integrity, can be a challenging task because of poor quality or missing documentation. If well ownership is transferred between multiple companies, obtaining the operational history and condition of the well can also be challenging.

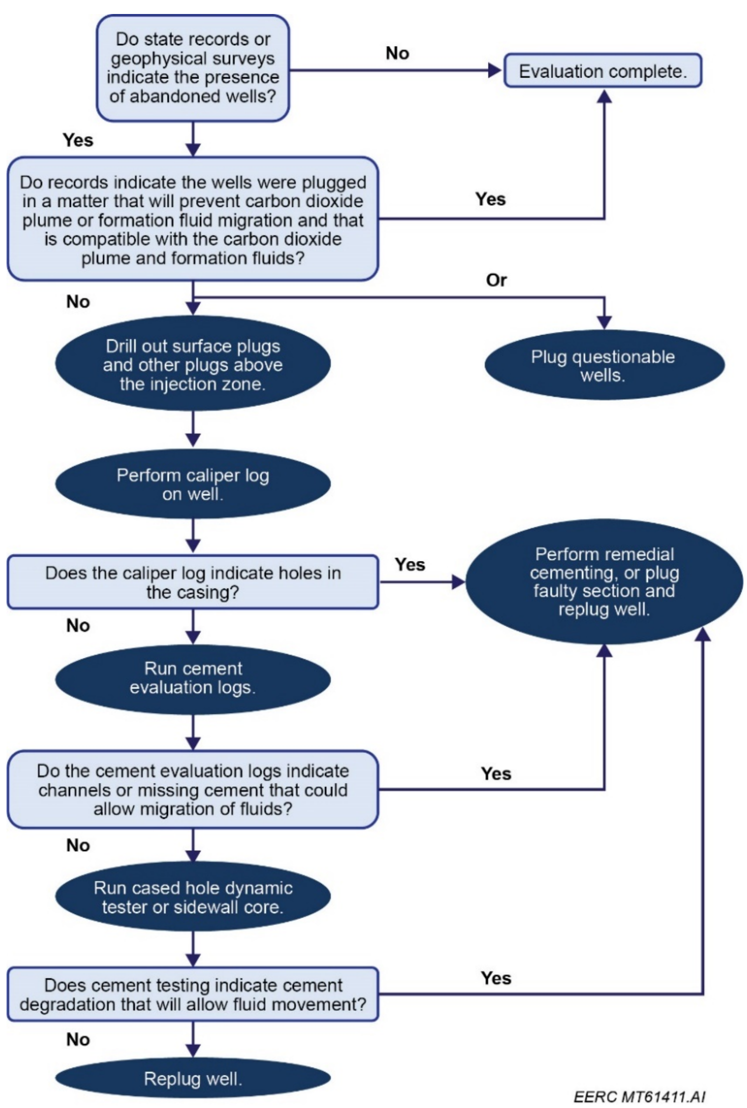

Figure 1. EPA decision tree designed to assist regulatory bodies in addressing the adequacy of existing abandoned wells and the construction of injection and monitoring wells for CCS projects.

Primary parameters for well evaluation include the casing, cementing, logging, and plug and abandonment methods (if applicable). Proper casing material (size, type, weight, and grade) and cement quality are crucial for CO_2 projects and wellbore integrity. When CO_2 encounters an aqueous subsurface environment, carbonic acid can develop, which can damage the structural integrity of the cement and create a corrosive environment for a wellbore's steel casing. The casing and the cement may degrade with time depending on the downhole temperature, pressure, stress conditions, and formation fluids. A quality cement job with good bonding to both the formation and casing is important to protecting the integrity of the cement and steel casing and maintaining overall well integrity. Cement material characteristics, type, weight, yield, and additives are vital for determining cement-bonding properties and the likelihood that the cement will resist degradation. Common wellbore logs (e.g., CBLs) (Figure 2) depict the quality of cement bonding to the casing and cement bonding to the wellbore rock, and indicate the depths of casing and cement, both of which are crucial for protection of USDWs.

Leakage pathways are the primary concern when evaluating a wellbore (Figure 3). Examples of leakage pathways from cement failures can include mud channels (section of annulus where the drilling mud was not replaced by cement), chimneys (very thin features resembling vertical cracks, likely caused by pressure from formation fluids breaking through cement during the setting process), and microannuli (debonding between cement and rock or cement and casing which appear after cement has set).

Cement quality degrades in the presence of persistent acidic conditions as the extent of the cement dissociation front propagates with time. These reactions result in increased cement strength and reduction of permeability and porosity in the initial stage. But over time, the effect reverses significantly, and the strength of the cement degrades (Kutchko and others, 2007; Duguid and others, 2011). Thus degradation of wellbore cement in the presence of carbonized, acidic fluids poses the risk of creating the leakage pathways over time. Understanding the local stress conditions acting on the cement–casing–formation sheath is very important to improve knowledge on leakage pathway creation together with geochemical and geomechanical processes (Patil and others, 2021).

