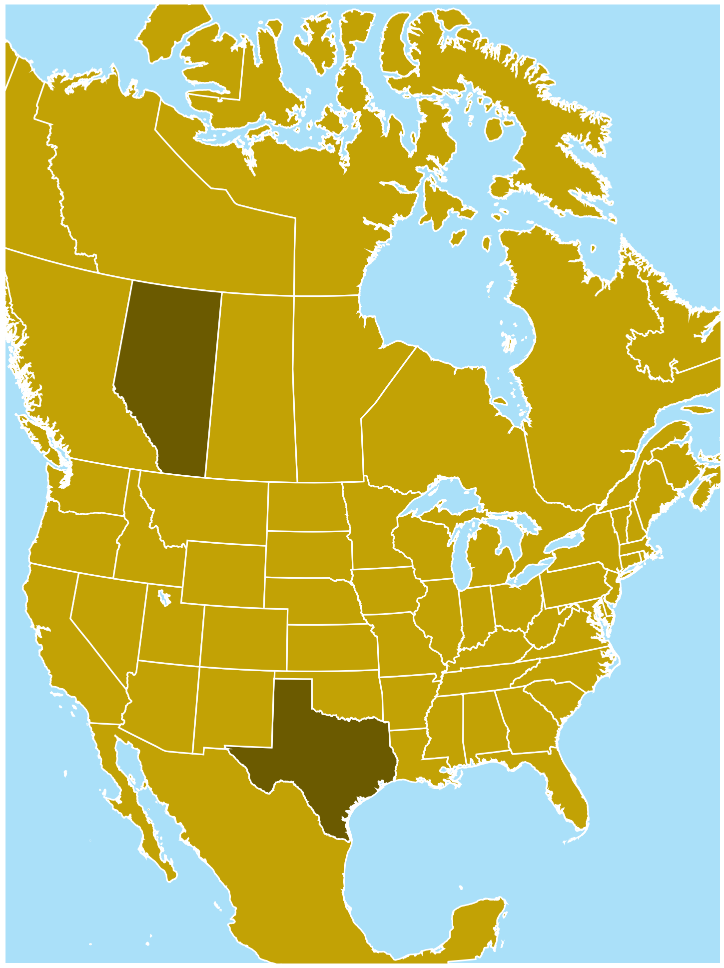

CCP4 - Review of CO_2 EOR

Transitioning to CCS in Texas and Alberta

April 2017

PARTICIPANT ORGANIZATIONS

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Prepared by: Lee Solsbery and Chris Hazell-Marshall
Reviewed by: Lisa Campbell

For and on behalf of
Environmental Resources Management Ltd

Approved by: Lisa Campbell

Signed:

Position: Partner

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CONTENTS

1 EXECUTIVE SUMMARY

The purpose of Carbon Capture and Storage (CCS) is to reduce emissions of greenhouse gases to the atmosphere as a climate change mitigation activity. However, given the relatively high costs currently associated with CCS, coupling CCS with Enhanced Oil Recovery (EOR) could provide a critical financial incentive to facilitate development of CCS projects in the near term. In the 2016 study of the CO_2 Capture Project "Best Practice in Transitioning from CO_2 EOR to CO_2 Storage," ERM found that there are no specific technological barriers or challenges in transitioning and converting a pure CO_2 EOR operation into a CO_2 storage operation. At the same time, there are a number of legal, regulatory and economic differences which must be addressed if an EOR project is to serve as a CCS project. The current study is a deeper analysis of these issues in two jurisdictions: Texas in the U.S.A. and Alberta in Canada.

<u>Texas</u>

The government of the state of Texas supports CCS to reduce greenhouse gas (GHG) emissions via financial incentives. These include incentives for advanced energy projects, which include CCS, and an authorization for CO_2 pipelines to become a common carrier. United States Internal Revenue Service also provides a tax credit under Section 45Q of its regulations for CCS projects, which may also apply.

The regulatory pathway for a CCS project is in place for Texas, though no projects have yet applied for or been permitted under the U.S. Environmental Protection Agency's Underground Injection Control Program's Class VI well requirements, which may be required for the protection of underground drinking water.

For GHG emissions reporting, the EPA recently approved the first Monitoring, Reporting, and Verification (MRV) plan under Subpart RR regulations for CO_2 storage for the Oxy Denver Unit. This unit is a CO_2 EOR project since 1983 but is now intending to be recognised as a CCS project, noting that the facility will still be producing oil. Subpart RR reporting is required for all CCS projects to report GHG emissions under EPA's GHG Reporting Program. In the post-closure period, responsibility for GHG reporting of any leaks of CO_2 to the atmosphere is not explicitly addressed. This ambiguity is a potential gap or uncertainty in the current regulatory pathway.

<u>Alberta</u>

The government of Alberta supports CCS with financial incentives. Financial disincentives are also set to encourage reduction of greenhouse gas emissions. Alberta introduced a carbon tax, starting at $20 per tonne in 2017 and increasing to $30 per tonne in 2018. Further, the federal government of Canada proposed a carbon tax of $50 per tonne by 2022.

The regulatory pathway for CCS in Alberta is established and in place. The Carbon Capture and Storage Statutes Amendment Act, 2010 has promoted and simplified the regulatory process for CCS. In addition, several legislative changes have been made recently, and more are expected. In particular, the CCS project closure process is new in Alberta and more development is needed. In summary, a measurement monitoring verification (MMV) plan must be approved and updated every three years. The project operator must demonstrate compliance according to the MMV plan in compliance with regulations. A closure plan is also required as part of the MMV plan. When the criteria for closure are met, the operator of the project can apply for a closure certificate.

A regulatory framework exists in Alberta for approving and operating EOR projects. The government of Alberta has further identified a need to supplement the EOR regulations with the expectation that EOR projects will mature into CCS. However, the applicable regulations have not yet been supplemented. Therefore, the framework to transition CO_2 EOR to CCS is not yet in place.

2 INTRODUCTION

Under the 2016 COP21 Paris Agreement which has now entered into force, a path forward to achieve an ambitious goal of stabilizing global temperatures to address climate change was forged. Experts agree that the role of Carbon Capture and Storage (CCS) – the long-term underground sequestration of Carbon Dioxide (CO_2) – is necessary to achieve the greenhouse gas (GHG) emission reduction goals set out under the Paris Agreement. The International Energy Agency (IEA) has estimated that CCS will need to contribute an estimated one-sixth of total CO_2 reductions by 2050 to limit global warming to 2°C [1]. CCS has been identified not only as the most effective technology to reduce CO_2 emissions from coal fired power generation, but also has the potential to achieve 'negative' GHG emissions from sequestering biogenic CO_2 emissions by biomass combustion or the production of biofuels [2]. Among the challenges to widespread adoption of CCS are the potential costs and uncertainties in the regulatory pathways for implementing the technology.

Enhanced Oil Recovery (EOR) - the injection of CO_2 into a reservoir to increase the production of oil – is a mature practice in the oil and gas industry. In many jurisdictions, the regulatory pathway to implement an EOR project is well established. The transition of an EOR project to CCS for long-term storage of CO_2 is of particular interest as some of the challenges faced by CCS alone are overcome, most notably in more favourable project economics.

The study documented in this report builds upon a series of previous studies investigating various aspects of CCS. The previous report completed in 2016 [3] focused on the use of CO_2 for EOR, an activity which has been undertaken extensively, particularly in Texas. The report sought to identify best practices and regulatory frameworks for transitioning projects from EOR to long-term storage CCS projects. The report identified a number of challenges or uncertainties in the regulatory frameworks in the transition from EOR to CCS.

The current study provides a more in-depth focus on the regulatory pathway to the successful implementation of a commercial scale carbon capture facility and sequestration of the captured CO_2 in EOR. This study specifically considers the regulatory frameworks in Texas, USA and Alberta, Canada. These locations have been identified as particularly favourable locations for potential CCS projects due to a history of CO_2 injection for EOR and/or existing CCS infrastructure.

This report is in two Stages:

[1] IEA website, http://www.iea.org/topics/ccs/

[2] Plants consume CO_2 for growth. Therefore when plant material is a source of sequestered CO_2, for example in a biomass power plant, or in some food and bio-oil manufacturing processes (see the ADM example later), net CO_2 in the atmosphere is negative.

[3] Carbon Capture Project, ***Best Practice in Transitioning from CO2 EOR to CO2 Storage**, 30 March 2016*

Stage 1 - This sets out the existing regulatory pathway for CCS, describing the regulatory pathway for CCS permitting without EOR. This is done to set the scene for what a CCS project requires before addressing what a new or existing EOR project is lacking to transition to CCS. The regulations have been reviewed to identify what is needed for a new CCS capture facility, new CO_2 pipeline, new injection infrastructure, new storage area and requirements for post-closure issues and long term monitoring.

Stage 2 - This investigates where regulation for CO_2-EOR and CCS differ. It focusses on identifying what a CO_2-EOR scheme needs to do to gain credit as CCS, and where regulation may be a barrier to transitioning from EOR to CCS.

3 STAGE 1: CCS REGULATORY FRAMEWORK

As discussed in the prior CCP4 report, there are regulatory pathways in place in Alberta and Texas for CO_2-EOR and to some extent for CCS. The regulatory pathway for CCS specifically is set out and reviewed in this section. In order to review the regulatory pathway for CCS in more depth, the study considers the entire lifecycle of a hypothetical CCS project, the key phases being:

- Planning, Permitting, and Construction;
- Operation; and
- Decommissioning and Post-Closure.

In the majority of cases, the regulatory pathway is clear as the regulations do not apply specifically to CCS, but to industrial projects in general. Where there are no special provisions for CCS-related projects, the report does not expand on those mature regulatory pathways.

For Texas and Alberta, respectively, a matrix has been prepared that summarizes the key regulations for each of the project phases (Planning, Permitting and Construction; Operation; Decommissioning and Post-Closure). A 'traffic light' system has been adopted to readily highlight those aspects of the project lifecycle where there are potential regulatory barriers, as follows:

- Green flag indicates that there is a clear pathway for a CCS facility through mature and tested regulations;
- Yellow flag indicates that there is regulation in place, but the pathway is unclear, the regulation is immature, and/or the regulation is untested for a CCS facility; and
- Red flag indicates that there is no regulation in place relating to CCS.

Where regulatory gaps are identified, possible pathways and any relevant examples from projects in other jurisdictions are discussed.

3.1 CCS REGULATORY PATHWAY IN TEXAS, USA

Key aspects to the development of a CCS project in Texas, USA are set out below for each phase of a hypothetical CCS project. The matrices are designed to allow rapid identification of points at which a CCS project could fail due to a regulatory gap, as opposed to the project design. Below each matrix a short description is provided of the key regulatory needs for that project lifecycle phase. In addition, any key variables have been identified to highlight where external factors will influence the regulatory needs and pathway.

