NEBRASKA INTEGRATED CARBON CAPTURE AND STORAGE PRE-FEASIBILITY STUDY

Final Report

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NEBRASKA INTEGRATED CARBON CAPTURE AND STORAGE PRE-FEASIBILITY STUDY

EXECUTIVE SUMMARY

In collaboration with the Nebraska Public Power District (NPPD), the Energy & Environmental Research Center (EERC) has conducted a pre-feasibility study for a commercial-scale carbon dioxide (CO_2) geologic storage complex in western Nebraska integrated with potential CO_2 capture at Gerald Gentleman Station (GGS). GGS is the largest coal-fired electricity-generating station in Nebraska, emitting 8.5 million metric tons (Mt) of CO_2 annually, and is located near the town of Sutherland. This pre-feasibility (Phase 1) project has been executed as part of the U.S. Department of Energy (DOE) CarbonSAFE program, a multiphase initiative to support the deployment of large-scale carbon capture and storage (CCS) projects. Each CarbonSAFE project is required to demonstrate the potential to capture and store at least 50 million tonnes (Mt) of CO_2 over a 25-year operational period.

The EERC and NPPD established a coordination team to identify challenges to a potential Nebraska CCS project, comprising local stakeholder organizations, which met twice in Lincoln and via several Webinars, providing feedback and guidance throughout the pre-feasibility study. The EERC also secured the technical support of Schlumberger Carbon Services and Computer Modelling Group Ltd. (CMG).

The project comprised four technical themes, all using published information sources.

1. ***Regional and stakeholder analysis, including identification of sensitive environmental areas, potential resource conflicts, and strategies for public outreach.***

A review of geographic and socioeconomic characteristics, in combination with geologic characterization in the subbasinal analysis described below, identified an area to the southwest and within a 75-mile radius of GGS as the most prospective for development of a storage site. This area largely avoided lands with protected status such as wetlands.

A public outreach plan has also been developed for implementation in any further phases of CCS assessment in western Nebraska, for example a CarbonSAFE Phase 2 feasibility study.

2. ***Scenario analysis, addressing economic and regulatory factors.***

GGS is the only single major source of CO_2 emissions capable of satisfying the CarbonSAFE 50-Mt scale requirement within the study region. Chemical absorption using amines was identified as the most viable technology for postcombustion CO_2 capture at GGS. The total cost of a CCS project at GGS was estimated to be between \$67/tonne CO_2 for capture and auxiliary boiler to minimize parasitic load and \$70/tonne CO_2 avoided cost, using the Carnegie-Mellon University Integrated Environmental Control Model (IECM). The total avoided cost included the capture facility and parasitic load, a flue gas desulfurization plant required for the use of amine solvent technology, transport via pipeline, and dedicated storage infrastructure.

Nebraska has no legislation in place to address typical CCS-specific issues, for example pore space ownership for storage. Long-term liability, therefore, falls under the U.S. Environmental Protection Agency Underground Injection Control (UIC) Class 6 program regulations.

3. ***Subbasinal analysis, addressing the potential for a dedicated subsurface "container" to store the required 50-Mt quantity of CO_2.***

Modeling and simulation studies identified an area to the southwest of GGS with the potential for storage of 50 Mt CO_2 in the Cloverly Formation, comprising sandstones with interbedded and intermingled shales. The area of review (AOR) that would be required for monitoring under a Class VI operating permit was estimated to be as high as 400–700 square miles, due to uncertain pressure effects. The viability of this storage option is subject to significant uncertainty due to the relatively limited amount of existing characterization data available to the pre-feasibility study; for example, dynamic simulation indicated that the proposed storage rate might require as little as two or as many as 14 injection wells. A key uncertainty is the relative proportion and distribution of sandstone and shale within the Cloverly Formation.

A preliminary, semiquantitative risk assessment also suggested uncertainty over storage capacity and injectivity constitute the most significant project risks at this pre-feasibility stage. No assessed risks were considered to rule out the possibility of a project moving to deployment.

4. ***National Risk Assessment Partnership (NRAP) validation, using software tools developed by the National Energy Technology Laboratory (NETL) to assess risks associated with the potential 50-Mt CO_2 storage complex.***

NRAP tools were used to assess hypothetical leakage scenarios. Results broadly supported the conclusion of the semiquantitative risk analysis – for example, even worst-case analysis of theoretical leakage scenarios found limited migration rates and impacts.

In summary, the work undertaken in this Phase 1 pre-feasibility study has shown that western Nebraska has potential to host a commercial-scale CCS project, including a dedicated storage "container" for 50 Mt of CO_2. However, the following key challenges would need to be overcome:

1. The business case for deploying CCS projects is uncertain; recently announced federal tax credits and sales of CO_2 for enhanced oil recovery may not cover the full costs of a CCS project at GGS, as estimated by this pre-feasibility study.

2. The potential 50-Mt CO_2 dedicated storage container defined in this pre-feasibility study should be regarded as having a relatively low level of readiness to support a CCS project.

3. Public outreach would be a vital element in western Nebraska, where sensitivities around such environmental issues as water resource protection and pipeline construction would need to be carefully addressed.

NEBRASKA INTEGRATED CARBON CAPTURE AND STORAGE PRE-FEASIBILITY STUDY

1.0 INTRODUCTION

In collaboration with the Nebraska Public Power District (NPPD), the Energy & Environmental Research Center (EERC) has conducted a pre-feasibility study for a commercial-scale CO_2 geologic storage complex in western Nebraska integrated with potential carbon dioxide (CO_2) capture at Gerald Gentleman Station (GGS). GGS is the largest coal-fired electricity-generating station in Nebraska, emitting 8.5 million metric tons of CO_2 annually, and is located near the town of Sutherland. This pre-feasibility ("Phase 1") project has been executed as part of the U.S. Department of Energy (DOE) CarbonSAFE program, a multiphase initiative to support the deployment of large-scale carbon capture and storage (CCS) projects. Each CarbonSAFE project is required to demonstrate the potential to capture and store at least 50 million tonnes (Mt) of CO_2 over a 25-year operational period.

The goal of this Phase 1 project was to assess commercial-scale CO_2 capture of industrially sourced CO_2 emissions from GGS (and/or other facilities) with subsequent dedicated geologic storage in Nebraska. Specific objectives to help achieve this goal were:

1. Establish a CCS coordination team for the Nebraska effort.

2. Assess the challenges for deployment of a commercial-scale CCS project in western Nebraska.

3. Combine a high-level, technical subbasinal evaluation in western Nebraska and a CO_2 source assessment at GGS and other CO_2-emitting facilities.

The EERC and NPPD established an engaged coordination team to identify and address potential challenges to a Nebraska CCS project. NPPD secured the support and cooperation of several key Nebraska entities, including the Nebraska Energy Office, Nebraska Department of Environmental Quality (NDEQ), University of Nebraska-Lincoln, Omaha Public Power District, Southwest Public Power District, and Lincoln Electric System. ION Engineering, Berexco LLC, and EBR Development LLC also supported the proposed effort, and the EERC secured the technical support of Schlumberger Carbon Services and Computer Modelling Group Limited (CMG).

A key outcome of the Phase 1 project is an assessment of the level of readiness of the identified storage complex toward ultimately demonstrating the CarbonSAFE 50-Mt storage ambition. All information used in the study is published and publicly available. The Phase 1 project was organized into the following component tasks:

- Regional and Stakeholder Analysis: identification of sensitive environmental areas, potential resource conflicts, and strategies for public outreach.

- Scenario Analysis: addressing economic and regulatory factors.

- Subbasinal Analysis: addressing the potential for a dedicated subsurface CO_2 storage complex to store at least 50 Mt of CO_2 over 25 years.

- National Risk Assessment Partnership (NRAP) Validation: using software tools developed by the National Energy Technology Laboratory (NETL) to assess risks associated with the potential 50-Mt CO_2 storage complex.

The following final report, therefore, provides a detailed account of the Phase 1 assessment, including expansion of the initial study region as more information was garnered during execution of project activities. Phase 1 efforts were initially concentrated on a 50-mile radius area centered on GGS. However, GGS was identified as the only point source of CO_2 emissions within the study region (Figure 1) capable of satisfying the CarbonSAFE 50-Mt-scale requirement. Subsequently, the study region was expanded to a 75-mile radius to incorporate more prospective geology for storage to the southwest.

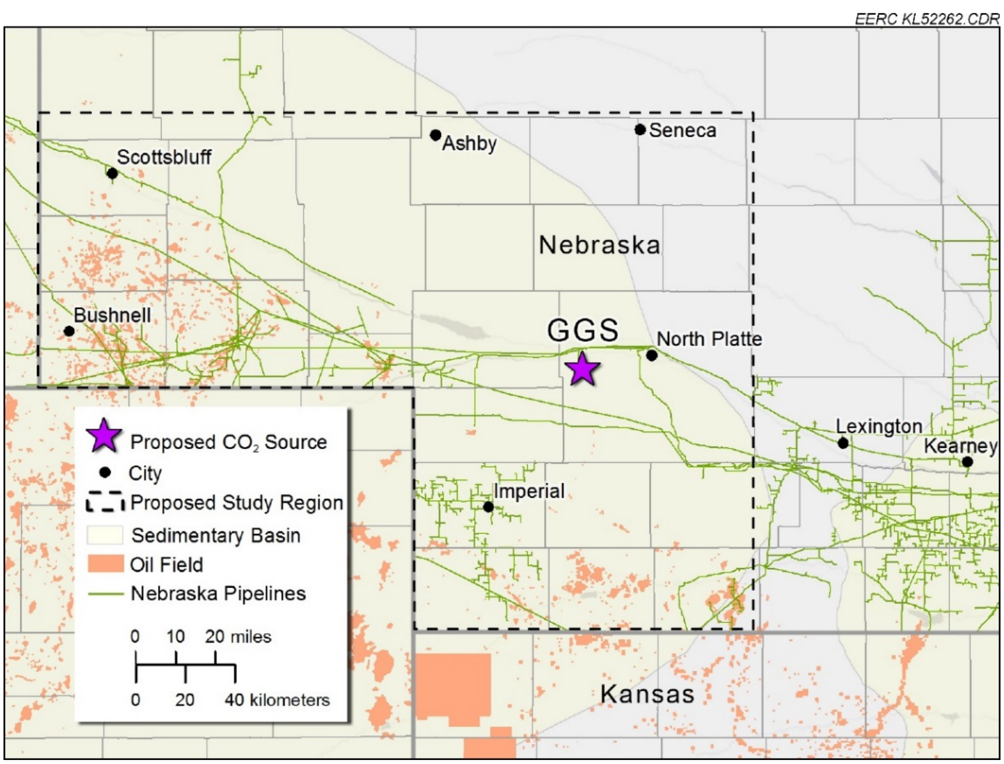

Figure 1. Location of study region and GGS.

