
Integrated Carbon Capture and Storage in the Louisiana Chemical Corridor

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Acronyms and Abbreviations

Term	Description
AEP	American Electric Power
AWF	America's WETLAND Foundation
Btu	British thermal units
CCN	Certificate of convenience and necessity
CCS	Carbon capture and storage
CFR	Code of Federal Regulations
CH4	Methane
CO	Carbon monoxide
CO ₂	Carbon dioxide
CRCL	Coalition to Restore Coastal Louisiana
CRS	Congressional Research Service
CWA	Clean Water Act
CWM	Cemented Wellbore Model
CZMA	Coastal Zone Management Act
Di	Distance index
Dth	Dekatherms
EA	Environmental assessment
EDF	Environmental Defense Fund
EIS	Environmental impact statement
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
FERC	Federal Energy Regulatory Commission
FONSI	Finding of no significant impact
Ft	Feet
FTA	Fault Tree Analysis
FWS	U.S. Fish and Wildlife Service
GIS	Geographic information system
GOM	Gulf of Mexico

GRN	Gulf Restoration Network
Gt	Gigatons
H ₂	Hydrogen
HCA	high consequence areas
IAM	integrated assessment model
IEA	International Energy Agency
IOU	Investor-owned utility
IRR	Internal rate of return
ITEP	Industrial Tax Exemption Program
LCA	Louisiana Chemical Association
LCC	Louisiana Chemical Corridor
LDNR	Louisiana Department of Natural Resources
LEAN	Louisiana Environmental Action Network
LED	Louisiana Department of Economic Development
LIGO	Laser Interferometer Gravitational-Wave Observatory
LMOGA	Louisiana Mid-Continent Oil and Gas Association
LOGA	Louisiana Oil and Gas Association
LPSC	Louisiana Public Service Commission
LTC	Louisiana Tax Commission
LWF	Louisiana Wildlife Federation
MAOP	Maximum allowable operating pressure
Mcf	Thousand cubic feet
MWM	Multi-segment wellbore model
NEPA	National Environmental Policy Act
NMFS	National Marine Fisheries Services
NRD	National Resource Damages
N ₂ O	Nitrous oxide
NETL	National Energy Technology Library, U.S. Department of Energy
NGL	Natural gas liquids
NPMS	National Pipeline Mapping System
NPV	Net present value

NRDC	Natural Resources Defense Council
NWF	National Wildlife Federation
OCAP	Organic Carbon Dioxide for Assimilation of Plants
OD	Outside diameter
OMR	Office of Mineral Resources
PHMSA	U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration
PPI	Producer price index
PR	Peng-Robinson
Psi	Pounds per square inch
Psig	Pounds per square inch gauge
ROW	Right-of-way
SMR	Steam methane reformation
SONAT	Southern Natural Gas Company
SONRIS	Strategic Online Natural Resources Information System
SDWA	Safe Drinking Water Act
TNC	The Nature Conservancy
UIC	Underground injection control
USDW	Underground sources of drinking water
USGS	U.S. Geological Survey
WLA	Well leakage assessment
WLI	Well leakage index

EXECUTIVE SUMMARY

There are a variety of methods by which carbon emissions can be avoided. The two most common include end-use energy efficiency and the adoption of renewables. Carbon capture and storage (CCS) technologies represent a third and often less-recognized method for mitigating carbon emissions. However, over the past twenty years, most CCS interest has been focused on the power generation sector and not on a broader set of applications that include other industrial and manufacturing sources.

Petrochemical and refining plants are some of the more energy-intense industrial activities in the U.S. These two sectors alone account for 74 percent of all U.S. industrial CO₂ emissions. In some parts of the country, these industries collectively account for a higher level of CO₂ emissions than power generation. Consider that in Louisiana, industrial carbon emissions, driven primarily by refining and petrochemical production activities, account for 54 percent of all CO₂ emissions relative to a U.S. industrial average of only 17 percent.

Industrial CCS may offer a lower-cost alternative to power generation-based capture activities since industrial processes can often remove carbon from non-combustion exhaust streams with higher CO₂ concentrations and pressures. Industrial CCS, however, is expensive. The capture component of an industrial CCS project is the largest individual cost item and can account for as much as half of an industrial CCS investment. Industrial CCS investment costs, however, are a little more nuanced than those associated with coal-fired power plants since they are driving in part by the CO₂ emissions purity and, as noted earlier, the partial pressure of the CO₂ source. Higher CO₂ concentrations and pressures allow for capture systems with lower operational and capital costs.

The South Louisiana industrial corridor is uniquely-situated to sustain an industrial CCS project. The region has a large number and wide variety of carbon emissions sources that could be tapped for an integrated CCS project. This study conducts an initial emissions screening analysis by identifying the top ten industrial carbon emission sources, six of which are in close proximity to one another in the South Louisiana industrial corridor. These six industrial locations, in total, account for as much as 24 metric tons (or “tonne”) of carbon emissions or 30 percent of the statewide total. The next step in the analysis was to identify one single industrial source for further feasibility analyses. For purposes of this feasibility study, the CF Industries facility, a very large ammonia production plant, was selected as the primary carbon source candidate.

The next step in this analysis focuses on identifying geological formations that could safely and cost-effectively store large CO₂ volumes. The screening process for these candidate storage locations focused on those areas that are: (a) in close proximity to the Louisiana industrial corridor; and (b) the potential size of the storage facility. Two locations became readily-apparent: Bayou Sorrel and Paradis.

Bayou Sorrel is a depleted oil field located in Iberville parish just southwest of Baton Rouge. The field has an aerial extent of 26,000 acres and is a stacked sand system spanning 2,500 feet to 10,500 feet in depth. An average depth of 7,100 feet was used for static and dynamic capacity estimation purposes. This field is estimated to have a static storage capacity of 133 Mt and a dynamic storage capacity ranging from a low of around 88 Mt to a high of about 338 Mt.

The Paradis field is located further south in the industrial corridor and is proximate to many large-scale refineries in the area. The Paradis field is located in St. Charles parish and has been

examined as a candidate field in a number of CO₂-EOR studies. The field sits atop a salt dome and is highly-faulted. The areal extent of the field is over 45,000 acres and is estimated to have a static storage capacity of 83.9 Mt and a dynamic capacity of between 16 Mt and 30 Mt.

Ultimately, Bayou Sorrel was selected as the final candidate site for economic feasibility purposes since it matches up well, from a geographical perspective, with the CF Industries source location, has higher overall storage capabilities, and appears to be a less risky storage location given various risk management sensitivities.

While Louisiana has an abundance of pipeline transportation assets, further analyses found that there are few if any natural gas pipeline repurposing opportunities for carbon transportation despite this being often cited as a viable option. CO₂ is usually compressed at very high pressures of around 2,200 pounds per square inch gauge (psig): an amount that is far in excess of what is normally found in natural gas transportation. The pipeline repurposing feasibility analysis conducted in this report finds that only 1.4 percent of the eligible 5,112 pipeline segments in the region could support conversion to carbon transportation. The results, however, are a function of the assumptions used in the repurposing feasibility analysis including those used to estimate each candidate pipeline segment's MAOP.

The integrated economic feasibility analysis shows that a CCS project in South Louisiana will likely not be economically viable. These economic feasibility results, however, are dependent upon the candidate source and sink and other factors driving project economics. The carbon source (CF Industries), for instance, has a considerably high volume of carbon emissions that can help to drive down capital unit costs. The storage facility (Bayou Sorrel) is also considerable large and in close proximity to the carbon host which helps to lower pipeline and booster pump capital costs. The costs are also depending upon the recently enacted corporate income tax reductions and Louisiana's ten-year Industrial Tax Exemption Program (ITEP). However, even with all these advantages, the break-even cost of developing an integrated facility are above the current IRS 45Q tax credits of \$50 per tonne.

The integrated economic feasibility analysis estimates that an overall capital CCS unit cost of \$69.74 per tonne and O&M costs of \$19.27 per tonne. Total "all-in" CCS unit costs for these candidate source/sink pair is estimated to be \$89.01 per tonne: an amount higher than the 45Q tax credit indicating that a large ammonia or comparable industrial application may not be economically feasible in South Louisiana.

The public perception of a CCS project in South Louisiana will likely be a function of: (a) the degree to which stakeholders are educated about CCS technologies; and (b) the degree to which environmental stakeholder groups oppose industrial CCS development. There is a reasonable chance that a South Louisiana CCS project will attain favorable public opinion since: (a) most Louisiana stakeholder groups are familiar with energy infrastructure development; (b) are familiar with the consistent efficiency upgrades and investments made at many of these petrochemical facilities; and (c) will not be responsible for a large share of the upfront cost subsidies that will be provided by the federal government to financially support the initial capital costs.

Two public perception challenges could arise to derail a CCS development. The first is associated with the perceived operational risk of a CCS project. The carbon captured at these facilities will likely be under very high pressure and is a potential asphyxiate. The second is the fact that some environmental groups have been lukewarm or even opposed to CCS projects, like

the Sierra Club. This opposition, however, appears to be more focused on power generation rather than industrial applications. Power generation applications often utilize “clean coal” technologies which these groups often oppose. Power generation projects are also competitors with renewable energy projects which these groups tend to prefer to CCS. Using these as bases for opposition for an industrial project is not well founded. Industrial projects do not use clean coal, but natural gas, and are not in direct competition with renewable energy resources.

Lastly, Louisiana has a favorable set of laws and regulations for CCS development. Louisiana has a long history with underground storage rights. Further, the Louisiana Legislature has passed statutes over the past several years that provide clear guidelines on how CO₂ will be injected into storage facilities and monitored. These statutes should reduce a considerable amount of business liability and legal risk for CCS developers.

1 INTRODUCTION

There are a variety of methods by which carbon emissions can be avoided. The two most common are end-use energy efficiency and the adoption of renewables (International Energy Agency [IEA], 2015). CCS technologies represent a third and often less-recognized method for mitigating carbon emissions. The IEA estimates that CCS technologies have the technical capability of capturing slightly under 100 gigatons of CO₂ emissions by 2050 (IEA, 2015). However, over the past twenty years, most CCS interest has been focused on the power generation sector and not on a broader set of applications that include other industrial and manufacturing sources.

The early policy and technical focus on power generation-based CCS makes sense. In the U.S. power generation, primarily from coal-fired generation facilities, accounts for 34 percent of 2016 CO₂ emissions; a formidable and concentrated sector worthy of focused attention (U.S. Environmental Protection Agency [EPA], 2018a). However, industrial emissions represent an equally large, albeit more heterogeneous source of carbon emissions that deserves an increasing amount of attention. This is particularly true in certain geographic areas, like the U.S. Gulf coast, and the upper Midwest; that are seeing a renaissance of new industrial investment and economic activity and, most likely, a future increase in carbon emissions.

There is a big difference, however, between the promotion of carbon capture technologies in the power generation sector and those for other manufacturing industries. Power generation in the U.S., for instance, is typically dominated by very large central-station facilities, owned and operated by regulated electric utilities. The highly-regulated nature of the power generation industry makes it a much easier sector in which to explore the use of CCS technologies since the costs of these emerging technologies can be spread across a large and often captive sales base over an extended time period. Industrial capture projects, on the other hand, do not have a large and captive sales base needed to securitize significant and often above-market CCS investments. Further, federal and state government regulators have played a major role in establishing power generation siting, certification, and fuel use policies, as well as providing various financial support mechanisms for emerging power generation technologies such as coal and nuclear. This type of direct regulatory intervention and support is not as pervasive for industrial and manufacturing activities.

While direct government subsidies and loan support programs can go a long way to encourage industrial CCS project development, there are very few in place today for industrial applications, and the opportunities for new direct financial support mechanisms are limited in current challenged budgetary environments. There are however, federal tax incentives, particularly the recently-modified credits offered under 26 U.S.C. 45Q (known in short as the “45Q tax credits”) that could serve as a meaningful financial support mechanism for industrial applications. The degree to which these credits impact the overall economic feasibility of an industrial CCS application will be discussed in greater detail in the economic feasibility section of this report.

1.1 INDUSTRIAL CARBON EMISSIONS

Petrochemical and refining plants are some of the more energy-intense industrial activities in the U.S. These two sectors alone account for 74 percent of all U.S. industrial CO₂ emissions (EPA, 2018a). In some parts of the country, these industries collectively account for a higher level of CO₂ emissions than power generation. Consider that in Louisiana, industrial carbon emissions,

driven primarily by refining and petrochemical production activities, account for 54 percent of all CO₂ emissions relative to a U.S. industrial average of only 17 percent (EPA, 2018a).

Industrial CCS may offer a lower-cost alternative to power generation-based capture activities since industrial processes can often remove carbon from non-combustion exhaust streams with higher CO₂ concentrations and pressures. Combustion exhausts commonly associated with power plants, for instance, usually have CO₂ concentrations of three to 14 percent, with partial pressures of two psia. Industrial sources, particularly in ammonia and ethylene oxide production, can have CO₂ concentrations at or close to 100 percent with partial pressures that range from 23 psia (ammonia) to 44 psia (ethylene oxide) (Metz et. al., 2005; Summers et. al., 2014).

However, industrial CCS is expensive. The capture component of an industrial CCS project is the largest individual cost item and can account for as much as half of an industrial CCS investment (Simbolotti, 2010). Industrial CCS investment costs, however, are a little more nuanced than those associated with coal-fired power plants since they are driven in part by the CO₂ emissions purity and, as noted earlier, the partial pressure of the CO₂ source. Higher CO₂ concentrations and pressures allow for capture systems with lower operational and capital costs.

The U.S. Gulf Coast is an area with a highly concentrated set of energy-intensive manufacturing activities, particularly in the chemical and refining sectors. It is also a region that has relatively small levels of coal-fired power generation meaning that regional CO₂ emission reduction solutions will have to come primarily from industry and not power generation utilities.

Louisiana has a number of large volume and highly-concentrated CO₂ emission sources from a variety of high-quality sources particularly in the South Louisiana area which also has a large concentration of legacy crude oil producing fields.

Most of the larger, higher quality industrial CO₂ sources in Louisiana are located along an area often referred to as the Mississippi River “industrial corridor” than spans the area between Baton Rouge and New Orleans. Ammonia and hydrogen production are the larger, more concentrated sources of in this region, followed by emissions from natural gas processing that are smaller and more dispersed throughout the state. Ethylene oxide is another potential large, high quality CO₂ source in this region, but individual plant/facility data are considered proprietary and are unavailable.

1.2 OBJECTIVES AND REPORT ORGANIZATION

One of the key gaps in the critical path towards the development of commercial-scale CCS applications in the U.S. has been in identifying the commercial opportunities and challenges associated with a commercial application (50 plus million metric ton of storage). Without this knowledge, most industrial CCS applications will bear a considerable level and wide range of project development risks. The goals of this report are to reduce the informational risks of a CCS project by providing background research that can be used to assess the feasibility of a CCS project in the Louisiana industrial corridor. While the economic feasibility analysis included project uses a specific industrial source and geological sink, a large part of the report’s findings, as well as its methodologies, can be generalized to examine other source/sink opportunities in the region.

The goals of the report are to meet the Phase 1 CarbonSAFE goals that include: (1) bringing together a team capable of addressing the technical and non-technical challenges specific to commercial-scale deployment of a CO₂ industrial storage project; (2) development of a plan

encompassing technical requirements as well as both economic feasibility and public acceptance of an eventual CCS project; and (3) high-level technical evaluations of the sub-basin and potential CO₂ storage locations.

The team utilized to develop this report includes subject-matter experts representing a number of academic disciplines that includes economics, ecology, public policy, law, geology, and petroleum engineering. Project team members are also very familiar with: (a) the region's chemical industry development and operations; (2) the region's subsurface geology; (3) the unique geological challenges for employing CCS in the region; (3) legal and regulatory issues unique to oil and gas development as well as CCS; and (4) a range of other business development, policy, and public perception issues that impact energy infrastructure development in the region.

This research finds that an industrial CCS project could technically be developed in the Louisiana industrial corridor given the fact that:

- There are a large number of geographically-concentrated and diversified sources of CO₂.
- There are a large number of geographically-concentrated and diverse storage locations (or “sinks”).
- There are sufficient number of opportunities to develop transportation infrastructure linking supply to storage in these areas.
- This is a region with a long history and commercial experience in moving and storing a number of different hydrocarbons, as well as other hydrocarbon wastes, into underground geological formations which should minimize public perception challenges and potential opposition to safely-developed and environmentally-favorable projects.

Unfortunately, the cost-effectiveness analysis included in this report finds that, while industrial CCS is technically feasible, and can be accomplished a break-even prices lower than many other parts of the U.S., it will likely not be cost-effective without considerable government financial support (over and beyond what is currently available at the federal and Louisiana level).

This report is organized into the following eight sections:

Section 1: Introduction. The introduction will provide an overview of the issues addressed in this CCS industrial feasibility analysis. The introduction will also provide an overview of the report's overall organization.

Section 2: Carbon sources. This section of the report will provide a detailed overview of Louisiana's historic industrial carbon emissions from a sector and firm-specific basis. The analysis will identify plant-specific carbon emissions and identify those sites likely to serve as a reasonable locations for industrial carbon capture. Total emission volumes by industrial process type (power generation, simple combustion, petrochemical activities, etc.) will be examined as well as the estimated purity of these carbon emissions. Top industrial candidates will be identified as well as a final preferred candidate site for the economic feasibility analysis.

Section 3: Carbon sinks. This section surveys and identifies geological sites with good carbon storage capacity and retention characteristics. Two primary fields (Bayou Sorrel and Paradis) are selected for further, more detailed examination as potential candidate locations. This section of the report presents the results of the static and dynamic aquifer storage analysis for the two

fields. Information of total areal extent, gross formation thickness, and total porosity are used along with a storage efficiency factor to find the pore volume available for storage for each field. The upper depth limit for CO₂ injection is dictated by the pressure and temperature conditions at which CO₂ exists in a supercritical state. The sensitivity of injection location and boundaries is also evaluated in the dynamic storage capacity estimates.

Section 4: Transportation issues. This section will examine a number of CO₂ transportation issues with a particular focus on the feasibility of repurposing existing natural gas transportation assets for carbon transportation purposes. A CO₂ transportation economic feasibility study is also provided, and the results of this transportation economic feasibility analysis are presented and discussed.

Section 5: Economic feasibility analysis. An overall economic feasibility analysis is provided for the candidate industrial capture location (CF Industries' ammonia plant) and a candidate underground storage location (the Bayou Sorrel field). The analysis identifies the underlying financial and economic assumptions of the economic feasibility model and discusses the break-even costs for this unique CCS configuration. The economic feasibility analysis also compares the break-even costs against currently-available federal financial incentives (45Q tax credits) to ascertain the attractiveness of a potential CCS project with this form of financial support.

Section 6: Public perception analysis. This section is comprised of two subparts. The first identifies and examines the various stakeholder groups that operate in Louisiana and are likely to influence industrial CCS development success. The second component of this section provides a comprehensive discussion of the factors likely influencing CCS adoption issues in Louisiana. The listing of “factors” comes from a composite survey identified in over a decade’s worth of academic research on CCS adoption. The analysis describes and defines each public perception factor, and then discusses its likely importance for Louisiana-specific industrial CCS adoption.

Section 7: Legal issues analysis. This section addresses several of the most important of the legal issues associated with such facilities (such facilities are sometimes called “CO₂ storage facilities” or “CCS facilities,” for carbon capture and storage facilities, in the legal section of this report). This section includes an analysis of various property law issues, such as who generally owns subsurface pore spaces beneath land in Louisiana, who owns pore spaces when a person other than the landowner owns mineral rights in the land, and what rights would a prospective owner-operator of a CCS facility to exercise eminent domain to acquire the surface and subsurface rights or ownership needed for a facility. The relevant state environmental statutes impacting CCS are also discussed as well as the means by which the owner-operator of a CCS facility could limit its risk for tort liability and limit its long-term duties to monitor and maintain a CCS facility.

Section 8: Conclusions. This section of the report will summarize the project’s research findings and conclusions.

This report also includes a number of technical appendices that provide further detail on many of the topics discussed in the individual report sections. These technical appendices include: #.

2 CARBON SOURCES: IDENTIFICATION AND RESOURCE SIZE

2.1 INTRODUCTION

The International Energy Agency (IEA) anticipates cumulative carbon emissions of 725 gigatons (Gt) during the time period 2002 to 2050. There is no single solution for reducing or avoiding these emissions. Any reductions will have to come from a variety of technologies and applications that include enhanced power generation efficiencies, created end-use energy efficiencies, and renewables, to name a few. CCS is recognized as having an important place in these mitigation alternatives as seen in Figure 1.

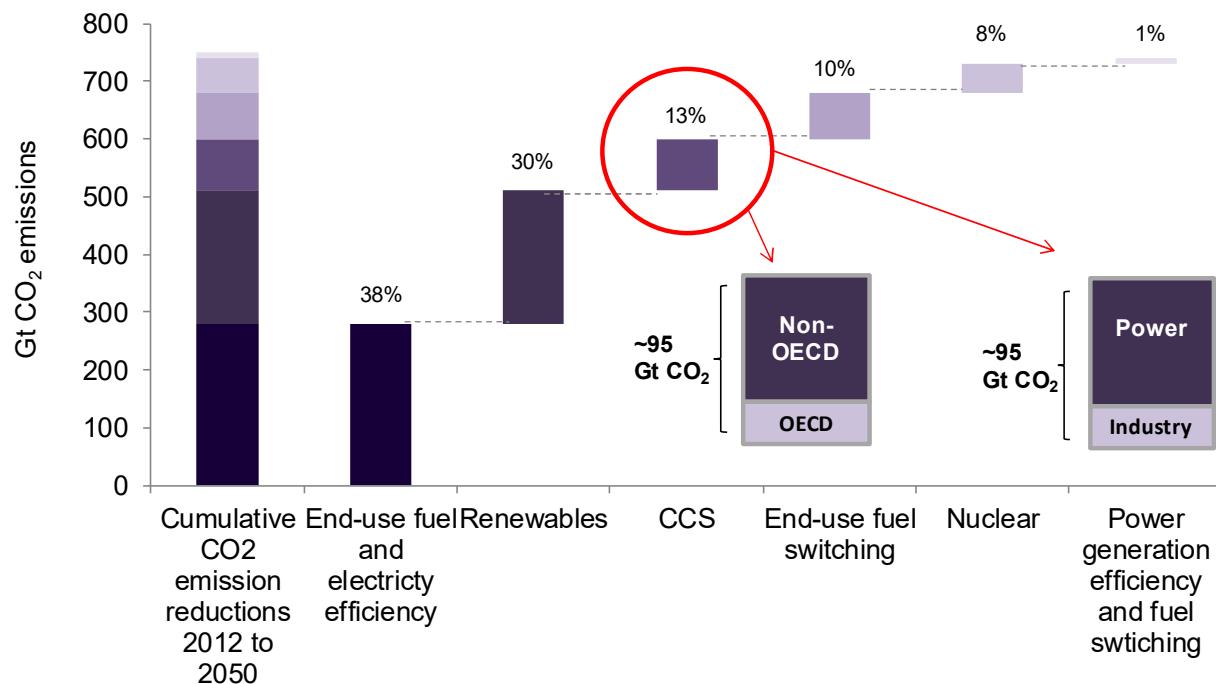


Figure 1. Technical potentials for global carbon emissions

Source: IEA, 2015.

The IEA estimates that as much as 13 percent (95 Gts) of the cumulative level of carbon emissions from 2012 to 2050 could be avoided through CCS applications in both the power generation and the industrial sectors. Over 75 percent of this opportunity will raise in the developing world, with the balance being limited to developed (OECD) countries. Further, most of these applications (over 75 percent) will be associated with the capture of carbon from power applications, with the balance being attributed to industrial capture opportunities.

The early policy and technical focus on power generation-based CCS makes sense. U.S. power generation, primarily from coal-fired generation facilities, accounts for 34 percent of 2016 CO₂ emissions; a formidable and concentrated sector worthy of focused attention (EPA, 2018a). However, industrial emissions represent an equally large, albeit more heterogeneous source of carbon emissions that deserves an increasing amount of attention. This is particularly true in several geographic areas, like the U.S. Gulf coast, and the upper Midwest; that are seeing a renaissance of new industrial investment and economic activity and, most likely, a future increase in carbon emissions.

There is a big difference, however, between the promotion of carbon capture technologies in the power generation sector and those for other manufacturing industries. Power generation in the U.S., for instance, is typically dominated by very large central-station facilities, owned and operated by regulated electric utilities. The highly-regulated nature of the power generation industry makes it a much easier sector in which to explore the use of CCS technologies since the costs of these emerging technologies can be spread over a very large, often captive sales base over a very long extended time period. Industrial capture projects, on the other hand, do not have a large, captive sales base needed to securitize large and often above-market cost CCS investments. Further, federal and state government regulators have played a major role in establishing power generation siting, certification, and fuel use policies, as well as providing various financial support mechanisms for emerging power generation technologies such as coal and nuclear.

The lack of emphasis on manufacturing and industrial applications creates both an opportunity and challenge. In the developed world, industrial capture applications can help to reduce carbon emissions in very large quantities. Consider that an average wind farm, consisting of as many as 40 wind turbines, accounting for 100 megawatts of power generation capacity, operating across 8,500 acres, can abate as much as 112,000 tonnes, annually, of carbon emissions. Yet, a carbon capture project at a relatively standard ammonia plant, that has a geographic footprint of about 800 acres, can abate as much as 400,000 tonnes of annual carbon emissions. Thus the “bang for the buck” associated with an industrial application is much more straightforward, and considerable, relative to renewables. The key to harnessing these industrial and manufacturing applications will be in having a good technical and economic understanding of the scope of these resources, their geographic location, and the cost of capturing, transporting, and sequestering emissions from these sources. This section of the report attempts to quantify those potential industrial “sourcing” opportunities within the Louisiana industrial corridor.

2.2 LOUISIANA CARBON EMISSIONS TRENDS

Petrochemical and refining plants are some of the more energy-intense industrial activities in the U.S. These two sectors alone account for 74 percent of all U.S. industrial CO₂ emissions (EPA, 2018a). And, in some parts of the country, these industries collectively account for a higher level of CO₂ emissions than power generation. Consider that in Louisiana, industrial carbon emissions, driven primarily by refining and petrochemical production activities, account for 54 percent of all CO₂ emissions relative to a U.S. industrial average of only 17 percent (EPA, 2018a).

Louisiana is a major carbon emitter, ranking in the top 10 states in total carbon emissions. As shown in Figure 2, Louisiana ranks fifth in total energy-related carbon emissions behind considerably more populous states such as Texas and California.

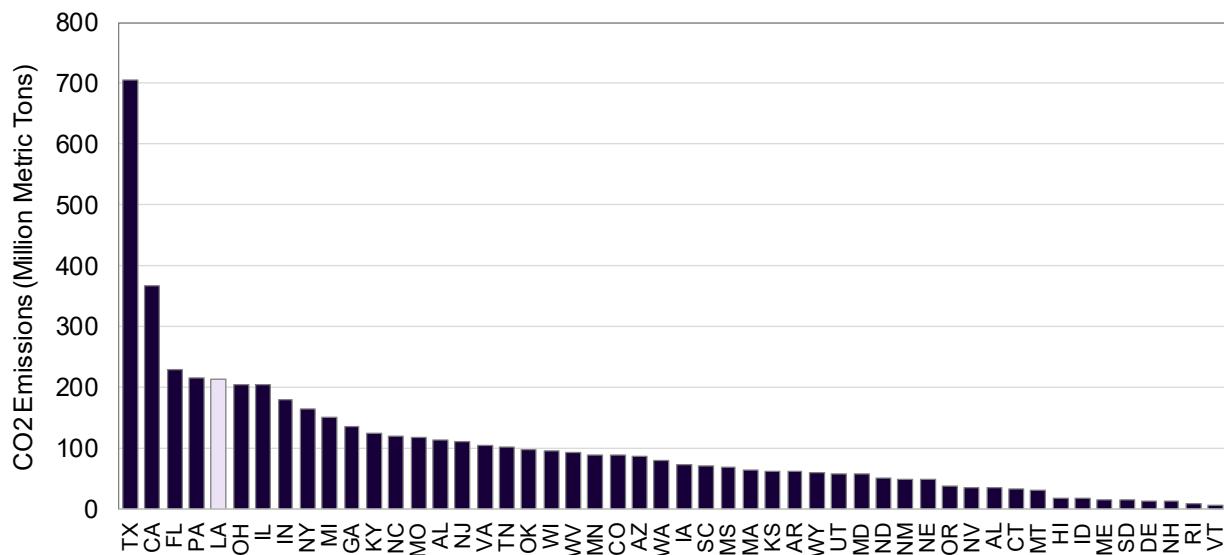
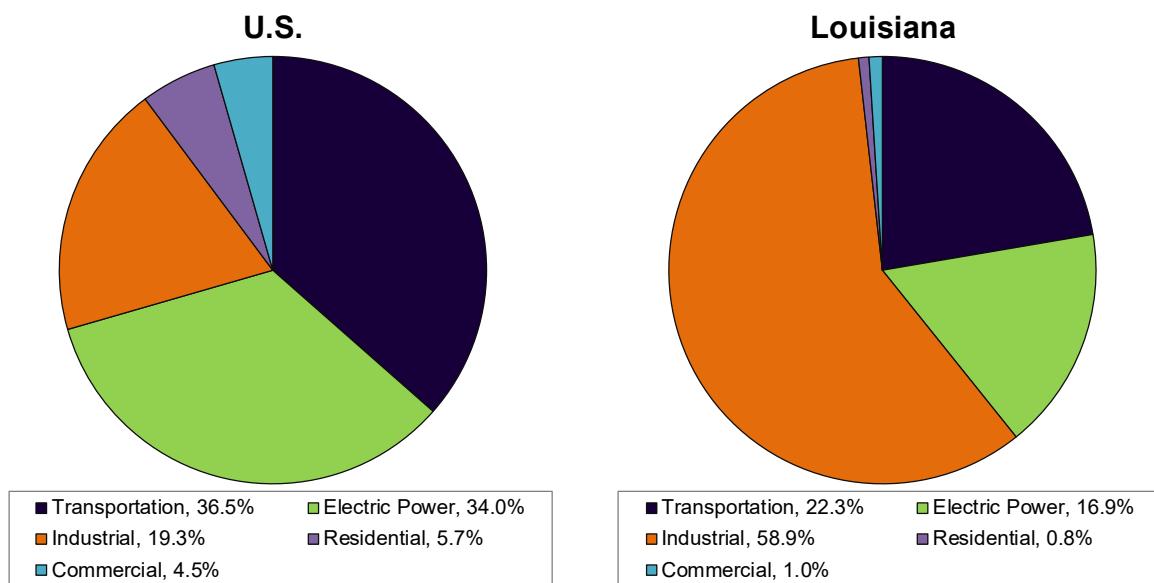


Figure 2. Energy-related carbon emissions by state, 2016

Source: EPA, 2018b.

Interestingly, the composition of Louisiana's carbon emissions differs dramatically from its top 10 peers, as well as the U.S. overall. Figure 3 shows that for the U.S. overall, 34 percent of fossil-fuel combustion-related CO₂ emissions are from electric power (mostly coal-fired) generation. Industrial emissions, on a U.S. average basis, only account for 19 percent of fossil-fuel combustion-related CO₂ emissions. Compare these U.S. average statistics with those for Louisiana where only 17 percent of its combustion-related CO₂ emissions comes from electric power generation yet almost 60 percent come from industrial sources. Thus, underscoring that the strategy to reduce carbon emissions in Louisiana will likely differ considerably from those in other large-emitting states.

Figure 3. U.S. and Louisiana CO₂ emissions from fossil fuel combustion, 2016

Source: EPA, 2018b.

For Louisiana, what is even more important, are the individual industrial sectors from which these fossil fuel combustion emissions originate. Figure 4 examines total Louisiana industrial emissions from fossil fuel combustion, as well as their relative share of total emissions. The chart shows that petrochemical facilities account for 40 million tonnes of emissions (29 percent); and refinery emissions that account for about 32 million tonnes (23 percent).

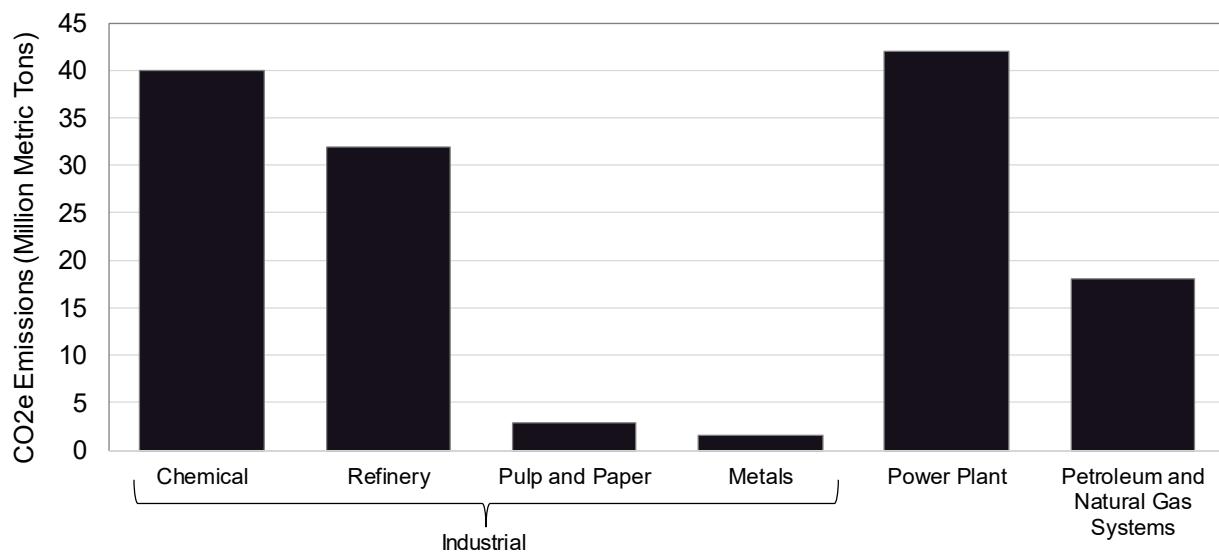


Figure 4. Louisiana fossil fuel combustion emissions, 2016

Source: EPA, 2018a.

Geographic proximity, as will be shown and discussed in more detail later in this report, can be an important consideration for any industrial CCS project. Clearly, the closer a source is to a sink, the lower the transportation cost of moving carbon to its sequestration location. However, a large number of high-volume sources of industrial carbon sources can also help to reduce average carbon capture costs given the high upfront capital required to collect and move the emissions. In other words, average capture costs will be lower for an area with a relatively larger volume of carbon emissions than one with a smaller volume of potential emissions. Figure 5 shows that South Louisiana is a well-positioned region for carbon capture given the large and diverse number of sources in a relatively geographically concentrated area.

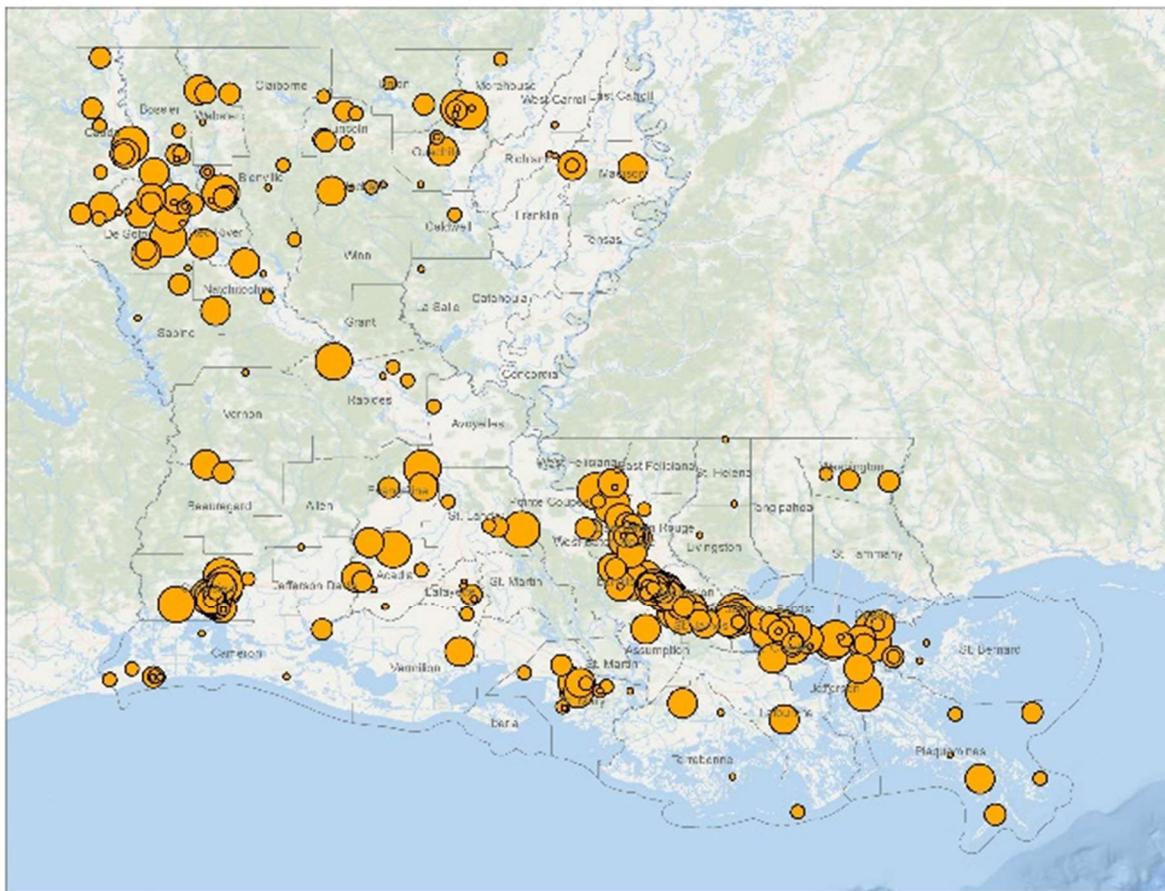


Figure 5. Louisiana industrial carbon source locations

Source: EPA, 2018c, author's construct.

2.3 ANALYSIS OF LOUISIANA'S INDUSTRIAL CARBON SOURCES

This analysis uses information on stationary sources of CO₂ emissions that are reported by industrial and other point sources to the U.S. Environmental Protection Agency (EPA) and its Greenhouse Gas Reporting Program (codified at 40 CFR Part 98). Facilities are required to submit data on emissions to EPA if they emit or store over 25,000 metric tons of CO₂ per year or if they supply products that emit over 25,000 metric tons of CO₂ per year when combusted. These regulations require reporting from approximately 8,000 facilities with total emissions of 3 billion metric tons CO₂e, or about 50 percent of total U.S. emissions. Because the regulations are targeted at large sources, all of plausibly economic sources for CO₂ supply are included. The data are available from EPA's Envirofact's database by facility, industry sector and, in some cases, facility process unit (EPA, 2018c).

Most of Louisiana's non-power sector carbon emissions come from two general sources: industrial locations and gas processing facilities. Figure 6 shows the recent trend in these carbon emissions which have been growing, on an annual average basis, of about two percent per year. The overwhelming share of these non-power sector emissions (94 percent) are associated with industrial point sources.

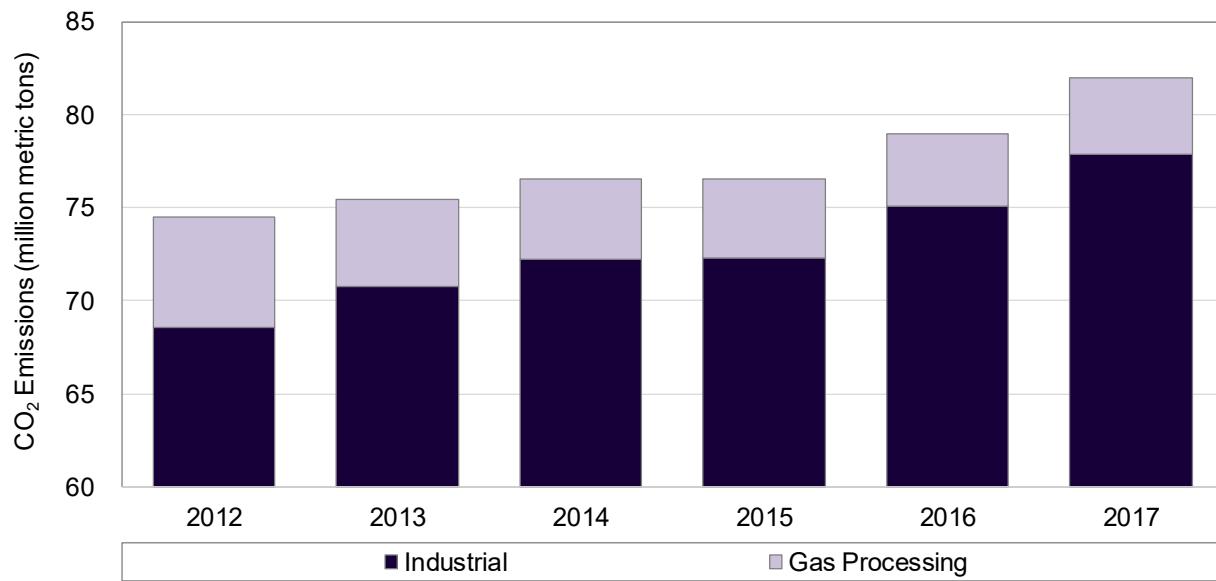


Figure 6. Louisiana industrial and gas processing facility carbon emissions

Source: EPA, 2018c.

Louisiana's industrial emissions trends differ from overall U.S. industrial carbon emission trends, as shown in Figure 7. U.S. industrial carbon emissions, for instance, have been falling consistently since 2013 whereas Louisiana's industrial carbon emissions have been increasing. U.S. industrial carbon emissions are comparable to 2012 levels, while Louisiana's have increased to a level that is close to 15 percent above those reported in 2012.

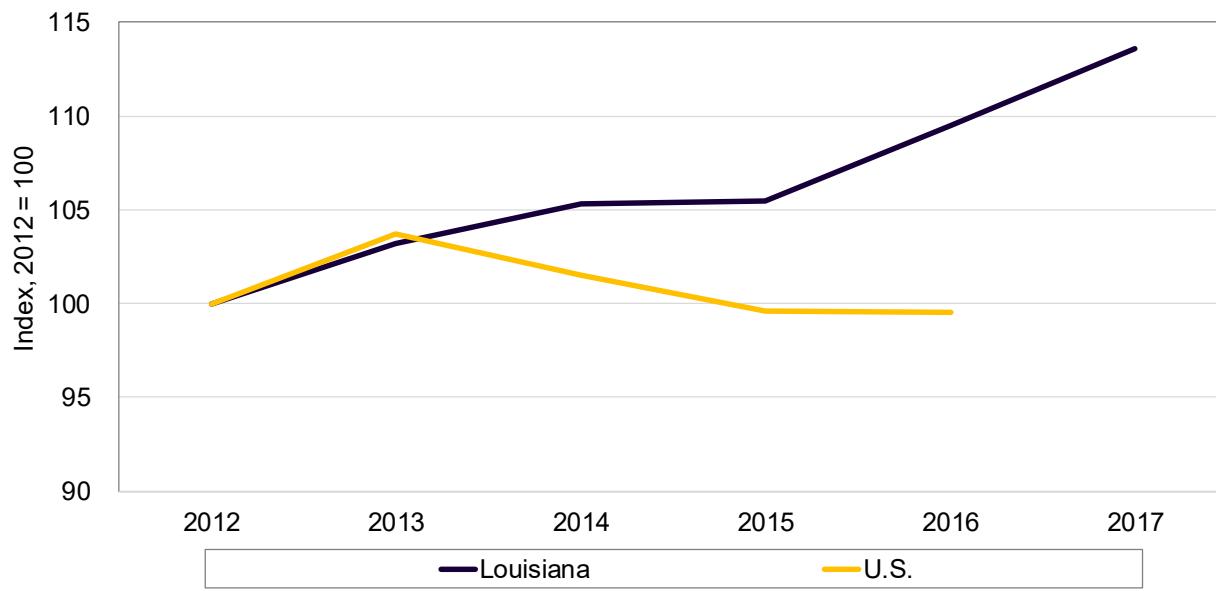


Figure 7. U.S. and Louisiana industrial carbon emissions

Source: EPA, 2018c.

Louisiana emissions trends have generally followed what appears to be on-site economic circumstances over the past several years. Figure 8 examines the relationship between Louisiana carbon emissions and total Louisiana industrial employment. Louisiana industrial carbon

emissions and employment were both increasing at comparable rates from 2012 through 2015, then the data series started to diverge. Industrial employment growth has been declined relative to 2015 levels over the past two years whereas industrial carbon emissions have continued to grow.

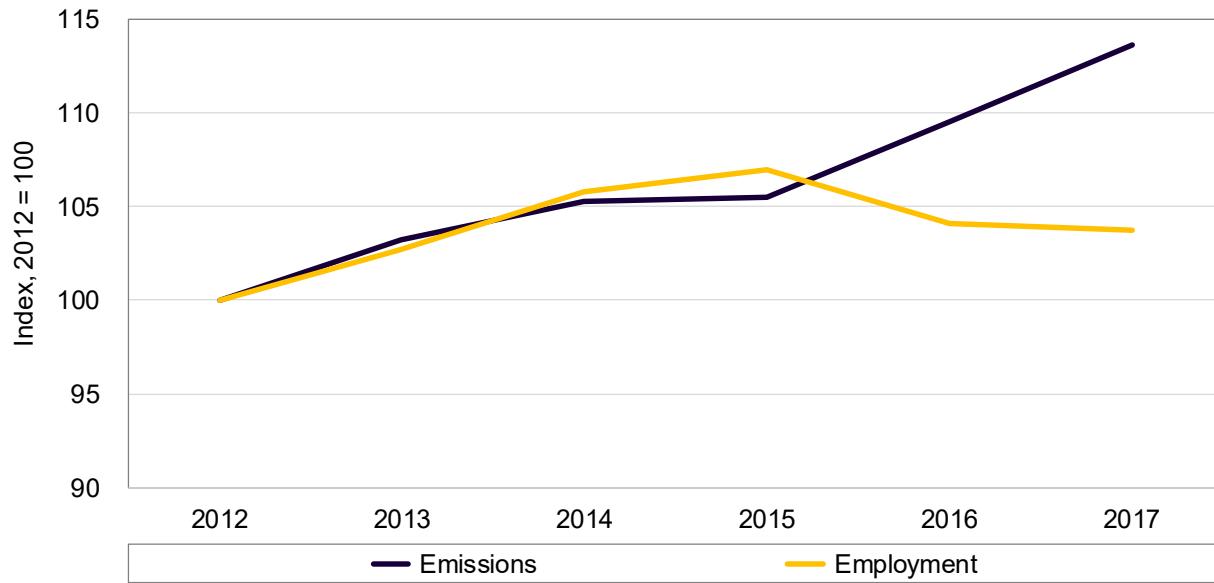
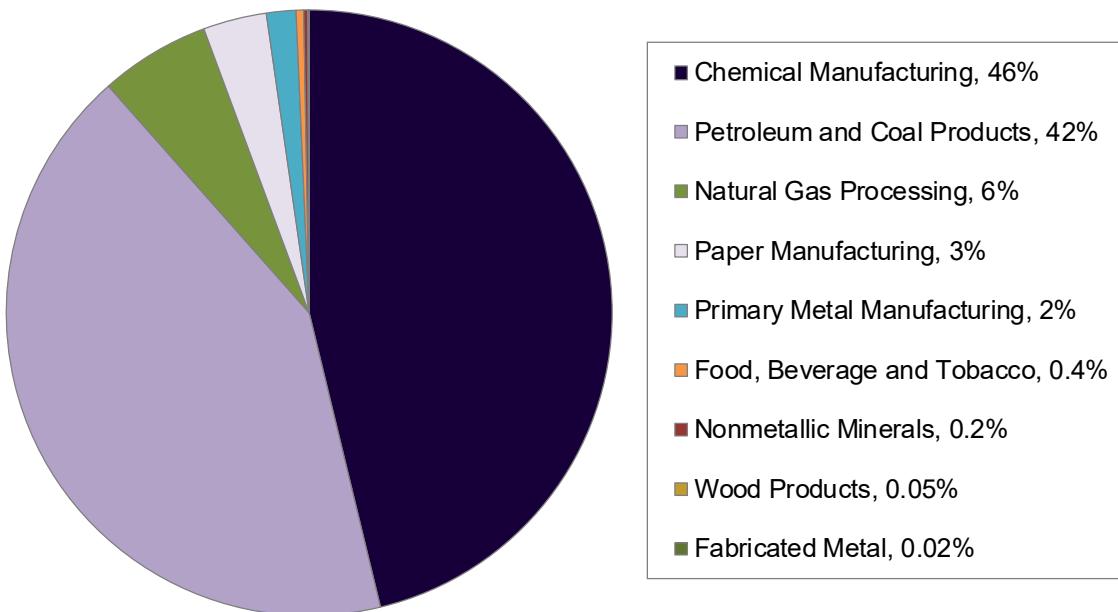


Figure 8. U.S. and Louisiana industrial carbon emissions

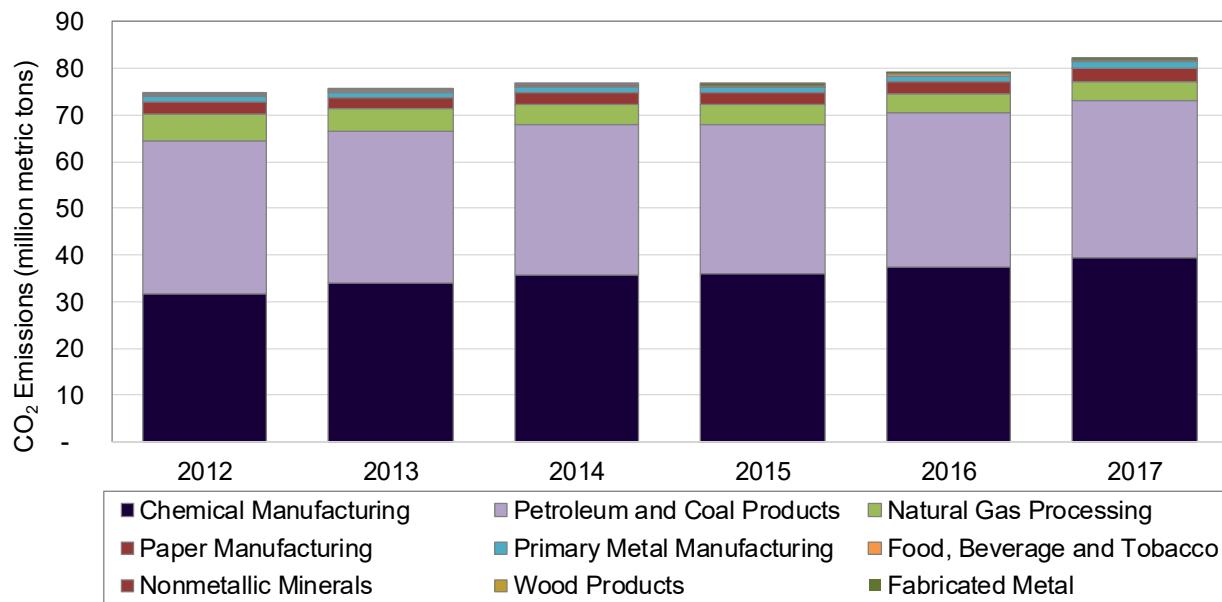
Source: EPA, 2018c and U.S. Census Bureau, 2018.

The disposition of Louisiana industrial carbon emissions is heavily skewed to the primary economic sectors in the Louisiana economy. Figure 9 highlights the skewness of this carbon emissions disposition that is almost exclusively skewed towards chemical manufacturing (46 percent) and petroleum refining (42 percent) sectors. The next closest industrial/manufacturing sector, in terms of carbon emissions, is the natural gas processing sector.

**Figure 9. Louisiana industrial carbon emissions by sector, 2017**

Source: EPA, 2018c.

The annual trends in Louisiana industrial carbon emission trends, discussed earlier, are also relatively steady on a per sector basis. Figure 10 shows that the two main sectors (petrochemical, refining) comprise, on a year-end and year-out basis, the overwhelming bulk of Louisiana's industrial carbon emissions. Thus, the candidate areas for identifying a unique industrial site, or sites, as noted earlier should be limited to South Louisiana, and the candidate industrial sectors should be limited to petrochemical and refining sectors.

**Figure 10. Louisiana industrial carbon emissions by sector, 2017**

Source: EPA, 2018c.

2.4 CARBON EMISSIONS TRENDS AT INDIVIDUAL INDUSTRIAL LOCATIONS

The next step in the industrial carbon emissions screening analysis is to identify all major point sources, located in South Louisiana, that are associated with either petrochemical or petroleum refining operations. Table 1 below rank orders the top ten industrial sites meeting the criteria from the largest to smallest emissions sources, on average, over the 2012 to 2017 time period. Collectively, these ten industrial facilities accounts for almost 40 million tons of carbon emissions, over 50 percent of all Louisiana industrial carbon emissions. Most of the locations (70 percent) are associated with refinery operations; the balance of which are petrochemical facilities.

Table 1. Top ten South Louisiana industrial carbon emission sources (annual emissions)

Facility Name	Facility Type	2012	2013	2014	2015	2016	2017
		(metric tons CO ₂)					
CF Industries Nitrogen - Donaldsonville	Chemical Manufacturing	5,201,108	5,312,449	5,388,579	5,663,578	6,314,632	7,787,715
ExxonMobil - Baton Rouge Refinery	Petroleum and Coal Products	6,444,414	6,323,991	6,257,201	5,970,862	6,182,582	6,102,386
Citgo Petroleum - Lake Charles	Petroleum and Coal Products	4,346,027	4,561,286	4,766,415	4,699,447	4,629,084	4,658,391
Norco Manufacturing Complex	Petroleum and Coal Products	3,981,999	3,498,212	3,529,020	3,440,424	3,887,900	3,982,608
Marathon Petroleum Company	Petroleum and Coal Products	3,934,015	3,918,742	3,924,963	3,949,417	3,778,079	4,014,786
Union Carbide Corp. - St Charles	Chemical Manufacturing	2,069,376	2,794,800	2,881,974	2,789,131	2,837,285	2,857,844
Valero Refining - New Orleans	Petroleum and Coal Products	2,384,289	2,747,273	2,589,605	2,509,828	2,777,647	2,514,636
Eagle US 2 LLC	Chemical Manufacturing	2,988,160	3,050,713	2,840,750	2,784,974	2,671,132	2,891,554
Phillips 66 - Alliance Refinery	Petroleum and Coal Products	2,163,263	2,403,978	2,111,565	1,962,580	2,570,326	2,790,463
Motiva Enterprises - Convent Refinery	Petroleum and Coal Products	2,031,251	1,975,545	2,083,624	2,257,249	2,358,841	2,357,948
Total		35,523,902	36,586,988	36,373,695	36,027,490	38,007,508	39,958,331

Source: EPA, 2018c.

The CF Industries ammonia plant is the largest carbon emission source in Louisiana with an annual average emissions rate of six million tons from 2012 to 2017. Carbon emissions from the CF Industries facility have increased from just over five million tons in 2012 to close to eight million tons in 2017. The ExxonMobil Baton Rouge refinery is the second largest source, followed by the Citgo Refinery and ultimately, the Norco Refinery in Norco, Louisiana. The Norco refinery, in fact, is largest industrial carbon emissions source that is physically located towards the center of Louisiana's industrial corridor, a point that will be revisited later.

Figure 11 underscores the geographically concentrated nature of these facilities in the state. All but two (Eagle US 2 LLC, Citgo)¹ of these top ten industrial carbon emission sources are within an 80-mile range of one another stretching from as far north as Baton Rouge (ExxonMobil Refinery) to as far south as Belle Chase's Phillips 66 Alliance Refinery (just south of New Orleans). Further, of these ten industrial locations, six are within a 40-mile distance of one another, and account for 30 percent of Louisiana's total industrial carbon emissions.²

¹These facilities are located in the greater Lake Charles, Louisiana industrial area.

² CF Industries, Norco, Marathon, Union Carbide, Valero and Motiva.

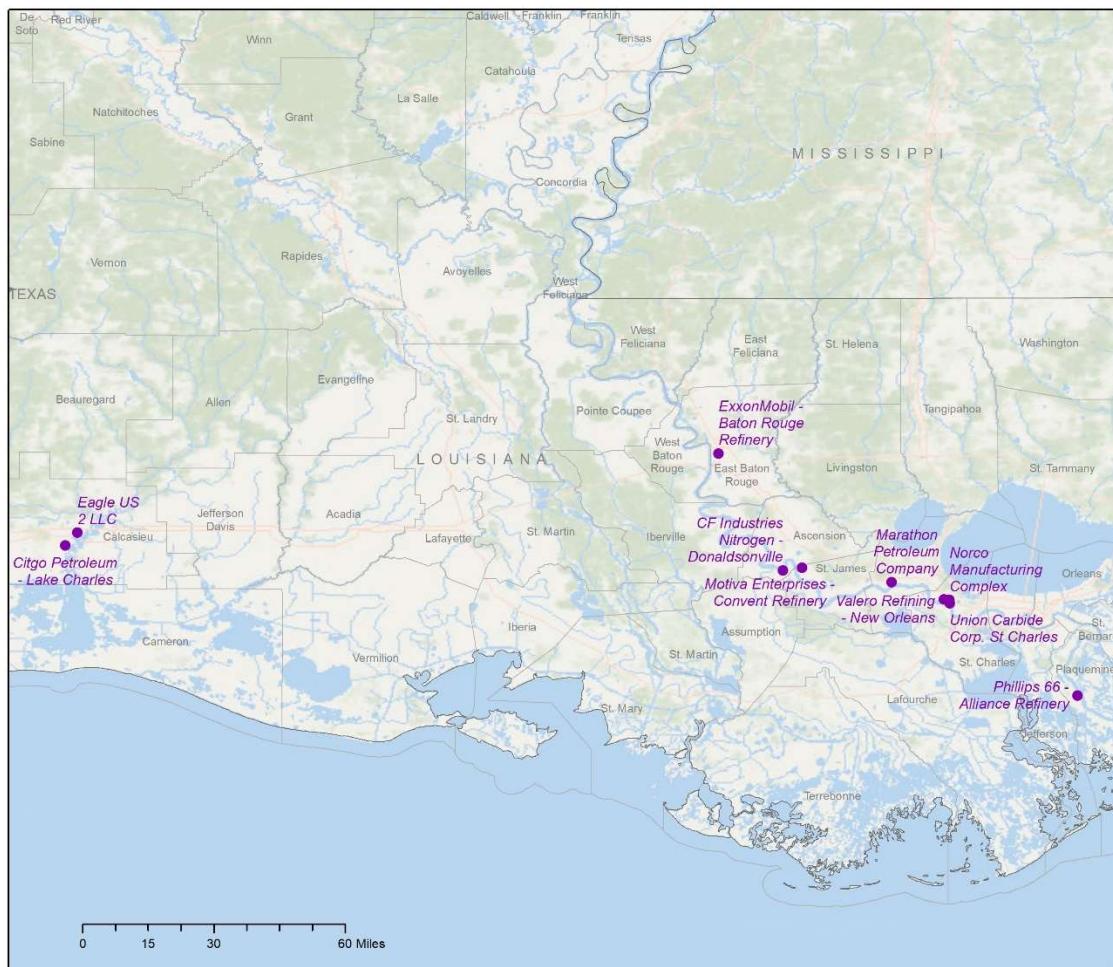


Figure 11. Top ten South Louisiana industrial carbon sources

Table 2 highlights the recent trends in carbon emission levels at each of these top ten industrial locations. Carbon emissions growth rates across these top ten industrial locations are not steady nor consistent. While most have seen increases, others have seen relatively significant decreases. Consider, for instance, that CF Industries, in addition to being the largest single point source for carbon emissions in the state, has seen considerable emissions growth during the 2015 to 2017 time period. The percentage change in carbon emissions at the CF Industries facility is double to three times the average emissions growth rate for the largest ten facilities, collectively. Over the past two most recent years of reported data, CF Industries reports carbon emissions growth rates of over 11 percent and 23 percent. These increases are likely attributable to the recent large-scale expansions at the CF facility.