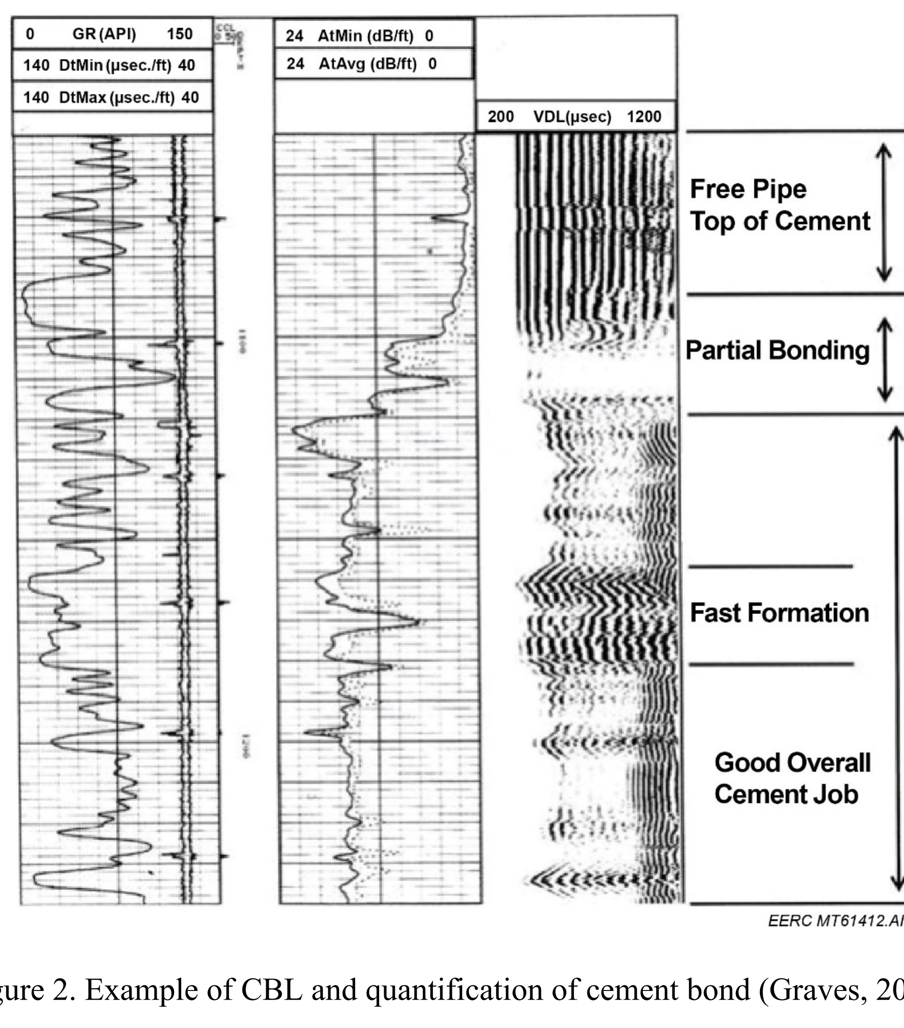

Figure 2. Example of CBL and quantification of cement bond (Graves, 2021).

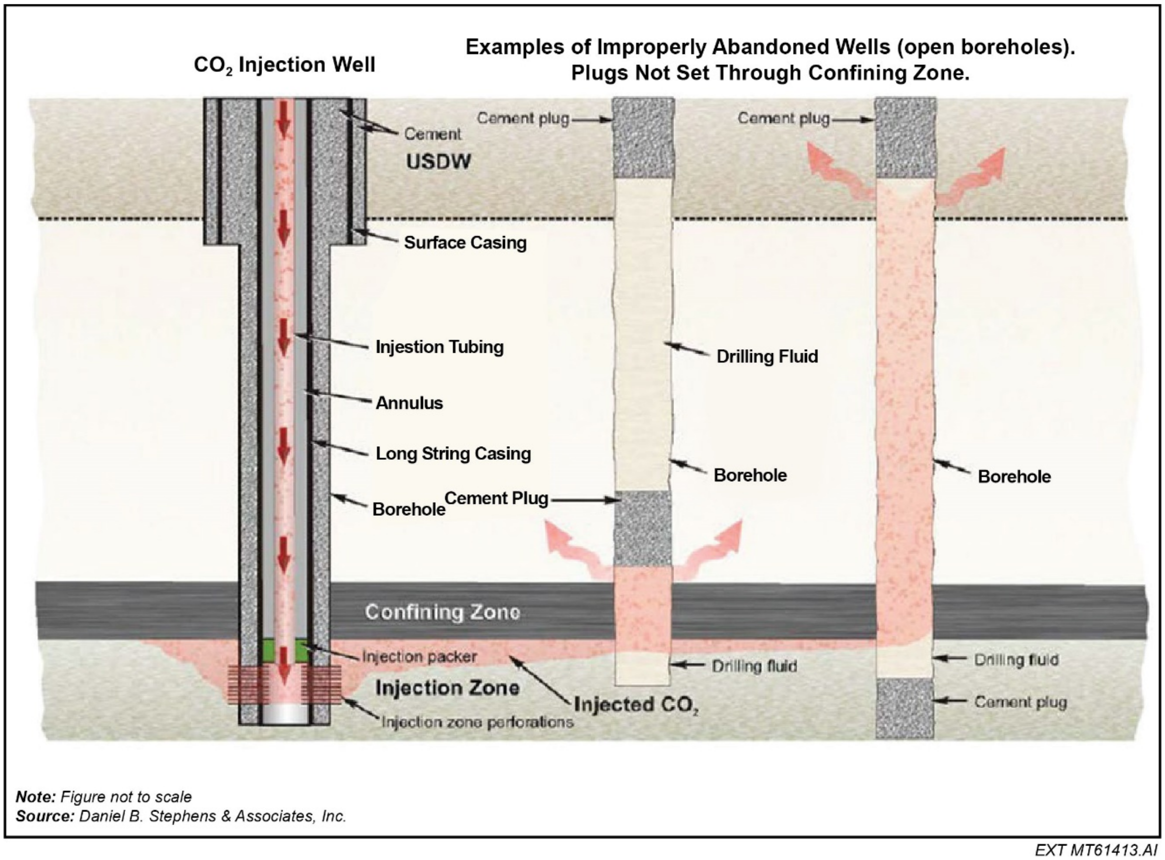

Figure 3. Wellbore diagram showing possible leakage pathways.

