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

REGULATORY PERSPECTIVE REGARDING THE GEOLOGIC STORAGE OF CARBON DIOXIDE (CO_2) IN THE PCOR PARTNERSHIP REGION

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EXECUTIVE SUMMARY

In 1994, the first international treaty on climate change came into effect (the United Nations Framework Convention on Climate Change [UNFCCC]) with the objective of stabilizing greenhouse gas concentrations in the atmosphere. Annual meetings of the UNFCCC resulted in the establishment of the Kyoto Protocol in 1997, which specified legally binding reductions in greenhouse gas emissions that had to be met by developed countries by 2012 and beyond. Canada ratified the Kyoto Protocol in 2002, while the United States, a signatory to the Kyoto Protocol, has neither ratified nor withdrawn from the protocol. Until such time that the protocol is ratified, it is nonbinding over the United States.

Given this overarching international climate change framework, research is being conducted in the United States and Canada on several greenhouse gas reduction strategies. One strategy captures industrial CO_2 emissions and sequesters the CO_2 in subsurface geologic formations. This strategy is known as carbon capture and storage, or CCS, and involves the dedicated storage of the CO_2 in both saline aquifers as well as depleted oil and gas reservoirs. A related strategy stores CO_2 during active CO_2 EOR (enhanced oil recovery) operations and is designated as carbon capture, utilization, and storage, or CCUS, since the captured CO_2 is utilized in the EOR process to mobilize residual oil from the formation while a portion of it is retained, or stored, in the reservoir. This associated storage of CO_2 during active CO_2 EOR operations has the potential to make a significant and immediate contribution toward the reduction of greenhouse gas emissions because it is part of an existing EOR industry in both the United States and Canada.

This report provides a regulatory perspective regarding the dedicated and associated geologic storage of CO_2 in the Plains CO_2 Reduction (PCOR) Partnership region; it does not address legislation or regulations specific to the capture or transportation of the CO_2 to the storage site. The PCOR region covers a large geographic area that includes portions of the United States (i.e., Iowa, Minnesota, Missouri, Montana, Nebraska, North Dakota, South Dakota, Wisconsin, and Wyoming) and Canada (Alberta, British Columbia, Manitoba, and Saskatchewan). This region has a diverse set of CO_2 emission sources, geologic formations, and a robust CO_2 EOR industry, making it ideal for implementing commercial CCS and CCUS greenhouse gas reduction strategies.

The status of the legislative and regulatory progress of each state/province to regulate CCS operations varies significantly. The states of North Dakota, Wyoming, and Montana and the provinces of Alberta and Saskatchewan have legislation and regulations in place, and these two Canadian provinces have permitted and initiated commercial CCS and CCUS projects. North

Dakota is the only state within the PCOR Partnership region that has applied for primacy over the rules of the US Environmental Protection Agency (EPA) for UIC (underground injection control) Class VI wells. The remaining states, along with the province of Manitoba, have no legislative or regulatory frameworks in place. In the absence of state primacy, the regulation of a commercial CCS project will be led by one of three EPA Regions, (5, 7, or 8), each with its own interpretation of the Class VI regulations.

North Dakota has embraced the guidance provided by the Interstate Oil and Gas Compact Commission (IOGCC) Model Statute/General Rules and Regulations for CCS by adopting two basic principles: 1) it is in the public interest to promote the geologic storage of CO_2 to reduce anthropogenic CO_2 emissions, and 2) the pore space of the state or province should be regulated and managed as a resource under a resource management philosophy. A resource management philosophy ensures that pore space ownership and postoperational liability are incorporated into the CCS/CCUS regulatory process, which is not possible using EPA's UIC regulations.

In general, three legal/regulatory obstacles have inhibited the commercial deployment of CCS technology to varying degrees throughout the PCOR Partnership region: 1) access to and use of pore space, 2) the permitting of CCS/CCUS projects, and 3) site closure and management of long-term, postoperational liability. Two different legislative/regulatory approaches have been taken in the PCOR Partnership region to address these obstacles: one in Canada and one in the United States.

Generally speaking, Canada, which has made significant government investments in commercial-scale facilities, has attempted to maximize the use of the existing legislative and regulatory framework of the oil and gas industry to regulate this new industry and has deferred the authority to do so to the provincial governments, with Alberta being an exception as it has moved forward with the development of CCS-specific regulations. The Canadian approach represents the resource management philosophy recommended by the IOGCC in that pore space ownership (e.g., in general, the Crown has been designated as the owner of pore space in Canada) and postoperational liability are incorporated into the regulatory process. This legislative/regulatory approach has proven to be successful, as Canada currently has four commercial-scale CCS/CCUS facilities under construction and/or in operation, including the first integrated carbon capture and storage operation involving a coal-fired, thermoelectric power plant (SaskPower Boundary Dam).

In contrast, the nature and uncertainty of the regulation of CCS/CCUS in the United States have inhibited the deployment of commercial facilities. The regulatory process is led by EPA at the federal level. EPA has created a new injection well class (Class VI) for the geologic storage of CO_2 and employs a waste management philosophy that does not recognize or manage pore space as a resource and does not adequately manage the postoperational liability of a storage project. These rules also inhibit the use of the existing CO_2 EOR operations for geologic storage of CO_2 by potentially forcing their transition from Class II injection wells to the new Class VI injection wells. To improve the legal/regulatory process for CCS/CCUS in the United States, it is recommended that legislation/regulation governing the subsurface storage of CO_2 be adopted at the state level, with the states of the PCOR Partnership region securing primacy of the Class VI rules of EPA and incorporating them into a resource management philosophy that is compatible with their existing oil and gas regulatory frameworks.

REGULATORY PERSPECTIVE REGARDING THE GEOLOGIC STORAGE OF CARBON DIOXIDE (CO_2) IN THE PCOR PARTNERSHIP REGION

1.0 INTRODUCTION

The large-scale deployment of geologic storage of carbon dioxide (CO_2) in the Plains CO_2 Reduction (PCOR) Partnership region[1] may well include dedicated storage in both deep saline aquifers and depleted oil and gas reservoirs (hereafter referred to as carbon capture and storage [CCS]) as well as the associated storage that occurs during active CO_2 enhanced oil recovery or CO_2 EOR (hereafter referred to as carbon capture utilization and storage [CCUS]). This deployment will be governed by regulatory frameworks that impose requirements on individual storage sites by both the federal governments of the United States (i.e., U.S. Environmental Protection Agency or EPA) and Canada (i.e., Environment Canada, the Ministry of Environment and Climate Change, and/or the Canadian National Energy Board) as well as various regulatory agencies of the individual states/provinces in which the storage sites are located.

Regulatory frameworks for the geologic storage of CO_2 have been evolving over the last decade in parallel with the deployment of large-scale geologic storage demonstration projects. During this period, some states and provinces within the PCOR Partnership region, most particularly North Dakota, Alberta, and Saskatchewan, have passed legislation and put regulations in place for the commercialization of the geologic storage of CO_2. Also of importance in the United States are the efforts of the Interstate Oil and Gas Compact Commission (IOGCC) and EPA. IOGCC has been actively engaged in developing legislative and regulatory guidance through its Geological CO_2 Sequestration Task Force, which was created in 2002. The IOGCC task force generated guidance documents regarding the technical, policy, and regulatory issues associated with the geologic storage of CO_2 in 2007, 2010, and 2014 (Interstate Oil and Gas Compact Commission, 2007; 2010a, b; 2014). At the same time, EPA has promulgated regulations specifically for the geologic storage of CO_2, commonly referred to as the Class VI rules, in recognition of the new class of injection wells that were added to the federal regulations under its Underground Injection Control Program for the subsurface injection of CO_2 (U.S. Environmental Protection Agency, 2010a).

Concurrent evolution of the technology and regulations for the geologic storage technology for CO_2 in the PCOR Partnership region is occurring in an environment where legislative and

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[1] Plains CO_2 Reduction Partnership (PCOR Partnership) region includes nine states (Montana, North Dakota, Minnesota, Wisconsin, Wyoming, South Dakota, Nebraska, Iowa, and Missouri) and four Canadian Provinces (British Columbia, Alberta, Saskatchewan, and Manitoba). The PCOR Partnership is managed by the Energy & Environmental Research Center (EERC) as part of the U.S. Department of Energy (DOE) National Energy Technology Laboratory's (NETL's) Regional Carbon Sequestration Partnership (RCSP) initiative.

regulatory frameworks exist that specifically address several analogous situations, including 1) naturally occurring CO_2 contained in geologic reservoirs, including natural gas reservoirs; 2) the injection of CO_2 into underground formations for CO_2 EOR operations; 3) the storage of natural gas in geologic reservoirs; and 4) the injection of acid gas (a combination of hydrogen sulfide [H_2S] and CO_2) into underground formations. Not surprisingly, this has resulted in a dynamic and complex regulatory/permitting landscape that is difficult for potential commercial operators of a CO_2 storage site to define, let alone successfully navigate.

The purpose of this report is to provide a regulatory perspective regarding the geologic storage of CO_2 in those states and Canadian provinces within the PCOR Partnership region by describing the regulatory frameworks that are evolving for both CCS and CCUS operations. The report consists of the following sections:

- Section 1, Introduction

- Section 2, Background – Legal/Regulatory CCS Frameworks, provides an overview of the primary international and national policies that are driving the capture and geologic storage of CO_2 and briefly summarizes the legal and regulatory CCS frameworks that have evolved over time in both the United States and Canada.

- Section 3, Legislative/Regulatory Frameworks for CCS Within the PCOR Partnership Region, provides an overview of the legislative/regulatory frameworks that have been put in place within the PCOR Partnership region to date along with brief examples of the regulatory processes that have been developed by the most proactive jurisdictions in the region, i.e., North Dakota, Alberta, and Saskatchewan. Of particular interest to the region is the ability to take full advantage of CO_2 EOR to advance the geologic storage of CO_2. The legislative and regulatory activities of the less active states and provinces of the PCOR Partnership region are also briefly presented along with the agencies that will likely be involved in regulating/permitting CCS and CCUS in these other jurisdictions. Integral to the legislative/regulatory discussion pertinent to the U.S. portion of the region is a description of IOGCC Model Statute/General Rules and Regulations for CCS, which evolved over the period from 2002 through 2014. This legislative/regulatory guidance delineates where there is overlap between the state and federal (EPA) jurisdictions in the United States for the primary phases of a geologic storage project, identifying those project phases that are strictly under the control of the individual states. The guidance also highlights the regulatory permits that are typically required for a large-scale storage project as well as the importance of regulating the geologic storage of CO_2 using a resource management philosophy (i.e., ownership of storage rights [reservoir pore space] and long-term, postoperational liability) as opposed to the current waste management philosophy of EPA (i.e., protection of water resources).[2]

- Section 4, Outstanding Permitting Challenges and Barriers, highlights the outstanding regulatory/permitting challenges and barriers to be addressed by the state and provincial regulatory authorities of the PCOR Partnership region to make large-scale deployment of

[2] EPA's waste management philosophy is embodied in the Class VI regulations, which do not adequately address pore space ownership and, consequently, cannot effectively manage the efficient use of the pore space resource.

the geologic storage of CO_2 a reality while preserving storage and mineral rights. By doing so, it will be possible to take advantage of an expanding CO_2 EOR industry while concurrently providing the necessary postclosure financial assurances to protect the states/provinces.

This report does not provide a step-by-step process for complying with the regulatory requirements necessary to deploy a large-scale CCS or CCUS project. However, it does describe the overarching regulatory framework, participating regulatory agencies, and unique aspects of geologic storage scenarios that need to be accommodated within this framework for large-scale deployment of the industry within the PCOR Partnership. This report also highlights the current progress of the state and provinces in the PCOR Partnership in developing regulatory frameworks for CCS and CCUS to meet the CO_2 storage needs of the region.

2.0 BACKGROUND – LEGAL/REGULATORY CCS FRAMEWORKS

The United Nations Framework Convention on Climate Change (UNFCCC) is the main international treaty of climate change. It is a “Rio Convention,” i.e., one of three adopted at the “Rio Earth Summit” in 1992. UNFCCC took effect on March 21, 1994, with the ultimate objective of “stabilizing greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic (i.e., human-induced) interference with the climate system” (United Nations Framework Convention on Climate Change, 2016a).

Beginning in 1995, yearly conferences have been held under the auspices of UNFCCC. They serve as the formal meeting of the UNFCCC parties (i.e., the conference of the parties or COP) to assess the progress in dealing with climate change and, beginning in the mid-1990s, to negotiate the Kyoto Protocol, which establishes legally binding obligations for developed countries to reduce their greenhouse gas emissions. As such, since 2005, the conferences of UNFCCC have served as the “Conference of the Parties Serving as the Meeting of the Parties to the Kyoto Protocol” or CMP. To date, there have been 22 meetings of COP and 12 meetings of CMP (United Nations Framework Convention on Climate Change, 2016b).

In 1997, during COP 3 in Kyoto, Japan, the Kyoto Protocol was adopted, which outlined greenhouse gas emission reduction obligations for developed nations and nations with economies in transition (Annex I countries). Most Annex I countries agreed to legally binding reductions of an average of 6% to 8% below 1990 levels between the years 2008 to 2012; the United States and Canada were required to reduce their greenhouse gas emissions by 6% and 7% below 1990 levels, respectively. The Kyoto Protocol also included what came to be known as Kyoto mechanisms, which included emission trading. Emission trading, commonly referred to as a “cap-and-trade system,” sets a maximum level of allowed CO_2 emissions for individual entities. An entity is permitted to exceed its maximum allowable CO_2 emissions only if it purchases CO_2 emission “credits” equal to or greater than the quantity of CO_2 emissions it plans to emit in excess of its allowable limit. However, the Congress of the United States did not ratify the Kyoto treaty after it was signed by President Clinton, and the administration of G.W. Bush explicitly rejected the protocol in 2001. Ratification of the Kyoto Protocol required ratification by 55 countries, including those accounting for 55% of developed-country emissions of CO_2 in 1990. In 2005, during the first

CMP, an agreement ("The Montreal Action Plan") was made to extend the life of the Kyoto Protocol beyond its 2012 expiration date and to negotiate greater reductions in greenhouse gas emissions. Multiple attempts to develop a post-2012 framework were made in subsequent COP/CMP meetings but with no success. Finally, at COP18/CMP 8, which was held in Doha, Qatar, in 2012, the Doha amendment to the Kyoto Protocol was produced and featured a second commitment period running from 2012 until 2020, which was limited in scope to 15% of the global CO_2 emissions because of the lack of commitments from Japan, Russia, Belarus, Ukraine, New Zealand (nor the United States and Canada, who are not parties to the protocol in that period) and because of the fact that developing countries like China, India, and Brazil are not subject to emission reductions under the Kyoto Protocol. The last meeting of COP/CMP that addressed climate change was held in Paris, France, in 2015. Negotiations at this conference resulted in the adoption of the Paris Agreement, which governs climate change reduction measures from 2020. This effort ended the work initiated in COP17/CMP 7 in Durban, South Africa, which began the process to negotiate a legally binding agreement comprising all countries by 2015 and governing the period post-2020.

Canada ratified the Kyoto Protocol in 2002, while the United States, a signatory to the Kyoto Protocol, has neither ratified nor withdrawn from the protocol as of the writing of this report. Until such time that the protocol is ratified, it is nonbinding on the United States.

Given this overarching international climate change framework, legislative and regulatory frameworks for CCS and CCUS have evolved over time in both the United States and Canada. A brief overview of these developments is provided in the remainder of this section.

2.1 United States

Even though the Kyoto Protocol is nonbinding, the United States has proceeded to move forward with efforts to reduce greenhouse gas emissions in the country by establishing compliance-related carbon markets, which include cap-and-trade systems as well as a carbon tax (i.e., a set price per ton for emitting CO_2 into the atmosphere) and developing greenhouse gas reduction strategies involving both CCS and CCUS. Carbon taxes have yet to be applied in the United States, but mandatory market-based cap-and-trade systems have been implemented elsewhere in the country, e.g., the Regional Greenhouse Gas Initiative, which was formed in 2009 and comprises a cooperative of states, including Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

Also, beginning in 2010, several key federal and state statutory and/or regulatory developments related to the geologic storage of CO_2 occurred in the United States. In December 2010, EPA issued a rule establishing a new well class (Class VI) in the Underground Injection Control (UIC) Program. The new rule specified the minimum technical criteria to protect underground sources of drinking water (USDW) from the long-term subsurface storage of CO_2 (U.S. Environmental Protection Agency, 2010a).

In September 2011, EPA became the acting authority for Class VI injection wells requiring all states to conform to the standards set forth in the UIC Class VI rules for all long-term subsurface CO_2 storage projects. However, this created significant uncertainty regarding the applicability of these rules to previously permitted UIC Class II injection wells should a CO_2 enhanced oil or gas recovery project ever transition to a geologic storage project (U.S. Environmental Protection Agency, 2010b). At issue is the determination of if, and when, such a transition occurs. EPA Class VI rules specify that such a transition shall be determined at the discretion of the EPA Regional Director based on a determination that the continued subsurface injection of CO_2 will result in an increased risk to USDWs compared to Class II operations. Nine specific criteria, or factors, must be considered in making this determination, one of which is the totally open-ended criterion, "as well as any additional site-specific factors as determined by the Director".[3] To address this uncertainty, EPA's Office of Groundwater and Drinking Water, within the Office of Water, issued a technical memorandum on April 23, 2015, to all Regional Water Division Directors entitled "Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI." In that memorandum, EPA stated that "the best implementation approach is for states to administer both the Class II and the Class VI UIC programs." The memorandum further encouraged states to "apply for primacy for all well classes, including Class VI" and simultaneously requested that the Regional Directors "assist states in submitting primacy applications for all well classes."

In June 2013, prior to the issuance of this EPA technical memorandum, but consistent with its recommendations, the State of North Dakota applied to Region 8 of EPA for primacy of the Class VI regulations. To date, over 3 years after that submission, North Dakota has not yet received a decision regarding its application. In recognition of the delay of EPA in responding to the North Dakota primacy application, as well as the inconsistency of this delay with the spirit of EPA's technical memorandum, IOGCC passed a resolution in September 2015 (Resolution 15.091 – "Clarifying Issues Related to the Transitioning of Class II Carbon Dioxide Enhanced Oil or Gas Recovery Projects to a Class VI Geologic Storage Project") which requested that "EPA ensure that states have the right to administer injection of CO_2 for EOR under Class II UIC" and:

1. "The states and owner/operators have the right to regulatory certainty that injection of CO_2 for EOR is managed as Class II UIC throughout the commercial life of each project."