Table 2. Top ten South Louisiana industrial carbon emission sources (annual percent change in emissions)

Facility Name	Facility Type	2013	2014	2015	2016	2017
(percent change, %)						
CF Industries Nitrogen - Donaldsonville	Chemical Manufacturing	2.1%	1.4%	5.1%	11.5%	23.3%
ExxonMobil - Baton Rouge Refinery	Petroleum and Coal Products	-1.9%	-1.1%	-4.6%	3.5%	-1.3%
Citgo Petroleum - Lake Charles	Petroleum and Coal Products	5.0%	4.5%	-1.4%	-1.5%	0.6%
Norco Manufacturing Complex	Petroleum and Coal Products	-11.7%	0.9%	-2.5%	13.0%	2.4%
Marathon Petroleum Company	Petroleum and Coal Products	-0.4%	0.2%	0.6%	-4.3%	6.3%
Union Carbide Corp, St Charles	Chemical Manufacturing	35.1%	3.1%	-3.2%	1.7%	0.7%
Valero Refining - New Orleans	Petroleum and Coal Products	15.2%	-5.7%	-3.1%	10.7%	-9.5%
Eagle US 2 LLC	Chemical Manufacturing	2.1%	-6.9%	-2.0%	-4.1%	8.3%
Phillips 66 - Alliance Refinery	Petroleum and Coal Products	11.1%	-12.2%	-7.1%	31.0%	8.6%
Motiva Enterprises - Convent Refinery	Petroleum and Coal Products	-2.7%	5.5%	8.3%	4.5%	0.0%
Total		3.0%	-0.6%	-1.0%	5.5%	5.1%

Source: EPA, 2018c.

The carbon emissions from South Louisiana industries arise from the combustion and reformation of natural gas and its derivatives. The large industrial carbon emission point sources do not burn or reform coal. Thus, from a longer run carbon capture perspective, it is unlikely that emissions at these facilities will change dramatically due to any fuel switching. This is both a positive and important consideration for capture projects since the economics of any project, as shown in greater detail later, will be driven in large part by capture volumes: the larger the capture volumes, the lower the unit cost of the overall CCS process.

Industrial natural gas use in South Louisiana, and the carbon emissions arising from that use, are mixed. Industrial facilities combust natural gas to make steam (in boilers), heat (in furnaces), and electricity (in power generation). Further, natural gas is used as a feedstock (reformation) to make a variety of intermediate inputs (such as hydrogen through steam methane reformation or “SMR”) and petrochemical commodities and products (such as various olefins, agricultural chemicals, and methanol). The ability, as well as the economics of capturing industrial emissions, therefore, will differ based upon the level and relative concentration of these on-site uses.

Table 3 shows the cumulative emissions for a five-year period (2012-2017) for each of the top ten industrial carbon emission sources in South Louisiana. These emissions are separated into “stationary combustion” which includes the emissions from steam and heat use; electricity generation; and from ammonia, hydrogen, petrochemical, and refining production. The last set of emissions, as will be examined in greater detail in a later section of this report, can be captured through various “pre-combustion” technologies that can often be more economic than the “post-combustion” technologies commonly associated with stationary combustion and power generation applications.

Table 3. Cumulative industrial emissions, top ten industrial locations (by emissions type, 2012-2017)

Facility Name	Facility Type	Stationary Combustion	Electricity Generation	Ammonia Production	Hydrogen Production	Petrochemical Production	Refining
(metric tons total emissions)							
CF Industries Nitrogen - Donaldsonville	Chemical Manufacturing	14,277,707	-	21,405,086	-	-	-
ExxonMobil - Baton Rouge Refinery	Petroleum and Coal Products	27,039,348	-	-	-	222,825	10,200,415
Citgo Petroleum - Lake Charles	Petroleum and Coal Products	20,730,968	-	-	-	-	7,077,450
Norco Manufacturing Complex	Petroleum and Coal Products	15,448,233	-	-	126,668	330,827	6,886,008
Marathon Petroleum Company	Petroleum and Coal Products	16,794,081	-	-	-	-	6,891,871
Union Carbide Corp. St Charles	Chemical Manufacturing	13,821,670	-	-	-	2,710,378	-
Valero Refining - New Orleans	Petroleum and Coal Products	5,869,363	-	-	3,781,646	-	5,981,683
Eagle US 2 LLC	Chemical Manufacturing	7,710,797	9,381,927	-	-	130,391	-
Phillips 66 - Alliance Refinery	Petroleum and Coal Products	8,901,410	-	-	-	-	5,172,241
Motiva Enterprises - Convent Refinery	Petroleum and Coal Products	7,572,384	-	-	130,006	-	5,429,001
Total		138,165,960	9,381,927	21,405,086	4,038,319	3,394,421	47,638,669
Percent of Total (%)		50.9%	3.5%	7.9%	1.5%	1.2%	17.5%

Note: The values in this table represent total emissions which is carbon emissions plus a minor amount of methane (CH₄) emissions and nitrous oxide (N₂O) emissions.

Source: EPA, 2018c.

As noted, CF Industries' ammonia facility in Donaldsonville, Louisiana is the largest regional industrial carbon emission source on a cumulative basis over the last five years. The detail in the table above underscores the deviation in process-related emissions. The majority of CF Industries' carbon emissions are associated with ammonia process applications (60 percent) rather than combustion processes. This means that an investment in pre-combustion related capture technologies will be relatively well-served relative to post-combustion applications with the location's boilers and furnaces. The same kind of emissions relationship (biased more towards process than combustion), does not hold for the other two petrochemical facilities on the list (Union Carbide and Eagle).

The breakdown of carbon emissions for the refineries shown in Table 3 are heavily dominated by combustion-related activities with the exception of the Valero Refinery. Most of the refineries in the table report about 30 percent to 35 percent of their total carbon emissions as being associated with reformation (refinery) or feedstock activities. These non-combustion activities, however, are still relatively considerable. The ExxonMobil Refinery, for instance, reports as much as 10.2 million metric tons in cumulative non-combustion related carbon emissions. Norco reports as much as seven million metric tons in non-combustion related emissions, moving it to the second highest reported source on a non-combustion as opposed to total carbon emissions basis, followed closely by the Citgo Refinery that is on the other side of the state in Lake Charles. The remaining refineries, with the exception of Valero, report far lower non-combustion emissions below six million tons on a cumulative five-year basis.

The Valero Refinery, however, reports non-combustion carbon-related emissions that are actually larger than the emissions arising from on-site combustion related activities. The SMR activities at the refinery, that produces hydrogen for the hydrostatic treaters at the refinery, coupled with the other refinery operations, results in as much as 9.6 million metric tons of carbon emissions, on a cumulative basis, relative to only 5.9 million metric tons associated with combustion activities. This cumulative 9.6 million metric tons rivals the amount produced at the ExxonMobil facility (10.4 million metric tons) and surpasses the totals for Norco, and Marathon, which are in the industrial river corridor location.

The last set of information examined relative to these South Louisiana industrial carbon emission

sources is the annual emissions aggregated in two categories (stationary/power generation; and chemical/refining; provided in Table 4) and the annual percent change, by major category (Table 5). Both tables show that: (a) the majority of the chemical related emissions are associated with reformation activities rather than combustion whereas, for the refineries, only about one-third of their total emissions are associated with feedstock/reformation activities; and (b) the trends in both sets of aggregate emissions are relatively stable. The stability of these emissions, over a longer period of time, creates a potentially positive economic environment for a large, capital-intensive carbon capture investment, the economics of which, will be discussed in greater detail later in this report.

Table 4. Annual industrial emissions, top ten industrial locations (by major emissions category, 2012-2017)

Facility Name	Facility Type	Stationary and Power Emissions						Chemical/Refining Emissions					
		2012	2013	2014	2015	2016	2017	2012	2013	2014	2015	2016	2017
		(metric tons total emissions)											
CF Industries Nitrogen - Donaldsonville	Chemical Manufacturing	2,130,532	2,147,449	2,169,798	2,285,291	2,604,845	2,939,791	6,375,083	6,380,501	5,872,026	8,019,867	6,736,320	5,790,845
ExxonMobil - Baton Rouge Refinery	Petroleum and Coal Products	4,706,171	4,547,577	4,464,192	4,425,866	4,431,877	4,463,664	1,769,639	1,807,847	1,822,486	1,574,323	1,781,365	1,667,581
Citgo Petroleum - Lake Charles	Petroleum and Coal Products	3,208,717	3,370,842	3,567,122	3,503,416	3,506,407	3,574,463	1,161,802	1,216,427	1,225,702	1,220,115	1,146,038	1,107,366
Norco Manufacturing Complex	Petroleum and Coal Products	2,634,378	2,491,199	2,361,313	2,337,936	2,809,360	2,814,046	1,397,863	1,095,325	1,235,652	1,184,796	1,172,484	1,257,380
Marathon Petroleum Company	Petroleum and Coal Products	2,841,031	2,730,496	2,822,965	2,890,378	2,748,709	2,760,501	1,117,108	1,216,474	1,133,056	1,088,120	1,057,309	1,279,802
Union Carbide Corp. St Charles	Chemical Manufacturing	1,798,474	2,448,546	2,633,486	2,344,214	2,358,386	2,238,564	291,242	381,524	272,255	524,124	522,722	718,512
Valero Refining - New Orleans	Petroleum and Coal Products	736,729	994,211	907,709	1,012,561	1,122,365	1,095,788	1,659,253	1,769,899	1,698,468	1,517,303	1,678,495	1,439,906
Eagle US 2 LLC	Chemical Manufacturing	2,944,622	3,030,503	2,826,818	2,765,938	2,653,261	2,871,582	46,577	23,339	16,877	21,887	20,602	22,928
Phillips 66 - Alliance Refinery	Petroleum and Coal Products	1,458,611	1,587,698	1,301,737	1,311,548	1,549,341	1,692,474	717,049	828,673	820,844	662,241	1,032,693	1,110,741
Motiva Enterprises - Convent Refinery	Petroleum and Coal Products	1,127,925	1,169,827	1,286,344	1,267,208	1,316,007	1,405,073	916,325	815,784	802,794	1,003,995	1,055,138	964,971
Total		23,587,191	24,518,348	24,341,485	24,144,355	25,100,560	25,855,948	15,451,941	15,535,793	14,900,160	16,816,777	16,203,166	15,360,032

Source: EPA, 2018c.

Table 5. Annual industrial emissions, top ten industrial locations (by major emissions category, 2012-2017)

Facility Name	Facility Type	Stationary and Power Emissions						Chemical/Refining Emissions					
		2013	2014	2015	2016	2017	2013	2014	2015	2016	2017		
		(percent change, %)											
CF Industries Nitrogen - Donaldsonville	Chemical Manufacturing	0.8%	1.0%	5.3%	14.0%	12.9%	0.1%	-8.0%	36.6%	-16.0%	-14.0%		
ExxonMobil - Baton Rouge Refinery	Petroleum and Coal Products	-3.4%	-1.8%	-0.9%	0.1%	0.7%	2.2%	0.8%	-13.6%	13.2%	-6.4%		
Citgo Petroleum - Lake Charles	Petroleum and Coal Products	5.1%	5.8%	-1.8%	0.1%	1.9%	4.7%	0.8%	-0.5%	-6.1%	-3.4%		
Norco Manufacturing Complex	Petroleum and Coal Products	-5.4%	-5.2%	-1.0%	20.2%	0.2%	-21.6%	12.8%	-4.1%	-1.0%	7.2%		
Marathon Petroleum Company	Petroleum and Coal Products	-3.9%	3.4%	2.4%	-4.9%	0.4%	8.9%	-6.9%	-4.0%	-2.8%	21.0%		
Union Carbide Corp. St Charles	Chemical Manufacturing	36.1%	7.6%	-11.0%	0.6%	-5.1%	31.0%	-28.6%	92.5%	-0.3%	37.5%		
Valero Refining - New Orleans	Petroleum and Coal Products	34.9%	-8.7%	11.6%	10.8%	-2.4%	6.7%	-4.0%	-10.7%	10.6%	-14.2%		
Eagle US 2 LLC	Chemical Manufacturing	2.9%	-6.7%	-2.2%	-4.1%	8.2%	-49.9%	-27.7%	29.7%	-5.5%	11.3%		
Phillips 66 - Alliance Refinery	Petroleum and Coal Products	8.9%	-18.0%	0.8%	18.1%	9.2%	15.6%	-0.9%	-19.3%	55.9%	7.6%		
Motiva Enterprises - Convent Refinery	Petroleum and Coal Products	3.7%	10.0%	-1.5%	3.9%	6.8%	-11.0%	-1.6%	25.1%	5.1%	-8.5%		
Total		3.9%	-0.7%	-0.8%	4.0%	3.0%	0.5%	-4.1%	12.9%	-3.6%	-5.2%		

Source: EPA, 2018c.

2.5 CONCLUSIONS

The industrial carbon emissions screening analysis has yielded a number of important insights into candidate locations for further economic feasibility analysis. Emission levels, however, are not the only criteria that makes a location suitable as a CCS candidate. The additional criteria can include, but is not limited to:

- The nature of the candidate location and whether it represents a world-class facility that is profitable and has the continued financial capability to support a large CCS capital investment.
- The financial condition of the company that owns any potential CCS industrial location.

- Having a large level of carbon emission that are either growing or at least stable and are, preferably, concentrated in reformation-process type applications as opposed to simple combustion activities.
- Being in a location with close proximity to other industrial carbon emission sources that could be coupled to create a larger source volume potentially leading to lower effective CCS unit costs.
- Being in a location that is relatively proximate to a number of potential storage facilities or carbon uses.

Many of the top ten industrial locations examined earlier meet the criteria outlined above. All are relatively large facilities and most have seen, and will likely continue to see, strong production activities and continued capital investment at their particular site. Most of the top ten industrial locations, for instance, have seen considerable recent capital investment in either additional distillation capacity (refineries) or additional productive capabilities (such as CF Industries and Union Carbide). This bodes well for a potential CCS investment, at least from a corporate and site-specific financial perspective. Many of the locations are also in close proximity to one another, with the exception of the Citgo Refinery. Again, this proximity is promising for the scalability of a project at, or in relation to any individual location.

For purposes of this analysis, CF Industries will be used as the candidate site to model overall feasibility. The facility has the largest set of emissions of any reported in the region, the facility produces high quality CO₂ thereby likely driving down its initial capital costs, the high quality carbon emissions have been growing over time, the CF facility is a world class scale facility (the largest of its type in the world) that has seen considerable recent capital investment and is likely to be in operation for a considerable period of time, an important consideration for the capital cost recovery of capture project.

3 CARBON SINKS: IDENTIFICATION AND TECHNICAL STORAGE CAPABILITIES

3.1 STATIC AND DYNAMIC CAPACITY ESTIMATES OF BAYOU SORREL AND PARADIS

The close proximity of large CO₂ emitters and depleted oil and gas reservoirs in the Louisiana Chemical Corridor (LCC) provide unique opportunities for CO₂ geological sequestration in coastal Louisiana. The identification of sites with good storage capacity and retention characteristics is of prime importance for successful CO₂ storage projects. In this study, the Bayou Sorrel and Paradis field located within close proximity of some of the large CO₂ emitters in the LCC, are analyzed as a potential candidate site for aquifer storage. The results of static and dynamic aquifer storage capacity estimates are presented in this study. A volumetric approach is used to estimate the static storage capacity, and reservoir simulations are performed to compute dynamic storage capacity. The field and well data from publicly available data sources are compiled to characterize the aquifer sands for prospective CO₂ sequestration intervals (i.e., non-productive sands), and pressure and temperature conditions.

Information of total areal extent, gross formation thickness, and total porosity are used along with a storage efficiency factor to find the pore volume available for storage. The upper depth limit for CO₂ injection is dictated by the pressure and temperature conditions at which CO₂ exists in a supercritical state. The Peng-Robinson (PR) equation of state is used in conjunction with subsurface pressure and temperature to determine the minimum depth at which CO₂ is supercritical. Multiple geological realizations are used for a realistic site-specific storage capacity estimate. The reservoir simulations capture the transient nature of the process and provide estimation of storage capacity under dynamic conditions. The sensitivity of injection location and boundaries is also evaluated in the dynamic storage capacity estimates.

In Bayou Sorrel field the results of the dynamic storage capacity estimate for a 1,000 ft thick interval at an average depth of 7,100 ft show that reasonable values of storage efficiency factors for this region are in the range of two to four percent. While for Paradis a high permeability shallower interval with 300 ft thickness and at an average depth of 4,700 ft, the storage efficiency is determined to be in the range of 0.12 to 2.4 percent. The results of the dynamic model also show that the nature of the storage zone boundary type, end point saturation and injection rate play significant roles in the estimation of dynamic storage capacity. These factors may induce more than 30 percent change in estimated dynamic storage value. The calculated storage efficiency factor may be applicable to other potential aquifer sites in this region, having similar geological characteristics.

3.1.1 Introduction

CO₂ can be stored in depleted oil and gas fields, deep saline aquifers or in coal seams or other formations that cannot be mined. Deep saline aquifers have the largest storage capacity amongst these. However, they also have the highest uncertainty in terms of their size and structural/stratigraphic traps as compared to hydrocarbon reservoirs (Jin et al. 2012) . CO₂ storage in saline aquifers is similar to CO₂ storage in depleted oil and gas reservoirs, the difference is in the water saturation (Bachu et al. 2007). Saline aquifers are initially saturated with water. This necessitates the estimation of site-specific CO₂ storage values, a key component in selection of a storage site. The selected site must have enough pore volume available to meet

the project economics, and at the same time it should retain the injected CO₂ for the lengthy duration necessitated by regulatory considerations. The economic considerations for a specific site may involve its close proximity to CO₂ sources, injection rates and pressure, number of wells required to achieve the desired injection rate, and combining storage with enhanced oil recovery (Goodman et al. 2011). The regulatory requirements includes protection of potable water sources, treatment of in-situ fluids, maximum injection limits to avoid any seismic event or fracture the rock, well spacing requirements and proximity to existing wells (Wilson et al. 2003). The EPA's underground injection control (UIC) regulations incorporate most of these requirements (EPA, 2016). A potential sequestration site must meet both of the economics and regulatory requirements.

3.1.2 Capacity estimates

The site storage capacity estimates for CO₂ geological sequestration processes can broadly be categorized as static and dynamic. Volumetric and compressibility methods are the two main static storage capacity calculation methods, while decline curve analysis, mass balance and reservoir simulation provide dynamic site-specific CO₂ storage estimates. In this study volumetric study will be used for the static storage capacity and reservoir simulations will be used for the dynamic storage capacity methods respectively. A brief introduction of both of these methods follows.

3.1.3 Static storage capacity

The static estimates can be performed by using the petrophysical data of the proposed candidate site. In the volumetric method the areal extent and height of the target formation, formation pressure and temperature, porosity and storage efficiency factor are used. Initial pressure and temperature data is used to calculate the CO₂ density and then static storage efficiency is calculated by using the equation (1)

$$G_{CO_2net} = A_t h_{net} \phi_{tot} \rho E_{net} \quad (1)$$

where A_t = areal extent of sand, h_{net} = sand thickness, ρ is the CO₂ density at initial reservoir conditions, ϕ_{tot} = total porosity, and E_{net} is the storage efficiency factor. The storage efficiency factor reflects how much total pore volume is filled by CO₂. A typical range is from 0.4 to 5.5 percent (Goodman et al. 2011). In saline aquifers it accounts for net to total area ratio that is suitable for CO₂ storage $E_{An/At}$, net to gross sand thickness $E_{hn/hg}$, and effective to total porosity $E_{\phi e/\phi tot}$. These terms account for the volume that is available to CO₂ sequestration. The areal E_A , microscopic E_d , vertical E_L and gravitational E_g sweep efficiencies take into account different barriers that prevent CO₂ from contacting 100 percent of the pore volume available. This is defined by equation (2), (Goodman et al. 2011)

$$E_{saline} = E_{An/At} E_{hn/hg} E_{\phi e/\phi tot} E_A E_L E_g E_d \quad (2)$$

The U.S. Department of Energy has specified some ranges of values for these terms (Goodman et al. 2011), which can be used to provide an initial guess for storage efficiency factor for a specific site. Then dynamic storage capacity estimates described in the next section can be used to verify the ranges for storage efficiency factor for that particular storage site.

3.1.4 Dynamic storage capacity

Numerical simulation, in principal, provides a realistic site specific storage capacity estimate, provided that a good data set for site characterization is available (Wallace 2013). The assumed value of storage efficiency factor can then be verified by using numerical simulations with an active injection scheme. In numerical simulations basic porous media fluid flow equations of continuity, momentum balance and energy balance are solved on grid cells. The simulations can address the relevant physical phenomenon of dissolution of CO₂ into brine, brine evaporation and salt precipitations (Ott et al. 2015) and CO₂ mineralization over very long time durations.

The typical steps involved in reservoir simulations are the creation of a three-dimensional geological model and estimation of petrophysical properties from available well log, core or past production data for the selected area. Then simulations are performed under various injection scenarios and sensitivity of the dynamic storage capacity to other uncertain parameters can be studied. Dynamic capacity is highly influenced by the petrophysical properties of the storage zone. These petrophysical properties include porosity, permeability, and relative permeabilities and end point saturations of the phases. In addition, storage zone boundary types, initial pressure, initial temperature and injection rate influence the dynamic capacity estimates.

Injection rate is one of the critical elements in dynamic storage estimates. The injection rate is mainly decided by the project economics, formation fracture pressure and avoidance of creating any seismic events. In next sections we describe the steps involved in estimation of field specific static and dynamic CO₂ storage capacity estimates for deep saline aquifers.

3.1.5 Bayou Sorrel

Bayou Sorrel is a nearly depleted oil/gas field and is located in Iberville Parish in Southern Louisiana with approximate location shown in Figure 12. Because the field has publicly available data that extends from near surface through several aquifer zones into a deep productive interval, this data can be used to characterize the aquifer zones to show the process for both the static and dynamic estimation of storage volume. The areal extent of the target region around the Bayou Sorrel field is approximately 26,000 acres. It is a stacked sand system. There are more than 21 sand intervals each of which has at least 80 ft thickness, spanning from 2,550 to 10,500 ft. A 1,000 ft thick zone at an average depth of 7,100 ft is selected for detailed static and dynamic capacity analysis. The results of the selected zones can be easily extrapolated to other zone if required to find the total storage capacity of this stacked sand system. The aquifer zones are similar to the productive interval in the field in that they are bounded by a fault along the northern edge of the area of interest (John et al. 2013). This fault has a maximum throw of approximately 250 ft.

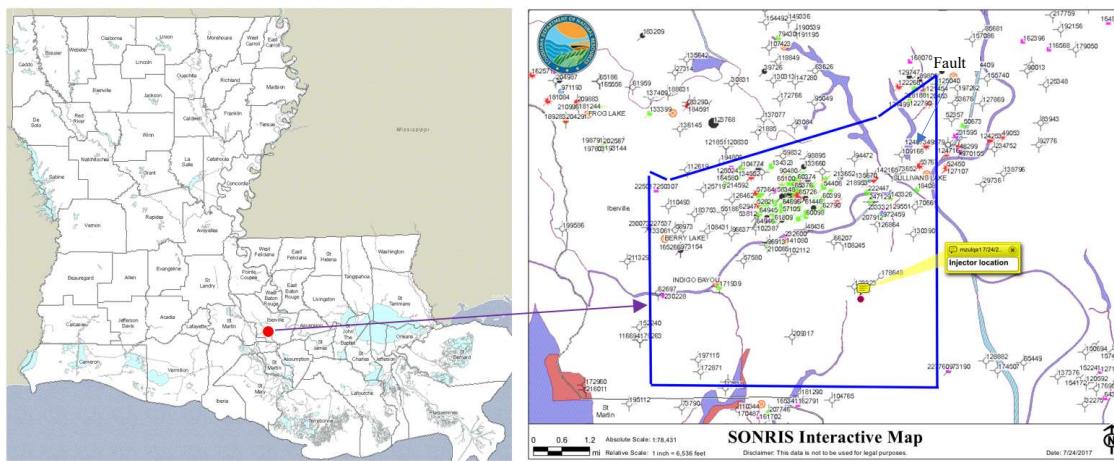


Figure 12. Approximate location and boundaries of potential candidate Bayou Sorrel site

The fault location is estimated from the well data as no seismic data was available. The injector location is selected to minimize wellbore leakage, by adopting the criteria specified in (Zulqarnain et al. 2017a). Therefore, it is located away from the main cluster of wells and is in a region where wells are sparsely located.

3.1.5.1 Site specific data

Site specific data was collected from the Louisiana Department of Natural Resources (LDNR), Strategic Online Natural Resources Information System (SONRIS). Well logs, production history, sand and well information can be obtained from this data source. The permeability data for the aquifer zones for this field are not available and therefore some uncertainty may be present in estimated permeability values.

3.1.5.2 Well Status

The well status of the Bayou Sorrel is provided in Table 6. Currently there are three wells designated as active-producing well. The current production is deeper than 10,000 ft.

Table 6. Well status for the Bayou Sorrel field

Well Status Description	Number of Wells
Active - injection	2
Active - producing	3
Temporary inactive	1
Orphan well-eng	3
Orphan well-injection and mining	1
Dry and plugged	36
Plugged and abandoned	111
Shut-in productive -future utility	1
Shut-in waiting on pipeline	1
	Field Total. 159

Source. SONRIS, 2018.

3.1.5.3 Production Information

The total produced hydrocarbons reported are shown in Table 7, which is approximately equal to 43.57 million metric tons of CO₂. Production data is reported to give an estimate of available storage size in hydrocarbon bearing formation and potential for enhanced oil recovery (EOR).

Table 7. Total produced hydrocarbon from Bayou Sorrel field

Field	Oil (bbl)	Gas (MSCF)
Bayou Sorrel	4.4286E+07	1.9647E+08

Source. SONRIS, 2018.

3.1.5.4 Sand tops and net zone thickness

Raster well logs were all that was available in SONRIS. These raster logs were imported in the Petrel software system (Petrel 2014), and sand tops were identified by cross sectional analysis. A total of 35 wells were used in delineating cross sections, running from west to east and north to south across the field. Some of the wells selected for cross section belong to neighboring fields or were dry holes and were intentionally selected to examine the sand continuity to neighboring areas. A contour map of sand top for the zone of interest is shown in Figure 13(a). It is an anticline structure cut by a fault of approximately 165 ft throw passing from the northeast to the southwest (John et al. 2013).

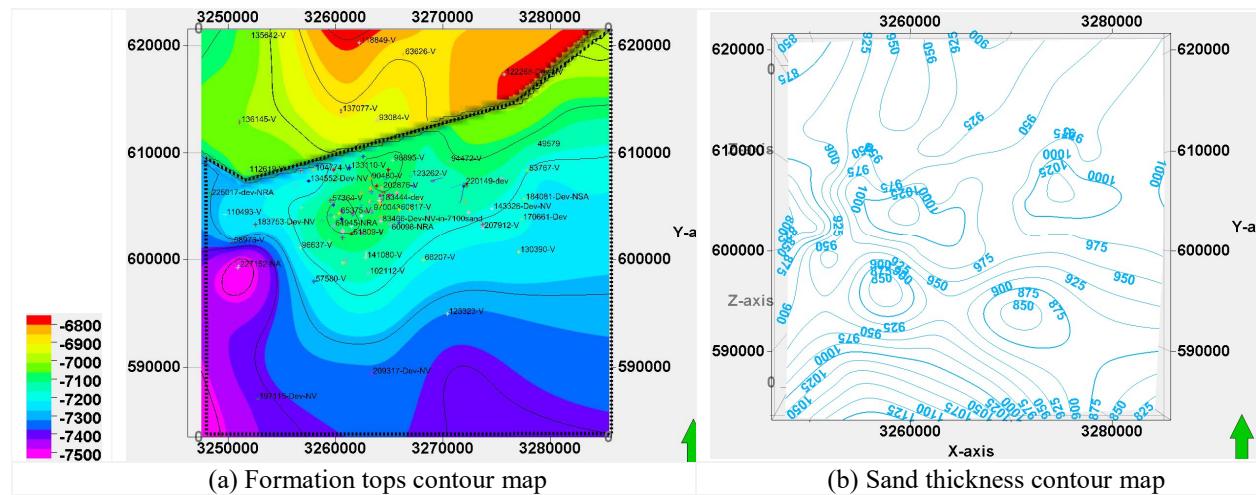


Figure 13. (a) Sand tops for the selected interval at an average depth of 7,100 ft depth, (b) average net thickness contour maps

The average total sand thickness is around 980 ft which is shown in the thickness map in Figure 13 (b). The sand does appear to be continuous in other neighboring areas as well.

3.1.5.5 Porosity and permeability

The facies and corresponding porosity values available from the well logs is reported in Table 8. The sand and shale intervals are identified by using a linear shale volume equation:

$$V_{sh} = \frac{SP - SP_{CS}}{SP_{SH} - SP_{CS}}$$

where V_{sh} is the estimated shale volume, SP is the log value of the SP curve at the depth of interest, SP_{CS} is the average log value in clean sand interval, SP_{SH} is the average log value in the pure shale. Four facies reported in Table 8 are defined for modeling purpose.

Table 8. Facies categorization and corresponding porosity range from well log data

Facies	Average Shale Content (%)	Average Porosity (%)
Sand	0-10	29-33
Medium fine sand	10-30	24-29
Fine sand	30-80	18-24
Shale	80-100	12-18

This data was used to populate the 3D geological model used for static and dynamic storage capacity estimates. The effective porosity distribution in the injection area for an upscaled simulation model is shown in Figure 14. The average porosity in the interval is 28 percent, with a maximum porosity of around 33 percent. More than one geological realization for the porosity distribution was created.

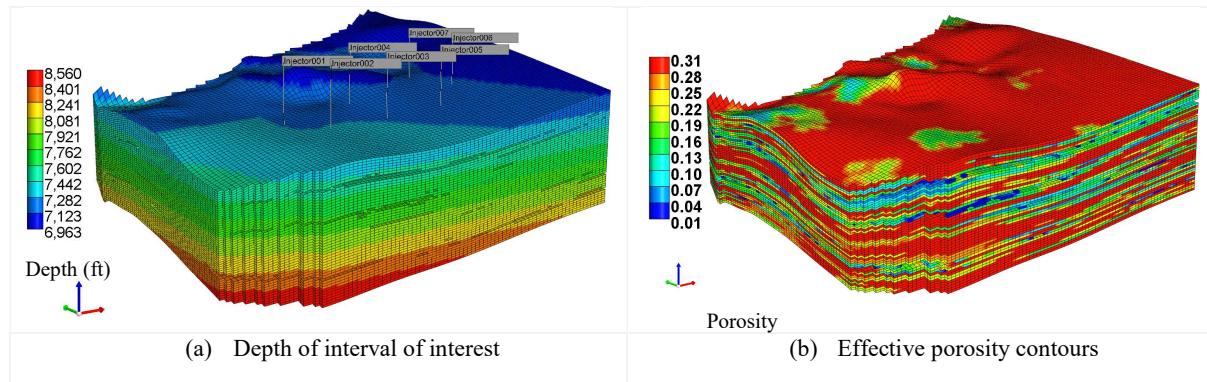


Figure 14. Depth of potential storage zone and effective porosity contours

3.1.5.6 Permeability and relative permeabilities

Both permeability and relative permeabilities play an important role in dynamic storage estimates. The core permeability data is not publicly available for the selected site. An approximation of permeability is obtained by using the Kozeny-Carman equation (Kozeny, 1927 and Carman, 1956) from the porosity distribution.

$$k = \frac{\phi^3 d^2}{72\tau(1 - \phi)^2}$$

where ϕ is effective porosity, d is sand grain diameter and tortuosity τ is given by (Du Plessis

and Masliyah 1991)

$$\tau = \frac{\phi}{[1 - (1 - \phi)^{2/3}]}$$

In order to verify whether the estimated permeability values obtained from this equation are reasonable, initial production well test data available from well history files in SONRIS is used in a multiphase fluid flow simulator and the correlation was found to be reasonable. Then the results were extrapolated for the zone of interest to find the permeability in that zone. The resultant porosity-permeability plot is shown in Figure 15 (a). The following correlation proposed by Holtz (2002) can also be used for permeability estimation for the Gulf of Mexico (GOM) region.

$$k = 7 \times 10^7 \phi^{9.606}$$

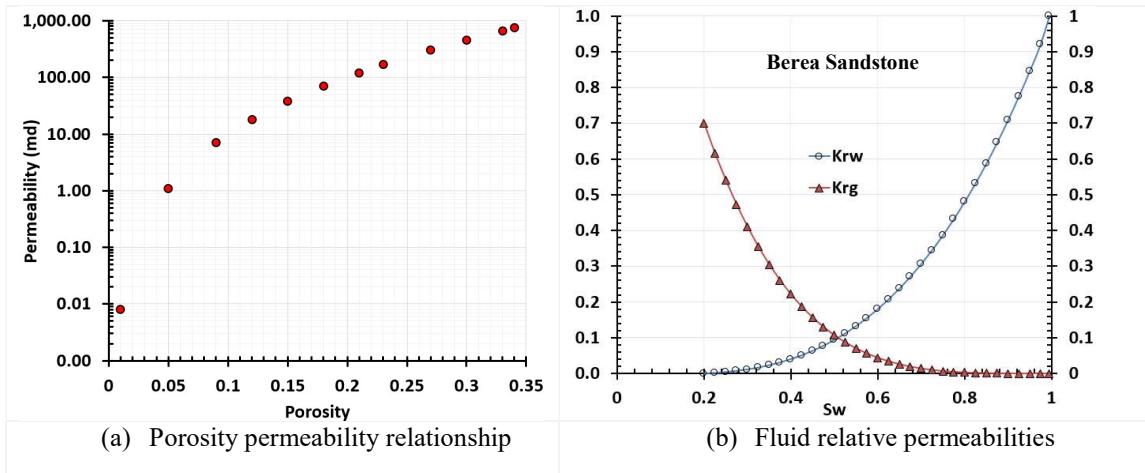


Figure 15. Permeability and relative permeability values for drainage

The relative permeability and end point saturations are also a critical element in determining the dynamic storage capacity (Burnside and Naylor 2014). The relative perm and capillary pressure data is extracted from (Krevor et al. 2012) and is representative of Berea sandstone. The relative permeability data is plotted in Figure 15 (b).

3.1.5.7 Pressure, temperature and CO₂ density

The geothermal gradient from the well log data is estimated to be 0.8°F/100 ft. The formation pore, litho and fracture pressures calculated from the publicly available data sources are shown in Figure 16. The formation is normally pressured with 0.465 psi/ft gradient (Nelson 2012). Litho pressure is estimated from the sandstone formation with 2.65 g/cc density and average porosity of 28 percent. CO₂ density is calculated by using the Peng-Robinson equation of state (Peng and Robinson 1976). All three parameters are shown in Figure 16.

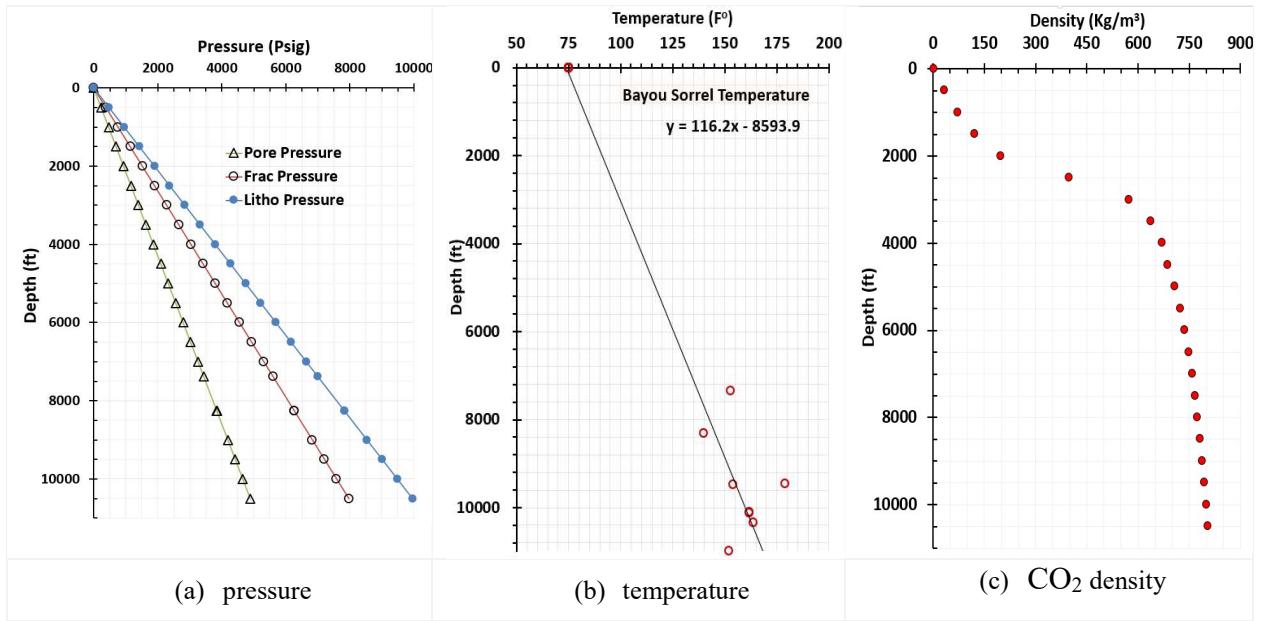


Figure 16. Pressure, temperature and density variations with depth for the selected site

3.1.5.8 CO₂ Density

The CO₂ density with depth is shown in Figure 17. The following relationship can be used to estimate the density at any given depth in the normal geo-pressure gradient regime, which prevail up to 3,500 m (11,500) ft in both Bayou Sorrel and Paradis field.

For $100 < D \leq 1000$

$$\rho(CO_2) = 6.32120847523 \times 10^{-7} (D^3) - 5.66720813505 \times 10^{-5} (D^2) + 1.56893179905 \times 10^{-1} (D) + 4.91006761818$$

For $1000 < D \leq 3500$

$$\rho(CO_2) = 1.529731922408 \times 10^{-8} (D^3) - 1.295809160250 \times 10^{-4} (D^2) + 4.031443264092 \times 10^{-1} (D) + 341.3206569470$$

where ρ is in kg/m³ and D is in meters.

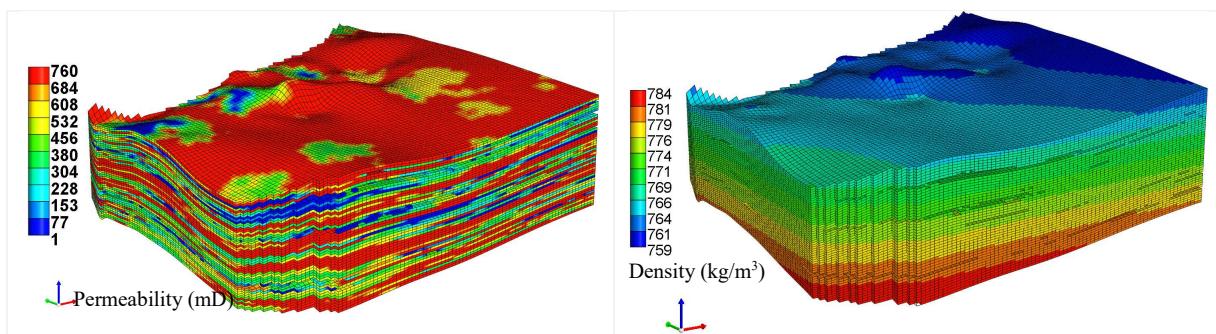


Figure 17. Effective permeability and density distribution on an upscaled simulation model for the injection zone

3.1.5.9 Rock compressibility and water salinity

A uniform compressibility value was assumed. The formation compressibility is calculated by using the Hall's correlation

$$C_f = 1.87 \times 10^{-6} \phi^{-0.415}$$

where ϕ is the average porosity of the rock. Formation water salinity was estimated based on the apparent water resistivity and by using the log interpretation chart (Schlumberger 2009). A value of 122,000 ppm was found corresponding to formation properties.

3.1.5.10 Static storage capacity

Based on the available field data and considering the areal extent of the region, the results of the static storage capacity are provided in Table 9. With an average porosity of 28 percent and for a storage efficiency factor of 2 percent, the targeted sand can store up to 133 mega tons of injected CO₂ at reservoir conditions.

Table 9. Bayou Sorrel static storage capacity estimates for an interval at an average depth of 7,300 ft

Static Model	Bayou Sorrel
Areal extent (ft ²)	1.10E+09
Areal extent (acres)	25257
Average depth to top of potential storage zone (ft)	7300
Average thickness of potential storage zone (ft)	990
Average porosity of potential storage zone (fraction)	0.28
Average CO ₂ density at potential storage zone (kg/m ³)	771.1
Static storage efficiency (fraction)	0.02
Static storage capacity (Mt)	133.182
Static capacity per unit volume (Kg/m ³)	4.318

3.1.5.11 Dynamic storage capacity

The results of the dynamic storage estimate for one of the geological realizations are presented in this section. Sensitivity of dynamic capacity to zone boundary type and injection rate is reported. CMG-GEM a commercially available reservoir simulation software that can model different chemical and mineral reactions of CO₂ during and after the active injection period is used for numerical simulations (CMG-GEM 2016). A grid with 79×79×30 blocks is used for numerical simulations. Grid block permeability values were assumed as isotropic in the horizontal directions, while vertical permeability is assumed to be 20 percent of the horizontal permeability. For a closed boundary the formation brine is not allowed to transmit across the zone boundaries, while for semi-closed and open systems the brine is allowed to leave the storage zone. The semi-closed system is modeled by assuming a semi-infinite aquifer attached to the boundaries of the storage zone. For open boundaries an infinite acting aquifer is assumed.

3.1.5.12 Zone boundary sensitivity

The type of zone boundary plays an important role in estimation of dynamic capacity. Three

scenarios for the storage zone boundary were considered, closed, semi closed and open boundaries. The simplistic and conservative approach is to consider that the targeted sand interval is a bounded system.

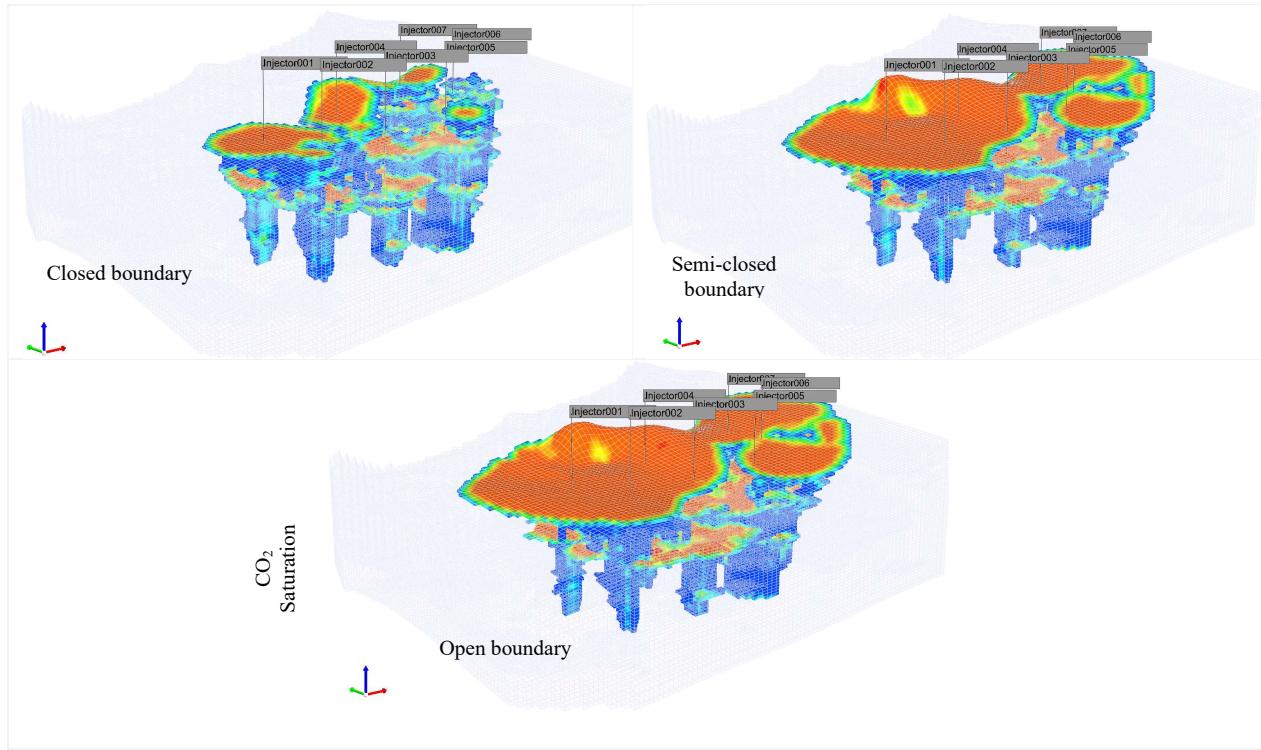


Figure 18. CO₂ spatial saturation profile at the end of injection period for (a) closed boundary, (b) semi closed, (c) and open boundary scenarios

For the bounded system, no fluid or pressure transmission is allowed across boundaries. This essentially is the utilization of fluid and rock compressibility before the formation fracture pressure limit is reached. In this study 80 percent of the litho pressure is assumed as formation fracture pressure. The entire zone was perforated for CO₂ injection. The CO₂ saturation at the end of an injection period of 50 years is shown in Figure 18 for each of the storage zone boundary conditions. Note that the CO₂ has the least spread in the case with a closed boundary condition, while for either semi-closed or open boundary conditions the spread is comparatively larger. The plume shapes and extent for semi-closed and open system are nearly identical. Note also that the well bottomhole pressure and injection rate plots, shown in Figure 19 are also required to completely understand the storage zone boundary effects.

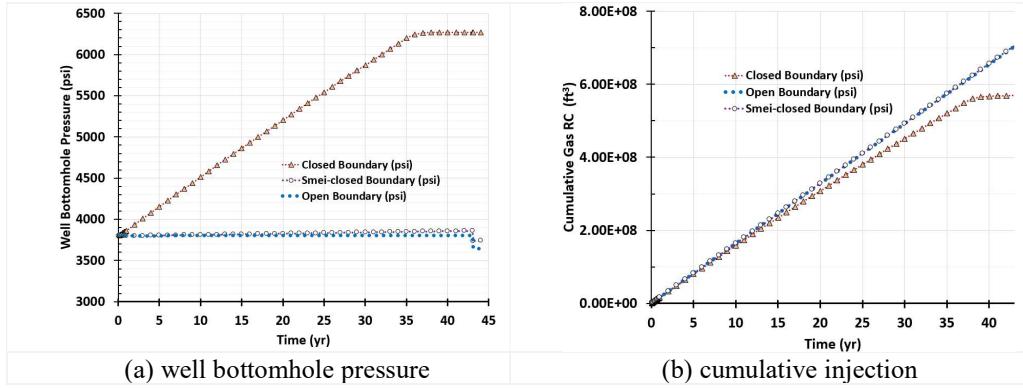


Figure 19. (a) Well bottomhole pressure and (b) injection rate for three boundary types (for one of the seven wells)

It can be observed from Figure 19(a), that for the closed boundary condition the well bottomhole pressure reaches its threshold value of 6247 psi. After that the injection rate shown in Figure 19 (b) significantly decreases to very low values. The pressure increase for either the semi-closed or open boundary scenario is not significant, and therefore injection rates are not altered much. Therefore, for closed boundary scenario, the injection is limited by the well's bottomhole pressure, while for the other two cases it is limited by the spread of the CO₂ plume. For semi-closed or open boundary type, the injection is stopped when the CO₂ front either reaches the delineated zone boundaries or the cluster of wells towards the northern boundary. The influence of different geological realization on the spread of CO₂ inside the storage zone for zones with semi-closed boundary type is shown in Figure 20.

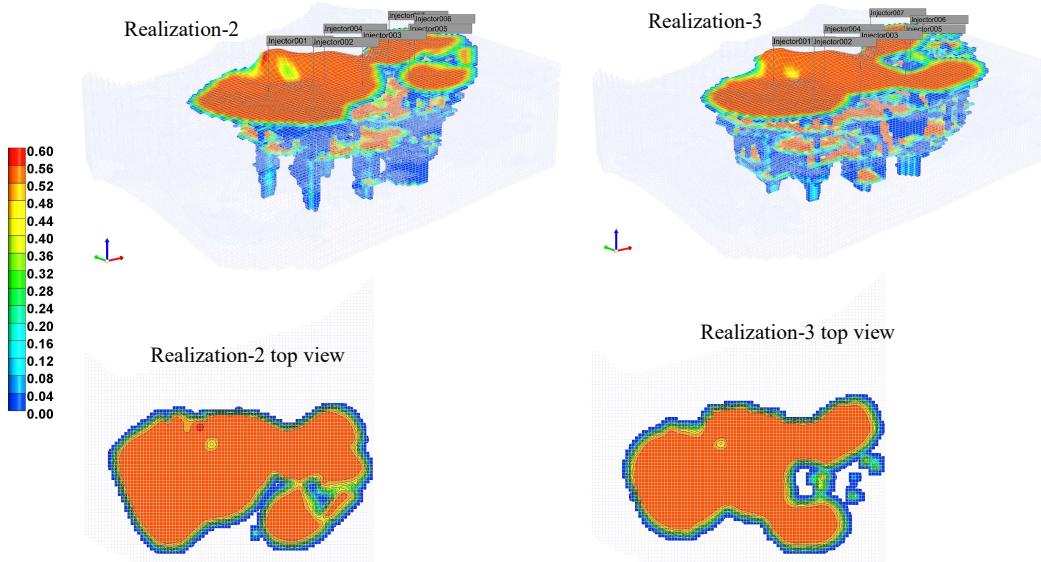


Figure 20. CO₂ spatial saturation profile at the end of injection period for realization 2 and 3, and top view of areal CO₂ footprint for assumed semi-closed boundaries

The dynamic capacity estimate for the three boundary condition scenarios is shown in Table 10.

Table 10. Dynamic capacity estimate for three boundary types

Geological Realization	Boundary Type	Number of Injection Wells	Injection Rate (kt/y)	Cumulative Injected (Mt)	Storage Efficiency
1	Closed	7	351.50	268.01	0.049
	Semi Closed	7	351.50	295.39	0.060
	Open	7	351.50	338.48	0.069
2	Closed	7	351.50	89.34	0.016
	Semi Closed	7	351.50	118.16	0.024
	Open	7	351.50	135.39	0.028
3	Closed	7	351.50	88.11	0.016
	Semi Closed	7	351.50	150.16	0.031
	Open	7	351.50	151.98	0.031

It can be observed that the zone boundary is a significant factor in determining the dynamic capacity. An increase in storage efficiency of nearly 40 percent is observed when the boundary type changes from closed to open.

3.1.6 Bayou Sorrel adjacent inter-field spacing potential

In the immediate vicinity of the Bayou Sorrel field, an extensive inter-field area with sparse well control is available as shown in Figure 21.

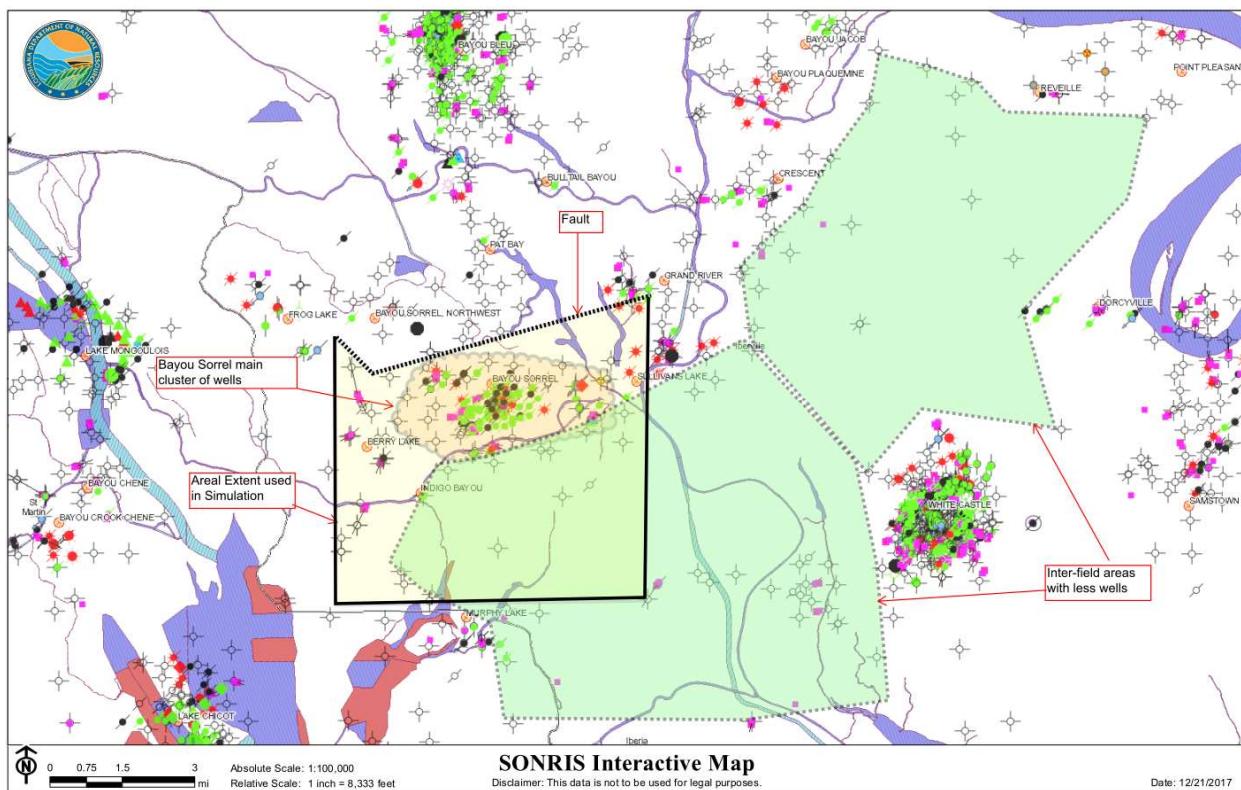


Figure 21. Bayou Sorrel adjacent area with sparse well locations

This inter-field area is several times larger than the Bayou Sorrel field dimensions, and therefore presents a reasonable storage opportunity. As wells are sparse in this areal extent, wellbore leakage risks are also reduced.

3.1.7 Paradis field

Paradis field is located in Saint Charles parish in Southern Louisiana with approximate location shown in Figure 22. This field has been used earlier for pilot CO₂-EOR studies (Bears et al. 1984, Bou-Mikael and Palmer 1989b, Hsu and Brugman 1986). The field sits nearly on the top of a salt dome and is highly faulted. The oil and gas production intervals range from a depth of 6,700 ft to the current production interval at approximately 13,000 ft.

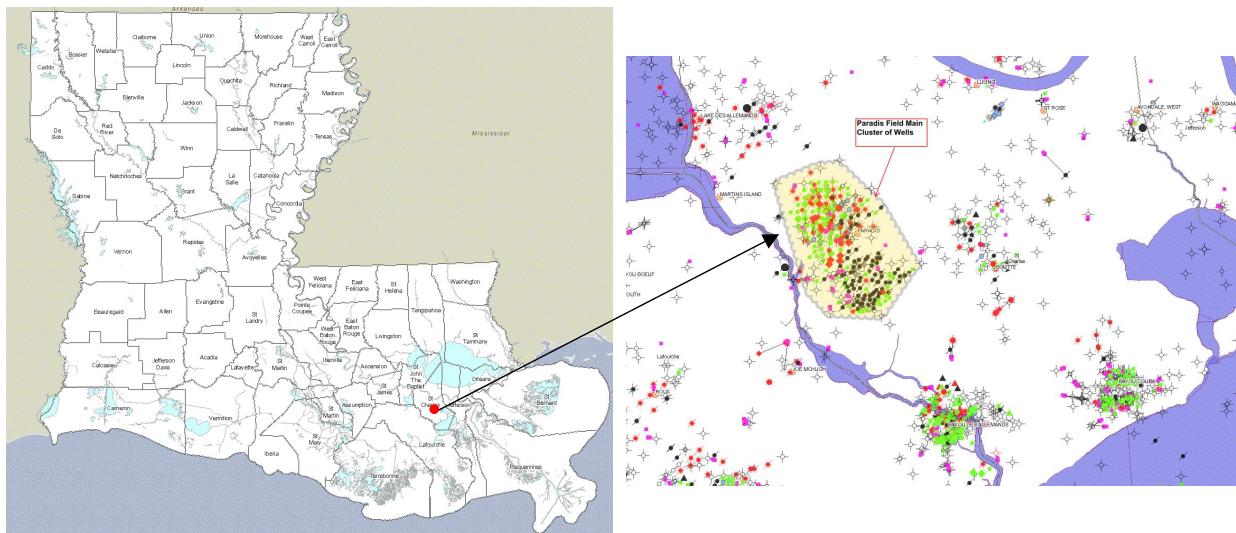


Figure 22. Approximate location and wells associated with Paradis Field

3.1.7.1 Well Status

The number of existing well and their current status is shown in Table 11. Sixteen of the total 411 wells are still producing. The current production interval is at a depth of approximately 13,000 ft.

Table 11. Paradis filed well status, total number of well and their categories are shown

Well Status Description	Number of Wells
Active- injection	7
Active – producing	16
Temporary inactive well	26
Reverted to single completion	20
Unable to locate well-no plugged and abandoned	2
Dry and plugged	48
Plugged and abandoned	240
Shut-in productive -future utility	28
Field Total. 387	

3.1.7.2 Production Information

The cumulative production of oil and gas from the Paradis field is reported in Table 12. In terms of areal extent, production and number of wells, it is nearly three times larger in comparison to Bayou Sorrel filed.