The TOC in the annulus is considered low when either not enough cement is pumped to fill the annulus to the surface or losses occur during the cementing process. Not enough cement can result in the potential for drilling mud, formation fluids, and pressures to travel within the annulus between the casing and exposed formations, creating potential cross-contamination and open leakage pathways, resulting in potential damage to the casing wall or casing collar threads that could allow a direct flow path for injectates to migrate and potentially enter USDW aquifers (Figures 4 and 5). Mud channels that occur during cementing can prevent a good bond between the cement and the formation and the cement to the casing. These channels can create flow paths or intermittent mud pockets that affect the integrity and strength of the wellbore (Figure 5). Microannuli are mechanical defects attributed primarily to fracturing and high-pressure fluid injection operations. Overpressuring the annulus can cause the cement interfaces to debond, resulting in a vertically propagating aperture, which is then sustained by cement density differences, pressure differentials, or temperature variations within the casing. Cement bond logs and the well's cement job application, found within the individual well file, can be used to quantify the existence of these potential issues and aid in addressing concerns regarding wellbore cement integrity.

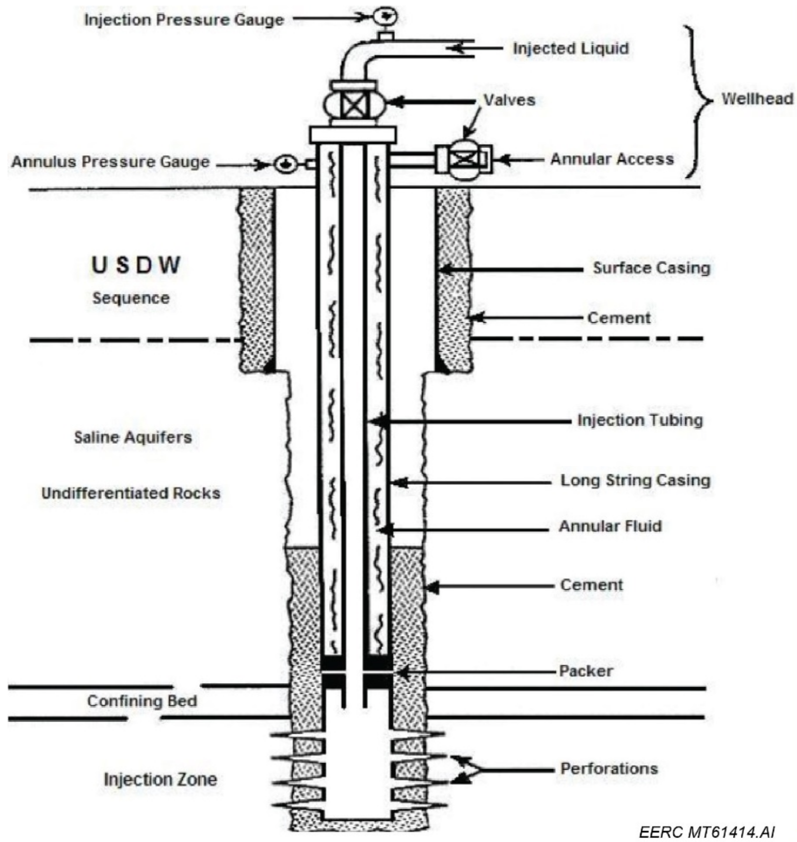

Figure 4. Example of injection wellbore for conducting MIT of annulus (Graves, 2021).

The setting depth of the surface casing is a key consideration when evaluating wellbores in the AOR. The underground freshwater zones can be sufficiently protected when the surface casing is set below the deepest USDW and cemented to surface. For example, in North Dakota all wells are required to set surface casing at least 50 ft below the base of the deepest USDW and cement to surface. If the surface casing is set short of the deepest USDW, additional consideration should be given in the evaluation and potential mitigation strategy. This is typically based on well era. Wells constructed in the early 1980s to present more than likely have surface casing set to an appropriate depth to ensure protection of USDWs.

External and internal MITs are key when evaluating a wellbore (Figure 4). MIT procedures and qualification standards are regimented by regulatory agencies. There are three main objectives in conducting MITs: 1) identifying leaks in the wellbore system (internal MIT), 2) identifying fluid entering into and remaining in the intended injection interval (external MIT), and 3) identifying crossflow of fluid into USDWs (external MIT) (Figure 5).