3.1.1 *Planning, Permitting and Construction Stage Regulatory Pathway in Texas*

Project element	CCS Facility, pipeline, wells and subsurface		
Project stage	Planning, Permitting, and Construction		
Media	Regulation(s)	Key Considerations	Flag
Air	Permit-by-Rule (PBR)) Texas Administrative Code (TAC) Title 30, Part 1, Chapter 106 New Source Review Air Permitting Regulations (TAC Title 30, Part 1, Chapter 116) Mass Emissions Cap and Trade Program (30 TAC Chapter 101, Subchapter H, Division 3)	PBR – 108 categories for minor emission sources Major sources also require PSD permit and Nonattainment New Source Review (NNSR) if in Non-attainment area Mass Emissions Cap and Trade program applicable if facility is major source of NOx in the Houston-Galveston-Brazoria non-attainment area.	
Subsurface	TX CO_2 Code (TAC Title 16, Part 1, Chapter 5)	Railroad Commission of Texas (RRC) drilling permit required	
Water	TX Injection Wells Act (Texas Water Code, Title 2, Subtitle D, Chapter 27); Underground Injection Code (UIC) Class VI (40 CFR Part 146, Subpart H)	RRC disposal well permit required. Applies to injection wells and underground storage reservoir. Additional requirements for wells located in special-purpose districts. While the RRC has primacy to implement UIC Class II well requirements, there are no states that have been approved by EPA for Class VI primacy. To date, no Class VI well permit applications have been submitted to or approved by EPA Region 6.	
GHG Reporting	None during the planning, permitting, and construction phase. Under the USEPA GHG Reporting Program Subpart RR, a Monitoring, Reporting, and Verification (MRV) Plan must be submitted and approved by EPA.	Not applicable	
Monitoring	No monitoring requirements prior to start-up. However, under the UIC Class VI well permit requirements, a Testing and Monitoring Plan must be submitted and approved by EPA.	Not applicable	
Incentives	Texas House Bill 469; Texas House Bill 3732; Texas House Bill 1356 IRS Section 45Q	Offers tax credits and other incentives for CCS equipment and advanced energy projects. United States Internal Revenue Service (IRS) Section 45Q expires after a certain quantity of CO_2 is stored, making its availability uncertain over the long term for project developers.	

Air Quality Regulatory Pathway

Prior to construction of a CCS project, facilities must evaluate potential emission sources and ascertain whether the facility will be a minor or major source of emissions. If the facility will be a minor source and all emission sources can be classified as one of the 108 emission categories recognized by the Texas Commission on Environmental Quality (TCEQ), the facility may claim a Permit-by-Rule (PBR). The advantages to authorizing emissions under PBR is that the time required to obtain a permit prior to construction is significantly reduced, the application required is significantly streamlined, in some cases construction can begin prior to authorization, and emission sources are not required to meet federal Best Available Control Technology (BACT).

If all emission sources at the facility cannot classify under PBR, a permit under New Source Review (NSR) for major sources will be required. If the site is located in an area that is in attainment of the national ambient air quality standards (NAAQS), it must apply for a Prevention of Significant Deterioration (PSD) permit, demonstrating that best available control technology (BACT) has been implemented. If the facility is located in a nonattainment[4] area, a Non-attainment New Source Review (NNSR) permit is required. Additional permitting requirements for NNSR include the installation of Lowest Achievable Emission Rate (LAER) control technology. The typical agency review time for an NSR permit is 18-24 months including two public notice periods and the permit must be issued prior to commencing construction.

Facilities that are a major source of NO_x and located in the Houston-Galveston-Brazoria ozone nonattainment area are subject to the Mass Emissions Cap and Trade (MECT) program. The facility must purchase the necessary offsets and submit an application at least 30 days before the start of operation.

Subsurface Regulatory Pathway

Under Texas CO_2 code, drilling or operating of an anthropogenic CO_2 injection well for geologic storage or constructing or operating a geologic storage facility cannot commence without first obtaining the necessary permit(s) from the Railroad Commission of Texas (RRC). The application must include plans pertaining to quality assurance and surveillance, well plugging, financial responsibility, emergency response, and post-injection care. Geological and hydrological information must also be submitted, as well as a surface map depicting the proposed location of the injection well. RRC drilling permits allow two years from the date of approval of first filing to undertake initial drilling of the well.

[4] In United States environmental law, a nonattainment area is an area considered to have air quality worse than the National Ambient Air Quality Standards as defined in the Clean Air Act Amendments of 1970 (P.L. 91-604, Sec. 109).

Water Quality Regulatory Pathway

Per the Texas Well Injection Act, a hazardous and non-hazardous disposal well permit must be obtained from the RRC prior to utilizing an injection well (or begin drilling an injection well) to dispose of industrial and municipal waste, to extract minerals, or to inject a fluid. The application must include a letter of determination to the Railroad Commission of Texas indicating that the CCS operations will not endanger the freshwater strata. The RRC typically completes its review within 30-45 days.

Pursuant to USEPA's Underground Injection Control (UIC) Requirements, prior to the issuance of a permit for the construction of a new Class VI well for CCS CO_2 injection wells, or the conversion of an existing Class II well to a Class VI well, the facility must obtain EPA approval. The permit application should contain an Area of Review (AoR), well construction and operation details, proof of financial responsibility, and five project-specific plans:

- AoR and Corrective Action Plan;
- Testing and Monitoring Plan;
- Well Plugging Plan;
- Post-Injection Site Care and Site Closure Plan; and
- Emergency Response Plan.

No states, including Texas, currently have primacy for implementing the UIC Class VI well requirements. Therefore, the permit for a Class VI CCS injection well must be submitted to and approved by the regional US Environmental Protection Agency (EPA) prior to drilling. The UIC Class VI permit application must include all of the five plans and these plans are expected to be updated during the life of the injection site. The regulatory pathway for a UIC Class VI permit entails permit application completeness review by the EPA regional office, an iterative process; draft permit issued by EPA; public comment period and possibly public hearing; issuance of final permit allowing construction to commence. The process took around eight years for one of the first projects to receive a Class VI well permit (see case study in *Section 3.1.5*).

UIC Class VI well requirements are extensive and entail:

- Extensive site characterization requirements
- Injection well construction requirements for materials that are compatible with and can withstand contact with CO_2 over the life of a CCS project;
- Injection well operation requirements;
- Comprehensive monitoring requirements that address all aspects of well integrity, CO_2 injection and storage, and ground water quality during the injection operation and the post-injection site care period;
- Financial responsibility requirements assuring the availability of funds for the life of a CCS project (including post-injection site care and emergency response); and

- Reporting and recordkeeping requirements that provide project-specific information to continually evaluate Class VI operations and confirm drinking water protection.

USEPA has issued final technical guidance documents to support Class VI well permit applicants in complying with the requirements. The number of Class VI well permits that have been approved by EPA has been limited, and while guidelines have been established, the regulatory pathway is largely untested in Texas under EPA Region 6. To date, no UIC Class VI well permit applications have been submitted to or approved by EPA Region 6.[5]

Incentives

Texas has three CCS incentives, including a sales tax exemption for CCS equipment (HB 469), incentives for advanced energy projects such as CCS (HB 3732), and an authorization for CO_2 pipelines to become a common carrier (HB 1356).

At the federal level, the US Internal Revenue Service (IRS) has tax incentives under Section 45Q of the tax code that make available a per-ton credit for CO_2 disposed of in secure geologic storage. The program provides $10 per metric tonne (MT) for CO_2 stored through EOR operations and $20 per MT for CO_2 stored in deep saline formations (adjusted for inflation from 2009). However, the Section 45Q incentive has restrictions: only high volume capture facilities (>500,000 MT per year) are able to claim credits; the total quantity of CO_2 stored for all projects combined against which credit can be claimed is also capped at 75 million MT of CO_2. At the time of writing approximately half of the available credits have been claimed to date. For CCS project developers, these restrictions create a disincentive for new projects that may not be able to claim the tax credit years later when CO_2 injection is operational. In 2016, two new congressional bills (H.R. 4622[6] and S. 3179[7]) were introduced to revise and expand the eligibility of tax credits under Section 45Q. The fate of these bills is uncertain under the current Congress and Administration.

[5] Email correspondence between Lisa Campbell, ERM, and Brian Graves, EPA Region 6, on 18 January 2017.

[6] https://www.congress.gov/bill/114th-congress/house-bill/4622

[7] https://www.govtrack.us/congress/bills/114/s3179/text/is

3.1.2 *Operational Stage Regulatory Pathway in Texas*

Project element	CCS Facility, pipeline, wells and subsurface		
Project stage	Operation		
Media	Regulation(s)	Key Considerations	Flag
Air	Title V Air Permitting Regulations (TAC Title 30, Chapter 122); Emission Inventory (EI) Regulations (TAC Title 30, Chapter 101); Mass Emissions Cap and Trade Program (30 TAC Chapter 101, Subchapter H, Division 3)	Title V permitting is required if the site is a major source. Emission Inventory Regulations apply if the facility operated during any portion of the previous calendar year. Mass Emissions Cap and Trade program applicable if facility is major source of NOx in the Houston-Galveston-Brazoria non-attainment area.	
Subsurface	TX CO_2 Code (TAC Title 16, Part 1, Chapter 5)	Comply with Railroad Commission of Texas permit. Requirements do not go into significant detail.	
Water	UIC Class VI (40 CFR Part 146, Subpart H)	Texas Commission on Environmental Quality (TCEQ) Injection Well Act applies to injection wells and underground storage reservoir. Requirements do not go into significant detail.	
GHG Reporting	GHG Mandatory Reporting Rule for CO_2 suppliers and underground injection (40 CFR Part 98, Subparts PP and RR)	Assuming the facility operated during a portion of the previous calendar year and emitted 25,000 metric tons of GHGs or more.	
Monitoring	UIC Class VI (40 CFR Part 146, Subpart H); TX CO_2 Code (TAC Title 16, Part 1, Chapter 5)	TCEQ Injection Well Act applies to injection wells and underground storage reservoir	
Incentives	Texas House Bill 3732; Texas House Bill 1356 IRS Section 45Q	Offers incentives for advanced clean energy projects, and authorization for CO_2 pipelines to become a common carrier.	

Air Quality Regulatory Pathway

Assuming the facility is a major source, an abbreviated Title V permit application would need to be submitted prior to start-up. The remainder of the application must be submitted upon request of TCEQ; however, this can be done after the facility begins operation. The Title V permit must be renewed every five years. NSR construction permits expire ten years after issuance would need to be amended as needed prior to a change in operations at the facility.

Every year by March 31, the facility is required to submit an emission inventory for emissions during the previous calendar year. This would include sample calculations that represent the actual operations of the facility during the previous calendar year for all criteria pollutants and Hazardous Air Pollutants (HAPs).

Facilities subject to the MECT program in the Houston-Galveston-Brazoria non-attainment area will need to submit an annual compliance report by March 31 after each control period. The necessary offsets must be obtained by January 31 since this is the deadline to report a transfer of credits to the TCEQ.

Subsurface Regulatory Pathway

In order to comply with the Texas CO_2 Code, the facility must submit testing records within 30 days after testing, although it is unclear how often testing must be done. Additionally, various event-driven operating reports must be submitted within 24 hours or 30 days of the event, depending on the event that occurs. Semi-annual and annual reports containing various monitoring parameters must also be submitted, depending on the parameter. The facility must provide the TCEQ with a schedule for testing and logging, and notify TCEQ in the event of any adverse financial circumstances.

Water Quality Regulatory Pathway

The UIC requirements pertaining to the operating phase pertain mostly to any changes to the reports and plans submitted during the permitting phase. No action is needed if there are no changes to these reports or plans. The facility must submit semi-annual reports of testing and monitoring results, 30-day advance notifications of well tests, well test results within 30 days of each test, and notifications of emergency situations within 24 hours of their occurrence.