2. "The Class II UIC program director has the right to determine if and when transition from Class II UIC to Class VI UIC is required to address risk."

These key elements of the IOGCC resolution are consistent with the recommendations in the IOGCC guidance documents as well as in the 2015 technical memorandum of the EPA Office of Water, both of which encourage states to secure Class VI primacy jurisdiction from EPA. The IOGCC resolution also recognizes that the Class VI rules of EPA include neither the regulation of the pore space of the state nor provide protection of the state from associated liability from what

[3] § 144.19(a): "Owners or operators that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI geologic sequestration permit when there is an increased risk to USDWs compared to Class II operations. In determining if there is an increased risk to USDWs, the owner or operator must consider the factors specified in § 144.19(b). The Director shall determine when there is an increased risk to USDWs compared to Class II operations and a Class VI permit is required" (U.S. Environmental Protection Agency, 2010b). Nine factors, or criteria, are identified in § 144.19(b), one of which is "Any additional site-specific factors as determined by the Director."

would otherwise be nonregulated CO_2 storage-related activity.[4] As such, it is a strong proponent of the states determining if and when transition from Class II UIC to Class VI UIC occurs, acknowledging that it is the states that are best positioned to administer a regulatory approach that meets the stringent requirements necessary to obtain Class VI primacy while at the same time implementing a resource management philosophy.

Most recently, in 2015, EPA finalized New Source Performance Standards (NSPS) under Clean Air Act (CAA) Section 111(b) that, for the first time, established standards for emissions of CO_2 for newly constructed, modified, and reconstructed affected fossil fuel-fired electric utility generating units (EGUs) (US Environmental Protection Agency, 2015). The rule essentially mandates the use of partial CCS by including it as part of the Best System of Emission Reduction (BSER). The implementation of this rule was delayed by a federal lawsuit that challenged EPA's conclusion that CCS is "adequately demonstrated and achievable," as is required by the CAA. It should be noted that EPA also concluded that a highly efficient new steam generating unit implementing full CCS is not the BSER at this time because the costs were predicted to be significantly more than the costs for implementation of partial CCS and significantly more than the costs for competing non-NGCC [natural gas combined cycle] base load, dispatchable technologies—primarily new nuclear generation.[5] While this rule has been delayed, it is clear that EPA believes CCS is critical to achieving reductions in greenhouse gas from fossil fuel EGUs and will likely be a part of this or any future NSPS established for CO_2 emissions.

2.2 Canada

In Canada, the jurisdiction for regulating the geologic storage of CO_2 lies primarily with the individual provinces, stemming from their jurisdiction over the direct ownership, management, and regulation of most natural resources. At the same time, the federal government (i.e., Environment Canada, the Ministry of Environment and Climate Change, and/or the Canadian National Energy Board) holds jurisdiction over international and interprovincial issues, including transboundary pipelines, uranium and nuclear power, offshore areas and federal lands, and works declared to be for the general benefit of Canada (e.g., science and technology). Responsibilities for environmental protection are shared between the federal (e.g., Navigable Waters Protection Act, Canadian Environmental Protection Act 1999, and the Canadian Environmental Assessment Act 2012) and provincial governments. Given this distribution of responsibilities and the nature of a geologic storage project, the regulation and permitting of these projects in Canada will primarily fall to the province, unless a project is transboundary in scope (e.g., pipeline crossing international or provincial borders), the components of a geologic storage project occur in areas of federal jurisdiction (e.g., offshore CO_2 storage), or the project has the potential to impact human and environmental receptors protected by federal environmental regulations.

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[4] No further federal statutory or regulatory actions regarding the geologic sequestration of CO_2 have been implemented since the IOGCC Resolution of 2015 was passed and to date, no state has secured primacy of the Class VI regulations.

[5] EPA defended its statement that CCS is "adequately demonstrated and achievable" by referring to SaskPower's Boundary Dam CCS Project in Estevan, Saskatchewan, Canada, which is the world's first commercial-scale fully integrated postcombustion CCS project at a coal-fired power plant. While the CCS has been integrated with a relatively small coal-fired utility boiler (110 MW), EPA stated that there is nothing to indicate that the post-combustion CCS system used at Boundary Dam could not be scaled-up for use at a larger utility boiler.

Canada has well-developed EOR/EGR (enhanced gas recovery) regulations (International Energy Agency, 2007). Several EOR operations, including CO_2 flooding, are active in Alberta and Saskatchewan, and regulations are in place in both provinces that govern the subsurface injection of hydrocarbon gas, acid gases, and CO_2 in deep saline aquifers and depleted hydrocarbon reservoirs. Accordingly, there is extensive operational experience with the separation, capture, transport, and injection of these gases in these provinces, and more importantly, a regulatory framework dealing with the permitting, operation, and abandonment of these operations already exists.

This framework may be expanded to cover the permanent geologic storage and the postabandonment stage of CO_2 storage operations, including monitoring and remediation. Issues that need to be considered in modifying the existing regulation include financial issues, incentives, liability, and ownership and access rights. Since the Canadian government owns most, but not all, of the subsurface, issues of ownership and access rights need to be considered carefully. Moving forward, the federal government in Canada is working toward producing a coherent regulatory framework building upon the regulatory frameworks that already exist.

With regard to specific greenhouse gas regulations, Canada has taken the following actions following the ratification of the Kyoto Protocol in 2002:

- In December 2009, Canada committed to a national greenhouse gas reduction target of 17% below 2005 levels by 2020 and inscribed this in the Copenhagen Accord. This 2020 target was aligned with that of the United States.

- To achieve its target of 17% reduction by 2020, Canada established and is implementing a comprehensive plan to reduce greenhouse gas emissions in all major emitting sectors on a sector-by-sector basis. On June 23, 2010, the Government announced it would take action to reduce CO_2 greenhouse gas emissions in the electricity sector by moving forward with regulations on coal-fired electricity generation.[6]

- In September 2012, Environment Canada released the "Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations." This regulation made Canada the first major coal user to ban construction of new coal plants using traditional technology. These regulations will phase out high-emitting coal-fired generation and promote a transition toward lower- or nonemitting types of generation, which includes fossil fuel-fired power with CCS. The performance standard element of the proposed regulations came into effect on July 1, 2015; regulated entities are subject to enforcement and compliance requirements and penalties as specified under the Canadian Environmental Protection Act of 1999 (Canadian Environmental Protection Agency, 1999a).

[6] In 2008, the latest year of emission data available under Canada's National Inventory Report under UNFCCC, greenhouse gas emissions from the electricity generation sector contributed about 16% (or approximately 120 megatons [Mt]) to Canada's inventory of emissions. In the same year, coal-fired electricity generation was responsible for 93 Mt of greenhouse gas emissions in Canada, which represents 78% of the total electricity sector emissions. Canadian historical data indicate that emissions in 2008 were about 19% above the 1990 levels (Canadian Gazette, 2011a).

The performance standards in the September 2012 regulations apply to new and old coal-fired electricity generation units. New units are those units that start producing electricity commercially on or after July 1, 2015; old units are generally defined as units that have reached their end of useful life, which is the latter of 45 years from the units' commissioning date or the end of their power purchase agreement (Minister of Justice, 2015).

Equivalency agreements with provinces, under which the federal regulations would stand down and the provincial regime would apply, can be established under Canadian Environmental Protection Agency (CEPA) if there is an enforceable provincial regime that would deliver an equivalent environmental outcome (Canadian Environmental Protection Agency, 1999b).

3.0 LEGISLATIVE/REGULATORY FRAMEWORKS FOR CCS WITHIN THE PCOR PARTNERSHIP REGION

The large-scale deployment of CO_2 geologic storage, which includes dedicated storage in both deep saline aquifers and in depleted oil and gas reservoirs as well as associated storage occurring during active CO_2 EOR, will require compliance with a formal regulatory process for individual storage sites. In the United States, the nature and extent of the regulatory process will be dictated by EPA and various regulatory agencies of the individual states; in Canada, it will be prescribed by one or more federal agencies, i.e., Environment Canada, the Ministry of Environment and Climate Change, the Canadian National Energy Board, and regulatory agencies within individual provinces. The remainder of this section briefly reviews these regulatory requirements and their supporting legislation within each of the states and provinces of the PCOR Partnership region.

3.1 Legislative/Regulatory Overview of the PCOR Partnership Region

The PCOR Partnership region has nine states (Iowa, Minnesota, Missouri, Montana, Nebraska, North Dakota, South Dakota, Wisconsin, and Wyoming) and four Canadian provinces (Alberta, British Columbia, Manitoba, and Saskatchewan). Across this region, the status of the legislative and regulatory progress that each of these entities has made to regulate the construction, operation, and closure of CCS/CCUS projects varies significantly. For example, the states of North Dakota, Wyoming, and Montana and the provinces of Alberta and Saskatchewan currently have legislation and regulations in place, and the province of British Columbia is the only jurisdiction in North America to have levied a tax on CO_2 emissions. Further, Alberta and Saskatchewan have permitted and initiated commercial CCS and CCUS projects. The remaining states (Iowa, Minnesota, Missouri, Nebraska, South Dakota, and Wisconsin) and province (Manitoba) have no such legislative or regulatory frameworks in place or, at best, have CCS-related legislative bills pending and/or are in the process of creating regulations.

Most state and provincial legislative action related to CCS occurred on the order of 15 to 20 years ago in reaction to the initial actions of the federal governments, beginning with the Kyoto Protocol in 1997, which introduced legally binding emission reduction targets for developed countries. Nevertheless, some state and provincial agencies delayed legislative and regulatory actions because of a lack of potential CCS/CCUS projects (e.g., lack of candidate sources of anthropogenic CO_2, lack of geologically suitable storage sites, and/or the lack of long-term financial drivers), a reliance upon existing regulatory frameworks for oil and natural gas activity, and/or uncertainty related to developing federal regulations (e.g., EPA UIC Class VI rules). As previously noted, to date, North Dakota is the only state in the PCOR Partnership region that has applied for primacy for UIC Class VI rules of EPA, which establish minimum federal requirements under the Safe Drinking Water Act (SDWA) for the underground injection and geologic storage of CO_2.[7] In the absence of obtaining primacy of the Class VI rules, the regulation of a commercial CCS project in the states of the PCOR Partnership region will be led by one of three EPA Regions: Regions 5, 7, or 8, each with its own interpretation of the Class VI rules. At the same time, the provinces of Alberta and Saskatchewan have built and operated commercial CCS and CCUS projects using their current oil and gas regulatory frameworks; no similar commercial activity has occurred in either British Columbia or Manitoba.

The associated storage of CO_2 during active CO_2 EOR is particularly important to the PCOR Partnership region as a means of achieving a reduction in CO_2 emissions. Its importance is largely due to the fact that there is a demonstrated economic incentive for injecting CO_2 into the subsurface as part of CO_2 EOR operations, which has already produced a commercially viable industry with an existing infrastructure. For example, since 1972, 12 U.S. states and two Canadian provinces (including Wyoming, Montana, Saskatchewan, and Alberta within the PCOR Partnership region) have successfully permitted, administered, and monitored over 130 CO_2 EOR projects. These projects were supplied with both natural and anthropogenic CO_2 through over 4500 miles of pipelines and have resulted in the production of millions of barrels of oil and the associated storage of millions of tons of CO_2 (Merchant, 2014). This industry is currently regulated by various state and provincial agencies (e.g., oil/natural gas and environmental/health agencies), which have oversight of the drilling, completion, and operation of production and injection wells; the construction and operation of interstate/intrastate, international, and interprovincial CO_2 pipelines (along with the federal permitting agencies of the United States or Canada); the siting and construction of operational facilities; and the abandonment and reclamation at the end of the economic life of the project.

However, the ability to take advantage of this existing CO_2 EOR industry and its infrastructure for the geologic storage of CO_2 is being threatened by the potential applicability of the Class VI rules of EPA. In particular, the threat of having a CO_2 EOR operation, with its permitted Class II injection wells, arbitrarily transitioned to a CO_2 storage operation by EPA and subjected to the requirements of the Class VI rule has virtually ensured that such a transition of this nature will not be pursued.[8] One issue of particular concern is the long-term postoperational liability that is associated with the containment of the "stored" CO_2. While five of the states in the PCOR Partnership region (i.e., Montana, Nebraska, North Dakota, South Dakota, and Wyoming) have primacy over UIC Class II wells, only one (North Dakota) has applied for primacy over the Class VI rule, leaving the transition determination in the hands of EPA.

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[7] As previously noted in this report, the state of North Dakota submitted an application for primacy of the Class VI rules to EPA Region 8 in June 2013 and has yet to receive a ruling on that application.

[8] Previously in this document, the nine risk-based criteria for making the determination of whether a Class II injection well transitions to a Class VI injection well were listed. Of these nine criteria, one criterion was totally open-ended and arbitrary: "Any additional site-specific factors as determined by the Director." Having such an important determination based on such an open-ended assessment by EPA represents a significant concern to most states and CO_2 EOR operators.

The state of legislative and regulatory affairs related to the geologic storage of CO_2 in the PCOR Partnership region provides a stark contrast in regulatory approaches. On the one hand, Canada has deferred to the provinces, which have relied heavily upon the existing provincial regulatory frameworks of the oil and gas industry (Saskatchewan and British Columbia) or developed consensus CCS regulatory frameworks (Alberta). This has resulted in the construction and operation of several commercial-scale CO_2 geologic storage projects, e.g., Shell Quest, Alberta Carbon Trunk Line, SaskPower Boundary Dam/Aquistore, and the Weyburn–Midale Project. On the other hand, the United States has elected to promulgate federal regulations for the geologic storage of CO_2 distinct and separate from the regulatory frameworks of the oil and gas industry. Of particular significance is the fact that these regulations have created regulatory uncertainty that is threatening the only commercially viable approach that currently exists for the geologic storage of CO_2 in the United States: CO_2 EOR. The end result of this regulatory action has been the lack of implementation of large-scale, commercial CO_2 storage projects in the United States.

The regulatory uncertainties in the United States should be reduced as CCS/CCUS projects are implemented and the respective states and EPA regions focus on moving forward with the regulatory permitting of these projects. This document does not attempt to predict the final resolution of those uncertainties or what regulatory requirements may be imposed in those states or provinces that currently have no active CCS/CCUS regulatory framework in place. Rather, it summarizes the legislative and regulatory frameworks that are currently in place in those states and/or provinces where progress has been made as a means of illustrating the types of regulatory requirements that may be imposed on a commercial CCS/CCUS project that is developed within the PCOR Partnership region. While it is not clear that the legislative and regulatory frameworks presented here can, or will be, used throughout the region, they will provide some insight and lessons learned regarding the existing regulatory challenges and how they are being addressed by the more proactive state and provincial regulatory authorities, thereby providing a framework for consideration by other states and provinces should they move forward with commercial CCS projects.

3.2 United States

3.2.1 CCS Legislation/Regulation

3.2.1.1 North Dakota

The state of North Dakota is a leader in developing a legislative and regulatory framework for implementing a CCS project. In 2008, the state formed a CO_2 storage work group, which was tasked with the development of a regulatory framework for the long-term geologic storage of CO_2. The process was initiated with the drafting of legislation in 2009 (Chapter 38-22 of the North Dakota Century Code) that followed the model statute proposed by IOGCC (IOGCC, 2010b). Of particular importance was an emphasis on the treatment of geologically stored CO_2 using a resource management philosophy as opposed to a waste disposal philosophy. Use of a resource philosophy allows for a unified approach that addresses the concurrent management of pore space ownership and long-term liability as well as potential environmental impacts. The promulgation of administrative rules governing the geologic storage of CO_2 (Chapter 43-05-01 of the North Dakota Administrative Code) followed this legislative effort. The time line of these legislative/regulatory developments is summarized below:

Legislative Action Time Line:

- Senate Bill No. 2139 (effective April 2009) – This bill assigned the title of pore space to the owner of the overlying surface estate and prohibited the severance of the leasing of pore space.
- Senate Bill No. 2095 (effective July 2009) – This bill granted authority to the North Dakota Industrial Commission (NDIC) to address the geologic storage of CO_2.

- House Bill No. 1014 – Appropriations Committee (2011) – A Carbon Dioxide Facility Administrative Fund was established from which NDIC was appropriated funds for the administration of the provisions of Chapter 38-22 of the North Dakota Century Code, the primary goal of which was to obtain primacy of the Class VI rules of EPA.

Administrative Rule-Making Time Line:

- Administrative Chapter 43-05-01, Geologic Storage of Carbon Dioxide (effective April 2010) – The promulgation of this rule put in place a regulatory framework for permitting CCS projects.

- Rule making and amendments to Chapter 43-05-01 (effective April 2013) – The existing rule, which complemented the existing laws for CO_2 EOR, was left in place. The requirements of the rule are at least as stringent as the federal requirements embodied in the UIC Class VI rules of EPA, which were promulgated in December 2010.

With the ultimate goal of achieving primacy of the UIC Class VI regulations, and following extensive interaction with EPA Region 8, the state submitted a formal primacy application to EPA on June 21, 2013. To date, EPA Headquarters (Washington, D.C.) has not yet made a determination regarding this application.

Based on this legislative and regulatory framework, the state of North Dakota developed a permitting process for the geologic storage of CO_2. This permitting process requires separate permits for drilling the injection well, injecting CO_2 into the subsurface, and activities related to underground gathering pipelines.[9] Details regarding this permitting process and the information requirements of the drilling and injection permits are provided in Appendix A of this document.

3.2.1.2 Other Active PCOR Partnership States

Aside from North Dakota, limited legislative and regulatory actions related to the geologic storage of CO_2 have been taken by the other states within the PCOR Partnership region. Direct evidence of this is provided in Table 1, which shows the primacy status for UIC well classes in the PCOR Partnership region states. As shown in this table, none of the states has primacy over the Class VI rules of EPA which govern the subsurface injection of CO_2 for geologic storage, and only

[9] Underground gathering pipelines are designed or intended to transfer oil or produced water from a production facility for disposal, storage, or sale purposes. Permitting requirements for these pipelines are presented in the pending proposed rule changes to Section 43-02-03-29.1, Underground Gathering.

