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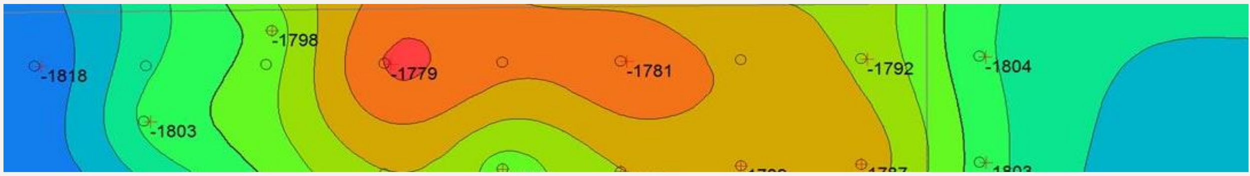

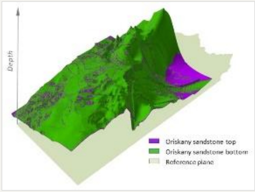

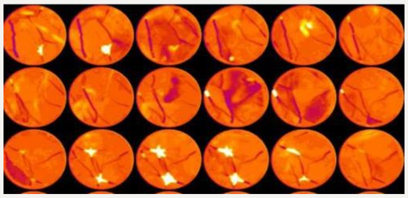

Underground Natural Gas Storage – Analog Studies to Geologic Storage of CO_2

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ACRONYMS AND ABBREVIATIONS

2-D	Two-dimension
3-D	Three-dimension
4-D	Four-dimensional
ADB	Advisory Bulletin
AoR	Area of review
AMA	Active monitoring area
API	American Petroleum Institute
bbl	Barrels
Bcf	Billion cubic feet
Bscf	Billion standard cubic feet
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CCS	Carbon capture and storage
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon dioxide
cP	Centipoise
DEQ	Michigan's Department of Environmental Quality
DOC	California Department of Conservation
DOE	Department of Energy
DOT	Department of Transportation
ECBM	Enhanced coalbed methane
EIA	Energy Information Administration
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
ESV	Emergency Shutdown Valve
FE	Fossil energy
FERC	Federal Energy Regulatory Commission
FP	Fort Peck
ft	Foot, Feet
GHG	Greenhouse gas
Gt, Gtonne	Gigatonne
H_2S	Hydrogen sulfide
ICCS	Illinois Industrial Carbon Capture and Storage Project
IEA	International Energy Agency
IFR	Interim Final Rule
IPR	Inflow performance relationship
LDC	Local distribution company
LNG	Liquefied natural gas
m^3	Cubic meter
Mcf	Thousand cubic feet
Mcf/d	Thousand cubic feet per day
mD	Millidarcy
MESA	Mission Execution and Strategic Analysis
MIT	Mechanical integrity testing/test
MMA	Maximum monitoring area
MMBbl	Million barrels
MMBbl/d	Million barrels per day
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
Mscf/d	Million standard cubic feet per day
MMscf/d	Million standard cubic feet per day
MRV	Monitoring, reporting, and verification
Mscf/d	Thousand standard cubic feet per day
Mt	Million tonnes
Mt/yr	Million tonnes per year
Mt.	Mount
MVA	Monitoring, verification, and accounting
N/A	Not available/applicable
N_2	Nitrogen
NATCARB	National Carbon Sequestration Database and Geographic Information System
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NGL	Natural gas liquid
NN	Navajo Nation
NRAP	National Risk Assessment Partnership
OOGM	Office of Oil & Gas Minerals
OPC	Outflow performance curve

PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES	Protecting Our Infrastructure of Pipelines and Enhancing Safety Act
PISC	Post-injection site care
psi	Pounds per square inch
psia	Pounds per square inch absolute
R&D	Research and development
rcf	Reservoir cubic feet
RCSP	Regional Carbon Sequestration Partnerships
ROW	Right-of-way
RP	Recommended Practice
RRCT	Railroad Commission of Texas
RSPA	Research and Special Programs Administration
scf	Standard cubic feet
SDWA	Safe Drinking Water Act
SoCal Gas	Southern California Gas Company
SPR	Strategic petroleum reserve
Task Force	Interagency Task Force on Natural Gas Storage Safety
tonne	Metric ton (1,000 kilograms)
TPC	Tubing performance curve
U.S.	United States
UIC	Underground Injection Control
USC	United States Code
USDW	Underground Source of Drinking Water
USGS	United States Geological Survey
VOC	Volatile organic compound
VSP	Vertical seismic profile
°C	Degrees Celsius
°F	Degrees Fahrenheit
°R	Degrees Rankine

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EXECUTIVE SUMMARY

The purpose of this report is to compile a stand-alone body of knowledge regarding historical and current underground natural gas storage operations that may be directly or indirectly relevant to carbon dioxide (CO_2) geologic storage in saline-bearing formations. This is the first of three planned documents that evaluate analog industries of CO_2 storage (the second focuses on wastewater disposal using United States [U.S.] Environmental Protection Agency [EPA] Underground Injection Control [UIC] Class I disposal wells, and the third on CO_2 enhanced oil recovery). Natural gas has been stored underground for over 100 years. This type of storage is necessary for meeting seasonal demand requirements as well as insuring against unforeseen supply disruptions. There are significant similarities that exist between natural gas storage and CO_2 geologic storage (and full-scale carbon capture and storage [CCS]) in terms of site selection and characterization, as well as operational procedures, and the equipment used. Therefore, the extensive operational history of underground natural gas storage operations provides a wealth of knowledge and lessons learned from which CO_2 storage stakeholders in industry, academia, and policy can benefit.

There are approximately 415 natural gas storage fields in use in the United States, a number that has been relatively consistent for over 25 years. Of these 415 fields, 223 (six noted as inactive) are owned by an interstate pipeline company or independent operator that offers storage services in interstate commerce and are, therefore, under the jurisdiction of the Federal Energy Regulatory Commission (FERC). Generally, underground natural gas storage is considered to have an outstanding safety record. But, over the 100-year-history of natural gas storage operations, there have been noted accounts of accidents and leakage incidents both in the subsurface and on the surface. Between 1972 and 2004, a series of single-point leaks occurred, all at salt cavern storage facilities. Most of these were a result of well casing or equipment failure. These leakage events serve as analogs for the potential release of CO_2 from geologic storage reservoirs. The most recent major leakage event occurred at Aliso Canyon in California in 2015 (through early 2016). It took approximately four months from when the leak was detected until it could be stopped via cement plugging through a relief well. Before the leak was stopped, approximately 5.7 billion cubic feet of natural gas had been released into the atmosphere. Recent incidents, like those associated with Aliso Canyon, the Moss Bluff facility in Texas, and the Yaggy Incident in Kansas, have resulted in scrutiny on current federal and state regulations pertaining to storage of natural gas underground, and are prompting potential regulatory changes (for instance, the PIPES Act of 2016). [1] These events have been analyzed and reviewed to understand the causes of the incidents, as well as the method used to mitigate the leak, so that CO_2 storage site operators can implement best-practices into future operations. Furthermore, public concern related to the development or operation of storage facilities (and associated leaks where noted), as well as steps taken to address any unfavorable perception have been documented. The goal of documenting the history around leaks and public perception of underground natural gas storage is to learn from these events. While leaks from natural gas storage have occurred over the industry's history, experience has demonstrated that large volumes of gas can be stored safely underground and over long

timeframes when the appropriate best-practices are implemented. Therefore, storing CO_2 in subsurface geologic formations at commercial scales should also be feasible if comparable best practices are demonstrated.

In fact, CO_2 storage has indeed been demonstrated globally, to some degree, and at various scales. But it has not yet been deployed close to the same magnitude of commercial analogs like underground natural gas storage, enhanced oil recovery, or deep well disposal. The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) has identified approximately 300 existing, planned, or recently-completed CCS-related projects (ranging from pilot testing to commercial scale) across the globe—approximately 110 of which received some level of direct support from DOE. Of those projects receiving DOE support, roughly 85 are in the United States. [2] Currently, 37 CCS projects across the globe (some of which include CO_2 enhanced oil recovery operations utilizing captured CO_2 from anthropogenic sources) are "large-scale"—only 17 of which are currently in operation, while the others are under construction or in development. [3] One approach believed to facilitate wider spread deployment of CO_2 storage (through integrated CCS) in the future is through continued research and development (R&D) support and technology advancement. [4] As CCS technologies and research continue to advance, demonstration projects become critical for validating that CO_2 capture, transport, injection, and storage can be achieved safely and effectively. Successful demonstration and deployment of CCS technologies can contribute toward building confidence and reducing costs through new innovations and advances in capture, storage, and monitoring technology and protocols. At all levels of R&D (applied R&D through field testing), CCS research can also benefit by drawing lessons from the history of other energy technologies and analog industries that were once considered risky and expensive early in their commercial development. However, building CCS into a key component for managing anthropogenically-derived CO_2 will likely require more than just technological feasibility; it also may require the development of both regulatory and incentive policies to support business models that can enable widespread adoption, will need improved community awareness of the importance and value of CCS, and must enable application to multiple industry types, each with distinctive emission footprints, markets, and costing structures. [4] [5] Therefore, analyzing comparable analogs to CO_2 storage can also provide insight into how widespread commercial deployment may have been facilitated or influenced by possible policy and/or regulatory drivers prominent throughout its operational history, as well as materialization of successful business-cases.

Worldwide experience of industrial analogs (e.g., underground natural gas storage) demonstrates that the technology required to transport CO_2 to a storage site and inject it deep into the ground currently exists and can be applied. This report presents a side-by-side comparison of major synergistic features (such as governing regulations, formation types used, national capacity estimates, and leakage risks) between underground natural gas storage as an analog to CO_2 storage in saline-bearing formations. The findings suggest that underground natural gas storage is a unique analog that can be used to help address technical and policy-related questions concerning CO_2 geologic storage. For instance, potential CO_2 storage sites and underground natural gas storage facilities are characterized in similar fashion and utilize similar geologic formation types; their performance is ultimately driven by a given storage sites' capacity, containment ability, injectivity, and (specific to natural gas storage) deliverability. However, they are regulated by entirely different governing bodies (the Department of Transportation's Pipeline Hazardous Materials Safety Administration [PHMSA], FERC, and state-specific agencies for underground natural gas storage, and EPA's UIC Program for CO_2 storage). In the context of this report, analogs provide examples or case studies that help pinpoint key success factors that are likely to be effective for CO_2 storage, as well as those that should be avoided. Best practices and lessons learned from analog industries can provide perspective from which future CO_2 storage R&D pursuits and field projects can benefit. Additionally, highlighting instances for how analogs to CO_2 storage overcome shared technical grand challenges and address regulatory requirements to achieve commercialization is another critical objective of this report.

1 INTRODUCTION

A balance must be found between preserving energy security and affordability and addressing growing concerns over emitting large volumes of carbon dioxide (CO_2) into the atmosphere. Approximately two-thirds of the anthropogenic (i.e., man-made) CO_2 emissions in the United States (U.S.) come from power generation facilities, industrial facilities (cement plants, ethanol plants, etc.), and residential sources. The other third can be attributed to transportation-derived emissions. [6] Carbon capture and storage (CCS) is one of many emerging strategies for managing or reducing the anthropogenic emissions of CO_2 into the atmosphere.

CCS involves the separation and capture of CO_2 from fossil fuel-based power generation and industrial processes prior to atmospheric release, followed by transport and safe, permanent injection (or beneficial CO_2 reuse and utilization) into deep underground geologic formations with the goal of reducing anthropogenic CO_2 emissions into the atmosphere. CCS can also include beneficial reuse of captured anthropogenically-derived CO_2 as a feedstock for generating products like commercial chemicals, plastics, improved cement, and for use in enhanced oil recovery (EOR). [7] CO_2 capture integrated with transport and geologic storage comprises a suite of technologies that can benefit an array of industries, including the power (fossil, biofuel, and geothermal) and refining industries. Additionally, CCS enables industry to continue to operate while emitting less CO_2, making it a powerful tool for managing anthropogenically-derived CO_2. However, long-term storage of CO_2 in subsurface formations must be safe, permanent, environmentally sustainable, and cost effective.

Suitable geologic storage formations can exist in both onshore and offshore settings, and each type of geologic formation presents different opportunities and challenges. [8] While the technologies required for CCS are at various stages of commercial readiness and only a few fully integrated projects that capture and store large volumes of CO_2 are being deployed worldwide, CCS remains an important option for managing anthropogenic CO_2 emissions and providing a bridge to a viable energy future. In addition, current CCS-based regulatory frameworks, particularly in the United States, require researchers to develop a more robust suite of technologies capable of cost-effectively providing useful data and information to CCS operators, policymakers, and other stakeholders to advance the CCS industry closer to commercialization. [9]

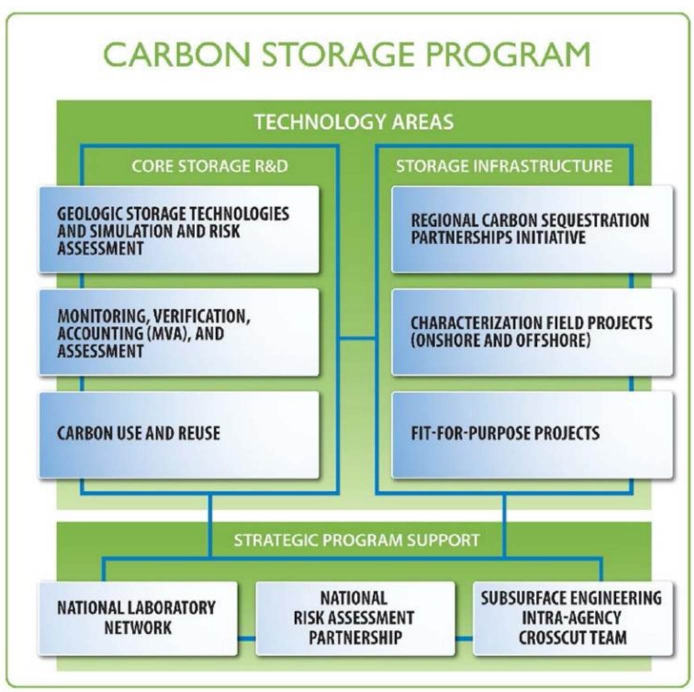
1.1 U.S. DOE'S EFFORTS TOWARD ADVANCING CARBON CAPTURE AND STORAGE

Addressing the potential adverse impacts resulting from anthropogenic CO_2 emissions is a top priority for the U.S. Department of Energy (DOE). [8] Particularly, DOE's Office of Fossil Energy (FE) has been developing a portfolio of CCS technologies that can capture, utilize, and permanently store CO_2 from man-made sources. The Carbon Capture Program, administered by FE and the National Energy Technology Laboratory (NETL), is conducting research and development (R&D) activities on Second Generation and Transformational carbon capture technologies with the potential to provide significant reductions in both cost and energy penalty as compared to currently available First Generation technologies. The Carbon Storage

Program, also administered by FE and NETL, is focused on ensuring the safe and permanent storage and/or utilization of CO_2 captured from stationary sources. CO_2 storage in geologic formations has enormous promise in oil and natural gas (NG) reservoirs, unmineable coal seams, saline reservoirs, basalt formations, and organic-rich shale basins. [8] The integration of these two programs has placed NETL at the forefront of research to develop safe and cost-effective CCS-related technologies for capture and long-term permanent geologic storage and/or use of CO_2. The technologies developed, and large-volume injection tests conducted through NETL's research are contributing towards increasing the knowledge of geologic reservoirs appropriate for CO_2 storage and the behavior of CO_2 in the subsurface. [10]

The Carbon Storage Program has focused on CCS technology development since its inception in 1997 with the goal of significantly improving the effectiveness and reducing the cost of implementing CCS technology. [8] [9] To accomplish this objective, the Carbon Storage Program focuses on developing technologies to utilize and store CO_2 from energy producers and other industries that rely on fossil-based energy sources without adversely affecting the supply of energy or hindering economic growth. The overall objective of the Carbon Storage Program is to develop and advance CCS technologies, both onshore and offshore, that will be significantly more effective, less costly, and ready for widespread commercial deployment in the 2025–2035 timeframe. The program has developed a diverse portfolio of applied research projects that includes industry cost-shared technology development projects, university research grants, collaborative work with other national laboratories, and research conducted in-house at NETL. The Technology Areas that comprise the Carbon Storage Program are shown in Exhibit 1-1. The Core Storage R&D research component is a combination of three Technology Areas and is driven by technology need as determined by industry and other stakeholders, including regulators.

Exhibit 1-1. Carbon Storage Program structure



The Storage Infrastructure Technology Area comprises the Regional Carbon Sequestration Partnerships (RCSP) and other large- and small-volume field projects, as well as "fit-for-purpose" projects and the newly-initiated Carbon Storage Assurance Facility Enterprise (CarbonSAFE) initiative; each initiative has its own focus on developing specific subsurface engineering approaches to address research needs critical for advancing CCS to commercial scale. It is in this Technology Area that various CCS technology options and their efficacy are being confirmed through field-based testing. These Core Storage R&D and Storage Infrastructure program components are being integrated to address technological and marketplace challenges. Overall, these two technology components sponsor applied research at laboratory and pilot scale, as well as support large-scale, large-volume injection field projects at pre-commercial scale to confirm system performance and economics. [11]

In all cases of R&D (applied R&D through field testing), CCS research benefits from drawing lessons from the history of other energy technologies and analog industries that were once considered risky and expensive early in their commercial development and are now commercially prominent. Building CCS into a key component for CO_2 management may require more than just technological feasibility; it may also require the development of both regulatory and incentive policies to support business models that can enable widespread adoption. [5] Furthermore, there is belief that a need exists for improved community awareness of the importance and value of CCS, and a necessity to enable CCS application to multiple industry types, each with distinctive emission footprints, markets, and costing structures. [4] Examples from analog industries that have faced similar technical hurdles but have eventually attained commercial success can provide insight into overcoming these types of challenges. For instance, Rai et al. [5] identified multiple non-technical factors that have facilitated commercial adoption of industries analogous to CO_2 storage. They analyzed the development of the U.S. nuclear-power industry, the U.S. sulfur dioxide-scrubber industry, and the global liquefied natural gas (LNG) industry to draw lessons for the CCS industry from these energy analogs that, like CCS today, were considered risky and expensive early in their commercial development. Through analyzing the development of the analogous industries to CCS, Rai et al. [5] arrived at three principal observations from which the analogous industries could achieve success:

- Government played a decisive role in the development of analog industries.
- Diffusion and penetration of these analog industries beyond early demonstration and niche projects is facilitated by the credibility of incentives for industry to invest in commercial-scale projects.
- The "learning curve" theory, where experience with technologies inevitably reduces costs, does not necessarily hold. Real learning is driven by more than just technical potential; it can also be influenced by the institutional environment present and any incentives towards cutting costs or boosting performance. The U.S. nuclear power industry and global LNG industry are noted examples where costs have increased with increasing capacity, contradicting the "learning curve" theory. Risky and capital-intensive technologies may be particularly vulnerable to wider-spread commercialization without accompanying reductions in cost.

Due to the importance of the Rai et al. findings, they are further explained in Appendix A: Overview of Rai et al., 2010. In addition to key points identified by Rai et al., others have noted [12] [13] that CCS-related research may also benefit from leveraging the data, lessons learned, and best practices from analogous industries with extensive operational histories.

1.2 Industrial Analogs For CO_2 Storage

The Intergovernmental Panel on Climate Change [14] and Rai et al. [5] identified several industrial analogs with experiences that are for the most part relevant to CO_2 storage. [15] A few of the more prominent examples of industrial (engineered) analogs to CO_2 geological storage include 1) CO_2 EOR since 1972, 2) subsurface natural gas storage for over 100 years, and 3) injection and disposal of hazardous (like corrosive, ignitable, reactive, and toxic materials including oil-based paints, degreasing solvents, or chlorinated solvents) and non-hazardous wastes (like municipal and industrial wastewater) into deep confined rock formations, which has occurred in the United States since the 1930s and began being regulated by the Environmental Protection Agency (EPA) in the 1980s. [16] The worldwide experience of these industrial analogs demonstrates that the technology required to transport CO_2 to a storage site and inject it deep into the ground currently exists and can technically be applied. As mentioned in the sections above, these types of analogs provide the CCS community with insights, lessons learned, and best practices across all aspects of their respective domains. Additionally, studying analogs with extensive operational history enables evaluation of their temporal and spatial scales; given that many processes that must be assessed when predicting the performance of a CO_2 storage site occur over long timescales and can be only partially simulated in the laboratory or observed in relatively short-term demonstrations. Analogs though often have substantial differences and rarely provide fully comprehensive insight into every aspect of an emerging technology (CO_2 storage in this case); [13] emphasizing the need for continued R&D that 1) develops application-specific technological building blocks, 2) supports the creation of markets for which the technology under development can be deployed and proven, and 3) informs relevant legislative and regulatory actions. [5] [13] Some major differences between CO_2 storage and these industrial analogs discussed above include:

- CO_2 is injected during EOR operations with the intent to increase oil and gas production. The CO_2 is considered an asset as part of CO_2 EOR. Therefore, CO_2 EOR operators try to maximize oil and gas production and minimize the amount of CO_2 left in the reservoir. The goal of CO_2 storage is saline-bearing formation is to permanently store large volumes of anthropogenically-derived CO_2 in the subsurface.
- Natural gas is seasonally stored in (cyclically injected into, as well as withdrawn from) deep geologic formations. A base, or cushion gas, made up of natural gas is normally sustained in the subsurface at relatively constant volume to maintain adequate pressure and deliverability rates throughout withdrawal seasons. CO_2 storage operations are based on "one-way" injection of CO_2 with no intent on reproducing it from the subsurface.
- Hazardous and non-hazardous waste disposal via deep well injection is similar to CO_2 storage in terms of practice, how the wells are designed, and how operations are

regulated. However, supercritical CO_2 is highly buoyant compared to the displaced formational fluids and can migrate vertically in the subsurface and threaten intrusion into shallower formations, including drinking water sources. [16] Municipal wastewater operations, for example, are in fact susceptible to upward migration because of the wastewater's lower salinity, and thus greater buoyancy, than the native saline water in injection and confining zone strata [17], but are not nearly as buoyant as supercritical CO_2.

In addition to these differences, significant similarities between these analog industries and CO_2 geologic storage exist in terms of site selection and characterization, as well as operational procedures and the equipment used. [18]

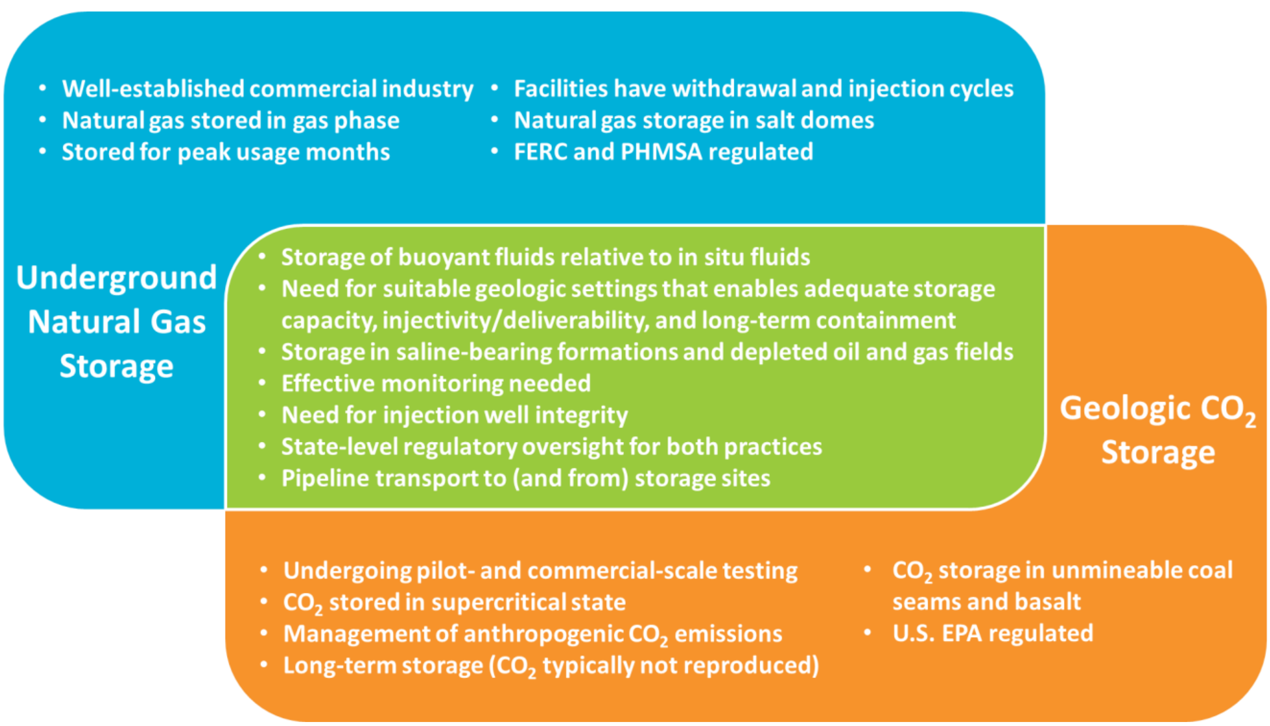
This report focuses on underground natural gas storage and CO_2 geologic storage in saline-bearing formations; both individually and in relation to each other. Underground natural gas storage was chosen as an analog to long-term CO_2 geologic storage because of the substantial amount of similarities that exist between the two practices in terms of site selection and characterization, as well as operational procedures, and the infrastructure needs. Additionally, the extensive operational history of underground natural gas storage provides extensive knowledge and insight into lessons learned from which CO_2 storage stakeholders in industry, academia, and policy can benefit from.

The objectives of this report are multifold. First, the report is to provide a body of knowledge that specifically relates to historical and current subsurface natural gas storage operations, which may relate directly or indirectly to CO_2 geologic storage operations in saline-bearing reservoirs. The second objective is to document site screening and selection methods, site characterization, and operating procedures that may also be relevant to future CO_2 storage operations. Best practices and lessons learned from the long history of underground natural gas storage in the United States can provide perspective from which future CO_2 storage R&D pursuits and field projects can benefit. Particularly, highlighting instances for how analogs to CO_2 storage overcame shared technical grand challenges (like those associated with identifying and ensuring injectivity, capacity [and deliverability for underground natural gas storage], and containment throughout operations), and addressing regulatory requirements to achieve commercialization is a critical component of this objective. Third, this report is intended to document and learn from any reported leakage identified from underground natural gas storage operations. While leaks from underground natural gas storage operations have occurred over the industry's history, experience has demonstrated that it is possible to safely store large volumes of gas underground over extended timeframes when appropriate best practices are implemented. Therefore, storing CO_2 in subsurface geologic formations at commercial-scales should also be feasible if comparable best practices are implemented. [15] Understanding the remedial actions that worked (as well as those that may not have been successful) in response to leakage events is also of importance. The last objective is to provide documentation of instances of public interaction concerning the development or operation of underground natural gas storage sites to provide insights into issues that might potentially arise during the development of a Class VI CO_2 storage well.

The underground storage of natural gas is a critical component of the natural gas supply system in the United States. There are total of 415[a] gas storage facilities containing almost 17,500 storage wells that are being used to provide natural gas storage services. Eighty percent of storage facilities employ geologic formations, or reservoirs, that are depleted of once in place natural gas and/or oil and have since been converted to depleted reservoir storage. The remaining facilities are engineered for gas storage by using deep, water-filled geologic formations, aquifers, or salt caverns created through a solution mining process. [19] The critical importance of natural gas storage in the Nation's energy portfolio drives natural gas storage operators to continually search for new equipment, processes, and methodologies to improve safety, reliability, reduce cycle times through improved deliverability, and reduce stranded (base/cushion) gas requirements.

Studying analogs to CO_2 storage helps to improve overall understanding of both the technical concept and its application—in this case, large-scale injection and CO_2 geologic storage in saline-bearing reservoirs involving millions of metric tons (tonnes) of CO_2. [13] In general, both underground natural gas storage and CO_2 geologic storage have striking similarities, as well as noticeable differences, which are worth evaluating (Exhibit 1-2).

Exhibit 1-2. Venn diagram highlighting major differences and similarities between underground natural gas storage and CO_2 geologic storage



Significant similarities between the two practices include underground storage of a buoyant fluid, the need for an adequately thick caprock (ideally with a secondary caprock above the

[a] As of November 2016, 223 facilities (six of which are noted as inactive) are owned by an interstate pipeline company or independent operator that offers storage services in interstate commerce and are, therefore, under the jurisdiction of the Federal Energy Regulatory Commission (FERC).

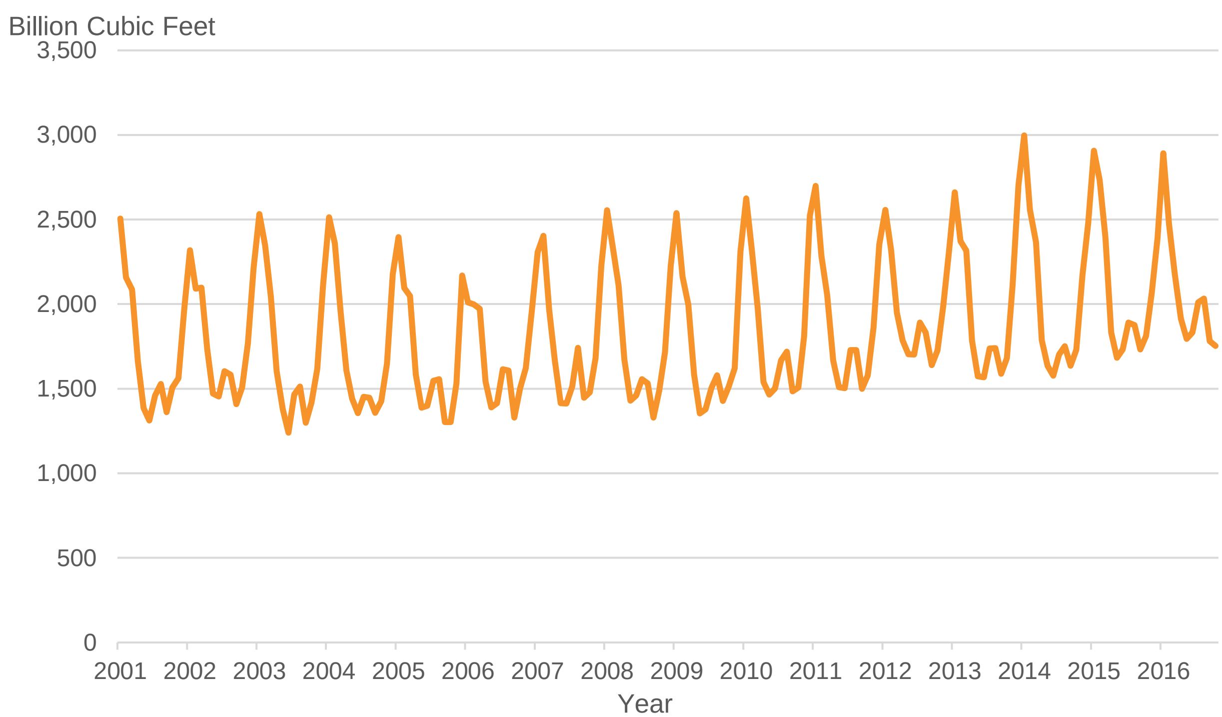
primary seal to ensure long-term containment), adequate pore space and permeability to enable sufficient storage capacity, injectivity—and in the case of natural gas storage—deliverability. For both practices, injection wells must be properly designed, installed, and monitored; maintained and abandoned wells in and near the project area must be located and plugged. [14] Additionally, the underground natural gas storage industry and emerging CO_2 storage practice have overlaps with respect to the types of reservoirs used for each operation, particularly depleted oil and gas reservoirs and saline-bearing formations (i.e., aquifers).

While several similarities and overlap between the two industries exist, there are major differences, which include the prominent governing regulations and regulatory bodies that oversee each practice, the varying levels of commercial application and experience of each practice, as well as the types and physical state of the injected fluid. The similarities and differences between these two practices are further compared in the sections below. The critical findings from the experience of underground natural gas storage can be leveraged in the future, as well as be used to demonstrate that a level of understanding for how failures that resulted in leakage events have occurred (and were remediated) in past underground natural gas storage operations has been achieved, so that CO_2 storage best practices can be developed and implemented.

2 Natural Gas Storage History and Overview

Natural gas is a colorless, odorless, gaseous mixture of multiple hydrocarbon chains, but the primary component is methane (CH_4). It may contain small or trace amounts of hydrocarbon gas liquids (ethane, butane, propane) and non-hydrocarbon gases (CO_2, hydrogen sulfide [H_2S], nitrogen [N_2]). Natural gas has many uses, the most important of which is as a source of fuel. [20] The volume of natural gas delivered to residential and industrial consumers is seasonal, such that peak usage occurs during colder winter months to heat homes and businesses. [21] Natural gas production, unlike consumer consumption, is dependent on many variables, but does not fluctuate monthly like consumer usage does. Exhibit 2-1 shows the variation in natural gas delivered to consumers in the United States over a 15-year period from 2001 through 2016. [22] The reduction in natural gas consumption during the summer months leads to a surplus that needs to be stored safely and cost-effectively. These fluctuations between gas production and usage led to the concept and creation of underground storage for natural gas.

Exhibit 2-1. Cyclical trend of natural gas delivered to consumers in the United States over time

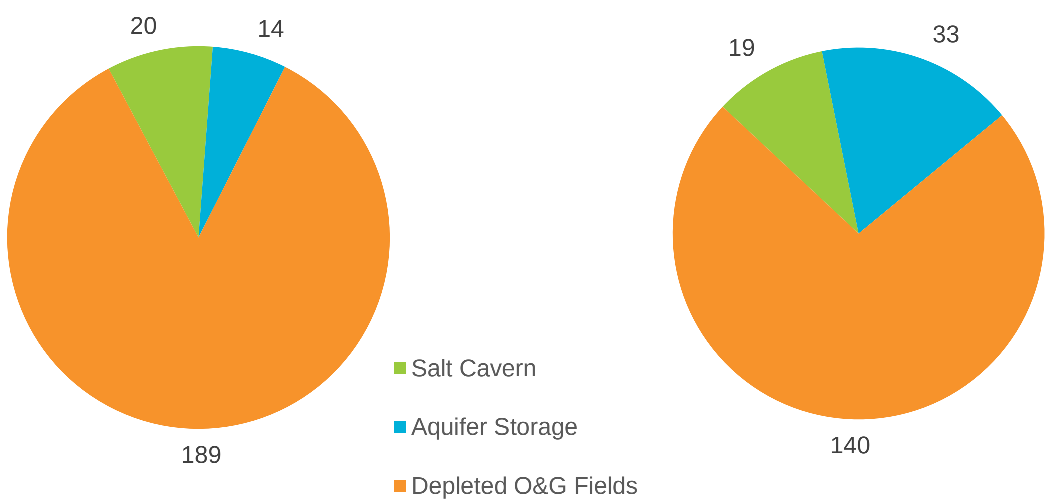


Natural gas storage facilities are subsurface reservoirs that contain surplus natural gas. A storage facility can be thought of as a well characterized interim reservoir in which natural gas is stored during periods of low demand and extracted during periods of high demand; for instance, when peak winter demand cannot be met by the combination of gas production and long-haul pipelines originating in the producing fields. [23] Storage facilities allow pipeline companies to balance the supply and demand of natural gas. For instance, roughly 20 percent of all the natural gas consumed during a typical winter heating season (five-month period) each year is supplied by underground storage. [24]

2.1 OVERVIEW

Underground natural gas storage in subsurface reservoirs was first proposed by the United States Geological Survey. The first successful North American gas storage project was completed in 1915 in Welland County, Ontario, Canada. The facility was a depleted gas reservoir that was converted to a natural gas storage reservoir. The following year, operations began in the Zoar field near Buffalo, New York. Not long after that, a technique called solution mining was utilized to create caverns within salt domes for storage. [25] These events set the stage for the future of underground storage facilities and eventually led to subsurface storage for crude oil, distillates, and natural gas liquids. There are 415 natural gas storage fields in use in the United States (223 for interstate commerce, 192 for intrastate commerce), a number that has been consistent since 2003 (along with capacity volume—discussed later in Section 2.3). [26] These storage reservoir types consist primarily of depleted oil and gas reservoirs, salt caverns, and aquifers. Exhibit 2-2 shows the distribution of these three natural gas storage reservoirs for both FERC-certified and non-FERC-certified projects. [27]

Exhibit 2-2. Current breakdown of FERC-certified (left) and non-FERC-certified (right) natural gas storage projects by reservoir type in the United States [27]



The natural gas industry has a long history of trial and error associated with determining the components and interdependent facilities required for a successful underground storage operation. Underground storage facilities typically include injection/withdrawal wells, observation wells, water disposal wells, gathering lines, dehydration facilities, gas measuring facilities, compressors, and more. Equipment is likely to vary from site to site dependent on several site-specific factors, most notably the type of storage reservoir—either salt cavern, aquifer, or depleted oil and gas field. These types of fields were selected based on their geologic characteristics, which include, but are not limited to, porosity, permeability, structure, and trapping mechanism. Geologic properties heavily influence the locations of new storage projects. Engineering properties of the storage reservoir such as its deliverability, total capacity, base gas, and working gas requirements are other considerations. Financial and regulatory-related impacts also dictate the feasibility of a potential new storage site. Today, in addition to traditional usage in meeting peak demands and ensuring supply reliability, underground natural gas storage is being used to meet several non-traditional uses including:

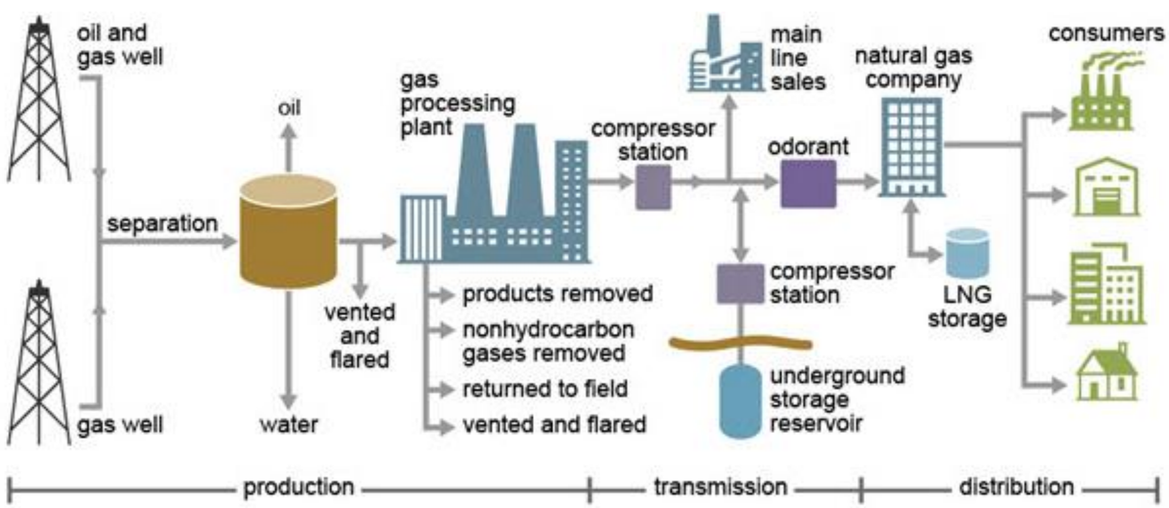
- Ensure liquidity at market centers to contain price volatility;
- Offset the reduction in traditional supplies;
- Increase the reliability of the working gas; and
- Offset the growing summer peak impacts from electricity generation and to support other electric generation loads.

These non-traditional uses of underground storage have been created by the unbundling of storage and new market conditions. [23]

2.1.1 Natural Gas Value Chain – Production Through Distribution

The framework of natural gas storage facilities starts and ends at the wellhead. Natural gas is first produced from a subsurface hydrocarbon reservoir, transported through various stages via a pipeline network, and then injected back into a subsurface storage reservoir (Exhibit 2-3). The process begins at the well head of a producing reservoir. The well produces hydrocarbon fluids consisting of either oil and gas or just gas. The fluid flows through the surface separation system, which is typically located on the well pad. Initial separation provides three product streams: oil, water, and natural gas. The natural gas is either vented and flared or transported to a gas processing plant depending on the quantity and quality of the produced gas. It is further broken down into usable and non-usable products at the gas processing plant. After processing, the usable natural gas is transported to a compressor station and delivered to various destinations, one of which may be an underground storage reservoir, where it may be compressed again before injection to ensure that it exceeds the current reservoir pressure and can be injected safely into the subsurface. [20]

Exhibit 2-3. Natural gas storage framework as a component of the natural gas value chain [28]



Source: U.S. Energy Information Administration (EIA)

2.2 Storage Options

Underground natural gas storage reservoirs are often characterized by size and volumes of stored natural gas. Per EIA, the volumetric measurement terms used to quantify the fundamental characteristics of an underground storage facility include total natural gas storage capacity, total gas in storage, base (cushion) gas, working gas capacity, working gas, deliverability, and injection rate. [29] These terms are further described in the bullets below:

- Total natural gas storage capacity: The maximum volume of natural gas that can be stored in accordance with its design, which includes reservoir properties, installed equipment, and operating procedures.
- Base gas: The volume of natural gas needed as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season.
- Working gas: The maximum amount of natural gas that can be stored and is available to the market. It can also be defined as the difference between the total gas storage capacity and base gas for a given storage facility.
- Total gas in storage: The volume of natural gas in the underground facility at any given time (includes base and working gas).
- Deliverability: A measure of the amount of gas that can be delivered (withdrawn) from a subsurface storage facility daily. Deliverability can also be referred as the deliverability rate, withdrawal rate, or withdrawal capacity and is typically expressed in terms of thousands of cubic feet per day (Mcf/d) or million cubic feet per day (MMcf/d). Deliverability can also be expressed in terms of equivalent heat content of the gas withdrawn from the subsurface storage facility.
- Injection rate: The amount of natural gas that can be injected into a storage facility daily, typically expressed in Mcf/d or MMcf/d. However, like deliverability, injection rate can also be expressed in terms of equivalent heat content of the gas injected into the subsurface storage facility.

Exhibit 2-4 shows the breakdown of capacity vs. in-storage volumes for a theoretical storage site to visually explain the terms in the bullets above. The x-axis displays the capacity and facility at multiple time stamps (t = 0, 1, 2). The capacity of the reservoir (blue bar) is constant provided no additional wells are added or removed from the field. However, in-storage volumes differ with time due to withdrawal and injection periods. The only volume that remains constant within the storage reservoir is the amount of base gas (orange bar) unless there are extenuating circumstances that require base gas to be produced.[b] [29]

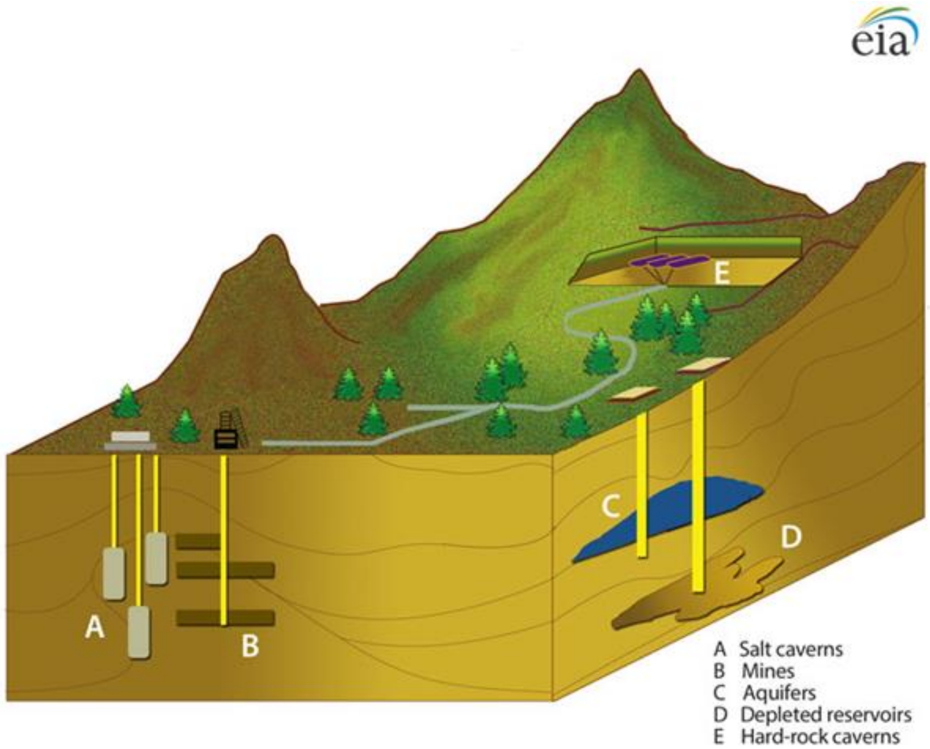
[b] Production of base gas, in some cases, could compromise reservoir integrity through permeability loss, especially for saline storage facilities where the base gas component can be upwards of 80 to 90 percent of the total gas volume. [21] [31]

Exhibit 2-4. Comparison of theoretical storage capacity estimates to actual in-storage volumes

An additional characteristic critical to the performance of an underground storage facility is deliverability. Deliverability, also known as withdrawal, is a measure of the amount of gas that can be withdrawn from a storage facility daily. The deliverability of a given facility varies depending on the amount of natural gas in the reservoir, the pressure in the reservoir, the compression capability available to the reservoir, and other factors. Injection rate—the amount of natural gas that can be injected into a storage facility daily [29]—is another crucial factor.

The three main types of storage reservoirs can be compared based on their storage measures, physical characteristics, and the benefits/challenges associated with each. They are depleted oil and/or gas reservoirs, salt caverns, and aquifers. Each storage type has unique characteristics that must be considered before utilizing it to store natural gas. Exhibit 2-5 from EIA's website gives a general view of the three types of storage reservoirs discussed, as well as additional sites, such as hard rock caverns and mines, which are not discussed in this document. Most active storage reservoirs in the United States are depleted oil and gas fields with approximately 300 active sites.

Exhibit 2-5. Underground natural gas storage options [29]



Source: U.S. EIA

These geologic formations are not found in all regions of the United States. Additionally, their depths and geologic properties can vary extensively both locally and regionally. Most of the entire East Coast, as well as the Central Plains states and some southwestern states, such as Nevada and Arizona, lack underground storage facilities (highlighted in Exhibit 2-7). As a result, natural gas pipeline customers who are not located near storage facilities are more vulnerable to service interruptions.

2.2.1 Depleted Oil and/or Gas Reservoirs

Depleted reservoirs have essentially produced all their economically recoverable hydrocarbons. They are commonly used to store natural gas for two main reasons: 1) the reservoir has proven it is geologically capable of holding hydrocarbons over extended periods and 2) subsurface and surface infrastructure may already exist. For these reasons, they are also typically the least expensive and most desirable type of storage formation to develop. Depleted reservoirs are mature fields with well-defined geological and operational information that can be conveyed to the storage company. Of the three storage types featured in this report, depleted reservoirs are the cheapest and easiest to develop, operate, and maintain. Despite their low cost, they must still have high porosity and permeability to translate into suitable storage reservoirs adequate for injecting and withdrawing large quantities of natural gas. [21]

The considerable number of active depleted oil and/or gas fields speaks to the benefits associated with their development. An upfront benefit of depleted fields is their wealth of pre-existing data, which reduces the need to conduct extensive, if any, data acquisition such as seismic, wireline logging, or exploratory drilling thus reducing development costs. Depleted reservoirs require minimal geologic characterization to define their containment, capacity, and deliverability, which could require extensive research to ensure economic outputs and mitigate subsurface leak pathways for un-discovered or less developed sites. An additional upfront benefit is the in-place infrastructure. Wells have already been drilled, gathering systems and separators are on location, and pipeline connections between wells to a transmission line exist. Therefore, the initial capital investment required to develop a storage reservoir would be significantly reduced due to the available data and existing infrastructure. The storage operator could focus less on the site design or construction but must consider approaches for the conversion and maintenance of the existing infrastructure. [29] In fields that house depleted gas reservoirs, the operator can expect high permeability ranging from 0.1 to 1 Darcy (100 to 1,000 millidarcy) with no mobile oil or water. [30] Depleted fields typically have a cushion gas, or base gas, requirement of around 50 percent of the total reservoir capacity. [31]

Depleted oil and/or gas fields may pose the risk of abandoned, or orphaned, wells penetrating the storage reservoir, which can serve as leakage conduits to neighboring formations or the atmosphere. As one example, on March 12, 2016, the *Tribune-Review* reported on Pennsylvania's efforts to find and plug abandoned oil and gas wells. Officials estimated that there could be as many as 200,000 abandoned oil and gas wells dating back to the 1860s. Older wells may have no record of ownership, or possibly no records at all. [32] The storage operator must thoroughly investigate the reservoir to ensure that all well penetrations that are not active are properly plugged. Storage operators face the additional challenge of hydrocarbon fluid interaction when depleted oil reservoirs are utilized for gas storage. Problems can occur when the injected gas interacts with the in-situ oil. The injected gas can potentially become enriched with heavier liquid hydrocarbons, which could result in condensate formation within the pipeline after production from the subsurface, requiring additional surface facilities to knock-out the hydrocarbon liquids. If the gas does not become enriched it could dissolve into the oil, leading to complications in inventory calculations. Depleted dry gas reservoirs are favored over depleted oil and gas or gas condensate reservoirs because they generally require less maintenance. This leads to depleted oil reservoirs being considered as storage candidates only when depleted dry gas reservoirs might not be available. [30]

2.2.2 Aquifers

An aquifer is a subsurface water-bearing formation that can be utilized for underground natural gas storage. Per the EIA, there are currently 47 active aquifer natural gas storage reservoir projects in the United States. Aquifer underground storage is most common in the mid-western United States where depleted reservoirs are not common. They are suitable for gas storage if the water-bearing sedimentary rock is overlaid with an impermeable cap rock. Aquifers may have geologic characteristics that are like those of depleted oil and gas fields, but they tend to require additional cushion gas, leading to less flexibility while injecting and withdrawing, which causes a reduction in the working gas fraction. [29]

The advantage of utilizing an aquifer for storage is the potential for pressure support. Aquifers that are "active" can provide pressure support through the encroachment of water from within the reservoir. This phenomenon is often referred to as a water drive, which is mobile water that encroaches on the producing fluid and provides pressure support. These aquifers support the reservoir pressure during periods of natural gas withdrawal and result in enhanced deliverability rates. This pressure support will help maintain higher deliverability rates over longer withdrawal periods. [29] The lack of benefits associated with aquifer storage is due to the complications surrounding their development. For this reason, they are used in regions where sufficient depleted reservoirs are not available.

Aquifers are typically considered the least desirable underground natural gas storage reservoirs and are more expensive candidates than depleted oil and gas fields to develop and operate. They are less geologically known and understood because little or no data from past wellbore penetrations exist, and their development requires extensive upfront data acquisition through seismic surveys or exploratory drilling, which in turn requires considerable time and financial investment. An accurate estimate of storage capacity in an aquifer cannot be made until further development and characterization (i.e., geologic properties like porosity and permeability, formational thickness, areal extent, and spill point) occurs. The subsequent challenge to the facility is the time and expense of designing, planning, and developing the storage infrastructure for aquifer storage. The storage operator must also decide what to do with the water in the aquifer, which must either be produced or compressed to the pressure needed for the natural gas to displace or push down the resident water. As the field is operated, additional gas dehydration and processing will be required to remove any water that is absorbed into the natural gas. Finally, the biggest limitation to utilizing an aquifer is the cushion gas requirement, which can be upwards of 80 to 90 percent of the total gas volume since there is no naturally occurring gas in the formation. [31] [33] This means that to begin the storage process, a certain amount of natural gas must be injected that will ultimately prove physically unrecoverable. Unlike depleted reservoirs, which can tap volumes of base gas if necessary, aquifers are negatively affected if base gas is produced, which can result in formation damage (like permeability reduction). This means that even after the storage facility is shut down the cushion gas will remain in place to prevent damaging the reservoir. [21]

2.2.3 Salt Caverns

The third type of underground storage is salt caverns. Salt caverns are created in underground salt domes or bedded salt formations through a process called leaching or solution-mining. [29] Solution mining is a process by which fresh water is used to create a cavern within the salt body. Fresh water injected into the borehole dissolves salt and becomes brine water. Continuously pumping fresh water during the operation forces out brine water and, as the process progresses, the cavern increases in size until it reaches the desired dimensions. Once the cavern has reached the desired size, natural gas is injected to remove the remaining water and to fill the cavern with gas. [34] Salt caverns are common to the Gulf Coast region of the United States, and they represent a growing share of U.S. natural gas storage deliverability.