For internal MITs, most regulatory agencies require a constant pressure for a minimum of 15 minutes (although industry recommendations are typically for 30 minutes to 1 hour depending on the state and on-site inspector) to be held on a shut-in wellbore while maintaining a pressure differential of no greater than 10%. Internal MITs are for the prevention of leakage through the

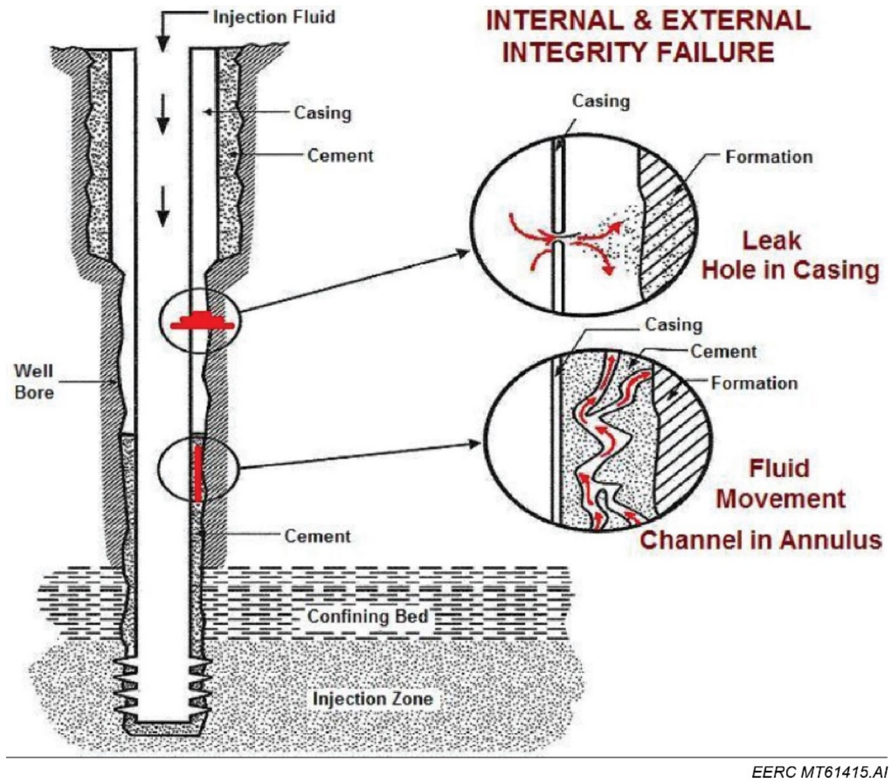

Figure 5. Examples of mechanical integrity failures in a wellbore (Graves, 2021).

walls of the well, i.e., in the casing and/or tubing. Internal MITs are pressure tests conducted by holding pressure in the annulus between the injection tubing and the long-string casing while the well injection operations are shut down. Casing inspection logs may be used for identifying casing integrity failures. During injection activities, the annulus pressure, injection pressure, and injection rate relationships must be monitored for continuous evaluation of integrity.

External MITs indicate potential fluid movement through the casing to wellbore annular space. Ultrasonic image logs (internal and external MIT), radioactive tracer surveys (RATS), temperature and noise logs, and several other types may be used to identify leakage pathways. The ultrasonic imager tool indicates the quality of the cement bond at the cement–casing interface and the casing wall thickness required for pipe inspection. This logging tool relays 360° data coverage, enabling the evaluation of the quality of the cement bond as well as the determination of the internal and external casing conditions. RATS is a flow-profiling log that can identify fluid migration in cement channels behind the casing and leaks between casing, tubing, and packer. Temperature surveys originated in the mid-1930s and can locate cement tops (because of heat from the exothermic reaction from cement), fluid migration, and gas intervals (by the cooling effect from expansion). Noise logs "hear" fluid flow, i.e., turbulence, occurring inside or outside the well tubulars, indicating channels behind casing, tubing, and/or casing leaks.

Well logging is the process of recording various petrophysical properties of rock/formations penetrated by drilling as well as cement and casing properties. Log responses are functions of lithology, porosity, fluid content, and textural variation of formation and cement. Casing inspection logs provide detailed evaluation of in-place well casing, employing two measurements of total casing wall and inner surface. These logs detect small defects and corroded areas in the pipe and defects on the inner and outer walls of the casing. Legacy wells may not have logging records in the well files unless integrity issues have been observed during operations, although, at a minimum, CBLs have likely been collected. The regulatory agency database may be the best source for logs if not available from operator well files, which could be the case in some older-era legacy wells. Advanced cement-logging techniques and interpretations can be conducted to evaluate the cement, cement debonding, and cement sheath between the casing and formation to clearly identify the presence of solids and liquids in the annular space, which helps the CCS project operator make informed decisions regarding data collection, monitoring, or remediation. As most legacy wells are plugged and abandoned, the well would require drilling out the cement plugs prior to running logs, which will increase expenditures and risks to the project. There are a variety of logging applications that can be performed on legacy wells to ascertain well integrity and answer the unknowns for risk assessments.

As CO_2 can be highly corrosive in the subsurface when mixed with native formation fluids (carbonic acid is formed), casing and cement providers have introduced CO_2 corrosion-resistant casing such as chrome alloy and cementing additives such as fly ash and silica flour. CO_2-resistant materials provide an additional consideration for injection or monitoring well recompletions. Cost and time requirements for drilling a new well could be similar to reentering and converting an existing wellbore. Recompleting methods will entail using the CO_2-resistant materials to address insufficient cement challenges (e.g., cement squeeze) or replacing casing strings. Recompletions are considered high risk as the work may result in limited injection rate or volume or increased injection pressure, which may impact the surface compression and injection facilities. If complete well records are not available, an existing wellbore may best be utilized as a monitor well. Converting these existing wells to a CO_2 injection well brings a high level of uncertainty because well evaluation is incomplete and a variety of activities may have been performed during the lifetime of the wells, which can cause pressure and temperature stress on the wellbore structure.