2.0 REGIONAL AND STAKEHOLDER ANALYSIS

The overall objective of the regional and stakeholder analysis was to analyze the geographic and socioeconomic characteristics of the project study area focused on NPPD's GGS to identify any potential CCS-related impediments. The geographic component of the analysis illuminates surface features to consider and account for during implementation of a potential CCS project, including evaluation of prospective impacts that a carbon storage effort may have on the local population and natural environment. The purpose of the stakeholder analysis is to identify avenues to initiate public outreach that gains local public acceptance of a potential CCS project.

Information from the regional analysis, used in collaboration with geologic model and simulation efforts (discussed further in Section 4), contributed to identify the project study area. Geographic information system (GIS) data were collected to determine specific locations of potential concern or areas to avoid should a CCS project be implemented. The GIS data were collected from a variety of sources such as the U.S. Department of Agriculture's Natural Resource Conservation Service and the state of Nebraska and incorporated into a geodatabase. The ability to layer results from surface and subsurface evaluations was crucial in determining viable sites for potential injection of CO_2 generated from GGS.

2.1 Project Area Description

GGS is located in Lincoln County in western Nebraska, just south of the Platte River system (Figure 2). Initial analysis of surface features such as environmentally sensitive or protected areas and subsurface geologic formations within a 50- and 75-mile radius around GGS suggested closer evaluation of the five-county area to the west and south. The counties included are Lincoln, Keith, Perkins, Chase, and Hayes (Figure 2). The geologic evaluation of suitable storage formations is provided in Section 4.0.

2.2 Protected and Sensitive Areas

An essential part in planning a potential CCS project is to evaluate the region for environmentally sensitive or protected areas. These areas may be legally protected, such as underground sources of drinking water (USDWs) or state or federal refuge systems, or they may be of importance to local stakeholders such as agricultural lands. Descriptions of the protected and sensitive areas in the project area are described in the following subsections.

Water Resources

Underground injection of any fluid, such as CO_2 for geologic storage, is regulated by the U.S. Environmental Protection Agency (EPA) to ensure the protection of USDWs. A USDW is defined by the Safe Drinking Water Act (USC § 300f [U.S. Environmental Protection Agency, 1974]) as an aquifer that contains water with TDS < 10,000 ppm.[1] The most commonly used aquifer in the five-county study area is the High Plains (aka, Ogallala) aquifer, at a depth of about 300 feet from the surface (U.S. Geological Survey, 2018), with few additional secondary aquifers available such as the Chardron and Pierre (Divine and Sibray, 2017), found at lower depths.

[1] Total dissolved solids, which comprises mostly dissolved minerals. By comparison, the TDS of ocean water is 30,000–40,000 ppm

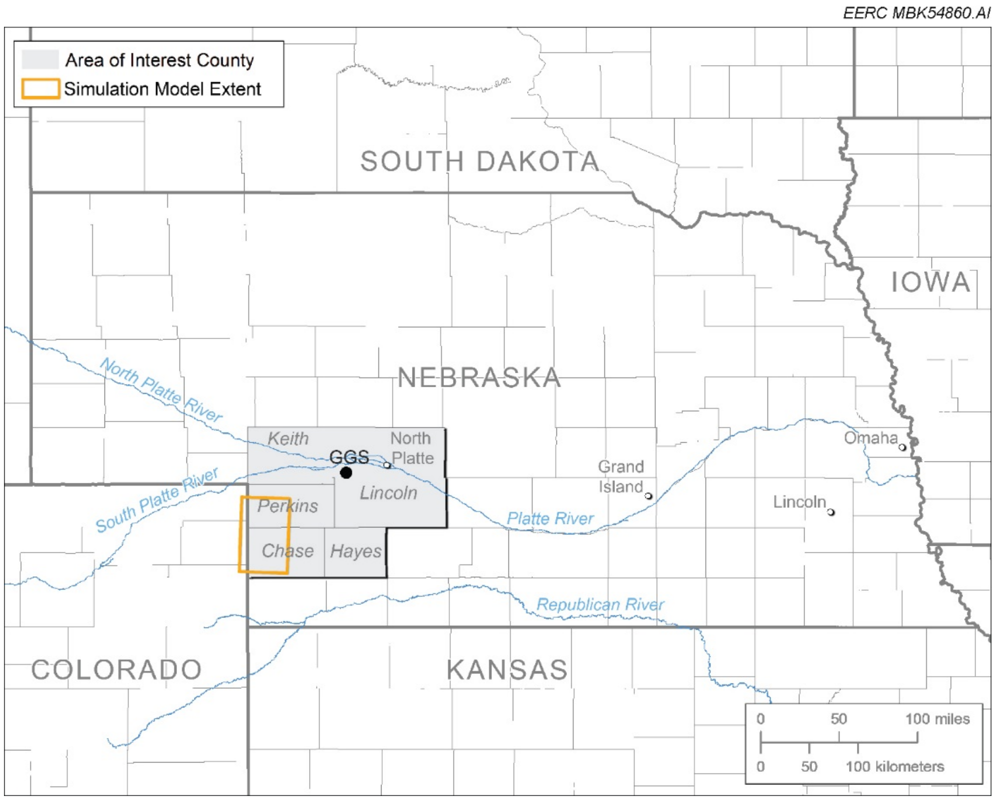

Figure 2. State of Nebraska showing and the location of GGS and the five-county study area, as well as the region of further geologic evaluation (orange rectangle).

The primary use of groundwater in the study area is for agricultural irrigation, which accounts for over 95% of daily groundwater withdrawals (Maupin and others, 2014) (Figure 3). Groundwater contributes about 80% of the publicly supplied drinking water for the entire state of Nebraska (Johnson and others, 2011), and the reliance on the Ogallala aquifer has greatly impacted water levels. In the project area, Chase and Perkins County groundwater levels have significantly declined, while Lincoln and Keith County groundwater levels have risen because of recharge from the Platte River system (Figure 4).

The North and South Platte River, just north of GGS, are the major waterways flowing through the study area. These two rivers join to form the Platte River just east of the city of North Platte in Lincoln County (Figure 2). The Platte River is approximately 300 miles long and ultimately joins the Missouri River at the eastern Nebraska border at Plattsmouth, Nebraska.

The Federal Emergency Management Agency (FEMA) identifies areas along waterways that are prone to flooding such as the Platte River as a Special Flood Hazard Area (SFHA). SFHAs are defined as areas that could be inundated by a base flood or greater event. A base flood event, often referred to as a 100-year flood, is the level of flooding that has a 1% probability of occurring in

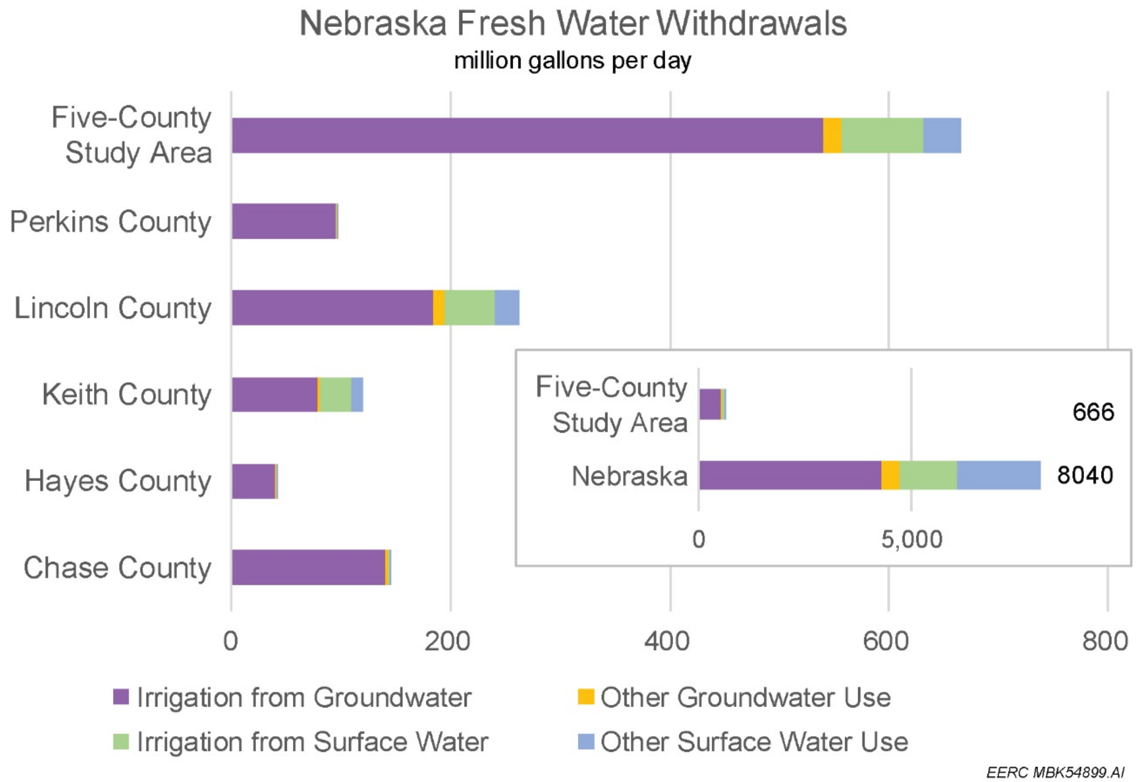

Figure 3. Comparison of fresh water withdrawals shows that a higher percentage of water use is for irrigation of agricultural crops in the counties of the study area rather than statewide withdrawals (Maupin and others, 2014).

any given year. In the unlikely event a pipeline would be constructed in an SFHA, a permit for floodplain management would need to be obtained before construction could begin. Because GGS is located to the south of the South Platte River and the region of focus for potential CO_2 storage is southwest of GGS (Figure 2), the placement of any CCS surface facilities would not impact flood-prone areas, with no pipeline crossing expected in the floodplain corridor land along the Platte River.