Salt domes are thick deposits that have been created from salt that has leached upwards from its original depositional position at the base of the Gulf Coast through overlying sedimentary layers to form dome-like structures. [21] They can be up to a mile in diameter and thousands of feet thick. Salt beds are older stratigraphic units found outside the Gulf Coast. They are wide continuous formations no more than 1,000 feet (ft) thick and are typically more expensive to develop and more prone to deterioration than salt domes. Salt beds are confined vertically by their overlying stratigraphic units. A few examples of thick and extensive salt beds occur in the southwestern United States within the Castile and Salado formations. In the Delaware basin (west Texas and southeast New Mexico), salt beds in the Castile formation can be 250 ft thick and cover most the basin. Also, in the Delaware basin (but not limited entirely to it) is the Salado formation, which is typically 75 to 90 percent salt and covers an area of approximately 25,000 square miles. The thickest accumulation of salt in the Salado is within a narrow band on the north and east edges of the Delaware basin, where the salt can be more than 1,700 ft thick. [21] [35]

The benefits associated with utilizing salt caverns, specifically, for natural gas storage are the flexibility, cycling frequency capability, and minimum base gas requirement. They are termed "flexible" storage reservoirs because of their ability to withdraw and accept large quantities of gas more rapidly compared to other storage types. This makes salt caverns promising candidates for short-term changes in demand or supply (Exhibit 2-6).

Exhibit 2-6. Underground storage reservoir type cycling comparison [23] [36]

Storage Type	Injection Period (days)	Withdrawal Period (days)
Aquifer	200 to 250	100 to 150
Depleted Oil/Gas Reservoir	200 to 250	100 to 150
Salt Cavern	20 to 40	10 to 20

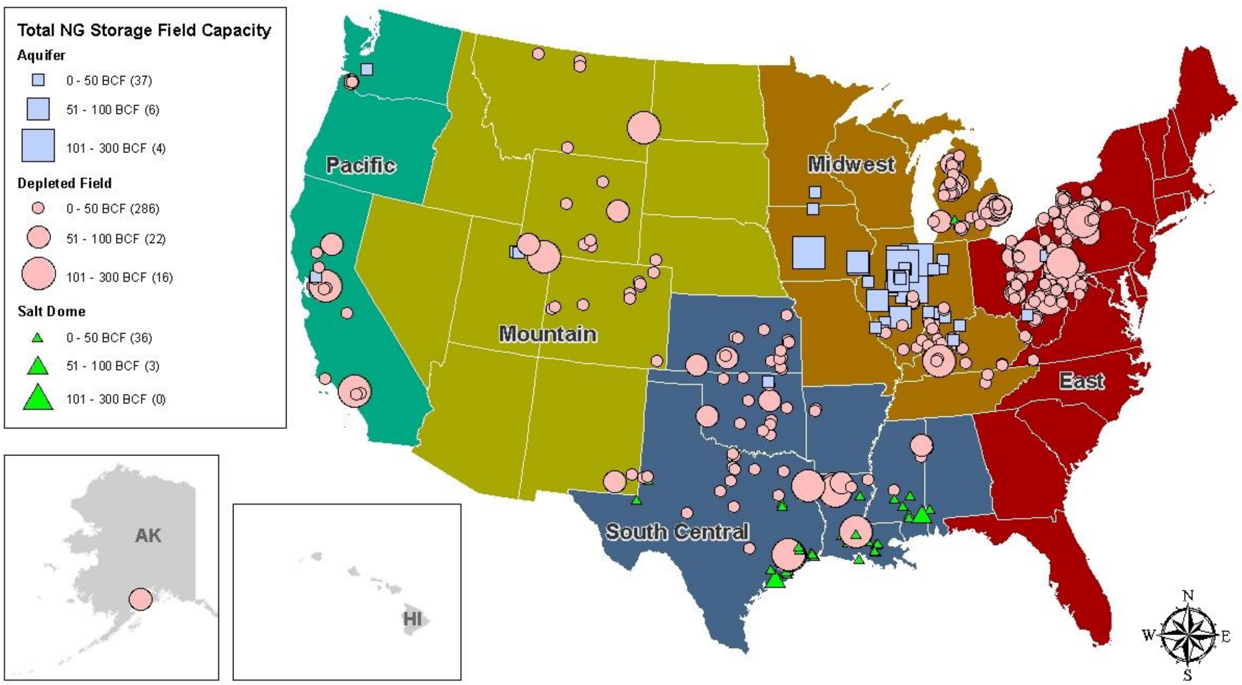
The cycles on salt caverns are much greater because of the ease associated with moving gas in and out of them. They can undergo 6 to 12 cycles per year compared to seasonal gas storage common in depleted and aquifer storage fields. Finally, they require less base gas, which results in higher volumes of working gas availability. The lower base gas requirements can contribute towards offsetting the higher capital cost associated with the development of salt caverns. [37] Salt caverns have a self-healing quality; cracks or potential leak paths can seal given the surrounding geologic pressure. A salt cavern can be compared to a tank or vessel because it degrades very little over time. Finally, salt caverns are typically one-hundredth the acreage of depleted gas reservoirs, providing a benefit in minimizing surface impacts associated with managing and operating storage.

Developing a salt cavern is expensive, however, due to the time requirements and resources needed. This expense occurs in multiple points in the development stage. The first cost incurred lies in the development of surface facilities to handle the storage and production of natural gas. The next cost is incurred when developing the salt cavern, which requires years of solution-mining and millions of gallons of water. [38] The third cost lies in treating or disposing of the produced brine. Finally, salt caverns are not well suited for base load requirements because of their relatively small capacity compared to that of depleted fields and aquifers. Salt caverns are more suitable for demand spikes or peak demand periods rather than sustaining a prolonged period of natural gas delivery. [21]

2.3 Regional Distribution and Capacity of Active U.S. Underground Storage Sites

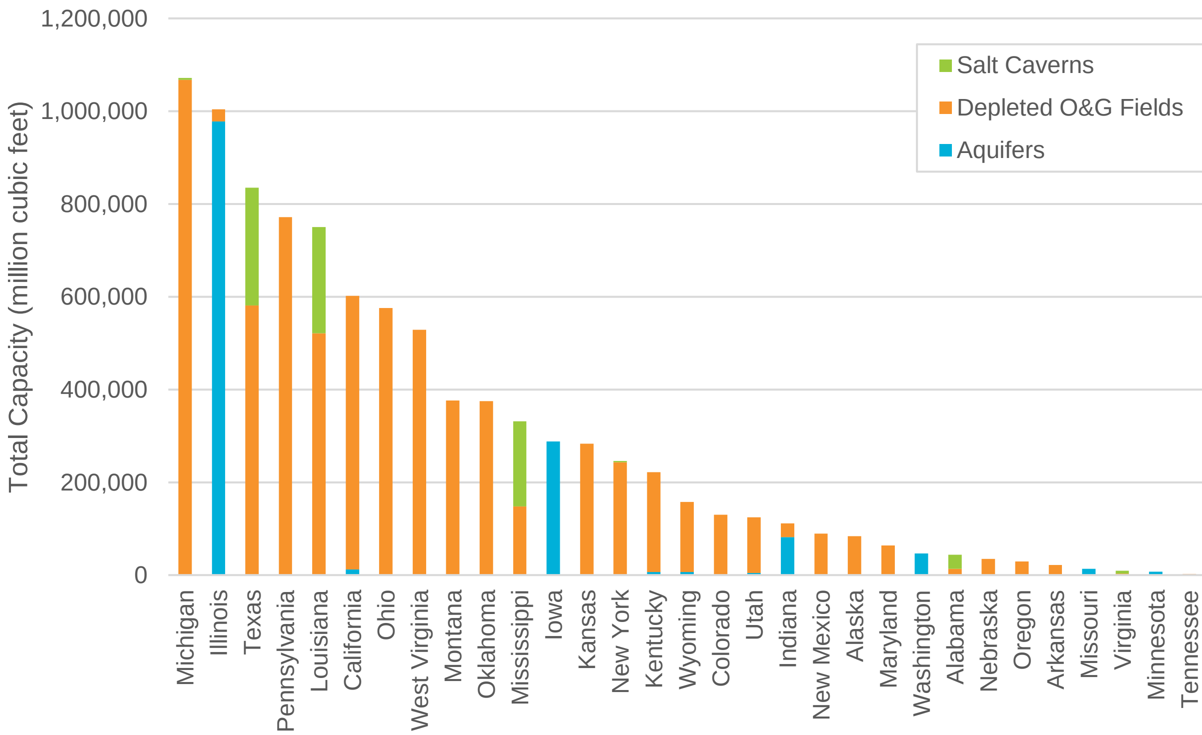
The United States has a well-distributed system of underground storage reservoirs that range across thirty-one states and is divided into five underground natural gas storage regions: East, Midwest, South Central, Mountain, and Pacific. It is important to note that to enhance the transparency and utility of natural gas storage reporting, the EIA modified the regions from three to five in 2015. EIA updated the geographic regions for storage reporting to provide better reporting granularity and to better connect the location of underground storage facilities with the markets they serve, as well as to accommodate changes in producing areas of the United States over the past several years. [39] Alaska is not included in any of the regions, but it is home to storage fields. [29] Exhibit 2-7 shows the distribution of underground natural gas storage sites by type and size. [27]

Exhibit 2-7. Underground natural gas storage facilities by type [26] [27]



EIA data show that the United States has approximately 9,230 billion cubic feet (Bcf) of underground natural gas storage capacity [26] distributed across various states and regions. Exhibit 2-8 shows the diverse types of storage facilities [27] broken down by region. Michigan has the largest underground storage capacity in the Nation, consisting mostly of depleted oil and gas fields. Illinois is second in overall storage capacity, but it consists mostly of aquifers. As mentioned in Section 2.2.3, storage in salt caverns is most prevalent in the Gulf Coast portion of the United States (Texas, Louisiana, and Mississippi hold most capacity for this storage type.)

Exhibit 2-8. Underground storage fields and capacity broken down into storage reservoirs by state [27]

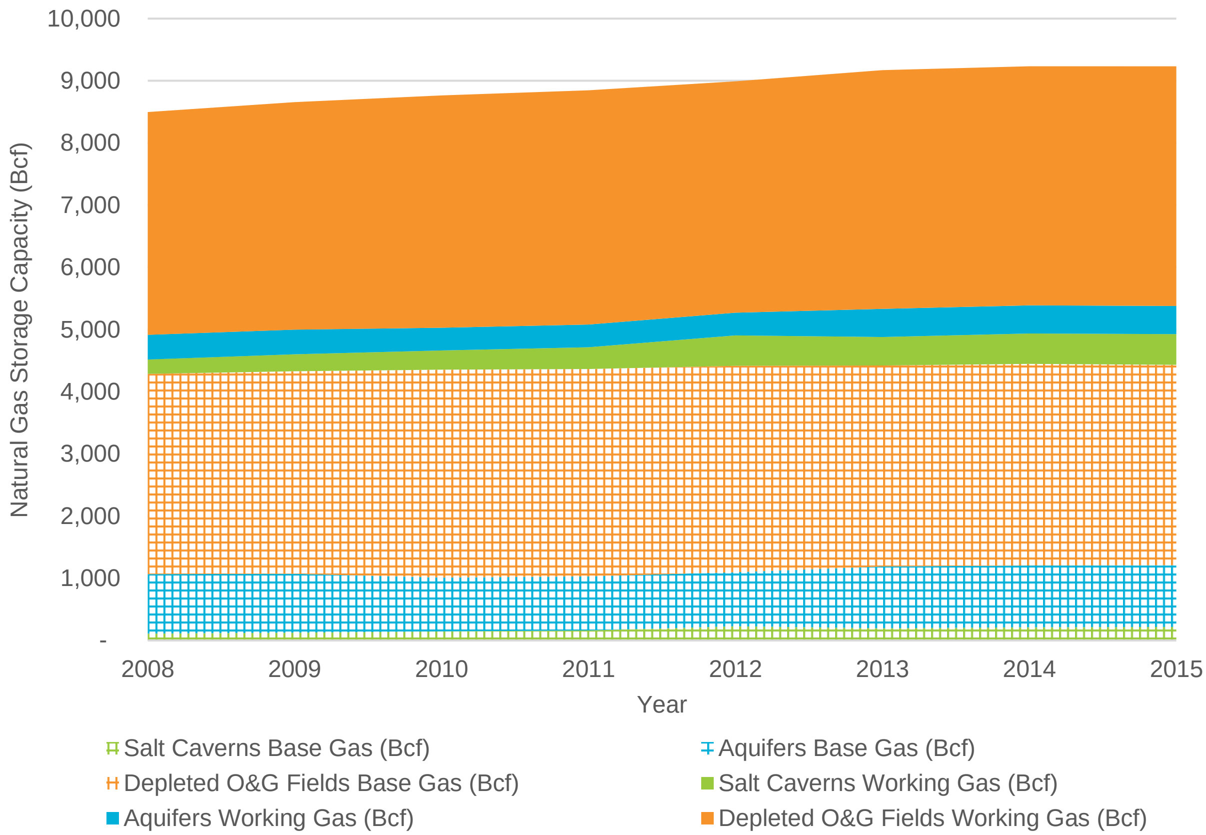


Storage reservoirs are often described by the volume capacity reported by FERC and EIA. FERC reports on and keeps track of certified storage facilities while the EIA tracks and reports on both certified and non-certified facilities. However, total reported storage capacity has never really been tested based on operating experience, thus the total working gas capacity is not exactly known. The working capacity of a reservoir is an alternative metric used when comparing regions or similar reservoirs, as it is directly related to the availability of supply. [23]

From 1968 through 1983, over 50 new fields were added, and volume of base gas increased from around 2,900 Bcf to 3,500 Bcf. Only two new fields came online from 1984 through 1989 and the volume of base gas remained nearly constant throughout that timeframe at 3,500 Bcf. An additional 19 fields came online from 1990 through 2003, and the volume of base gas increased to 4,300 Bcf, with the bulk of the increase in the early 1990s then leveled out through 2003. By 2003, base gas consisted of nearly 60 percent of the total volume of gas. [23] While the volume of base gas increased with additional capacity, the working gas mirrored demand, which did not increase at the same rate as capacity additions. [23] However, recent EIA data (as of November 30, 2016) indicate that from 2008 through 2015, the working gas volume has steadily increased, and the cushion base gas averaged about 50 percent of the total operating capacity. [26]

A breakdown of the base gas capacity, working gas capacity, and total gas capacity (base gas + working gas) by storage type since 2008 is provided in Exhibit 2-9. [26]

Exhibit 2-9. U.S. capacity estimates for the various storage types since 2008



The map in Exhibit 2-7 shows that regional distribution of underground natural gas storage is concentrated in the upper Ohio Valley, Michigan, Illinois, Gulf Coast and South-Central locations. This regional distribution is based on historical natural gas usage patterns and suitable geology providing either a depleted oil/gas reservoir, a saline reservoir, or opportunity to create a salt cavern. In New England and the adjourning areas of upstate New York, the local geology is typically not suitable for underground storage.

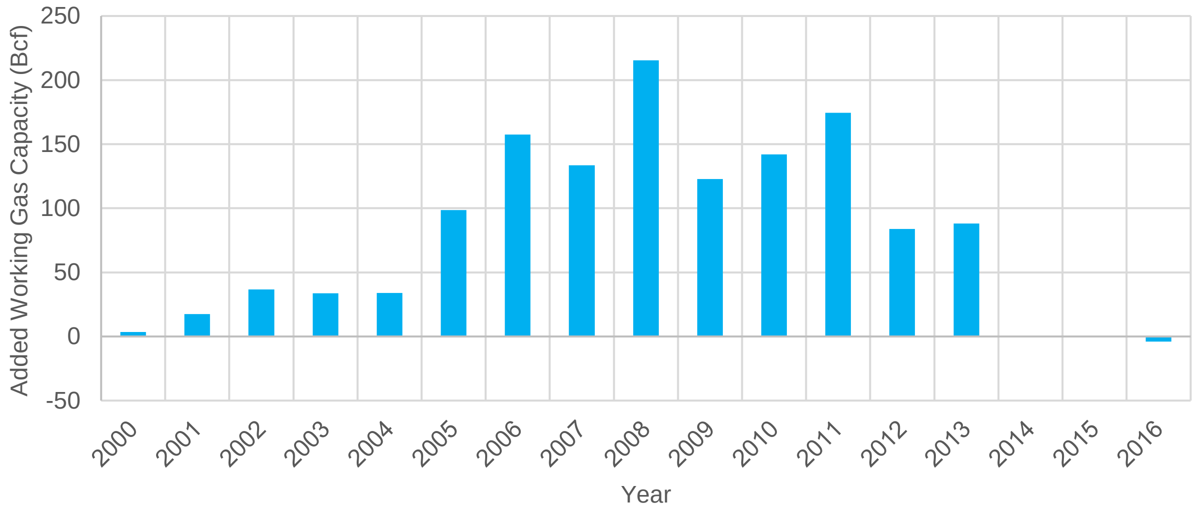
2.3.1 Recent Underground Natural Gas Storage Projects

As of 2015 there were four-hundred and fifteen active storage fields in the United States [26] that possess approximately 9,230 Bcf of storage capacity. They are owned and operated by 136 different storage operators. The number of storage fields has remained consistent over recent history. FERC has jurisdiction over underground storage projects owned by interstate pipeline companies or storage projects that offer storage services in interstate commerce.

FERC and EIA both store data on recent or upcoming U.S. natural gas storage expansions or additions. EIA generates a report on upcoming storage projects compiled from various sources such as FERC, trade press, company websites, and more. The reports outline the operator, location, type of storage reservoir, and the added total working capacity. The additional working gas capacity added from new storage fields and modifications since 2000 equals 1,342 Bcf. The most significant additions took place between 2005 and 2011, as seen in Exhibit 2-10.

[40] These values were pulled from FERC's database from storage operators under their jurisdiction meaning this does not account for storage fields not under FERC's jurisdiction.

Exhibit 2-10. Working gas capacity additions since 2000 per FERC's storage jurisdiction [40]



There have been no new natural gas storage projects proposed since 2013. There was some loss in working gas capacity in 2016 for an Equitrans, L.P. site in Pennsylvania. Recent trends limiting growth in natural gas storage working capacity have been attributed to the following market conditions [27]:

- The 2015 injection season began with working natural gas storage levels below the five-year average;
- Continuing growth in natural gas production displacing some amount of storage withdrawals;
- An unseasonably warm early winter in October and November 2015 reducing early withdrawals from storage;
- Storage reaching record high levels in November 2015; and
- The Henry Hub spot price hovering between $2.00 and $3.00 per million British thermal units for almost all of 2015.

However, as of October 2017, EIA has indicated that there are several new pending underground natural gas storage projects as well as several expansion projects [41] (Exhibit 2-11). Pending projects are those for which an application has been submitted, but a final decision has not yet been reached. The projects listed in Exhibit 2-11 may include new storage fields as well as enhancements or changes to existing fields. These new fields demonstrate potential increases to both storage capacity and deliverability in the near future. FERC has reported that only one pending storage project that serves interstate commerce is under review, which is a proposed capacity reduction effort at the Tres Palacios Gas Storage Facility in Texas. [42]

ICF International, in collaboration with Oak Ridge National Laboratory, conducted a study on the U.S. natural gas storage market which also recognizes the lack of recent storage expansions in the United States outlined in Exhibit 2-10. This work was part of a larger study which also includes sections on natural gas outlook and vulnerability, ethane market outlook, and LNG. Its objective was to better understand if natural storage capacity in the U.S. can meet future market needs based on evolving natural gas demand and supply conditions. [43] Essentially, ICF reviewed storage utilization and valuation trends across the U.S. and identified potential future market needs for storage capacity with the Gas Market Model®. [44] Three primary market assumptions were provided by DOE as a study basis:

- Low Gas and Oil Resource Case - reflects an environment with wide application of energy efficiency measures and renewable generation in the power sector. It also features low oil and gas resource levels throughout the continent.
- Base Case - reflects a market environment with readily available economic natural gas and oil resources in the U.S. Therefore, natural gas demand is increased, mainly from power sector growth in the South Atlantic region and LNG exports out of the Gulf.
- High Gas and Oil Resource Case - reflects an optimistic outlook for U.S. gas demand, which increases from 70 Bcf per day in 2016 to 83 Bcf/per day by 2035. Most of the demand growth is attributed to the power sector demand in the South Atlantic and Midwest regions of the U.S., whereas other regional demand remains flat through the projection period.

An overview of key findings from this study are provided in the bullets below. The findings provide perspective to the expected underground natural gas storage needs (relative to current capacity) as growth in gas use in the power section and increased LNG exporting is expected to occur. In that regard, no significant capacity expansions are expected, but higher deliverability storage options become preferred. [43]

- Growth in power sector gas consumption and the need to compensate for variations in renewable generation may heighten the demand for high deliverability storage that can provide flexible natural gas supplies in a short period of time.
- Despite exceptional production growth from shale resources accompanied by moderate demand growth, several storage facilities are still underutilized. Even in the event extreme conditions like the 2013/2014 Polar Vortex winter, U.S. storage inventory levels have shown to recover quickly.
- Under high gas and oil resource case, LNG exports out of the Gulf Coast and power demand growth from South Atlantic improve the utilization of high deliverability storage facilities in the Gulf. However, large scale expansions are not expected.
- Under the base case, increased natural gas demand was noted; primarily from power sector growth in the South Atlantic region and LNG exports out of the Gulf Coast. Since demand from other regions remains flat, the incremental needs for storage capacity remains low. Expected demand from the power and LNG export sectors could improve

the utilization of current capacity in the Gulf coast states, however, no incremental storage development is expected.

- Gas demand growth in the highly seasonal residential and commercial sector could widen demand differentials between winter and summer, resulting in need for seasonal supply sources, such as storage.

Exhibit 2-11. Upcoming U.S. underground natural gas storage facilities per U.S. EIA [41]

Project Name	Operator Company	Year in Service	Development Status	State	FERC Regulated	Total Capacity (Bcf)	Working Capacity (Bcf)	Deliverability (MMcf/day)	Field Type
New Facilities Planned									
Bobcat Gas Storage Cavern 3	Spectra Energy Corp	2017	Terminated	LA	Yes	12	10	-	Salt Dome
Crowville Salt Dome Project Cavern 2	Perryville Gas Storage LLC	2017	Operational	LA	Yes	4	-	600	Salt Dome
East Cheyenne Phase 2: Lewis Creek Field	NGS Energy LP	2017	Construction	CO	Yes	12	7	350	Depleted Reservoir
Golden Triangle Storage Cavern 3	AGL Resources	2017	Planned	TX	Yes	11	7	-	Salt Dome
Golden Triangle Storage Cavern 4	AGL Resources	2017	Planned	TX	Yes	11	7	-	Salt Dome
Magnum Gas Storage Project 1	Magnum Gas Storage	2017	Planned	UT	Yes	3	-	125	Salt Dome
Magnum Gas Storage Project 2	Magnum Gas Storage	2017	On Hold	UT	Yes	3	-	125	Salt Dome
Magnum Gas Storage Project 3	Magnum Gas Storage	2017	On Hold	UT	Yes	3	-	125	Salt Dome
Magnum Gas Storage Project 4	Magnum Gas Storage	2017	On Hold	UT	Yes	3	-	125	Salt Dome
D'Lo Gas Storage Cavern 1	D'Lo Gas Storage LLC	2018	On Hold	MS	Yes	-	8	400	Salt Dome
D'Lo Gas Storage Cavern 2	D'Lo Gas Storage LLC	2018	On Hold	MS	Yes	-	8	400	Salt Dome
D’Lo Gas Storage Cavern 3	D’Lo Gas Storage LLC	2018	Planned	MS	Yes	-	8	400	Salt Dome
Pine Prairie Energy Center Cavern 6 and Cavern 7	Pine Prairie Energy Center	2018	On Hold	LA	Yes	-	24	-	Salt Dome
Expansion Projects									
Pine Prairie Energy Center Expansion Phase III	Pine Prairie Energy Center	2017	Construction	LA	Yes	N/A	8	300	Salt Dome
Aliso Canyon Expansion	Southern California Gas Company	2018	On Hold	CA	No	N/A	-	-	Depleted Reservoir
Mist Storage Expansion Project	Northwest Natural Gas Co.	2018	Construction	OR	No	N/A	3	120	Depleted Reservoir
Seneca Lake Gallery 2 Expansion	Arlington Storage Company	2018	Terminated	NY	Yes	N/A	1	145	Salt Dome

2.4 Cost of Underground Natural Gas Storage

Natural gas storage costs are driven by several factors, including the quality and structure of the geology of the proposed storage site, the amount of surface facilities needed, the amount of horsepower needed for compression, proximity to existing pipeline infrastructure, and the level of permitting needed. Newer gas storage projects can benefit from leveraging existing infrastructure to re-work and expand older high-quality depleted reservoirs, which lowers development costs and avoids creating new issues pertaining to the environment. Among the three types of storage fields (salt cavern, depleted reservoir, and aquifers), salt caverns are generally the most expensive to develop on a capacity basis. [23] However, their ability to perform several withdrawal and injection cycles each year (up to 12 times for some facilities) reduces the per-unit cost of each cubic foot of gas injected and withdrawn due to better deliverability. [29] A 2016 study performed by ICF International and completed for the INGAA Foundation presented underground natural gas storage costs on a Bcf of working gas capacity basis as highlighted in Exhibit 2-12. [45] [46] The costs presented vary depending on the underground storage reservoir type utilized. Costs for newly developed facilities have an average of $32 million per Bcf of working gas capacity across storage reservoir types, and an average of $27 million per Bcf of working gas capacity for facility expansion projects.

Exhibit 2-12. Underground natural gas storage costs by reservoir type [45]

Reservoir Type	Facility Expansion ($Millions per Bcf Working Gas Capacity)*	New Facility ($Millions per Bcf Working Gas Capacity)*
Salt Caverns	$30	$35
Depleted Oil and/or Gas Reservoirs	$17	$20
Aquifers	$34	$42

*Costs are in 2015 dollars

FERC indicates that much of the more recent underground natural gas storage projects involve re-working and expanding older high-quality depleted reservoirs to generate improved deliverability using newer technologies like horizontal drilling. These projects minimize development costs by leveraging the existing infrastructure and avoiding many environmental issues. [23] Exhibit 2-12 provides insight into the potential cost savings from facility expansion based on reservoir type.

Also, worth noting, the costs to develop these sites can vary among regions. The Gulf Coast region, as reported by FERC, is typically a low-cost benchmark for underground natural gas storage development and operational costs, with higher costs occurring in other regions; as the Mid-Western facilities are typically the next most expensive, followed by the Rockies, the Northeast, and finally California and the Pacific Northwest. [23]

2.5 STRATEGIC PETROLEUM RESERVE

The strategic petroleum reserve (SPR) contains the United States' supply of emergency crude oil. The supply is federally owned and operated and exists in underground salt caverns along the Gulf coast. The SPR categorizes its storage reservoirs in the same manner as the natural gas industry by recording storage design capacity, drawdown, and various storage measures. The SPR utilizes salt caverns because of their withdrawal capabilities and minimal leak/migration problems. The Gulf Coast was selected due to its central location near transmission lines capable of quickly transporting crude to any region of the United States. The four SPR sites are Bayou Choctaw, West Hackberry, Big Hill and Bryan Mound. [47]

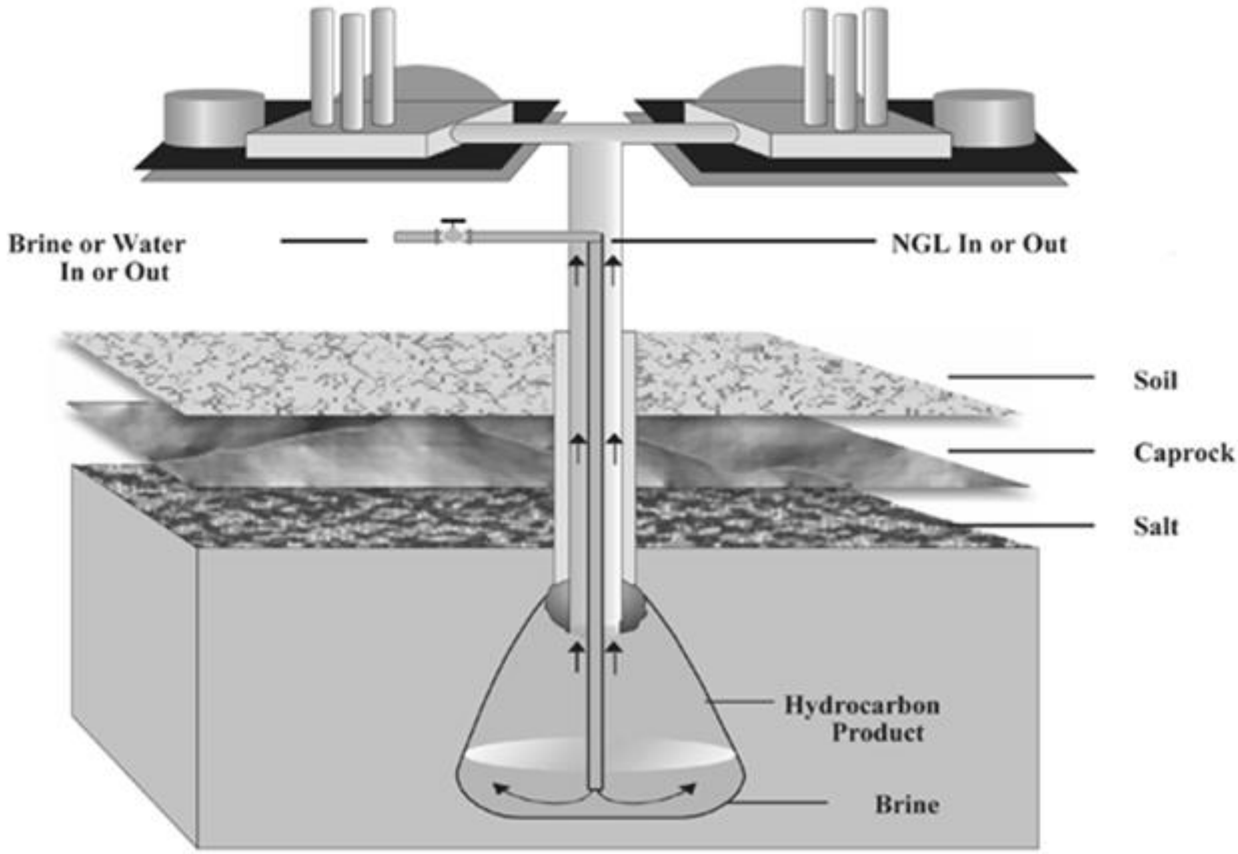
The U.S. Government acquired salt caverns in the mid-1970s to begin creating the SPR. The caverns' initial capacity was 250 million barrels, which over time was not enough to meet potential demand necessitating the creation of additional caverns. The "self-healing" salt walls make salt caverns an environmentally secure storage option for hydrocarbons. The natural difference in temperature between the top and bottom of the caverns keeps the crude oil continuously circulating, which maintains the oil at a consistent quality. Crude oil is extracted by pumping water down the borehole; the crude oil floats on the water and is extracted. The SPR benefits from technology and procedures developed by the natural gas storage industry. [48]

2.6 NATURAL GAS LIQUID STORAGE

Natural gas liquids (NGLs) are hydrocarbons and are in the same family of molecules as natural gas and crude oil. Ethane, propane, butane, isobutane, and pentane are all NGLs. NGLs are used across all sectors of the economy as inputs for petrochemical plants, energy for heating and cooking, and are blended into vehicle fuel. Increased light oil and liquid-rich natural gas production from unconventional shale reservoirs has contributed to increased NGL production. NGL production in the United States is growing rapidly (approximately 3.5 million barrels per day [MMBbl/d] in 2016) and is forecasted to increase to 4.1 MMBbl/d in 2018. [49] The NGLs—either mixed (Y-gas) or purified product—are maintained through pressure and temperature as a hydrocarbon liquid. NGLs are injected or removed through pumping of working liquids (brine or water) (Exhibit 2-13).

NGLs are processed and removed from oil and natural gas. The resulting mixed NGLs, or fractionated product, is stored in dedicated pipelines and in above ground and underground facilities. NGL pipelines and storage facilities maintain and transport NGLs in a liquid state. Primary hubs typically have processing and large underground storage capability, and secondary hubs typically have processing and above ground storage capability (Exhibit 2-14). The largest primary hub is Mont Belvieu with almost 250 MMBbl of storage.

Exhibit 2-13. NGL underground storage in a salt formation concept

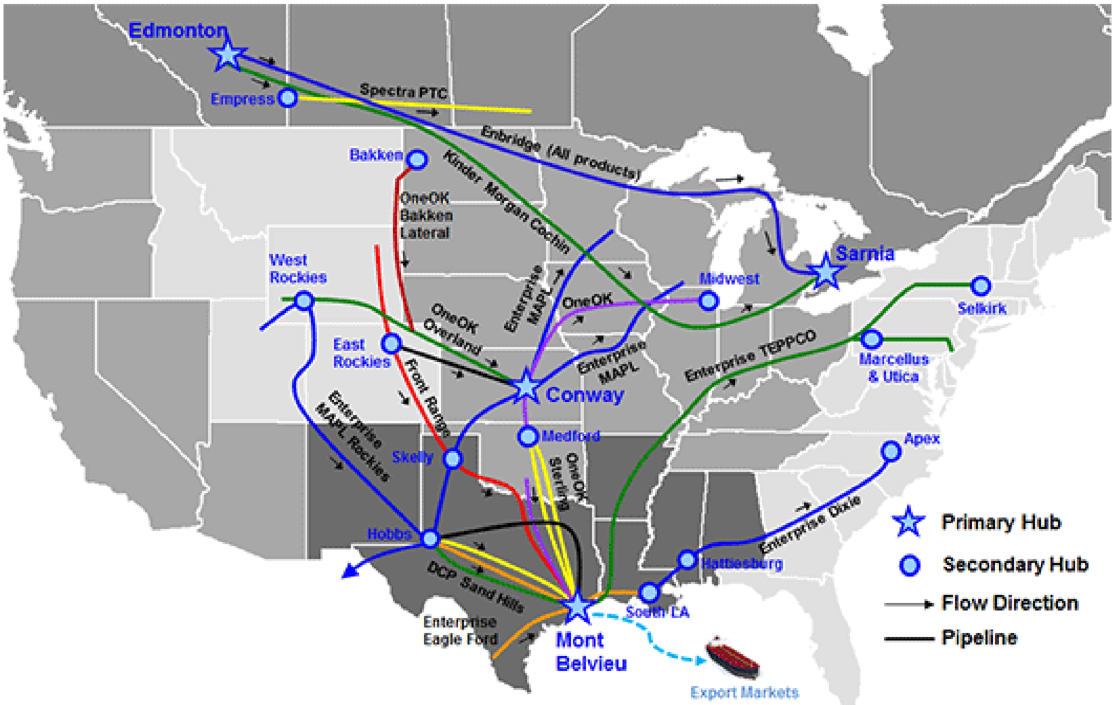


Source: Modified from U.S. Securities and Exchange Commission Registration Statement for Duncan Energy Partners L.P. [50]

NGL pipelines and product storage facilities are important components of the midstream energy infrastructure (Exhibit 2-14). Underground storage caverns (or wells) and above ground storage tanks are used to store mixed and pure NGLs. Underground storage facilities are in Canada at Sarnia, Ontario and Edmonton, Alberta, and in the United States at Conway, Kansas and Mont Belvieu, Texas. Mont Belvieu is the largest underground storage facility with approximately 100 storage caverns at depths of 4,000 to more than 5,000 ft in one of the world's largest salt dome formations (Exhibit 2-15). Some of these caverns are over 2,000 ft tall and hold more than a supertanker.[c] One of the operators at Mont Belvieu, Enterprise Products Partners LP, has 37 caverns with combined capacity of about 127 MMBbl. [51] Three other operators add an additional 103.6 MMBbl of storage capacity. New storage sites have been proposed to help manage the increase in NGL production, including a site in the Salina Salt along the Ohio River in the Appalachian basin. [52]

[c] A very large crude carrier (160-320 thousand dead weight tonnes) can carry between 1.9 million and 2.2 MMBbl of crude oil, which would roughly translate to 135,000 – 157,00 tonnes of LNG (assuming LNG density = 450 kilograms per cubic meter and one-barrel volume equivalent to 0.159 cubic meters). [243]

Exhibit 2-14. NGL pipelines and storage hubs as of 2013



Used with permission from the Canadian National Energy Board and Competition Bureau [53]

Exhibit 2-15. Mont Belvieu volatile hydrocarbon storage site

Used with permission from The Center for Land Use Interpretation [54]

Additional NGL storage could occur in the Appalachian Basin region given recent regional development and planned development in petrochemical production facilities using ethane as a feedstock. State officials in Pennsylvania, Ohio, and West Virginia are promoting a program to enhance economic development by expanding the market for ethane production from the liquids-rich Marcellus Shale gas fields in southwestern Pennsylvania and Utica Shale fields in eastern Ohio and northern West Virginia. The program is based on linking storage fields to end users in southern Pennsylvania, West Virginia, northeastern Kentucky via pipeline. A lack of downstream ethane demand, in combination with insufficient storage, transport, and processing infrastructure in the U.S. Northeast, causes a supply surplus, and subsequent ethane rejection into natural gas pipelines. However, suitable ethane storage options could enable the ethane to be removed from the natural gas stream and stored for use in the U.S. Northeast as a petrochemical feedstock, instead of being rejected and utilized for heating value. [55]

The Appalachian Storage Hub is a $10+ billion infrastructure project that would enable the petrochemical, as well as other downstream sectors, to collaboratively grow and expand, leading to an economic revitalization of the Appalachian Basin. [56] The Appalachian Oil & Natural Gas Research Consortium[d] conducted a one-year geologic study to determine the potential to create an Appalachian Storage Hub for NGLs by identifying potential subsurface geologic reservoirs for the secure, long-term storage of ethane and other products derived from the liquids-rich Marcellus and Utica shale plays. [57] Target storage intervals of interest include both salt caverns and depleted oil and gas formations like the Greenbrier Limestone, Salina Group salts, and gas reservoirs in sandstones like the Keener, Berea, Venango, Bradford, Elk, Oriskany, Newburg, and Rose Run. The research team defined an area of interest on both sides of the Ohio River that extends from southwestern Pennsylvania in the north as far as the Kanawha River Valley in southern West Virginia and conducted a regional stratigraphic study of all potential storage candidate formations and reservoirs in this area. Detailed reservoir characterization and field-level studies were then performed on the best candidates following a screening down-select process. The study has confirmed that there are multiple storage options that can be exploited, with the most promising being portions of the Greenbrier Limestone, the Newburg and Oriskany Sandstones, and Salina F4 Salt. [57]

As of date of this report, the storage hub is still in a conceptual stage aside from the geologic evaluation performed by the Appalachian Oil & Natural Gas Research Consortium, as well as a handful of other studies. [58] However, projects like the Shell Chemicals Ltd ethylene cracker plant (Beaver County, Pennsylvania) and Mountaineer NGL Storage facility (Monroe County, Ohio) have been announced and are starting to take shape. [59] [60] On a federal level, the Appalachian Ethane Storage Hub Study Act of 2017 was introduced to Congress in May 2017, which directs the Secretary of Energy and the Secretary of Commerce, in consultation with other relevant federal agencies, to conduct a feasibility study of establishing a subterranean ethane storage and distribution hub in the Marcellus, Utica, and Rogersville shale plays in the United States. The study is expected to include analysis of potential storage locations based on favorable geology, the economic feasibility, as well as benefits of the project, infrastructure

[d] The Appalachian Oil & Natural Gas Research Consortium is funded by a grant from the Benedum Foundation to the West Virginia University Foundation, with matching funds from industry partners and cost share provided by the state geological surveys in Ohio, Pennsylvania, and West Virginia. [57]

needs, geologic storage capacity capability, and proximity to production sites and potential industrial consumers. Additionally, the study must be completed within two years of enactment of the Appalachian Ethane Storage Hub Study Act. [61] To date, the Appalachian Ethane Storage Hub Study Act has been referred to the Senate Committee on Energy and Natural Resources. As a supplementary effort, the U.S. DOE published an NGL Primer in December 2017 that focuses on the resource potential of NGLs, specifically in the Appalachian region of the country. [60] The NGL primer is intended to help educate the public on NGLs, particularly what they are, how they are used, and the recent market developments regarding opportunities for new downstream investments using ethane as a petrochemical feedstock. [62]

3 Regulatory Overview of Subsurface Storage Operations: Underground Natural Gas Storage and CO_2 Geologic Storage

Storage sites for both underground natural gas storage and CO_2 injection and storage must meet certain regulatory standards pertaining to the design, construction, operations, maintenance, demonstration of well integrity, monitoring, threat/hazard identification and risk assessment, and emergency response and preparedness to ensure safe and effective operations. [63] [64] Both practices face a similar set of technical challenges as part of implementation, and may use similar equipment and infrastructure as part of deployment (discussed further in Section 4 and Section 5). However, the two practices differ significantly in the governing bodies responsible for overseeing each operation. For instance, the governing body overseeing a given underground natural gas storage project relies heavily if the storage field in question serves inter or intrastate commerce. As for CO_2 injection operations, EPA's UIC Program oversees and regulates operations; however, state-level UIC primacy affords some states oversight responsibility, depending on well class. The subsections below summarize the regulatory perspective to both underground natural gas storage, as well as CO_2 storage operations in the United States. This information provides insight into the regulatory drivers surrounding each practice and provides a basis for understanding how each operation is typically deployed.

3.1 Underground Natural Gas Storage – Regulatory Perspective

Natural gas storage and transmission are essential for ensuring reliability of domestic energy supplies, and in turn, appropriate regulations are essential for ensuring the safety of such systems. This section provides an overview of the current regulations as well as the push toward more stringent requirements in the future.

In general, the operation and maintenance of above-ground components and equipment associated with underground storage is regulated by the Department of Labor's Occupational Safety and Health Administration. Safety and operational standards for natural gas pipelines as part of storage facilities are set and enforced by the Department of Transportation's Pipeline Hazardous Materials Safety Administration (PHMSA). Regulatory responsibility for permitting and inspection of wells and facilities receiving or storing gas currently differs for interstate and intrastate gas storage infrastructure. For instance, underground natural gas storage facilities that are serviced by interstate pipelines are classified as "interstate" facilities and are subject to the permitting authority of FERC. On the other hand, intrastate underground storage facilities are facilities that exist exclusively within the boundaries of a given state and receive/deliver natural gas from/to an intrastate pipeline. State public utility commissions and state oil and gas boards establish their own regulatory frameworks for these facilities. State regulations must meet federal requirements at a minimum. Of the Nation's 415 underground storage facilities, 192 are interstate facilities and 223 are intrastate facilities. [65] From a gas transport perspective PHMSA has been regulating gas pipelines for decades in partnership with the states, including the surface piping at underground natural gas storage facilities up to the wellhead. Until recently, PHMSA has not exerted its regulatory authority over underground gas storage facilities, which include wells and related “downhole” infrastructure. PHMSA has recently notified the public of its intent to exercise its Federal rulemaking authority in the domain of underground natural gas facilities from the wellhead and extending downhole to include wellbore tubing and casing. Several states have issued and enforced rules related to their intrastate facilities.

3.1.1 Federal Energy Regulatory Commission

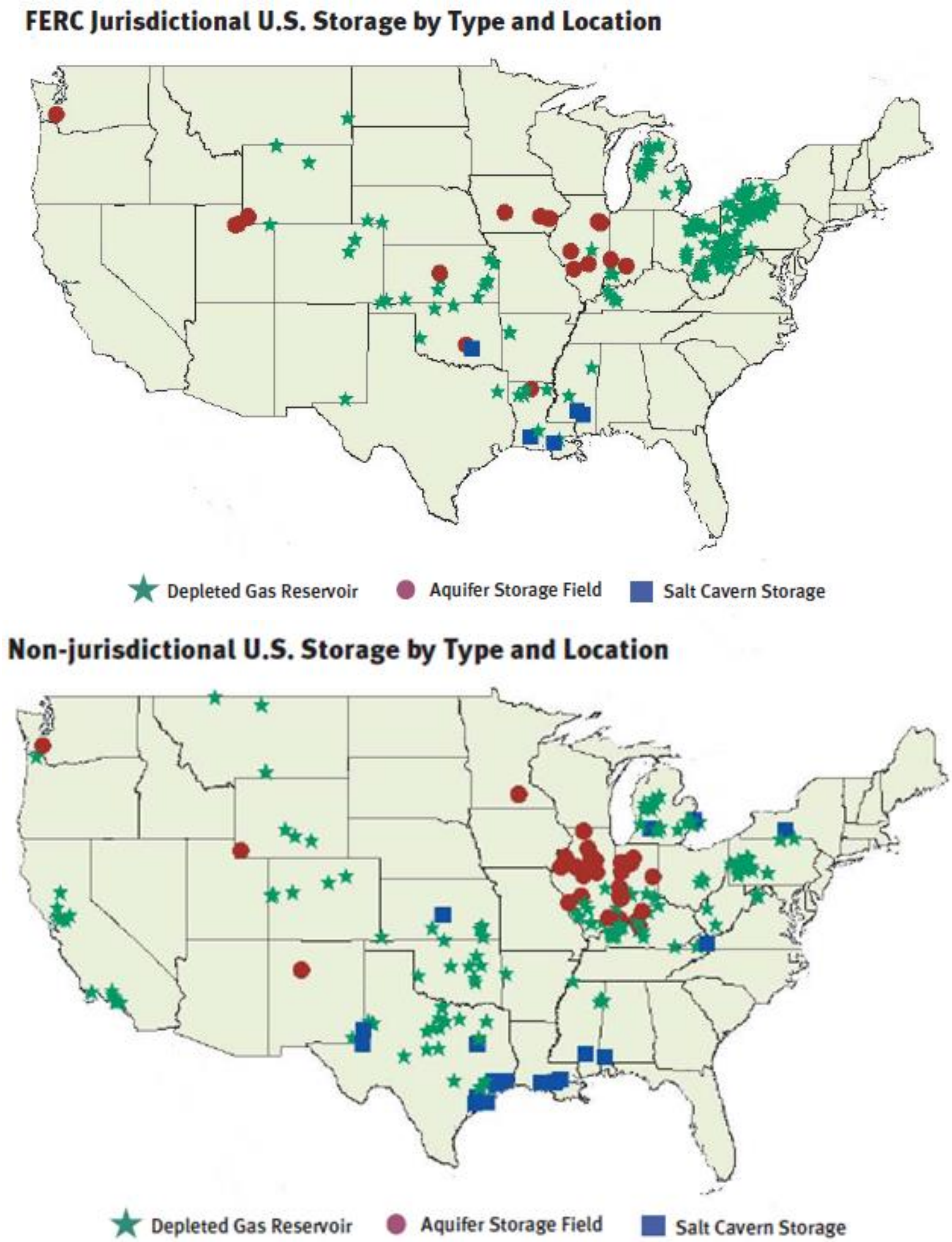
FERC, formed in 1977, is an independent agency within DOE that regulates the wholesale and transmission of electricity, natural gas, and oil. FERC also reviews proposals to build interstate natural gas pipelines,[e] create reliability standards, conduct mergers and acquisitions and corporate transactions by electricity companies, and issue licenses for hydroelectric and natural gas storage projects. FERC has jurisdiction over any underground natural gas storage facilities owned by an interstate pipeline company or independent operator that offers storage services in interstate commerce.

FERC developed two maps that illustrate both FERC jurisdictional and non-jurisdictional underground storage project locations in 2004. [f] The maps, shown in Exhibit 3-1, show large numbers of natural gas storage projects owned by interstate pipeline companies or independent operators. [23] As of November 2016, there were 223 different interstate fields (six noted as inactive) for underground natural gas storage operated by 65 companies. [66]

[e] FERC has disclaimed jurisdiction over CO_2 pipelines under the Natural Gas Act, even when small amounts of natural gas may also be transported with the CO_2. [244] In fact, no federal agency has jurisdiction over CO_2 pipelines or eminent domain. CO_2 pipeline siting is currently regulated at the state level, and interstate CO_2 pipelines are regulated for safety by the Department of Transportation under 49 U.S. Code Section 601.

[f] FERC also has up-to-date jurisdictional natural gas storage field information on its website (see https://www.ferc.gov/industries/gas/indus-act/storage.asp).

Exhibit 3-1. FERC jurisdictional and non-jurisdictional U.S. natural gas storage based on 2004 underground natural gas storage data



Used with permission from FERC [23]

While FERC has jurisdiction over any underground storage project that serves interstate commerce, FERC regulates project access and tariff design only, rather than facility design, operation, and maintenance. For example, an operator who seeks to apply market-based rates should follow FERC's requirements in 18 Code of Federal Regulations (CFR) §284 Part M - Application for Market-based Rates for Storage. The regulation for facility design, safety operation, and maintenance falls to PHMSA under the Protecting Our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2016 (discussed in Section 3.1.2.2).

3.1.1.1 FERC Order Number 636

Issued in April 1992, FERC Order Number 636 completed the final steps toward pipeline unbundling. Under previous FERC orders, pipeline companies were encouraged to provide transportation service on a nondiscriminatory basis, without favoring their own source of supply. Order 636 was designed to allow more efficient use of the interstate natural gas transmission system by fundamentally changing the way pipeline companies conduct business. It required interstate pipeline companies to unbundle, or separate, their sales and transportation services. [67] Order 636 states that pipelines must separate their transportation and sales services, so that all pipeline customers have a choice in selecting their gas sales, transportation, and storage services from any provider, in any quantity. It affords natural gas sellers an even playing field in moving natural gas from the wellhead to the end-user by imposing a rate design that promotes competition among natural gas suppliers. It enables the complete unbundling of transportation, storage, and marketing, allowing the customer to choose the most efficient method of obtaining its gas. Prior to Order 636, pipelines would bring natural gas from producers and sell it to customers, mostly local gas utilities, in competition with other sellers with “bundled” rates. These “bundled" rates included charges for services such as transportation, storage, and peak shaving. Essentially, Order 636 meant that pipelines could no longer engage in merchant gas sales or sell any product as a bundled service. [68] Overall, the policy goals of Order 636 were to enhance competition in the natural gas industry and to ensure that adequate and reliable service is maintained. [69] The direct impacts of FERC Order 636 on underground natural gas storage include: [67]

- Required pipeline companies to provide customers with expanded access to interstate storage capacity.
- Enabled a capacity release market for transportation and storage capacity by permitting firms to release unwanted capacity to those desiring capacity. FERC requires pipelines to provide all firms equal and timely access to relevant capacity availability information using electronic bulletin boards.
- Required pipeline companies to redesign their transportation tariff rates so that most fixed costs could be recovered through a capacity reservation fee charged to firm customers (uninterruptible). This reservation fee is charged monthly to reserve daily capacity, based on customer peak period requirements. Interruptible customers do not reserve daily capacity and are not charged a reservation fee. Variable costs are recovered through a usage fee applied on a volumetric basis to the gas actually transported. The new rate design (straight fixed-variable) intends to help promote competition among gas suppliers by eliminating any price distortions inherent in the previously used rate design (modified fixed-variable), which allocated certain fixed costs

such as return on equity and related taxes to a commodity (usage) charge. This charge was levied on a per unit basis and applied to the volume of gas actually used, thus affecting costs for both firm and interruptible customers.