Most P&A wells were not designed to withstand high-CO_2-concentration downhole conditions. CRA tubulars and CO_2-resistant cement were typically not used during legacy well construction, and downhole pressure and temperature conditions may have further degraded the material strength and elevated the corrosion susceptibility. Assessments for the loss of containment along the wellbore and determining the complexity in restoring well integrity need to be considered when estimating possible leakage pathways. Risks need to be identified and remedial action plans designed for restoring well integrity, if necessary. Leakage rate modeling can be performed to identify and evaluate the associated risks for designing the remedial action plan to safeguard the CO_2 storage site.

Locating P&A wells can be a big challenge if the wellheads have been removed and the casing strings were cut below ground level. Possible CO_2 leakage pathways in P&A wellbores are shown in Figure 6. They are a) between casing interface and annular cement interface, b) between cement plug and casing interface, c) through cement plug and annular cement, d) through corroded casing wall, e) between annular cement and casing interface, and f) between annular cement and formation interface.

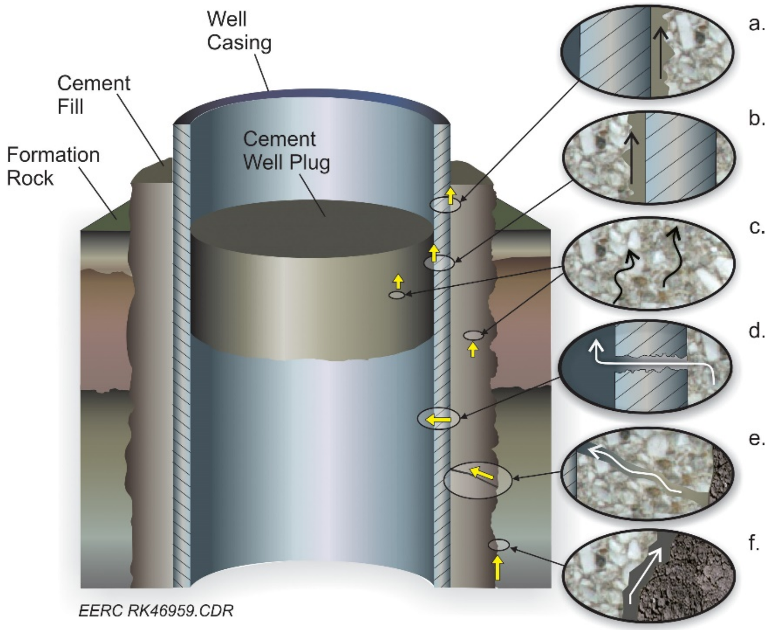

Figure 6. Possible CO_2 leakage pathways from subsurface to atmosphere along an example P&A well (Celia and others, 2004).

Consequences of failed integrity could include possible contamination of USDWs, leaks to the atmosphere, or financial losses. Further, CO_2 loss from the storage formation could have implications on tax credits (i.e., Section 45Q). Therefore, well integrity risk assessment is imperative for CCS projects and should be carefully addressed during project planning.

Legacy Well Risk Assessment Corrective Action Plan

The primary objective of wellbore integrity assessment is to ensure the protection of USDWs by confirming that no pathways exist for communication between the legacy wellbores and the proposed injection formation and to prevent the injectate or formation fluids (i.e., brine) from impacting USDWs. To accomplish this goal, all the wellbores in the AOR, and specifically those that penetrate the proposed storage zone, must be identified and evaluated (Figure 7). Each well identified within the AOR of the project's proposed storage complex will be evaluated based on well information obtained from individual well records. These records should provide the necessary information to determine the history of the legacy wells, i.e., drilled, completed, operated, and plugged. Federal, state, and provincial databases and individual well files must be thoroughly reviewed, with the individual well data tabulated. Technical interpretation of the well data will provide pertinent information to populate the risk assessment. A decision tree for evaluating individual wells is shown in Figure 8. Risks are to be identified, reviewed, and ranked accordingly. The risk-ranking outcome will determine the necessity for remediation or monitoring of the legacy wellbore. This leads to the creation of an action plan to assure the regulatory authority that the identified wellbores were sufficiently abandoned, have the required integrity, or will require further work. Based on the evaluation of the individual well information, a determination

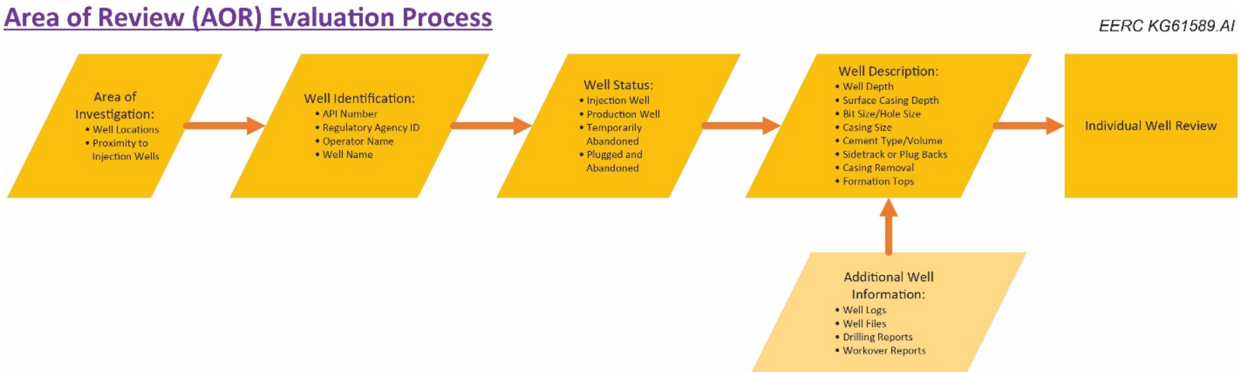

Figure 7. Information gathered from individual well records during the evaluation process.