Table 1. Status of Primacy for UIC Well Classes in States of the PCOR Partnership Region

	Iowa			Minnesota			Missouri			Montana			Nebraska			North Dakota			South Dakota			Wisconsin			Wyoming		
Well Class	State	EPA	Tribal	State	EPA	Tribal	State	EPA	Tribal	State	EPA	Tribal	State	EPA	Tribal	State	EPA	Tribal	State	EPA	Tribal	State	EPA	Tribal	State	EPA	Tribal
I		X			X		X				X		X			X				X		X			X		
II		X			X		X			X		X	X			X			X		X	X			X		
III		X			X		X				X		X			X				X		X			X		
IV		X			X		X				X		X			X				X		X			X		X
V		X			X		X				X		X			X		X		X	X	X			X		X
VI		X			X			X			X			X		*	X			X			X			X	

* North Dakota applied for primacy of Class VI rules in June 2013 and has yet to be given approval by EPA.

one state, North Dakota, has applied for such primacy. Under these circumstances, the permitting of the geologic storage of CO_2 throughout the entire region will be dictated by these Class VI rules as implemented by EPA (Directors of Regions 5, 7, or 8 and Headquarters). The CCS permitting requirements of the Class VI rules are described in detail in the final rule (U.S. Environmental Protection Agency, 2010a). For a state to achieve primacy over these Class VI rules, it must develop state regulations that are as, or more, stringent than these federal regulations.

It is also important to note that seven of the nine states in Table 1 do have primacy over Class II injection wells (exceptions are Iowa and Minnesota), which are used for the subsurface injection of CO_2 during EOR. Two of these nine states, South Dakota and Montana, share jurisdiction of the Class II wells with the Indian tribes that are located within the state. The importance of Class II primacy to the geologic storage of CO_2 is rooted in the potential transition of Class II wells to Class VI wells, as currently described in the Class VI rules. Significant storage of CO_2 occurs in the subsurface during CO_2 EOR operations; however, following the end of the project life of a CO_2 EOR operation, operators are unlikely to continue operations for the purpose of storing CO_2 if there is the potential of being transitioned to Class VI wells and subjected to the liability and reporting requirements of the Class VI rules. For states without primacy over of the Class VI rules, the determination of that transition is out of their hands and will be made by EPA.

There has been some legislative and regulatory activity in the other states of the PCOR Partnership for regulating the future geologic storage of CO_2. The relevant activities of these other states, as documented by the IOGCC (Interstate Oil and Gas Compact Commission, 2010b) and the CCS Reg project (Pollack and others, 2010) are presented here. Contact information for the primary participating state agencies in all of the states and provinces in the region are provided in Appendix B.

3.2.1.3 Montana

The Interim Committee on Energy and Telecommunications of the Montana legislature began to examine the possibility of developing draft carbon storage legislation as early as 2007. In 2009, legislation (Senate Bill 498 or SB498) was passed and signed into law on May 6. However, most elements of this law will not be effective until the state applies for, and is granted, primacy of the Class VI rules of EPA. To date, Montana has not yet filed an application for primacy nor promulgated CCS or CCUS regulations, leaving EPA Region 8 to regulate all UIC well classes in Montana.[10]

More specifically, in 2007, the following House Bills (HB) were enacted in Montana:

- HB3: Provided property tax incentives for all equipment used for the capture, transportation, and geologic sequestration of CO_2 placed into service after June 2007. It also identified EOR equipment as eligible for the property tax incentive.

[10] The Montana Department of Environmental Quality (MDEQ) has the authority to apply for primacy in the state of Montana.

- HB25: Mandated that the Montana Public Services Commission may not approve applications for electric capacity generation fueled by coal constructed after January 1, 2007, unless the facility captures and sequesters a minimum of 50% of its CO_2.

- HB24: Provided common carrier status to CO_2 pipelines.

At the same time, SB498 (Montana CCS policy) specifically addressed sequestration site permitting, property rights (i.e., pore space ownership), long-term stewardship, and EOR status as follows:

- Sequestration site permitting: The bill authorized the Montana Board of Oil and Gas Conservation to regulate CCS.

- Property rights: The bill declared that pore space was the property of the surface owner unless deeds to severance documents established otherwise. The operator was designated as the owner of the CO_2 and liable for the storage facility during operations. The Board was authorized to order unitization of a storage reservoir upon application of persons owning storage rights to 60% of the storage capacity of the proposed storage area. For the purposes of administering the law, the bill specified that the injected CO_2 is not a pollutant, nuisance, hazardous, or deleterious substance.

- Long-term stewardship: The bill permitted the transfer of liability to the state following issuance of a certificate of completion by the Board, which can be issued upon determination that the injected CO_2 is stable and will be retained in the geologic storage reservoir, not less than 15 years after carbon dioxide injection end. The bill also established a geologic storage reservoir program account to be used to cover the costs of any long-term liabilities.

- EOR status: The bill did not impede or impair EOR operations, including the right to sell emission reduction credits associated with EOR. It specified that the term carbon dioxide injection well did not include UIC Class II wells and that the Board shall develop rules for the conversion of EOR (Class II) wells to CO_2 injection (Class VI) wells.

3.2.1.4 Wyoming

Seven bills were passed into law by the Wyoming legislature that focused on various aspects of the geologic storage of CO_2 during the period from 2008 through 2010 (i.e., SB1, HB89, and HB90 in 2008; HB57, HB58, and HB80 in 2009; and HB17 in 2010). In 2013, the Department of Environmental Quality (DEQ) of Wyoming promulgated regulations addressing Class VI injection wells and facilities pursuant to Article 3 (Water Quality), Chapter 11 (Environmental Quality) of Title 35 (Public Health and Safety) of the 2013 Wyoming statutes.

Briefly, the specific areas of interest to the geologic storage of CO_2 that were addressed in each of these laws and regulations are provided below:

- SB1 (2008): Appropriated funds for research into carbon capture and sequestration technologies and for geologic evaluation of potential CO_2 sequestration sites. The Wyoming DEQ was authorized to submit grant applications for up to $1.2 million to the Federal Office of Surface Mining for evaluation of potential carbon dioxide sequestration sites and other activities related to carbon management.

- HB89 (2008): Declared pore space as the property of the surface owner; ownership may be severed.

- HB90 (2008): Instructed the Wyoming DEQ to write rules for geologic sequestration of CO_2. Draft rules for the permitting of a sequestration site were issued by DEQ in March 13, 2009. The bill also confirmed that the mineral estate is dominant, and it exempted the injection of CO_2 for EOR from the provisions of the bill. The bill did not impede or impair EOR operations, including the right to sell emission reduction credits associated with EOR if an EOR operator converts to geologic sequestration. Lastly, a working group was established to report to the legislature on financial assurance requirements for geologic sequestration sites and on the duration of the postclosure care period by September 30, 2009.

- HB57 (2009): Reaffirmed that the mineral estate is dominant regardless of whether the pore space is vested in the surface owner(s) or owned separately from the surface.

- HB58 (2009): Identified the operator as the owner of the CO_2 and liable during operations. It also specified that the owner of pore space is not liable for any effects of geologic sequestration.

- HB80 (2009): Specified procedures for unitization, including requirements for applications, hearings, and determinations. The plan for unitization must be approved by persons who own 80% of the pore space storage capacity within the unit area.

- HB17 (2010): Directed DEQ to specify insurance, bonding, financial assurance requirements for geologic sequestration permits, and procedures for releasing bonds or termination of insurance instruments after the administrator issues a completion and release certificate (a minimum of 10 years after injection stops). The bill established a geologic sequestration special revenue account for the purpose of measuring, monitoring, and verifying geologic sequestration sites following site closure; however, the bill did not specify the source of funds for this account, which could include CO_2 taxes or fees which would be collected during CCS operations. The bill clarified that the existence of the special revenue account does not constitute an assumption of any liability by the state for geologic sequestration sites or the injected CO_2. and

- Wyoming Statute Section 35-11-313 (2013): These carbon sequestration/permit requirement regulations state that no person shall sequester CO_2 unless authorized by a UIC permit issued by DEQ. The injection of CO_2 for EOR purposes or other minerals approved by the Wyoming Oil and Gas Conservation Commission (WOGCC) shall not be subject to the provisions of this regulation unless the operator converts to geologic sequestration upon the cessation of oil and gas recovery operations.

To date, Wyoming has not filed a primacy application for UIC Class VI wells, leaving the EPA Region 8 responsible for issuing Class VI permits for CCS projects in Wyoming. At the same time, the WOGCC currently has primacy for UIC Class II wells and the Wyoming DEQ has primacy for UIC Class I wells.

3.2.1.5 Remaining PCOR Partnership States

The remaining states in the PCOR Partnership have little or no legislative and regulatory activity related to the geologic storage of CO_2. A summary of relevant legislative/regulatory activities that has occurred in these states is provided below:

- Iowa: Iowa has not yet enacted legislation or promulgated regulations pertaining to the geologic storage of CO_2, and the state has not issued any laws or rules to regulate emissions from coal-fired power plants in the state. In 2007, Iowa did establish the Iowa Climate Change Advisory Council with a charge to identify policies and strategies for the state to respond to the challenge of global climate change. In December 2008, the council released its Final Report (Iowa Climate Change Advisory Council, 2008). In 2015, EPA issued the NSPS that established standards for emissions of CO_2 for newly constructed, modified, and reconstructed affected fossil fuel-fired electric utility generating units (U.S. Environmental Protection Agency, 2015); however, the Iowa Department of Natural Resources (IDNR) has yet to determine the best way to comply with these standards. Currently, EPA Region 7 regulates all UIC well classes in Iowa.

- Minnesota: Minnesota has not yet enacted legislation or promulgated regulations pertaining to the geologic storage of CO_2. It is, however, an active member of the Midwest Governor's Association, which has studied the development of CCS rules, regulations, and infrastructure. In addition, a bill was enacted in 2007 (SF 2096) which appropriated $90,000 for a study of the geologic sequestration capacity in Minnesota. Currently, the Minnesota Department of Health (MDH) regulates oil and natural gas exploration in the state; EPA Region 5 regulates UIC well classes.

- Missouri: The Missouri Department of Natural Resources (DNR), through its Oil and Gas Council, proposed amendments to the Oil and Gas Drilling and Production regulations in October 2015. However, these amendments did not address regulations pertaining to the geologic storage of CO_2. EPA Region 7 regulates all UIC well classes in Missouri.

- Nebraska: Nebraska has yet to enact legislation or promulgate regulations pertaining to the geologic storage of CO_2. EPA Region 7 regulates all UIC well classes in Nebraska.

- South Dakota: In 2009, South Dakota passed a bill, HB 1129, which requires the Public Utilities Commission to regulate CO_2 pipelines. CO_2 is defined as a fluid that consists of more than 90% carbon dioxide molecules compressed in a supercritical state; no other legislation or promulgation of regulations pertaining to geologic storage of CO_2 has been enacted. EPA Region 8 regulates all UIC well classes in South Dakota.

- Wisconsin: Wisconsin has not yet enacted legislation or promulgated regulations pertaining to the geologic storage of CO_2, and there is no pending legislation or regulations. However, in 2008, the Wisconsin Public Service Commission did commission a report on the potential for geologic storage of CO_2 entitled "An Investigation to Explore the Potential for Geologic Sequestration of Carbon Dioxide Produced by Wisconsin's Electricity Generation Fleet." The report was published in March 2010 and recommended 1) Wisconsin officials support continued federal funding of CCS demonstration projects in other states and 2) state officials continue to collaborate with the federal government and other states on legal, regulatory, and technological issues where such collaboration is appropriate and advantageous to Wisconsin; i.e., Wisconsin should consider joining the Midwest Geological Sequestration Consortium and participate in the Midwestern Governors Association's new Regional CCS Task Force. EPA Region 5 regulates all classes of UIC wells in Wisconsin.

3.2.2 IOGCC[11] Guidance – Model Statute/General Rules and Regulations for CCS

Since 2002, the Geological CO_2 Sequestration Task Force of the IOGCC has been developing guidance for U.S. states on the formation of legal and regulatory frameworks for the storage of carbon dioxide in non-hydrocarbon-bearing geologic formations. This guidance was documented in a series of reports produced during each of the three phases of DOE's RCSP Program:

- "A Regulatory Framework for Carbon Capture & Geological Storage" (Phase 1: January 24, 2005) (Interstate Oil and Gas Compact Commission, 2005).

- "Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces" (Phase II: September 25, 2007) (Interstate Oil and Gas Compact Commission, 2007).

- "A Review of State and Provincial Action to Create a Legal and Regulatory Infrastructure for Storage of Carbon Dioxide in Geologic Structures" (Phase II: April 1, 2010) (Interstate Oil and Gas Compact Commission, 2010a).

- "IOGCC CCGS Task Force Phase II Biennial Review of the Legal and Regulatory Environment for the Storage of Carbon Dioxide in Geologic Structures" (Phase II: September 30, 2010) (Interstate Oil and Gas Compact Commission, 2010b).

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[11] The IOGCC is a multistate government agency that promotes the conservation and efficient recovery of domestic oil and natural gas resources while protecting health, safety, and the environment. IOGCC member states and international affiliates have established effective regulation of the oil and natural gas industry through a variety of programs designed to gather and share information, technologies, and regulatory methods.

- “Guidance for States and Provinces on Operational and Post-Operational Liability in the Regulation of Carbon Geologic Storage” (Phase III: September, 2014) (Interstate Oil and Gas Compact Commission, 2014).

The Phase I report examined the technical, policy, and regulatory issues related to the safe and effective storage of CO_2 in subsurface geologic media for both the dedicated storage of CO_2 and the associated storage of CO_2 during active enhanced hydrocarbon recovery. The Phase II reports produced Model Statute and Model Rules and Regulations for the geologic storage of CO_2, which occurred in two steps: 1) the primary components of a Model Statute and Model Rules and Regulations were developed in 2007 and 2) these initial statutory/regulatory models for the non-EOR-related geologic storage of carbon (CCS) in states and Canadian provinces were reviewed and updated in April 2010 and, again, in September 2010. The Phase III report, while not including an updated review of state and provincial regulatory developments or a top to bottom update of the model statute, rules, and regulations, did augment the previous guidance in two critical areas: operational and postoperational liability.

In addition to providing the model statute and model rules and regulations (see Appendix C and Appendix D, respectively), IOGCC recommended that states and provinces embrace two basic principles to facilitate the orderly development of CO_2 storage projects within their boundaries: 1) it is in the public interest to promote the geologic storage of CO_2 to reduce anthropogenic CO_2 emissions and 2) the pore space of the state or province should be regulated and managed as a resource under a resource management philosophy as introduced in the 2007 guidance. Addressing these two basic principles should be done by the state or province prior to storage occurring within its boundaries.

The legislative and regulatory guidance for the storage of CO_2 in non-hydrocarbon-bearing geologic formations that was developed by IOGCC is embodied in a model statute and model rules and regulations (Interstate Oil and Gas Compact Commission, 2014). While these documents were generated with a focus on the United States, the IOGCC specifically states that the model statute and model rules and regulations can be made applicable to Canadian provinces by replacing “state” with “province” or “provincial,” as appropriate. However, to date, neither the model statute nor the model rules and regulations have been actively used by the Canadian provinces of the PCOR Partnership.

3.2.2.1 Regulatory and Jurisdictional Authority of a Long-Term CO_2 Geologic Storage Project

The 2014 guidance of IOGCC identified five phases of a geologic storage project:

- Phase I – Exploratory
- Phase II – Permitting
- Phase III – Storage
- Phase IV – Closure
- Phase V – Postclosure

The flow of a typical project through all of these phases, from start to finish, is shown in Figure 1. Also highlighted in this figure is the U.S. federal/state regulatory and jurisdictional division of authority for each phase. As shown, Phases I (Exploratory) and V (Postclosure) are exclusively under state jurisdiction, while Phases II (Permitting), III (Storage), and IV (Closure) are under both state and federal (i.e., UIC Class VI) jurisdiction.

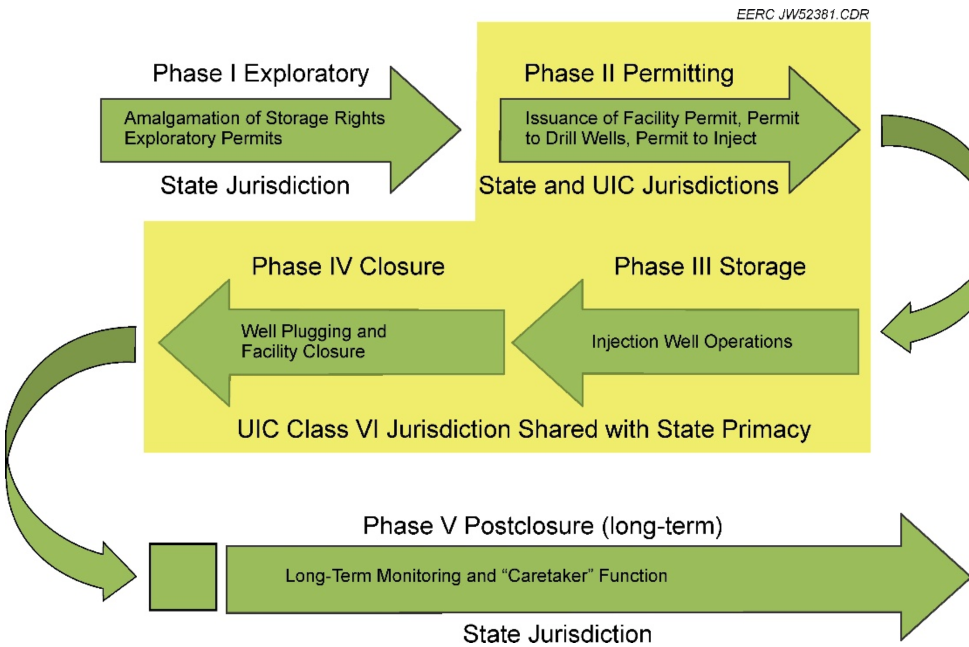

Figure 1. State and federal (UIC Class VI) jurisdiction of the phases of a CCS project (yellow highlighted phases are under concurrent state and federal jurisdiction; nonhighlighted phases are exclusively under state jurisdiction) (Interstate Oil and Gas Compact Commission, 2014).

