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Combining CO_2 Enhanced Oil Recovery with Permanent Storage in Mexico

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Combining CO_2 Enhanced Oil Recovery with Permanent Storage in Mexico

FINAL REPORT
Review of Current Status and Identification of Key Issues

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Final Report

Review of Current Status and Identification of Key Issues

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Executive Summary

The goal of the current project is to review state-of-the-art practices related to combining carbon dioxide (CO_2) enhanced oil recovery (EOR) with geologic storage for carbon capture, utilization and storage (CCUS) in Mexico. This was accomplished by an assessment of the requirements a CO_2-EOR project must satisfy in order to qualify as a permanent storage project to earn carbon credits. The material presented is based on review of latest literature, discussions with relevant experts, as well as Battelle's direct experiences from multiple in-house geologic CO_2 storage projects. The report focuses on the key technical and practical considerations and provides an overview of related technologies for economic and efficient CO_2-EOR storage.

The technology and operational practices for CCUS have been developed over decades of CO_2-EOR experience established in the oil and gas industry. Hence, the key barriers and uncertainties in accounting for associated CO_2 storage during CO_2-EOR operations are not technical but economic and policy-related. While economic favorability can be improved by investing in improvements to the current CO_2 infrastructure, strong constructive policy measures for geologic CO_2 storage are also important.

CO_2-EOR projects demonstrating storage of anthropogenic CO_2 in Mexico may be eligible to provide carbon credits. The minimum requirements to gain storage credits according to protocols stated in the United Nations Framework Convention on Climate Change Clean Development Mechanism (CDM), California Cap-and-Trade Regulation Instructional Guidance, American Carbon Registry, and U.S. Environmental Protection Agency regulatory guidance were compared and contrasted. The protocols typically outline requirements as performance measures without prescribing technologies to meet these requirements. Accordingly, there is significant flexibility for the project proponent to fashion the project details and submit for approval plans that describe how requirements will be met.

Many of the requirements for storage within EOR will be built on the operator's business as usual, but others will require additional effort to confirm storage integrity. Secure permanent geologic storage of CO_2 must be documented by operators by showing how sites have been characterized and existing wells evaluated to ensure containment. EOR projects may require some operational or reporting modifications to qualify for regulatory and other credit-related requirements. Additional monitoring or reporting, for instance, may be needed to track and demonstrate CO_2 storage beyond typical EOR operations. Likewise, modeling efforts may be modified to optimize storage and for use as a tool to show storage integrity in the reservoir of interest.

The monitoring, reporting and verification (MRV) plan to track the CO_2 storage within the EOR project boundaries and developed in consultation with the pertinent regulatory and credit granting agencies is a major consideration that helps the operator proactively manage project risks. Because the monitoring program in any of the protocols mentioned above is derived from risk assessment, the recommendations for the MRV program presented in this report form a 'tiered' approach based on the risks identified. Primary requirements would be reservoir zone monitoring to adequately track the pressure, temperature and CO_2. Should leakage signals be detected, the second tier of monitoring for leakage detection and management would be implemented by monitoring above-zone; and, as the third tier, near-surface and surface monitoring would be implemented.

While the same monitoring and modeling technologies are applicable for CCUS and geologic storage projects, CCUS project operators may need to make additional investment in monitoring, measurement and reporting to characterize, manage and ensure long-term integrity of storage as well as optimal EOR operations. The CO_2 quantification and reporting requirements as well as the post-closure obligations are

crucial to provide a pathway to the credit standards that constitute best practices for responsible geologic storage operations while protecting stakeholder support for the same.

While CO_2-EOR projects demonstrating storage of anthropogenic CO_2 may be eligible to earn carbon credits, this study did not identify any CO_2-EOR projects with associated storage, or transitioning to storage without EOR, as having applied for or received credits. The lack of experience with applying CDM and European Union protocols to CCS projects in general and to EOR projects in particular could prove a hindrance, as could the absence of any provisions in these protocols that are specifically tailored to oil field operations. Under the European Union Emission Trading System Directive, an offset project involving the incidental storage of anthropogenic CO_2 in association with an EOR project in Mexico could be creditworthy if it meets the requirements of the CDM CCS methodology. Because no such projects have been considered and credited to date, however, uncertainty surrounds the qualification process. Practical implementation will be indispensable to qualification without imposing untenable economic costs. Although the ongoing process for developing ISO standards for CO_2 capture, transportation and storage - including incidental storage in association with EOR - promises to provide a better pathway to credits, final standards are still several years away.

An offset project in Mexico has the potential to qualify for credit for the California Cap-and-Trade Program; however, significant steps must be accomplished before the availability of credit could be a reality. First, the California Air Resources Board (ARB) needs to approve a Compliance Offset Protocol for CO_2 geologic sequestration associated with EOR. In addition, that approved protocol must include Mexico within approved project area. Before that process is completed, it would also be useful to have California ARB approval of an early action quantification methodology for geologic sequestration associated with CO_2-EOR. This approval could be based on the American Carbon Registry protocol, but that protocol would need to be expanded to include Mexico in addition to the U.S. and Canada.

Despite the challenges imposed by the evolving regulatory and credit mechanisms, it is widely agreed that the CO_2-EOR projects provide a viable and economically attractive pathway for greenhouse gas emission reduction and a potential bridge to storage in saline formations. However, there is a need to build more project experience and test the various credit mechanisms under realistic conditions. For Mexico, any planned EOR field tests, even if these are huff-n-puff or small-scale pilots offer an early opportunity to build the practical knowledge and lay the foundation for successful credit accruals for future full-scale projects. Therefore, it is recommended that the risk management, modeling, monitoring, and accounting activities identified in this report be implemented and evaluated as a prototype in the upcoming feasibility tests.

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Acronyms

3D	three-dimensional
ACR	American Carbon Registry
API	American Petroleum Institute
ARB	Air Resources Board
ARI	Advanced Resources International
ASEA	(Mexico) Safety, Energy and Environment Agency
CBL	cement bond log
CCR	California Code of Regulations
CCS	carbon capture and storage
CCUS	carbon capture, utilization, and storage
CER	certified emission reduction
CMG	Computer Modeling Group
CMM	(Mexico) Centro Mario Molina
CNH	(Mexico) National Hydrocarbon Commission
CO_2	carbon dioxide
DOE	Department of Energy
EOR	enhanced oil recovery
EU ETS	European Union Emissions Trading System
FEP	Features, Events and Processes
GHG	greenhouse gas
H_2S	hydrogen sulfide
HCPV	hydrocarbon pore volume
IEAGHG	International Energy Agency Greenhouse Gas R&D Program
IMP	Mexican Institute of Petroleum
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
JI	Joint Implementation
Metric ton	1000 kg (also denoted as tonne)
mD	millidarcy
MIT	mechanical integrity test
MRCSP	Midwest Regional Carbon Sequestration Partnership
MVA	monitoring, verification, and accounting

MRV	monitoring, reporting, and verification
MST	monitoring, sampling, and testing
NETL	National Energy Technology Laboratory
PCOR	Plains CO_2 Reduction
PEMEX	Mexico's state oil company
PENS	Predictive Engineered Natural Systems
PNC	pulsed neutron capture
psi	pounds per square inch
PTRC	Petroleum Technologies Research Centre
ROZ	residual oil zone
RRC	Railroad Commission of Texas
SCADA	supervisory control and data acquisition
SEM	static earth model
SEMARNAT	(Mexico) Department of Environment and Natural Resources
SENER	(Mexico) Department of Energy
UIC	underground injection control
UNFCCC	United Nations Framework Convention on Climate Change
U.S. EPA	United States Environmental Protection Agency
WAG	water-alternating-gas

Chapter 1 Introduction

1.1 Background

Evolving environmental regulatory directives have generated interest and investment to reduce carbon dioxide (CO_2) emissions from large point sources using carbon capture and storage (CCS) technologies. CCS is a suite of technologies integrated to capture and transport CO_2 from major point sources to a storage site where the CO_2 is injected down wells and into porous geological formations deep below the surface. There it is trapped and permanently stored. CO_2 enhanced oil recovery (CO_2-EOR) is a promising option to move CCS forward by enabling development of carbon capture at industrial sites and pipeline infrastructure for CO_2 transport. When executed synergistically, EOR and CCS are referred to as carbon capture, utilization, and storage (CCUS).

CO_2-EOR is a proven technology that has been underway in the U.S. for decades, beginning in the Permian Basin and expanding to other regions of the United States (Figure 1-1). Today, there are more than 136 active commercial CO_2-EOR projects in the United States. Combined, they inject more than 3 billion cubic feet of CO_2 and produce more than 300,000 barrels of oil per day (Kuuskraa and Wallace, 2014). An estimated 14 million metric tons of industrial CO_2 was stored in 2014 through CO_2-EOR (Kuuskraa and Wallace, 2014). One barrier to increased use of CO_2-EOR is limited supply of available, affordable CO_2. CCUS technology development can accelerate deployment of viable options for reducing CO_2 emissions related to large point sources while increasing oil production.

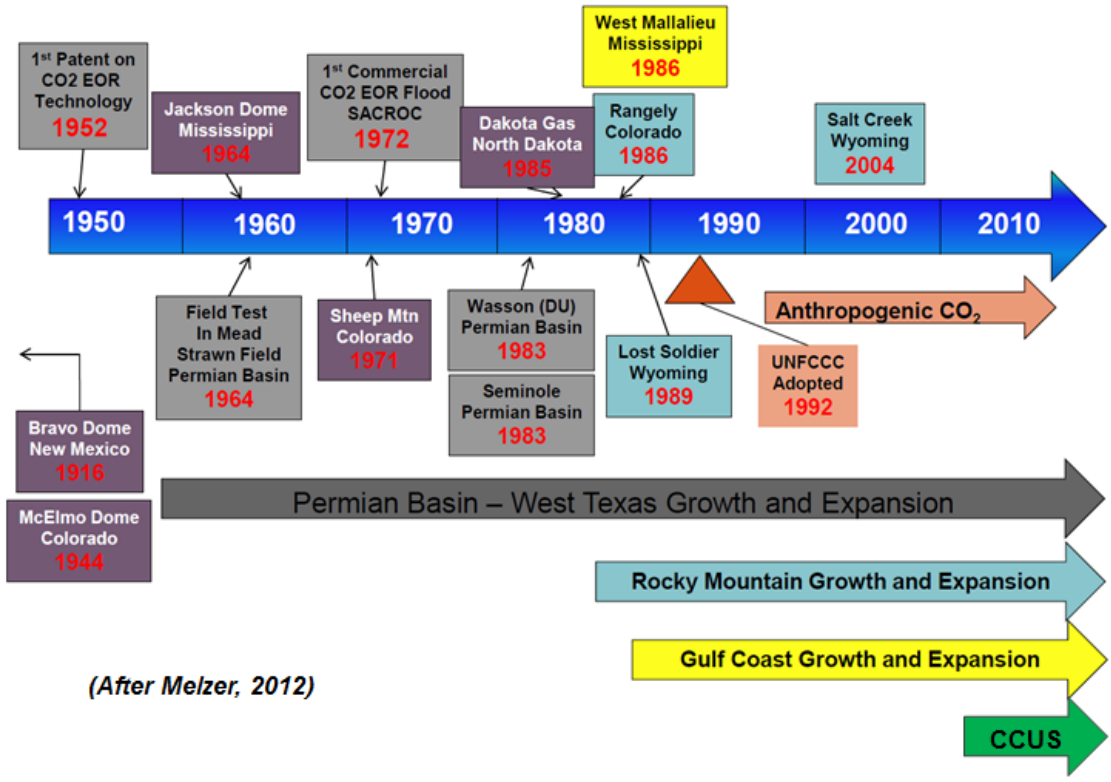


Figure 1-1. Technology status for CO_2-EOR and CCUS

The CO_2-EOR phase of a project does not need to be complete before CO_2 storage occurs. Associated storage is recognized as a valid mitigation strategy. In a memorandum dated April 23, 2015, the United States Environmental Protection Agency (U.S. EPA, 2015) clarified that CO_2 storage associated with wells permitted for EOR is a common occurrence and that CO_2 can be safely stored where injected through permitted wells for purpose of oil or gas-related recovery. Greenhouse gas mitigation frameworks and protocols support CO_2-EOR storage as a reduction technology that can be credited when used in an offset project. These include United Nations Framework Convention on Climate Change (UNFCCC) Clean Development Mechanism, European Union Directives, California Cap-and-Trade Regulation, American Carbon Registry, and others. Because CO_2-EOR with associated storage is recognized as a valid mitigation strategy, this report examines issues related to associated storage, along with CO_2-EOR transitioning to pure storage. Hereafter, this report generally refers to these approaches as CO_2-EOR storage projects unless otherwise distinguished.

1.2 Objectives

The objectives of this assignment were identify technical issues: (1) to ensure future CO_2-EOR operations in Mexico can be recognized as permanent storage, and (2) that the mass of injected CO_2 is considered towards national emission reduction goals and/or eligible for national or international credit trading mechanisms. In this initial step, the Project Task Force, which includes representatives of PEMEX (Mexico's state oil company), SENER (Department of Energy), the World Bank and other organizations[1], focused on additional requirements that a CO_2-EOR project has to satisfy to qualify as storage. This was achieved through a review of existing literature; compilation of expert views; and identification of key issues related to CO_2-EOR storage projects. The findings of the research were shared with the Mexican stakeholders to ensure recommendations can be implemented before start of CO_2-EOR projects. A summary of the methodology and outcomes are provided here:

- **Review of Current Status on CO_2-EOR Storage** - Battelle conducted a literature review including 10 documents provided by World Bank and two documents added by Battelle (see Appendix A and Section 2.1). Battelle also solicited expert opinions through personal interviews and discussions (see Section 2.2). Lastly, a summary of key reservoir parameters related to CO_2-EOR and storage was developed for the region surrounding Cinco Presidentes fields from published literature (see Section 2.3).
- **Identification of Key Issues** - The information collected during the literature search and expert interviews was compiled and synthesized into tables and figures to highlight key issues for CO_2-EOR storage with relevance to Mexico. This was supplemented with Battelle's experience in conducting CO_2 storage and utilization projects in the US. Key issues and recommendations are summarized in Section 3.0. International frameworks for receiving offset credits are summarized in Section 4.0.
- **Technology Transfer** - Technology transfer activities included the completion of the interim report, stakeholder workshop, final report, and a training workshop to distribute information about combining CO_2-EOR with permanent storage for stakeholders in Mexico. Key stakeholder groups included PEMEX, SENER, SEMARNAT (Department of Environment and Natural Resources), CMM (Centro Mario Molina), IMP (Mexican Institute of Petroleum) and others. See Appendix B for the workshop agendas and list of participants.

[1] IMP (Mexican Institute of Petroleum), CNH (National Hydrocarbon Comission), ASEA (Safety, Energy and Environment Agency) and SEMARNAT (Ministry of Environmnet and Natural Resources)

Chapter 2 Literature Survey on the State-of-the-Art CO_2-EOR Storage

The objectives of the literature review and expert interviews were to assess current expert views on the issues concerning combining CO_2-EOR with geological storage (i.e., CO_2-EOR storage projects); identify key issues that need to be addressed with respect to Mexico; and provide recommendations to PEMEX on how to implement the required measures to enable CO_2-EOR projects to qualify for permanent storage. The literature review and interviews served as the foundation and support for the recommendations contained in Section 3. The current view on technical and economic barriers, optimization strategies; monitoring, reporting, and verification (MRV) requirements, and other issues are presented below.

2.1 Literature Review

The literature review provided a critical and in depth evaluation of technical and economic issues related to combining CO_2-EOR with permanent storage. The survey included primarily literature identified by the client with additional literature selected based on relevance and newness. Twelve sources of information were reviewed in detail, including journal papers, independent consulting reports, research papers and guidance documents published between 2008 and 2015. Collectively, the literature explored topics such as technical issues, crediting and monitoring requirements, and site selection (Table 2-1). A detailed summary of the most pertinent information contained in these documents is included in Appendix A.

CO_2-EOR storage is being increasingly recognized as an important strategy for mitigating climate change. The use of CO_2-EOR for purpose of geologic storage has many practical advantages. Literature and experts generally view CO_2-EOR as a proven technology. Technologies and methodologies for injection, production and monitoring have been in use and refined over the past few decades. Other than CO_2 supply and processing, candidate CO_2-EOR sites typically have modest infrastructure demands, because in most cases existing wells can be used directly or with some modifications for injection and production. Finally, a number of monitoring methodologies for establishing the quantity of CO_2 stored have been demonstrated.

However, some key differences exist between CO_2-EOR and CO_2-EOR storage. First, the motivation for these two types of projects is different. For CO_2-EOR projects, the motivation is oil production. For permanent storage, the motivation is storing CO_2 or earning CO_2 credits. The second key difference is the impact that incentives to store anthropogenic CO_2 can have on project economics. For CO_2-EOR projects, the incentive is to recycle CO_2; for storage, the incentive is to operate in a manner that store increasing amounts of CO_2 in the subsurface, while still enabling incremental oil production. A third key difference is the incremental monitoring and reporting requirements for CO_2-EOR storage that go beyond those for CO_2-EOR projects, adding cost and uncertainty as to what is required to qualify for storage. Challenges and opportunities arise where these differences occur. The literature survey examined these differences and how they have been addressed.

Table 2-1. A broad overview of the literature consulted upon and the issues discussed by each

Paper or Report Name	Description	Economics	Optimization Strategies	MRV
Technical Challenges in the Conversion of CO_2-EOR Projects to CO_2 Storage Projects (CSLF, 2013)	A comprehensive summary on various issues surrounding the use of CO_2 for EOR and/or CO_2 sequestration operations. Concludes that the fundamental challenges for all such CO_2 projects, transitory or otherwise, are not technical in nature.	X		X
CO_2-EOR: Factors Involved in Adding CCUS to Enhanced Oil Recovery (Melzer, 2012)	Highlights the significance and possibilities for CCUS via the medium of CO_2-EOR. The report stresses that CO_2-EOR is an effective solution to storing CO_2 due to the synergies possible, the number of opportunities available as well as the volume of CO_2 that can be put away in such reservoirs, but cites regulatory and economic impediments.	X		X
Geologic Carbon Storage through Enhanced Oil Recovery (Hill, Hovorka et al., 2013)	Various aspects associated with CO_2 storage in an EOR project are discussed, ranging from an overview of tertiary recovery in the U.S. to CO_2 supply-demand to CO_2 transport pipelines. Most noteworthy discussions are centered on the attractive potential for CO_2 storage via residual oil zones (ROZs) and advantages that CO_2-EOR storage has over pure storage.		X	X
Optimization of CO_2 Storage in CO_2 Enhanced Oil Recovery Projects (ARI and Melzer Consultanting, 2010)	Geared toward educating policymakers on the immense possibilities and the potential environmental implications of CO_2-EOR projects for CO_2 storage, and strongly suggests that resolving the uncertainty in the regulatory and legal issues surrounding CCS/CO_2-EOR is a worthwhile cause.		X	X
CO_2-driven Enhanced Oil Recovery as a Stepping Stone to What? (Dooley et al, 2010)	Plays the role of devil's advocate and is written primarily to push forth the view that CO_2-EOR is neither a sustainable means in itself nor the correct way forward to achievable commercial deployment of CCS.	X		
Global Technology Roadmap for CCS in Industry Sectoral Assessment: CO_2 EOR (Godec, 2011)	Discusses the immense potential for CCS and the growth of the EOR industry and also presents unique information summarizing the economic factors for EOR.	X		
Modeling the Transition from Enhanced Oil Recovery to Geologic Carbon Sequestration (Bandza and Vajjhala, 2014)	Presents a study made to reveal the price-point combinations (global oil and CO_2) at which four projects representing the spectrum of EOR without storage and pure CO_2 storage become economical for widespread deployment.	X		
Transitioning of Existing CO_2-EOR Projects to Pure CO_2 Storage Projects (Jafari and Faltinson, 2013)	Discusses a strategy to optimize both CO_2 storage and incremental oil recovery during the transitory period so as to remain economical. Illustrates a scheme for a hybrid or transitioning project.	X	X	
From EOR to CCS: The Evolving Legal and Regulatory Framework for CSS (Marston and Morre, 2008)	This study of the regulatory framework currently in place in the U.S. reveals that this will not be a stumbling block for operators wishing to transition from CO_2-EOR to CO_2 storage.			X
Methodology for GHG Emission Reductions from Carbon Capture and Storage Projects (ACR, 2015)	A comprehensive guidance document that establishes all of the requirements, equations and the process for operators storing CO_2 in oil and gas reservoirs to qualify their projects for carbon credits under the American Carbon Registry (ACR) program, as of April 2015.			X
Greensites and Brownsites: Implications for CO_2 sequestration characterization, risk assessment, and monitoring (Wolaver, Hovorka, et al, 2013)	Presents the view that monitoring approaches are site-specific, and must be based on a classification on whether they are greensites or brownsites (i.e., site history). The paper defines the classification scheme before discussing the three main undertakings of characterization, risk assessment and monitoring design of a project.			X
Draft UIC Program Guidance on Transitioning Class II Wells to Class VI Wells (USEPA, 2013) and Technical Guidance on Greenhouse Gas Reporting Rule (USEPA, 2010)	Two guidance documents are relevant: 1) a draft document designed as a detailed set of guidelines for CO2-EOR projects that U.S. operators want to be permitted as a geologic sequestration wells (Class VI) rather than as EOR injection well (Class II); 2) technical support document for complying with the minimum requirements indicated by the U.S. EPA regulations under greenhouse gas (GHG) reporting rule – Subparts RR and UU under the Clean Air Act.			X

2.1.1 Economics

The literature and interviews indicate that technical barriers are minimal compared to economic barriers. Given that candidate sites for CO_2-EOR usually have already experienced significant development activities, infrastructure demands are relatively modest compared to an undeveloped site. The technologies and methodologies for injection production and monitoring have been proven over the past few decades. Methodologies for establishing the quantity of CO_2 stored in order to acquire credit have been explored and are awaiting wide-scale establishment. The lack of CO_2-EOR storage projects may be largely because anthropogenic CO_2 is not available or economically feasible in many current EOR operations. In Mexico, for example, the amount of CO_2 available from industrial sources within a 100 km radius of the Villahermosa Basin is estimated at a negligible 1% of the CO_2 required for CO_2-EOR, while that for the Tampico-Misantla basin is at a better but still insufficient 11% (Godec, 2011). This suggests that government investment in research - to bring down the cost of capture and infrastructure for sustainable supply of anthropogenic CO_2 to close the supply-demand gap - could expand CO_2-EOR storage opportunities.

Pursuit of CO_2 credits may increase the economic viability of CO_2-EOR projects. Most of the cost in CO_2-EOR projects is obtaining the CO_2. *Modeling the Transition from Enhanced Oil Recovery to Geologic Carbon Sequestration* (Bandza and Vajjhala, 2014) provides a thumb-rule means of assessing whether to proceed with CO_2-EOR or CO_2 storage based on various key economic drivers (e.g., price of oil, CO_2 prices). After determining the CO_2-EOR potential, an analysis is performed for income from CO_2 credits obtained versus cost of incremental monitoring and reporting that will need to be performed. Economic scenarios described by Bandza and Vajjjhala (2014) illustrated that most storage strategies require substantial incentives to support and accelerate widespread deployment.

2.1.2 Optimization Strategies

The literature review yielded different strategies and technologies to optimize oil production and CO_2 retention/storage such as exploiting residual oil zones (ROZs), and assessing when to transition to CO_2-EOR. Advanced Resources International (ARI) and Melzer Consulting (2010) provides a brief summary of the state-of-the-art CO_2-EOR technology as well as next-generation technology recommendations. These include investigating ROZs as a source of incrementally recoverable oil reserves – with the added benefit of incidental CO_2 storage. Three promising reservoir development strategies for improved oil recovery and improved CO_2 storage include:

1. *Fill-up period* using water, to repressurize reservoir before implementing CO_2-EOR;
2. *Fill-up period* using CO_2, to repressurize reservoir before implementing CO_2-EOR; or
3. Skipping the waterflood and implementing CO_2-EOR as soon as possible.

Jafari and Faltinson (2013) built a simple hypothetical model for reservoir simulation with generic data: 160 acres and an inverted five-spot pattern. The strategy was aligned with a conventional EOR strategy for 30 years (depletion, water flooding, followed by water-alternating-gas [WAG] process), and then a hybrid strategy of injecting only CO_2 (rather than continuing the WAG process) and producing oil for the next 20 years. The end of the project was characterized by conversion into a pure storage project where CO_2 was injected with all producers shutoff for the last three years. The main finding was this strategy of moving from the conventional CO_2-EOR to a hybrid CO_2-EOR storage program resulted in an increase of 67% of CO_2 stored in the reservoir accompanied by a 9% increase in incremental oil recovery.

2.1.3 Monitoring, Reporting, and Verification Requirements

A number of documents provided guidance on MRV requirements that a CO_2-EOR project has to satisfy to qualify as storage (Table 2-2). American Carbon Registry protocols and U.S. EPA Program Guidance documents outline requirements as well as performance measures without prescribing technologies. Accordingly, there is significant flexibility for the project proponent to fashion the project details and submit for approval plans that describe how requirements will be met. Common themes on developing MRV plans include: (1) monitoring requirements need to be site specific and risk weighted; (2) additional baseline and post-injection data acquisition are required; and (3) the results of monitoring need to be transparent.

CO_2-EOR operations are mainly monitored to check that bottom-hole and reservoir pressures are being maintained within the operational constraints, to track the movement of the CO_2 injected, and to ensure that the wells are complying with integrity standards – especially due to the potential for flow assurance problems stemming from the corrosive nature of CO_2 in pipelines and hydrate forming hazards. Monitoring and surveillance for these objectives are usually implemented via gauges for injection/production and pressure data, geochemical analysis of produced fluids, and well logs and/or downhole sensors that measure tracer concentration, fluid saturations, resistivity and casing integrity. Seismic surveys have also been used to monitor for CO_2 plume movement. Additional monitoring requirements for storage include demonstrating integrity of the producing reservoir, verification of the quantity of stored CO_2, wellbore integrity monitoring, plume pathways monitoring, near-surface monitoring, and surface monitoring (CSLF, 2013).

Wolaver et al. (2013) describes the major items, processes and properties at varying depth intervals (surface, intermediate and injection zone) for depleted oil and gas fields as a useful means of anticipating project monitoring requirements. For developed sites such as depleted oil fields, monitoring is centered around high well density and old wells providing leakage pathways, out-of-pattern migration of CO_2, and undetected damage to geologic seal quality as a result of development.