Additional environmentally sensitive areas located within the study area include wetlands and small feeder streams. Wetland types in the study area include temporary, seasonal, semipermanent, and permanent wetlands. Areas containing larger semipermanent and permanent wetlands would be avoided by any potential CCS efforts.

Overall, by siting potential CO_2 injection to the southwest of GGS and avoiding the Platte River system (including floodplain), impact to surface water resources would likely be avoided. In addition, a viable CCS project is one designed and operated in a manner that prevents any injected CO_2 from migrating into overlying USDWs (Underground Injection Control Program, 2014). The geologic formations investigated as part of this pre-feasibility study for potential CO_2

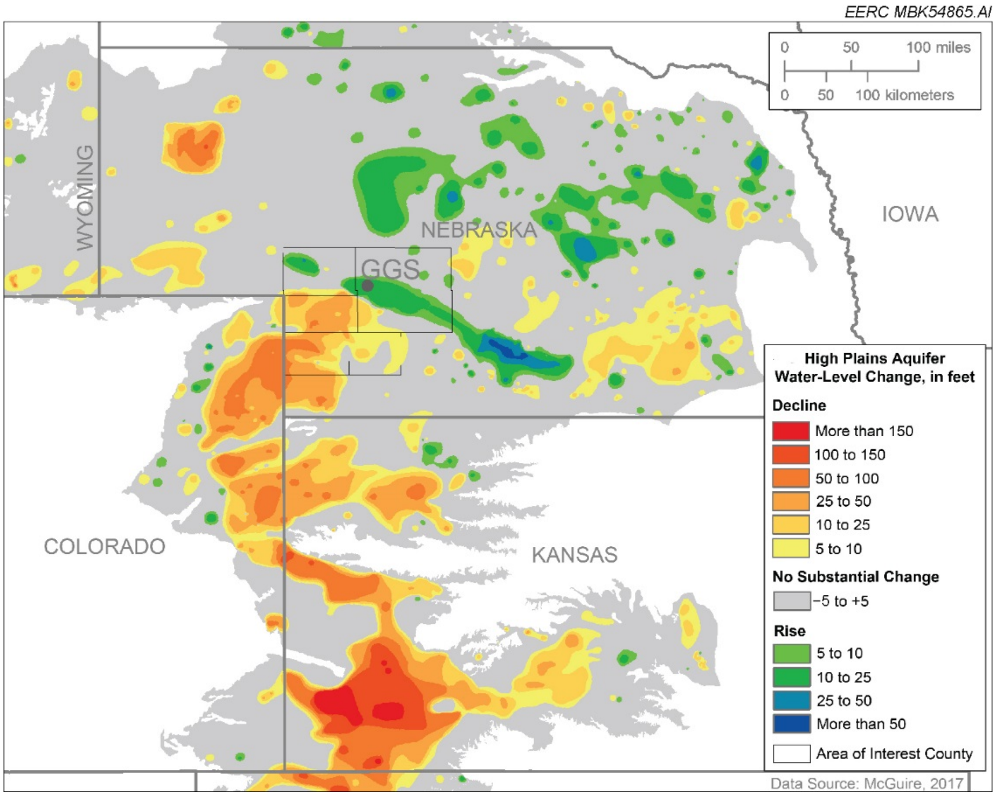

Figure 4. Water-level change in the High Plains aquifer (Data source: McGuire, 2017).

storage are the Cloverly and Cedar Hills Formations, approximately 2000 feet below the deepest USDW located in the Pierre Formation (Figure 13). These formations were partially chosen for investigation because of the hundreds of feet of shale and other sealing layers from the Pierre, such that no USDW would be impacted by any potential CCS efforts.

Land Cover

The five-county study area is a rural, sparsely populated region heavily influenced by agriculture. Land cover in this region is primarily grasslands and cropland, with corn plantings covering about 21% of the land (Figure 5). For the general public, the sensitive land cover types consist of wetlands and open water areas as these types are environmentally important to wildlife and for human use. Cropland and pasture will be of local interest, but any potential CCS-related impacts would be limited to the individual landowners where injection and monitoring might occur.

Cultural

Authorized by the National Historic Preservation Act of 1966, the National Park Service's National Register of Historic Places is part of a national program to coordinate and support public and private efforts to identify, evaluate, and protect America's historic and archeological resources. According to this resource, the study area contains minimal cultural resource sites, which would be accounted for in any potential CCS project implementation activities.

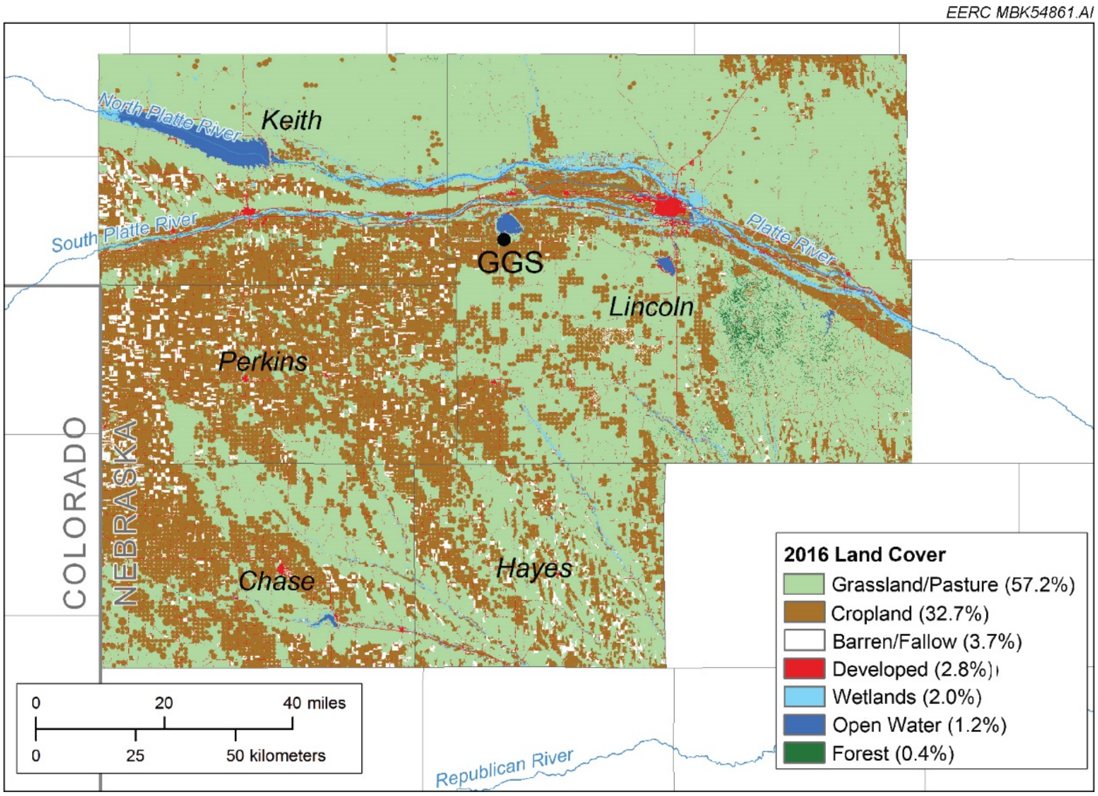

Figure 5. Land cover for the five-county regional analysis (Source: U.S. Department of Agriculture Natural Resources Conservation Service, 2016).

Wildlife/Habitat

The study area contains multiple state and federal wildlife management areas, wildlife refuges, and other protected environmental habitats, particularly along the North and South Platte Rivers (Figure 6). Relatively few areas like this are located in the southwestern direction from GGS. Any potential CCS project activities would thus take measures to avoid these wildlife habitats and account for the conservation of any threatened or endangered species that may require special management or protection.

2.3 Regulatory Environment

The state of Nebraska has not contemplated or promulgated statutes regarding CCS at this time. No regulatory environment currently exists for pore space ownership, financial assurance, closure, or long-term liability. In addition, no state regulatory agency has been selected for primacy, rulemaking, and oversight should statutes related to CCS be introduced.