Table 12. Paradis Total hydrocarbon production to date

Field	Oil (bbl)	Gas (MSCF)
Paradis	1.5661E+08	1.3568E+09

3.1.7.3 Areal extent Petrophysical properties 3D maps

The topography of the Paradis field and the region selected for simulation is an anticline structure with most of the wells centered on the anticline as shown in Figure 23.

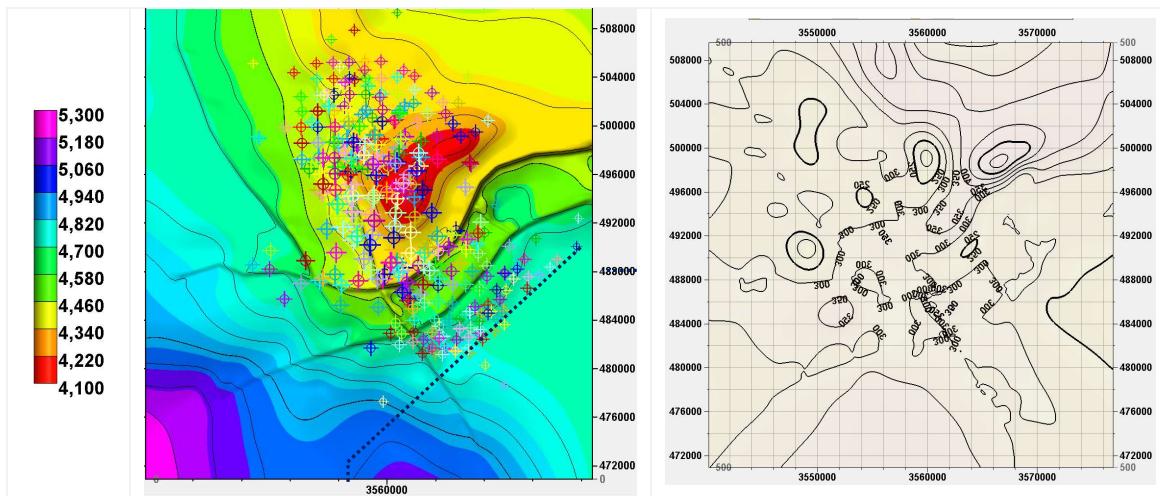


Figure 23. Paradis Field, main cluster of well and selected region for simulation modeling

In order to avoid well related leakage, the injection wells are located to the south-eastern region of the inter-field spacing, where relatively few wells exist. The modeled area is shown by the yellow polygon in Figure 24.

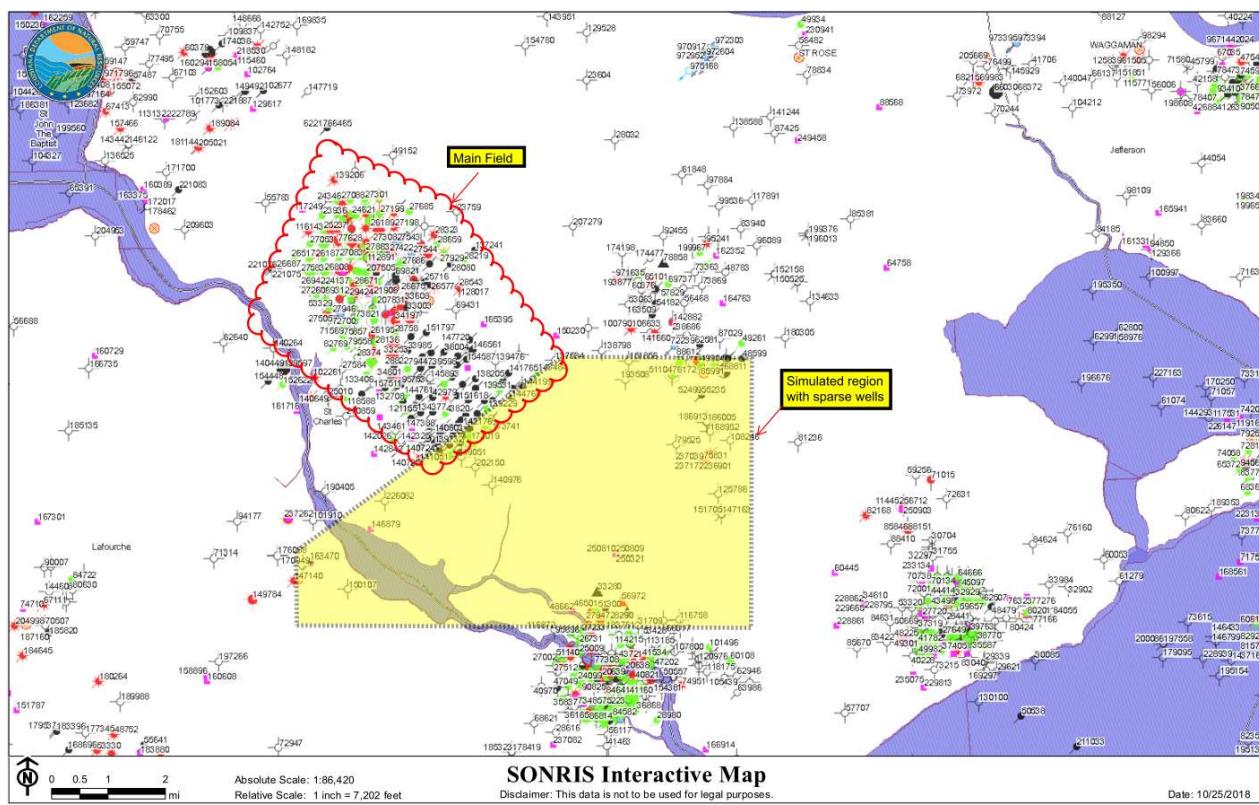


Figure 24. Areal extent of the simulation model

Additional wells from neighboring fields are used to construct the simulation model. The simulation model extent and petrophysical properties used in the simulation are shown in Figure 25. The porosity and permeability of the zone are higher compared to the Bayou Sorrel aquifer zone which was deeper than in Paradis.

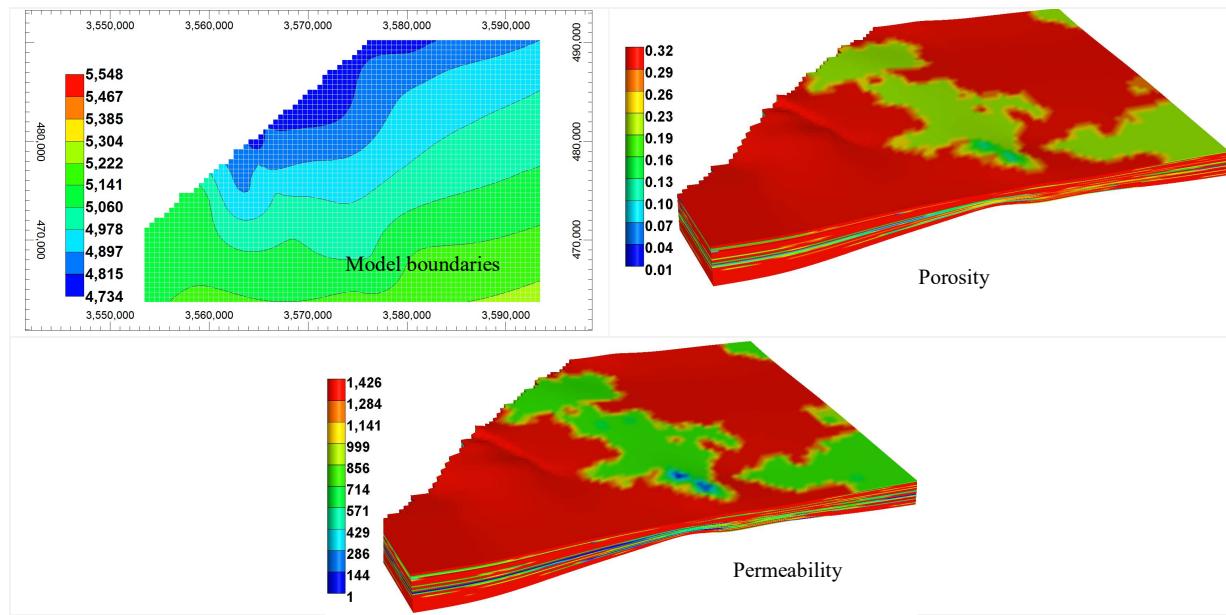


Figure 25. Paradis model extent and petrophysical properties

3.1.7.4 Static storage capacity

The static storage capacity for Paradis field is shown in Table 13. Although the areal extent of Paradis is larger than the Bayou Sorrel, the thickness of the potential storage zone is about one third.

Table 13. Paradis static storage capacity

Static Model	Paradis
Areal extent (ft ²)	1.98E+09
Areal extent (acres)	45395
Average depth to top of potential storage zone (ft)	4300
Average thickness of potential storage zone (ft)	350
Average porosity of potential storage zone (fraction)	0.3
Average CO ₂ density at potential storage zone (kg/m ³)	714
Static storage efficiency (fraction)	0.02
Static storage capacity (Mt)	83.957
Static capacity per unit pore volume (Kg/m ³)	4.284

3.1.7.5 Dynamic capacity

The dynamic storage efficiency factor for Paradis is shown in Table 14. The investigated interval is approximately 300 ft thick and is at an average depth of 4700 ft. It can be noticed that the dynamic storage efficiency factor is lower as compared to Bayou Sorrel. There are several factors that contribute to these lower dynamic storage efficiency factors. The burial depth is shallower than in Bayou Sorrel, so that at the initial pressure in the storage zone is lower. This results in lower CO₂ density at reservoir conditions and thus gravity segregation plays some role.

The CO₂ rises rapidly to the caprock and quickly reaches the boundaries. The second factor is the high permeability of the storage zone. High permeability allows the fluids to propagate quickly and they reach the model boundaries quickly. The third factor comes from the geological setting of the storage zone. The selected zone does not have many shale streaks as were in the Bayou Sorrel field. So, the upward movement of the CO₂ is not hampered by the intermittent low permeability shale streaks. The fourth contribution come from the relatively high dip angle of the formation. Paradis sits on top of a salt dome, so the injected CO₂ moves rapidly towards the center of the filed. The role of faults in hampering this motion needs to be investigated, as Paradis is heavily faulted in comparison to Bayou Sorrel.

Table 14. Paradis dynamic storage efficiency factors for a 300 ft thick interval at a depth of 4,700 ft

Geological Realization	Boundary Type	Number of Injection Wells	Injection Rate (ktonnes/y)	Cumulative Injected (Mt)	Storage Efficiency
1	Closed	7	351.50	16.19	0.012
	Semi Closed	7	351.50	27.09	0.024
	Open	7	351.50	27.09	0.024
2	Closed	7	351.50	16.10	0.012
	Semi Closed	7	351.50	29.55	0.026
	Open	7	351.50	29.55	0.026
3	Closed	7	351.50	16.19	0.012
	Semi Closed	7	351.50	27.09	0.024
	Open	7	351.50	27.09	0.024

3.1.7.6 CO₂ saturation contours plots

The CO₂ saturation contours plots are shown in Figure 26.

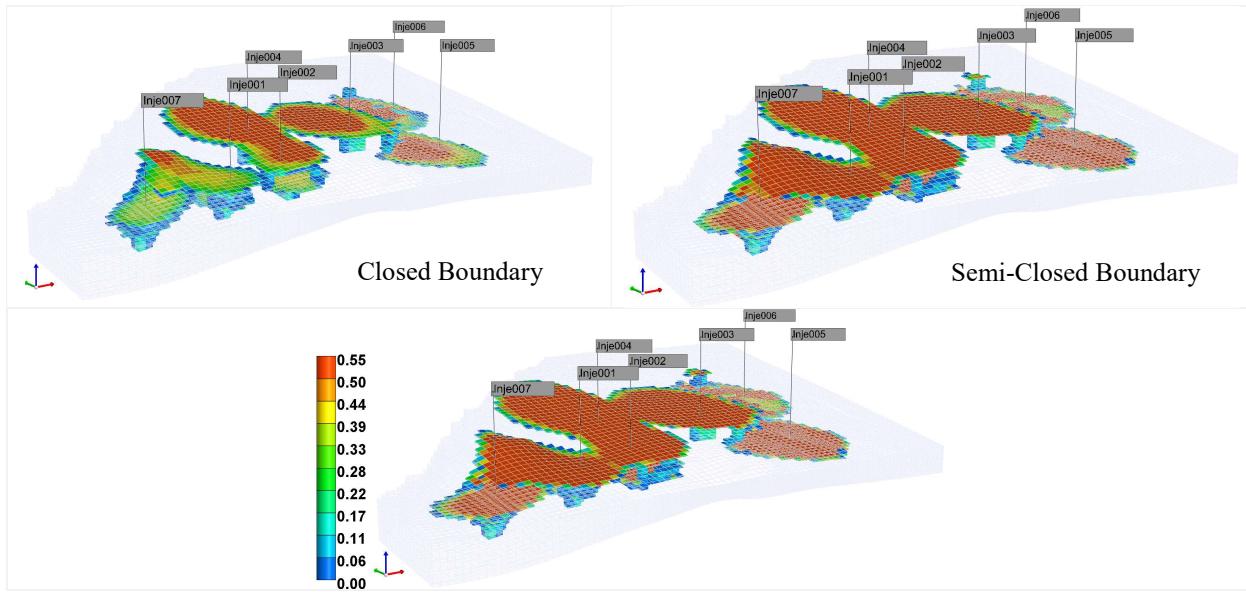


Figure 26. CO₂ distribution for closed boundary, semi-closed and open boundary

Due to relatively higher dip compared to Bayou Sorrel field, the injected CO₂ has greater tendency to move towards the north where the field's anticline is located. This movement may be impeded by the exiting faults, provided that they act as barriers.

3.1.7.7 Dynamic capacity influence of geological realization

In order to study the impact of variation in geological features, three geological realization were modeled. Though significant changes were not observed in storage efficiency, but difference exists in the distribution of the CO₂ inside the storage zone, shown in Figure 27.

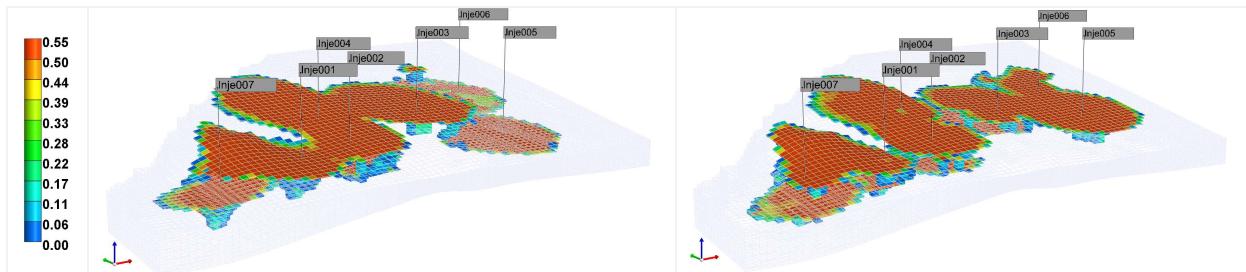


Figure 27. Paradis results of two geological realization

3.1.8 Storage potential in inter-field areas surrounding Paradis

Similar to Bayou Sorrel, the adjoining inter-field spacing in Paradis with sparse well location provide a good opportunity to be considered as potential storage zones. The Paradis field and inter-field spacing are highlighted in Figure 28.

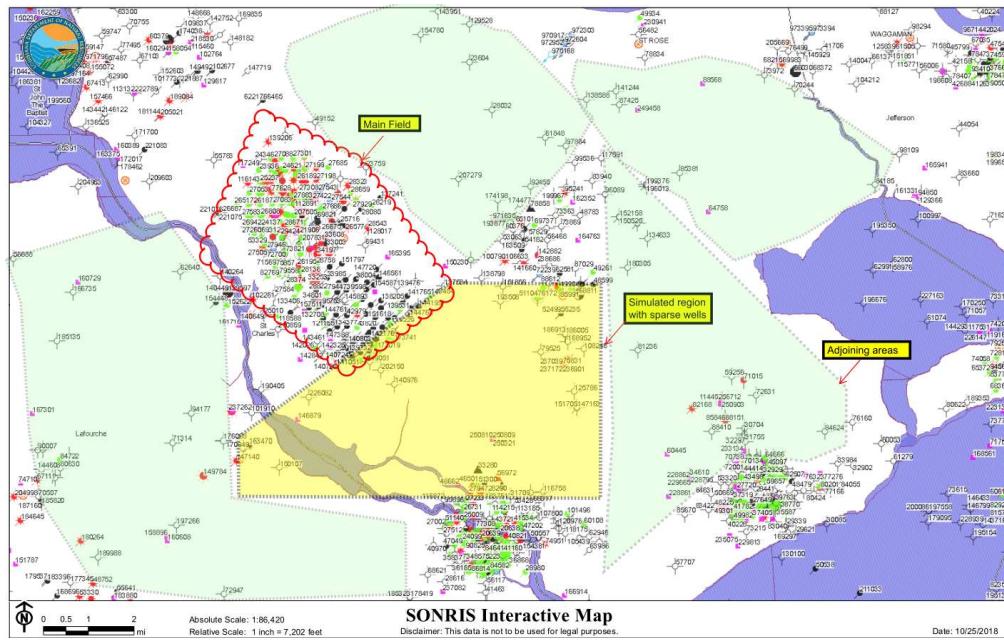


Figure 28. Paradis well location and inter-field spacing

These inter-field zones can provide significant storage capacity, with lower well leakage as well.

3.1.9 Summary and conclusions

Static and dynamic saline aquifer CO₂ storage capacity estimates for two potential sites in the Louisiana Chemical Corridor are performed. The volumetric method is used for the static capacity and numerical simulations are used for the dynamic capacity estimates. Publicly available raster logs are used to build three dimensional geological models and in estimation of the petrophysical properties for these models. An average total porosity of 28 percent was estimated for a 1,000 ft thick zone of interest located at an average depth of 7,100 ft.

Permeability data for the selected zone is estimated from correlations and is verified from initial production reports from producing wells in the oil and gas bearing zone. The estimated storage capacity ranges from 94 to 132 MMt, depending on the zone boundary type and operational conditions. This translates to storage efficiency factors in the range of 0.016 to 0.031. The selected example site is a stacked sand system with multiple thick sand zones having suitable conditions for supercritical CO₂ storage. Therefore, the total storage capacity will be some multiple of the values reported in this study.

The zone of investigation in Paradis field is a shallow interval as compared to Bayou Sorrel field. Due to its shallow depth, high formation dip angle and high permeability the dynamic storage efficiency factor comparatively lower than the Bayou Sorrel. Moreover, Paradis is a comparatively higher faulted region and has a higher density of wells. Paradis therefore carries high leakage risks.

3.1.10 Dynamic storage sensitivity

Thick and high permeability saline aquifers are an integral part of GOM basin (Bou-Mikael and Palmer 1989a, Dai et al. 2017), and many similar basin settings around the world. Due to their high pore volume, these zones offer substantial storage capacity for CO₂ sequestration. In order

to fully utilize the capacity that these zones offer, it is utmost essential to identify the mechanisms that govern the underground movement of injected CO₂. Otherwise a large portion of storage capacity may not be optimally utilized. In this study we address the fluid movement governing mechanisms for these zones. The objective is to have quantitative and qualitative measure of the influence of different competing mechanism and identify the parameters that affects the dynamic storage capacity of these zones. Another objective is to present a simplified formulation to have a reasonable estimate the dynamic capacity, that can be further used to optimize the storage capacity of these zones.

3.1.11 Inspection analysis and numerical experimental design

Inspection analysis is one of the methods used to obtain dimensionless scaling parameters for a process under consideration. It is used when mathematical model of governing equations along with initial and boundary conditions are known (Sonin 2001). One main advantage of dimensional analysis is the ability to combine dimensional variables and form dimensionless scaling parameters. Inspection analysis and numerical design of experiments have been used in the petroleum industry to study EOR by using CO₂ and geothermal energy exploitation (Afonja 2013, Ansari 2016, Novakovic 2002, Shook et al. 1992, Wood et al. 2008). EOR by using CO₂ under some conditions represents similar transport mechanisms to those of CO₂ sequestration. We use Hammersley sequence sampling as the experimental design technique in this study. It is a low discrepancy space filling technique.

3.1.11.1 Response surface analysis

In response surface analysis a polynomial regression analysis is used to analyze the relationship between storage efficiency and derived dimensionless numbers. The generalized equation of the response surface is given as

$$y = \beta_0 + \beta_1 X_1 + \beta_2 X_2 + \cdots + \beta_{11} X_1^2 + \beta_{22} X_2^2 + \cdots + \beta_{12} X_1 X_2 + \beta_{13} X_1 X_3$$

Where y is the response variable, β_0 is the intercept, $\beta_1 \dots, \beta_{11} \dots, \beta_{12} \dots$ are coefficients for linear, quadratics and cross terms of dimensionless numbers X_1, X_2, \dots etc.

3.1.11.2 Dimensionless numbers

$$N_\alpha = \frac{L}{H} \tan \alpha \quad \text{Dip Angle Group}$$

$$R_L = \frac{L}{H} \sqrt{\frac{k_z}{k_\xi}} \quad \text{Effective Aspect Ratio}$$

$$M = \frac{k_{rge} \mu_w}{k_{rwe} \mu_g} \quad \text{End Point Mobility Ratio}$$

$$N_g = \frac{k_\xi k_{rg} \Delta \rho g \cos \alpha}{q_g \mu_g} \frac{(2\pi r_w H^2)}{L} \quad \text{Gravity/Buoyancy Number}$$

S_{wr} Irreducible Water Saturation

$$P_{iD} = \frac{P_i}{P_{atm}} \quad \text{Dimensionless Initial Pressure}$$

3.1.12 Problem setup

In this section we describe the problem setup and the range of dimensionless numbers used in the analysis. A schematic of the simulation setup and the range of dimensionless numbers are shown

in Figure 29 (a) and (b) respectively. Assuming a perfect symmetry, only a quarter section of a rectangular domain is modeled. A constant injection rate is used in the middle of the domain. To model a large aquifer while lowering the computational cost, the volume of the outermost boundary cells is increased by a value of 500.

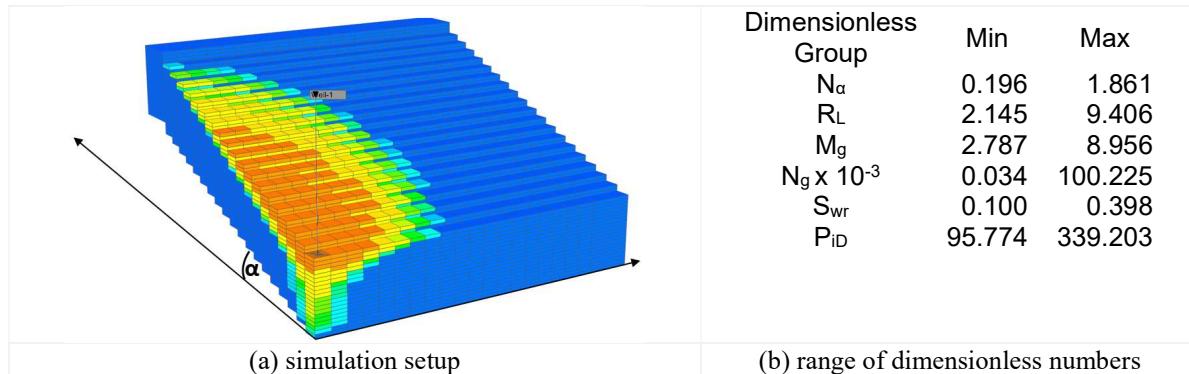


Figure 29. Storage zone schematic showing the inclination of the zone, injector is located at left and a constant pressure boundary is applied at the right by assuming an infinite acting aquifer. The brine is allowed to escape to infinite acting aquifer.

The maximum dip angle observed in the field conditions ranged from 0.5 to 1.3 (Zulqarnain et al. 2017), but in simulation up to 5 degrees were used to account for formations with high hip dip angles as well.

An initial pressure range of 1400-5000 psi is used in the simulations. By assuming a typical GOM hydrostatic pressure gradient of 0.465 psi/ft, this translates to a depth range of 3000-11000 ft. Initial temperature is calculated by using the log data (Zulqarnain et al. 2017a). The fluid properties for dimensionless numbers are calculated using Peng-Robinson equation of state (Peng and Robinson 1976). Brooks-Corey (Brooks and Corey 1964) model is used for relative permeability calculations. The relative permeability and capillary pressure data for Berea sandstone is adopted from Krevor et al. (2012), which has similar petrophysical properties like the ones used in this study. Residual water saturation and relative permeability combination and three of capillary pressure curves used in the simulation are shown in Figure 30. The reservoir simulations were performed using CMG-GEM (CMG-GEM 2016), a multiphase compositional reservoir simulator. The simulation results are then used in response surface regression analysis to judge the relative statistical significance of dimensionless numbers.

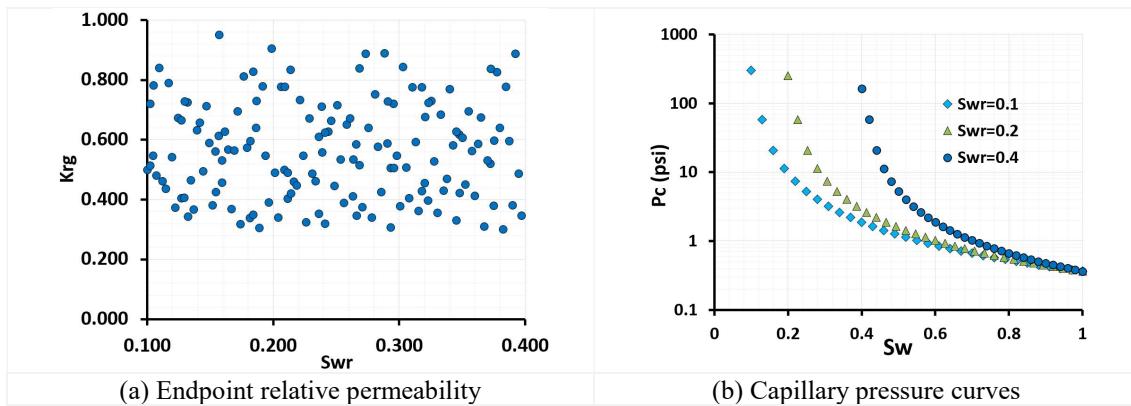


Figure 30. Gas relative permeability endpoint values and residual water saturation variation

3.1.13 Relative significance of dimensionless number

Relative significance of dimensionless number is shown in Figure 31. The bar chart shown in Figure 31, is based on the *F* test values. Comparatively higher *F* value shows the relative statistical significance of that number. Gravity number has the highest *F* value and therefore, it is the most significant dimensionless number, followed by aspect ratio number and then dip number.

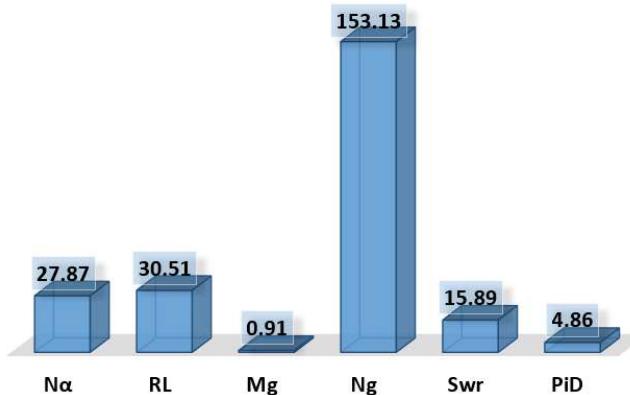


Figure 31. Relative significance of dimensionless number base on ANOVA results

3.1.14 Correlation for storage efficiency

A correlation is fitted to the response surface is shown below.

$$\begin{aligned}
 SE = & 0.288656 - 0.046475N_\alpha - 0.015737R_L - 0.003128M_g - 236.650983N_g - 0.220628S_{wr} \\
 & - 0.000053073P_{iD} + 0.01577N_\alpha^2 + 0.000907R_L^2 + 0.000039967M_g^2 + 87702N_g^2 \\
 & + 0.126309S_{wr}^2 + 0.000000507P_{iD}^2 - 0.000616N_\alpha R_L + 0.001328M_g N_\alpha - 0.000254M_g R_L \\
 & - 0.198848N_g N_\alpha + 5.36662N_g R_L + 2.461564N_g M_g - 0.004653S_{wr} N_\alpha + 0.002416S_{wr} R_L \\
 & + 0.005786S_{wr} M_g + 94.384227S_{wr} N_g - 0.000033624P_{iD} N_\alpha - 0.000003184P_{iD} R_L \\
 & - 0.000000925P_{iD} M_g - 0.08612P_{iD} N_g - 0.000082765P_{iD} S_{wr}
 \end{aligned}$$

The correlation provides reasonable accurate results. Most of the predictions falls within ± 10 percent, more deviation is observed when combination of higher values of dimensionless

numbers exists. In majority of the cases values are under predicted, so in a way it provides conservative estimates, shown in Figure 32.

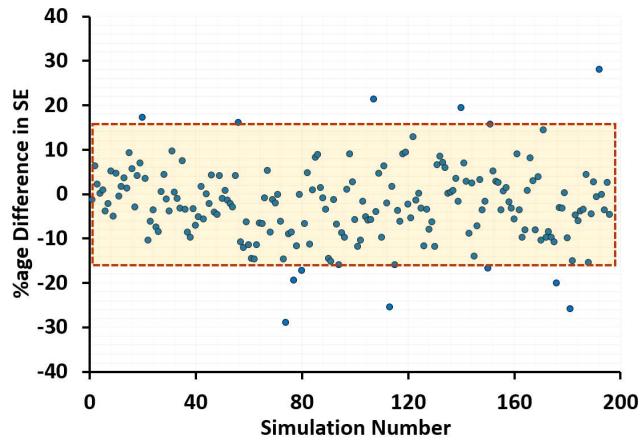


Figure 32. Percentage difference in storage efficiency between simulated and fitted value

In order to check the accuracy of the developed correlation, ten hypothetical reservoir settings, not used in generating the data for correlation are used. The dimensionless number fall within the range of used in the design of experiments. Comparison of the simulated and predicted values is shown in Table 15. Reasonable accurate values are predicted by the correlation, with an error of up to ± 10 percent.

Table 15. Application of fitted correlation to synthetic zones

Case Number	Length (ft)	Height (ft)	Dip Angle	Depth (ft)	kh (md)	Kv/Kh	Rate (mt/y)	Simulated Value (SE)	Predicted Value (SE)	Percent Deviation
1	6942	60	3	9677	406	0.05	0.71	0.0969	0.1017	4.96
2	6942	70	1.5	7527	545	0.09	0.84	0.0843	0.0825	-2.09
3	6942	100	0.6	5591	822	0.15	1.43	0.0720	0.0671	-6.89
4	6942	120	1	6452	627	0.14	1.59	0.0736	0.0668	-9.19
5	6942	90	3	8602	472	0.08	1.15	0.0786	0.0819	4.24
6	6942	150	3	5376	936	0.10	2.94	0.0560	0.0506	-9.68
7	6942	130	1.5	6452	719	0.15	2.80	0.0805	0.0754	-6.37
8	6942	50	1	7957	406	0.05	0.66	0.1227	0.1137	-7.39
9	6942	80	1.5	8602	472	0.08	1.15	0.1027	0.1029	0.14
10	6942	110	1.5	4301	627	0.10	1.29	0.0567	0.0546	-3.68

3.2 LEAKAGE ASSESSMENT USING NRAP TOOLS

The selection of depleted oil and gas fields as potential CO₂ geological storage sites has both positive and negative aspects that need to be considered. The positives are that the storage capacity or pore volume can be reliably estimated from field's production history, and reservoir characterization can be performed with more readily available well, log or seismic data without additional expenses. The main drawback is the presence of wells in the field, as each well may provide a leakage pathway for injected CO₂. The leakage potential of a well is a function of its proximity to injection wells, cement coverage in the potential storage zone, well abandonment conditions including cementing of the annular space, and the nature of any barriers to prevent CO₂ leakage to the surface. Qualitative and quantitative risk-based approaches can be used to identify the wells that have comparatively higher leakage probabilities in comparison to other wells. The objective of this study is to use a risk-based approach to identify and categorize wells based on their leakage potential in depleted oil and gas fields. This will not only help in planning injection strategies but may also help in selection of remediation strategies. The model may be presented well by using the Fault Tree Analysis (FTA) technique. It implements screening criteria and a tier-based approach in which wells are screened and categorized into different tiers based on different well characteristics. The well characteristics include the physical distance from injection wells, the quality and portion of cement coverage of wells in the target zone, the regulations at the time of well completion, the leakage potential of sealing barriers for the targeted zone, the number of overlying shale and sand intervals and leakage of either CO₂ or brine to shallower wells, the nature and quality of permanent or temporary well abandonment procedures, and the quality and length of annular space covered with cement for shallower well casings or sections. Existing models for well leakage are used to quantitatively estimate the leakage rate. The risk of leakage is presented qualitatively and quantitatively in the form of leaked CO₂ volume to shallow aquifers or to the atmosphere. The approach is used for a representative depleted oil and gas field in southern Louisiana to show an example application of the process. The developed model provides a means to systematically identify the wells that are more likely to leak and have high consequences. Due to the reduced order nature of the tool, it should prove to be a useful tool in the planning and execution phase of the CO₂ sequestration process.

3.2.1 Introduction

A fundamental step in the selection of a storage site for CO₂ sequestration is to make sure that the selected site not only meets project economics but also has good storage and long terms retention features. The safety of the storage site becomes the prime importance and dictates the decision of selecting a particular site. The selection of depleted oil and gas fields as a potential CO₂ geological storage site has both positive and negative aspects that need to be considered. The positives are that the storage capacity or pore volume can be reliably estimated from field's production history, and reservoir characterization can be performed with more readily available well, log or seismic data without additional expenses. The main drawback is the presence of wells in the field, as each well may provide a leakage pathway for injected CO₂. In addition to wells, CO₂ may also leak from failure of cap rock and from faults or fractures. Possible CO₂ leakage pathways are depicted in Figure 33.

Depending on the flow area available in a well, the pressure differential, proximity of leaky well to the CO₂ injection well and the nature of the spread of CO₂ (sweep) in the field due to

heterogeneity, wells coming into contact with the CO₂ plume may act as possible leakage pathways. For brine leakage only, the pressure differential and a wellbore offering the least resistant path to flow may be the only necessary conditions for leakage to occur. The main emphasis in this study is placed on the leakage of CO₂. The information of wellbore flow path available may be estimated from publicly available data sources. This work utilizes the Louisiana Department of Natural Resources SONRIS system (SONRIS, 2017). Based on the available data, the wells in a depleted field may be categorized by different features, including drilling date and the nature of cementing regulations at that time, plug and abandonment data and corresponding regulations or procedures adopted to plug a well (Watson and Bachu, 2009).

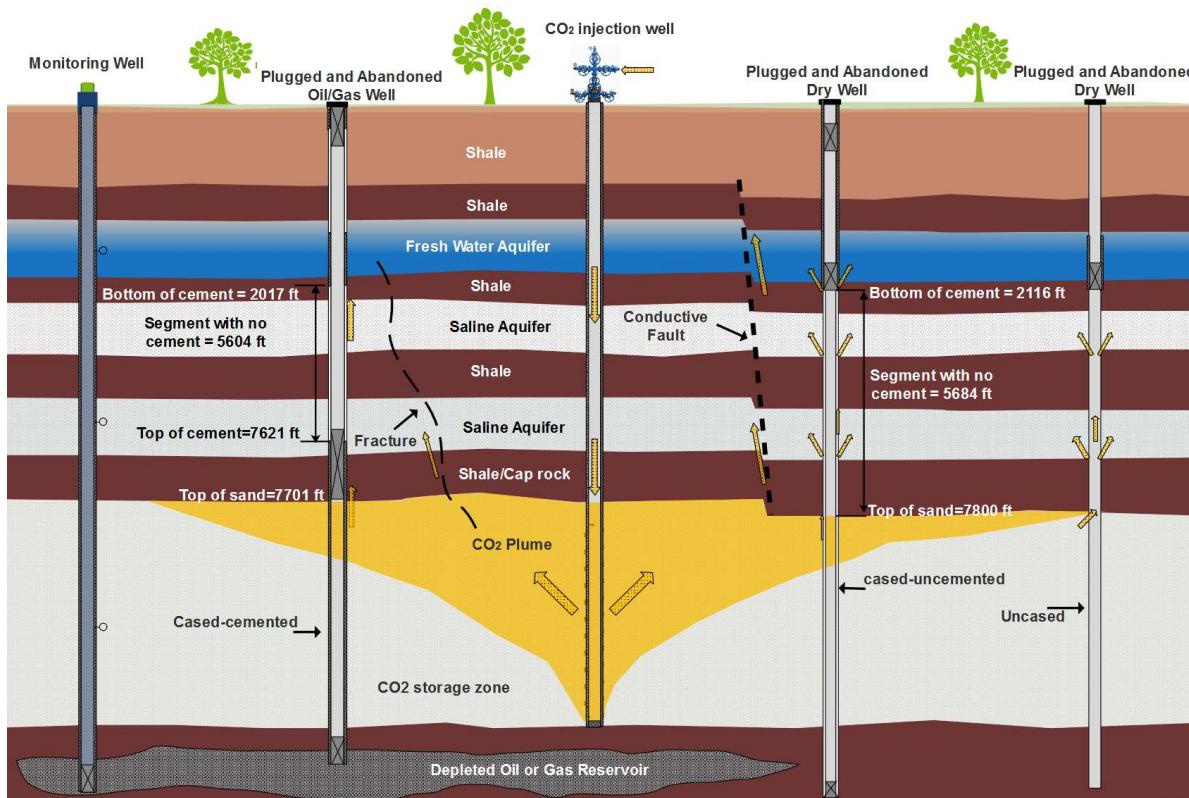


Figure 33. Probable CO₂ leak paths for storage in a deep saline aquifer

Note: three well types based on the cement coverage in the storage zone are shown; and the storage formation height is exaggerated to show the plume spread.

Risk based approaches have been used in the past by researchers to estimate CO₂ leakage risk from storage zones via wellbores. A brief review of some of the most relevant work is presented here. Watson and Bachu (2007) developed a model to identify the wells with higher leakage potential by using the regulatory data. They used a score-based approach to evaluate the deep and shallow leakage potential of a wellbore. They used the spud date, abandonment data and other wellbore information to form the basis of their score system. They pointed out that elastomer bridge material used during the well plugging procedure may be damaged when it comes into contact with CO₂. In another study, Watson and Bachu (2008) used regulatory and wellbore data to evaluate the wells for gas or CO₂ leakage. They noted that majority of the leakage factors depends on the processes adopted during drilling, completion and abandonment

phases of a well. Stauffer et al., (2009) used wellbore permeability as a key quantitative measure of a well's leakage potential. They used the amount of CO₂ or brine that could leak along the degraded cement intervals as the basis of their criteria. Celia et al. (2009) studied the effects of depth on the injection rates and showed that the leakage risk decreases for deeper storage zones and for zones with smaller number of wells penetrating the storage zone.

Nogues et al. (2012) proposed a simplified formulation to estimate the leakage along old wells and pointed out that there could be high uncertainties associated with different parameters in estimation of maximum probable leakage. Duguid et al. (2013) analyzed the cementing data of some old wells and concluded that cement for most of the wells was largely intact and was not degraded due to brine exposure. Syed et al. (2014) studied the interaction of CO₂ with well cement and presented a relationship showing the reduction in cement permeability as a result of this interaction. Duguid et al., (2014) studied the cement integrity of an old well for CO₂ injection project and found mixed results for annular cement. They found that, in some well sections the cement had very poor quality, and it will not work as a barrier against leaking fluids; however, in some sections the cement retained its properties and can act as a barrier. Gaurina and Mavar (2017) investigated the CO₂ leakage risk from a storage zone and looked at different leakage sources and categorized the leaks according to their severity. Results of these findings along with additional parameters of prime importance forms the basis of well leakage risk criteria proposed in this study.

The main objective of the current study is to form a criteria to categorize the leakage potential of plugged and abandoned wells, and identify the wells that are most likely to leak, and suggest the strategies to reduce the leakage risk. According to cement coverage of a well in the storage zone, the wellbore may be categorized as either

- Cased-cemented
- Cased-uncemented
- Uncased

We briefly go over each well category, describing in detail the probable leakage pathways and other important parameters necessary for leakage risk categorization.

3.2.2 Category-1. Wells with complete cement coverage in the storage zone

In these wells, casing in the entire storage zone is cemented. Based on the historical data (Ozyurtkan et al., 2011) and references therein, the fluids from the storage zone may migrate to shallower permeable formations through either cement sheath, casing-cement or cement-formation micro annuli, or may flow inside the casing if casing integrity has been compromised over the years. These possible flow paths have been depicted in Figure 34(a). These flow path assumptions are valid only if formations have not collapsed in the wellbore. It is highly probable in South Louisiana, that some of wellbores may have collapsed over time. In that case some of the above-mentioned flow paths may be unavailable for leaky fluids.

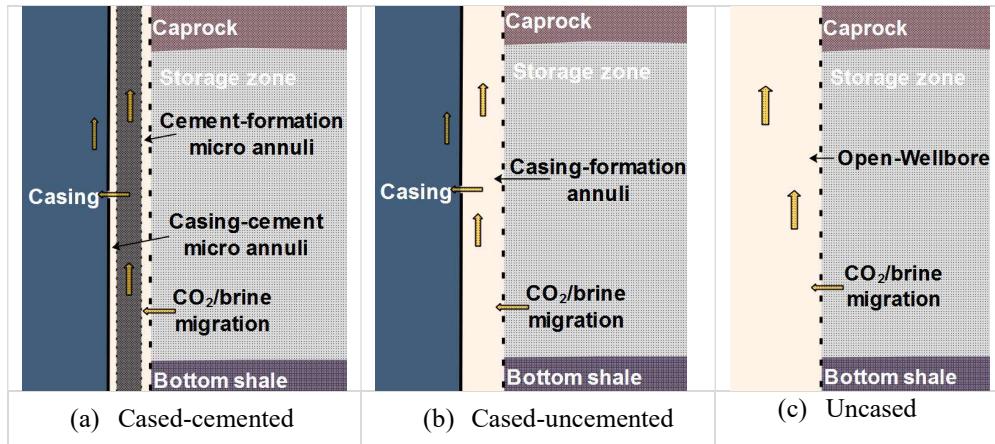


Figure 34. Possible fluid migration paths along wellbore inside the storage zone, for (a) a cemented casing, (b) non-cemented casing, (c) no casing

Note: the size of the micro annuli has been exaggerated to show details.

3.2.3 Category-2. Wells with no cement coverage in storage zone

In these wells the casing in the storage zone is not cemented. Casing was set deeper than the storage zone and cement top is deeper than the storage zone's top. For these wells the casing-formation annular gap is open to flow, unless formation collapses have occurred in the cap rock that might hinder the fluid migration from storage zone. The possible leak flow paths for this wellbore type are depicted Figure 34(b).

3.2.4 Category-3. Wells with no casing

It is possible that some of the dry wells may only have surface casing for the protection of fresh water aquifer and the rest of the deeper well section may not be cased at all. In a worst case scenario, the entire wellbore area may provide a path for leakage fluids to escape from the storage zone, shown in Figure 34(c). In the next section the rational adopted for estimating the leakage risk potential of these three types of wells is briefly explained.

3.2.5 Leakage risk classification criteria

A well's leakage potential from a storage zone can be attributed to the following factors

- Wellbore type. Higher leakage rate and high probability of leakage is expected for uncased wellbore sections in comparison to cased-uncemented and cased-cemented wellbores;
- Injector-Leaky well distance. The distance a potential leaky well is from the injection well is another important parameter in CO₂ leakage risk classification. Due to operational conditions and dynamic storage zone variable constraints, the CO₂ plume may not reach every well in the field. Therefore, wells in the immediate vicinity of an injector well are more likely to have higher CO₂ leakage than the ones at greater distance;
- Storage zone boundaries. Depending on the storage zone extent, the boundary may behave as a closed, semi-closed or open boundary system. Pressure buildup rate is

much higher in bounded storage zones as compared to semi-closed or open boundary zones. Higher pressure buildup may translate to higher leakage rates;

- Overlaying buffer layers (segments). In unconsolidated sands, it is likely that over time some portions of the wellbores may have been blocked by formation collapse. This may greatly influence the leakage rates, especially for uncased wells, as these may greatly alter the permeability of the buffer or collapsed zone.

The proposed leakage risk criteria in the form of a flow chart is shown in Figure 35(a)

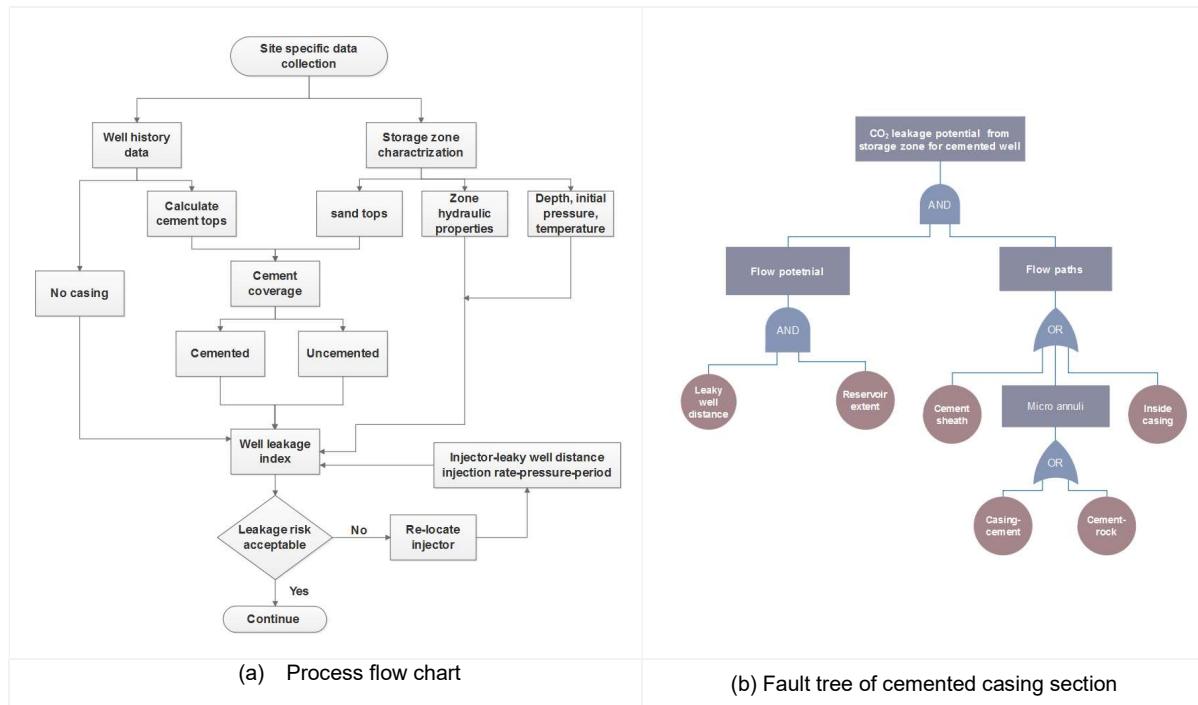


Figure 35. (a) Flow chart of a well's leakage risk classification, (b) Fault tree of category-1 well section

It starts with site specific data collection, sand and cement top calculations and finally calculating the leakage risk. The corresponding fault tree is shown in Figure 35(b) as well. Fault tree analysis (FTA) is a top-down approach and is a logical representation of the many events and component failures that may combine to cause the system or top event failure (Stamatelatos, 2002 and Zulqarnain, 2015). It uses ‘logic gates’ (mainly AND or gates) to show how ‘basic events’ may combine to cause the critical ‘top event’. The top event in the present study is the leakage from the storage zone. One important aspect that is highlighted by the fault tree of a cased-cemented wellbore (Figure 35(b)) is the fact that leakage potential is a combination of flow potential and flow area available. A weakly cemented wellbore segment may not necessarily imply CO₂ leakage, unless other conditions also exist. Therefore, flow potential and flow paths are connected by AND gate. An AND gate is activated when all the inputs are available, while an OR gate becomes active if any one of the inputs are available. For example, when flow potential exists, the fluid may leak through either of the three potential leak paths. Similar well specific fault trees may be constructed for cased-uncemented and uncased wells. Brine leakage FTA will be slightly different than the fault tree for CO₂ leakage as plume extent or sweep are not involved. As pressure builds up the brine may leak, through available flow

paths.

Next, field specific data to be used for quantitative measurement of the effect of different parameters in defining a well's leakage potential is examined.

3.2.6 Field Specific data analysis

Bayou Sorrel is a nearly abandoned oil and gas field in southern Louisiana and is selected as an example case to show the steps necessary to evaluate the leakage potential through wells. In this field, the majority of the wells were drilled in the 1950's and 60's, as shown in

Figure 36 (a). Here the well permit date is used as approximate proxy for the actual drilling dates, as for some of the wells the actual start of drilling (spud date) was not available. A representative set of 14 wells were randomly selected from the total of 176 wells in the area to assess the leakage risk of each well. The approximate locations of these 14 wells are shown in Figure 36(b). A majority of the abandoned oil and gas wells are located in the center of the field where the productive sands were located, while wells towards the outer boundary are mostly dry wells and are sparsely located.

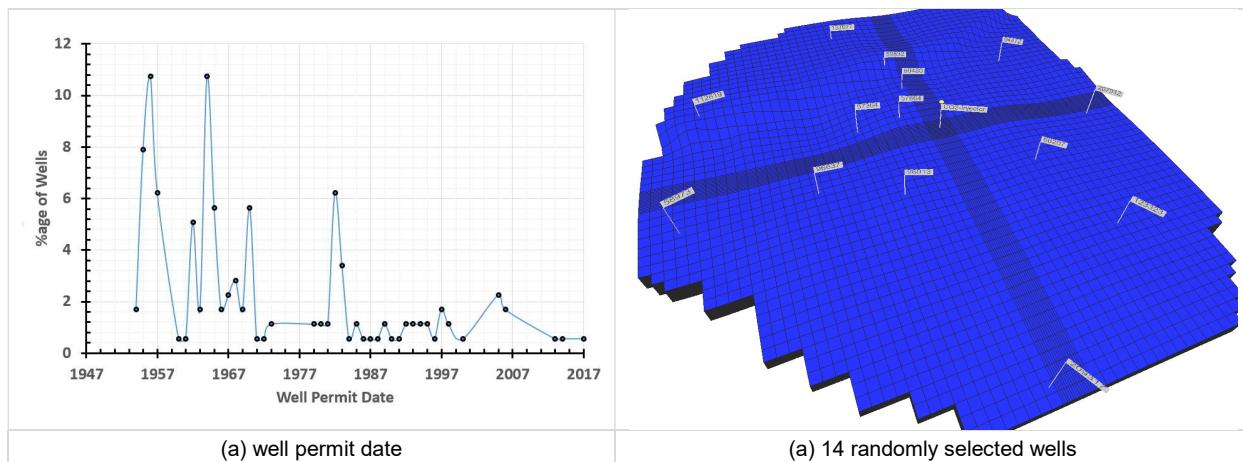


Figure 36. (a) Well permit dates; and (b) 14 selected wells for cement coverage calculation

Well log data is used to identify the top and bottom of the storage zone, with an average depth of 7,900 ft. The injector is initially located in the center of the field to maximize the distance from the zone boundaries. Cement tops are determined by using the well cementing data and by using the following formulation, Bourgoyn et al., (1991).

$$L = \frac{\left(Sacks \times \frac{cement\ volume}{sack} - cement\ volume\ left\ in\ casing \right)}{annular\ capacity \times cement\ access\ factor}$$

For wells in which cement access factor was not calculable, a conservative value of 2 was used, as usually an access factor of 1.5 - 1.75 is used, Bourgoyn et al., (1991). The storage zone, cemented intervals, nature of the well (dry plugged or abandoned production well), cement plugs and year in which either the well was plugged or the last workover are given in Figure 37.

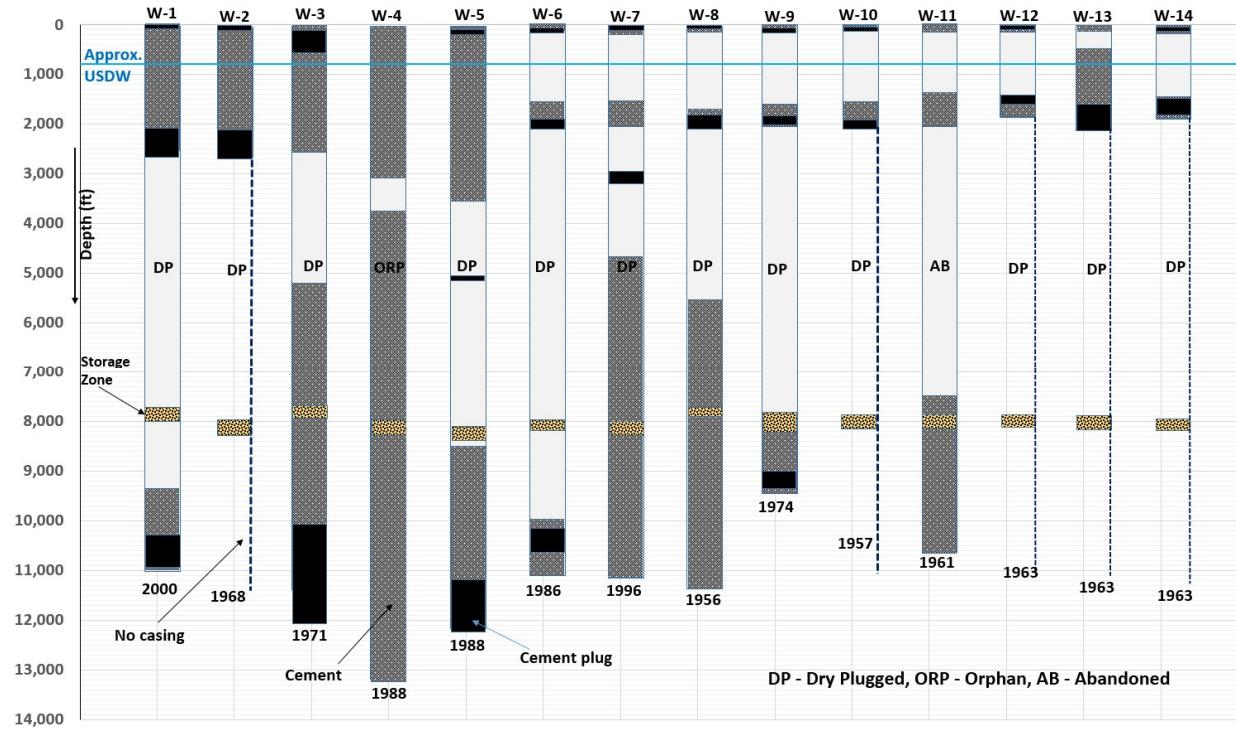


Figure 37. Data of 14 selected wells annuli with storage zone, cemented intervals, nature of well (dry plugged or abandoned oil and gas well), cement plugs and year in which last work was performed on well

The USDW lower depth for this area is in the range of 300-500 ft. A conservative value of 800 ft is selected to allow some margin for depth variations. There are approximately 27 aquifer layers in between the selected storage zone at an average depth 7900 ft and the USDW bottom which is at approximately 800 ft. The average sand and shale thickness of these buffer layers are 131 and 115 ft respectively.

A closer examination of the data shows that dry and plugged wells drilled in 1950's and 60's may only have surface casing installed to protect the fresh water aquifer, with an average casing setting depth of 2,000 ft. These wells may provide the largest leak threat, provided that the wellbore has not collapsed in these wells. These wells need special attention due to the large flow area available to leaking fluids and very high permeabilities in the region. Leakage models used in this study are briefly explained in the next section.

3.2.7 Leakage rate modeling

The amount of CO₂ leakage is the basic element of well leakage risk assessment, consequences can be presented in the form of leaked volume to shallow fresh water aquifers or to the atmosphere. The multi-segment Wellbore Model (MWM) and Cemented Wellbore Model (CWM), available in the NRAP-Well Leakage Assessment (WLA) toolset are used (Huerta and Vasylkivska, 2016). A brief description of the models is provided below.

3.2.8 Cemented wellbore model (CWM)

This model is based on the results of 3-D numerical simulations of injection into a storage zone with an abandoned wellbore (Jordan et al., 2015). Leakage is treated as a flow through porous media by using Darcy's law, (Huerta and Vasylkivska, 2016). In its simplest form the flow rate

is estimated from

$$Q = k_{eff} A \frac{\psi_L - \psi_T}{L}$$

where Q is the volumetric flow rate, k_{eff} is the effective permeability, A is the cross-sectional area of flow, ψ_L and ψ_T are leakage potential at the leakage source and sink respectively and L is the leak path length. This model can be used to calculate leakage to an overlying shallow aquifer and a thief zone. The thief zone is of fixed thickness and should not be located at a depth less than one third the depth of the storage zone (Huerta and Vasylkivska, 2016). Time varying pressure and CO₂ saturation data from reservoir simulation are used as model inputs. In this study this model is only used to study the effect of storage boundary type on CO₂ leakage rates.

3.2.9 Multi segment wellbore model (MWM)

This model can calculate leakage to multiple overlying aquifers or thief zones and was developed by Nordbotten et al. (2009). This model focuses on modeling flow across large distances and does not take into account the flow in cement fractures and cracks. Flow inside the annulus is modeled and wellbore permeability along each overlying shale zone is prescribed along with the aquifer permeabilities. The model assumes constant density of CO₂ and does not incorporate any geochemical or geomechanical processes taking place inside the wellbore. This model is used to carry out the sensitivity analysis of wellbore type (cased-cemented, cased-uncemented or uncased), distance between the injector and leaky well and number of buffer layers (or barrier zones) between storage zone and leak outlet.

3.2.10 Wellbore permeability calculations

For pure cement, permeability is reported in the range of micro to millidarcy (Ozyurtkan et al., 2013), while the permeability of a cemented wellbore is reported to be in the range of 1.7 mD to 170mD (Gasda et al., 2013). Therefore, in this study for a cemented wellbore an average value of this reported range, 86 mD is used. For cased-uncemented annuli and uncased wellbore, we use the following two equations to find the permeability in these cases. Flow rate for a circular porous medium is expressed as by Darcy law

$$q = k \pi r^2 \frac{\Delta P}{\mu L}$$

while the Hagen–Poiseuille's equation is used for flow inside circular pipe

$$q = \frac{\pi r^4}{8} \frac{\Delta P}{\mu L}$$

Comparing these two equations, the equivalent permeability for a circular pipe can be expressed as

$$k = \frac{r^2}{8}$$

The calculated values of the permeabilities for a wellbore with ID = 9.875", and casing OD = 7", are shown in Table 16.