While the same monitoring technologies applicable for CO_2-EOR are applicable to storage, more formal reporting will be required, including development of a MRV Plan (ACR, 2015; U.S. EPA, 2010). A significant difference between CO_2-EOR and CO_2-EOR storage is the post-injection long-term monitoring requirement for CO_2-EOR storage. While the ACR suggests a post-injection monitoring period of 5 years for CO_2-EOR storage projects, the clean development mechanism (CDM) requirements suggest a post-injection monitoring period of 20 years. While the U.S. EPA does not have a default minimum requirement for CO_2-EOR storage, the U.S. EPA post-injection monitoring requirements for geological storage only is 50 years by default– but this time period can be shortened per the discretion of the U.S. EPA Director. A common method for evaluating leakage is subsurface pressure monitoring and evaluation of changes in pressure. Operators of CO_2-EOR storage projects need to be aware and be proactive about post-injection and site closure requirements. MRV Plans can help show safe and non-hazardous conditions, maintaining trust of the public in the region.

2.1.4 Other Requirements

The International Organization for Standardization (ISO) is in the process of developing standards for capture, transport, and storage within Technical Committee 265: Carbon Dioxide Capture, Transportation, and Geological Storage. Storage standards are being developed for CCS and CO2-EOR-Storage. CO2-EOR-Storage was split from CCS in-part, due to the inherent differences in the level of understanding on the hydrocarbon production reservoir as compared to a CCS storage unit. The separate standards also provide an opportunity to develop accounting schemes that reflect differences in site operations; injection

Table 2-2. Comparison of requirements between ACR, CDM, and EPA Rules

Issue	American Carbon Registry (ACR)	Clean Development Mechanism (CDM)	Environmental Protection Agency (EPA) Class II to Class VI plus Reporting via Subpart RR
Risk Assessment and Mitigation	File Risk Mitigation Covenant or similar, including ACR right to access property to conduct inspections. Identify leakage pathways and remediate where possible. Develop a catalog of wells penetrating at or near the injection zone; repair or monitor wells with leakage potential. Undertake a simulation study of potential storage failure scenarios, considering a range of uncertainty for parameters and site characteristics.	Perform risk and safety assessment for entire CCS chain (not just storage), periodically updated to reflect monitoring data. Develop remedial measures and response plans to stop or control unintended CO_2 emissions or leakage. Perform an environmental and socio-economic impact assessment, periodically updated to reflect monitoring data.	For those projects that do transition from CO_2-EOR to CO_2 storage, the permitting authority can authorize EOR wells for a storage operation and will use risk-based criteria to understand if conversion is appropriate and/or necessary. Delineate the maximum monitoring area – the area expected to contain the free phase CO_2 plume until injected CO_2 is not expected to migrate in the future in a manner likely to result in surface leakage or release. Identify potential surface leakage pathways in the maximum monitoring area and assess the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.
Pre-Injection Characterization and Monitoring	Operator has the option to decide if pre-injection data is needed. Storage volume expected to contain CO_2, plume extent and duration of plume migration must be assessed via the use of a reservoir model and flow simulations. Identify leakage pathways and remediate where possible. Operator must develop a detailed catalog of wells penetrating at or near the injection zone and proceed to repair or monitor wells with leakage potential.	Perform monitoring to establish baseline data. Assess all known and inferred structures within the injection and cap rock formations for risk of migration of injected CO_2 via a 3D reservoir model. Assess injected CO_2 fate and migration, with a particular focus on vetting for risks of seepage to surface. Develop a monitoring plan, site preparation, well construction, injection rates and pressures, O&M protocols, and timing and management of site closure based on the results of the above fluid flow and simulation study. Describe the process for history matching and use the monitoring data to calibrate and update numerical models. Monitoring plan must be periodically updated to reflect the analysis of the monitoring data.	Define strategy for setting monitoring baselines for surface leakage Define strategy for detecting and quantifying any CO_2 surface leakage Identify all artificial penetrations that may penetrate the confining zone and either confirm that those have mechanical integrity if operational or have been properly plugged. Corrective action must be performed on any artificial penetrations that could serve as leakage pathways.

Table 2-2. Comparison of requirements between ACR, CDM, and EPA Rules (Continued)

Issue	American Carbon Registry (ACR)	Clean Development Mechanism (CDM)	Environmental Protection Agency (EPA) Class II to Class VI plus Reporting via Subpart RR
During-Injection Monitoring	Use a fluid flow model to periodically compare material balances for fluids as observed and predicted. Undertake a simulation study of potential storage failure scenarios, considering a range of uncertainty for parameters and site characteristics. Perform monitoring for the most sensitive parameters as identified from the above study. Tools selected and sampling frequency must be specified (justified). Select and locate (other) monitoring equipment in a manner that provide confidence in CO_2 storage and identify leakage. Establish reasonable detection thresholds for these equipment. Monitor the various accounting-related terms must be implemented and reported, to the minimum sampling frequency specified in the document.	Identify monitoring technologies, location, and sampling frequency to enable: 1. Assurance of environmental integrity and safety. 2. Detection and estimation of quantity of CO_2 stored in site. 3. Confirmation that injected CO_2 is contained and behaving as predicted. 4. Detection and estimation of the rate/mass of CO_2 seepage either via cap rock, overburden and surrounding domains or via wells with potential for leakage. 5. Monitoring and measurement of relevant parameters of groundwater properties, soil and surface CO_2 concentrations measurements, etc. 6. Timely remedial action in the event of CO_2 seepage. 7. Measurement of temperature at the top and bottom of injection and observation wells. 8. Detection of corrosion or degradation of transport and injection facilities.	Develop and implement an EPA-approved MRV plan that includes the following five major components: 1. Delineation of the maximum monitoring area, and active monitoring areas; 2. Identification of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing of surface leakage of CO2 through these pathways; 3. Strategy for detection and quantification of surface leakage; 4. Approach for establishing the expected baselines; and 5. Considerations made to calculate site-specific variables for the mass balance equation.
Post-Injection Monitoring	Minimum of 5 years of Post-Injection. If no migration of the injected CO_2 is detected and the modelled failure scenarios indicate that CO_2 remains contained within the storage volume, then it is considered adequate assurance that no atmospheric leakage has occurred**. Otherwise, monitoring requirements will be extended in 2 year increments until no leakage is assured.** 1. Monitor for appropriate parameters, such as pressure, in injection zone and above confining layer. 2. Evaluate data to detect movement in CO_2 plume. 3. Updating lateral boundaries of storage volume, based on assessment of CO_2 migration.	Minimum of 20 years of Post-Injection. If no migration of the injected CO_2 is detected and the modelled failure scenarios indicate that CO_2 remains contained within the storage volume, then it is considered adequate assurance that no atmospheric leakage has occurred**. Otherwise, monitoring requirements will have to be extended in 10 year increments until no leakage is assured.** Monitoring is for the same parameters described for "During Injection". An evaluation must be performed in the event of seepage to determine the quantity of seepage for compensation purposes.	Default value of 50 years of Post-Injection for Projects transitioning to geological storage (i.e., converts from a Class II permit to a Class VI permit). Post-injection monitoring (period to be determined by US EPA) required for Subpart RR. The post-injection site care period can be reduced upon a showing that "based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs," and the period will be extended if that demonstration cannot be made even at the end of 50 years. Specific monitoring methods and tools should be site specific and designed for the following objectives: 1) verify plume is stabilizing and pressures are equilibrating and 2) detecting potential leakage
Reporting/ Accounting	ACR details the methods and equations to quantify baseline emissions, project emissions, and emission reductions in Equations 4.1 to 4.21 (ACR, 2015).	Determine project boundaries to include an accounting for all GHG emissions as a part of the baseline assessment and monitoring. Verification will be achieved by history matching and, where necessary, updating the numerical models used to characterize the geological storage. The numerical models will be adjusted to address significant deviations between observed and predicted behavior.	Subpart RR requires facilities to collect quarterly data and submit annual reports on the annual amount of CO_2 sequestered. The mass balance equations RR-11 or RR-12 (EPA, 2010) are used to calculate the amount of CO2 that is reported as sequestered and accounts for quantity of CO_2 in emissions, the produced gas, the quantity remaining in the oil and gas, and finally the total quantity sequestered.

only for CCS and injection and production for CO_2-EOR-Storage. The CO_2-EOR-Storage standard is several years from completion.

2.2 Interviews

Semi-structured interviews were conducted to obtain information on technical issues facing CO_2-EOR storage projects. A list of participants was developed based on judgment and knowledge of the person's relevant project experience. Of the 10 people identified, six agreed to the interview. Although the sample size is small, participants represented a variety of perspectives because of differing areas of expertise and project experience. The research team conducted interviews with program managers, principal investigators, and regulators for projects such as IEA Greenhouse Gas R&D Program (IEA GHG) Weyburn-Midale CO_2 Monitoring and Storage Project, the Plains CO_2 Reduction (PCOR) Partnership Bell Creek Project, Midwest Regional Carbon Sequestration Partnership (MRCSP) Michigan Basin Project, Southeast Regional Carbon Sequestration Partnership (SECARB) Anthropogenic Project, Summit Capture Project, and more (Table 2-3). This variety in project experience permitted discussion about technical and policy approaches pertaining to the issues of CO_2-EOR storage. The information gathered from these subject matter experts reflects on both actual practice and opinion.

A set of questions was prepared in advance and sent prior to the teleconference to allow the participants to prepare (Figure 2-1). The research team wanted to be able to compare responses and develop themes by having focused topics, but also have the freedom to ask a few spontaneous questions. The advantage of having a conversation (as opposed to filling out a survey) is being able to hold a more in-depth discussion and to thoroughly understand the answers provided. All of the interviews were conducted by telephone. Individual interviews took between 30 minutes and an hour to complete. The list of questions was discussed in varying levels of depth depending on the person's perspective and area of expertise. The interview responses were compiled in a spreadsheet and reviewed for common themes.

Table 2-3. Interviews

Person	Current Position	Project Experience
Neil Wildgust	Principal Manager, Carbon Storage Global Carbon Capture Storage Institute, North America	Chief Project Officer at PTRC, responsible for managing all technical projects including the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project.
Charles Gorecki*	Senior Research Manager, Energy & Environmental Research Center	Program Manager for PCOR Partnership. PCOR is working to develop and implement monitoring, verification, and accounting concepts for large-scale (>1 million metric tons per year) CO_2 storage and EOR operations.
Adam Wygant	Supervisor Permitting & Technical Services Section, Michigan Department of Environmental Protection	Regulating water floods and some CO_2 floods in Michigan, including the site of the MRCSP large-scale demonstration project.
Nigel Jenvey	Manager of Carbon Solutions for BP Group Technology	Chairman of the CO_2 Capture Project, a joint industry project which BP operates on behalf of several oil and gas companies. Petroleum engineering background.
Sue Hovorka	Senior Research Scientist, Bureau of Economic Geology, University of Texas at Austin	Leading teams in field CO_2 injections to assess geologic sequestration for SECARB and others.
Sasha Mackler	Vice President, Summit Carbon Capture, Summit Power Group, LLC	Commercial and policy aspects. Summit is developing several CCS projects, most notably the Texas Clean Energy Project, a gasification facility with 90% carbon capture that will produce electric power and fertilizer, as well as captured CO_2

*Charles Gorecki was joined by John Hamling and Ed Steadman from PCOR Partnership for the interview

Goal

- ❑ Examine technical issues in transitioning CO_2-EOR sites to CO_2-Storage Projects for credits in Mexico

Question/Topics

- ❑ What are the key technical challenges for CO_2 credits from EOR?
- ❑ What is the status of technology development for CO_2 storage assessment in oil fields?
- ❑ Examples of current projects with CO_2-EOR based storage credits/research
- ❑ What is the minimum monitoring desired vs required – Mass balance (input/output), pressure, long-term monitoring?
- ❑ What is needed for storage assessment and site closure after EOR operations are over?
- ❑ What level of risk management is needed for EOR storage?
- ❑ Any other information on the topic or CO_2-EOR projects/fields in Mexico

Figure 2-1. Research goals and questions set

2.2.1 Consolidated Interview Responses

- Key technical challenges for CO_2 credits from CO_2-EOR storage
  - Strong agreement that the challenges are not technical in nature. CO_2-EOR is a mature technology and a depleted oil and gas field has demonstrated injectivity and containment (qualities that need further characterization for many saline reservoirs). CO_2-EOR storage operations should be performed in a manner that does not change the risk profile.
  - Accounting is a key requirement – technology advancements that would assist CO_2-EOR projects include improved metering, practicable leak detection technologies (e.g., autonomous), and a skilled workforce in environmental compliance monitoring to reduce costs and overcome economic challenges posed by additional requirements to obtain CO_2 credits. Another technical area that may require further development is producing from the ROZ. There is one EOR site in Texas producing from the ROZ.
  - Lack of protocols and projects earning CDM credit is another significant nontechnical challenge. The proposed CO_2-EOR storage project by PEMEX could be the first-of-its-kind in Mexico. A pathway for earning credits is emerging - the ACR recently published a protocol for EOR-storage and the U.S. EPA recently clarified that CO_2 storage can be included as part of EOR projects. In addition, International Organization for Standardization (ISO) standards are being developed and are anticipated to being completed in the next four years.
- Status of technology development for CO_2 storage assessment in oil fields
  - The California offset methodology and the European Commission requirements under the CCS directive may be used to guide project planning. CDM is the better model because the EU CCS Directive would not apply to Mexico, while the CDM protocol would apply.
  - CO_2-EOR projects are only beginning to explore obtaining recognition of the quantities of CO_2 being stored. Pilot projects help to provide experience to regulatory authorities and policy makers.

- European Directive requirements include accounting for energy consumption for operations including extraction, compression, and heating for EOR because these added steps make EOR more energy intensive.
- Operators should consider skipping the water flooding step, particularly in lower permeability formations (1 to 10 mD range).

- Examples of current projects with CO_2-EOR based storage credits/research
  - None of the people interviewed could offer an example of a current project receiving storage credits
  - The U.S. and Canada are the key players in CO_2-EOR. Brazil is also a player. China is rapidly accelerating its progress toward CO_2-EOR, with the prime motivation of increasing oil recovery.
  - In the U.S., researchers have completed and/or are completing a number of large scale demonstration projects to examine issues related to CO_2-EOR storage. These large-scale projects are testing monitoring technologies and modeling techniques to assess their effectiveness for use with CO_2-EOR storage.
  - In Canada, the Weyburn-Midale project is a well-known example of a CO_2-EOR based storage research project. The extent of monitoring required for a commercial CO_2-EOR storage project would be a smaller subset than performed for the Weyburn-Midale research project.
  - Lessons learned from these projects include:
    - Three-dimensional (3D) seismic is useful for characterization. When conducted over time, time-lapse (4D) seismic may be powerful tool for monitoring CO_2 migration. However, the cost of repeat events is a key consideration. Furthermore, seismic may not be applicable in many geologic settings.
    - Passive seismic/microseismic used on downhole array offered dual benefits – it produced useful data to learn about the reservoir and provided stakeholder assurance.
    - Consider deploying lower cost monitoring techniques first followed by higher cost technologies. For example, using pulsed neutron capture (PNC) logs first and performing seismic second, to parse out CO_2 saturation/pressure.
    - On the environmental side, baseline soil gas monitoring/near surface monitoring proved to be valuable for establishing a frame-of-reference when the project faced a leakage allegation at the Weyburn-Midale Project. Near surface monitoring in combination with analysis of isotopic signatures helped to differentiate normally occurring CO_2 from potential leakage.
    - Satellite based technologies such as InSAR (interferometric satellite radar) could be cost-effective, but the feasibility of this technology is site specific.
  - In the U.S., obtaining tax credits is an available incentive for CO_2-EOR projects with incidental storage and this mechanism is being pursued, particularly in Texas.

- What is the minimum monitoring desired versus required – Mass balance (input/output) pressure, long-term monitoring?
  - CO_2-EOR storage projects require a different approach to monitoring compared to pure saline projects. Because EOR is intensively engineered, only modest, if any, monitoring is required.
  - The minimum monitoring requirements include mass balance, pressure, and downhole temperature.

- All but one person interviewed noted that well integrity was the most important item to monitor.
- Monitoring requirements to receive credits are not known. In the U.S., demonstrating storage of CO_2 in EOR projects requires meeting both Underground Injection Control (UIC) permit requirements and GHG reporting requirements. Exactly which requirements apply will depend on the protocols under which credits are sought. For example, obtaining quantification of CO_2 storage under EPA's GHG reporting regime requires reporting pursuant to subpart RR. (No EOR projects have opted into subpart RR since the rule was established.)
- The topic yielded a variety in the opinions on the importance of environmental compliance monitoring from “not required/don’t do it” to “required/do it”. One commonality was that appropriate environmental compliance monitoring technologies could include those meaningful for public perception, even if the technology is not applicable to reservoir performance.
- Modeling will likely be required - something more sophisticated than mass balance to demonstrate an understanding of the subsurface.
  - History matching is a great tool and augments mass balance. Tune simulations to monitoring data to gain better confidence in model results.
  - Understanding fracture pressure of caprock is required if there is a need to go above discovery pressure to get to minimum miscible pressure. Microseismic monitoring may also be helpful in this case.
- The burden of monitoring is in the reporting. Industry is already doing most of the monitoring and modeling that could be used to demonstrate storage. However, industry may be inclined to avoid the public disclosures required to get credits and demonstrate storage because of concerns regarding privacy and loss of competitive advantage. These concerns will need to be addressed.

- What is needed for storage assessment and site closure after EOR operations are over?
  - Nearly all interviewed raised the concern about the stranded oil left behind and the implications for site closure. The stranded oil may have a future value due to new technologies or higher oil prices. In such situations, the field owner may wish to reenter the fields for production, leading to potential loss of storage CO_2. Handling of credits in such situations is not clear at this point.
  - A risk-based approach is required. If the pressure is stable and the wells are built and abandoned properly, the site is low risk even after the engineering controls are removed. On the other hand, if the operator goes above discovery pressure (but below fracture pressure), the risk profile changes. Additional characterization, monitoring, and modeling may be necessary because the operator may need to rely on predictive modeling rather than historical data.
  - Additional leakage monitoring and modeling to demonstrate permanent storage are manageable tasks within a bounded frame of time. A reasonable post-injection monitoring step may be necessary to encourage acceptance of CO_2-EOR.
- What level of risk management is needed for EOR storage?
  - Site specific
  - Depends on the reservoir type. Closed reservoirs such as reefs are straight forward. An open reservoir would be more complicated if there was a possibility the CO_2 or other fluids could go beyond project boundaries to a leakage pathway.
  - Pure saline reservoirs are much different because they are likely to be larger and do not have proven containment until additional characterization is conducted. CO_2-EOR storage projects are

likely to be smaller in size and, if the reservoir remains at or below discovery pressure, the risk profile has not changed compared to an EOR-only project.

  - Wellbore integrity is the biggest issue – an operator should monitor casing performance, which can degrade rapidly. Options include mechanical integrity tests (MITs), sustained casing pressure, and annulus pressure monitoring.

- Any other information on the topic or CO_2-EOR projects/fields in Mexico
  - None offered

2.3 Region-Specific Considerations

Regional information pertaining to the Isthmus Saline Basin, where the Cinco Presidentes Oilfield is located, was gathered using publicly available literature specific to CO_2-EOR assessments in Mexican oilfields. A brief discussion of regional geology and CO_2 sources near Cinco Presidentes follows.

2.3.1 Regional Geologic Information

An assessment to determine prospective regions of Mexico for CO_2 storage in geologic formations that considered geologic and tectonic factors was performed to divide Mexico into one of “inclusion” or “exclusion” zones (Dávila, Jiménez et al., 2010; Lacy, Serralde et al., 2013). The “inclusion” zone refers to a zone that has been recommended for CO_2 storage due to its positive outlook for CO_2 storage capacity, trap effectiveness and safety. As shown in Figure 2-2, the Cinco Presidentes oil field falls within the inclusion zone.

The Cinco Presidentes field occurs in the Isthmus Saline Basin and is one of the largest oilfields in southeast Mexico, with more than 200 million of barrels of oil and 300 trillion cubic feet of gas cumulative produced through 1980, and more than 200 producing wells (Peterson, 1983). The basin consists of plays both onshore and offshore with proven hydrocarbon production. Of the three generic types of plays in the region (Neogene, Paleogene and Mesozoic), the Neogene sandstones have proven hydrocarbon production both onshore and offshore, with over 2.1 billion barrels of oil. The Cinco-Presidentes and Orca plays are the dominant plays of the various ones occurring in this group (Robles-Nolasco, Pliego-Vidal et al. 2004; Soto-Cuervo, Ortega-Gonzalez et al. 2009). Fields in this region are frequently associated with diapiric salt structures with complex faulting due to salt intrusion (Peterson, 1983). Porosity and permeability are generally excellent, with porosity varying between 14 to 39%, while permeability is between 6 mD to 2.6 D. Play thickness may be between 5 and 60 m. The basin generally contains light oil varying between 27 and 38º American Petroleum Institute (API) gravity. Table 2-4 summarizes this information about the general subsurface conditions and geologic features of the offshore Neogene plays in the Isthmus Saline Basin. More site-specific geologic characterization and testing would be required for detailed design of CO_2 storage systems. However, these general parameters provide context for risk assessment, monitoring, operations, and site closure.

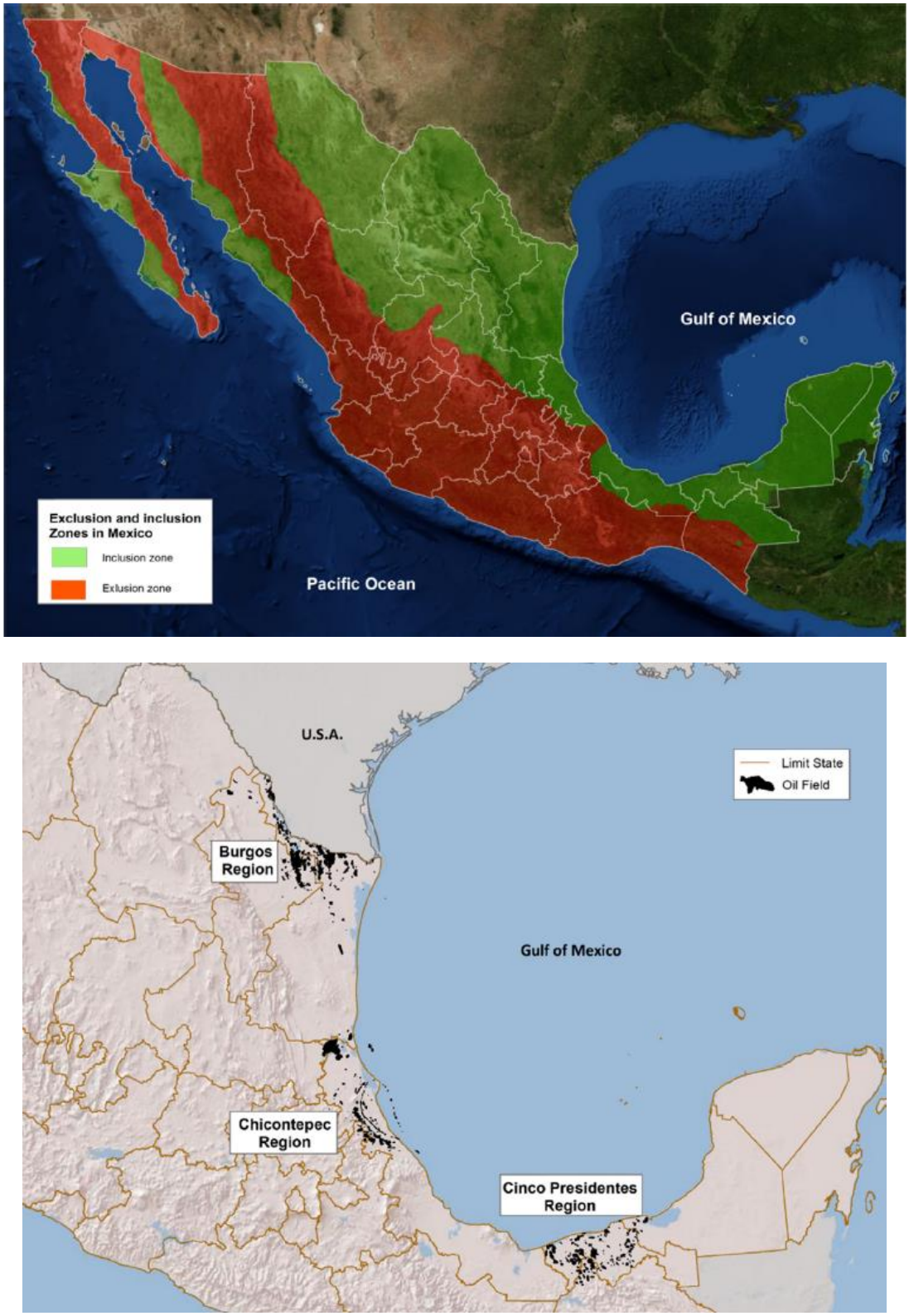


Figure 2-2. Zones suitable for CO_2 storage in green (top map) and the location of the Cinco Presidentes oilfield (bottom map) in Mexico (Lacy, Serralde et al. 2013)

Table 2-4. General subsurface conditions and geologic features in Cinco Presidentes Region

Parameters	Range
Play Types	Early-Middle Pliocene (Cinco Presidentes Turbiditas Play and Cinco Presidentes Barras Play) Middle-Late Pliocene (Orca Turbiditas Play and Orca Barras Play)
Depth	2500 meters
Thickness	5-60 meters in reservoirs
Lithology	Miocene-Pliocene mix of marine and fluvial deltaic turbidities (sandstone, siltstone, shale, salt)
Geologic Structures	Complex mixture of compressive, extensive, structures with salt intrusions
Trapping Mechanisms	Mixture of anticlines, salt dome pinchouts, sealing faults, lithologic traps
Porosity	14-39%
Temperature	~80 º C in reservoirs
Permeability	5 md – 2.6 d in reservoirs
Hydrocarbons	Mix of oil (27-38º API), condensates, gas

2.3.2 Regional CO_2 Sources

A study assessing the potential for CCUS for EOR using CO_2 from nearby fossil fuel industrial plants suggested that in general positive factors exist for the Cinco Presidentes region (Lacy, Serralde et al., 2013). About 2.1 million metric tons of CO_2 per year may be captured for use within a 180 km radius from anthropogenic sources of CO_2 for this region, mainly from PEMEX's industrial facilities – gas/petrochemical plants, refineries, etc. These sources and their distances to some of the fields in the region are shown in Figure 2-3 and Figure 2-4.