3.1.2 Pipeline Hazardous Materials Safety Administration

PHMSA is a U.S. Department of Transportation (DOT) agency that regulates the safety of pipeline facilities at the federal level. Piping leading to or from underground storage facilities is currently regulated by PHMSA on related pipelines. If the underground storage serves interstate commerce, then it is also regulated by FERC for access and rates. For safety regulation of underground storage facilities, however, the jurisdiction is not clear. Following the recent leak from the Aliso Canyon incident (discussed further in Section 6.1.4), PHMSA issued an Interim Final Rule (IFR) on December 14, 2016, revising the federal pipeline safety regulations to address safety issues for downhole facilities, including well integrity, wellbore tubing, and casing at underground natural gas storage facilities. The IFR also addresses construction, maintenance, risk management, and integrity management procedures for these facilities and incorporates concepts from the recent American Petroleum Institute (API) industry Recommended Practices (RP) 1170 for salt caverns storing natural gas and 1171 for storage in depleted hydrocarbon reservoirs and aquifer reservoirs.

3.1.2.1 PHMSA Advisory Bulletin

In February 2016, in response to the Aliso Canyon Underground Natural Gas Storage Facility incident,[g] PHMSA issued Advisory Bulletin (ADB) ADB-2016-02 to all operators and owners of underground storage facilities. The purpose was to remind them to consider the overall integrity of their facilities to ensure the safety of the public and operating personnel and to protect the environment. In this advisory, PHMSA suggested that all owners and operators of underground storage facilities identify the potential of facility leaks and failures, review the operation of the shut-off and isolation system, and update emergency plans, as necessary. [70]

3.1.2.2 PIPES Act of 2016

The PIPES Act of 2016 was passed into law on June 22, 2016, with the intent to amend Title 49 of the Code of Federal Regulations "to provide enhanced safety in pipeline transportation, and for other purposes." [71] The Act also amends the definition of an underground natural gas storage facility as "a gas pipeline facility that stores natural gas in an underground facility, including a depleted hydrocarbon reservoir, an aquifer reservoir, or a solution-mined salt cavern reservoir." [72]

The Act requires PHMSA to issue, within two years of passage, "minimum safety standards for underground natural gas storage facilities." [73] These minimum safety standards would close the regulatory gap created by the absence of state-level regulation for wells and downhole pipe

[g] The Aliso Canyon Underground Natural Gas Storage Facility incident was a massive natural gas leak that released about 95,000 tons of natural gas before being capped. It was discovered on October 23, 2015. [245]

and tubing for interstate facilities and the general lack of adequate, consistent standards for all intrastate facilities.[h]

3.1.2.3 PHMSA Safety of Underground Natural Gas Storage Facilities Interim Final Rule

In July 2016, PHMSA held a public meeting to discuss federal pipeline safety regulations for underground natural gas storage facilities. After discussions with facility owners and operators, state regulators, and residents of the Aliso Canyon area, PHMSA concluded that the two recent RPs— API RP 1170 and API RP 1171—should be incorporated into federal regulation. These practices guide how operators should manage facilities with regular and site-appropriate monitoring, maintenance, emergency response, and remediation.

In December 2016, PHMSA released the IFR (81 FR 91860) in response to Section 12 of the PIPES Act of 2016 to revise the federal pipeline safety regulations in 49 CFR Part 191 and Part 192 to incorporate API RP 1170 and 1171 to address safety issues at underground natural gas storage facilities. Under the IFR, the previously non-mandatory RPs are now mandatory. Operators are permitted to deviate from these RPs only if they "provide a sufficient technical and safety justification in their program or procedural manuals as to why compliance with a provision of the recommended practice is not practicable and not necessary." [74] The IFR also requires operators to submit regular reports on infrastructure characteristics, incident reports with safety-related concerns, and data for a national registry. Natural gas operators would have 12 months from the IFR effective date (January 18, 2017) to comply. However, on January 18, 2017, PHMSA received a petition from industry for reconsideration of the IFR. [75] The petition was based on two fronts: 1) that the IFR implementation period for new storage requirements (i.e., one-year from rule date) was not practicable and should be reasonably extended; and 2) the IFR made several non-mandatory sections of the API RPs as mandatory, which could result in unnecessary burdens for operators. [75] As a result, PHMSA agreed to provide revisions and clarification on the IFR in response to requests from industry. [76] PHMSA indicated the final rule will have addressed the petition comments, as well as revise the enforcement requirements listed in the IFR. Additionally, PHMSA would not enforce on any new rules for one year. [76] According to DOT, PHMSA intends to issue the final rule by September 26, 2018. [77]

Ultimately, PHMSA (or the state entity who is certified with PHMSA) will monitor the implementation of these requirements in the interim and will begin inspecting facilities to enforce the requirements. PHMSA will continue to evaluate the safety of underground storage facilities and incrementally build regulation based on the IFR to ensure the safety of underground natural gas storage facilities. [74]

3.1.3 State-Level Regulation Examples for Underground Natural Gas Storage

The key responsibility of the states is the protection of the environment, especially drinking-water aquifers, from being threatened by the injection and subsurface storage of natural gas.

[h] States are free to create more stringent standards for intrastate pipelines, if they are compatible with the minimum standards in Section 12 of the Act.

States oversee issuing permits based on the assumption that the facility operators must implement projects within the parameters of required federal, state, and local regulatory agency permits, and operations that exceed permitted levels require new discretionary permits and additional review. When soliciting a permit for an underground natural gas storage project, applicants must provide information demonstrating that the intended reservoir is suitable and that it can be operated safely to prevent waste of resources, uncontrolled escape of gases, pollution of drinking water aquifers, and endangerment of life or property.

Regulations for underground natural gas storage operations and associated monitoring activities vary among states. [15] For example, Pennsylvania, a major natural gas producer, has about 60 underground natural gas storage facilities. State-level regulations enforced by the Pennsylvania Department of Environmental Protection primarily consist of regular inspections and implementation of well monitoring and testing programs to safeguard against natural gas leaks. [78] Other states have more stringent oversight. In California, several state regulatory bodies have jurisdiction over natural gas storage. The California Public Utilities Commission requires that utilities obtain authorization before constructing or expanding storage facilities. The California Department of Conservation (DOC) has primary jurisdiction over enforcing storage facility safety regulations. Following the Aliso Canyon leak, DOC instituted emergency regulations, effective February 2016, that remain in effect until DOC crafts new permanent regulations. The emergency regulations require storage operators to provide DOC with more detailed information about the operating conditions of the facility, regularly test safety valves, monitor and test reservoir pressure, test for leaks and develop a protocol for addressing leaks, and develop a risk management plan. [79] While the emergency regulations were in place, DOC initiated a rulemaking procedure to consider permanent rules regarding underground storage. Between May 2017 and March 2018, the DOC sent several rounds of public notices seeking comments on proposed regulations for underground gas storage projects. [79]

As mentioned in previous sections above, FERC has jurisdiction over the approximately 223 of the 415-underground natural gas storage facilities that are part of the interstate gas pipeline network, [66] but federal regulators deferred to state agencies for underground natural gas storage oversight in 1997. The Research and Special Programs Administration (RSPA) [i] issued Advisory Bulletin ADB-97-04 (July 10, 1997) to operators of gas and hazardous liquid underground storage facilities advising them on the design and operating guidelines and applicable state and RSPA regulations for underground storage facilities. RSPA concluded that given the varying and diverse geology and hydrology across the United States, underground natural gas storage requirements would ultimately be tailored to a state's specific circumstances. Additionally, ADB-97-04 encourages state action and voluntary industry action to assure underground storage safety instead of proposing additional federal regulations. [80] Additionally, the U.S. EPA has authority under the Safe Drinking Water Act (SDWA) of 1974 to regulate the underground injection of fluids, both hazardous and non-hazardous; however, an amendment to the act excludes natural gas storage facilities. [80] [81] A paper developed by de Figueiredo et al. [82] out of the Massachusetts Institute of Technology examining legal and regulatory issues involving CCS and analog industries indicated that the legislative history of the

[i] The Research and Special Programs Administration was a precursor to the PHMSA. [80]

exemption is based on two specific reasons; 1) that natural gas storage was deemed to not pose a threat to drinking water quality, and 2) natural gas storage operators have an economic incentive to prevent natural gas leakage.

The following is a description of the regulations for natural gas storage facilities of the five U.S. states with the most natural gas storage capacity.

3.1.3.1 Michigan

Michigan has nearly 1,071 Bcf [27] of underground natural gas storage facility capacity (roughly 282 Bcf being FERC-regulated) [66], all located in Michigan's Lower Peninsula, making it the largest underground natural gas storage capacity in the United States. Michigan's Department of Environmental Quality (DEQ) regulates activities that may impair or destroy the state's waters, which include inland lakes and streams, the Great Lakes, wetlands, and groundwater. The DEQ Office of Oil & Gas Minerals (OOGM) regulates drilling activities and anything related to minerals (coal, oil, and gas classified as minerals). The OOGM's main policy is to limit waste and achieve maximum resource recovery. The Michigan Public Service Commission (Department of Labor and Economic Growth) is responsible for regulating electric utilities (apart from municipal utilities) and for regulating natural gas utilities and their production, distribution, and storage.

Michigan is an example of a state that developed regulations for ensuring the integrity of injection wells, but specifically excluded gas storage wells from these regulations, even after the Aliso Canyon incident in California. Injection wells for brine disposal or secondary oil recovery are required to perform a pre-injection annulus integrity pressure test followed by a repeat pressure test every five years, and collect data on injection pressures, injection rate, and quantities of oil, gas and brine produced. Operators must report these data at regular intervals. However, gas storage wells are specifically exempted from these requirements. [83] [84]

3.1.3.2 Illinois

Illinois has nearly 1,000 Bcf of underground natural gas storage facility capacity (roughly 46 Bcf being FERC-regulated), [66] The Illinois Oil and Gas Act, Part 240 of the Illinois Administrative Code, regulates oil and gas operations under the Department of Natural Resources. Subpart R sets the groundwater protection and operating requirements and the drilling and conversions of gas storage and observation wells in underground gas storage fields. These include [85]:

- Requirement to submit storage field maps annually;
- Permitting requirements;
- Construction, operating, and reporting requirements for gas storage and observation wells;
- Storage field operating requirements; and
- Plugging requirements for storage and observation wells that are no longer used.

3.1.3.3 Texas

Texas has over 830 Bcf of underground natural gas storage facility capacity (roughly 195 Bcf being FERC-regulated), [66] The Texas Administrative Code provides a comprehensive regulatory structure for the underground storage of any gas under Rule §3.96 – "Underground Storage of Gas in Productive or Depleted Reservoirs." The Railroad Commission of Texas (RRCT) has regulatory authority over oil and gas pipelines and storage. Groundwater protection is delegated to the Department of Agriculture, the RRCT, and the State Soil and Water Conservation Board. The RRCT also regulates natural gas utilities. Examples of specific regulations in Texas include [86]:

- Permitting requirements;
- Well casing requirements;
- Pressure observation valve and leak detection requirements;
- Warning system, emergency response plan, and safety training requirements;
- Storage field operating requirements, including wellhead pressure monitoring and gas volume metering;
- Record keeping and reporting requirements;
- Integrity testing every five years; and
- Plugging requirements for storage and observation wells that are no longer used.

3.1.3.4 Pennsylvania

Pennsylvania has over 774 Bcf of underground natural gas storage facility capacity in 26 counties (roughly 446 Bcf being FERC-regulated). [66] Gas storage regulations were adopted in 1985 with the passage of the Oil and Gas Act, and most recently amended by the 2012 Oil and Gas Act (Act 13). Gas storage facility operators are presently required to [78]:

- Case and cement gas storage wells to ensure no gas can leak from them;
- Conduct monthly inspections of all gas storage injection and producing wells and all wells used for observation (monitoring);
- Annually inspect the gas storage reservoir and storage protective area to make sure no gas is leaking, or other hazardous condition exists;
- Implement gas storage well monitoring and integrity testing programs once every five years;
- Not exceed pressures that may cause the gas to begin leaking;
- Notify DEP within 24 hours of making emergency repairs to gas storage wells and submit a written explanation of the emergency and what action was taken within five days;
- Keep records of well inspection results and pressure data, integrity testing data, and inspections of abandoned and plugged wells; and

- Notify DEP 15 days before the gas storage well is plugged to prevent migration of gas or other fluids within or outside of the well.

3.1.3.5 Louisiana

Louisiana has about 750 Bcf of underground natural gas storage facility capacity (roughly 454 Bcf being FERC-regulated). [66] Of the top five states for natural gas storage capacity, Louisiana has the least specific laws regarding natural gas storage. Revised Statute 30:22, entitled, *Underground storage of natural gas, liquid hydrocarbons, and carbon dioxide*, sets forth the following [87]:

- Prior to using an underground reservoir as a storage facility, a public hearing must be held with the Commissioner of Conservation. The Commissioner must find that the facility is suitable and feasible for such use, the use of the underground reservoir for the storage of natural gas will not contaminate other formations containing fresh water, oil, gas, or other commercial mineral deposits, and the proposed storage will not endanger lives or property.
- The Commissioner shall issue such orders, rules, and regulations as may be necessary for protecting any such underground storage reservoir, strata, or formations against pollution or against the escape of natural gas, liquid hydrocarbons, or CO_2 therefrom, including such necessary rules and regulations as may pertain to the drilling into or through such underground storage reservoir.

3.1.4 American Petroleum Institute Recommended Practices 1170 and 1171

The API is a U.S. oil and natural gas trade association. API develops standards and recommended practices that detail safe and effective operating standards for the oil and natural gas industry, which have been adopted by state, federal, and international organizations. [88] As mentioned in Section 3.1.2.3, API published two recommended practices documents for underground natural gas storage: API RP 1170 and API RP 1171. The API RP 1170 (published July 2015), or “Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage,” describes the appropriate measures to safely construct and operate a salt cavern storage reservoir. The API RP 1171 (published September 2015), or “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs,” describes the proper measures to manage the integrity of storage wells within depleted hydrocarbon fields and aquifer storage reservoirs.

The API RP 1170 is the recommended practice that provides the functional recommendations for salt cavern facilities used for natural gas storage service. It covers facility geomechanical assessments, cavern well design and drilling, and solution mining techniques and operations, including monitoring and maintenance practices. The API RP 1171 provides guidance on natural gas storage in depleted oil and gas reservoirs and aquifers. It focuses on storage well, reservoir, and fluid management for functional integrity in design, construction, operation, monitoring, maintenance, and documentation practices. Guidance is provided pertaining risk management, site security, safety, emergency preparedness, and procedural documentation and training across key aspects of underground storage, like storage design, construction, operation, and maintenance. API RP 1171 guidance has a strong overlap and relevance to CO_2 storage and is therefore discussed in more detail below.

The goal of the API RP 1171 is to reduce potential risks through the implementation of a standard well integrity management program, a major focus in terms of safe and effective underground natural gas storage. API RP 1171 was developed during a three-year effort by a working group that included representatives from PHMSA, FERC, state regulators, and industry to develop natural gas storage well and reservoir integrity standards that combine consensus best practices, regulations, and concepts adapted from risk management and safety management systems. The API RP 1171 includes sections on natural gas storage well integrity management processes, lessons learned from historical storage well events, technical design components of a storage facility, and operational approaches to managing storage well integrity. Operators are currently modifying their existing integrity management processes to meet the more robust standards established in API RP 1171. Operators estimate that it may take seven-to-ten years for full conformance. [19]

The natural gas storage well integrity management process and risk-based approach section of API RP 1171 outlines the comprehensive risk assessment of natural gas storage facilities. The risk-based approach to well integrity recommended by API RP 1171 includes 1) data collection, documentation, and review; 2) hazard and threat identification; 3) risk assessment; 4) risk treatment – developing preventative and mitigation measures; and 5) periodic review and reassessment. For the risk assessment to be effective, the operator must take a holistic approach to storage well and field integrity. This led API to include three fundamental components in its risk management program: physical plant design, processes, and human factors. Failure to account for any of the three components in the risk management program can result in a minor event escalating into a major incident. [19] The standard includes a decision flowchart for effective well integrity management approaches (Appendix B: American Petroleum Institute Recommended Practice 1171 Reference Material). The document also includes lessons learned from historical storage well events that operators can use to help them move forward (Appendix B: American Petroleum Institute Recommended Practice 1171 Reference Material). A comprehensive literature analysis was conducted to generate metrics such as the number of incidents, occurrences of threats, fatalities, and other key safety indicators for historic well events. The metrics were used to analyze approximately 14,000 wells in 226 fields, which is over 80 percent of the storage wells across nearly 54 percent of the active storage fields in the United States. The analysis shows that most threats or incidents occur during normal well operations or are due to faulty equipment (Appendix B: American Petroleum Institute Recommended Practice 1171 Reference Material). These findings strengthen the need for a standardized document that details safe and effective operations to ensure that the number of incidents related to routine well work is reduced. [19]

The design of storage wells was also addressed under API 1171. The design components highlighted by API RP 1171 include 1) wellhead equipment, 2) well configurations, 3) zonal isolation, 4) cementing practices, 5) cement design, 6) cement evaluation, and 7) well closure. The common goal for each design factor is to ensure containment of subsurface fluids to their respective zones. Each component in the well design adds an additional layer of integrity and/or is used to verify the integrity of a specific zone. [19] In general, the purpose of this portion of API RP 1171 is to ensure that a well is properly constructed, maintained, and monitored to minimize the possibility of fluids invading the surrounding rock layers with the caveat that wells are likely to vary in construction and design from location to location.

The safe operation of storage wells is the last step in preventing and mitigating potential threats and/or hazards. API's storage well operation preventative program includes 1) well integrity evaluation; 2) well integrity demonstration, verification and monitoring; 3) well barriers and potential leak paths; 4) site security, inspections, and emergency response; and 5) procedures and training. These five steps set a standard for how to evaluate, monitor, and mitigate storage well integrity issues through the successful implementation of well design and post-evaluation techniques. The fifth step, procedures and training, aims to remove the human factors from the well integrity problem. If proper procedures and site personnel training are deficient, then well site operations will be ineffective at preventing future integrity issues regardless of the quality of the design, monitoring, and/or evaluation programs. [19]

3.2 CO_2 Geologic Storage – Regulatory Perspective

One of the major differences between underground natural gas storage and CO_2 geologic storage relates to the governing bodies responsible for overseeing each operation. EPA's UIC Program (which was created under the SDWA) regulates underground injection activities in the United States As discussed in Section 3.1.3, the SDWA has special provisions which specifically exempts applicability of natural gas storage to the UIC Program. [82] Nevertheless, the UIC Program mission is to develop minimum federal requirements and safeguards to protect public health by preventing injection wells from contaminating underground sources of drinking water (USDWs). [64] EPA has suggested that different applications of fluid injection (i.e., CO_2 injection specifically for geologic storage, CO_2 EOR, liquid waste disposal, and solution mining) inherently involves unique technical challenges despite noticeable similarities in approach. As a result, six classes of injection wells were developed under the UIC Program, in which each class is based on the type and depth of the injection activity, and the potential for that injection activity to result in endangerment (outlined per 40 CFR 144.12) of a USDW. [89] States can assume primary responsibility for implementing the UIC requirements program pending EPA approval (discussed in Section 3.2.1.2). [82] The subsections below summarize regulations pertaining to CO_2 storage operations in the United States and provide comparison between the requirements for the different well types.

3.2.1 EPA Underground Injection Control (UIC) Program Federal Regulations for CO_2 Storage Operations

EPA is tasked with establishing and enforcing any regulations associated with injecting and storing CO_2 in the subsurface. Existing regulations in the United States relevant to the geologic storage of CO_2 (including EOR and ECBM) involve protecting groundwater and USDWs[j] from

[j] A USDW is an aquifer or a part of an aquifer that is currently used as a drinking water source, or a potential groundwater source needed as a drinking water source in the future. A USDW is defined in 40 CFR 144.3 as "an aquifer or its portion: (a)(1) Which supplies any public water system; or (2) Which contains a sufficient quantity of groundwater to supply a

brine and CO_2 plume infiltration under EPA's UIC Program. Currently, the UIC Program defines six classes of wells (Classes I to VI) per the type of fluid they inject and where the fluid is injected. This program provides for regulation of construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal.

The SDWA of 1974 establishes requirements and provisions for the UIC Program. Federal regulations pertaining to the UIC Program can be found in Title 40 of the Code of Federal Regulations (CFR). [89] Exhibit 3-2 provides a summary of the CFR parts applicable to underground injection and disposal of fluids.

Exhibit 3-2. Federal UIC-related regulations and pertaining parts within the CFR [64]

CFR Section	Description
Part 144	UIC Program: provides minimum requirements for the UIC program promulgated under the SDWA.
Part 145	State UIC Program Requirements: outlines the procedures for EPA to approve, revise, and withdraw UIC programs that have been delegated to the states.
Part 146	UIC Program – Criteria and Standards: includes technical standards for various classes of injection wells.
Part 147	State UIC Programs: outlines the applicable UIC programs for each state.
Part 148	Hazardous Waste Injection Restrictions: describes the requirements for Class I hazardous waste injection wells.

3.2.1.1 UIC Well Classes Applicable to CO_2 Geologic Storage

In December 2010, EPA finalized minimum federal requirements under the SDWA for underground CO_2 injection for geologic storage based on the unique challenges of preventing potential leakage and endangerment to USDWs. Prior to these requirements, early research in CO_2 geologic storage used Class I, Class V (saline CO_2 storage), or Class II (enhanced recovery and CO_2 storage) wells. The final rule applies to owners and/or operators of wells that will be used to inject CO_2 into the subsurface for long-term storage. [90] This new Class VI well classification contains conditions designed to protect USDWs by compelling site operators to adhere to specific requirements (outlined in 40 CFR 146 Subpart E) related to siting, construction, operation, testing, monitoring, and closure. These regulations address the unique nature of CO_2 injection for geologic storage, including the relative buoyancy of CO_2, subsurface mobility, corrosivity in the presence of water while under subsurface pressure and temperature conditions, as well as the large injection volumes anticipated at geologic storage projects. [91] The rule also affords owners or site operators the flexibility to inject CO_2 at various depths to address injection in various geologic settings in the United States in which geologic storage can occur, including very deep formations and oil and gas fields that are being transitioned for use as CO_2 storage sites. [92]

public water system; and (i) Currently supplies drinking water for human consumption; or (ii) Contains fewer than 10,000 milligrams per liter total dissolved solids; and (b) Which is not an exempted aquifer." [89]

The suite of wells classifications under the UIC Program fall under the following six categories listed in the bullets below. [93] Four of the six classes (I, II, V, and VI) have, at one point, been permitted for CO_2 storage-related operations:

- Class I: Wells injecting hazardous and non-hazardous, industrial, and municipal wastes below USDWs
- Class II: Wells related to oil and gas production, mainly injecting brine and other fluids, as well as CO_2 for EOR applications
- Class III: Wells injecting fluids associated with solution mining of minerals, such as sodium chloride (NaCl) and sulfur (S), as well as for in-situ uranium leaching
- Class IV: Wells injecting hazardous or radioactive wastes into or above USDWs (generally only used for bio- remediation). This well class was banned by EPA in 1984
- Class V: Injection wells not included in Classes I through IV that are typically used as experimental technology wells. They range from simple shallow wells to complex experimental injection technologies
- Class VI: Class of injection wells specifically for long-term geologic storage of CO_2

The technical operational criteria vary for each well depending on the intended operation, well use, and type. Exhibit 3-3 below provides a summary of the current mandatory technical requirements as indicated by 40 CFR 146 Subparts A, B, C, F, and G for well types most directly applicable to geologic storage of CO_2 (i.e., Class I, II, V, and VI). In Exhibit 3-3, Class I and Class V well requirements were grouped together. Several early CO_2 storage pilot studies carried out by the RCSPs injected under both Class I and Class V prior to establishment of Class VI, and requirements for subsurface CO_2 injection for both well classes were similar. [92] Furthermore, there are no federal requirements written specifically for Class V experimental technology wells, but EPA issued a guidance document in 2007 that applies to CO_2 geologic storage projects that are to be permitted as Class V experimental technology wells, which provides suggested guidelines for permitting and operating near-term pilot projects prior to commercial-scale implementation. This guidance does not, however, substitute for the SDWA or EPA's UIC regulations, nor is it a regulation itself, but it does set Class V requirements for monitoring that are nearly as stringent as Class I UIC regulations. [94]

Exhibit 3-3. Summary of technical requirements based on the governing regulations for Class I, Class II, Class V, and Class VI UIC injection wells

Requirement	Class I and Class V [95]	Class II	Class VI
Siting and Characterization	▪ Confirm fluids will be injected into formation that is below the lowermost formation containing, within one-quarter mile of the well, a USDW by completing geologic studies of injection and confining zones to demonstrate: ○ Receiving formations are sufficiently permeable, porous, and thick enough to receive fluids at proposed injection rate without requiring excessive pressure ○ Formations are large enough to prevent pressure build up and injected fluid would not reach aquifer recharge areas ○ There is a low-permeability confining zone to prevent vertical fluid migration of injection fluids ○ Injected fluids are compatible with well materials and rock and fluid in injection zone ○ Area is geologically stable ○ Injection zone has no economic value ▪ Complete wireline log runs and tests to inform well construction compatibility with the subsurface **Additional requirements for Hazardous Waste Wells:** ▪ Confirm fluids will be injected into formation that is below the lowermost formation containing, within one-quarter mile of the well, a USDW by completing structural studies to demonstrate: ○ Injection and confining zones are free of vertically transmissive fissures or faults	▪ Site new wells in such a fashion that they inject into formation that is separated from any USDW by confining zone that is free of known open faults or fractures within the Area of Review (AoR) ▪ Demonstrate the presence and adequacy of injection and confining zones by presenting information on geologic formations ▪ Create map showing injection well or project area for which permit is sought and applicable AoR ▪ Develop maps, cross-sections, and a list of penetrations into the injection zone, and of regional geology ▪ Perform specific wireline log runs and tests to inform well construction compatibility with the subsurface	▪ Demonstrate wells will be sited in areas with suitable geologic system comprising injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive total anticipated volume of CO_2 stream and confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain injected CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in confining zone(s) ▪ Identify and characterize additional zones, if required ▪ Run appropriate wireline logs, surveys, and tests to determine or verify depth, thickness, porosity, permeability, and lithology of, and salinity of any formation fluids in all relevant geologic formations to ensure conformance with injection well construction requirements ▪ Complete extensive site characterization, including the analysis of wireline logs, maps, cross-sections, USDW locations; determining injection zone porosity, identifying any faults, and assessing seismic history of area

Requirement	Class I and Class V [95]	Class II	Class VI
	○ Low seismicity and probability of earthquakes ○ Proposed injection will not induce earthquakes		
Area of Review (AoR)	▪ Determine AoR by using mathematical model, such as modified Theis equation, to calculate zone of endangering influence or fixed radius of at least one-quarter mile ▪ Identify and address any improperly completed or abandoned wells through corrective action within AoR **Additional requirements for Hazardous Waste Wells:** ▪ Make radius minimum of two miles ▪ Demonstrate fluids will remain in the injection zone while they are hazardous by no-migration petition ▪ Conduct modeling to show either the waste will remain in the injection zone for 10,000 years or it will be rendered non-hazardous before migration	▪ Determine AoR by using mathematical model, such as modified Theis equation, to calculate zone of endangering influence or fixed radius of at least one-quarter mile around an injection well or width of one-quarter mile for circumscribing area around injection area ▪ Identify all known wells that penetrate the proposed injection zone, or all known wells that penetrate formations that may be affected by the increase in pressure ▪ Recognize and address any improperly completed or abandoned wells within AoR	▪ Determine AoR by computational model, which accounts for the physical and chemical properties of all phases of the injected CO_2 stream. This modeling is based on available site characterization, monitoring, and operational data ▪ Identify and address any improperly completed or abandoned wells through corrective action within AoR ▪ Delineate the AoR over the project lifetime (at least every five years)
Well Construction	▪ Require well to be cased and cemented to prevent movement of fluids into or between USDWs. The casing and cement used in the construction of new wells must be designed for the life expectancy of the well ▪ Confirm annulus between tubing and long string of casings is filled with a fluid approved by the UIC Program ▪ Inject through tubing and packer, packer set immediately above injection zone, annulus between tubing and casing filled with fluid approved by Director ▪ Ensure engineering designs are approved by regulatory agency	▪ Case and cement wells to prevent movement of fluids into or between USDWs ▪ No specific regulations for tubing and packer requirements in 40 CFR 146 Subpart C	▪ Confirm all well materials are compatible with fluids with which the materials may be expected to come into contact ▪ Verify surface casing extends through base of lowermost USDW and is cemented to surface using single or multiple strings of casing and cement ▪ Ensure at least one long string casing extends to injection zone and is cemented by circulating cement to surface in one or more stages ▪ Determine cement and cement additives are compatible with CO_2 stream and formation fluids and are of sufficient quality and quantity ▪ Verify tubing and packing materials are compatible with fluids with which materials may be expected to

Requirement	Class I and Class V [95]	Class II	Class VI
	▪ Perform tests during drilling to ensure no vertical migration of fluid **Additional requirements for Hazardous Waste Wells:** ▪ Receive UIC Program approval of casing, cement, tubing, and packer prior to construction ▪ Verify and implement detailed requirements for tubing and packer with direction of Director ▪ Set surface string casing below lowest USDW and cement back to surface ▪ Set long string (inner) casing to injection zone and cement back to surface		come into contact. Injection conducted through the tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director ▪ Fill annulus between tubing and long string casing with non-corrosive fluid
Operation	▪ Calculate injection pressure to ensure it does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs during injection ▪ Complete quarterly reporting on injection and pressures, injected fluids, and monitoring of USDWs within the AoR **Additional requirements for Hazardous Waste Wells:** ▪ Utilize automatic alarms and shutdown devices ▪ Notify permitting authority within 24 hours if problem occurs	▪ Calculate injection pressure to assure it does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs during injection ▪ Prohibit injection between the outermost casing protecting USDWs and the wellbore	▪ Ensure compliance with approved AoR and Corrective Action Plan and Emergency and Remedial Response Plan ▪ Ensure injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) ▪ Utilize alarms, automatic surface shut-off systems, and down-hole shut-off systems that initiate when operational parameters diverge beyond permitted ranges
Mechanical Integrity Testing (MIT)	▪ Conduct internal and external MITs every five years **Additional requirements for Hazardous Waste Wells:** ▪ Conduct internal MIT yearly ▪ Test cement at base of well annually	▪ Conduct internal and external MITs every five years ▪ Evaluate absence of significant leaks by monitoring tubing-casing annulus pressure with sufficient frequency, pressure test with liquid or gas, or records of monitoring showing absence of significant changes in relationships between injection pressure and injection flow rate for certain specified types of enhanced recovery wells	▪ Evaluate absence of significant leaks by initial annular test and continuous monitoring of injection pressure, rate, injected volumes, pressure on the annulus between tubing and long string casing, and annulus fluid volume ▪ Use tracer survey or temperature or noise log at least once a year to determine the absence of significant fluid movement

Requirement	Class I and Class V [95]	Class II	Class VI
		▪ Use results of temperature or noise logs or cementing records demonstrating presence of adequate cement to determine absence of significant fluid movement	▪ Run casing inspection log to determine presence or absence of corrosion in long string casing, if required
Monitoring	▪ Monitor and record annulus pressure, containment in injection zone, and characteristics of injected fluid and watch for fluid movement into USDWs within AoR ▪ Perform continuous monitoring for pressure changes in the first aquifer overlying the confining zone, the use of indirect, geophysical techniques to determine the position of the waste front, periodic monitoring of the groundwater quality in the first aquifer overlying the injection zone, and/or periodic monitoring of the groundwater quality in the lowermost USDW if the Director requires based on site-specific assessment of the potential for fluid movement from the well or injection zone **Additional requirements for Hazardous Waste Wells:** ▪ Comply with explicit procedures for reporting and correcting problems due to lack of mechanical integrity ▪ Develop and follow a waste analysis plan ▪ Analyze wastewaters as specified in the plan	▪ Monitor nature of injected fluids at time intervals sufficiently frequent to yield data representative of their characteristics ▪ Complete periodic injection pressure, flow rate, and cumulative volumes (produced and injected) monitoring weekly for disposal wells and monthly for EOR ▪ Perform annual fluid chemistry as needed or required by permit ▪ No specific regulations for record keeping in 40 CFR 146 Subpart C	▪ Ensure compliance with approved Testing and Monitoring Plan ▪ Use continuous recording devices to monitor the injection pressure, rate, volume and/or mass, and temperature of the CO_2 stream; pressure on the annulus between the tubing and the long string casing, and annulus fluid volume ▪ Monitor corrosion of well materials ▪ Complete pressure fall-off test at least once every five years ▪ Perform periodic monitoring of the groundwater quality and geochemical changes above confining zone(s) or additional identified zones ▪ Test and monitor to track extent of CO_2 plume and presence of elevated pressure by using direct or indirect methods ▪ Perform surface air monitoring and/or soil gas monitoring to detect movement of CO_2 that could endanger a USDW, if required ▪ Review Testing and Monitoring Plan periodically; review cannot be conducted less than once every five years ▪ Provide quality assurance and surveillance plan for all testing and monitoring requirements
Injection Well Plugging	▪ Plug well with cement, tag well, test plugs, and submit plugging and abandonment report ▪ Ensure abandoned well is in state of static equilibrium **Additional requirements for Hazardous Waste Wells:**	▪ Provide 45-day notice before plugging and abandonment ▪ Plug well with cement and utilize Balance Method, Dump Bailer Method, Two-Plug Method, or other alternative method to place cement plugs	▪ Provide 60-day notice in writing before plugging ▪ Ensure compliance with approved Injection Well Plugging Plan ▪ Flush each well with buffer fluid, determine bottom-hole reservoir pressure, and perform final external MIT

Requirement	Class I and Class V [95]	Class II	Class VI
	▪ Conduct pressure fall off and MITs ▪ Continue groundwater monitoring until injection zone pressure cannot influence USDW ▪ Flush well with non-reactive fluid ▪ Plug well by either Balance Method, Dump Bailer Method, Two-Plug Method, or other alternative approach approved by the Director ▪ Tag each plug used appropriately and test for seal and stability before closure is completed ▪ Inform authorities about the well, its location, and zone of influence	▪ Confirm abandoned well is in state of static equilibrium with mud weight equalized top to bottom	▪ Submit plugging report within 60 days after plugging
Proof of Containment and Post-Injection Site Care (PISC)	▪ No specific regulations in 40 CFR 146 Subpart B **Additional requirements for Hazardous Waste Wells:** ▪ Adhere to site-specific post-closure plan, which includes the pressure in the injection zone before injection began, the anticipated pressure in the injection zone at the time of closure, the predicted time until pressure in the injection zone decays to the point that the well's cone of influence no longer intersects the base of the lowermost USDW, predicted position of the waste front at closure, the status of any cleanups required, and the estimated cost of proposed post-closure care ▪ Continue to conduct any required groundwater monitoring required until pressure in the injection zone decays to the point that the well's cone of influence no longer intersects the base of the lowermost USDW	▪ No specific regulations in 40 CFR 146 Subpart C	▪ Monitor site following cessation of injection to show position of CO_2 plume and pressure front and demonstrate that USDWs are not being endangered ▪ Maintain PISC for 50 years or until proof of non-endangerment to USDWs is demonstrated ▪ Ensure compliance with approved PISC and Site Closure Plan
Site Closure	▪ No specific regulations in 40 CFR 146 Subpart B **Additional requirements for Hazardous Waste Wells:**	▪ No specific regulations in 40 CFR 146 Subpart C	▪ Provide at least 120-day notice before site closure ▪ Plug all monitoring wells in manner that will not allow movement of injection or formation fluids that endanger USDW

Requirement	Class I and Class V [95]	Class II	Class VI
	▪ Provide notice of intent to close within 60 days prior to well closure ▪ Develop closure plan with well plugging approach ▪ Provide post-closure report 60 days after closure		▪ Submit site closure report within 90 days of site closure
Financial Responsibility	▪ Provide certificate that assures, through performance bond or other appropriate means, the resources necessary to close, plug, or abandon the well **Additional requirements for Hazardous Waste Wells:** ▪ Demonstrate and maintain financial responsibility that meets estimate cost of post-closure plan by using instrument(s) such as trust fund, surety bond, letter of credit, financial test, insurance, or corporate guarantee ▪ Confirm available funds are no less than the amount identified in § 146.72(a)(4)(vi)	▪ Provide certificate that assures, through performance bond or other appropriate means, the resources necessary to close, plug, or abandon the injection well	▪ Demonstrate and maintain financial responsibility by using instrument(s); such as trust fund, surety bonds, letter of credit, insurance, self-insurance (i.e., financial test and corporate guarantee), escrow account, or any other instrument(s); to cover costs of corrective action, injection well plugging, PISC and site closure, and emergency and remedial response ▪ Update cost estimates of performing corrective action on wells in AoR, plugging injection well(s), PISC and site closure, and emergency and remedial response periodically to account for any amendments to plans (AoR and corrective action, injection well plugging, PISC and site closure, or emergency and remedial response)

In addition to the UIC well regulations listed in Exhibit 3-3 above, CO_2 storage owners/operators must also meet the requirements of EPA finalized regulations for "Mandatory Reporting of Greenhouse Gases for Injection and Geologic Storage of Carbon Dioxide" (referred as Subpart RR under 40 CFR 98.440–449). Subpart RR requirements are meant to provide EPA with a consistent greenhouse gas (GHG) activity record for all future geologic storage projects. They also ensure that appropriate consideration is given to key monitoring elements of geologic storage projects. Facilities carrying out geologic storage operations must report basic information on the amount of CO_2 received for injection; develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; and report the amount of CO_2 stored. [96] The MRV plan must specify a strategy for detecting and quantifying surface release of CO_2 and an approach for establishing baselines for monitoring CO_2 surface releases. The MRV plan identifies the maximum monitoring area (MMA) and the active monitoring area (AMA). The MMA is defined as the area that must be monitored and is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized. It also includes an additional all-around buffer zone of at least one-half mile. The AMA is defined as an overlay between 1) the area projected to contain the free phase CO_2 plume at the end of a specific timeframe established by the operator, plus an all-around buffer zone of one-half mile or greater if known release pathways extend laterally more than one-half mile; and 2) the area projected to contain the free phase CO_2 plume at the end of five years after the specific monitoring timeframe has passed. [97] This timeframe established as part of the AMA allows operators to phase in monitoring so that during any given time interval, only that part of the MMA in which leakage might occur needs to be monitored. [96] The MRV plan must be developed by the project supervisor and approved by the EPA Administrator. Once the required reports are submitted to EPA, they will be evaluated to determine if the CO_2 plume is being properly contained and safely monitored. The boundaries of the AMA must be periodically re-evaluated and approved by the EPA Administrator. As the AMA increases, the monitoring, verification, and accounting (MVA) plan will need to be reviewed to better assure proper containment. [97]

These regulations are meant to complement the UIC Class VI well regulations. Specifics of GHG reporting requirements for geologic storage projects are contained in CFR Title 40, Part 98.[k]

3.2.1.2 State and Regional Primacy Control of UIC Injection Wells

In addition to the federal requirements highlighted in Exhibit 3-3, many states have either enacted CCS requirements or are currently doing so. [90] EPA encourages state and regional governments, as well as tribes and territories, to seek primary enforcement responsibility or "primacy" for UIC well permitting, including UIC Class VI CO_2 injection wells. EPA asserts that state and regional entities are better equipped to address local concerns and handle geological assessments in their respective areas. State or regional primacy includes the right to approve permit applications and revisions, control over permitting decisions, and responsibility for oversight of injection wells.

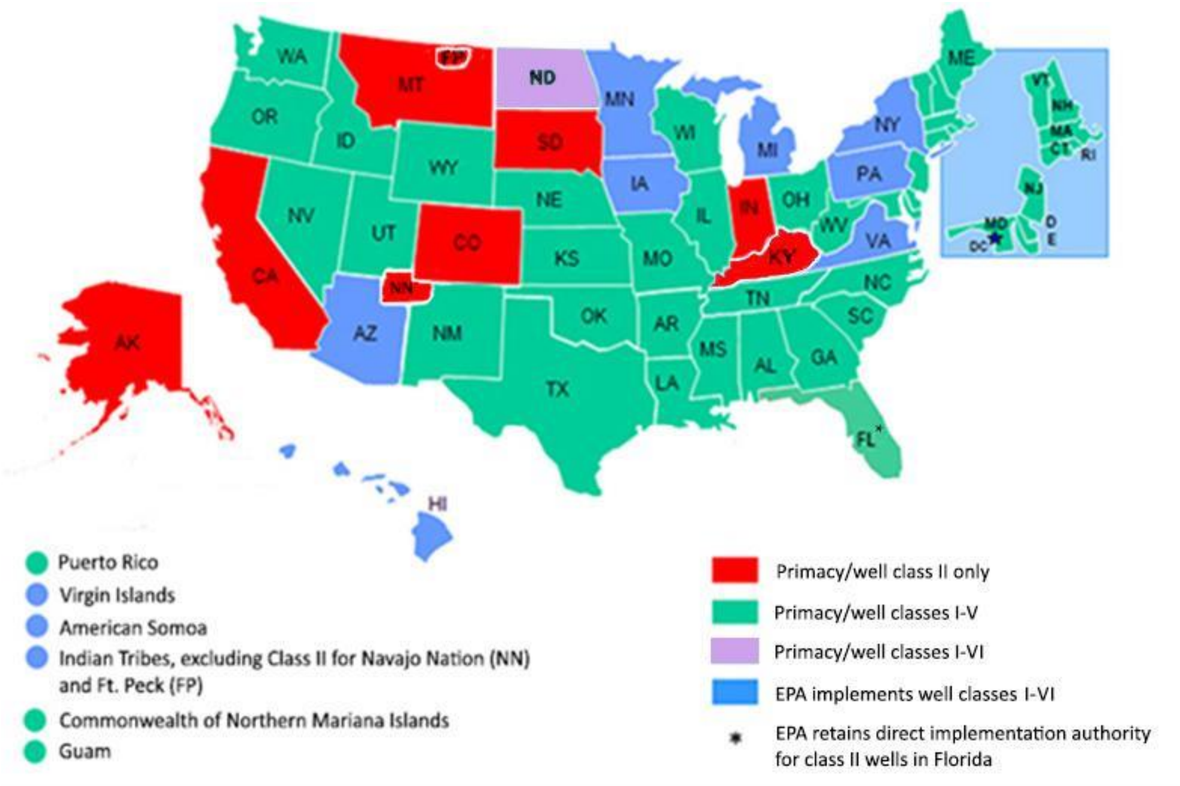
[k] More information on EPA's GHG Reporting Program can be found at: https://www.epa.gov/ghgreporting.

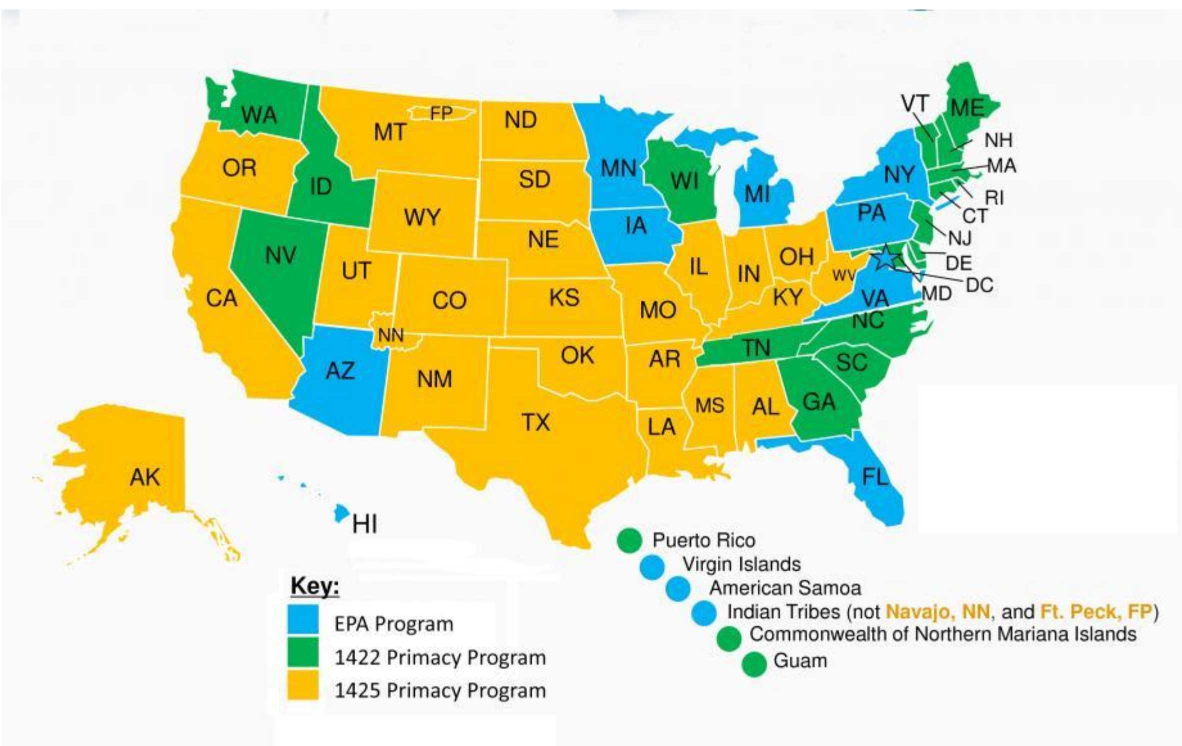
Primacy programs are established under Section 1422 and Section 1425 of the SDWA. These sections are explained in more detail below: [98]

- SDWA Section 1422 (42 U.S.C. §300h-1) enables states and American Indian Tribes to have primary enforcement responsibility for underground injection controls if the state/tribe can meet the minimum EPA requirements for authorization to assume primary enforcement responsibility. Programs authorized under this section have primacy for Class I, II, III, IV, V, and VI wells, and applicants may apply for primacy for all well classes, classes I – V only, or Class VI only.
- SDWA Section 1425 (42 U.S.C. §300h-4) describes optional demonstrations a state may make for the portion of the UIC Program related to oil and natural gas operations. This section allows EPA to approve existing state Class II (oil and gas) programs if the state can show that the program is effective in preventing endangerment of USDWs but does not require meeting EPA's minimum requirements.

As of May 2018, 34 states and three territories have EPA-approved primacy programs for well classes I, II, III, IV and V. [98] In addition, seven states and two tribes have applied for and received primacy approval for Class II wells only (Exhibit 3-4). If a state/tribe/territory does have primacy for a given well type, the specific requirements of that state/tribe/territory could be equally, and possibly more stringent than EPA minimum.

Exhibit 3-4. National maps featuring states, territories, and tribes UIC primacy status (top), and Class II-specific primacy status (bottom) [98]





Source: U.S. EPA

EPA is currently accepting new applications for state control of UIC wells and program revisions to existing primacy agreements to include Class VI well permitting rights; in April 2018, EPA issued a final rule for the state of North Dakota to assume primary enforcement authority for regulating Class VI injection wells in the state, except for those located on American Indian lands. [98] This rule came in response to the state of North Dakota submitting a program revision application in June 2013 to add Class VI injection wells to its SDWA Section 1422 UIC Program. [99] The state of Wyoming has developed regulations pertaining to Class VI injection wells and applied for UIC Class VI primacy. [100] [101] As of December 2018, the application is under review by EPA. States with no primacy agreements in place, or with primacy over Class II wells only, may choose to apply for primacy over all UIC well classes (I-VI) or over UIC Class VI wells only. States that already have primacy over UIC well Class I–Class V may seek to add primacy for Class VI wells by applying for a program revision. [98]

4 UNDERGROUND NATURAL GAS STORAGE SITE SELECTION, CHARACTERIZATION, AND OPERATIONS

As discussed in Section 2.2, three prominent storage types have historically been used for underground storage of natural gas: natural reservoirs such as depleted oil and gas reservoirs and aquifers, and man-made options like salt caverns. Katz and his colleagues formalized a process to design and operate a natural gas storage reservoir that focused on three objectives: 1) accessing the desired capacity, 2) prevention against migration, and 3) developing and maintaining desired deliverability. [102] [103] The requirements associated with a preferred site for natural gas storage are the same as those for CO_2 storage. For example, the key characteristics for CO_2 storage (as highlighted in Section 5.3) include capacity, containment, and injectivity, which are directly align to those proposed by Katz and his colleagues for natural gas storage. The major difference between the two practices is that most of the stored natural gas is produced (and new gas is re-injected) on a yearly basis. CO_2 is continually injected for the duration of operations (which could be from 10 to 50 years), followed by closure operations and PISC. [18] However, the need to assess critical geologic parameters for project operational success remains the same regardless of storage operation type, and their presence can be determined through site selection and characterization.

Underground natural gas storage projects can be complex developments. In addition to the suggested requirements by Katz and colleagues, [102] [103] the INGAA Foundation, Inc. has indicated that natural gas storage sites (if possible) should also qualify for 1) a relatively high volume of working gas as a percentage of total gas (low cushion gas requirements) if possible; and 2) injection into a relatively shallow reservoir. [104] There is a sequence of steps and actions for developing and implementing natural gas storage project that can be broadly divided into the following major project phases:

- **Site screening and selection:** Involves evaluating regions and sub-regions that are potentially suitable for natural gas storage based on need for storage, quantity of storage needed, and market location. Typically, location is selected to either improve operational efficiency or market efficiency (leveling wellhead production rates vs. meeting peak and seasonal demands). Potential sites that meet the necessary screening criteria are selected for further, detailed characterization.
- **Site characterization:** Builds on screening of selected sites to develop a more detailed characterization and understanding of the subsurface to assess a potential site's suitability for storage as a function of containment, capacity, and deliverability. Depending on the availability of data and existing understanding of the site, this could involve acquisition of new data sources as described in the following subsections below.
- **Permitting:** Utilizes data from site characterization showing storage zones are suitable and secure and will not endanger the environment or human health over the life of the facility to solicit a natural gas storage permit application. Permitting of federally regulated interstate natural gas facilities will have a mandated permitting process regulated by FERC before receiving any required FERC certificate, which involves the

identification of environmental issues through scoping and preparation of an environmental impact statement or environmental assessment. [105] Once a permit is approved and the operator has obtained relevant permits pertaining to the Clean Water Act, Coastal Zone Management Act, and Clean Air Act, a project can begin site construction and operations. Permitting of gas storage facilities at the state level consists of administrative and technical reviews of an application submitted by a gas storage operator. The purpose of the reviews is to assure that the construction and operation of the storage facility will be conducted in a matter that protects the environment and prevents migration of gas out of the storage zone, and depends on several factors including location, depth to protected groundwater, the type of storage media, the location and condition of existing wells in the storage project area, and the operation specification of a storage project. [106]

- **Construction and development:** Includes finalizing project design plans, conducting surveys, and completing right-of-way acquisition. [105] Installation of infrastructure, including wells, extraction equipment, pipelines, dehydration facilities and compressors is also conducted during this phase. Most of this equipment is generally lacking for aquifer storage sites compared to depleted oil and gas fields where oil and gas development may have occurred.
- **Operations and maintenance:** Operational planning commences; active transportation and injection/withdrawal of natural gas occurs; surface and subsurface monitoring system are deployed to assure that the gas is not leaking form the storage reservoir, usually by monitoring wells that are specifically drilled and constructed with and outside of the injection zone; and well integrity testing.
- **Closure, and restoration:** Ceases injection; well is plugged, the associated equipment will be removed, surface returned to near original condition. During 2016, 52 natural gas storage fields were reported as inactive across the United States; [107] and in 2018, operators have filed official requests for approval from FERC to abandon two different storage fields. [108]

This section emphasizes 1) considerations for natural gas storage site selection and characterization pertaining to accessing the desired capacity, prevention against migration, and developing and maintaining desired deliverability as well as 2) providing an overview of natural gas storage operations. The most relevant natural gas storage analogs to CO_2 storage include storage in depleted oil and gas reservoirs and aquifers. The content in the following subsections is mostly related to underground natural gas storage development and operations in those formation types. Regulations on these topics will dictate how they are implemented and will likely vary from state to state, but emerging themes will be evident and based more on the over-arching objectives. In general, screening and characterization of a potential natural gas storage site can be adapted from a process developed by Tek that identifies the tasks involved in selecting an aquifer storage site (which provides a strong analog to CO_2 storage in saline-bearing formations and does share similarities to development in a depleted oil and gas formation). [109] Once the need for storage has been identified—along with the quantity of storage and market location—several screening phases follow. Site screening involves determining containment, capacity, and injectivity, while screening for economic feasibility involves more detailed analysis involving site-specific geologic evaluation utilizing logging, well tests, water samples, and the evaluation of caprock integrity. Screening for economic feasibility could also include evaluation of the supporting infrastructure needs (well type and design, pipelines, and equipment) to successfully operate the facility. [109] This procedure by Tek and the objectives proposed by Katz serve as the basis for the subsequent subsections. [102] [103] [109] For practicality, an overview of the development of a salt cavern is not described in detail as part of this report.