Table 16. Permeability of cemented, cased-uncemented and uncased wellbore

Wellbore Type	Cased-cemented (mD)	Cased-uncemented (mD)	Uncased (mD)
Segment Permeability	8.48E+01	7.91E+12	1.59E+13

Now we select the three wells representing the cased-cemented, cased-uncemented and uncased wellbore from 14 well data set and calculate the average wellbore permeabilities for these categories. Well No.4 is selected as a representative example of a cemented wellbore as it has longer segments of cemented annulus. This wellbore has three segments, two cemented and one cased-uncemented segment. We used an average permeability in series to find the average permeability of the wellbore, which is the used in the wellbore leakage model. The average permeability is given by the following expression

$$k_{avg} = \frac{\sum_{i=1}^n L_i}{\sum_{i=1}^n \left(\frac{L}{k}\right)_i}$$

To represent cased-uncemented and uncased wellbore, well # 6 and 12 are selected, based on their cement coverage. The value of average wellbore permeabilities of these three representative example wells are shown in Table 17.

Table 17. Permeability of the representative three wellbore type

Wellbore	Cased-Cemented (mD)	Cased-uncemented (mD)	Uncased (mD)
Average wellbore permeability	9.23E+01	8.81E+02	1.02E+03

In the next section we form the basis of the well leakage risk assessment criteria.

3.2.11 Well leakage index (WLI)

Now we form the criteria to define the well leakage index, which can be used to identify the wells that have relatively large leakage risk in comparison to other wells. We assign a range of values from 0 to 1 for each of the four factors of wellbore type, distance of leaky well to injection well, storage zone boundary types and number of buffer layers. Where the value 0 shows no influence and a value of 1 shows maximum influence. These four factors can be used to estimate the leakage potential of the well by calculating the well leakage index

$$WLI = CI \times DI \times LI \times BI$$

where WLI is the Well leakage index, CI is the cement index, DI is the distance index, LI is the layer index and BI is the boundary type index. Results of the CO₂ leakage models are used to assign values to these indices. Therefore, the computed value of the well leakage index will provide a quantitative measure of a well's leakage potential.

Based on the WLI a tier-based approach can be developed, bounded by the limits of WLI from 0

to 1. The assumed well tiers based on the WLI are shown in Table 18.

Table 18. Well tiers for a specific field based on the WLI

Well Tiers	WLI range (fraction of field's maximum WLI)	Remarks
1	WLI <= 0.25	Wells with minor leakage risk
2	0.25 <= WLI <=0.50	Wells with moderate leakage risk
3	0.50 < WLI <=0.75	Wells with high leakage risk
4	0.75 < WLI	Wells with severe leakage risk

Now the results of a sensitivity study of wellbore types, injector to leaky well distance, storage zone boundary type and effect of buffer layers are presented in next section. MWM and CWM leakage models are used to carry out this sensitivity analysis.

3.2.12 Results and discussions

The results of the sensitivity analysis of the different indices are presented in this section. The CO₂ leakage volume to a fresh water aquifer or to the atmosphere is computed and is normalized by the highest leaked volume. For example, for the wellbore type sensitivity analysis, the leaked volume for uncased or open wellbore is used to normalize the leaked volume of all three well types, as this represents the highest leaked rate. In this way the highest leaked volume has a fraction of 1 and other categories have values that are a fraction of 1. These fractions are then used to define corresponding indices, which are used to calculate the well leakage index.

3.2.13 Sensitivity of wellbore type

The MWM is used to carry out this sensitivity analysis. The model allows a maximum of 29 aquifers with 30 shale layers in-between the storage zone and the atmosphere. The Bayou Sorrel field sand data was used to define 29 gross sand intervals between the storage zone at an average depth of 7,900 ft and the atmosphere. A single value of permeability of 500 mD is used for shallow aquifers.

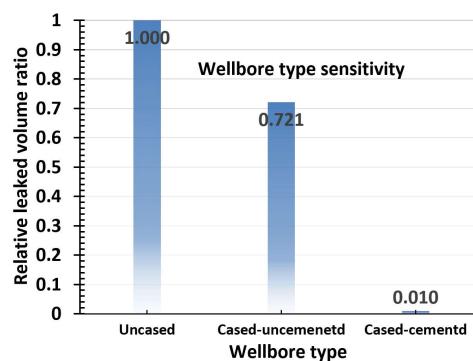


Figure 38. Leakage normalized volume, for three wellbore types for a leaky well at a distance of 328 ft from injector location with a storage zone having open boundaries

The average permeabilities of uncased, cased-uncemented and cased-cemented wellbores shown in Table 17 are used. The normalized leakage volume for the three well types for an active injection period of 30 years is shown in Figure 38. A 30 percent reduction in the total leaked CO₂

volume is observed when the category shifts from uncased open wellbore to cased-uncemented wellbore and an even more significant reduction is observed for a cased-cemented wellbore. We use this information to define the cement index specified in Table 16.

3.2.14 Sensitivity of injector-leaky well distance

The MWM is used to carry out this sensitivity analysis. Due to the nature of the CO₂ displacement in the storage zone, the distance between the injection and the leaky well becomes one of the important parameter for CO₂ leakage risk classification. In this section we examine the results of sensitivity of leaked volume to injector-leaky well distance. A leaky well at a distance of 328 ft is used to normalize the leaked volume, as it has the highest leaked volume. The results of the leakage model for a cemented wellbore configuration with open zone boundaries scenario for an active injection period of 30 years are shown in Figure 39. A nearly 66 percent drop can be noticed for the first 3,281 ft and then the cumulative leakage volume decreases slowly shown in Figure 39. Maximizing the injector-leaky well distance especially the distance from uncased wells will results in substantially reducing the CO₂ leakage volume through wellbore over the course of a projects' life. This parameter can be optimized during the planning phases of a project.

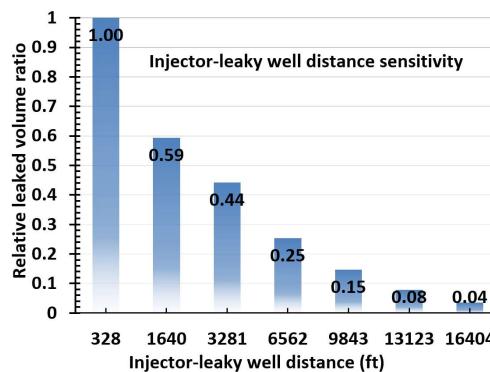


Figure 39. Normalized leaked volume variation with injector to leaky well distance, for a cemented wellbore and with a storage zone having open boundaries

3.2.15 Sensitivity of storage zone boundary type

The storage zone boundary condition dictates the pressure buildup in the zone. Pressure builds rapidly for a closed boundary system, as compared to a semi-closed or an open boundary system. Reservoir simulations are performed to obtain pressure and CO₂ saturation profiles for a cemented wellbore model set of inputs. Three simulation runs were carried out for a closed, semi-closed and open boundary storage zone, at a constant injection rate of 2.46 Mton/year (0.1 m³/s). A constant rate scenario is assumed to be consistent, as for other wellbore leakage models a constant rate of 0.1 m³/s was used. For a closed system the injection rate is reduced as the well bottom hole pressures reaches 80 percent (6267 psi) of the fracture pressure, and injection is continued for a total 52 years, Figure 40(a). This 52 year time frame is selected due to the fact that in nearly this time, the CO₂ front reaches the storage zone boundary for the more open boundary scenarios, detailed information about problem setup can be found in (Zulqarnain et al. 2017). Therefore, the same injection period is used for all three boundary types. In order to capture the sensitivity of pressure buildup only, a well located in close proximity (328 ft m) to

the injection well is selected, so that the plume extent does not affect the results. The CO₂ plume extent for the three boundary types is shown in Figure 40. Commercially available software Petrel (2014) and CMG-GEM (2017) are used to create 3D geological model and perform reservoir simulations respectively. Plume extent is taken care by the injector-leaky well distance sensitivity analysis.

The smallest spread of the CO₂ plume is seen in the closed system for the studied constant injection rate Figure 40(b). For this case the bottom hole pressure limit is reached within 5.41 years, with an increase of 2491 psi from initial zone pressure. The CO₂ plume is mainly concentrated around the injection well and a very large portion of the storage zone remain upswept by CO₂. This will have implications for CO₂ and brine leakage rates. For a majority of the wells, CO₂ leakage will not occur during the injection period, but brine may leak excessively to overlaying zones due to high pressure buildup. Since the CO₂ plume is of limited extent, the injection well should be located such that it is away from the leaky well locations towards the edges of the storage zone to further reduce the CO₂ leakage risk. The majority of wells are concentrated in the middle of the field, where the injector is currently located in the simulations.

In the semi-closed system Figure 40(c), it was assumed that the pressure in the storage zone is supported by a limited extent neighboring aquifer having a size 3 times the size of the storage zone size. Pressure increases with time and an increase of 2184 psi was noted in the well bottom-hole pressure after a period of 52 years. The plume during the injection period does not reach the zone boundary. Also, the spread of CO₂ is not homogeneous, therefore some of the wells towards the outer north-west and south-west edges of storage zone do not encounter the CO₂ plume.

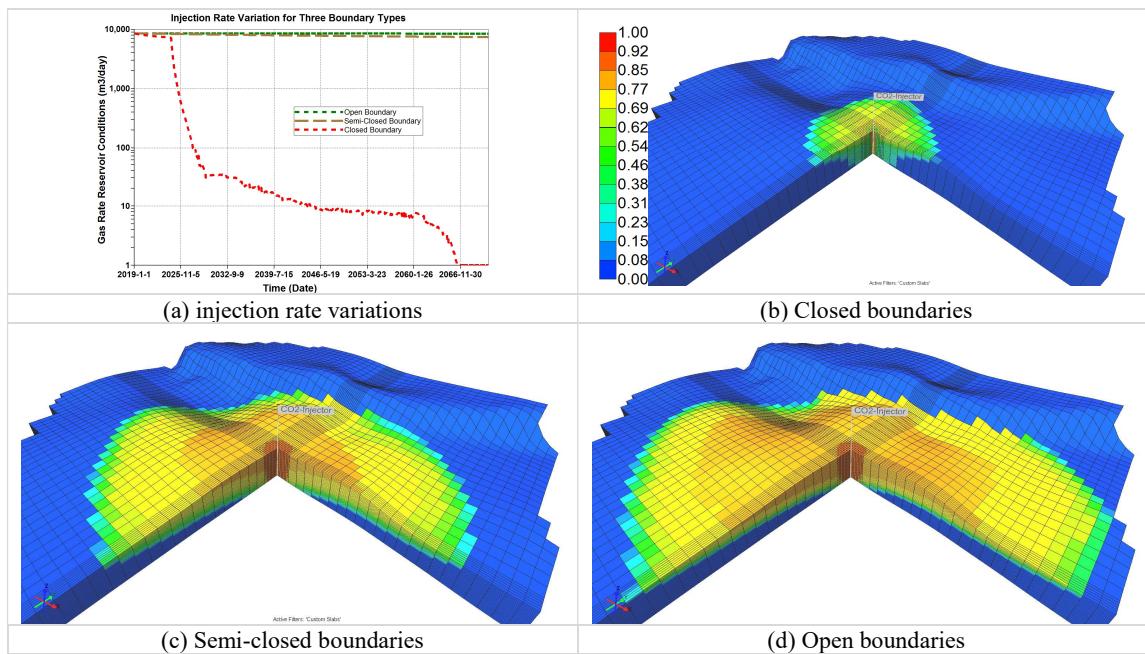


Figure 40. CO₂ plume extent for (a) closed boundary, (b) semi-infinite and (c) open boundary storage zone

For the open boundary system, pressure of the storage zone does not increase substantially, with an increase of only 201 psi noted in the injection well's bottomhole pressure over the injection period of 52 years. The extent of the CO₂ plume is largest in open boundary system as can be

seen in Figure 40(d). However, there are still some portions of the storage zone in which the CO₂ plume has not yet reached. The CO₂ plume may keep spreading due to buoyancy even after CO₂ injection has stopped, but at a substantially reduced rate. The results presented here are only for the time interval of active CO₂ injection period.

When we collectively look at the results, we can observe the following trends. In the case of the closed boundary system, the pressure increase is the highest and plume spread is lowest. While in the case of the open boundary system, the pressure increase is the smallest and the plume extent is largest. The storage zone with semi-closed boundary behaves in-between these open and closed systems.

The temporal profile of pressure and CO₂ saturation for leaky wells are extracted from the reservoir simulation data, and are used as inputs to the Cemented Wellbore Model (CWM). The cumulative CO₂ leaked volume is used as an indicator to see the relative difference of different boundary types. The leaked CO₂ volume is normalized using the closed boundary scenario data and results are shown in

Figure 41.

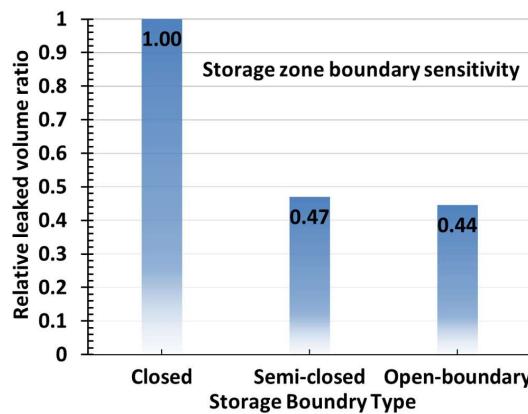


Figure 41. Normalized leaked volume sensitivity to storage zone boundary type, for a cemented wellbore type having a distance of 300 ft from the injector location

The difference in the leaked volume ratio between the closed and the semi-closed boundary type is substantial and there is only a small change between the semi-closed and the open boundary scenario.

3.2.16 Sensitivity of buffer layers

In South Louisiana with unconsolidated formations, it is possible that over time some of the wellbore sections may have been collapsed. A majority of the drilled formations are made up of shale and therefore shale is the cause of most of the wellbore problems. A collapsed wellbore section may act as a barrier and the wellbore permeability may be altered substantially. This is especially true in the case of an uncased wellbore. This in turn may prevent the migration of leaky fluids through the wellbore. In this section we study the hypothetical but plausible scenario that some wellbore sections may have been collapsed over time and the permeability of these sections is reduced substantially as compared to an open wellbore. A good section of cemented wellbore may fall under this category. An uncased wellbore configuration is used to study the

buffer layer effects. We assume the thickness of each buffer layer is approximately 100 ft (30 m) and select shale layers having nearly the same thickness in the upper portions of the well with less than 4,000 ft depth and carry out the sensitivity analysis. A permeability value of 0.01 mD is assumed for these buffer layers. The results of the leakage rate to fresh water aquifers are reported in Figure 42.

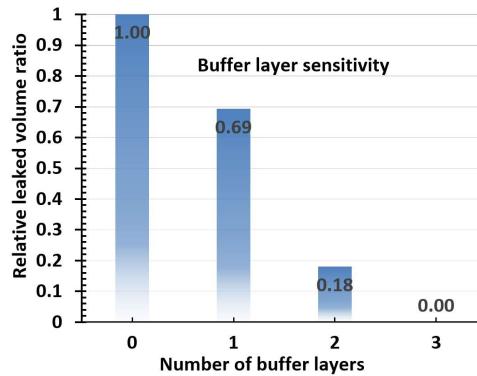


Figure 42. Normalized leaked volume sensitivity to buffer or barrier layers, for an open wellbore configuration at a distance of 300 ft from injector location for a storage zone with open boundaries

A nearly 30 percent reduction in leakage volume is noted if one such buffer layer or segment exists and a higher reduction of nearly 82 percent is noticed if two buffer or collapsed zones are present each of which has 100 ft length and 0.01 mD permeability.

3.2.17 Calculation of the wellbore leakage index

Based on the results of the sensitivity of four wellbore parameters, we now formulate the criteria to assign the indices to different parameters. The suggested values based on the modeling results are shown in Table 19.

Table 19. Assign indices to different variable categories

Variables	Category-1	Category-2	Category-3
Wellbore Type	Cased-cemented	Cased-uncemented	Uncased
Cement Index (CI)	0.01	0.72	1
Injector-leaky well distance (m)	5000	1000	100
Distance index (DI)	0.04	0.44	1
Boundary Type	Open boundary	Semi-closed	Closed
Boundary Index	0.44	0.47	1
No. of Buffer Layers	2	1	0
Layer Index (LI)	0.18	0.69	1

Now we apply these criteria to the sample of 14 selected wells. The field is bounded by a fault to the north, so most probably it will behave like a semi-closed system. The well information and

assigned indices are shown in Table 20. After calculation of the well leakage index for each of the wells, we use the criteria specified in Table 18, to assign the well tiers, in order to identify the wells that have relatively higher leakage potential. Initially we use the WLI value for no buffer layers as a conservative approach to assign the well tiers.

Table 20. Assigned variable indices for the 14 selected wells for well types 1-cased-cemented, 2-cased-uncemented, 3-uncased

Well Sr. No.	Wellbore Type	Cement Index	Injector-leaky well distance (ft)	Distance Index	Storage zone boundary type	Well leakage index when number of buffer layers		
						0	1	2
1	2	0.72	984	0.73	0.47	2.4602E-01	1.6975E-01	2.3180E-02
2	3	1.00	2297	0.52	0.47	2.4272E-01	1.6748E-01	2.2563E-02
3	1	0.01	4921	0.33	0.47	1.5370E-03	1.0605E-03	9.0477E-07
4	1	0.01	1640	0.60	0.47	2.8203E-03	1.9460E-03	3.0462E-06
5	2	0.72	9843	0.15	0.47	5.2372E-02	3.6137E-02	1.0505E-03
6	2	0.72	5906	0.28	0.47	9.5333E-02	6.5780E-02	3.4806E-03
7	1	0.01	6890	0.24	0.47	1.1440E-03	7.8937E-04	5.0123E-07
8	1	0.01	984	0.73	0.47	3.4169E-03	2.3577E-03	4.4715E-06
9	2	0.72	16404	0.03	0.47	9.4121E-03	6.4943E-03	3.3927E-05
10	3	1.00	11483	0.12	0.47	5.4734E-02	3.7766E-02	1.1473E-03
11	1	0.01	328	1.00	0.47	4.7002E-03	3.2431E-03	8.4606E-06
12	3	1.00	4921	0.33	0.47	1.5370E-01	1.0605E-01	9.0477E-03
13	3	1.00	2625	0.48	0.47	2.2713E-01	1.5672E-01	1.9757E-02
14	3	1.00	9843	0.15	0.47	7.2739E-02	5.0190E-02	2.0264E-03

The results of the assigned well tiers are shown in Figure 43. From this distribution it is easy to identify the wells with the highest leakage potential. Wells assigned to tier-4 need special attention, as these have the highest leakage potential. Well 1 falls in tier-4 primarily due to its close proximity to the injection well and its wellbore category of cased-uncemented, which have relatively higher permeability values than cased-cemented wellbores. Similar arguments are true for other wells as well. Now we examine the effect of buffer layers. As can be seen in Figure 43, the presence of only one buffer segment or layer reduces the leakage risk of some of the wells, visible by their well tier shift to lower values. The presence of more buffer layers or well segments that may act as barriers will further reduce the leakage risk of wells.

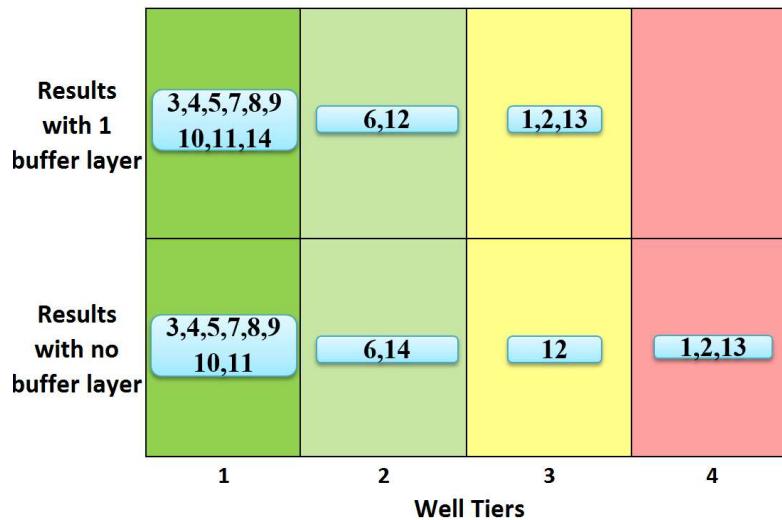


Figure 43. Well tiers assigned to 14 selected wells, based on their well leakage index value

The criteria used to define indices have a range from 0 to 1. These ranges may be revised and may be calibrated to account for the relative effect of different indices. In that case the ranges may not necessarily be restricted between 0 and 1 and relatively higher values of such an index would be the indicators for concern.

3.2.18 Conclusions of single well leakage modeling results

A risk-based approach is presented that can be used to identify wells that have relatively higher leakage potential as compared to other wells penetrating a storage zone. The method uses qualitative and quantitative measures of assessing a well's leakage potential. The approach uses well leakage index as the primary variable to categorize the wells into four tiers, with tier-1 having lowest and tier-4 having highest leakage potential. The cement data of a representative sample of 14 wells from a Louisiana oil field is used to categorize the wellbore types into cased-cemented, cased-uncemented or uncased wellbores to calculate their respective leak permeabilities. The results of well cement data show that dry and plugged wells drilled in the 1950's and 60's need special attention. These wells may only have surface casing installed to protect fresh water aquifers and well segments passing through the deeper storage zones may not be cased. These wells may provide the largest flow area to leaking fluids provided that the wellbore has not collapsed. It was also observed that all wells had some sort of protection for the fresh water aquifers, either cemented surface casing or cement plugs installed at an average depth of 2,000 ft. Well leakage index is based on the cement coverage of the well section passing through the storage zone, the well's proximity to the injection well, the nature of the storage zone boundaries and the number of buffer barrier layers or zones between the storage zone and the base of the USDW. The CO₂ leakage to the USDW is calculated for a period of 30 years and average leaked volume is estimated for a constant storage zone injection rate of 2.46 Mt/year. The leaked volume is normalized for each variable category and a well leakage index is calculated based on these normalized values. The well leakage index provides a quantitative measure of a well's leakage risk. It is also noted that optimization of injector location is of prime importance for well leakage risk assessment. If possible, it should be located in the field where wells are sparsely located. The proposed risk-based model to categorize the wells based on the

well leakage index should facilitate in the planning and execution stages of a project.

3.2.19 Bayou Sorrel - IAM model-multiple well leakages results

In this section results of integrated assessment model (IAM) are presented. The results for the simulated region where well are sparsely located and for the scenario of injection in the vicinity of main cluster of wells in the middle of the field are compared, to see the impact of location of the injection well in the area of least number of well. The presented results are the average values of the 11 statistical realizations considered. The wells are treated as cemented wells. Different sand interval between the storage zone and shallow aquifer are lumped together as a single intermediate reservoir.

Table 21. Shallow aquifer and intermediate reservoir properties

Parameter	Shallow Aquifer Properties	Intermediate Reservoir
Elevation (m)	304.8	1500
Pressure (MPa)	3.21	15.78
Temperature (C°)	28.1	46.84
Permeability (m²)	7.575E-13	7.0705E-13
Porosity	0.3	0.29
Thickness (m)	NA	500

The following reservoir parameters are used for the storage zone. The injection rate was taken to be 2.64 Mt/yr, which is the cumulative injection rate of seven injection wells. Other parametric variations are shown in Table 22.

Table 22. Storage zone parametric variations used to calculate the leakages

Parameter	Distribution	Mean	St. Dev.	Min	Max
Thickness (m)	Normal	250	20	1	300
Permeability (m²)	Normal	6.06E-13	7.07E-14	1.00E-15*	1.00E-11*
Porosity	Normal	0.25	0.02	0.01*	1*
Residual Water Solution	Normal	0.15	0.05	0*	1*
Residual CO₂ Saturation	Normal	0.15	0.05	0*	1*

Note: * denote the model constraints

3.2.19.1 Leakage well locations

Model's built in statistical tools are used to randomly locate the wells within the storage zone boundaries.

Table 23. Scenarios considered for leaky well fractions Bayou Sorrel Field

Scenario	No. of Wells	Mean	St. Dev.	Min	Max
1	Injector located away from cluster of wells	5	2	3	7
2	Injector located in the center of the field	55	5	35	70

3.2.19.2 Scenario-1 Injector at the corner of the field

Leakage rate from the modeled zone are shown in Figure 44. There were 15 wells that were present in the simulated model, and 30 percent of them were treated as leaking. With this assumption, less than 0.1 percent of the total injected CO₂ leaks from the storage zone through wells.

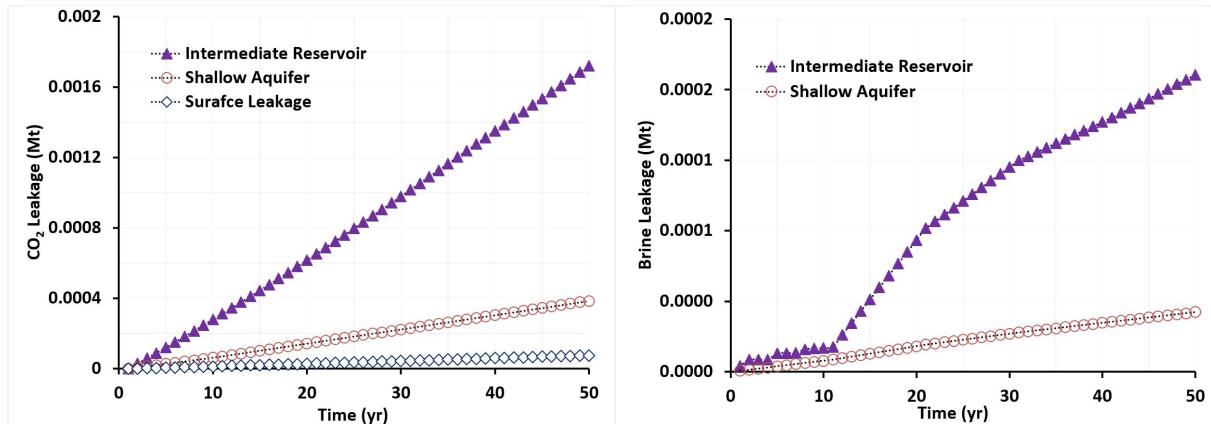


Figure 44. CO₂ and brine leakage rate to a thief zone and shallow aquifer

3.2.19.3 Scenario-2 Injector is in the center of the field

If same injection is carried out in the field having wells are clustered together. The leakage rate seems to be nearly linearly increasing with the number of wells and is shown Figure 45. It is nearly 10 time the leakage as compared to scenario-1.

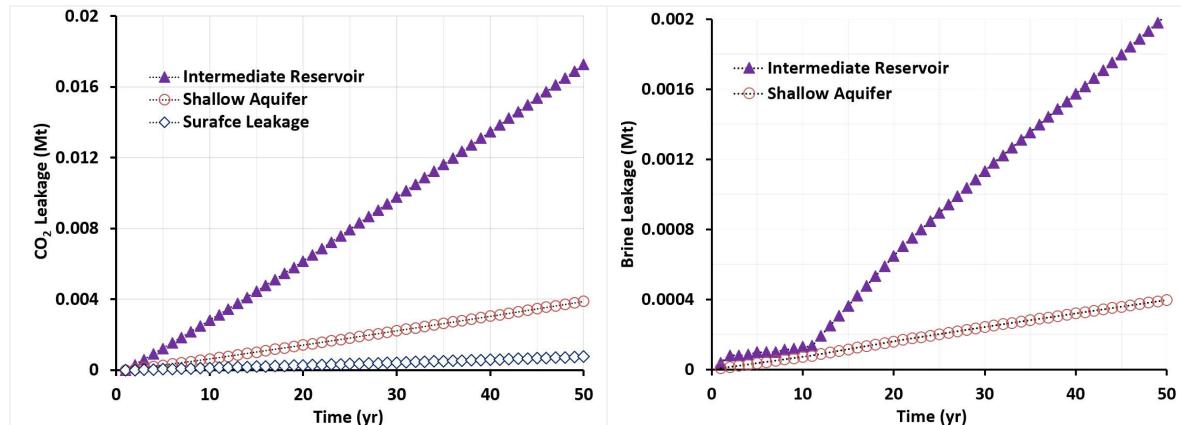


Figure 45. CO₂ and brine leakage if the injector is located within the cluster of wells

3.2.20 Paradis- Multiple well leakages results- IAM model

For Paradis filed the shallower and intermediate reservoir properties used in integrated assessment model are provided in Table 24.

Table 24. Shallow aquifer and intermediate reservoir properties considered

Parameter	Shallow Aquifer Properties	Intermediate Reservoir
Elevation (m)	304.8	406
Pressure (MPa)	3.21	4.27
Temperature (C°)	28.1	29.68
Permeability (m²)	7.575×10^{-13}	1.313×10^{-13}
Porosity	0.3	0.3
Thickness (m)	NA	250

The following reservoir parameters are used for the storage zone. The injection rate was taken to be 2.64 Mt/yr, which is the cumulative injection rate of seven injection wells. Other parametric variations are shown in Table 25.

Table 25. Storage zone parametric variations used to calculate the leakages

Parameter	Distribution	Mean	St. Dev.	Min	Max
Thickness (m)	Normal	60	30	1	100
Permeability (m²)	Normal	1.21×10^{-12}	1.21×10^{-13}	$1.00 \times 10^{-15}^*$	$1.00 \times 10^{-11}^*$
Porosity	Normal	0.25	0.02	0.01*	1*
Residual Water Solution	Normal	0.15	0.05	0*	1*
Residual CO₂ Saturation	Normal	0.15	0.05	0*	1*

Note: * denote the model constraints

3.2.20.1 Leakage well locations

Model's built in statistical tools are used to randomly locate the wells within the storage zone boundaries.

Table 26. Scenarios considered for leaky well fractions Paradis field

Scenario	No. of Wells	Mean	St. Dev.	Min	Max
1	Injector located away from cluster of wells	15	3	7	25
2	Injector located in the center of the field	125	15	75	200

3.2.20.2 Scenario-1 Injector at the corner of the field

Leakage rate from the modeled zone are shown in Figure 46. There were 15 wells that were present in the simulated model, and 30 percent of them were treated as leaking. With this assumption, less than 0.1 percent of the total injected CO₂ leaks from the storage zone through wells.

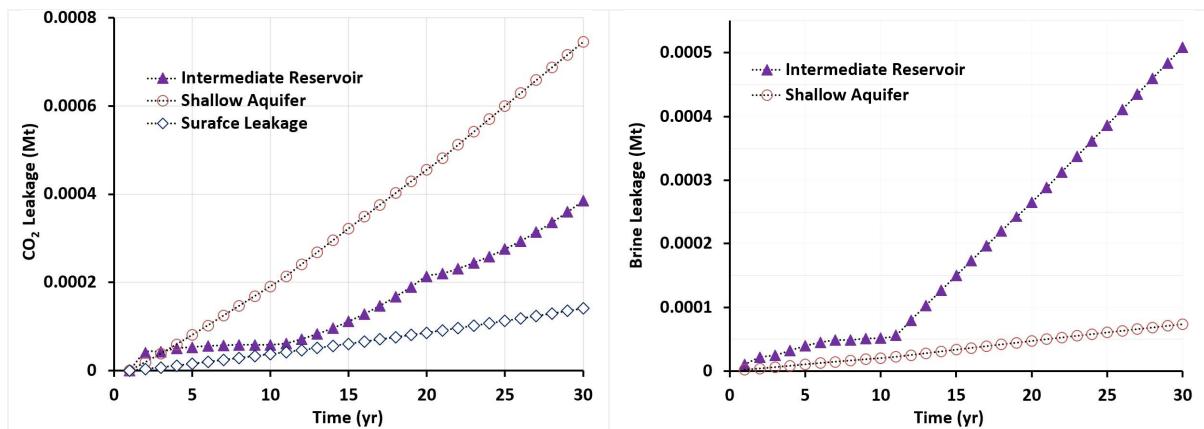


Figure 46. CO₂ and brine leakage rate to a thief zone and shallow aquifer

3.2.20.3 Scenario-2 Injector is in the center of the field

If same injection is carried out in the field having wells are clustered together. The leakage rate seems to be nearly linearly increasing with the number of wells and is shown Figure 47. It is nearly 10 time the leakage as compared to scenario-1.

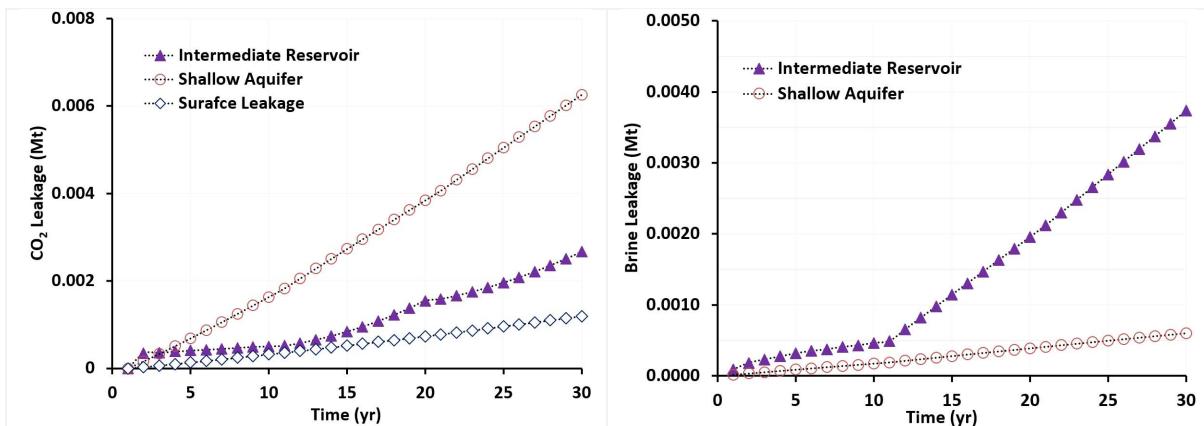


Figure 47. CO₂ and brine leakage if the injector is located within the cluster of wells

3.2.21 Caprock leakage

Caprock leakage is also another important element in storage long term integrity analysis. NSEAL one of the tools available in NRAP is used to estimate the probable leakage rates from caprock. The permeability of the shale caprock with a porosity in the range of 14 to 20 percent, is in the range of 1 to 2 μ D (reference). In order account for variation in permeability of the caprock three cases with varying caprock permeability are considered for Bayou Sorrel and Paradis fields. The assumed variations in caprock permeability are shown in Table 27.

Table 27. Caprock permeability variations considered

Cases	Mean (μ D)	St. Dev. (μ D)	Min (μ D)	Max (μ D)
-------	-----------------	---------------------	----------------	----------------

1	2	0.5	0	5
2	10	1	0	20
3	20	2	0	40

3.2.21.1 Bayou Sorrel NSEAL results

For Bayou Sorrel a total of 133 MT, corresponding to 2 percent storage efficiency was injected during the 50-year time frame. The stochastic height of the cap rock with mean of 250 m and standard deviation of 50 m was assumed. The reported total leakages are for the 200 years' time frame, 50 years of injection and then 150 years of monitoring. From the reservoir simulation results the average saturation of 2 percent on the top layer was calculated is assumed to be prevalent for the entire 200 years. Similarly, a constant pressure, 350 psi above the initial reservoir pressure was used. These settings were taken from the reservoir simulation results at the end of injection phase. Assuming these conditions for the entire 200 years yields a conservative estimate of leakage rates.

Table 28. Caprock leakage rates for Bayou Sorrel, NSEAL Results

Cases	Pressure (Mpa)	Avg. CO ₂ Saturation	CO ₂ Injected (MT)	CO ₂ Leakage (MT)	Brine Leakage (MT)	Percent Leaked/ Injected
1	26.25	0.02	1.33E+08	244233	5.75E+06	0.1836
2	26.25	0.02	1.33E+08	1.07E+06	2.53E+07	0.8068
3	26.25	0.02	1.33E+08	2.11E+06	4.97E+07	1.5872

3.2.22 Paradis NSEAL results

For bayou sorrel a total of 68 MT, corresponding to 2 percent storage efficiency was injected during the 30 years' time frame. The stochastic height of the cap rock with mean of 100 m and standard deviation of 5 m was assumed. The reported total leakages are for the 200 years' time frame, 30 years of injection and then 170 years of monitoring. From the reservoir simulation results the average saturation on the top layer was calculated is assumed to be prevalent for the entire 200 years. Similarly, a constant pressure, 250 psi above the initial reservoir pressure was used. These settings were taken from the reservoir simulation results at the end of injection phase. Assuming these conditions for the entire 200 years yields a conservative estimate of leakage rates.

Table 29. Caprock leakage rates for Bayou Sorrel, NSEAL Results

Cases	Pressure (Mpa)	Avg. CO ₂ Saturation	CO ₂ Injected (MT)	CO ₂ Leakage (MT)	Brine Leakage (MT)	Percent Leaked/ Injected
1	16.32	0.02	6.89E+07	268167	6.75E+06	0.3892
2	16.32	0.02	6.89E+07	1.18E+06	2.97E+07	1.7141
3	16.32	0.02	6.89E+07	2.32E+06	5.84E+07	3.3701

3.3 FAULT LEAKAGE AND ASPHALTENE PRECIPITATION

Some additional work was performed beyond the contractual requirements, that covers fault related leakages and asphaltene precipitation.

3.3.1 Faults related leakages

In southern Louisiana faults are part and parcel of geological settings, therefore it is crucial to quantitatively estimate the fault related leakages. An effort was made to address the complex fault related leakage.

Estimation of faults leakage potential is an essential component of CO₂ storage integrity analysis. The selection of deep saline aquifers for CO₂ storage in these settings mandates the modeling of fault-related fluid flow to estimate the most probable leakage rates. Faults usually have complex structures with heterogeneities and anisotropies over a range of scales because of which local capillary trapping becomes significantly important. Reservoir simulation results for a representative normal fault in a potential storage site in southern Louisiana with homogenous, fault damage zone are presented. Three cases are modeled to study the sensitivity of dissolution and local capillary trapping. Our results show that dissolution and local capillary trapping impede the upward migration of CO₂, and may reduce leaked volume by more than 19 percent in some of the cases. It is also noted that presence of high permeability connected streaks may lessen the positive contributions of dissolution and local capillary trapping in reducing CO₂ leakage.

Numerical Model Setup

The model setup and boundary condition details are shown in Figure 48. CO₂ is injected at the lower half portion of bottom sand, north side of lowest sand and all of the upper sands allow the fluids to leave in the N-S direction, fluid can also exit through the fault rock at the topmost sand. Eleven CO₂ flux reporting stations defined at different fault-sand interfaces are also shown (white lines), these are used to report the CO₂ fluxes rising vertically through these zones.

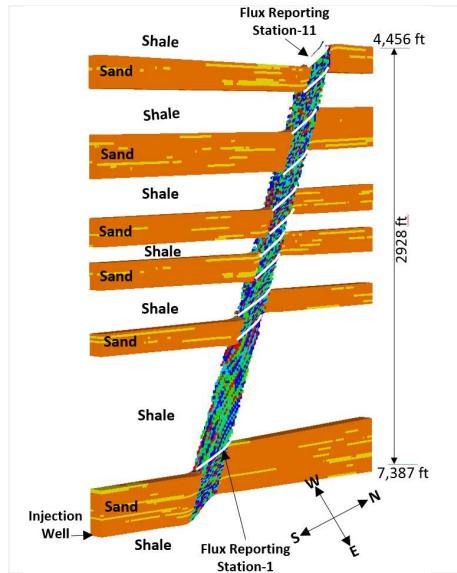


Figure 48. Model setup details

The injection well is located at a distance of nearly 710 ft away from the fault with an injection rate of 21 t/day. The rate of 21 t/day is the fraction of a total injection rate of 0.34 million tons per year. This fraction was calculated by considering a circular storage zone with radius of 710 ft, and then rate for the model was obtained by multiplying the pore volumetric ratio of model by the total circular zone pore volume. The sand and shale intervals information are extracted from the well log data from two wells on opposite sides of a fault in the Bayou Sorrel field in southern Louisiana. It is a normal fault having a vertical throw of nearly 150 ft. Eleven fault-sand interfaces along different sand intervals are defined shown in Figure 48. The amount of CO_2 rising through these interfaces is used for quantitative leakage rate estimates. Well log data is used to define the initial formation pressure and temperature, with a 0.465 psi/ft hydrostatic gradient and 0.76 $^{\circ}\text{F}/100$ ft geothermal gradient Zulqarnain et al. (2017). Pure CO_2 was injected at a constant injection rate and rate is reduced if well bottom hole pressure reaches to 80 percent of the total stress at the bottom of the well.

The permeability of the fault structure considered is shown in Figure 49. Extrapolation boundary was imposed on end of each sand interval, which allows the fluids to leave the simulation domain laterally. Similarly, extrapolation boundary was used at the exit of shallowest sand interval at station 11, which allows the fluids to move vertically. In a homogenous fault permeability model, it is assumed that shale smearing creates a fault zone that has a uniform permeability. This permeability is two orders of magnitude less than clean sands and two orders of magnitude higher than shale sands with very low permeability.

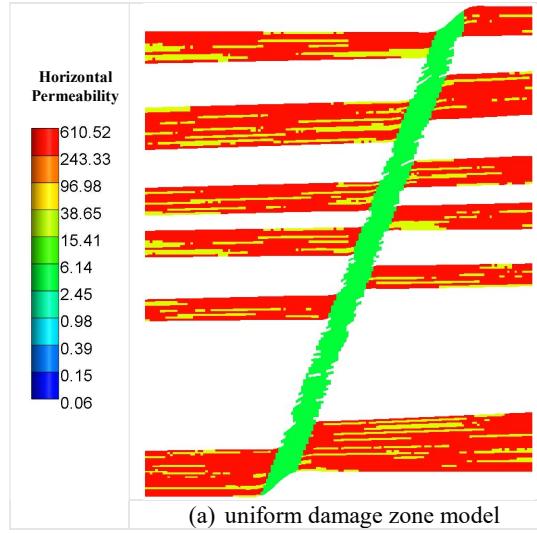


Figure 49. Horizontal permeability distribution considered in this study

Homogenous fault zone

The modeling results for the homogeneous fault zone model are presented in this section. Contours plots of CO₂ saturation at the end of 30 years injection period are shown in Figure 50. A difference in the saturation profile can be noticed in the upper sands where activation of dissolution delays the rise of CO₂ plume. Similarly, when capillary pressure scaling is activated alongside dissolution, it further impedes the upward migration of CO₂ plume. Although the fault damage zone is homogeneous, but adjustment of its capillary pressure due to its lower porosity and permeability resulted in a capillary pressure-scaling factor of 5.1. This additional resistance is responsible for hindering the upward movement in comparison to cases 1 and 2. Therefore, a small reduction in CO₂ leakage volume is noted in the upward direction from the injection zone, and this amount of CO₂ prefers to move across the fault damage zone laterally.

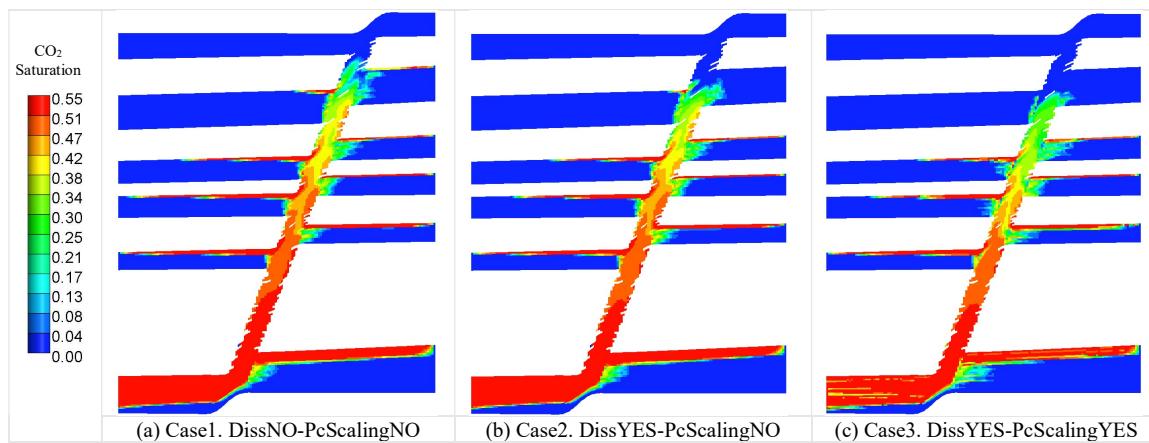


Figure 50. CO₂ saturation profile for homogeneous fault model at the end of 30 years of injection phase for
(a) Case1 no dissolution and no capillary pressure scaling, (b) Case2 dissolution and no capillary pressure scaling, (c) Case3 dissolution and capillary pressure scaling.

In order to quantitatively estimate the resulting changes, flux reporting stations at the top and bottom of each of sand interval within the fault structure were defined in the simulation model. Station 1 is defined at the top of lower most sand interval in which CO₂ is injected and station 11 is at the uppermost sand-fault interface where the fault exits the top sand, these stations are shown in Figure 48. Instantaneous and cumulative amount of CO₂ passing through stations 1 and 10 is reported and is shown in Figure 51.

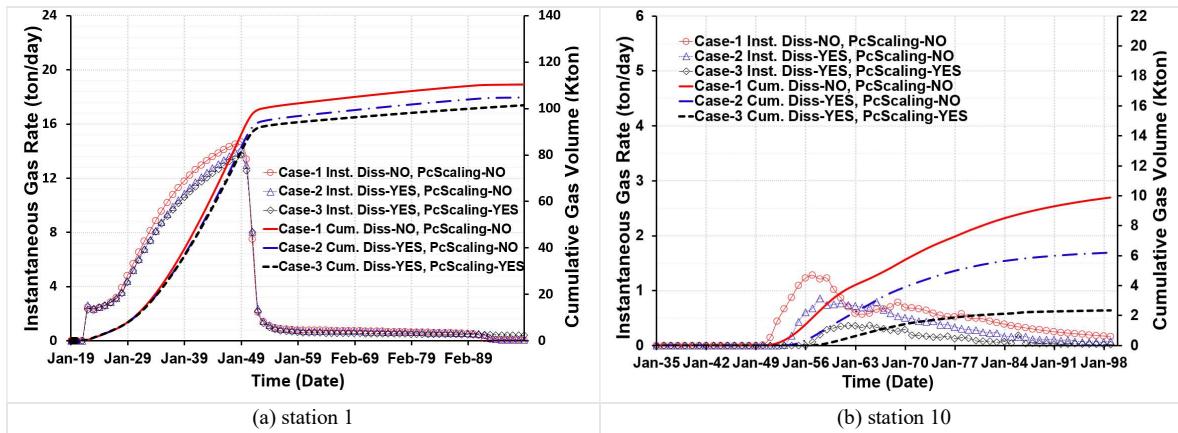


Figure 51. Temporal variation of CO₂ volumetric flow rate for cases 1, 2 and 3 (a) station 1 defined at the top of lowermost sand interval, and (b) at station 10 which is defined at the bottom of the top most sand interval in simulation setup

Note: There are y-axis scale differences between (a) and (b).

A minor delay in the discharge of CO₂ from the lowermost sand interval is noted after including dissolution and capillary pressure scaling in the base model Figure 51(a), which is not visible in the plot due to the large scale of the x-axis. The instantaneous and volumetric flow at stations 1 and 10 show the impact of inclusion of dissolution and capillary scaling. Dissolution and dissolution plus capillary scaling reduces the amount of CO₂ escaping through fault zone. A reduction of 5 percent is noted in the total amount of CO₂ migrating upward at station 1 when dissolution is included and a further 3 percent reduction is observed due to capillary pressure scaling.

At station 10, a spread is observed in CO₂ breakthrough time between case-1 and cases-2 and 3. Dissolution causes a delay of 3 years and capillary pressure scaling adds nearly 4 additional years to breakthrough time at station 10. For a homogeneous fault damage zone, the migrating CO₂ is equally likely to move in the fault structure due to the assumed uniform petrophysical properties. Therefore, we see a gradual change as we go from non-dissolution (case-1) to the dissolution (case-2) and dissolution plus local capillary trapping case-3.

3.3.2 Asphaltene precipitation

At both Paradis and Bayou Sorrel sites, depleted hydrocarbon formations may be targeted for CO₂ storage. One concern with CO₂ sequestration in depleted hydrocarbon reservoirs is the tendency of CO₂ to cause asphaltene precipitation (the heaviest part of crude oil consists of carbon, hydrogen, nitrogen, oxygen, and sulfur at which is insoluble in n-heptane and can be dissolved in benzene and toluene at room temperature) because of changes in one or more parameters of pressure, temperature and composition of the reservoir fluids. Asphaltene

precipitation during CO₂ injection causes formation damage which may alter porosity, permeability, well injectivity, and dynamic storage capacity. The effect of asphaltene precipitation on injectivity and CO₂ storage capacity is currently under investigation and will be reported in the next reporting period.

A literature review shows that studies on the asphaltene precipitation during CO₂ injection have been either from phase behavior point of view or its application on EOR. In this study, a depleted oil reservoir with an asphaltic oil at a residual oil saturation is considered. Given some PVT properties of the oil, Flory-Huggins solution theory with a correctly tuned Peng-Robinson equation of state and a multiphase flash calculation are used to model the amount of precipitated asphaltene during the pressure change and CO₂ injection. The resulting solid model, at which specifies the asphaltene reference fugacity at a reference pressure and the asphaltene molar volume, is then implemented in an advanced general equation-of-state compositional reservoir simulator where models asphaltene precipitation during CO₂ sequestration in a two-dimensional reservoir. Changes in porosity and permeability due to asphaltene precipitation are then calculated using Kozeny-Carman formula and the results are elucidated.

Results thus far show that the asphaltene precipitation may result in reduction of permeability in the immediate vicinity of the injection well. A reduction of 8 percent was noted after 500 days of injection for the conditions studied. A reduction in permeability translates to reduction in well injectivity. The deposited amount of asphaltene and resultant changes in well injectivity are shown in Figure 52 and Figure 53.

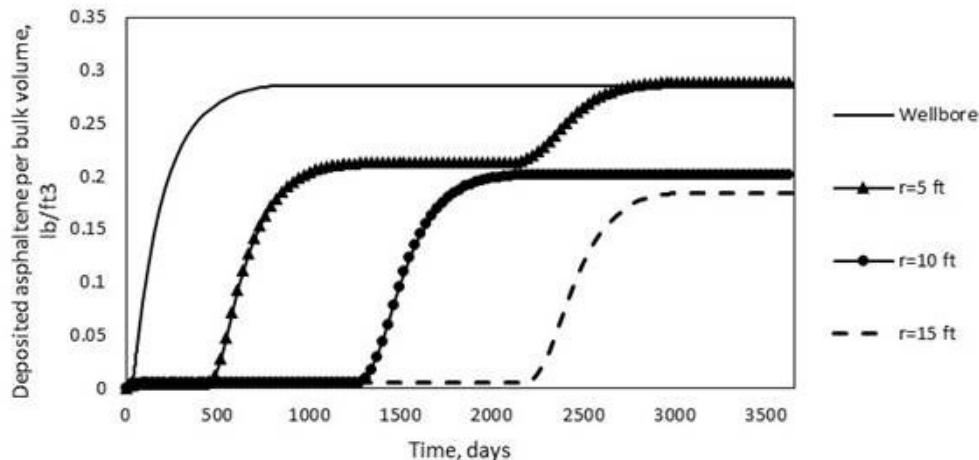


Figure 52. Temporal variation of asphaltene at different distances from the injection well

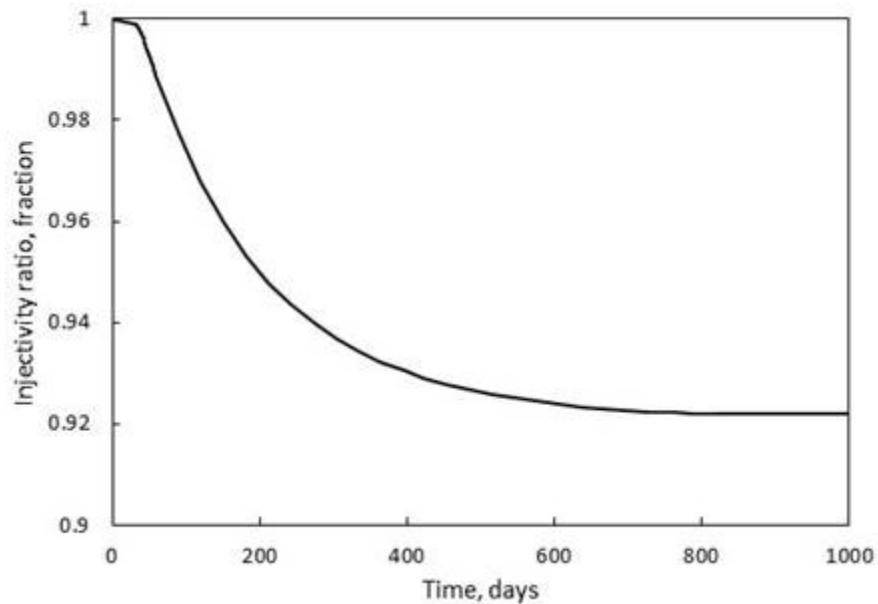


Figure 53. Temporal variation of well injectivity

3.4 BASELINE MONITORING: ANALYZE DIGITAL SEISMIC DATABASE OF A NATIONAL GRAVITATIONAL-WAVE OBSERVATORY (LIGO) FOR NATURAL EARTHQUAKES

3.4.1 Collection and characterization of relevant seismic data and storage evaluation methodologies

For this purpose, we will access the data, create methodology most suitable for automatic detection of significant events in their data and ultimately will confirm the existing national earthquake catalog for our region of sequestration or improve the current catalog with new events. In our standard approach we automatically identify suitable seismic events by manually training of a short-term average/long-term average ratio filter.

What is LIGO?

The Laser Interferometer Gravitational-Wave Observatory (LIGO) consists of two widely separated installations within the United States -- one in Hanford Washington and the other in Livingston, Louisiana -- operated in unison as a single observatory. We access the data base at the Livingston site. Although not established to record earthquakes LIGO has earthquake-quality seismometers, at three locations, on the tips and corner of its L-shaped layout. These instruments assist in inertial isolation of the experiment from ground motion. Teleseismic events of high magnitude saturate the feedback isolation system at LIGO and cause the experiment to shut down. Our project attempts to mine the same data set for earthquake arrivals in our local area.

An example of the description of one of the seismometers: L1:***ISI-STS-HAM 5*** is as follows:

ISI Internal Seismic Isolation

Active seismic isolation that is internal to the vacuum system. BSC ISIs have two platforms: stage 1 and stage 2. HAM ISIs have one stage: stage 1. Each ISI stage is mechanically isolated from the previous stage by a set of blade springs, and the resulting resonance is actively damped. Each stage is actively isolated (in addition to damping) from the previous stage.

GND	Ground motion monitor
STS	Streckeisen STS-2 inertial sensor The most useful frequency range of this sensor is from 0.05Hz to ~30Hz (we generally look up to 10Hz). (Very loud sources may be visible above the noise floor at higher frequencies.)
HAM5	Auxiliary optic chamber #5 HAM = Horizontal Access Module. HAM5 houses mirrors SR3 and SRM of the Signal Recycling Cavity (SRC). Additional information on each of the sensors is available online.

Since 2014, five seismometers have been running with the generic channel name :

L1:***ISI-GND_STS_HAM2_X_DQ*** where we can replace HAM2 with HAM5 and ITMY for the 3 corner station seismometers, and ETMX, ETMY for the end stations seismometers. In this terminology we can replace X with Y and Z for the other axis of each seismometer. The X and Y axis are oriented along the tow arms of the L-shaped structure.

3.4.2 MOU with LIGO organization:

After a regular tele-meeting of the LSC, Lorenzo is added as a senior member of the LSU LIGO group.

Participation was reestablished for a second year in summer of 2018.

3.4.3 Installation of Software on LSU secure server to access and download data from LIGO servers:

New Matlab codes use nds2client libraries automate data downloading of required sensor data.

Software installed:

- “CentOS 7.x”
- “Kerberos” provides a secure connection to LIGO server
- “Matlab” (2 commercial seats) downloads data from LIGO robotic tape library using data handling software (nds2client) and connected via “SWIG”.

3.4.4 Download and Management of Data sets from LIGO servers

(~1TB)

3.4.4.1 Data Search and Download

Most data are archived on tapes accessible in a remote robotic library. Tapes merge all data types from the LIGO center and are searched linearly for the relevant sensor data. Over 100,000 data channels are available and so, only recent, or popular, data are stored on disk. Older data are on tape and must be staged back to disk on demand. The robotic library comprises four T10000C tape drives and has 875 installed tapes.

A search for data requires one commercial Matlab seat. A search that spans 4 years of data tapes, collected by three-component seismic stations, uses two commercial Matlab seats and takes 2 months.

Data are separated into raw sensor amplitude files together with an associated meta-data file, both in a binary (matseis) format that contains information on sample rates, instrument type and time ranges for the collected data.

LIGO Livingston (LLO) 30°33'46"N 90°46'27"W

Table 30. Station data: Station names, time ranges searched and size of downloaded data sets

Station type	Sensor Name(s)	Maximum Data Range	Size (GB)
end station	L1:ISI-GND_STS_ETMX-X_DQ	1/1/14 to 8/31/17	
	L1:ISI-GND_STS_ETMX-Y_DQ	1/1/14 to 8/31/17	
	L1:ISI-GND_STS_ETMX-Z_DQ	1/1/14 to 8/31/17	
			108
end station	L1:ISI-GND_STS_ETMY-X_DQ	1/1/14 to 8/31/17	
	L1:ISI-GND_STS_ETMY-Y_DQ	1/1/14 to 8/31/17	
	L1:ISI-GND_STS_ETMY-Z_DQ	1/1/14 to 8/31/17	

			209
corner station	L1:ISI-GND_STS_ITMY-X_DQ	1/1/15 to 8/31/17	
	L1:ISI-GND_STS_ITMY-Y_DQ	1/1/15 to 8/31/17	
	L1:ISI-GND_STS_ITMY-Z_DQ	1/1/15 to 8/31/17	
			119
end station	L1:ISI-GND_STS_HAM2-X_DQ	1/1/14 to 8/31/17	
	L1:ISI-GND_STS_HAM2-Y_DQ	1/1/14 to 8/31/17	
	L1:ISI-GND_STS_HAM2-Z_DQ	1/1/14 to 8/31/17	
			141
end station	L1:ISI-GND_STS_HAM5-X_DQ	1/1/14 to 8/31/17	
	L1:ISI-GND_STS_HAM5-Y_DQ	1/1/14 to 8/31/17	
	L1:ISI-GND_STS_HAM5-Z_DQ	1/1/14 to 8/31/17	
			89
		(~Oct 2010 till April 2014)	
	L1 : PEM-EX_SEISZ_OUT_DQ		
	L0 : PEM-EX_SEISZ ?		
	L1:SEI-ETMX_STS2_Z	(~Jan 2006 till Sep 2010)	
	L1:SEI-ETMY_STS2_Z	(~Jan 2006 till Sep 2010)	
	L1:SEI-LVEA_STS2B_Y	(~Jan 2006 till Sep 2010)	
	L1:HPI- ITMY_BLND_L4C_Z_IN1_DQ	(~Dec 2012 till now)	
	L1:HPI- ITMY_BLRMS_HP_30M_100M		
			Total
			666

3.4.4.2 Seismic Station (3-component data):

Each station has a specific period of activity which can be discontinuous ranging from 2014 – Sept. 2018 from 3-component seismometers. Because LIGO was not in continuous operational until late in 2016, data from earlier years are not available as continuous recordings.