GHG Reporting

Reporting requirements under the USEPA Greenhouse Gas Reporting Program must be met for producers of CO_2 and underground injection of CO_2. The applicable Subparts under the GHGRP include:

- Subpart PP – applies to suppliers of CO_2. Under Subpart PP, facilities need to document mass or volumetric flow of extracted or transported CO_2 streams, as well as the mass of CO_2 imported or exported. There is no reporting threshold, meaning that all CO_2 suppliers must report.
- Subpart RR – applies to all underground injection of CO_2 for geologic sequestration. Under Subpart RR, facilities must monitor CO_2 that is received, injected, and produced. Subpart RR also requires a Monitoring, Reporting, and Verification (MRV) Plan to be submitted within 180 days of receiving a UIC permit. All CCS projects are required to meet the reporting requirements.
- Subpart UU – applies to underground injection of CO_2 for EOR. All EOR projects are required to meet the reporting requirements.

Report submissions are due annually by March 31 for emissions during the previous calendar year.

Incentives

Two of the three aforementioned CCS incentives in Texas apply to the operation stage, including incentives for advanced energy projects such as CCS (HB 3732), and an authorization for CO_2 pipelines to become a common carrier (HB 1356). The IRS tax credit under Section 45Q may also apply.

3.1.3 *Decommissioning and Post-Closure Stage Regulatory Pathway in Texas*

Project element	CCS Facility, pipeline, wells and subsurface		
Project stage	Decommissioning and Post-Closure		
Media	Regulation(s)	Key Considerations	Flag
Air	Emission Inventory (EI) Regulations (TAC Title 30, Chapter 101); Mass Emissions Cap and Trade Program (30 TAC Chapter 101, Subchapter H, Division 3)	Emission Inventory Regulations pertain mostly to the operation phase, but may be required if the facility operated during any portion of the previous calendar year. Mass Emissions Cap and Trade program applicable if facility is major source of NO_x in the Houston-Galveston-Brazoria non-attainment area	
Subsurface	TX CO_2 Code (TAC Title 16, Part 1, Chapter 5)	Comply with Railroad Commission of Texas permit	
Water	UIC Class VI (40 CFR Part 146, Subpart H)	Applies to injection wells and underground storage reservoir. New guidance has been finalized by EPA on post-injection site care, including well plugging, and site closure.	
GHG Reporting	GHG Mandatory Reporting Rule for CO_2 suppliers and underground injection (40 CFR Part 98, Subparts PP and RR)	Greenhouse Gas Reporting requirements pertain mostly to the operation phase, but may be required if the facility operated during the previous calendar year and emitted 25,000 metric tons or more of GHGs.	
Monitoring	UIC Class VI (40 CFR Part 146, Subpart H); TX CO_2 Code (TAC Title 16, Part 1, Chapter 5)	Applies to all facilities that obtained permits during the permitting and construction phase.	
Incentives	None available	Not applicable	

Air Quality Regulatory Pathway

While air permitting requirements apply mainly to the construction and operation phases of a CCS project, Emission Inventory requirements must be met if the facility operated during any portion of the previous year. As in the operation phase of a CCS project, actual measurement of emissions with sample calculations representative of the processes of the facility during the previous calendar year must be submitted by March 31. If the facility operates for part of the previous calendar year and the annual emissions are below the reporting threshold, the facility may submit a letter indicating that the facility is being decommissioned, and emission inventory requirements are no longer applicable. Additionally, facilities would be well advised to sell any unused NO_x offsets per the MECT program, if located in the Houston-Galveston-Brazoria non-attainment area.

Subsurface Regulatory Pathway

Under the Texas CO_2 code, facilities are bound by the well plugging and closure plan, and will need to demonstrate that no amendment to the plan is needed to TCEQ via monitoring data and modelling results. Monitoring as specified in the well closure plan will need to be conducted until TCEQ determines that the CO_2 plume will not endanger underground drinking water sources.

Water Quality Regulatory Pathway

Pursuant to the UIC requirements, facilities are required to submit a notice of intent to plug the well at least 60 days prior to doing so. Within 60 days after plugging the well, a plugging report must be submitted. The requirements do not go into detail in describing what the plugging report must include. Facilities are bound by the site closure and well plugging plans that were submitted during the permitting phase, and will need to submit amendments to these plans as needed. Facilities are also required to monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that Underground Sources of Drinking Water (USDWs) are not being endangered. Once the non-endangerment demonstration is approved, a notice of intent to close the site must be submitted 120 days prior to site closure. A site closure report must be submitted following closure and monitoring plan for a default period of 50 years post injection unless specific conditions are achieved earlier.

GHG Reporting

The Greenhouse Gas Reporting requirements pertain mostly to the operation stage, similarly to Emission Inventory requirements, as no explicit requirements exist for facilities that are being decommissioned. Nevertheless, if the facility operated during any portion of the previous calendar year, sample greenhouse gas emission calculations must be submitted by March 31.

Currently, there is no clarity on the party responsible for reporting potential leakage of CO_2 post-closure from a CCS project that reported avoided emissions under Subpart RR during the operational stage of the project. Presumably, the obligation for reporting post-closure CO_2 leakage would follow the party who received recognition for the avoided CO_2 emissions during the operational stage of the project. This ambiguity about the party responsible for reporting post-closure CO_2 leakage is a gap or uncertainty in the current regulatory pathway.

3.1.4 *Summary of Texas CCS Regulatory Pathway*

The Texas government supports CCS as a means to reduce greenhouse gas emissions via House Bill financial incentives. Additionally, regulatory frameworks exist mostly for the initial and operation phases, especially when it comes to permitting and monitoring. Regulatory framework for the decommissioning phase pertains mostly to subsurface concerns and to post-well closure monitoring.

		Media					
		Air	Subsurface	Water	GHG Reporting	Monitoring	Incentives
Phase	Planning and Permitting						
	Operation						
	Decommissioning and Post-Closure						

3.1.5 *Case Study: Archer Daniels Midland Illinois Industrial Carbon Capture and Sequestration Project*

Archer Daniels Midland (ADM) operates a corn ethanol production facility in Illinois and captures high concentration CO_2 from the fermentation of biomass for injection on a 200 acre site adjacent to the plant. Because the CO_2 generated is biogenic, the plant has the ability to generate negative CO_2 net emissions. This facility was selected by the US Department of Energy (DOE) in Phases 1 and 2 of the Industrial Carbon Capture and Storage Program in 2009/2010, with over $140 million in DOE funding. The project is precedent setting on two counts:

- Received approval of the UIC Class VI permit in 2014 from USEPA Region 5; and
- Received USEPA approval of the Subpart RR and UU Monitoring, Reporting and Verification (MRV) Plan in January 2017. [8]

This project holds the first Subpart RR and UU MRV Plan to be approved by EPA for a project with a UIC Class VI permit. ADM plans to inject 5.5 million MT of CO_2 over a 5 year period from the facility. The MRV Plan entails groundwater geochemical monitoring from three aquifers above the injection zone, as well as plume and pressure front subsurface monitoring using direct fluid sampling, and indirect pulse neutron logging/reservoir saturating testing every two years. In addition, 3D surveys in years 1 and 10 following the conclusion of injection operations will be completed to compare relative to baseline.

This project demonstrates that with the right incentives - in this case a grant from the DOE - a CCS project can overcome the regulatory hurdles to gain approvals. While the process was lengthy – on the order of eight years from initial grant approval to final approvals for injection – it has paved the way for more projects to follow this regulatory pathway in the USA.

[8] https://www.epa.gov/sites/production/files/2017-01/documents/adm_mrv_plan.pdf

Box 3.1 Summary of Key Points

There is limited practical experience that can be drawn upon to test potential regulatory uncertainty. However, the examples that are available suggest that the regulatory authorities have an appetite to support CCS projects. This is highlighted by the ADM project where CCS was successfully permitted despite the regulatory gaps. This case has proven the regulatory pathway in Texas, and also in the USA as a whole.

3.2 *CCS REGULATORY PATHWAY IN ALBERTA, CANADA*

Historically, Canada and specifically Alberta have committed to reducing GHG emissions. Most recently, Alberta's Climate Change Strategy includes a reduction of CO_2e to 14% below 2005 emissions by 2020, and the Government of Canada's Regulatory Framework on air emissions includes a reduction of GHG emissions to 20% below 2006 levels by 2020. Both recognize the role of CCS in meeting the emission reduction targets. The introduction of carbon taxes in Canada (with Alberta starting at $20 per tonne in 2017 and increasing to $30 per tonne in 2018, and a pending federal carbon tax calling for $50 per tonne by 2022) will provide further incentive to reduce emissions.

The Government of Alberta initiated a Regulatory Framework Assessment (RFA)[9] in March 2011, to look at the regulations that currently apply to CCS in Alberta, and regulations and best practices in other parts of the world. The RFA includes conclusions and recommendations that will inform the ongoing development of the CCS regulatory framework in Alberta. The key points of this review are set out in Annex B, as extracted directly from the executive summary of the Government report.

[9] The final report, Carbon Capture and Storage Regulatory Framework Assessment (Alberta Energy, 2013), details the findings of the review, and includes over 70 conclusions and recommendations (http://www.energy.alberta.ca/CCS/3843.asp)

3.2.1 *Planning, Permitting and Construction Phase Regulatory Pathway in Alberta*

Project element	CCS Facility, pipeline, wells and subsurface		
Project phase	Planning, Permitting, and Construction		
Media	Regulation(s) [10]	Key Considerations	Flag
Air	None specific to CCS	CO_2 is not considered a pollutant in Alberta	
Subsurface	Carbon Sequestration Tenure Regulation (Alta Reg. 68/2011) *Mines and Minerals Act* (MMA), Revised Statutes of Alberta 2000 Chapter M-17	This regulation establishes the process to obtain tenure or lease rights for pore space to evaluate the suitability of a potential storage site or to store CO2. Sequestration lease required for rights to subsurface storage of CO2	
Water	*Water Act* (Revised Statutes of Alberta 2000 Chapter W-3)	Provides a framework for protection of non-saline groundwater, although not specific to CO_2.	
GHG Reporting	Carbon Sequestration Tenure Regulation (Alta Reg. 68/2011)	Applicants are required to submit a Measurement, Monitoring and Verification (MMV) Plan	
Monitoring	Carbon Sequestration Tenure Regulation (Alta Reg. 68/2011)	Applicants are required to submit a MMV Plan	
Incentives	*Carbon Capture and Storage Funding Act* (Statutes of Alberta, 2009 Chapter C-2.5)	A $2 billion CCS funding program to enable large-scale CCS projects in Alberta.	

Currently, a CCS project in Alberta is treated as any petroleum development that includes wells, pipelines or other structures, and requires a licence to construct and operate, and for approval of injection and monitoring wells.

The initial application and permitting for CCS in Alberta includes:

- Initial acquisitions;
- Discretionary activity review and potential Environmental Impact Assessment (EIA); and
- Regulatory applications and approvals.

The initial acquisitions stage includes obtaining subsurface and surface rights. Other requirements needed to conduct exploration and development activities must also be met (see Appendix A). For CO_2 sequestration, subsurface rights agreements include evaluation permits and carbon sequestration leases. After subsurface rights are obtained, surface rights must be acquired because permission is required to access the land.

Any petroleum development that includes wells, pipelines or other structures requires a licence from the Alberta Energy Regulator (AER)[11] to construct and

[10] The Acts and Regulations listed in this table are specific to permitting a CCS project. The Acts and Regulations applicable to the surface and subsurface developments required for a CCS project, which are typically related to oil and gas developments, are listed in Appendix A.

operate, and for approval of injection and monitoring wells. After drilling, completion and testing, proponents can apply to the AER for an injection scheme approval. Applicants are also required to submit a Measurement, Monitoring and Verification (MMV) Plan for approval, although there is little guidance on what an MMV Plan must contain.