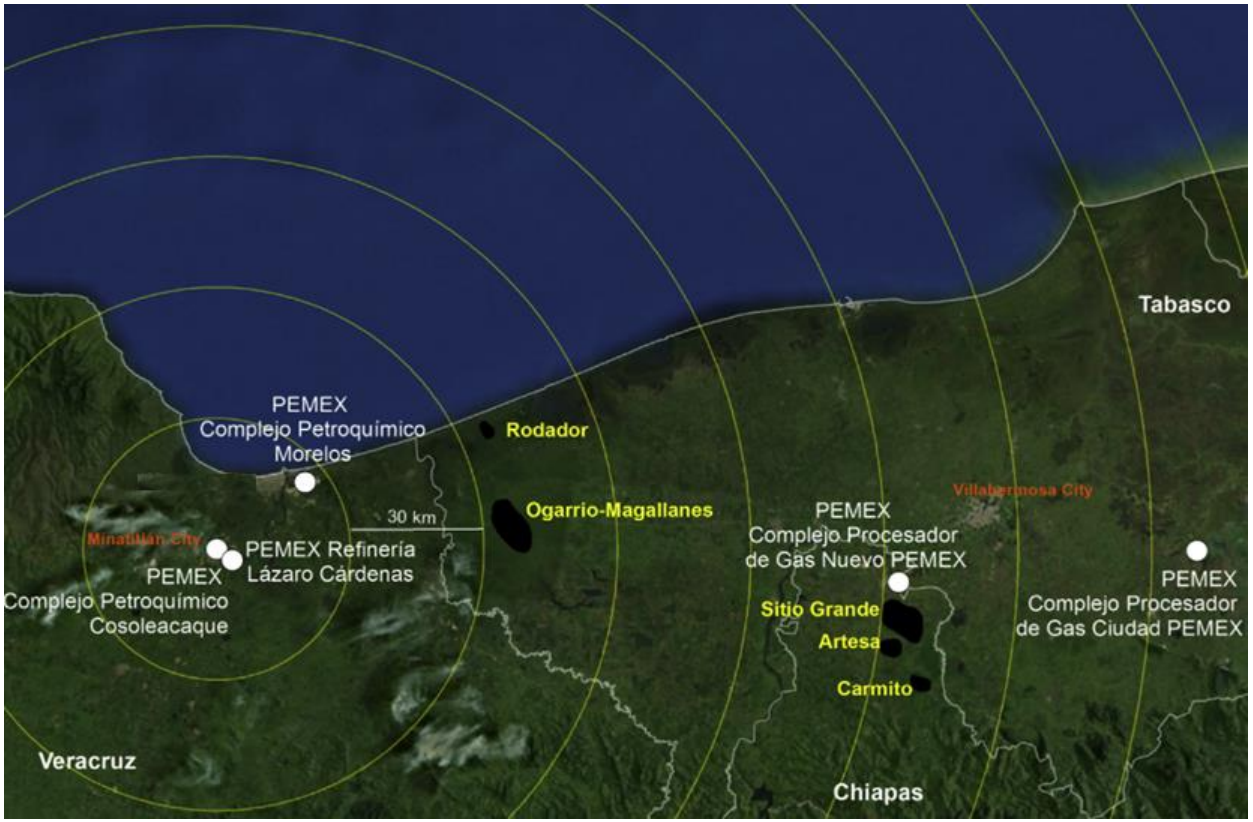


Figure 2-3. Major PEMEX industrial sources of CO_2 (>0.5million metric tons/year) in Cinco Presidentes region (the area of interest) (Source: Lacy, Serralde et al., 2013)

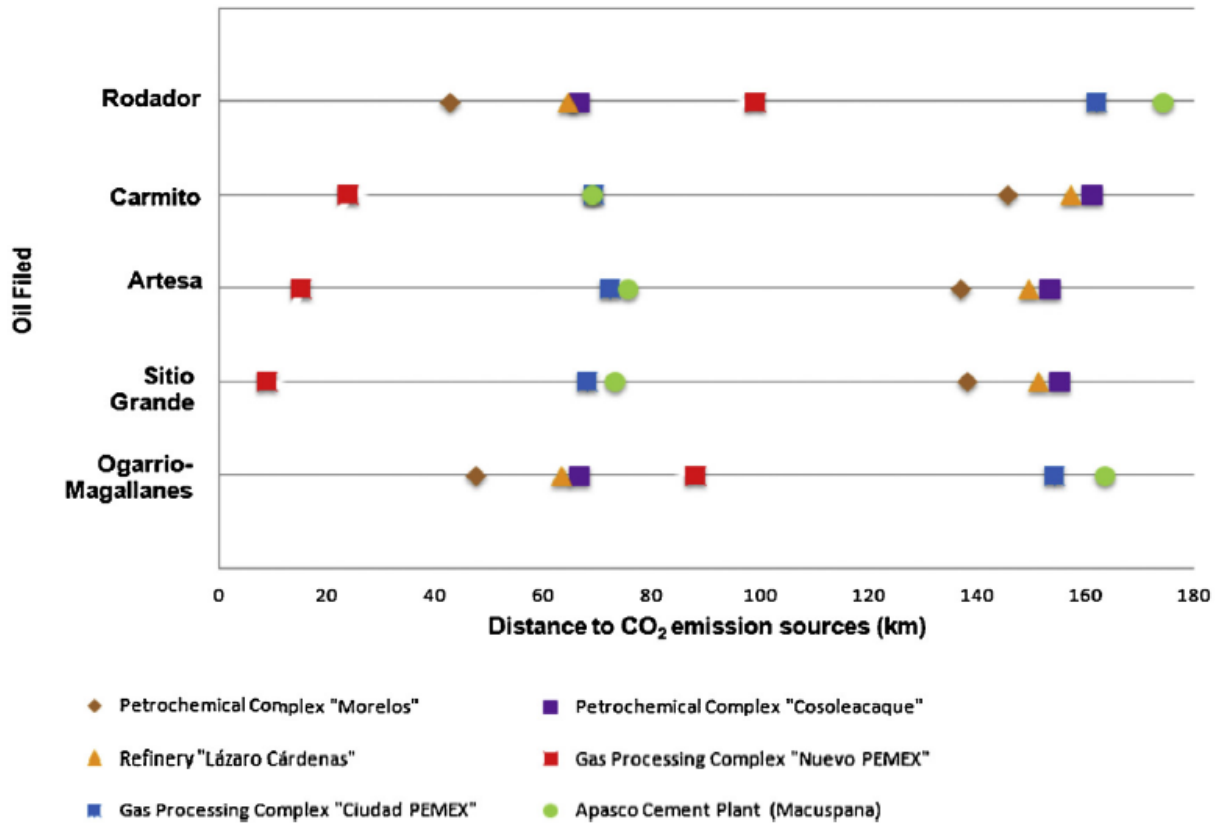


Figure 2-4. Distances of PEMEX industrial sources of CO_2 to some of the oilfields in the Cinco Presidentes region (Source: Lacy, Serralde et al. 2013)

2.4 Conclusions

The current view of CO_2-EOR storage projects is that these types of projects are technically feasible and eligible for CDM credits. However, significant economic and regulatory incentives and anthropogenic sources of CO_2 are pre-cursors for widespread deployment. The protocols for obtaining credits typically outline requirements as performance measures without prescribing technologies. As a result, the project proponent has significant flexibility to develop and submit risk-based plans using fit-for-purpose methodologies that describe how requirements will be met. However, the first-of-a-kind nature of CO_2-EOR-storage projects could prove a hindrance, as could the absence of any provisions in protocols that are specifically tailored to oil field operations. The developing ISO standards for CO_2 capture, transportation and storage, which will include incidental storage of anthropogenic CO_2 in association with EOR, promises to provide a better pathway to credits. In absence of prescriptive requirements in the near term, EOR operators are advised to answer a series of questions when pursuing associated storage or transitioning to storage without production:

- What are the specific risks at this site?
- What modeling tools would be useful?
- How do I prove containment?
- What baseline or other frame-of-reference data could be useful to collect?
- How will I measure, monitor and verify the amount of CO_2 stored?
- What is the appropriate post-injection monitoring strategy to demonstrate that 99% of the CO_2 within the reservoir will be stored for at least 100 years?
- What are the legal and regulatory issues for transitioning to storage without production?

The following section examines these issues in more detail.

Chapter 3 Identification of Key Issues for CO_2-EOR Storage Projects

The information collected during the literature search and expert interviews was compiled and synthesized to highlight key issues for CO_2-EOR storage projects with relevance to Mexico. This task builds upon previous work and summarizes the options and challenges for CO_2-EOR storage.

3.1 Risk Assessment Options

Risk assessment methods are used to characterize and catalog the safety attributes of storage sites (WRI, 2008; Intergovernmental Panel on Climate Change [IPCC], 2005). The risk assessment process often includes site screening, selection, and characterization of a geologic CO_2 storage site to provide guidance in CO_2 storage system design, operation, and closure (Department of Energy National Energy Technology Laboratory [DOE-NETL], 2011). Risk factors may be classified as both programmatic (related to project progress and costs) and technical (related to the scientific and engineering integrity of the storage system) (DOE-NETL, 2013). Because CO_2 is a natural gas present throughout the environment, CO_2 storage risk analysis methods are often focused on leakage pathways rather than the quantitative expression of risk as probability multiplied by consequence. Several risk analysis tools (qualitative and quantitative) have been developed to evaluate CO_2 storage sites, such as:

- A Generic Features, Events and Processes (FEP) Database for the Assessment of Long-Term Performance and Safety of the Geological Storage of CO_2 (Savage et al., 2004) - Databases of FEPs are tools to support the assessment of long-term safety and performance of geological CO_2 storage. The FEP database is divided into seven main classes, covering events as broad as neotectonics to microscopic processes such as complexation of CO_2 with heavy metals. This tool and supporting details is available on-line at https://www.quintessa.org/case-studies/online-database-of-features-events-and-processes-for-co2.html.
- Certification Framework Based on Effective Trapping for Geologic Carbon Sequestration (Oldenburg et al., 2009) - A simple framework for evaluating leakage risk for certifying operation and decommissioning of geological CO_2 storage sites
- A System Model for Geologic Sequestration of Carbon Dioxide (Stauffer et al., 2009) - CO_2 Predictive Engineered Natural Systems (PENS) is a software tool that links together physics-based process-level modules that describe the entire CO_2 sequestration pathway, starting from capture at a power plant and following CO_2 through pipelines to the injection site and into the reservoir.

Risk analysis typically involves “brainstorming” sessions with subject-matter experts led by an experienced risk management facilitator. The risk analysis is designed to address all phases of the project, from well preparation, to characterization, injection, monitoring, and post-injection well closure. Risk analysis also considers other activities, such as scenarios related to project management as well as maintenance and workover activities.

In addition to risk analysis tools, studies have focused on specific processes such as CO_2 migration through boreholes and geologic pathways (Celia et al., 2004). Recently, DOE-NETL has led a National Risk Assessment Partnership to quantify long-term risks at CO_2 sequestration sites (Pawar et al., 2014).

The risk assessment may take advantage of the geologic and production histories of depleted oil fields to provide confidence in capacity, injectivity, model prediction, and long-term CO_2 retention. Most depleted fields have undergone significant site characterization as part of exploration and production. As a result, there is an inherent confidence in the reservoir injectivity and effectiveness of the containment. In contrast, saline reservoirs have not undergone characterization similar to the oil fields. Therefore, additional sub-surface data collection through seismic surveys and drilling is required to demonstrate capacity and retention capability. However, high well density for production may increase uncertainty regarding long-term well-retention in depleted oil fields compared to CO_2 storage in saline reservoirs. In addition, factors such as the potential for damage to the confining layers during operation should be evaluated during characterization.

3.1.1 Wellbore Integrity Analysis

Potential CO_2 migration through existing oil and gas wells is considered a major risk factor for CO_2 storage. Wellbore integrity is especially important for transitioning from CO_2-EOR to CO_2 storage because oil fields typically have many legacy wellbores that penetrate the confining layers.

The potential for wellbore leakage is identified during the risk assessment. Depending on the outcome of the risk assessment, a more detailed review on the status of wells in the area, or wellbore integrity analysis, may be required. Data such as well location, construction, depth, rock formations penetrated, plugging methods, and status are compiled on wells near the field location to determine if the wells may be pathways for CO_2 migration.

Well casing may be subject to corrosion in CO_2 environments in the subsurface. This is especially relevant to CO_2-EOR fields that alternate water and CO_2 injection. Well casing is used in oil and gas wells to stabilize the borehole, prevent unconsolidated material from entering the borehole, reduce corrosion, and protect underground aquifers. Casing and tubing are classified by API type of steel (H-Q) and minimum yield strength (40,000 to 125,000+ pounds per square inch [psi]). In general, higher grades of steel are designed for deeper wells, higher temperatures, higher pressures, and corrosion resistance. Many grades of steel are designed to be more ductile to prevent brittle failure from hydrogen sulfide (H_2S) gas.

In relation to CO_2 storage, existing oil and gas well casing may be affected if it comes in contact with CO_2 or CO_2/water mixture in the subsurface. Pure CO_2 is referred to as “sweet gas” when encountered in the oil and gas industry and can cause pitting and pinhole leaks in casing, joints, tubing, and packers. API grade of L-80 or greater is recommended for these applications. Other options for corrosion resistance include alloy plating (nickel, chrome, etc.), polymer coatings, stainless steel, and fiberglass casing (Popoola et al., 2013).

Table 3-1 summarizes casing/tubing materials for CO_2 storage applications. These options are typically more expensive and more difficult to handle in the field and are susceptible to damage due to scrapes, nicks, and scratches. Many operators use common steel grades (J-55) with few problems as long as they produce or inject relatively pure CO_2. However, some EOR fields encounter significant corrosion when injecting water alternating CO_2 gas. Tubular design should take into account reservoir conditions and the composition of and conditions of the fluids being injected and produced. Corrosion modeling can be incorporated into tubular design to ensure the carbonic acid, high chlorides, and H2S are accounted for when selecting metal grades and alloys. Dry CO2 is generally not considered to be corrosive, allowing the use of mild steels (e.g. J and K grades). H2S may require special grades or metallurgies (e.g. L80 as

opposed to N80). In projects where corrosion risk is high or corrosion risk needs to be minimized less common alloys may be employed. For example, at Shell's Quest Carbon Capture and Storage Project highly corrosion resistant Cr25 duplex steel was selected to minimize corrosion risk.

Table 3-2 summarizes wellbore integrity items and evaluation factors for CO_2 storage applications. Several research studies have described items that may affect well integrity such as cement degradation (Duguid et al., 2004; Kutchko et al., 2007), leakage pathways (Gasda et al., 2004; Huerta et al., 2009), and well construction methods (IEA, 2009). These items may affect storage security at an CO_2-EOR site and may need to be addressed for CO_2-EOR storage.

Table 3-1. Casing/tubing materials, applications, and limitations

Material	Type	Applications	Limitations
Carbon and Low-Alloy Steel	Hardness <HRC 22	"Dry" CO_2 transmission, shallow casing (i.e., conductor casing).	Brittle at temperatures < -20°F. Corrodes in presence of wet CO_2 or H_2S. Corrodes more rapidly when CO_2 partial pressure exceeds 15 psia or temperature > 300°F.
Stainless Steel (Martensitic)	Hardness <HRC 22 (AISI 410; 9Cr/1Mo)	"Dry" or "wet" CO_2 transmission.	Oxygen, H_2S, H_2O, increasing partial pressures of CO_2, or Cl rapidly increase corrosion rates, especially at temperatures > 200°F.
Stainless Steel (Austenitic)	Hardness < HRC 22; 35 (AISI 304, 316; Nitronic-50)	"Dry" or "wet" CO_2 transmission.	Oxygen, H_2S, H_2O, and Cl increase corrosion rate, especially at temperatures > 150°F.
Bimetallic	Carbon steel outer, corrosion-resistant inner (Alloy 625)	Inexpensive carbon steel handles stresses, is protected from corrosion by liner. Cheaper than high-alloy steel pipe.	Segments must be joined by special welding technique. Very susceptible to problems (including galvanic corrosion) if holes form in liner.
Other Internally-coated Carbon Steel	Phenolics, epoxy-phenolics, glass epoxies, nickel	Provides extra protection to inexpensive steels (alternative to more expensive material).	Only effective when not damaged (i.e., scratched). Damaged areas will corrode quickly.
Fiberglass	–	Can be used alone or as an outer covering to protect carbon steel from corrosion.	Pure fiberglass may not withstand high pressures, can be brittle when cold, and its length can vary dramatically with temperature.
Fiberglass-Reinforced Plastic	Polyester/glass, epoxy/glass	Currently used in natural CO_2 production and oil-field injection.	CO_2 swells and alters resin, worse at increasing pressures. Results in brittleness, delamination. H_2S limits service temperatures. Length varies dramatically with temperature.

Table 3-2. Well integrity items and evaluation factors

Wellbore Integrity Item	Evaluation Factors
Cement degradation	Cement type, cement age, additives, hydrogeologic conditions
Cracks and Microannulus	Cement age, plug intervals, cement type
Acid-Gas Zones	Geologic logs, drilling logs, hydrogeologic zones
Channeling	Cementing procedures, cement age, cement mix
Casing Corrosion	Well logs, casing schedules, case studies
Wellhead Leaks	Fugitive emission data, gas storage field data, regulatory data
Sustained Annulus Pressure	MIT, historical Class II injection pressure data, field monitoring data

3.1.2 Recommendations

- **Perform FEP risk screening and leakage pathway analysis to identify major risk factors related to geology, environment, operations, people, natural hazards, and other factors at project location**. A comprehensive risk assessment screening should be completed for the project to aid in CO_2-EOR storage. The risk assessment should be designed to provide guidance on injection system operations, the monitoring program, reservoir simulations, and other project activities. An initial risk screening may be completed using the FEPs performance and safety screening process to identify possible technical risk items. The screening analysis is based on initial site characterization information such as maps of deep wells, well plugging records, geological cross sections, review of existing seismic surveys in the area, and geotechnical data (geophysical well logs, rock core tests, and drilling logs). This may be followed by a risk screening based on leakage pathway analysis and FEP programmatic review of risks that may inhibit project performance or safety, and site-specific review of wellbore integrity for wells near the site location. Additional data should be collected if necessary to complete the risk assessment.

- **Survey surface environmental features related to CO_2 storage risk.** To support the risk assessment, a systematic survey of the site features should be completed to describe geologic setting, surface features, and risk pathways. Well records should be reviewed to identify all wells at the project sites, including active wells, abandoned wells, and groundwater wells. Surface features such as wetlands, streams, lakes, and other ecological areas may be identified from maps. Groundwater resources in the project area should also be described if present. The geologic setting description may include identification of confining layers, faults, fractures, and other features that may affect storage security. Geologic structures in the region may also be analyzed as they pertain to CO_2 migration and trapping. Hydraulic parameters of deep rock formations may be summarized based on well logs, well tests, and geotechnical core tests. Hydrologic conditions in the deep reservoirs should also be described. Buildings, landowners, and human activities in the area may be evaluated to determine any surface features that may be affected by injection activities. In addition, the existing infrastructure and proposed injection process may be defined in relation to the environmental setting.

- **Complete survey of wellbore conditions for pilot-scale project.** The wellbore integrity study examines the condition of existing wells in the test site area to determine their potential for CO_2 leakage. Wellbore integrity issues are discussed in more detail in Section 3.2.
- **Review risk framework options for larger scale CO_2 storage expansion.** Additional risk assessment work may include pathway analysis, leakage simulations, risk certification framework, leakage monitoring, and other qualitative and quantitative methods. In general, these methods are related to complexity of the site. For example, if the site has several hundred legacy oil and gas wells in poor condition, further risk assessment work may be warranted. However, a site with 10 to 20 relatively new wells may not require additional risk studies.
- **Perform a review of area to characterize well integrity and remediate.** For both CO_2-EOR and storage, several steps may be completed to examine the condition of wells. Oil and gas well records may be divided into three categories of information: (1) well construction and status information; (2) plugging and abandonment details; and (3) cement bond logs (CBLs). Data such as well location, construction, depth, rock formations penetrated, plugging methods, and status are compiled on wells near the field location to determine if the wells may be pathways for CO_2 migration. Table 3-3 presents a list of options to evaluate the overall condition of boreholes in the study area.
- **Monitor casing performance, which can degrade rapidly.** Injection well integrity is demonstrated via monitoring of pressure, annulus pressure and fluids, wireline logging, corrosion coupons, and mechanical integrity (packer/tubing leaks). Any losses that are detected must be remediated.

3.2 Reservoir Simulations

The performance of CO_2-EOR processes is evaluated and validated at each site from operational indicators as well as reservoir simulation studies. Simplified empirical models as well as detailed numerical simulation models are possible to study and/or predict CO_2-EOR performance over time. Model scales vary from local-scale site-specific to regional models depending on the end objectives or metrics being investigated for the project stage under consideration. Summaries of multi-site CO_2-EOR field data are available in literature (Hadlow, 1992; Manrique et al., 2007) along with work to extend predictions of CO_2-EOR performance using simulation models (Merchant, 2010).

Table 3-3. Options for investigation of wellbore integrity at CO_2 storage sites

Task	Objectives	Methods
Well Survey	Locate and summarize condition of wells within the injection area	Review well records, site walkover, remote sensing
Cement Integrity Evaluation	Analyze cement conditions for wells in the region in terms of materials, methods, and long-term integrity	Evaluate CBLs, cement types, additives, cement volumes, actual cement tops, and possible associations with sustained casing pressure.
Well Casing Evaluation	Examine well casing conditions and long-term integrity of casing in the region	Analyze available casing inspection logs, cement evaluation logs, and/or records of casing failures. Assess casing installation procedures, materials, and condition as indicators of well integrity
Hydrologic Conditions	Describe hydrologic factors that may affect well integrity	Summarize reservoir pressure, temperature, fluids, geochemistry, and petrology for different well categories and geologic settings

The CCUS modeling approach is similar to traditional CO_2-EOR studies, however, with a shift in the optimization objectives from maximizing the oil production with minimal new CO_2 intake, to maximizing both oil production as well as CO_2 retention. CCUS modeling objectives also include:

- Modeling to complement monitoring program to aid regulatory compliance by analyzing fluid dynamics in the system during pre-injection, injection and post-injection periods.
- Evaluating technical and economic scenarios for decision-making on optimum completion and operation strategies.

EOR fields being considered for geological storage have the benefit of extensive documentation of historical production and recovery data. Screening of sites for new EOR fields is generally based upon a consideration of geologic conditions (e.g., trap effectiveness, reservoir depth, etc.), fluid properties (e.g., minimum miscibility pressure) as well as other engineering parameters (e.g., sweep efficiency and primary recovery efficiency). Existing EOR fields on the other hand, are screened based on demonstrated CO_2 injectivity and potential storage capacity. Additionally, reservoir models (Law et al., 2004), simplified predictive models of CO_2 performance (Azzolina et al., 2015) and related economic models (Bandza et al., 2014) aid in the site screening and feasibility analysis of CCUS projects. As the selected site is characterized and more detailed geologic and operational data are processed, detailed conceptual and numerical models are developed to help investigate and predict CO_2 interaction with the original fluids in place during EOR and storage phases of the project. These analyses play critical roles during project feasibility evaluation, design, implementation and post-injection closure phases.

Dai et al. (2013) performed simple sensitivity and uncertainty analysis using geostatistical Monte Carlo simulations for CO_2 storage potential in an EOR setting in Texas. Azzolina et al. (2015) analyzed WAG CO_2 floods to come up with useful statistical information to estimate CO_2 storage in CO_2 EOR operations with various degrees of confidence. Detailed simulation work has documented the expected trapping mechanisms for the injected CO_2, evaluating the possible long-term fate of stored CO_2 correlating to field observations at the Weyburn project (Zhou et al., 2004).

Modeling studies have considered co-optimizing CO_2 storage and EOR (Jessen et al., 2005; Ramirez Salizar, 2009) by managing parameters such as well placement, sweeping the ROZs and injection ratios. Reservoir simulation studies thus provide an efficient method to analyze the interplay of operational and geologic controls in various scenarios to compare and optimize CCUS performance metrics such as CO_2 utilization, oil recovery and CO_2 stored (Ettehadtavakkol et al., 2014; Hill et al., 2013). Hybrid techniques are being proposed as effective strategies to transition from traditional CO_2-EOR to CO_2 storage without production (Jafari et al., 2013). Simple reservoir models have also been used to identify and evaluate alternative CO_2 production/injection strategies to increase CO_2 storage in conjunction with EOR such as injecting CO_2 earlier, injecting CO_2 longer by possibly skipping the waterflood stage prior to the CO_2 flood (ARI Inc. & Melzer Consulting, 2010).

Modeling is also extremely useful in tackling practical issues such as wellbore integrity analysis. A number of modeling efforts have assessed the general range of impacts of well leakage on the basis of semi-quantitative data available (e.g., Nordbotten et al., 2004). However, field-specific testing and analysis would provide a more robust quantification of the frequency and magnitude of well leakage.

Detailed numerical simulations of CCUS in the reservoir of interest thus help investigate the interaction of the injected CO_2 with the original fluids in place and optimize oil production as well as CO_2 retention (Melzer, 2012) in the subsurface. Geomechanical integrity considerations drive operational limits such as well injection rates and bottomhole pressure constraints. CO_2 phase behavior complexity influences its

interaction with the original fluids in the subsurface. Figure 3-1 shows the phase change observed during MRCSP large-scale CO_2 injection testing in a depleted carbonate reef setting. The project uses material balance calculations, pressure transient analysis as well as detailed numerical models, both black oil and compositional, to understand different metrics representing reservoir response to CO_2 injection (Ravi Ganesh et al., 2014; Kelley et al., 2014).

The detailed numerical modeling approach entails a two-step process that includes: 1) developing a static earth model that defines the geologic framework of the reef followed by 2) developing a dynamic fluid flow model.

The static earth model (SEM) of the reservoir is constructed with the available geologic information (logs, seismic data, etc.) in industry-standard tools such as Petra® and Petrel® (Figure 3-2). This model of the geological architecture of the system of interest is effectively a 3D database for the project that can be tailored for different scenario analyses. The crucial inputs to the dynamic model from the 3D SEM are the spatial distribution of porosity, permeability and initial fluid saturations in the reservoir.