For 2017 and 2018 we selectively examine dates for which we have notification from the U.S. Geological Survey (USGS) that earthquakes were detected within 500 km of the LIGO.

However, none of these reported events were observable in the available data for those. Prior to 2014 data are not continuously available from the LIGO database.

3.4.4.3 Event Identification

Results: No events within the 500 km radius have been identified over the period of the study in the available data downloaded from LIGO.

Because all sensors in the data base lie within 6 km of each other their mutual close proximity we run a rolling correlation between different sensors but over common time periods to distinguish local noise (operator traffic, local instrument movements) from possibly real events

that affect the whole facility almost simultaneously (Figure 54 and Figure 55). In Figure 54, vertical-component data from two stations at two ends of the arms of the LIGO show strong and sharp rise in the temporal correlation, indicating a common possible seismic event. However, the long duration of the event and absence of any recorded local events in the USGS network are more suggestive of a distance epicenter outside our radius of interest.

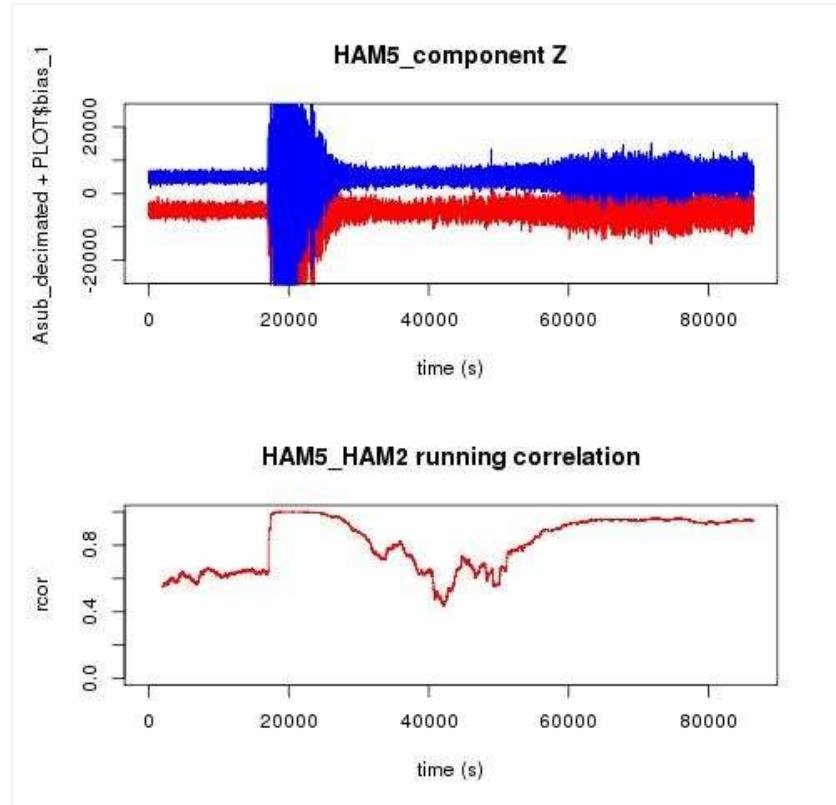


Figure 54. Example rolling correlation that does not represent local events.

Figure 55 is an example false event. The green line (a) is HAM5 data showing a short-lived amplitude anomaly (relative units) at about 60000 s from the start of the recording period. Sites ETMX (line b) and HAM5 lie 4 km separate. USGS reports an earthquake of magnitude 2.9 near Larkinsville, Alabama on Dec 19, 2017 at 11.55 UTC (300 seconds before the end of this record—black arrow). The red line (c) is the calculated rolling correlation between the data sets and shows no unusual correlation relative to the rest of the record. The period of recording spans 24 hours for Dec 19.

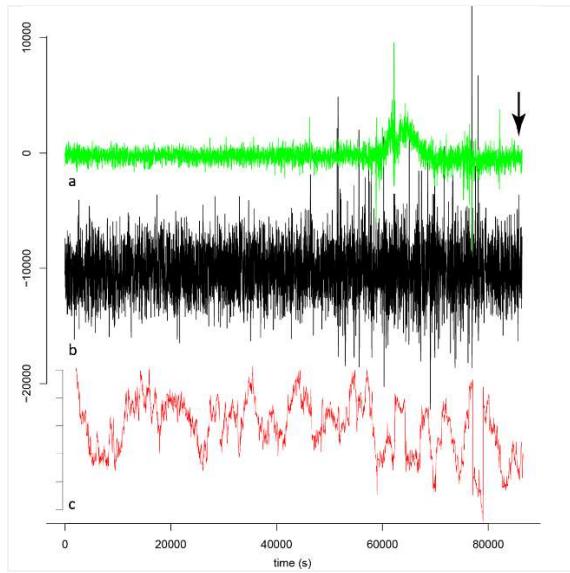


Figure 55. Example false event.

We inspect each LIGO seismogram visually at the time periods corresponding to reported events within a radius of 500 km of LIGO, a practical distance for earthquakes that may be detectable at the LIGO observatory.

We review published earthquake event catalogs from the USGS website and receive continuous updates. We integrate these events into a publishable map using open source GMT command line tools for map generation in many common formats, both scalable vector graphics (e.g. Postscript) and common pixel-based image-formats (e.g., JPEG).

Recommendations:

Potential future work for monitoring induced seismicity would require permanent stations no more than 10's km away from injection sites.

3.4.5 Model Development

From these event extractions we will create a preliminary velocity-depth model, using publicly available well-logs. We will determine first-order event locations using open source software ISOLA.

3.4.6 Results

The greatest site amplification in the Louisiana area is likely from shorter period waves (8-1 2 s) At these periods, the expected amplification is similar to that in central western portions of the US but lower than the eastern half of the country. Seismic attenuation factors ($> 1/150$) are also comparably higher than in the east (Bowden et al. 2017).

Baseline monitoring of natural seismic activity can serve as a reference to inform public and make scientific decisions on the effects of CO₂ injection based on syn- and post-injection monitoring of possible induced micro-earthquakes. North Louisiana is a region highly suitable for location of CO₂ storage, monitoring, validation and accounting. In particular, our chosen injection well site correctly minimizes the potential for fault reactivation. Among Gulf Coast

states, only Florida, which has a lower combination of seismic events and ground shaking probability (Ellsworth 2013) than the state of Louisiana and in particular the parish of our chosen work site. During the period of this project no notable events have been detected at seismometers in the center of the state at LIGO and adds support to the low potential for natural seismic activity.

Also, because no events were detectable, a velocity-depth relationship was constructed only from public sources. Available sonic logs only cover productive oil and gas intervals so we consider that a good general model gradient above the top of geopressured interval ranges from ~ 400 m/(s.km) (Yu and Hilterman 2013) to ~ 500 m/(s.km) (Chopra and Huffman 2006) with a shallow velocity of 1500-1800 m/s starting at about 500 m to 1 km depth.

3.4.7 Ongoing on-line seismic catalogue and map

If new events are determined we will publish an online catalog and location map on an LSU website.

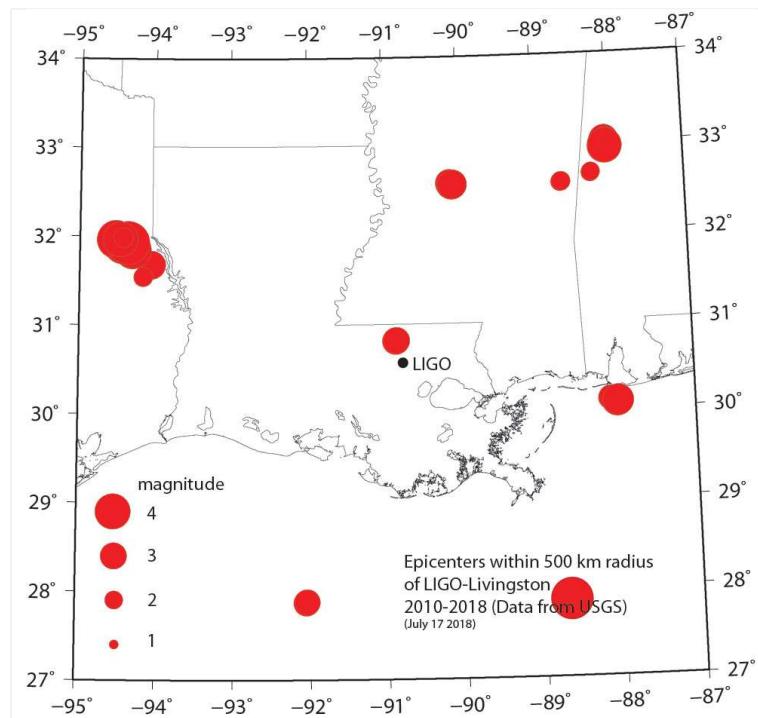


Figure 56. Location of seismic epicenters within a 500 km radius of the LIGO observatory available from the USGS Earthquake data base for the period between 2010 and 2018 (up to 9/26/2018).

Note: no events are detectable in the LIGO database for this time period and for when data were available to examine (www.geol.lsu.edu/jlorenzo/)

3.4.8 Deliverable

If additional seismic events are located in the LIGO database, we will create map of earthquake epicenters (location and magnitudes) and published on an LSU web server for public consideration.

4 CARBON PIPELINE TRANSPORTATION ISSUES (PIPELINE REPURPOSING ANALYSIS)

4.1 INTRODUCTION

To date, the infrastructure linking CO₂ sources to sinks (or users in the case of EOR) is seriously limited. There are currently 5,200 miles of CO₂ pipelines in the U.S., a majority of which are in west Texas. This investment pales in comparison to the 300,000 miles of natural gas transmission infrastructure in the U.S. (Dooley et al., 2009). Wallace et al. (2015) predicts that 1,000 miles of CO₂ pipeline will need to be built every year until 2030 in order to keep up with the pace of EOR potentials alone, much less projects designed for just permanent storage. High upfront capital costs, often in excess of \$500,000 per mile, are one of the important barriers to this development (Smith, 2014). In addition, CO₂ pipelines will likely be considered relatively new and novel types of development that could lead to regulatory and environmental review and permitting delays and potentially, as well be discussed later in this report, public perception and opposition challenges.

One potential option that may reduce overall CO₂ transportation development cost is to convert or “repurpose” existing or underutilized natural gas infrastructure (Rabindran et al., 2011; Noothout et al., 2014; Onyebuchi et al., 2017). According to the Pipeline and Hazardous Materials Safety Administration (PHMSA, 2017), in 2016, Louisiana had over 24,000 miles of natural gas pipelines. South Louisiana natural gas production has declined dramatically over the past several decades creating potential repurposing opportunities for assets that may be facing utilization challenges.

There are a variety of rationales for repurposing existing natural gas pipelines for CO₂ transportation. First, repurposing existing natural gas and crude oil pipelines reduces material use requirements, reduces waste entering landfills, and reduces potential land degradation. Second, repurposing natural gas and crude oil pipelines reduces expensive entry costs for CO₂ projects or potential CO₂ transportation companies (Herzog, 2011). Third, the conversion of existing older natural gas pipelines may reduce harmful methane emissions which are a significant contributor to climate change and ultimately loss revenue for the natural gas operator (Kirchgessner et al., 1997). Overall, repurposing natural gas pipelines is seen, at least in theory, as an economical and environmentally friendly way to facilitate CCS.

However, repurposing natural gas pipelines is not costless nor without its own set of regulatory hurdles. There are a number of regulatory requirements that govern the conversion of natural gas pipelines for other transportation purposes. Historically, operators have relied on Title 49 of CFR 195.114 that specifies pipelines that are acceptable for conversion to alternative commodity transport. Furthermore, the unconventional shale revolution has created a certain degree of competition for the repurposed use of these lines, particularly for the movement of NGLs.

There have been numerous pipeline projects in recent years involving flow reversals and conversions to transport other products. This increase in proposed conversions has sparked federal regulatory agencies to issue new guidelines for the process. PHMSA Docket No. 2014-0040 has provided new guidance for re-evaluating pipelines in consideration for transporting different commodities. While the PHMSA only needs to be notified if the conversion project cost over \$10 million, the guidelines are applicable to all conversion projects.

There are a number of special considerations for repurposing natural gas pipelines for CO₂ transport use (Seevam et al., 2010; Serpa et al., 2011; Noothout et al., 2014; Brownsort et al., 2016). One of the most important considerations is recognizing that the physical properties of CO₂ and natural gas are fundamentally different (Averill and Eldredge, 2012). Transporting CO₂ is most economical in its supercritical phase which occurs at or above 1,070 psi while natural gas is generally transported at lower pressures which can range between 188 psi to 1,493 psi (Rabindran et al., 2011). Any pipeline expected to move CO₂ at a supercritical phase would need to be rated well above 1,070 psi to account for the pressure drop dictated by the terrain and the temperature fluctuations of the region. In fact, most technical specifications for CO₂ transportation suggest pressures in the ranges of 1,200 psi to 2,200 psi (World Resources Institute, 2008). CO₂ can be transported in its gaseous state if natural gas pipelines are not rated for supercritical CO₂ level pressure, but the transportation economics of doing so are less attractive.

Determining pipeline conversion applicability is a considerable challenge in repurposing natural gas pipelines to CO₂ transport. Identifying candidate conversions is a complex task given that various factors can impact utilization such as region, prices, economic factors and weather trends. Average annual utilizations of many natural gas pipeline segments are often less than the design capacity, despite the fact that they may test capacity levels on individual extremely cold days. Additionally, pipelines are broken into many smaller segments and natural gas can enter (receipt) or exit (delivery) at various points along the route. For example, pipeline A-B-C-D might have a design capacity of 100 tonnes per day, but if 50 tonnes of CO₂ enters at point A and C, and exit at B and D, the total delivered volume is at capacity; however, the overall pipeline is only being utilized, on average, at 50 percent.

Another major hurdle in determining ideal conversion/repurposing candidates is ascertaining the pipe segment's Maximum Allowable Operating Pressure (MAOP) which is a measure of a pipeline's capacity (in pressure terms) and is a function of the pipe's diameter, steel strength, wall thickness and can also be influenced by the population density of the area (see 49 CFR 192.111, 192.5 for additional specifications). The National Pipeline Mapping System (NPMS), tasked with keeping geospatial records of all the pipelines in the U.S., have not traditionally gathered data on MAOP. In 2014, PHMSA moved to add MAOP to NPMS reports through Docket 2014-0092. The proposed guidelines underwent several comment periods and revisions, but as of late 2016 there has yet to be a final ruling. Unfortunately, to date, there is still no database accessible to the public or government regulators that contains MAOP information or the components needed to directly calculate MAOP.

The repurposing of natural gas pipelines to transport CO₂ has been frequently suggested as a way to cut overall CCUS costs (Metz et al., 2005; Oosterkamp and Ramsen, 2008; Seevam et al., 2010; Rabindran et al., 2011; Noothout et al., 2014; Brownsort et al., 2016; Onyebuchi et al., 2017). Several government agencies have even gone as far as providing guidelines for the minimum standards. However, no study has developed a methodology for screening an individual or set of natural gas pipelines for conversion to CO₂ transportation. The aim of this section of the report is to develop a model that can screen an individual pipeline segment, or set of South Louisiana pipeline segments, that are located, generally in the South Louisiana region, but in particular, in the candidate area (between the CF Industries plant and the Paradis field) and could be potentially repurposed for CO₂ transportation purposes.

4.2 REPURPOSING PIPELINES: PRIOR EXAMPLES

Repurposing natural gas and crude oil pipelines is still a relatively new idea, and the details of the few successful projects that do exist are often sparse. But examining these case studies can provide valuable insight to help constrain the pipeline screening process. One of the more contentious conversion projects involves the Tennessee Gas Pipeline Company infrastructure crossing Kentucky (Federal Energy Regulatory Commission (FERC) Docket No. CP15-88). Tennessee Gas petitioned to convert their natural gas pipeline to natural gas liquids while also reversing the flow. The public's main concern stemmed from the pre-1950s method of heating pipe segments before bending which has been shown to cause wrinkle bends. Using the relic bending technique is thought to diminish the strength of the pipe. Ultimately, residents feel the pipe slated for conversion is inadequate for repurposing because the standards and methods used during 1940s construction are inferior to today's standards.

The only example of a natural gas to CO₂ conversion in the U.S. is the West Gwinville Pipeline operated by Denbury Resources. The 16-inch natural gas pipeline spanning 50 miles in Mississippi was purchased by Denbury from the Southern Natural Gas Company (SONAT) and then converted to carry CO₂ for EOR purposes. SONAT had strong interest in selling the pipe system since production had declined thereby lowering its natural gas transport revenue. At the time, operational expenditures had begun to exceed the annual revenue generated from natural gas transportation undermining the profitability of this particular line segment. Revenue decreases could largely be attributable to declining natural gas transportation volumes on this part of SONAT's system. Denbury expected the total project cost of this natural gas pipeline conversion project to be around \$5.2 million.

The National Energy Technology Laboratory (NETL) CO₂ Transport Cost model (2014) allows users to estimate the cost of a new CO₂ pipeline, which in turn, can be compared to the above-referenced natural gas pipeline conversion projects. The Denbury conversion project, for instance, spans 50 miles and is expected to have a transportation capacity of 3.5 million tonnes of CO₂ per year. The NETL Transport Cost model, therefore, estimates that the cost of developing this pipeline, new, would be about \$41 million: a savings of over \$35 million. Thus, at least from this example, the conversion of a natural gas line to a CO₂ conversion project would be beneficial.

Internationally, there are two additional CO₂ conversion projects of interest that may have some domestic applicability. The first is referred to as the Organic Carbon Dioxide for Assimilation of Plants (OCAP) pipeline located in the Netherlands and repurposed in 2004. The OCAP was originally a crude oil pipeline that had been out of service for nearly 25 years before being repurposed to transport CO₂. The 26 inch, 51 mile pipeline transports CO₂ in the gaseous phase at pressures ranging from 101 psi to 304 psi (Global CCS Institute, 2014, Ros et al., 2014) and supplies 300,000 tonnes per year of CO₂ captured from hydrogen production to local greenhouses (van Berkum, 2009).

The second is the No. 10 Feeder located in Scotland: comprised of a 36-inch, 174-mile natural gas pipeline originally constructed for a MAOP of 1,160 psi. With an error margin less than 100 psi, the proposal calls for transporting CO₂ at 493 psi due to the risk of two-phase flow during extreme temperature fluctuations (Element Energy, 2014). Supercritical CO₂ was not needed in either case because the projects' end goal are not EOR but permanent storage. The No. 10 Feeder purchase and conversion is estimated between \$71-102 million, but the cost to build new,

using the NETL Transport Cost Model, is estimated to be around \$217 million (ScottishPower CCS Consortium, 2011). Even though the most economical way to transport CO₂ is in the supercritical phase, companies have found it acceptable to transport in the gaseous phase if repurposing pipelines. Gaseous transport may be an important aspect for repurposing natural gas infrastructure because natural gas is generally transported at lower pressures and thus will increase the number of opportunities for repurposing.

4.3 ESTIMATING PIPELINE REPURPOSING OPPORTUNITIES: DATA AND METHODS

This analysis, following a process similar to the industrial scoping analysis discussed earlier, will focus on Louisiana's southernmost 38 parishes (collectively "South Louisiana"): an area where, as established earlier in this report, most of the large CO₂ sources and sinks are located. The analysis will combine several geospatial datasets to determine which pipelines are ideally situated near both a source (industrial emissions) and sink (storage fields). The list of potential pipelines will be systematically narrowed by each segment's capacity to carry CO₂ and depending upon pipe material. Finally, only pipelines within parishes with declining gas production will be considered as a proxy for declining economic viability as natural gas pipelines (and candidates for conversion). Once a complete list of candidate pipeline segments has been selected, their specifications will be incorporated into the NETL Transport Cost Model to determine the avoided cost of repurposing these natural gas pipelines as opposed to building them as new CO₂ transportation lines.

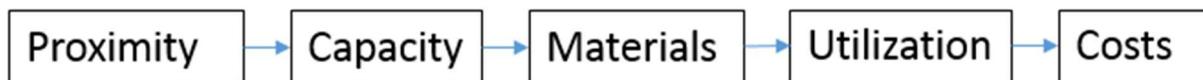


Figure 57. Screening process schematic

4.3.1 Selection by Geographical location

There are 66 industrial CO₂ point sources (sources) in South Louisiana based upon data included in the 2014 USEPA GHG mapping tool (US EPA, 2017a). Industrial sources were chosen due to their high CO₂ concentrations (Summers et al., 2014). A prior study identified 62 potential EOR fields (sinks) (Advanced Resources International, 2006) that were then extracted from the SONRIS GIS Access database based on field IDs (SONRIS, 2017). Natural gas pipelines from MAPSearch (2017) were then selected as candidate segments to link their earlier identified sinks and sources. Figure 58 provides a map identifying all sources, sinks and repurposing pipeline segment candidates.

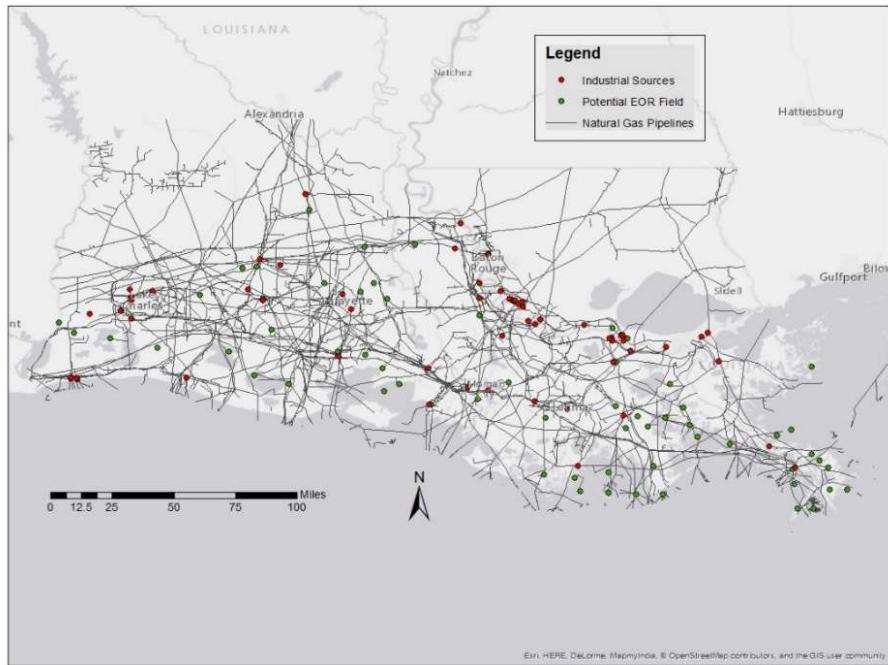


Figure 58. South Louisiana natural gas pipelines, industrial carbon sources and sinks

The average distance between sources and sinks is estimated to be 11 miles which has been used as a screen for evaluating candidate conversion natural gas pipeline segments. This screen implies that only pipelines within 10 miles of a source and sink will be considered in this repurposing analysis. Higher distance thresholds for pipe selection are not plausible since the NETL Transport Cost model suggests it would be more economical to build a new pipeline straight to the closest sink rather than buy and repurpose a pipeline then build an additional 10 miles of interconnecting pipe.

There are a number of candidate segments within five miles of both a source and a sink. However, not all pipelines within the 10-mile buffer make practical sense. The list of potential candidates was systematically narrowed further by: (1) eliminating segments which were integral to a natural gas operator's overall system; (2) were nonsensical (i.e. within the 10 mile buffer but would not provide a useful route); or (3) where the distance needed to tie into the repurposed pipeline was greater or equal to the distance of building a new pipeline straight from source to sink.

4.3.2 Selection by Capacity

MAOP and capacity, as noted earlier, are not reported by pipelines on a line segment basis. Thus, a proxy method of determining capacity and pipeline pressure capabilities, on a per segment basis, is needed in order to assess whether an individual pipeline segment has the ability to move high pressure CO₂. The capacity of a natural gas pipeline segment to transport CO₂ can be calculated by using what is known as the “Ideal Gas Law Equation” given as:

$$PV = nRT \quad (1)$$

Where P = pressure, V = volume, n = the amount of gas (moles), R = universal gas constant, and T = temperature. Equation 1 assumes CO₂ and methane are “ideal gases” and, thus, are interchangeable. While ideal gases are theoretical in nature, the Ideal Gas Law can be used to provide a rough approximation of the amount of CO₂ pipelines can carry (McAllister, 2005). Equation 1 will require proxies for P (MAOP) and n (Capacity) while variables V, R and T are assumed to be constant. Equation 1 can be rewritten as Equation 2 to find a new capacity at a desired pressure:

$$\frac{P_{MAOP}}{P_{new}} = \frac{Capacity_{MAOP}}{Capacity_{new}} \quad (2)$$

Where PMAOP = pressure at original MAOP design, Pnew = desired new pressure, CapacityMAOP = the capacity at designed MAOP, and Capacitynew = capacity at the new desired pressure.

The only information publicly available to calculate the designed MAOP is the outside diameter (or “OD”) of a given pipeline segment.³ Further, a proxy for pipeline-designed MAOP can be inferred based on previously built pipelines. Using applications from the FERC Approved Major Pipeline database, a list was compiled of reported pipeline OD, capacity, and associated MAOP for projects completed during 2009-2017 (FERC, 2017). Linear regression was used to determine there is no a relationship between OD and MAOP.⁴ The resulting average MAOP information will act as the proxy for PMAOP in Equation 2 based on each candidate pipe’s OD.⁵ The lowest recorded value from the FERC MAOP data compilation will be used as Pnew. Also, average pipeline MAOP will be fed into the NETL Transport Cost Model to determine if actual operating conditions differ in cost from the ideal conditions (1,200 psi to 2,200 psi) suggested in the literature (World Resources Institute, 2008).

Total system capacity for a given operator is publicly accessible but is an unhelpful metric for the purposes of studying individual segments. According to 18 CFR 284.13, interstate and major non-interstate pipelines must post design and operational capacity for meter stations on their informational postings website. Segment capacity, generally measured in dekatherms, (dth) (million British thermal units (btu)), or in a few cases thousand cubic feet (Mcf), can be inferred by finding meter stations connecting of interest pipe segments. Operational capacity data gathered from informational postings will act as the proxy for the CapacityMAOP in Equation 2. The Capacitynew can be found by using the FERC MAOP, new desired MAOP and capacity found from informational postings.

Jaramillo et al. (2009) reported the five EOR projects in their study ranging in daily annual CO₂ purchases of 0.6 million tonnes to 11.5 million tonnes. The CO₂ pipelines operated by Kinder Morgan, which have an outside diameter (OD) that vary from 16 inches to 30 inches, have transport capacities ranging from 5,000 tonnes per day to 62,000 tonnes per day. To be conservative, this study only considered pipelines able to sustain an EOR project which would require a given segment’s capacity to be between 12,000 tonnes per day to 62 million tonnes CO₂ per day. Any candidate pipe with a Capacitynew below 12,000 tonnes of CO₂ per day will

³ Pipe OD was gathered from the NMPS (2017) when missing from MAPSearch (2017).

⁴ Summary statistics for the regression are: ($\beta_1=5.62$, t-stat = 1.15, $p = 0.2552$, $R^2 = 0.033$)

⁵ In the event that an unusual OD had no MAOP data from FERC applications (e.g. OD 12.75 in), the lower MAOP of the next higher and lower OD was chosen.

be eliminated from the analysis.

4.3.3 Line Segment by Pipe Characteristic

As previously stated, limited spatial information is available for specific segments. However, gathering and transmission pipe information can be inferred from 2016 PHMSA Annual Reports. Operators are required to report miles of pipe for each material category (steel, cast iron, wrought iron, and plastic), the number of miles for cathodic protection and coatings, and the number of miles by decade installed. The 2016 PHMSA annual reports were searched by operator to find what material the pipes are potentially constructed with, any protections in place, and what decade the pipes were most likely built.

Candidate segments were limited to carbon steel pipelines, constructed after 1950, with cathodic protection and coatings since these pipe materials are viable for high pressure. Since PHMSA annual reports do not contain spatial information, only operators with high percentages of bare steel, cast/wrought iron pipes and pipes installed before 1950, or low percentages of corrosive protections will be eliminated. This resulted in no pipe segments being eliminated from the analysis.

4.3.4 Selection by Natural Gas Production

Detailed flow data, on a per segment basis, is largely unavailable making a per segment utilization analysis difficult. Transmission data can be gathered from the daily deliveries from informational postings; however, operators are only required to keep the last 120 days of deliverability data available to the public, significantly limiting any type of trend analysis. The best proxy that can be developed is to gather parish-level gas production data, at least in Louisiana, is from the LDNR SONRIS database. Using this proxy assumes segments only transport gas produced in their respective parish, which might not be the case for every segment, but gives a general idea of which pipelines might be underutilized. Monthly parish production data was collected from SONRIS from 1977-2016. Individual years were summed and then percent decline was calculated from the difference between gas production during the peak year and 2016.

4.3.5 Cost Calculations

The final set of candidate pipe segments were the ones utilized for cost modeling purposes. The final set of candidate repurposing/conversion segments were incorporated into the NETL (2014) Transport Cost Model in order to estimate the avoided cost of converting the identified segments to CO₂ transport service. The financial and other inputs used in developing transport costs are discussed in greater detail later in the cost effectiveness section of this report.

4.4 PIPELINE REPURPOSING MODELING: RESULTS AND DISCUSSION

4.4.1 Geographical Screen

The repurposing candidate screening process started with 5,112 pipe segments that was reduced to 509 ideally-located segments using a 10-mile buffer. These candidate segments are comprised of 39 operators which collectively span an aerial coverage over 3,234 geographic miles. Once integral and nonsensical segments were removed, the potential list of ideal candidates is reduced to 73 segments spread among 23 operators collectively spanning over 753 miles.

4.4.2 Capacity Screen

Not all FERC applications contained information about MAOP, only about half of applicants report their MAOP. Table 31 shows that most natural gas pipelines approved for construction during 2009-2017 were found to operate at 1,440 psi or less, a significantly lower pressure than what is recommended to transport supercritical CO₂. When the NETL cost model was adjusted to account for the lower MAOP (1,200 psi to 1,400 psi), the cost for constructing pipelines increases substantially compared to the ideal operating conditions (1,200 psi to 2,200 psi).

Table 31. Descriptive statistics, average pipeline reported MAOP (2009-2017)

Outside Diameter (inches)	Average MAOP (psi)	Standard Deviation (psi)	Number of Records
6	750	-	1
8	1,200	-	1
12	750	-	1
16	1,291	312	5
20	920	448	4
24	1,054	380	7
26	1,054	-	1
30	1,434	159	5
36	1,170	167	6
42	1,231	274	8

Specifically, larger volume (5 million tonnes) project operational expenditures (over 30-year period) increased by \$30 million because additional compressors would be needed over longer distances (100 miles), or capital expenditures increased \$3 million because larger diameter pipes would be needed for shorter distances (10 miles). Smaller volume project costs (0.5 million tonnes) were similar for both long and short distances.

The U.S. natural gas infrastructure, constructed during 2009-2017, is generally under-rated (pressure-wise) for transporting CO₂ in the supercritical phase. The compression variation between the suggested upper (2,200 psi) and lower (1,200 psi) limit of supercritical pressures is used to minimize the use of costly compression. This does not necessarily mean the current infrastructure must be ruled out since there are two repurposing options for the pipes that includes either: (1) shorten the distance between compressor stations by increasing the number of compressors; or (2) increase the size of the pipe diameter. The latter of the two options is cheaper but requires a larger upfront capital cost. Another repurposing option, as noted from the case studies, is to transport CO₂ in the gaseous phase. Brownsort et. al. (2016) found that while transporting in the gaseous phase is less economic than transporting in the supercritical phase, it can be more economical than building a new pipeline to accommodate higher pressures. This study chose to operate the candidate pipes in the gaseous phase (P_{new} = 750 psi) given the relatively low MAOP at design.

The list of 73 potential pipe segments was narrowed further after collecting daily natural gas capacity for individual operators from informational postings. A large number of interstate pipeline segments were removed since most are not required to report capacity and thus no information was available. Additionally, some segments had apparently been sold at the time of this analysis and operator information had not been updated in MAPSearch (2017) or the NPMS

(2017).

It is important to note that the ultimate set of selected pipe segments is entirely a function of the afore-discussed screening criteria, which itself is required due to limited data. More accurate data, therefore, may lead to differing results. After eliminating segments without capacity data, the screening process estimates 31 possible natural gas pipeline segments are available for reconversion. After incorporating segment specific CapacityMAOP into Equation 2, the candidate segments' Capacitynew were found to range from 2,700 tonnes per day to 41,000 tonnes per day when operating the segment at the 750 psi gaseous phase pressure. Further, of the 31 selected candidate segments, only 16 segments have the ability to carry enough CO₂ to sustain a higher pressure supercritical CO₂ capture process. These 16 pipeline segments cover 203 miles, and range in size from 6 inches to 30 inches and can collectively carry 359,000 tonnes of CO₂ per day.

While the methodology presented here for calculating CO₂ transportation capacity is a rough approximation, it is assumed to be a conservative estimate for several reasons. First, the 750 psi chosen as the Pnew for all pipelines in Equation 2 is the lowest operating pressure found for natural gas pipelines constructed during the last eight years. Secondly, the use of reported informational postings used as the capacity (CapacityMAOP) are only records of gas flowing passed the meter stations at receipt and delivery points. Meter stations represent the actual, or average, amount of natural gas entering or exiting during a reporting period leaving open the possibility of potential additional capacity. The only step in the process where there is the potential for inflated estimated capacity values is in assuming methane and CO₂ are ideal gases. A possible improvement to this method would be to use the van der Waals equation which includes correction factors to account for the differences in molecular structures of specific gases. However, the gas specific equation is cumbersome to utilize and has its own methodological issues and is not necessary to generate first-order estimates.

4.4.3 Selection by pipe material characteristic

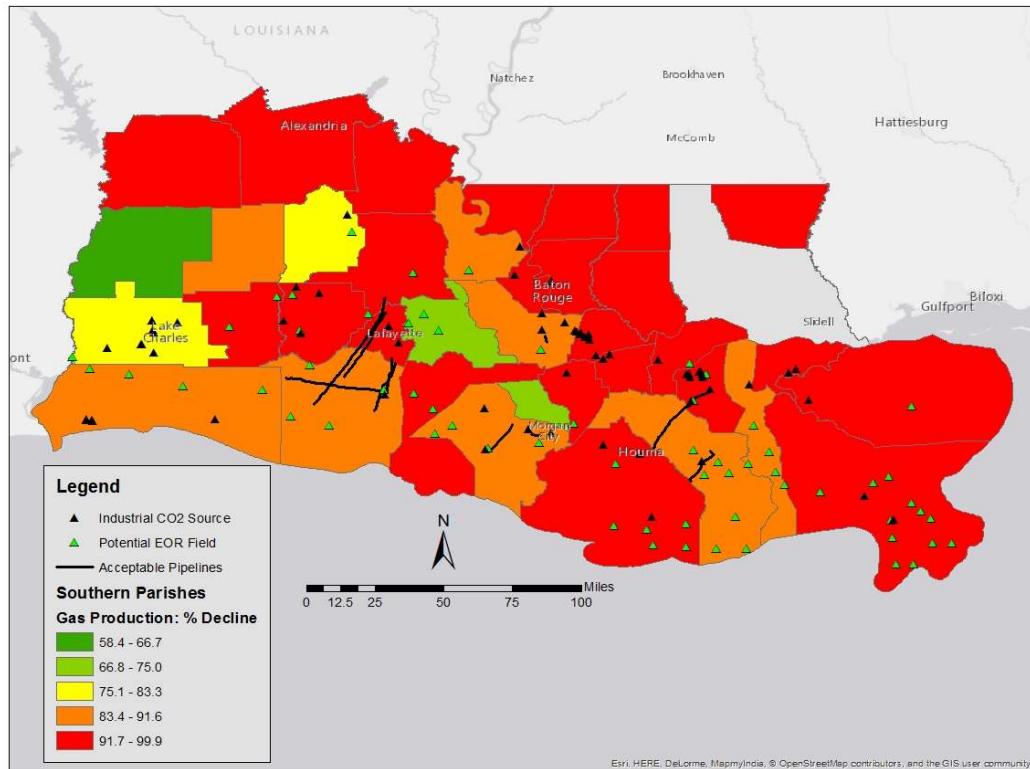
The PHMSA annual reports indicate that most all companies who operate the candidate pipeline segments report that their pipes are cathodically protected and coated. Further, the majority of these companies report that these pipe segments were constructed during the 1950-70s, except for portions of SONAT and Texas Gas Transmission infrastructure which both date back to at least the 1940s. Older pipelines (pre-1950) were subject to the relic pipe bending process which results in wrinkle bends. However, no operator had a majority of pipe predating 1950 and, in addition, any chosen pipe segment would need to be thoroughly inspected before conversion. Thus, no further reduction in the number of candidate pipe segments was required. General information regarding a candidate operator's overall infrastructure can be found in Table 32.

Table 32. PHMSA pipeline material and vintage characteristics (2016)

Operator	Pre-1950, unknown (percent)	Cathodic Protection and Coating (percent)	Carbon Steel (percent)
ANR Pipeline Company	--	100%	100%
Boardwalk Louisiana Midstream	--	100%	100%
Bridgeline Holdings L.P.	10.0%	100%	100%
Columbia Gulf Transmission Comp	--	99.9%	100%
Florida Gas Transmission Company	0.4%	100%	100%
Natural Gas Pipeline Company of America	--	100%	100%
Southern Natural Gas Company	12.2%	100%	100%
Texas Eastern Transmission Corp	3.3%	100%	100%
Texas Gas Transmission	32.1%	100%	100%

4.4.4 Natural gas production screen

Gas production for the 38 parishes of South Louisiana have all declined at least 58 percent since peak production. Only four parishes (Beauregard, St. Martin, Evangeline and Calcasieu) have seen declines less than 80 percent, while 32 have declined over 85 percent. All 16 candidate pipe segments are located within parishes which have declined at least 83 percent from peak production which means all segments are potentially being underutilized and no further reduction in candidate segments is required. See Figure 59 for final natural gas repurposing candidates.

**Figure 59. Ideal natural gas pipelines for CO₂ repurposing**

4.4.5 Cost calculations

After summing the length of pipes for each OD and modeling the cost using the NETL cost model, the 203 miles of pipeline were found to cost \$168.85 million in capital expenditures to construct brand new. The cost per miles is about \$830,000. The segment lengths and cost of each OD is presented in Table 33.

Two case studies were examined as a test on the cost estimates in this work. Denbury Resources and the No. 10 Feeder repurposing projects are estimated to have saved 88 percent and 68 percent on capital expenditures, respectively. Given the modeled cost of building the 16 identified pipe segments in South Louisiana, companies could potentially save between \$114 and \$148 million dollars on capital expenditures by repurposing. Of course, there is large uncertainty in the potential savings given the small number of conversion projects and the limitations of modeled costs of building new pipelines. Thus, a range of estimates was more appropriate than the use of a point estimate for the capacity and cost of repurposed pipelines.

Table 33. Estimated ideal candidate replacement costs new

OD (inches)	Length (miles)	Cost to build new (\$)
6	12.5	\$3,940,000
12	45.7	22,400,000
14	5.5	4,350,000
16	2.5	2,560,000
18	46	33,500,000
20	17.2	16,200,000
22	27.8	26,800,000
26	13.7	17,500,000
30	31.8	\$41,600,000
Total	202.7	\$168,850,000

4.5 CONCLUSIONS

This pipeline repurposing analysis found a general lack of information specifying segment MAOP, year installed, material and capacity. Pipeline design specifications are important information, not just for deciding which pipelines can be repurposed, but for land managers, emergency response personnel and energy industry analysts. Further, inferring information about MAOP based on OD or capacity was not found possible using linear regression techniques. Instead, average values were used to approximate those associated with the pipeline segments under investigation.

Given the constraints of the methods, only 1.4 percent of the 5,112 pipeline segments in South Louisiana are co-located near both a sink, a source and are likely repurposing candidates. Of the candidate conversion segments with information, only about half are able to carry enough CO₂ to sustain a typical EOR project. The 16 pipe segments identified in this analysis represent less than one percent of Louisiana's total natural gas infrastructure. More importantly for this overall study is the fact that most of these potential segments are outside of the area needed for the two prime source/sink locations identified earlier in this analysis: the CF Industries plant and the

Paradis field. Thus, for the balance of this study, new transportation alternatives will have to be considered.

5 CAPTURE, TRANSPORT AND STORAGE ECONOMIC FEASIBILITY ANALYSIS

5.1 INTRODUCTION

A break-even cost analysis was conducted to estimate the potential effectiveness of carbon capture, transportation and storage for the candidate South Louisiana industrial facility (CF Industries). The candidate site is a very large ammonia producer; in fact, this particular facility in South Louisiana has seen several capacity expansions over the past decades and, at 4.3 million tonnes per year of production capacity, is one of the largest ammonia facilities in the world. This analysis is intended to define the break-even cost of developing a CCS project for these source/sink locations.

Most ammonia facilities in North America reform natural gas into hydrogen (H_2), carbon monoxide (CO) and carbon dioxide (CO_2) (Worrell et al., 2000). Unconverted CO_2 is then shifted to produce additional H_2 and CO_2 . The optimal hydrogen-to-nitrogen ratio in this production process requires a relatively high level of CO_2 , thus a significant amount of CO_2 is often captured, post-shift, and reused to produce urea. The urea, in turn, is synthesized by reacting ammonia with CO_2 . This integral use and production of high-quality CO_2 in the ammonia production process makes this particular industrial process an attractive carbon capture application.

Ammonia is a concentrated source of nitrogen and basic feedstock for nitrogen products. It is synthesized from hydrogen sources (natural gas or coal), steam and air.

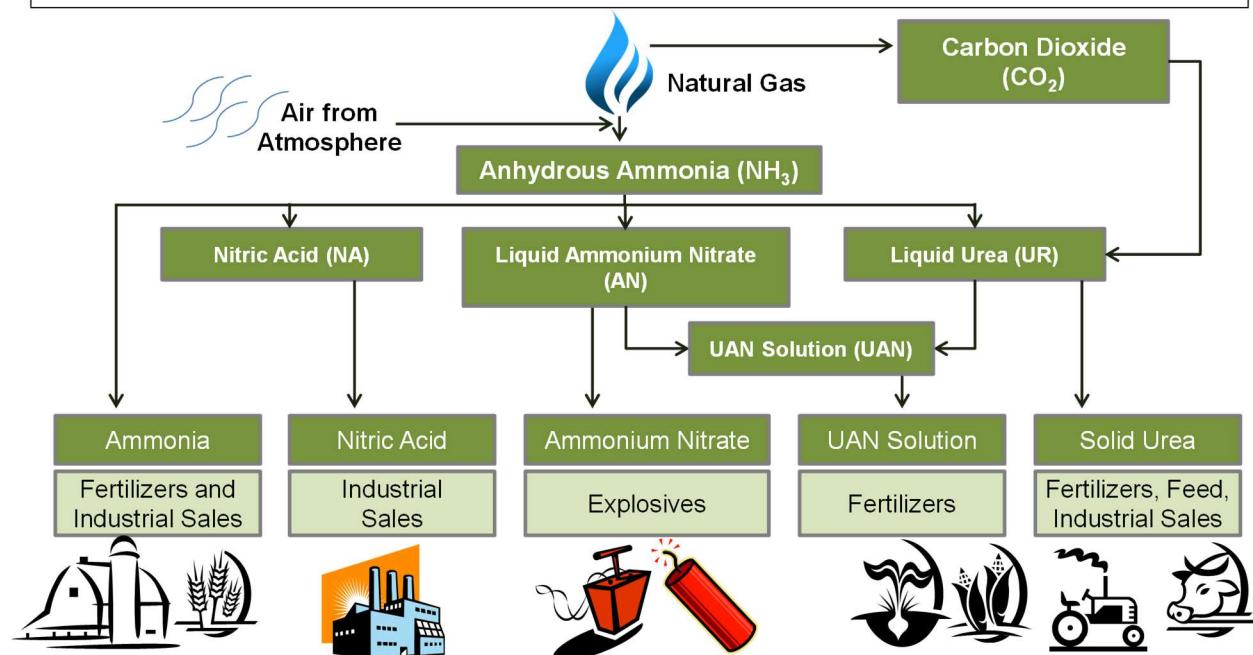


Figure 60. Ammonia production process
Source: Author's construct from diagram at Potash, 2013.

Cost estimates in this analysis are the total of fixed and variable operating costs associated with the capture, transport and storage of CO_2 . No additional commercial opportunities are examined,

such as the use of CO₂ for EOR. Thus, the analysis is strictly cost-related in nature, negating the need for developing any form of net cash flow or profitability (internal rate of return (IRR)) analysis. Total costs and unit costs (\$ per tonne) of CO₂ basis are provided. These estimates will determine the degree to which an individual South Louisiana industrial CCS project can be cost-effective given certain levels of financial support. The final estimate can be used to compare to a variety of financial support mechanisms like cap-and-trade style credits, or other tax incentive opportunities outlined in the 45Q provisions that are part of the federal tax code (26 CFR 45).

Three break-even cost modules have been developed in this analysis corresponding to each CCS function (capture, transport, storage). All cost estimates are adjusted for inflation and are reported in 2017 dollars. In some instances, cost streams that arise over longer periods of time will be discounted and provided on a net present value (NPV) basis. All three models rely heavily on input data from prior NETL CCS reports and analyses, each of which will be discussed in greater detail within each of the subsections below. Cost estimates provided here are specific to the CF Industries ammonia plant but can be generalized to other high purity carbon sources in South Louisiana.

5.2 CAPITAL COST CARRYING FACTOR

The capital costs of a large carbon capture project will be amortized over time, such that some form of annual non-cash credit can be applied to earnings (income) to account for the asset's depreciation. Typically, a "pro forma" analysis of these types of investments are usually performed in order to assess its financial IRR. At this point in time, and for purposes of this analysis, all CCS investments are considered to be "non-revenue generating;" that is, the investments are not being made to facilitate new or expanded production or a diversification into a new line of production. These investments represent a cost with no potential income generation. The one exception that can arise in a CCS project would be if the environmental attributes (emissions reductions) could be sold in some form of credit market (like a cap-and-trade market) or if the carbon capture could be sold for commercial activities such as EOR. As noted, neither commercial opportunity is being considered in this feasibility analysis. Thus, the use of a traditional pro forma financial analysis is probably not the appropriate way of examining the true financial implications of making CCS investments.

Instead, this feasibility study uses a capital carrying factor to levelized the annual capital costs associated with this particular capture opportunity. A capital carrying factor is often expressed in a percentage basis and represents the fixed annual share of capital that has to be recovered from a particular investment in order to assure a minimum fixed rate of return. The carrying factor, when multiplied by the total project capital investment (which is \$95 million in this ammonia production example), defines the annual capital cost recovery amount that will be needed for the project to "break-even." Summers, et.al. (2014) (hereafter referred to as "Summers-NETL") utilized a capital carrying cost factor in order to develop a break-even price. This carrying factor, however, suffered from a number of challenges, in general, and specific to a Louisiana CCS application. This feasibility study utilizes a carrying factor that differs from the Summers-NETL estimate in a number of ways including:

- The carrying factor has been updated for the Tax Cut and Jobs Act of 2017 which lowers federal corporate income taxes to 21 percent.

- The carrying factor utilizes a Louisiana-specific average corporate income tax rate of five percent.
- Some cost of capital assumptions have been updated to account for dramatic changes in capital markets, particularly the substantial decreases in interest rates, and more specifically, corporate debt rates. CF Industries, for instance, reports incremental coupon rates on its corporate debt at around three percent, not the eight percent that was used in the Summers-Netl analysis. Further, an updated return on equity of 12 percent is used rather than the exceptionally high 20 percent assumption used in the Summers-Netl analysis. The assumed 50-50 percent capital structure, however, has been maintained.

These changes overall, lower the Summers-Netl capital cost carrying factor from a high rate of 15.2 percent rate to a more reasonable rate of 9.6 percent.

5.3 CARBON CAPTURE COSTS

One of the challenges with carbon capture is its high upfront capital requirements. However, the capital costs for industrial applications can be more competitive than those associated with coal-fired electric power generation facilities. Further, high purity industrial sources often require even fewer capital costs than lower purity sources arising from industrial processes such as refinery hydrogen and cement.

Summers-Netl developed an extensive set of greenfield (new) and retrofit cost estimates for nine different industrial applications including: ethanol, ammonia, natural gas processing, ethylene oxide, coal-to-liquids, gas-to-liquids, refinery hydrogen, metals and cement. These estimates are developed of a standard plant design (for each industrial process) and can be thought of as a “typical” facility for each industrial process (hereafter, this will be referred to as a “typical plant” or “reference plant”). Cost estimates utilized in the analysis appear to be developed from a literature survey of the technical and trade literature. The Summers-Netl study finds that low-purity processes require additional CO₂ separation and purification investments. High purity processes, like ammonia manufacturing, do not require such additional capital.

The CO₂ coming from the high purity ammonia process is assumed to be captured from a stripping vent. The high-quality CO₂ limits the necessary capital investment to a handful of items that are itemized below in Table 34. While these capital investments are limited, relative to a post-combustion or lower-quality capture process, they are still considerable and are comprised of a number of major capital upgrades.

First, the facility will need additional duct work and piping to accommodate the new capture process. The Summers-Netl study estimates these costs from its literature survey at \$1.6 million in 2011 dollars (equipment and materials costs only) for its reference plant. These estimates are adjusted for 2017 inflation using the “petrochemical manufacturing” price index that is part of BLS’ producer price index (PPI) (PCU 325110325110). The compressor cost component was adjusted using the “air and gas compressor manufacturing” PPI (PCU333912333912). Current period 2017 estimates for these costs for a typical plant are \$901,000 (Table 34). Adjustment of these costs for the scale needed for CF Industries increases to \$11.4 million in 2017 dollars (Table 35).

The largest capital component needed in the ammonia capture process is associated with the on-

site compression requirements and intercoolers. These costs, in 2017 dollars, are estimated to be \$18.9 million for the reference plant (Table 34), and increase to \$239.3 million for a capture project that would be comparable to accommodate a capture project that is as large in size as a CF Industries application (Table 35).

The remaining capital costs associated with an ammonia capture project are those associated with the cooling water chiller unit and a host of collective investments that can be generally referred to as the “balance of plant” costs (instrumentation, measurement, site buildings, utilities, etc.). The Summers-NETL study estimates these investments (along with the cooling water chiller) at \$3.1 million in 2011 dollars (Table 34). The updated 2017 balance of plant investments (including cooling water chiller) are for a CF Industries size application collectively around \$21.4 million (Table 35).

Table 34. Original and updated Summers-NETL reference ammonia plant, fixed capital costs

	Total Cost		Unit Cost (\$/tonne)	
	(2011 \$)	(2017 \$)	(2011 \$)	(2017 \$)
Capital Expenditures - CO2 Removal and Compression Costs				
Duct work/piping	\$ 1,645,200	\$ 901,380	\$ 4.22	\$ 2.31
CO2 compression including intercoolers	16,833,600	18,944,280	43.20	48.62
Cooling water chiller unit	1,135,200	621,959	2.91	1.60
Balance of plant (instruments, site, bldg.)	1,960,800	1,074,293	5.03	2.76
Total	\$ 21,574,800	\$ 21,541,912	\$ 55.37	\$ 55.29

Table 35. Estimated ammonia plant capture capital costs, CF Industries scale (\$2017)

	Total Cost (2017 \$)	Unit Cost (2017 \$/ tonne)
Capital Expenditures - CO2 Removal and Compression Costs		
Duct work/piping	\$ 11,386,923	\$ 2.31
CO2 compression including intercoolers	239,318,559	48.62
Cooling water chiller unit	7,857,060	1.60
Balance of plant (instruments, site, bldg.)	13,571,285	2.76
Total	\$ 272,133,827	\$ 55.29

Total capital costs for an ammonia capture project are estimated to be \$21.6 million in 2011 dollars using the Summers-NETL Study. Updating these costs for inflation and new financial drivers (interest costs, etc.) leads to total ammonia capture project costs of \$21.5 million, or \$55.29 per tonne in 2017 dollars for the study’s reference plant. The 2017 total ammonia capture costs for a project in the Louisiana industrial corridor, is estimated to be \$272.1 million, or \$55.29 per tonne.

A project of this nature will also have a number of variable operating expenses. These variable expenses, however, pale in comparison to the capital costs discussed above, particularly the

compression costs. The variable costs developed by Summers-NETL study were used as the starting point for this analysis. The first step is to update these Summers-NETL ammonia capture variable costs for inflation. Table 36 provides the original and updated (inflation-adjusted) variable costs for the reference plant.

Table 36. Original and updated Summers-NETL reference ammonia plant, variable operating costs

	Total Cost		Unit Cost (\$/tonne)	
	(2011 \$)	(2017 \$)	(2011 \$)	(2017 \$)
Variable Expenses - Annual O&M/Operating Expenses				
Fixed O&M				
Labor Expense (O&M; A&G)	\$ 1,007,000	\$ 551,720	\$ 2.58	\$ 1.42
Property Taxes and Insurance	432,000	1,950,550	1.11	5.01
Variable O&M				
Variable O&M (Non-labor materials expense)	2,158,000	2,077,319	5.54	5.33
Water, other utilities	77,000	74,121	0.20	0.19
Electricity	2,487,000	2,177,558	6.38	5.59
Owners Costs (start-up and financing)				
	5,199,000	5,199,000	13.34	13.34
Total	\$ 11,360,000	\$ 12,030,267	\$ 29.16	\$ 30.88

The second step in the analysis was to: (a) adjust the costs for the much larger operating scale comparable to the CF Industries facility in Donaldsonville; and (b) adjust the costs for a number of location-specific factors. First, property taxes were adjusted to account for the ten-year ITEP that waives property taxes on major industrial capital investments for the first ten operating years. Second, parish-specific property taxes were estimated using specific depreciation and assessment ratios used by the Louisiana Tax Commission (LTC). Lastly, region specific industrial electricity rates were used to estimate the variable electricity costs of running the on-site compression.

Table 37 provides a summary of the variable expenses estimated to be associated with operating an ammonia capture project in the Louisiana industrial corridor. Annual variable operating costs are driven by a few large categories. First, property and ad valorem taxes account for about 27 percent of total annual operating costs (\$24.6 million). These costs are actually relatively lower in Louisiana than in other places around the U.S. since a facility of this nature would be eligible, and likely receive, a ten-year tax exemption offered to all new manufacturing activities. Second, non-labor variable expenses, that includes utilities, account for more than half of a large-scale ammonia capture project (CF Industries scale) at around \$54.7 million per year.

Table 37. Estimated ammonia plant capture operating costs, CF Industries scale (\$2017)

	Total Cost (2017 \$)	Unit Cost (2017 \$/ tonne)
Variable Expenses - Annual O&M/Operating Expenses		
Fixed O&M		
Labor Expense (O&M; A&G)	\$ 6,969,749	\$ 1.42
Property Taxes and Insurance	24,640,826	5.01
Variable O&M		
Variable O&M (Non-labor materials expense)	26,242,271	5.33
Water, other utilities	936,355	0.19
Electricity	27,508,565	5.59
Owners Costs (start-up and financing)	5,199,000	1.06
Total	\$ 91,496,767	\$ 18.59

Total capture costs are the sum of the capital and annual operating expenses. Table 38 summarizes these costs for a CF Industries scale facility, and compares them to the 2011, and 2017 total operating costs for a reference plant included in the original Summers-Netl capture cost study. Total capture costs in the Summers-Netl model are estimated to be \$32.9 million, or \$84.53 per tonne, in 2011 dollars. Inflation and other updates to these cost figures leads to a 2017 cost estimate of \$33.6 million or \$86.16 per tonne. Total capture costs for an ammonia facility in the Louisiana industrial corridor, at a CF Industries scale, are estimated to be \$363.6 million (2017 dollars) or \$73.88 per tonne (2017 dollars).

Table 38. Estimated ammonia plant capture operating costs, CF Industries scale (\$2017)

	Total Cost			Unit Cost (\$/tonne)		
	Summers-Netl		CF Industries	Summers-Netl		CF Industries
	(2011 \$)	(2017 \$)	Scale (2017 \$)	(2011 \$)	(2017 \$)	Scale (2017 \$)
Capital Expenditures	\$ 21,574,800	\$ 21,541,912	\$ 272,133,827	\$ 55.37	\$ 55.29	\$ 55.29
Variable Expenses	\$ 11,360,000	\$ 12,030,267	\$ 91,496,767	\$ 29.16	\$ 30.88	\$ 18.59
Total Capture Cost	\$ 32,934,800	\$ 33,572,179	\$ 363,630,593	\$ 84.53	\$ 86.16	\$ 73.88

5.4 CARBON TRANSPORTATION COSTS

Transport costs can be estimated using a recently-developed carbon transportation model developed by NETL (Grant, et. al., 2014). This model is mathematical in nature and solves for CO₂ transportation costs given certain input assumptions. The model configures a pipeline system on a “point-to-point” basis and is driven primarily by the large upfront capital investments required for the system that include pipeline materials and installation costs, surge tank investments, a pipeline control system and various booster pumps (that can be selected as a

user input). O&M costs are driven primarily by the electricity costs needed to run the booster pumps. Compression costs are not included in the transport model, but instead, as noted earlier, are included as one of the predominant capital investments required in the capture process. Any additional compression costs that may be needed at the storage location, due to pressure drops that arise within the transportation system (moving from point A to point B), are included in the storage cost estimation process that will be discussed in the following subsection.

The NETL transport model also includes a number of assumptions regarding project finance that include accounting for an annual depreciation allowance, financial cost rates (debt, equity), capital structure, and taxes. The same financial assumptions utilized for the capture model were utilized in the transport model which differ considerably from the default values utilized in the report accompanying the NETL transport cost model.

The NETL model assumes that CO₂ enters into the pipeline system at 2,200 psig which means that the CO₂ will travel through the assumed point-to-point system in a dense liquid phase. The pipeline segment that would be needed for this particular project, if developed, would need to run from the CF Industries plant near Donaldsonville, Louisiana to the Paradis field: a distance of 53.9 kilometers or 38.8 miles. This distance was calculated along a path that was deemed the closest between the two points, but one that traversed across as much existing South Louisiana pipeline right-of-way (ROW) as possible and can be thought of as an estimate of the ROW-distance between the two locations, and not a “straight line” or “point-to-point” distance.