Prior to the AER providing approval for CO_2 sequestration, the application is referred to Alberta Environment and Parks (AEP) for review. As part of regulatory review, the Minister may impose additional conditions. CCS projects do not specifically require an environmental impact assessment (EIA). However, an assessment may be triggered through a regulatory review of the project as a discretionary activity. Once final approval is obtained from the AER, the construction of the project can commence subject to regulatory requirements (see Appendix A) and approval conditions.

The *Carbon Capture and Storage Statutes Amendment Act, 2010* (also known as Bill 24) has promoted and simplified the regulatory process for CCS in Alberta. However, for some aspects of the regulatory process, the applicability of existing regulations and the roles and responsibilities among various government departments is unclear.

[11] Previously Energy Resources Conservation Board

3.2.2 *Operational Phase Regulatory Pathway in Alberta*

Project element	**CCS Facility, pipeline, wells and subsurface**		
Project phase	**Operation**		
Media	**Regulation(s)**[12]	**Key Considerations**	Flag
Air	*Environmental Protection and Enhancement Act* (EPEA), Revised Statutes of Alberta 2000 Chapter E-12	Air Monitoring Directive and Ambient Air Quality Objectives	
Subsurface	Carbon Sequestration Tenure Regulation, Alta Reg. 68/2011	Carbon sequestration lease applicants are required to adhere to the MMV Plan.	
Water	*Water Act,* Revised Statutes of Alberta 2000 Chapter W-3	Provides a framework for protection of non-saline groundwater, although not specific to CO_2.	
GHG Reporting	Alberta Government Quantification Protocol for CO_2 Capture and Permanent Storage in Deep Saline Aquifers	Monitoring requirements for CO_2 capture and storage in order to qualify to generate carbon credits.	
Monitoring	Carbon Sequestration Tenure Regulation, Alta Reg. 68/2011	Carbon sequestration lease applicants are required to adhere to their MMV Plan. Updated MMV Plans must be submitted every three years along with an updated closure plan. Some changes to the MMV are suggested per the RFA, and surface access concerns for monitoring exist.	
Incentives	Specified Gas Emitters Regulation (Alta. Reg. 139/2007).	Emitters can generate offset credits which can be sold by improving emissions intensity below the baseline according to the Regulation. Additionally, carbon credits can be generated by adhering to the Quantification Protocol for CO_2 Capture and Permanent Storage in Deep Saline Aquifers. However, holders of carbon sequestration leases must pay into a Post-Closure Stewardship Fund (PCSF) at a yet to be specified rate per tonne of CO_2 injected.	

During operations, monitoring must demonstrate compliance with regulations and approval conditions. Although there is little guidance on what an MMV Plan must contain, it is expected that data is gathered to demonstrate containment, conformance and use of the pore space. Monitoring results must

[12] The Acts and Regulations listed in this table are specific to operating a CCS project. The related Acts and Regulations applicable to operations that are typical to oil and gas projects are listed in Appendix A.

also be incorporated into simulations and models so that predicted and actual behaviour can be compared and the MMV Plan can be updated. Updated MMV Plans must be submitted every three years, and include a Closure Plan (although, like the MMV Plan, there is little guidance on what a Closure Plan must contain).

3.2.3 *Decommissioning and Post-Closure Phase Regulatory Pathway in Alberta*

Project element	**CCS Facility, pipeline, wells and subsurface**		
Project phase	**Decommissioning**		
Media	**Regulation(s)**[13]	**Key Considerations**	Flag
Air	*Environmental Protection and Enhancement Act* (EPEA), Revised Statutes of Alberta 2000 Chapter E-12	Air Monitoring Directive and Ambient Air Quality Objectives	
Subsurface	*Mines and Minerals Act* (MMA), Revised Statutes of Alberta 2000 Chapter M-17 Carbon Sequestration Tenure Regulation , Alta Reg. 68/2011	Carbon sequestration lease applicants are required to adhere to the MMV and Closure Plans and apply for a closure certificate.	
Water	*Water Act*, Revised Statutes of Alberta 2000 Chapter W-3	Provides a framework for protection of non-saline groundwater	
GHG Reporting	Carbon Sequestration Tenure Regulation	Carbon sequestration lease applicants are required to adhere to their to the MMV and Closure Plans and apply for a closure certificate	
Monitoring	Carbon Sequestration Tenure Regulation, Alta Reg. 68/2011	Owners are required to submit and adhere to their MMV and Closure Plan. and apply for a closure certificate	
Incentives	Carbon Sequestration Tenure Regulation, Alta Reg. 68/2011	Upon meeting performance criteria set out in the MMV and Closure Plans, an operator can apply for a closure certificate. The Government of Alberta will undertake a review to determine if all the requirements for closure have been met and issue a closure certificate and becomes the owner of all injected CO_2, and assumes all obligations of the lessee, including responsibilities related to wells and facilities, the environment and land	

[13] The Acts and Regulations listed in this table are specific to decommissioning a CCS project. The related Acts and Regulations that are typical to oil and gas projects are listed in Appendix A.

If MMV and Closure Plan performance criteria are met, an operator can apply for a closure certificate. The Government of Alberta will review it to determine if all the requirements for closure have been met. However, the Carbon Sequestration Tenure Regulation provides little detail on what a Closure Plan must contain, and the *Mines and Minerals Act* does not specify what subsurface performance criteria must be met to receive a closure certificate.

The time period for monitoring after decommissioning is not yet decided, but a 10-year minimum period before issuing a closure certificate is being considered.

Project element	**CCS Facility, pipeline, wells and subsurface**		
Project phase	**Post-Closure**		
Media	**Regulation(s)**	**Key Considerations**	**Flag**
Air	*Carbon Capture and Storage Statutes Amendment Act, 2010* (also known as Bill 24)	Receipt of a closure certificate signifies that a project has been closed and responsibility and long term liability for the sequestered CO_2 are transferred from the operator to the Government of Alberta, in perpetuity.	
Subsurface	*Carbon Capture and Storage Statutes Amendment Act, 2010* (also known as Bill 24)	Receipt of a closure certificate signifies that a project has been closed and responsibility and long term liability for the sequestered CO_2 are transferred from the operator to the Government of Alberta, in perpetuity.	
Water	*Carbon Capture and Storage Statutes Amendment Act, 2010* (also known as Bill 24)	Receipt of a closure certificate signifies that a project has been closed and responsibility and long term liability for the sequestered CO_2 are transferred from the operator to the Government of Alberta, in perpetuity.	
GHG Reporting	*Carbon Capture and Storage Statutes Amendment Act, 2010* (also known as Bill 24)	Receipt of a closure certificate signifies that a project has been closed and responsibility and long term liability for the sequestered CO_2 are transferred from the operator to the Government of Alberta, in perpetuity.	
Monitoring	*Carbon Capture and Storage Statutes Amendment Act, 2010* (also known as Bill 24)	Upon receipt of a closure certificate and ownership and liability for the CO_2 has been transferred to the Government of Alberta, the province will be responsible for conducting post-closure monitoring and any potential remediation.	
Incentives	*Carbon Capture and Storage Statutes Amendment Act, 2010* (also known as Bill 24)	Upon receipt of a closure certificate and ownership and liability for the CO_2 has been transferred to the Government of Alberta, the province will be responsible for conducting post-closure monitoring and any potential remediation.	

Note: The uncertainty in the monitoring period may flag some of the post-closure issues as a regulatory risk.

When issuing a closure certificate, the Government of Alberta becomes the owner of all injected CO_2, and assumes all obligations of the lessee, including responsibilities related to wells and facilities, the environment and land.

However, the liabilities assumed by the government do not include liability for CO_2 credits.

The *Carbon Capture and Storage Statutes Amendment Act* established a Post Closure Stewardship Fund (PCSF) to cover the costs associated with some of the liabilities and obligations in the post-closure period, and to protect the Alberta public from bearing those costs. Holders of carbon sequestration leases must pay into the PCSF at a yet to be specified rate per tonne of CO_2 injected.

3.2.4 Summary of Alberta CCS Regulatory Pathway

The Government of Alberta supports CCS as a means to meet GHG emission reduction targets. As such, financial incentives – and disincentives – are in place to reduce greenhouse gas emissions and to promote CCS.

To address regulatory barriers to CCS, several legislative changes have recently been made, and more are expected pending review and implementation of the recommendations of the RFA. Of note, the CCS project closure process is new in Alberta and more development is needed to protect proponents, operators and the public.

		Media					
		Air	Subsurface	Water	GHG Reporting	Monitoring	Incentives
Phase	Planning, Permitting and Construction						
	Operation						
	Decommissioning						
	Post-Closure						

Note: The uncertainty in the monitoring period may flag some of the post-closure issues as a regulatory risk

3.2.5 *Case Study: Quest CCS Project, Alberta*

The Quest CCS Project was built on behalf of the Athabasca Oil Sands Project (AOSP) joint venture owners - Shell Canada Energy (operator and 60% owner), Chevron Canada Limited (20%), and Marathon Oil Canada Corporation (20%), with support from the Governments of Canada and Alberta. The AOSP includes the Muskeg River and Jackpine mines (located northeast of Fort McMurray, Alberta), the Scotford Upgrader and the Quest facility (both located near Fort Saskatchewan, Alberta). Quest claims to be the world's first commercial-scale CCS project in an industrial processing facility, designed to capture and store more than one million tonnes of CO_2 annually.

In 2008, the Alberta government announced its climate change strategy and identified CCS as a key technology needed to meet the Province's target reductions. A task force on CCS was formed, which included a representative from Shell on one of the working groups. The task force determined that CCS demonstration projects were needed ahead of regulation to demonstrate viability and to spur development. Around the same time, the Alberta and Canadian governments established funds aimed at encouraging CCS projects. Shell submitted applications for Quest and was successful in acquiring C$745M from the Government of Alberta and C$120M from the Government of Canada. As part of the funding agreement, Quest published Annual Summary Reports throughout the project development and during operation[14]. Case studies have also been published, focusing on learnings from project implementation[15] and stakeholder engagement[16].

In addition to the government funding, government support was required to enable the development of policy and regulatory frameworks tailored to CO_2 storage, MMV systems, and closure. Acts were in place for extraction, disposal of fluids, and the storage of gas, but not for the subsurface sequestration of CO_2. The Alberta government had to learn about the technicalities associated with sequestration and amend existing legal and regulatory frameworks, and Shell had to understand the processes the regulators followed to establish new legislation. In late 2009, the legislative and regulatory strategy was defined, in December 2010 the Alberta government introduced the Act, and Regulations were in place by April of 2011. Once the regulations were introduced, Shell applied for sequestration leases.

Quest combines proven technology and integrated surface and subsurface development. CO_2 captured from the Scotford facility is transferred via a 65 km pipeline and injected to a deep saline aquifer, located about 2 km below ground, below groundwater levels and oil and gas reservoirs.