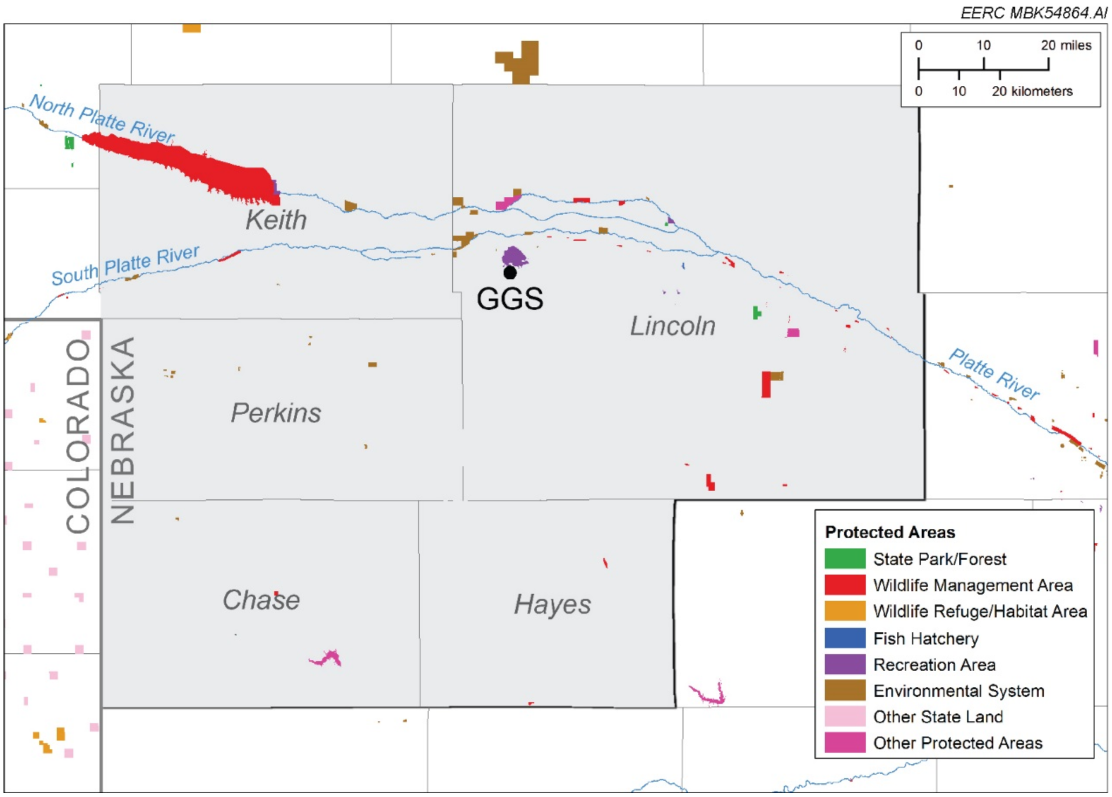

Figure 6. Protected areas in study area.

As a result, existing federal regulations would guide any CCS efforts in Nebraska. EPA administers the Underground Injection Control (UIC) Program that consists of six classes of injection wells. CO_2 injection activities fall into one of two classes, depending on the purpose of the injection. Class II wells are used to inject fluids associated with oil and natural gas production, in this case CO_2 for enhanced oil recovery (EOR). Class VI wells inject CO_2 into the subsurface for the sole purpose of dedicated geologic storage. UIC regulations contain a variety of measures to ensure that all USDWs are protected. Therefore, permitting of Class VI wells through EPA would be required for implementation of a potential dedicated CO_2 storage project in Nebraska. The region has, however, some oil and gas development. If, by chance, a CO_2 EOR effort were to become a viable option, then Class II regulations would be applied.

2.4 Existing Resource Development

The potential study area was reviewed to determine the potential impact to any current or future mineral or other resource development should a CCS project come to fruition. Although there has been past exploration for hydrocarbons in the study area, most existing exploration and production wells are no longer in operation and have been plugged and abandoned.

Renewable energy development, primarily wind energy such as the proposed wind project in Keith County (Kansas Energy Information Network, 2018), could potentially occur in the area. Most wind energy development, however, occurs in northern and eastern Nebraska. Wind energy development could conceivably affect the location of CCS surface installations. Any future CCS activity would likely be able to avoid these oil/gas or wind energy development areas, thus limiting impacts on resource development.

2.5 Pipeline Rights of Way

Although no CO_2 pipelines exist in the vicinity of GGS, a significant number of petroleum and natural gas pipelines cross the landscape (Figure 7). If pipeline construction were part of a future CCS project in this region, siting the pipeline in existing pipeline corridors should be considered to minimize impacts to landowners.

2.6 Community Impact Analysis

To be successful, a CCS project needs to be compatible with the existing social setting of an area as well as with the physical character of the geology and the landscape. This involves efforts to understand, anticipate, and address public perceptions as well as addressing the issues relevant to a particular community or region. Although no outreach occurred to the general public during this pre-feasibility effort, the investigation laid a foundation for constructive public engagement regarding CCS in the region through three actions: 1) proactive engagement with key industry, government, and academic stakeholders; 2) a community impact analysis based on published information on issues and regional social character; and 3) the preparation of a *Community Outreach Plan* (Appendix A) which serves as a source document intended to facilitate future CCS public engagement in the region.

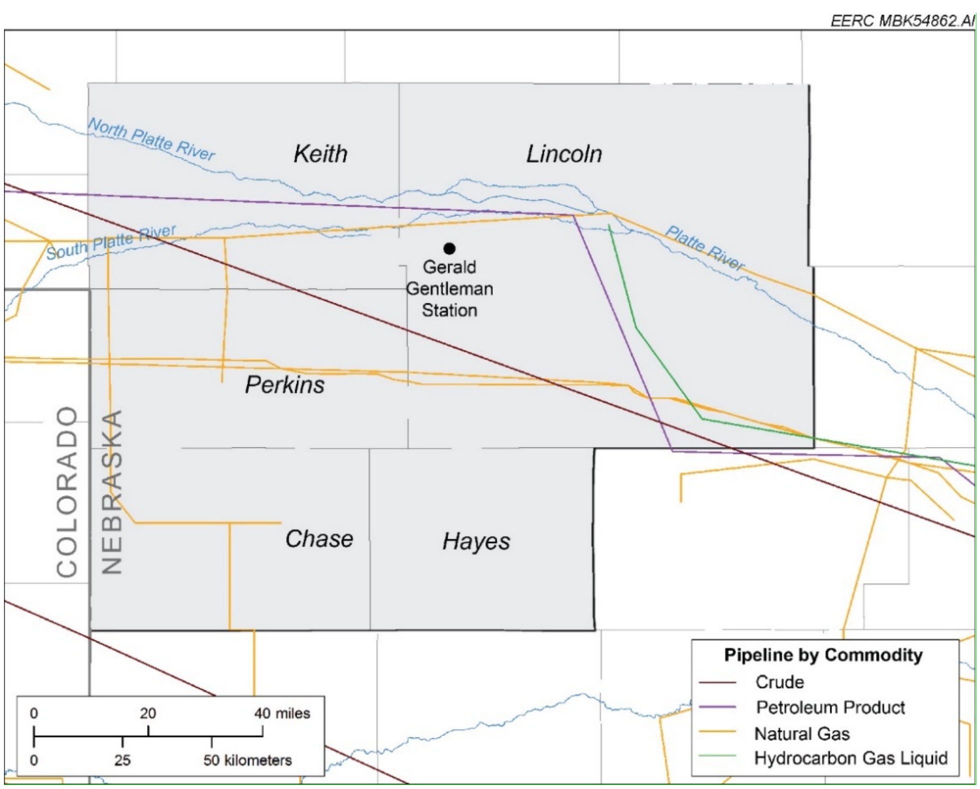

Figure 7. Pipeline routes in study area.

Regional Demographics

The potential study area is a rural, sparsely populated region with an economy based on agriculture. Population plateaued in the region from the period of 1920 to 1970, while over the past 50 years, the population has grown by a third in Lincoln County, driven primarily by the growth of North Platte. The five-county study area has a population of 51,947 people (2015 census). Population centers in this rural area of the state are the towns of North Platte (population 24,420), Ogallala (4605), Imperial (1917), Sutherland (1446), and Grant (1250) (Figure 8). Together, these communities account for about 65% of the combined populations of these five counties. Additional community and demographic information can be found in Appendix A in the community outreach plan.

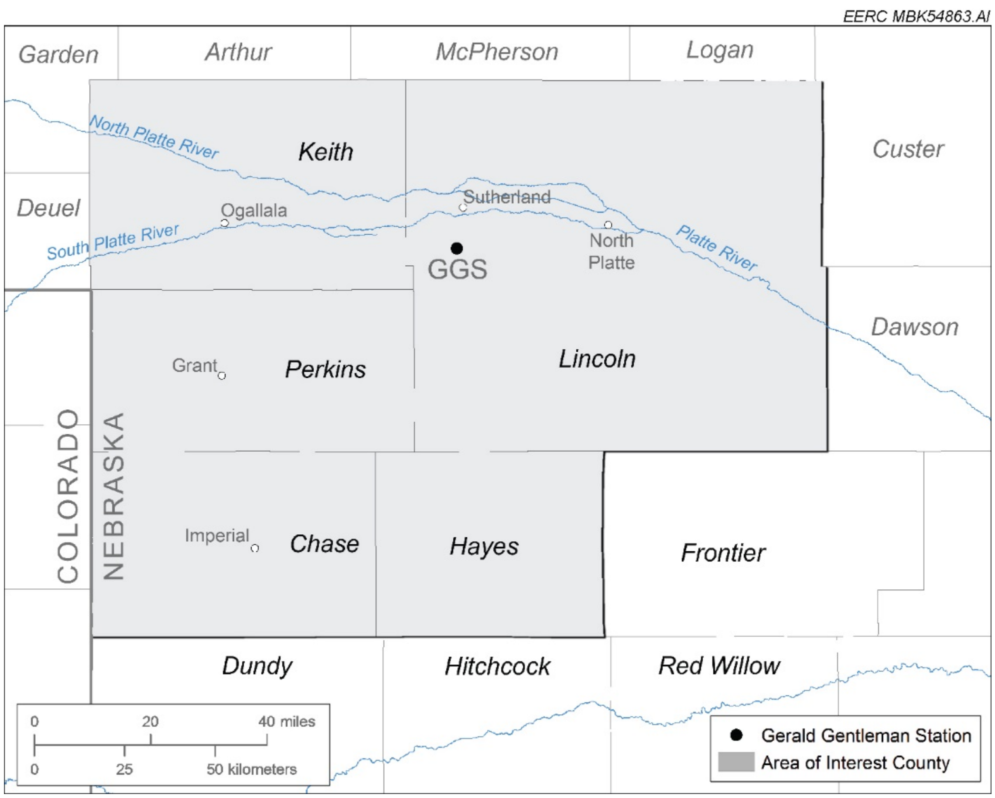

Figure 8. Population density map of the study area.