The capital costs associated with the purchase of the pipe is perhaps the single largest capital cost associated with developing a CO₂ pipeline. Pipeline diameter and length are important determinants of overall pipeline costs. Further, CO₂ pipelines often have considerably thicker wall thicknesses relative to natural gas pipelines, given their higher operating pressures as discussed in an earlier section of this report. The NETL transport cost model uses an iterative process to estimate both: (a) minimum pipeline diameters; and (b) any required booster pumps to sustain pressures over long distances or those with changing elevations.

Lastly, once the NETL model calculates minimum pipeline diameters, it has three different modules that can be used to estimate pipeline capital costs. These three different modules are based upon differing specifications from three different academic models authored by Parker (2004), McCoy and Rubin (2008), and Rui, et.al. (2011). A comparison of the results from these three formulations relative to observed values for three recently developed CO₂ pipelines is provided in the report accompanying the NETL transport model. The comparative analysis shows that the Parker specification leads to estimated transportation costs that are relatively high to observed values, whereas the McCoy and Rubin and Rui, et. al. specifications lead to estimated costs that are below observed values. Both of the lower-than-observed specifications yield estimate that are close to one another, with the McCoy and Rubin specification being the higher of the two, and thus, can be very roughly thought of as a mid-range estimate relative to the three specifications, not the observed values.

The South Louisiana candidate capture project CO₂ transport costs is provided in Table 39. The NETL transport model estimates that a 12-inch pipeline system, spanning 32.8 miles and one booster pump, will be needed for this application. Total transportation capital costs for this system are estimated at \$26 million, or \$5.29 per tonne in 2017 dollars. Total annual O&M costs are estimated to be \$1.4 million or \$0.29 per tonne in 2017 dollars. This leads to total CO₂ transportation costs, specific to this particular application, of \$27.4 million, or \$5.57 per tonne in

2017 dollars.

Table 39. Estimated South Louisiana capture project CO₂ transportation costs

	Total Cost (2017 \$)	Unit Cost (2017 \$/ tonne)
Capital Expenditures		
Materials	\$ 4,150,260	\$ 0.84
Labor	8,046,132	1.63
ROW-Damages	2,798,338	0.57
Miscellaneous	5,824,865	1.18
CO ₂ Surge Tanks	1,510,496	0.31
Pipeline Control System	135,799	0.03
Pumps	3,556,881	0.72
Total Capital Expenditures	\$ 26,022,771	\$ 5.29
Variable Expenses - Annual O&M/Operating Expenses		
Pipeline O&M	\$ 287,171	\$ 0.06
Pipeline related equipment and pumps O&M	173,439	0.04
Electricity costs for pumps	947,842	0.19
Total Variable Expense	\$ 1,408,452	\$ 0.29
Total Transportation Cost	\$ 27,431,223	\$ 5.57

5.5 CARBON STORAGE AND MONITORING COSTS

Storage and monitoring costs also use the formulations and parameters included in the NETL Saline Storage Cost Model (Grant, et. al., 2014, hereafter “NETL Storage Model”) to estimate the costs of developing the Paradis field for CO₂ sequestration and storage. This NETL storage model estimates the costs, given certain user inputs, for the permanent storage of CO₂ in a saline aquifer. The primary costs associated with this model are associated with the compliance requirements for storage wells as required by the EPA. These storage regulations are enumerated under the EPA’s UIC Program regulations for Class VI injection wells, which are authorized by the SDWA. Further, any storage facility of this nature must also comply with Subpart RR of the Greenhouse Gas Reporting Rule authorized by the Clean Air Act.

The underlying structure of the NETL storage model was developed from a combination of prior EPA analyses as well as those conducted by NETL. The cost of drilling and equipping an injection well are taken from the 2006 API-Joint Industry Association Survey. NETL notes in its 2014 report accompanying the Storage Model, that some of these data has been supplemented from “conversations with industry personnel while at conferences.”

The NETL Storage Model utilizes a number of fixed generic storage locations across various producing basins in the U.S. including the Illinois, East Texas, Williston, and the Powder River Basin. This feasibility analysis will utilize the East Texas region formulation. This analysis will also utilize the “base case” model parameters included in the model formulation.

Total injection and storage costs for an ammonia capture project in the Louisiana industrial corridor are provided in Table 40. Total injection and storage costs are estimated to be \$47.1 million, or \$9.56 per tonne in 2017 dollars.

Table 40. Estimated South Louisiana capture project CO₂ injection and storage costs

	Total Cost (2017 \$)	Unit Cost (2017 \$/ tonne)
Capital Expenditures		
Compression OPEX	\$ 13,379,850	\$ 2.72
Equipment for fluids (annualized lease)	23,761,920	4.83
Equipment for water (annualized lease)	7,981,242	1.62
Total Capital Expenditures	\$ 45,123,012	\$ 9.17
Variable Expenses - Annual O&M/Operating Expenses		
Compression OPEX	\$ 701,897	\$ 0.14
Equipment for fluids (annualized lease)	229,024	\$ 0.05
Equipment for water (annualized lease)	233,920	\$ 0.05
Annual O&M; workovers	765,952	\$ 0.16
Total Variable Expense	\$ 1,930,793	\$ 0.39
Total Injection Cost	\$ 47,053,804	\$ 9.56

5.6 TOTAL CCS COST ESTIMATES

Table 41 estimates the break-even price for CO₂ capture, transportation and storage in South Louisiana using the CF Industries ammonia plant as the carbon source, and the Paradis field for permanent storage. The overall break-even price is \$89.01 per tonne in 2017 dollars. The capital costs associated with the development of the capture, transportation and storage investments accounts for the majority of the total break-even costs. The O&M costs are a much smaller share of overall costs (22 percent). The majority of the costs (83 percent) are associated with CO₂ capture.

Table 41. Estimated total integrated project CCS costs, CF Industries scale

	Total Cost (2017 \$)	Unit Cost (2017 \$/ tonne)
Capital Expenditures		
CO2 Capture	\$ 272,133,827	\$ 55.29
CO2 Transportation	26,022,771	5.29
CO2 Injection and Storage	45,123,012	9.17
Total Capital Expenditures	\$ 343,279,609	\$ 69.74
Variable and Operating Expenses		
CO2 Capture	\$ 91,496,767	\$ 18.59
CO2 Transportation	1,408,452	0.29
CO2 Injection and Storage	1,930,793	0.39
Total Variable Expense	\$ 94,836,012	\$ 19.27
Total Injection Cost	\$ 438,115,621	\$ 89.01

While these costs, on per unit basis, are high, they are still lower, on a per unit basis, to the Summers-NETL reference cost of \$86.16 per tonne when the estimates are converted to \$2017 dollars. Thus, a large ammonia capture project in South Louisiana is likely more competitive than other reference-style projects around the U.S. but is still not cost-effective enough to be supported by a 45Q tax credit of \$50 per tonne. The addition of another \$15.13 per tonne in transport and storage costs simply drives the total integrated costs of \$89.01 per tonne to a level that is too high to be supported without additional financial support or some alternative financial support mechanism like a larger revenue stream from an operation integrated with enhanced oil recovery or EOR. A cost-effectiveness analysis of an EOR-integrated project is beyond the scope of this project and includes a number of different risks and costs that also may not be supportable under current economic conditions.

6 CCS PUBLIC PERCEPTION ISSUES

6.1 INTRODUCTION

Public perception about the development of CCS projects will be highly influenced by the actions of stakeholder groups that represent a range of individual, business, industrial and government interests. Louisiana is a small state, with a population of about 4.6 million and a highly concentrated set of stakeholder interests. This section is comprised of two parts. The first identifies the stakeholder groups that operate in Louisiana and will likely influence CCS project development success. This section is not intended to be a comprehensive list of all stakeholder groups, but rather those more likely to influence CCS-related development. The second part of this section provides a discussion of the factors likely to influence CCS development in Louisiana. The list of “influencing factors” was developed from a comprehensive review of over a decade’s worth of academic research on CCS adoption. Most of this research has been survey-based or utilizes concentrated focus groups. The analysis describes and defines each factor, and then discusses its importance for Louisiana-specific CCS adoption.

6.2 LOUISIANA STAKEHOLDERS AND INTERESTS

6.2.1 Industrial interests

Louisiana’s energy manufacturing industries are dominated by large petrochemical firms and refineries. Major petrochemical firms operating in the state include Axial, PPG, Dow, BASF, CF Industries, Honeywell, Sasol, to name a few. Collectively, the industry is represented by the Louisiana Chemical Association (LCA). The LCA is a trade association founded in 1959 and designed to promote a positive business climate for chemical manufacturing and ensure long-term economic growth for its 63-member companies located at over 100 sites across Louisiana.

The LCA is governed by a board of directors that represents 17-member companies. These board members are primarily individual LCA plant managers or divisional vice presidents. The LCA is located in Baton Rouge and has a full-time, professional staff with experience addressing overall industry, environmental, health, safety, security, and legal/government affairs issues. The LCA represents its members before state executive agencies, the Governor’s office, the Legislature and its various committees, and, in some instances, intervenes in federal and state judicial proceedings around the state. The LCA is also very active at the local and parish level and engages local communities in a number of different ways, including the use of community advisory boards.

Utilities represent the other major industrial group in Louisiana that will likely have a considerable interest in CCS issues. Louisiana is comprised of three major publicly-traded investor-owned utilities (IOUs) as well as 11 rural cooperative and 20 municipal utilities (Louisiana Public Service Commission [LPSC], 2019 and LDNR, 2019). The investor-owned utilities, which own the overwhelming share of the state’s power generation, are perhaps the most interested in CCS issues, and, as will be discussed later, have played a large role in developing a number of Louisiana statutes facilitating the design and regulation of in-state CCS. Louisiana has three major IOUs: Entergy Corporation; CLECO; and AEP-SWEPCO. All three have coal fired generation and would likely have some interest in exploring more CCS-related options and alternatives in Louisiana.

In Louisiana, Entergy Corporation is located throughout the southern half of the state, generally south of the I-10/I-12 corridor as well as certain portions in the northeast corner of the state. Overall, the company serves 2.9 million customers across five different jurisdictions with an operating company responsible for providing service in each location: Louisiana (Entergy-Louisiana); Texas (Entergy-Texas); Arkansas (Entergy Arkansas); Mississippi (Entergy Mississippi); and the City of New Orleans (Entergy New Orleans). Historically, Entergy's power generation resources have been developed and operated to serve the entire "system" not just one particular state or operating company. Entergy's power generation fleet is heavily dominated by natural gas and nuclear. The company does own one, older coal facility located in Westlake, Louisiana with a capacity of 385 MW, which represent a significant share of the company's overall fuel mix.

CLECO, formerly known as the "Central Louisiana Electric Company" operates primarily in the central part of the state, with an additional service territory in the south Acadiana region and a few of the parishes on the northern part of Lake Pontchartrain. The company serves over 288,000 retail customers across the state. CLECO's fuel mix includes high share of coal-fired generation relative to other Louisiana utilities. CLECO, in fact, developed and operates the last coal-fired generation facility constructed in Louisiana.

AEP-SWEPCO is an affiliate of American Electric Power (AEP) which is headquartered in Columbus, Ohio and is one of the larger utilities in the U.S. SWEPCO, for short, serves over 230,000 customers in the northwestern part of the state, primarily in the greater Shreveport area. Like CLECO, SWEPCO owns (directly or jointly) a number of coal-fired generation facilities throughout the state, and in east Texas. Most of these facilities utilize regionally-mined lignite.

6.2.2 Industry interests

The state's oil and gas interests are represented by two main trade association. The first is the Louisiana Mid-Continent Oil and Gas Association (LMOGA) which represents what it characterizes as the "major" vertically-integrated oil companies. Over time, this membership has expanded to include most of the major natural gas and petroleum pipeline companies operating in the state. LMOGA represents its member companies across the entire oil and gas value chain including exploration and production, refining, transportation, marketing and mid-stream companies. LMOGA has over 80 members that include major pipeline companies, but also firms that provide support services to vertically integrated oil and gas operations such as environmental and safety consultants, regulatory consultants, law firms, and other equipment and service providers.

LMOGA is likely to be an important stakeholder in the development of CCS-related projects for a number of reasons. First, LMOGA members include the vertically integrated oil companies that have been producing in Louisiana since the turn of the last century. These members have considerable sub-surface experience in Louisiana and will be familiar with the opportunities to inject and store carbon in legacy reservoir-based locations. Second, LMOGA members include many "mid-stream" companies that specialize in storage and transportation services, particularly pipeline transportation. These companies will likely have considerable interest in new business opportunities in underground carbon storage and transportation. Third, LMOGA has a number of members that specialize in government affairs, legal issues, and safety and environmental consulting that can bring considerable experience and perspective to potential CCS projects.

The second major oil and gas trade association in Louisiana is the Louisiana Oil and Gas

Association (LOGA) which represents independent oil and gas companies, particularly those focused on exploration and production activities. LOGA members include a large number of service companies that support independent oil and gas activities in on-shore and off-shore Louisiana. LOGA members include firms already engaging in certain types of CO₂ recovery and usage activities, particularly those associated with EOR. Examples of these companies that are utilizing carbon in their operations include Denbury Resources (transport provider and EOR developer) and Hilcorp (EOR developer).

6.2.3 Government interests

There likely two main state executive agencies that will have a meaningful and direct interest in CCS activities: the Louisiana Department of Natural Resources and the Office of Conservation. LDNR ensures that the state's natural resources are used in a responsible and sustainable fashion. There are a number of divisions within LDNR that have certain policy or regulatory functions that will influence CCS and/or can help to facilitate CCS projects.

The first office of importance within LDNR is the "Office of Technology Assessment," which is the technical and analytic arm of the Office of the LDNR Secretary. This office and its director, serves as the interface between the U.S. Department of Energy and the State of Louisiana. As its name suggests, this office also keeps up with and assesses state-of-the-art technologies and innovations in the Louisiana energy economy, which would include CCS-related projects.

The second office of importance within LDNR is the Office of Mineral Resources (OMR) which manages the state's mineral assets in granting and administering leases on state-owned lands and water bottoms for developing and producing, primarily oil and gas, as a means of revenue in the form of royalties, bonuses, and rentals to the state's general fund. OMR's Assistant Secretary also serves as the Secretary of the Louisiana Mineral and Energy Board. OMR serves as support staff to the Board's operations and responsibilities and provides technical advice and expertise for the Board's monthly meetings and oil and gas lease sales.

The second state administrative agency that will have a direct impact on CCS development in Louisiana is the Office of Conservation which is charged with conserving and regulating oil, gas, and lignite resources of the state (on both private and state lands). Its statutory responsibility is to regulate the exploration and production of oil, gas and other hydrocarbons and lignite; to control and allocate energy supplies and distribution; and to protect public safety and the environment from oilfield waste, including regulation of underground injection and disposal practices.

There are two other executive agencies that may have some peripheral interest in CCS: the Louisiana Department of Economic Development (LED) and the Louisiana Public Service Commission (LPSC). LED is the primary agency responsible for promoting economic activity in the state. Its goals are to maintain and retain existing Louisiana businesses and industries and to recruit new business and industries to expand the state's economic base. LED promotes new capital investment in the state, including that associated with advanced technologies. LED would likely play a partnering role in promoting CCS since it represents an advanced capital-intensive technology that would help to maintain, and potentially expand the state's employment base.

The second executive agency that will have an important, but likely indirect interest in CCS development is the LPSC, an independent regulatory agency dedicated to serving the public interest by assuring safe, reliable, and reasonably priced services provided by public utilities and

motor carriers. The LPSC is the state's utility regulator and, as noted earlier, utilities in the state, particularly those that have coal-fired resources, will likely have some interest in how CCS progresses in Louisiana, even if that process starts at industrial rather than power generation locations.

6.2.4 Non-governmental organizations/other interest groups

America's WETLAND Foundation (AWF) was established in 2002 to raise public awareness of the impacts of Louisiana's wetland loss and to gain support for efforts to conserve and save coastal Louisiana (AWF, 2019). AWF was launched by former Louisiana governor Mike Foster and acts as a forum for problem-solving and sharing of best practices for environmental and economic interests. AWF has been educating the public through international conferences, summits and restoration projects coupled with pro-active media relations and public outreach.

Clean Water, Land & Coast is an environmental group made up of concerned residents from Terrebonne, Lafourche, Vermilion parish with a vision of returning Louisiana's coast, fresh water and land to its natural gas state (CWLC, 2019). The group works to raise awareness about coastal restoration efforts and keep the public up to date on the status of parish lawsuits involving oil and gas companies. The organization was formed in 2013 and its website stores several memos and documents showing that oil and gas companies have known for decades that their practices would have harmful impacts on Louisiana's land, water and coast.

The Coalition to Restore Coastal Louisiana (CRCL) is the state's oldest, statewide non-profit organization dedicated to coastal restoration (CRCL, 2019). Established in 1988 the CRCL has evolved into a multi-faceted organization with expertise in policy, science, outreach and on the ground restoration. The group advocates for policy at the local, state and federal level and develops policy papers to serve as a guide for advocacy goals. CRCL's outreach and engagement program works to engage the public to inform them of restoration plans and discuss community impacts. The group also initiated the Oyster Shell Recycling Program that collects shell from New Orleans-area restaurants and returns the shell to Louisiana waters to construct oyster reefs and an aquaculture program to support Louisiana's oyster fishery.

The Environmental Defense Fund (EDF) is an international organization with more than two million members and a staff of 700 scientists, economists, policy experts, and other professionals (EDF, 2019). In Louisiana, EDF advocating and working as part of Restore the Mississippi River Delta, which is a coalition of local and national organizations. This group released a report in 2017 outlining 17 priority projects for restoring the Delta and coastal Louisiana. Restore the Mississippi River Delta coalition also includes the National Wildlife Federation, National Audubon Society, Lake Pontchartrain Basin Foundation and the Coalition to Restore Coastal Louisiana. EDF is also engaged in showing coastal planners and decision makers how natural infrastructure like dunes and barrier islands can lessen damage from erosion and storms. EDF is also exploring financial approaches such as environmental impact bonds which are pay-for-success debt financing in which investors purchase a bond and repayment to investors is linked to the achievement of a desired environmental outcome.

Gulf Restoration Network (GRN) acts to unite and empower people to protect and restore the natural resources of the Gulf Region (GRN, 2019). The group works on several issues, from conserving marine life and Gulf fisheries, to sustaining coastal communities and defending wetlands, to protecting water and resisting dirty energy. The group has worked to ensure that funding received after the BP spill disaster is used responsibly to restore the coast. In 2017 GRN

settled a lawsuit in Alabama challenging the misuse of National Resource Damages (NRD) funds given to the state. The state had approved the construction of a lodge and conference center for the Gulf State Park Enhancement Project. However, with the settlement, the resources will be used to maintain public access amenities in the Gulf State Park. The group has recently opposed the Bayou Bridge pipeline proposed crossing of the Atchafalaya River Basin. GRN demanded an Environmental Impact Statement and a review of all pipeline dams in the Basin.

The Louisiana Bucket Brigade (LBB) is an environmental health and justice organization that supports “fenceline communities” or communities adjacent to hazardous sites (landfills, refineries, chemical plants, pipelines) (LBB, 2019). In October 2017, the organization joined with 13 other environmental, health and science groups to challenge the EPA’s decision to delay implementation of a major chemical safety rule. The Louisiana Bucket Brigade has also been very involved in the controversy surrounding the Bayou Bridge Pipeline. The group also publishes a bi-monthly report called “Spotlight on Spills” to compile information on oil spill accidents both inland and offshore.

The Louisiana Environmental Action Network (LEAN) is a community-based organization established in 1986 to provide tools and services to individuals and communities facing environmental problems (LEAN, 2019). The purpose of LEAN is to foster cooperation and communication between individual citizens and corporate and government organizations in an effort to assess and mend the environmental problems in Louisiana. LEAN collaborates with numerous organizations to educate the public and community leaders about issues such as water quality and coastal integrity and to target polluters and compel compliance with environmental regulations.

The Louisiana Wildlife Federation (LWF) works to conserve the natural resources of Louisiana, with an emphasis on fish and wildlife and their habitats (LWF, 2019). The LWF also protects the rights of Louisiana citizens to enjoy these resources in accordance with sound, scientifically established resource management principles, and to accomplish this primarily through education and advocacy. The LWF represents conservationists that include hunters, anglers, campers, birders, boaters and other outdoor enthusiasts.

The National Wildlife Federation (NWF) works throughout the U.S. to protect the country’s landscapes, wildlife and natural resources (NWF, 2019). The NWF’s South Central Region includes 12 states along the Gulf Coast and into the Midwest. The organization has campaigned to ensure that fines and penalties assessed after oil spills are used to protect and restore the Gulf’s estuaries and coastal habitats. The NWF has also works to propel state and federal actions on projects to restore the Mississippi River Delta as it is an important coastal habitat for wildlife. It also has a number of initiatives to protect and restore forests in the region.

The Nature Conservancy (TNC) acts to tackle big picture problems of climate change, land and water conservation, food and water sustainability and the thoughtful planning and smart growth of cities. In Louisiana, the Nature Conservancy of Louisiana serves as a steward to protect and maintain more than 285,000 acres of state land (TNC, 2019). Specifically, TNC has constructed six miles of oyster reef in Louisiana to help protect coasts and marshes from erosion and storm surges. Oyster reefs provide valuable wildlife habitat which in turn helps fuel local commercial and sport-fishing industries. TNC is also working with landowners and other partners to protect the Atchafalaya River Basin with a 5,000 acre preserve. And, it recently completed a \$4.5 million restoration project to reconnect 25 miles of former floodplain forest back to the Ouachita

River. TNC created the Conservation Fellows program in Louisiana to engage graduate students in interdisciplinary research where fellows work with a university professor on a research need identified by TNC. In tandem with their academic experience, fellows become active participants on TNC's conservation team, engaging all facets of conservation from scientific to social and economic.

The Delta Chapter of the Sierra Club has 3,000 members working to advance the cause of protecting Louisiana's environment in a number of ways, including sponsoring a campaign to take mercury out of the environment, identifying and protecting the state's scenic rivers, and working to save the cypress and keep the Atchafalaya Basin safe (Sierra Club, 2019). The Delta Chapter works to raise public awareness and advises the state legislature on public health and environmental issues.

6.3 COMMONLY-ACCEPTED PUBLIC PERCEPTION FACTORS

Seigo, et. al. (2014) survey the literature and identify ten different "factors" influencing public perception about CCS adoption. The challenge with this list of factors, however, is that they are not independent of one another and there is often a high degree of collinearity associated with each. Consider, for instance, the "acceptance" factor identified by Seigo, et. al. (2014). The public's acceptance of a CCS technology application will be highly dependent upon other listed factors such as "experience," and "fairness," along with several other factors in the authors' list. Thus, it is hard to evaluate them independently of one another. The public perception factors do however identify the potential influences on how a CCS project would be perceived in a local community. Thus, each of these factors will be discussed in this sub-section, along with an analysis of how each is likely to be important in determining CCS public perception in Louisiana.

6.3.1 Acceptance/Attitude

The acceptance/attitude factor measures the degree to which individuals or society overall supports (or opposes) a particular technology, or technology application, and whether individuals will engage in activities that either support (or oppose) this technology or application.

The degree to which South Louisiana communities will accept a CCS application will itself be a function of several other factors discussed below particularly "knowledge," "experience," "fairness," "perceived costs," and "perceived benefits." It is highly likely that a CCS application in South Louisiana will largely be accepted, but this is not to suggest that some opposition could not arise. As noted earlier, South Louisiana has been home to large petrochemical facilities dating back to at least the Second World War. A major capital addition associated with an air emissions-improving technology would likely be acceptable, particularly at a facility like the CF Industries location in Ascension Parish. The CF Industries facility, as noted earlier, has recently more than doubled its production capacity with a \$2.2 billion investment. This major expansion was strongly supported by local, parish and state stakeholder groups. It seems questionable that the same interest groups, that supported the initial capacity expansion investments, would, in the future, oppose an additional on-site capital investment designed to improve the air emissions characteristics of the plant.

The one area that could raise an acceptance issue concerns safety issues associated with a major CO₂ leak somewhere along the CCS value chain, particularly with high pressure transportation or a permanent storage location. For instance, CO₂ is an asphyxiant and a Class 2 (non-flammable)

hazardous material by the U.S. Department of Transportation, under 49 CFR Section 195. Major energy infrastructure tends to get general support from most South Louisiana communities, but some applications that have certain safety-related issues can face some challenges. Some issues of this nature have arisen in the past (during the 2004-2007 time period), for example, with regards to siting LNG regasification facilities (although the issue has not re-emerged with the more recent permitting of Louisiana-based liquefaction/export facilities). The key to overcoming any opposition on this topic will be education about the CCS process and its current and anticipated safety record.

6.3.2 Knowledge

The knowledge factor can have both “self-assessed” and “objectively-assessed” components. The self-assessed describes what an individual believes is his or her understanding of a technology whereas objectively-assessed uses measure that attempt to determine this knowledge on an independent basis.

Knowledge is an important component and repeated studies in the literature suggest that the public overall does not have a good understanding of CCS technologies: Louisiana is likely to be no different. However, there are likely some localized places in the state that may have some familiarity with various aspects of the CCS process, particularly the relationship between CCS and EOR, or how gasification and other technologies can be used to capture carbon in industrial production processes. However, this familiarity will likely be limited to those working in or supporting, various petrochemical and industrial gas processes in South Louisiana.

As with any CCS application, knowledge and education will be an important aspect of developing Louisiana-based CCS projects. The public will need to be familiarized with both CCS technologies and benefits. The success of any South Louisiana CCS project will rest on the degree to which the public is educated about the processes (capture, transport, storage) and the overall benefits of CCS. As will be noted later, the fact that many in the state are familiar with energy manufacturing and its benefits, could serve as an important stepping stone to understanding the benefits of CCS and its relationships with many existing industries. Further, and as will be discussed more below, the possibilities for the creation of a wide-range of beneficiaries across the CCS value chain could also create a unique level of support in Louisiana that differs from other places in the country.

6.3.3 Experience

The experience factor measures experience with both CCS technologies as well as what can be thought of as “related” or “similar” technologies. It is doubtful that many South Louisiana communities are familiar with CCS technologies. Many communities do, however, have a high degree of familiarity and experience with the technologies included in a CCS application. For instance, most South Louisiana communities are familiar with petrochemical plant operations, pipeline and other commodity transportation, oil and gas technologies, and underground storage of commodities and oilfield wastes. Therefore, experience is likely to be a very important factor in determining South Louisiana CCS acceptance. It is likely that many South Louisiana communities will accept a CCS application if the continuity of the application with other already existing industrial, transport and storage applications can be established.

This continuity, however, could be used by some groups, particularly NGOs, as a rationale to oppose a South Louisiana CCS project. Parfomake (2008), for instance, in his Congressional

Research Service (CRS) analysis holds a relatively pessimistic view regarding CCS adoption due to less than ideal experiences with other energy industry infrastructure development. This analysis, however, is heavily slanted to power plant, as opposed to industrial capture applications.

Verma and Stephens (2006), and Carley et. al. (2012) also note that NGO acceptance and advocacy related to CCS is mixed: just because one environmental group supports CCS does not mean that it is as readily accepted by others. The authors of both studies, for instance, note that while the Natural Resources Defense Council (NRDC) has moderately accepted CCS, Greenpeace and the World Wildlife Federation have been opposed to these applications. In addition, the Sierra Club that has actively opposed a CCS project in Mississippi over the past several years. These “mixed” NGO positions, however, are heavily influenced by power plant capture applications, not industrial capture applications. This is important since many NGOs are wary of CCS applications for power generation as a means of: (a) sustaining what they see as an unsustainable resource (coal); and (b) distracting valuable financial resources away from other carbon mitigating power generation technologies like renewables. This type of opposition, however, is not as applicable with an industrial capture application since: (a) most of these facilities do not use coal and are, in fact, heavy users of more clean-burning natural gas; and (b) do not have any appreciable renewable alternatives.

6.3.4 Trust

Trust includes the degree to which communities or individuals trust major stakeholders in the technology development process. This includes industry, government and non-government organizations such as various social interests and environmental groups.

Trust can be an important issue in discussing major public policy initiatives, and this issue will be important for a South Louisiana CCS project. However, the role that trust plays in an industrial CCS project will likely differ considerably given the difference in how the financial and performance risks of an industrial project differs from a power generation capture project.

Consider that most all power generation-related CCS projects in the U.S. have been developed by regulated, vertically integrated electric utilities. Power plants with a gasification unit, therefore, will require: (a) utility regulatory approval (through what is typically known as a “certificate of convenience and necessity” or “CCN” determination); and (b) long-term financial backing and support from a regulated utility’s customer base (something that also has to be approved by utility regulators).

Trust is important for many stakeholders, particularly their trust of utility regulators “doing the right thing” in approving the development as well as the financing, of a given technology option (in this case, a power generation-based CCS application). Trust is important since these power generation CCS projects are developed with the expectation that they will be long-lived assets (in excess of 30 years) and will provide valuable societal services in return for the regulator-approved financial backing. If something goes awry with the adoption and operation of the new CCS technology, a utility’s customers will likely be the ones assuming all, or a good portion of the financial and performance risk of the CCS project. Here the financial risk is defined as the risk that the project will come on-line at its originally-anticipated cost, whereas the performance-related risk is defined as the risk associated with the project actually capturing the CO₂ emissions in a fashion consistent with the power generation-related project’s original design and expectations.

The public policy “risks,” and public “trust” associated with an industrial CCS project are entirely different from that associated with a power plant. First, an industrial facility, like CF Industries, will be adding technology at an existing facility, and will face standard permitting requirements, but will not face a CCN like a power plant. Second, an industrial facility, like CF Industries, will not be receiving a significant degree of technology-specific subsidies that will be paid for by a localized group of citizens like a utility power plant. Granted, a facility of this nature in South Louisiana, will be entitled to participate in the ten-year ITEP but there are no other technology-specific subsidies available in the state.

Further, as noted earlier, Louisiana does not have an extensive network of NGOs with significant resources to spend either in support, or in opposition, to major technology projects. To the extent these NGOs exist, they have typically been in opposition to on-site industrial expansions. It could be likely that many of these NGOs will have issues with a CCS project because they have a long history of having what they perceive to be “trust” issues with both government environmental regulators and industry. For instance, in opposition to a planned crude oil pipeline, the Louisiana Bucket Brigade accused the State of Louisiana as having a “too cozy” relationship with the parent company of the pipeline and stated that company representatives had an “ease of access” that activist groups do not have (Baurick, 2018).

6.3.5 Fairness

The literature notes that the fairness factor measures an individual’s or community’s perception of the fairness of the technology development process. This includes the perception about the distribution of costs, the distribution of benefits, and the distribution of risks. Few empirical studies, however, have explored or included measures of fairness in their public perception surveys, focus groups, and other analyses (Seigo, at.al., 2014).

In South Louisiana, the development of a CCS project has the ability to create a number of widespread benefits that might not be as prolific in other areas of the country. Consider, for instance, that a CCS project in South Louisiana will represent an important capital investment, of several million. This by itself will create direct, indirect and induced economic benefits that will “ripple” throughout the local and state economies. Contractors, engineering firms, consultants, environmental specialists, and a cordon of other local professionals will need to be brought together to construct and operation such a project.

In addition, there will likely be some sort of financial bonuses and royalties that will be paid to land-owners that have the rights to the storage facilities that will be used to permanently sequester the carbon captured from the area’s industrial plants, like CF Industries. In some instances, these lands will be privately-held, and the benefits of the CCS project will accrue to local landowners. In other instances, that are beyond the example in this study, these property rights to these permanent underground storage facilities could be held by the state, and in such instances, the revenue streams that accrue to the state could be included in its overall general revenue budget dispersing the benefits of the CCS project broadly across the state via various different types of public expenditures.

6.3.6 Affect

The affect factor has been described in the literature to represent an individual or community’s positive and negative “feelings” about a technology like CCS. It is not entirely clear that “affect” will be as meaningful in South Louisiana as it may be in some other location in the U.S.

As noted earlier, most South Louisiana households and businesses have a high degree of familiarity with chemical and refining operations. The addition of new technologies at an ammonia plant, that are capturing waste streams from the production process are not likely to be seen any differently than any other on-site plant efficiency investment like a combined heat and power application. The transportation and storage components of this project, however, may raise other, likely safety-related concerns that will need to be addressed and are discussed in more detail later in this section on “perceived risks.”

6.3.7 Perceived costs

The perceived cost factor can include a wide range of measurable (financial) and non-measurable (non-financial) costs. Further, these costs can accrue to either individuals (private costs) or to society (societal), overall. The difference between societal and private costs are often referred to as “externalities” since they represent the “spillover” impacts that private decisions can have on society and can often be remedied through the use of financial subsidies, tax credits and supports, and other financial mechanisms such as the use of tradable allowances through what are called “cap-and-trade” markets. Thus, from a public perception perspective, the internalization of a negative externality, through the development of an industrial CCS project, should be well-received provided that the cost of this societal investment is shared in some way with the beneficiaries of this societal investment.

The earlier cost effectiveness analysis included in this Report showed that a South Louisiana industrial CCS project will be able to financially stand on its own since the application will: (a) incur substantial capital costs with no corresponding revenue stream; and (b) the capital investment will not be offset by any on-going reductions in operating costs, at least in a foreseeable future without GHG regulations. Thus, some external funding support, like the federal 45(q) tax credits for permanent storage, discussed earlier, will be needed to cover the CCS projects’ development cost and internal ROR. The earlier cost-effectiveness analysis also incorporates a state property tax exemption (the ITEP) that will help to make a South Louisiana industrial CCS project more cost-effective.

The combination of the two financial support mechanisms ensures that a good share of the project’s supplemental financing will come from a broad federal tax base, not just a more localized group of South Louisiana stakeholders like a group of utility ratepayers. This is an important distinction between a potential South Louisiana project, for instance, and the Kemper CCS project that was being developed in neighboring Mississippi.

6.3.8 Perceived risks

The perceived risk factor measures the public’s concerns about issues that could go wrong with a technology application like CCS. Risks, like costs and benefits, can be measurable and non-measurable. In addition, these risks can accrue to either individuals or society, overall. Safety-related risks associated with carbon transport and storage are likely to be the two largest issues in the development of a South Louisiana industrial CCS project. The transportation of carbon over high pressures, higher than what is commonly found for natural gas, will be an important issue for the public. Public opposition to a CO₂ pipeline could become more pronounced if these pipelines traverse any high consequence areas (HCA) or other environmentally-sensitive areas.

Earlier findings in this Report reached the general conclusion that the technical ability to re-purpose natural gas lines to CO₂ transportation lines would be extremely limited particularly if

the CO₂ is being transported at supercritical pressures. Given the potential technical and design incompatibilities, public perception could become more challenged if older pipes are converted from natural gas service to CO₂ transportation.

Underground storage raises a number of comparable safety-related challenges and potential public perception concerns. The CF Industries application, for instance, is estimated to have a capture capability of 4.9 million metric tons per year. Over a ten-year period, this could total 49 million metric tons of carbon being injected into an underground reservoir. This could lead to a number of public perception concerns given some accidents that have occurred over the past several years with underground hydrocarbon storage, particularly those underground natural gas storage facilities that are solution mined from salt formations.

For instance, in 1980 a drilling rig in Lake Peigneur accidentally punctured the top of a salt mine beneath the lake. The hole in the bottom of the lake drained with such force that it sucked eleven barges and 65 acres of surrounding land into the caverns below. It also created a temporary inlet through the Delcambre Canal which connects to the Gulf of Mexico and transformed the lake from freshwater to brackish waters (Millhollin, 2013 and Pope, 1980). The salt mine was closed in 1986, and AGL Resources has been using the caverns dome to store natural gas since 1994. However, efforts by AGL to expand the storage capacity of the caverns beneath the lake were put on hold repeatedly over environmental and resident concerns (Millhollin, 2013). Similarly, in 2012, a collapsing underground salt cavern caused a sinkhole in Assumption Parish, pushing crude oil and methane to the surface (Golden, 2018). Residents of Bayou Corne were evacuated until 2016.

Granted, these examples have been associated with salt formation and nothing in this report envisions the use salt caverns for CO₂ storage. Sometimes, however, these technical details are lost on the public and all they know is that accidents happen when large volume of hydrocarbons and other oilfield wastes are injected into the ground. Current public perception challenges with seismicity and the injection of drilling fluid wastes in unconventional formations, particularly Oklahoma, only add to these issues. Thus, perceived risk will be an important public perception area that will need to be addressed in any CCS industrial project in South Louisiana.

6.3.9 Outcome efficacy

The literature suggests that outcome efficacy measures one's beliefs about the degree to which his or her actions affect technology (CCS) implementation. In other words, the degree to which an individual makes a difference in the technology adoption process, positively or negatively.

The degree to which outcome efficacy will be important in South Louisiana is not entirely clear. The literature also seems indifferent about the importance of this factor. Further, few studies have explored the degree to which this efficacy matters. This same literature hints that the factor may not be that important given opposing stakeholder sentiments that there is little they can do, positively or negatively, to influence large-scale technology adoption although such a hypothesis runs counter to the experience, for instance, in renewable energy adoption.

Nevertheless, it could well be the case that outcome efficacy is not a considerably important factor in a mature, energy-manufacturing economy like South Louisiana given the repeated and consistent adoption of new technologies designed to improve efficiency and reduced environmental impacts. While there could be some efficacy issues with some limited stakeholder groups, like NGOs, these efficacy factors are more than likely less important than

others discussed earlier such as knowledge, and perceived costs, benefits and risks.

6.3.10 Problem perception

The problem perception factor measures an individual's awareness of the problem and the degree to which a specific technology can be used to address this problem.

A considerable amount of CCS public perception-related academic research, particularly survey-based research, focuses more on what could be called “issues identification” or “problem perception” than on the use of CCS as a technology to mitigate carbon emissions. The emphasis on “problem perception,” in part, is not that surprising given the timing of these studies (early 2000s) and the relationship between the potential problem and CCS as a potential solution. In other words, the public has to appreciate that there is a climate change problem before being able to discern whether CCS is an acceptable solution.

However, in Louisiana, public perceptions about the “perceived problem” is likely to be less of an issue for CCS acceptance and adoption than it may be in other areas of the country. South Louisiana stakeholders are likely to see considerable economic benefits from CCS adoption regardless of their position on climate change. A South Louisiana project, as noted earlier, will likely spread a number of benefits across a wide range of individual stakeholders and stakeholder groups. The public, at large, will benefit by reducing potentially harmful carbon emissions. The public will also benefit from the large number of capital expenditures that will arise from the project and the economic benefits arising from those expenditures. The public will also benefit since the financial support for the project will not originate locally, with state taxpayers or utility ratepayers, but will come from federal taxpayers (through the 45Q credits) and will therefore be spread across the country.

Industry will benefit by finding a technically feasible solution to its carbon emissions challenges, along with the federal financial support that will make the CCS project cost-effective, at least for large ammonia manufacturing applications. Supporting industries, like engineering firms, environmental support firms, drilling service companies, among others, will benefit from the economic “multiplier” benefits of the CCS investment as well as its ongoing operations.

State and local government will benefit from the increased tax revenues associated with the capital expenditures and ongoing sales tax receipts that will arise from a CCS project. In addition, state agencies will receive payment streams from the CCS project to support ongoing monitoring and verification activities for the project.

Thus, it is hard to discern any major stakeholder group that would not see some form of benefit associated with a CCS investment, particularly if that investment were ultimately tied to a commercial activity such as EOR.

7 CCS LEGAL ISSUES

Any proposal to construct and operate facilities in Louisiana to permanently store carbon dioxide in a subsurface reservoir will raise many legal issues. This section addresses several of the most important of the legal issues associated with CCS facilities. For example, as Task 5, this report will address various property law issues, such as who generally owns subsurface pore spaces beneath land in Louisiana, who owns pore spaces when a person other than the landowner owns mineral rights in the land, and what rights would a prospective owner-operator of a CCS facility to exercise eminent domain to acquire the surface and subsurface rights or ownership needed for a facility. Task 6 analyzes some of the most notable environmental statutes that likely would apply to a CCS facility and discusses permits that would be required. Task 7 discusses means by which the owner-operator of a CCS facility could limit its risk for tort liability and limit its long-term duties to monitor and maintain a CCS facility.

In addition, as a supplement to the legal discussions that constitute Tasks 5, 6, and 7, this report contains appendices that relate to legal issues. First, because Louisiana has a civil law property regime whose rules and terminology will be new to many lawyers outside the state, Appendix A gives a brief review of Louisiana's civil law property system. Second, Appendix B contains a narrative summary and overview of the Louisiana Geologic Sequestration of Carbon Dioxide Act. The Act is referenced during discussion of the use of eminent domain in Task 5 and during discussion of ways that the owner-operator of a CCS storage facility can limit its liability in Task 6, but the Act is of sufficient importance that a unified, narrative summary of the Act is warranted. Appendix 2 contains such a summary. For similar reasons, Appendix C contains the text of the Act. Finally, Appendix D contains the text of certain other Louisiana statutes that are particularly notable.

7.1 ANALYSIS OF LEGAL ISSUES RELATING TO ACQUISITION OF PROPERTY RIGHTS THAT WILL BE NEEDED FOR PROJECT, SUCH AS PORE SPACE RIGHTS AND SURFACE RIGHTS

In order to construct and operate CO₂ storage facilities, the would-be operator will need certain property rights, including surface rights and subsurface rights. A company that does not have such rights can seek to acquire the necessary rights from the current owners, but before doing so, the company must determine who the current owners are. Below, this report analyzes such legal issues as: (1) who, if anyone, owns pore spaces beneath land in Louisiana; (2) how the prospective operator of a CO₂ storage facility could use eminent domain to acquire property rights in subsurface pore spaces; (3) how the prospective operator of a CO₂ storage facility could use eminent domain to acquire property rights relating to the surface; and (4) the impact that the "due regard" doctrine might have on the relationship between the owner-operator of a CO₂ storage project and persons who own land or mineral rights in the area where the project will be located.

7.1.1 Who Owns Pore Spaces Beneath Land in Louisiana?

The question of who, if anyone, owns pore spaces beneath land in Louisiana, should be divided into two questions. First, who owns subsurface pore spaces for the general case in which no person other than the landowner owns mineral rights relating to the land? Second, who owns subsurface pore spaces if a person other than the landowner owns mineral rights relating to the land.

7.1.1.1 Who generally owns subsurface pore spaces?

In the United States, state law generally governs issues relating to the nature and extent of a landowner's ownership (*Stop the Beach v. Florida*, 2010; *Phillips v. Washington*, 1998). Accordingly, Louisiana law will govern any questions regarding the ownership of subsurface pore spaces beneath lands within the state.

Louisiana does not have a statute that explicitly refers to ownership of "pore spaces,"⁶ but Louisiana Civil Code article 490 states: "Unless otherwise provided by law, the ownership of a tract of land carries with it the ownership of everything that is directly above or under it."⁷ Notably, no other law provides for anyone other than the landowner to own pore spaces or other natural features of the subsurface. This might seem sufficient to ensure that the answer to the question "Who owns subsurface pore spaces?" is "The Landowner." But the question merits further discussion. After all, Civil Code article 490 suggests that a landowner generally owns all the airspace above his land, yet a Louisiana landowner can neither prohibit an airline from flying airplanes over his land at high altitude nor charge the airlines a fee for doing so. With respect to the subsurface, however, other provisions of Louisiana law support, rather than undermine, the notion that the landowner owns the subsurface.

For example, Louisiana Mineral Code article 5 (La. Rev. Stat. 31:5) provides that the owner of land owners the solid minerals beneath his or her land. Indeed, Mineral Code article 5 states that, while solid minerals remain in place in the subsurface, ownership of those minerals cannot be owned by anyone other than the landowner.

Mineral Code article 5, which was enacted as part of the original Mineral Code in 1974, codifies a jurisprudential rule previously established by the Louisiana Supreme Court in *Wemple v. Nabors Oil & Gas Co.* (1923), which cited Article 505 of the Louisiana Civil Code of 1870, the source of current Civil Code art. 490. In that case, the court held that an act of sale which purported to grant one party ownership of the surface, while leaving the other party as owner of solid minerals in the subsurface, could not be given literal effect. The court stated that Louisiana law does not allow separate ownership of the surface and subsurface, and that the landowner necessarily has "dominion over the soil and all that lies directly above and below it." The court stated that a landowner can grant someone else the right to mine for solid minerals, as well as the right to own any solid minerals that the person brings under his possession, but that the landowner must remain the owner of the subsurface, including solid minerals for so long as the solid minerals remain in place in the subsurface.

The landowner's ownership of the subsurface is also recognized in the rules governing the production of oil, gas, groundwater, and other substances found naturally in liquid or gaseous form in the subsurface. Because such substances, can migrate in the subsurface, Louisiana law provides that no one owns those substances while they are found in their natural state. But Mineral Code

⁶ In Louisiana, unlike in common law states, legislation is the primary source of law. Louisiana Civil Code article 1 states that, "The sources of law are legislation and custom." It is widely acknowledged that, as between these two, "legislation is the superior source of law in Louisiana." La. Civ. Code art. 1 cmt. (a); *see also* La. Civ. Code art. 3 cmt. (d).

⁷ La. Civ. Code art. 490. Article 490's provision that the landowner's ownership extends to the space above and below the surface corresponds to the common law's *ad coelum* doctrine. One court explained the *ad coelum* doctrine by stating that "the colorful Latin maxim of *cujus est solum ejus est usque ad coelum et ad inferos*" can be translated as meaning "for whoever owns the soil, it is theirs up to Heaven and down to Hell." (*Alyce Gaines Johnson Special Trust v. El Paso E&P Co.*, 2011).

article 6 (La. Rev. Stat. 31:6) provides that the owner of land has the exclusive right to use the subsurface to explore for such substances and to “reduce them to possession and ownership.”⁸

Louisiana’s law of trespass also recognizes the landowner’s ownership of the subsurface. For example, in *Gliptis v. Fifteen Oil Co.* (1944), the plaintiff alleged that the defendant’s drilling operations had constituted a subsurface trespass. The Louisiana Supreme Court stated:

It is conceded that during drilling operations some oil and gas wells drilled normally—i.e., without effort to direct their downward course—drift or deviate from a vertical or upright line, and that it frequently happens that a well located on the surface of the owner’s land near to his property line deviates or swings so far away from the vertical that it passes through, and is bottomed in, his neighbor’s property. When this happens, there is a ‘subsurface trespass’, whether the deviation is normal or whether it is brought about by intentional controlled directional drilling. Any unlawful physical invasion of the property of another is a trespass.

(Gliptis v. Fifteen Oil Co., 1944)

The Louisiana Supreme Court discussed a similar alleged trespass in *Nunez v. Wainoco Oil & Gas Co.* (1986). In *Nunez*, the allegedly trespassing well was the unit well for a compulsory drilling unit. The court held that the existence of a compulsory drilling unit⁹ altered the rules for subsurface trespass, and on that basis the court dismissed the plaintiff’s claim. But the court again seemed to accept the general proposition that a landowner owns the subsurface beneath his land.

In a few cases in Louisiana, plaintiffs have alleged that a defendant committed a subsurface trespass by conducting injection disposal operations that caused a plume of waste fluid to migrate into the subsurface of the plaintiff’s land. In most of these cases, the plaintiffs’ trespass claims were rejected—sometimes at the summary judgment stage—because they did not prove any damages, but the courts seemed to accept the proposition that the plaintiff landowners owned the subsurface pore spaces beneath their tracts of land. (*Boudreax v. Jefferson Island Storage & Hub*, 2001).

And notably, in one of those injection disposal cases the plaintiffs’ claims survived summary judgment (*Mongrue v. Monsanto Co.*, 1992). In that case too, the court was concerned about whether the plaintiffs could prove damages, but the court held that the plaintiffs had raised a genuine issue of disputed fact by alleging that they incurred harm because the defendant’s injection operations would prevent the plaintiffs using or leasing the subsurface beneath their land for storage (*Id.* at *4). Thus, implicit in the plaintiffs’ successful argument against summary judgment was the notion that the plaintiffs-landowners owned the subsurface, including the pore spaces into which the waste fluids injected by the defendant allegedly would migrate, and therefore the

⁸ Mineral Code article 6 provides that the owner of land does not own the oil and gas in place, but that is not an indication that the landowner does not own pore spaces and the subsurface generally. The non-ownership of oil and gas is based on the fact that those substances can flow from one property to another in response to differences in pressure, so that oil and gas that is initially beneath one tract of land may travel to the subsurface of another tract. See *Frost-Johnson Lumber Co. v. Salling’s Heirs*, 1922.

⁹ A “[u]nit [is] an area of land … as to which parties with interests therein are bound to share minerals produced on a specified basis.” La. Rev. Statute 31:213. A unit can be formed by agreement or by order a governmental agency with appropriate authority. *Id.* A unit formed by an order issued from a governmental agency is called a “compulsory unit.” *Id.*

plaintiffs had standing to complain about the alleged trespass.¹⁰

Finally, given that the law does not recognize a landowner's right to control the airspaces high above his land, even though the language of Civil Code article 490 seems to recognize his ownership of those spaces, it is worthwhile to examine the airspace issue in more detail, in order to consider whether it can be distinguished from a landowner's presumed ownership of the subsurface. Although it seems clear that a Louisiana landowner has no authority to control the airspaces high above his land, little or no direct authority exists in the form of Louisiana statutes or court decisions dealing with this issue. However, cases from other jurisdictions probably serve as a good proxy for Louisiana decisions. As previously noted, a feature of the common law is the *ad coelum* doctrine, the substance of which seems virtually identical to Civil Code article 490.¹¹ Nevertheless, landowners in common law states are not allowed to control the airspaces high above their lands. The reasons for this are the same reasons that Louisiana landowner cannot control the airspaces high above their land.

Consider *Thrasher v. City of Atlanta* (1934). In *Thrasher*, the plaintiff brought a claim for trespass based on aircraft flying over his land. At that time, Georgia's Civil Code declared that "the right of the owner of lands extends downward and upward indefinitely" (*Id.* (citing Ga. Civ. Code § 3617 (1910))). Further, that Code stated that "the owner of realty having title downwards and upwards indefinitely, an unlawful interference with his rights, below or above the surface, alike gives him a right of action" (*Id.* (citing Ga. Civ. Code § 4477 (1910))). Nevertheless, the Georgia Supreme rejected the plaintiff's trespass claim. The noted the importance of air travel to society, and potentially that could have served as a public policy rationale for restricting a landowner's ownership of the airspaces high above his property, but ultimately the court based its rejection of the trespass claim on a more traditional analysis of property rights (*Id.*, 819).

The court concluded that the relevant provisions of Georgia's Civil Code were based on the common law's *ad coelum* doctrine and therefore should be interpreted as including any limitations existing within that doctrine. The court analyzed the doctrine and concluded that the full, literal expression of the doctrine is mere dicta. The court explained that, "[t]he common-law cases from which the *ad coelum* doctrine emanated were limited to facts and conditions close to earth and did not require an adjudication on the title to the mansions in the sky." Therefore, the pronouncements from such cases were mere dicta with respect to higher altitudes.

The Georgia Supreme Court stated that "[p]ossession is the basis of all ownership" and that title to land therefore "can hardly extend above an altitude representing the reasonable possibility of man's occupation and domain." The court reasoned that a landowner could claim possession to the height of any building, and perhaps the landowner could be deemed to hold actual possession of the space immediately above the "trees, buildings, and structures affixed to the soil." Further, if a neighbor constructed a tall building with an overhang projecting over the landowner's property, that construction would demonstrate that the space was subject to actual possession and therefore

¹⁰ The plaintiffs later voluntarily dismissed their trespass claims so that they could immediately appeal the district court's judgment dismissing the claims asserted under another theory—namely, a takings without compensation. The United States Fifth Circuit affirmed the lower court's ruling, however, putting an end to the plaintiffs' case. *See Mongrue v. Monsanto Co.*, 2001.

¹¹ *See Alyce Gaines Johnson Special Trust v. El Paso E&P Co., L.P.*, 2011, (citing Civil Code art. 490 and stating: "As the Louisiana Civil Code makes clear Louisiana property law embraces the colorful Latin maxim of *cujus est solum ejus est usque ad coelum et ad inferos* ('for whoever owns the soil, it is theirs up to Heaven and down to Hell').")

the overhang might be the basis for a trespass action.

But flying through the airspace at high altitude is not an act of possession. Therefore, air travel at low altitude across a person's property might constitute a trespass, and the operation of aircraft at higher altitudes that actually interferes with a landowner's use of the land might constitute a nuisance,¹² but air travel at higher altitudes would not constitute a trespass.¹³

In other cases in which landowners have complained about aircraft flying over their property, courts similarly have concluded that the *ad coelum* doctrine is dicta to the extent that it suggests title to land extends to indefinite altitudes. Accordingly, landowners may be entitled to relief if low-altitude flights over their lands cause actual harm or inconvenience, but they are not entitled to relief for high altitude flyovers that do not cause harm or inconvenience.¹⁴ A particularly notable decision is the 1946 United States Supreme Court opinion in *United States v. Causby* (1946).

In *Causby*, a plaintiff who lived near an airfield brought suit, asserting that low-level flights had effected a “taking” of his property and that he was entitled to compensation. The Court ruled that, under the facts shown, the plaintiff could assert a takings claim because the flights seriously impaired the plaintiff's use and enjoyment of his property. Thus, although the Court acknowledged that a landowner's ownership extends upward from the surface to encompass “at least as much of the space above the ground as he can occupy or use in connection with the land,” the Court held a landowner would not have a basis in law to complain about the mere fact that aircraft fly over his property at high altitudes. The Court explained that the “[ad coelum] doctrine has no place in the modern world,” and the “public interest” requires that the air be a “public highway.”¹⁵ Some of the court's language suggested that it was resting its holding on a public policy rationale, though the court's suggestion that ownership might extend only so far as a person could actually use and enjoy the property has overtones of basic property law.

The Restatement (Second) of Torts reaches a similar result. Section 159 establishes a general rule that trespasses may occur “above the surface of the earth,” but the Section also states that an aircraft's flight over land will not constitute a trespass unless the aircraft “enters into the immediate

¹² See *Thrasher v. City of Atlanta*, (1934) at 825-26 (demonstrating that the landowner “may complain of any [flights] tending to diminish the free enjoyment of the soil,” though the air travel might be at altitudes above the altitude subject to possession, and it could be a nuisance if the air travel causes harm or inconvenience).

¹³ The decision is based on a conclusion that ownership does not extend indefinitely upward. If a court concluded that ownership extended indefinitely upward, but that constructive possession did not, such reasoning might also bar a trespass claim, given that a landowner would not have actual possession of high elevations and that a person must have actual or constructive possession in order to bring a trespass claim. But if ownership extended indefinitely upward, a landowner might be able to bring a claim based on some other theory, such as ejectment.

¹⁴ See *Smith v. New England Aircraft Co.* (1930) (noting altitude of “possible effective possession” as potential limit on trespass claims); see *Swetland v. Curtiss Airports Corp.* (1930) (noting that decisions suggesting title to land extended to indefinite heights did not involve disputes over alleged trespasses at altitudes generally used in air travel); *Rochester Gas & Elec. Corp.* (1933) (“[I]t may be confidently stated that, if [[the ad coelum] maxim ever meant that the owner of land owned the space above the land to an indefinite height, it is no longer the law.”).

¹⁵ *United States v. Causby* (1946) at 261, 266 (“The airspace, apart from the immediate reaches above the land, is part of the public domain.”). The Ohio Supreme Court applied the reasoning that the *ad coelum* doctrine does not apply in its full literal expression in support of its holding that a plaintiff did not have a takings claim based on a zoning law that limited heights of buildings near an airport. *See also Vill. of Willoughby Hills v. Corrigan* (1972) (“It is now well settled that the doctrine of the common law, that the ownership of land extends to the periphery of the universe, has no place in the modern world.”). Such reasoning goes further than the decisions that hold that a landowner's ownership does not extend beyond the height he can reasonably possess, but is consistent with the proposition that the *ad coelum* doctrine is not applied literally.

reaches of the air space next to the land, and ... it substantially interferes with the other's use and enjoyment of his land.”¹⁶

Someone could argue that subsurface spaces have public utility for injection disposal and subsurface storage of fluids, and that subsurface pore spaces should be treated like high-altitude airspaces—as a regulated “public highway.” And some court decisions seem to have effectively done so in the injection disposal context (*Boudreaux v. Jefferson Island*, 2001; *Chance v. BP Chemicals, Inc.*, 1996).¹⁷ In contrast, in the subsurface storage context, authorities seem to have recognized implicitly a landowner’s ownership of the subsurface. For example, the federal Natural Gas Act authorizes a company to use eminent domain in certain circumstances to acquire the right to use the subsurface of a landowner’s land for the storage of natural gas (see 15 U.S.C. § 717f; *Columbia Gas Transmission v. Exclusive Gas*, 1985; *Mississippi River Transmission v. Tabor*, 1985; and *Transcontinental Gas Pipe Line Corp v. 118 Acres of Land*, 1990). Louisiana law grants similar authority (La. Rev. Stat. 19:1 *et seq.*; *Mid-Louisiana Gas Co. v. Sanchez*, 1973). Thus, rather than establishing a rule that the landowner does not own the subsurface spaces that will be used for storage, these statutes implicitly recognize such ownership by providing companies a means to acquire subsurface storage rights from the landowner.

“Still,” someone might argue, “the subsurface storage of CO₂ is really a form of disposal, unlike the storage of a valuable product that will be withdrawn at a later date,” and perhaps Louisiana law would not recognize a landowner’s ownership of pore spaces when someone else wishes to use those pore spaces for the long-term storage and sequestration of CO₂. But available authority suggests otherwise. The Louisiana legislature has enacted legislation that authorizes a company, in certain circumstances, to use eminent domain to acquire from a landowner the right to use the subsurface for long-term sequestration of CO₂. Thus, rather than asserting that a landowner lacks ownership of subsurface pore spaces in this context, the legislature has implicitly recognized such ownership by providing a means for a company to acquire from the landowner the right to use the subsurface.

In short, under Louisiana law, the landowner almost certainly owns subsurface pore spaces beneath his or her land. Further, such a landowner probably can protect his or her ownership with a cause of action in trespass in the event that a subsurface fluid migrates into the subsurface of the landowner’s land. For these reasons, it will be important that the operator of a carbon dioxide storage facility acquire rights to use the subsurface of all areas where the CO₂ may migrate.

7.1.1.2 Who Owns Pore Spaces Beneath Land in Louisiana When a Person other than the Landowner Owns Mineral Rights Relating to the Land?