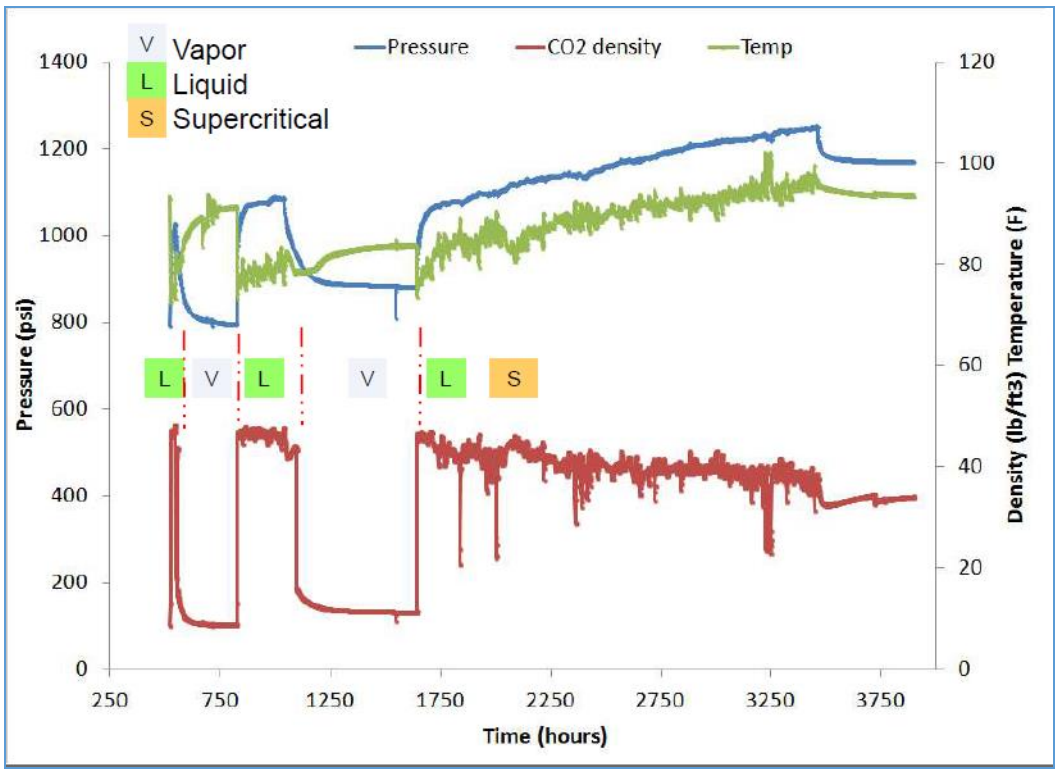


Figure 3-1. Complex CO_2 phase behavior changes reservoir response over time during injection period. Example from MRCSP large-scale CO_2 injection test in a depleted carbonate reef setting

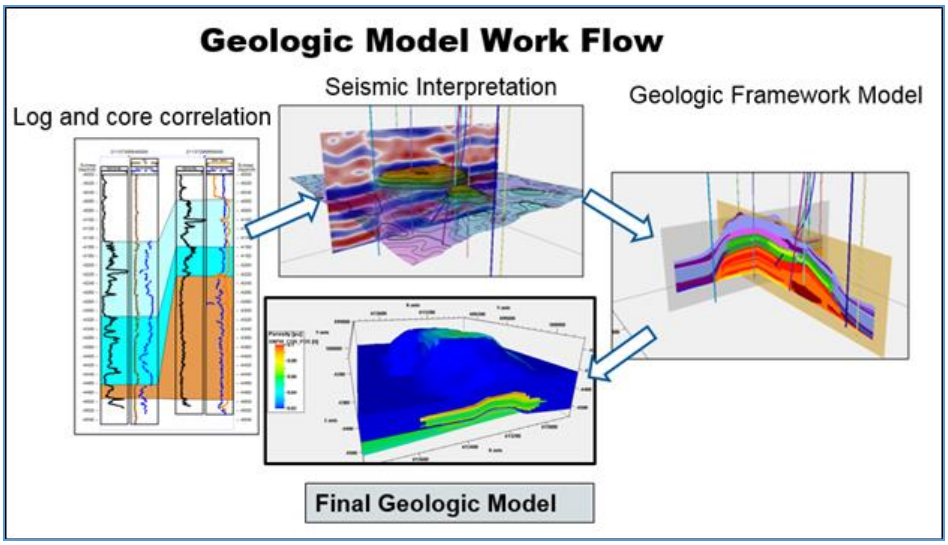


Figure 3-2. Geologic model or SEM schematic flow diagram

The 3D SEM can then be imported into a dynamic reservoir simulation tool for fluid flow modeling using a standard reservoir simulation workflow. Compositional and black-oil simulators such as industry-standard Computer Modeling Group (CMG, 2010) and Eclipse (Schlumberger, 2012) are commonly used tools for detailed numerical simulations. Information about fluid properties, rock compressibility, relative permeability models, rock matrix properties, historical pressure and temperature conditions and well details such as perforation depths and well schedules are utilized in reservoir simulations to effectively assess CO_2 utilization and geologic storage potential in the potential CCUS field (Figure 3-3). A calibrated model of the reservoir is useful for predictive simulations of CCUS and other related sensitivity analyses. The calibration is done by history-matching the primary (and secondary) production phase in the reservoir model. This calibrated model would be followed by simulation of CO_2 injection to better understand the field-scale processes involved in the interaction of CO_2 with the oil, hydrocarbon gas and water in place.

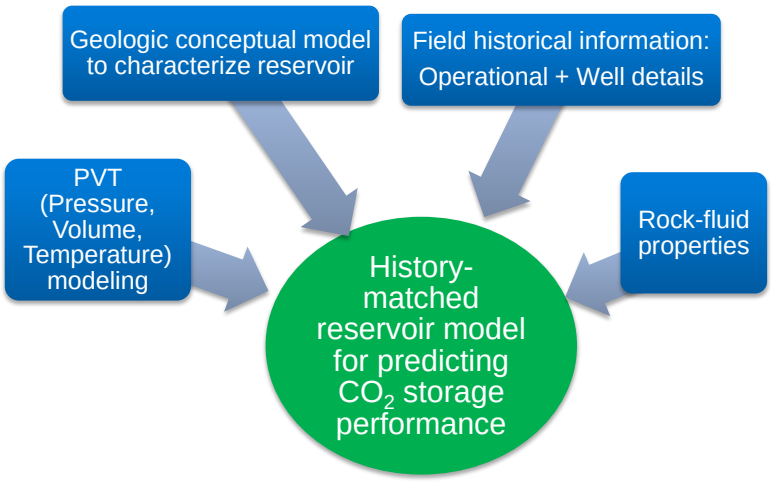


Figure 3-3. Dynamic modeling inputs consideration for evaluation of CO_2-EOR field performance and geologic storage potential

Continuous integrated numerical reservoir models help manage the CCUS operations by enhancing the understanding of the subsurface dynamics while ensuring system integrity. As projects seek recognition of CO_2-EOR storage, the optimization objective can be further tuned to transition from maximizing both CO_2 retention and oil recovery to maximizing CO_2 storage in the desired subsurface volume.

3.2.1 Recommendations

- **Integrate reservoir modeling and analysis with CCUS operations and monitoring activities.** Reservoir modeling is an integral driver of the site selection, performance evaluation, and management of field activities for optimization of operations as well as validation of long-term integrity of geologic CO_2 storage. The optimal modeling tools are to be identified based on objectives and level of detail required for analysis during respective project stages.
- **Periodically update models during the course of the project with latest field data for relevant and valid predictions of CO_2-EOR performance.** Reservoir models are constantly updated as the understanding of the reservoir evolves over the course of the CCUS project. It is therefore essential to integrate reservoir modeling and analysis with CCUS operations and monitoring activities. Continuously updating models with the latest field data serves to provide relevant and valid predictions of CO_2-EOR performance.

3.3 Monitoring, Reporting, and Verification Requirements

Monitoring requirements can be grouped into different categories based on the objective: mandatory requirements for credits (mass balance, wellbore integrity, conformance monitoring, including post injection); performance monitoring (not required but done as part of EOR operations); and environmental monitoring (not required but may be invaluable).

More formal reporting will be required, including development of a MRV Plan. The MRV Plan should contain the following:

- Determination of storage volume
- Identification of potential leakage pathways
- Remediation of potential leakage pathways
- Injection and post-injection monitoring strategy to demonstrate storage of CO_2
- A plan for monitoring parameters.

The project-specific MRV Plan should be developed by a professional with demonstrated expertise, which means at least three years of experience monitoring CO_2-EOR projects and/or published, relevant peer-reviewed academic research on monitoring of CO_2 storage (ACR, 2015).

The objective of pre-injection characterization and subsurface baseline monitoring is to establish baseline conditions and compare with injection and post-injection measurements. Characterizing pre-injection conditions requires a proactive and comprehensive approach. Factors that could provide a false signal of leakage include noisy data due to development activities and naturally occurring shallow/surface hydrocarbon accumulation. The operator must decide the approach for surface/near surface monitoring for CO_2 loss based on the credit mechanism and risk tolerance. Some factors to consider:

- Reservoir type – open or closed
- Past experience proving lack of leakage pathways
- Extent of engineering controls
- Availably of cost effective monitoring technology cable of detecting leakage
- Regulatory perception
- Public perception

Views on monitoring requirements vary, but there are three common themes: (1) monitoring activities are site specific and risk weighted; (2) monitoring activities for CO_2-EOR storage projects may need additional baseline and post-injection data acquisition; and (3) monitoring activities need to be transparent and subject to independent review.

A detailed site characterization is conducted to identify potential leakage pathways (Figure 3-4). Even for a site with demonstrated containment, assessing for leakage pathways is an important part of developing a monitoring plan. Conduits for CO_2 leaks include CO_2 injection wells, oil or gas production wells, monitoring wells, abandoned wells, and faults and fractures. Geomechanical effects and well leakage are the main technical issues associated with site selection for projects combining CO_2-EOR with permanent storage. Operations performed on the reservoir during primary and secondary recovery may have geomechanically altered the reservoir by creation of new migration pathways and older legacy wells are risk factors by offering a potential pathway for CO_2 to migrate upwards. Near surface monitoring that can discriminate a leakage signal from background concentrations and that can account for the noise generated by previous site use are among the recommended strategies for CO_2-EOR sites that are applicable to storage (Wolaver et al., 2013).

The ACR Protocol offers the following guidance: “Depending on site-specific conditions, the Project Proponent shall determine whether the monitoring approach would benefit from establishing pre-injection levels. If deemed beneficial, these measurements shall be done for a period of times that allows for the collection of data that are representative of site conditions prior to the initiation of injection. On-going research on pre-injection monitoring techniques and approaches can be used as a valuable resource to develop a project-specific monitoring plan. Innovative strategies to determine sources of groundwater contamination in the absence of pre-injection data, which include the use of stable carbon isotopic signatures, noble gases, and other metrics like hydrogen carbonate can be adapted for brownfields sites. The results of ongoing research on soil monitoring can provide data to determine its value in a pre-injection monitoring approach.” (ACR, 2015)

3.3.1 Recommendations

- **Develop a strategy for detecting and quantifying any CO_2 surface leakage and to establish a “baseline” for comparison.** This could include near-surface, surface and atmospheric monitoring, performed in stages and triggered upon leakage being detected via subsurface monitoring. In addition, there are approaches to detect CO_2 surface leakages from air and space.
- **Develop a MRV plan to help proactively manage project risks.** Since the monitoring program for any CCUS project is derived from risk assessment; the monitoring program should form a ‘tiered’ approach based on the risks identified (see Section 3.8 for further discussion). Project performance-based measures constituting primary requirements would be reservoir zone monitoring to intensively track the pressure, temperature and CO_2 plume. Leakage detection and management can be

implemented by monitoring above-zone and possibly less intensive surface monitoring. Table 3-4 summarizes the relevant monitoring zones. Table 3-5 summarizes monitoring options applicable for CO_2 storage sites.

3.4 Accounting

The amount of CO_2 that can be stored as a result of EOR operations is determined by many factors. These include both operational factors and geologic or reservoir related factors. The operational stages are especially relevant to the project transitioning from CO_2-EOR to CO_2 storage. After the start of CO_2-EOR operations, past operations including primary depletion must be included in the analysis of overall storage capacity available.

In addition to the operational factors, the CO_2 storage potential and injectivity in the reservoirs is significantly influenced by the fluids, geologic and reservoir properties. Examples of these include the size of the reservoir; relative permeability of reservoirs to CO_2; connectivity between adjacent reefs or between reefs and surrounding rocks; reservoir temperature and pressure as well as configuration of wells, which impacts the residual saturation (immobile phase) CO_2 trapped; solubility of CO_2 in brine and oil; and mineralogical trapping, allowable pressure increase (to avoid fracturing the caprock). An understanding of these subsurface factors is important for determining ultimate storage potential as well as ensuring the integrity of storage in each reservoir.

For the purposes of reporting CO_2 retained in the reservoir, the reported amount of CO_2 stored may be calculated as the difference between the CO_2 injected and the CO_2 produced. Accounting requires that the fields be monitored, tracking the facilities and instrumentation used to measure CO_2 flow rates and bookkeeping of any losses.

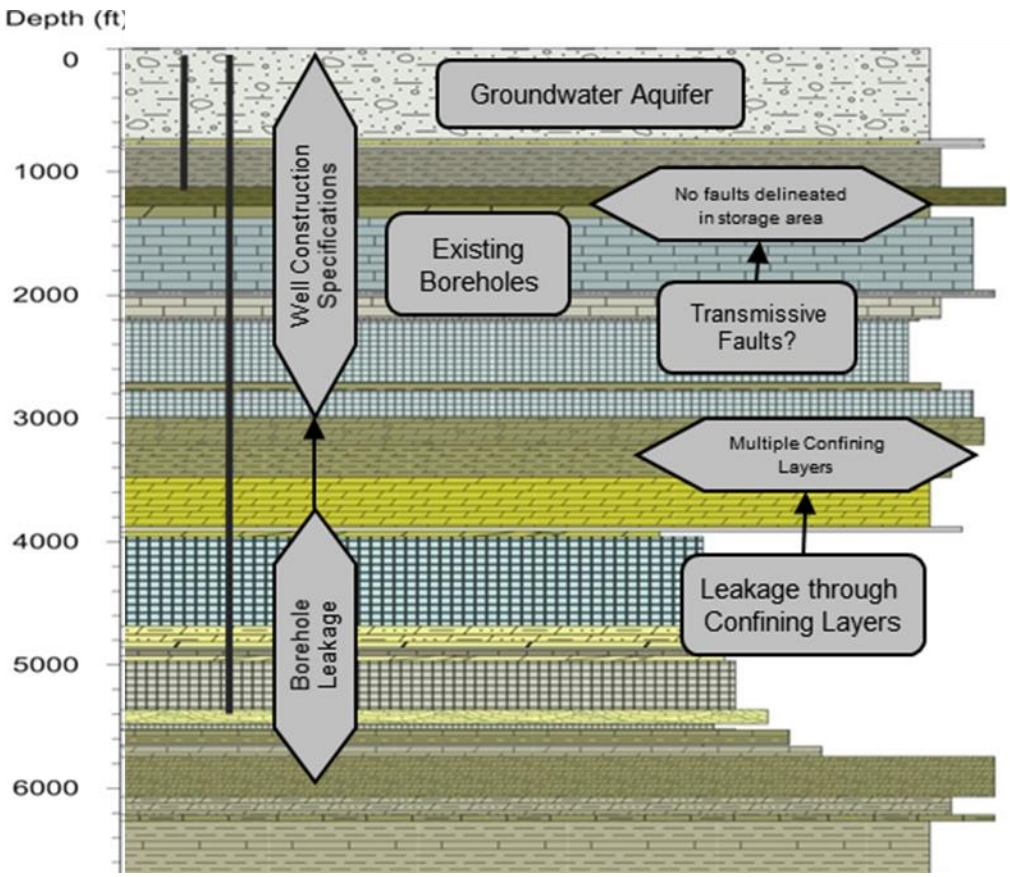


Figure 3-4. Example leakage pathway assessment for MRCSP Large-Scale Injection Project

Table 3-4. Relevant monitoring zones

Monitoring zone	Property or Process	Description
Injection	Trapping effectiveness	Close monitoring spacing using existing wells; active CO_2 management reducing monitoring area; identify unintended out-of-pattern CO_2 migration
Intermediate (Above Zone Monitoring)	Pressure perturbations Naturally occurring hydrocarbons	Hydrocarbons/brine injection and/or production at various depths; pressure perturbation active or stabilizing Long hydrocarbon history can create signals mistakenly interpreted as leakage
Near Surface	Natural hydrocarbons Legacy practices	Monitoring to discriminate leak from background Monitoring must account for noise generated by previous site use

(Table modified from Wolaver et al., 2013).

Table 3-5. Example monitoring approaches for CO_2 storage site (Source: Al Edian et al., 2015)

Application	Examples of Instrumentation	Readiness Level* (after NETL, 2012)
Wellbore Integrity Monitoring	• Well logs • Wellbore annulus pressure • Distributed temperature measurements • Tracers that are injected behind the casing and their movement monitored to indicate the presence of leak paths at the casing-cement-rock interface • Wellhead pressure and temperature • Bottom hole pressure and temperature • Geophysical wireline logs • Wellhead fluid sampling	Generally at commercial or demonstration stage New solutions are at development stage, e.g., fiber optics and cableless solutions
Plume pathways monitoring	• 3 or 4 D seismic, including in which the source and recording instrumentation are at the surface; vertical seismic profiling, in which the source is at the surface but the recording instruments are in wells; and cross well seismic in which both the source and recording instruments are in wells • Gravity methods, surface and well based, that use the difference in density between CO_2 and water as a means of detection • Electrical and electromagnetic methods that use the difference in electrical conductivity between CO_2 and water, which is generally assumed to be saline for the purposes of CO_2 storage. • Tiltmeters • Pressure and water quality above storage formation	Generally at commercial or demonstration stage. Controlled-source electromagnetic (CSEM) surveys is at development stage
Near-surface, surface and atmospheric monitoring	• Water samples extracted from vadose zone, near-surface or shallow groundwater formations and analyzed for CO_2 (pH), and/or CO_2-water-rock reaction products and/or for tracers. • Sensors placed at ground surface in the vicinity of the well to measure CO_2 concentrations in the air. • Soil gas surveys • Atmospheric CO_2 concentrations • Eddy covariance sensors • Flux accumulation chambers • Optical sensors • Sea water sampling • High resolution acoustic sampling • Multi-beam echo sounding	Generally at commercial or demonstration stage. New solutions, such as multi-tube remote samplers, wind-vane samplers and portable isotopic carbon analyzers, fiber optic sensors for soil-CO_2, are under development
Air- and satellite-borne monitoring	• InSAR • Hyperspectral • Gravimetry	Generally at demonstration stage.

*The following categories are used for readiness:

- Development: first step in the development of novel tools for effective CO_2 release detection and monitoring.
- Demonstration: technologies deployed at a limited number of commercial-scale operations; technologies used in the oil and gas industry with limited applications in CCS; validated prototypes used in multiple stand-alone demonstration projects.

- Technologies in the commercial stage of development have been systematically tested and utilized in multiple commercial-scale injection sites across a wide variety of geological settings and site conditions.

3.4.1 CO_2 Accounting and Measurement Systems

Accounting of the cumulative net CO_2 stored is based on monitoring activities of field operations and methods to quantify CO_2 stored in EOR systems. The typical monitoring activities include metering of the CO_2 injection volume, recycling of CO_2 gas produced with oil, and new CO_2 compressed. Metering data and historical records can be used to estimate cumulative net CO_2 stored for EOR projects. This methodology is described in the net CO_2 storage calculations for EOR at other DOE Partnerships [e.g., MRCSP (Gupta et al., 2014), SECARB, PCOR], NETL guidance (NETL, 2010; NETL, 2011; NETL, 2012), U.S. EPA regulations (U.S. EPA, 2010), and other research (Hovorka, 2010; ARI, 2007), wherein the CO_2 storage amount is evaluated from the injected, produced, recycled and purchased quantities of CO_2.

Overall, most CO_2 EOR processes involve injection of newly acquired CO_2 from a capture facility and recycled CO_2 that is produced from the field itself. A processing facility may serve as the gas-liquid separation facility where all production fluids from EOR field operations are separated into individual fluid streams (oil, brine and gas) in multiple stages as necessary. Not all injected CO_2 is produced back from the reservoir. The produced gas may be compressed, commingled with pure CO_2 from the capture facility. This recycled CO_2 is re-injected along with the make-up CO_2 from the capture facility back into the system. A simplified process flow diagram of such a typical closed-cycle CO_2-EOR system is shown in Figure 3-5.

Recycled CO_2 may be measured with flow meters at the processing facility. In addition, each of the injector pipelines may be monitored with a Coriolis flow meter to measure CO_2 injection at the well. A Coriolis flow meter measures the mass flow rate directly. Coriolis flow meters may require periodic calibration to ensure the data recorded are considered to be within an acceptable margin of error. Facility reviews, operational monitoring, and historical operations may also be examined to determine if there was measurable CO_2 emitted from the subsurface.

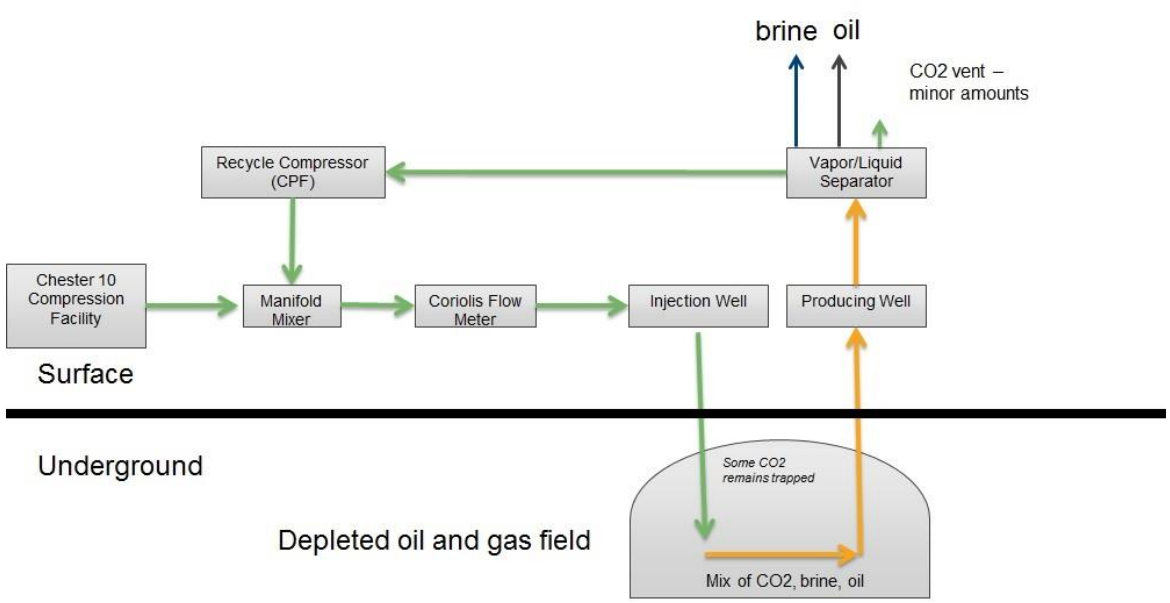


Figure 3-5. Example diagram of closed loop CO_2-EOR cycle (source: Gupta et al., 2014)

The high-pressure and low-pressure gas-liquid separators contain an orifice flow meter that measures the volume of the produced/recycled gas. The processing facility has various process taps where samples can be taken periodically for monitoring composition of the produced gas and recycled gas prior to injection within the EOR reefs.

All of the CO_2-EOR fields may continuously record data to a central computer, with daily production and injection flow meter files generated for operations management. Daily mass balances can then be automatically computed based on the amount of oil, hydrocarbon gas, CO_2 and brine produced on a per-well and combined on a per area basis with the previous daily totals.

As CO_2-EOR projects transition to storage without production, the number of streams that would be accounted for reduces significantly since all production is stopped in this phase. Field history including the mass balances indicating incidental CO_2 stored during EOR operations would be also accounted in the cumulative storage volumes that would be reported at the end of the storage project.

3.4.2 Metrics for Estimating CO_2 Stored in the EOR Fields

A number of metrics derived from operational data monitoring can be tracked over time for desired intervals to account for CO_2 and evaluate storage potential. Some examples are given below:

- Fluid Production and Injection by Field – this is a key metric for performance including production of oil, brine, natural gas, and CO_2 over specific periods, such as daily, weekly and yearly since start of EOR.
- Pure CO_2 (purchased or make-up CO_2) compressed at a CO_2 compression facility
- Produced, vented and recycled CO_2
- Injected CO_2 by well and by field
- Composition analysis of recycled gas streams through periodic sampling
- The percent net CO_2 retained can be computed for each field as a percentage of total injection =

$$\frac{(\text{Cumulative } CO_2 \text{ Injected} - \text{Cumulative } CO_2 \text{ Produced} - \text{Cumulative } CO_2 \text{ vented})}{\text{Cumulative } CO_2 \text{ Injected}}$$

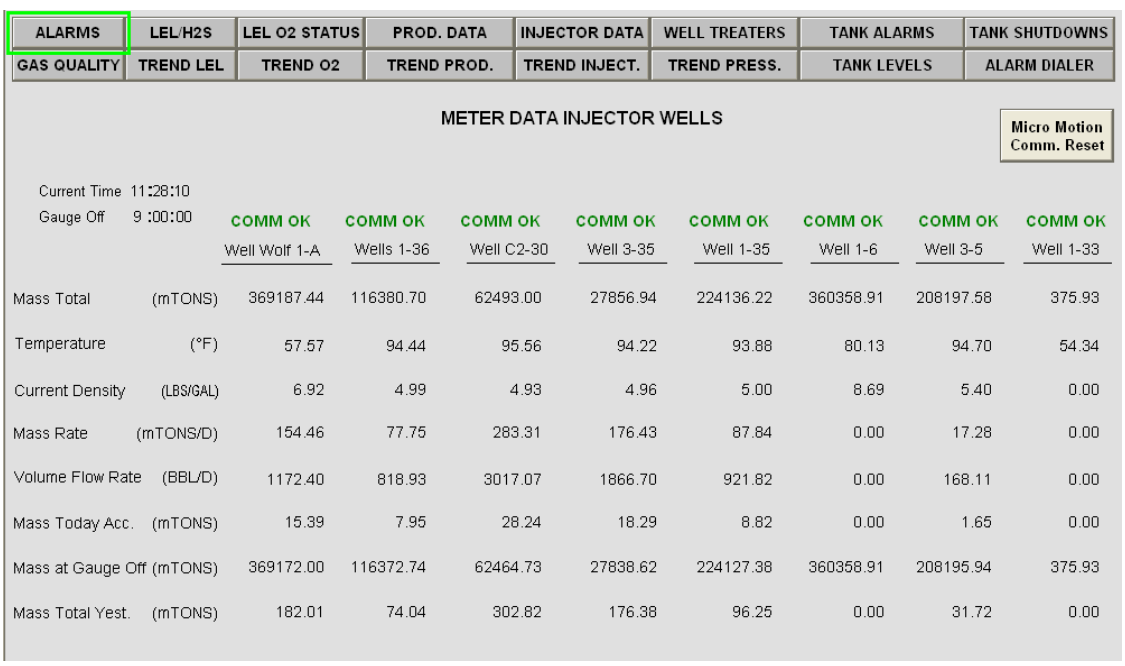
- Several other metrics that can offer insights into the efficiency of EOR or storage processes can be considered, such as:
  - Injection to withdrawal ratios
  - CO_2 utilization ratio (CO_2 injected versus incremental oil produced). An increasing ratio may indicate that the field is approaching maturity and may be considered for transition towards long-term storage without production.
  - Incremental oil recovery factor (percentage of original oil in place) as a function of cumulative CO_2 retained
  - CO_2 utilization ratio as a function of total CO_2 injected

- Ratio of CO_2 stored/CO_2 injected compared to the cumulative incremental oil produced
- Uncertainty quantification for CO_2 retention and utilization
- Decline curve analysis to forecast oil recovery and net CO_2 retained
- Ultimate potential storage capacity.