3.2.2.2 Permitting Guidance for CO_2 Geologic Storage Projects

IOGCC has proposed a model statute (Appendix C) as well as general rules and regulations (Appendix D) to permit the geologic storage project described in Figure 1 (Interstate Oil and Gas Compact Commission, 2014). The model rules and regulations provide a regulatory framework for states to consider as they attempt to permit these projects within the current maze of existing and proposed federal and state regulations. While it is recognized that the framework of IOGCC only represents generic guidance, it does provide a useful, comprehensive benchmark against which to evaluate the current legislative and regulatory progress that has been made by the states and provinces within the PCOR Partnership region.

3.2.2.3 Key Aspects of the IOGCC Model Statute

The IOGCC model statute establishes the state as having the jurisdiction and authority to "conduct hearings and promulgate and enforce rules, regulations, and orders concerning the geologic storage of carbon dioxide." To provide further clarification of the purview of the state, the model statute also:

- Excludes "the use of carbon dioxide as a part of or in conjunction with any enhanced recovery methods where the sole purpose of the project is enhanced oil or gas recovery."
- Expressly authorizes the state "to develop rules to allow conversion of an existing enhanced recovery operation into a carbon dioxide storage project."
- Recognizes the commodity status of carbon dioxide by authorizing the state, under certain circumstances, "to regulate withdrawal of previously stored carbon dioxide for EOR and other uses that do not involve release to the atmosphere."

Among other specific requirements for a specific geologic storage project, the model statute specifies that a state require the storage operator to record a certificate, entitled "Certificate of Operation of Carbon Dioxide Storage Project," in the county or counties in which the project is located. This certificate must contain a statement that the "storage operator has acquired by eminent domain or otherwise all necessary ownership rights with respect to the Carbon Dioxide Storage Project and the date upon which the Carbon Dioxide Storage Project shall be effective." It further indicates that the states have the responsibility to "issue such orders, permits, certificates, rules, and regulations" for the purpose of "regulating the drilling, operation, well plugging and abandonment, and removal of surface buildings and equipment of the Carbon Dioxide Storage Project to protect the Carbon Dioxide Storage Project against pollution, invasion, and the escape or migration of carbon dioxide or other formation fluids so as not to endanger USDW." For more details regarding the model statute, the reader is referred to Appendix C or the Interstate Oil and Gas Compact Commission (2010b).

3.2.2.4 Permit Requirements of the IOGCC Model Rules and Regulations for a CO_2 Geologic Storage Project

The model rules and regulations proposed by IOGCC include three primary permits for a CO_2 geologic storage project[12]:

1. CO_2 storage project (CSP) permit
2. Well drilling and completion permit
3. Well operation permit

A brief description of the information requirements for each of these permits is provided below. For more details regarding these requirements, the reader is referred to Appendix D or Interstate Oil and Gas Compact Commission (2010b).

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[12] This report assumes that the exploratory investigations required for the selection of the site have been completed and the site has been selected for the commercial storage facility. For this reason, the permitting required to conduct exploratory drilling and other associated investigation activities, such as seismic operations, in Phase I of Figure 1 are not addressed. States permit these activities using well-documented and well-understood regulatory permitting processes.

CO_2 Storage Project Permit

Any CSP operator must obtain a license from the state and hold the necessary property rights for construction and operation of the CSP. To obtain this license, the CSP operator must submit an application to the state containing maps (e.g., map showing existing well(s) locations and pertinent surface facilities within the project boundaries), technical evaluations (e.g., technical evaluation describing the reservoir and a geologic/hydrogeologic evaluation for the geologic storage unit, including the cap rock seal and monitoring zones), and other supporting information and plans, including the identification of any productive oil and gas zones and freshwater horizons in the vicinity of the storage unit; the amount of CO_2 to be injected; and plans for public safety, emergency response, worker safety, corrosion and leak detection, and site closure. Lastly, a performance bond is required that must be sufficient to cover the abandonment or remediation of the project should the operator not perform or cease to exist.

Well Drilling and Completion Permits

Following approval of the CSP permit application, a permit application to “drill, deepen, convert, or reenter a previously plugged and abandoned well for the purposes of CO_2 storage” must be obtained. Examples of the types of information to be included with this permit application are a certified plat map showing the location of the injection and monitoring wells; a prognosis specifying the drilling, completion, or conversion procedures for the injection or subsurface observation well; wellbore schematics; the depths of the proposed reservoir and the deepest USDW; a description of the casing for both the injection and observation wells or the proposed casing program; the proposed method of testing casing before use of the CO_2 injection well; and a geophysical log through the reservoir to be penetrated.

The well drilling and completion permits, when issued, have a limited lifetime. For example, as part of the model rules and regulations, the IOGCC included a provision that these permits would expire 12 months from the date of issuance if the permitted well has not been drilled or converted within that time period.

Operating Permit for CO_2 Injection Well

Finally, an application for an operating permit must be submitted that includes such information as a schematic diagram of the surface injection system and its appurtenances; a final wellbore diagram; a diagram of the CO_2 injection well depicting the casing, cementing, perforation, tubing, plug, and packer records; and cement bond logs and the results of mechanical integrity tests, if applicable.

Amendments to the CSP well permits are allowed but will require resubmission of the above-referenced technical information for the proposed amendments.

3.2.2.5 Other Considerations

The UIC Class VI rule promulgated by EPA is limited to the protection of “underground source[s] of drinking water.” On the other hand, the IOGCC Model Rules and Regulations

(Interstate Oil and Gas Compact Commission, 2010b) represent a resource management philosophy that addresses all aspects of a CO_2 geologic storage project, including property rights, pore space management, and environmental protection. This CO_2 resource management philosophy is preferred to that of the waste management philosophy embodied in the Class VI rules of EPA. The states are believed to be in the best position to administer a combined regulatory approach that meets the requirements of the Class VI rule while at the same time implements the resource management philosophy that is articulated in the IOGCC guidance. For this reason, IOGCC recommends that any state with the potential for CCS adopt legislation and promulgate regulations along the general lines of its model statute and model rules and regulations and obtain primacy of the UIC Class VI rule. As states obtain primacy jurisdiction from EPA for Class VI injection wells, examples of legislation and rules and regulations that meet the Class VI requirements will evolve that will form the basis for updated model statutes, rules, and regulations for the states.

States seeking to obtain Class VI primacy from EPA will need to develop regulations that ensure the protection of USDWs by requiring operators to submit a UIC Class VI injection well permit. It is important to note that Class VI well permits will also be required for wells in other well classifications where their transition to Class VI has been determined. This is particularly relevant in the PCOR Partnership region should EPA continue to have the authority to make the site-specific determination that a Class II injection well is transitioning to a Class VI injection well. The specific, risk-based factors for making this determination and applying the Class VI permitting requirements have been developed by EPA and include the following:

1. Increase in reservoir pressure within the injection zone
2. Increase in CO_2 injection rates
3. Decrease in reservoir production rates
4. The distance between the injection zone and USDWs
5. The suitability of the Class II area of review (AOR) delineation
6. The quality of abandoned well plugs within the AOR
7. The owner's or operator's plan for recovery of CO_2 at the cessation of injection
8. The source and properties of injected CO_2
9. Any additional site-specific factors as determined by the Director

Any one of the above factors may not necessarily result in a determination that a Class II owner or operator must apply for a Class VI permit; rather, all factors must be evaluated comprehensively to inform a Director's (or owners' or operators') decision. The IOGCC model statute recognizes the importance of such a regulatory determination and believes it can most effectively be made by the individual states. For this reason, the IOGCC model statute advocates that the states "develop rules to allow conversion of an existing enhanced recovery operation into a Carbon Dioxide Storage Project." However, for this to be possible, the state will need to submit, and have approved, a Class VI primacy application.

The Class VI rules are unique to the United States. There are no equivalent federal rules in existence in Canada at this time although the provinces do have to comply, through equivalency agreements, with the 2012 Canadian regulations (Reduction of Carbon Dioxide Emissions from

Coal-Fired Generation of Electricity Regulations) regarding old and new coal-fired electricity generating plants (Canadian Environmental Protection Agency, 1999b).

3.3 Canada

All four provinces that are part of the PCOR Partnership Region, i.e., Alberta, British Columbia, Manitoba, and Saskatchewan, have proceeded with some form of legislation and regulations for CCS projects, building largely upon an extensive regulatory foundation in the oil and gas sector. The efforts of each of these provinces have produced a range of regulatory frameworks for CCS.

Similar to securing regulatory authority from EPA, in accordance with Section 10 of the Canadian Environmental Protection Act of 1999 (Canadian Environmental Protection Agency, 1999b), the provinces of Canada can enter into "equivalency agreements" with the federal government to minimize the duplication of environmental regulations. To date, all of the provinces of the PCOR Partnership region have equivalency agreements in place that address the geologic storage of CO_2; however, only Alberta and Saskatchewan have developed regulations and licensed CCS and CCUS projects.

3.3.1 Province of Alberta

3.3.1.1 CCS Legislative/Regulatory Development

Energy regulation in the province of Alberta spans more than 75 years and has evolved over time. While many aspects of CCS projects are covered through its existing oil and gas regulations, some pieces of legislation and regulation are specific to CCS.[13] The most important pieces of CCS-related legislation and regulation include:

- 2009 – Carbon Capture and Storage Funding Act: This act created a $2 billion CCS funding program to encourage and expedite the design, construction, and operation of large-scale CCS projects in Alberta.[14]

- 2010 – Carbon Capture and Storage Funding Regulation: This regulation authorized spending for the Regulatory Framework Assessment (RFA) as well as for education and research regarding CCS projects.

- 2010 – Carbon Capture and Storage Statutes Amendment Act: This act addressed two key barriers preventing CCS from moving forward in Alberta: 1) long-term liability for CO_2 stored underground and 2) pore space ownership. This act allowed the provincial government to assume long-term liability for storage sites once the sites were properly closed and the operators demonstrated through long-term monitoring that the stored CO_2

[13] Knowledge Sharing Reports on CCS and CCUS in Alberta are updated annually and are publicly available from Alberta Energy, http://www.energy.alberta.ca/CCS.

[14] $1.3B of this fund was allocated to two commercial-scale projects: 1) Shell Quest (oil sands) and 2) the Alberta Carbon Trunk Line or ACTL (bitumen refinery and fertilizer plants).

was stable. The act also made it mandatory for CCS operators to contribute to a Post-Closure Stewardship Fund, which provided funds for ongoing monitoring and any required future maintenance and remediation.

- 2011 – Carbon Sequestration Tenure Regulation: This regulation, which was in response to applications for carbon sequestration leases, established the process for obtaining tenure or lease rights for pore space to evaluate the suitability of a potential storage site or to store CO_2.

As authorized by the Carbon Capture and Storage Funding Regulation, the province of Alberta initiated a CCS RFA in March 2011 to ensure the necessary regulations were in place before large-scale CCS projects started operations. The RFA focused on the primary periods in the life cycle of a CO_2 sequestration project as delineated in Figure 2. It examined the regulations that currently apply to CCS in Alberta as well as regulations and best practices in other parts of the world. It examined, in detail, the technical, environmental, safety, monitoring, and closure requirements that apply to a CCS project. The RFA was completed in December 2012 (Alberta Energy, 2013), and a final report was provided to the Alberta Energy Minister in in 2013 that included 25 actionable items for consideration by the government of Alberta. One recommendation, in particular, was that the province of Alberta and the regulator should coordinate the development of a CCS Regulatory Guidance Document, similar to the existing Upstream Oil and Gas Authorizations and Consultation Guide, to a) provide detailed information on all approvals and authorizations related to CCS; b) document roles and responsibilities for regulators and government departments; c) provide detailed information on the process for acquiring pore space tenure and a permit to inject CO_2; d) provide detailed information on the requirements for the issuance of a closure certificate; and e) include process maps, regulatory flowcharts, Web links, etc. The development of this CCS guidance document was driven by the conclusion that there was limited information available on the CCS regulatory process in the province and most of it was either outdated or difficult to access. By creating the CCS Regulatory Guidance Document, Alberta would be able to communicate the regulatory process and requirements for CCS project proponents, operators, stakeholders, and the public. This and the other recommendations and conclusions put forward in the final report are being reviewed on an ongoing basis to inform and guide the government of Alberta's policies and regulatory refinements specific to carbon capture and storage (G. Ouellette, August 2016).

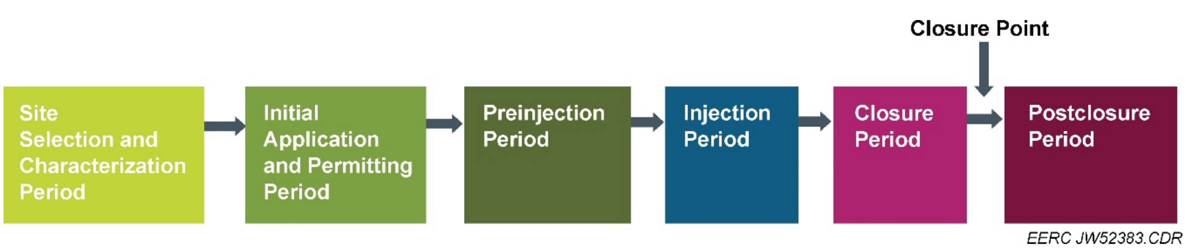

Figure 2. Periods in the life cycle of a CO_2 sequestration project provided in the RFA of the province of Alberta.

In 2013, the Alberta Energy Regulator (AER) was created to streamline the regulatory functions related to energy development, which were previously held by the Alberta Environment and Sustainable Resource Development (ESRD). This transition is now complete, and AER is now the single regulator of energy development in Alberta, with purview over all aspects of a project, including application and exploration; construction and development; and abandonment, reclamation, and remediation (http://www.aer.ca).

3.3.1.2 Permitting of a CCS Project

The initial application and permitting period for a CCS project in Alberta begins when a proponent applies for a tenure agreement for the chosen site. The three stages to this process are briefly described below[15]:

1. Initial acquisitions – This stage includes obtaining subsurface and surface rights as well as any other requirements needed to further characterize the chosen site:

    - For the geologic storage of CO_2, subsurface rights agreements include evaluation permits and carbon sequestration leases. Proponents seeking permanent sequestration of CO_2 into the deep subsurface, the subject of this report, would acquire a carbon sequestration lease, which will be subject to the regulatory requirements as recommended by the Regulatory Framework Assessment for CO_2 sequestration (Alberta Energy, 2013).

    - Surface rights must be acquired to access the land. This process differs for private versus public land. Private land requires an agreement between the lessee and the landowner. On public lands, a mineral surface lease must be obtained from AER.

2. Discretionary activity review and potential Environmental Impact Assessment (EIA) – Following the initial acquisitions stage, a review is completed to determine whether a project requires a provincial EIA, which is now also administered by AER.

3. Regulatory approvals – Regulatory approvals are initiated with a well license application to AER, which can be completed while the project is in the initial acquisitions stage. For a CCS project, an evaluation well(s) may be drilled to acquire the specific information needed for approval of an injection scheme. A CCS proponent must apply to AER for approval of injection and monitoring wells, which sets out the technical requirements of an injection well. After drilling, completion, and testing of an injection well, proponents must apply to AER for an injection scheme approval, which currently requires an applicant to have all proposed injection wells completed and test results available prior

[15] Prior to the formation of AER in 2013, this process was administered by a combination of the Alberta ESRD through the Alberta Energy Resource Conservation Board (ERCB). In 2015, AER enacted the New Activity Life Cycle Analysis (NALCA) Program, which provides a single permit application for all energy development activities. This action resulted in a reduction of permit application and processing time while maintaining all of the previous regulatory compliance functions (Ms. Jennifer Steber, Alberta Energy Regulatory Executive Vice President, Stakeholder and Government Relations Division, 2016, Personal communication).

to scheme approval. Applications under this directive provide information necessary for AER to determine that there will be containment of the disposal fluid.

Prior to AER providing final approval, additional conditions may be imposed on the project. Once final approval is obtained from AER, the project can commence subject to conditions and regulatory requirements.

3.3.2 Province of British Columbia

British Columbia is relying on its existing regulatory framework for oil and natural gas to regulate the geologic storage of CO_2.[16] This framework has legislation and regulations in place governing storage reservoir rights and underground storage and disposal. More specifically, with regard to CCS, the province released its Natural Gas Strategy in 2012, which committed the government to promote the use of CCS by completing the development of a CCS regulatory framework. In January 2014, in accordance with a Carbon Capture and Storage Regulatory Policy Discussion and Comment Paper, the Ministry of Natural Gas Development was to introduce this CCS regulatory policy framework under the Petroleum and Natural Gas Act and the Oil and Gas Activities Act (Province of British Columbia, 2014). This CCS regulatory framework was drafted in 2014 by a cross-government team, which included the oil and gas regulators of the province. The framework provides a robust regulatory model that addresses key CCS issues such as reservoir selection, security of CO_2 storage, monitoring, and long-term liability. The ultimate goal of this framework is to ensure that a regulatory regime is in place for commercial CCS projects to proceed by addressing regulatory barriers to CCS projects and providing regulatory certainty to CCS developers. In the fall of 2015, the Natural Gas Development Statutes Amendment Act was passed and provided the first round of amendments to the Petroleum and Natural Gas Act and the Oil and Gas Activities Act to enable CCS (International Energy Agency, 2014).

3.3.3 Province of Saskatchewan

Saskatchewan has a long history with the subsurface injection of CO_2 with over 30 years of injection as part of CO_2 EOR operations, which accounts for 27 million metric tons of anthropogenic CO_2 as of the beginning of 2015 (Wist, 2015). The regulatory framework for CCS in the province is derived largely from this experience in the oil and gas industry, where CO_2 transport and injection have been regulated for many years. Its rule making is modeled on the regulatory framework developed in Alberta but with alterations dictated by provincial differences related to the geology, economy, and industrial facilities and opportunities.