[14] Quest Carbon Capture and Storage Project Annual Summary Report(s). Shell Canada Energy, 2012, 2013, 2014, 2015. http://www.energy.alberta.ca/CCS/3848.asp

15 The Quest for Less CO2: Learnings from CCS Implementation in Canada – A Case Study on Shell's Quest CCS Project. Shell International B.V., 2015. http://hub.globalccsinstitute.com/sites/default/files/publications/196788/quest-less-co2-learning-ccs-implementation-canada.pdf

16 Case Study: Shell Canada Quest Carbon Capture and Storage Project. Pembina Institute, 2014. https://www.pembina.org/reports/ccs-shell-casestudy-public-engagement.pdf

Securing local stakeholder support was a critical step of the regulatory process. Even though the Scotford facility consists of an upgrader and an oil refinery and chemicals facility, the concept of capturing and storing CO_2 underground was seen as new in Alberta, so it was important to gain local support and broader public acceptance, particularly from the local governments of the City of Fort Saskatchewan and Thorhild County. The key successes of the stakeholder engagement process were to:

- Consider and build upon the history of the site, recognizing the need to be integrated with Shell's outreach activities already underway in the area;
- Establish channels of communication early on, enabling formal and informal engagement to seek information and answer the questions or concerns of stakeholders, including government and the public. Open houses were held to answer questions and inform the public on the project, and also drew in suggestions and feedback from local residents, one of which was a groundwater quality-monitoring program, which is now part of the MMV program;
- Collaborate with the Pembina Institute, a Canadian non-governmental organization that is a credible and trusted voice among both members of the public and other key stakeholders and often sought for their views on energy matters.
- Develop a Community Advisory Panel made up of local residents, members of the academic community, political and regulatory representatives, with the primary purpose to share regular updates about the project, specifically the MMV program and results, and for Shell to take recommendations from the Panel on the best approach to communicate the results.

Upon conclusion of the detailed engineering studies and the regulatory processes, including stakeholder engagement, in Q2 of 2012, the final investment decision was made in September 2012. Early works started in Q4 2012 and construction was completed early in 2015. In November 2015, Quest was on stream and injecting CO_2.

The Quest MMV program was key to meeting Alberta's CCS regulatory requirements, and the ability to demonstrate safe, long-term integrity of the CO_2 storage supports public acceptance. The Quest MMV program covers a wide range of technologies and analysis throughout the atmosphere, biosphere, hydrosphere and geosphere and is designed according to a systematic risk assessment focusing on ensuring containment and conformance. To achieve these two objectives, the expected effectiveness of appropriate site selection, site characterization, and engineering designs were verified, and additional safeguards were created to provide an early warning to trigger control measures if needed. The transfer of long-term liability to the Alberta government will be supported by MMV activities that verify that the storage performance conforms to model-based forecasts and that the forecasts are consistent with permanent secure storage at an acceptable risk. However, the Quest MMV program tests multiple approaches to determine optimal

MMV requirements for future projects, so the program is not a precedent for future projects but learnings from the program can inform future projects.

CO_2-EOR is an established method in the oil and gas industry of extracting more oil from oil fields as they become depleted. However, some of the CO_2 injected into oil fields will remain in situ after closure of the oil fields. There is the potential that this can be regarded as carbon sequestration. At the present time the regulation of CO_2-EOR is designed solely to consider CO_2 injection activities associated with enhancing oil recovery and extending oil field working life. It is not designed to meet the requirements of CCS pertaining to the permanent geological disposal of CO_2. There are benefits in recognising CO_2-EOR as a means of permanent storage of CO_2. These relate principally to: reducing emissions and atmospheric concentrations of CO_2; national inventory reporting of CO_2 emissions; reputational enhancement for oil and gas companies; and financial reward for the storage of CO_2.

However, the aims of CO_2-EOR and CCS differ. CO_2-EOR is designed to maximise the production of oil from a reservoir and there is little focus on the long term fate of the CO_2 once it is within the reservoir. Indeed, it is in the operators' interest to minimize the proportion of injected CO_2 that remains trapped in situ. CCS is designed to permanently lock away CO_2, and there is considerable attention paid to the long term fate of the CO_2. As a result, the motivations for doing CO_2-EOR and the criteria for a site suitable for CO_2-EOR will rarely fully meet the criteria required for a CCS site. This section therefore focusses on identifying if it is possible for a CO_2-EOR project to become a CCS project and if it is possible, what steps need to be taken for a CO_2-EOR project to be recognised as a CCS project.

In addition to a general discussion of the regulatory requirements around recognising CO_2-EOR as CCS, a case study is presented on the Occidental Permian's Denver Unit oil production operation in West Texas. This is the first CO_2-EOR project in Texas that has been able to gain recognition also as a CCS project from a GHG monitoring standpoint, and there are some particular points of interest in how this was achieved.

4.1 REVIEW PROCESS

A number of steps were undertaken to fulfil this objective:

- Identify where regulations for CO_2-EOR and CCS are the same and where they differ, based upon the findings of Stage 1 of the study. As EOR is associated with the recovery of oil from underground reservoirs, this will focus on the regulatory needs for the injection phase, wells and post-closure phases.

- Where regulations differ between CO_2-EOR and CCS, the study will identify in what respect they are different. This principally relates to the different objectives of CO_2-EOR and CCS as discussed above. Examples include: well type (for Texas, UIC Class II vs. Class VI);

establishing long term containment; and the needs of CO_2 leak monitoring; etc.

- Is there a mechanism in place that allows CO_2-EOR to be classified as CCS?

- What regulatory needs must be fulfilled to allow a CO_2-EOR project to become a CCS project? How can an EOR project become classified as CCS and gain credit for the carbon storage?

- If there are points at which the regulatory framework is unclear, absent or difficult to achieve, what are the critical points to allow a CO_2-EOR project to gain recognition as a CCS project? If there are no critical points, what are the potential regulatory steps to transition a CO_2-EOR project to be recognised as a CCS project?

4.2 *REGULATORY PATHWAY FOR CO_2-EOR TO CCS IN TEXAS*

4.2.1 *Comparison of CO_2-EOR and CCS Regulation*

This section identifies where regulations for CO_2-EOR and CCS are the same and where they differ, based upon the findings of Stage 1 of this study. As CO_2-EOR is associated with the recovery of oil from underground reservoirs, the focus is on the regulatory needs for developing the wells, the injection of CO_2, decommissioning and post-closure of the facilities and reservoirs.

Planning, Permitting, and Construction

NSR and PSD air permitting regulations are comparable if the well injection facility will emit criteria pollutants or Hazardous Air Pollutants (HAPs). If the facility is located in the Houston-Galveston-Brazoria non-attainment area and will be a major source of NO_x, it will also be applicable to the MECT program.

Under the Texas CO_2 code, the proposed CO_2-EOR facility must submit a registration application with Texas RRC. This differs from the permit application that is required for CCS facilities, and is analogous to the difference between a PBR registration and an NSR permit application for air emissions. The application for CO_2-EOR facilities requires an initial $500 fee, contact information and location of the proposed facility, and demonstration that the reservoir is undergoing enhanced recovery. Similar to the CCS permit application, plans pertaining to testing, monitoring, and reporting are required to be submitted with the CO_2-EOR registration application.

Permitting under the Texas Well Injection Act applies to hazardous and non-hazardous disposal wells that are intended to dispose of industrial and municipal waste, to extract minerals, or to inject a fluid. Thus, the Texas Well Injection Act requirements are comparable for EOR and CCS.

Pursuant to USEPA's UIC Requirements, wells used for EOR purposes are classified as Class II wells. Unlike Class VI wells used for CCS, which always require a permit, Class II wells can be authorized either by rule or by permit.

Both Class II and Class VI wells are subject to construction requirements, which specify that the injection well be separated from drinking water aquifer, and as such Class II wells are required to be cased to prevent movement of fluids into drinking water aquifers. Logging and testing will need to be conducted during the drilling of a new Class II well, and a logging and testing report must be submitted to the agency. Additionally, fluid pressure, fracture pressure, and physical characteristics (physical characteristics, fracture pressure (gradient), fluid pressure) of injection zone are required to be monitored and reported. Lastly, the facility will need to prepare a plan for plugging and abandonment of the well and demonstrate financial responsibility, as Class VI injection facilities also need to do.

EPA has recently published its guidance on transitioning from a Class II to Class VI well. It allows for injecting CO_2 for the primary purpose of long-term storage into an oil and gas reservoir under a Class II EOR permit, unless there is an increased risk to USDWs compared to Class II operations. The regulatory authority will determine if there is an increased risk to USDWs compared to Class II operations and whether a Class VI permit is required.

Note that currently EPA has regulatory authority for all Class VI permits, as no states have been granted primacy by EPA. It is also worth noting that the State of North Dakota has formally requested that the USEPA re-open its guidance for transitioning from a Class II to a Class VI well specifically related to the State having primacy to run the Class II program but not the Class VI program, and this State’s view that aspects of EPAs’ Class VI guidance result in the EPA reaching back into Class II aspects under State administration. The outcome of this request from North Dakota for USEPA to re-open aspects of its transition guidance has not been determined.

The following are the considerations stated by the USEPA for determining if a Class VI permit is required:

- Increase in reservoir pressure within the injection zone(s);
- Increase in carbon dioxide injection rates;
- Decrease in reservoir production rates;
- Distance between the injection zone(s) and USDWs;
- Suitability of the Class II area of review delineation;
- Quality of abandoned well plugs within the area of review;
- The owner's or operator's plan for recovery of CO2 at the cessation of injection;
- The source and properties of injected carbon dioxide; and
- Any additional site-specific factors as determined by the regulator.[17]

Operators considering the transition from CO2 EOR to CCS may entail the following operational scenarios:

- CO2 EOR operation continues to produce oil while "primarily" storing CO2, without increasing risk. In this case, a Class VI permit may not

[17] 40 CFR 144.19 - Transitioning from Class II to Class VI

be required, if the operator can demonstrate minimal risk to the aquifer.

- CO2 EOR operation converts to storage only. While this scenario could theoretically demonstrate minimal risk to the aquifer and not require a Class VI permit, it is more likely that a Class VI permit would be required.
- Re-permitting to Class VI, which may involve retrofitting wells and complying with other requirements of Class VI wells (e.g., AoR, monitoring).

Operation

Title V and Emission Inventory (EI) air regulations for CCS and CO_2-EOR are comparable if the well injection facility emits criteria pollutants or HAPs. If the facility is located in the Houston-Galveston-Brazoria non-attainment area and will be a major source of NOx, it will need to maintain emission credits, similar to CCS facilities.

The Texas CO_2 Code for CO_2-EOR pertains to monitoring and reporting, as is the case for CCS. The facility will be required to meter the volume of anthropogenic CO_2 injected, and install continuous recording devices to monitor injection pressure and other physical parameters of the CO_2 injected, to be reported to TCEQ, although the reporting frequency is not specified. Corrosion monitoring must be performed and reported quarterly. A certified statement confirming compliance with the Texas CO_2 code is required in addition to an annual $10,000 fee for each enhanced recovery facility.

Comparable to CCS, the UIC requirements for CO_2-EOR pertaining to the operation phase consist mostly of monitoring and reporting requirements. As with Class VI wells used for CCS, Class II wells are subject to operation requirements concerning injection pressure, and monitoring requirements pertaining to such parameters as hydrocarbon injection, flow rate, and volume. Monitoring results will need to be summarized monthly and annually, depending on the parameter, and sent to the agency.

While not explicitly stated, the Greenhouse Gas reporting requirements are applicable to CO_2-EOR operations. Subpart UU of the Greenhouse Gas reporting requirements applies generically to any quantity of CO_2 injected into the subsurface, while Subparts PP and RR explicitly state that they are not applicable to CO_2-EOR. Subpart UU is similar to Subpart RR in that facilities must monitor CO_2 that is received, injected, and produced, and that sample calculations and emissions report submissions are due annually by March 31 for emissions during the previous calendar year.