A question that some people might ask is whether this general rule applies in the event that some person other than the landowner has been granted a right to explore for or produce minerals from the subsurface of the land. The landowner will own the pore spaces even if some person other than the landowner owns mineral rights relating to the land. This is probably the most-typical result across the United States (See, e.g., *Lightning Oil Co. v. Anadarko E&P Onshore*, 2017; *Dick*

¹⁶ Restatement (Second) of Torts § 159 (1965). Cf. Restatement (First) of Torts § 159 (which states that a trespass can occur “above the surface of the earth,”), and Restatement (First) of Torts § 194 (which provides that air travel over land will not constitute a trespass if the travel complies with applicable regulation and it has a legitimate purpose, is conducted in a reasonable manner, and occurs “at such a height as not to interfere unreasonably with the possessor’s enjoyment of the surface of the earth and the air space above it.”).

¹⁷ For further discussion of subsurface ownership issues, see Hall, 2014.

Properties, LLC v. Paul H. Bowman Trust, 2010) and it certainly is true in Louisiana (La. Civ. Code art. 490; *Sutton v. Southern Natural Gas Co.*, 1981; *Southern Natural Gas Co. v. Poland*, 1981; *Mississippi River Transmission Corp. v. Tabor*, 1985; and *United States v. 43.42 Acres of Land*, 1982).

This conclusion is supported by case law and statutory law. Unlike most other states, Louisiana does not recognize the concept of a severed mineral estate. This was first established nearly a century ago by the Louisiana Supreme Court. In *Frost-Johnson Lumber Co. v Salling's Heirs*, (1922), the parties disputed the issue of who had the right to explore for oil and gas on the property. On one side, were the heirs to the former landowner, who had sold the land more than a decade before, while “[e]xcepting and reserving” from the sale the ownership of all minerals, as well as the right to use the surface of the land for the purpose of mining or exploring for oil and gas. They argued that this reservation created a severed mineral estate and that they owned any oil or gas in the subsurface, as well as the right to explore for those substances.

On the other side were the new landowners. They argued that the exception and reservation contained in the act of sale did not create a severed mineral estate. Rather, it created a right in the nature of a servitude that reserved to the seller the right to explore for and produce oil and gas, and also the right to ownership of any oil and gas produced. Further, asserted the landowners, this servitude has terminated because it had not been used in more than ten years, and under Louisiana law a servitude terminates by prescription of nonuse if it is not used in any ten-year period.

The Louisiana Supreme Court sided with the landowners. The court reasoned that, because oil and gas are fugacious and will move to a point of low pressure (such as an oil and gas well) without respect to property lines, no one owns naturally-occurring oil and gas in place in the subsurface. Thus, even a landowner who has retained all mineral rights in his land does not own any own and gas found naturally in the subsurface, though in such cases a landowner will have the exclusive right to explore for and produce such oil and gas by operations on and beneath his land, and he will become the owner of any oil or gas that he produces in such operations. And, if a landowner cannot own the oil and gas in place in the subsurface, the landowner cannot reserve ownership of oil and gas in place when selling the land. But in the act of sale, the parties had intended that the seller retained some sort of rights. The court reasoned that, with respect to oil and gas, the reserved right was best characterized as being in the nature of a servitude.

But *Frost-Johnson* merely established that no one can own oil and gas in place. It did not decide the broader question of whether Louisiana law will allow the creation of a severed mineral estate. The court faced that issue the following year in *Wemple v. Nabors Oil & Gas Co.*, 97 So. 666 (La. 1923). In *Wemple*, a landowner purported to sell ownership of the solid minerals beneath his land to a buyer. More than ten years later, the then-current landowner and the successor-in-interest to the buyers of the mineral rights disputed the issue of who had a right to explore for and produce solid minerals. During the intervening time there had been no mineral exploration or production. The Louisiana Supreme Court held that the landowners did. The court reasoned that the concept of a severed mineral estate is a common law notion that is alien to Louisiana’s civil law system, and that Louisiana does not recognize or allow the creation of a severed mineral estate. Thus, although the act of sale purported to transfer ownership of solid minerals to someone other than the landowner, the act of sale could not validly do so. Nevertheless, the court wanted to give some effect to the act of sale, so the court interpreted the contract as one granting the buyer a servitude

to explore for and produce minerals, and to own any minerals actually produced.¹⁸

These cases are still good law. In 1974, the Louisiana Legislature adopted the Mineral Code, which was effective on January 1, 1975. This Code, which is found in Title 31 of the Louisiana Revised Statutes, now is the governing law in Louisiana with respect to the nature of mineral rights, but the Mineral Code has not changed the result of *Frost-Johnson* and *Wemple*. For example, Mineral Code article 5 (La. Rev. Stat. 31:5) governs solid minerals. It states: “Ownership of land includes all minerals occurring naturally in a solid state. Solid minerals are insusceptible of ownership apart from the land until reduced to possession.” Thus, even if a landowner grants a mineral servitude to someone, giving that person the right to mine solid minerals and become the owner of any solid minerals that are recovered in mining operations, the landowner remains the owner of the solid minerals so long as they remain as natural deposits in the subsurface. And, if the landowner, rather than the mineral servitude owner, owns the solid minerals while they remain in place, it seems even more clear that the landowner, rather than the mineral servitude owner, must own the pore spaces beneath the surface.

A different Mineral Code article governs ownership of oil and gas. In particular, Mineral Code article 6 (La. Rev. Stat. 31:6) provides:

Ownership of land does not include ownership of oil, gas, and other minerals occurring naturally in liquid or gaseous form, or of any elements or compounds in solution, emulsion, or association with such minerals. The landowner has the exclusive right to explore and develop his property for the production of such minerals and to reduce them to possession and ownership.

Thus, even if a landowner creates a mineral servitude that gives the servitude owner the right to explore for and produce oil and gas, the servitude owner will merely have a right of use. The servitude owner will not have corporeal ownership of any portion of the subsurface.

The Mineral Code articles dealing with mineral servitudes are consistent with the proposition that a servitude owner does not have corporeal ownership of the subsurface. Mineral Code article 22 recognizes that a mineral servitude owner has the right to *use* the land owned by the landowner to explore for and produce oil and gas, but the article does not grant the mineral servitude owner any ownership of the subsurface.¹⁹ For similar reasons, under Louisiana law the lessee under a mineral lease does not have corporeal ownership of any portion of the surface or subsurface.

Further, unless the instrument that creates a mineral servitude or mineral lease grants subsurface storage rights to the servitude owner or lessee, subsurface storage rights remain with the landowner. This is confirmed by the handful of Louisiana cases in which courts have discussed the question of who is entitled to compensation—the landowner or other person who owns mineral rights—when a company uses eminent domain to acquire the right to use the subsurface for storage.

For example, in *Southern Natural Gas Co. v. Poland* (1981), a natural gas company used powers of eminent domain, pursuant to Louisiana Revised Statute 19:12, to expropriate²⁰ the rights

¹⁸ Of course, in *Wemple*, because the servitude had not been used for more than ten years, it had terminated.

¹⁹ Mineral Code article 114 (La. Rev. Stat. 31:114) states: “A mineral lease is a contract by which the lessee is granted the right to explore for and produce minerals.”

²⁰ Expropriation is the Louisiana term for taking property by use of eminent domain. Expropriation is essentially the same as the process that is called “condemnation” on the federal level.

necessary to use to use a depleted natural gas reservoir for natural gas storage. The court stated the expropriator must pay compensation for three things: (1) the value of the subsurface storage it would use; (2) the value of any surface rights that it would need; and (3) the value of any recoverable hydrocarbons remaining in the reservoir being expropriated. The court stated that the landowner was the person entitled to compensation for the subsurface storage rights, as well as any surface rights being expropriated. As for the compensation to be paid for any recoverable hydrocarbons remaining in the reservoir, the landowner would be entitled to that compensation if he or she owned the mineral rights associated with the land, but otherwise that the person owning mineral rights would be entitled to compensation for the recoverable hydrocarbons.

Sutton v. Southern Natural Gas Co. (1981) was another dispute regarding the expropriation of rights for the construction and operation of a natural gas storage facility. As in *Poland*, the court distinguished between the value of the storage rights and surface rights, for which the landowner would receive compensation, and any recoverable hydrocarbons, for which the owner of mineral rights would be compensated.

The United States Fifth Circuit relied on *Sutton* and *Poland* in *Mississippi River Transmission Corp. v. Tabor* (1985). There, the Fifth Circuit stated that the landowner is the person entitled to compensation for any storage rights and surface rights being expropriated, and that the person owning mineral rights (which sometimes will be the landowner and sometimes will be someone else) is entitled to compensation for any recoverable reserves remaining in the reservoir that is expropriated.

Another case from the early 1980s also involved a dispute regarding who was entitled to compensation for subsurface storage rights, though the case involved the right to store hydrocarbons in an underground salt dome cavern, rather than in pore spaces. In *United States v. 43.42 Acres of Land* (1982), the federal government used eminent domain to condemn rights in a salt dome cavern in South Louisiana, which the government wanted so that it could utilize solution mining to construct a cavern in the salt dome and then use the cavern as storage for the Strategic Petroleum Reserve.

Two groups claimed the right to compensation from the federal government. One group was the Barbe heirs, who previously had owned the land beneath which the salt dome was located. The second group was the Hamiltons, who were the current landowners. The Barbe heirs had sold the land to the Hamiltons, but in the act of sale the Barbe heirs had reserved all mineral rights, including the right to mine for salt. That reservation had the effect of severing the ownership of mineral rights from the ownership of the land itself,²¹ with the Barbe heirs owning the mineral rights and the Hamiltons owning the land. In reasoning analogous to that in the cases discussed above, the court concluded that the Barbe heirs had a right to compensation for the loss of their right to mine salt, but that the Hamilton heirs, as landowners, had the right to be compensated for the value of using the salt dome cavern for storage.

The court explained that it was the landowners who were entitled to compensation for the use of the cavern because, if not for the expropriation, it would be the landowners, rather than the mineral owners, would own any cavern left behind after the mining of salt. In reaching its conclusion, the court relied in part on Louisiana Civil Code art. 490. The court also noted that, under Louisiana law, the Barbe heirs' mineral rights did not give them ownership of the salt in place in the salt dome. Instead, their mineral rights merely gave them the exclusive right to mine the salt, as well

²¹ Under Louisiana law, this created a mineral servitude in favor of the Barbe heirs.

as the right to own any salt that they had mined. And, if the Barbe heirs did not own the salt while it was in place underground, it would make no sense to hold that they owned the vacant space that remained after the salt had been removed.

Another federal court case in Louisiana reached the same result. In *United States v. 43.42 Acres of Land* (1981), the federal government was using eminent domain authority to acquire the right to remove salt in order to create a salt dome cavern that the government would then use to store oil for the Strategic Petroleum Reserve. Because the federal government was taking private property, the owners of the property rights being taken were entitled to compensation. As it turned out, the land in question was burdened by a mineral servitude (520 F. Supp. at 1044),²² and the landowners and servitude owners disagreed regarding the allocation of the compensation that the government would pay.

The owners of the mineral servitude argued that they were entitled to the entirety of the compensation. The landowners disagreed. As the landowners saw it, the federal government was acquiring two rights: (1) the right to remove salt; and (2) the right to use the resulting cavern as storage space. The landowners could not reasonably dispute the proposition that the mineral servitude owners were entitled to compensation for the government's taking of the salt. After all, if not for the government's exercise of eminent domain, the mineral servitude owners would have had a right to remove the salt (520 F. Supp. at 1044). But the landowners argued that they were entitled to compensation for the government's taking of the right to use the salt dome cavern as storage space.

The court agreed with the landowners. The court noted that a mineral servitude owner has the exclusive right to explore for and produce minerals, and he has the right to use the land for purposes of such exploration and production. But he does not own the land itself or the subsurface of the land where the minerals are found. Therefore, it would make no sense to conclude that the empty space from which minerals are removed belongs to the servitude owner. Instead, the landowner owns that space. Accordingly, the landowners in *43.42 Acres*, not the mineral servitude owner, were entitled to compensation for the value of using the subsurface salt dome cavern for storage (520 F. Supp. at 1046).

The same reasoning would apply to ownership of the pore spaces in a depleted reservoir or a brine reservoir. Accordingly, the pore spaces of a depleted reservoir or brine reservoir would be owned by the persons who own the tracts of land above the reservoir that would be used as storage space for the CCS project.

7.1.2 Analysis of Eminent Domain Statutes and the Development of a Strategy for Acquiring Subsurface Rights Needed for a Project

As noted above, the landowner likely will own the pore spaces beneath his or her land, as well as the right to bring a claim for subsurface trespass in the event that a person causes a fluid to enter the subsurface of his or her land without permission or other authority. For this reason, it will be necessary for a company that seeks to operate a CO₂ storage facility to acquire the right to use the subsurface. Such a company could do this either by: acquiring ownership of the land beneath which a CO₂ plume will migrate; acquiring subsurface storage rights from the owners of land

²² Unlike most states, Louisiana law does not recognize mineral estates, but it allows a landowner to create a mineral servitude in favor of some other person. *Wemple v. Nabors Oil & Gas Co.* (1923); *see also* La. Rev. Stat. 31:16. The owner of a mineral servitude has the exclusive right to explore for and produce minerals from the land, and will own any minerals that he reduces to physical possession (La. Rev. Stat. 31:21).

above which the plume will spread; or by acquiring ownership of the land itself in some areas and only subsurface storage rights in other areas.

Because it likely would be less expensive to acquire subsurface storage rights than to acquire ownership of the land itself, a CO₂ storage operator may choose to acquire only subsurface storage rights for much of the area where storage rights are needed. On the other hand, in areas where the company will need subsurface storage rights and the company also will wish to use and control the surface, the company may wish to acquire ownership of the land itself.

Another question the company will need to consider is whether it will wish to prevent anyone from drilling an oil and gas well through the storage reservoir. If so, the company may need to acquire ownership of the land itself. At the very least, the company would need to acquire both storage rights and all mineral rights. A challenge associated with this approach though, is that Louisiana property law generally does not recognize the ability to create a permanent severance of mineral rights from land ownership. If the CO₂ storage operator does not wish to preclude all drilling through the reservoir, the company has more options. It could: acquire the land itself (including all rights in minerals); or acquire the land, while not acquiring mineral rights; or acquire only subsurface storage rights.

After the operator determines the portions of the subsurface that will be needed, the first step in acquiring subsurface rights will be to identify the owners of the land above the subsurface areas that are needed. Then, the company can seek to acquire whatever rights it wants by negotiation. If the company is not able to acquire the necessary rights by negotiation, it can turn to eminent domain.

Louisiana Revised Statute 30:1108(A)(1) provides that a CCS operator who has obtained a certificate of public convenience and necessity from the Louisiana Office of Conservation can use the power of eminent domain to acquire subsurface rights, as well as the surface rights needed to support a CCS facility and the pipelines necessary to serve it. No carbon capture and sequestration projects have yet been built in Louisiana, but Louisiana Revised Statute 30:1102 declares carbon capture is “in the public interest.” For this and other reasons, it is reasonable to expect that the Commissioner of Conservation would be favorably inclined toward a well-planned CCS project and that the Commissioner therefore would cooperate in granting a certificate of public convenience and necessity upon the operator demonstrating the reasons that the project is sound.

Louisiana Revised Statute 30:1108 specifies that the procedure to be used in acquiring rights by eminent domain, for purposes of a CCS project, are the procedures specified in Louisiana Revised Statute 19:2. These procedures are commonly used in other types of eminent domain proceedings in Louisiana and are not unduly burdensome or difficult to utilize.

7.1.3 Analysis of Eminent Domain Statutes and the Development of a Strategy for Acquiring the Surface Rights Needed for a Project

In this Subtask 5.3, this report discusses the nature of the surface rights that will be needed for a CCS project and the availability of eminent domain as a means to acquire such rights.

7.1.3.1 The types of rights that are needed

The operator of a CCS project will need the right to use the surface of the land in certain areas. For example, the operator will need the right to run pipelines to carry CO₂ from its anthropogenic sources to the site where the CO₂ will be injected into the subsurface. The operator also will need surface use rights at the location where the injection into the subsurface will occur. Further, in

addition to having the right to use the surface, the operator may wish to preclude other persons from using the surface in certain areas.

Under Louisiana law, different types of property rights can give a person the right to use land, including ownership, servitudes, and such other real rights as the law allows (La. Civ. Code art. 476). First, there is outright ownership. Louisiana Civil Code article 477 defines ownership, stating, “Ownership is the right that confers on a person direct, immediate, and exclusive authority over a thing.” Article 477 goes on to state that “[t]he owner of a thing may use, enjoy, and dispose of it within the limits and under the conditions established by law.” Other articles elaborate, stating a general rule that “a proprietor may do with his estate whatever he pleases,” (La. Civ. Code art. 667) and that “[t]he owner may make works on, above, or below the land as he pleases, and draw all the advantages that accrue from them, unless he is restrained by law or by rights of others.” (La. Civ. Code art. 490)

Second, there are servitudes. Louisiana recognizes two kinds of servitudes—personal and predial (La. Civ. Code art. 533). A personal servitude runs in favor of a particular person, either a natural person or a juridical person ((La. Civ. Code art. 534). In contrast, a predial servitude runs is a charge on one estate that runs in favor of whatever person owns another estate (La. Civ. Code art. 534). An example of a predial servitude is a rite of passage over a servient estate that benefits a dominant estate that has no access to a public road. The kind of servitude that is relevant in the context of a CCS project is a personal servitude. Louisiana law recognizes three types of personal servitudes—usufructs, rights of habitation, and rights of use. The most relevant here is the right of use. A right of use confers upon a person the right to use property belonging to another person in a specified way (La. Civ. Code art. 639). An example of a right of use is a so-called pipeline right-of-way, sometimes called (in Louisiana) a pipeline servitude (*Vintage Assets, Inc., v. Tennessee Gas Pipeline Co. LLC*, 2018; and *Ethridge v. UCAR Pipeline, Inc.*, (2014)). This type of right gives the pipeline company the right to use a certain portion of the property owned by another person to construct, operate, and maintain a pipeline.

Third, there is the catch-all category of other real rights recognized by law. “Real rights confer direct and immediate authority over a thing.” (La. Civ. Code art. 476 cmt. (b))²³ This is contrasted with personal rights—that is, contractual rights—that merely obligate a particular person to allow the holder of the right to use a thing. It is not obvious that any real right other than a right of use would be useful to a person seeking to acquire the surface rights needed to construct, own, and operate a CCS facility.

Finally, in addition to some sort of right directly over a thing (such as ownership, a servitude, or another type of real right), a person who wished to construct, own, and operate a CCS facility could obtain a contractual right to use the surface of land by acquiring a lease. Louisiana Civil Code article 2688 provides that a lease is a “contract by which one party, the lessor, binds himself to give to the other party, the lessee, the use and enjoyment of a thing for a term in exchange for a rent that the lessee binds himself to pay.” A lease must have a term—that is, a particular duration (La. Civ. Code art. 2678), and the term may not exceed ninety-nine years (La. Civ. Code art. 2679).

The ninety-nine-year limit on the term of a lease may make the contract of lease an undesirable way to acquire the surface rights necessary for the injection site. The company may wish those rights to last for more than ninety-nine years. A lease might work as a way acquire the rights

²³ The Civil Code refers to “real rights,” but the Civil Code itself does not define “real rights,” even though the concept of real rights is important in civilian doctrine.

necessary for a pipeline because the period during which a CCS facility accepts CO₂ for injection may be less than ninety-nine years. But to the extent that the owner-operator of a CCS storage facility may need to resort to eminent domain to acquire rights, the types of rights acquired by court order are likely to be a type of property right, such as a servitude, rather than a contractual right, such as a lease. Accordingly, this report will not devote further discussion to leases, though a long-term lease is a potential way to acquire by contract the rights to use the surface of land owned by another person.

Another issue that the owner-operator of a CCS storage facility will need to consider is whether it wishes to preclude oil and gas drilling or other drilling in the subsurface of the area where the CCS project will be located. Precluding such activity may not be necessary for areas where the company merely needs the right to use the surface to run a pipeline. Further, it may not be necessary for areas where the CO₂ storage reservoir will be located. If, however, the owner-operator of the CCS facility wishes to preclude drilling, the company will need to make sure that it acquires the mineral rights associated with the land associated with the reservoir. Otherwise, a person holding mineral rights might be entitled to drill a well.

7.1.3.2 Acquisition of the rights needed for a CCS facility

The strategy for securing rights-of-way for transport infrastructure for a CCS project is similar to that for acquiring pore space rights. After the prospective owner of a CCS facility determines what land which is needed, the owner can hire some combination of landmen, abstractors, and title lawyers (collectively, “land professionals”) to determine who owns the land that is needed. Because persons other than the landowners might have rights to use the land, the land professionals also will need to determine if persons other than the landowner have rights to use the property. Such rights could include publicly-recorded surface leases, rights of use (such as an existing pipeline right-of-way), mineral leases, or mineral servitudes.

Once the landowners and any other persons with existing surface use rights are identified, the operator of a CCS project could negotiate with such individuals in an attempt to acquire the ownership or rights of use needed for the CCS project. If it is impossible to reach a voluntary agreement with one or more of the landowners or other persons with existing surface use rights are identified, an operator who has acquired a certificate of convenience and public necessity from the Louisiana Office of Conservation could use eminent domain to acquire such rights. The authority for the exercise of eminent domain would be Louisiana Revised Statute 30:1108, the same statute that authorizes the use of eminent domain to obtain pore space rights, and the procedure to be used in exercising eminent domain would be the process outlined in Louisiana Revised Statute 19:2, the same statute that governs the procedure for obtain pore space rights by eminent domain.

7.1.4 Analysis of Potential Impact of Due Regard Doctrine on Relationship Between a CCS Operator and Persons Who Own Mineral Rights Associated with the Land Where the CCS Project is Located

A non-landowner who owns a mineral servitude or mineral lease typically has the right to use the surface and subsurface of the land as reasonably necessary to explore for minerals (La. Min. Code arts. 23, 114 (La. Rev. Stats. 31:23, 31:114)).²⁴ In such cases, the mineral rights owner has a duty

²⁴ See also *Caskey v. Kelly Oil Co.* (1999) (quoting with approval a secondary authority and stating “Even in the absence of a clause setting forth the types of surface activities the lessee may engage in on the leased premises, the

to exercise his rights with “reasonable regard” for the rights of the landowner (La. Min. Code art. 11 (La. Rev. Stat. 31:11)). The requirement that the mineral rights owner exercise its rights with reasonable regard for the rights of the landowner likely requires the mineral rights owner to also exercise his rights with due regard for the person who acquires surface or subsurface rights from the landowner.

Accordingly, if a company acquired subsurface storage rights from a landowner, without acquiring all mineral rights relating to the land, a person holding the mineral rights likely would have to exercise his rights with reasonable regard for the rights of the owner-operator of the CO₂ storage site. Accordingly, the owner of a mineral servitude or mineral lease likely would have to take reasonable steps to avoid interfering with the CCS operator’s operations. But this likely would not require the mineral rights owner from drilling through the reservoir used for CO₂ storage, particularly if the mineral rights owner acquired his mineral rights before the CO₂ storage facility was in operation. For this reason, if the owner-operator of a CO₂ storage facility wishes to avoid all chance that the non-landowner would have a right to drill through the storage reservoir, the storage operator likely would need to use eminent domain to acquire any outstanding mineral servitude or mineral lease, or at least to acquire such rights for depths at and below the storage reservoir. The storage operator might not need to acquire any existing mineral rights to the extent those rights apply to depths shallower than the storage reservoir.

Similar reasoning applies to a landowner’s interest in minerals. Generally, a landowner has the right to use his or her land to explore for minerals (*See, e.g.*, La. Min. Code art. 6 (La. Rev. Stat. 31:6)). Further, if a landowner’s interest in minerals is burdened with a mineral servitude or mineral lease, the landowner also typically will own a reversionary interest in minerals. That is, if the landowner who does not have a right to explore for minerals generally will obtain (or re-obtain) such rights if the mineral servitude or mineral lease terminates. For similar reasons, if the owner-operator of a CO₂ storage facility wishes to preclude any possibility of someone drilling through the storage reservoir, the storage operator may wish to acquire the landowner’s rights in minerals—both any rights that are not burdened by a mineral servitude or mineral lease, as well as any reversionary interest the landowner might have in minerals.

7.2 ANALYSIS OF RELEVANT REGULATIONS AND NECESSARY PERMITS

Various regulations would apply to a CO₂ storage project and certain permits will be required. Some of the most notable are the Safe Drinking Water Act, which will require that an operator obtain a permit; the National Environmental Policy Act, which likely will require an Environmental Impact Statement; and the Clean Water Act, which may require a “§ 404” permit.

7.2.1 Analysis of Need for a Safe Drinking Water Act Permit

Congress enacted the Safe Drinking Water Act (SDWA) in 1974 (*W. Va. Univ. Hosps. v. Casey*, 1991; *Miami-Dade Cnty. v. EPA*, 2008; *Legal Envir. Assistance Found., Inc. v. EPA*, 1997) in order “to assure that water supply systems serving the public meet minimum national standards for protection of public health” (H.R. Rep. No. 93-1185 (1974); *see also Miami-Dade*, at 1052). The SDWA addresses several issues, including the establishment of maximum contaminant levels (42 U.S.C. § 300g-1 (2000)), prohibitions on the use of lead pipes in drinking water systems (*Id.* §

lessee has an implied right to use the surface to the extent ‘reasonably necessary’ to explore for and drill oil and gas wells.”). *Edwards v. Jeems Bayou Production Co.* (1987); *Leger v. Petroleum Engineers, Inc.* (1986) (mineral lessee had right to use leased premises as “reasonably necessary”).

300g-6), protection of underground sources of drinking water (*Id.* § 300h), and water treatment (*Id.* § 300j).

Part C of the SDWA addresses the protection of underground sources of drinking water (USDW). Part C requires the EPA to develop regulations for state-based UIC programs, including “minimum requirements for effective programs to prevent underground injection which endangers drinking water sources” (*Id.* § 300h-h(8); *Miami-Dade* at 1052). The SDWA directs that the minimum requirements developed by the EPA must include the mandate that an effective State UIC program shall “prohibit … any underground injection in such State which is not authorized by permit … [or] rule,” (*Id.* § 300h(b)(1)(A)) and that the state shall not authorize by permit or rule “any underground injection which endangers drinking water sources” (*Id.* § 300h(b)(1)(B))

If the EPA determines that a particular state has developed a UIC program that meets the EPA’s minimum regulatory standards, that state may assume primary responsibility, or “primacy,” for regulating underground injections (*Id.* § 300h-1(b)(3)). If a state fails to develop a satisfactory UIC program, the EPA is required to develop a UIC program for that state (*Id.* § 300h-1(c)). Similarly, if a state obtains primacy for SDWA UIC enforcement, but the EPA subsequently determines that its UIC program no longer meets minimum standards, the EPA must develop a UIC program for that state.

The SDWA provides two procedures for a state to obtain primacy for its UIC regulations. First, 42 U.S.C. § 300h-1(b)(1)(A) (2010) provides that a state can obtain primacy by showing that its UIC regulations satisfy all the regulations promulgated by the EPA under 42 U.S.C. § 300h. Those EPA regulations are found in 40 C.F.R. § 145 (2011).

An alternative procedure is provided by 42 U.S.C. § 300h-4(a). That provision allows a state to gain primacy by demonstrating that its UIC regulations meet the requirements set forth in 42 U.S.C. § 300h(b)(1)(A), and that its regulatory program “represents an effective program to prevent underground injection which endangers drinking water sources” (*Legal Env'tl. Assistance Found., Inc. v. EPA*, 2001). The procedure authorized by 42 U.S.C. § 300h-4(a) is a more “flexible” process than that authorized by 42 U.S.C. § 300h-1(b)(1)(A), but the more flexible process for obtaining primacy only applies to certain types of injection wells. Specifically, this process applies to the “portion of any state underground injection control program which relates to: (1) the underground injection of [produced water]; or (2) any underground injection for the secondary or tertiary recovery of oil or natural gas” (42 U.S.C. § 300h-4(a) (2000)).

The regulations developed by the EPA are mostly found in Title 40, Part 144 of the Code of Federal Regulations. These regulations contain numerous substantive requirements for UIC programs, including the requirements that a state’s UIC program must satisfy in order for the state to obtain primacy. For example, Part 144 now establishes six (originally there were five) classes of UIC wells, with particular regulatory requirements for each (40 C.F.R. § 144.6 (2011)). Class VI wells—a relatively new class—are wells for the injection of carbon dioxide for carbon sequestration (40 C.F.R. § 144.6(f)). Class II wells are wells in which fluids are injected for disposal of produced water and certain wastewater associated with oil and gas production, “enhanced recovery of oil or natural gas,” or for storage of liquid hydrocarbons (40 C.F.R. § 144.6(b)). This Class includes some wells in which carbon dioxide is injected for purposes of enhanced oil recovery.

The first class, Class I wells, are wells used to inject wastes “beneath the lowermost formation containing, within one-quarter mile of the well bore, an underground source of drinking water.”

(40 C.F.R. § 144.6(a)). Class III wells are wells associated with certain mining activity (40 C.F.R. § 144.6(c)). Class IV wells are wells used for injection of wastes into a formation that contains an underground source of drinking water within one-quarter mile of the well (40 C.F.R. § 144.6(d)). Class V wells are injection wells that do not fit into any other category of injection well (40 C.F.R. § 144.6(e)).

About thirty-three states have primacy for Classes I through V, and about nine additional seven states have SDWA primacy for Class II only or all Classes except I and VI. Only one state has primacy for all Classes.²⁵ Louisiana has primacy for Classes I, II, III, IV, and V, but not for Class VI (40 C.F.R. § 147.950).

Until recently, no state had primacy for Class VI wells. In part, this is because Class VI is a relatively new class. Indeed, most states desiring primacy for their SDWA UIC programs obtained primacy for each of the original five classes of injection wells before the federal regulations that established the category of Class VI wells were promulgated. Further, a few states that desired primacy only for certain classes of injection wells had acquired primacy for those classes for the Class VI regulations were promulgated. Because primacy is granted on a class-by-class basis, when federal regulations established a new class of injection wells (Class VI wells), no state had primacy. Further, because there is relatively little Class VI well activity, most states likely felt no urgency to begin the process of acquiring primacy for Class VI.

Recently, North Dakota acquired primacy for Class VI wells (83 Fed. Reg. 17758). North Dakota's Class VI regulations provide a template or example of a program that was approved by the EPA for primacy. The existence of this template may encourage other states, including Louisiana, to seek primacy for Class VI wells, but for now Louisiana does not have primacy for Class VI wells. When a state has not obtained primacy for one or more classes of wells, that portion of the state's UIC program is administered by the EPA regional office whose territory includes that state. Thus, if Louisiana still has not obtained primacy for Class VI wells by the time someone seeks to construct a CCS facility in this state, that person would need to apply for a Class VI injection well permit by submitting an application to EPA Region 6, whose main office is in Dallas, Texas (40 C.F.R. § 1.7).²⁶

But Louisiana law appears to authorize the Louisiana Office of Conservation to develop a regulatory program for Class VI wells. If Louisiana acquires primacy for Class VI wells through the Office of Conservation before the prospective owner-operator of a CCS storage facility applies for a SDWA permit, that person would submit its application for a Class VI permit to the Office of Conservation. The Louisiana Office of Conservation is a state agency that is placed within the LDNR (La. Rev. Stat. 36:359(D)), but the Office of Conservation remains largely independent of LDNR (La. Rev. Stat. 36:806)²⁷ and is “directed and controlled by a commissioner of conservation, who shall be appointed by the governor, with the consent of the Senate, for a term of four years.” (La. Rev. Stat. 30:1). The Office of Conservation is the primary regulator of oil and gas activity in Louisiana,²⁸ with authority that includes the regulation of enhanced recovery operations

²⁵ Information on each state may be found at 40 C.F.R. Part 147 (2011). *See also* EPA, 2018d.

²⁶ EPA's principal office for Region 6, which encompasses Louisiana, is in Dallas); 40 C.F.R. § 144.1 (if a state does not have an underground injection control program, EPA must establish one for that state).

²⁷ Providing that DNR's secretary, deputy secretary, and undersecretary generally shall have no authority regarding the “quasi judicial, licensing, permitting, regulatory, rulemaking, or enforcement powers or decisions of the assistant secretary of the office of conservation”.

²⁸ The Office of Conservation's powers are established by Louisiana Revised Statute 30:4.

involving the use of carbon dioxide (La. Rev. Stat. 30:4(C)(10)) and the use of pipelines to transport CO₂ for use in such operations (La. Rev. Stat. 30:4(C)(17)).

7.2.2 Analysis of National Environmental Policy Act Requirements

The National Environmental Policy Act (NEPA) was adopted in 1969. Unlike many environmental statutes, NEPA does not impose substantive requirements. Instead, it is procedural. It requires the federal government to evaluate and document the environmental impacts that certain federal actions are likely to cause. NEPA also generally requires the federal government to consider alternative actions, including a “no action” alternative.

In particular, NEPA provides that “all agencies of the Federal Government shall . . . include in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the [] environment” an environmental impact statement (42 U.S.C. § 4332(2)(C)). An “environmental impact statement” (EIS) is a detailed statement prepared by the action agency as to the environmental impacts of the proposed action, adverse environmental impacts that cannot be avoided, alternatives to the proposed action, the relationship between short-term and long-term uses of the environment, and irreversible and irretrievable commitments of resources. For situations when it is not clear to a federal agency whether an EIS is required, regulations provide a decision tree for federal agencies to follow:

- (1) If the proposed federal action is a type of action that normally requires an environmental impact statement, the agency should prepare an environmental impact statement;
- (2) If the proposal action is subject to a categorical exclusion, then neither an environmental impact statement nor an environmental assessment must be prepared;
- (3) If the proposed action is not subject to a categorical exclusion, but does not normally require an environmental impact statement, the agency must prepare an environmental assessment. Based on the environmental assessment, the agency must then either make a determination to prepare an environmental impact statement or prepare a finding of no significant impact (FONSI) (40 C.F.R. § 1508.4).

A “categorical exclusion” from the requirement to prepare either an environmental assessment or EIS is based on an agency determination that a category of actions rarely has a significant effect on the environment, but even if an action is a type for which a “categorical exclusion” exists, an EIS is still required if extraordinary circumstances warrant an EIS (40 C.F.R. § 1508.4).

An environmental assessment (EA) is a much less detailed document than an environmental impact statement. Its purpose is not to conduct the detailed analysis required in an EIS, but rather to “(1) [b]riefly provide sufficient evidence and analysis for determining whether to prepare an environmental impact statement or a finding of no significant impact” and “(2) [a]id an agency’s compliance with [NEPA] when no environmental impact statement is necessary” (40 C.F.R. § 1508.9). As the decision tree indicates, if based on an EA the agency determines that an EIS is not required, then it must issue a FONSI. Otherwise it must prepare an EIS. A FONSI is a document prepared by an agency that briefly describes the reasons why the action will not have a significant effect on the environment.

The term “major Federal actions” includes the granting of federal environmental permits.

Accordingly, the requirement for an EIS may be triggered by the need for a carbon capture and storage project's need to obtain a permit under the Safe Drinking Water Act or the Clean Water Act (CWA). Further, there is a substantial chance that a carbon storage project built in Louisiana would need a § 404 CWA permit (as will be discussed below). The need for a CWA permit is another reason that the requirement for an EA likely will be triggered.

7.2.3 Analysis of Potential Requirement for a § 404 Permit Under the Clean Water Act

In 1972, the United States Congress passed legislation that is commonly known as the Clean Water Act (33 U.S.C. §§ 1251 *et seq.*). The stated purpose of the legislation was “to restore and maintain the chemical, physical, and biological integrity of the Nation's waters” (33 U.S.C. § 1251(a)). A key section of the CWA provides that “the discharge of any pollutant by any person” into the “waters of the United States” is “unlawful,” except as allowed pursuant to certain specified provisions of the CWA itself (33 U.S.C. §§ 1311(a), 1362). The phrase “discharge of a pollutant” is defined broadly to include “any addition of any pollutant to navigable waters from any point source” (33 U.S.C. § 1362(12)).

And perhaps more importantly, the terms “pollutant” and “navigable waters” are also defined broadly—perhaps more broadly than someone might expect upon a simple reading of the statutory text. The term “pollutant” is defined broadly under the CWA to include not just what one normally thinks of as a contaminant; it also includes solids such as “dredged spoil . . . rock, sand, [and] cellar dirt” (33 U.S.C. § 1362(6)). Under this broad definition, almost any construction activity—because such activities involve disturbing the dirt and often involve the deposit of fill material—can constitute the “discharge of a pollutant.”

Of course, to fall under the scope of the Clean Water Act, such a discharge must be a discharge into “navigable waters,” but “navigable waters” has been defined, for purposes of the Clean Water Act, to include waters that are not navigable, as well as some areas that are not even “waters” and instead are land. The Clean Water Act defines “navigable waters” as meaning “waters of the United States, including the territorial seas” (33 U.S.C. § 1311(a)). In a series of decisions, courts have given an expansive interpretation to “waters of the United States.” For example, in *United States v. Bayview Homes, Inc.* (1985), the United States Supreme Court has held that wetlands adjacent to a navigable body of water are part of “waters of the United States.” For this reason, a person may need a Clean Water Act permit in order to conduct construction work in a “wetland.” In Louisiana, many areas constitute “waters of the United States” because the areas include either waters that are navigable, non-navigable waters that are connected to waters that are navigable, or wetlands that are adjacent to or near such waters.

The permits that typically are needed in order to conduct work in wetlands are often called “§ 404 permits” because section 404 of the Clean Water Act (33 U.S.C. § 1344) authorizes the U.S. Army Corps of Engineers to issue such permits. Depending on where a carbon storage project is located, a § 404 permit may be needed for the construction of surface facilities at the storage site, as well as for construction of portions of any carbon dioxide pipelines that may serve such as storage facility.

7.2.4 Analysis of Other Potentially Relevant Regulations and Permit Requirements

Congress enacted the Endangered Species Act (the ESA) in 1973, finding that “various species of fish, wildlife, and plants in the United States have been rendered extinct as a consequence of economic growth and development un-tempered by adequate concern and conservation . . .” (16

U.S.C. § 1531). For species other than marine species, the ESA is enforced by the U.S. Fish and Wildlife Service (FWS) (16 U.S.C. § 1532(15)).²⁹

The ESA applies to both “endangered” and “threatened” species as those terms are defined in the statute, although a species is not considered endangered or threatened until it is listed as such by the FWS (or, for marine species, the National Marine Fishers Service). An “endangered” species is a species that the appropriate agency determines is “in danger of extinction throughout all or a significant portion of its range . . .” (16 U.S.C. § 1532(3)(6)). A “threatened” species is a species that the agency determines is “likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range.” The primary ways that the ESA protects endangered and threatened species are through its prohibition of the “take” of a species under ESA § 9, and the provisions of ESA § 7 that: (1) require federal agencies to consult with the FWS; and (2) prohibit federal actions that jeopardize endangered or threatened species. Each of these restrictions is discussed below.

For purposes of the ESA, the word “take” is given a broad meaning. The term “take” is defined in the ESA as “to harass, harm, pursue, hunt, shoot, wound, kill, capture, or collect, or to attempt to engage in any such conduct” (16 U.S.C. § 1532(19)). Further, for an activity that harasses, harms, or kills an endangered to constitute a “take,” it is not necessary that the person who conducts the activity have intended to harass, harm, or kill a plant or animal that is a member of an endangered species. Generally, there is strict liability, so even an activity that results in incidental and unintended harm to a member of an endangered species can be a basis for liability, though in some circumstances it is possible to obtain an incidental take permit in advance, as a shield against liability for a “take.” The ESA is not likely to block a CCS project, but an analysis of a CCS project’s potential impact on endangered species—for example, a CO₂ pipeline’s impact on habitat—will have to be made. Further, it is possible that the ESA might require some adjustments to a project, such as an adjustment to a proposed pipeline route, in order to avoid a “take.”

The prohibition on federal actions that would jeopardize a threatened or endangered species is potentially relevant in the context of a CCS project because an agency’s granting of a federal permit constitutes a federal “action,” and certain federal permits likely will be needed for such a project, such as a Safe Drinking Water Act permit for a Class VI well and possibly a § 404 permit under the Clean Water Act.

The prohibition on federal actions that jeopardize protected species is given effect in a multi-step process. First, a federal agency proposing to take an action must inquire of FWS whether any threatened or endangered species “may be present” in the area of the proposed action (16 U.S.C. § 1536(c)(1); and *Thomas v. Peterson*, 1985). If an endangered species is present, the agency that is considering taking a federal action must prepare a “biological assessment” to determine whether such species “is likely to be affected” by the action (16 U.S.C. § 1536(c)(1); and *Thomas v. Peterson*, 1985).³⁰ If the assessment determines that a threatened or endangered species “is likely to be affected,” the agency must formally consult with the FWS (16 U.S.C. § 1536(a)(2)). After the formal consultation, FWS will issue a “biological opinion” (16 U.S.C. § 1536(b)). If the biological opinion concludes that the proposed action would jeopardize the species or destroy or

²⁹ The National Marine Fisheries Services (NMFS) administers the ESA for marine species listed in 50 C.F.R. §§ 222.23(a), 227.4.

³⁰ The biological assessment may be part of an environmental impact statement or environmental assessment that is conducted under the National Environmental Policy Act (NEPA) (*Thomas v. Peterson*, 1985).

adversely modify habitat that FWS has designated as “critical” for the species, the action may not go forward unless the FWS can suggest an alternative that avoids such jeopardization, destruction, or adverse modification (16 U.S.C. §§ 1536(b)(3)(A)). The prohibition on agency action that would jeopardize a protected species is not likely to preclude a CCS project, but it is possible that the analyses described above may have to be performed, and it also is possible that the ESA may require an adjustment to a proposed project (for example, an adjustment to a proposed pipeline route), in order to obtain a federal permit, the granting of which would constitute federal “action” by the agency that grants the permit.

There also is potential for certain laws relating to activities in coastal areas to apply. One noteworthy law is the federal Coastal Zone Management Act (CZMA). The CZMA, which was enacted in 1972, is codified at 16 U.S.C. §§ 1451 through 1466. The CZMA is designed in part to encourage states to develop plans to manage coastal development and protect natural resources in coastal areas (16 U.S.C. § 1452). Further, a portion of the CZMA imposes a requirement that federal agency’s activities generally must comply with state coastal management plans (16 U.S.C. § 1456). Because certain federal permits may be necessary for a CO₂ storage project, this federal act effectively may require compliance with a state’s coastal management laws (not to mention that state law also might impose an obligation for a project to meet certain requirements).

In Louisiana, the relevant state law is the State and Local Coastal Resources Management Act of 1978 (*See* La. Rev. Stat. 49:214.21 *et seq.*). The Act applies to activities in a broad portion of South Louisiana, including areas not immediately adjacent to the coast (*See* La. Rev. Stat. 49:214.24). If a CO₂ storage facility or pipelines serving it (or both) are located in the area to which the Act applies, the owner-operator of the facility may need to obtain state permits. Those permits may impose conditions on the project in order to minimize adverse impacts to the environment. If an adverse impact is unavoidable, the owner-operator may be required to perform compensatory mitigation. The Louisiana regulations that have been promulgated pursuant to the Act are found at Louisiana Administrative Code title 43, part I, chapter 7. A detailed discussion of what permit requirements or mitigation might be required would depend on the specifics of a particular storage facility’s location and design.

7.3 ANALYSIS OF ISSUES RELATING TO LIABILITY

A major concern that affects the viability of a carbon capture and storage project is liability. The most important potential liabilities are: tort liability for any potential accidents or storage cavern failures that might cause damage to other persons or their property; and the obligation to monitor and maintain the carbon storage site. Accordingly, the discussion below focuses on these liabilities. The discussion is arranged under three “subtasks”—the first being an analysis of the legal theories and damages theories that plaintiffs likely would assert in the event of an accident at the site, the second subtask being an analysis of potential means to limit liability in the event of an accident, and the third subtask being an analysis of potential bases to transfer to some other person the liabilities and the responsibility for long-term management of a storage facility.

7.3.1 The legal theories and damages theories that plaintiffs likely would assert in the event of an accident at a storage facility.

As with other industrial projects, there is the potential for an accident to occur during the construction or operation of a storage facility. Such an accident could range from a worker injury to a catastrophic failure of storage cavern integrity that leads to a carbon dioxide plume reaching

the surface and causing harm to multiple individuals. The discussion below examines: the standards for liability; the extent of liability; time limitations on liability; and the potential to transfer to another person all liabilities arising after an agreed time.

7.3.1.1 Standards for Liability and Legal Theories a Plaintiff Likely Would Assert

As the law stands now, strict liability in tort is unlikely to apply to the operation of CO₂ pipeline and storage facilities in Louisiana. Instead, a plaintiff likely would have to prove that conduct of the owner or operator of such facilities fell below a standard of reasonable conduct.

In Louisiana, tort law is governed by the articles contained in Book III, Title V, Chapter 3 of the Civil Code, which includes articles 2315 through 2324.2. There are some differences between Louisiana tort law and the common law of torts. For example, statutory reforms from the mid-1990s largely eliminated the concept of strict liability from Louisiana law.³¹ Further, punitive damages generally are unavailable under Louisiana law.³² But the similarities between Louisiana's tort law and the tort law found in common law are substantial. For example, under Louisiana tort law, as under the common law, liability generally must be based on either negligent conduct or an intentional tort.

Negligence

If any plaintiffs ever file a tort claim, alleging that an incident relating to a carbon dioxide pipeline or storage facility in Louisiana has caused them harm, the plaintiffs likely assert a claim in negligence. Like other states, Louisiana recognizes tort claims based on negligence. Civil Code article 2315 states in part: "Every act whatever of man that causes damage to another obliges him by whose fault it happened to repair it." Thus, article 2315 contemplates liability based on "fault"—either negligence or an intentional tort (*Hero Lands Co. v. Texaco, Inc.* (19750; and *Peters v. Allen Parish School Bd* (2008)). Civil Code article 2316 states: "Every person is responsible for the damage he occasions not merely by his act, but by his negligence, his imprudence, or his want of skill." The Louisiana Supreme Court has described these two articles as the "fountainhead" of tort liability (*Langlois v. Allied Chemical* (1971)), and together the articles form a basis for a claim in negligence.

Garde

It is possible that a plaintiff alleging harm might assert a claim based on *garde* liability. Louisiana Civil Code article 2317 states, "We are responsible ... for the damage ... caused by ... the things which we have in our custody." Louisiana courts have referred to liability based on having custody of a thing that causes damages *garde* liability. A person has "custody" over a thing if he has a right to direct and control the thing. A court likely would conclude that the owner-operator of a carbon dioxide pipeline and storage facility has "custody" over those facilities.

At one time, the *garde* liability imposed by article essentially was a form of strict liability for

³¹ The virtual elimination of strict liability was brought about by Acts 1996, 1st Ex. Session, No. 1.

³² A prohibition on the award of punitive damages in the absence of express statutory authorization had traditionally been part of Louisiana law. *See, e.g., International Harvester Credit Corp.*, (1988). Over the years, the legislature has enacted a handful of exceptions, such as those found in Civil Code articles 2315.3 (child pornography), 2315.4 (driving while intoxicated), 2315.7 (criminal sexual conduct), 2315.8 (domestic abuse), and 2315.9 (terrorism). At one time, a Civil Code article authorized the award of punitive damages when tortious activity involved the storage or handling of hazardous substances, but that article was repealed, *see Ross v. Conoco, Inc.*, (2002), and none of the current bases for an award of punitive damages is likely to apply to conduct involving the transport or storage of carbon dioxide.

harms caused by buildings or structures that a person had in his or her “custody.” This gave plaintiffs a significant incentive to assert *garde* liability as a legal theory for any harm caused by a thing that could be characterized in the custody of a defendant. In 1996, however, the Louisiana Legislature enacted Civil Code article 2317.1,³³ which has been interpreted as adopting a negligence standard for liability under article 2317 for damages caused by a thing in a person’s custody (*Burmaster v. Plaquemines Parish Government*, 2008). Thus, although an amended form of article 2317 remains in the Civil Code, a plaintiff who asserts a claim under this article effectively must prove that a defendant was negligent. This greatly reduces the significance of *garde* liability and thus lessens the likelihood that a plaintiff will raise *garde* as a separate legal theory.

Neighborhood (nuisance)

Another legal theory that plaintiffs might assert is based on the “obligations of neighborhood,” which are imposed by Civil Code articles 667 through 669. These articles are not in the section of the Civil Code dealing with tort claims, and the Louisiana Supreme Court has stated that claims based on the “obligations of neighborhood” are not tort claims. On the other hand, like obligations in tort, the obligations of neighborhood arise without a contract. Further, the Louisiana Supreme Court has recognized that claims based on the obligations of neighborhood are similar to claims based on the common law of nuisance (*Rodrigue v. Copeland*, 1985), and of course nuisance claims typically are characterized as tort claims. Accordingly, this report will discuss claims based on the obligations of neighborhood in the portion of the report addressing potential tort liability.

The primary source of the obligations of neighborhood is Civil Code article 667, which imposes limitations on a person’s use of the property that he or she owns (Articles 668 and 669 do not enlarge the liability imposed by 667). Prior to 1996, the Louisiana Supreme Court held that article 667 was a basis for holding a landowner liable for harms that his activities on his property caused to a neighbor, even if the landowner’s conduct met standards of reasonableness. Such liability was sometimes compared to the strict liability that can be imposed pursuant to the common law’s “ultrahazardous activity” jurisprudence. The 1996 legislation amended Civil Code article 667 to provide in relevant part:

Although a proprietor may do with his estate whatever he pleases, still he cannot make any work on it, which may deprive his neighbor of the liberty of enjoying his own, or which may be the cause of any damage to him. However, if the work he makes on his estate deprives his neighbor of enjoyment or causes damage to him, *he is answerable for damages only upon a showing that he knew or, in the exercise of reasonable care, should have known that his works would cause damage, that the damage could have been prevented by the exercise of reasonable care, and that he failed to exercise such reasonable care.* (See La. Civ. Code art. 667; Acts 1996, 1st Ex. Session, No. 1).

Article 667 goes on to state that a “proprietor” can be liable without regard for this knowledge or

³³ Article 2317.1 states:

The owner or custodian of a thing is answerable for damage occasioned by its ruin, vice, or defect, only upon a showing that he knew or, in the exercise of reasonable care, should have known of the ruin, vice, or defect which caused the damage, that the damage could have been prevented by the exercise of reasonable care, and that he failed to exercise such reasonable care. Nothing in this Article shall preclude the court from the application of the doctrine of *res ipsa loquitur* in an appropriate case.

reasonable care “if the damage is caused by an ultrahazardous activity,” but that, for purposes of such liability, “ultrahazardous activity … is strictly limited to pile driving or blasting with explosives” (La. Civ. Code art. 667) Because neither pile driving nor blasting are likely to play a major part in the construction and operation of a CO₂ transport and storage system, article 667 is unlikely to be a source of liability in the absence of conduct falling below a standard of reasonableness.

Trespass

If the factual bases of a plaintiff’s claim included allegations that carbon dioxide stored in the subsurface migrated into the subsurface or airspace of plaintiff’s property without the plaintiff’s permission or some other grounds for the right of entry, and that the carbon dioxide then caused harm, the plaintiff might assert a claim for trespass. To support liability under Louisiana law, the entry must be intentional or negligent (*See, e.g., Terre Aux Boeufs Land Co., Inc. v. J.R. Gray Barge Co.*, 2001). If the operator of a storage facility believed that it had acquired the right to enter certain land to build or operate certain facilities, or believed it had acquired the right to use the subsurface of certain land for storage, the operator might commit an intentional trespass. Putting aside that possibility, a plaintiff that asserted a trespass claim would have to show that the defendant acted negligently. And, whether the plaintiff alleged an intentional trespass or negligent trespass, Louisiana law would require the plaintiff to show damages in order to recover in trespass. Louisiana law does not provide a basis for a nominal damages award in the absence of actual damages.

7.3.1.2 Extent of Liability

In most cases, tort liability is not solidary (the civil law’s concept of joint and several liability (*Veazey v. Elmwood Plantation Associates, Ltd.*, 1994)). Instead, a tortfeasor’s share of liability for a plaintiff’s injuries is in proportion to the tortfeasor’s fault, relative to the total fault of all persons, including the fault of the plaintiff himself, all defendants, and all other persons (including any person immune from tort liability, such as an employer that is immune under worker’s compensation laws) (La. Civ. Code art. 2323). This system of pure comparative fault gives some protection to defendants. At one time, a deep-pocketed defendant with a slight degree of fault could be liable for all or a substantial portion of a plaintiff’s damages. On the other hand, in the event that a defendant is found to be wholly at fault or to a high degree of fault, the defendant could still be liable for all or a major portion of a plaintiff’s damages.

7.3.1.3 Time Limit on Liability

The limitations period for actions in tort generally is one year (La. Civ. Code art. 3492).³⁴ As limitations periods go, this is relatively short, but for several reasons this is not a great restriction on an operator’s risk. First, many harms that a person might incur from operations of a carbon dioxide pipeline or storage facility will be evident immediately. Further, Louisiana has a doctrine commonly called *contra non valentem*, which operates somewhat like the common law’s discovery rule to delay the running of a limitations period in some circumstances if a plaintiff was not aware of the tortious conduct that caused his harm (*Peak Performance Physical Therapy & Fitness, LLC v. Hibernia Corp.*, 2008). Further, if an accident occurs, a court may conclude that the tortious conduct occurred at the time of or shortly before the accident, rather than at some point in time

³⁴ In Louisiana, limitations periods for civil actions are called periods of “liberative prescription.” *See* La. Civ. Code art. 3447.

more than a year before.

7.3.2 Analysis of Potential Means to Limit Liability in the Event of an Accident.

The Louisiana Geologic Sequestration of Carbon Dioxide Act puts certain caps on liability in the event of an accident for which the owner-operator of a CCS facility is liable. This could reduce risk and have a positive effect on CCS project economics.

In particular, Louisiana Revised Statute 30:1109(B) places an upper limit on certain types of liability. “In any civil liability action against the owner or operator of a storage facility, carbon dioxide transmission pipeline, or the generator of the carbon dioxide being handled by either the facility or pipeline, the maximum” liability for “compensatory damages for noneconomic loss” (noneconomic loss would include pain and suffering), the maximum liability would be \$250,000 “per occurrence,” except that the liability limit for noneconomic damages would be \$500,000 “for wrongful death; permanent and substantial physical deformity, loss of use of a limb or loss of a bodily organ system; or permanent physical or mental functional injury that permanently prevents the injured person from being able to independently care for himself or herself and perform life sustaining activities.”

This provision has never been interpreted by a court. There are some important interpretative questions to be answered. For example, is one “per occurrence” limit for an incident. Or, is there one “per occurrence” limit for each “civil action”? Or, is there a separate “per occurrence” limit for each plaintiff? If the damages limit is a total, collective “per occurrence” limit for all plaintiffs, no matter how many different lawsuits are filed, the limitation would substantially reduce risk for a CCS operator. If there is a separate “per occurrence” limit for each “civil action,” this would still provide substantial protection for a CCS operator, and it might push plaintiffs away from pursuing class actions or mass actions. If there is a separate “per occurrence” limit for each plaintiff, the limitation still would significant protection for the CCS facility owner, though obviously less significant than under scenarios in which there is not a separate limit for each plaintiff. The statute does not limit “economic damages,” such as damages for harm to property or earnings capacity.

7.3.3 Analyses of Bases for Transferring Liability and Responsibility for Long Term Management of Storage Facility to Another Person|

Because the goal of a CCS facility is to store carbon dioxide in the subsurface for a very long time, a CCS project entails certain long-term liabilities. These include the potential liability for harms that arise from some accident, as well as the responsibility for the long-term monitoring, maintenance, and management of the facility. The long-term and ongoing nature of these liabilities could deter private investment in a CCS facility, but the Louisiana Geologic Sequestration of Carbon Dioxide Act provides certain provisions that may enable the owner-operator of a CCS facility to transfer liabilities to someone else. Such a transfer could reduce the owner-operator’s risk and have a positive effect on CCS project economics. Below, this report discusses the Act’s provisions relating to transfer of liabilities to the State of Louisiana or to another person.

7.3.3.1 Transfer of Liability to the State

One of these provisions is found at Louisiana Revised Statute 30:1109(A). It provides a general rule that ten years after the cessation of injection into a storage facility, if the operator demonstrates “that the reservoir is reasonably expected to retain mechanical integrity and the carbon dioxide will reasonably remain emplaced,” the Commissioner of Conservation “shall issue a certificate of

completion of injection operations, ... at which time ownership to the remaining project including the stored carbon dioxide transfers to the state.” At that time, “the storage operator, all generators of any injected carbon dioxide, all owners of carbon dioxide stored in the storage facility, and all owners otherwise having any interest in the storage facility, shall be released from ... any and all liability associated with or related to that storage facility which arises after the issuance of the certificate of completion of injection operations.”

But there is an important exception to this liability release. Louisiana Revised Statute 30:1109(A)(2) state that the “release from liability will not apply to the owner or last operator of record of a storage facility if the Carbon Dioxide Geologic Storage Trust Fund has been depleted of funds such that it contains inadequate funds to address or remediate any duty, obligation, or liability that may arise after issuance of the certificate of completion of injection operations.” This provision has not yet been interpreted by a court, but it may mean that, when an obligation is owed to a person, that person must first look to the Carbon Dioxide Geologic Storage Trust Fund, but once that Fund is exhausted the owner or last operator of the CCS facility could be liable. The Trust Fund is established by Louisiana Revised Statute 30:1110, and is funded primarily by any fees and fines associated with carbon sequestration projects in the State of Louisiana. It is not clear how much money is likely to build up in such the Trust Fund.

The transfer of liability to the state may be a particularly attractive option to the owner-operator of a CCS facility because the Louisiana Geologic Sequestration of Carbon Dioxide Act seems to provide that, when the required conditions are satisfied, a transfer of the CCS facility to the state would relieve the former owner-operator from future tort liability, as well as from liability for future maintenance and monitoring obligations.

7.3.3.2 Transfer of Liability to Another Person Other than the State

The goal of a carbon dioxide storage project will to store the CO₂ in the subsurface for a very long time. A possible challenge to making a CO₂ storage project viable is finding a company that would be willing be willing to own and operate a project that would bring a relatively short-term stream of income, but a near-permanent risk of tort liability and a near-permanent obligation to maintain and monitor the facility. The Louisiana Geologic Sequestration of Carbon Dioxide Act provides a potential solution to this challenge.

Louisiana Revised Statute 30:1111 states that, if ownership of a CCS facility is transferred from one party to another (not counting a transfer in ownership to the state pursuant to La. Rev. Stat. 30:1109), the transferor may establish a “site-specific trust account ... for the purpose of providing a source of funds for long-term maintenance, monitoring, and site closure or remediation of that storage facility at such time in the future when closure or remediation of that storage facility site is required.” If the Commissioner of Conservation approves the site-specific trust account and the account is fully funded, the party transferring ownership of the CCS facility is released from liability to the state “for any site closure costs or actions associated with the transferred storage facility site.”