The usefulness of some of these metrics will be determined and driven by available data from field monitoring during different project phases as fields transition to CO_2-EOR-storage and approach maturity of EOR operations.

System monitoring data may be integrated into a supervisory control and data acquisition (SCADA) system that records system parameters across injection and production wells. Figures 3-6 and 3-7 show example SCADA system data across eight CO_2 injection wells and five production wells, respectively. The system integrates total mass injected, temperature at the wellhead, density, mass rate, volume flow, daily mass injected, and previous day mass injected. The integrated data set helps track system performance across the entire CO_2-EOR system.

The mass balance accounting of cumulative net CO_2 stored is based on cumulative CO_2 injection, which consists of the recycled CO_2 gas produced and new CO_2 compressed in operations as indicated earlier. Cumulative CO_2 injection may reflect variable injection schedules. Figure 3-8 shows an example plot of total CO_2 injected in several fields during a two-year monitoring period. As shown, cumulative CO_2 injection volume was 4.2 million metric tons CO_2.Total average injection rate was 1,297 million metric tons CO_2 per day, which included new pure CO_2 compressed and produced/recycled CO_2. Cumulative CO_2 injected does not reflect the net CO_2 retained in the reservoirs, because CO_2 is cycled through the EOR system. Cumulative CO_2 produced with EOR was approximately 2.8 million metric tons. Thus, total CO_2 retained in the reef was measured at 1.4 million metric tons CO_2.



		COMM OK Well Wolf 1-A	COMM OK Wells 1-36	COMM OK Well C2-30	COMM OK Well 3-35	COMM OK Well 1-35	COMM OK Well 1-6	COMM OK Well 3-5	COMM OK Well 1-33
Mass Total	(mTONS)	369187.44	116380.70	62493.00	27856.94	224136.22	360358.91	208197.58	375.93
Temperature	(°F)	57.57	94.44	95.56	94.22	93.88	80.13	94.70	54.34
Current Density	(LBS/GAL)	6.92	4.99	4.93	4.96	5.00	8.69	5.40	0.00
Mass Rate	(mTONS/D)	154.46	77.75	283.31	176.43	87.84	0.00	17.28	0.00
Volume Flow Rate	(BBL/D)	1172.40	818.93	3017.07	1866.70	921.82	0.00	168.11	0.00
Mass Today Acc.	(mTONS)	15.39	7.95	28.24	18.29	8.82	0.00	1.65	0.00
Mass at Gauge Off	(mTONS)	369172.00	116372.74	62464.73	27838.62	224127.38	360358.91	208195.94	375.93
Mass Total Yest.	(mTONS)	182.01	74.04	302.82	176.38	96.25	0.00	31.72	0.00

Figure 3-6. Example SCADA data from eight CO_2 injection wells

ALARMS	LEL/H2S	LEL O2 STATUS	PROD. DATA	INJECTOR DATA	WELL TREATERS	TANK ALARMS	TANK SHUTDOWNS
GAS QUALITY	TREND LEL	TREND O2	TREND PROD.	TREND INJECT.	TREND PRESS.	TANK LEVELS	ALARM DIALER

PRODUCTION METER DATA

		COMM OK	COMM OK	COMM OK	COMM OK	COMM OK		
		Well 5-35	Well 4-30 & 2-30	Well 2-6	Well 3-36	Wolf C	L.P. Booster	
Gas Orifice Plate	(Inches)	2.500	2.500	2.750	2.500	2.500	1.500	
Gas Run Size	(Inches)	3.826	6.000	3.826	6.000	6.000	1.932	
Gas Diff. Pressure	(In H20)	0.05	108.90	-0.07	128.76	-0.07	93.96	Compressor Discharge Pressure
Gas Static Pressure	(PSIG)	272.96	283.25	25.46	277.62	1.21	285.28	1401.3
Gas Temperature	(°F)	49.78	114.66	52.72	92.17	54.02	66.67	
Gas Flow Rate	(Mcf/d)	0.00	4310.2	0.00	4960.5	0.00	1937.4	
Gas Prod. Today	(Mcf)	0.00	322.52	0.00	459.54	0.00	237.29	Total Gas Prod. Y'day
Gas Prod. Y'day	(Mcf)	0.0	3918.6	1738.7	3632.3	0.0	1962.7	11252.3
Contract Hour (Guage-Off)		9:00	9:00	9:00	9:00	9:00	9:00	
Current Date and Time		10/18/12 11:40:29	10/18/12 10:33:12	10/18/12 11:37:31	10/18/12 11:39:03	10/18/12 11:38:29		

Figure 3-7. Example SCADA data from five production wells

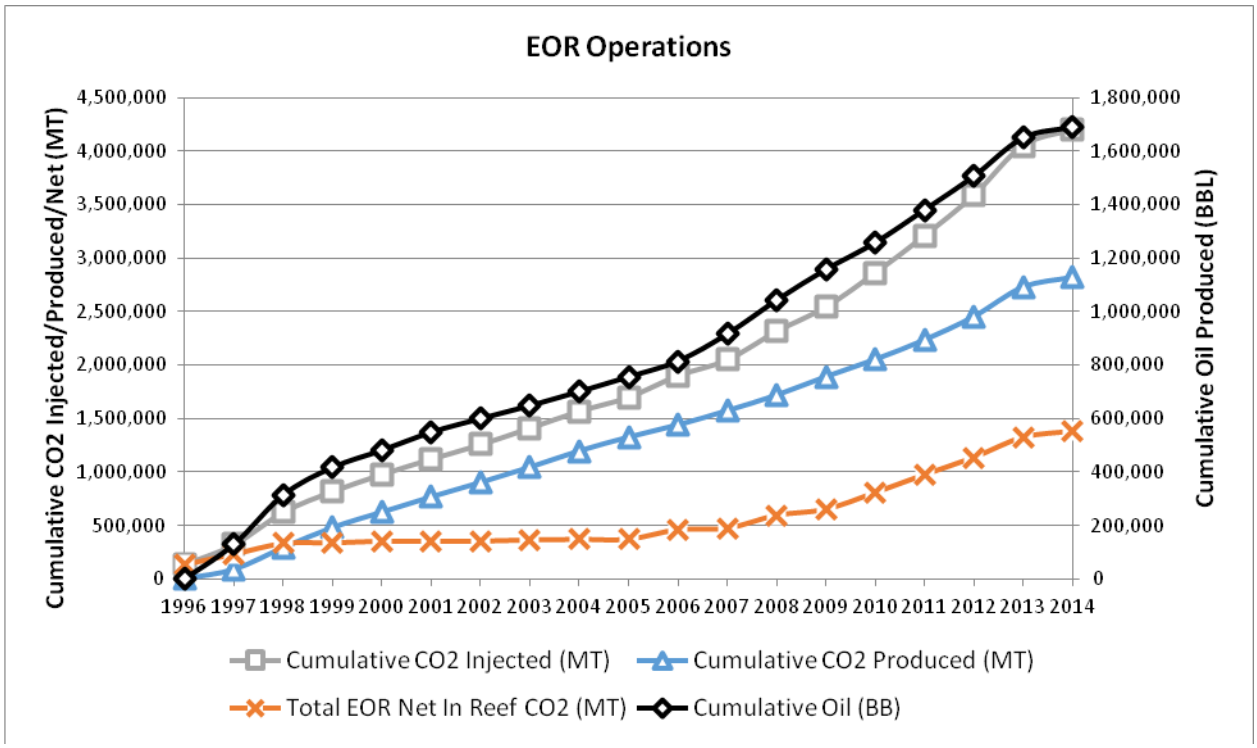


Figure 3-8. Example graph of cumulative net CO_2 retained in EOR units over time

Assuming losses are negligible (as determined by material balance in the preceding paragraph), the cumulative net CO_2 stored in these fields is calculated based on the cumulative CO_2 injection minus the cumulative produced/recycled CO_2 gas:

Net CO_2 Retention = (Cumulative CO_2 Injected (Mt) – Cumulative CO_2 Produced (Mt))

Depending on the EOR system setup, it may be necessary to account for CO_2 leakage and fugitive CO_2 emissions between the metering equipment and the injection or production wellheads. For example, the U.S. EPA GHG Mandatory Reporting Requirements for CO_2 EOR account for CO_2 losses in surface equipment:

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \qquad \text{(Eq. RR-11)}$$

where

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) as equipment leakage or vented emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

CO_{2FP} = Total annual CO_2 mass emitted (metric tons) as equipment leakage or vented emissions from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity

Most CO_2-EOR systems will have excellent trapping mechanisms, thus CO_2 leakage should be zero. Positioning flow meters near wellheads may minimize equipment leakage not accounted for by system monitoring.

3.4.3 Recommendations

- **Review CO_2 flow metering equipment and flow circuit to ensure all streams are tracked adequately and reliably.** This may include metering CO_2 flow rates at injection wellheads, periodic measurements of CO_2 density, CO_2 produced with EOR, and recycled CO_2. Develop a process flow diagram illustrating metering locations, equipment, pipelines, CO_2 recirculation, and interconnections for the CO_2-EOR system. Plan for periodic measurements of CO_2 flow stream chemistry at key locations. Plan for annual calibration of metering equipment.
- **Develop plan for accounting for CO_2 net balance based on relevant metrics**. This plan should identify key locations where CO_2 is metered for both injection wells and production. The plan may also include options for examining leakage/fugitive emissions at wellheads, and how this relates to

CO_2 storage accounting. The plan should examine accuracy of flow metering equipment in relation to accounting goals. Periodic calculation of net CO_2 retained will aid in tracking CO_2 storage performance and CO_2-EOR operations.

- **Plan for periodic (monthly) reports on CO_2 storage volumes**. Develop reporting template for accounting CO_2 storage volumes, injection pressures, monitoring well data, CO_2 composition, and operational parameters. Based on net CO_2 retained in the reservoir, track the total CO_2 retained in the reservoir over time to help determine any anomaly in the CO_2 storage process, such as migration out of the storage zone.
- **Consider CO_2 leakage potential in surface EOR system (pipelines, oil processing, wellheads).** This effort may be necessary to fulfill CO_2 storage credits. Leakage monitoring may include analysis of fugitive emissions.

3.5 Post-Injection Monitoring and Site Closure

Post-injection monitoring and site closure requirements are key differences between CO_2-EOR and CO_2-storage. At the end of the EOR operation, oilfield operations are terminated and wells are plugged and abandoned in accordance with the applicable oil and gas regulations and applicable industry standards and practices. At the end of the CO_2 injection period into a storage reservoir, the CO_2-storage project enters a post-injection monitoring phase, followed by site closure. While the well plugging and abandonment procedures may remain the same between CO_2-EOR and CO_2-EOR storage, EOR operators need to implement a post-injection monitoring strategy that will continue to account for the CO_2 that was stored in association with EOR operations to receive credits. The operator will remain responsible for maintenance, monitoring and control, reporting, and corrective measures pursuant to a post-closure plan until the site meets the applicable closure requirements to show containment without future leakage.

The MRV Plan (described in Section 3.3) should contain the post-injection monitoring strategy to demonstrate storage of CO_2. According to the ACR (2015), the minimum requirements for post-injection monitoring should include:

- Recording subsurface pressure and evaluating changes in pressure measurements to determine if the changes are indicative of leakage.
- Implementing other monitoring tools in accordance with the site's monitoring plan to ensure no leakage.
- Performing post-injection monitoring for a minimum of 5 years (note: CDM requires 20 years of post-injection monitoring).

Once injection is completed, the key activities for post-injection monitoring and site closure for a CO_2 storage project are summarized in Table 3-6.

Table 3-6. Post-injection monitoring and site closure activities

Activity	Objective	Methods
Post-injection Monitoring	Demonstrate stabilization of pressures and CO_2 plume	Wellhead/downhole pressure monitoring, well logs, vertical seismic profile, 3D seismic, near surface or surface leakage monitoring (if needed)
Reservoir Simulations	Demonstrate plume stability and trapping mechanisms	Reservoir models, analytical equations
Well Plugging and Abandonment	Effectively seal wells to prevent wellbore leakage	Industry standard well plugging and abandonment methods
Site Closure	Close out site, remove surface equipment, legacy documentation	Demobilize equipment, site closure reports, submit permitting reports

3.5.1 Recommendations

- **Integrate post-injection monitoring with CO_2-EOR operations activities.** Post-injection monitoring is completed to demonstrate that pressures and plume have stabilized in the subsurface. In general, pressures may be measured at the wellhead and/or downhole with pressure tools and loggers. Figure 3-9 shows a figure of downhole pressure buildup over time at a CO_2 storage site. Additional methods may be employed to track the CO_2 saturation in the subsurface such as geophysical saturation logs, vertical seismic profiles, 3D seismic surveys, etc. In general, these methods may be integrated with other monitoring and operations to determine the stabilization of the CO_2 plume in the subsurface. Figure 3-10 shows a typical schedule for monitoring into the post-injection periods. Overall, these activities may be completed on a more periodic basis to track the CO_2 plume as the CO_2 stabilizes in the subsurface. Based on data from pilot-scale CO_2 storage tests, and on Battelle's experience and review of other small-scale CO_2 injection projects, the stabilization period appears to be more of a function of the injection period. U.S. EPA has proposed a nominal post-injection monitoring period of more or less than 50 years for Class VI UIC wells. Site closure could be achieved at a period of even less than five years if closure requirements are met.

- **Use reservoir simulations to validate/establish conformance.** Reservoir simulations may be completed to determine pressure front, predict CO_2 migration, and demonstrate CO_2 trapping mechanisms. In general, this may involve similar numerical modeling described in Section 3.6. Once injection ceases, a representative reservoir model may be calibrated to monitoring data during the post-injection period to provide more accurate representation of the CO_2 storage (including the migration and stabilization process). Therefore, modeling results presented in this period recalibrated as more information is collected from during project operations.

- **Develop plugging and abandonment plans for wells once system stabilization has been determined to be acceptable**. Following all injection and monitoring activities, project wells should be plugged and abandoned using best practices to prevent communication of fluids between the injection reservoir and the overlying underground sources of drinking water. The action should be based on the existing oil and gas standards (ISO, API, etc.) and oil and gas regulations. Integrity of the wells may be confirmed by completing a CBL and pressure/temperature log on each of the wells. The wells with perforations (the injection reservoir monitoring wells and the intermediate monitoring wells) may be plugged using a cement retainer method to cement the perforated intervals and a balanced plug method to cement the well above the perforated zones and the cement retainer. A plugging plan should explain the depth in the well that plugs are planned, placement of cement retainers, and the type, grade, and quantity of materials to be used in plugging. The cement and other

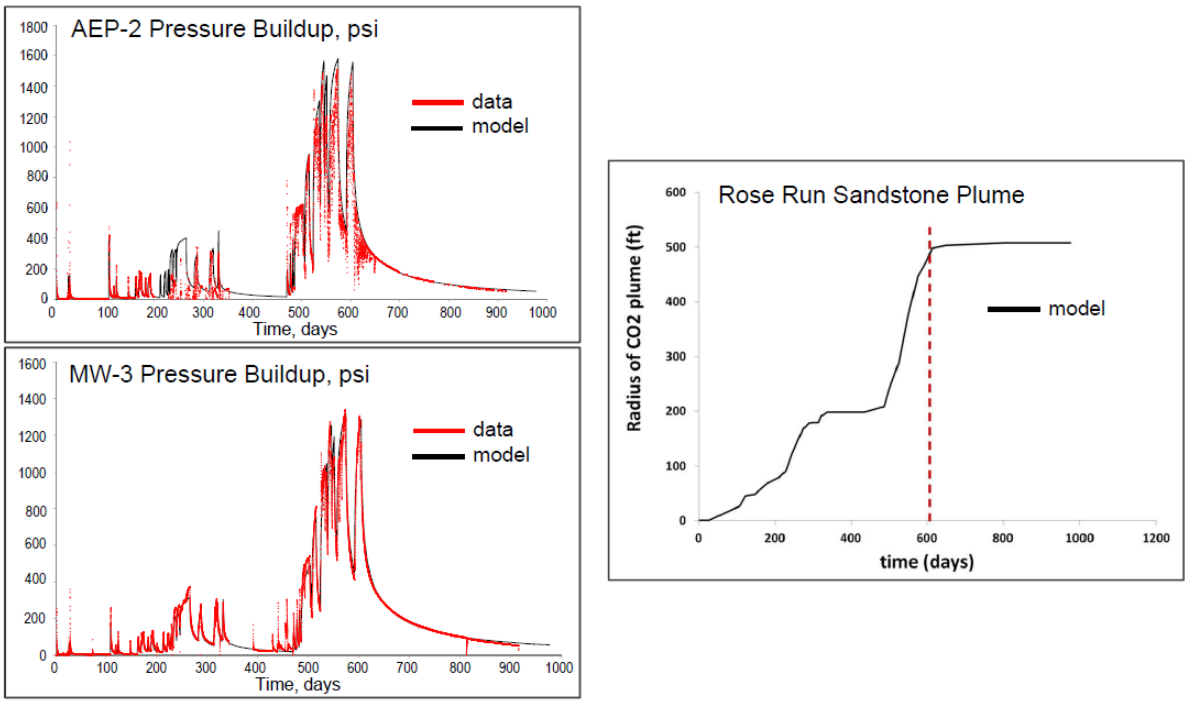


Figure 3-9. Example pressure monitoring and plume during CO_2 storage operations and post-injection periods (Graphs illustrate pressure buildup during injection, pressure falloff after injection, and CO_2 plume radius stabilization.)

Activity	Before Injection	Early Injection	Mid Injection	Late Injection	After Injection
CO_2 flow		X	X	X	
Pressure and temperature		X	X	X	X
Wireline logging	X		X		X
Borehole gravity	X				X
Fluid sampling	X		X		X
Vertical seismic profile	X				X
Microseismic	X			Under planning	
Satellite radar	X	X	X	X	X

Figure 3-10. Example of a monitoring schedule for a small-scale research project at an EOR research field at MRCSP Michigan Basin site

materials in the storage zone must be compatible with the CO_2 and water mixtures, so acid resistant cement is recommended.

- **Close out the project once the conditions in the subsurface have stabilized and the wells have been plugged.** Relying on the information collected from the MRV Plan, the process of site closure establishes that the injected CO_2 is stored, there is a sufficient understanding of the characteristics of the storage zone, and that the CO_2 does not pose a leakage risk. This activity may include cessation of injection and production operations, removal of surface equipment, site closeout reports, final permitting, and documentation of the storage zone in oil and gas records.
- **Determine how to ensure permanent CO_2 storage without limiting potential future oil extraction.** "Permanent" means either that GHG reductions are not reversible, or provide mechanisms to replace any reversed GHG emission reductions to ensure that all credited reductions endure for at least 100 years (for instance, if an EOR operator desires to use the CO_2 in other depleted oil and gas fields or if an unforeseen technology improvement allows for economical extraction of stranded oil remaining in the reservoir). An approved accounting methodology may be required to allow for CO_2 to be utilized for future purposes.
- **Recognize post-closure site access and other liability concerns related to CO_2 storage integrity.** EU directive requires financial instruments by the operator to ensure that closure and post-closure obligations are met, as well as obligations to take corrective measures in case of leakages or significant irregularities. See Section 4.2 for further discussion.

3.6 Economics

As discussed in Section 2, the barriers for pursuing co-optimized CO_2 storage with EOR are primarily economic. Developing a CO_2-EOR storage project is a high capital-outlay venture. One reason is the limited availability of a source of anthropogenic CO_2 and the high cost of CO_2 itself. The high cost of CO_2 creates incentive for EOR operators to recycle CO_2 rather than purchase new quantities. Another factor is the cyclic nature of oil prices which makes capital intensive projects such as CO_2-EOR less attractive as operators seek to maximize profitability during high oil price periods by a combination of limiting the number of EOR projects and recycling CO_2.

Oil prices have the greatest impact on the economics of a project. The expenditures associated with CO_2 are the largest project expense (amounting to nearly half the cost of revenue). The cost categories for EOR include:

- Well drilling and completion
- Lease equipment for new producing wells and new injection wells
- Converting existing production wells into injection wells
- Reworking/transition costs from water flood to CO_2-EOR
- Operations and maintenance
- CO_2 recycle plant investment
- Fluid transporting costs (including orifical list and re-injection)
- CO_2-hub distribution cost.

3.6.1 Recommendations

Economic models illustrate that storage-related strategies require substantial incentives to support near-term deployment. Budgetary requirements for monitoring and reporting, as well as optimization strategies, need to be considered. Project plans that cover project life cycle and include one or more surface, near surface and/or subsurface monitoring techniques need to be developed. The market for CO_2 storage must be aided by environmentally conscious government entities by placing an economic (rather than regulatory) incentive on using anthropogenic CO_2 for EOR. Government investment in research to bring down the cost of capture is needed to increase economic viability of CO_2-EOR storage.

3.7 Legal and Regulatory Issues

Table 3-7 provides a description of potential legal and regulatory issues for transitioning from CO_2-EOR to CO_2 storage without production. A detailed review of legal and regulatory requirements for transitioning CO_2-EOR to CO_2 storage was not a primary objective of this project. However, these requirements may affect the site characterization, operations, monitoring, and site closure for CO_2 storage projects. Legal aspects related to CO_2 storage may include subsurface rights, surface property access, liability issues, and long-term financial mechanisms for funding site closure. In general, the main regulatory items for CO_2-EOR storage may include environmental permits, monitoring reports, and site closure reports. As described in Section 4.0, international standards may require some level of monitoring, accounting, and documentation for certification of carbon storage credits. Readers are referred to a companion World Bank project on legal and regulatory issues for implementing CO_2 storage in Mexico for more information.

3.7.1 Recommendations

- Identify any key stakeholders related to subsurface hydrocarbon intrusions, surface landowners, and sensitive environmental areas.
- Estimate long-term liability and financial mechanisms for project administration.
- Review findings of companion World Bank contract on legal and regulatory issues related to CO_2 storage in Mexico.

Table 3-7. Summary of potential legal and regulatory issues for CO_2-EOR storage

Issue	Description
Subsurface Rights	Subsurface mineral rights may be held by other parties, requiring legal agreements with other companies.
Surface Access	Equipment for CO_2 storage may require access to additional land or properties, requiring legal agreements with landowners
CO_2 Migration	CO_2 may migrate out of storage zone and affect groundwater resources, surface, or other oil and gas zones
Long-term Liability	Long-term monitoring of CO_2 storage may require legal and financial mechanisms, including modifications in leases and other contractual obligations to expand operators rights"

3.8 Recommended Next Steps

Despite the challenges imposed by the evolving regulatory and credit mechanisms, it is widely agreed that the CO_2-EOR projects provide a viable and economically attractive pathway for greenhouse gas emission reduction and a potential bridge to storage in saline formations. However, there is a need to build more project experience and test the various credit mechanisms under realistic conditions. For Mexico, any planned EOR field tests, even if these are huff-n-puff or small-scale pilots offer an early opportunity to build the practical knowledge and lay the foundation for successful credit accruals for future full-scale projects. Therefore, it is recommended that the risk management, modeling, monitoring, and accounting activities identified in this report be implemented and evaluated as a prototype in the upcoming feasibility tests.

Figure 3-11 illustrates the layout of a hypothetical CO_2-EOR storage project. The MRV plan should include a delineation of the area that will be actively monitored as well as the broader maximum monitoring area identified based on the extent of the injected CO_2 over the long-term life of the project. The areas are delineated such that the maximum monitoring area (inclusive of the active monitoring area) features during the pre-injection characterization phase of the project. The MRV plan during the injection through the closure phases of the CCUS project covers the active monitoring area. The maximum monitoring area (inclusive of the active monitoring area) is once again examined during the post-closure project phase as part of the MRV plan.