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16 In November 2007, British Columbia passed the Greenhouse Gas Reduction Targets Act (GGRTA), which set legislated targets for reducing greenhouse gases. The act became effective in January 2008 and set minimum target reductions in greenhouse gas emissions at 33% below 2007 levels by 2020. Interim reduction targets of 6% by 2012 and 18% by 2016 were also established to guide and measure progress. A further emission reduction target of 80% below 2007 levels is required for 2050. Also, effective July 1, 2008, a tax of Can$10 per metric ton of CO_2 was imposed on fossil fuels burned for transportation, home heating, and electricity; this tax was increased to Can$30 per metric ton of CO_2 in 2012. This tax is a revenue-neutral tax as all revenues from this tax were used to reduce personal and corporate income taxes (British Columbia, 2008).

Briefly, the CCS industry is being regulated in Saskatchewan through amendments to its Oil and Gas Conservation Act (OGCA) which occurred in 2011. These amendments expand its powers and oversight for the storage of CO_2 and other greenhouse gases and clarify the government's regulatory oversight of non-oil-and-gas substances, in particular with respect to the storage and sequestration of CO_2 and other greenhouse gases in subsurface formations (i.e., approval of all plans related to the injection, storage, or disposal of oil and gas wastes or non-oil-and-gas substances in subsurface formations). For example, the term "non-oil-and-gas waste" was replaced with "non-oil-and-gas substance" to clarify the scope to include substances from the CCS industry, and the Minister was granted the authority to approve or refuse a CO_2 storage plan. Examples of other applicable parts of the regulation to CO_2 storage included well testing and measurement, data requirements, and records and reporting requirements. The amended legislation also expanded the scope of Saskatchewan's orphan well and facility liability management program beyond the oil and gas industry to the regulation of wells for other nonrenewable resource management purposes, such as the storage of CO_2 for carbon sequestration. Following these amendments to the act, the Oil and Gas Conservation Regulations of 2012 were passed, which provided greater oversight of carbon storage.

In addition to the amendments to the OGCA, other legislative/regulatory items of importance to the implementation of CCS in the province are 1) the Crown Minerals Act authorizes agreements for the lease of pore space where the Crown is the owner of minerals on Crown lands; 2) the long-term liability for storing CO_2 is borne by well license holders, regulated under the OGCA; and 3) a 2009 amendment to the 1998 Pipelines Act covers CO_2 pipelines for non-oil-and-gas purposes. Analogues for liability transfer to the Crown exist in the mining sector in acts such as the Reclaimed Industrial Sites Act, which addresses the long-term liability issues posed by uranium mine development. Lastly, in addition to using the OGCA, targeted new legislation to deal with policy issues associated with dedicated, large saline aquifer disposal projects is also being considered.

3.3.4 Province of Manitoba

Manitoba is the only province in the PCOR Partnership that has no CCS regulatory framework in place or under development. This is largely due to that fact that almost all electrical power generated in Manitoba is derived from renewable energy sources, making the province a relatively small contributor to the overall greenhouse gas emissions of Canada.[17] However, the province has engaged in a number of activities related to the reduction of greenhouse gases in an effort to make its electrical system among the cleanest in Canada. Most notably, the province enacted the Climate Change and Emissions Reductions Act on December 5, 2013. Manitoba has also signed Letters of Agreement and Memoranda of Understanding with several governments (e.g., the United States of America, Canada, the province of British Columbia, the state of California, and South Australia), and associations (e.g., Canadian Standards Association and Canadian Climate Exchange). These documents commit the province to a number of cooperative activities related to the reduction of greenhouse gases (e.g., the development of a climate change registry, participation in cap-and-trade programs, and development of market-based solutions to reduce greenhouse gas emissions) and further affirm its commitment to continue to reduce

[17] In 2010, Manitoba had only one coal plant, which had a capacity of 98 megawatts and which represented only 1% of the coal-generating capacity of Canada (Canadian Gazette, 2011b)

greenhouse gas emissions. Regarding the latter, in December 2015, Manitoba announced targets of reducing greenhouse gases by one-third by 2030 and of being carbon-neutral by 2080 (CBC News, 2015).

4.0 OUTSTANDING CHALLENGES AND BARRIERS

Previous reviews have identified the regulatory and legal obstacles to the commercial deployment of CCS technology (McCoy and others, 2010; Interstate Oil and Gas Compact Commission, 2007, 2014). Three main obstacles have been highlighted: 1) access to and use of pore space, 2) permitting of geologic storage projects, and 3) management of long-term liability. The manner in which each of these obstacles has been, or is being, addressed by the U.S. states in the PCOR Partnership region is discussed below. The perspective of the Canadian provinces in the PCOR Partnership region regarding these obstacles is separately addressed given the differences in the legislative and regulatory landscapes between Canada and the United States.

4.1 Access to and Use of Pore Space

Uncertainty regarding access to pore space for the geologic sequestration of CO_2 has been an obstacle to the commercial development of CCS projects. There are questions about whether the pore space is a stand-alone property estate or a property right that is inextricably tied to the surface estate, whether the pore space is a protectable property interest whose use requires compensation, and whether limiting absolute protection of pore space interests through legislation represents an unconstitutional regulatory “taking” of private property.

Three states within the PCOR Partnership region, Montana, North Dakota, and Wyoming, have acted on the pore space issues and have established that pore space is tied to the surface estate (Montana SB498, North Dakota SB2139, and Wyoming HB89); however, both North Dakota and Wyoming prohibit the severance of pore space from the surface estate, while Montana permits severance if it is provided for by deed or severance documents. In addition, compulsory unitization, similar to that used in oil field development, has also been adopted. In all three states, landowners are compelled to be part of a sequestration unit once a certain percentage of the landowners have voluntarily committed their pore space to be developed and used for sequestration. Threshold percentages of 60% (Montana and North Dakota) and 80% (Wyoming) have been specified for this purpose.

An alternative to unitization is the use of eminent domain. A prerequisite for eminent domain is the declaration that the geologic storage of CO_2 is in the public interest. The use of this language was recommended in the model statue of IOGCC (Interstate Oil and Gas Compact Commission, 2010b, 2014) and was adopted by North Dakota in its legislation, SB2095, which granted authority to NDIC to address the geologic storage of CO_2. However, similar language is not present in the CCS legislation of either Montana or Wyoming.

4.2 CCS Project Permitting

As indicated previously, Montana, North Dakota and Wyoming have promulgated regulations for the permitting of CCS projects. Each of these states has elected to delegate the permitting responsibilities to different agencies. Specifically, both North Dakota and Montana delegated permitting authority to their oil and gas regulatory authorities: NDIC and the Montana Board of Oil and Gas Conservation, respectively. However, Montana also incorporated environmental input into the permitting process (i.e., air emissions and water quality through the Montana DEQ) by adopting the administrative procedural rules as specified in Rule 36.22.202 of the Environmental Policy Act. On the other hand, Wyoming delegated the permitting of CCS projects to its environmental agency, DEQ, through HB90. The permitting requirements are presented in Wyoming Statute Section 35-11-313.

Regardless of current state regulations, effective with the promulgation of the EPA Class VI rules in December 2010, the permitting of CCS projects within the PCOR Partnership states will be under EPA control and will be governed by the requirements of that federal regulation until such time that a primacy application has been filed by the state and approved by EPA. To secure this primacy, each state must promulgate state regulations that are at least as stringent as the requirements of the EPA Class VI rule. To date, only North Dakota has filed for primacy of these rules. Consequently, any entity seeking to permit a CCS project in the PCOR Partnership region must comply with the Class VI rules, as written, and must receive approval for their permit from EPA. The PCOR Partnership states are located within EPA Regions 5, 7, and 8.

Of particular importance to the PCOR Partnership region is the regulatory handling of CO_2 EOR projects, which are currently operating with Class II permits that have been issued either by the state (i.e., Missouri, Nebraska, North Dakota, Wisconsin, and Wyoming) or EPA (Iowa, Minnesota, Montana, and South Dakota) (see Table 1). Although Montana, North Dakota, and Wyoming have excluded CO_2 EOR from their current legislative and regulatory CCS initiatives, the lack of primacy of the Class VI rules will ultimately leave the decision regarding the transition of CO_2 EOR operations to geologic storage of CO_2 to the discretion of the EPA Directors, either at the regional or headquarters level or both. This reclassification of CO_2 EOR operations will introduce additional long-term liability and carbon credit issues that will likely eliminate the use of CO_2 EOR as a CO_2 emissions reduction strategy; i.e., CO_2 EOR operations will likely be terminated rather than be used for CO_2 storage under the Class VI rules. To address this obstacle, IOGCC has made it clear (Interstate Oil and Gas Compact Commission, 2007: Appendix I – Model Statute, Section 10), and EPA Office of Ground Water and Drinking Water has confirmed (U.S. Environmental Protection Agency, 2015), that it would be best if the states administered both the Class II and the Class VI UIC programs. EPA Office of Water further acknowledged that it expects that states approved for primacy for the Class VI program will administer the program through their oil and gas programs.

4.3 Site Closure and Management of Long-Term Liability

Under SDWA, EPA is unable to release the operator from federal liability in the postclosure phase of a CCS project. This perpetual federal liability has been cited as a threat to the viability of the CCS industry. To address this obstacle, and expressed in its broadest form, IOGCC recommended the following language in its Model Statute: 1) the state would, after issuance of the Certificate of Closure, assume complete responsibility for the storage site and 2) the state would also concurrently assume near-complete liability from the operator under federal and state law, to be financed by a long-term state trust fund that would be funded by an appropriately greater tax or fee on each ton of CO_2 injected (Interstate Oil and Gas Compact Commission, 2014). The trust fund was recommended to address long-term site care (monitoring and maintenance).

North Dakota and Wyoming have embraced the guidance of IOGCC to address the liabilities associated with closing a site and its long-term management following closure. Specifically, financial assurance mechanisms have been put in place to ensure that CCS projects are properly closed. North Dakota requires performance bonds for the CO_2 injection and observation wells and the surface facility, the amounts to be determined by NDIC. Wyoming requires public liability insurance or self-insurance for the CCS operations and bonds or other financial assurance to cover the costs of meeting permit requirements, including monitoring, remediation, and site closure. To determine when closure has been successfully attained, both states have established site closure criteria:

- North Dakota: position and characteristics of the injected CO_2 must be provided along with a reasonable expectation that the mechanical integrity of the reservoir will be maintained.

- Wyoming: the closure period is a 10-year period following the cessation of CO_2 injection. Monitoring data for 3 years are required to demonstrate that the CO_2 plume is stable, and it must be established that CO_2 will not present a risk to human health, safety, or the environment.

Upon achieving closure in both states, the bonds are released, and monitoring and remediation become the responsibility of the state or federal agency.

Following closure, and in keeping with the IOGCC guidance, all liabilities associated with the site will be transferred to the state in Montana, North Dakota, and Wyoming, and the costs of these liabilities will be covered by establishing long-term stewardship funds that will be developed during the CCS operations.

4.4 Canadian Perspective

The permitting conditions in Canada for CCS projects are significantly different and more favorable compared to the United States. Evidence of this is the number of commercial-scale CCS projects that are operating within the provinces of the PCOR Partnership as compared to the states. This development is attributable to a couple of key regulatory factors that have circumvented the permitting obstacles discussed above. First, the pore space in Canada is largely owned by the provinces, which would assume the permanent liability related to the injected carbon dioxide once the CCS operator has collected data substantiating that the stored carbon dioxide is "contained."[18]

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[18] The statutory vesting of pore space in Alberta provides the most certainty for CCS operators as they are able to deal with a single owner, the Crown. The regime in British Columbia provides a reasonable amount of confidence for an operator seeking a storage site since the Crown owns much of the subsurface and has a compulsory acquisition-type

Second, there is no federal regulation that is equivalent to EPA's Class VI rules, leaving the provinces as solely responsible for the permitting of CCS projects according to their respective equivalency agreements with the Canadian federal government. Leaving this responsibility to the province has provided them with the regulatory flexibility to permit these projects under the existing oil and gas regulatory frameworks, as evidenced in Saskatchewan and Alberta. This flexibility has also facilitated the continued permitting of CO_2 EOR, making it a significant contributor to the portfolio of CO_2 emission reduction strategies.

5.0 CLOSING COMMENTS

The PCOR Partnership covers a large geographic area that includes portions of both the United States and Canada. It includes a variety of CO_2 emission sources and geologic formations capable of safely sequestering captured, anthropogenic CO_2. The large-scale deployment of CCS and CCUS across the region as a greenhouse gas reduction strategy is governed by a mix of federal/state jurisdictions in the United States and federal/provincial jurisdictions in Canada, all of which began developing legislation and regulations sometime after the signing of international agreements such as the Kyoto Protocol in 1997.

Two legislative/regulatory approaches have been taken in the PCOR Partnership region to regulate the commercial deployment of CCS and CCUS, one in Canada, and one in the United States. The former, which was spurred by significant government investments in commercial-scale facilities, has largely utilized the existing legislative and regulatory framework of the oil and gas industry to regulate this new industry and has deferred the authority to do so to the provincial governments. In addition, the approach used in Canada represents the resource management philosophy recommended by IOGCC in that pore space ownership and postoperational liability are incorporated into the regulatory process. As a result of this legislative/regulatory approach, Canada currently has four commercial-scale CCS/CCUS facilities in operation, including the first integrated CCS operation involving carbon capture at a coal-fired, thermoelectric power plant.

In contrast, the regulation of CCS and CCUS in the United States is being led at the federal level by EPA, which has defined a new injection well class for the geologic storage of CO_2 (i.e., Class VI) and is employing a waste management philosophy. This philosophy does not recognize or manage pore space as a resource and is incapable of releasing the operator from federal liability in the postclosure phase of a project. At the same time, these new federal rules also inhibit the use of the existing CO_2 EOR operations and infrastructure of the oil and gas industry for the associated geologic storage of CO_2 by forcing their transition from Class II wells to the new Class VI wells. The additional postclosure liabilities and onerous reporting and accounting requirements that accompany this transition essentially guarantee that the operators of CO_2 EOR facilities will opt to terminate their operations rather than undergo this transition. The regulatory uncertainty that has resulted from this top-down regulatory approach, in combination with the lack of a business case for CCS in the United States, has dramatically slowed down the large-scale commercial development of CCS or CCUS in the United States. To address this issue and foster the commercial

system in place accompanied by compensation to affected landowners. The Saskatchewan situation presents the most risk to operators as the compulsory unitization mechanism does not apply to CO_2 storage and there is no means of addressing situations where there are private holdouts (Global CCS Institute, 2015).

deployment of CCS and CCUS in the PCOR Partnership region, it is imperative that the states of the region secure primacy of the Class VI rules of EPA and incorporate them into a resource management philosophy compatible with the existing oil and gas regulatory framework.

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APPENDIX A

PERMITTING FLOWSHEET AND DETAILED INSTRUCTIONS FOR PERMIT APPLICATIONS FOR DRILLING OF CO_2 INJECTION WELLS AND CO_2 INJECTION IN NORTH DAKOTA

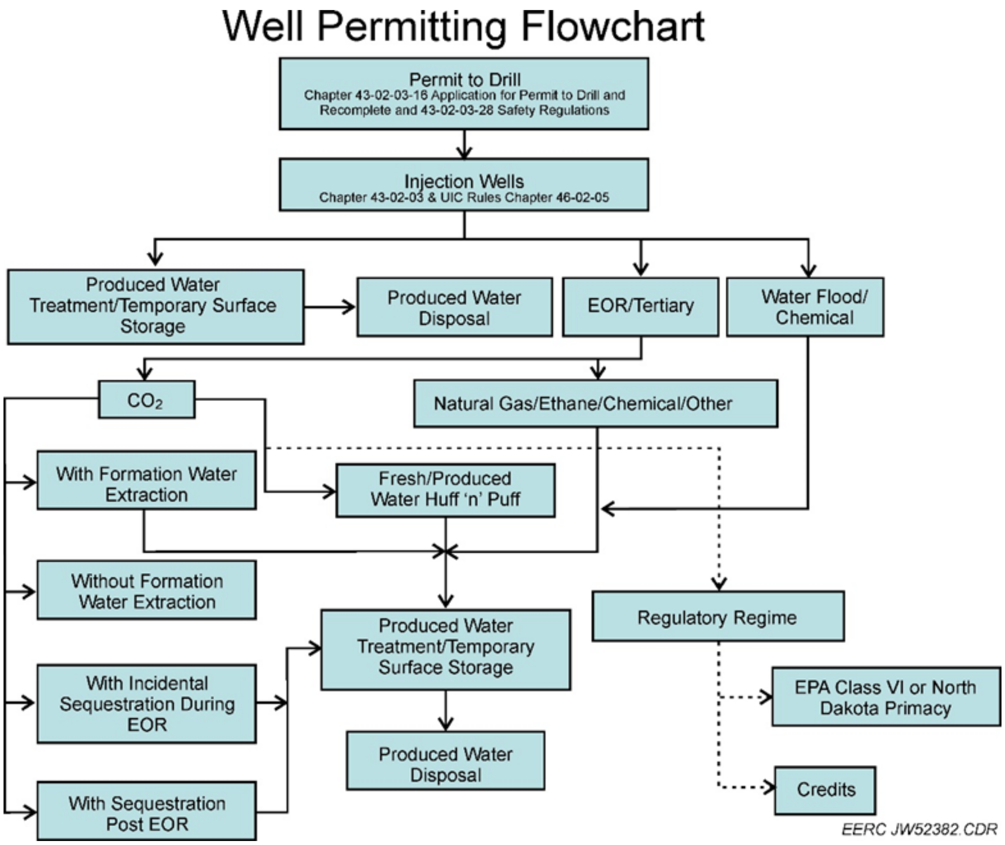

Figure A-1 provides a flowchart for the permitting of a CO_2 injection well for a carbon capture and storage (CCS) operation. Critical to this process are two permits: 1) Permit to Drill a CO_2 Injection Well and 2) Permit to Inject CO_2. The detailed instructions and information required for the applications for these permits are provided in Tables C-1 and C-2, respectively.

APPLICATION FOR PERMIT TO DRILL - FORM 1

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN 4615 (10-2014)

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
PLEASE SUBMIT THE ORIGINAL AND ONE COPY.