This provision would appear to release the transferor from liability not only for future remediation and closure costs, but it is not clear that this would release the former-owner operator from potential liability to third persons in the event of an accident. However, given that Louisiana has a pure comparative fault system and, for the most part, has eliminated strict liability, a former owner-operator who no longer has responsibility for maintaining and monitoring a site will be at substantially reduced risk for tort liability.

The ability to transfer responsibility for future remediation and closure costs to another person could be very attractive for a company that wishes to move liability from its balance sheet.

8 CONCLUSIONS

The South Louisiana industrial corridor is one of the more uniquely-situated regions in the country to sustain an industrial CCS project. The region has a large number and wide variety of carbon emissions sources that could be tapped for an integrated CCS project. The leading industrial capture candidates, for instance, are all present in not only the industrial corridor, but many other industrial locations around the state, such as Lake Charles. These major industrial carbon sources include ethylene oxide and ammonia producers, natural gas processors, and petroleum refineries.

The key to developing a South Louisiana CCS project will be in developing multiple industrial opportunities to attain development scale and scope that can lead to synergies and hopefully technological improvements and development efficiencies. This study has identified the top ten industrial carbon emission sources, six of which are in close proximity to one another in the South Louisiana industrial corridor. These six industrial locations, in total, account for as much as 24 million tonnes of carbon emissions or 30 percent of the statewide total. This represents a considerable carbon source for capture purposes. Ultimately, the CF Industries location in Donaldsonville, Louisiana was chosen as the project candidate site given its large capture opportunities and location relative to other potential geological storage facilities.

This research, after identifying a specific large carbon source (CF Industries), identified a number of large geological locations for permanent carbon storage. The screening process for these candidate storage locations focused on those areas that are: (a) in close proximity to the Louisiana industrial corridor; and (b) the potential size of the storage facility. Two locations became readily-apparent: Bayou Sorrel and Paradis.

Bayou Sorrel is a depleted oil field located in Iberville parish just southwest of Baton Rouge. The field has an aerial extent of 26,000 acres and is a stacked sand system spanning 2,500 feet to 10,500 feet in depth. An average depth of 7,100 feet was used for static and dynamic capacity estimation purposes. This field is estimated to have a static storage capacity of 133 Mt and a dynamic storage capacity ranging from a low of around 88 Mt to a high of about 338 Mt.

The Paradis field is located further south in the industrial corridor and is proximate to many large-scale refineries in the area. The Paradis field is located in St. Charles parish and has been examined as a candidate field in a number of CO₂-EOR studies. The field sits atop a salt dome and is highly-faulted. The areal extent of the field is over 45,000 acres and is estimated to have a static storage capacity of 83.9 Mt and a dynamic capacity of between 16 Mt and 30 Mt.

Ultimately, Bayou Sorrel was selected as the final candidate site for economic feasibility purposes since it matches up well, from a geographical perspective, with the CF Industries source location, has higher overall storage capabilities, and appears to be a less risky storage location given various risk management sensitivities.

While Louisiana has an abundance of pipeline transportation assets, it would appear from the analysis conducted here that there are few if any repurposing opportunities for carbon transportation despite this being often cited as a viable option. Captured carbon is usually compressed at very high pressures of around 2,200 psig: an amount that is far in excess of what is normally found in natural gas transportation. The pipeline repurposing feasibility analysis conducted in this report finds that only 1.4 percent of the eligible 5,112 pipeline segments in the region could support conversion to carbon transportation. The results, however, are a function of the assumptions used in the repurposing feasibility analysis including those used to estimate each

candidate pipeline segment's MAOP.

The economic feasibility analysis shows that a CCS project in South Louisiana is not economically viable, even with the recently-updated 45Q tax credits of up to \$50 per ton for permanent storage by 2024. The integrated economic feasibility analysis conducted in this report estimates an overall capital CCS unit cost of \$69.74 per tonne and O&M costs of \$19.27 per tonne. Total “all-in” CCS unit costs for these candidate source/sink pair is estimated to be \$89.01 per tonne: an amount higher than the 45Q tax credit indicating that a large ammonia or comparable industrial application may not be economically feasible in South Louisiana.

The public perception of a CCS project in South Louisiana will likely be a function of: (a) the degree to which stakeholders are educated about CCS technologies; and (b) the degree to which environmental stakeholder groups oppose industrial CCS development. There is a reasonable chance that a South Louisiana CCS project will attain favorable public opinion since: (a) most Louisiana stakeholder groups are familiar with energy infrastructure development; (b) are familiar with the consistent efficiency upgrades and investments made at many of these petrochemical facilities; and (c) will not be responsible for a large share of the upfront cost subsidies that will be provided by the federal government to financially support the initial capital costs.

Two public perception challenges could arise to derail a CCS development. The first is associated with the perceived operational risk of a CCS project. The carbon captured at these facilities will likely be under very high pressure and is a potential asphyxiate. The second is the fact that some environmental groups have been lukewarm or even opposed to CCS projects, like the Sierra Club. This opposition, however, appears to be more focused on power generation rather than industrial applications. Power generation applications often utilize “clean coal” technologies which these groups often oppose. Power generation projects are also competitors with renewable energy projects which these groups tend to prefer to CCS. Using these as bases for opposition for an industrial project is not well founded. Industrial projects do not use clean coal, but natural gas, and are not in direct competition with renewable energy resources.

Lastly, Louisiana has a favorable set of laws and regulations for CCS development. Louisiana has a long history with underground storage rights. Further, the Louisiana Legislature has passed statutes over the past several years that provide clear guidelines on how CO₂ will be injected into storage and monitored. These statutes should reduce a considerable amount of business liability and legal risk for CCS developers.

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APPENDIX A: LOUISIANA'S CIVIL LAW PROPERTY SYSTEM

In the United States, the major areas of private law that govern the rights and duties of private persons with respect to one another—property, contract, and tort law—are matters of state law, rather than federal law. In most states, these governing rules are based in judge-made common law. But in Louisiana, a civil law system prevails. Thus, within this state, the Louisiana Civil Code contains the main provisions that constitute the state's property law,³⁵ as well as its contract³⁶ and tort law.³⁷ As between these three areas of law—property, contract, and tort—Louisiana's civil law property system is probably the one that varies the most from its common law analogue, though even with respect to property law there are some similarities between the common law and civil law.

Like the common law, Louisiana's Civil Code divides property into different categories and applies different rules to each category. One division is that between “movables” and “immovables”—a division that is analogous to the common law's division between real property and personal property. Louisiana's concept of immovable property is roughly analogous to the common law's concept of real property (*Goodrich Petroleum Corporation*, 2018). Louisiana Civil Code article 462 states: “Tracts of land, with their component parts, are immovables.” Buildings also are classified as “immovables.”³⁸ Similarly, Louisiana law's concept of movable property is roughly analogous to the common law's concept of personal property (*Goodrich Petroleum Corporation*, 2018). Under Louisiana law, “movables” include “things, whether animate or inanimate, that normally move or can be moved from one place to another,” as well as “[r]ights, obligations, and actions that apply to a movable thing” (La. Civil Code arts. 471, 473). As one court stated, “In civil law systems, ‘things’ are divided into movables and immovables, as opposed to the common law system where they are divided into personal and real property” (*Ark-La-Tex Timber Co., Inc.*, 2007).

Another of the divisions found in the Civil Code—that between corporeal and incorporeal property—is analogous to the common law's division between tangible and intangible property. Louisiana Civil Code article 461 explains that, “Corporeals are things that have a body, whether animate or inanimate, and can be felt or touched.” Article 461 goes on to explain that, “Incorporeals are things that have no body, but are comprehended by the understanding, such as the rights of inheritance, servitudes, obligations, and right of intellectual property.”

³⁵ Book II of the Louisiana Civil Code, consisting of Code articles 448 through 818, contain Louisiana's main property law provisions.

³⁶ Title IV of Book III of the Louisiana Civil Code governs “conventional obligations” or contracts. This title includes Code articles 1906 through 2057. The Civil Code contains other provisions that are relevant to contracts, though. For example, Title III of Book III contains provisions that apply to all obligations—whether the obligations arise from a contract or some other source. Title III of Book III includes Code articles 1756 through 1905. Further, Book III contains some sections that apply to specific types of contracts, such as contract of sale (Title VII), exchange (Title VIII), and so forth.

³⁷ The main body of Louisiana's tort law is contained in Chapter 3 (Of Offenses and Quasi Offenses) of Book III (Of the Different Modes of Acquiring the Ownership of Things), Title V (Obligations Arising Without Agreement) of the Louisiana Civil Code. Chapter 3 includes Civil Code articles 2315 through 2324.2.

³⁸ Article 463 states: “Buildings, other constructions permanently attached to the ground, standing timber, and unharvested crops or ungathered fruits of trees, are component parts of a tract of land when they belong to the owner of the ground.” Article 464 states: “Buildings and standing timber are separate immovables when they belong to a person other than the owner of the ground.”

Finally, Louisiana law divides things into categories based on who may own the thing. “Common things” are things that cannot be owned by anyone (La. Civ. Code art. 449). Common things include the air and the high seas (La. Civ. Code art. 449). Things are susceptible of ownership, but only by the state or its political subdivisions, are classified as “public things” (La. Civ. Code art. 450). Public things include “running waters, the waters and bottoms of natural navigable water bodies, the territorial sea, and the seashore.” Civil Code article 450 states that these things “are owned by the state or its political subdivisions in their capacity as public persons.” Finally, “private things” are things that generally can be owned by anyone, including natural persons, juridical persons (such as corporations), or governmental entities “in their capacity as private persons.” Examples of private things include land, buildings, computers, and staplers. Thus, natural persons can and do own computers, as do companies and governmental entities.

It is noteworthy, however, that some private things are not owned by anyone. Such a thing is *res nullius*—a thing that is not owned by anyone, though it is susceptible of ownership (See La. Civ. Code art. 3412 cmt. (d)). A thing can be *res nullius* either because no one has ever owned it or because a prior owner has abandoned it. If a thing is *res nullius*, the first person who takes possession of the thing becomes the owner. Civil Code art. 3412 states: “Occupancy is the taking of possession of a corporeal movable that does not belong to anyone. The occupant acquires ownership the moment he takes possession.”

Under Louisiana law, natural subsurface deposits of oil, gas, other fugacious minerals, and groundwater are examples of things that are *res nullius*—that is, these substances are susceptible of ownership, but these substances are not owned by anyone when located in natural deposits in the subsurface because the fluids in such natural deposits have never been “reduced to possession.”³⁹ However, consistent with the concept of occupancy, these substances become the property of whoever first produces them.

The Louisiana Civil Code articles dealing with the law of occupancy (See La. Civ. Code arts. 3412-3420) apply only to corporeal movables, not to immovables (La. Civ. Code art. 3412. See also Trahan, 2012). There is no conceptual reason why the law of occupancy could not apply to immovable property, assuming the existence of immovable property that was *res nullius*.

³⁹ See La. Min. Code arts. 6 (La. Rev. Stat. 31:6). Throughout the United States, the general rule is that the landowner has the exclusive right to conduct operations on and beneath his land for the production of oil and gas. Further, under the rule of capture, which appears to have been adopted universally in the U.S. with respect to oil and gas, a person who recovers oil and gas from a well located where he had a right to operate such a well becomes the owner of that oil and gas, even if a portion of the oil and gas drained from beneath another person’s property. But states disagree about a conceptual issue—does the landowner own the molecules of oil and gas while they are in place in natural deposits beneath his land, or does he merely have (1) the exclusive right to conduct operations on and beneath his property and (2) the right to ownership of whatever oil and gas he recovers from a well located on his property? The majority rule is that the landowner owns the oil and gas in place, while the minority rule is that the landowner merely has the exclusive right to conduct operation and to own whatever hydrocarbons he recovers. The majority rule is illustrated by *Lightning Oil Co. v. Anadarko E&P Onshore, LLC*, 2017 (in this case, the owner of the interest in minerals was not the landowner, because there was a severed mineral estate, but the owner of the mineral estate had a possessory interest in the oil and gas in place). The minority rule is represented by *Gerhard v. Stephens*, 1968 and Louisiana Mineral Code article 6. See also La. Civ. Code art. 3412 cmt. (g). Even in states in which the owner of a mineral interest has a possessory interest in the oil and gas in place, that does not mean that the owner of the owner of a severed mineral interest owns the pore spaces or the rock matrix that surrounds the oil and gas molecules. Instead, the general rule is that those still belong to the landowner. See, e.g., *Lightning Oil Co. v. Anadarko E&P Onshore, LLC*, 2017.

Indeed, under international law, occupation of land that was *res nullius* is a recognized way of a nation acquiring sovereignty over territory (Smith, 2010). For reasons of policy, however, some jurisdictions seek to avoid the possibility of land being *res nullius* by providing (for example) that ownership of land cannot be abandoned (*Gerhard v. Stephens*, 1968). Louisiana's limitation of the law of occupancy to corporeal movables is consistent with such a policy.

Some aspects of Louisiana's civil law property system cause Louisiana oil and gas law have some differences from the oil and gas law of other states. For example, most other states allow a permanent severance of mineral interests from the other benefits associated with ownership of the land. When such a severed mineral interest is created, it sometimes is called a "mineral estate." But in the early 1920s the Louisiana Supreme Court held that the concept of separate estates in the same land is a common law concept that does not exist within Louisiana's civil law system (*Wemple v. Nabors Oil & Gas Co.*, 1923). If parties to an agreement purport to create a severed mineral interest, their agreement is not rendered null, but it is not recognized as creating a permanent mineral estate. Instead, under Louisiana law, such an agreement establishes a mineral servitude, which is a type of real right. (*Wemple v. Nabors Oil & Gas Co.*, 1923; *see also* La. Min. Code arts. 16 and 21 (La. Rev. Stats. 31:16 and 31:21). Under Louisiana law, a real right terminates by prescription of nonuse if it is not used for any period of ten-consecutive years (*See* La. Civ. Code arts. 621, 631, 645, 3448; *see also* La. Min. Code art. 27).

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La. Civil Code art. 3448

La. Civil Code arts. 3412-3420

Louisiana Mineral Code article 6.

Louisiana Mineral Code article 16 (La. Rev. Stats. 31:16)

Louisiana Mineral Code article 21 (La. Rev. Stats. 31:21)

Louisiana Mineral Code article 27 (La. Rev. Stat. 31:27).

La. Revised Statute 31:6

APPENDIX B: NARRATIVE DISCUSSION OF THE LOUISIANA GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE ACT

The Louisiana Geologic Sequestration of Carbon Dioxide Act was enacted by Act No. 517 of the 2009 Regular Session of the Louisiana Legislature. The Act is codified at Louisiana Revised Statutes 30:1101 through 30:1111. The first section of the Act (La. Rev. Stat. 30:1101) merely gives a name to the Act.

The second section (La. Rev. Stat. 30:1102) declares a public policy in favor of the sequestration of carbon dioxide, listing several potential benefits. First, declares the Act, “[t]he geologic storage of carbon dioxide will benefit the citizens of the state and the state’s environment by reducing greenhouse gas emissions.” The Act goes on to state that carbon dioxide could be a valuable commodity and that “the geologic storage of carbon dioxide may allow for the orderly withdrawal” of CO₂ for various uses, “commercial, industrial, or other uses, including the use of carbon dioxide for enhanced recovery of oil and gas.” Therefore,

It is the public policy of Louisiana and the purpose of this Chapter to provide for a coordinated statewide program related to the storage of carbon dioxide and to also fulfill the state’s primary responsibility for assuring compliance with the federal Safe Drinking Water Act, including any amendments thereto related to the underground injection of carbon dioxide. (La. Rev. Stat. 30:1104(A)(4))

The second section of the Act also provides that the Louisiana Commissioner of Conservation has jurisdiction to enforce the Act, but a subsequent section specifies in much greater detail the duties and powers of the Commissioner under the Act (La. Rev. Stat. 30:1104(A)(4)).

The third section (La. Rev. Stat. 30:1103) defines several terms.

The fourth section of the Act (La. Rev. Stat. 30:1104) is the one that defines in detail the duties and powers of the Commissioner with respect to carbon storage (La. Rev. Stat. 30:1104(A)(4)). The section states that the Commissioner has the authority to regulate carbon dioxide storage facilities, including the pipelines that carry CO₂ to a storage site (La. Rev. Stat. 30:1104(A)(1)), and that the Commissioner has authority, after notice and hearings, to issue regulations or orders necessary for the proper administration and enforcement of the Act (La. Rev. Stat.

30:1104(A)(2)). The fourth section also gives the Commissioner the authority to issue certificates of public convenience and necessity for storage facilities and pipelines that service CO₂ storage facilities (La. Rev. Stat. 30:1104(A)(1); *see also* La. Rev. Stat. 30:1107). Such certificates are significant because possession of such a certificate is required before a person may use the subsurface to store carbon dioxide and because a person who holds such a certificate has authority to use eminent domain to acquire surface and subsurface rights necessary to construct and operate a storage site and the pipelines necessary to service the site (La. Rev. Stat. 30:1104(C)).

The fourth section also sets forth certain findings that the Commissioner must make, after a public hearing in the parish where a storage facility will be located, before a person may operate a carbon dioxide storage facility or exercise eminent domain to acquire rights to operate a storage facility. Before authorizing the operation of a CO₂ storage facility, the Commissioner must conclude that the reservoir proposed for the storage of carbon dioxide is suitable for such use. To support such a conclusion, the Commissioner must find that use of the reservoir for

storing carbon dioxide will not cause contamination of other formations containing “fresh water, oil, gas, or other commercial mineral deposits” and that the proposed project will not endanger human lives or cause a hazardous condition to property” (La. Rev. Stat. 30:1104(C)).

The fourth section seems to contain an internal discrepancy regarding what type of finding the Commissioner must make with respect to the proposed storage reservoir’s capability to produce oil or gas in paying quantities. A portion of the section states that “no reservoir, any part of which is producing or is capable of producing oil, gas, condensate, or other commercial mineral in paying quantities, shall be subject to [use for CO₂ storage], unless all owners in such reservoir have agreed thereto” (La. Rev. Stat. 30:1104(C)) But the same part of the section goes on to state that, “[i]n addition,” no reservoir shall be used for carbon dioxide storage unless the Commissioner finds either that all quantities of oil, gas, condensate, or other commercial minerals therein” that are capable of production in paying quantities have been produced or that the reservoir has greater utility for the storage of carbon dioxide than for production of any remaining oil, gas, condensate, or other minerals and that three-fourths of the owners, excluding certain lessors, have consented (La. Rev. Stat. 30:1104(C)).

The fifth section (La. Rev. Stat. 30:1105) addresses certain procedural issues, including the rules for hearings. The sixth section (La. Rev. Stat. 30:1106) provides that the Commissioner authority to take steps for enforcement of the Safe Drinking Water Act and for penalties for violation of Louisiana Geologic Sequestration of Carbon Dioxide Act. The seventh section (La. Rev. Stat. 30:1107) governs the Commissioner’s issuance of certificates of public convenience and necessity for CO₂ storage projects, as well as certificates of completion to recognize that final injection operations at a storage facility are complete. The eighth section (La. Rev. Stat. 30:1108) contains certain substantive provisions regarding the use of eminent domain for carbon dioxide storage projects and adopts by reference the procedural provisions of Louisiana Revised Statute 19:2.

The remaining three portions of the Louisiana Geologic Sequestration of Carbon Dioxide Act govern liability and the creation of funds to address liabilities and long-term management of a storage site. The ninth section (La. Rev. Stat. 30:1109) of the Act provides limits on liability of the operator of a carbon dioxide storage site for long-term maintenance of the site, as well as certain limits on tort liability. For example, this section states:

Ten years, or any other time frame established by rule, after cessation of injection into a storage facility, the commissioner shall issue a certificate of completion of injection operations, upon a showing by the storage operator that the reservoir is reasonably expected to retain mechanical integrity and the carbon dioxide will reasonably remain emplaced, at which time ownership to the remaining project including the stored carbon dioxide transfers to the state. (La. Rev. Stat. 30:1109(A)(1))

Further, upon the issuance of the certificate of completion, any performance bonds posted by the operator to satisfy regulatory or permits requirements will be released (La. Rev. Stat. 30:1109(A)(3)), and responsibility for continued monitoring and any remediation of the site will be transferred to a Carbon Geologic Storage Trust Fund that is authorized by Louisiana Revised Statute 30:1110. The release of the operator’s liability generally will not apply, however, “if the Carbon Dioxide Geologic Storage Trust Fund has been depleted of funds such that it contains inadequate funds to address or remediate any duty, obligation, or liability that may arise after

issuance of the certificate of completion of injection operations" (La. Rev. Stat. 30:1109(A)(2)). In addition, the release from liability will not apply if the operator "intentionally and knowingly concealed or intentionally and knowingly misrepresented material facts related to the mechanical integrity of the storage facility or the chemical composition of any injected carbon dioxide" (La. Rev. Stat. 30:1109(A)(3)).

This section also puts a cap on certain types of monetary damages awards. In particular, the section provides

In any civil liability action against the owner or operator of a storage facility, carbon dioxide transmission pipeline, or the generator of the carbon dioxide being handled by either the facility or pipeline, the maximum amount recoverable as compensatory damages for noneconomic loss shall not exceed two hundred fifty thousand dollars per occurrence, except where the damages for noneconomic loss suffered by the plaintiff were for wrongful death; permanent and substantial physical deformity, loss of use of a limb or loss of a bodily organ system; or permanent physical or mental functional injury that permanently prevents the injured person from being able to independently care for himself or herself and perform life sustaining activities. In such cases, the maximum amount recoverable as compensatory damages for noneconomic loss shall not exceed five hundred thousand dollars per occurrence. (La. Rev. Stat. 30:1109(B)(1))

The tenth section of the Act (La. Rev. Stat. 30:1110) establishes a Carbon Dioxide Geologic Storage Trust Fund that is to be administered by the Commissioner of Conservation. The Commissioner is authorized to levy certain fees on the operators of CO₂ storage facilities to obtain money for the Fund.

Finally, the eleventh section of the Act (La. Rev. Stat. 30:1111) provides rules for the establishment of site-specific trust accounts. The purpose of site specific trust accounts is to give a party that is transferring ownership of a storage site to a new owner to means to relieve itself of potential future liabilities (absent such a site specific trust account), a former owner of a site might be liable for obligations associated with a site in the event that the new owner cannot satisfy those obligations (La. Rev. Stat. 30:1111(H)). The section provides that if parties decide to establish a site-specific trust account, the Commissioner shall require that an estimate be made of the future costs of monitoring and maintaining the storage site, and that the estimate must be made by a contractor approved by the Commissioner (La. Rev. Stat. 30:1111(B)). If the parties then establish a site-specific trust account that contains sufficient funds to satisfy the estimate, the party that transferred its ownership to another person will be relieved of future liability, and that liability will then rest with the new owner (La. Rev. Stat. 30:1111(E)).

APPENDIX C: TEXT OF THE LOUISIANA GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE ACT

Louisiana Revised Statutes

Title 30. Minerals, Oil, and Gas and Environmental Quality

Subtitle I. Minerals, Oil, and Gas

Chapter 11. Louisiana Geologic Sequestration of Carbon Dioxide Act

La. Rev. Stat. 30:1101. Short title

This Chapter shall be known and may be cited as the “Louisiana Geologic Sequestration of Carbon Dioxide Act”.

La. Rev. Stat. 30:1102. Policy; jurisdiction

A. It is declared to be in the public interest for a public purpose and the policy of Louisiana that:

(1) The geologic storage of carbon dioxide will benefit the citizens of the state and the state’s environment by reducing greenhouse gas emissions.

(2) Carbon dioxide is a valuable commodity to the citizens of the state.

(3) Geologic storage of carbon dioxide may allow for the orderly withdrawal as appropriate or necessary, thereby allowing carbon dioxide to be available for commercial, industrial, or other uses, including the use of carbon dioxide for enhanced recovery of oil and gas.

(4) It is the public policy of Louisiana and the purpose of this Chapter to provide for a coordinated statewide program related to the storage of carbon dioxide and to also fulfill the state’s primary responsibility for assuring compliance with the federal Safe Drinking Water Act, including any amendments thereto related to the underground injection of carbon dioxide.

B. The commissioner of conservation shall have jurisdiction and authority over all persons and property necessary to enforce effectively the provisions of this Chapter relating to the geologic storage of carbon dioxide and subsequent withdrawal of stored carbon dioxide.

La. Rev. Stat. 30:1103. Definitions

Unless the context otherwise requires, the words defined in this Section have the following meaning when found in this Chapter:

(1) “Carbon dioxide” means naturally occurring, geologically sourced, or anthropogenically sourced carbon dioxide including its derivatives and all mixtures, combinations, and phases, whether liquid or gaseous, stripped, segregated, or divided from any other fluid stream thereof.

(2) “Commissioner” has the same meaning as provided in R.S. 30:3(2).

(3) “Gas” has the same meaning as provided in R.S. 30:3(5).

(4) "Geologic storage" means the long-or short-term underground storage of carbon dioxide in a reservoir.

(5) "Office" means the office of conservation, Department of Natural Resources.

(6) "Oil" has the same meaning as provided in R.S. 30:3(4).

(7) "Person" means any natural person, corporation, association, partnership, limited liability company, or other entity, receiver, tutor, curator, executor, administrator, fiduciary, or representative of any kind.

(8) "Reservoir" means that portion of any underground geologic stratum, formation, aquifer, or cavity or void, whether natural or artificially created, including oil and gas reservoirs, salt domes or other saline formations, and coal and coalbed methane seams, suitable for or capable of being made suitable for the injection and storage of carbon dioxide therein.

(9) "Storage facility" means the underground reservoir, carbon dioxide injection wells, monitoring wells, underground equipment, and surface buildings and equipment utilized in the storage operation, including pipelines owned or operated by the storage operator used to transport the carbon dioxide from one or more capture facilities or sources to the storage and injection site. The underground reservoir component of the storage facility includes any necessary and reasonable aerial buffer and subsurface monitoring zones designated by the commissioner for the purpose of ensuring the safe and efficient operation of the storage facility for the storage of carbon dioxide and shall be chosen to protect against pollution, and escape or migration of carbon dioxide.

(10) "Storage operator" means the person authorized by the commissioner to operate a storage facility. A storage operator can, but need not be, the owner of carbon dioxide injected into a storage facility. Ownership of carbon dioxide and use of geologic storage is a matter of private contract between the storage operator and owner, shipper or generator of carbon dioxide, as applicable.

(11) "Waste" in addition to its ordinary meaning, means "physical waste" as that term is generally understood in the storage industry.

La. Rev. Stat. 30:1104. Duties and powers of the commissioner; rules and regulations; permits

A. The office of conservation's actions under this Chapter shall be directed and controlled by the commissioner. The commissioner shall have authority to:

(1) Regulate the development and operation of storage facilities and pipelines transmitting carbon dioxide to storage facilities, including in accordance with the provisions of R.S. 30:1107, the issuance of certificates of public convenience and necessity for storage facilities and pipelines serving such projects approved hereunder.

(2) Make, after notice and hearings as provided in this Chapter, any reasonable rules, regulations, and orders that are necessary from time to time in the proper administration and enforcement of this Chapter, including rules, regulations, or orders for the following purposes:

(a) To require the drilling, casing, and plugging of wells to be done in such a manner as to prevent the escape of carbon dioxide out of one stratum to another.

(b) To prevent the intrusion of carbon dioxide into oil, gas, salt formation, or other commercial

mineral strata.

- (c) To prevent the pollution of fresh water supplies by oil, gas, salt water, or carbon dioxide.
- (d) To require the plugging of each abandoned well and the closure of associated surface facilities, the removal of equipment, structures, and trash, and to otherwise require a general site cleanup of such abandoned wells.
- (3) Make such inquiries as he deems proper to determine whether or not waste, over which he has jurisdiction, exists or is imminent. In the exercise of this power the commissioner has the authority to collect data; to make investigations and inspections; to examine properties, papers, books, and records; to examine, survey, check, test, and gauge injection, withdrawal and other wells used in connection with carbon storage; to examine, survey, check, test, and gauge tanks, and modes of transportation; to hold hearings; to provide for the keeping of records and the making of reports; to require the submission of an emergency phone number by which the operator may be contacted in case of an emergency; and to take any action as reasonably appears to him to be necessary to enforce this Chapter.
- (4) Require the making of reports showing the location of all wells used in connection with a storage facility, and the filing of logs, electrical surveys, and other drilling records.
- (5) Prevent wells from being drilled and operated in a manner which may cause injury to neighboring leases or property.
- (6) Prevent blowouts, caving, and seepage in the sense that conditions indicated by these terms are generally understood in the storage business.
- (7) Identify the ownership of all wells used in connection with a storage facility, tanks, plants, structures, and all other storage and transportation equipment and facilities.
- (8) Nothing in this Chapter shall prevent an enhanced oil and gas recovery project utilizing injection of carbon dioxide as approved under R.S. 30:4.
- (9) Approve conversion of an existing enhanced oil or gas recovery operation into a storage facility, if necessary, taking into consideration prior approvals of the commissioner regarding such enhanced oil recovery operations.
- (10) Promulgate rules and regulations requiring interested persons to place monitoring equipment of a type approved by the commissioner on all storage facilities, and ancillary equipment necessary and proper to monitor, verify carbon dioxide injections, and to prevent waste. It shall be a violation of this Chapter for any person to refuse to attach or install a monitor within a reasonable period of time when ordered to do so by the commissioner, or in any way to tamper with the monitors so as to produce a false or inaccurate reading.
- (11) Regulate by rules, the drilling, casing, cementing, injection interval, monitoring, plugging and permitting of injection, withdrawal and other wells which are used in connection with a storage facility and to regulate all surface facilities incidental to such storage operation.
- (12) Require the plugging of each abandoned well or each well which is of no further use and the closure of associated surface facilities, the removal of equipment, structures, and trash, and other general site cleanup of such abandoned or unused well sites.
- (13) Promulgate rules related to the setting and collection of fees and civil penalties pursuant to this Chapter.

B. Only a storage operator as defined in R.S. 30:1103(10) shall be held or deemed responsible for the performance of any actions required by the commissioner under this Chapter.

C. Prior to the use of any reservoir for the storage of carbon dioxide and prior to the exercise of eminent domain by any person, firm, or corporation having such right under laws of the state of Louisiana, and as a condition precedent to such use or to the exercise of such rights of eminent domain, the commissioner, after public hearing pursuant to the provisions of R.S. 30:6, held in the parish where the storage facility is to be located, shall have found all of the following:

(1) That the reservoir sought to be used for the injection, storage, and withdrawal of carbon dioxide is suitable and feasible for such use, provided no reservoir, any part of which is producing or is capable of producing oil, gas, condensate, or other commercial mineral in paying quantities, shall be subject to such use, unless all owners in such reservoir have agreed thereto. In addition, no reservoir shall be subject to such use unless either:

(a) The volumes of original reservoir, oil, gas, condensate, salt, or other commercial mineral therein which are capable of being produced in paying quantities have all been produced.

(b) Such reservoir has a greater value or utility as a reservoir for carbon dioxide storage than for the production of the remaining volumes of original reservoir oil, gas, condensate, or other commercial mineral, and at least three-fourths of the owners, in interest, exclusive of any "lessor" defined in R.S. 30:148.1, have consented to such use in writing.

(2) That the use of the reservoir for the storage of carbon dioxide will not contaminate other formations containing fresh water, oil, gas, or other commercial mineral deposits.

(3) That the proposed storage will not endanger human lives or cause a hazardous condition to property.

D. The commissioner shall determine with respect to any such reservoir proposed to be used as a storage reservoir, whether or not such reservoir is fully depleted of the original commercially recoverable natural gas, condensate, or other commercial mineral therein. If the commissioner finds that such reservoir has not been fully depleted, the commissioner shall determine the amount of the remaining commercially recoverable natural gas, condensate, or other commercial mineral of such reservoir.

E. The commissioner may issue any necessary order providing that all carbon dioxide which has previously been reduced to possession and which is subsequently injected into a storage reservoir shall at all times be deemed the property of the party that owns such carbon dioxide, whether at the time of injection or pursuant to a change of ownership by agreement while the carbon dioxide is located in the storage facility, his successors and assigns; and in no event shall such carbon dioxide be subject to the right of the owner of the surface of the lands or of any mineral interest therein under which such storage reservoir shall lie or be adjacent to or of any person other than the owner, his successors, and assigns to produce, take, reduce to possession, waste, or otherwise interfere with or exercise any control there over, provided that the owner, his successors, and assigns shall have no right to gas, liquid hydrocarbons, salt, or other commercially recoverable minerals in any stratum or portion thereof not determined by the commissioner to constitute an approved storage reservoir. The commissioner shall issue such orders, rules, and regulations as may be necessary for the purpose of protecting any such storage reservoir, strata, or formations against pollution or against the escape of carbon dioxide therefrom, including such necessary rules and regulations as may pertain to the drilling into or through such storage reservoir.

La. Rev. Stat. 30:1105. Hearings; notice; rules of procedures; emergency; service of process; public records; request for hearings; orders and compliance orders

- A. All public hearings under this Part shall be conducted pursuant to the provisions of R.S. 30:6.
- B. All rules, regulations, and orders made by the commissioner under this Chapter shall be in writing and shall be entered in full by him in a book kept for that purpose. This book shall be a public record and shall be open for inspection at all times during reasonable office hours and shall be available on the Department of Natural Resources website. A copy of a rule, regulation, or order, certified by the commissioner, shall be received in evidence in all courts of this state with the same effect as the original.
- C. Any interested person has the right to have the commissioner call a hearing for the purpose of taking action in respect to a matter within the jurisdiction of the commissioner as provided in this Section by making a request therefor in writing and paying the hearing fee set by the commissioner, as provided by law for hearing conducted pursuant to R.S. 30:6. Upon receiving the request and payment of the required fees the commissioner shall promptly call a hearing. After the hearing and with all convenient speed and within thirty days after the conclusion of the hearing, the commissioner shall take whatever action he deems appropriate with regard to the subject matter.

La. Rev. Stat. 30:1106. Underground injection control

- A. The commissioner shall have authority to perform any and all acts necessary to carry out the purposes and requirements of the federal Safe Drinking Water Act, as amended, relating to this state's participation in the underground injection control program established under that act with respect to the storage and sequestration of carbon dioxide. To that end, the commissioner is authorized and empowered to adopt, modify, repeal, and enforce procedural, interpretive, and administrative rules in accordance with the provisions of this Chapter.
- B. Whenever the commissioner or an authorized representative of the commissioner determines that a violation of any requirement of this Chapter has occurred or is about to occur, the commissioner or his authorized representative shall either issue an order requiring compliance within a specified time period or shall commence a civil action for appropriate relief, including a temporary or permanent injunction.
- C. Any compliance order issued under this Chapter shall state with reasonable specificity the nature of the violation and specify a time for compliance and, in the event of noncompliance, assess a civil penalty, if any, which the commissioner determines is reasonable, taking into account the seriousness of the violation and any good faith efforts to comply with the applicable requirements.
- D. (1) Except as otherwise provided by law, any person to whom a compliance order is issued and who fails to take corrective action within the time specified in the order or any person found by the commissioner to be in violation of any requirement of this Section may be liable for a civil penalty to be assessed by the commissioner or court, of not more than five thousand dollars a day for each day of violation and for each act of violation. The commissioner in order to enforce the provisions of this Section may suspend or revoke any permit, compliance order, license, or variance that has been issued to said person in accordance with law.
(2) No penalty shall be assessed until the person charged has been given notice and an opportunity

for a hearing on such charge. In determining whether or not a civil penalty is to be assessed and in determining the amount of the penalty, or the amount agreed upon in compromise, the gravity of the violation and the demonstrated good faith of the person charged in attempting to achieve rapid compliance, after notification of a violation, shall be considered.

E. The commissioner, or attorney general if requested by the commissioner, shall have charge of and shall prosecute all civil cases arising out of violation of any provision of this Section including the recovery of penalties.

F. Except as otherwise provided herein, the commissioner may settle or resolve as he may deem advantageous to the state any suits, disputes, or claims for any penalty under any provisions of this Section or the regulations or permit license terms and conditions applicable thereto.

La. Rev. Stat. 30:1107. Certificates of public convenience and necessity; certificate of completion of injection operations

A. The commissioner shall issue a certificate of public convenience and necessity or a certificate of completion of injection operations to each person applying therefor if, after a public hearing pursuant to the provisions of R.S. 30.6, held in the parish where the storage facility is to be located, he determines that it is required by the present or future public convenience and necessity, and such decision is based upon the following criteria; (1) the proposed storage facility meets the requirements of R.S. 30:1104(C) and (2) the proposed storage facility meets the requirements of any rules adopted under this Chapter. However, if any person has previously been issued a certificate of public convenience and necessity or a certificate of completion of injection operations by the commissioner, that certificate continues to remain valid and in force.

B. The commissioner shall issue a certificate of completion of injection operations to the operator applying therefor, if after a public hearing pursuant to R.S. 30:6, it is determined that such operator has met all of the conditions required for such certificate, including the requirements of R.S. 30:1109.

C. Anything in this Chapter, or in any rule, regulation, or order issued by the commissioner under this Chapter to the contrary notwithstanding, accepting or acting pursuant to a certificate of public convenience and necessity or a certificate of completion of injection operations issued under this Chapter, compliance with the provisions of this Chapter, or with rules, regulations, or orders issued by the commissioner under this Chapter, or voluntarily performing any act or acts which could be required by the commissioner pursuant to this Chapter, or rules, regulations, or orders issued by the commissioner under this Chapter, shall not have the following consequences:

(1) Cause any storage operator or carbon dioxide transporter of carbon dioxide for storage to become, or be classified as, a common carrier or a public utility for any purpose whatsoever.

(2) Subject such storage operator or such carbon dioxide to storage transporter to any duties, obligations, or liabilities as a common carrier or public utility, under the constitution and laws of this state.

(3) Increase the liability of any storage operator or carbon dioxide for storage transporter for any taxes otherwise due to the state of Louisiana in the absence of any additions or amendments to any tax laws of this state.

La. Rev. Stat. 30:1108. Eminent domain, expropriation

A. (1) Any storage operator is hereby authorized, after obtaining any permit and any certificate of public convenience and necessity from the commissioner required by this Chapter, to exercise the power of eminent domain and expropriate needed property to acquire surface and subsurface rights and property interests necessary or useful for the purpose of constructing, operating, or modifying a storage facility and the necessary infrastructure including the laying, maintaining, and operating pipelines for the transportation of carbon dioxide to a storage facility, together with telegraph and telephone lines necessary and incidental to the operation of these storage facilities and pipelines, over private property thus expropriated; and have the further right to construct and develop storage facilities and the necessary infrastructure, including the laying, maintaining, and operating of pipelines along, across, over, and under any navigable stream or public highway, street, bridge, or other public place; and also have the authority, under the right of expropriation herein conferred, to cross railroads, street railways, and other pipelines, by expropriating property necessary for the crossing under the general expropriation laws of this state. The right to run along, across, over, or under any public road, bridge, or highway, as before provided for, may be exercised only upon condition that the traffic thereon is not interfered with, and that such road or highway is promptly restored to its former condition of usefulness, at the expense of the storage facility and the pipeline owner if different from the storage operator, the restoration to be subject also to the supervision and approval of the proper local authorities.

(2) In the exercise of the privilege herein conferred, owners or operators of such storage facilities and pipelines shall compensate the parish, municipality, or road district, respectively, for any damage done to a public road, in the construction of storage facilities, and the laying of pipelines, telegraph or telephone lines, along, under, over, or across the road. Nothing in this Chapter shall be construed to grant any transporter the right to use any public street or alley of any parish, incorporated city, town, or village, except by express permission from the parish, city, or other governing authority.

B. The exercise of the right of eminent domain granted in this Chapter shall not prevent persons having the right to do so from drilling through the storage facility in such manner as shall comply with the rules of the commissioner issued for the purpose of protecting the storage facility against pollution or invasion and against the escape or migration of carbon dioxide. Furthermore, the right of eminent domain set out in this Section shall not prejudice the rights of the owners of the lands, minerals, or other rights or interests therein as to all other uses not acquired for the storage facility.

C. The eminent domain authority authorized under this Chapter shall be exercised pursuant to the procedures found in R.S. 19:2, and shall be in addition to any other power of eminent domain authorized by law.

D. The commissioner is neither a necessary nor indispensable party to an eminent domain proceeding, and if named as a party or third party has an absolute right to be dismissed from said action at the expense of the party who names the commissioner. The commissioner shall recover all costs reasonably incurred to be dismissed from the action, including attorney fees.

La. Rev. Stat. 30:1109. Cessation of storage operations; liability release

A. (1) Ten years, or any other time frame established by rule, after cessation of injection into a storage facility, the commissioner shall issue a certificate of completion of injection operations,

upon a showing by the storage operator that the reservoir is reasonably expected to retain mechanical integrity and the carbon dioxide will reasonably remain emplaced, at which time ownership to the remaining project including the stored carbon dioxide transfers to the state. Upon the issuance of the certificate of completion of injection operations, the storage operator, all generators of any injected carbon dioxide, all owners of carbon dioxide stored in the storage facility, and all owners otherwise having any interest in the storage facility, shall be released from any and all duties or obligations under this Chapter and any and all liability associated with or related to that storage facility which arises after the issuance of the certificate of completion of injection operations.

(2) Provided the provisions pertaining to site-specific trust accounts are not applicable, such release from liability will not apply to the owner or last operator of record of a storage facility if the Carbon Dioxide Geologic Storage Trust Fund has been depleted of funds such that it contains inadequate funds to address or remediate any duty, obligation, or liability that may arise after issuance of the certificate of completion of injection operations.

(3) Such release from liability will not apply to the owner or operator of a storage facility, carbon dioxide transmission pipeline, or the generator of the carbon dioxide being handled by either the facility or pipeline if it is demonstrated that any such owner, operator, or generator intentionally and knowingly concealed or intentionally and knowingly misrepresented material facts related to the mechanical integrity of the storage facility or the chemical composition of any injected carbon dioxide. In addition, upon the issuance of the certificate of completion of injection operations, any performance bonds posted by the operator shall be released and continued monitoring of the site, including remediation of any well leakage, shall become the principal responsibility of the Carbon Dioxide Geologic Storage Trust Fund.

(4) It is the intent of this Section that the state shall not assume or have any liability by the mere act of assuming ownership of a storage facility after issuance of a certificate of completion of injection operations.

B. (1) In any civil liability action against the owner or operator of a storage facility, carbon dioxide transmission pipeline, or the generator of the carbon dioxide being handled by either the facility or pipeline, the maximum amount recoverable as compensatory damages for noneconomic loss shall not exceed two hundred fifty thousand dollars per occurrence, except where the damages for noneconomic loss suffered by the plaintiff were for wrongful death; permanent and substantial physical deformity, loss of use of a limb or loss of a bodily organ system; or permanent physical or mental functional injury that permanently prevents the injured person from being able to independently care for himself or herself and perform life sustaining activities. In such cases, the maximum amount recoverable as compensatory damages for noneconomic loss shall not exceed five hundred thousand dollars per occurrence.

(2) If Paragraph (1) of this Subsection, or the application thereof to any person or circumstance, is finally determined by a court of law to be unconstitutional or otherwise invalid, the maximum amount recoverable as damages for noneconomic loss shall thereafter not exceed one million dollars per occurrence. This provision shall not supersede any contractual agreement with respect to liability between a plaintiff and an owner or operator of a storage facility, a carbon dioxide transmission pipeline, or the generator of the carbon dioxide.

C. Nothing in this Chapter shall establish or create any liability or responsibility on the part of the commissioner or the state to pay any costs associated with site restoration from any source other

than the funds or trusts created by this Chapter, nor shall the commissioner or the state of Louisiana have any liability or responsibility to make any payments for costs associated with site restoration if the trusts created herein are insufficient to do so.

D. The commissioner or his agents, on proper identification, may enter the land of another for purposes of site assessment or restoration.

E. The commissioner and his agents are not liable for any damages arising from an act or omission if the act or omission is part of a good faith effort to carry out the purpose of this Chapter.

F. No party contracting with the Department of Natural Resources, office of conservation, or the commissioner under the provisions of this Chapter shall be deemed to be a public employee or an employee otherwise subject to the provisions of Parts I through IV of Chapter 15 of Title 42 of the Louisiana Revised Statutes of 1950.

La. Rev. Stat. 30:1110. Carbon Dioxide Geologic Storage Trust Fund

A. (1) There is hereby established a fund in the custody of the state treasurer to be known as the Carbon Dioxide Geologic Storage Trust Fund, hereinafter referred to as the "fund", which shall constitute a special custodial trust fund which shall be administered by the commissioner, who shall make disbursements from the fund solely in accordance with the purposes and uses authorized by this Chapter.

(2) After compliance with the requirements of Article VII, Section 9(B) of the Constitution of Louisiana relative to the Bond Security and Redemption Fund, and after a sufficient amount is allocated from that fund to pay all of the obligations secured by the full faith and credit of the state which become due and payable within any fiscal year, the treasurer shall pay into the fund, an amount equal to the monies received by the state treasury pursuant to this Chapter. The monies in this fund shall be used solely as provided in this Section and only in the amount appropriated by the legislature. All unexpended and unencumbered monies remaining in this fund at the end of the fiscal year shall remain in the fund. The monies in the fund shall be invested by the state treasurer in the same manner as monies in the state general fund and all returns of such investment shall be deposited to the fund. The funds received shall be placed in the special trust fund in the custody of the state treasurer to be used only in accordance with this Chapter and shall not be placed in the general fund. The funds provided to the commissioner pursuant to this Section shall at all times be and remain the property of the commissioner. The funds shall be used only for the purposes set forth in this Chapter and for no other governmental purposes, nor shall any branch of government be allowed to borrow any portion of the funds. It is the intent of the legislature that this fund and its increments shall remain intact and inviolate.

B. The following monies shall be placed into the fund:

(1) The fees, penalties, and bond forfeitures collected pursuant to this Chapter. All fees and self-generated revenue remaining on deposit for the office of conservation at the end of any fiscal year shall be deposited into the fund.

(2) Private contributions.

(3) Interest earned on the funds deposited in the fund.

(4) Civil penalties for violation of any rules or permit conditions imposed under this Chapter, or

costs recovered from responsible parties for geologic storage facility closure or remediation pursuant to this Section and R.S. 30:1104, 1105, and 1106.

(5) Any grants, donations, and sums allocated from any source, public or private, for the purposes of this Chapter.

(6) Site-specific trust accounts; however, the monies of such accounts shall not be used for any geologic storage facility other than that specified for each respective account.

C. The commissioner is hereby authorized to levy on storage operators the following fees or costs for the purpose of funding the fund:

(1) A fee payable to the office of conservation, in a form and schedule prescribed by the office of conservation, for each ton of carbon dioxide injected for storage. This fee is to be determined based upon the following formula:

(a) $F \times 120 < M$

(b) "F" is a per unit fee in dollars per ton set by the office of conservation.

(c) "120" is the minimum number of months over which a fee is to be collected.

(d) "M" is the Maximum Payment of five million dollars and is the total amount of fees to be collected before the payment of the fee can be suspended as provided in this Section.

(e) The fee cannot exceed five million dollars divided by one hundred twenty divided by the total tonnage of carbon dioxide to be injected, $((\$5,000,000/120)/ \text{total injection tonnage of carbon dioxide})$.

(f) Once a storage operator has contributed five million dollars to the trust fund, the fee assessments to that storage operator under this Section shall cease until such time as funds begin to be expended for monitoring and caretaking of any completed storage facility. The treasurer of the state of Louisiana shall certify, to the commissioner, the date on which the balance in the fund for a storage operator equals or exceeds five million dollars. The fund fees shall not be collected or required to be paid on or after the first day of the second month following the certification, except that the commissioner shall resume collecting the fees on receipt of a certification from the treasurer that, based on the expenditures or commitments to expend monies, the fund has fallen below four million dollars for the storage operator. If at any time the balance in the trust fund exceeds an authorized amount determined by multiplying five million dollars by the number of active and completed storage facilities within the state, the collection of fees from the operators of storage facilities that have already contributed five million dollars to the trust fund will be suspended until such time as the balance in the trust fund falls below such authorized amount, at which time they will be reinstated.

(g) At the end of each fiscal year, the fee may be redetermined by the commissioner based upon the estimated cost of administering and enforcing this Chapter for the upcoming year divided by the tonnage of carbon dioxide expected to be injected during the upcoming year. The total fee assessed shall be sufficient to assure a balance in the fund not to exceed five million dollars for any active storage facility within the state at the beginning of each fiscal year. Any amount received that exceeds the annual balance required shall be deposited in the fund, but appropriate credits shall be given against future fees or fees associated with other storage facilities operated by the same storage operator.

(2) An annual regulatory fee for storage facilities that have not received a certificate of completion of injection operations payable to the office of conservation, in a form and schedule prescribed by the office of conservation, on the carbon dioxide storage facility in an amount not to exceed fifty thousand dollars for Fiscal Year 2010-2011 and thereafter. Such fee shall be based upon the annual projected costs to the office of conservation for oversight and regulation of such storage facilities.

(3) An application fee payable to the office of conservation, in a form and schedule prescribed by the office of conservation, by industries under the jurisdiction of the office of conservation. The commissioner may, by rule in accordance with the Administrative Procedure Act, increase any application fee to an amount not in excess of eight and one-half percent above the amount charged for the fee on July 1, 2010.

D. The provisions of the Louisiana Tax Code shall apply to the administration, collection, and enforcement of the fees imposed herein, and the penalties provided by that code shall apply to any person who fails to pay or report the fees. Proceeds from the fees, including any penalties and interest collected in connection with the fees, shall be deposited into the fund.

E. The fund shall be used solely for the following purposes:

(1) Operational and long-term inspecting, testing, and monitoring of the site, including remaining surface facilities and wells.

(2) Remediation of mechanical problems associated with remaining wells and surface infrastructure.

(3) Repairing mechanical leaks at the site.

(4) Plugging and abandoning remaining wells or conversion for use as observation wells.

(5)(a) Administration of this Chapter by the commissioner in an amount not to exceed seven hundred fifty thousand dollars each fiscal year.

(b) The Oil and Gas Regulatory Fund created by R.S. 30:21 may be used for the administration of this Chapter as authorized by this Paragraph until June 30, 2014. Any such payments from the Oil and Gas Regulatory Fund shall be repaid from the Carbon Dioxide Storage Trust Fund by June 30, 2018.

(6) Payment of fees and costs associated with the administration of the fund or site-specific accounts.

(7) Payment of fees and costs associated with the acquisition of appropriate insurance for future storage facility liability if it should become available, either commercially or through government funding.

F. The commissioner is authorized to enter into agreements and contracts and to expend money in the fund for the following purposes:

(1) To fund research and development in connection with carbon sequestration technology and methods.

(2) To monitor any remaining surface facilities and wells.

(3) To remediate mechanical problems associated with remaining wells or site infrastructure.

(4) To repair mechanical leaks at the storage facility.

- (5) To contract with a private legal entity pursuant to this Chapter.
- (6) To plug and abandon remaining wells except for those wells to be used as observation wells.

G. The commissioner shall keep accurate accounts of all receipts and disbursements related to the administration of the fund and site-specific trust funds and shall make a specific annual report addressing the administration of the funds to the Senate Committee on Natural Resources, the House Committee on Natural Resources and Environment, and the Senate Committee on Environmental Quality before March first.

H. Every five years the commissioner shall submit a report to the Senate Committee on Natural Resources, the House Committee on Natural Resources and Environment, and the Senate Committee on Environmental Quality before March first, that assesses the effectiveness of the fund and other related provisions in this Part and provides such other information as may be requested by the legislature to allow the legislature to assess the effectiveness of this Chapter.

La. Rev. Stat. 30:1111. Site-specific trust accounts

A. If a storage facility site is transferred from one party to another, not including a transfer to the state pursuant to R.S. 30:1109, a site-specific trust account may be established to separately account for each such site for the purpose of providing a source of funds for long-term maintenance, monitoring, and site closure or remediation of that storage facility site at such time in the future when closure or remediation of that storage facility site is required. For purposes of this Chapter, a transfer shall be deemed to have been made once there is a change in ownership of any kind at a storage facility site. Once established, the site-specific trust account shall survive until completion of site closure or remediation of the associated storage facility site.

B. In the event the parties to a transfer elect to establish a site-specific trust account under this Section, the commissioner shall require a storage facility long-term maintenance, monitoring, and site closure assessment to be made to determine the long-term maintenance, monitoring, and site closure requirements existing at the time of the transfer, or at the time the site-specific trust account is established. The storage facility long-term maintenance, monitoring, and site closure assessment shall be conducted by approved site assessment contractors appearing on a list approved by the commissioner or acceptable to the commissioner. The storage facility long-term maintenance, monitoring, and site closure assessment shall specifically detail the long-term maintenance, monitoring, and site closure needs and shall provide an estimate of the long-term maintenance, monitoring and site closure costs needed to maintain and restore the storage facility site based on the conditions existing at the time of transfer, or at the time the site-specific trust account is established.

C. The party or parties to the transfer shall, based upon the long-term maintenance and site restoration assessment, propose a funding schedule which will provide for the site-specific trust account. The funding schedule shall consider the uniqueness of each transfer, acquiring party, and storage facility site. Funding of the site-specific trust account shall include some contribution to the account at the time of transfer and at least quarterly payments to the account. Cash or bonds in a form and of a type acceptable to the commissioner, or any combination thereof, may also be considered for funding. The commissioner shall monitor each trust account to assure that it is being properly funded. The funds in each trust account shall remain the property of the commissioner.

D. The commissioner may approve the site-specific trust account for a storage facility site upon

review of the assessment and the site-specific trust account that has been proposed for that storage facility site as provided in the regulations. Such approval shall not be unreasonably withheld.

E. When transfers of storage facility sites occur subsequent to the formation of site-specific trust accounts but prior to the end of their economic life, the commissioner and the acquiring party shall, in the manner provided for in this Section, again redetermine cost and agree upon a funding schedule. The balance of any site-specific trust account at the time of subsequent transfer shall remain with the storage facility site and shall be a factor in the redetermination.

F. Once the commissioner has approved the site-specific trust account, and the account is fully funded, the party transferring the storage facility site and all prior owners, operators, and working interest owners shall not thereafter be held liable by the state for any site closure costs or actions associated with the transferred storage facility site. The party acquiring the storage facility site shall thereafter be the responsible party for the purposes of this Part.

G. The failure of a transferring party to make a good faith disclosure of all material storage facility site conditions existing at the time of the transfer may render that party liable for the costs to address such undisclosed conditions to regulatory standards in excess of the balance of the site-specific trust fund.

H. Except as provided in Subsection E of this Section, the parties to a transfer may elect not to establish a site-specific trust account; however, in the absence of such account, the parties shall not be exempt from liability as set forth in Subsection F of this Section.

I. After site closure has been completed and approved by the commissioner, funds from a site-specific trust account shall be disbursed as follows:

(1) The balance of the account existing in the site-specific trust account will be remitted to the responsible party.

(2) Such account shall thereafter be closed.

J. The provisions of this Chapter regarding the implementation of site-specific trust accounts shall not be implemented until the rules and regulations pertaining to such trust accounts are finally adopted.

APPENDIX D: OTHER, SELECTED LOUISIANA STATUTES

La. Civ. Code art. 490. Accession above and below the surface

Unless otherwise provided by law, the ownership of a tract of land carries with it the ownership of everything that is directly above or under it.

The owner may make works on, above, or below the land as he pleases, and draw all the advantages that accrue from them, unless he is restrained by law or by rights of others.

La. Rev. Stat. 19:2. Expropriation by state or certain corporations, limited liability companies, or other legal entities

Prior to filing an expropriation suit, an expropriating authority shall attempt in good faith to reach an agreement as to compensation with the owner of the property sought to be taken and comply with all of the requirements of R.S. 19:2.2. If unable to reach an agreement with the owner as to compensation, any of the following may expropriate needed property:

- (1) The state or its political corporations or subdivisions created for the purpose of exercising any state governmental powers.
- (2) Any domestic or foreign corporation, limited liability company, or other legal entity created for, or engaged in, the construction of railroads, toll roads, or navigation canals.
- (3) Any domestic or foreign corporation, limited liability company, or other legal entity created for, or engaged in, the construction or operation of street railways, urban railways, or inter-urban railways.
- (4) Any domestic or foreign corporation, limited liability company, or other legal entity created for, or engaged in, the construction or operation of waterworks, filtration and treating plants, or sewerage plants to supply the public with water and sewerage.
- (5) Any domestic or foreign corporation, limited liability company, or other legal entity created for, or engaged in, the piping and marketing of natural gas for the purpose of supplying the public with natural gas as a common carrier or contract carrier or any domestic or foreign corporation, limited liability company, or other legal entity which is or will be a natural gas company or an intrastate natural gas transporter as defined by federal or state law, composed entirely of such entities or composed of the wholly owned subsidiaries of such entities. As used in this Paragraph, "contract carrier" means any legal entity that transports natural gas for compensation or hire pursuant to special contract or agreement with unaffiliated third parties.
- (6) Any domestic or foreign corporation, limited liability company, or other legal entity created for the purpose of, or engaged in, transmitting intelligence by telegraph or telephone.
- (7) Any domestic or foreign corporation, limited liability company, or other legal entity created for the purpose of, or engaged in, generating, transmitting, and distributing or for transmitting or distributing electricity and steam for power, lighting, heating, or other such uses. The generating plants, buildings, transmission lines, stations, and substations expropriated or for which property was expropriated shall be so located, constructed, operated, and maintained as not to be dangerous to persons or property nor interfere with the use of the wires of other wire using companies or, more than is necessary, with the convenience of the landowners.

- (8) All persons included in the definition of common carrier pipelines as set forth in R.S. 45:251.
- (9) Any domestic or foreign corporation, limited liability company, or other legal entity created for or engaged in piping or marketing of coal or lignite in whatever form or mixture convenient for transportation within a pipeline as otherwise provided for in R.S. 30:721 through 723.
- (10) Any domestic or foreign corporation, limited liability company, or other legal entity composed of such corporations or wholly owned subsidiaries thereof engaged in the piping or marketing of carbon dioxide for use in connection with a secondary or tertiary recovery project for the enhanced recovery of liquid or gaseous hydrocarbons approved by the commissioner of conservation. Property located in Louisiana may be so expropriated for the transportation of carbon dioxide for underground injection in connection with such projects located in Louisiana or in other states or jurisdictions.
- (11) Any domestic or foreign corporation, limited liability company, or other legal entity engaged in any of the activities otherwise provided for in this Section.
- (12) Any domestic or foreign corporation, limited liability company, or other legal entity composed of such corporations or wholly owned subsidiaries thereof engaged in the injection of carbon dioxide for the underground storage of carbon dioxide approved by the commissioner of conservation. Property located in Louisiana may be so expropriated for the underground storage of carbon dioxide in connection with such storage facility projects located in Louisiana, including but not limited to surface and subsurface rights, mineral rights, and other property interests necessary or useful for the purpose of constructing, operating, or modifying a carbon dioxide facility. This Paragraph shall have no effect on nor does it grant expropriation of the mineral rights or other property rights associated with the approvals required for injection of carbon dioxide into enhanced recovery projects approved by the commissioner under R.S. 30:4.