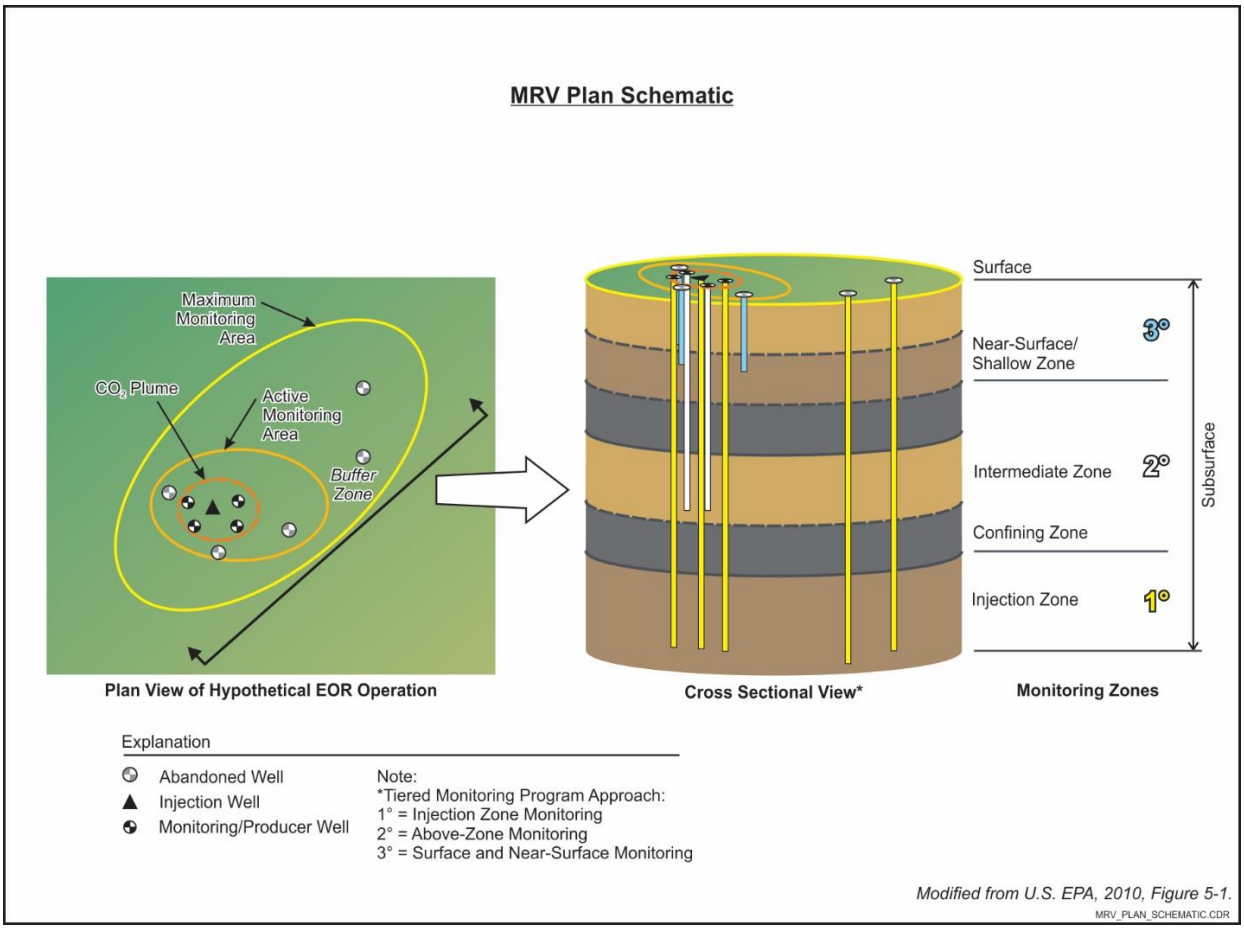


Figure 3-11. Hypothetical monitoring scheme

The MRV Plan must be justified for the geologic and operational conditions at the site and is complemented by integrated modeling and risk assessment activities that are continuously updated with field data during the course of the project. The monitoring program should attempt to achieve reliable accounting and leakage identification by efficiently tracking indicator parameters such as CO_2 rates, pressure, temperature and fluid phase compositions. These parameters are generally tracked in EOR operations as part of the flood management exercise and are hence expected to be adequate for typical reporting and accounting purposes. However, CCUS projects require that the MRV program demonstrate and verify long-term geologic CO_2 storage to obtain carbon credits. For this, additional monitoring-related efforts would be based on the assessment and associated risk management of potential leakage pathways over the lifetime of the CCUS project.

One recommendation is to approach the MRV using general 'tiers' of primary, secondary and tertiary levels of monitoring implemented according to the results of the modeling and risk assessment activities. As levels move from primary through to the tertiary, the intensity of effort involved, the number of complementary technologies used and the frequency of monitoring could reduce. This enables the monitoring system to focus on intensively targeting the most dynamic and probable 'failure' components while ensuring additional levels of defenses to manage and restore system integrity in case of failure (i.e., leakage in this context). Project performance-based measures constituting primary requirements would be standard field management tools to intensively and reliably track the bottomhole pressure, bottomhole temperature, CO_2 injection and production rates. These indicator parameters help evaluate formation and well integrity as impacted by the most dynamic system component (i.e., injection zone). The injection zone is dynamically subjected to varying pressures and contact with CO_2 and is hence subjected to the highest level of evaluation and operational control during the life of the project. The injection and monitoring wells are highly instrumented components and are regulated to ensure least levels of uncertainty with respect to geomechanical and geophysical system integrity. Pressures in a CO_2-EOR setting are regulated and vary within expected ranges depending on the pore volume replacement due to injection and production operations. Any unexpected deviations in the pressure and temperature are an expedient and reliable indicator of fluid migration into or out of that zone. In these cases, the secondary levels of monitoring in the above-zone or overburden layers (intermediate zones) would be employed to ensure leakage identification and quantification. Variations in the indicator parameters monitored in these intermediate zones aid in tracking and mitigating any potential fluid migrating out of the injection zone. The shallow zone and surface monitoring setup would be the tertiary level of defense that is judiciously employed as an assurance of system integrity to maintain stakeholder confidence in the field operations.

Potential leakage pathways or 'failure' components need to be identified in the MRV Plan and their evaluation, based on the risk assessment, is initially qualitative in nature. The potential system components that could contribute to unwarranted migration of injected CO_2 either as a free-phase or dissolved-phase during CO_2 EOR operations include wells (both existing operational as well as abandoned), fractures and faults as well as structural features such as reservoir dip. Apart from a thorough investigation of the well integrity, all operating wells and 'high risk' abandoned wells must be instrumented to regularly track pressures with suggested built-in measurement redundancies. The possibility of induced seismicity, both due to pre-existing faults and fluid injection activating transmissive features as a result of increased pore pressures, needs to be assessed and managed if occurring. Subsurface modeling complements a proactive monitoring strategy and provides supporting information of each identified risk and associated uncertainties while considering the varying distribution of CO_2 in different fluid phases throughout the life of the project.

To judge if a particular measured parameter is a cause of concern, it is necessary to establish the baseline conditions or the parameter range absent any leak. Pre-injection monitoring of different system

components such as wells, injection zone, overburden and surface helps in understanding the acceptable variability in key indicator parameters. Some surface monitoring may possibly be deployed in the primary tier as part of the baseline monitoring and corrective action plan to address well integrity concerns. Leakage verification and quantification may include more frequent monitoring of identified risk areas, denser spatial coverage of the monitored region or the deployment of supplemental monitoring technologies. Targeted leakage rates are to be measured and compared with detection capabilities of the monitoring technologies used.

For CCUS projects quantifying storage credits, there is an additional post-injection monitoring period where the operator has to demonstrate plume stabilization. The CO_2 plume could be considered stable depending on the rate of movement of the free-phase CO_2 and/or the pressure changes over a certain period of time. The operator could thus prove using both the trends of the post-injection monitoring results and predictive reservoir modeling to show that the rate of the free-phase CO_2 plume movement is lesser than a certain threshold value in any direction and the pressure change on the reservoir is also lesser than a certain threshold value.

Note that EOR operations contain monitoring that is only internally reported. In many cases, new and different monitoring is not required for storage, but open reporting is required. The monitoring plan must be known to get public support of credits. Common requirements for mechanisms offering credits for CO_2-EOR storage projects are discussed in the next section of this report.

Chapter 4 International Framework for Receiving Credits

4.1 UNFCC Clean Development Mechanism (CDM)

The CDM provides an opportunity for nations not in Kyoto Protocol Annex I to contribute to GHG reductions. CDM projects allow the creation of certified emission reductions (CERs) that can be used by Annex I nations to help meet their GHG emission reduction requirements along with emission reduction units. CDM projects are conducted in non-Annex I nations by public or private entities under circumstances that satisfy all of the applicable requirements. Because Mexico is a non-Annex I nation, there is the potential to conduct CDM projects in Mexico that would generate CERs that could be used by Annex I nations to meet GHG emission reduction requirements. A project that achieves geologic storage of CO_2 in association with EOR has the potential to qualify as a CDM project.

The requirements for CO_2 capture and storage in geological formations to be approved as CDM project activities are governed by Decision 10/CMP.7 of the UNFCCC Conference of the Parties serving as the meeting of the Parties to the Kyoto Protocol, including the detailed modalities and procedures set forth in the Annex to that decision. These specific requirements supplement the general modalities and procedures for a CDM as defined in Article 12 of the Kyoto Protocol established by Decision 3/CMP.1.

In addition to the normal eligibility requirements for CDM projects, a CCS project must meet more specific requirements for:

a. Selection, characterization and development of geological storage sites

b. Risk and safety assessment

c. Environmental and socio-economic impact assessments to confirm the technical and environmental viability of the proposed CCS project activity

d. A project design document that addresses the specifics of operation and a monitoring plan

e. Documenting how project participants have secured the necessary rights to store CO_2 in the targeted subsurface pore space

f. Protecting affected entities, individuals and communities against environmental damage, property damage or personal injury

g. Stopping, controlling or remediating any unintended seepage of CO_2

h. Liability arrangements that meet the laws and regulations of the host Party as well as the UNFCCC requirements

i. Financial assurance provisions to cover at a minimum the costs of ongoing monitoring, any net reversal of storage, any required remedial measures, and verification and certification for at least 20 years after the project ends.

The boundary of a CCS project includes above-ground components, including the installation where the CO_2 is captured; any treatment facilities; transportation equipment, including pipelines and booster stations along a pipeline, or offloading facilities in the case of transportation by ship, rail or road tanker; any reception facilities or holding tanks at the injection site; the injection facility; and all subsurface components, including the geological storage site and all potential sources of seepage, as determined

during the characterization and selection of the geological storage site. The project boundary will also encompass the vertical and lateral limits of the CO_2 geological storage site that are expected to be occupied by the CO_2 plume as it stabilizes over the long term during the post-closure phases.

General baseline considerations are intended to “promote consistency, transparency and predictability” and are designed to ensure that net reductions in anthropogenic emissions are real and measurable, and provide an accurate reflection of what has occurred within the project boundary. They also address the “additionality” requirement of Article 12, paragraph 5 (c) of the Kyoto Protocol, which specifies that reductions in emissions must be “additional to any that would occur in the absence of the certified project activity.” Finally, the determination of project boundaries should be made to include an accounting for all GHG emissions as a part of the baseline assessment and monitoring.

CCS projects must be designed so that there are no significant risks of seepage, no significant environmental or health risks, and provisions for compliance with all laws and regulations of the host Party. The geological storage site must not be located in international waters. “All available evidence, such as data, analysis and history matching, [must] indicate that the injected CO_2 will be completely and permanently stored such that, under the proposed or actual conditions of use, no significant risk of seepage or risk to human health or the environment exists” (UNFCCC, 2012).

Characterization of the CCS project site calls for collection of sufficient data and information to characterize the geological storage site and determine potential seepage pathways. To characterize the geological storage site architecture and surrounding domains it is necessary to assess all known and inferred structures within the injection and caprock formations to see if any would facilitate migration of injected CO_2. In particular, this involves 3D static earth modeling of the geological storage site. There will also be an assessment of how the injected CO_2 can be expected to behave within the geological storage site architecture and surrounding domains, with a particular focus on the risk of seepage. Based on these characterization steps, a site development and management plan is established to address the preparation of the site, well construction, injection rates and maximum allowable pressure, operating and maintenance protocols, as well as the timing and management of closure.

A comprehensive and thorough risk and safety assessment is required to assess the integrity of the geological storage site and potential impacts on human health and ecosystems. The risk and safety assessment must cover the full chain of the CCS project, provide assurance of safe containment of CO_2, yield operational data for the site development and management plan, take account of the effects of potential induced seismicity or other geological impacts, and provide a basis for developing remedial measures (including plans for responses to stop or control unintended CO_2 emissions from surface CCS installations or seepage). It should also include a communication plan.

Monitoring of CCS project activities is intended to provide assurance of the environmental integrity and safety of the geological storage site, confirm that the injected CO_2 is contained within the geological storage site and within the project boundary, ensure that injected CO_2 is behaving as predicted, ensure that good site management is taking place, detect and estimate the flux rate and total mass of CO_2 from any seepage, determine whether timely and appropriate remedial measures have been carried out in the event of seepage; and determine the reductions in anthropogenic emissions by sources of GHGs that have occurred as a result of the registered CCS project activity.

Specifically, the monitoring plan should consider the range of technologies described in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories and other good practice guidance (IPCC, 2006). The monitoring plan must specify which parameters and information will be monitored and collected, and the

location and frequency of application of different monitoring techniques during the operational phase, closure phase and post-closure phase of the CCS project. The plan will identify the techniques and methods to detect and estimate the quantity of the CO_2 stored in the geological storage site, detect potential seepage via pathways in caprock formations, overburden and surrounding domains in the geological storage site, and estimate the flux rate and total mass of any CO_2 seepage. The plan will also describe the process for history matching, using the monitoring results to calibrate and update the numerical models used to characterize the geological storage site. To provide the necessary inputs, the monitoring plan will also need to provide for:

- measurement of the CO_2 stream and composition
- measurement of the temperature and pressure at the top and bottom of the injection well(s) and observation well(s)
- monitoring and measurement of various geological, geochemical and geomechanical parameters, such as fluid pressures, displaced fluid characteristics, fluxes and microseismicity
- monitoring and measurement of relevant parameters in the overburden and surrounding domains of the geological storage site, such as the monitoring of groundwater properties, soil gas measurements and measurements of the surface concentrations of CO_2 in the air, which shall be calibrated to detect signs of seepage, at an appropriate frequency
- detection of corrosion or degradation of the transport and injection facilities.

Verification will be achieved by history matching and, where necessary, updating the numerical models used to characterize the geological storage. The numerical models will be adjusted to address significant deviations between observed and predicted behavior.

Monitoring of the geological storage site begins before injection activities to provide adequate collection of baseline data. All monitoring should be conducted at appropriate frequencies and will not be terminated earlier than 20 years after the end of the last crediting period of the CDM project, and then only if no seepage has been observed at any time in the past 10 years and if all available evidence from observations and modeling indicates that the stored CO_2 will be completely isolated from the atmosphere in the long term.

The CDM verification and certification process applies to all projects and for CCS projects focused on determining whether the plans approved for the project are properly implemented, including the monitoring plan, the site development and management plan, and any remedial measures and plans described in the risk and safety assessment. Monitoring and operational data are to be analyzed and compared with the initial modeling to determine whether significant deviations were observed during history matching. If so, the process calls for a recharacterization of the geological storage site, an update of the risk and safety assessment, an update of the environmental and socioeconomic impact assessments, a revision to the project boundary, and a revision to the monitoring plan. In addition, deviations from expected behavior require assessments to determine “whether seepage occurred from the geological storage site of the CCS project activity during the verification period.” Where any seepage has occurred, there must be an evaluation to whether a net reversal of storage has occurred and a quantification of the amount of the net reversal for compensation purposes. At the end of the project, the verification process must provide a determination that the geological storage site has been successfully closed.

4.2 European Union CCS Directive

In the European Union CCS is regulated under the EU CCS Directive on Geological Storage of CO_2 (Directive 2009/31/EC), which became effective on June 25, 2009. As an enabling Directive, it does not require CCS to be developed as a technology, but any CCS project must follow its provisions under legislation enacted by the nation in which the project is located. The Directive primarily establishes the legal framework for geological storage with little attention paid to capture or transport. It provides detailed requirements that focus on selection of storage sites (Art. 4), exploration permits (Art. 5), storage permits (Art. 6), operation, closure and post-closure obligations (Chapter 4) and provision for transfer of responsibility (Art. 18).

Earlier, the European Union adopted its Emissions Trading Directive (Directive 2003/87/EC) (EU ETS), which establishes a cap-and-trade program. CCS was not included in the original 2003 ETS Directive but was added in 2009 (European Union Emissions Trading Directive Annex I [Directive 2009/29/EC]). CO_2 that is captured, transported and stored according to the CCS Directive is considered as not emitted. Yet the EU ETS does require that emission allowances must be purchased to compensate for any stored CO_2 that escapes to the atmosphere. Currently, CO_2 storage associated with EOR can qualify for full credit but is subject to all of the requirements of the CCS Directive.

Under the EU ETS, companies receive or buy emission allowances which can be traded. Companies can also buy limited amounts of international credits from emission-saving projects around the world to satisfy their emission allowance requirements. The EU ETS chose to allow companies to buy international credits to help incentivize investment in clean technologies and low-carbon solutions, particularly in developing countries.

The European Union also seeks to encourage the establishment of cap-and-trade programs and other new market mechanisms in developing countries by inviting them to connect with the EU ETS program to create a system of globally linked economy-wide cap-and-trade systems. This goal has been given additional momentum by the 2011 decision in Durban to set up a new market mechanism under the UNFCCC. The European Union is also exploring the idea of setting up pilot programs in sectoral crediting.

Under the new UNFCCC mechanism, verifiable and additional emission reductions achieved against ambitious crediting thresholds would generate international credits. Sales of these credits could raise revenues for the host countries while helping developed countries to meet their emission commitments and EU ETS operators to comply with their obligations. Credits from this new market mechanism could be used in addition to credits from the CDM or the Joint Implementation (JI) mechanism.

The EU ETS legislation allows participants to use most categories of CDM and JI project credits except nuclear energy projects, afforestation or reforestation activities, and projects involving the destruction of industrial gases. The European Union wants to see more use of standardized baselines and alternative ways of assessing additionality. For advanced developing countries, the European Union seeks to have CDM offsets replaced over time by the new market mechanism covering broad segments of the economy and incentivizing net emission reductions. CDM would then be focused on least developed countries.

4.3 California Offset Credits

Assembly Bill 32 (AB 32), the California Global Warming Solutions Act of 2006 (AB 32, Statutes of 2006, Chapter 488) charged the California Air Resources Board (ARB) with “monitoring and regulating sources of emissions of greenhouse gases that cause global warming in order to reduce emissions of greenhouse

gases" (Health and Safety Code section 38510). AB 32 required ARB to prepare a "scoping plan" for achieving the maximum technologically feasible and cost-effective GHG emission reductions by 2020 (Health and Safety Code section 38561(a)). The AB 32 Scoping Plan identified a cap-and-trade program as one of the strategies to reduce the GHG emissions. Under cap-and-trade, an overall limit on GHG emissions from capped sectors is established by the cap-and-trade program and facilities subject to the cap will be able to trade permits (allowances) to emit GHGs.

ARB approved the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation (Cap-and-Trade Regulation) in October 2011. The regulation provides for the establishment, administration, and enforcement of the California Greenhouse Gas Cap-and-Trade Program by applying a statewide GHG emissions cap on covered entities and providing a mechanism for trading instruments used to comply with the cap. The Cap-and-Trade Program provides flexibility about how sources may comply with the overall cap. One alternative allows covered entities to use a limited number of offset credits to satisfy a portion of their compliance obligation. An offset credit represents a reduction or removal of GHGs by an activity that can be measured, quantified, and verified. Individual offset projects can be implemented to generate offset credits, which can then be sold and used by a covered entity as a compliance instrument in the Cap-and-Trade Regulation (ARB Cap-and-Trade Regulation Instructional Guidance 6.2). The Cap-and-Trade Regulation allows offset projects to be located in the United States, United States Territories, Canada, or Mexico. 17 California Code of Regulations (CCR) §§95972(c) and 95973(a)(3). Although this criterion is established in the Regulation, individual compliance offset protocols (COPs) may specify a more limited geographic area within that range. For example, the protocol for Compliance Offset Protocol Livestock Projects, October 20, 2011, is only applicable in the United States (ARB Cap-and-Trade Regulation Instructional Guidance 6.3).

An offset credit is equivalent to a GHG reduction or GHG removal enhancement of one metric ton of CO_2e (CO_2 equivalent). The GHG reduction or GHG removal enhancement must be real, additional, quantifiable, permanent, verifiable, and enforceable and may only be issued to offset projects using approved COPs. At present there is no approved Compliance Offset Protocol for carbon capture and geologic sequestration, but the regulation recognizes its potential use by defining the category of "CO_2 Supplier" to be facilities that "capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture the CO_2 stream in order to utilize it for geologic sequestration where capture refers to the initial separation and removal of CO_2 from a manufacturing process or any other process." 17 CCR §95802(a)(58). In establishing the compliance obligation for CO_2 suppliers, the regulation provides that the emissions exclude "CO_2 verified to be geologically sequestered through use of a Board-approved carbon capture and geologic sequestration quantification methodology that ensures that the emissions reductions are real, permanent, quantifiable, verifiable, and enforceable" (17 CCR §95852(g)).

ARB has taken an initial step toward development of a quantification methodology for carbon capture and geologic sequestration by contracting with Lawrence Berkeley National Laboratory to "conduct a scoping study on existing carbon capture and storage quantification methodologies appropriate for California's specific geology and hydrology." [CARB, Semi-Annual Report to the Joint Legislative Budget Committee on Assembly Bill 32 (Chapter 488, Statutes of 2006), The California Global Warming Solutions Act of 2006 p. 14 (July 2014)]. This likely would lead to development of a monitoring, verification, and accounting methodology that is appropriate for incorporation into the Cap-and-Trade Program.

There is a limited possibility for a project to qualify for offset credits under the early action provisions even before ARB has approved a Compliance Offset Protocol. The early action provisions are designed to recognize parties that made early reductions in GHGs. The Early Action Offset Program is limited in scope and only allows GHG reductions or removal enhancements that occur within a specific time frame

and achieve under approved quantification methodologies to qualify under the program. ARB may adopt additional early action quantification methodologies; however, ARB will only adopt early action quantification methodologies for project types for which it also adopts a Compliance Offset Protocol (ARB Cap-and-Trade Regulation Instructional Guidance 6.14).

Early action emission offset credits (EAOCs) are issued by programs that must be approved by ARB, referred to as Early Action Offset Programs. An Early Action Offset Program is a program that is approved by ARB to issue early action offset credits. If the program is approved to be an Offset Project Registry and has been issued an Executive Order, it qualifies as an Early Action Offset Program (ARB Cap-and-Trade Regulation Instructional Guidance 6.14.2). All offset projects developed under an ARB Compliance Offset Protocol must be listed with an ARB approved Offset Project Registry. Offset Project Registries will help facilitate the listing, reporting, and verification of compliance offset projects, and issue registry offset credits. ARB has approved three Offset Project Registries: ACR, Climate Action Reserve and Verified Carbon Standard.

The ACR has an approved Methodology for Greenhouse Gas Emission Reductions from Carbon Capture and Storage Projects (ACR, 2015), which is discussed in the following section in more detail. Eligible projects under the methodology are those that “capture, transport and inject anthropogenic CO_2 during enhanced oil recovery (EOR) operations into an oil and gas reservoir located in the US or Canada where it is sequestered.” (ACR, 2015, Page 1).

Early action offset credits must also meet the requirements for regulatory verification. If ARB determines that an early action offset credit meets the requirements of the Regulation, the early action offset credit must be retired or cancelled by the issuing Early Action Offset Program in its system before ARB will issue an ARB offset credit that may be used for compliance purposes (ARB Cap-and-Trade Regulation Instructional Guidance 6.14).

4.4 American Carbon Registry

In April 2015, the ACR approved a final methodology that outlines the requirements and process for CCS Project Proponents that store CO_2 in oil and gas reservoirs to qualify their projects for carbon credits under the ACR program. The methodology is based on the accounting framework developed by the Center for Climate and Energy Solutions (formerly the Pew Center on Global Climate Change) [A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February, 2012]. Projects are eligible that capture, transport and inject anthropogenic CO_2 during EOR operations into an oil and gas reservoir located in the U.S. or Canada. Projects are required to have clear and uncontested ownership of the pore space and all necessary land surface use rights to conduct post-injection monitoring activities and, if necessary, remediation.

Under the ACR program, project boundaries include a physical boundary, a temporal boundary, and a GHG assessment boundary. The physical boundary encompasses all emission sources, and the assessment boundary covers GHGs emissions from each source. The temporal boundary includes the temporal parameters affecting project validity and the duration of required project activities, including all monitoring.

The ACR CCS Methodology describes Baseline as a counterfactual scenario that forecasts the likely stream of emissions or removals that would occur in the absence of the project, i.e., the "business as usual" case. This serves as a reference case against which to compare GHG emissions associated with the project and derive net emission reductions (ACR, 2015, page 9). The ACR CCS Methodology allows the use of two different types of baselines “referred to as Projection-based and Standards-based.” ACR

defines the Projection-based as "a baseline that would correspond with the project's actual CO_2 capture site, absent the capture and compression system located at the CO_2 source." This calculation "uses data collected in the project condition to represent the quantity of emissions prevented from entering the atmosphere." Alternatively, a "Standards-based baseline can be based on a technology or specified as an intensity metric or performance standard (e.g., tonnes of CO_2 equivalent [tCO_2e] per unit of output).... A Standards-based baseline is sector specific, at minimum, to ensure reasonable accuracy, and it could have a different emissions profile than the technology used at the CO_2 capture site."

The ACR CCS Methodology provides a detailed set of quantification methodologies including a "calculation procedure for the CO_2 capture process [that] reflects the delineation of the boundary of the capture site, which encompasses the source of CO_2, as well as auxiliary equipment associated with the CO_2 capture and compression systems" (ACR, 2015, page 21). For transportation, the quantification process "includes the full pipeline system from the CO_2 delivery point at the capture site (downstream of the compressor) to the CO_2 delivery point at the storage site. The calculation methodology also applies to CO_2 transported in containers (e.g., by barge, rail or truck)" (ACR 2015, page 29).

"The emissions calculation procedures for CO_2 storage cover direct CO_2, CH_4, and N_2O emissions from stationary combustion; CO_2 and CH_4 emissions from venting and fugitive releases to the atmosphere; and indirect CO_2e emissions from purchased electricity use. The procedures also account for any CO_2 that is produced with the hydrocarbons and transferred offsite (i.e., the CO_2 is not re-injected into a reservoir that is within the project boundary) and leakage of injected CO_2 from the reservoir to the atmosphere. GHG sources include CO_2 receiving, injecting, recycling and re-injection equipment; CO_2 injection and production wells, hydrocarbon processing and storage facilities; and the CO_2 storage reservoir" (ACR, 2015, page 35).