4.1 Accessing Desired Capacity

A potential natural gas storage reservoir must be comprehensively investigated before advancing to the development stage. Its capacity must be assessed to determine if it can hold economic volumes of natural gas, regardless of the storage formation type. The storage capacity—or capacity—represents the total amount of gas stored in the subsurface. The working capacity is the volume of gas that is available to market. Site operators utilize the working capacity to analyze the potential cash flow of future operations. The capacity of the storage reservoir depends on geological parameters such as porosity, thickness, areal extent, fluid saturations, depth of reservoir (pressure and temperature gradients), stratigraphy and structural setting. The areal extent of a storage reservoir is influenced by boundary conditions determined by stratigraphy (changes in lithology) and structure (faults, structural dip of stratigraphy). [110] The final geologic parameter needed to calculate storage capacity is the displacement efficiency. This value describes the amount of in-situ water or oil that will be displaced by the injected gas, which will make room for additional gas storage. The three fundamental parameters of the capacity equation are porosity, fluid saturation, and thickness; these can be calculated using analogues or provided through actual measurements. Analog sites can be used to infer about geologic properties of untested reservoirs if the untested reservoirs are adjacent to developed fields or known geology. Measured parameters can be determined using direct or indirect measurement methods and are used to further characterize the reservoir. Direct measurements include routine core analyses on a sample from the storage reservoir. Indirect measurements include wireline logging or seismic data acquisition. The input parameters of the capacity estimate must be properly determined to accurately screen and later characterize each reservoir. Routine core analysis can determine the porosity and other geologic parameters of interest (i.e., permeability and fluid saturations) as well as geophysical properties. Wireline logging can be used to assess porosity, permeability, fluid saturations, and formation thickness. Often, direct measurements (such as on core samples) are used in tandem with and to calibrate indirect measurements to more realistically interpret the subsurface over a larger area.

4.1.1 Capacity Estimates

The total capacity of any underground storage reservoir consists of its working gas, cushion gas, and physically unrecoverable gas volumes. [21] Two methods of evaluating capacity, or inventory, of the storage reservoir were investigated by Okwananke et al. [111]: 1) volumetric; and 2) inventory-based methods. These methods have been developed specifically for storage in depleted reservoirs, but the general volumetric concepts should translate to aquifers. Depleted reservoirs are considered prime candidates for storage and are typically pressurized back to their original discovery pressures (which can be estimated using 0.43 – 0.52 pounds per square inch (psi) per foot depth ratio) once converted to storage reservoirs. However, in some cases, depleted reservoirs can be pressured greater than their discovery pressures (0.7 psi per foot depth ratio) if high quality caprock is available. [111]

In general, the approaches presented below are based on single values for reservoir properties and, therefore, assume homogenous conditions. Storage reservoir area, thickness, and porosity strongly influence the overall storage capacity. These approaches can provide high-level estimates of capacity, but more detailed evaluations would be needed to refine capacity estimates to account for reservoir heterogeneities. For instance, Jiao and Surdam (2013) received drastically different results for capacity estimates for a CO_2 storage application within the same formation (Weber Sandstone) when comparing approaches that were based on either homogenous conditions or accounted for heterogeneous conditions. [112]

The volumetric method (adapted from Okwananke et al.) is a commonly used approach due to the simplicity of its calculation. The major drawback of this method is that the results depend on the quality of the reservoir data and may result in high capacity estimates if reservoir heterogeneity is not properly quantified. A simplified form of the volumetric equation is adapted from Okwananke et al. is described in Equation 4-3 below. This equation infers that the total gas content that can be stored (G) is equal to the sum of the gas content to the present gas/water contact (G_{gwc}; Equation 4-1) and the residual gas content in water (G_r; Equation 4-2). [111] This volumetric equation can be used to calculate two gas content components: G_{gwc} and G_r. G_{gwc} is the gas content above the present gas/water contact and G_r is the residual gas content in an underlying water saturated zone. These two components can be used to further characterize depleted reservoirs with a gas/water contact and underlying water zone. These distinct categories of gas storage are important to recognize and quantify because they affect the operation of the storage reservoir.

$$G_{gwc} = 43{,}560 A_g h_g \varphi \left(\frac{P_{top}}{Z}\right)\left(\frac{T_{stp}}{P_{stp} T_{top}}\right)(1 - S_{w,irr}) \qquad \textit{Equation 4-1}$$

$$G_r = 43{,}560 A_w h_w \varphi \left(\frac{P_{top}}{Z}\right)\left(\frac{T_{stp}}{P_{stp} T_{top}}\right) S_{g,r} \qquad \textit{Equation 4-2}$$

$$G = G_{gwc} + G_r \qquad \textit{Equation 4-3}$$

Where:

P_{top} = maximum allowable reservoir pressure (pounds per square inch absolute [psia])

P_{stp} [I] = standard base pressure (14.5 psia)

[I] P_{stp} is essentially a theoretical pressure point at which reservoir pressure conditions are at or near standard (i.e., 14.7 psi). It serves as an absolute minimum pressure point equal to atmospheric conditions from which full volumetric storage capacity estimations can be made. Field operators could choose to replace the P_{stp} term with an alternative lower

43,560 = conversion factor to reservoir cubic feet per acre-foot (rcf/acre-ft)

T_{top} = top reservoir temperature (degrees Rankine [^oR])

T_{stp} = standard temperature (491.67 ^oR)

A_g = area of reservoir occupied by gas (acres)

A_w = area of reservoir occupied by water (acres)

h_g = net effective formation thickness occupied by gas (ft)

h_w = net effective formation thickness occupied by water (ft)

φ = porosity (decimal)

$S_{w,irr}$ = average irreducible water saturation above the gas-water contact (decimal)

$S_{g,r}$ = residual gas saturation below the gas-water contact (decimal)

Z = real gas deviation factor (decimal)

The volumetric estimation for gas derived from Equation 4-3 is dependent on the following assumptions [111]:

1. Constant volume reservoir
2. No gas present in the initial formation water
3. The average porosity value used properly accounts for reservoir heterogeneity
4. Reservoir pressure does not vary across the reservoir

Should a storage site operator utilize the volumetric method and notice unaccounted for deviations from the calculated to the measured capacity volume at an operational site, there could be non-effective gas in place. Non-effective gas is a volume that has no significant impact on the performance of the storage facility. This category of gas can result from injected gas migrating out of the working gas pore volume or immobile gas that was already present in the reservoir prior to injection. In addition to non-effective gas, non-recoverable gas may also be present within the system. Non-recoverable gas is the amount of gas left in a storage reservoir that previously had existing and economically-viable quantities of natural gas and had undergone a period of production. However, due to petrophysical limitations or possibly economic considerations, native natural gas is left in place (inventory to the left of the abandonment pressure point [P/Z_{ab} point] in Exhibit 4-1). The non-recoverable gas volume depends on the abandonment pressure, which varies from reservoir to reservoir. The volume of non-recoverable gas may also depend on the reservoir drive mechanism. For instance, in aquifer storage projects and some depleted natural gas reservoirs, water drive could be impacting the storage system. Water advancing through the reservoir toward producing wells may result in discontinuous gas saturation within higher water saturation zones. As this process continues, water will interfere with operations and can eventually lead to non-economic conditions resulting in field abandonment. [111] The non-effective and non-recoverable volumes are important to reservoir characterization and detailed analysis is required to accurately determine the storage levels. As potential storage reservoirs progress from the initial

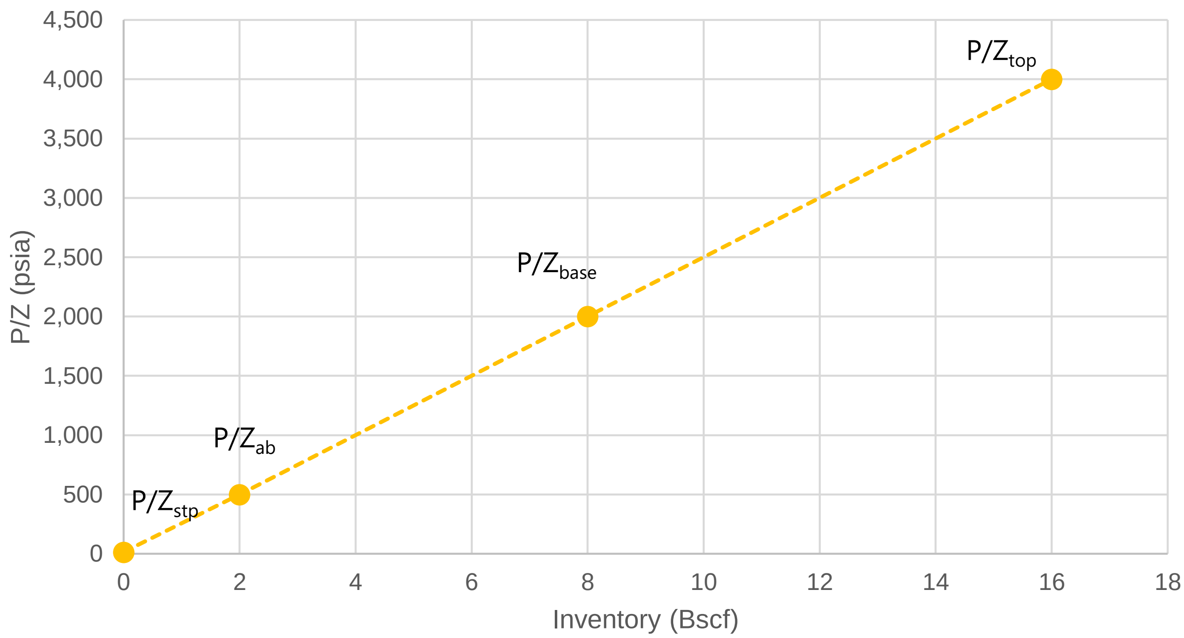
pressure point between P_{stp} and the P/Z_{ab} point in Exhibit 4-1 if more suitable site-specific pressure data is known. However, temperature (Tstp) may need modified to reflect any changes from altering the pressure term.

volume estimate through more detailed volumetric screening and into the characterization stage, an inventory analysis can be carried out to determine the volume of the various gas categories and can be used to understand withdrawal as pressures drop during gas production. Appendix C: Non-Recoverable Gas provides the equation for estimating non-recoverable gas.

4.1.2 Inventory Analysis

Inventory analyses are performed on existing storage reservoirs to determine current volumes of gas stored at a given time. They can also be performed on new reservoirs to characterize the potential storage capacity and working gas volume for individual prospects. The inventory analysis uses the material balance equation, which is based on the conservation of mass, and can be plotted to generate a linear sloped line based on pressure (P) divided by the gas deviation factor (Z) to arrive at P/Z, which is plotted on the y-axis, and cumulative gas produced G_p, on the x-axis. Storage operators have modified this analysis to determine the total inventory within a hypothetical storage reservoir as well as the volumes of different categories of gas in storage. Exhibit 4-1 depicts the P/Z versus inventory graph, which can be utilized to assess multiple points over the life of the storage reservoir. The uppermost P/Z_{top} represents the total amount of gas in storage at the maximum operating pressure, whereas the middle point P/Z_{base} represents the maximum amount of base gas capacity and pressure point. The inventory between P/Z_{top} and P/Z_{base} represents the reservoir's working gas range. P/Z_{ab} is the pressure and inventory point at base (cushion) gas, which is essentially non-recoverable. This trend-line could be assessed at potential P/Z data points to calculate the inventory volume of the field or reservoir. [111] The P/Z_{stp} point in Exhibit 4-1 is in reference to standard pressure needed to calculate the capacity equations in Equation 4-1 and Equation 4-2 in terms of standard cubic feet (scf) of gas.

Exhibit 4-1. Inventory analysis using a modified material balance approach on a hypothetical storage reservoir subject to no gas losses or gains



For the example in Exhibit 4-1, this hypothetical case assumes a storage system of constant pore volume (e.g., a "tank" with no water drive) and that does not exhibit any gas loss or gain, hence a x- and y-axis intercept at 0. Reservoirs that experience gas loss outside of the formation (i.e., leakage) would have a similar trendline to Exhibit 4-1, but shifted to the right with an x-intercept greater than 0. [111] When the storage reservoir experiences a gas gain (possibly through communication with a deeper high-pressure reservoir), the pressure-content line will have a parallel shift to the left. These shifts to the right or left on the x-axis represent non-effective gas.

In general, the inventory approach provides a measurement of a given reservoir's performance for gas that is left in the storage reservoir or that needs to be injected into it for the corresponding P/Z values to be achieved. For instance, when the storage reservoir behaves like a true volumetric tank and does not experience losses or gains, the P/Z vs. inventory plot that will intercept near zero on the x- and y-axes like Exhibit 4-1 (however, the slope of the line will vary for different storage reservoirs). When the storage reservoir is prone to gas loss, a higher volume of gas above the normal quantity is required in the storage since a portion of it migrates away from the storage horizon. Under this case, the P/Z vs. inventory plot that will intercept at zero on the y-axis and >0 on the x-axes. When a storage reservoir is subject to gas migration into the reservoir (or perhaps existing gas is already in place), a reduced amount of gas needs to be injected into or left in the reservoir for it to perform optimally and hence makes more gas available for use. Under this case, the P/Z vs. inventory plot that will intercept at >0 on the y-axis and at zero on the x-axes.

The inventory of a reservoir (x-axis parameter in Exhibit 4-1) at any point in time can also be viewed as the sum of the total remaining native gas and injected gas. The general formula for inventory is shown in Equation 4-4: [111]

$$Q = 43{,}560 Ah\varphi\left(\frac{PT_{stp}}{P_{stp}TZ}\right)(1 - S_w)$$

Equation 4-4

Where:

- Q = amount of gas in the storage reservoir (scf)
- A = reservoir area (acres)
- 43,560 = conversion factor to reservoir cubic feet per acre-foot (rcf/acre-ft)
- h = reservoir thickness (ft)
- φ = porosity (decimal)
- P = current reservoir pressure (psia)
- P_{stp} = standard pressure (14.5 psia)
- T = current reservoir temperature that cannot exceed T_{top} (^oR)
- T_{stp} = standard temperature (491.67 ^oR)
- S_w = average reservoir water saturation (decimal)
- Z = real gas deviation factor (decimal)

The general formula can be manipulated to calculate the various amounts of storage gas within a facility. The method used to determine the capacity of the reservoir or inventory of a currently operating storage facility depends on the maturity of the project and the accuracy of the data obtained. The volumetric equation is often used to screen a storage prospect. The depletion or inventory analysis method is often used to further define the reservoir and determine the various amounts of stored gas. Despite the differences in use, the data needed are similar, and each parameter can be captured to fulfill a screening or characterization purpose. The needed parameters are described in the following sections, many of which can be acquired through common characterization approaches.

4.1.3 Porosity Evaluation

Porosity is defined as the pore volume divided by the bulk volume and indicates the ability of rock to store fluids. The equation (Equation 4-5) for porosity is:

$$\phi = \left(\frac{V_p}{V_b}\right)$$

Equation 4-5

Where:

- V_p = pore volume (volume)
- V_b = bulk volume (volume)
- ϕ = porosity (decimal)

Initial screening for porosity can be done through analogs of nearby fields, similar rock types, and similar depositional environments. Publicly available information pertaining to well logs and formational porosity maps can be useful tools to infer formational porosity on a screening level. Porosity measurements acquired through coring and laboratory testing on cores can be too expensive and time consuming for initial screening. A single sample may suffice for initial screening if the potential heterogeneity of the formation is documented and considered during the screening period, and perhaps the core can be correlated with a broader existing well logging data set.

Additional time must be taken to accurately depict the formation's porosity when characterizing its geology. This can be done through well logging and core lab measurements. A distinction also must be made between the effective and total porosity within the system. The total porosity value represents all the pore space within a reservoir. The effective porosity value accounts for the interconnectivity of pores within the system. The effective porosity will be less than or equal to the total porosity depending on the type of reservoir and number of isolated pores within the system. A storage operator will need to quantify the effective porosity because it describes the effective pore space that will contain the natural gas that is injected, stored, and produced. [113]

4.1.4 Fluid Saturation

Fluid saturations within the reservoir are based on the type and amount of fluid in the system, which may include water, gas, or hydrocarbons. Any given fluid saturation volume is represented using Equation 4-6:

$$S_f = \frac{V_f}{V_p}$$

Equation 4-6

Where:

S_f = fluid saturation (decimal)

V_f = volume of fluid (volume)

V_p = pore volume (volume)

The saturation distribution of the fluids in place is based on the relationship presented in Equation 4-7:

$$1 = S_w + S_o + S_g$$

Equation 4-7

Where:

S_w = water saturation (decimal)

S_o = oil saturation (decimal)

S_g = gas saturation (decimal)

Initial screening efforts will utilize laboratory core measurements and well logs to determine a reservoir's saturation profile. Depending on the quality of the core sample and capturing technique, the results must be used appropriately. The results may be skewed if core samples deteriorate during extraction or the sample is not tested under reservoir-like conditions. Well logging may be used to better determine fluid saturations during more detailed site characterization. Information from multiple well logs, including resistivity and porosity logs, is needed to accurately characterize fluid saturations across a reservoir. Resistivity logs measure impedance or the extent to which a substance resists the flow of electrical current. It is the inverse of conductivity. In general, hydrocarbons are non-conductors while formation water (i.e., brine) is conductive. The log readings can be used along with Archie's equation (Equation 4-8) (for clean sand) to determine water saturation: [114]

$$S_w = \left(\frac{a * R_w}{\varphi^m * R_t}\right)^{1/n}$$

Equation 4-8

Where:

S_w	= water saturation (decimal)
R_w	= resistivity of the formation water (ohm-meter)
R_t	= true resistivity of the formation partially saturated with hydrocarbons and water (ohm-meter)
n	= water saturation exponent (1.8 to 4.0, but normally 2.0 is used)
a	= cementation constant (0.61 and 1.0 have been values utilized in literature) [114]
φ	= porosity (decimal)
m	= cementation exponent (1.7 to 3.0, but normally 2.0 is used)

The cementation factor (m) and water saturation exponent (n) may vary, but standard industry practice has been that they are equal. Several authors have composed publicly available lists of *m* and *n* for various rock types.

4.1.5 Formation Thickness

Formation thickness is directly proportional to the quantity of natural gas that can be store as well as the rate of injection or production. Formation thickness can be determined from several data sources. The most common, and accurate, is wireline logs. Mudlogging or logging while drilling and seismic data are also suitable sources of formation thickness.

Existing well logs can be analyzed to infer the formation thickness using the gamma ray or spontaneous potential log track. An initial screening can be performed from a single well log, but likely multiple logs will be needed to infer formation thickness across the area of interest. A reading from a single log alone may result in an overestimate of the total sand thickness across the area of interest; for instance, if the sand pinches out. Relying solely on a single log reading may also result in an underestimate of thickness if the sand thickens elsewhere. These reasons emphasize the need for a broader evaluation. The presence or absence of intermittent shale stringers within a sandstone reservoir, for example, can also make a difference in the net thickness of the reservoir. Knowledge of the formation's depositional environment will help the geologist responsible for reservoir characterization understand the stratigraphy and should increase the accuracy of the initial screening calculations.

Field-wide characterization of the formation thickness will ultimately require multiple well logs (either through drilling or purchase of log data) to map the spatial continuity of the reservoir, and possibly integrate with other non-invasive techniques like seismic surveys. In addition, the net formation thickness must be determined based on petrophysical cutoffs (e.g., porosity suitability, permeability suitability, formational connectivity).

4.1.6 Area

The areal extent of a reservoir is critical for calculating potential storage volumes, and ultimately capacity. The areal extent of depleted oil and gas reservoirs is typically defined through extensive data sets acquired throughout the reservoir's life of being a producing reservoir prior to use as an underground natural gas storage target. If the field is a new development, then new data must be acquired via seismic surveys, existing well logs, or through exploration drilling to understand the extent of the storage zone (typical for storage projects in saline-bearing formations). It may take several years of operations to fully understand the areal extent of a new reservoir.

Initial screening of the areal extent of the reservoir can utilize seismic surveys. Land seismic surveys utilize vibrating skids that are mounted on trucks or low-impact explosives that are placed in drilled holes. Receivers, which are typically geophones, are pushed into the soil and measure the ground motion. The images that seismic surveys create can illuminate potential subsurface drilling hazards, support the design of well trajectories, and help generate subsurface models that increase the understanding of the reservoir. [115] Seismic surveys are typically performed in two-dimension (2-D) or three-dimension (3-D) (often depending on the exploration or data acquisition budget, or surface access feasibility). 2-D seismic is a seismic survey that is gathered along a straight line for a pre-determined distance. The final product is a vertical cross-section of the subsurface that can be analyzed for spill point, structure, and faults. The areal extent can be determined if multiple 2-D runs are performed. 3-D seismic is a seismic survey in which sound detectors are placed over an area, and the sound source is moved from location to location through the area. 3-D seismic provides a much more detailed picture and more meaningful information, but at a significantly higher cost than 2-D surveys. [115]

After the initial screening, the reservoir can be further characterized through exploration or development drilling. Drilling will help delineate the areal extent of the reservoir, but it can be extremely expensive. Additionally, there are risks associated with investing in drilling a well that unintentionally falls completely outside of the target reservoir. Typically, storage operators do not consider exploration drilling as an option for determining reservoir areal extent due to its expense and risk (i.e., it would have to be conducted over the entire reservoir area to provide any efficacy). The data needed to determine areal extent can be acquired through extensive seismic surveying at a fraction of the cost (albeit still a substantial cost).

4.1.7 Pressure & Temperature

Reservoir pressure is a function of depth and can be influenced by an operational history associated with the formation in question (e.g., production or injection of fluids). Reservoir temperature also a function of depth, but also can be influenced by other factors (e.g., seepage of hotter fluids from deeper formations). The capacity and inventory equations discussed above utilize average reservoir pressure and temperature measurements. Pressure and temperature are used to convert the natural gas from a surface volume to subsurface volume. It is possible to estimate subsurface pressure and temperature using known regional gradients or prominent the fluid system in the absence of known formational pressures and temperatures. Exhibit 4-2 provides some examples of pressure gradients used for various fluid systems; however, gradients are likely to vary from site to site and basin to basin. Other widely used best practices for estimating reservoir pressures and temperatures based on depth which are agnostic to fluid systems is an average 0.443 psi/foot for pressure and 15 degrees Fahrenheit (°F)/1,000 ft (25 to 30 degrees Celsius [°C]/kilometer) for temperature. [116]

Exhibit 4-2. Pressure gradients for various fluid systems [117]

Fluid System	Pressure Gradient (psi/ft)
Gas	0.10 or less
Oil	0.25 – 0.35
Water	0.4 – 0.55

Exhibit 4-2 provides some examples of fluid gradients within a reservoir where there are distinct gas, oil, and water contacts and separate fluid zones. In the case of a depleted gas reservoir being analyzed as a potential gas storage reservoir, there would likely be subsurface temperature measurements from well logs and bottom-hole pressure measurements (or estimates from surface pressures) from multiple wells. Therefore, there should be no need to use gradient estimates at specific sites; however, these types of gradients could be useful in initial screening or understanding the extent of aquifer invasion after depletion of a gas reservoir. Additionally, for an aquifer storage prospect without any logs, regional pressure and temperature gradients would be used for initial screening as well.

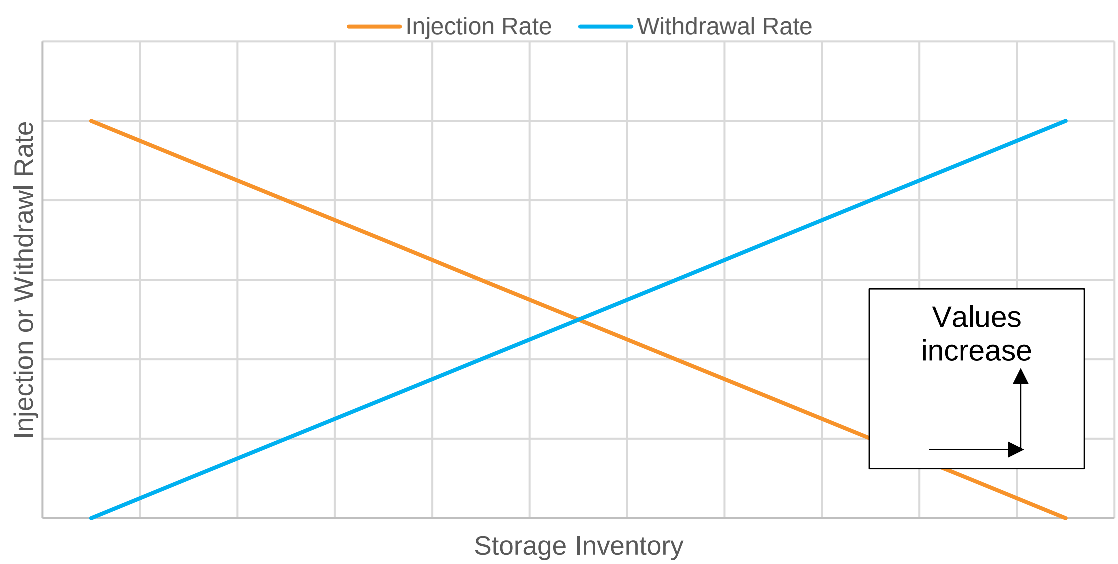
4.2 Developing and Maintaining Deliverability

The expected deliverability of a storage reservoir is another critical component that needs to be evaluated and determined before a storage operator commences development on a facility. The deliverability is the volume of gas that can be withdrawn over a specified period and is used to determine if a prospective storage facility can meet expected market demand at peak demand times. The gas injection rate is also important as injection of gas during periods of low demand enables the field to replenish its capacity. Injection rate is quantified as the volume of natural gas injected over a specified period. In the United States, injectivity and deliverability are typically expressed in millions of standard cubic feet per day (MMscf/d) or thousands of standard cubic feet per day (Mscf/d). These two parameters are a function of the reservoir parameters discussed earlier. They are associated with the reservoir's thickness, permeability, fluid properties, well pressure drawdown/buildup, and other reservoir and wellbore parameters. Developing and maintaining deliverability and injectivity requires knowledge of the reservoir, execution of individual well and field-wide production and injection testing, routine well remediation work, and well-designed field development and operation strategies. The process of converting a depleted field to storage or creating a new storage field requires precise planning, well-executed engineering design, and proper maintenance. The screening and characterization of a field's potential injection and withdrawal rates require an understanding of the storage field's technical design and all associated input parameters.

4.2.1 Injection Rate

Injection rate is the rate at which natural gas is injected into the storage reservoir to replenish capacity. This rate is selected such that it does not exceed formation fracture pressures. As mentioned in the section above, it is commonly reported in MMscf/d or Mscf/d, and it varies depending on the location and size of the facility and the seasonal storage drawdown and replenishment schedule. The injection rate diminishes over the injection period such that it is inversely proportional to the total amount of gas in storage. Therefore, the injection rate is highest when the storage reservoir is at the end of the withdrawal season when reservoir pressure is low and decreases over the injection season as seen in Exhibit 4-3. [31]

Exhibit 4-3. Injection and withdrawal rate versus storage inventory



Determining the maximum or optimum injection rate along with the injection schedule is important to the storage system and success of the facility. Over injecting, or exceeding injection pressure limits, can generate pressure fluctuations that would result in caprock integrity issues. Maximum injection rates are difficult to assess because they vary based on the type of storage reservoir, reservoir boundary condition, and geological properties. A preliminary screening of the reservoir properties can help to determine a likely range of values for individual well injection rates. The screening criteria of most importance are formation permeability, formation pressure, formation net thickness, and degree of formation damage surrounding the wellbore (i.e., wellbore skin effects). In fact, horizontal permeability has perhaps the most significant effect on determining injection rate. [118]

The injectivity of a well must always consider the fracture gradient of the reservoir. That is the bottom-hole injection pressure, expressed in pounds per square inch per foot of depth (psi/ft) that will result in fracturing of the formation. The parameter that is often unknown while injecting is the bottom-hole flowing pressure, which should be kept below the fracture propagation pressure. The injectivity index equation specific to the reservoir type, single phase or multiphase injection, can be employed to determine the expected bottom-hole pressure during injection. Equation 4-9 is the general formula for injectivity index for radial steady-state and semi-steady state single phase flow. [119]

$$II = \frac{Q}{P_{bh} - P_e} = \frac{kh}{141.2 * \mu_w * B_w * \left(\ln\frac{r_e}{r_w} + S\right)}$$ *Equation 4-9*

Where:

II	= injectivity index for radial, one-dimension flow (Mscf/day/psi or millidarcy [mD]/centipoise [cP]/ft)
Q	= well injection rate (Mscf/d)
P_{bh}	= injection pressure for bottom hole flowing conditions (psia)
P_e	= far-field reservoir pressure (psia)
k	= permeability (mD)
h	= injection interval height (ft)
μ_w	= fluid viscosity (cP)
B_w	= gas formation volume factor (reservoir volume/standard conditions volume) (dimensionless)
r_w	= wellbore radii (ft)
r_e	= drainage radii (ft)
S	= total near-wellbore skin (dimensionless)

Equation 4-9 can be re-arranged to calculate bottom-hole pressure (Equation 4-10) under steady-state flow conditions. Over time, the average reservoir pressure will increase as natural gas storage levels increase, which will increase the bottom hole injection pressure. This can be analyzed over time with a given set of parameters such as constant flow rate, changing flow rates, and changing average reservoir pressures associated with an increase or decrease in storage levels. [120]

$$P_{bh} = P_e + \frac{Q\mu_w}{2\pi kh}\left(\ln\left(\frac{r_e}{r_w}\right) + S\right)$$ *Equation 4-10*

However, it is critical that assumed inputs to equations are not the only basis for estimating injection rate. Injectivity tests can be used to determine the rate and pressure at which fluid can be pumped into a formation without fracturing. Data acquired can inform site operators on the types and number of wells required to ensure the needed injection rate. The size and number of compressors are additional factors that must be determined based on the quantities of natural gas that must be cycled through the storage reservoir and the expected maximum injection pressure. If excessive compression is required to achieve the desired rate, the storage project might not be economical. The same goes if the formation cannot accept natural gas at a sufficient enough rate and at a pressure that will not damage the caprock or reservoir.

4.2.2 Deliverability

The deliverability of, or production from, a gas storage well is subject to the same reservoir parameters applicable to the injection rate. The oil and gas industry has studied gas well performance for decades in the natural gas storage and production industries. The deliverability of a well can be broken up into two distinct curves: inflow performance and outflow performance. Deliverability of a natural gas storage reservoir has contractual obligations for the storage operator.

4.2.2.1 Inflow Performance Relationship

The inflow performance relationship (IPR) describes the well production rate as a function of bottom-hole flowing pressure. At any given time in the well's life, an IPR can be generated that depicts the amount of gas that will flow into the wellbore in Mscf of gas per day for a given bottom-hole flowing pressure in psi. The IPR changes over the life of a well as the reservoir pressure, fluid composition, and other reservoir properties change. [116] Gas well performance curves require additional analysis and often well tests are necessary to derive the final inputs to the relationship for a given well.

In 1935, Rawlins and Scheullhardt presented an empirical equation to describe the inflow of a natural gas well. [121] Their equation (Equation 4-11) is often referred to as the back-pressure equation:

$$\mathrm{q} = \mathrm{C}\left(\mathrm{P}_{\mathrm{r}}^{2} - \mathrm{P}_{\mathrm{wf}}^{2}\right)^{\mathrm{n}} \qquad \textit{Equation 4-11}$$

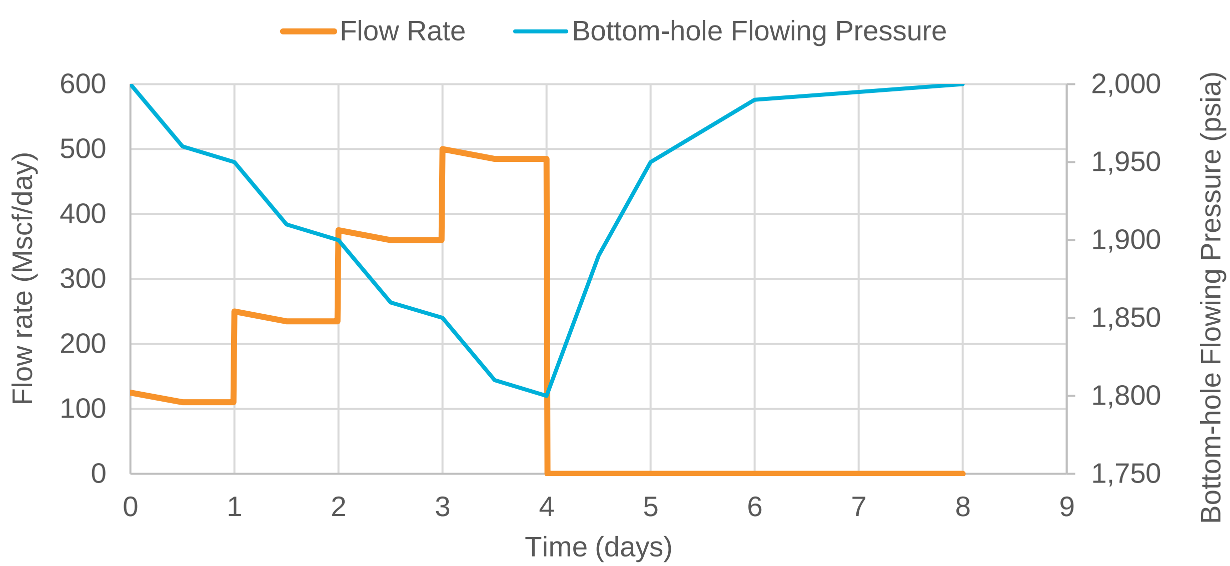
Where:

q	= gas flow rate (Mscf/d)
C	= reservoir flow coefficient (dimensionless)
P_r	= shut-in reservoir pressure (psia)
P_{wf}	= flowing bottom-hole pressure (psia)
n	= a numerical constant that typically varies between 0.5 (under high turbulence) and 1.0 (no turbulence) [122]

When the equation is plotted in a log-log regression it generates a straight line from which the *C* and *n* constants can be extrapolated. [121] The data necessary for generating the graph must be obtained through well tests at various flowing bottom-hole pressures. An initial screening based on this form of the equation would be difficult as there are no charts or graphs that outline the change in constants C and n for various reservoir types. The constants must be determined empirically through well testing, which is generally carried out at the reservoir characterization stage. Initial screening of the deliverability rate can be done on depleted oil or gas reservoirs as the operator will previously have generated IPRs for their wells. For fields that have not been developed, the inflow of a reservoir is highly dependent on pressure drawdown, or the difference between reservoir and flowing bottom-hole pressure, and permeability. The fluid composition of the injected natural gas will remain relatively constant across all storage reservoirs. An initial screening can be performed on the input parameters, but a calculated value requires characterization of the producing environment.

Characterizing the flow rate of a well using Equation 4-11 requires a four-point or flow-after-flow test. The well must be produced at a series of stabilized flow rates and the corresponding bottom-hole flowing pressures at the sand face must be measured. A theoretical flow-after-flow test is depicted in Exhibit 4-4. A major drawback occurs in low-permeability formations, which take extended periods of time to reach stabilized flow rates. [123]

Exhibit 4-4. Hypothetical flow-after-flow test example



The back-pressure method presented by Rawlins and Schellhardt is not overly rigorous, but it is reported to still be widely used in deliverability analysis and provides adequate results for high-permeability gas wells. [124] However, a more robust and updated equation (Equation 4-12) to estimate flow rates (specific to low pressure reservoirs P < 2,000 psia [125]) has been developed [121]:

$$q = \frac{0.703kh\left(P_r^2 - P_{wf}^2\right)}{T\mu_{avg}Z_{avg}\left(\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + S\right)}$$

Equation 4-12

Where:

q = gas flow rate (Mscf/d)

k = permeability (mD)
h = reservoir thickness (ft)
P_r = shut-in reservoir pressure (psia)
P_{wf} = flowing bottom-hole pressure (psia)
T = current reservoir temperature (°R)
μ_{avg} = gas viscosity at average pressure P_{avg} (cP)
Z_{avg} = gas deviation factor at average pressure P_{avg} (dimensionless)
P_{avg} = $(p_r - p_{wf})/2$ (psia)
r_e = radius of external boundary (ft)
r_w = radius of the wellbore (ft)
S = skin factor (dimensionless)

Equation 4-13 demonstrates how key geologic characteristics, like permeability, temperature, and reservoir thickness, impact deliverability. The original back-pressure equation (Equation 4-11) relies on a reservoir flow coefficient (i.e., C term) to account for similar geologic parameters, therefore their individual contribution to deliverability is not apparent from the equation alone. However, Equation 4-10 can be simplified into a similar format as the back-pressure equation (Equation 4-13) [121]:

$$q = \frac{C\left(P_r^2 - P_{wf}^2\right)}{\mu_{avg} Z_{avg}}$$

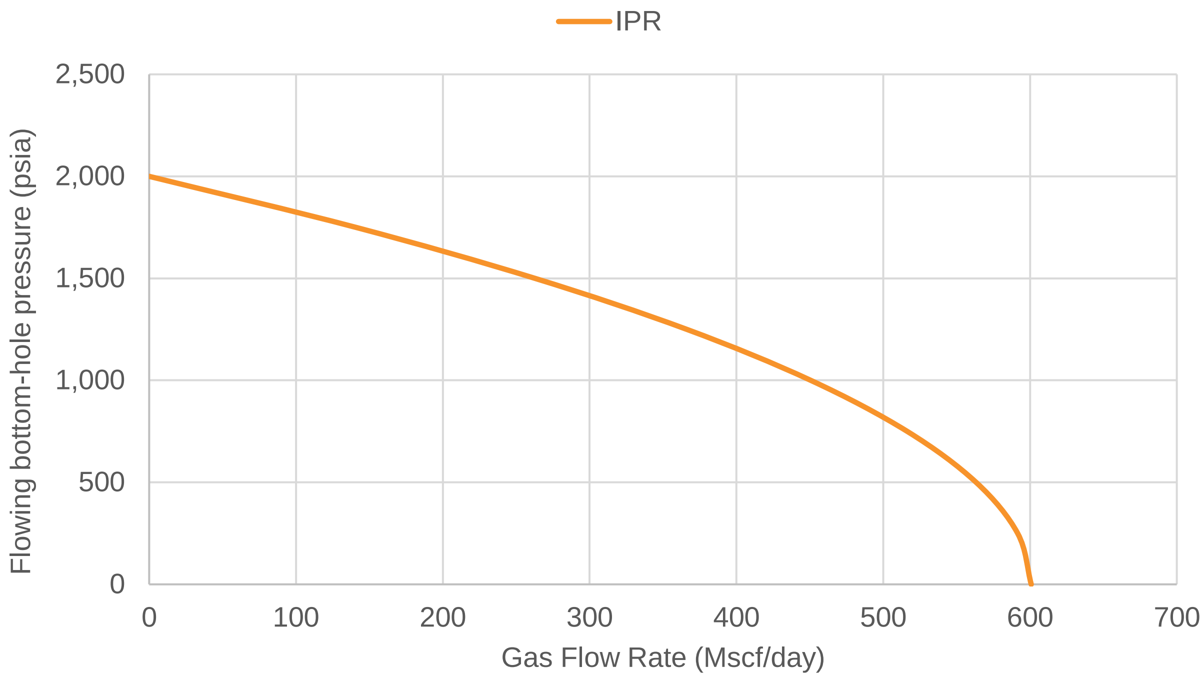
Equation 4-13

Where:

q = gas flow rate (Mscf/d)
C = reservoir flow coefficient (dimensionless)
P_r = shut-in reservoir pressure (psia)
P_{wf} = flowing bottom-hole pressure (psia)
P_{avg} = $(p_r - p_{wf})/2$ (psia)
μ_{avg} = gas viscosity at average pressure P_{avg} (cP)
Z_{avg} = gas deviation factor at average pressure P_{avg} (dimensionless)

Equation 4-12 helps to illustrate the effect of each parameter on the flowrate rather than them being lumped into a single constant. For instance, one would look for a reservoir that has high permeability, significant thickness, and low skin factor because that would result in a high deliverability rate. After the initial screening of a reservoir has been completed, additional well tests can be conducted to refine the inflow relationship. Equation 4-13 requires a single-flowing well test to determine C. The only restriction to this method is that the shut-in reservoir pressure must be known. Equation 4-13 can be used to calculate an IPR curve, which graphs the flowing bottom-hole pressure versus the flow rate as seen in Exhibit 4-5.

Exhibit 4-5. Theoretical gas inflow performance relationship



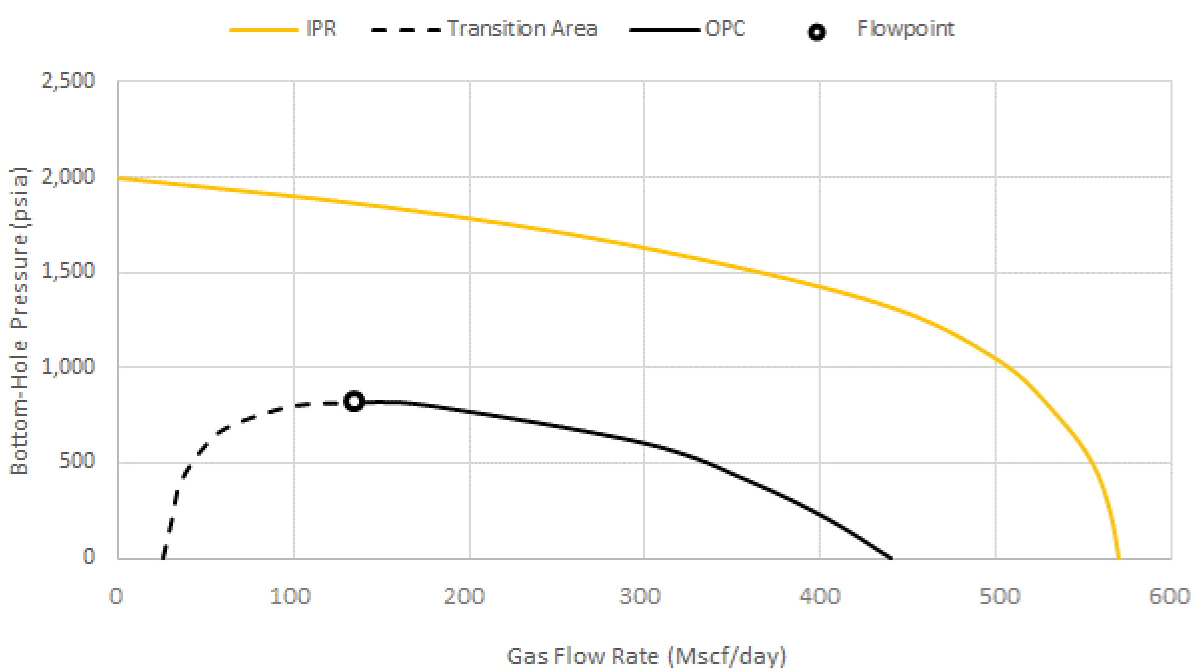
A gas well's performance cannot be determined simply by selecting the desired flow rate or bottom-hole flowing pressure, shown in on Exhibit 4-5. Rather, an additional curve is needed to calculate the optimum surface rate for the well with a given set of parameters and operating conditions. This secondary curve is known as the outflow performance relationship (discussed in the next section).

4.2.2.2 Outflow Performance Relationship

The outflow performance curve (OPC) represents the well's flowing behavior from the sand face (the reservoir exposed to the well at the wellbore) to the surface rather than from the reservoir to the sand face. Two methods are commonly used to calculate the outflow performance: flowing bottom-hole pressure equations or vertical gradient curves. If the gas well produces significant amounts of water or hydrocarbon liquids, then the outflow performance relationship will be like the theoretical curve through this region as the well is being opened to flow and as it is closed to cease flow. In Exhibit 4-6, the solid black line represents the operating range for a theoretical well and its theoretical set of parameters. Additionally, the circle in Exhibit 4-6 represents the apex of the curve and is referred to as the "flow point." The flow point marks the minimum sustainable flow rate possible for this well; it is at the maximum flowing tubing pressure. Dry gas wells do not produce liquids and there is no transition area (dashed line); the entire outflow performance curve is the operating range. The outflow relationship is dependent on tubing size and the deliverability can be optimized by plotting multiple performance curves for various tubing sizes. A reservoir's deliverability can be initially assessed based on its depth and either available (in existing wells) or recommended tubing and casing sizes. The tubing diameter and depth will affect the amount of gas that can flow to the surface. Lifting liquids requires higher bottom-hole pressures and can reduce the rate of production at the wellhead. The operating conditions of a reservoir can be determined based on simple assumptions such as depth, pressure gradient, produced fluid composition, and operating pressures. These parameters can be used to assess the expected wellhead production rates and equipment necessary to develop of prospective natural gas storage reservoir.

The dashed line in Exhibit 4-6 represents the unstable transition area of flow. Every well will pass through this region as the well is opened to start flow and closed to cease flow. The solid black line represents the operating range for this well per its given set of parameters. Finally, the circle represents the apex of the curve and is referred to as the "flow point." [121] The flow point marks the minimum sustainable flow rate possible for this well; it is at the maximum flowing tubing pressure. Dry gas wells do not produce liquids and there is no transition area (dashed line); the entire outflow performance curve is the operating range. The outflow relationship is dependent on tubing size and the deliverability can be optimized by plotting multiple performance curves for various tubing sizes. A reservoir's deliverability can be initially assessed based on its depth and either available (in existing wells) or recommended tubing and casing sizes. The tubing diameter and depth will affect the amount of gas that can flow to the surface. Lifting liquids requires higher bottom-hole pressures and can reduce the rate of production at the wellhead. The operating conditions of a reservoir can be determined based on simple assumptions such as depth, pressure gradient, produced fluid composition and operating pressures. These parameters can be used to assess the expected wellhead production rates and equipment necessary to develop prospective natural gas storage reservoir.

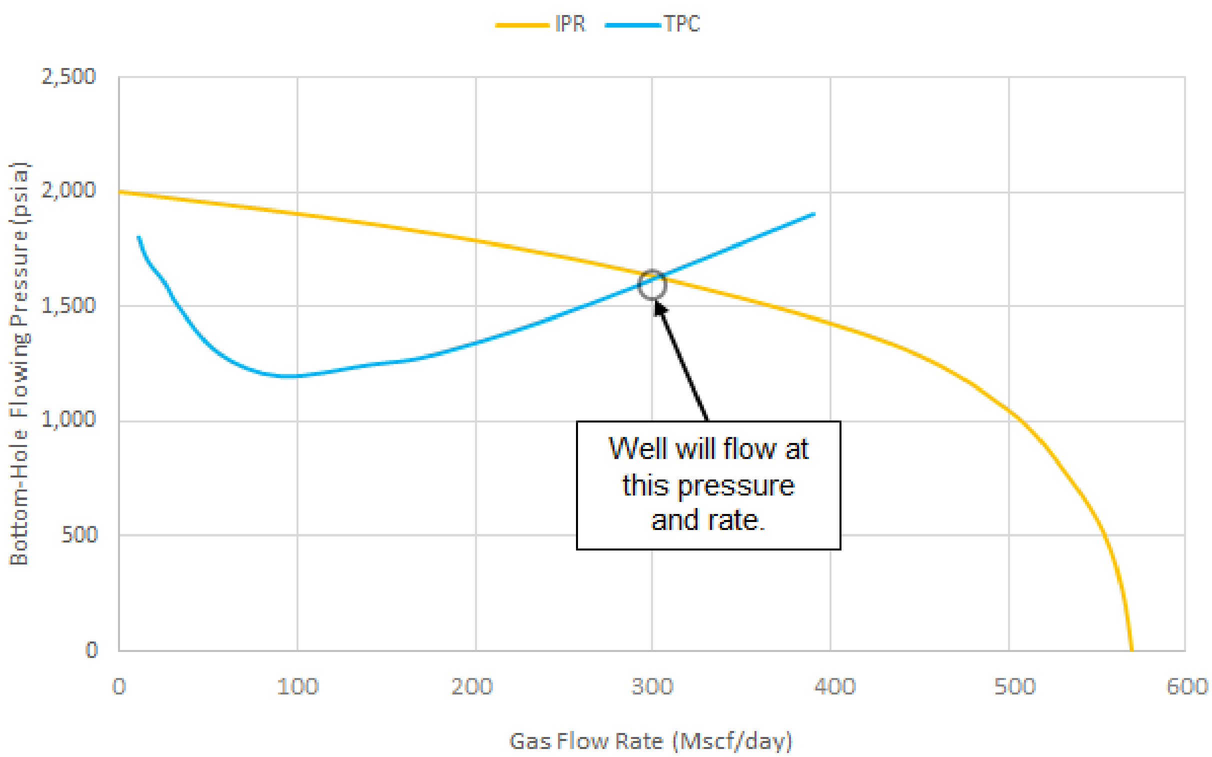
Exhibit 4-6. Theoretical outflow performance curve



Reservoir characterization efforts would be needed to gain a full understanding of the composition of the reservoir fluid and the change in its composition over the life of the reservoir to properly inform overall well design. The composition of the produced fluid will remain constant in, for example, a salt cavern storage reservoir (which is fully enclosed and a relatively closed system) compared to an aquifer, which must deal with in-situ water that may encroach into the gas storage zone and be produced. Additional efforts will be necessary to determine the various design specifications of the components of the tubing string such as the joint connections, tubing API grade, overall length, diameter and any recommended internal coatings. These specifications will be based on several design considerations such as expected loads, pressures, fluid composition (e.g., brine corrosivity or the presence of hydrogen sulfide from reservoir souring), and more.

The final type of outflow performance relationship is the tubing performance curve (TPC). The TPC is a set of flowing bottom-hole pressures with corresponding gas flow rates for a specific sized tubing string at a constant wellhead pressure. [121] The TPC intersects the inflow performance curve at a point referred to as the well's deliverability, which is the rate and pressure at which the well will flow, shown in Exhibit 4-7.

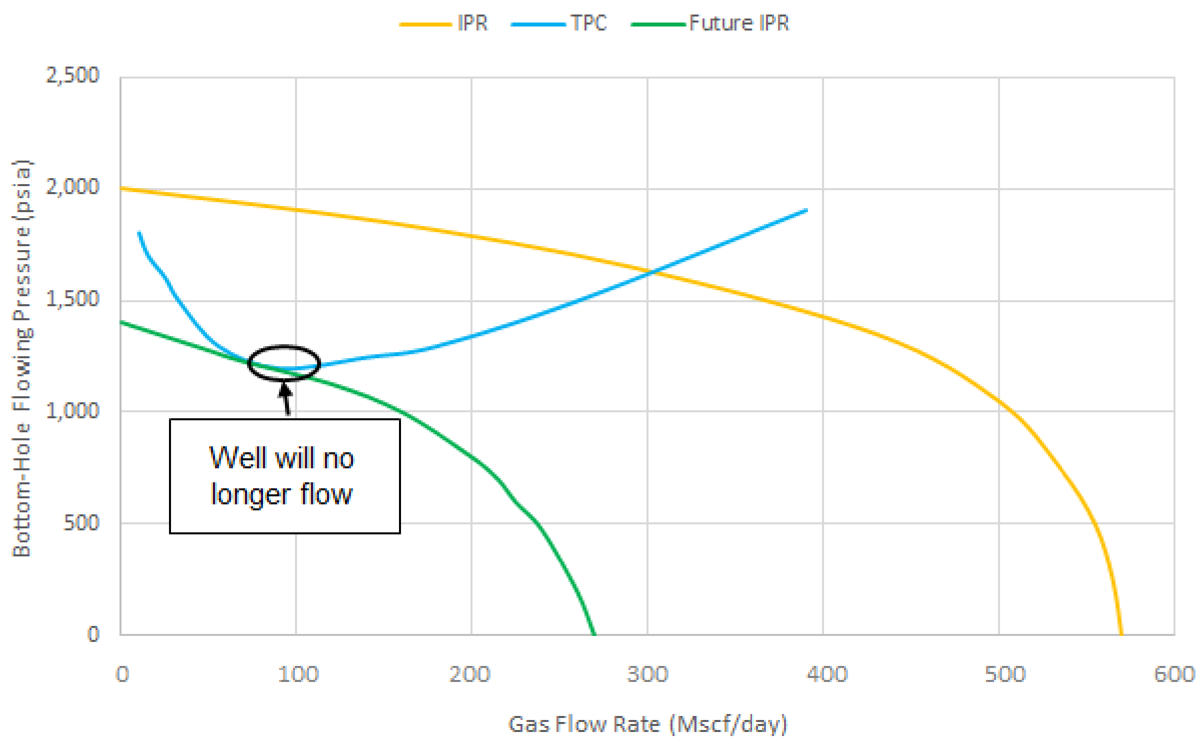
Exhibit 4-7. Theoretical well deliverability



Tubing performance curves are useful in determining the abandonment point or pressure where production can no longer be maintained. In Exhibit 4-8 the point of abandonment is referenced by the tangential intersection of the tubing performance curve and the future IPR. As previously discussed, the IPR will change over time due to diminishing reservoir pressure, but the TPC will remain constant since it is a function of tubing size and surface wellhead pressure. The analysis can be ongoing throughout the life of a well to understand the change in

IPR and the resulting flowrate changes until abandonment or injection of new storage gas takes place.