Local Economic and Industrial Trends

The state of Nebraska is recognized as having significant agricultural activity, which represents nearly a quarter of the state's workforce, generates 25% of the state's labor income, and accounts for over 40% of the state's economic output (Thompson and others, 2012).

The local workforce occupations in the five-county study area are shown in Table 1. The largest portions of workers are employed in educational services, health care, and social assistance

Table 1. Number of Workers over 16 years of Age by Industry (Source: 2015 American Community Survey 5-year Estimate, ([U.S. Census Bureau, 2015])

	Counties									Statewide	
Industries	**Keith**	**Perkins**	**Hayes**	**Chase**	**Subtotal**	**%**	**Lincoln**	**Total**	**%**	**Total**	**%**
Agriculture, Forestry, Fishing and Hunting, and Mining	474	301	205	440	1420	17.2	769	2189	8.6	44,287	4.6
Construction	244	177	46	165	632	7.7	839	1471	5.7	64,837	6.7
Manufacturing	312	37	11	110	470	5.7	628	1098	4.3	105,135	10.9
Wholesale Trade	110	89	3	61	263	3.2	410	673	2.6	26,947	2.8
Retail Trade	531	112	42	328	1013	12.3	2512	3525	13.8	112,767	11.6
Transportation and Warehousing and Utilities	274	113	63	113	563	6.8	3231	3794	14.8	54,194	5.6
Information	76	10	6	78	170	2.1	275	445	1.7	18,590	1.9
Finance and Insurance, and Real Estate and Rental and Leasing	143	78	13	108	342	4.2	650	992	3.9	71,684	7.4
Professional, Scientific, and Management, and Administrative and Waste Management Services	290	30	6	80	406	4.9	763	1169	4.6	79,427	8.2
Educational Services and Health Care and Social Assistance	743	374	108	308	1533	18.6	4315	5848	22.8	230,596	23.8
Arts, Entertainment, and Recreation, and Accommodation and Food Services	469	31	21	102	623	7.6	1539	2162	8.4	76,206	7.9
Other Services, Except Public Administration	258	71	6	102	437	5.3	774	1211	4.7	43,102	4.5
Public Administration	192	76	19	78	365	4.4	655	1020	4.0	40,362	4.2
Total	**4116**	**1499**	**549**	**2073**	**8237**		**17,360**	**25,597**		**968,134**	

Source: 2015 American Community Survey 5-year Estimate (U.S. Census Bureau, 2015).

at 22.8%, followed by transportation, retail trade, and agriculture. Interestingly, agriculture becomes the second most popular field when Lincoln County—and the city of North Platte—is excluded, at 17.2% (in the remaining four counties), slightly behind education and health care. Furthermore, Thompson and others (2012) analyzed the southwest region, which includes the five-county study area plus four additional rural counties (Frontier, Dundy, Hitchcock, and Red Willow) shown in Figure 8, and found that the economic output for the region from agriculture is 46.1% and agriculture-related workforce employment is 34%. The difference in employment numbers is explained by their inclusion of agriculture-related work in other industries such as transportation, manufacturing, research/education, and tourism.

The takeaway from the analysis of the local economy is that agriculture is a significant factor in the lives of people in the potential CCS project area, and as such, planning of CCS-related activities must ensure minimal impact to the resources (e.g., groundwater, agricultural land, etc.) that are perceived as paramount to the local economy.

Regional Public Perception of CCS and Related Issues

Local public support is vital for any CCS project as access to private land is essential for the installation and operation of well pad infrastructure, pipeline routing, pore space ownership payments, and area of review (AOR) monitoring activities. Prior to engaging the local public, some knowledge of their values and perceptions of climate change is critical to provide direction for public engagement. The Yale Survey on Climate Change provides insight into regional attitudes and can help predict the public's perceptions and attitudes toward climate mitigation strategies. Key details from the Yale survey for the five-county study area are provided in Table 2.

Additional information regarding the public's perception of climate change and CCS can be found in the community outreach plan (Appendix A).

Outreach

Even though no outreach activities occurred as part of this pre-feasibility effort, a CCS coordination team consisting of engaged Nebraska stakeholders and technical members was created to address any identified project-related challenges. The coordination team consisted of representatives from NPPD, NDEQ, Nebraska Energy Office, Omaha Public Power District, University of Nebraska-Lincoln (UNL), Southwest Public Power District, Lincoln Electric System, ION Engineering, Berexco LLC, and EBR Development LLC. The coordination team held two in-person meetings in Lincoln, Nebraska, and three WebEx calls throughout the project, providing project updates and opportunities for questions and comments (see Appendix B for coordination team meeting information).

In addition, a community outreach plan (Appendix A) was developed to 1) educate and inform the public, public opinion leaders, and decision makers; 2) evaluate public perception of CCS; and 3) develop mitigation approaches to any identified potential conflicts. As described in the plan, public outreach activities for a potential CCS project would begin with a detailed baseline

Table 2. Yale Survey

		Five County	Nebraska	USA
Beliefs	Believe global warming is happening	56%	64%	69%
	Believe global warming is caused mostly by human activities	42%	48%	52%
	Trust climate scientists about global warming	61%	66%	70%
Risk Perception	Worried about global warming	47%	51%	56%
	Believe global warming is already harming people in the United States	37%	44%	50%
	Global warming will harm me personally	32%	33%	38%
	Global warming will harm people in the United States	50%	51%	56%
	Global warming will harm people in developing countries	54%	57%	61%
	Global warming will harm future generations	62%	65%	69%
	Global warming will harm plants and animals a great deal	59%	63%	68%
Policy Support	Support funding for research into renewable energy sources	77%	81%	80%
	Support the regulation of CO_2 as a pollutant	66%	71%	74%
	Support strict CO_2 limits on existing coal-fired power plants	46%	63%	68%
	Support the requirement of utilities to produce 20% electricity from renewable sources	56%	62%	65%
Behaviors	Never discuss global warming	74%	70%	64%

assessment of stakeholder groups, which documents their current CCS knowledge/opinions and assesses their communication preferences. Stakeholder groups and the general public would be engaged through individual contact, meetings (e.g., open house), and the dissemination of project-focused outreach materials. An outreach advisory group, composed of representatives of the project partners and key stakeholders, would advise on the development of outreach time lines, activities, and products.

This site-specific outreach plan would then direct all outreach activities for the duration of a potential CCS project, if implemented. The plan, therefore, incorporates social characterization with engagement strategies and tracking:

1. Social Characterization – Detailed baseline of attitudes and concerns pertinent to implementation of the proposed project for the community, opinion leaders, and key groups.

2. Engagement Strategies:
    - Formation of an Outreach Advisory Board

    - Regional and Local Engagement – Meetings and other communication to inform Nebraska officials and regional opinion leaders.

- Community Open House – Community meetings hosted by the project team outlining major project milestones.

- Landowner Engagement – Contacts, home visits, and meetings geared specifically to engage with the many landowners in the project area.

- Web Site – Development and maintenance of a project public information Web site featuring basic project explanation and meeting notices as well as fact sheets, video clips, project updates, project partners, and contact information.

- Toolkit – Development of a background document, fact sheets, and frequently asked questions from which project personnel and partners can draw to prepare content for print and electronic media.

- Community Display – Dissemination of project posters and informational material in select public locations such as the public library and community government offices.

- Educator Outreach – Periodic educational sessions for students and teachers in local schools.

3. Tracking – Documentation of all outreach products, activities, communication, and interactions to measure project engagement. Feedback from project team members and interested stakeholders will help refine outreach activities to improve future outreach efforts as the project moves forward.

The outreach plan developed during this project could be modified and adapted for use in future CCS projects in the region. Any future outreach efforts would be conducted through collaboration with the existing CCS coordination team and build upon pre-feasibility activities. In keeping with DOE Best Practices (U.S. Department of Energy National Energy Technology Laboratory, 2017), outreach task activities would be coordinated with the project development plan and the leadership team and liaise with other outreach efforts through a project outreach advisory group featuring outreach specialists from project partners and key stakeholders.

2.7 Summary and Conclusions

A thorough review of the geographic and socioeconomic characteristics of the project area was conducted to identify any concerns related to regional CCS should efforts progress toward implementation. The analyses show several potential surface locations suitable for development of a commercial CCS project; however, when overlapped with geologic formations suitable for storage, the area to the south and west of GGS was identified as the study area of focus.

The review of protected and environmentally sensitive areas within the five-county study area identified favorable conditions for the location of potential CCS surface facilities. Land use within the area is dominated by agricultural activities and includes shallow (<300 feet), well-protected USDWs. Few state or federally protected lands (refuges, wetlands, etc.) or culturally protected areas exist within this region.

The state of Nebraska has not contemplated or promulgated statutes regarding CCS at this time. No regulatory environment currently exists for pore space ownership, financial assurance, closure, or long-term liability. In addition, no state regulatory agency has been selected for primacy, rulemaking, and oversight should statutes related to CCS be introduced.