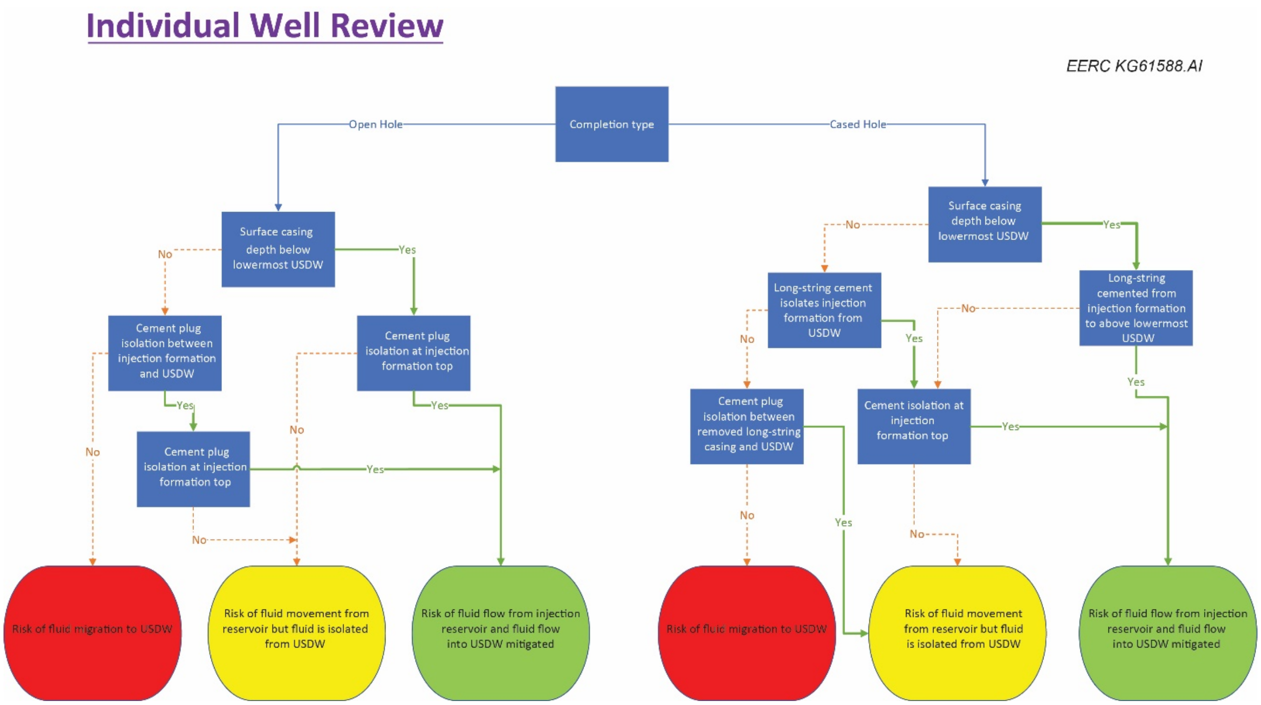

Figure 8. Decision tree for evaluating the integrity of individual wells based on well file records.

of the associated risks will be identified, with each risk ranked, and resulting in a plan for remediation and/or monitoring provisions, if necessary. If remediation work is required, a technical evaluation should be completed, with procedural methods developed to ensure that the injectate will be contained within the storage reservoir and not endanger USDWs or any other underground productive horizons (Figure 9). The site-specific monitoring and measurement system would then identify any possible CO_2 leakage during the operational phase.

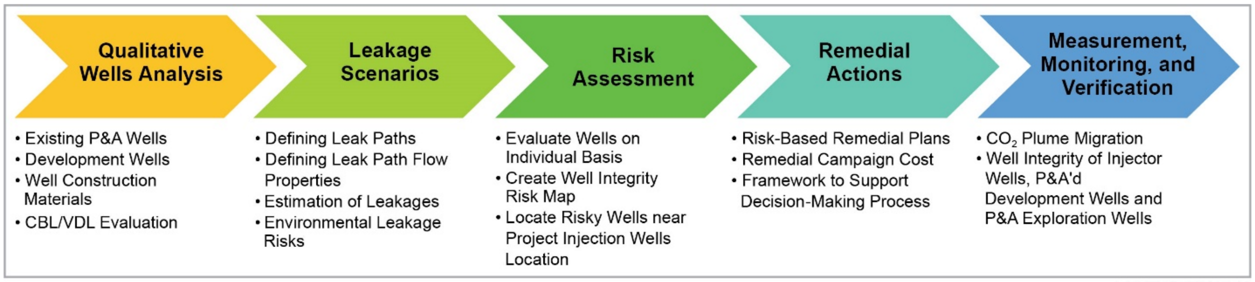

Figure 9. Concept for well integrity risk management (Patil and others, 2021).