Exhibit 4-8. Theoretical tubing performance curve at abandonment



The calculation of inflow and outflow is important to the planning and design of the field. The number of wells required to effectively drain and re-inject natural gas into the storage reservoir depends on each well's deliverability and injectivity. The number of natural gas wells needed to develop a field has not been well documented, but logic can be used to assess the challenge. Section 4.2.3.1 provides a basis from which operators may determine the injection and production well volume needed for a given underground natural gas storage field.

4.2.3 Field Development

Storage operators are challenged with determining the number of wells required to meet the economic deliverability requirements while also recharging the capacity during the injection period. The injection and production at a storage reservoir are determined by the design and the demand criteria (rates and pressures) of the site. The design of the site considers the type of storage reservoir, existing infrastructure (if any), and expected operation and maintenance activities. [126] The demand requirement is quantified in a written contract binding the storage operator to a set of storage volumes and deliverability targets. The overall development of the storage reservoir and the number of wells will be weighted by these criteria.

4.2.3.1 Design

The design of the storage site dictates the injection and deliverability rate of the reservoir. Characteristics of a storage site that affect the design include, but are not limited to, the reservoir type, existing infrastructure, and potential issues that can result in reduced injection and deliverability rates. The distinct types of storage reservoirs have their own advantages and disadvantages. Existing infrastructure can either ease or complicate the design phase depending on condition, suitability, and location. Finally, issues can arise from injected fluid interactions or pre-existing formation damage that can result in injection and withdrawal limitations.

The type of storage reservoir plays a significant role in determining the number of wells necessary to develop a storage field. Salt caverns have a unique development style in which a single well is used to create a single salt cavern. This eliminates the determination of the number of wells but adds the problem of determining the number of salt caverns needed to achieve the necessary storage volumes and withdrawal rates. Additionally, development of salt cavern storage sites generates a large quantity of brine, which requires additional management (like deep well disposal, dehydration, or treatment). Aquifers pose the problem of having no prior infrastructure and often little to no existing subsurface data available. Determining the number of wells needed will require extensive data acquisition and upfront cost. Additionally, aquifers require high injection rates (and potentially pressures) to displace in situ water, which drives up well costs and may reduce the number of wells that can be economically drilled. Finally, aquifers will require interference testing to understand the necessary spacing between injectors. Interference testing observes the pressure disturbance at adjacent wells to understand inter-well communication. [116] Wells that are spaced closely will interfere during both the injection and production phases. During the injection phase, interference will likely drive up injection pressures or may even result in well integrity issues. Appropriate well spacing will affect the number of potential well locations, which may reduce or increase the number of wells.

Existing infrastructure is analyzed to determine the viability of reconditioning and repurposing for storage. Depleted oil and gas fields can benefit from the significant cost savings of utilizing existing infrastructure and may require few or no new wells to develop the reservoir. Depleted oil and gas fields are mature, developed fields that have undergone extensive field development. The major cost associated with developing a depleted field is to re-condition and re-purpose the wells to ensure they are compliant with safety guidelines and will produce at the desired rates. Poorly cased wells will need to be plugged and abandoned, which is a cost not associated with aquifers or salt caverns. In older depleted fields, improperly abandoned oil and gas wells, and sometimes even water wells, may need to be located and properly plugged before re-pressurization can occur. Salt caverns and aquifers are generally developed in new or untouched areas, so they do not have the benefits (or costs) of utilizing existing infrastructure.

The final design criteria that influences the number of wells required in a storage facility is the reduction in injection and deliverability due to reservoir issues. Whether existing infrastructure or new facilities are being utilized problems may exist with the reservoir. A frequent problem is compressor lubricant carryover, which can occur in older compressors and causes plugging of the near-wellbore region. [126] This can result in severely reduced productivity and the near well-bore region must be cleaned out to restore deliverability. Formation damage effects can also lead to drastically reduced injection rates. Formation damage can occur in highly pressure depleted wells or high permeability zones that have been substantially infiltrated by mud. [126] This may require well workover to enhance production or new wells be drilled to compensate for the reduction in productivity of the reservoir. Wellbore or formation damage that cannot be resolved may require an additional or replacement well to be drilled to ensure that the necessary volumes of natural gas are delivered to market. The demand of a region dictates the volumes of natural gas that the storage facility must deliver to market.

The equations provided in the previous sections provide basis from which operators may estimate the injection and production well volume needed for a given underground natural gas storage field/site. Specifically, Equation 4-10 (when solving for Q) can be used to estimate an injection rate, and Equation 4-12 and/or Equation 4-13 can be used to estimate production rates for a given well based on field-specific geologic characteristics. Depending on the injectivity and deliverability requirements of the field/site, the number of wells needed can then be estimated based on scaling-up injectivity and productivity volumes at the well-level to the site/field level.

4.2.3.2 Demand

The demand is the volume of gas to be produced from the storage facility over a given time during the producing season. The number of wells in a storage facility will be influenced by the volume of gas needed to fulfill the demand (i.e., deliverability). The storage operator may be contracted to provide a specific working gas volume and a maximum withdrawal and injection capacity. The contract may also designate an approximate withdrawal and injection curve set forth to ensure that gas is consistently provided over time rather than in intermittent large volumes. [127] These contract requirements and individual well performance results can guide the storage operator towards an approximate number of wells. The number of wells needed to meet peak demand can be calculated by dividing the contract daily volume requirements by the withdrawal capacity for an individual well. Alternatively, the contractual demand may be less than the field's total capacity or deliverability, requiring only a partially developed reservoir. The number of wells will need to be carefully planned so the returns will not be diminished by drilling an unnecessary number of wells.

4.3 PREVENTION OF MIGRATION

The final consideration before developing a storage reservoir is the integrity of the caprock and other wellbores. The caprock should prevent the hydrocarbons from escaping and flowing upward into shallower formations. The integrity of the caprock can be compromised if its threshold pressure is exceeded, or if transmissive faults and/or fractures are present. Existing wellbores within the storage project vicinity also pose potential leakage risks and must be evaluated to ensure integrity or be reworked if insufficient integrity is discovered. Each pathway for migration must be thoroughly reviewed to ensure there are no risks for gas (or other subsurface fluid like brine) from migrating out of the injection reservoir. Natural gas is a highly mobile fluid that can easily move through minor fractures or leakage pathways. Leaking natural gas can diminish storage volumes and result in a loss of revenue as well as creating environmental hazards and legal liabilities.

4.3.1 Caprock Integrity

The integrity of the caprock must be thoroughly studied to determine if there are possible leakage pathways. These pathways can exist due to threshold pressures, faults and/or fractures, and existing wells. Each of these three criteria must be screened assess a potential storage reservoir, and advanced characterization methods have been developed to avoid developing a hazardous reservoir. The following information describes the screening and characterization of the various caprock integrity issues that may be hazardous to a storage operator's operations.

4.3.1.1 Threshold Pressure

The threshold displacement pressure (or simply "threshold pressure") (different from fracture pressure) is the minimum pressure needed to initiate the leakage of the gas through the caprock. A caprock, typically a low permeability shale, can be substantially saturated with water, which is known as the wetting phase. The non-wetting phase, or natural gas, will displace the wetting phase of the caprock once the threshold displacement pressure has been met or exceeded. At this point the non-wetting phase begins to displace the wetting phase as it migrates through the caprock eventually breaking through to the overlying formations. The threshold pressure is important to the storage operator because the operator cannot exceed this limit without hindering the integrity and safety of the storage facility. The initial pressure of a reservoir before it is depleted is known as the discovery pressure. Storage operators can increase the storage reservoir pressure above the discovery pressure to increase the volume of gas that can be stored. The storage operators must determine the amount of "overpressure" a caprock can withstand before gas would leak out of the reservoir. The threshold pressure helps the storage operator determine the maximum level of overpressure that can be applied to the caprock before its integrity is compromised.

Threshold pressures are not consistent from one formation to the next and require extensive testing to determine their value. Up front investigation can be done to determine if the caprock has already exceeded its threshold pressure and allowed fluids to escape into overlying formations. If hydrocarbons were found above the potential caprock and it can be proved that the hydrocarbons originated from underlying strata, then it can be inferred that the caprock has poor sealing qualities, one of which may be a low threshold pressure. Additionally, if there are no hydrocarbons above the potential caprock it can be inferred that the caprock's threshold pressure was not exceeded and it may be a candidate for storage. Depleted oil and gas fields must be analyzed to determine if they can be pressured above their discovery pressures when converted to a gas storage reservoir. Thomas and Katz wrote a technical paper on threshold pressures for gas storage caprocks. They discussed a series of equations that can be used to predict threshold pressures for low-permeability samples of rock if their permeability, porosity and formation resistivity are known. [128] This method can be used if well logs are available as each of the three parameters are easily determined from a standard logging suite.

Experimental procedures performed in a lab setting can be used to further characterize the threshold pressure. Thomas and Katz studied the effects of threshold displacement pressure by performing a series of laboratory tests. They created an experimental program utilizing an apparatus and multiple core samples to study the effects of meeting and exceeding the threshold displacement pressure. They found that the flow of gas just after the threshold pressure was exceeded was uniform. Additional tests included subjecting the sample to various delta pressures and determining their sealing quality after threshold pressure was exceeded. They discovered that the caprock can potentially reseal itself after the threshold pressure has been reached if the delta pressure is reduced to zero and water can flow back into the caprock. [128] Advanced methods include analyzing the impact of different injected fluids and their effects on the threshold pressure. A group from the Japan Petroleum Exploration Company documented their work on advanced threshold pressure analysis that can further characterize the caprock's integrity if different fluids are injected or used to analyze the samples. [129]

4.3.1.2 Faults and/or Fractures

The caprock integrity is also at risk when faults and/or fractures are present within the system. Faults and fractures can act as conduits for natural gas to escape into overlying formations. They can form from many geologic events including plate motions, folding, gravitational sliding, volcanic intrusion, crustal unloading, and fluid injection or extraction. [130] Faults and fractures can both result from the same events, but each is a specific geologic characteristic within the subsurface. A fault is a break in the rock across which there is an observable displacement. A fracture is a crack or breakage within the rock in which there has been no movement. Included within the fracture family is a joint, which is when the walls of a fracture move perpendicular to each other. [116] There are many visualization methods that can aid the geologist in visualizing and picking out faults and fractures in the subsurface.

The first method that can be used to screen the caprock for any fractures or faults is to observe surface outcrop exposures of fractures and faults. Fractures that can be visually observed at the surface are preserved in the subsurface and can be mapped to determine if they will compromise the caprock's integrity. Faults are not typically exposed at the surface. Faults can be observed through seismic surveying and mapping. Seismic data can be used to tie surface data to the subsurface. Additional methods to determine faults and fractures include well log analysis and core analysis. Both methods can be performed with relative ease using pre-existing logs and core samples. Log analysis can be used to determine if there are any faults through the area of interest. Wells logs from adjoining wells may illustrate and offset on depth to the same horizon due to faulting. This requires multiple logs, which may not be available for new storage reservoir projects. Cores can also provide features about the fault zones and fractures of the rock, if they are available. A core goniometry can be performed on the sample, which traces the structures and planes on the core. This provides the operator with a 360-degree representation of the area represented by the core. [131] This method can be used on multiple cores to gain an understanding of potential fractures or faults within the system and can be performed quickly to screen any unwanted reservoirs.

Advanced methods are utilized to determine precise location, throw, width, and other characteristics of faults and fractures. These methods can be broken down into single well or multi-well observations. Methods of detecting fractures include borehole measurements, which require a single or multiple wellbore to conduct testing. Borehole image logs are used to depict and evaluate any fractures that can be detected in the wellbore. Image logs are useful for fracture identification, but it can be difficult to analyze faults with small displacement yet cut across multiple formations. A useful tool to assess both fractures and faults present near a well is the vertical seismic profile (VSP). The VSP is performed in a borehole with the seismic source location either at the surface or located in an offset borehole (i.e., cross-well VSP approach). This seismic data can be correlated to well logs, further increasing the ability to trace a fault or fracture over some distance. Simon Emsley's paper on VSP utility illustrates the uses and accuracy of the VSP data to accurately depict subsurface faults and fractures. [132] Seismic will likely be the best option to characterize the storage reservoir. The difference between screening and characterizing will be in the number of survey runs made and the type of seismic surveys conducted. Characterization of the reservoir can justify acquisition of new 3-D seismic data to get every possible view point of the subsurface structure to identify possible faults and fractures. The International Association of Geophysical Contractors provides many publications on seismic survey operations, data acquisition and application of seismic survey techniques. [133]

4.3.1.3 Leakage Through Existing Wells

The final subsurface consideration for caprock integrity is potential leakage through existing wells. Section 2.2.1 briefly discusses the challenge associated with developing a reservoir with existing wells penetrating the storage prospect, the locations of which are not always known. The total number of orphaned wells in the United States is not known, but it may be staggeringly high. Ohio and Pennsylvania are two states that have created "orphaned well programs" due to high estimates of wells that are unaccounted. Pennsylvania has estimated hundreds of thousands of wells drilled since 1859 that either have no known operator or have been left to deteriorate without proper plugging. [134] These wells pose a serious risk to storage operations and a storage prospect may not be economic once the investment required to locate and properly plug and abandon all existing wells within the prospective area has been determined.

Initial well screening during the site screening phase will require a thorough background check of the proposed storage site area and vicinity. EPA constructed a document that outlines the process for finding abandoned wells within a field whether they are plugged or unplugged. The three objectives to finding these wells may be to provide an overview of their presence in the area, determine the status of a well, or simply locate a well. [135] An understanding of the overlying and underlying formations will provide insight into whether a hydrocarbon reservoir ever existed and whether (or not) it was developed. If the site had a previously operated hydrocarbon reservoir, then the site must be thoroughly vetted to determine if there are any wells. The initial screening may include performing a site walk to identify any wellheads or pipeline equipment using a metal detector, visiting the local regulatory office to obtain well records, and meeting with local operators to collect well information. The initial screening should quantify the potential number of orphaned wells, issues with abandonment practices that could affect storage, and review well files with field or operator visits. Additional technologies used to identify abandoned wells include infrared imaging, aerial photographs, or geophysical methods. [135] Every opportunity must be taken to verify that the wells penetrating the seal of a storage reservoir have been properly plugged. A study by Kang et al. [136] showed that not only are unplugged wells contributing to methane emissions, but improperly or inadequately plugged wells are also a significant factor in methane leaks. A device called a gas sniffer can be used to detect methane leaks from wells, which could help find hidden wells or diagnose poorly plugged wells. Finally, for sites that were never developed or contain no hydrocarbon reservoirs, (a likely scenario for aquifer or salt cavern sites), well screening is still needed to ensure no potential leakage pathways are present from the targeted storage formation.

When more promising sites have been screened and detailed site characterization is planned on a smaller subset of down-selected sites, a deeper review of orphaned wells in the project vicinity should occur to determine leakage risk potential. Drilling and cementing practices have evolved over the years and vintage wells that are plugged and abandoned may need additional work to ensure leakage potential is minimized. The diameter and lengths of casing must be determined from well records, so an accurate estimate of cement can be ordered and pumped down hole. Geologic information such as fracture gradients and fluid loss coefficients will be needed to construct the proper slurry density and volume, so it does not fracture or get lost in the formation. Each well may or may not require its own blend of cement and unique cementing procedure. The challenge in characterizing the wells is that each state has its own regulations and each well has its own design, including the variety of formations it penetrates. Fields and Martin addressed the issue of properly plugging and abandoning wells in their 1997 technical document describing the process of removing well equipment, cleaning the wellbore, and plugging and testing the well. The Global CCS Institute provided an overview of Fields and Martin's plugging and abandonment activities. [137] Additionally, wells that penetrate the storage reservoir must be tested to ensure that they can withstand the constant changes in pressure during storage cycles along with the expected maximum inventory pressure. The original design of these wells very likely did not account for such conditions; therefore, they may need additional work to prepare them for storage operations.

4.3.2 Monitoring

The monitoring of a natural gas storage reservoir is just as important as screening and characterizing the integrity of the caprock. Operators and regulators came together to propose a technical document that outlines the integrity issues that have previously troubled the industry. Recent events, such as the Aliso Canyon accident, have caused the creation of documents such as the API RP 1171, which documents the proper procedures for the design, construction, operation, monitoring and maintenance programs of a storage field. [138] Storage monitoring is performed on any system component where failure can result in an integrity-compromising event. Monitoring covered in the API RP 1171 includes, but is not limited to, wellhead equipment, well integrity, and well barriers or leak paths.

4.3.2.1 Wellhead Equipment

The wellhead is constructed of surface-mounted valves, which are used to control the flow into or out of the well. The wellhead equipment must conform to API 6A standards such that multiple, redundant valves and components must be available to isolate the flow and provide control. Included in the wellhead assembly are ports that allow for measuring and monitoring devices necessary to monitor pressures and flow rates from the different casing strings. The wellhead equipment will be designed for given specifications, which require constant monitoring to ensure operating pressures or any treatment pressures are within the specified limits. The corrosive potential of formation fluids that will enter the casing and be produced out of the wellhead equipment must be monitored to ensure that the valves and ports do not degrade over time. [19]

4.3.2.2 Well Configurations

Wellhead configurations have changed over time and depend on the storage reservoir and operating conditions. API has reported technical details regarding casing and tubing strength, but API RP 1171 provides a new storage well configuration. The configuration includes a minimum of two casings: the surface casing and production casing. The cementing of these strings, whether partial or to the surface, provides additional isolation between the formations and produced fluids. These elements provide the foundation for managing the integrity of the storage well. See Appendix D: American Petroleum Institute Recommended Practice 1171 Well Configuration for an example storage well description.

4.3.2.3 Well Integrity

Each well is evaluated on a case-by-case basis to determine its integrity and ensure safe operations. In addition to storage operator wells, there may be third party wells that penetrate the storage formation or other formations associated with storage operations. The integrity of a storage well is assessed by reviewing well design, drilling, completion records, wellhead inspections, and other operating conditions. A well's risk profile includes monitoring tasks and evaluation frequency requirements required to demonstrate and verify its integrity. Operating limits are frequently re-evaluated based on operation, configuration, or condition changes. The well is constantly monitored so that any readings outside of the normal limits will require immediate action from the operator who determines the next steps. [19]

4.3.2.4 Well Barriers and Leak Paths

API RP 1171 attempts to discuss and diagnose historical leaks that operators have encountered due to specific well completions. Well barriers attempt to mitigate or reduce leakage pathways, but often choosing a specific type of well completion can lead to a specific set of failure mechanisms. For instance, a production casing without tubing can result in wellhead seal failures, production casing leaks, and/or downhole annular breaches. The API provides these scenarios to make operators aware of the potential hazards and hopes that annular barrier monitoring and evaluations are performed more frequently. In addition, site-specific risk assessments must be performed to identify and resolve any potential failures before they occur. [19]

4.4 Operations

Storage operations take place year-round with two general periods of operation: injection and withdrawal. The injection period will include transporting natural gas to the injection site, maintaining surface injection equipment, and injecting natural gas into the subsurface. The withdrawal period includes producing the natural gas, treating of the produced natural gas and any produced fluids, and transport of the produced natural gas to consumers. Despite the similarities between the two periods they require different equipment and operating conditions. The first phase of the process includes delivery to the injection site.

4.4.1 Gas Site Delivery

Delivery of gas to the well site requires that it arrive in a specified volume and quality. Typically, gas produced from the oil and/or gas wellhead will contain various contaminants and NGLs that must be removed before transportation and subsurface storage. Natural gas that is delivered and stored in underground reservoirs is primarily methane, which requires processing to reach transportation and storage quality. [33] The quality of natural gas is kept consistent as it must meet a specific quality measurement to be transported on the mainline natural gas transportation system in the United States. Depending on the location of the storage reservoir and the nearest source of natural gas it can be transported via an interstate, intrastate, or Hinshaw pipeline network.[m] [28] Storage operators are primarily pipeline companies, which enables them to utilize their pipeline networks for gas delivery to storage sites. [139] The gas that is delivered to a storage well site is in the gaseous phase and has been compressed at compressor stations to ensure the natural gas flows and reaches its destination at a pre-determined pressure.

4.4.2 Injection Equipment and Storage Pressures

Once natural gas has been delivered to the facility or storage site it must be injected into the subsurface. Initial steps before it is injected may include metering, scrubbing, compression, and cooling. A metering station is a monitoring system that determines the volume of natural gas that passed through the pipeline without impeding the flow. [33] Metering stations determine the volume of gas before it is injected into the subsurface, which allows operators to track injected and produced volumes. The next phase is scrubbing the natural gas.

A scrubber is a device that removes undesired contaminants from the flow stream such as dirt, water, or liquids. [116] The natural gas may travel across the country through multiple pipelines and the scrubber can remove any liquids that could have accumulated in the pipeline. Scrubbing is a necessary step because any debris or liquids could result in severe damage to the compressor. [140] After scrubbing the incoming gas stream, it then travels to the compressor.

Gas pipeline flow requires a fraction of the pressure needed to inject natural gas into the subsurface. The gas that is injected into the subsurface must exceed the pressure of the reservoir. This requires compressors at the surface compressing the natural gas to the desired

[m] A Hinshaw pipeline network receives natural gas from interstate pipelines and delivers natural gas to consumers for consumption within a state border. [28]

pressure. As the storage reservoir fills up with natural gas, the reservoir pressure rises and injection of additional volumes of gas will require additional compression. There may be multiple stages of compression to reach the desired injection pressure, but each stage requires a cooling component due to the increase in temperature that accompanies gas compression. [140]

Cooling of the natural gas reduces the effect of the heated gas on the equipment and increases compression efficiency. Cooling systems utilize giant fan blades that pull cool air across a set of tubes that contain the natural gas. Tubing material that aids in the cooling is utilized to increase the effectiveness and minimize the cooling time. The number of coolers is dependent on the number of compressors as a cooler is required after each round of compression. [140] Finally, the natural gas is sent from the cooler to the wellhead for injection.

At the wellhead, the natural gas is injected into the subsurface at the desired pressure. Site operators must be mindful of pressure limits that are not to be exceeded while injecting natural gas into the subsurface. These pressure limits include any valve, casing, or tubing pressure limits that may result in equipment failure. Typically, these components will be pressure tested to withstand pressures that exceed the maximum injection pressure by a safety factor. The most important pressure limit is determined by the fracture gradient measured in psi per foot of depth. The fracture gradient determines the pressure that induces fractures in a subsurface rock formation at a given depth. This is the fracturing pressure. If the fracturing pressure is exceeded, then fractures created in the injection zone can grow into overlying formations (caprock) or cause high permeability streaks within the reservoir for gas to flow through. Exceeding the fracturing pressure could result in unsuitable storage conditions.

4.4.3 Operational Monitoring

A review of the key well components critical to reservoir monitoring and gas containment is discussed in Section 4.3.2. The monitoring activities of a storage site include observation wells, which are drilled to specific depths associated with the reservoir, caprock, and other significant formations (for example, potable water aquifers overlying the storage reservoir caprock). Observation wells may be heavily used in depleted oil and gas fields where wells are abundant or in areas of relatively inexpensive drilling costs. The monitoring requirements also change from reservoir to reservoir depending on the design of the field. They may also vary from state to state. Per subchapter H #78.403 of the Pennsylvania code as an example:

> Gas storage field monitoring may consist of annular and tubing pressure monitoring, reservoir engineering evaluation in the form of pressure/volume inventory studies, gauge calibration programs, wellsite inspection programs, casing inspection programs, pressure and flow testing programs, internal and external inventory auditing programs or a combination of monitoring procedures approved by the Department that verify the gas storage reservoir’s integrity. [141]

Monitoring activities include observing the reservoir through gauges, observation wells, and analytical calculations that verify reservoir and well integrity. As mentioned, API has written multiple procedures on the application of monitoring techniques to the functional integrity of storage reservoirs. The most recent publication is the API RP 1171 (discussed in Section 3.1.4), which details the functional integrity of depleted reservoirs and aquifers. [138]

4.4.4 Withdrawal

The start of the withdrawal season occurs in or near November each year; at this point operators must switch from injecting to producing natural gas. The withdrawal period (typically November through March) incorporates additional steps not important or necessary to the injection of natural gas. The stages included in the production of natural gas include production, separation, cooling and dehydration, and odorizing. The first stage of the production phase is natural gas being produced through the wellhead.

The wellhead, or Christmas tree, is a system of valves that provide surface flow-control for the well. [116] The wellhead is necessary to control flow and monitor pressures. As natural gas flows up and through the wellhead it is diverted to separation equipment.

Separation is an additional step commonly used to separate out water and/or heavier hydrocarbon liquids picked up during the storage period from the produced natural gas. The separator utilizes gravity and heat to separate the various fluids. The oil and water will be piped and stored in tanks for sale or disposal. [140] Any hydrocarbon liquids will be sold while the water will be treated and then disposed of per federal or state regulations. The natural gas will flow into the cooling and dehydration system.

The stored natural gas is heated to subsurface temperatures while in storage and must be cooled before it can flow into the pipeline network. The cooling system is the same one implemented during the injection stage with a dehydration unit attached. The dehydration unit knocks out any remaining water vapor using an antifreeze-like substance. The dehydrator is the last stage of treatment before the natural gas is transferred into a pipeline for eventual distribution to consumers, so it must effectively remove any remaining water from the natural gas. [140] Finally, the gas flows into a unit that odorizes the gas.

The odorizing unit adds a man-made aroma to the natural gas. Natural gas is an odorless substance and without the man-made aroma it could leak without being detected within residential areas. Odorization has been regulated to ensure that specific lines are odorized, and natural gas samples have a minimum detectable limit. Gas within a pipeline must contain a natural odorant or be odorized so that a concentration in the air of one-fifth the lower explosive limit of gas is readily detectable by a person with a normal sense of smell. [142]

4.4.5 Reporting Requirements

Reporting requirements vary from field to field and operator to operator. FERC has jurisdiction over interstate pipelines and independently operated storage projects that offer storage services to interstate commerce. There are various reporting requirements such as Form No. 549D, which requires a quarterly reporting of transportation and storage of intrastate natural gas. [143] Per Subpart C #284.126 the natural gas must be reported as a quantity, with a specific date, and include delivery points and type of service. The EIA can quantify natural gas storage operations with their annual and monthly reporting requirements. EIA currently has three forms associated with the storage and distribution of natural gas. These forms include an annual natural gas report, monthly natural gas quantities, and an underground natural gas storage report.[n] The main difference in FERC and EIA reporting requirements, is that EIA asks operators to standardize their data to a pressure (14.7 psia) and temperature (60 °F), which is manually checked for reasonableness and accuracy. [144] The EIA uses the reported data to generate useful tables and graphs that are free to the public.

[n] Each report has unique requirements, which can be read at http://www.eia.gov/dnav/ng/TblDefs/NG_DataSources.html.

5 CO_2 GEOLOGIC STORAGE: TECHNICAL DIGEST AND PROJECT PHASES

CO_2 geologic storage is the process of injecting CO_2 captured from an industrial (e.g., cement processing plant) or energy-related source (e.g., power plant) into deep subsurface rock formations for long-term storage (i.e., saline-bearing formations). [91] This section provides a brief, but comprehensive, overview of CO_2 storage in terms of the general concept, key technical considerations and requirements, and insight into successes (and where applicable, challenges) of field-based R&D and commercial-scale projects. The information in this section will provide a basis from which to compare CO_2 storage operations with analogous underground natural gas storage (outlined in Section 4). Outlining the technical considerations and operations for each practice is important towards fully understanding the major similarities and differences between underground natural gas storage and CO_2 storage operations.

5.1 CO_2 GEOLOGIC STORAGE TECHNICAL OVERVIEW

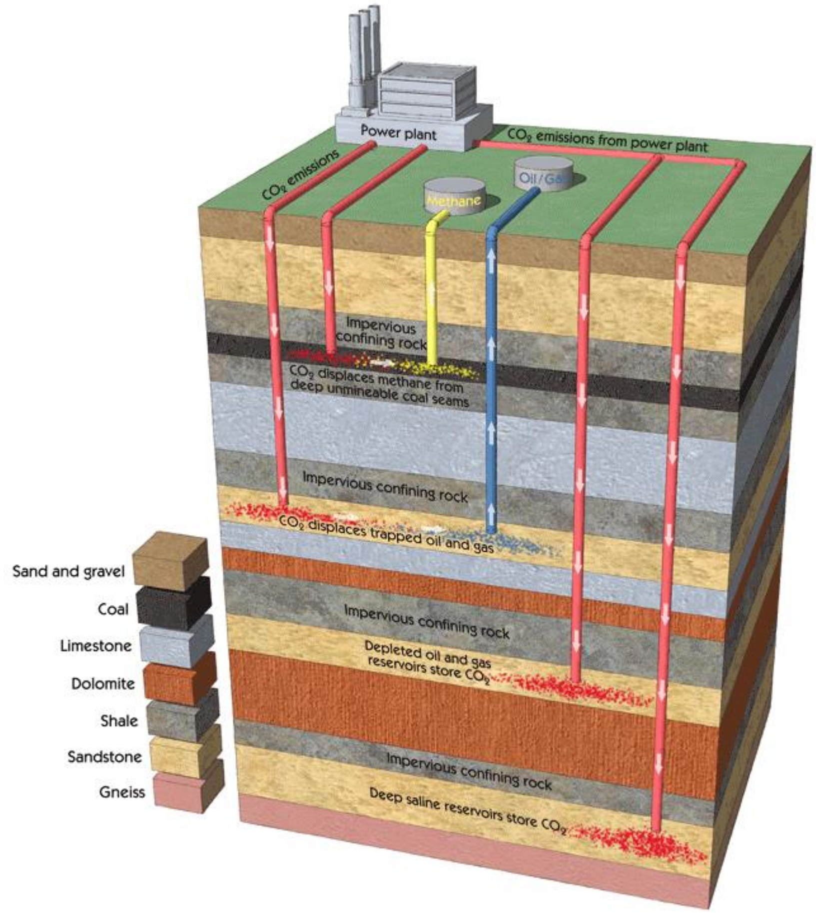
According to the Intergovernmental Panel on Climate Change, geologic storage of CO_2 currently represents the best and likely only short-to-medium term option for significantly reducing the CO_2 emitted into the atmosphere. [14] This is further supported in the International Energy Agency's (IEA) *Energy Technology Perspectives* studies, in which CCS is a vital component within a portfolio of low-carbon energy technologies needed to attain emission reduction trajectories in scenarios like 2DS.[o] [145] The practice of storing CO_2 underground could be applied immediately based on the experience to date from the oil and gas industry and from the deep disposal of liquid wastes. [14] The storage of CO_2 in geologic formations shares many comparable features to oil and gas accumulations in hydrocarbon reservoirs and CH_4 in coalbeds. The transportation, injection, and monitoring of CO_2 in the subsurface has been implemented for decades for EOR, while other industries, such as acid gas disposal, deep wastewater and hazardous waste injection, and natural gas storage, are analogous to CO_2 geologic storage and have been in successful operation for decades. [18] The worldwide experience with these types of industrial analogs demonstrates that the technology of bringing CO_2 to a geologic storage site and injecting it deep into the ground currently exists and can be easily applied. Although the technologies pertaining to each component of the CCS value chain (CO_2 capture, transport, and storage) are at various stages of maturity, and in some cases, they have been separately proved and deployed at commercial scales (like CO_2 pipelines, and injecting CO_2 into the subsurface for EOR applications), [146] fully-integrated CCS systems are still considered costly and not entirely matured. [147] [148] Continued research is needed to significantly improve the effectiveness of CO_2 storage-related technologies, reduce the cost of implementation, generate operational data, illustrate best practices, and provide for lessons learned. This type of information can be used to inform regulators and industry on the safety and permanence of CCS and help toward facilitating widespread commercial deployment. [11]

[o] The 2DS as described by IEA is based on technology implementation across all energy sectors that would achieve an 80 percent chance of limiting average global temperature increase to 2 °C by the 2050 timeframe. [246]

Generally, five storage formation types, each having unique challenges and opportunities, have been considered candidates for carbon storage: 1) depleted oil and gas reservoirs, 2) unmineable coal seams, 3) saline formations, 4) organic-rich shales, and 5) basalt formations. For comparison, the practice of underground natural gas storage also utilizes saline formations and depleted oil and gas reservoirs. However, long-term CO_2 storage using Class VI wells is most likely to occur in saline-bearing formations. CCS involves candidate storage site selection through screening and initial characterization followed by a more detailed site characterization utilizing seismic surveys, core analysis, and modeling. These efforts help ensure that candidate storage sites can safely store CO_2 for extended periods. MVA efforts focus on the development and deployment of technologies that can provide an accurate accounting of stored CO_2 and a high level of confidence that it will remain safely and permanently stored during and after the injection process. Risk assessments are conducted throughout the CCS process to identify and quantify the potential health and environmental risks associated with carbon storage and help identify appropriate measures to ensure that those risks remain low. [9] [149]

Identifying suitable geologic storage sites involves a methodical and careful analysis of both the technical and non-technical aspects of potential sites. Geologic storage of CO_2 is accomplished by injecting it deep enough (~2,600 ft or greater) to take advantage of its dense, supercritical phase, which maximizes use of available storage (see Exhibit 5-1—offshore storage not demonstrated in this example). Porous rock formations that hold, or (as in the case of depleted oil and gas reservoirs) have previously held, fluids such as natural gas, oil, or brines, are promising potential candidates for CO_2 storage. Large-scale injection of fluids into the deep subsurface for disposal of produced water from oil and gas operations, injection of water for a waterflood to repressurize a depleted oil reservoir, or injection of CO_2 to enhance oil production has occurred for many decades. On a smaller scale, injection disposal of hazardous and non-hazardous wastes has also occurred for many decades. The basic principles involved in such activities are well established and most countries have regulations governing them. In the United States, EPA's UIC Program is the primary governing body for underground fluid injection. Captured CO_2 stored through injection has, to date, been performed on a relatively small scale, but if it were to be used to significantly capture and manage a sizeable portion of emissions from existing stationary sources, the injection rates would have to be on a scale similar to water injection in many oil and gas operations. [14]

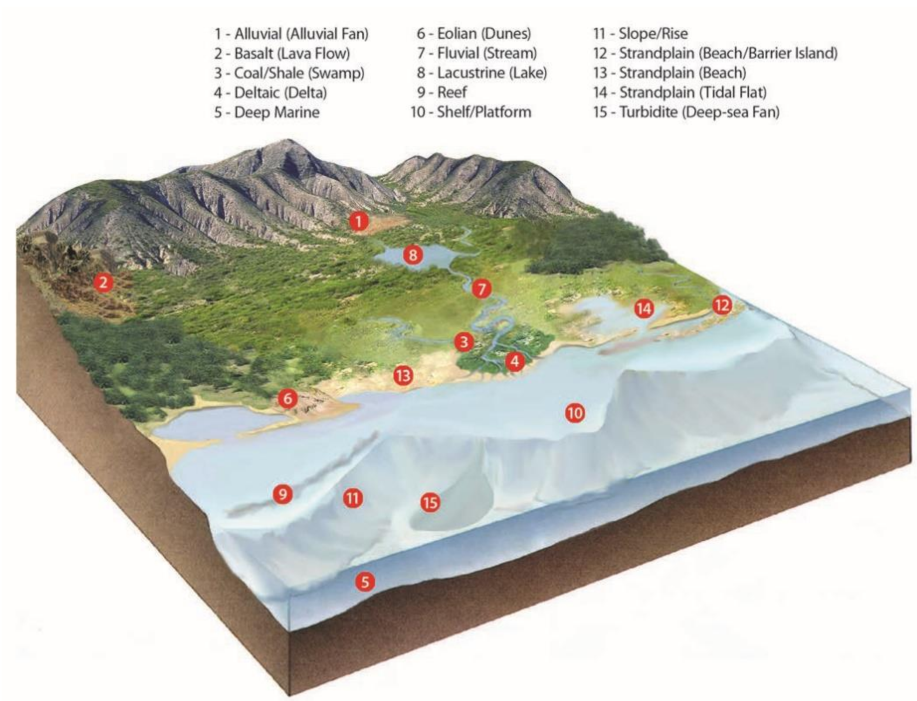
Exhibit 5-1. Conceptual diagram of captured CO_2 from a power plant being stored in diverse types of storage formations specific to an onshore setting [150]



Source: Ohio Department of Natural Resources

Suitable storage formations can be in both onshore and offshore sedimentary basins (natural large-scale depressions in the earth's crust that are filled with sediments, i.e., sedimentary rocks). [14] Basins suitable for CO_2 storage have a thick accumulation of sediments with formations that can be porous and permeable (storage reservoir candidates) or tight (seal/caprock candidates), having almost no porosity and permeability. Each type of geologic formation presents different opportunities and challenges. For instance, within a given formation, there could be the presence of both high permeability and high porosity storage reservoir zones, as well as low permeability zones that can trap fluids (liquid or gas) within the storage reservoirs and prevent movement to overlying formations. Within the reservoir, the distribution of porosity and permeability is determined by constituent mineralogy (sand, carbonate, shale) reflecting depositional environments. The depositional environment (Exhibit 5-2) influences reservoir architecture, how injected fluids will move through the reservoir and be held in place. Certain geologic properties may be more favorable for long-term containment of liquids and gases within individual storage reservoirs. [8] In the IEA Greenhouse Gas R&D Programme document *Development of Storage Coefficients for CO_2 Storage in Deep Saline Formations Technical Study*, depositional environments that represent the most common settings for sedimentary rock accumulation have been assessed based on their unique properties, which impact the behavior and, inevitably, the storage capacity of the given environment. [151]

Exhibit 5-2. Schematic of possible depositional environments [149]



For fluid flow in porous media, knowledge of how depositional environments formed, and directional tendencies are imposed by the depositional environment can influence how fluids flow within these systems today, and how CO_2 in geologic storage might flow in the future. The fluid(s) contained within the candidate storage formation are also of importance and can influence the approach toward the injection of CO_2.

5.2 Geologic Storage Formations

Optimal storage of CO_2 in the subsurface occurs when the injected CO_2 is in its supercritical phase. Supercritical CO_2 exists at temperatures more than 88 °F (31.1 °C) and pressures more than approximately 1,057 psi (72.9 atmospheres). At these temperatures and pressures, CO_2 has properties like those of both a gas (viscosity) and liquid (density). The main advantage of storing CO_2 in the supercritical state is to maximize utilization of available storage volume. [8] Temperature and fluid pressures are greater than the supercritical point of CO_2 in most places on Earth at depths below about 2,600 ft (800 meters). CO_2 injected at this depth or deeper will remain in the supercritical state. [11] Under these high pressure and temperature conditions, the density of CO_2 will range from 50 to 80 percent of the density of water depending on specific site conditions. [14] For natural gas storage, natural gas remains in the gas phase (not considering NGLs – See Section 2.6).

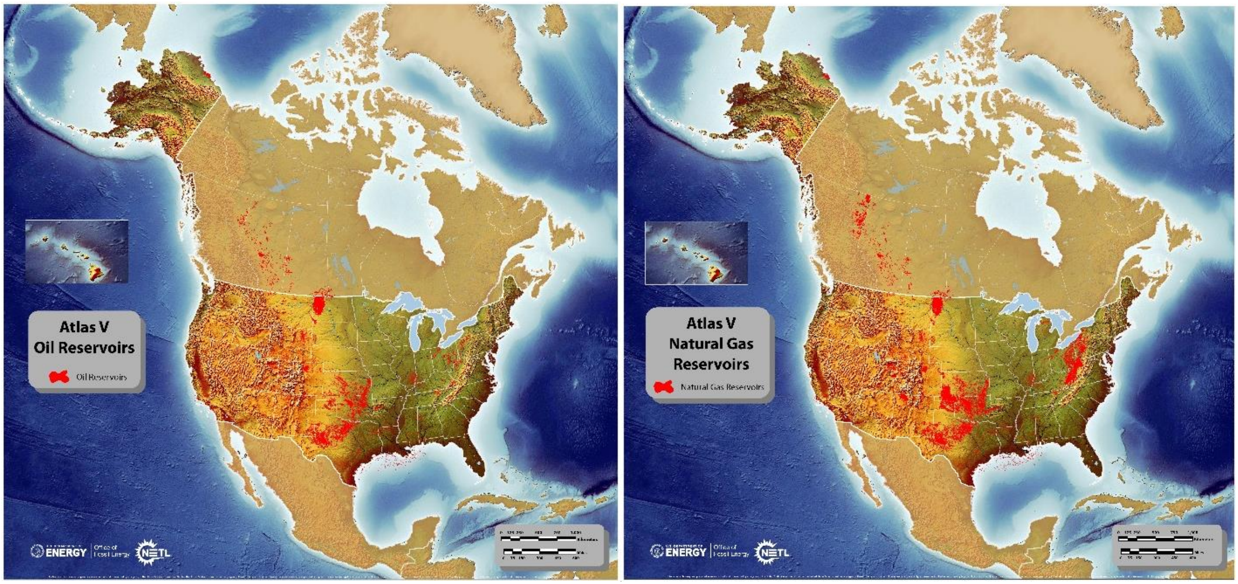
Three of the most promising underground storage reservoir types include saline, depleted oil and gas reservoirs, and unmineable coal seams. Other potential storage reservoirs may be found in organic-rich shales and basalt formations. These types of storage reservoirs can be found throughout the world and have the resource potential to hold CO_2 emissions from large point sources into the distant future. [152] Depleted oil and gas reservoirs are similar to saline reservoirs and demonstrate the security of their seals by retaining the accumulated oil and gas over millions of years. Many oil and gas fields contain stacked reservoirs (different reservoirs that overlie each other) with characteristics (i.e., good porosity) that make for excellent multiple target locations at one geographic location. [8] [149] The subsections below provide an overview of the possible CO_2 storage formation types as well as the advantages and challenges.

5.2.1 Oil and Gas Reservoirs

Oil and gas (natural gas) reservoirs are porous rock formations (usually sandstones or carbonates) containing crude oil and/or natural gas that have been physically trapped. There are two main types of physical traps: 1) stratigraphic traps caused by differences in rock lithologies and 2) structural traps in which the rocks have been folded or faulted to create a trapping mechanism. Oil and gas reservoirs are ideal geologic storage sites because they have held hydrocarbons for millions of years under conditions suitable for CO_2 storage. Likewise, their architecture and properties are well known because of hydrocarbon exploration and production. In addition, due to oil and gas exploration and production, infrastructure (and data) exists that facilitates CO_2 transportation and storage. NETL, through the RCSP initiative, has determined that CO_2 storage resource estimates for oil and natural gas reservoirs in the United States and parts of Canada are between approximately 186 and 232 billion tonnes[p] (Exhibit 5-3). [8]

[p] CO_2 resource assessments included in Section 5.2.1 through 5.2.3 are calculated from low (P_{10}) and high (P_{90}) efficiency factors. [8] The methodology for this approach is outlined in Appendix E: Overview of the United States Department of Energy Methodology for Estimating Geologic Storage Potential for Carbon Dioxide.

Exhibit 5-3. Map display of oil reservoirs (left) and natural gas reservoirs (right) in parts of North America that were assessed by NETL under the RCSP initiative [8]



Traditionally, oil production from reservoirs occurs in three distinct phases. In the primary recovery phase, the natural pressure in a reservoir and artificial lift is used to extract oil. This process usually accounts for recovery of 10 to 20 percent of original oil in place. The secondary recovery phase involves the injection of water to increase reservoir pressure and displace the oil toward producing wells. This process produces an additional 20 to 30 percent of the original oil in place. Together, these two phases account for the recovery of 30 to 50 percent of the original oil in place, still leaving a significant amount of the oil in the reservoir. [153] Tertiary recovery, or EOR, is frequently conducted with CO_2 for additional recovery of the original oil in place. Injected CO_2 increases the oil mobility, making it easier for the oil to reach producing wells. [8]

EOR is an attractive option for CO_2 storage. CO_2 EOR has the potential to accelerate CO_2 emission reductions and storage by providing value to the captured CO_2 as a commodity for EOR instead of simply treating it as a waste product. The value of the CO_2 as a commodity for EOR could contribute to the funding of the capture of CO_2 from power generation or industrial CO_2 sources. [153] [154] [155] In North America, CO_2 has been injected into oil reservoirs to increase oil recovery for more than 40 years. Further EOR development of depleted oil and gas reservoirs may provide an invaluable market for deployment of CCS technology.

The objective of CCS (to permanently store anthropogenic CO_2) is not the same as that of CO_2 EOR (to maximize economic production of oil), and continued work is needed to reconcile the differing goals of CCS (a Class VI permit injection operation), and CO_2 EOR (a Class II permit operation). Regardless of the overall of goal of either operation, both are regulated and permitted under EPA's UIC Program. Therefore, requirements pertaining to the specific well type used (UIC Class II or Class VI) are tailored to the unique circumstances expected of the specific operation to ensure protection of underground sources of drinking water (USDW). The CO_2 EOR industry has traditionally not focused on CO_2 storage permanence in the subsurface, even though much of the injected CO_2 remains stored in the reservoir. It has been suggested that because of Class VI requirements, many within the EOR industry expect that incremental operational and/or post-closure monitoring (particularly of the injection zone, flow paths, pressure containment, wellbore integrity, and long-term storage) could encouraged beyond the conventional practices typical of traditional Class II CO_2 EOR operations (see details related to "Mandatory Reporting of Greenhouse Gases for Injection and Geologic Storage of Carbon Dioxide" under Section 3.2.1.1). [153] The complexity and cost of any additional monitoring may play a large role in whether the CO_2 EOR industry decides to participate in larger-scale CCS. [153] In addition, CCS in mature oilfields presents a challenge due to the abundance of preexisting wells and wellbores that can act as high-permeability leakage pathways from the storage/oil producing formation to USDWs or the atmosphere, which increases the risk of conducting CO_2 storage projects (also a potential challenge for underground natural gas storage fields). Current well closure and abandonment technology appears sufficient to contain CO_2 at most sites; however, older wells may suffer from a variety of conditions that limit their integrity, including improper cementation and plugging, overpressure, corrosion, and other failure conditions. Therefore, the condition of wells penetrating the caprock must be assessed; which is an important objective for oil and gas operators as to ensure no loss of natural gas and oil assets (and subsequently purchased CO_2). [14]

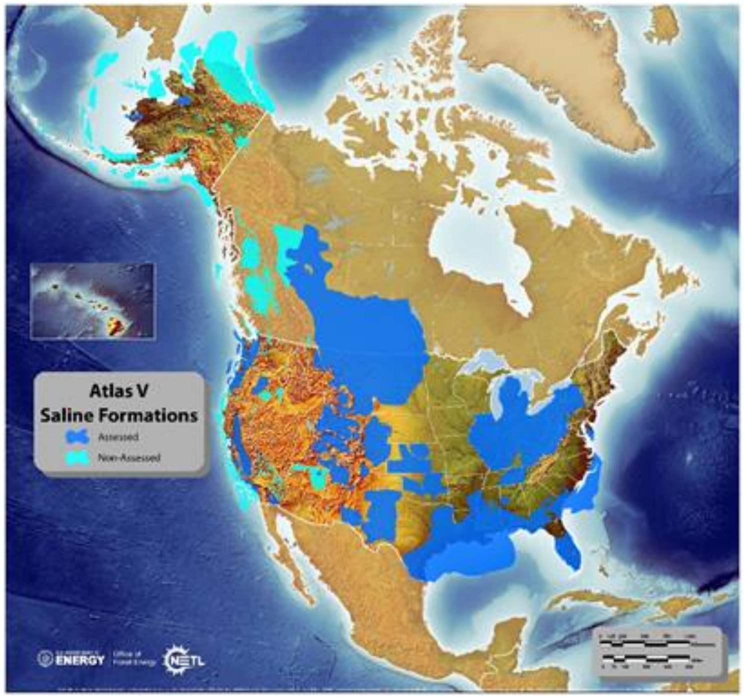
Currently, CO_2 EOR is regulated by EPA's UIC Program under Class II wells (40 CFR 146 Subpart C). EPA developed Class II UIC regulations for wells that inject fluids associated with oil and gas production. The portion of Class II UIC regulations most applicable to the storage of CO_2 in the subsurface relate to enhanced energy recovery. In later stages of oil field production, CO_2 can be injected into the subsurface to further mobilize any residual oil in place and extend the productive life of the oil field. Class II UIC regulations require specific well construction, reservoir management, and monitoring techniques to track the use of CO_2 as an injectate into the producing formation. [9] [11]

5.2.2 Saline Formations

Located both in the United States and globally, deep saline formations have the greatest potential to store anthropogenic CO_2 because of their large areal distribution and storage resource potential. These formations occur in both onshore and offshore sedimentary basins. [14] CO_2 storage resource estimates for saline formations in North America conducted by NETL and RCSPs range between 2,379 and 21,633 billion tonnes (Exhibit 5-4). [8] These resource estimates for storage capacity (calculated at the formation, basin, and continent scales) are not always straightforward. Saline formation storage lacks the economic incentives of an EOR project; however, it could serve as buffer storage for EOR operations.

Formation waters contain appreciable amounts of salts that have either been leached from the surrounding rocks or from seawater that was trapped when the rock was formed. To protect USDWs, EPA has determined that the water or brine of a saline formation used for CO_2 storage must be greater than 10,000 parts per million of total dissolved solids—a measure of the amount of dissolved solids, mostly salts, in formation water. Most drinking water supply wells contain a few hundred parts per million or less of total dissolved solids. [91] The brine concentrations in saline formations typically considered for geologic storage of CO_2 make the fluids difficult to treat and render suitable for agriculture or human consumption.