As a result, existing federal regulations would guide any CCS efforts in Nebraska. EPA administers the UIC Program that consists of six classes of injection wells. CO_2 injection activities fall into one of two classes, depending on the purpose of the injection. Class II wells are used to inject fluids associated with oil and natural gas production, in this case CO_2 for enhanced oil recovery (EOR). Class VI wells inject CO_2 into the subsurface for the sole purpose of permanent geologic storage. UIC regulations contain a variety of measures to ensure that all USDWs are protected. Therefore, permitting of Class VI wells through EPA would be required for implementation of a potential dedicated CO_2 storage project in Nebraska. The region has, however, some oil and gas development. If, by chance, a CO_2 EOR effort were to become a viable option, then Class II regulations would be applied.

Any future CCS activity would likely be able to avoid oil/gas or wind energy development areas, thus limiting impacts on resource development. Although there has been past hydrocarbon exploration in the five-county area, the potential for impacts on current and future resource development remains low. The area contains mostly dry exploration and production wells that have been plugged and abandoned.

Although no CO_2 pipelines exist in the vicinity of GGS, a significant number of petroleum and natural gas pipelines cross the landscape. If pipeline construction were part of a future CCS project in this region, siting the pipeline in existing pipeline corridors should be considered to minimize impacts to landowners.

The community impact analysis provided substantial insight, along with the development of the community outreach plan that focuses on delivering technically accurate information in a proactive and transparent manner to address the concerns of citizens in the region. Local stakeholder support is vital for any CCS project as access to private land is essential for the installation and operation of well pad infrastructure, pipeline routing, and monitoring activities. Prior to engaging local stakeholders, some knowledge of their values and perceptions of carbon management is critical to provide direction for public engagement. This includes considerations related to CCS technology and the regional issues related to a commercial CCS project. The community outreach plan provides a regional overview focused on roles, approach and guidelines, outreach considerations, project narrative, audiences, strategies, toolkit components, time line, tracking and assessment, and resources.

3.0 SCENARIO ANALYSIS

A scenario analysis was performed to develop a strategy to identify national and regional incentives and/or challenges that would face a potential CCS project in western Nebraska. Technical requirements related to CO_2 capture, dehydration, compression, transport, injection, and monitoring; economic feasibility; and public acceptance of CCS were explored.

3.1 CO_2 Resource Assessment

Identification of Large CO_2 Sources

EPA's FLIGHT (Facility Level Information on GreenHouse gas Tool) database was used to identify any large sources of CO_2 within a 75-mile radius of GGS. According to the EPA's FLIGHT database, GGS's Unit 2 (GGS2) produced 3.24 million tonnes of CO_2 in 2016. Two additional sources were also identified: J Bar J Landfill in Ogallala, which emits only 17 tonnes CO_2/yr (emissions primarily from methane generation), and Mid America Agri Products Wheatland LLC in New Madrid, an ethanol producer that emits about 49,000 tonnes CO_2/yr (U.S. Environmental Protection Agency, 2016). These are shown in Figure 9. Neither of these sources is large enough to meaningfully contribute to the CarbonSAFE program goal of storing a minimum 50 Mt CO_2 over a 25-year period (i.e., averaging >2 million tonnes annually). Therefore, the CO_2 resource assessment focused solely on GGS2.

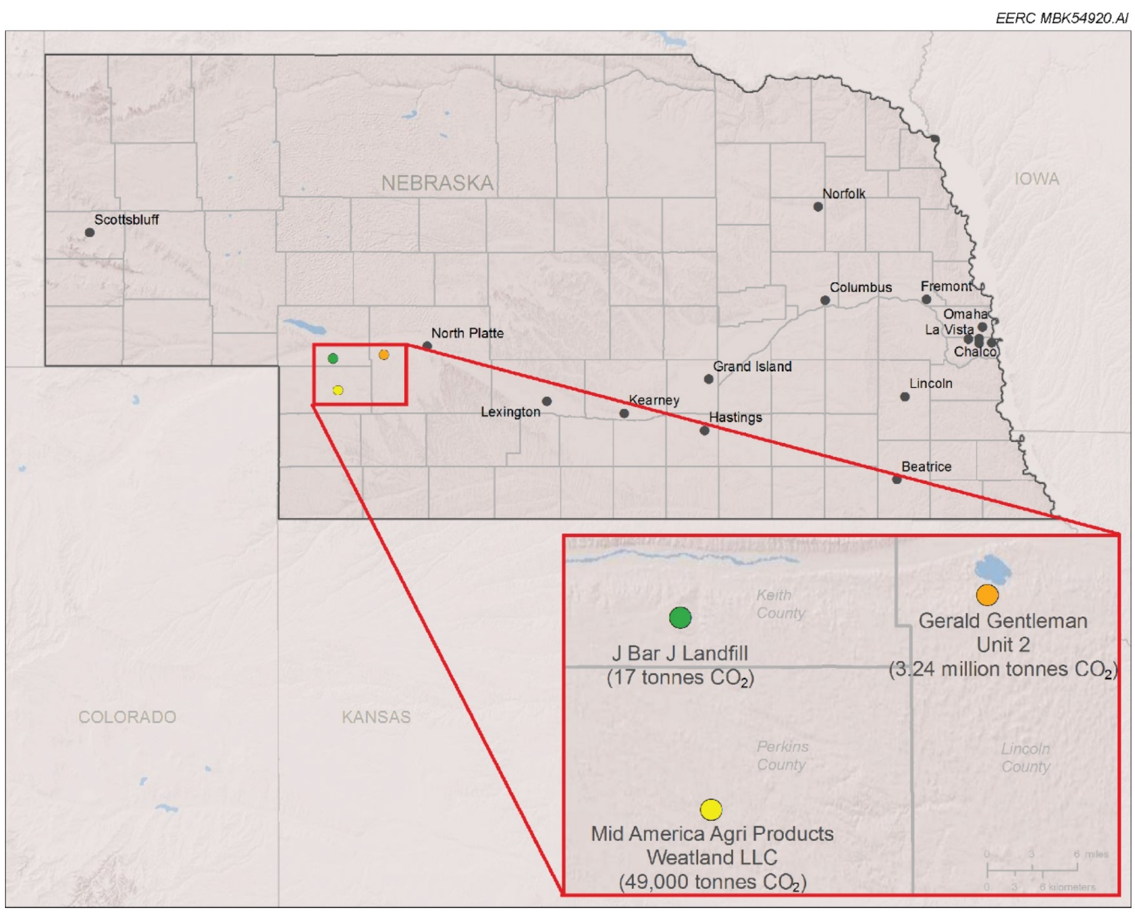

Figure 9. Point sources within 75 miles of GGS.

Capture, Dehydration, and Compression Technologies and Infrastructure

Several commercial CO_2 capture technologies were assessed for applicability to a coal-fired power plant, such as membranes and absorption. Membranes have not been proven effective when ultrafine particulate (such as are entrained in a flue gas stream) is present. Absorption using solvent scrubbing can be accomplished with physical solvents or chemical solvents such as amines. Physical solvents work best when the pressure of the gas stream is over 200 psi, but the pressure of flue gas leaving a power plant is roughly 20 to 30 psi. This type of system would add significant operating costs to pressurize the flue gas for capture in addition to compression for geologic storage. Chemical absorption using amines for capturing CO_2 is currently in commercial use at two power plants: Boundary Dam Unit 3 and Petra Nova. Therefore, amine solvents were investigated for viability in a potential GGS CCS scenario.

Amine solvents react with SO_x and NO_x to form heat-stable salts, effectively removing portions of the amine from service, so these compounds are reduced to very low levels in the flue gas prior to entering the CO_2 capture system. GGS2 would require the installation of a wet flue gas desulfurization (FGD) unit to remove SO_x from the flue gas. The unit's low-NO_x burner and overfire air would likely prevent the formation of NO_x such that a selective catalytic reduction (SCR) system would not be needed.

The CO_2 stream leaving an amine solvent capture system would consist primarily of CO_2 and water. The water must be removed prior to transport of the CO_2 to prevent pipeline corrosion. Dehydration of a large CO_2 stream is typically accomplished by scrubbing using a glycol, such as triethylene glycol (TEG). The wet CO_2 is contacted with dry glycol in an absorber, where the water is absorbed in the glycol. The wet glycol is transferred from the absorber to a regeneration system in which the CO_2 is separated from the water using a fractionation column and heat supplied by a reboiler. The absorbed water is boiled off, and the dry glycol is cooled and pumped back to the absorber. Figure 10 shows a TEG dehydration system.

The CO_2 stream is then compressed to supercritical state (at least 88°F and 1180 psi) prior to transport. A pipeline is the most economical way to transport large quantities of CO_2. Maintaining CO_2 supercriticality ensures that it is transported in a single phase. For large mass flow rates and discharge pressures up to about 2900 psi, an integrally geared centrifugal compressor is usually used. Figure 11 shows an integrally geared centrifugal compressor.

Pipeline Infrastructure

Pipeline technology is well known, having have been used to transport CO_2 in the United States for more than 40 years. A typical CO_2 pipeline is made of carbon steel. For a potential scenario of CO_2 transported from GGS2, it was assumed that the pipeline would be about 121 km (75 mi) long, 18 inches in diameter, and buried. Kinder Morgan has developed specifications enabling reliable CO_2 transport via pipeline (Global CCS Institute, 2012). Thicker-walled pipe or an impervious liner sleeve could be investigated for use if the CO_2 stream does not meet the quality specifications upon exiting the capture system. This approach might be less expensive than adding another unit operation to the CO_2 capture plant to deal with the contaminant in question, such as oxygen.

EERC MBK54909.AI

Figure 10. A TEG dehydration system (image from Q.B. Johnson Manufacturing, 2012).