Type of Work	Type of Well	Approximate Date Dirt work Will Start	Confidential Status

Operator	Telephone Number

Address	City	State	Zip Code

Name of Surface Owner or Tenant

Address	City	State	Zip Code

WELL INFORMATION

☐ Notice has been provided to the owner of any permanently occupied dwelling within 1,320 feet.

☐ This well is not located within five hundred feet of an occupied dwelling.

Well Name	Well Number

	Qtr-Qtr	Section	Township	Range	County
At Surface F L F L			N	W	
If Directional, Top of Pay F L F ☐ L			N	W	
Proposed Bottom Hole Location F L F ☐ L			N	W	

Latitude of Well Head ° ' "	Longitude of Well Head ° ' "	NAD Reference	Description of (Subject to NDIC Approval)

Ground Elevation Feet Above S.L.	Acres in Spacing/Drilling Unit	Spacing/Drilling Unit Setback Requirement Feet	Industrial Commission Order

Objective Horizons	Pierre Shale Top

Proposed Surface Casing	Size - "	Weight Lb./Ft.	Depth Feet	Cement Volume Sacks	**NOTE: Surface hole must be drilled with fresh water and surface casing must be cemented back to surface.**

Proposed Longstring Casing	Size - "	Weight(s) Lb./Ft.	Longstring Total Depth Feet MD Feet TVD	Cement Volume Sacks	Cement Top Feet	Top Dakota Sand Feet

Base of Last Salt (If Applicable) Feet	Estimated Total Depth (feet) Feet MD Feet TVD	Drilling Mud Type (Vertical Hole - Below Surface Casing)

Proposed Logs

Comments

I hereby swear or affirm that the information provided is true, complete and correct as determined from all available records.	Date

Signature	Printed Name	Title

Email Address(es)

FOR STATE USE ONLY

Permit and File Number	API Number 33-
Field	
Pool	Permit Type

FOR STATE USE ONLY

Date Approved
By
Title

PLEASE SEE INSTRUCTIONS https://www.dmr.nd.gov/oilgas/rules/fillinforms.asp

Figure A-1. Form 1.

Table A-1. Detailed Instructions: Application for Permit to Drill a CO_2 Injection Well in North Dakota (Form 1 SFN 4516) (Source: www.dmr.nd.gov/oilgas/rules/forms/form1.pdf)

1	All applications for permit to drill must be e-filed, except in extenuating circumstances. Operators must file an ePermit authorization form, and e-mail to apd@nd.gov. The Bismarck office will then issue a user-ID and password to access the online Form 1 or Form 1H.
2	Please refer to Section 43-02-03-16 of the North Dakota Administrative Code (NDAC) regarding an application for permit to drill.
3	Wellsite preparation other than surveying and staking is forbidden prior to approval of an application for permit to drill.
4	Verbal approval may be given for site preparation by the Director in extenuating circumstances, although no drilling activity shall commence until the application is approved.
5	The application for permit to drill shall be accompanied by a bond pursuant to Section 43-02-03-15 NDAC, or the applicant must have previously filed such bond with the Commission, otherwise the application is incomplete.
6	Any incomplete application for permit to drill received by the Commission has no standing and shall not be deemed filed until it is completed.
7	The application for a permit to drill a well shall be accompanied by an accurate plat certified by a registered surveyor showing the location of the proposed well with reference to the nearest lines of a governmental section and referenced to true north. Also, the application must include an accurate pad layout which indicates cut and fill and the proposed cuttings pit location. In addition, a production pad facilities layout plat is required.
8	The application for permit to drill a directional well shall be accompanied by an accurate plat certified by a registered surveyor showing the internal dimensions of the spacing or drilling unit.
9	The application for permit to drill shall be accompanied by a drilling prognosis which shall include the following: the proposed total depth (including measured depth if appropriate) to which the well will be drilled, the estimated depth to the top of important geologic markers, the estimated depth to the top of objective horizons, the proposed mud program, the proposed casing program including size and weight, the proposed depth at which each casing string is to be set, the proposed amount of cement to be used, and the estimated top of cement.
10	A gamma ray log must be run to ground level, CBL [cement bond log]) must be run on the intermediate or production casing, and open hole logs are required (unless waived by the Director).
11	The application for permit to drill shall be accompanied by the general completion technique.
12	The application for permit to drill shall comply with NDIC-PP (Permit Policy) 1.01, 1.02, 1.03, 1.04, 1.05, 1.06, 2.01, 2.02, 2.03, and 2.04. Also, the application shall include confirmation that a legal street address was requested as required by NDAC 43-02-03-16.
13	The application for permit to drill shall be accompanied by a permit fee of $100.
14	The approved application for permit to drill shall terminate and be of no further force and effect unless a well is drilling, or has been drilled, below surface casing on the first anniversary of the date of issuance or renewal.

APPLICATION FOR INJECTION - FORM 14

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN 18669 (08-2012)

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM. PLEASE SUBMIT THE ORIGINAL AND TWO COPIES.
APPROVAL MUST BE OBTAINED BEFORE WORK COMMENCES.

Permit Type ☐ Enhanced Recovery ☐ Saltwater Disposal ☐ Gas Storage	Injection Well Type ☐ Converted ☐ Newly Drilled			Commercial SWD ☐ Yes ☐ No
Operator	Telephone Number	Will Oil be Skimmed? ☐ Yes ☐ No		
Address	City	State		Zip Code
Well Name and Number	Field or Unit			

LOCATIONS

At Surface F L F L	Qtr-Qtr	Section	Township N	Range W	County
Bottom Hole Location F L F L	Qtr-Qtr	Section	Township N	Range W	County

Geologic Name of Injection Zone	Top Feet	Injection Interval Feet	
Geologic Name of Top Confining Zone	Thickness Feet	Geologic Name of Bottom Confining Zone	Thickness Feet
Bottom Hole Fracture Pressure of the Top Confining Zone PSI		Gradient PSI/Ft	
Estimated Average Injection Rate and Pressure BPD @ PSI		Estimated Maximum Injection Rate and Pressure BPD @ PSI	
Geologic Name of Lowest Known Fresh Water Zone			Depth to Base of Fresh Water Zone Feet
Total Depth of Well (MD & TVD) Feet	Logs Previously Run on Well		

CASING, TUBING, AND PACKER DATA (Check If Existing)

NAME OF STRING	SIZE	WEIGHT (Lbs/Ft)	SETTING DEPTH	SACKS OF CEMENT	TOP OF CEMENT	TOP DETERMINED BY
Surface ☐						
Intermediate ☐						
Long String ☐						

				TOP	BOTTOM	SACKS OF CEMENT
Liner ☐						

				TYPE
Proposed Tubing				

Proposed Packer Setting Depth Feet	Model	☐ Compression ☐ Permanent ☐ Tension

FOR STATE USE ONLY

Permit Number and Well File Number	
UIC Number	Approval Date
By	
Title	

Figure A-2. Form 14.

COMMENTS

I hereby swear or affirm that the information provided is true, complete and correct as determined from all available records.		Date
Signature	Printed Name	Title

Above Signature Witnessed By

Witness Signature	Witness Printed Name	Witness Title

Instructions

1. Attach a list identifying all attachments.
2. The operator, well name and number, field or unit, well location, and any other pertinent data shall coincide with the official records on file with the Commission. If it does not, an explanation shall be given.
3. If an injection well is to be drilled, an Application for Permit to Drill - Form 1 (SFN 4615) shall also be completed and accompanied by a plat prepared by a registered surveyor and a drilling fee.
4. Attach a lithologic description of the proposed injection zone and the top and bottom confining zones.
5. Attach a plat depicting the area of review (1/4-mile radius) and detailing the location, well name, and operator of all wells in the area of review. Include: injection wells, producing wells, plugged wells, abandoned wells, drilling wells, dry holes, and water wells. The plat shall also depict faults, if known or suspected.
6. Attach a description of the needed corrective action on wells penetrating the injection zone in the area of review.
7. Attach a brief description of the proposed injection program.
8. Attach a quantitative analysis from a state-certified laboratory of fresh water from the two nearest fresh water wells. Include legal descriptions.
9. Attach a quantitative analysis from a state-certified laboratory of a representative sample of water to be injected.
10. Attach a list identifying all source wells, including location.
11. Attach a legal description of land ownership within the area of review. List ownership by tract or submit in plat form.
12. Attach an affidavit of mailing certifying that all landowners within the area of review have been notified of the proposed injection well. This notice shall inform the landowners that comments or objections may be submitted to the Commission within 30 days, or that a hearing will be held at which comments or objections may be submitted, whichever is applicable. Include copies of letters sent.
13. Attach all available logging and test data on the well which has not been previously submitted.
14. Attach schematic drawings of the injection system including current well bore construction and proposed well bore and surface facility construction.
15. Attach a Sundry Notice - Form 4 (SFN 5749) detailing the proposed procedure.
16. Attach a diagram representing the traffic flow and the maximum number of trucks staged on site.
17. Attach a printout of a map obtained at http://www.nd.gov/gis/apps/HubExplorer/ with surficial aquifers (under hydrography) active, and proposed location plotted on printout.
18. Read Section 43-02-05-04 of the North Dakota Administrative Code to ensure that this application is complete.
19. The original and two copies of this application and attachments shall be filed with the Industrial Commission of North Dakota, Oil and Gas Division, 600 East Boulevard, Dept. 405, Bismarck, ND 58505-0840.

Figure A-2 (continued). Form A-2.

APPENDIX B

CONTACT INFORMATION FOR STATE/PROVINCIAL AGENCIES INVOLVED IN THE REGULATION OF THE GEOLOGIC STORAGE OF CO_2 IN THE PCOR PARTNERSHIP REGION

ALBERTA, CANADA

Alberta Energy Regulator — www.aer.ca
Contact the Customer Contact Centre at:
Phone: 403-297-8311
Toll-Free: 1-855-297-8311
Fax: 403-297-7336
inquiries@aer.ca

BRITISH COLUMBIA, CANADA

British Columbia Oil and Gas Commission — www.bcogc.ca
Public Enquiries and Concerns
Fort St. John: 250-794-5200
Victoria: 250-419-4400
Call toll-free via Enquiry BC
1-800-663-7867

IOWA

Iowa Department of Natural Resources — www.iowadnr.gov
Iowa DNR Customer Service:
515-725-8200 (phone)
515-725-8202 (fax)
EPA in Iowa – U.S. Environmental Protection Agency — www.epa.gov/io
Region 7 913-551-7003

MANITOBA, CANADA

Manitoba Growth, Enterprise and Trade — www.manitoba.ca
(As of May 3, 2016, Manitoba Mineral Resources is now a part of the Department of Growth, Enterprise, and Trade.)
Mineral Resources, Petroleum Branch — www.manitoba.ca/iem/petroleum
Phone: 204-945-6577
Toll-Free: 1-800-223-5215

MINNESOTA
Minnesota Department of Health — www.health.state.mn.us/divs/eh
Environmental Health Division
(651) 201-5000

EPA in Minnesota – U.S. Environmental Protection Agency — www.epa.gov/mn
Region 5 321-353-6288

MISSOURI

Missouri Department of Natural Resources	www.dnr.mo.gov
Missouri Geological Survey	www.dnr.mo.gov/geology
Geological Survey Program	
800-361-4827	
573-368-2100	
EPA in Missouri – U.S. Environmental Protection Agency	www.epa.gov/mo
Region 7 913-551-7003	

MONTANA

Montana Department of Natural Resources and Conservation	http://dnrc.mt.gov
406-444-2074	
Montana Board of Oil and Gas Conservation	http://bogc.dnrc.mt.gov
Phone: (406) 656-0040	
Fax: (406) 655-6015	
Montana Department of Environmental Quality	http://deq.mt.gov
406-444-2544	
EPA in Montana – U.S. Environmental Protection Agency	www.epa.gov/mt
Region 8 303-312-6312 or in the Region 8 states 800-227-891	

NEBRASKA

Nebraska Oil and Gas Conservation Commission	www.nogcc.ne.gov
308-254-6919	
Nebraska Department of Environmental Quality	www.deq.state.ne.us
(402) 471-2186	
Toll-Free: (877) 253-2603	
Fax: (402) 471-2909	
EPA in Nebraska – U.S. Environmental Protection Agency	www.epa.gov/ne
Region 7 913-551-7003	

NORTH DAKOTA

North Dakota Industrial Commission 701-328-3722 Fax: 701-328-2820	www.nd.gov/ndic
NDIC Department of Mineral Resources Oil and Gas Division Phone: (701) 328-8020 Fax: (701) 328-8022	www.dmr.nd.gov/oilgas
North Dakota Department of Health Environmental Health Section Phone: 701-328-5150 Fax: 701-328-5200	www.ndhealth.gov www.ndhealth.gov/ehs
EPA in North Dakota – U.S. Environmental Protection Agency Region 8 303-312-6312 or in the Region 8 states 800-227-8917	www.epa.gov/nd

SASKATCHEWAN, CANADA

Government of Saskatchewan Ministry of Economy Minister's Office 306-787-8687 Energy Resources 306-787-2528 Minerals, Lands and Resource Policy Division 306-787-8178 Petroleum and Natural Gas Division 306-787-2592	www.economy.gov.sk.ca
Oil and Gas Resources Licensing, Field Office Operations and Minister's Orders Issued by Petroleum Development	www.economy.gov.sk.ca/oilgas
Government of Saskatchewan Ministry of Environment 1-800-567-4224	www.gtds.gov.sk.ca

SOUTH DAKOTA

South Dakota Geological Survey 605-677-5227	www.sdgs.usd.edu
South Dakota Department of Natural Resources (605) 773-3351 or 1-800-GET-DENR (1-800-438-3367)	www.denr.sd.gov
EPA in South Dakota – U.S. Environmental Protection Agency Region 8 303-312-6312 or in the Region 8 states 800-227-8917	www.epa.gov/sd

WISCONSIN

Wisconsin Department of Natural Resources — www.dnr.wi.gov
Call toll-free 1-888-WDNRINFo (1-888-936-7463)

EPA in Wisconsin – U.S. Environmental Protection Agency — www.epa.gov/wi
Region 5 321-353-6288

WYOMING

Wyoming Oil and Gas Conservation Commission — www.wogcc.state.wy.us
307-234-7147

Wyoming Department of Environmental Quality — http://deq.wyoming.gov
307-777-5985

EPA in Wyoming – U.S. Environmental Protection Agency — www.epa.gov/wy
Region 8 303-312-6312 or in the Region 8 states 800-227-8917

APPENDIX C

IOGCC MODEL STATUTE

IOGCC MODEL STATUTE[1]

GEOLOGIC STORAGE OF CARBON DIOXIDE

Section 1. Legislative Declaration; Jurisdiction[2]

(a) The Legislature of the State of _________ declares that (1) the geologic storage of carbon dioxide will benefit the citizens of the state and the state's environment by reducing greenhouse gas emissions; (2) carbon dioxide is a valuable commodity to the citizens of the state; and (3) geologic storage of carbon dioxide gas may allow for the orderly withdrawal as appropriate or necessary, thereby allowing carbon dioxide to be available for commercial, industrial, or other uses, including the use of carbon dioxide for enhanced recovery of oil and gas (EOR).

(b) The State Regulatory Agency shall have the jurisdiction and authority over all persons and property necessary to administer and enforce effectively the provisions of this article concerning the geologic storage of carbon dioxide. In exercising such jurisdiction and authority granted to it, the State Regulatory Agency may conduct hearings and promulgate and enforce rules, regulations, and orders concerning geologic storage of carbon dioxide.

(c) Nothing in this article shall apply to the use of carbon dioxide as a part of or in conjunction with any enhanced recovery methods where the sole purpose of the project is enhanced oil or gas recovery. The State Regulatory Agency is expressly authorized to develop rules to allow conversion of an existing enhanced recovery operation into a Carbon Dioxide Storage Project.

Section 2. Definitions

Carbon dioxide. For purposes of this statute, carbon dioxide is defined as an emissions stream containing carbon dioxide of sufficient purity and quality as to not compromise the safely and efficiency of the reservoir to effectively contain the carbon dioxide.

Oil or gas. Oil, natural gas, or gas condensate.

Reservoir. Any subsurface sedimentary stratum, formation, aquifer, or cavity or void (whether natural or artificially created) including oil and gas reservoirs, saline formations and coal seams, suitable for or capable of being made suitable for the injection and storage of carbon dioxide therein.

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[1] Canadian provinces should replace "state" with "province" as appropriate.
[2] The purpose of this section is to make clear that the primary goal is to permanently store carbon dioxide to mitigate its impact on global climate change; however, given the commodity status of carbon dioxide, under certain circumstances states need statutory authority to regulate withdrawal of previously stored carbon dioxide for EOR and other uses that do not involve release to the atmosphere.

Carbon Dioxide Storage Project. The underground reservoir, underground equipment, and surface buildings and equipment utilized in the storage operation, excluding pipelines used to transport the carbon dioxide from one or more capture facilities to the storage and injection site. The underground reservoir component of the Carbon Dioxide Storage Project includes any necessary and reasonable areal buffer and subsurface monitoring zones designated by the State Regulatory Agency for the purpose of ensuring the safe and efficient operation of the Carbon Dioxide Storage Project for the storage of carbon dioxide and shall be chosen to protect against pollution, invasion, and escape or migration of carbon dioxide.

Storage operator. Any person, corporation, partnership, limited liability company, or other entity authorized by the State Regulatory Agency to operate a Carbon Dioxide Storage Project.

Geologic storage. Permanent or short-term underground storage of carbon dioxide in a reservoir.

Section 3. State Regulatory Agency Approval; Recordation or Order, Certificate of Operation of Carbon Dioxide Storage Project

The use of a reservoir for storage of carbon dioxide is hereby authorized, provided that the State Regulatory Agency shall first enter an order, after public notice and hearing, approving such proposed geologic storage of carbon dioxide and designating the horizontal and vertical boundaries of the geologic storage. In order to establish a Carbon Dioxide Storage Project for carbon dioxide, the State Regulatory Agency shall find as follows:

That the Carbon Dioxide Storage Project is suitable and feasible for the injection and storage of carbon dioxide.

That a good faith effort has been made to obtain the consent of a majority of the owners having property interests affected by the Carbon Dioxide Storage Project and that the operator intends to acquire any remaining interest by eminent domain or otherwise allowed by statute.