Decommissioning and Post-Closure

Similarly to CCS operations, air quality regulations pertain mostly to the operation phase of a CO_2-EOR project. However, the EI requirements must be met if the facility operated during any portion of the previous year, and remaining NO_x credits may be sold.

There are no well plugging and closure plan requirements under the Texas CO_2 code as it pertains to CO_2-EOR; however, standards for certification must be met prior to well plugging, which may differ from well plugging plan or well closure plans as required for CCS. It would be expected that the plugging and post-closure requirements would at least be the same as that required for petroleum wells.

UIC requirements for the decommissioning and post-closure phase for CO_2-EOR include requesting approval for plugging and abandonment from the agency; however, it is unclear when this must be submitted. The information to be supplied includes the number and types of plugs to be used; the type, grade, and quantity of cement to be used; the method of plug placement; and the procedure used to determine cement plug location. This contrasts with submitting a notice 60 days in advance for CCS. Unlike CCS wells, CO_2-EOR wells must be plugged with cement.

The Greenhouse Gas Reporting requirements pertain mostly to the operation phase, similar to CCS, as no explicit requirements exist for CO_2-EOR facilities that are being decommissioned. Nevertheless, if the facility operated during any portion of the previous calendar year, a greenhouse gas emissions report is due on March 31.

4.2.2 *Key Regulatory Differences in Texas*

Planning, Permitting, and Construction

The Texas CO_2 Code requires CCS operations to obtain a permit, whereas only a registration is needed for CO_2-EOR. The materials to be submitted for the CO_2-EOR registration application are less in-depth. Post-injection care and well plugging plans are not required for CO_2-EOR, and facilities do not need to demonstrate financial responsibility in advance.

The UIC requirements for CO_2-EOR are less stringent than the UIC requirements for CCS, and the permitting and authorization procedures also differ. CO_2-EOR wells are regulated as Class II wells, which may either be authorized by permit or by rule, whereas CCS wells are regulated as Class VI wells, and can only be authorized by permit. A Class II well can be authorized by rule if the operator injects into an existing well within one year after the UIC program becomes effective for the first time. In addition, Class VI well requirements include a number of provisions not required under Class II rules:

- Baseline geochemistry and seismic history;
- Post-Injection Site Care and Site Closure Plan;
- Emergency and Remedial Response Plan;
- More extensive Area of Review, including computational modelling and Corrective Action Plan;
- Financial responsibility and allowable instruments to address corrective action, post-injection site care and site closure, and emergency and remedial response.

Operation

Similar to the Planning, Permitting, and Construction phase, the Texas CO_2 Code requirements pertain mostly to reporting and monitoring, but are less stringent for CO_2-EOR than for CCS, although an annual $10,000 fee is required for CO_2-EOR. Fewer parameters need to be reported for CO_2-EOR than for CCS, and no event-driven reporting is specified for CO_2-EOR. Corrosion reporting is required for CO_2-EOR, but not for CCS.

Comparable to CCS, the UIC requirements for CO_2-EOR pertaining to the operation phase consist mostly of monitoring and reporting requirements. Numerous monitoring parameters are required for both (i.e. injection pressure), but the requirements are less detailed for CO_2-EOR. For example, Class VI requires plume and pressure front tracking, potentially surface air and soil monitoring, corrosion and ground water quality monitoring that goes beyond Class II requirements.

CCS and CO_2-EOR operations are both subject to the Greenhouse Gas reporting requirements; however they are applicable to different subparts, as follows:

- Subpart PP applies to suppliers of CO2, including the capture of CO2 from process units, extraction of CO2 from production wells, and import and export of CO2. Subpart PP would only apply to operators that also supply the CO2 for either CCS or CO2-EOR. It requires that the quantity of CO2 supplied be reported.
- Subpart RR applies to the geologic sequestration of CO2. Subpart RR does not apply to EOR unless the operator has an approved Monitoring, Reporting, and Verification (MRV) plan, or the wells are permitted as Class VI under the UIC program. Subpart RR requires an approved MRV plan that entails delineation of the monitoring area, identification and quantification of potential surface leakage pathways, and monitoring details for quantifying CO2 stored, fugitive and vented CO2.
- Subpart UU applies to the injection of CO2, but is not applicable if the operator reports under Subpart RR. Subpart UU applies to CO2 EOR and any CCS operations that do not report under Subpart RR.

Decommissioning and Post-Closure

As mentioned above, there is no well plugging plan or well closure plan for CO_2-EOR. Instead, certification standards for well plugging must be met. These include flushing the well with a buffer fluid, measuring the bottomhole reservoir pressure, performing final tests to determine mechanical integrity, and ensuring that the material to be used in plugging is compatible with the CO_2 stream and the formation fluids.

Per the UIC requirements, CO_2-EOR facilities for decommissioning are required to request approval for abandonment, whereas for CCS facilities pre-plugging activities, notice of intent to plug, and a plugging report are required. Class VI wells also require post injection site care or monitoring and a site closure plan, whereas Class II wells have no such requirements.

4.2.3 *Regulatory Transition Mechanisms from CO_2-EOR to CCS in Texas*

The regulatory framework has been reviewed to identify if there is a mechanism in place that allows CO_2-EOR to be transitioned to CCS.

Planning, Permitting, and Construction

Prior to adding or removing emitting equipment, or incurring any operational changes that result in a change in the quantity of air emissions or the pollutants that are released, facilities are required to obtain authorization from TCEQ via a construction permit amendment. This applies to transitioning from CO_2-EOR to CCS.

Per UIC requirements, facilities seeking to convert a Class II well to a Class VI well will need to apply for a Class VI permit when there is an increased risk to USDWs compared to Class II operations. TCEQ and EPA Region 6 determine this on the basis of increases in injection zone pressure, decreases in production rates, and increases in injection rate, distance to USDWs, among other factors. Presently, only EPA Region 6 has the authority to issue a UIC Class VI well permit.

The Texas CO_2 Code requirements for CCS do not preclude an enhanced oil recovery project from opting into a regulatory program that provides carbon credit for anthropogenic CO_2 sequestered through the enhanced recovery project. It is assumed that facilities transitioning from CO_2-EOR to CCS will need to apply for a permit to do so, although this is not explicitly stated.

Operation

It is assumed that once a CO_2-EOR project is approved as a CCS project, the regulations pertaining to operation of a CCS project will be applicable, including the preparation, approval and adherence to a MRV Plan per Subpart RR of the Greenhouse Gas Reporting requirements. However, no specific transition framework exists.

Decommissioning and Post-Closure

It is assumed that once a CO_2-EOR project is approved as a CCS project, the regulations pertaining to the decommissioning and post-closure phase of a CCS project will be applicable; however, no specific transition framework exists. It is assumed that all necessary permits will be obtained during the time when CO_2-EOR operations transition to CCS operations, as opposed to when the facility is being decommissioned.

4.2.4 *Case Study: Occidental Permian Denver Unit*

Occidental Permian (Oxy) operates CO_2 flooding for the purpose of enhancing the recovery of oil (i.e., EOR) at the Denver Unit in the Permian Basin in West Texas. The Denver Unit CO_2 flooding has been in operation since 1983, with plans for continued EOR for decades. Oxy proposes to continue with the CO_2 injection activities in the future for a period of at least 2016 to 2026 (the Specified Period), and is the first to successfully be approved by EPA for monitoring CO_2 storage. The project sets a precedent for setting out a potential pathway to transition EOR to CCS in the US.

The US EPA issued an assessment and approval for the first Monitoring, Reporting and Verification (MRV) Plan[18] for the project, under the US greenhouse gas reporting rule for CO_2 geological storage (subpart RR). This is the first MRV plan approved for CCS under subpart RR in the US for any facility. The project is also notable as a CO_2-EOR project and the wells are permitted under UIC Class II (i.e., EOR), rather than Class VI, which would normally be required for CCS.

There are a number of specific points that were addressed by Occidental in their MRV Plan. One of the most critical was undertaking analysis of the subsurface structures to determine the potential for CO_2 leakage. For CO_2-EOR, leakage of CO_2 from the reservoir is not an issue of particular importance; however, for CCS leakage is a critical issue to respective EPA Class II and VI regulators. The sub-surface assessment undertaken by Occidental provided evidence that there were:

> *"…no faults or fractures… in the project area… and that there are no leakage pathways at the Denver Unit that are likely to result in significant loss of CO_2 to the atmosphere".*

Occidental successfully made the case that the only leakage pathways were active and inactive well bores, with monitoring activities to detect leakage and mitigate risks. The specific monitoring activities in the MRV Plan include:

- Visual sighting of ice crystals, indicating leakage of the pressurized supercritical CO_2;
- Monitoring of H_2S via personal monitors to detect trace amounts of H_2S from leaks;
- Pressure monitoring of active and inactive wells, and changes in production levels for producing wells.

Monitoring during the specified period of 10 years includes reservoir pressure management, monitoring of operational wells along the boundaries of the lease, and simulations to model fluid behaviour in the reservoir. It is expected that it will be possible to make this demonstration within 2 – 3 years after

[18] USEPA (2015) Oxy Denver Unit CO_2 Subpart RR Monitoring, Reporting and Verification (MRV) Plan Final Version December 2015 https://www.epa.gov/sites/production/files/2015-12/documents/denver_unit_mrv_plan.pdf

injection for the Specified Period ceases and will be based upon predictive modeling supported by monitoring data.[19]

Reporting of the CO_2 sequestered in subsurface geological formations will entail a mass balance approach, taking into account the CO_2 injected, recycled, produced, and lost (fugitives, vents). After the 10 year specified period, Oxy will prepare a demonstration within 2-3 years "supporting the long-term containment determination and submit a request to discontinue reporting under the MRV Plan."

The Oxy project sets important regulatory precedents for Subpart RR accounting, but longer-term uncertainties around post-closure liability and CO_2 ownership remain. As discussed by IEA,[20] one of the key elements is that the project relies heavily upon existing oil and gas regulations and that the monitoring is undertaken as part of the ongoing oil production operations. Secondly, the project is permitted as a Class II well site and the MRV Plan only covers a period of 10 years, during active injection. The MRV Plan does not address closure, post-closure monitoring, or future assessment around the potential requirement to transition from Class II to Class VI wells.

4.3 *REGULATORY PATHWAY FOR CO_2-EOR TO CCS IN ALBERTA*

4.3.1 *Comparison of CO_2-EOR and CCS Regulation*

The governments of Alberta and Canada recognize the potential for EOR as a method of CCS, and as a means of helping to meet the emission reduction targets.

Alberta's regulations under the *Oil and Gas Conservation Act* apply to the approval and operation of CO_2-EOR. However, although CCS, CO_2-EOR (and Acid Gas Disposal) projects share many similarities and may overlap, they are subject to different regulatory frameworks in Alberta. These regulations are being reviewed, revised and implemented to address regulatory barriers.

Currently, a CO_2-EOR project in Alberta is regulated as any petroleum development that includes wells, pipelines or other structures, and requires a licence from the AER to construct and operate. Likewise, a CO_2-EOR project in Alberta requires a closure certificate from the AER for the wells, pipelines or other structures to be considered decommissioned.

4.3.2 *Key Regulatory Differences*

As discussed above, the *Oil and Gas Conservation Act* and its regulations provide a regulatory framework for approving and operating CO_2-EOR projects. However, the RFA and a review sponsored by the Alberta Economic

[19] 40 CFR 144.19 - Transitioning from Class II to Class VI.

[20] IEAGHG (2016) Information Paper: 2016-IP16; the first MRV plan approved by the USEPA for greenhouse gas reporting of CO_2 geological storage is for a CO_2-EOR operation.