EERC MJ39626.CDR

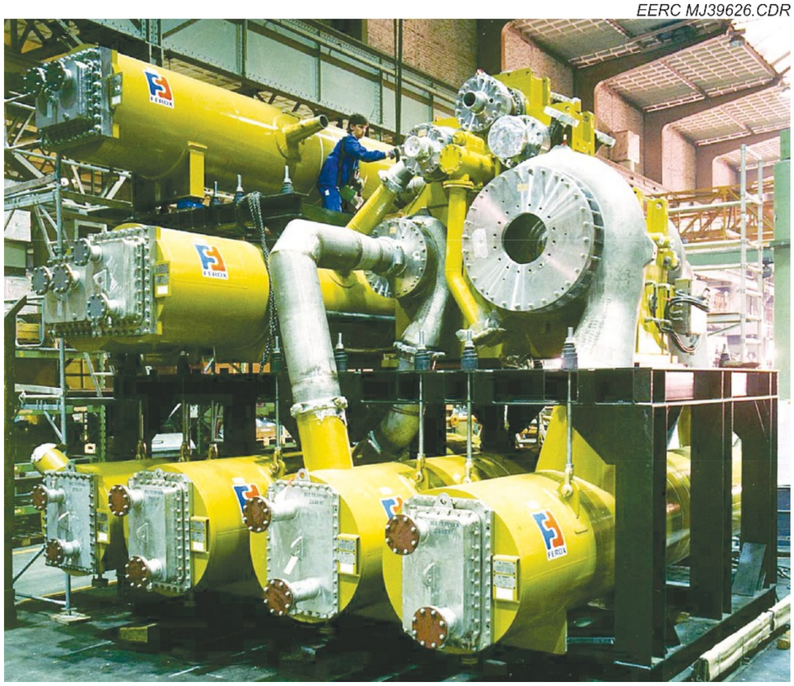

Figure 11. A ten-stage integrally geared centrifugal compressor with its intercoolers.

Injection Infrastructure and Location

The primary CCS injection scenario considered is potential CO_2 injection into a saline formation for dedicated geologic storage. In this case, the infrastructure needed for injection is minimal compared to that used at an EOR site. Infield injection infrastructure would consist of the CO_2 supply system (the CO_2-carrying pipeline and any necessary infield transport lines), the injection wells with associated instrumentation, and a SCADA (supervisory control and data acquisition) system to monitor and control injection operations.

An average of four injection wells was estimated to properly inject and store 50 Mt of CO_2 over a 25-yr period in the western Perkins and Chase Counties of the five-county study area previously defined (Figure 2). Spacing between wells would be 10–20 km (6.2–12.4 miles), with the nearest well 60 km (37.3 miles) from GGS2. Section 4.0 provides details of the geologic storage evaluation and potential injection locations for CO_2 from GGS2 that were determined through modeling and simulation.

Monitoring Technologies

A preliminary well design was developed for the primary potential CCS scenario with two drivers in mind: 1) to address the technical goals for storing >50 Mt CO_2 permanently and 2) to address the risk reduction and mitigation goals for storing CO_2 securely. A comprehensive geologic characterization would first be performed via the following techniques:

- Collecting geologic core and formation fluid samples to determine mineralogy, porosity, permeability, and geochemical reactivity to CO_2.

- Conducting well logs.
  - Triple combo, dipole sonic/fracture finder, spectral gamma ray (GR), and spontaneous potential (SP) logs that provide formation information, to complete the result of core analysis, includes porosity, density, temperature, resistivity, lithology, mineralogy, geomechanical properties, and existence of fractures.
  - Cement bond and variable density logs that provide cement bond quality behind casing to ensure the protection of USDW and reduce the risk of CO_2 migrating to the shallow subsurface or the surface.

Reservoir surveillance includes the numerous activities designed and implemented to observe and quantify the CO_2 injected and stored. CO_2 plume movement can be monitored using borehole-to-surface electromagnetic (BSEM) analysis that leverages the salinity contrast between the injected CO_2 and native formation fluid and provides an image of the CO_2 plume around the injector well at the beginning of the project as well as at the end. Periodic formation fluid sampling in the monitoring well can also note geochemical changes once CO_2 breaks through to the monitoring well. Downhole pressure and temperature gauges can be used to continuously monitor the CO_2 injection profile in the injection and monitoring wells, while flowmeters and digital pressure and temperature sensors could be installed on the wellhead to measure surface injection parameters, including rate, pressure, and temperature. Further details about these monitoring technologies and approaches are provided in Appendix C.

3.2 Financial and Economic Evaluation

To obtain operation and cost estimations about the application of investigated CO_2 capture technologies to the GGS, GGS2 was modeled using the DOE NETL-funded Carnegie-Mellon University Integrated Environmental Control Model (IECM), Version 9.5. The IECM is a computer-modeling program that systematically analyzes the cost and performance of emission control equipment at coal-fired power plants (Integrated Environmental Control Model, 2018). The user can configure the power plant to be modeled with a variety of pollution control devices.

A baseline model was built to mimic GGS2 as it currently exists and operates. The baseline CO_2 emission output was checked against actual values from GGS2 for 2016 and found to be within 1%. This indicates that results obtained from incorporating CO_2 capture information could be considered accurate. Major assumptions made when using the IECM for modeling GGS2 included:

- CO_2 capture at GGS2 is a retrofit on NPPD-owned property.
- All capture types require the installation of a wet FGD with a demister.
- The pipeline would be 121 km (75 mi) in length.
- The CO_2 pressure leaving GGS2 would be 1500 psia to provide the estimated injection pressure of about 1300 psia at the potential storage site.
- The use of a flue gas bypass and a 65% overall CO_2 removal efficiency to produce roughly 2 Mt CO_2 annually for potential geologic storage. Other capture rates were modeled to show the effect of capture rate on cost per tonne CO_2.

Modeling Assumptions

A pre-feasibility economic assessment was conducted for CO_2 capture at GGS2, using the assumptions listed above. Costs were grouped together as one-time capital expenses (CAPEX) and recurring operating expenses (OPEX). CAPEX categories included capture equipment, pipeline, Class VI well installation, Class VI permitting, and a 3-D seismic survey. OPEX consisted of recurring annual expenses (plant labor, materials, maintenance, chemical usage, energy usage, etc.) for GGS2 as modeled using the IECM.

Capture scenarios modeled for GGS2 included 65%, 80%, and 90% with and without an auxiliary boiler for two commercial amine solvent technologies: Cansolv and Fluor's Econamine FG+ (Table 3). The 65% capture scenario is the minimum capture level needed at GGS2 to average 2 Mt per year CO_2 output (i.e., to meet the CarbonSAFE program minimum 50-Mt CCS requirement over a 25-yr period).

Table 3. GGS2 IECM Modeling Matrix

Solvent			**Econamine FG+**			
% Capture	65	80	90	65	80	90
Auxiliary Boiler?	Yes	Yes	Yes	No	No	No
Solvent			**Cansolv**			
% Capture	65	80	90	65	80	90
Auxiliary Boiler?	Yes	Yes	Yes	No	No	No

In order to achieve accurate estimated costs from IECM, financial inputs for each system process were assigned in each capture scenario case. The percent of total capital requirement (%TCR) is a feature of the IECM that allows the user to compute additional expenses by retrofitting the capture system. A system that has TCR at 100% means it is completely paid off, whereas TCR at 0 means that no dollar amount has been invested in this process. The key assumptions in the model for GGS2 relative to the TCR were:

- NO_x control = 100%
- Total suspended particulate (TSP) collection system = 100%
- Mercury control = 50%
- SO_x control for a wet FGD system = 0
- CO_2 capture system = 0

GGS2 CO_2 Capture Retrofit Cost Summary

The twelve capture scenarios were modeled using IECM for an assumed retrofit situation at GGS2, and the cost of capture was computed on a dollars per tonne basis to allow for direct cost comparison of the scenarios.

The estimated costs for CO_2 capture can be calculated two different ways: *capture* or *avoided*. The *capture cost* is strictly the estimated cost of an added capture system and its additional operation requirements (e.g., labor, water, etc.). It is typically used to compare different capture systems or solvents. The *avoided cost* does not have a universal definition that enables consistent calculation but typically estimates the total impact of implementing capture on a specific power plant. For example, the avoided cost takes into account lost sales for any electricity and/or steam usage by the capture system (a.k.a., derating or the parasitic load), which equates to an increased cost for the electricity sold on a per kW basis. The IECM, therefore, calculates an avoided cost using the cost of electricity and associated CO_2 emissions on a kWh basis for a plant as it currently operates by comparing the operating cost of the power plant with capture to the operating cost without capture by the following equation:

$$\text{Avoided Cost} = \frac{\text{Cost of Electricity}_{\text{with capture}} - \text{Cost of Electricity}_{\text{without capture}}}{CO_2\text{ Emissions}_{\text{without capture}} - CO_2\text{ Emissions}_{\text{with capture}}} \qquad \text{[Eq. 1]}$$

where the cost of electricity is given in \$/MWh and the emissions in tonnes/MWh.

All of the estimated costs are presented in Tables 4 and 5. The costs indicate that, if applied at GGS2, the Fluor Econamine FG+ process might be less expensive on a per tonne basis than the Cansolv process. The capture costs given in the table include the capital and operating costs associated with the capture system and the wet FGD unit. The avoided costs include not only the costs of the wet FGD and capture equipment but also the costs associated with the derating of the power plant that occurs because of the steam and electricity usage by the capture and FGD systems, i.e., the parasitic load. Most capture systems using amines result in a parasitic load on the power plant of about 30%–35%. In other words, providing the low-pressure steam and electricity needed to operate the capture system reduces by about 35% the amount of power that the plant can produce and put on the grid for distribution and sale. One approach for reducing the parasitic load is to employ a natural gas-fired boiler to produce the steam needed for the capture system. Additional approaches to produce the electricity needed for the capture facility, such as an auxiliary turbine incorporated with the boiler, could be also considered.