REMEDIATION CONSIDERATIONS FOR LEGACY WELLS LOCATED IN A CCS PROJECT AREA

Legacy wells are classified historical wells that were previously drilled, completed, produced, shut in (inactive or temporarily abandoned), and plugged and abandoned. Legacy well development started in the PCOR Partnership region in the late 1800s (in Wyoming). Accordingly, this has resulted in a wide range in the age of the wells and the regulations in place at the time the wells were originally drilled, completed, produced, shut in, or abandoned.

Within the PCOR Partnership region, most states and provinces had oil and gas regulatory authorities in place by the 1950s. API standardized cementing practices in the mid-1950s. The 1972 Clean Water Act and subsequent amendments resulted in protection of USDWs. Throughout the history of oil and gas development, state and provincial regulations, along with the oil and gas industry itself, have undergone changes. The rules associated with oil and gas operations have been amended to reflect activity level, improvements in drilling and operating technologies, and compliance with environmental and safety requirements. These amendments created a standardization of practices that evolved into the governing state and provincial regulations used to ensure USDW protection that includes but are not limited to:

- Upgrades in casing metallurgical properties, grades, and weights.
- Requirements for additional openhole and cased-hole logging for geologic control and identification, including directional surveys and directional steering.
- Isolation of zones with enhanced classes of cements and additives, casing cement placement and staging, and displacement methods.
- Requirements for CBLs and additional cased-hole inspection logs to identify well integrity.
- Requirements for specific cement plug placement and the number of cement plugs at abandonment.

- In some instances, regulations requiring placement of cement into perforations (squeeze cementing) or use of cement retainers for well plug and abandonment.

Feasibility of Existing Wellbores for CO_2 Injection Wells

In the United States, Class I, II, and VI UIC well regulations, and in Canada, CO_2 injection well regulations, are quite stringent and specific for protection of the environment. The option to drill a new well for CO_2 injection or utilize an existing wellbore may be considered, whether for CO_2 storage or for CO_2 EOR. For the use of an existing wellbore, a complete and thorough review to meet regulatory, technical, and operational requirements is critical. The review involves determining the wellbore work required to properly contain the injected CO_2 within the proposed zone of interest for complete zonal isolation and ensuring the isolation and protection of USDWs. The feasibility of using an existing well for CO_2 injection mandates compliance with the stringent injection well construction regulations.

The primary parameters to review in converting an existing wellbore into a CO_2 injection well include the age of the well, the isolation strings of casing employed (sufficient weight, grade, and metallurgy applicable for CO_2 service), and casing string-setting depths. In addition, the cementing constituents, volumes, defined TOC, and drilling procedures must be reviewed. The historic well completion techniques and operational or production methods are important factors that must also be reviewed. The conversion of an existing wellbore into a CO_2 injection wellbore increases risk, as it may require significant remediation to ensure isolation of the intended injection zone from the USDW. USDW isolation and protection will be the greatest concern of the regulatory body to approve conversion of an existing wellbore to CO_2 injection.

Reentry of P&A Legacy Wellbores

The plugging and abandonment regulations have evolved with time, becoming more rigorous in the protection of USDWs and the environment. For P&A wellbores that penetrate the CO_2 injection zone, regulators may specify that cement plugs be placed to isolate the injection zone and the USDWs. Wellbores are likely to be identified from the risk assessment as not meeting today's stringent abandonment requirements for isolation of the injection zone from the USDW. Legacy well records may not adequately describe the wellbore conditions at the time of abandonment. The reentry of an existing P&A wellbore requires knowledge of the fluid in the wellbore, type of cement and plug placement, and other well file information. Successfully reentering an abandoned well can present significant challenges in order to not damage the wellbore and thus impact integrity. Drilling out existing plugs, staying within the original wellbore, and encountering shale intervals that have sloughed into the wellbore, unknown equipment, or debris can further complicate reentry. The type and age of the fluids in the wellbore or other existing completion issues can also inhibit a successful reentry of a well. Additionally, reentry can create new migration pathways for fluids to escape the targeted injection formation. Therefore, reentering P&A legacy wellbores will typically pose a high risk with potential to be a significant expense to the project.

Well reentry to remediate legacy wells can also be challenging. If the wellbore cannot be properly prepared for replugging, placement of new cement plugs may fail. Some wellbore conditions may not have been optimum at the time of plugging (e.g., unstable openhole/hole in casing/collapsed casing/lost equipment or tubulars, etc.), which will require additional remediation time, cost, and effort to correct. If the assessment determines wellbore conditions pose a risk to successful reentry and successful remediation for zonal isolation is doubtful, the project operator should develop a monitoring plan. The operator should discuss the options available for monitoring and seek approval from the regulatory agency to permit such monitoring options during and after CO_2 injection. An approved monitoring plan may be the most cost-effective and safest option to protect USDWs and meet regulatory requirements.

Legacy Well Remediation Plan

For every CO_2 geologic storage project, a remediation plan for all applicable wells needs to be developed and approved prior to any well work. The remediation plan needs to provide the following.

Procedures. For each identified well requiring corrective action, procedural steps are required to implement a well workover for corrective action. Best engineering practices encompass safe and environmentally proactive procedures in the oil and natural gas industry to remediate wells. The well procedures for each identified well must be developed by experienced teams of engineers, geologists, and operations personnel to ensure the isolation of the injection zone and the USDW. The well workover procedures will be reviewed with the appropriate state or provincial regulator to ensure that the proposed work meets current permit requirements and rules for plug and abandonment to ensure the protection of USDWs. Appropriate regulatory agency approval may stipulate that agency inspectors be on-site during work procedures. Procedures will be developed by the operator for each specific well identified for remediation. As stated, best engineering, safety, and environmental practices must be followed.