Development Authority (AEDA)[21] identified a need to deal with various issues such as pore space ownership, unitization, tenure application process, surface rights, and short and long term liability for CO2-EOR projects to become CCS projects. Issues such as unitization and surface rights remain, and the application of the *Carbon Capture and Storage Statutes Amendment Act, 2010,* regarding post-closure transfer of ownership and liability for the CO_2 to the Government of Alberta, is not clear.

Because not all CCS opportunities can include EOR (for example, coal-fired power plants located a long distance from suitable oil fields), and because EOR is intended to benefit producers (by realizing an incremental increase in the oil extracted from an existing well) the provincial and federal governments' economic incentives are focused on reducing emissions using capture technology development and deployment. The financial incentive – or disincentive – of federal and provincial carbon taxes have been imposed on large industrial facilities since 2007. In 2017, the carbon price was extended to the entire provincial economy via a carbon tax on commercial fuels. Large final emitters paid $15 / tonne from 2007 to 2015, $20 / tonne in 2016, and $30 / tonne in 2017. An economy-wide fuel tax on carbon is $20 / tonne in 2017 and $30 / tonne in 2018; this is set to increase to $50 / tonne by 2022.

4.3.3 *Regulatory Transition Mechanisms for EOR to CCS*

The regulatory framework has been reviewed to identify if there is a mechanism in place that allows CO_2-EOR to be classified as CCS. Where this is explicitly stated or described this is identified.

Planning, Permitting and Construction

The *Oil and Gas Conservation Act* and its regulations provide a regulatory framework for approving and operating EOR projects. The RFA and the study by the AEDA in 2009 identified a need to supplement these regulations in the future with the expectation that EOR projects will mature into CCS. However, the applicable regulations have not yet been supplemented.

Operation

It is assumed that once an EOR project is approved as a CCS project, the regulations pertaining to operation of a CCS project will be applicable, including the preparation, approval and adherence to a MMV Plan. However, this transition framework is not yet in place.

Decommissioning

A CO_2-EOR project requires a closure certificate from the AER for the wells, pipelines or other structures to be considered decommissioned.

[21] The report, Carbon Capture and Storage in Enhanced Oil Recovery (AEDA, 2009) was an impetus for the RFA (http://www.assembly.ab.ca/lao/library/egovdocs/2009/aleda/173910.pdf)

It is assumed that a CO_2-EOR project approved as a CCS project is subject to the preparation, approval and adherence to MMV and Closure Plans. However, this transition framework is not yet in place.

Post-Closure

It is assumed that the *Carbon Capture and Storage Statutes Amendment Act, 2010,* regarding post-closure transfer of ownership and liability for the CO_2 to the Government of Alberta, will apply once a CO_2-EOR project becomes a CCS project. However, this transition framework is not yet in place.

4.4 POLICY FRAMEWORKS TO INCENTIVIZE CCS

Policies to promote CCS are needed to fully enable CCS technology to the extent needed to achieve the objectives set out in the Paris Agreement. Many countries included CCS as part of their initial Nationally Determined Contributions (NDCs) country commitments to reduce GHG emissions, and many more countries (including the US) allow CCS as a compliance mechanism. In fact, the IEA has estimated that CCS will need to contribute an estimated one-sixth of total CO_2 reductions by 2050 to limit global warming to 2°C,[22] and even more to achieve the ambitious goal of 1.5°C. CCS has been identified not only as the most effective technology to reduce CO_2 emissions from coal fired power generation, but also has the potential to achieve 'negative' GHG emissions from sequestering CO_2 emissions from biomass combustion or biofuels production.

While the need for CCS is recognized, the implementation of this technology in planned or active projects is extremely limited. A number of factors discourage implementation of CCS, but chief among them is high cost and regulatory uncertainty.

While addressing the high cost of CCS is a complex issue, policies and incentives can go a long way to encourage project developers to integrate CCS as an effective GHG reduction measure. Below are some of the potential ways that incentives could be shaped to promote CCS and/or CO_2-EOR:

- Federal and State/Provincial Grants: In Canada and the US, federal grants have helped incentivize CCS project development. For example, both the Quest project in Alberta and the ADM Industrial CCS project in Illinois were incentivized by federal grants. Broader availability of grants at both federal and state levels would help promote further investment in CCS and CO_2-EOR.
- Carbon Pricing: Putting a price on carbon can result in a demand for offsets that, if structured appropriately, can provide a financial incentive for CCS. The carbon tax in Alberta and the carbon tax in Norway (currently at $80/MT) are both examples of governments using carbon pricing to help incentivize CCS.

[22] IEA website, http://www.iea.org/topics/ccs/

- Extend and Expand Tax Incentives: In the US, the IRS Section 45Q provides tax credits of $20/MT and $10/MT for CCS and CO_2-EOR, respectively. While these tax credits are important, they are too low and have limitations that create uncertainties for project developers as discussed previously (i.e., program is capped at 75 million MT, owner of CO_2 emitting facility and capture equipment must be the same, and minimum eligibility threshold of 500,000 MT per year). New legislation was introduced in both the House and Senate to revise the 45Q tax incentives to be more inclusive and offer more long-term certainty that the credits will be available to project developers. In a recent report on state and federal policy drivers to encourage CO_2-EOR, the level of tax credits would need to be substantively higher at "$35 per MT for EOR storage and $50 per MT for saline storage" to achieve around "50 million MT of annual CO_2 capture coming on line by 2030, or about 10 GW of power plant carbon capture capacity installed."[23]
- Contracts to Stabilize CO_2 Prices. Traditionally, CO_2 prices in contracts have been indexed to the price of oil. This has created market risk and earnings uncertainty, stifling investment in CCS and CO_2-EOR. The last Senate Energy bill included a provision for the DOE to study how contracts for differences (CfDs) could be established to provide a uniform oil price index over the term of the contract to provide financial certainty for CCS project developers. The concept is that the federal government either pays or gets paid for the delta between actual oil prices and the CfD contractual price.
- Incentivizing Private Capital[24]: In the US, the federal government allows the states permission to issue over $30 billion per year of tax-exempt private activity bonds (PABs). Allowing CCS and CO_2-EOR projects to participate in the PAB market would offer attractive debt financing alternatives. Similarly, if Congress extended master limited partnership (MLP) eligibility to CCS projects the cost of equity would be reduced, thus attracting private capital.

[23] Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO2-EOR Industry, Dec. 2016.

[24] Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO2-EOR Industry, Dec. 2016.

5 KEY FINDINGS

The Paris Agreement that entered into force on November 4, 2016 sets out an aggressive path forward for reducing GHG emissions in order to stabilize global temperatures to well below 2°C. In order to meet such ambitious goals, widespread adoption of CCS is necessary (e.g., IEA estimates that CCS will need to account for an estimated one-sixth of the reductions by 2050). However, CCS remains a high cost option with low uptake at commercial scale, principally due to cost and regulatory uncertainty. CO_2-EOR projects, in contrast, are primarily implemented to increase oil and gas production, with any long term storage of CO_2 an ancillary benefit if the price of CO_2 is credited; otherwise it is a financial liability. These projects could potentially be transitioned to CCS and help meet the longer-term GHG reduction goals.

Chapter 2 examined the regulatory pathways in two jurisdictions, Texas, USA and Alberta, Canada, to identify gaps in the regulations and policies/incentives that could be put in place to help overcome those gaps. The study sets out the regulatory pathway for CCS without EOR, to set the stage for what a CCS project requires before comparing to an EOR project. The differences between CCS and EOR regulatory requirements are then examined to identify areas of focus for the transition of EOR to CCS. Key policies and incentives are identified that could help influence project developers to invest in CO_2-EOR and/or CCS.

Table 5.1 below shows a summary of the regulatory pathway for a CCS project in Texas and Alberta, where green indicates that regulations are in place, amber that the pathway is unclear or unproven, and red that there is no pathway.

Table 5.2 shows a summary of the CO_2-OER to CCS regulatory pathway, summarising Section 4 of this report. Green indicates where clear regulations are in place for recognising CO_2-EOR as CCS; amber where the regulations are absent or unproven.

Table 5-1. Summary of CCS Regulatory Pathways in Texas and Alberta

Location	Project Phase	Media					
		Air	Subsurface	Water	GHG Reporting	Monitoring	Incentives
Texas, USA	Planning and Permitting						
	Operation						
	Decommissioning and Post-Closure						
Alberta, Canada	Planning, Permitting and Construction						
	Operation						
	Decommissioning						
	Post-Closure						

Table 5-2. Summary of CO_2EOR to CCS Transition in Texas and Alberta

Location	Project Phase	Status	Comments
Texas, USA	Planning and Permitting		Uncertainties exist around transition from Type II to Type VI wells
	Operation		CO2 EOR and CCS have similar compliance requirements
	Decommissioning and Post-Closure		Uncertainty in well plugging requirements
Alberta, Canada	Planning, Permitting and Construction		A clear regulatory framework exists for CCS and separately for CO_2-EOR. However, the Government of Alberta has not yet put in place regulatory framework for the transition, and uncertainty remains.
	Operation		
	Decommissioning		
	Post-Closure		

5.1 *TEXAS REGULATORY PATHWAY FOR CCS*

The Texas government supports CCS as a means to reduce greenhouse gas emissions via House Bill financial incentives. The regulatory pathway for a CCS project is in place for Texas, although no projects to date have either applied for or been permitted under the UIC Class VI requirements to protect drinking water. The regulatory pathway is in place for a CCS project in Texas, with the following key points:

- In all phases of a CCS project, the regulatory pathway for water quality is unproven in Texas because there have been no projects to date in EPA Region 6 that have applied for a UIC Class VI well permit. However, in EPA Region 5, there have been Class VI permits approved including the ADM Illinois Industrial CCS project (presented as a case study). Because the requirements for a UIC Class VI well permit are rigorous and no experience exists in EPA Region 6, this has been flagged as being an existing, but unproven, pathway;
- GHG reporting under Subpart RR is required for all CCS projects. EPA recently approved the first MRV Plan under Subpart RR for the Oxy Denver Unit project in Texas that is permitted under UIC Class II (i.e., as EOR injection well). EPA has also recently approved a Subpart RR MRV Plan for the ADM CCS project in Illinois that is permitted under UIC Class VI. For the post-closure phase, responsibility for GHG reporting for any leaks of CO_2 to the atmosphere is not explicitly addressed in the Subpart RR MRV Plans approved to date. Rather, there is a fixed period of reporting for each of the MRV Plans approved to date. Presumably, the obligation for reporting post-closure CO_2 leakage would follow the responsible party who received recognition for the avoided CO_2 liability from emissions credits during the operational stage of the project. This ambiguity about the party responsible for reporting post-closure CO_2 leakage is a gap or uncertainty in the current regulatory pathway.

5.2 *TEXAS REGULATORY PATHWAY FOR TRANSITIONING FROM CO_2-EOR TO CCS*

In Texas, the regulatory pathway for an EOR project is mature, with over 30,000 CO_2-EOR projects permitted to date. While this is the case, only one project has recently been accepted by EPA to monitor and account for the CO_2 injected as a long-term storage project. The Oxy Denver Unit has been operational since 1983, injecting CO_2 for EOR in the Permian Basin. Although it is permitted as an EOR project with a Class II well permit approved by the Texas RRC, Oxy has opted to report the avoided GHG emissions from the project as a CCS project under Subpart RR of the GHG Reporting Rule, and an MRV Plan has been approved for this Texas project. Oxy has also recently gained approval for a second Subpart RR MRV Plan for the Hobbs Field CO_2-EOR project in New Mexico[25] that is similar to the Denver Unit project.