The ACR CCS Methodology recognizes that "any injected CO_2 that is not produced with the oil remains contained in the oil reservoir because of the confining layer above the oil reservoir that traps it in place. This is the same confining layer that formed an effective seal and contained the oil and gas in the reservoir for millions of years and now serves to trap the CO_2. However, Project Proponents must quantify atmospheric leakage of CO_2 emissions from the storage volume, if they arise. Atmospheric leakage shall be monitored during the entire Project Term, which includes the injection period and a time-period following the end of injection as defined in Section 2.2. Methods to assure the long-term storage of CO_2 beyond the Project Term will be required; these and associated reversal risk mitigation measures are outlined in Section 5.4" (ACR, 2015, page 45).

The MRV Plan for CCS projects under the ACR CCS Methodology is required to include the following components:

- Determination of the storage volume that is expected to contain the injected CO_2 during and after the injection period, determined through modeling and flow simulations.
- Identification of potential leakage pathways within this storage volume (usually well bores, faults, and fractures). This information can also feed into the flow simulation model as a potential source of uncertainty.
- Remediation of potential leakage pathways, as needed. This can help reduce the probability of leakage and reduce uncertainty in detecting atmospheric leakage.
- Development of a monitoring strategy to demonstrate effective retention of anthropogenic CO_2 during injection and post-injection periods and for detection of the potential for atmospheric leakage.

- A strategy for quantifying any atmospheric leakage of CO_2.
- A plan for monitoring the following parameters:
  - Total volume of gas (containing CO_2 and other compounds) produced from the primary process
  - Percentage of CO_2 in the gas stream from the primary process
  - Units of output from the CO_2 capture facility (e.g., MWh)
  - Non-captured CO_2 emissions from the primary process
  - Stationary combustion emissions for CO_2, CH_4, and N_2O
  - Indirect CO_2 emissions from purchased and consumed electricity, steam, and heat
  - Vented and fugitive CO_2 emissions from CO_2 transport (mass balance)
  - Vented and fugitive CO_2 emissions from CO_2 storage
  - CO_2 transferred offsite, and
  - Atmospheric leakage of CO_2 from storage.

(ACR, 2015, page 55 and Table 5-3).

The monitoring strategy must be designed to demonstrate effective retention of the injected anthropogenic CO_2 within the production reservoir during and after injection. Based on site evaluation and geological parameters, simulations of potential failure scenarios, and the sensitivities of individual parameters to the outcomes of those simulations, the Project Proponent shall determine the specific monitoring parameters to be monitored, the monitoring tools to be used, and the sampling frequency. A fluid flow model is considered to be an essential component of the monitoring strategy. "Working with the EOR operator, required data (existing and newly collected) shall be compiled to develop a fluid flow model that is calibrated with production history and used to predict CO_2 distribution during the injection and post-injection phases of the EOR project" (ACR, 2015, page 57).

With respect to baseline monitoring, the ACR CCS Methodology states that, "depending on site-specific conditions, the Project Proponent shall determine whether the monitoring approach would benefit from establishing pre-injection levels." If the decision is made to take these measurements, they should "be done for a period of time that allows for the collection of data that are representative of site conditions prior to the initiation of injection."

Following completion of CO_2 injection, it is still required that monitoring continue during the post-injection phase until the end of the project to assure that no atmospheric leakage occurs, or if it does then to quantify any leakage. The minimum post-injection monitoring period for CCS projects is five years (ACR, 2015, page 58). Project Proponents must demonstrate that the CO_2 captured and stored is permanently sequestered underground (ACR, 2015, page 76).

Since CCS projects involve capture, transport, and sequestration processes, which are often conducted by different companies, the ownership to the title of CO_2 credits associated with the project's emission reductions must be clearly defined. This can be done through contracts among the parties in which one of the companies has clear ownership of the credits (ACR, 2015, page 76).

4.5 Analogous Mechanism: Texas Railroad Commission

The Railroad Commission of Texas (RRC) adopted a rule in 2011 relating to Certification of Geologic Storage of Anthropogenic CO_2 Incidental to Enhanced Recovery of Oil, Gas, or Geothermal Resources. 16 TAC §§5.301 - 5.308, 36 Tex. Reg. 4397 (July 8, 2011). The RRC adopted the rule to implement legislation that amended the Texas Water Code and the Texas Natural Resources Code to provide for the implementation of projects involving the capture, injection, sequestration, or geologic storage of CO_2. The rule provides for certification of geologic storage of anthropogenic CO_2 incidental to enhanced recovery operations for which: (1) there is a reasonable expectation of more than insignificant future production volumes or rates as a result of the injection of anthropogenic CO_2; and (2) operating pressures are not higher than reasonably necessary for enhanced recovery.

The rule requires the operator of the CO_2 project to implement a monitoring, sampling, and testing (MST) plan that starts with analysis of chemical and physical characteristics of the CO_2 stream. It also requires continuous monitoring of injection pressure, rate of injected CO_2, and volume of injected CO_2. The operator must maintain the mechanical integrity of the injection wells and demonstrate external mechanical integrity once every five years. Corrosion monitoring is required for well materials that will come into contact with water for loss of mass, thickness, cracking, pitting, and other signs of corrosion. In addition, the operator must "fill the annulus between the tubing and the long string casing with a corrosion inhibiting fluid approved by the director."

Annual monitoring of the injection zone pressure in the productive reservoir is required, supplemented by a pressure falloff test at least once every five years. The rule also calls for monitoring wells "as needed for continuous monitoring for pressure changes in an appropriately porous and permeable formation above the confining zone" along with "periodic monitoring of the useable quality water strata overlying the productive reservoir to monitor for changes in quality due to CO_2 injection." The plan also must use "indirect, geophysical techniques to determine the position of the CO_2 fluid front."

To allow "an operator to make a determination by mass balancing or actual system modeling of the quantities of anthropogenic CO_2 permanently stored," the plan must "ensure that the injected anthropogenic CO_2 is confined to the productive reservoir" and account for:

- the volumes of anthropogenic CO_2 injected into the productive reservoir
- the anthropogenic CO_2 separated from the enhanced recovery production
- the anthropogenic CO_2 entrained in the production
- the volume of produced anthropogenic CO_2 recycled for injection into the reservoir
- any *de minimis* losses of anthropogenic CO_2
- the volume of make-up anthropogenic CO_2 injected to the enhanced recovery project.

As an alternative to preparing a new MST plan for the enhanced recovery facility under the RRC rule, the person registering the project and obtaining the storage certification may comply with the rule submitting a copy of the information submitted to the U.S. EPA to comply with the Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide.

In all cases, the operator "must use a master meter or a series of master meters to meter the total volume of anthropogenic CO_2 injected into the enhanced recovery facility." In addition, the operator is required to individual well meters to meter the volume of anthropogenic CO_2 injected into each injection well. To

address situations where anthropogenic CO_2 is commingled outside the enhanced recovery facility with other CO_2, the operator is required to report "the total volume of anthropogenic CO_2 in the mixed stream and may account for the anthropogenic CO_2 for the master meter and injected well volumes on an allocated basis." Essentially, the operator will be required to develop an accounting scheme and demonstrate that it that will track the anthropogenic CO_2 on a proportional basis that avoids overstating the quantities of anthropogenic CO_2 stored.

The rule adopted by the RRC is also noteworthy because a number of other states have begun to enact legislation that would authorize their oil and gas regulators to certify the quantities of anthropogenic CO_2 that incidentally stored in association with CO_2 EOR operations. The RRC rule also served as a starting point for the development of an ISO standard for the recognition and quantification of anthropogenic CO_2 incidentally stored in association with CO_2 EOR.

4.6 Conclusions

4.6.1 Consistent Requirements

The common thread that runs through all of the geologic storage methodologies for quantifying the anthropogenic CO_2 that is incidentally stored in association with EOR is the need to accurately determine the actual GHG emission reductions achieved by the offset project. This starts with the establishment of a project baseline that reflects a conservative estimate of business-as-usual performance. In most cases, this includes consideration of GHG emissions associated with each step in the project chain from the anthropogenic CO_2 capture project, through processing and compression of the captured CO_2, transportation by pipeline or any other means, and into the EOR operation itself. Consideration includes not only overt releases at every stage, such as through fugitive emissions or leakage, but also emissions associated with power and energy usage at each stage. Although it typically will consider the CO_2 entrained in the produced oil and gas sent to market, it does not typically include any consideration of GHG emissions that might result from the eventual combustion of those fuels. Those emissions will be considered in conjunction with the projects and operations in which that combustion occurs.

In some frameworks, such as California, there will be consideration not only of the "activity-shifting leakage" described in the preceding paragraph, but also of "market-shifting leakage" that results from relocation of activities. In those cases, the quantification process will require accounting for both the activity-shifting leakage and the market-shifting leakage. "Activity-shifting leakage" means increased GHG emissions or decreased GHG removals that result from the displacement of activities or resources from inside the offset project's boundary to locations outside the offset project's boundary as a result of the offset project activity. "Market-shifting leakage," in the context of an offset project, means increased GHG emissions or decreased GHG removals outside an offset project's boundary due to the effects of an offset project on an established market for goods or services.

All quantification frameworks will require some accounting for any uncertainty in the quantification of the various factors included in the calculations. Where the equations for calculation are not dictated by the quantification methodology, most regimes require detailed explanation of the process and equations that have been used to calculate the storage quantities.

Most of these methodologies are also similar in requiring that the credited GHG emission reductions must be real, additional, quantifiable, permanent, verifiable, and enforceable. Requiring that the emission reductions (or emissions "removed" or "avoided") be "additional" (sometimes called an "additionality" requirement) means that the GHG emission reductions must exceed any reductions or removals

otherwise required and must also exceed any that would otherwise occur in a conservative business-as-usual scenario. Requiring that the reductions be “enforceable” means there must be authority to hold a particular party liable for taking the steps necessary to result in the reductions and to take appropriate enforcement action for any violations. The requirement that reductions be “permanent” means either that GHG reductions are not reversible, or that the credit management regime provides mechanisms to replace any reversed GHG emission reductions to ensure that all credited reductions endure for at least 100 years. Requiring that the reductions be “quantifiable” means there must be an ability to accurately measure and calculate the GHG reductions or removals relative to a project baseline in a reliable and replicable manner, while accounting for the uncertainty, for activity-shifting leakage and for market-shifting leakage if that is also required. Requiring that reductions be “verifiable” means that an offset assertion is well documented and transparent, such that it lends itself to an objective review by an accredited verification body.

A requirement that the GHG reductions be “real” amounts to a reiteration of all of these characteristics and means that any credited GHG reductions or GHG enhancements must result from a demonstrable action or set of actions, and that they are quantified using appropriate, accurate, and conservative methodologies that “account for all GHG emissions sources, GHG sinks, and GHG reservoirs within the offset project boundary.”

4.6.2 Legal and Regulatory Issues for Qualifying for Credits

Under the European Union Emission Trading System Directive, an offset project involving the incidental storage of anthropogenic CO_2 in association with an EOR project in Mexico could be creditworthy if it meets the requirements of the CDM CCS methodology. Because no such projects have been considered and credited to date, however, uncertainty surrounds the qualification process. Practical implementation will be indispensable to qualification without imposing untenable economic costs. Moreover, recent policy expressions within the European Union suggest movement toward replacing CDM offsets by a new market mechanism covering broad segments of the economy and incentivizing net emission reductions. Under such a new regime, the qualification of offsets would be focused on projects in least developed countries.

For the California Cap-and-Trade Program, although an offset project in Mexico has the potential to qualify for credit, significant steps must be accomplished before the availability of credit could be a reality. Most importantly, the California ARB needs to approve a Compliance Offset Protocol for CO_2 geologic sequestration associated with EOR. In addition, that approved protocol must include Mexico within approved project area. Before that process is completed, it would also be useful to have California ARB approval of an early action quantification methodology for geologic sequestration associated with CO_2 EOR. This approval could be based on ACR protocol, but that protocol would need to be expanded to include Mexico in addition to the U.S. and Canada.

4.6.3 Summary and Concerns

GHG mitigation frameworks and protocols support carbon storage associated with CO_2-EOR as a reduction technology that can be credited when used in an offset project. These include UNFCCC Clean Development Mechanism, European Union Directives, California offsets, ACR and others. More importantly, CO_2-EOR projects demonstrating carbon storage in Mexico may be eligible for credits. The protocols typically outline requirements as performance measures without prescribing technologies to meet these requirements. Accordingly, there is significant flexibility for the project proponent to fashion the project details and submit for approval plans that describe how requirements will be met. Nevertheless, as described herein, there are significant non-technical hurdles that may constrain or

prevent CO_2-EOR projects from meeting the requirements include the lack of an approved California Compliance Offset Protocol for carbon capture and geologic sequestration and the fact that the existing ACR protocol that could play a role in the California offsets program currently excludes projects in Mexico. The lack of experience with applying CDM and European Union protocols to CCS projects in general and to EOR projects in particular could prove a hindrance, as could the absence of any provisions in these protocols that are specifically tailored to oil field operations. Although the ongoing process for developing ISO standards for CO_2 capture, transportation and storage, specifically including the incidental storage of anthropogenic CO_2 in association with EOR promises to provide a better pathway to credits, final standards are still several years away. Other potential hindrances could come in the form burdensome quantification and reporting requirements and in the form of long-lived and cumbersome post-closure operator and host nation obligations.

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Appendix A: Literature Review Summaries

1. OVERVIEW

Battelle conducted a literature review to assess current expert views on issues concerning geological storage, either by transition of carbon dioxide (CO_2)-enhanced oil recovery (EOR) to storage, or by combining CO_2-EOR with storage; identify key issues that need to be addressed in the Mexican context; and provide recommendations to PEMEX on how to implement the required measures that will enable CO_2-EOR projects to qualify for geological storage. The survey included primarily literature identified by the client and additional literature. Sources of information published between 2008 and 2015 are reviewed in detail below, including journal papers, independent consulting reports, research papers, and guidance documents. Collectively, the literature explored technical and economic issues, risk assessment, monitoring, reporting, verification, and accounting requirements, and other topical matters.

2. Literature Review: Discussion and Key Points

2.1 Final Report by the CSLF Task Force on Technical Challenges in the Conversion of CO_2-EOR Projects to CO_2 Storage Projects (CSLF, 2013)

This 2011 report conducted for the Carbon Sequestration Leadership Forum (CSLF) served primarily as a comprehensive summary on various issues surrounding the use of CO_2 for EOR and/or CO_2 sequestration operations. The report acknowledges economic and policy-related barriers but steers clear of any detailed discussion on that subject, considering it to be beyond the study's scope. Instead, the study focuses mainly on technical decisions associated with each end of the spectrum – CO_2 EOR and CO_2 storage – as well the intermediate zones of dual CO_2-EOR/carbon capture and storage (CCS) and the projects transitioning from CO_2-EOR to CO_2 storage. Particularly relevant for our purposes are the discussions surrounding regulatory requirements, monitoring and surveillance (M&S), and site selection criteria for each type of project in this spectrum. Overall, the fundamental challenges for all such CO_2 projects, transitory or otherwise, are not technical in nature.

The CSLF report's most salient findings are as follows:

1. For projects in the middle of the spectrum, the absence of baseline data for monitoring and the lack of a well-established regulatory and legal framework present a unique challenge.

2. CO_2 injection wells in EOR projects must meet well-established Class II regulations that place strict controls on the construction and operation of these wells. The construction regulations specify standards for cementing, casing, and testing the well for integrity via logging and other means, while the operations regulations stipulate that the operator must monitor the nature of injected fluid, the injection pressure (so as not to create new fractures), flow rates, and cumulative volumes.

3. The regulatory requirements for CO_2 storage are typically similar to those of CO_2-EOR, with additional demands on the monitoring and reporting side. The regulations are geared toward ensuring/demonstrating long-term storage of the CO_2.

4. The M&S requirements and the technologies recommended to meet them, for projects in transition between CO_2-EOR and CO_2 storage, are nearly identical to those for pure CO_2-storage.

5. M&S for pure CO_2 storage projects requires more extensive and extended activities compared to CO_2-EOR projects, owing to the necessity to cover a wider range of parameters for a longer period of time. Figure 1 matches the M&S activities at each stage of a CO_2-EOR or pure CO_2 storage project.

6. The main technical issues unique to site selection for projects in transition between CO_2-EOR and CO_2 storage involve geomechanical effects and well-leakage.

7. A prospective CO_2 storage site is screened out if it is located shallower than 800 meters (m) (with the exception of hydrocarbon reservoirs with proven containment of fluids), is lacking at least one major and extensive barrier to CO_2 upward movement, is an area of high natural or induced seismicity, is over-pressured (with a pressure gradient 21 to 23 kilopascals per meter [kPa/m]), and, critically, does not allow for any form of successful monitoring whatsoever.

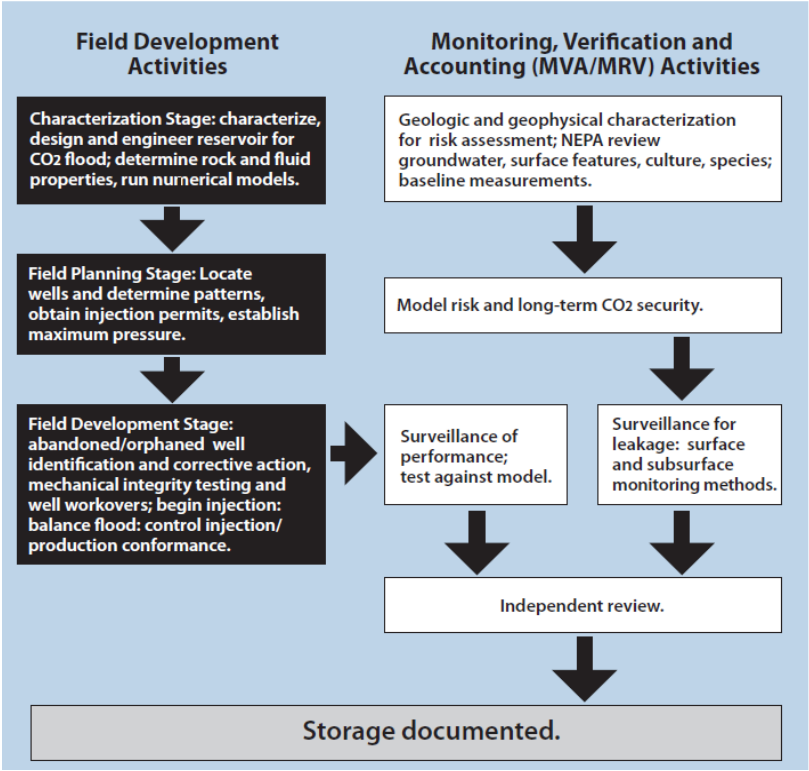

Figure A-1. M&S activities as they correspond to each stage of field development (Source: CSLF, 2013).

2.2 Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR): Factors Involved in Adding Carbon Capture, Utilization and Storage (CCUS) to Enhanced Oil Recovery (Melzer 2012)

L. Stephen Melzer wrote this US-centric report in February 2012, with a view to highlighting the significance and possibilities for CCUS via the medium of CO_2-EOR. The report stresses that CO_2-EOR is an effective solution to storing CO_2 due to the synergies possible, the number of opportunities available, and the volumes of CO_2 that can be put away in such reservoirs. In particular, the report suggests that CO_2-EOR has the potential to accelerate the CCUS movement due to its commoditizing effect on CO_2. However, he concedes that CCUS efforts do need to be propped up further, in an economic sense, in the form of carbon tax, carbon trading credits, etc., and/or any other mechanism to lower capture costs. The report also suggests that only small changes to the regulatory structure need to be made so that companies voluntarily choose to “opt into” storage, since the security of storage

associated with injecting CO_2 into EOR candidate sites (with an established hydrocarbon seal, by definition) means that the regulatory structure that applies to EOR can be reused. The report recommends setting up a framework for site-selective monitoring reporting requirements.

The Melzer report's most salient findings are as follows:

1. CO_2 flood surveillance needs and CCUS Monitoring Measurement and Verification needs are nearly identical.

2. Companies can expect up to 90 to 95% of purchased CO_2 to be stored in the reservoir through incidental storage during typical closed-loop EOR operations. The appropriate metric to measure and report storage is defined as:

$$\textbf{CO2 Stored}\ (\%) = \frac{\textbf{Total CO2 Injected} - \textbf{CO2 Produced} - \textbf{CO2 Losses}}{\textbf{Purchased CO2 Injected}}$$

3. There is tremendous synergistic opportunity between CCUS and CO_2-EOR; however, for CCUS to gain traction at a much higher pace, regulators must work to lower costs by: a) incentivizing CO_2 capture companies via real-time capture credits, instead of at the end of EOR projects; b) raising awareness among industries of the marketable value of their CO_2 by-product; and c) not introducing any new regulation/monitoring requirements for EOR projects claiming CO_2 storage credit.

2.3 Geologic Carbon Storage through Enhanced Oil Recovery (Hill, Hovorka et al. 2013)

This 2013 paper, much like the CSLF report (CSLF, 2013), touches upon the various aspects associated with CO_2 storage in an EOR project, ranging from an overview of tertiary recovery in the United States to CO_2 supply-demand to CO_2 transport pipelines. Of these topics, the most noteworthy discussions are centered on the attractive potential for CO_2 storage via residual oil zones (ROZs), the advantage EOR-storage or CCUS has over pure storage.

The Hill et al. paper's most salient findings are as follows:

1. The report suggests that if the residual oil saturation in the ROZ is at least 20%, it can be just as successfully developed via EOR as the Main Pay Zones (MPZs), and so recommends deepening existing wells in projects where this is deemed to be true (see Figure 2).

2. CO_2-EOR is far more advantageous an option than pure CO_2 storage for reasons such as decades of operational experience; ability to assess storage capacity and injectivity with more certainty due to availability of production and performance data; ability to manage the CO_2 plume, etc. Table 1 summarizes the advantages of CO_2-EOR compared to pure CO_2 storage in saline aquifers.

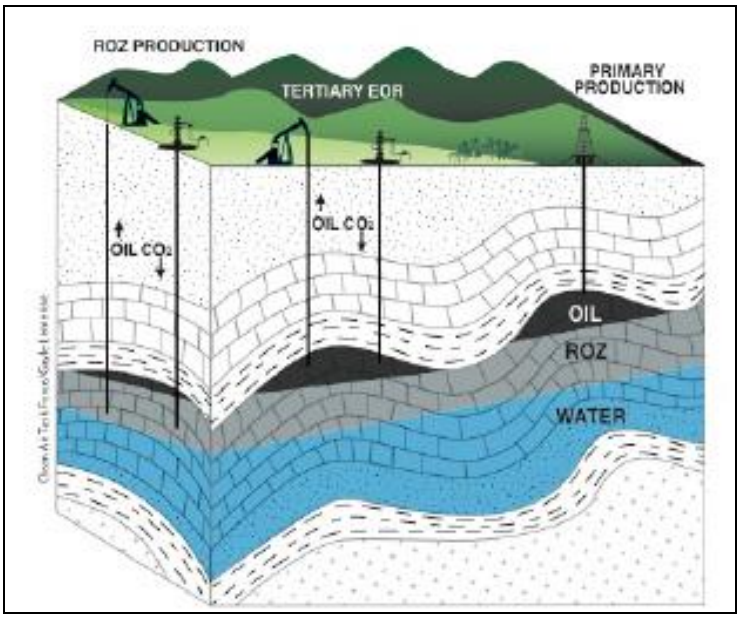

Figure A-2. MPZ (oil) overlying the ROZ, both of which are above the water zone. (Hill, Hovorka et al. 2013)

Table A-1. Summary of the advantages of CO_2-EOR storage over pure CO_2 storage in saline aquifers.

Criteria	Storage Only-Saline	EOR with Incremental Storage
Land	Greenfield	Brownfield - already impacted by oil-industry operations
CO_2 Management	CO_2 injection	CO_2 injection, production, recycle
Pressure Build-up Risk	Potential for large areas of pressure increase	Pressure management is goal of EOR
	Pressure management may be needed	
CO_2 Trapping	Inferred trapping mechanisms	Demonstrated trapping
Solubility of CO_2	Weakly soluble	High solubility in oil
Subsurface Information Density	Few wells; sparse information	Many wells; subsurface well known
Mechanical Integrity / Risk of Well Failure	Few wells, carefully drilled, cased and cemented	Many existing wells, some in unacceptable condition
		Expense to remedy/identify, and re-enter to plug/repair
Pore Space Access	Variable by state; evolving	Existing legal framework
Revenues to offset CO_2 Capture Cost	No	Yes
Monitoring, Verification, Accounting (MVA)	MVA is based on comprehensive geologic study	Existing reservoir production and surveillance knowledge contributes to development of MVA
		Integrity of existing wells a principal leakage concern
Public Acceptance	Unknown	Likely to be good. Public familiar/comfortable with oil production

2.4 Optimization of CO_2 Storage in CO_2 Enhanced Oil Recovery Projects (Advanced Resources International (ARI) and Melzer Consulting 2010)

This 2010 study was performed with a view toward educating policymakers on the immense possibilities and the potential environmental implications of CO_2-EOR projects for CO_2 storage. It strongly suggests that resolving the uncertainty associated with regulatory and legal issues surrounding CCS/CO_2-EOR is worthwhile, chiefly because of the potential synergy that can occur between CCS and CO_2-EOR industries: oil production ensures the economic viability of CCS, while CCS can ensure a reliable and affordable supply of CO_2 for EOR operations.

This study's most salient findings are as follows:

1. The report recommends applying next-generation CO_2-EOR technologies, developing ROZs as opposed to MPZs, and employing a variety of other increasingly 'smarter' methods.

2. The report highlights the immense commercial potential of ROZs, not only for oil but also for CO_2 storage capacity.

3. "Next-generation" technologies include:
   a. Isolating previously poorly swept reservoir intervals where CO_2 can be injected in the future.

   b. Optimally placing horizontal injection and production wells to target bypassed zones.

   c. Optimizing the pattern-flood by improving well alignment and spacing, so as to integrate the improved assessment of field behavior and geology.

   d. Using physical materials or chemicals to divert and direct CO_2 into poorly swept zones.

   e. Adding polymers or other viscosity-enhancing chemicals to improve the mobility ratio between injected fluid and oil and improve incremental oil recovery.

   f. Extending the miscibility range by adding chemical agents.

4. Repressurizing using water or CO_2 or skipping the waterflood altogether to implement CO_2-EOR earlier and produce better results. These three alternatives also store a greater amount of CO_2 and allow the operator to get credit earlier (Figure 3).