Schedules. The project operator must develop a procedural completion timeline for the remediation plan for approval by the appropriate regulatory agency and inclusion in the project permit application. This schedule details the compliance work to be completed and the timeline for work performed prior to injection start-up and staged work to be scheduled after start of injection. The schedule is to be regularly updated as work is performed or as reservoir conditions dictate. From the timeline, well work can be planned and commenced on approval by the regulating body. The operator should anticipate that the schedule will undergo revision once well work starts because of unpredictable circumstances encountered on reentering an existing wellbore that may impact (lengthen or shorten) the time to complete the well work. As these unexpected events are identified, communication must be relayed to the governing body(s).

Also, the operator will work with the governing body(s) to provide answers to any questions and/or if events cause significant changes to project plans and to attend hearings to review and propose new remediation plans, as required. All remediation plans are to ensure containment of the injectate within the intended zone to prevent leakage pathways into the USDW or other determined bodies of freshwater. Staged remediation is defined as an orderly progression of remediating legacy wells outside of the CO_2 plume and pressure front such that all wells ensure isolation of the USDW. Because the CO_2 plume and pressure front move over time, wells further away from the injection wells but still within the expected areal plume and buffer area for the project may not require remediation prior to the initiation of the project. As a result, the remediation is staged or extended over time based on the anticipated expansion of the CO_2 plume and pressure front and the ranked risk assessment.

The time frame to complete individual well remediation work could range from a few days to several weeks depending on well conditions, availability of services and materials, and weather. In general, once the well remediation plan is approved by the governing body(s), contracts between the operator and third parties that will provide the services, materials, and labor for all related remediation efforts can be generated. Appropriate permits will be submitted and approved by the appropriate regulator(s) prior to commencement of remediation operations.

Budget. The project operator must know the anticipated range of total costs for the corrective actions identified from the well reviews and risk assessment. Upon identification and ranking of the risks found in the evaluation of the wellbore, risk scenarios are identified and cost estimates for the well work can be created. Projected costs will be contingent on the latest remediation cost data available, as well work costs vary with time. Costs should be based on the best available technologies, the number of wells, and the scope of individual well work identified. Pending well work costs are likely to range from several hundred thousand to over a million dollars per well. While the budget is based on the current knowledge of the wellbores and costs for work to be performed, the operator should include contingencies for unknown complications on reentry, which could result in higher-than-anticipated costs.

CONCLUSIONS

The 45Q tax credit and other incentive programs are generating significant interest in developing commercial CCS projects in the PCOR Partnership region. Site selection plays a vital role for project developers to be able to demonstrate storage permanence and ultimately satisfy the accounting requirements for the 45Q tax credit and other incentive programs. Additionally, regulations exist for each applicable jurisdiction (e.g., federal, state, provincial) that require protection of local groundwaters (e.g., USDWs) from subsurface injection of fluids, including CO_2. A properly characterized project site will have geology that has sufficient storage capacity, injectivity, and overlying and underlying sealing formations (cap rock). One of the primary risks to migration of CO_2 out of the storage formation is via legacy wellbores, typically from historical oil and gas exploration and production. Wellbore integrity refers to the ability of the wellbore to isolate the penetrated geologic formations and prevent vertical migration of CO_2 or other fluids along or into the wellbore.

CCS project operators will be responsible for conducting a robust risk assessment for all aspects of their project, including an evaluation of wellbore integrity for all legacy wellbores in the project's defined AOR to ensure those wells will not compromise containment of the injected CO_2. A risk-based approach evaluates each well within the AOR with consideration of the well's location relative to the CO_2 injection well. Higher-risk wells located within or near the expected CO_2 plume and pressure front will likely require some form of remediation. Wells that are deemed higher risk may need to be remediated prior to CO_2 injection to fulfill permitting requirements. However, wells that are not expected to be impacted by CO_2 injection operations for a number of years may be part of a staged approach and remediated at some point in the future, after CO_2

injection has already begun. Wells that are higher risk but are not expected to be impacted by the CO_2 plume may only be monitored to ensure containment of the CO_2. This is typically evaluated on a well-by-well or project-by-project basis, with all remediation plans needing to be reviewed and approved by the appropriate regulatory bodies.

Well integrity evaluations and subsequent remediation of the identified wells can be an intensive and costly operation. However, ensuring proper containment for CCS operations is important to ensure there are no environmental impacts from CO_2 injection. In addition to the need to minimize environmental impacts, federal tax credits and/or LCFS carbon credits may be reduced or denied if CO_2 containment is not properly addressed and accounted for in the project's planning and operation. A properly developed and executed risk assessment and remediation plan can help reduce the risk of any future wellbore integrity issues and ensure project success.

PCOR PARTNERSHIP PROJECT RECOMMENDATIONS

The results of this report illuminate the benefits of further work in the area of wellbore integrity and risk assessment. The authors support the development of a regulatory-driven risk assessment tool, which would include a risk-ranking template for legacy wellbores that can provide a base for CCS project developers across multiple jurisdictions. Further, regular updates to regulatory changes across federal, state, and provincial agencies across the PCOR Partnership would ensure that project developers have consistent access to the latest developments in regulatory language around the topic of wellbore integrity.

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