[25] USEPA (January 2017) Oxy Hobbs Field CO2 Subpart RR Monitoring, Reporting and Verification (MRV) Plan

To transition from a CO_2-EOR to a CCS project, a number of considerations would need to be addressed:

- In EPA's final guidance on transitioning from a UIC Class II to Class VI permit, it allows for injecting CO_2 for the primary purpose of long-term storage into an oil and gas reservoir under a Class II EOR permit, unless there is an increased risk to USDWs. The considerations for determining if a Class VI permit is required include factors such as the suitability of the Class II area of review delineation and plan for recovery of CO_2 at the cessation of injection, along with specific monitoring metrics. While some uncertainty remains, this guidance allows project developers more clarity to address some of the areas that will be subject to review and plan in advance for managing the risk under a Class II permit. For example, a more robust area of review delineation and monitoring program than is required under a Class II permit may avoid the requirement to obtain a Class VI permit in the future.
- While EOR projects are not required to report avoided emissions, voluntary opt in for reporting under Subpart RR of the GHG Reporting Rule would be necessary for a project transitioning from CO_2 EOR to CCS. As part of the Subpart RR requirements, a MRV Plan must be approved by the EPA to commence reporting avoided emissions under Subpart RR. To date, EPA has only recently approved three MRV Plans under Subpart RR, two of which are for CO_2-EOR projects in the Permian Basin in Texas and New Mexico.
- In the decommissioning and post-closure phase, there is no specific framework that exists for transitioning a CO_2-EOR to CCS project, outside of the UIC Class II to VI permitting guidance. It is assumed that once a CO_2-EOR project is approved as a CCS project, the regulations pertaining to the decommissioning and post-closure phase of a CCS project will be applicable.

While no projects have formally gone through this transition in Texas, the Oxy CO_2-EOR projects (Texas: Denver Unit and New Mexico) that recently gained approval for their Subpart RR MRV Plans are precedent setting and should be closely followed.

5.3 *ALBERTA REGULATORY PATHWAY FOR CCS*

The Government of Alberta supports CCS as a means to meet GHG emission reduction targets, with financial incentives and disincentives in place to reduce greenhouse gas emissions and to promote CCS. The introduction of carbon taxes in Canada will provide further incentive for CCS projects.

The regulatory pathway in Alberta is established and in place. The *Carbon Capture and Storage Statutes Amendment Act, 2010* (also known as Bill 24) has promoted and simplified the regulatory process for CCS in Alberta. In addition, several legislative changes have recently been made, and more are expected. In particular, the CCS project closure process is new in Alberta and more development is needed to protect proponents, operators and the public.

During operations, monitoring must demonstrate compliance with regulations and an MMV Plan must be approved, and be updated every three years. A Closure Plan is also required as part of the MMV Plan, and if the performance criteria are met, and operator can apply for a closure certificate. The time period for monitoring after decommissioning is not yet decided, but a 10-year minimum period before issuing a closure certificate is being considered. When issuing a closure certificate, the Government of Alberta becomes the owner of all injected CO_2, and assumes all obligations of the lessee, including responsibilities related to wells and facilities, the environment and land. However, the liabilities assumed by the government do not include liability for CO_2 credits. A Post Closure Stewardship Fund (PCSF) has been established which requires holders of carbon sequestration leases to pay into the fund. While recent legislative changes have been made, more are expected pending the implementation of the RFA.

5.4 ALBERTA REGULATORY PATHWAY FOR TRANSITIONING FROM CO_2-EOR TO CCS

A regulatory framework exists in Alberta for approving and operating EOR project. However, the Albertan government has identified a need to supplement the EOR regulations with the expectation that EOR projects will mature into CCS. However, the applicable regulations have not yet been supplemented. As such, the transition framework is not yet in place.

5.5 POLICY FRAMEWORKS TO INCENTIVIZE CCS AND CO_2-EOR TRANSITION TO CCS

Although regulatory frameworks are in place in Texas and Alberta for CCS, these pathways are less certain for the transition of CO_2-EOR to CCS. Enhanced policies and incentives to fully enable CCS technology to overcome market and regulatory barriers are needed. Such policies and incentives that could help promote CCS and CO_2-EOR include:

- Federal and state/provincial grants, such as DOE grants for CCS projects in the US;
- Carbon pricing that ascribes a monetary value to avoided CO_2 emissions, such as carbon taxes in Alberta;
- Improved tax incentives, such as the proposed changes to IRS Section 45Q in the US to extend and expand the tax credits for CCS and CO_2-EOR;
- Contractual arrangements to encourage CO_2-EOR, such as contracts for differences to stabilize CO_2 prices in the US;
- Incentives for private capital through market mechanisms, such as private activity bonds and master limited partnerships in the US;
- Clarification of liability if CO_2 leaks from CO_2-EOR post closure.

It was currently not possible to assess the potential of market mechanisms under the Paris Agreement to facilitate CCS projects in the future because the definition, structure, operation and coverage of such mechanisms have yet to be determined. Although greater clarity on the nature of such market mechanisms is awaited, it is encouraging to note that an approved methodology already exists under the UNFCCC GHG accounting procedures for reporting emissions avoided by CCS projects.

The Intergovernmental Panel on Climate Change (IPCC) Guidelines for National GHG Inventories now in force contain a specific chapter on GHG reporting for CCS projects (IPCC 2006 Guidelines, Volume 2, Chapter 5 - http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol2.html).

Since the national GHG inventories prepared under these IPCC Guidelines will be the basis for measuring each country's progress toward meeting its national contributions under the Paris Agreement, the emissions avoided from CCS projects should be recognised as part of such contributions. Whether and how the avoided emissions recognised from CCS might receive credit or be tradeable under future market mechanisms remains to be seen.

Project element	CCS Facility, pipeline, wells and subsurface
Project phase	**Planning, Permitting, and Construction[26]**
Regulation	**Requirements**
Environmental Protection and Enhancement Act (EPEA), Revised Statutes of Alberta 2000 Chapter E-12	• EPEA aims to protect air, land, and water • EPEA and accompanying regulations sets out which activities require approvals and the requirements for obtaining them. • prohibits the release of a substance in an amount that may cause a significant adverse effect • CCS projects do not require an environmental impact assessment (EIA) under EPEA, but an EIA may be triggered by AER as a discretionary activity
Public Lands Act, Revised Statutes of Alberta 2000 Chapter P-40	• Alberta Environment and Parks (AEP) regulates the construction and operation of surface infrastructure, by means of: o a mineral surface lease on public lands o an approval under the Conservation and Reclamation (C&R) Regulation, requiring C&R plans describing the pipeline and injection well construction and operation and the associated environmental protection measures. • Construction and operation of surface infrastructure on private land requires an agreement between the lessee and the landowner
Alberta Land Stewardship Act, Statutes of Alberta, 2009 Chapter A-26.8	• Required compliance with any approved regional plans
Oil and Gas Conservation Regulations (OGCR), Statutes of Alberta, 2009 Chapter A-26.8	Required approvals from Alberta Energy Regulator (AER) according to: • Directive 008: - Surface Casing Depth Requirements – regulates the minimum requirements for the depth of surface casing. • Directive 009: Casing Cementing Minimum Requirements, and Directive 010: Minimum Casing Design Requirements – regulate the minimum requirements for well cementing and design. • Directive 036: Drilling Blowout Prevention Requirements and Procedures – the requirements for drilling blowout prevention. • Directive 44: Requirements for Surveillance, Sampling, and Analysis of Water Production in Hydrocarbon Wells Completed Above the Base of Groundwater Protection - for wells completed in fresh water aquifer(s). • Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements – for CO2 disposal well approval • Directive 56: Energy Development Applications and Schedules - for Well License approvals to drill injection, deep

[26] The Acts and Regulations listed in this table are specific to permitting a CCS project. The Acts and Regulations applicable to the surface and subsurface developments required for a CCS project, which are related to oil and gas developments, are listed in Appendix A.

	monitoring and groundwater monitoring wells, or to change well type from test to injection (if applicable); for a pipeline (non-routine) to transport CO2 • Directive 065: Resources Applications for Oil and Gas Reservoirs – for an approval to dispose of CO2 • Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry
Canadian Environmental Assessment Act (CEAA 2012)	Project may require an EIA if federal funding is available and pursued. The CEAA and EPEA may rely on the Canada–Alberta Agreement for Environmental Assessment Cooperation. (In the past, the Agreement has designated AEP as the lead party, and Natural Resources Canada (NRCan), as the responsible authority under federal legislation, determined that a screening-level EA was required under the CEAA.)
Pipeline Act, Revised Statutes of Alberta 2000 Chapter P-15	Applies to all pipelines in Alberta, with exceptions related to on-site pipelines and federal (NEB) jurisdiction
Historical Resources Act, Revised Statutes of Alberta 2000 Chapter H-9	To meet Alberta Culture requirements, a Historical Resources Impact Assessment (HRIA), assessing potential impacts to historical and palaeontological resources is required
Oil Sands Conservation Act, Revised Statutes of Alberta 2000 Chapter O-7	If applicable, to construct and operate facilities for the capture of CO2
Water Act, Revised Statutes of Alberta 2000 Chapter W-3	Licensing will be determined by AEP. Typical carbon capture infrastructure will not require a new Water Act approval. However, AEP approval may be needed for pipeline agreements (e. g., dispositions for Crown lands) at watercourse crossings.
Fisheries Act, R.S.C., 1985, c. F-14	Authorizations from the Department of Fisheries and Oceans Canada (DFO) can be required for watercourses crossings by surface infrastructure.
Navigable Waters Protection Act, R.S.C., 1985, c. N-22	Approval by Transport Canada can be required for watercourse crossings by surface infrastructure.
Canada Transportation Act, S.C. 1996, c. 10	Authorizations for railway crossing agreements for surface infrastructure will be determined by the Canadian Transportation Agency.

Project element	**CCS Facility, pipeline, wells and subsurface**
Project phase	**Operation**
Regulation	**Requirements**
Oil and Gas Conservation Regulations (OGCR), Statutes of Alberta, 2009 Chapter A-26.8	Approvals from Alberta Energy Regulator (AER) under: • Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry • Directive 077: Pipelines – Requirements and Reference Tools - describes the integrity management programs for CO2 pipelines • Alberta Energy Regulator Directive 51 - Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements – describes the monitoring requirements for injection wells.
Environmental Protection and Enhancement Act (EPEA), Revised Statutes of Alberta 2000 Chapter E-12	• EPEA aims to protect air, land, and water prohibits the release of a substance in an amount that may cause a significant adverse effect • Air Monitoring Directive and Ambient Air Quality Objectives • Facility or operation specific EPEA Approval for environmental monitoring.

Project element	CCS Facility, pipeline, wells and subsurface
Project phase	**Decommissioning**
Regulations	**Requirements**
Oil and Gas Conservation Regulations (OGCR), Statutes of Alberta, 2009 Chapter A-26.8	Directive 020: Well Abandonment – addresses the conformance and containment requirements for abandonment of wells used for CO2 sequestration
Environmental Protection and Enhancement Act (EPEA), Revised Statutes of Alberta 2000 Chapter E-12	• EPEA aims to protect air, land, and water prohibits the release of a substance in an amount that may cause a significant adverse effect • Facility or operation specific EPEA Approval for decommissioning.

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