Exhibit 5-4. Map display of saline formations in parts of North America that were assessed by NETL under the RCSP initiative [8]



Potential storage reservoirs require a confining zone (often referred to as a caprock or seal) that overlies the porous rock layer providing a primary trapping mechanism for the stored CO_2. Other, secondary trapping mechanisms within the reservoir include CO_2 dissolution into brine (solubility trapping), chemical reactions with the minerals and fluid to form solid carbonates (mineral trapping), or trapping of migrating buoyant CO_2 (residual trapping). A great deal of knowledge about certain saline formations exists because of prior oil industry experience in oil and gas exploration and production. However, that knowledge attained was ancillary as part of the pursuit of hydrocarbon resources. Also, there are a great many saline formations about which little is known. The potential for successfully storing CO_2 in saline formations is more uncertain than that in oil and gas reservoirs as saline reservoir management parameters are less well defined. However, saline formations are widespread with enormous storage resource potential. Recent CCS projects are proving the potential for reliable, long-term storage (discussed in Section 5.7). [2] [14]

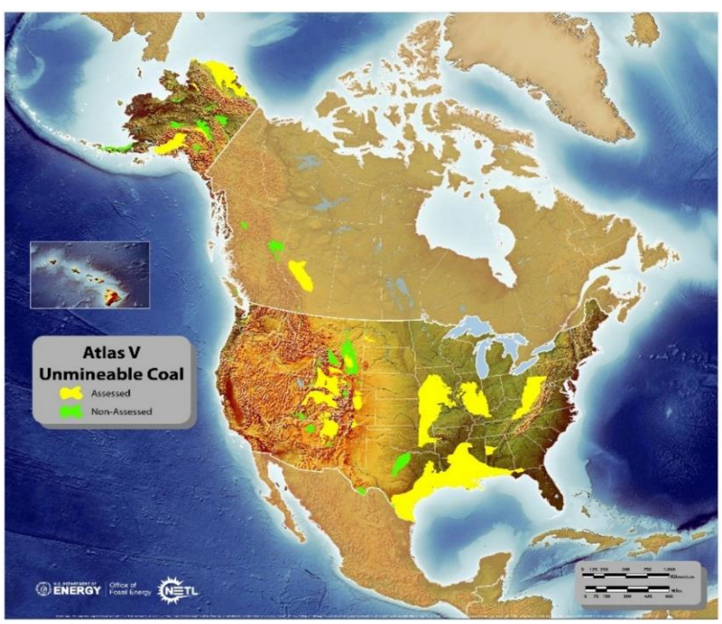
5.2.3 Unmineable Coal Seams

Coal seams that are considered unmineable because of geological, technological, or economic factors (typically too deep, too thin, or lacking the internal continuity to be economically mined with today's technologies) may have potential for CO_2 storage. Coal seams that have never been disturbed can contain considerable amounts of methane (up to 25 cubic meters (m^3) per metric ton of coal). [156] Coal preferentially adsorbs CO_2 over methane, which is naturally found in coal seams. Experimental CO_2/CH_4 adsorption ratios have been found to range from 2 to 13 (typical adsorption isotherms measured as millimole of gas adsorbed per gram of coal) depending on coal type. This property, known as adsorption trapping, is the basis for CO_2

storage in coal seams (as well as by some physical trapping in the cleats of the coal). [8] In general, gas stored by sorption in the coal matrix accounts for approximately 95 to 98 percent of the gas in the coal seams. Shi and Durucan [157] indicate that the shape of adsorption isotherms of different gases to coal can provide information on the adsorption process, porosity, and surface area of the adsorbent. Methane and CO_2 adsorption on coal is usually described by a Langmuir-type isotherm, indicating that the adsorption is dominated by micropore-filling processes. [157] Gas adsorption occurs primarily in the micropores of the coal matrix, and a significant proportion of the total open pore volume in coal is located in the micropores. [157]

CO_2 storage resource estimates for unmineable coal seams in North America provided by NETL and the RCSPs range between 53 and 113 billion tonnes (Exhibit 5-5). CO_2 injected (typically in gaseous state) through wells into unmineable coal seams flows through cleat systems (fractures in coal that provide some permeability), diffuses into the coal matrix, and is adsorbed onto the coal micropore surfaces, freeing up gases with lower affinity to coal (i.e., methane). [14] Methane is typically recovered from coal seams by dewatering and depressurization, but this approach can leave significant amounts of methane trapped in the seam. Enhanced coalbed methane (ECBM) recovery processes are possible through injecting and storing CO_2 into unmineable coal seams to boost methane recovery. ECBM recovery parallels CO_2 EOR operations because it provides an economic benefit (both domestically and globally) from the recovery and sale of the methane gas, which helps to offset the cost of CO_2 storage. However, the coal must be of sufficient permeability (a physical property which dictates CO_2 injectivity) to allow for CO_2 storage. Coal permeability varies widely, depends on the effective stress, and usually decreases with increasing depth. Most coal bed methane-producing wells worldwide are less than 3,280 ft (1,000 meters) deep. [14]

Exhibit 5-5. Unmineable coal seams in parts of North America that were assessed by NETL under the RCSP initiative [8]

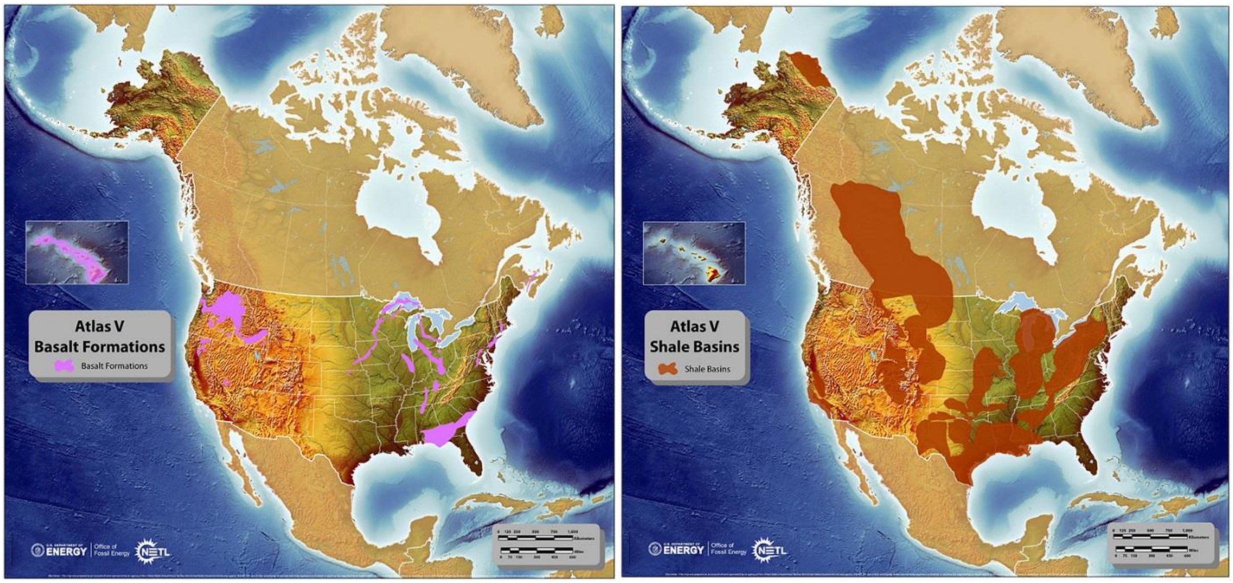


For CO_2 storage in coal or ECBM recovery to occur, the ideal coal seam must 1) have sufficient permeability; 2) be homogeneous, confined, laterally continuous, and vertically isolated; 3) be simple in structure with minimal faulting and folding; 4) have suitable gas saturation conditions, 5) have the ability to be dewatered, and 6) be considered unmineable. [8] [14] Since CO_2 does not need to be in the supercritical phase to be adsorbed by coal, CO_2 storage in coal can occur at shallower depths than in oil and gas reservoirs and saline formations (which require at least 2,625 ft [800 meters depth] to attain conditions conducive to supercritical CO_2). However, geologic storage in unmineable coal seams through adsorption processes is still a relatively undeveloped geologic storage technology and needs additional research because of the technical risks associated with swelling of the solid coal matrix during the adsorption process, resulting in reduced cleat aperture and overall permeability. [152] A critical factor of coalbed reservoirs is that the coal matrixes have shown (through both experimental and theoretical studies) to shrink on desorption of gases. This shrinkage effect related to methane desorption is considered to significantly reduce coalbed permeability caused by increasing compaction with reservoir pressure depletion during primary methane production. [157] This reduced permeability is a threat to CO_2 injectivity, and research to optimize CO_2 storage in coal and provide insight into the effect of CO_2 injection on coalbed permeability and injectivity has been ongoing as part of NETL's Carbon Storage Program. [11]

5.2.4 Basalt and Organic-Rich Shales

Basalt and organic-rich shale formations are promising geologic storage types. Basalt formations have a relatively large amount of potential storage resource, and, along with their geographic distribution, makes them an important formation type for possible CO_2 storage, particularly in the Pacific Northwest and the southeastern United States (Exhibit 5-6). Basalt formations are geologic formations of solidified lava. Basalt commonly has low porosity, permeability, and pore space continuity and any permeability is generally associated with fracture networks. [14] These formations have a unique chemical makeup that could potentially convert all the injected CO_2 to a solid mineral form, thus trapping and isolating it from the atmosphere permanently. The chemistry of basalts enables injected CO_2 to react with magnesium and calcium in the rock to form the stable carbonate mineral forms of calcite and dolomite. [8] Thus, basalts could offer one of the safest options for permanently storing CO_2 in the subsurface. Some key factors affecting the capacity and injectivity of CO_2 into basalt formations are effective porosity of top flow layers and interconnectivity. DOE is focusing research efforts on better understanding the mineralization reactions and kinetics that occur when CO_2 interacts with basalt formations, as well as developing more effective monitoring and modeling tools for basalt storage applications. [8] [152]

Exhibit 5-6. Map display of basalt (left) and organic-rich shales (right) in parts of North America that were assessed by NETL under the RCSP initiative [8]



Organic-rich shales are present in many parts of the world and provide another potential geologic storage option. [8] [14] Shales are formed from silicate minerals of a very fine grain size known as clay. The plate-like structure of these clay particles causes them to stratify, resulting in rock layers with extremely low permeability. As a result, shales provide the seal for many oil and gas reservoirs and are most often considered as the confining zone or caprock for geologic storage. In addition to potential storage of CO_2, efforts to use CO_2 for enhanced gas recovery from shales are ongoing. Recent advances in horizontal drilling and hydraulic fracturing technologies have increased the energy sector's ability to produce natural gas from organic-rich shales. These technologies, coupled with the fact that CO_2 is preferentially adsorbed over methane, will improve the feasibility of storing CO_2 in these unconventional reservoirs. The potential for CO_2 storage in oil or gas shale is relatively unknown, but the large volumes of shale suggest that the potential storage resource capacity could be significant. [8] [14] While additional engineering of the shale would add to the cost (which may include additional characterization efforts, reservoir stimulation, and possibility monitoring-related activities), the potential for enhanced recovery of the natural gas could provide a potential economic offset to the storage process. [149]

5.3 KEY GEOLOGIC CHARACTERISTICS COMMON TO SUCCESSFUL UNDERGROUND CO_2 STORAGE

The oil industry has developed full-system approaches for safe and cost-effective injection of CO_2 into the subsurface for EOR applications. Over 40 years of industry experience indicate that CO_2 EOR projects have been successfully implemented that demonstrate CO_2 injection into the subsurface covering a range of depths, reservoir qualities, pressures, and temperatures. Additionally, pilot and commercial-scale CO_2 storage projects in saline formations as well as unmineable coal seams have also occurred. Several projects worldwide have implemented and validated, or are continuing to implement and validate, safe and effective CO_2 injection and storage operations for long-term subsurface CO_2 storage. [2] [9] [152] Safe, efficient, and reliable long-term storage of CO_2 requires knowledge and observance of key parameters and reservoir characteristics that, based on historical CO_2 EOR and CCS-demonstration projects, go into the design and construction of a successful project that can deliver an efficient and reliable result. From a technical perspective, a CO_2 storage site operator (for any application type, including storage in saline-bearing formations, CO_2 EOR, and even enhanced gas recovery in unmineable coal seams) must ensure, at a minimum, that the candidate storage site: [158]

- Has the necessary capacity for storage
- Meets the conditions necessary for injectivity of CO_2 in the subsurface at the desired rate
- Has adequate depth to store CO_2 in a supercritical phase (typically greater than 2,600 ft). Exceptions do exist, for instance, CO_2 injection into unmineable coal seams
- Provides for safe injection and storage such that CO_2 leakage is avoided, or, if it happens, it is minimized and benign
- Is constructed, operated, and monitored to assure safe operations
- Non-endangerment is established for site to be decommissioned

Many of the requirements in the list above can be directly attributed to key geologic characteristics that are common to safe, efficient, and successful CO_2 storage operation; injectivity (rate at which CO_2 can be injected), capacity (volume of CO_2 the subsurface can hold), and containment (CO_2 retention in the subsurface). [159] [160] The key geologic characteristics that are foundational to these criteria are presented below.

- **Injectivity** is the measure of the ability of a formation or reservoir to accept fluids or gas. Units of injectivity can vary with the data source and include m^3/day/Pascal/meter or barrels/day/psi/ft. Injectivity is proportional to a formation's permeability (often expressed in mD). Injection is directly proportional to permeability, height or thickness of reservoir open to injection, and the bottom-hole and reservoir pressure differential. Horizontal wells expose more of the reservoir to the wellbore for injection providing for larger injection rates while maintaining safe injection pressures below fracture gradient. Injectivity can be estimated for a given site by several means, including data from past production history (especially for oil and gas fields), injection or leak-off tests, well pump/injection tests, conventional core analysis, and injectivity from analogous reservoir types. [161]
- **Capacity** is a measurement of the potential volume of a given formation for storage of a liquid or gas. Pore volume is a bulk term based on the product of formation thickness, area, and porosity. Estimates of pore volume can be derived from data generated through core analysis, wireline logs, or geophysical surveys; in some cases, 3-D seismic surveys may be combined with existing well data to estimate the formation porosity. [162] [163] A second key parameter in estimating capacity is the utilization factor, or the effective pore volume. [151] [164] This is the fraction of the pore volume that would retain or store injected CO_2. Utilization factors, or storage coefficients, are a function of

the fluid already present in the reservoir, and reservoir heterogeneity at all scales, ranging from pore-throat diameters to kilometer-scale connectivity, unit architecture, and residual phase (or capillary) trapping. [151] The utilization factor is also a function of the development strategy and injection well planning, such that capacity can be increased by more wells, through optimized well design, and/or placement of wells in the reservoirs. [161]

One approach to estimating CO_2 storage capacity developed by the U.S. DOE is based on volumetric methods and considers in-situ fluid distributions and fluid displacement processes. The U.S. DOE methodology is intended to produce high-level estimates of CO_2 storage resource potential in saline-bearing formations, depleted oil and gas reservoirs, and unmineable coal seams. This resource estimate is on a regional and national scale for the United States and Canada. Like oil and gas resource estimates, CO_2 storage estimates will be proved through site-specific characterization and operations. [164] A brief overview of the DOE methodology for saline formations, oil and gas formations, and unmineable coal seams is presented in Appendix E: Overview of the United States Department of Energy Methodology for Estimating Geologic Storage Potential for Carbon Dioxide. The U.S. Geological Survey (USGS) developed a probabilistic assessment methodology to evaluate CO_2 geologic storage that uses Monte Carlo analysis of all critical factors to express the assessed capacity as a range in P10, P50, and P90. The USGS methodology is for estimating the storage resource of an individual storage assessment unit and requires substantial unit-specific data to conduct the analysis. [165] There are several other documented CO_2 storage capacity estimation approaches in existence in addition to the USGS and U.S. DOE approaches. In 2011, IEA invited experts from the geological surveys of Australia, Canada, Germany, the Netherlands, the United Kingdom, and the United States to seminars to explore ways to improve the consistency of geologic storage resource estimates. As part of the IEA seminars, six CO_2 storage atlases which contained capacity estimation methodology for different countries/regions were reviewed. Findings from the review indicated that there were significant differences between the methods and their applications. For instance, the participants concluded that the methodologies were not all based on the same scientific assumptions, they all relied on acquiring differing amounts of data, and they would produce wide ranges of capacity estimates. [166] The report generated from the seminars outlined key considerations for estimating a storage resource and contrasted the approaches used from the different countries. Additionally, the report provided best practices and guidance that should be followed to conduct CO_2 storage resource assessments across geologic settings, regardless of the amount of available geologic data, moving forward. In many instances, the USGS methodology discussed above contained many of the IEA report's suggested guidance (probabilistic capability, subdivision of geologic units for assessment, and a strong go-by for efficiency factor use). [166] Conversely, the U.S. DOE methodology discussed above is deterministic in nature and intended for use on the regional and national scale. But, the development of the CO_2-Storage prospeCtive Resource Estimation Excel aNalysis tool by NETL enables implementation of the U.S. DOE methodology to account for geologic unit subdivision to the formation scale and probabilistic analysis capability, [167] [168] which enables better alignment of the U.S. DOE methodology to the IEA report's suggested guidance.

- **Containment** is essential for effectively storing large volumes of CO_2 in the subsurface. Since injected CO_2 is buoyant relative to other subsurface fluids (formation brine), gravitational (buoyancy) forces will drive CO_2 upward from the injection point to the top of the storage formation. A confining zone (also called a caprock, confining unit, or seal) is a geologic formation that overlies the reservoir formation preventing further migration. For a confining zone to be effective, it must 1) be laterally extensive and thick enough to counter the total buoyant forces of the accumulated CO_2 in the reservoir, 2) possess low vertical permeability, 3) have high capillary entry pressure, 4) possess sufficient thickness, and 5) be void of leakage conduits (either improperly sealed wellbores, extensive fracturing, or faulting). Marine and lacustrine shales and thick deposits of evaporites (like anhydrite/gypsum and salts) are common caprocks in a confining zone. Containment through this physical trapping contains very high fractions of CO_2 and acts immediately to limit vertical CO_2 migration. However, other trapping mechanisms (e.g., capillary trapping, dissolution trapping, and mineral trapping) can often work in combination to ensure that CO_2 remains in the storage reservoir. [161]

Not all the information necessary to assess these factors is typically readily available without investing in drilling, surveying, and sampling activities. Many of these parameters are identified during the initial screening and site-selection phases of a potential CCS project, and further validated through the site characterization phase (see Section 5.4 for details on these phases). Furthermore, the key parameters discussed above are consistent with those proposed by Katz et al. [102] [103] for successful natural gas storage design and operations, which include 1) accessing desired capacity, 2) developing and maintaining deliverability; and 3) preventing migration. It is clear how each of these three categories for subsurface natural gas storage is similar to the same parameters for CO_2 geologic storage. Appendix F: Selected Characteristics of Carbon Capture and Storage Projects Worldwide provides a list of a selected group of ongoing or recently completed CCS projects that features each project's key geologic characteristics for a comparative analysis of successful and non-successful injections.

While these technical considerations are a must, a potential CCS operator must also consider whether the project is economically viable from a cost-effectiveness perspective, is acceptable to the public, and meets the necessary regulatory requirements for CO_2 injection.

5.4 Phases of a CO_2 Geologic Storage Project

CO_2 injection and storage projects can be complex undertakings. As mentioned in Section 5.3, a CO_2 saline storage site operator should ensure, at a minimum, that the candidate storage site 1) has the necessary capacity for storage; 2) meets the conditions necessary for injectivity to introduce CO_2 in the subsurface at the desired rate; 3) has adequate depth to contain CO_2 as a dense phase (typically greater than 2,600 ft); 4) provides for safe injection such that CO_2 leakage is prevented; 5) is safely constructed, operated, and monitored; and 6) is safely decommissioned. [158] There is a sequence of steps and actions for developing and implementing a CO_2 storage project that can be broadly divided into the following major CO_2 storage project phases:

- **Site screening and selection:** Involves evaluating regions and sub-regions that are potentially suitable for CO_2 geologic storage based on analyses of readily accessible data. CO_2 source-to-sink matching is also critical. Potential sites that meet the necessary screening criteria can be selected for further, detailed characterization
- **Site characterization:** Builds on screening of selected sites to develop a more detailed characterization and understanding of the subsurface to assess a potential site's suitability for storage as a function of containment, injectivity, and capacity
- **Permitting (injection):** Utilizes data from site characterization to build a CO_2 injection permit application. Once an injection permit is approved, injection wells are drilled, tested, and correlated with submitted geologic data; CO_2 injection authorized. MVA wells and equipment are also installed
- **Operations:** Begins pre-injection drilling; operational planning commences; active transportation and injection of CO_2 occurs; site monitoring is conducted
- **Closure of injection operations:** Involves the cessation of CO_2 injection; injection well(s) will be plugged, the associated equipment will be removed
- **PISC and site closure:** Includes monitoring of storage reservoir to assess stability of CO_2 plume and establish non-endangerment. Once non-endangerment is declared, site closure can be completed

The following subsections describe each of the project phases in more detail. Each phase could vary depending on the intended storage operation. For instance, there are differences expected in how one would characterize a potential storage site under a CO_2 EOR application compared to injection and storage into a saline-bearing formation. In addition, this approach is expected to be consistent for CO_2 storage in both on and offshore geologic settings.

5.4.1 Site Screening and Selection

The first step in any CO_2 saline storage project is to identify potential reservoirs amenable to the process. Aspects to be considered include reservoir depth, porosity, areal extent, thickness, permeability, and the state of reservoir seals. Like an underground natural gas storage endeavor, these aspects are of critical importance to a given site's injectivity, capacity, and containment. For instance, UIC Class VI guidance pertaining to siting criteria indicates that Class VI wells must be sited in areas with a suitable geologic system, which includes (per 40 CFR 146.83):

- An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO_2 stream
- Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected CO_2 stream and displaced formation fluids and

allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s)

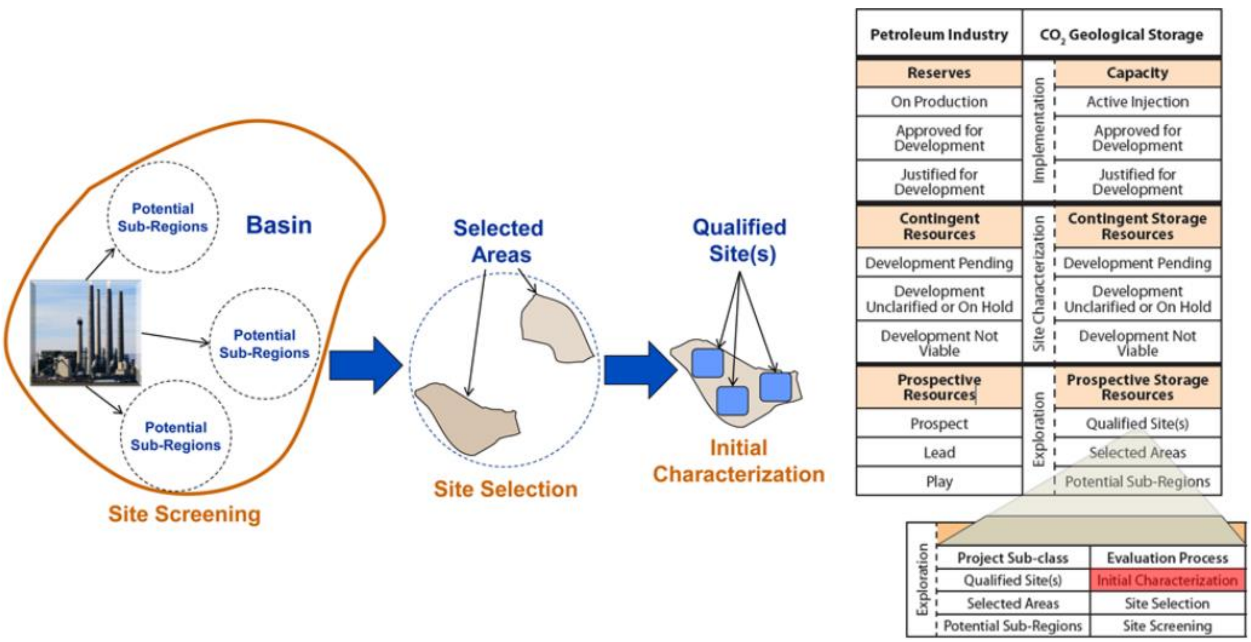
In addition, matching sources of CO_2 to potential storage sites—considering projections for future socio-economic development—is also particularly important. [14] Therefore, the site screening phase involves the evaluation of regions and sub-regions that are potentially suitable for safe CO_2 injection, capacity, and retention. The analysis in this step relies on readily accessible information that can be obtained from public sources (e.g., data, reports, masters/doctorate thesis or professional papers, etc.), state geological surveys, state departments of natural resources, groundwater management districts, academic research, previous EPA UIC injection well permits, and the U.S. National Carbon Sequestration Database and Geographic Information System (NATCARB). [169] Technical information to be collected from these sources during initial characterization of down-selected sites includes existing core sample data, well log data, available seismic surveys, records from existing or plugged and/or abandoned wells, and other available geologic data (some of which may have to be purchased from third-party vendors, which would be more prudent than acquiring new characterization data). [169] Adequate porosity and thickness (for storage capacity) and permeability (for injectivity) are critical components of a suitable storage site. It is also important to determine if the storage formation is capped by extensive confining units (such as shale, salt or anhydrite beds) to ensure that CO_2, brine, or other fluids do not migrate to overlying, shallower rock units and, possibly, to the surface. [14]

A preliminary estimate of an AoR [170] could be developed during the initial characterization stage. The AoR is a region surrounding the geologic storage project where USDWs may be endangered due to the elevated pressure in the storage reservoir. It is delineated using computational modeling that accounts for the physical and chemical properties of the injected CO_2 stream and displaced fluids. The size of the AoR is a function of both the planned injection volumes and the target reservoir characteristics, and it can have a significant impact on the non-technical factors of a project, such as monitoring locations, property and pore space ownership, land use, and available infrastructure.

Other items to be addressed during the site screening phase is evaluation of surface access, as well as pore space ownership. From a surface access perspective, factors that should be considered include the location of geologic storage sites in relation to CO_2 emissions sources, competing land uses, impact on environmentally sensitive areas, terrain and topography, and availability of infrastructure. For CO_2 pipelines, surface and near-surface competition may come from other industries that require the same rights-of-way (ROW). This may include utility transmission lines, water pipelines, and oil and natural gas pipelines. There may also be roads, rivers, and railroads to traverse, requiring special easements or ROWs. In addition, surface competition for well sites may occur at CO_2 EOR sites, where well spacing may play a key role in injection and recovery rates. From a pore space ownership perspective, in the United States, the jurisdiction for pore space ownership resides with the states. However, the legal treatment of pore space at the state level varies significantly, and project developers should gain an early understanding of the state rules governing promising areas being considered in the Site Selection stage. [169]

Screened regions and sub-regions can then be ranked based on criteria established prior to initial screening, and the highest-ranking selected areas can advance to the next evaluation stage (Exhibit 5-7). This process is analogous to the maturation of a petroleum project from "play" to "lead," and to "prospect." [169] Overall, the goal of the site screening and selection phase is to establish a down-selected list of potential qualified sites that may have the storage resource potential to accept and safely store the anticipated quantity of CO_2 at the injection rate needed for the storage project. Other factors specific to CO_2 EOR and ECBM projects would relate to understanding the potential of hydrocarbon production at candidate sites.

Exhibit 5-7. Graphical representation of a geologic storage project from site screening through selection of a qualified site for initial characterization. Petroleum-based and proposed CO_2 storage-based resource classification systems are included for perspective [171]



5.4.2 Site Characterization

Site characterization is one of the most important steps for ensuring the safety and integrity of a CO_2 geologic storage project as well as demonstrating that the site is capable of meeting required storage performance criteria outlined in Section 5.3. [14] Site characterization efforts are investigative processes in which the project operator acquires site-specific geological information to better understand (with supporting data) the geologic conditions that were identified during an early site screening phase. [9] Much of the site-specific data are collected, geologic and environmental baselines are established, and permit applications are developed during this phase. Permits could be required for certain site-characterization activities such as seismic reflection surveys or a stratigraphic test well. EPA has published several Class VI guidance documents intended to assist both UIC Program directors in implementing the Class VI program, and Class VI well owners or operators in complying with the Class VI regulations [172], including one specific to site characterization. [173] The types of site characterization information specified by the Class VI rule that must be provided with a Class VI well permit application include

- Maps and cross-sections of the AoR [40 CFR 146.82(a)(3)(i) and 146.82(a)(2)]; and the general vertical and lateral limits of all USDWs, water wells, and springs within the AoR, their positions relative to the injection zone(s), and the direction of water movement (where known) [40 CFR 146.82(a)(5)]
- Location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the AoR, along with a determination that they will not interfere with containment [40 CFR 146.82(a)(3)(ii)]
- Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s) and on lithology and facies changes [40 CFR 146.82(a)(3)(iii)]
- Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s) [40 CFR 146.82(a)(3)(iv)]
- Information on the seismic history of the area, including the presence and depths of seismic sources, and a determination that the seismicity will not interfere with containment [40 CFR 146.82(a)(3)(v)]
- Geologic and topographic maps and cross-sections illustrating regional geology, hydrogeology, and the geologic structure of the local area [40 CFR 146.82(a)(3)(vi)]
- Baseline geochemical data on subsurface formations, including all USDWs in the AoR [40 CFR 146.82(a)(6)]
- Information on the compatibility of the CO_2 stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s) [40 CFR 146.82(c)(3)]
- Results of formation testing [40 CFR 146.82(c)(4)]
- All available logging and testing program data on the well [40 CFR 146.82(c)(7)]

The conceptual approach for site characterization and selection is a process in which a small number of candidate sites are identified based on readily available information and preferences. Then selected candidate sites are further investigated, including conducting site-specific risk assessments, to evaluate and rank them (Exhibit 5-7). As a site is characterized in further detail, the operator gradually begins to understand the distinctions of the site-specific geology. [161] Detailed site characterizations are conducted to finalize selection of the most suitable sites and prepare permit applications. The suitability of a site for storage is a function of its containment, injectivity, and capacity with specifics including 1) effectiveness of a confining zone in preventing upward migration of CO_2 and other fluids, 2) injectivity of the storage reservoir, and 3) volumetric capacity of the reservoir to hold injected CO_2. Similar to characterizing a new underground natural gas storage site, detailed site characterization tools may include both data collection (e.g., seismic and well logging, core analysis, and injectivity tests) and 3-D mathematical models of the selected injection and confining zone(s). [169] Much of the data collected at this point will necessarily be site-specific, and data used for developing geological models will be used to simulate and predict the performance of the site (injection rates, CO_2 plume movement, pressure front estimation, refining the AoR estimate, etc.). [14] A critical goal of site characterization is to establish baselines for key geologic, geochemical, geomechanical, hydrologic, and flux parameters prior to CO_2 injection. These baseline values will be used later to support monitoring of a project providing reference points from which to identify changes resulting from CO_2 injection. [169] Site characterization may be easier to complete for areas for which significant pre-existing data is available (i.e., mature oil and gas fields). In areas for which very little pre-existing data about the subsurface are available, site characterization could be a more complex process that may require more time and expense to complete. [161]

Successful site characterization is the most important step for ensuring the safe and economical operation of a CO_2 storage site that meets minimum UIC Class VI siting criteria specified in 40 CFR 146.83. [169] Other considerations when screening for and characterizing candidate storage sites include 1) extensively faulted and fractured sedimentary basins, or parts thereof, that may require careful characterization to determine if they would be good candidates for CO_2 storage and 2) the possible presence of fossil fuels and the exploration and production maturity of the basin. Mature sedimentary basins could be primary targets for CO_2 storage both because of their well-known characteristics and portions of the infrastructure needed for CO_2 transport and injection may already be in place. [14] Outreach and public engagement are also a critical component of a CO_2 storage project. [169] In some cases, site characterization may involve extensive field work to determine a site's suitability for a CO_2 storage project. This fieldwork might include conducting visual assessments of the community and seismic surveys, as well as drilling boreholes and test wells. If site characterization activities include these steps, then an outreach plan needs to be developed and implemented to educate the surrounding communities and stakeholders, as well as to build relationships that can be used to facilitate sharing of information during the lifetime of the project. [169]

Additionally, data acquired from site characterization are used to prepare five plans (Area of Review and Corrective Action Plan, Testing and Monitoring Plan, Injection Well Plugging Plan, Post-Injection Site Care and Site Closure Plan, and Emergency and Remedial Response Plan) required for permitting a Class VI permit. [161]

5.4.3 Permitting (Injection)

Permitting requirements diverge significantly depending on the end use of the CO_2 injection operation. For instance, CO_2 storage operations are required to inject under UIC Class VI well permits, and CO_2 injection for enhancing hydrocarbon recovery is mandated under UIC Class II well permits. Generally, for both types of well classes, the information gathered during site characterization is assembled into an injection permit application, a reservoir model, and the preliminary project design.

For UIC Class VI wells, the site operator must submit a UIC Class VI permit application (with the appropriate plans) to the applicable regulatory agency prior to installing and operating a well to inject CO_2. Each CO_2 injection well requires its own permit although several Class VI wells can have a common AoR. Once an injection permit is granted, an operator will drill, test, and complete the permitted injection well(s). New wireline logging, core(s), fluid samples, and wellbore seismic data acquired from the new injection well(s) are correlated with data from the five submitted plans mentioned above. If no major revisions in the plans are needed based on review of new data, then injection of CO_2 can be authorized. Major revisions would require re-opening the permitting process. Once injection begins, the site operator has 180 days to develop and submit the MRV plan for Subpart RR compliance. [174] Applying for a Class VI injection permit is a significant undertaking that is complex and time consuming. There can be a significant delay between the completion of site characterization and initiation of operational phases due to processing and review of injection permits. As one example, the Illinois Industrial CCS Project (ICCS) Class VI permit process began with application submission in July 2011, but their Class VI permit was not awarded until December 2014. Injection of CO_2 did not begin until April 2017. [175] Class VI permits are issued for the operating life of the facility and PISC per 40 CFR 146.36.

Class VI operations must be able to provide financial responsibility for CO_2 storage operations. This is demonstrated during the permit application process. Financial responsibility requirements are designed to ensure that, should owners or operators fail to fulfill their obligations, funds are available to pay a third party to carry out required geologic storage activities related to closing and remediating geologic storage sites if needed, during injection or after wells are plugged, so that they do not endanger USDWs. These requirements are also designed to ensure that the private costs of geologic storage of CO_2 are not passed along to the public. [176] The financial responsibility instrument(s) that can be used as per 40 CFR 146.85 may include any of these qualifying instruments: 1) trust fund, 2) surety bond, 3) letter of credit, 4) insurance, 5) self-insurance, 6) escrow account, or 7) another instrument(s) satisfactory to EPA. The financial responsibility qualifying instrument(s) must be sufficient to cover the cost of the following components of the UIC Class VI rule:

- Corrective action (that meets the requirements of § 146.84)
- Injection well plugging (that meets the requirements of § 146.92)
- PISC and site closure (that meets the requirements of § 146.93)
- Emergency and remedial response (that meets the requirements of § 146.94)

5.4.4 Operations

The operations phase is the project phase in which active CO_2 transportation and injection occurs at the selected storage site. Information obtained during site screening and selection, as well as site characterization, and the engineering requirements dictated by the CO_2 source, provide a technical basis for operational planning. The preliminary activities of this phase can include operational planning, site preparation, drilling monitoring well(s) as needed, and facility construction. Some of this work may be done during the permitting phase when the injection wells are drilled and tested. During injection operations, activities include monitoring and collecting operational data per the approved plans. [161]

Monitoring is a major component of the CO_2 injection operations. It is during the operational phase that the bulk of the MVA activities occur, the most critical is tracking the movement of the underground CO_2 plume and pressure front to ensure safe operating conditions, detecting leaks, and ensuring that USDW are not contaminated by brine or CO_2. [177] Plume monitoring will determine whether the injected CO_2 is behaving as predicted. If not, modifications to the operating procedure may be required. If a leak is detected, remedial action may be necessary. A detailed risk assessment and analysis performed early in the project should identify appropriate actions to mitigate various leak scenarios should a leak occur, either during operation or after project closure. Several mandatory monitoring requirements under EPA's UIC Program (see Section 3.2.1) dictate MVA approaches for projects and are normally established before an injection permit is issued.

Planning for operations will be different depending on the purpose of the selected site—if it is for geologic storage or for CO_2 EOR. An overview of the operations phase is provided in Section 5.4.4.1 for CO_2 storage in saline formations and Section 5.4.4.2 for CO_2 EOR to highlight the different perspectives.

5.4.4.1 Saline Storage Operations

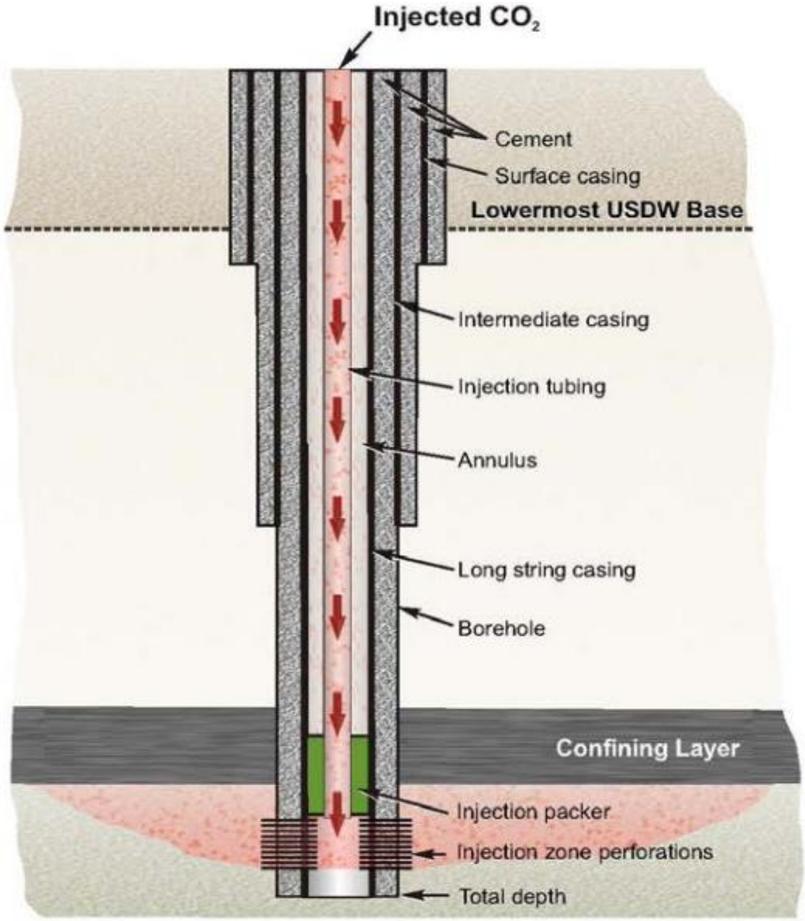
Storage of CO_2 in saline reservoirs is an attractive option for CCS operations. For instance, the storage resource potential for saline reservoirs is estimated to be substantial. [8] Additionally, saline storage capacity potential is much greater than that for depleted oil and gas reservoirs, and saline reservoirs are also widespread geographically, providing more opportunities for CO_2 storage from many emission sources. [8] The preservation of caprock integrity, storage permanence, and pressure management within the storage reservoir are key considerations for CO_2 storage in saline-bearing formations. [178] In addition, management of brine fluids in the reservoir could play a key role in saline storage operations due to possible pressure increase(s) within the formation during CO_2 injection. Brine extraction could reduce the formation pressure, but additional production wells and fluid handling at the surface will be needed (and either a follow-on water treatment or disposal option). Generally, the resultant pressure front within the saline storage reservoir extends much further than the CO_2 plume, creating an expanded area in which the risk to seal integrity (creating fractures or activating faults) and displacement of formation brine increases. To quantify the risk of CO_2 leakage, it is necessary to determine the extent of the CO_2 plume and pressure front and assess potential leakage pathways for CO_2 or brine. Monitoring the magnitude and location of pressure build-up in the reservoir is important for operators and regulators evaluating pressure induced risks. Additionally, CO_2 storage operations revolve around one-way injection of CO_2; this approach significantly differs from underground natural gas storage, in which cyclical injection and production periods of natural gas occurs.

Operators of Class VI wells are required to take diligent action and follow approved plans during the operational phase of a CO_2 storage project to ensure safe and effective operations. For instance, UIC Class VI regulations require operators to not exceed injection pressure of 90 percent of the fracture pressure of the injection zone(s) to ensure that the injection does not initiate new fractures or propagate existing fractures. Only during permitted stimulation of the injection zone(s) can an operator exceed 90 percent of the fracture pressure. Other safeguards include performance standards for well construction to ensure that CO_2 cannot move between formations along the wellbore. For instance, all well materials must be compatible with fluids in which the materials may be expected to come into contact (e.g., CO_2 formation brines) and must meet or exceed standards developed for such materials by the API, American Society for

Testing and Materials International, or other comparable standards deemed acceptable by EPA. Additional well construction requirements include the following (Exhibit 5-8 below is a schematic of a typical Class VI well [not to scale] and highlights the components as they are described in the bullets below):

- Filling the well annulus between the tubing and the long string casing with a non-corrosive fluid [40 CFR 146.88(c)]
- Surface casing must extend through the base of the lowermost USDW and be cemented to the surface using single or multiple strings of casing and cement [40 CFR 146.86(b)(2)]
- At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages [40 CFR 146.86(b)(3)]
- Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the API, American Society for Testing and Materials International, or other comparable standards acceptable by EPA [40 CFR 146.86(c)(1)]
- All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval [40 CFR 146.86(c)(2)]
- Install and use 1) continuous recording devices to monitor the injection pressure, the rate, volume and/or mass, and temperature of the CO_2 stream, the pressure on the annulus between the tubing and the long string casing, and annulus fluid volume [40 CFR 146.88(e)(1)]; 2) for onshore wells, alarms and automatic surface shut-off systems or, down-hole shut-off systems (e.g., automatic shut-off, check valves), or other mechanical devices that provide equivalent protection [40 CFR 146.88(e)(2)]; and 3) for offshore wells within State territorial waters, alarms and automatic down-hole shut-off systems designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit [40 CFR 146.88(e)(3)]

Exhibit 5-8. Schematic example of a UIC Class VI injection well featuring key well components and relation to USDWs, confining layer, and injection zone [179]



Source: U.S. EPA

Commercial-scale CO_2 injection projects are anticipated to operate for upwards of 30 to possibly 60 years—in some cases, even longer depending on the duration of PISC. [161] It is expected that many of the baseline project conditions may change dramatically over the project lifetime as a result of injection. Monitoring, analysis of collected data, and reservoir modeling are needed throughout a project's operational life to understand the impacts of injection. For CO_2 injection and storage using a Class VI well, the following operational phase monitoring and subsequent modeling is required:

- Tests of both continuous and periodic well mechanical integrity [40 CFR 146.89]
- Analysis of the CO_2 stream with sufficient frequency to yield data representative of its chemical and physical characteristics [40 CFR 146.90(a)]
- Installation and use of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added [40 CFR 146.90(b)]

- Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis [40 CFR 146.90(c)]
- Periodic monitoring of the groundwater quality and geochemical changes above the confining zone(s) [40 CFR 146.90(d)]
- Testing and monitoring to track the extent of the CO_2 plume and the presence or absence of elevated pressure by using: 1) direct methods in the injection zone(s) [40 CFR 146.90(g)(1)] and 2) indirect methods (like seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO_2 detection tools) [40 CFR 146.90(g)(2)]
- Delineation of the AoR at a frequency no less than every five years during operation [40 CFR 146.84(b)(2)(i)]. This includes predicting the projected lateral and vertical migration of the CO_2 plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed period as determined by EPA. The model would be built on existing site characterization, monitoring, and operational data [40 CFR 146.84(c)(1)]

5.4.4.2 Enhanced Recovery and CO_2 Storage Operations

Separate from CO_2 storage in saline-bearing formations, captured anthropogenic CO_2 can also be utilized for injection operations that promote additional hydrocarbon recovery as well as CO_2 storage. [180] Examples of these types of operations include CO_2-based EOR and ECBM. The storage reservoir types applicable to these operations is described above in Section 5.2.1 and Section 5.2.3, respectively. CCS in storage formations applicable to enhanced recovery provides an opportunity for greater recovery of domestic oil, natural gas, and coalbed methane, combined with permanent storage of anthropogenic CO_2.

The use of CO_2 for EOR operations began in the early 1970s. CO_2 EOR production is typically developed in phases across an oil field, with the injection and production wells organized in a specific pattern. [155] The amount and pattern of production and injection wells can vary by oil field, as well as change over the life of the production operation. During EOR operations, injected CO_2 is brought to the surface along with the produced oil, while a portion of it remains in the reservoir and can be considered stored. The produced CO_2 is separated, compressed, and reinjected into the reservoir. New CO_2 is purchased and added to the injected volume to replace the CO_2 left in the reservoir. For each “cycle” of injection, the “stored” portion of CO_2 can potentially be a large portion of the CO_2 injected (generally considered to be 30 to 40 percent but will likely vary based on the geologic properties of the reservoir in question). Overall, this CO_2 that remains in the formation as part of the oil production cycle is a form of geologic storage, as the CO_2 will be contained indefinitely within the reservoir. This is often referred to as incidental storage. [181] It should be noted that EOR operations are closed-loop processes and the produced CO_2 is not released into the atmosphere. [14] The use of CO_2 in tertiary oil recovery operations helps to extend the productive life of an oil reservoir and enables the extraction of a significant volume of oil that might have otherwise been left in place. Recently, CO_2 storage as a component of EOR operations has been the focus of several research initiatives. CO_2 that has been (or can be) stored in the subsurface during EOR operations in depleted oil reservoirs provides an industrial analog framework based on extensive geologic characterization, existing pipeline infrastructure, extensive reservoir management, and regulations conducive to the long-term storage of CO_2 in the subsurface. CO_2 EOR is discussed in further detail as an analog to CO_2 storage in saline-bearing formations in the NETL report titled *CO_2 Leakage During EOR Operations – Analog Studies to Geologic Storage of CO_2*. [182] Research efforts to improve CO_2 EOR injection volume and sweep efficiency, improvements to oil productivity, as well as the mobility of CO_2 in the subsurface, will play a significant role in the continued development of EOR as a means of permanently storing anthropogenic CO_2 in the subsurface. [149]

As described in Section 5.2.3, enhanced coalbed methane (i.e., ECBM) recovery processes may be possible through injecting and storing CO_2 into unmineable coal seams to boost methane recovery. Closure of Injection Operations

5.4.5 Closure of Injection Operations

Most site closure activities will take place once all injection has ceased. Site closure activities could include decommissioning surface equipment (associated with injection), plugging injection wells, restoring the site, and preparing and submitting site closure reports. Surface facilities not associated with PISC may be removed, including buildings, access roads and parking areas, sidewalks, underground electric and telecommunication facilities, and fencing. In addition, the land could be reclaimed to a pre-development state or for other uses (like agriculture). [161] [183] Site closure, as described here, relates specifically to the cessation of injection operations and preparation of the site for post-injection monitoring and site care. The closure requirements could vary depending on the specific UIC well class (Exhibit 3-3). For instance, for Class VI wells, regulatory requirements suggest that the injection well would be flushed, the bottom-hole reservoir pressure after injection determined, and a final external MIT performed. Additionally, monitoring wells must be plugged in a fashion that prohibits fluid movement from endangering USDWs.

5.4.6 Post-Injection Site Care and Site Closure

The PISC phase comprises preparing the CO_2 storage site for long-term monitoring per the approved plan leading to the decommissioning and closure of the site. In general, the PISC phase of a project is intended to ensure the safety of USDWs, that the stored CO_2 plume presents a non-endangerment. Monitoring and modeling as well as tracking the decrease in pressure of the CO_2 plume are critical to establish non-endangerment. [184] UIC regulations indicate that the owner or operator shall continue to conduct PISC monitoring for the duration of the permit-approved timeframe, 50 years (Exhibit 3-3). The operator can apply for the duration of PISC to be reduced upon application of the Class VI permit and again following cessation of injection operations prior to PISC. Even with a reduced period for PISC, non-endangerment can still be demonstrated. Once non-endangerment is established, the site can be closed. All wells used for monitoring are plugged, and surface monitoring equipment is removed. All well sites and surface equipment sites are reclaimed, and the permit is released.

5.5 The Cost to Implement CO_2 Storage

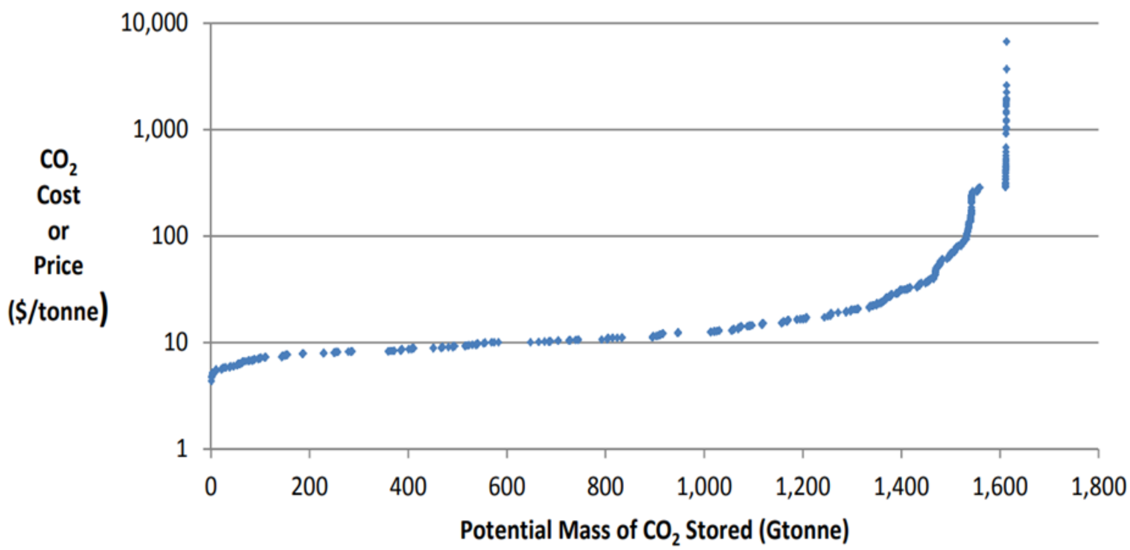
The potential costs of commercial-scale CCS are still not fully understood, particularly from a fully integrated (capture, transportation, and storage) perspective. [148] The challenge stems mainly from estimating storage costs, which is not a simple or straightforward process. [185] A typical storage project involves the time-intensive steps of site screening, site selection and characterization, permitting and construction, operations, and PISC and site closure. [186] Therefore, most CCS cost studies typically exclude, or assign a fixed constant for storage cost. [186] [187] However, such a simplistic approach ignores the large variation in storage cost due to differences in operational monitoring and reservoir quality. [185] [188]

The geologic heterogeneity of storage formation characteristics is the major driver of site specific cost variability. [189] Reservoir depth, thickness, permeability, and porosity affect injectivity, storage capacity, and formation pressures, which, along with structural setting, impact the aerial extent of the CO_2 plume, one of the primary cost drivers of storage costs. [190] [191] A smaller plume footprint, particularly when physically constrained by dome or anticlinal structures, lowers cost by reducing the number of wells needed for monitoring or injection, permit requirements, and the need for surface access. [174] In general, the lowest storage costs, both for drilling and monitoring, will be associated with formations that have the highest storage capacity, even if those reservoirs are further away from a CO_2-generating source. [185] [189] [192] Typically, these are relatively thick, shallow (but still at a depth where CO_2 remains in a supercritical state) and highly permeable formations. [14]

The impact of regulation on cost, including monitoring requirements, liability and long-term management of CCS projects, remains uncertain. [187] EPA's UIC Program requires Class VI well owners or operators to demonstrate and maintain financial responsibility to cover the cost of corrective action, well plugging, emergency and remedial response, and PISC activities. [91] Since the PISC stages could last more than 50 years, the selection of a financial instrument and its associated parameters like pay-in period, tax rate, and administrative fee could have a drastic impact on total storage cost.