That the use of the Carbon Dioxide Storage Project for the geologic storage of carbon dioxide will not contaminate other formations containing fresh water or oil, gas, coal, or other mineral deposits.

That the proposed storage will not unduly endanger human health and the environment and is in the public interest.

Upon the State Regulatory Agency's issuance of an order of approval as set forth above, said order, or a certified copy thereof, shall be filed for record in the probate court [or other appropriate entity of jurisdiction where land records are filed] of the county or counties in which the Carbon Dioxide Storage Project is to be located.

Prior to commencing injection of carbon dioxide, the storage operator shall record in the county or counties in which the Carbon Dioxide Storage Project is located, and with the State Regulatory Agency, a certificate, entitled "Certificate of Operation of Carbon Dioxide Storage

Project," which shall contain a statement that the storage operator has acquired by eminent domain or otherwise all necessary ownership rights with respect to the Carbon Dioxide Storage Project, and the date upon which the Carbon Dioxide Storage Project shall be effective.

If any depleted pool for any previously established field(s) or producing unit(s) for hydrocarbons is contained within the boundaries of the geologic storage, the State Regulatory Agency may, after public notice and hearing, in its order of approval for such Carbon Dioxide Storage Project order that such field(s) or unit(s) shall be dissolved as of the effective date of the Carbon Dioxide Storage Project as set forth in the Certificate of Operation of Carbon Dioxide Storage Project.

Section 4. Protection Against Pollution and Escape of Carbon Dioxide

The State Regulatory Agency shall issue such orders, permits, certificates, rules, and regulations, including establishment of appropriate and sufficient financial sureties as may be necessary, for the purpose of regulating the drilling, operation, and well plugging and abandonment and removal of surface buildings and equipment of the Carbon Dioxide Storage Project to protect the Carbon Dioxide Storage Project against pollution, invasion, and the escape or migration of carbon dioxide or other formation fluids so as not to endanger USDWs.

Section 5. Eminent Domain or Other Applicable Statutory Authority[3]

a) Any storage operator is hereby empowered, after obtaining approval of the State Regulatory Agency as herein required, to exercise the right of eminent domain provided by law, to acquire all surface and subsurface rights and interests necessary or useful for the purpose of operating the Carbon Dioxide Storage Project, including easements and rights-of-way across lands for transporting carbon dioxide among facilities constituting said Carbon Dioxide Storage Project. Such power shall be exercised under the procedure provided by other applicable laws relating to eminent domain.[4]

b) No rights or interests in storage facilities acquired for the injection, storage, and state authorized withdrawal of carbon dioxide by a party who has obtained an order from the State Regulatory Agency under the provisions of Section 2, shall be subject to the exercise of the right of eminent domain authorized by the article. The State Regulatory Agency, however, may reopen an earlier order for the purpose of balancing the interests

[3] Although the Task Force determined that the most likely mechanism for amalgamating the property rights (surface or subsurface) necessary for the permitting and operation of a Carbon Dioxide Storage Project is eminent domain, the Task Force also recognizes that particular states might have other mechanisms more appropriate for this purpose, e.g., unitization. It is important to note, however, that the Task Force has concluded that the amalgamation of property rights is absolutely necessary to properly permit, construct, and operate a carbon dioxide storage project. Further, the eminent domain power outlined in this model statute is an eminent domain authority solely authorized within the carbon dioxide storage statute and is in addition to any eminent domain authority that may already be possessed by a non-government entity such as a public utility.

[4] In the exercise of the power of eminent domain, a state might consider allowing a storage operator the right of early entry if such right is not otherwise specifically authorized in those circumstances where the eminent domain process may be lengthy.

of both projects. Nothing in this article shall alter or revise any power of eminent domain that may exist under any other authority.

c) The right of eminent domain granted in this section shall not prevent the right of the owner of said land or of other rights therein to drill through the geologic storage so appropriated in such manner as shall comply with the rules and regulations of the State Regulatory Agency issued for the purpose of protecting the Carbon Dioxide Storage Project against pollution or invasion and against the escape or migration of carbon dioxide. Furthermore, the right of eminent domain granted in this section shall not prejudice the rights of the owners of said lands or other rights or interests therein as to all other uses not acquired for the Carbon Dioxide Storage Project.

Section 6. Establishment of Carbon Dioxide Storage Project Trust Fund[5]

There is hereby established the Carbon Dioxide Storage Project Trust Fund to be administered by the State Regulatory Agency. There is hereby levied on the storage operator[6] a tax or fee equal to $------- on each ton of carbon dioxide injected for storage for the purpose of funding the Carbon Dioxide Storage Project Trust Fund. The trust fund shall be utilized solely for long-term monitoring of the site, including remaining surface facilities and wells, remediation of mechanical problems associated with remaining wells and surface infrastructure, repairing mechanical leaks at the site, and plugging and abandoning remaining wells under the jurisdiction of the State Regulatory Agency for use as observation wells. The trust fund shall be administered by the State Regulatory Agency.

Section 7. Administration Expenses for this Article Relating to Geologic Storage of Carbon Dioxide

For the purpose of funding the administration and enforcement of these laws relating to geologic storage of carbon dioxide by the State Regulatory Agency during the operational phase of the Carbon Dioxide Storage Project, and for the purpose of compliance inspections including the expense of inspecting, testing, and monitoring the geologic Carbon Dioxide Storage Project, there is hereby levied on the storage operator a per ton tax or fee collected as a percentage of the fee or tax levied in Section 6. The State Regulatory Agency may utilize these monies as it deems appropriate solely for administering and enforcing this article.

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[5] The purpose of the Trust Fund will be to provide the State Regulatory Agency with sufficient funds to provide long-term "caretaking" of the facility and to allow the operator and the producer of carbon dioxide the necessary regulatory certainty that ultimately includes release from liability. Based on a particular state's requirements, each state will have to determine the methodology used to provide adequate funding, which would need to include a detailed analysis of the costs anticipated over the lengthy project "caretaking" time frames contemplated.

[6] It is contemplated that the tax or fee will be assessed to and paid by the state-permitted entity. However, in all likelihood the facility operator would recover the tax or fee from the generator of the carbon dioxide.

Section 8. Liability Release[7]

Ten years[8] or other time frame established by rule) after cessation of storage operations, the State Regulatory Agency shall issue a Certificate of Completion of Injection Operations, upon a showing by the storage operator that the reservoir is reasonably expected to retain mechanical integrity and remain emplaced, at which time ownership to the remaining project, including the stored carbon dioxide, transfers to the state. Upon issuance of the Certificate of Completion of Injection Operations, the operator and all generators of any injected carbon dioxide shall be released from all further State Regulatory Agency liability associated with the project. In addition, upon the issuance of the Certificate of Completion of Injection Operations, any performance bonds posted by the operator shall be released and continued monitoring of the site, including remediation of any well leakage, shall become the responsibility of the Carbon Dioxide Carbon Dioxide Storage Project Trust Fund.

Section 9. Cooperative Agreements

The State Regulatory Agency is authorized to enter into cooperative agreements with other governments or government entities for the purpose of regulating carbon dioxide storage projects that extend beyond state regulatory authority under this article.[9]

Section 10. Certifying Storage Amounts.

a) The State Regulatory Agency may also make such certification for carbon dioxide stored under this chapter. The State Regulatory Agency, under procedures and criteria it may adopt, may certify the amount of injected carbon dioxide stored in a Carbon Dioxide Storage Project or during or in connection with enhanced recovery of oil or natural gas.

b) The purpose for certifying storage amounts is to facilitate using the stored carbon dioxide for such matters as reporting, carbon credits, allowances, trading, emissions allocations and offsets, and for other similar purposes.

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[7] The intent of this section is to provide a methodology whereby the operator and the generator of the carbon dioxide can be released from future liability. This aspect of the statute will allow for regulatory certainty by the industry and help to promote the development of carbon dioxide storage.

[8] While the task force decided that a 10-year time frame prior to release of the operator and carbon dioxide generator from liability might allow adequate time to determine that there are no known issues as to the integrity of the Carbon Dioxide Storage Project, the amount of time prior to release of the operator and generator from liability is ultimately a state decision. Time periods ranging from 3 to 10 years were discussed, as well as times longer than 10 years. The task force, however, believed that a transfer of caretaking responsibility of a stabilized project would be necessary to encourage timely development.

[9] Such an agreement might allow the state that hosts the injection well to take the lead in permitting and might allow other affected states the right to “certify” a project in much the same way as is done under the current program under Section 404 of the Clean Water Act in the United States.

APPENDIX D

IOGCC MODEL GENERAL RULES AND REGULATIONS

IOGCC MODEL GENERAL RULES AND REGULATIONS

GEOLOGIC STORAGE OF CARBON DIOXIDE

Section 1.0. Applicability

The following rules and regulations shall govern the geologic storage of CO_2 in geologic reservoirs. These rules apply to all CO_2 storage operations occurring within the territorial jurisdiction of the state.[28]

Section 2.0. Definitions

The following terms, as used in these regulations for geologic CO_2 storage facilities, shall have the following meanings:

CO_2 means an emissions stream containing carbon dioxide of sufficient purity and quality as to not compromise the safety and efficiency of the reservoir to effectively contain the CO_2.

CO_2 Facility (CF) means all surface and subsurface infrastructure including wellhead equipment, down hole well equipment, compression facilities and CO_2 flow lines from injection facilities to wells within the Geological Storage Unit (GSU), monitoring instrumentation, injection equipment, and offices. CF does not include the main transportation pipeline to the GSU and pump stations along that pipeline.

CO_2 Flow Lines means the pipeline transporting the CO_2 from the CF injection facilities to the wellhead.

CO_2 Injection Well means a well-used to inject CO_2 into and/or withdraw CO_2 from a reservoir.

CO_2 Storage Project (CSP) means the project in its entirety, including CF and GSU.

CSP Closure Period means that period of time (10 years unless otherwise designated by the State Regulatory Agency [SRA]) from the permanent cessation of active CSP injection operations until the expiration of the CSP performance bond, unless monitoring efforts following the operational period demonstrate to SRA that a different time frame is appropriate.

CSP Operational Period means the period of time in which injection occurs.

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[28] This document is drafted using the word "state." Canadian provinces should substitute either the word "province" or "provincial" as required. Similarly, Canadian provinces should substitute as appropriate the definitions of Underground Sources of Drinking Water (USDW) and Safe Drinking Water Act (SDWA) here and in the following text.

CSP Operator means that entity required by SRA to hold the permit.

CSP Permit means the permit issued by the state or province to operate a CSP.

CSP Post Closure Period means that period of time after the release of the CSP performance bond.

Formation Fracture Pressure means the pressure, measured in pounds per square inch, which, if applied to a subsurface formation, will cause that formation to physically fracture.

Fresh Water means USDW unless otherwise defined by SRA.

Geological Storage Unit (GSU) means the reservoir used by an entity that holds the SRA permit authorizing CO_2 injection activities.

Geologist or Engineer means a person qualified by education and experience to be recognized as an expert by SRA.

Reservoir means for the purposes of these rules any subsurface sand, stratum, formation, or cavity or void (whether natural or artificially created), including oil and natural gas reservoirs, saline formations, and coal seams, suitable for or capable of being made suitable for the injection and safe and efficient storage of CO_2 therein.

SRA means the State Regulatory Agency designated by the state as responsible for administering these regulations.

Subsurface Observation Well means a well either completed or re-completed for the purpose of observing subsurface phenomena, including the presence of CO_2, pressure fluctuations, fluid levels and flow, temperature, and in situ water chemistry.

Underground Sources of Drinking Water (USDW) means:

(1) An aquifer or its portion:

  (A) Which supplies any public water system.
  (B) Which contains a sufficient quantity of ground water to supply a public water system.
    (i) Currently supplies drinking water for human consumption.
    (ii) Contains fewer than 10,000 mg/L total dissolved solids.

(2) An aquifer or its portion which is not an exempted aquifer as defined in the U.S. Safe Drinking Water Act[29] (SDWA).

[29] 42 U.S.C. § 300(h) (1) (1976).

Section 3.0. General Requirements

Section 3.1. Site Access

SRA shall, at all times, have access to and may inspect all CO_2 storage operations and records for the purpose of determining that performance is being conducted in accordance with the CSP permit, or the requirements pursuant to Sections 3.0–9.0, or in accordance with the orders of SRA approving CO_2 storage operations.

Section 3.2. CSP Permit Transfer

Transfer Notification by Transferor: The CSP operator shall notify SRA, in writing, in such form as SRA may direct, of the sale, assignment, transfer, conveyance, exchange, or other disposition of the CSP by the operator of the CSP as soon as is reasonably possible, but in no event later than the date that the sale, assignment, transfer, conveyance, exchange, or other disposition becomes final. The operator shall not be relieved of responsibility for the CSP until SRA acknowledges the sale, assignment, transfer, conveyance, exchange, or other disposition, in writing, and the person or entity acquiring the CSP is in compliance with all appropriate requirements. The operator's notice shall contain all of the following:

(1) The name and address of the person or entity to which the CSP was or will be sold, assigned, transferred, conveyed, exchanged, or otherwise disposed.

(2) The name and location of the CSP, and a description of the land upon which the CSP is situated.

(3) The date that the sale, assignment, transfer, conveyance, exchange, or other disposition becomes final.

(4) The date when possession was or will be relinquished by the operator as a result of that disposition.

Transfer Notification by Transferee: Every person or entity that acquires the right to operate a CSP, whether by purchase, transfer, assignment, conveyance, exchange, or other disposition, shall, as soon as it is reasonably possible, but not later than the date when the acquisition of the CSP becomes final, notify SRA in writing, of the person's or entity's operation. The acquisition of a CSP shall not be recognized as complete by SRA until the new operator provides all of the following material:

(1) The name and address of the person or entity from which the CSP was acquired.

(2) The name and location of the CSP, and a description of the land upon which the CSP is situated.

(3) The date when the acquisition becomes final.

(4) The date when possession was or will be acquired.

(5) Performance bonds required by Geologic CO_2 Storage regulations 4.0 (10) and (11).

Section 4.0. CO_2 Storage Project (CSP) Permit

Section 4.1. CSP Permit Requirements

No CSP shall be constructed or operated without:

(1) The CSP operator holding the necessary and sufficient property rights for construction and operation of the CSP. The CSP operator is deemed to be holding such rights for any individual property to the extent that the applicant has initiated unitization or eminent domain proceedings related to that property and thereby gained the right of access to the property. The intention of the CSP operator to employ unitization or eminent domain to acquire property rights shall be included in public notice as defined in Section 5.0; and

(2) Obtaining a license from SRA.

Application for a CSP permit shall be submitted to SRA as required and shall include the following:

(1) A current site map showing the boundaries of the GSU, the location and well number of all proposed CO_2 injection wells, including any subsurface observation wells and the location of all other wells, including cathodic protection boreholes, and the location of all pertinent surface facilities within the boundary of the CSP;

(2) A technical evaluation of the proposed CSP, including but not limited to, the following:

(A) The name of the GSU.

(B) The name, description, and average depth of the reservoir or reservoirs to be utilized for geologic CO_2 storage.

(C) A geologic and hydrogeologic evaluation of the GSU, including an evaluation of all existing information on all geologic strata overlying the GSU, including the immediate caprock containment characteristics and all designated subsurface monitoring zones. The evaluation shall include any available geophysical data and assessments of any regional tectonic activity, local seismicity, and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation shall focus on the proposed CO_2 storage reservoir or reservoirs and a description of mechanisms of geologic confinement, including but not limited to, rock properties, geochemical interactions, regional pressure gradients, structural features, and sorption characteristics with regard to the ability of that confinement to prevent migration of CO_2 beyond the proposed storage reservoir. The evaluation shall also identify any productive oil and natural gas zones occurring stratigraphically above, below, or within the GSU and any freshwater-bearing horizons known to be developed in the immediate vicinity of the GSU. The evaluation shall include exhibits and plan view maps showing the following:

(i) All wells, including but not limited to, water, oil, and natural gas exploration and development wells, and other man-made subsurface structures and activities, including coal mines, within one mile of the outside boundary of the GSU.

(ii) All manmade surface structures that are intended for temporary or permanent human occupancy within the GSU and within one mile of the outside boundary of the GSU.

(iii) Any regional or local faulting.

(iv) An isopach map of the proposed CO_2 storage reservoir or reservoirs.

(v) An isopach map of the primary and any secondary containment barrier.

(vi) A structure map of the top and base of the storage reservoir or reservoirs.

(vii) Identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored CO_2 or associated fluids.

(viii) An evaluation of the potential displacement of in situ water and the potential impact on groundwater resources, if any.

(ix) Structural and stratigraphic cross-sections that describe the geologic conditions at the reservoir.

A geologist or engineer shall conduct the geologic and hydrogeologic evaluation required under this paragraph. As appropriate, existing geologic, geophysical, or engineering data available on the proposed GSU may be incorporated into the evaluation;

(D) A review of the data of public record for all wells within the CSP Permit, which penetrate the reservoir or primary and/or secondary seals overlying the reservoir designated as the CO_2 storage reservoir, and those wells that penetrate the geologic CO_2 storage reservoir within one mile, or any other distance as deemed necessary by SRA, of the boundary of the GSU. This review shall determine if all abandoned wells have been plugged in a manner that prevents the movement of CO_2 or associated fluids from the geologic CO_2 storage reservoir. A geologist or engineer shall conduct the review required under this paragraph.

(E) The proposed calculated maximum volume and areal extent for the proposed GSU using a method acceptable to and filed with SRA.

(F) The proposed maximum bottom hole injection pressure to be utilized at the reservoir. The maximum allowed injection pressure, measured in psig, shall be approved by the SRA and specified in the permit. In approving a maximum injection pressure limit, the SRA shall consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The SRA shall approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults transecting the confining zone to become transmissive. In no case may injection pressure cause movement of injection or formation fluids in a manner that endangers a USDW.