2.5 CO_2-driven Enhanced Oil Recovery as a Stepping Stone to What? (Dooley, Dahowski et al. 2010)

This 2010 report for the US Department of Energy plays the role of devil's advocate, written primarily to promote the view that CO_2-EOR is neither a sustainable means in itself nor the correct way forward to achievable commercial deployment of CCS. The report cites two main arguments against using CO_2-EOR to make CCS more economically viable: first, the comparatively greater complexities associated with EOR, and second, the poor economics of CO_2 demand.

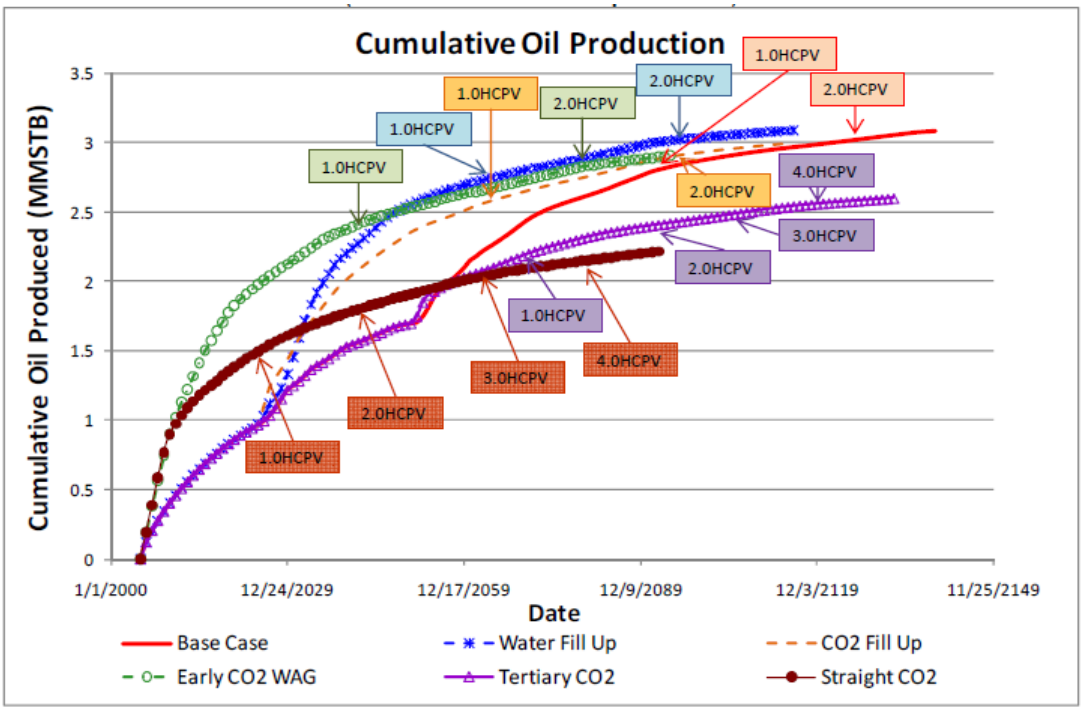

Figure A-3. Summary of three alternatives to implement CO_2-EOR earlier compared with standard approach (ARI and Melzer, 2010).

The most salient findings of the Dooley et al. report are as follows:

1. Most complexities associated with CO_2-EOR are often overlooked when positing that EOR is the optimal means of storing CO_2.
2. The number of wells and other production infrastructure required for CO_2-EOR is much greater than that required for disposal into deep saline aquifers.
3. Additional complexity is added because credits have to be assigned to the project. For example, it is very difficult to produce the requisite baseline and historical emissions data in order for a CO_2-EOR project to be classified accordingly.
4. The assertion that CO_2 capture is economical enough to encourage CO_2-EOR (which then heightens demand for CO_2) relies heavily on the assumption that CO_2 supplies will remain scarce in the future, which may not be the case.
5. Overall, the dependence on CO_2-EOR as a means of triggering wide-scale deployment of CCS projects is undermined by the high cost of a CO_2 capture technology that produces only a low-value-added product.

2.6 Global Technology Roadmap For CCS in Industry Sector Assessment: CO_2 Enhanced Oil Recovery (Godec 2011)

This report, prepared by Advanced Resources International Inc., was published in May 2011. It contains discussions very similar to those mentioned in other reports. While presenting much of the same information regarding the immense potential for CCS and the growth of the EOR industry, the report also (a) presents unique information summarizing the economic factors associated with EOR, and (b) recommends the type of CO_2 required for CO_2-EOR/CCS operations.

The most salient findings of this report are as follows:

1. CO_2-EOR is a high capital-outlay venture; as a result, oil-prices have the greatest impact on the economics of a project.

2. Expenditures associated with CO_2 (natural or anthropogenic) are the single largest project expense and can amount to nearly half the cost of revenue.

3. The two Mexican basins considered in particular suggest that an EOR recovery efficiency of around 20% is attainable, with around 0.32 tonnes of CO_2 used for every barrel of incremental oil extracted.

4. For Villahermosa basin, the portion of CO_2 for EOR purposes available from industrial sources within a 100-kilometer (km) radius is estimated at a negligible 1%, while that for the Tampico-Misantla basin is at a better (but still insufficient) 11% (Table 2).

5. Anthropogenic CO_2 cannot be the only source to carry out a CO_2-EOR operation; further investment into transportation and capture infrastructure is required.

2.7 Modeling the Transition from Enhanced Oil Recovery to Geologic Carbon Sequestration (Bandza and Vajjhala 2014)

This paper, published in 2014 in *Managerial and Decision Economics*, presents a study conducted to reveal the price-point combinations (global oil and CO_2) at which four projects representing the spectrum of pure EOR and pure CO_2 storage - referred to as geologic storage (GS) – become economical for widespread deployment (Table 3).

This paper's most salient findings are as follows:

1. The price of CO_2 alone cannot provide the desired financial impetus for wide-scale deployment of pure CO_2 operations.

2. Any future price rises in CO_2 or CCS bonus' that occur in the future will incentivize hybrid CO_2-EOR.

Table A-2. Summary of selected basins with various estimates, including oil technically recoverable via EOR, CO_2/oil ratio, and CO_2 quantity stored. The last two rows show results for the Villahermosa and Tampico-Misantla basins in Mexico (Source: Godec, 2011).

Basin Name	Country	Location	Recovery Efficiency	Large Field OOIP Favorable for Miscible CO_2-EOR (MMBO)	EOR Recovery Efficiency	Large Field EOR Oil Technically Recoverable (MMBO)	CO_2/Oil Ratio (tonnes/BBL)	CO_2 Stored in Large Fields (Gigatons)
Mesopotamian Foredeep Basin	Saudi Arabia	Onshore	32%	449,559	20%	89,069	0.31	27.2
Maracaibo Basin	Venezuela	Offshore	31%	77,851	18%	14,307	0.32	4.5
East/Central Texas Basins	United States	Onshore	34%	44,024	21%	9,392	0.26	2.4
West Siberian Basin	Russia	Onshore	34%	204,091	21%	43,683	0.27	11.7
Villahermosa Uplift	Mexico	Onshore	34%	51,529	24%	12,333	0.34	4.1
Tampico-Misantla Basin	Mexico	Onshore	30%	11,227	16%	1,799	0.3	0.5
Total (54 Basins)			**33%**	**2,240,904**	**21%**	**468,530**	**0.3**	**139**

Table A-3. Four strategies spanning the spectrum of EOR and pure CO_2 storage, or geologic storage (GS) (Source: Bandsz and Vajjhala, 2014).

Strategy	Process(s) optimized	Oil extraction	CO_2 storage	Description
Indifferent	EOR	✓		Oil extraction is the sole objective without consideration of CO_2 storage.
Afterthought	EOR *then* GS	✓	✓	Oil extraction is the initial objective, and CO_2 storage is the final objective.
Planned	EOR *and* GS	✓	✓	Co-optimization of oil extraction and CO_2 storage is the objective for the entirety of the operation.
Dedicated	GS		✓	CO_2 storage is the sole objective without consideration of oil extraction.

2.8 Transitioning of Existing CO_2-EOR Projects to Pure CO_2 Storage Projects (Jafari and Faltinson 2013)

This study was performed mainly to illustrate a scheme for transitioning from a CO_2-EOR project to a pure CO_2 storage project – a hybrid project. The authors discuss a strategy to optimize both CO_2 storage and incremental oil recovery during the transitory period, so as to remain economical. The authors built a simple hypothetical model for reservoir simulation with generic data: 160 Acres, inverted 5-spot pattern with porosities populated via a statistical distribution and the permeability field established via empirical relationship. The strategy was aligned with a conventional EOR strategy for 30 years (depletion, water flooding, followed by water-alternating CO_2-gas [WAG] process), and then a hybrid strategy of injecting only CO_2 (rather than continuing the WAG process) and producing oil for the next 20 years. The end of the project was characterized by conversion into a pure storage project where CO_2 was injected with all producers shut-off for last three years. This sequence is shown in Figure A-4.

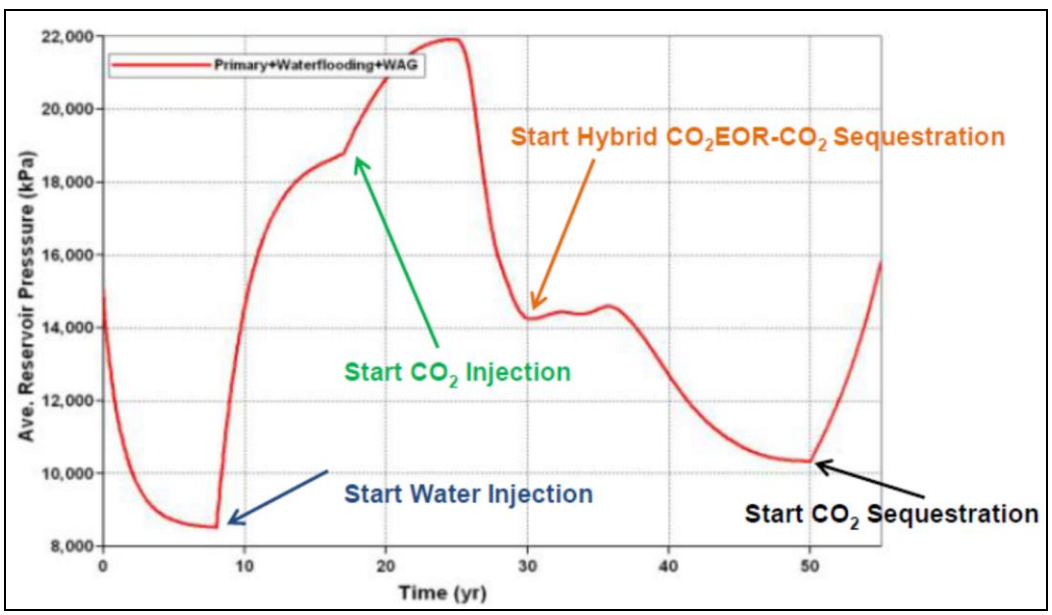

Figure A-4. The average pressure response due to each event in the reservoir model (Source: Jafari and Faltinson, 2013).

The most salient findings of the Jafari and Faltinson study are as follows:

1. The strategy of moving from the conventional CO_2-EOR to hybrid CO_2-EOR/storage program actually resulted in an increase of 67% of CO_2 stored in the reservoir while still accompanied by a 9% increase in incremental oil recovery.

2. This increase justifies the argument that a hybrid strategy (as opposed to a pure EOR strategy) can subsidize the high costs currently associated with carbon capture.

2.9 From EOR to CCS: The Evolving Legal and Regulatory Framework for Carbon Capture and Storage (Marston and Moore 2008)

This report, published in 2008 in the *Energy Law Journal*, essentially details the current status of regulations in the United States as they pertain to the purchase, transport, injection, and storage of CO_2**. This study reveals that the current regulatory framework will not be a stumbling block for operators wishing to transition from CO_2-EOR to CO_2 storage, which is a position different from that taken by other publications in this review.** By means of context, the study also summarizes the state of the industry for CCS operations.

The Marston and Moore report's most salient findings are as follows:

1. Existing state and federal safety regulations of CO_2 pipelines already enforces that operators must implement and maintain a system of communication and crisis-management protocols to respond in a timely fashion, but only to any sudden and large-volume leaks.

2. The issue of detecting long-term smaller-volume leakage is a thorny one with respect to assigning incentives and assigning liability.

3. While the US Environmental Protection Agency's (EPA) Class II classification means that underground drinking water sources are protected, further effort needs to be (and is being) exerted to ensure that the CO_2 stream is contaminant-free prior to injection, and to understand the interaction/motion of CO_2 with the rock and fluid after injection.

2.10 Methodology for Greenhouse Gas Emission Reductions from Carbon Capture and Storage Projects (American Carbon Registry 2015)

This document establishes all the requirements, the equations, and the process for operators storing CO_2 in oil and gas reservoirs to qualify their projects for carbon credits under the American Carbon Registry (ACR) program, as of April 2015. It is meant as a guidebook for someone looking to pursue this option in the United States. The following aspects are discussed in this methodology document:

1. Project Eligibility

2. Project Boundaries

3. Baseline Assessment

4. Quantification Methodology – CO_2 credits are simply the established baseline quantity less the sum total quantity of emissions in all the three boundaries of the CCS project (Figure 5). Calculations discussed:

a. Calculation of Projection-based Baseline.

b. Calculation of Standards-based Baseline

c. CO_2 Project Emissions.

d. CO_2 Capture Calculation Procedure.

e. CO_2 Transport Calculation Procedure.

f. CO_2 Storage Calculation Procedure.

g. Emissions Reductions / Credits - These are the excess of the CO_2 Project emissions over and above the baseline.

5. MRV plan

6. Further notes and guidance on monitoring strategy

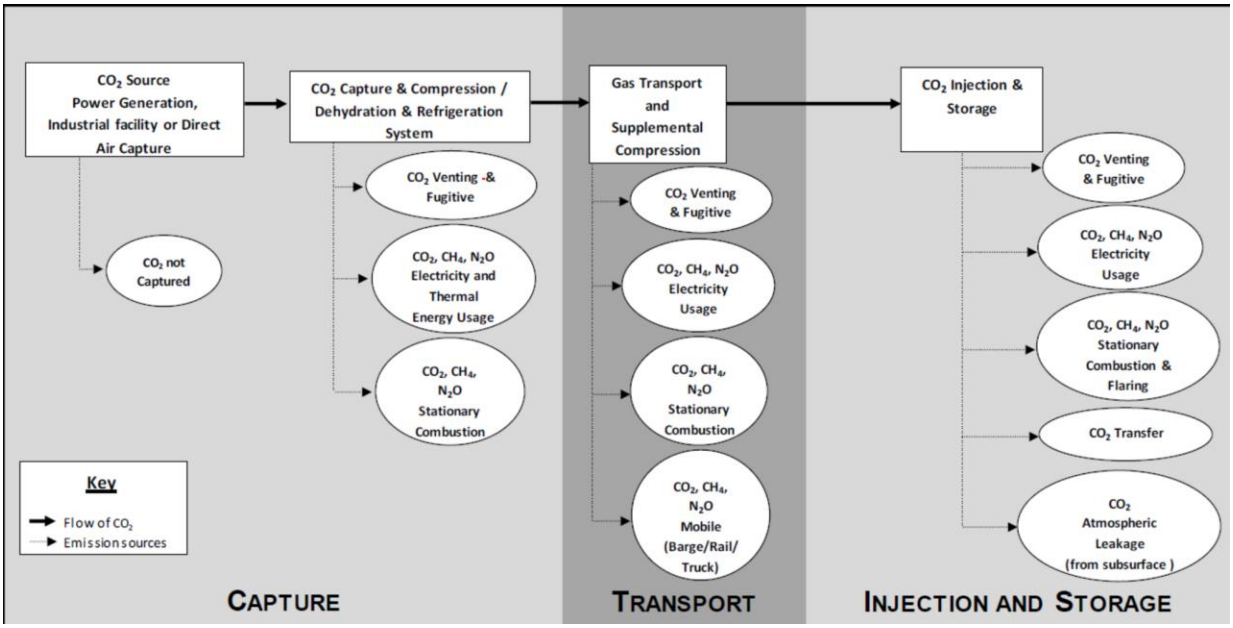

Figure A-5. Data used to determine the volumetric quantity of emission must be sourced from one of these three divisions only. (Source: American Carbon Registry, 2015)

2.11 Greensites and Brownsites: Implications for CO_2 Sequestration Characterization, Risk Assessment, and Monitoring (Wolaver, Hovorka Et Al. 2013)

This study, published 2013, mainly takes the view that monitoring approaches are site-specific, and must be based on a classification on whether they are greensites or brownsites (i.e., site history). The paper defines the classification scheme before discussing the three main undertakings of characterization, risk-assessment, and monitoring design of a project. These issues are examined at the level of the injection zone, the intermediate interval, and the near-surface.

This study's most salient findings are as follows:

1. Typically, brown*fields* refer to areas that have had previous significant surface industrial or commercial use, while green*fields* refer to undeveloped areas. The authors extend this idea to development of the subsurface in defining green*sites* and brown*sites*, for the selection of EOR or CCS activities. The factors influencing the development of greensites and brownsites are shown in Figure 6 and Table 4.

2. The authors suggest classifying sites into one of these two categories to simplify the process of devising an effective monitoring strategy. A summary of these differences, in terms of characterization, risk assessment, and monitoring design are provided for the three zones of interest (from the injection zone, intermediate zone, to the near surface) in Table 5 through Table 7.

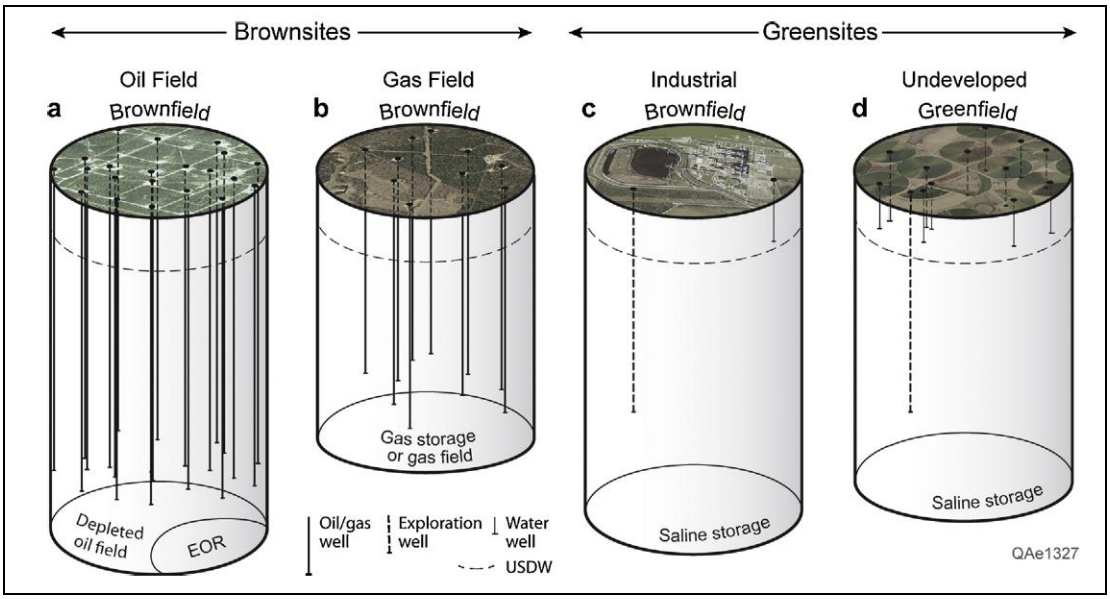

Figure A-6. Classification of potential EOR or storage reservoirs into either greensites or brownsites (Source: Wolaver et al., 2013).

Table A-4. The main factors behind site development (Source: Wolaver, Hill et al., 2013).

Factors influencing greensite and brownsite development.

Property or process	Greensite	Brownsite
Oil-field best practices	No previous oil-field activity; little subsurface information available	Previous characterization and performance assessment commercially motivated
Protection of drinking water resources	Required at both sites	
Demonstration of greenhouse gas containment	CO_2 accounting and credits required at both sites	
Permitting of CO_2 injection wells	No existing permitted sites in the United States; some in development in United States and internationally	Many existing permits; oil-field unitization can cause delays in conversion to CO_2-EOR
Liability	Not well known	Well developed for CO_2-EOR
Financing	Mechanism to offset CO_2 capture and storage costs is immature, requires government incentive	Mature; however, oil price uncertainties and CO_2-handling infrastructure cost may be barriers to project investment
Public acceptance	Lack of public experience could be a project risk	Traditionally have been acceptable owing to profits gained by industry and communities

Table A-5. Differences between greensites and brownsites in the injection-zone (Source: Wolaver, Hill et al., 2013).

Injection-zone characterization, risk assessment, and monitoring focused on injectivity and capacity, lateral plume migration, and trapping mechanisms.

Item	Property or process	Greensite	Brownsite
Characterization	Capacity and injectivity	Unproven; focus of program because no previous production or injection	Hydrocarbon production or water injection shows reservoir pressure response, compartmentalization, capacity
	Lateral plume migration and trapping	Based on modeling and analogs; limited fluid and reservoir property data (assume uniform brine)	Based on historical fluid handling; heterogeneous hydrocarbon distribution following production; variable distribution of oil, gas, brine
Risk assessment	Capacity and injectivity	High material uncertainty until large CO_2 volume injected and monitored	Low material uncertainties because of history-matched model of the site from production history
	Lateral plume migration and trapping	Lateral migration remains a material uncertainty for project duration	Lower lateral migration risk because of trapping reservoir-seal geometry; active CO_2 management reduces plume size
Monitoring	Trapping effectiveness	Target CO_2 saturation, thickness, pressure; minimal monitoring infrastructure	Close monitor spacing using existing wells; active CO_2 management reduces monitoring area; identify unintended out-of-pattern CO_2 migration

Table A-6. Differences between greensites and brownsites in the intermediate-interval (Source: Wolaver, Hill et al., 2013).

Intermediate-interval characterization, risk assessment, and monitoring to assure CO_2 containment.

Item	Property or process	Greensite	Brownsite
Characterization	Integrity of confinement	Unproven; improperly abandoned dry holes may be leakage paths; require characterization	Trapped hydrocarbon accumulation demonstrates performance; wells are potential leakage pathways
	Legacy uses	Shallow hydrocarbons less common	Oil and/or CH_4 and/or H_2O produced and/or injected from/into zones above CO_2 injection zone; hydrocarbons can degrade to CO_2
Risk assessment	Geomechanical seal damage	Evaluate geomechanical competence during CO_2 injection	Assess depressurization-induced fractures during previous hydrocarbon production (as well as during CO_2 injection)
	Well penetrations	Less vertical migration risk because of few wells	Many wells penetrate intermediate interval, vertical migration risk; UIC testing and remediation reduce well leakage risk
Monitoring	Pressure perturbations	Quiescent pressure profile; groundwater production may be only noise	Hydrocarbon/brine injection and/or production at various depths; pressure perturbations active or stabilizing
	Naturally occurring hydrocarbons	None, low interference	Long hydrocarbon history can create signals mistakenly interpreted as leakage

Table A-7. Differences between greensites and brownsites in the near-surface (Source: Wolaver, Hill et al., 2013).

Item	Property or process	Greensite	Brownsite
Characterization	Natural hydrocarbons	Lack of hydrocarbons	Naturally occurring shallow/surface hydrocarbon accumulations; oxidation of hydrocarbons to CO_2 and resulting changes in pH, Eh, and dissolved constituents
	Legacy practices	Conditions assumed to be near equilibrium, seasonal and areal land use variations accounted for with baseline	Evaluate legacy practices and remediation for transients that might interfere with or be mistaken for leakage signal
Risk assessment	Natural hydrocarbons	–	Possible upward migration of reservoir hydrocarbons following CO_2 injection
	Legacy practices	Assumed minor	Mobilization of historical near-surface salts during later site construction
Monitoring	Natural hydrocarbons	–	Monitoring to discriminate leak from background
	Legacy practices	Assumed no impact	Monitoring must account for noise generated by previous site use

–, not applicable.

3. Overall, greensites require greater effort in the characterization phase, to demonstrate capacity, injectivity, and long-term storage integrity. Following this characterization, risk assessment must be performed to highlight the major sources of practical uncertainty, with monitoring being designed around counteracting these risks. For greensites, the undisturbed pore fluids offer uncertainties associated with locating the CO_2 plume and an unproven seal.

4. For brownsites, on the other hand, the risks (and subsequently the monitoring) are centered around high well density and legacy wells providing potential leakage pathways for CO_2, out-of-pattern migration of CO_2, and undetected damage to geologic seal quality as a result of development activities.

2.12 Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells. (Office of Water, US Environmental Protection Agency, December 2013)

This document, like the earlier ACR document discussed, is designed as a detailed set of guidelines for wells that US operators want to be permitted as a geologic sequestration well (Class VI) rather than a typical injection well (Class II). It is intended to be a “go-to” reference for wells that are currently Class II to qualify and obtain a Class VI permit. All regulations are intended to protect consumers under the Safe Drinking Water Act (SDWA). The reader is encouraged to refer to Section 4 of the document for all the specifics needed to obtain permitting as a Class VI.

2.13 General Technical Support Document for Injection And Geologic Sequestration Of Carbon Dioxide: Subparts RR and UU Greenhouse Gas Reporting Program (Office of Air and Radiation, US Environmental Protection Agency, November 2010)

This technical support document offers illustrative examples for complying with the minimum requirements indicated by the US EPA regulations under Greenhouse gas reporting rule – Subpart RR and UU under the Clean Air Act. Key points to note are as follows:

1. Companies can choose to opt in for more detailed reporting (subpart RR rule) or keep with a simple mass balance (CO_2in – CO_2out) reporting (subpart UU).

2. To get credits, companies will need to report under the RR. For example, currently the Internal Revenue Service (IRS) has tax credits for CO_2-EOR (~$10/tonne). These credits are tied to more detailed RR reporting. Similarly, credits for CO_2 reduction under Clean Power Plan (111-B) would be tied to RR.

3. The level of effort is based on the risk and assessment of leakage pathways. Typical monitoring/modeling by EOR operators will be enough in many cases for RR reporting; however, if there is perceived risk from leakage pathways (such as faults, wells, etc.), then a more detailed plan should be submitted and executed. The MRV plan can include mechanical integrity testing, well surveys, and surface leakage monitoring.

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