NETL developed a FE/NETL CO_2 Saline Storage Cost Model (Storage Cost Model), which is used to estimate the revenues and cost associated with implementing a saline storage project (does not estimate costs for CO_2 capture or transport). The model is built by utilizing scientific and engineering principles that are influenced by subsurface injection. It is based on ensuring compliance with the UIC Class VI regulations developed by EPA for constructing, operating, permitting, and closing injection wells used to place CO_2 underground for storage. The model contains geographical and geological data for 226 reservoirs across 48 states in the United States to simulate the CO_2 first-year break-even costs based on currently available technology. [174] Reservoir data is sourced from the NATCARB database. Storage reservoirs can be modeled under three structural settings: dome, anticline, and regional dip. With the baseline assumption [174], injecting 3.2 million tonnes (Mt) of CO_2 for 30 years, the lowest CO_2 break-even price is \$4.30/tonne and the highest is over \$1,000/tonne in 2011 dollars (2011\$), based on currently available technology. Exhibit 5-9 presents the cost-supply curve from the NETL baseline study. [174] The y-axis is the first-year break-even price of CO_2 (\$/tonne) in 2011\$. The x-axis is the cumulative potential CO_2 storage capacity for a given price (gigatonnes [Gt or Gtonne]). The cost curve represents the potential cumulative mass of CO_2 that can theoretically be stored in the 226 storage reservoirs under the corresponding per tonne price. The potential storage cost supply curve shows an upsloping to vertical trend on the right-hand side indicating poor quality, high cost storage reservoirs. [186] The left-hand side of the curve shows approximately 550 Gt of potential storage capacity is available for under $10/tonne and approximately 1,350 Gt potential storage capacity is available for under $25/tonne. Both potential storage capacity numbers exceed the estimation by EIA that if 90 percent of all the CO_2 emitted from power plants and stationary industrial sources over the next 100 years were captured, the mass of captured CO_2 would be approximately 315 Gt. [193]

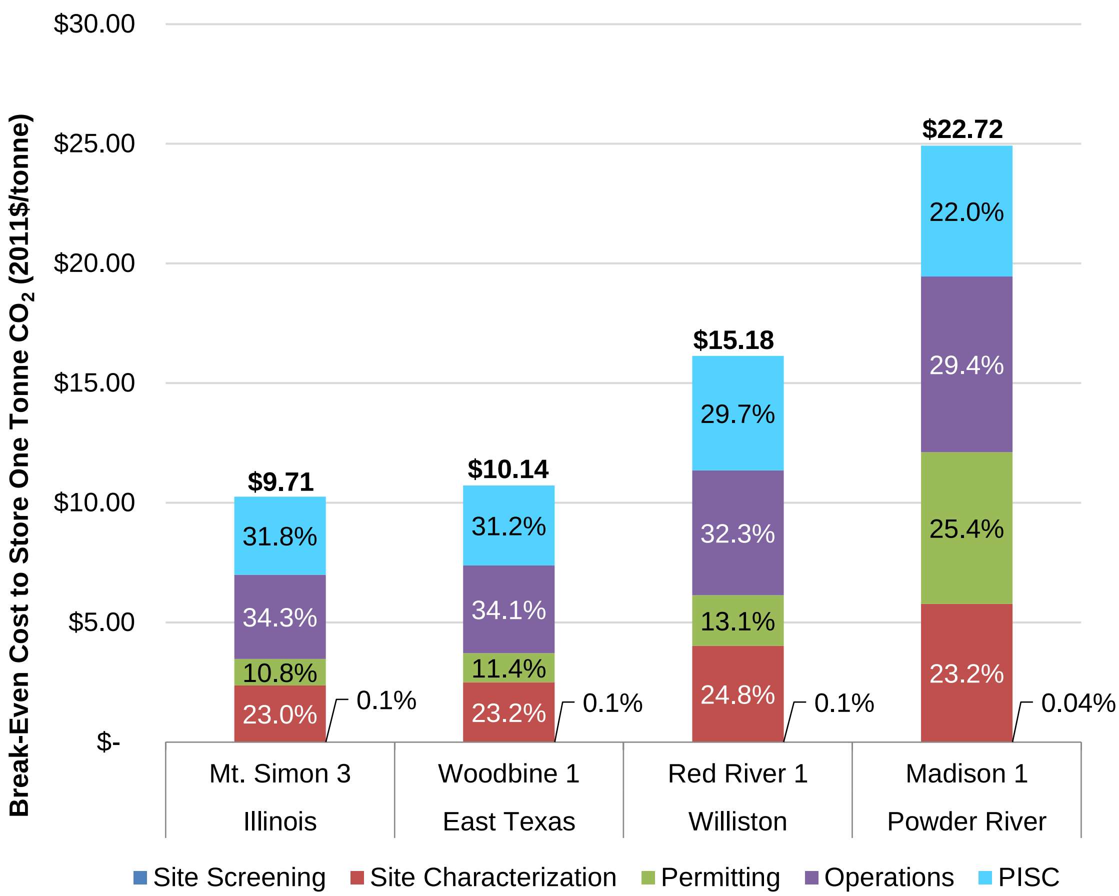
Exhibit 5-9. Cost supply curve for baseline case [174]



Another NETL study estimated the storage cost variability in four different basins: Illinois, East Texas, Williston, and Powder River, using region specific results from the Storage Cost Model. [190] The study established three scenarios to model a low-cost case, base case, and high-cost case to account for the variation in geologic characteristics of multiple formations and their reservoir subsets in each basin. The model parameters of trust fund growth rate, monitoring well spaces, PISC length, and project stage durations were changed between the three scenarios, but remained identical between basins. The results of this study, for example, show that the Mt. Simon reservoirs in the Illinois Basin are the low-cost providers with low, base, and high cost case estimates at $5.61/tonne, $9.71/tonne, and $18.99/tonne in 2011$, respectively.

Exhibit 5-10 shows the break out of storage costs (in 2011$/tonne) by project stage (site screening, site selection and characterization, permitting and construction, operations, and PISC) for one reservoir in each of the four basins. Cost breakouts presented were for the regional dip structural setting for each formation and the reservoir combination that provides CO_2 storage resource potential at 25 Gt. Costs for site characterization, operations, and PISC (which are impacted by the size of the CO_2 plume), were similar for the Mt. Simon 3 reservoir in the Illinois Basin and the Woodbine 1 reservoir in the East Texas Basin, but increased for the Red River 1 reservoir in the Willison Basin and Madison 1 reservoir in the Powder River Basin due to an increasing plume size and number of monitoring wells required. The greatest overall cost contribution difference between reservoirs is related to permitting, which increases when more injection wells are needed to meet targeted injection rates (influenced strongly by permeability and reservoir thickness). For instance, permitting costs are the highest for the Madison 1 reservoir because of the relative need of more injection wells compared to the other reservoirs.

Exhibit 5-10. CO_2 break-even price to store one tonne of CO_2 by project stage for reservoirs at 25 Gt for base case (regional dip structure) [190]



As noted, estimating storage costs is not a straightforward process and is highly dependent on variations in reservoir geology. However, since CO_2 capture is fixed to the source, storage is an important CCS variable, and is required to achieve a minimum integrated CCS cost. Additionally, it has been shown that the unit cost of storage decreases with increasing mass of CO_2 stored. [192]

5.6 Comparison and Contrast of CO_2 Geologic Storage with Underground Natural Gas Storage Operations

The content presented in previous sections of this report shows that underground natural gas storage is a quality analog that can be used to help address technical and policy-related questions concerning CO_2 geologic storage—more specifically focused on long-term CO_2

storage in saline-bearing formations using UIC Class VI wells. In the context of this report, analogs are identified as examples or case studies that help identify features that are likely to be effective for CO_2 storage and those that should be avoided. In addition, analogs help to compare two different industries—in this case underground natural gas storage and CO_2 geologic storage.

This section presents a side-by-side comparison of major synergistic features (such as governing regulations, formation types used, national capacity estimates, leakage risks, and others) between underground natural gas storage as an analog to CO_2 storage. In general, natural gas is a potentially more dangerous gas than CO_2 given its flammability, but it has been successfully stored underground for decades with numerous natural gas storage sites existing throughout the United States and worldwide. However, over its 100-year operational history, a relatively-small sample of known leakage incidents (discussed in Section 6) has blemished the natural gas storage industry safety record to some degree, and even prompted potential regulatory changes (for instance, the PIPES Act). [1] Findings from these specific incidents can serve as learning opportunities for informing future CO_2 storage best practices and ensuring safe operations. [13]

There are several significant similarities between the two practices including underground storage of a buoyant fluid, the need for an adequately thick caprock (ideally with a secondary caprock above the primary seal to ensure long-term containment), adequate pore space and permeability to enable sufficient storage capacity, injectivity—and in the case of natural gas storage—deliverability. For both practices, injection wells must be properly designed, installed, monitored; maintained and abandoned wells in and near the project area must be located and plugged. [14] Careful control of injection pressure and final reservoir pressure based on geomechanical properties is necessary under both practices to avoid damage to the caprock (with similar precautions needed for enhanced recovery projects). Overall, most of these parameters can be properly identified through geologic characterization and selection of storage sites. [13]

While prominent similarities exist between the two practices, there are major differences including the prominent governing regulations and regulatory bodies that oversee each practice, the varying levels of commercial application and experience of each practice (natural gas storage and CO_2 EOR are commercialized industries, whereas CO_2 storage in saline-bearing formations is still a relatively new concept that has been undergoing pilot and early commercial-scale testing), and the types and physical state of the injected fluid.

The similarities and differences are worth mentioning and have been compared in detail below. Exhibit 5-11 is a tabularized summary of the major synergistic features for both underground natural gas and CO_2 geologic storage (for both enhanced recovery via CO_2 EOR or ECBM, as well as storage in saline-bearing formations) for an easy side-by-side comparison.

Exhibit 5-11. Comparison of key items pertaining to underground natural gas storage, enhanced recovery and CO_2 storage, and saline CO_2 storage

Item	Natural Gas Storage	Enhanced Recovery and CO_2 Storage	Saline CO_2 Storage
Purpose	Store gas for peak usage months	Increase hydrocarbon recovery (tertiary recovery) with the use of natural or anthropogenic CO_2 Reduce carbon emissions to atmosphere from anthropogenic CO_2 sources	Reduce CO_2 emissions into the atmosphere through injection of captured CO_2 into deep, confined rock formations for long-term storage
Technology Inception	Early-1900s	Early-1970s	Mid-1990s Class VI well promulgated: 2010
Number of Active Fields or Projects	415 in United States	Approximately 136 active – United States only [194]	Three active projects in the United States under the UIC Class VI
Formation Types	Saline-bearing formations Depleted oil and gas fields Salt caverns	Depleted oil and gas reservoirs Residual oil zones Unmineable coal seams Organic shale	Saline-bearing formations
Injected Fluid Phase	Gas	Gas or supercritical CO_2	Supercritical CO_2
Prominent Regulations	PIPES Act of 2016 Energy Policy Act of 2005	SDWA UIC Class II: ▪ 40 CFR 144 Subpart A ▪ 40 CFR 146 Subpart C Clean Air Act Subpart UU	SDWA UIC Class VI: ▪ 40 CFR 144 Subpart A ▪ 40 CFR 146 Subpart H Clean Air Act Subpart RR
Regional Prominence	Reference Exhibit 2-7	Reference Exhibit 5-3 for oil and gas reservoirs Reference Exhibit 5-5 for unmineable coal seams Reference Exhibit 5-6 for organic shales	Reference Exhibit 5-4
Potential National Storage Capacity	Depleted oil and gas fields ~7,078 Bcf of natural gas Saline-bearing formations	Estimated resource potential: Depleted oil and gas reservoirs 186 – 232 billion tonnes of CO_2	Estimated resource potential: Saline-bearing formations 2,379 – 21,633 billion tonnes of CO_2

Item	Natural Gas Storage	Enhanced Recovery and CO_2 Storage	Saline CO_2 Storage
	~1,446 Bcf of natural gas Salt caverns ~709 Bcf of natural gas	Unmineable coal seams 53 – 113 billion tonnes of CO_2	
Injection Well Design Considerations	Storage wells must contain a minimum of two casing strings: surface and production Cementing each string provides additional zonal isolation by sealing the space between the formation and casing Additional strings can include intermediate casing and production tubing depending on the depth of the target reservoir and well costs	Cased and cemented to prevent movement of fluids into or between USDWs (based on state requirements where state primacy is established) Injection formation fluid pressure, estimated fracture pressure, and physical/chemical characteristics of the injection zone must be understood to inform proper well design Periodic observation of injection pressure, flow rate, cumulative injection volume Injection pressure limited to 80 percent of fracture pressure (for most states)	Well materials compatible with fluids present in the subsurface Surface casing must extend through base of lowermost USDW and be cemented to the surface At least one long string casing with centralizers from surface to injection zone and cemented back to the surface Tubing and packer required to inject CO_2 Annulus between tubing and long string casing must be filled with a non-corrosive fluid Continuous recording devices needed to monitor pressures, flowrate, volume/mass, and CO_2 stream temperature Alarms and shut-off systems may be required Injection pressure limited to 90 percent of fracture pressure
Number of Injection Wells	Likely to vary from site to site; the key driver in the number of wells needed is to attain desired peak deliverability Lateral migration of natural gas not considered acceptable; therefore, projects may require many wells	Considerable number of wells (often pattern based [5-spot, 9-spot, etc.]) to maximize CO_2 sweep efficiency and hydrocarbon production	Injection well count tied to mass of captured CO_2 requiring storage injection. Spare injection capacity needed to allow well shut-in for maintenance
Prominent Containment Mechanism	Stratigraphic or structural trapping mechanism	CO_2 EOR = formational residual trapping ECBM = adsorption Enhanced recovery in organic shale = adsorption	Structural/stratigraphic trapping with overlying low permeability formation providing a seal Secondary trapping mechanisms

Item	Natural Gas Storage	Enhanced Recovery and CO_2 Storage	Saline CO_2 Storage
Leakage Risks	Wellbore failures Caprock integrity – faults and fractures	Wellbore failures Surface equipment leakage	Wellbore failures Caprock integrity – faults and fractures
Commercial-scale Examples	Baker Field, Montana – NG Clear Lake Field, Texas – NG Washington 10 Complex, Michigan – NG Oakford Field, Pennsylvania – NG Mont Belvieu, Texas – NGL	Weyburn-Midale Project – Canada SACROC – West Texas Farnsworth Unit – West Texas West Hastings Unit – Texas Gulf Coast Pump Canyon CO_2-ECBM storage demonstration – New Mexico Allison Unit CO_2-ECBM Pilot – New Mexico	Sleipner – North Sea, Norway Snøhvit CO_2 Storage Project – Barents Sea, Norway In Salah – Algeria SECARB Cranfield Project – Mississippi Illinois Basin Decatur Project – Illinois ICCS – Illinois

A case study that compares capacity between a real-world (on a volume basis) underground natural gas storage facility or an NGL facility and a potential CO_2 storage operation would be a useful way to comparatively evaluate the relative size of each operation. For an NGL comparison, a simple approach would be to estimate the amount of CO_2 that could be stored if a facility such as Mont Belvieu (a large NGL storage facility) was converted to a CO_2 storage field. This example assumes 127 MMBbl of NGL storage (Section 2.6) and supercritical CO_2 with a density of around 29.2 pounds per cubic foot (at 1,300 psi and 105 °F - pressure and temperature typical of a geological storage formation at 3,000 ft depth; comparable depths to Mont Belvieu). Under these conditions, the salt caverns at Mont Belvieu could store roughly 9.4 Mt of CO_2 based solely on a volumetric basis. This is roughly the volume of 90 percent of the CO_2 captured from one 550-megawatt supercritical pulverized coal power plant for three years. [195] Therefore, a storage site of this size would be insufficient to store a commercial-scale volume of CO_2. However, such facilities could be extremely useful for providing temporary storage buffers for a large-scale CO_2 storage system. Given the prevalence of suitable salt formations in the Gulf Coast, Midcontinent (Conway, Kansas), Midwest (Sarnia, Ontario) and the Appalachian basin (Salina Salt), the NGL analog provides a useful first target for a pilot-scale analog for CO_2 geologic storage. But, there are other existing natural gas storage sites in either depleted oil and gas fields or saline-bearing reservoirs that could accommodate a volume of CO_2 equivalent to a commercial-scale CO_2 storage operation.

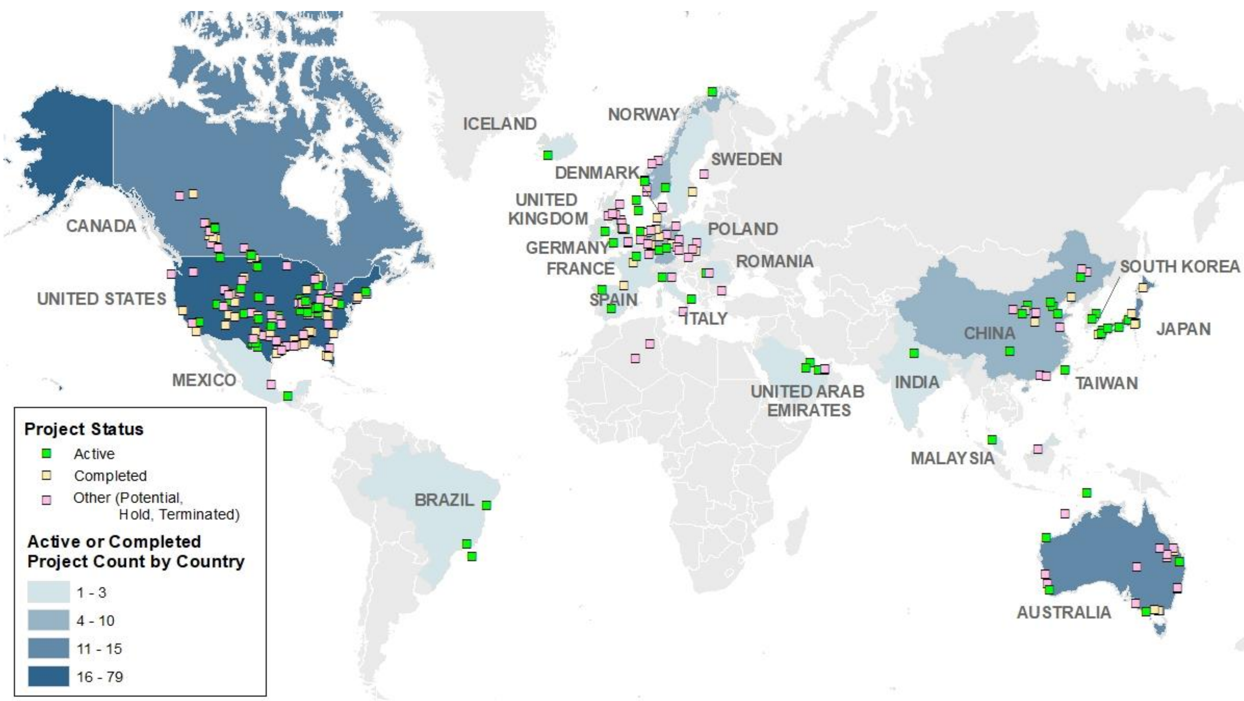
Assuming the same density of supercritical CO_2 of around 29.2 pounds per cubic foot (1,300 psi and 105 ^{o}F), other existing natural gas storage sites can be evaluated based on their total storage capacity to compare the gas volume managed in relation to commercial-scale CO_2 storage projects. For instance, the Baker Field storage facility (depleted field) located in Montana and operated by the Williston Basin Interstate Pipeline Company, has a total field capacity of 287 Bcf, a working gas capacity of 167 Bcf, and a base gas capacity of 122 Bcf. [107] Based on these capacity values, the total reservoir storage volume would be approximately equal to 3.6 Bcf, with 2.1 Bcf of working reservoir volume and 1.5 Bcf of base reservoir volume (assuming the natural gas density change with depth). Utilizing the 29.2 pounds per cubic foot density for supercritical CO_2, the Baker Field storage facility essentially has a capacity of approximately 47.8 Mt of CO_2 based on total field natural gas storage capacity. The base gas alone at the Baker Field site occupies the same volume as approximately 20 Mt of CO_2, a significantly larger volume than any CO_2 storage operation to date (Appendix F: Selected Characteristics of Carbon Capture and Storage Projects Worldwide). The Baker Field's base gas volume alone could essential store nearly 6 years' worth of emissions from a single CO_2-generating source of a similar size to the example in the paragraph above (550 MW supercritical pulverized coal power plant with 90 percent CO_2 capture - which is approximately 3.5 Mt of CO_2 per year). While the Baker Field site has the largest registered storage capacity in the United States per the EIA [107], there are numerous other sites throughout the United States with greater than 100 Bcf natural gas storage capacity (i.e., ~17 Mt CO_2 storage capacity) based on this type of volumetric evaluation.

It is important to note that this evaluation utilizes the geostatic pressure and temperature gradients presented in Section 4.1.7 to estimate pressure and temperature at depth, opposed to known site-specific conditions. Also, it does not allude to the size of the resulting CO_2 plume and pressure front and does not consider the injectivity and fracture pressure of the storage formation as part of the assessment. For salt caverns, the specific cavern dimensions would define the CO_2 plume and the pressure front.

5.7 Examples of Successful Demonstration of CCS Technology

As CCS technologies and research continue to advance, demonstration projects become critical for validating that CO_2 capture, transport, injection, and storage can be achieved safely and effectively. Successful demonstration and deployment of CCS technologies can contribute toward building confidence and reducing costs through new innovations and advances in capture, storage, and monitoring technology and protocols. In 2018, NETL had identified over 300 existing, planned, or recently-completed CCS-related projects (ranging from pilot testing to commercial-scale) across the globe (Exhibit 5-12). [2] The Global CCS Institute indicates that 37 CCS projects across the globe are of "large-scale;" 17 of which are currently in operation, while the others are under construction or in development. [3] CCS has and continues to be successfully demonstrated throughout the world. As R&D activities continue to advance CCS toward commercialization, demonstration projects that implement and validate safe and effective CO_2 injection and storage technologies become critically important. This section highlights several CCS-related projects that have occurred, or are occurring, in the United States and world-wide.

Exhibit 5-12. Map of active or recently completed CCS-related projects worldwide [2]



5.7.1 DOE's Regional Carbon Sequestration Partnerships

DOE supports a portfolio of small- and large-scale CO_2 storage field projects with the goal of improving the effectiveness of CCS technology and reducing the cost of implementation in preparation for widespread commercial deployment. Part of that portfolio includes the RCSP Initiative, which conducts both small- and large-scale CO_2 storage field projects. They comprise of seven public/private partnerships, including more than 400 organizations, and span 43 U.S. states and four Canadian Provinces. [9] [152] [159] The RCSP Initiative is implemented in three phases: 1) Characterization Phase, 2) Validation Phase (small-scale field projects; less than 500,000 tonnes total for EOR or 100,000 tonnes total for saline), and 3) Development Phase (large-scale field projects, greater than 1,000,000 tonnes). Field projects occur in different depositional environments in both saline and oil and gas formations, and involve integrated system testing and validation of critical components, including geologic storage, simulation and risk assessment, and monitoring, verification, and accounting technologies. [8] In addition, the RCSPs have worked to support regulatory policy development, develop human capital, encourage stakeholder engagement, develop carbon mitigation plans, and enhance CCS education and public outreach. Several field projects are integrating anthropogenic CO_2 capture and subsequent storage from CO_2 sources such as power plants, ethanol generation, and natural gas processing. The field projects conducted as part of the RCSP initiative provide direct observations of the behavior of CO_2 in the subsurface, enabling improved confidence that CO_2 can be injected and stored safely. [9] Over 1.25 Mt of CO_2 has been safely injected and stored across 19 different projects during the RCSP Validation Phase. [11] In addition, the other eight RCSP Development Phase projects have injected over 14 Mt of CO_2 (as of December 2017). [196] Results obtained from these efforts will provide the foundation for validating that CCS technologies can be commercially deployed and monitored throughout the United States.

5.7.2 Sleipner Saline Storage Project

The Sleipner project began in 1996 and was the world's first commercial CCS project for storing CO_2 in a deep saline reservoir. The Sleipner gas development area is in the middle of the Central North Sea (approximately 160 miles west of Norway) embracing the Sleipner East and West gas and condensate fields. [197] Norwegian greenhouse gas regulations required that the CO_2 concentration be reduced to a maximum of 2.5 percent. Sleipner West, however, produces gas with CO_2 content in the range of 4 to 9 percent. To meet this regulatory requirement and avoid being subject to progressively increasing taxes on carbon emissions, the CO_2 was separated from the gas and injected into the Utsira Formation (a sandstone reservoir around 820 ft thick) approximately 2,625 to 3,610 ft below the sea level.

The total injected CO_2 is around 16.2 Mt from inception to June 2016, with the purity of the CO_2 at around 99 percent. The initial estimated total volume of CO_2 that was anticipated to be injected at Sleipner was 25 Mt over the field's 25-year lifetime. [197] However, the estimation has been revised to around 17.5 Mt by 2020 due to a lower CO_2 content and a decreasing production profile for Sleipner West. [197] This project employs 3-D and four-dimensional (4-D) (time-lapse) seismic surveys, seabed micro gravimetric surveys, electromagnetics surveys and seabed imaging surveys as part of a sophisticated monitoring program.

5.7.3 Snøhvit Saline Storage Project

Snøhvit is the first major offshore development on the Norwegian continental shelf that utilizes seabed-based facilities opposed to surface installations. [198] The project began producing natural gas and bringing it to land for liquefaction in 2007, and started capturing CO_2 in 2008. [199] Nine total wells have been drilled and are utilized on Snøhvit; eight for production and one for reinjecting carbon dioxide. [198] The produced natural gas contains 5 to 8 percent CO_2, which is separated and transported 95 miles from the Melkoya LNG plant back to the Snøhvit field via an 8-inch diameter pipeline. [200] Besides CCS being a mandate from the Norwegian State, an added incentive for CCS came from the CO_2 tax imposed on CO_2 emissions from offshore petroleum operations. The tax rate has progressively been raised to $65 USD per metric ton in 2016.

The total injected CO_2 to date is nearly 4 Mt via one injection well, with the purity of the CO_2 at around 99 percent. The estimated total volume of CO_2 to be stored is between 15 to 20 million tons based on the approximate 30-year lifespan of the LNG plant. [200] The initial targeted CO_2 injection reservoir was the Tubåen sandstone formation (About 328 ft thick and from 8,400 to 8,760 ft below the sea surface). In early 2010, Statoil discovered the formation had less capacity than expected, and the well was recompleted in a shallower formation. The project employs time-lapse seismic surveys, reservoir pressure monitoring, time-lapse gravimetric surveys, and reservoir simulation to monitor the behavior of the injected CO_2.

5.7.4 Air Products and Chemicals Inc. CO_2 Capture and Storage Project – CO_2 EOR

Air Products and Chemicals, Inc. has retrofitted two steam methane reformers with a vacuum swing adsorption system to separate the CO_2 from the process gas stream at their hydrogen plant at Valero Refinery in Port Arthur, Texas. Compression and drying processes follow the CO_2 capture, which concentrates the initial stream (containing from 10 to 20 percent CO_2) to greater than 97 percent CO_2 purity. The first steam methane reformer began capturing CO_2 in December 2012 and the second in March 2013. When operating at full capacity, both plants capture approximately 1 Mt of CO_2 per year. [201] The compressed CO_2 is then delivered to the Denbury "Green" CO_2 Pipeline for transport to EOR projects in southeast Texas. An MVA program is employed at one of these EOR sites, the West Hastings Field, to ensure the injected CO_2 remains in the underground geologic formation. As of mid-2016, the project has captured and injected over 3 Mt of CO_2 for EOR operations. [201] The project has demonstrated the integration of CCS within an existing hydrogen business, and it represents a major step in advancing CCS technologies from the demonstration stage to commercial viability. Nationwide, the CO_2 captured for use in EOR is expected to result in approximately 1.6 to 3.1 million barrels of additional domestic oil production annually.

5.7.5 Petra Nova Project – CO_2 EOR

Petra Nova Parish Holdings, a joint venture between NRG Energy and JX Nippon Oil and Gas Exploration, has retrofitted the existing W.A. Parish Generating Station coal-fired power plant located in Thompsons, Texas with CO_2 capture equipment. The goal of this project is to advance fully integrated CCS technologies from the demonstration stage to commercial viability. [202] The project is demonstrating the ability of the CO_2 capture technology, supplied by Mitsubishi Heavy Industries, to capture 90 percent of the CO_2 emitted from a 240-megawatt equivalent flue gas stream. The project is designed to capture and store 1.4 Mt of CO_2 per year, making it the largest post-combustion CO_2 capture project installed on an existing coal-fueled power plant. [203] The captured CO_2 is being sent through an 80-mile pipeline to the West Ranch oil field near Vanderbilt, Texas (operated by Hilcorp Energy Company) for CO_2 EOR. The West Ranch oil field has produced oil continuously since 1938. However, in recent years, production rates at West Ranch have declined through the use conventional production techniques alone. To increase production, CO_2 captured from the W.A. Parish Generating Station is being injected into the field for EOR. [204] It is expected that oil production will increase from around 300 barrels per day to up to 15,000 barrels per day while also storing CO_2 underground. In January 2017, NRG Energy, Inc. and JX Nippon Oil and Gas Exploration Corporation announced that the Petra Nova Project had begun commercial operations. [202] [205] By October of 2017, the project had captured more than one million tons (~907,000 tonnes) of CO_2. [206]

5.7.6 Weyburn-Midale Project – CO_2 EOR

The Weyburn-Midale CO_2 storage monitoring project was initiated to research the deployment of a variety of monitoring technologies for geologic storage of CO_2 in the subsurface. The project was launched in 2000 by the Government of Canada, the Government of Saskatchewan, Cenovus Energy, and the Petroleum Technology Research Centre in Regina, Saskatchewan. CO_2 was captured at the Great Plains Synfuels coal gasification plant near Beulah, North Dakota and piped over 200 miles to two carbonate fields in Saskatchewan, Canada for CO_2 EOR. A total of 22 Mt of CO_2 was injected and monitored at the storage site at the end of the monitoring project in 2012. [207] This project helped develop and demonstrate a variety of technologies related to reservoir simulation, risk assessment, and MVA, including predictive modeling validation and multi-component seismic data processing. [208] The commercial EOR portion of the project was run by EnCana Corporation, and the research portion investigating CO_2 storage potential was run by the Petroleum Technology Research Council. [9] Project personnel completed a best practices manual upon completion of the monitoring project. [209] Since the completion of the monitoring project in 2012, commercial CO_2 EOR operations have continued at Weyburn-Midale. By 2015, an estimated 24 Mt of CO_2 had been stored, and approximately 55 Mt total are estimated to eventually be stored over the total life of the project. [210]

6 Natural Gas Leakage Risk and Implications for Class VI Wells

A significant quantity of natural gas has leaked from natural gas storage facilities due to well defects and injection/withdrawal process errors throughout history. These leakage events serve as analogs for the potential release of CO_2 from geologic storage reservoirs. Therefore, essential information could be obtained by reviewing the key features, events, and processes that were reported on previous natural gas leakage events, as well as the health, safety, and environmental consequences associated with each. The most recent major event occurred at the Aliso Canyon storage field in California in 2016 and will be discussed in more detail later in this section, as it resulted in federal action.

Natural gas leaks can result in substantial greenhouse gas emissions in addition to the danger of fire and the potential for injury, fatalities, property damage and the loss of gas revenue. Natural gas is a greenhouse gas for which climate-related costs can be assigned. For example, the estimated social costs of the climate-related impacts from the Aliso Canyon emissions were reported by PHMSA to be approximately $123 million (with a range of $55 million to $344 million, depending on the discount rate). [74] A CO_2 leak would also be a greenhouse gas event, not only in and of itself, but also because it runs counter to the purpose of sequestering CO_2 in the first place.

Although natural gas is not toxic, leaks from natural gas storage facilities can still release other harmful substances into the air. For example, the Aliso Canyon storage facility uses abandoned petroleum-bearing formations. The escaping gas from a failed attempt to plug the well caused residual petroleum from the formations to be expelled from the well, resulting in the deposition of an oily residue on many nearby residences and vehicles. [65] Nearby residents also complained of headaches and nausea, believed to be from the sulfur compounds added to the natural gas to give it an odor. [74]

Finally, the shutdown of a natural gas storage facility resulting from a leakage event could put a substantial strain on the supply of gas to end users during times of high demand. For example, officials feared that the loss of the Aliso Canyon facility would cause regional electric generation shortages in southern California in 2016. [211] Fortunately, electric curtailments were avoided in 2016; however, cold weather in January 2017 forced SoCal Gas to ask customers to curtail gas usage. [212] Other communities in the United States could face similar issues if a leak occurs in their region. There could be as many as 12 underground gas storage facilities in the United States that in the event of a shutdown event would affect upwards of two gigawatts or more of electric generation capacity. [65]

There have been several events of single-point leaks (e.g., a leak from a failed part of the system that results in entire system failure, like a failure from valve or other critical piece of equipment, well casing failure, or a packer failure) from natural gas storage sites, as well as some leaks that were more widely dispersed or from more than one location. Between 1972 and 2004, every single-point failure occurred at a salt cavern storage facility; none occurred at a depleted reservoir or aquifer gas storage facility. [213] These events are listed in Exhibit 6-1 below.

Exhibit 6-1. Catastrophic events involving salt cavern facilities since early 1970s [213]

Facility	Location	Fuel	Year	Description	Reported Cause	Volume of Release	Duration of Release	Status of Facility
Major events with loss of life or serious injuries and property damage								
Yaggy	Kansas	Natural gas	2001	Fire and explosion	Casing failure	143 MMcf	Undetermined; days to months	Ceased operation
Brenham	Texas	NGL	1992	Fire and explosion	Valve failure	3,000 to 10,000 bbl; equivalent to 7-24 MMcf natural gas	Several hours	Closed; request to reopen denied by the RRCT in 1994
Mont Belvieu	Texas	NGL	1985	Fire and explosion	Casing failure	Unknown	Unknown	Continues to be a major NGL storage center
Mont Belvieu	Texas	NGL	1980	Fire and explosion	Casing failure	800 cubic ft of propane	Days; exact number unknown	Continues to be a major NGL storage center
West Hackberry	Louisiana	Oil	1978	Fire	Packer failure	72,000 bbl oil	Several hours	Now part of Strategic Petroleum Reserve
Minor events where only property damage occurred								
Moss Bluff	Texas	Natural gas	2004	Fire and explosion	Valve failure	6 billion cubic ft	7 days	Active
Magnolia	Louisiana	Natural gas	2003	Gas leak and evacuation	Casing failure	35 million cubic feet	2-3 weeks	Inactive
Stratton Ridge	Texas	Natural gas	1990	Cavern failure/ abandonment	Leak-failed MIT	Unknown	Not applicable	Abandoned
Mont Belvieu	Texas	NGL	1984	Fire and explosion	Casing failure	Unknown	41 days	Continues to be a major NGL storage center
Eminence	Mississippi	Natural gas	1972	Loss of storage capacity	Salt creep	Not applicable	Not applicable	Active

6.1 Underground Natural Gas Storage Leakage Case Studies

The following is a description of selected case studies of major leakage events from underground natural gas storage sites in situations analogous to CO_2 storage situations. The cause and result of each event is captured and discussed. It is important to note that of the five case studies described in the section below, only the Leroy Natural Gas Site in Wyoming was a FERC-regulated facility.

6.1.1 Leroy Natural Gas Site, Wyoming

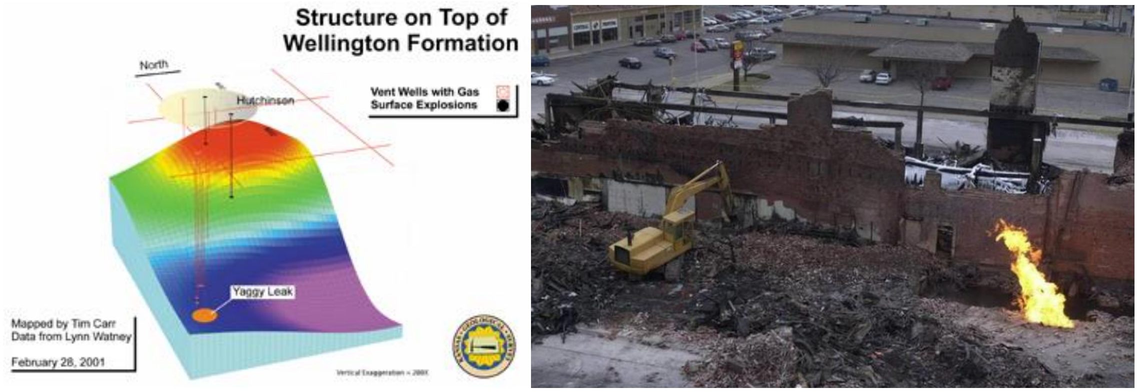
This incident is not included in Exhibit 6-1 above because it is a multipoint leakage event and an aquifer storage facility. The Leroy Gas Storage Facility is an aquifer reservoir developed by

Mountain Fuel Supply Company in Uinta County, Wyoming. The natural gas was injected into and extracted from the T-10 zone, a highly permeable sandstone aquifer at the depth of about 2,950 ft (900 meters) in the lower Thaynes Formation. Gas was observed bubbling in a surface stream in November 1978. The leak was due to either leaky wellbores or a leaking fault in the reservoir, or a combination of both. Several methods were used to understand, monitor, control, and reduce the leak. These included logging, surveying, sampling, and testing techniques, tracer work, computer simulation, and engineering analysis. The computer simulation established a correlation between the leak rate and the pressure in the reservoir. [214] Based on tracer tests, pressure/inventory data, and computer modeling, it was determined that leakage from the storage reservoir only occurred when a threshold pressure of 1,700 pounds per square inch gage (11.72 MPa) was exceeded. Chen et al. [215] performed a 3-D simulation of the site and results indicate that fault leakage remains an open possibility, but not conclusively. When the reservoir pressure reached the peak during injection season in 1975, modeling results from Chen et al. indicated that gas may have started to migrate from the fault zone to the permeable Nugget Formation overlying the caprock. The gas leak did not affect operations at the gas storage project and no adverse health/safety effects were reported. The average annual leakage rate from 1976 to 1981 was estimated at about 3 MMcf per year. After 1981, gas leakage was controlled by limiting maximum injection pressures; the facility is still active. [12] [214]

6.1.2 Yaggy Incident, Hutchinson, Kansas

The Yaggy Incident occurred on January 17-18, 2001 in Hutchinson, Kansas. Natural gas explosions burned businesses and killed two people in Hutchinson, a town of 40,000. Geyser-like fountains (some as high as 30 ft) of natural gas and salt water started bubbling up in several locations around town (Exhibit 6-2). Emergency response teams evacuated residents from 191 homes. Officials cut off natural gas supplies to the downtown area on the mistaken assumption that the explosion and fire were due to a pipeline leak. Later it was determined that 143 MMcf of natural gas leaked from a well casing in the Yaggy natural gas storage field northwest of town. Natural gas was stored at depths greater than 500 ft in caverns in the Hutchinson Salt Member of the Permian Wellington Formation. After an initial high-pressure gas release around the storage site, gas appeared to have traveled up-dip toward Hutchinson (8-miles away) along previously unknown permeable subsurface pathways. The gas reached the surface through unplugged brine wells that had been drilled into a brine layer 200 ft below the natural gas storage interval. Some of the brine wells dated back to the 1800s. The existence of the old salt-solution wells was unknown to the operators of the storage facility, the Kansas State Geologic Survey, city personnel, and its inhabitants. The source of the gas leak was stopped by plugging the damaged well, and the surface leaks were stopped by plugging the abandoned brine wells. The Kansas Geological Survey, National Aeronautics and Space Administration Jet Propulsion Lab, and University of Wisconsin all participated in the search for gas leaks and the brine wells. [216] A series of wells were drilled in and around Hutchinson to find and vent remaining underground gas that had migrated near the town to the surface. Gas has not been extracted from the Yaggy field since 2012.

Exhibit 6-2. Structure contours on top of Wellington Formation (left) and photo from downtown Hutchinson, Kansas after explosion



Source: Interagency Task Force on Natural Gas Storage Safety [65]

6.1.3 Moss Bluff Incident, Liberty County, Texas

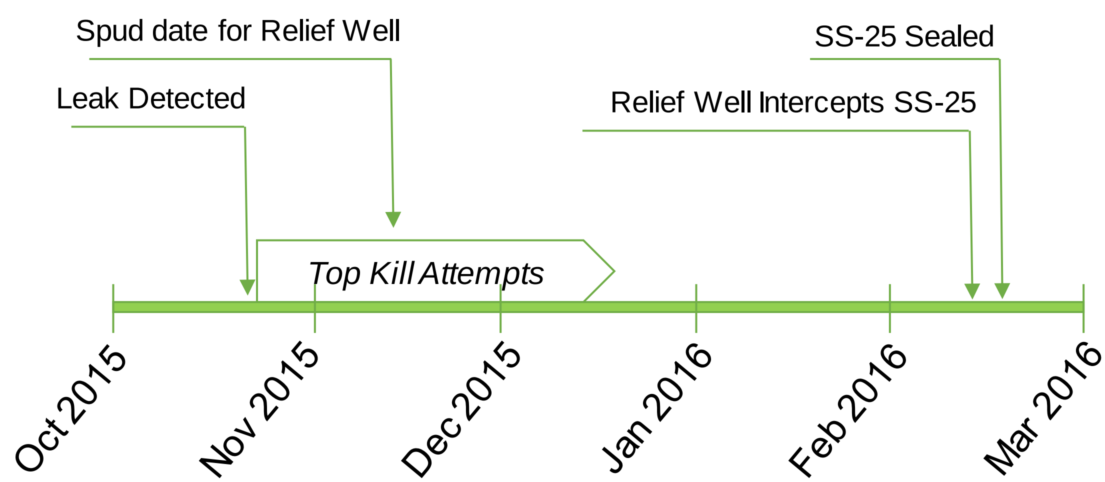
On August 19, 2004, a series of unusual events, some with unknown causes, led to a gas leak and fire at the Moss Bluff Hub Partners salt cavern storage facility in Liberty County, Texas. The fire lasted six-and-a-half days until all six Bcf of gas in the cavern was burned. [217] The 640-acre Moss Bluff storage facility consists of three separate underground caverns leached out of a naturally occurring salt formation beneath the surface. The facility was operating in normal "de-brining" mode where brine is withdrawn from the cavern as gas is injected. Brine was produced to the surface through an 8 5/8-inch well producing casing string and transported to an above-ground holding pond. A separation in the 8 5/8-inch production casing at a depth of about 3,724 ft in the salt cavern allowed storage gas to seep into the casing and flow into an 8-inch diameter pipe located above ground, which triggered an emergency shut down. The resulting mechanical forces (water hammer) produced by the sudden surge of flow caused the 8-inch piping between the wellhead and the emergency shut down valve to breach causing the fire. The heat of the flame eventually melted the wellhead assembly, allowing gas to escape from the 20-inch diameter conductor casing at the surface. The reason for the breach of the 8 5/8-inch well casing was not known. Another factor contributing towards the incident was weakening in the 8-inch above-ground pipe from internal corrosion (despite the pipe only being in operation for four years). The RRCT ultimately fined the operator for failure to maintain a pipeline that ruptured, resulting in the leak, loss of well control and subsequent explosion. The cost of gas lost from the event was reported as $42 million (2004$). [218] Moss Bluff is still active, with a maximum daily delivery rate of 1 Bcf per day.

6.1.4 SoCal Gas's Aliso Canyon Leak, California

The Southern California Gas Company's (SoCal Gas) Aliso Canyon facility has 115 storage wells and is the second-largest storage facility of its kind in the United States. It is an intrastate facility, and subject to the authority of the California Public Utility Commission (CPUC), which is certified by PHMSA to regulate the intrastate gas pipeline facilities in California. On October 23, 2015 Aliso Canyon Well SS25 developed a natural gas leak near an area known as Porter Ranch, a suburb of Los Angeles, California. Natural gas is stored in a sandstone reservoir formation at approximately 8,500 ft below ground surface in the Sesnon-Frew Reservoir. Investigators believe the leak originated from the subsurface (downhole) well casing. The well was drilled in 1953 and converted to natural gas storage in 1972. [65]

Several attempts were made to try and stop the leak (Exhibit 6-3). One day after the leak was discovered and continuing until December 22, 2015, SoCal Gas conducted eight separate "top kill" operations to stop the leak. "Top kill" operations involve pumping heavy drilling muds, fluids, and other material (together known as "kill fluids") into the leaking well to plug the well from above. Barite mud and calcium chloride solutions were systematically pumped with lost circulation materials. However, successive top kill attempts caused erosion and expansion of the vent over time. Additionally, the wellhead experienced significant vibrations and movement, and was required to be secured with a bridge structure. None of the top kill attempts were successful at stopping the leak. Modeling and simulation conducted by Lawrence Berkeley National Laboratory suggested that the high gas flow rates and geometry of the lower section of the well severely inhibited the effectiveness of top kill attempts. SoCal Gas implemented the drilling of a relief well for a "bottom kill" approach in early November 2015. This type of operation involves drilling a relief well to intercept the leaking well at depth and pumping drilling muds and cement through the relief well into the leaking well to generate a seal and stop the leak. The relief well was successful in finally plugging SS-25 on February 12, 2016, and no other relief wells were needed.

Exhibit 6-3. Timeline of key events during the Aliso Canyon leak



Source: Interagency Task Force on Natural Gas Storage Safety [65]

Before the leak was finally stopped (via a cement plug) in mid-February 2016, approximately 5.7 Bcf of natural gas had been released into the atmosphere. [74] Operator-reported costs associated with the leak were approximately $763 million as of November 2, 2016. [74] As of January 2017, the storage field has not returned to full service, but state regulators allowed it to reopen at a third of its previous capacity in mid-January 2017. [212] By July 2017, California state energy regulators had allowed SoCal Gas to start injecting gas into Aliso Canyon following a facility upgrade. In February 2018, SoCal Gas produced natural gas from Aliso Canyon several times to supplement an increase in gas demand resulting from a spell of cold weather in the region. [219]

A series of air pollutant monitoring initiatives were conducted during and after the Aliso Canyon leak event. The two air pollution control agencies conducting emergency ambient air monitoring in response to the Aliso Canyon natural gas leak included the South Coast Air Quality Management District and the California Air Resources Board. SoCal Gas and the Los Angeles Unified School District also collected ambient air samples on facility property and in the Porter Ranch community. Additionally, the University of California at Los Angeles conducted ambient air monitoring as part of their own initiative. [65] Results from these studies are discussed in the Interagency Task Force on Natural Gas Storage Safety 2016 report [65] developed in the aftermath of the Aliso Canyon incident, and a summary of the sampling results is presented in Exhibit 6-4 below.

Exhibit 6-4. Summary of ambient air pollutant monitoring conducted by various organizations following the Aliso Canyon leak

Organization	Monitoring Approach	Findings
South Coast Air Quality Management District [220]	Continuous methane monitoring efforts (in tandem with California Air Resources Board) Mobile methane measurement surveys using tandem global positioning equipment and a LI-CORE 7700 methane analyzer H_2S monitoring Instantaneous grab samples were collected when odors were present Metal sampling Soil sampling (first two inches on the ground)	Methane 1-hour daily maximum values ranged from approximately 2 – 96 parts per million depending on monitoring location. However, a sharp decrease in ambient methane levels noted after the gas leak from well SS-25 was stopped on February 12, 2016. Several routes in and around Porter Ranch and neighboring communities were selected for these mobile methane surveys and conducted during different times of the day and under different meteorological conditions. The highest methane concentrations measured to date (upwards of 70 parts per million) were recorded at night south of the Aliso Canyon Facility. These results support the placement of the fixed monitoring sites. Instantaneous samples from before December 7, 2015 indicated the presence of H2S above nuisance levels in the neighboring areas of the Aliso Canyon Facility. Several metals were found in Porter Ranch homes that are consistent with metals found in drilling fluids, similar to those used by Southern California Gas Company to plug the leaking well. Soil sampling indicated that most of the metals were found at levels that are within the range typically found in soil in the Western U.S. region. Barium and cadmium, in some instances, were found to be slightly higher than normal.
SoCal Gas [221] [222]	Discrete sampling[q] between 10/30/2015 through 3/11/2016 using	Sample data does not indicate that an acute health hazard exists from any of the VOCs measured in the Porter Ranch neighborhood because of the Aliso Canyon natural gas

[q] Typically included instantaneous grab samples and 12- and 24-hour canisters collecting volatile organic compounds (VOC), semi-volatile organic compounds, metals, carbon monoxide, species common to natural gas (ethane, methane, etc.) and sulfur species. [65]

Organization	Monitoring Approach	Findings
	SUMMA® canisters and Tedlar bags	leak. Highest benzene level in the Porter Ranch community (measured on November 10, 2015) was roughly 70 percent of the benzene acute Reference Exposure Level.[r] Recently measured exposures to benzene are below the level of concern for chronic health effects (near background levels) Residents downwind from the Aliso Canyon facility described experiencing symptoms such as headaches, nausea, abdominal discomfort, dizziness and respiratory irritation. These are believed to be cause by the added chemicals to enable detection of leaks by smell (odorant), primarily tert-butyl mercaptan and tetrahydrothiophene. Exception for one sampling event (11/12/2015 near Porter Ranch Estates neighborhood), sulfur-containing compounds were below Reference Exposure Levels.
Los Angeles Unified School District [223]	Real-time sampling conducted using a hand-held monitors and air-sampling canisters to determine health threats in and around school campuses. Sampling conducting during school days.	Results posted are from sampling events that occurred between December 2015 and February 2016 Sampling results seem to indicate that VOCs sampled at all locations are well below Reference Exposure Levels Radon levels detected were well below EPA action levels of 4.0 picocurie per liter
Other On-site Emissions Measurements [65] [224]	Infrared monitoring Aircraft measurements	Infrared monitoring completed in tandem between South Coast Air Quality Management District, California Air Resources Board, and SoCal Gas detected no natural gas leaks at the well SS-25 and within a radius of 1,000 ft surrounding well SS-25. Several flights funded by the National Aeronautics and Space Administration were made for rapid response airborne surveys over Aliso Canyon with two Jet Propulsion Laboratory imaging spectrometers. Airborne samples collected over the first 6 weeks of the release, the average leak rate was estimated to be approximately 47 tonnes of methane per hour. The leak rate showed a decreasing trend after the initial 6 weeks Results show a large and sustained reduction compared to the release rate of 20,000 kilograms per hour measured release rate prior to the establishment of control of the well on 2/11/2016. Measurements after the leak stopped indicate only limited, residual, off-gassing likely from the soil and likely to no affect the Porter Ranch or surrounding communities.

[r] Levels of airborne contaminants that are not anticipated to cause health effects. [222]

6.1.4.1 Follow on Regulation Changes

In response to the Aliso Canyon leak, Congress passed the PIPES Act, signed into law by President Obama in June 2016. The PIPES Act created a task force having representatives from six Federal agencies, and from state and local governments. The task force's job was to analyze the Aliso Canyon event and recommend ways to prevent future incidents. The Act also required that DOT PHMSA use the task force's findings and recommendations to develop minimum federal safety standards for underground gas storage. The task force focused on three primary areas: 1) underground gas storage well integrity, 2) public health and environmental effects from a natural gas leak like the one at the Aliso Canyon underground gas storage facility, and 3) energy reliability concerns in the case of future natural gas leaks. The task force made over 40 specific recommendations, which are summarized later in this chapter.

On December 14, 2016, PHMSA issued an IFR revising the Federal pipeline safety regulations to address safety issues for downhole facilities, including well integrity, wellbore tubing, and casing at underground natural gas storage facilities. [74] The Aliso Canyon incident also brought attention to Emergency Shutdown Valve (ESV) systems for mitigation of leakage or blowout events. Offshore production wells are required to have downhole safety valves and platform safety systems, including emergency shut down systems. However, cavern storage operations are only required to have surface safety systems (including ESV), but there are no state oil and gas regulations that require the use of downhole safety valves. One of the recommendations of the PHMSA task force is that operators evaluate the need for subsurface safety valves on new, removed, or replaced tubing strings or production casing. [19]

6.2 Interagency Recommendations for Future Underground Natural Gas Storage Best Practices

The Interagency Task Force on Natural Gas Storage Safety (Task Force), formed as part of the PIPES Act in the aftermath of the Aliso Canyon incident, made over 40 recommendations for future natural gas storage best practices. The Task Force include scientists, engineers, and technical experts from across the Department of Energy (including five national laboratories[s]), DOT, EPA, the Department of Health and Human Services, the Department of Commerce, the Department of the Interior, FERC, and the Executive Office of the President. The recommendations generated were based on research and analysis by Task Force experts, including discussions with industry representatives, state regulators, and environmental groups. Chapter 3 of the final Task Force report discusses the recommendations in detail. [65] The following subsections provide a short summary of the report recommendations; some are specifically applicable to natural gas storage facilities (due to flammability and explosion concerns, or for withdrawal of stored gas, for example), but several others would be of interest to operators/developers of CO_2 storage facilities as well. Additionally, under each subsection where applicable, a reference to CO_2 geologic storage (e.g., Class VI well) regulations that relate to the subsection topic was identified to distinguish where and how CO_2 storage is held accountable for similar best practices.

[s] NETL was directly involved in this effort.