(3) The extent of the CO_2, determined by utilizing, as appropriate, all available geologic and reservoir engineering information and reservoir analysis, and the projected response and storage capacity of the GSU.[30]

(4) A detailed description of the proposed CF public safety and emergency response plan. The plan shall detail the safety procedures concerning the facility and residential, commercial, and public land use within one mile, or any other distance as deemed necessary by SRA, of the outside boundary of the CSP Permit. The public safety and emergency response procedures shall include contingency plans for CO_2 leakage from any well, flow lines, or other permitted facility. The public safety and emergency response procedures also shall identify specific contractors and equipment vendors capable of providing necessary services and equipment to respond to such CO_2 injection well leaks or loss of containment from CO_2 injection wells or the CO_2 storage reservoir. These emergency response procedures should be updated as necessary throughout the operational life of the permitted storage facilities.

(5) A detailed worker safety plan that addresses CO_2 safety training and safe working procedures at the CF.

(6) A corrosion monitoring and prevention plan for all wells and surface facilities.

(7) A CF leak detection and monitoring plan for all wells and surface facilities. The approved leak detection and monitoring plan shall address:

(A) Identification of potential release to the atmosphere.

(B) Identification of potential degradation of groundwater resources with particular emphasis on USDWs.

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[30] Reservoir analysis may include but not be limited to the use of any of various computational type models, if appropriate for characterization.

(C) Identification of potential migration of CO_2 into any overlying oil and natural gas reservoirs.

(8) A GSU leak detection and monitoring plan utilizing subsurface observation wells to monitor any movement of the CO_2 volume outside of the permitted GSU. This may include the collection of baseline information of CO_2 background concentrations in groundwater, surface soils, and chemical composition of in situ waters within the GSU. The approved subsurface leak detection and monitoring plan shall be dictated by the site characteristics as documented by materials submitted in support of the application with regard to CO_2 containment and address:

(A) Identification of potential release to the atmosphere.

(B) Identification of potential degradation of groundwater resources with particular emphasis on USDWs.

(C) Identification of potential migration of CO_2 into any overlying oil and natural gas reservoirs.

(9) The proposed well casing and cementing program detailing compliance with Section 6.0.

(10) A CSP performance bond shall be sufficient to provide financial assurance to SRA to cover the abandonment or remediation of the CSP should the CSP operator not perform as required or cease to exist. The CSP bond shall be maintained after closure of the facility in accordance with Section 9.0 below.

(11) A well performance bond for each CO_2 injection and subsurface observation well to SRA in an amount established by SRA. The amount of the bond shall be sufficient to provide financial assurance to SRA to cover the plugging and abandonment or the remediation of a CO_2 injection and/or subsurface observation well should the CSP operator not perform as required in accordance with the permit or cease to exist.

(12) The payment of the application fee.

(13) Any other information that SRA requires.

(14) A closure plan.

Section 4.2. Amendment to CSP Permit

The following changes to the original CSP permit conditions will require compliance with all the provisions of Section 4.1 above:

(1) Any change in the original areal extent of the CSP permit.

(2) Utilization of other reservoirs not specified in the original CSP permit.

(3) Any proposed increase in the permitted CO_2 storage volume.

(4) Any change in the chemical composition of the injected CO_2 from the CO_2 composition at the time of permitting.

Other significant changes to approved operational parameters contained in the original CSP permit will require compliance with Section 4.1(b).

Section 5.0. Amalgamation of Subsurface Rights to Operate GSU

Each application required under Section 4 shall include a public hearing before SRA for the purposes of joining the necessary property ownership rights, as defined by the state or before the state regulatory agency responsible for amalgamating these rights. These hearings at the discretion of the state regulatory agencies may be combined and heard simultaneously.

Each applicant for a CSP shall give notice of the filing of an application on or before the date the application is filed with SRA by mailing notice via first class mail to the following:

(1) Each operator of hydrocarbon or other mineral extraction activities, or mineral lessee of record within one-half mile external to the boundary of the proposed CSP Permit.

(2) Each owner of record of the surface property and minerals within the boundaries of the proposed CSP Permit.

(3) Each owner of record of the surface property and minerals within one-half mile external to the boundary of the proposed CSP Permit.

(4) Any other parties as required by SRA.

The above notice shall contain a legal description of the proposed CSP Permit along with the date, time, and place of the hearing before SRA and include notice of the right to file comments.

In addition to mail notice to the above parties, public notice via publication shall be required. The public notice shall indicate that an application has been filed with SRA for a CSP and indicate the location of the proposed project and the date, time, and place of the hearing before SRA to determine issuance of the application. Publication shall be in a newspaper of statewide circulation and in a local newspaper in a county or parish newspaper of each county/parish in which the CSP is located. The notice shall indicate that objections may be filed within 15 days of the date of publication.

Objections received by SRA shall be in writing and specify the nature of the objection.

Upon review of the application submitted in accordance with Section 4 and following the Rights Amalgamation Hearing specified in this section, authorization to commence construction of the CSP shall be issued following approval by SRA.

Section 6.0. CSP Wells

Section 6.1. CSP Well Permit Application Requirements

Following receipt of authorization to commence the CSP issued by SRA in accordance with Section 4, the applicant shall submit applications to drill, convert, or, upon demonstration of mechanical integrity, re-enter a previously plugged and abandoned well for CO_2 storage purposes. Application for permits to drill, deepen, convert, re-enter (drill out a previously plugged well) or operate a well shall be submitted on a form prescribed by SRA and shall include at a minimum:

(1) A plat prepared by a licensed land surveyor showing the location of the proposed CO_2 injection or subsurface observation well. The plat shall be drawn to the scale of one (1) inch equals one thousand (1,000) feet, unless otherwise stipulated by SRA and shall show distances from the proposed well to the nearest GSU boundary. The plat shall show the latitude and longitude of the well in decimal degrees to five (5) significant digits. The plat shall also show the location and status of all other wells that have been drilled within one-fourth (1/4) mile, or any other distance deemed necessary by SRA, of the proposed CO_2 injection or subsurface observation well.

(2) A prognosis specifying the drilling, completion, or conversion procedures for the proposed CO_2 injection or subsurface observation well.

(3) A well bore schematic showing the name, description, and depth of the proposed reservoir and the depth of the deepest USDW; a description of the casing in the CO_2 injection or subsurface observation well, or the proposed casing program, including a full description of cement already in place or as proposed; and the proposed method of testing casing before use of the CO_2 injection well.

(4) A geophysical log, if available, through the reservoir to be penetrated by the proposed CO_2 injection well or if a CO_2 injection or subsurface observation well is to be drilled, a complete log through the reservoir from a nearby well is permissible. Such log shall be annotated to identify the estimated location of the base of the deepest USDW, showing the stratigraphic position and thickness of all confining strata above the reservoir and the stratigraphic position and thickness of the reservoir.

No later than the conclusion of well drilling and completion activities, a permit application shall be submitted to operate a CO_2 injection well and shall include at a minimum:

(1) A schematic diagram of the surface injection system and its appurtenances.

(2) A final well bore diagram showing the name, description, and depths of the reservoir and the base of the deepest USDW; a diagram of the CO_2 injection well depicting the

casing, cementing, perforation, tubing, and plug and packer records associated with the construction of the CO_2 injection well.

(3) A complete dual induction or equivalent log through the reservoir of the CO_2 injection well. Such log for wells drilled for CO_2 injection operations shall be run prior to the setting of casing through the CO_2 storage reservoir. Logs shall be annotated to identify the estimated location of the base of the deepest USDW, showing the stratigraphic position and thickness of all confining strata above the reservoir and the stratigraphic position and thickness of the reservoir unless previously submitted. When approved in advance by SRA, this information can be demonstrated with a dual induction or equivalent log run in a nearby well or by such other method acceptable to SRA.

(4) An affidavit specifying the chemical constituents of the injection stream other than CO_2 and their relative proportions.

(5) Proof that the long string of casing of the CO_2 injection well is cemented adequately so that the CO_2 is confined to the GSU. Such proof shall be provided in the form of a cement bond log or the results of a fluid movement study or such other method specified by SRA.

(6) The results of a mechanical-integrity test, if applicable to well type, of the casing in accordance with the pressure test requirements, of this section, if a test was run within one calendar year preceding the request for issuance of a conversion permit for a previously drilled well.

Section 6.2. Permit Issuance

Upon review and approval of the application to drill, deepen, convert, re-enter, (drill out a previously plugged well) or operate a CO_2 injection well, submitted in accordance with Section 6.1, SRA shall issue permits to drill and operate.

A permit shall expire twelve (12) months from the date of issuance if the permitted well has not been drilled or converted.

Section 6.3. CSP Well Operational Standards

Surface casing in all newly drilled CO_2 injection and subsurface observation wells drilled below the USDW shall be set 100 feet below the lowest USDW and cemented to the surface or other protective measures as deemed appropriate by SRA.

The long-string casing in all CO_2 injection and subsurface observation wells shall be cemented with a sufficient volume of cement to fill the annular space to a point 500 feet above the top of the storage reservoir.

Any liner set in the well bore shall be cemented with a sufficient volume of cement to fill all of the annular space between the liner and the adjacent casing.

All cements used in the cementing of casings in CO_2 injection and subsurface observation wells shall be of sufficient quality to maintain well integrity in the CO_2 injection environment.

All casings shall meet the standards specified in either of the following documents, which are hereby adopted by reference:

(1) The most recent American Petroleum Institute (API) Bulletin on performance properties of casing, tubing, and drill pipe.

(2) "Specification for casing and tubing (U.S. customary units)," API specification 5CT, as published by the API in October 1998.

(3) Other casing as approved by SRA.

All casings used in new wells shall be new casing or reconditioned casing of equivalent quality that has been pressure-tested in accordance with the requirements of paragraph (e). For new casings, the pressure test conducted at the manufacturing mill or fabrication plant may be used to fulfill the requirements of paragraph (e).

The location and amount of cement behind casings shall be verified by a cement evaluation log, or any other evaluation method approved by SRA, that is capable of evaluating radial cement quality and identifying the location of any channels.

All CO_2 injection wells shall be completed with and injection shall be through tubing and packer.

All tubing strings shall meet the standards contained in paragraph (e) of this regulation. All tubing shall be new tubing or reconditioned tubing of equivalent quality that has been pressure-tested. For new tubing, the pressure test conducted at the manufacturing mill or fabrication plant may be used to fulfill this requirement.

All wellhead components, including the casing head and tubing head, valves, and fittings, shall be made of steel having operating pressure ratings sufficient to exceed the maximum injection pressures computed at the wellhead and to withstand the corrosive nature of CO_2. Each flow line connected to the wellhead shall be equipped with a manually operated positive shutoff valve located on or near the wellhead.

All packers, packer elements, or similar equipment critical to the containment of CO_2 shall be of a quality to withstand exposure to CO_2.

An accurate, operating pressure gauge or pressure recording device shall be available at all times, and all injection wells shall be equipped for installation and operation of such gauge or device. Gauges shall be calibrated as required by SRA and evidence of such calibration shall be available to SRA upon request.

All newly drilled wells shall establish internal and external mechanical integrity as specified by SRA and demonstrate continued mechanical integrity through periodic testing as determined by SRA. All other existing wells to be used as CO_2 injection wells will demonstrate mechanical integrity as specified by SRA prior to use for CO_2 injection and be tested on an ongoing basis as determined by SRA using these methods:

(1) Pressure tests. CO_2 injection wells, equipped with tubing and packer as required, shall be pressure-tested as required by SRA. A testing plan shall be submitted to SRA for prior approval. At a minimum, the pressure shall be applied to the tubing casing annulus at the surface for a period of 30 minutes and shall have no decrease in pressure greater than 10% of the required minimum test pressure. The packer shall be set at a depth at which the packer will be opposite a cemented interval of the long string casing and shall be set no more than 50 feet above the uppermost perforation or open hole for the CO_2 storage reservoir.

(2) SRA may require additional testing such as bottom hole temperature and pressure measurements, tracer survey, temperature survey, gamma ray log, neutron log, noise log, casing inspection log, or a combination of two or more of these surveys and logs, to demonstrate mechanical integrity.

Supervision of mechanical integrity testing. SRA may witness all mechanical integrity tests conducted by each CSP operator for regulatory purposes.

If a CO_2 injection well fails to demonstrate mechanical integrity by an approved method, the operator of the well shall immediately shut in the well, report the failure to SRA, and commence isolation and repair of the leak. The operator shall, within 90 days or as otherwise directed by SRA, perform one of the following:

(1) Repair and re-test the well to demonstrate mechanical integrity.
(2) Plug the well in accordance with state requirements.
(3) Comply with alternative plan as approved by SRA.

All CO_2 injection wells shall be equipped with shutoff systems designed to alert the operator and shut in wells when necessary.

Additional requirements may be required by SRA to address specific circumstances and types of projects not specified in these rules.

Section 6.4. Amendment to CSP Well Permits

An amendment to the CSP Well Permit for (1) a change in injection formation, and/or (2) a modification of maximum allowable injection rate and pressure, shall comply with the provisions of Section 6.1 (c)(5) and (6), 6.3 (b), (g), (h), (i), (l) and (m) above.

Modification of well construction shall comply with the provisions of Section 6.1 (b) (3) and 6.3 (m).

Section 7.0. CSP Operational Standards

Section 7.1. Safety Plans

Each operator of a CSP shall implement a SRA-approved CF public safety and emergency response plan and the worker safety plan proposed in Section 4. This plan shall include emergency response and security procedures. The plans, including revision of the list of contractors and equipment vendors, shall be updated as necessary or as SRA requires. Copies of the plans shall be available at the CF and at the nearest operational office of the holder of the CSP Permit.

Section 7.2. Leak Detection and Reporting

Leak detectors or other approved leak detection methodologies shall be placed at the wellhead of all CO_2 injection and subsurface observation wells. Leak detectors shall be integrated, where applicable, with automated warning systems and shall be inspected and tested on a semi-annual basis and if defective, shall be repaired or replaced within 10 days. Each repaired or replaced detector shall be re-tested if required by SRA. An extension of time for repair or replacement of a leak detector may be granted upon a showing of good cause by the operator of the CSP. A record of each inspection, which shall include the inspection results, shall be maintained by the operator for at least five years and shall be made available to the state oil and natural gas regulatory agency upon request.

The operator of a CSP shall immediately report to SRA any leaks detected at the surface facility and associated well equipment specified in (a) above.

The operator of a CSP shall immediately or, as soon as practicable, report to SRA any pressure changes or other monitoring data from subsurface observation wells that indicate the presence of leaks in the GSU indicating the lack of confinement within the reservoir of the CO_2.

The operator of a CSP shall immediately report to SRA any other indication of lack of containment of CO_2 to the reservoir not associated with wells and surface equipment.

Section 7.3. Other General Requirements

Each operator shall be required to conduct a corrosion monitoring and prevention program approved by SRA.

Identification signs shall be placed at each facility in a centralized location and at each well site and show the name of the operator, the facility name, and the emergency response number to contact the operator.

Section 8.0. Operational Review and Reporting Requirements

Section 8.1. Operational Injection Reports

The volume of CO_2 injected since the last reporting, the average injection rate, average composition of the CO_2 stream, wellhead and down hole temperature and pressure data and/or other data pertinent to or storage certification as required by SRA shall be reported quarterly or as required by SRA.

These quarterly reports shall be compiled and summarized annually to provide updated projections of the response and storage capacity of the GSU. The projections shall be based on actual GSU operational experience, including all new geologic data and information. All anomalies in predicted behavior as indicated in the most current permit conditions shall be explained and, if necessary, the permit conditions amended in accordance with Section 4.1.

Section 8.2. Annual Operational Report and Review

An annual operational report shall be required by the SRA and include:

(1) A comprehensive review of all monitoring and operational data to determine whether a re-evaluation of the area of review is required.

(2) Whether an update of any required monitoring, safety, corrosion, or other required operational plans are necessary or warranted.

An annual operational report and its findings may be submitted to the SRA as an affidavit signed by an appropriate company official confirming that the company has conducted the required annual review, which will include the submission of any updated or modified plan for the review and approval of the SRA.

Following the annual review, the SRA may require additional information, modification, or revision of the submitted plans before approval.

Section 9.0. CSP Closure

Prior to the conclusion of the operational period the CSP permit holder shall provide an assessment of the operations conducted during the operational period, including but not limited to, the volumes injected, extracted, any and all chemical analyses conducted, summary of all monitoring efforts, etc. The report shall also document the position and characteristics of the areal extent of the CO_2 and a prediction of the extent and movement of the CO_2 volume anticipated during the CSP closure period.

The permittee shall submit a monitoring plan for the CSP closure period for approval by SRA, including but not limited to a review and final approval of which wells will be plugged and which wells will remain unplugged to be used as CSP closure and post-closure period subsurface observation wells.

Following well plugging, all associated surface equipment shall be removed and the well site returned to its original land use to the extent possible.

The well casing shall be cut off at a depth of 5 feet below the surface and a steel plate shall be welded on top identifying the well name and that it was used for CO_2 injection.

In conjunction with the permittee, SRA shall develop a continuing monitoring plan for the CSP Closure Period, including but not limited to, a review and final approval of which wells shall remain unplugged for use as monitoring wells.

All remaining wells not used for monitoring purposes shall be properly plugged and abandoned, all CF equipment and facilities shall be removed, and the CSP site reclaimed in accordance with SRA requirements.

Section 10.0. Post Closure Period

Prior to authorization to begin the Post-Closure Period, the owner or operator must demonstrate to the SRA, based on monitoring, other site-specific data, and appropriate modeling, that no additional monitoring is needed to assure that the CSP does not pose an endangerment to USDWs.

The SRA shall approve the transition to the Post-Closure Period if the owner or operator demonstrates the following:

(1) The estimated extent of the CO_2 plume and the area of elevated pressure.

(2) That there is no significant leakage of either CO_2 or displaced formation fluids endangering USDWs.

(3) That the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway into a USDW.

(4) That the injection wells at the site completed into or through the injection zone or confining zone are plugged and abandoned in accordance with these requirements.

SRA shall have full control of and responsibility for the remaining unplugged wells to be used by SRA as CSP post-closure period subsurface observation wells or for other purposes as deemed necessary by SRA.

At the conclusion of the CSP closure period, the CSP performance bond maintained by the CSP operator may be released, and continued monitoring of the site, remediation of any well leakage, including wells previously plugged and abandoned by the CSP operator, shall become the responsibility of designated state or federal agency programs and the CSP operator and generator of the CO_2 shall be released from further SRA regulatory liability relating to the CF.