6.2.1 Task Force Recommendations for Ensuring Well Integrity

Operators should phase out wells with single point of failure designs. New wells can be designed to have double barriers. Existing wells with single-point-of-failure designs (i.e., failure at one spot in the system results in entire-system failure) should have a risk management plan that includes a rigorous monitoring program, well integrity evaluation, leakage surveys, mechanical integrity tests (MITs), conservative assessment intervals, and a plan to phase out these designs.

Operators should undertake rigorous well integrity evaluation programs. Evaluations should include: 1) compilation and standardization of all available well records; 2) an integrity testing program that includes leakage surveys and cement bond and corrosion logs; 3) a risk management plan to guide future monitoring, maintenance, and upgrades; 4) establishment of design standards for new well casing and tubing; and 5) establishment of safe operating pressures for existing casing and tubing.

Operators should prioritize integrity tests that provide hard data on well performance. Integrity tests should be planned with the following in mind:

- Monitoring, logging, and MIT must be top priorities for lowering risk to well integrity, as they provide hard data on well performance. Noise and temperature logs should be run annually to detect leaks. Operators should also perform integrity assessment inspections for casing wall thickness (corrosion) on all wells, if recent data are unavailable. Operators should maintain detailed integrity and maintenance records and well diagrams of piping and other equipment.
- Well integrity tests should be performed to minimize total risk, which includes risks to storage integrity associated with the testing, risks to personnel, etc. Well integrity testing should use a tiered approach, with less invasive, routine testing performed more frequently and comprehensive testing performed less frequently and as needed.
- Well integrity testing should use multiple methods and not rely on a single diagnostic. These should include temperature and noise logs, casing corrosion logs, cement bond logs, and pressure tests, recognizing that the optimal diagnostic program will be site-specific and may change over time as data are collected and evaluated.

Operators should deploy continuous monitoring for wells and critical gas handling infrastructure. This includes monitoring of annular and tubing pressure, surface leak detection, and potential cyber security risks (especially if the monitoring network is tied to a real-time control system).

Pertaining to Class VI regulations for a CO_2 storage operation, the major themes identified in the recommendations for ensuring natural gas well integrity relate to the following CFR parts:

- 40 CFR 146.86 – Injection well construction requirement
- 40 CFR 146.87 – Logging, sampling, and testing prior to injection well operation
- 40 CFR 146.89 – Mechanical integrity

- 40 CFR 146.90 – Testing and monitoring requirements

6.2.2 Task Force Recommendations for Managing Risk

Comprehensive risk management plans, describing preventative and mitigation measures should be developed and reviewed periodically. These plans should document the risk management strategy, identify risks, define responsibilities among stakeholders, assess risks, and provide appropriate responses. Regulators should review the plans as part of the standard inspection and oversight process.

Operators should institute more complete and standardized records management systems to ensure that documentation of essential information is created, maintained, protected, and retrievable when needed. The records management processes should allow an operator to track records throughout their entire information life cycle, so that it is always clear where a record exists, which is the most current version of the record, and the history of change or modification of the record.

Operators should develop and begin implementing risk management transition plans within one year from the date when new minimum Federal standards are issued for compliance. Regulators should inspect operator records during routine inspections to ensure that the transition plans have been properly implemented. Operators and regulators need to account for a broad range of risk factors. This is best achieved through rigorous implementation of an objective risk assessment that accounts for uncertainties, rather than simply applying reactive protocols to address specific scenarios. New regulations and voluntary industry guidelines should both anticipate future events and address past events, including geologic factors, changes in the proximity of human population centers relative to gas storage facilities, weather-related complications to field operations, and emergency response. Risk management and emergency response plans should consider human factors in procedures and training. Industry should create a guidance document that discusses human factors principles in mitigating risk in underground gas storage facilities.

Pertaining to Class VI regulations for a CO_2 storage operation, the major themes identified in the recommendations for natural gas well risk management relate to the following CFR parts:

- 40 CFR 146.83 – Minimum criteria for siting (excessive risk could deem a potential storage site unsatisfactory)
- 40 CFR 146.94 – Emergency and remedial response

6.2.3 Task Force Recommendations for Research and Data Gathering

DOE and DOT should conduct a joint study of downhole safety valves to evaluate key uncertainties related to their costs and benefits for the U.S. natural gas storage industry. Additionally, DOE and DOT should conduct a joint study of casing-wall thickness assessment tools to rigorously test and compare the ability of these techniques to identify, locate, and characterize corroded casings. DOE, industry, and other stakeholders should review and evaluate wellbore simulation tools that can be, or currently are, applied for analyzing adverse well events. The review results that are broadly applicable throughout the oil and gas industry should be disseminated at industry forums. Ultimately these tools should be applied to the development of storage well integrity plans.

Data gathering gaps should be addressed as follows:

- State and/or Federal agencies should consider undertaking a phased-data gathering project to identify the locations of unknown wells at or near underground natural gas storage facilities. This may include site-scale geophysical or ground truth surveys, as well as collection and integration of data from multiple historical sources, such as maps, property records, leases, or aerial photography.
- State and/or Federal agencies or other stakeholders should collect and analyze data on the proximity of storage facilities to population centers to better quantify the risk factors, considering projected changes to land use, infrastructure, and human population centers.
- State regulators and PHMSA should collaborate to collect data on fires, leaks, or other hazardous incidents. These data should be publicly available in a format that allows easy aggregation to provide a better understanding of individual and system risks. It is particularly important to work with states that already collect and/or publish limited data.

Pertaining to Class VI regulations for a CO_2 storage operation, the major themes identified in the recommendations for natural gas research and data gathering relate to the following CFR parts:

- 40 CFR 146.82 – Required Class VI permit information
- 40 CFR 146.83 – Minimum criteria for siting
- 40 CFR 146.87 – Logging, sampling, and testing prior to injection well operation
- 40 CFR 146.89 – Mechanical integrity
- 40 CFR 146.90 – Testing and monitoring requirements
- 40 CFR 146.93 – Post-injection site care and site closure

6.2.4 Task Force Recommendations towards Immediate Regulatory Action

Existing industry recommended practices (specifically API RP 1170 and 1171) should be incorporated into applicable regulatory codes, they should be adopted in a manner that can be enforced, and they should be supplemented with reporting and recordkeeping requirements as necessary.

6.2.5 Task Force Recommendations for Addressing Gas Leak Health Concerns

When human health and environmental threats are present and multiple jurisdictions are involved, local, State, and Federal agencies should form a Unified Command early in the response effort. The Unified Command should identify a liaison to the affected communities to ensure direct communication with affected residents. In jurisdictions with natural gas storage, operators, regulatory agencies, and other responding agencies should compile and maintain a roster of potential subject matter expert advisors. The Unified Command could consult the roster to quickly convene a group that would be able to provide decision makers with advice on complex technical issues. Regulatory agencies at Federal, state, and, as appropriate, local levels should review their existing authorities and regulations to identify and address potential gaps, ultimately improving the existing state certification program for intrastate gas pipelines.

6.2.6 Task Force Recommendations for Ambient Air Pollutant Monitoring During an Incident, and Public Health Risk Assessment

In case a leak occurs, state and local monitoring agencies in areas with gas storage should be equipped with sufficient equipment to set up a robust ambient air monitoring network in the surrounding communities to characterize the potential health impacts associated with natural gas leaks. State and local monitoring agencies should establish an emergency air monitoring plan for quick deployment of the ambient air monitoring network if a leak were to occur. The collected ambient air quality data should be posted in a prompt, easily accessible, and easy-to-understand format.

State and local monitoring agencies should collaborate with storage facility operators to develop facility-specific chemical fingerprints of the natural gas in storage. Once the chemical fingerprints are known, targeted monitoring plans should be developed to make a quick and targeted response to a leak event. Such a plan should prioritize the sampling of pollutants of greatest health concern. State and local monitoring agencies should also collaborate with stakeholders to determine local background levels of methane and other pollutants of concern. Further research is needed to determine the acute and chronic effects of exposure to natural gas odorants (t-butyl mercaptan and tetrahydrothiophene). Relevant agencies should review the results of the SoCal Gas-funded study ordered by the South Coast Air Quality Management District Hearing Board and consider any relevant findings or recommendations. Monitoring and analysis by state and local agencies should continue, and risk data should be updated if conditions change.

In the event of a future well leak, responding agencies should include health-related expertise in the response. Responding agencies should consider establishing a network of health and risk assessment professionals prior to a leak event. After a leak has been identified, the network should be convened regularly to assess collected air sampling data and the potential for health impacts from related pollutant exposures. Natural gas facilities and local and State agencies should identify laboratories with the capability to measure sulfur compounds at low detection limits. If feasible, analytical methods to detect odorants at concentrations below odor thresholds should be used during incidents. State and local air monitoring agencies should consider developing systems to collect source samples safely during a release and should consider conducting robust source testing/characterization. Information collected on the chemical constituents of sources could be used in conjunction with air dispersion and deposition modeling to help inform decisions.

Pertaining to Class VI regulations for a CO_2 storage operation, the major themes identified in the recommendations for natural gas ambient air pollution monitoring relate to the following CFR parts:

- 40 CFR 146.90 – Testing and monitoring requirements
- 40 CFR 98.448 – Geologic sequestration MRV plan

6.2.7 Task Force Recommendations towards Greenhouse Gas Emissions

State and local air monitoring agencies should consider having a methane monitoring framework to improve understanding of the magnitude of a leak. The framework and measurements should build on data already reported to Federal, State, and/or local agencies. State and local air agencies should begin methane monitoring as soon as possible following the initial detection of a leak. When possible, future leaks from natural gas storage facilities should be measured with multiple methods to confirm measurements.

In advance of a leak, state emergency management agencies should determine whether they have access to aircraft and/or other mobile measurement technologies that can be deployed rapidly. Studies of natural gas releases should quantify emissions in such a way that they can be included in inventories. EPA tracks greenhouse gas emissions over time using the Inventory of U.S. Greenhouse Gas Emissions and Sinks[t]. Many states track greenhouse gas emissions over time using state-level inventories. Emissions estimates from leak events can be incorporated into such emissions inventories.

Pertaining to Class VI regulations for a CO_2 storage operation, the major themes identified in the recommendations for natural gas storage greenhouse gas emissions relate to the following CFR parts:

- 40 CFR 98.440 – 449 (Subpart RR)

6.2.8 Task Force Recommendations for Post Well Closure Indoor Air and Source Sampling/CASPER Health Assessment

Facility operators and emergency responders should use caution when determining the composition of well-kill fluids and should consider the possible health risks that might result from exposure to toxic substances present in the fluids. If a large volume of kill fluid or other material is expelled along with natural gas, the appropriate state or local agency should test exposed homes for the presence of potential or known constituents before residents return. Soil samples taken at or near the source should be collected and analyzed for contaminants associated with the release.

[t] The inventory can be found at https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2014.

Collection and analysis of source and ambient samples should be conducted to enable evaluations of links between receptors (such as ambient monitors and residential surface samples), emissions from the leak, and emissions from other emission sources nearby, and to support evaluations of health risks associated with exposure to the mix of constituents emitted. Responding agencies should develop a plan for post-incident sample collection and analysis and should integrate the plan into the initial incident response. In-home pollutant mitigation and cleaning activities should only be performed by certified professionals under adequate supervision.

State and local health and environmental agencies should consider developing standardized approaches for collecting health information and linking it with environmental monitoring data for use in public health hazard assessment.

Pertaining to Class VI regulations for a CO_2 storage operation, the major themes identified in the recommendations for natural gas storage post-well closure indoor air sampling relate to the following CFR parts:

- 40 CFR 146.93 – Post-injection site care and site closure
- 40 CFR 146.90 – Testing and monitoring requirements

6.2.9 Task Force Recommendations for Establishing a Greenhouse Gas Mitigation Plan

States with underground natural gas storage should review their legal authorities to require greenhouse gas mitigation of fugitive emissions from underground natural gas storage facilities.

6.2.10 Task Force Recommendations of Further Analyses and Tool Requirements

DOE should work with the Department of Homeland Security and other organizations to analyze a broader range of storage-related disruption scenarios and contingencies. DOE, the North American Electric Reliability Corporation (NERC), and appropriate national laboratories should proceed with the proposed Special Reliability Assessment on Single Points of Disruption to Natural Gas Infrastructure, which will examine reliability impacts on the bulk power system in the event of disruptions of service from key storage facilities[u].

Power and gas system planners and operators should jointly develop, validate, and apply combined models to improve the capability and ensure the adequacy of the combined infrastructure.

DOE, in coordination with NERC, the International Organization for Standardization, and others should consider performing a scoping study to examine the quality and relevance of electronic bulletin board data and data from other sources for assessing real-time reliability risks, determine the costs of developing and testing a computer-based analytic tool capability for this

[u] NETL is engaged as an advisor on this study.

purpose, examine who would pay to maintain the tool on a long-term basis, and consider whether user fees would be an effective way to fund its maintenance.

6.2.11 Task Force Recommendations for Utility Regulatory Requirements and Standards

There needs more focus towards reducing the likelihood and impacts of gas curtailments. Suggested actions from the Task Force include:

- State agencies should consider requiring natural gas local distribution companies (LDCs) and electric utilities under their jurisdiction to collaborate in the joint development of procedures for managing future natural gas curtailments to minimize impacts.
- State agencies should consider whether to make changes in current LDC tariffs to establish more specific provisions concerning the allocation of gas among electric generators in advance of curtailment of service from an LDC-owned storage facility. This review should also address the states' end-use curtailment rules, which may include force majeure policies under which service to natural gas-fired power plants with firm contracts could be curtailed.
- Manage short-term variability of generators' demand for gas. Federal and State regulators should consider the operational demand characteristics of natural gas-fired generation when developing or reviewing the regulatory framework for planning, building, and operating the natural gas delivery system. Avoid mismatches between nominated gas flows and actual gas demand. Both gas and electric industries should continue to review and improve existing processes and the timing of information flows pertaining to energy bidding and/or gas nominations processes so that both systems are balanced and can operate within their respective reliability parameters. Similarly, the two industries should work together to develop flexible pipeline services to accommodate the changing needs of the electricity industry.

6.3 LESSONS LEARNED FROM CASE STUDIES

Although these were natural gas facilities, several lessons can be taken from the case studies that would be applicable to future CO_2 storage facilities as well. PHMSA seeks to avoid single-point failures; this was their first recommendation. Typical single-point failures involve valves and compressor parts whose failure can cause a shutdown or service interruption at any storage facility; well casing corrosion was also a factor in some cases. Downhole shutoff valves should be considered as standard in all CO_2 storage injection wells and are required as such for UIC Class VI wells (under 40 CFR 146.88). Other recommendations pertaining to key lessons from case studies include:

- The Yaggy incident showed the need for comprehensive monitoring, with some suggesting the installation of perforated or slotted monitoring pipes adjacent to all storage wells in Yaggy would have made the leak easier to detect. [23] Operators will be mandated to install observation wells near the storage reservoir and complete a compositional analysis of the gas from shallower reservoirs and within the observations wells for comparison to the storage reservoir gas to identify potential gas leakage or migration pathways per API standards that would be implemented under the PIPES Act. [138]

- Over pressuring at the Leroy site resulted in migration of gas along a fault line. Leakage of gas was resolved once injection pressure was reduced. [214] [215] Operators will need to verify that the pressure required for injection does not exceed the design pressure of the reservoir (threshold pressure), well head, and associated facilities to help prevent loss of caprock integrity, migration along a fault, and wellbore leakage. [70] In CO_2 storage applications, above zone monitoring is required, in which geochemical samples are taken in the formation above the storage reservoir confining layer (per 40 CFR 146.90). Changes in baseline geochemical data in the above zone monitoring interval may suggest a leak through the confining layer has occurred. Researchers at the University of Texas at Austin have installed pressure sensors above the confining layer as part of the Petra Nova Capture Project as an added monitoring caution. A substantial increase in pressure in the above zone monitoring interval can indicate a leak and prompt injection shut down and remediation. [225]
- The Moss Bluff Incident demonstrates the importance of maintaining well integrity to ensure public safety and to prevent the loss of well control. The Task Force [65] recommends that operators should undertake rigorous well integrity evaluation programs, including testing for corrosion.
- API standards indicate that an operator of a storage site will be required to develop and implement a structured emergency preparedness/response plan to address accidental releases, equipment failure, natural disasters, and third-party emergencies. In conjunction, the Task Force has recommended the use of emergency shutdown valve systems for leak mitigation. The SS-25 well which leaked as part of the Aliso Canyon incident coincidentally had an underground safety valve, but it was removed in the late 1970’s during well workover operations and was not replaced. [65]
- Initial attempts to stop the leak at Aliso Canyon were unsuccessful, as the reservoir characteristics which can influence fluid flow rates at depth were unknown. API standards required an operator to review and update reservoir geologic characterizations and mapping as new data becomes available, which should help towards improved planning of future mitigative actions. [138]
- The Task Force recommends that each storage operator have a complete and standardized records management systems to ensure that documentation of essential information is created, maintained, protected, and retrievable when needed. [65] Ideally, certain data sets like these could be made available to the public. A similar reporting example may be the MRV plan in CO_2 storage applications. As part of the Greenhouse Gas Reporting Program, geologic storage operators must report the amount of CO_2 received for injection and stored, as outlined in an MRV plan. Typically, mass balance equations are used to establish measurable quantities of stored CO_2 in the subsurface.

- Communication with the surrounding community should be open, early and frequent regarding the utilization of damage prevention notifications systems, hazards related to unintended releases, procedure for reporting releases, and action to be taken for public safety during a release. [138] This is vital to allaying fears about leaks and their effects. Unfavorable public perception can be greatly reduced by clear, understandable, transparent dialog with residents and government officials.

7 CONCLUSIONS

It is important that regulators, the scientific community, and the public become confident that CO_2 geologic storage can be safe and secure. To this regard, evidence in the form of industrial analogs like natural gas storage can be used to show that geological storage of CO_2 can indeed be carried out effectively and safely when best practices are implemented. Through this report, it is possible to see how the underground natural gas storage industry provides case studies that enable identification of key features and considerations that are likely to be effective for CO_2 storage, as well as learning points from leakage incidences. Studying analogs to CO_2 storage helps to improve overall understanding of both the technical concept and its application—in this case, large-scale injection and geological storage of CO_2 in saline-bearing formations involving millions of tonnes of CO_2. [13]

There are significant similarities that exist between natural gas storage and CO_2 geologic storage (and essentially full-scale carbon capture and storage [CCS]) in terms of site selection and characterization, as well as operational procedures, and the equipment and infrastructure used. Significant similarities noted in this report between the two practices include underground storage of a buoyant fluid, the need for an adequately thick caprock (ideally with a secondary caprock above the primary seal to ensure long-term containment), adequate pore space and permeability to enable sufficient storage capacity, injectivity—and in the case of natural gas storage—deliverability. For both practices, injection wells must be properly designed, installed, monitored, and maintained. Any abandoned wells in and near the project area must be located and, if needed, properly plugged to prevent leakage pathways. [14] [63] Careful control of injection pressure and final reservoir pressure based on geomechanical properties is necessary under both practices to avoid damage to the caprock (with similar precautions needed for enhanced recovery projects). Generally, these types of parameters can be properly identified through site selection and geologic characterization of candidate storage sites. [13] Additionally, the operations for both practices are concerned with achieving sufficient injection volumes and rates (in the case of natural gas storage, sufficient deliverability), and monitoring for leakage, both underground and at surface facilities.

The underground natural gas storage industry and emerging CO_2 storage practice have overlaps with respect to the types of reservoirs used for each operation. For instance, there are basically three types of underground natural gas storage reservoirs that have been extensively utilized in the United States: depleted oil and gas reservoirs, aquifers, and salt caverns. Aquifers, or saline reservoirs, present the largest resource potential for CO_2 storage applications, followed by depleted oil and gas reservoirs, which are important for their EOR potential. While salt caverns are not considered for CO_2 storage, other candidate reservoirs with potential CO_2 storage applicability that have not been used historically for underground natural gas storage include unmineable coal seams, organic-rich shales, and basalt formations. Stakeholders for both storage practices can mutually benefit from past work and research conducted on these types of reservoirs. For instance, natural gas storage operators have a long history of successful operations and have, therefore, developed an understanding of reservoir properties and performance in the presence of natural gas, particularly for depleted oil and gas fields. However, there is limited information on aquifers due to a lack of oil and gas exploration and their limited use for natural gas storage (except for the U.S. Midwest). Additionally, aquifers tend to need additional cushion gas, leading to less flexibility while injecting and withdrawing, which causes a reduction in the working gas fraction. The Carbon Storage Program's Infrastructure Area initiatives (like the RCSP and Geologic Site Characterization Projects) have conducted several research projects in aquifers, generating substantial characterization data of saline-bearing formations across the United States. These data could be of use to future natural gas storage development initiatives to aid natural gas storage operators in better understanding these reservoirs and screening for future sites without having to perform extensive characterization. Therefore, there seems to be ample opportunity for stakeholders from each practice to collaborate on data and knowledge sharing to improve their respective operations.

Despite several similarities and overlap between the two industries, there are major differences that include the prominent governing regulations and regulatory bodies that oversee each practice, the varying levels of commercial application and experience of each practice (natural gas storage and CO_2 EOR are commercialized industries, whereas CO_2 storage in saline-bearing formations is still a relatively new concept that has been undergoing pilot and commercial-scale testing), and the types and physical/chemical state of the injected fluid (for instance, CO_2 is more soluble in water than CH_4, CO_2 in the supercritical state is more dense relative to CH_4, but CH_4 is highly flammable if leaked into the atmosphere). Additionally, in underground natural gas storage operations, the natural gas is both injected and withdrawn, whereas for CO_2 storage, only injection occurs. [226]

Over the long history of underground natural gas storage operations, several leakage events have occurred due to well defects and injection/withdrawal processes. Past leakage events from underground natural gas storage facilities have impacted and continue to impact the way they are regulated today. PHMSA regulates the safety of underground natural gas storage facilities, based on the recently released IFR, which was in response to the PIPES Act of 2016. In this IFR, API RP 1170 and API RP 1171 were incorporated into the federal pipeline safety regulations to address safety issues at underground natural gas storage facilities. Current state-level regulations for underground natural gas storage operations and associated monitoring activities vary among states but the main themes regarding assurance of safety and protection of the environment are relatively common among the subset of state regulations reviewed as part of this report. The API RPs are based on accumulated knowledge and experience from the underground natural gas storage industry and are intended to promote long-term integrity and safety through comprehensive storage facility design guidelines that provide flexibility for case-by-case and site-specific conditional assessments. [19] Therefore, the infusion of API RP concepts through the PIPES Act IFR holds promise for ensuring added consistency in storage facility design and operations moving forward. From a CO_2 storage perspective, the U.S. EPA is tasked with establishing and enforcing regulations associated with injecting and storing CO_2 in the subsurface. The existing regulations in the United States relevant to the geologic storage of CO_2 (including EOR and ECBM) involve protecting groundwater and USDW from brine and CO_2 plume infiltration under EPA's UIC Program. The UIC Program is responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal. Currently, EPA defines the six classes of wells (Class I to Class VI) per the type of injected fluid and location of injected fluid. In several cases, state agencies hold primacy over certain UIC well classes when they can demonstrate equally stringent requirements in operating, injecting, and storing CO_2 as the minimum EPA requirements for authorization to assume primary enforcement responsibility. For Class VI wells, the operational, monitoring, and post-closure requirements are extensive. Throughout its history, underground natural gas storage has often been carried out using older wells that have been repurposed and were operated in a way that provided only one protective barrier between the reservoir and the environment (i.e., the casing). For instance, the casing in Aliso Canyon SS-25 well was reported to be over 70 years old at the time of the blowout and was used for both injection and withdrawal of natural gas. [227] This is an example of the single-point failure design the Interagency Task Force on Natural Gas Storage Safety recommended against for underground natural gas storage wells moving forward. [65] Underground injection wells regulated under EPA's UIC Program for oil and gas, liquid waste disposal, and CO_2 geologic storage are typically required to use at least a two-point failure configuration, which includes injection and production through tubing packed off inside the casing, which is a substantially safer overall well design. [226] Furthermore, the article from Oldenberg [226] has suggested that CO_2 storage operations could be substantially less prone to leakage (on a per well or per metric tonne of CO_2 basis) as compared to underground natural gas storage for the following reasons:

- New CO_2 storage injection wells will be modernized and built-for-purpose.
- CO_2 storage injection wells will be regulated by informed agencies (either EPA's UIC Program or a state agency with UIC primacy).
- The CO_2 storage process mainly involves injection at nearly constant rates, which places less strain on wells and wellheads arising from pressure and temperature variation over the project timeframe.
- CO_2 storage infrastructure at the surface should have less likelihood of failure than that of underground natural gas storage surface infrastructure because of the one-way injection concept (i.e., no periodic withdrawals).

Since PHMSA has agreed to provide revisions and clarification on the IFR pertaining to the PIPES Act, and will revise the enforcement requirements listed within (expected to be publicly released in September 2018), [77] it is currently unknown if the new requirements for implementing safe underground natural gas storage will be equally stringent as those for UIC Class VI. However, there are noted similarities between API RPs and UIC Class VI guidance when comparing the two in terms of achieving similar risk preventative and mitigation objectives as documented in Exhibit B-3.

The extensive operational history of underground natural gas storage, which has spanned over 100 years, does provide extensive knowledge and insight into lessons learned from which CO_2 storage stakeholders in industry, academia, and policy can benefit. While CO_2 storage has been demonstrated globally at various scales, it has not yet been deployed close to the same magnitude of commercial analogs like underground natural gas storage. Wider spread deployment of CO_2 storage (through integrated CCS) in the future could be facilitated through continued R&D support and technology advancement. Successfully demonstrating and deploying CCS technologies can ultimately contribute toward building confidence and reducing costs through new innovations and advances in capture, storage, and monitoring technology and protocols. At all levels of R&D (applied R&D through field testing), CCS research benefits by drawing lessons from the history of these other energy technologies and analog industries with shared technical grand challenges and approaches. Through this report (and others like it pertaining to wastewater disposal using UIC Class I disposal wells, [228] and CO_2 enhanced oil recovery [182]), critical findings from the experience of underground natural gas storage can be leveraged in the future, as well as used to gain a level of understanding for how failures that resulted in leakage events have occurred and were remediated in past underground natural gas storage operations, so that CO_2 storage best practices can be developed and implemented moving forward.

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APPENDIX A: OVERVIEW OF RAI ET AL., 2010

Rai et al. [5] identified that several successful technologies, including energy technologies, have faced challenges like those faced by carbon capture and storage (CCS). They analyzed the development of the United States (U.S.) nuclear-power industry, the U.S. sulfur dioxide-scrubber industry, and the global liquefied natural gas industry to draw lessons for the CCS industry from these energy analogs that, similar to CCS today, were risky and expensive early in their commercial development. This appendix captures key messages from the Rai et al. study.[v]

Rai et al. began their analyses by identifying the main obstacles to scaling and widespread deployment of CCS. The analyses highlight how each analogous industry overcame challenges similar to CCS and how each evolved with respect to technology innovation and demonstration, cost, technology diffusion, and business risk reduction. These challenges to CCS are:

- **Extremely high capital intensity of fully developed CCS projects**: Capital costs are projected to increase nearly 50 percent for coal power plants with CCS compared with the non-CCS option; however, early commercial projects may benefit from subsidies/grants. [229] In addition, high capital expenditures usually translate to an extended time horizon over which the project must generate positive cash flows to become commercially viable. Ensuring this type of income stream over extended durations can be difficult when employing new technologies with unproven track records. Therefore, the requirement of large capital investments in CCS projects presents a major hurdle.
- **Uncertain revenue stream owing to the lack of reliable and sufficiently high pricing for CO_2 abatement**: The lack of an inherent value of CO_2 (as opposed to nuclear power or liquefied natural gas) requires regulatory action (or financial incentives) to generate revenue streams for CCS projects. Currently, CCS can increase the cost of electricity upwards of 50 to 75 percent per megawatt hour generated. [195] Typically, the demand for high-cost electricity is prompted through policy incentives (like mandatory renewables portfolio standards as in many U.S. states) and feed-in-tariffs for electricity from renewable energy sources (like those in Germany). But no demand-pull schemes exist for CCS. Putting a price on carbon may still not generate enough incentive to attract the necessary scale of investments in CCS for widespread deployment. Therefore, most CCS projects in operation or with a high probability of successful development depend on other circumstances that do not apply at broad scale. These include special government policies (e.g., Norway's carbon tax, which incentivizes CO_2 storage) and the unique opportunity for enhanced oil recovery from mature fields when oil prices are high. CCS projects will remain risky undertakings until reliable systems become available that more broadly ensure cost recovery.
- **Uncertainties in regulation and technical performance**: There is extensive experience world-wide in capturing CO_2 in the chemicals and natural-gas processing industries. However, technology and operational experience is still lacking for CCS from power

[v] The study can be found at http://ilar.ucsd.edu/_files/publications/studies/2010_carbon-capture.pdf.

plants. The shortage of experience makes cost and performance predictions difficult, which also contributes to additional uncertainty pertaining to the long-term viability of investments in commercial-scale CCS. Uncertainty can also lead to over-regulation of CCS operations (in terms of capture as well as permitting requirements), requiring excessive monitoring and risk reduction and management options that drive up costs to implement.

- Complex value chain that multiplies risks and uncertainties across the whole series of activities that together compose a viable CCS project: Scale-up of CCS would require collective action of commercial entities that would make up each portion of the CCS value chain; each of which has very different risk profiles. For example, the U.S. power generation industry is dominated by risk-averse regulated utilities, whereas much of the knowledge about CO_2 geologic storage is typically held by oil companies that thrive on risk. The diversity in the risk profiles across the same value chain may be prohibitive towards investment, as the partners across the value chain may find it difficult to manage co-dependent commercial risk. CCS is not yet at the point in which the ability of the CCS industry to organize at scale in different regions and regulatory contexts has been fully tested, but relevant players do understand the complexity of the CCS value chain and the challenges with sorting out details and integrating at a commercial-scale.

Through analyzing the development of the analogous industries to CCS, Rai et al. arrived at three principal observations from which the analogous industries could achieve success:

1. Government has had a decisive role in the development of analog industries. For instance, analog industries typically benefitted from government support for early research and development, as well as for deployment in niche markets. There are similar steps being taken today for CCS development both in the United States and internationally.
2. Diffusion and penetration of these technologies beyond early demonstration and niche projects is facilitated by the credibility of incentives for industry to invest in commercial-scale projects. In the United States, the modified 45Q tax credit and updated corporate tax structures could provoke a business case for CCS. [230] [231]
3. The “learning curve” theory, where experience with technologies inevitably reduces costs, does not necessarily hold. Real learning is driven by more than just technical potential; it can also be influenced by the institutional environment present and any incentives towards cutting costs or boosting performance. The U.S. nuclear power industry and global liquefied natural gas industry are noted examples where costs had increased with increasing capacity, contradicting the “learning curve” theory. Stakeholders in the CCS community must remain mindful that cost reduction is not automatic as more projects progress—it can be derailed especially by non-competitive markets, unanticipated shifts in regulation, and unexpected technological challenges. Risky and capital-intensive technologies may be particularly vulnerable to wider-spread commercialization without accompanying reductions in cost.

APPENDIX B: AMERICAN PETROLEUM INSTITUTE RECOMMENDED PRACTICE 1171 REFERENCE MATERIAL

The American Petroleum Institute (API) Recommended Practice (RP) 1171 provides guidance on natural gas storage in depleted oil and gas reservoirs and aquifers. The exhibits within this section were adapted from information given in RP 1171. A decision flowchart for effective well integrity management approaches is shown in Exhibit B-1. Exhibit B-2 lists potential threats and hazards of underground natural gas storage wells. Preventative and mitigation programs for storage wells cross walked against similar UIC Class VI requirements are shown in Exhibit B-3.

Exhibit B-1. Flow chart adapted from API RP 1171 for storage well integrity management process [19]

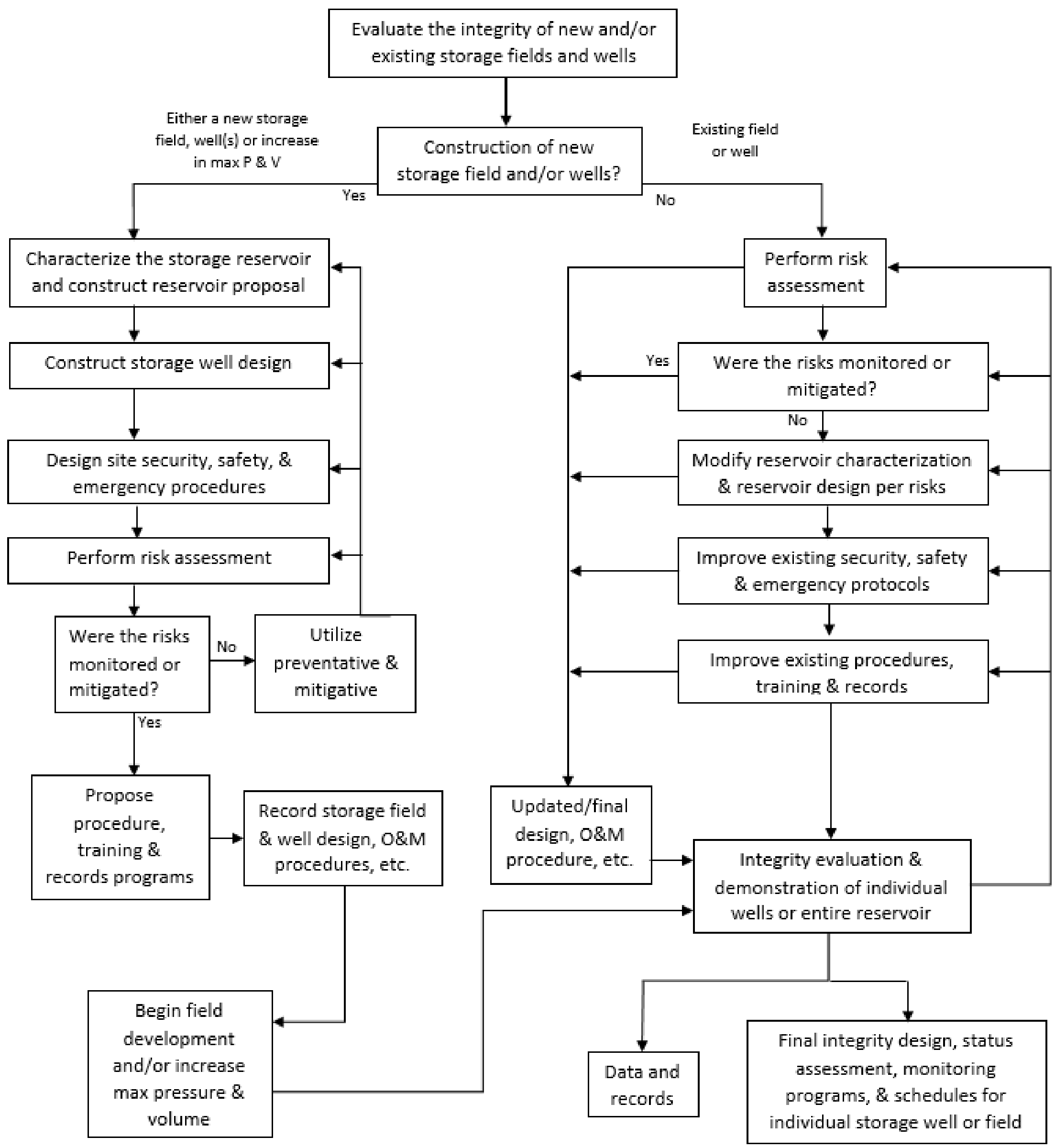


Exhibit B-2. List of potential threats and hazards of underground natural gas storage wells adapted from API RP 1171 [19]

Field or Well Hazards	Description	Consequences
Storage well integrity problems due to material or equipment failure	Containment failure from poorly sealed storage well(s) due to corrosion, cement failure, or defects in the material or parts	• Loss of stored natural gas • Damage to well site facilities • Safety hazard to individuals within vicinity • Loss of storage well and/or up-hole water sources • Reduction or termination of field performance
Storage facility and operational design	Containment failure from poorly completed wells, inadequately plugged well(s), or poorly executed operations	• Storage gas escapes to the atmosphere • Loss of stored natural gas • Damage to well site facilities • Safety hazard to individuals within vicinity • Loss of storage well and/or up-hole water sources • Reduction or termination of field performance
Field or well servicing activities	Poor field-based practices related to inadequate training, failure to follow rules, and inexperienced field workers	• Loss of stored natural gas • Damage to well site facilities • Safety hazard to individuals within vicinity • Loss of storage well and/or up-hole water sources • Reduction or termination of field performance
Drilling or workover intervention	Containment failure due to poor well control measures during routine operation	• Drilling or service rig damage • Tools lost or dropped in hole • Hazard to individuals operating rig equipment • Reduction or termination of field performance • Abandonment of well

Non-operator damages	Damage to wells unrelated to routine operations or storage company	• Accidental damage or vandalism resulting in damage to the following components of the storage facility:
		  o Secondary facilities
		  o Status change of storage wells
		  o Future reliability issues for wells
		  o Public impact due to gas release

Un-avoidable natural disasters	Weather and natural-forces damage	• Facility and service impacts due to natural forces:
		  o Flooding
		  o Earthquakes
		  o Subsidence

Exhibit B-3. Preventative and mitigation programs for storage wells adapted from API RP 1171 and cross walked against similar UIC Class VI requirements [19]

Field or Well Hazards	API Monitoring Programs and Mitigation Actions	Similar UIC Class VI Requirement
Storage well integrity problems due to material or equipment failure	• Casing monitoring program • Storage pressure, deliverability, and working capacity monitoring • Cement bond evaluation • Casing or tubing corrosion • Leakage pathways surveillance • Shutdown valves for surface and subsurface equipment • Maintain equipment and inspect various components	Ensure well integrity through the following requirements: • All well materials must be compatible with fluids with which the materials may be expected to come into contact • Two layers of corrosion-resistant casing required and set through lowermost underground source of drinking water (USDW). Cement compatible with subsurface geology • Surface casing must extend through the base of the lowermost USDW and be cemented to the surface using single or multiple strings of casing and cement • Corrosion monitoring of the well materials • Pressure fall-off test at least once every five years • Utilize alarms and automatic shut-off systems that initiate when operational parameters diverge beyond permitted ranges
Storage facility and operational design	• Compile and routinely evaluate potential leakage pathways (plug and abandon wells) • Update standards for new wells • Review completion designs and determine if monitoring is required	• At least one long string casing must extend to the injection zone and be cemented by circulating cement to the surface • Cement and cement additives must be compatible with the CO_2 stream and formation fluids • Tubing and packer materials must be compatible with fluids with which the materials may be expected to come into contact • Annulus between the tubing and the long string casing must be filled with a non-corrosive fluid • Determination of an area of review (AoR) (update at least every five years) and provide appropriate corrective action in wells that serve as potential leakage conduits • Injection pressure not to exceed 90 percent of fracture pressure of injection zone
Field or well servicing activities	• Field-based procedures • Proper training and supervision to establish safety procedures	Not specifically addressed, as the objective of the UIC Program is to protect groundwater resources; however, corrective action requirements are in place to address wells which may serve as leakage conduits within the AoR
Drilling or workover intervention	• Company and contractor safety and training programs • Drilling and workover protocols and procedures	Not specifically addressed, as the objective of the UIC Program is to protect groundwater resources

APPENDIX C: NON-RECOVERABLE GAS [111]

The amount of non-recoverable gas is of interest in storage reservoirs since it relates to the mechanics of storage reservoirs. Abandonment pressure varies for different gas fields. Common abandonment pressure values are in the range of 50 – 100 pounds per square inch. The non-recoverable gas content of a field is the gas that is left at the abandonment pressure. Equation C-1 is the equation of non-recoverable gas.

$$Q_m = V_{ab}(1 - S_w)\left(\frac{1}{B_g}\right) + (V_{max} - V_{ab})(1 - S_w)(1 - F_{sw})\left(\frac{1}{B_{g,m}}\right) + (V_{max} - V_{ab})F_{sw}S_{gr}\left(\frac{1}{B_{g,m}}\right) + Q_s \qquad \textit{Equation C-1}$$

Where:

- Q_m = non-recoverable gas (standard cubic feet [scf])
- V_{ab} = volume of reservoir space at abandonment (reservoir cubic feet [rcf])
- S_w = water saturation (fraction)
- B_g = formation volume factor at abandonment (rcf/scf)
- V_{max} = maximum volume of reservoir space ever containing gas (rcf)
- F_{sw} = sweep factor (fraction)
- $B_{g,m}$ = formation volume factor at the mean reservoir pressure (rcf/scf)
- S_{gr} = residual gas saturation (fraction)
- Q_s = gas dissolved in water (scf)

The calculation of non-recoverable gas breaks down each part of the reservoir into an equation. The first term on the right-hand side of Equation C-1 is the gas content for the uninvaded zone above the gas-water contact at abandonment. The second term represents the gas content of the un-swept or bypassed zone below the gas-water contact. The third term represents the residual gas content for the swept portion below the gas-water contact. The final term is the amount of gas that is dissolved in water.

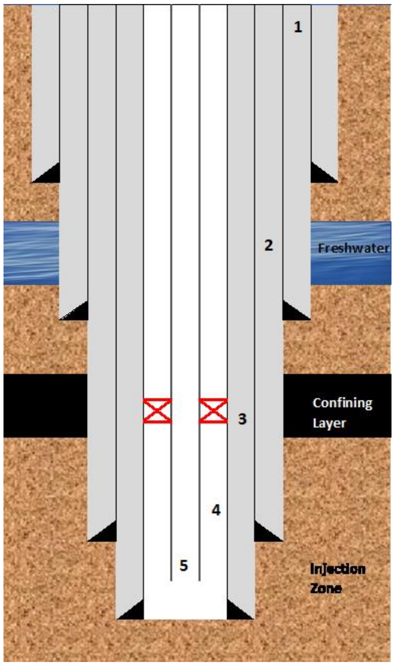
Appendix D: American Petroleum Institute Recommended Practice 1171 Well Configuration

The American Petroleum Institute (API) Recommended Practice (RP) 1171 provides guidance on natural gas storage in depleted oil and gas reservoirs and aquifers. Exhibit D-1 outlines each well component and describes the purpose and general design criteria. [88] Exhibit D-2 is an example of a hypothetical well schematic for underground natural gas storage based on API RP 1171.

Exhibit D-1. API RP 1171 well configuration

Well Label	Type	Purpose	Design Criteria
1	Conductor Casing	Controls near-surface movement of the earth	Cemented to surface
2	Surface Casing	Isolates well from freshwater sources	Cemented to surface
3	Intermediate Casing	Isolates well from intermediate formations and allows for deeper drilling	Some wells require multiple strings; Casing cement top must isolate any hydrocarbon zones
4	Production Casing	Isolates natural gas from other formations	Good primary cement job is critical
5	Production Tubing	Gas can be injected or withdrawn through tubing and is used to increase velocity of flow rate	Not cemented in place, but hung from a packer or the surface wellhead assembly

Exhibit D-2. Example well schematic



APPENDIX E: OVERVIEW OF THE UNITED STATES DEPARTMENT OF ENERGY METHODOLOGY FOR ESTIMATING GEOLOGIC STORAGE POTENTIAL FOR CARBON DIOXIDE

The United States (U.S.) Department of Energy (DOE) methodology is intended for external users, such as the Regional Carbon Sequestration Partnerships, future project developers, and governmental entities, to produce high-level carbon dioxide (CO_2) resource assessments of potential CO_2 storage reservoirs in the United States and Canada at the regional and national scale; however, the methodology is general enough to be applied globally.[w] DOE's methodology was used to evaluate three types of storage formations: oil/gas reservoirs, saline formations, and unmineable coal seams. The oil/gas reservoirs were assessed at the field level, while saline formations and unmineable coal seams were assessed at the basin level. [164] The general methodology for each storage type is provided below.

Oil and gas reservoir CO_2 storage resource estimating:

The volumetric-based CO_2 storage resource estimate is based on the standard industry method to calculate original oil-in-place or original gas-in-place. The general form of the volumetric equation to calculate the CO_2 storage resource mass estimate (G_{CO2}) for geologic storage in oil and gas reservoirs is shown in Equation E-1:

$$G_{CO2} = A \times h_n \times \phi_e (1 - S_{wi}) \times B \times \rho_{CO2std} \times E_{oil/gas}$$ *Equation E-1*

Where:

- A = area that defines the oil or gas reservoir being assessed (Length^2)
- h_n = net oil and gas column height in reservoir (Length)
- ϕ_e = average effective porosity in the volume defined by thickness (Length^3/Length^3)
- S_{wi} = average initial water saturation in area (A) and thickness (h_n) (Length^3/Length^3)
- B = fluid formation factor converts standard oil or gas volume to subsurface volume (at reservoir pressure and temperature) (Length^3/Length^3)
- ρ_{CO2std} = standard density of CO_2 evaluated at standard pressure and temperature (Mass/Length^3)
- $E_{oil/gas}$ = CO_2 storage efficiency factor (Length^3/Length^3)

Saline formation CO_2 storage resource estimating:

The volumetric equation to calculate the CO_2 storage resource mass estimate (G_{CO2}) for geologic storage in saline formations is shown in Equation E-2:

$$G_{CO2} = A_t \times h_g \times \phi_{tot} \times \rho \times E_{saline}$$ *Equation E-2*

[w] The DOE methodology can be found at https://www.netl.doe.gov/File%20Library/Research/Carbon-Storage/Project-Portfolio/Goodman-Paper.pdf.

Where:

A_t = area that defines the basin or region being assessed ($Length^2$)

h_g = gross thickness of saline formation within A_t (Length)

ϕ_{tot} = total porosity in volume defined by thickness ($Length^3/Length^3$)

ρ = density of CO_2 evaluated at pressure and temperature at depth ($Mass/Length^3$)

E_{saline} = CO_2 storage efficiency factor ($Length^3/Length^3$)

Unmineable coal seam CO_2 storage resource estimating:

Equation E-3 is the volumetric equation to calculate the CO_2 storage resource mass estimate (G_{CO2}) for geologic storage in unmineable coal seams:

$$G_{CO2} = A \ x \ h_g \ x \ C_{s,max} \ x \ \rho_{CO2std} \ x \ E_{coal}$$

Equation E-3

Where:

A = area that defines the coal basin or region being assessed ($Length^2$)

h_g = gross thickness of coal seam(s) within A (Length)

$C_{s,max}$ = absorbed maximum standard CO_2 volume per unit of in-situ coal volume ($Lenth^3/Length^3$)

ρ_{CO2std} = standard density of CO_2 evaluated at standard pressure and temperature at depth ($Mass/Length^3$)

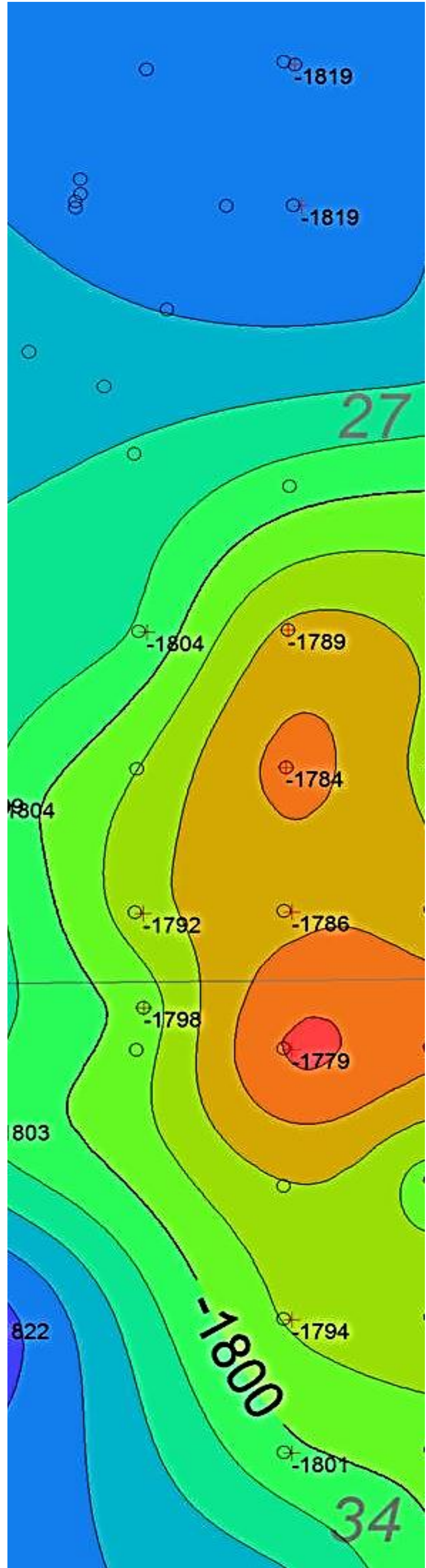
E_{coal} = CO_2 storage efficiency factor ($Length^3/Length^3$)

APPENDIX F: SELECTED CHARACTERISTICS OF CARBON CAPTURE AND STORAGE PROJECTS WORLDWIDE

Exhibit F-1 is a list of ongoing or recently completed carbon capture and storage (CCS) projects in the United States (U.S.) and internationally. This list features key parameters (that pertain to critical criteria like injectivity, capacity, and containment) that all successful geologic CO_2 projects possess. This list supplies a comparative analysis of each project's geologic properties, depth, and injection volume.

Exhibit F-1. Worldwide CCS projects list

Project Name	Location	Storage Formation	Storage Formation Depth (Below ground surface)	Porosity (%)	Permeability (millidarcy)	CO_2 Injection Rate/Volume	Project Type	Status	Reference
U.S.-Based CCS-Related Projects									
Midwest Geological Sequestration Consortium Illinois Basin Decatur Project	Decatur, Illinois, United States	Mount Simon Sandstone	5,545 feet	15-25	10-1,000	0.33 Mt/yr,1 Mt total	Saline Storage	Completed November 2014	[160] [232]
Southeast Regional Carbon Sequestration Partnership Cranfield Project	Natchez, Mississippi, United States	Lower Tuscaloosa Sandstone	8,500 feet	25	50-1,000	1.5 Mt/yr, 5.37 Mt total	Saline Storage	Completed January 2015	[233]
Plains CO_2 Reduction (PCOR) Partnership Bell Creek Field Project	Southeast of Montana, United States	Muddy Sandstone	4,300-4,500 feet	25-35	150-1,175	1 Mt/yr	EOR	Active	[234] [235]
Petra Nova Capture Project	Jackson County, Texas, United States	Frio Sandstone	5,000-6,300 feet	28-32	200-2,000	1.4 Mt/yr	EOR	Active	[3] [236] [237]
Air Products and Chemicals EOR Project	Port Arthur, Texas, United States	Frio Sandstone	5,700 feet	29	500-1,000	1 Mt/yr	EOR	Active	[3] [236] [238]
Internationally-Based CCS-Related Projects									
Weyburn-Midale Project	Weyburn Saskatchewan, Canada	Charles Formation	3,281-4,921 feet	26	15	3 Mt/yr	EOR	Active	[3] [236]
Snøhvit CO_2 Storage Project	Barents Sea, Norway	Saline Tubasan Sandstone Formation	8,530 feet	10-16	130-890	0.7 Mt/yr	Saline Storage	Active	[236] [239]
Sleipner Project	North Sea, Norway	Utsira Formation	2,297-3,281 feet	24-40	1,000-3,000	0.9 Mt/yr	Saline Storage	Active	[236] [239]
Gorgon Storage Project	Onshore Barrow Island, Australia	Dupuy Formation	7,476 feet	22	25-100	3.4-4.0 Mt/yr	Saline Storage	Active	[3] [240]
In Salah CCS Project	Algeria	Krechba Formation	5,900-6,230 feet	17	2.5-10	1-1.2 Mt/yr, 3.8 Mt total	Saline Storage	Injection suspended in June 2011	[3] [236] [241]
PCOR Zama	Zama City, Alberta, Canada	Keg River Formation	5,000 feet	10	100-10,000	0.133 Mt/yr of acid gas	EOR	Active	[11] [159] [236]
Nagaoka	South Nagaoka, Japan	Pleistocene Haizume Formation	2,624-3,937 feet	22.5	6	40 tonnes/day, 0.01 Mt total	Saline Storage	Completed in 2010	[241] [242]



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