Figure 12 shows the estimated cost of capture when employing a natural gas-fired auxiliary boiler to produce the steam needed to regenerate the amine solvent. The graph compares this cost with the avoided cost. Multiple conclusions can be drawn from the plot. The first is that the most economical capture may occur at roughly an 82% capture level. Secondly, as indicated, adding an auxiliary boiler to reduce the power plant derate is similar in capture cost to the estimated avoided cost of the Econamine FG+ process, regardless of process type. The avoided cost of the Cansolv system is still considerably higher than the capture cost using the auxiliary boiler, particularly at lower capture levels (<80%).

Because the estimated avoided cost and capture costs of including an auxiliary boiler are similar, further investigation would be required by NPPD to determine the optimal approach for GGS2. To operate the power plant at its design capacity (the most cost-effective operation) and allow derating for capture system operation would provide less electricity for sale on the grid but lower the capital investment for capture (i.e., without an auxiliary boiler). This might be an appealing option if the electrical load has been less than maximum for several years and less electricity is being sold. Conversely, installing an auxiliary boiler system would allow nearly full plant electricity production to be put on the grid, presumably bringing in more money from electricity sales should the market be robust.

Overall Scenario Costs

The potential GGS2 capture system is the largest component of the total CCS scenario expenses. Additional costs from CO_2 transport, well infrastructure, and fieldwork were incorporated with the capture and avoided costs to produce an overall project economic projection.

Pipeline cost estimates were performed using the DOE NETL CO_2 Pipeline Cost Model as well as the transport module within the IECM. Table 6 summarizes the estimated pipeline costs on

Table 4. Capture and Avoided Costs as Estimated by the IECM for GGS2

Capture Level	65%			80%			90%		
Cost Type, $/tonne	**Capture Only**	**Capture with Wet FGD Unit**	**Avoided Cost**	**Capture Only**	**Capture with Wet FGD Unit**	**Avoided Cost**	**Capture Only**	**Capture with Wet FGD Unit**	**Avoided Cost**
Solvent									
Econamine FG+	31.30	40.10	73.40	29.80	36.30	68.00	31.10	36.70	67.30
Cansolv	47.80	56.50	101.00	39.50	46.54	76.25	41.20	47.40	74.99

Table 5. Capture Costs with an Auxiliary Boiler as Estimated by the IECM for GGS2

Capture Level	65%		80%		90%	
Cost Type, $/tonne	**Capture Only**	**Capture with Wet FGD Unit**	**Capture Only**	**Capture with Wet FGD Unit**	**Capture Only**	**Capture with Wet FGD Unit**
Solvent						
Econamine FG+	61.70	72.10	56.50	64.90	57.80	65.20
Cansolv	67.10	77.20	30.00	68.10	61.90	69.00

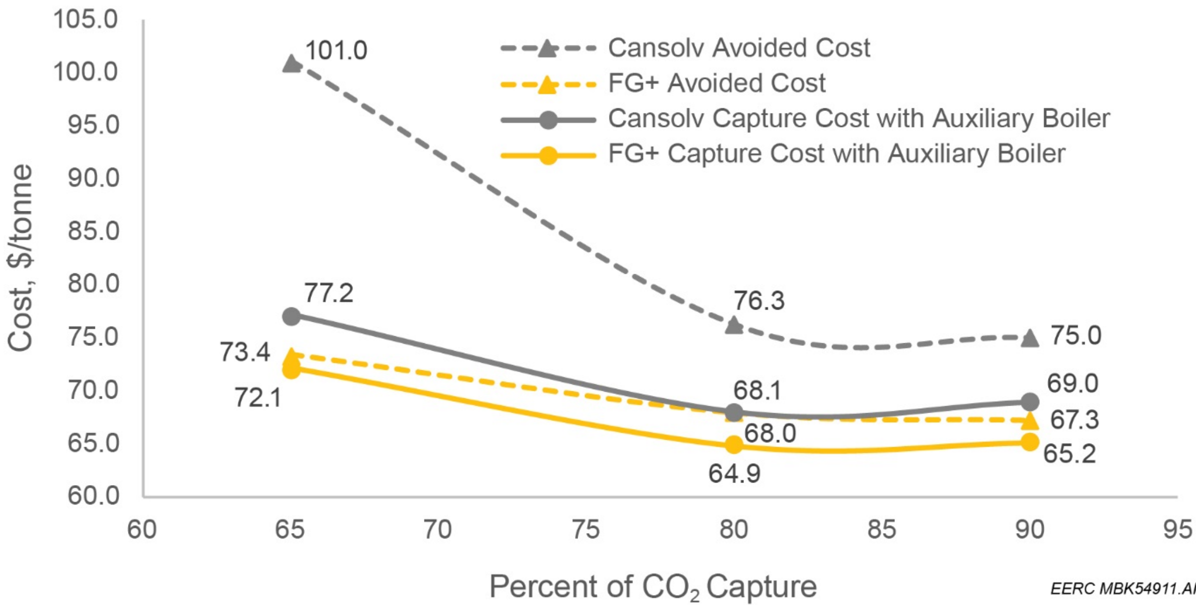

Figure 12. Capture costs using a natural gas-fired auxiliary boiler to provide steam compared with avoided costs estimated by the IECM for Fluor's Econamine FG+ and Cansolv processes if deployed at GGS2, assuming inclusion of the wet FGD unit as a part of the capture system. This comparison shows the costs associated with adding capture and accepting the derate (i.e., the avoided cost) against adding capture plus an auxiliary boiler, which puts the same amount of power on the grid as GGS2 currently does.

Table 6. Preliminary Pipeline Economics for Potential CO_2 from GGS2[1]

Capture Level (CO_2 Produced)	**90% (3 million tonnes/yr)**			**80% (2.6 million tonnes/yr)**		**65% (2.1 million tonnes/yr)**	
Pipe Diameter, in.	**20[2]**	**18**		**18**		**18**	
Model	DOE	DOE	IECM	DOE	IECM	DOE	IECM
CAPEX, million	$96	$86	$70	$86	$70	$75	$65
OPEX, million[3]	$22	$22	$11	$22	$11	$22	$11
Total, million[3]	*$120*	*$110*	*$81*	*$108*	*$81*	*$97*	*$76*
Total CO_2 Transported,[3] million tonnes	89			79		64	
Cost CO_2, per tonne	**$1.3**	**$1.2**	**$0.9**	**$1.4**	**$1.0**	**$1.5**	**$1.2**

[1] Values may not add up as all numbers are rounded to two significant figures.
[2] The IECM did not calculate a 20-in. pipe diameter.
[3] Total over the assumed 30-yr pipeline lifetime.

a per tonne basis, ranging from \$0.90/tonne to \$1.50/tonne CO_2. Pipeline modeling included the following assumptions:

- Pipeline length = 75 mi
- Inlet pressure (at GGS2) = 1500 psia
- Outlet pressure (at injection site) ≈ 1300 psia
- A standard 30-yr pipeline operating lifetime
- All values converted to 2014\$
- CAPEX includes materials, labor, and right(s)-of-way

Estimated costs for a potential injection and geologic storage site were provided by Schlumberger Carbon Services. These costs included 1) drilling and completion of a Class VI injection well; 2) drilling a stratigraphic test well, followed by plugging and abandoning procedures; and 3) drilling and completion of a monitoring well. As mentioned previously, an average of four injection wells was estimated to inject and store 50 million tonnes of CO_2 over a 25-year period. Thus the overall CCS estimated costs include four Class VI injection wells. Potential monitoring expenses included baseline and 3-D seismic surveys in addition to an instrumented monitoring well. A summary of these estimated costs is given in Table 7.

Table 7. Estimated Well Drilling and Seismic Analysis Costs[a]

Well Type	Estimated CAPEX, \$million
Class VI Injection AFE[b]	4.2
Stratigraphic Test Well AFE	3.0
Monitoring Well AFE	4.9
Seismic	
3-D Seismic Survey (12.3 mi^2)	0.7 (range = 0.5–1.2)

[a] Estimates were acquired through Schlumberger.
[b] Authorization for expenditure.

Overall estimated CCS costs, shown in Table 8, were compiled based on the best-case scenario for capture at GGS2 (80% capture using FG+), as well as the most economical pipeline, well costs, permitting, and seismic estimates. Any additional monitoring requirements necessary for permitting Class VI wells have not been factored into these estimated costs. All costs were converted to a \$/tonne basis to allow for ease of comparison and evaluation of the various components. In this assumed best-case scenario, total CCS project costs are estimated as \$70/tonne of CO_2 captured from GGS2 with potential geologic storage in western Nebraska.

Table 8. Overall Combined Estimated CCS Costs for Economic Evaluation

Component	Capture Costs, \$/tonne	Avoided Costs, \$/tonne	Capture + Auxiliary Boiler Costs, \$/tonne
FG + 80% Capture	36.7	68.0	64.9
Pipeline[a]	1.37	1.37	1.37
Four Class VI Injection Wells[b]	0.32	0.32	0.32
One Stratigraphic Test Well[b]	0.06	0.06	0.06
One Monitor Well[b]	0.1	0.1	0.1
12.25-mi^2 3-D Seismic Survey[b]	0.01	0.01	0.01
Permitting[c]	0.24	0.24	0.24
Total, \$/tonne	**38.8**	**70.1**	**67.0**

[a] DOE NETL CO_2 Model: assumes 18-inch, 75-mile pipeline with injection at 1300 psi, over 30 years in 2014 U.S. dollars.
[b] Calculated from Schlumberger estimate.
[c] Assumes permitting costs for four Class VI injection wells.

Revenue Assessment

Possible revenue from potential CO_2 production at GGS2 for an EOR market was also investigated. As part of this assessment, tax credits available through the Bipartisan Budget Act of 2018 under the Enhancement of Carbon Dioxide Sequestration Credit (formerly known and hereafter referred to as Section 45Q) were evaluated as an opportunity for CO_2 suppliers to potentially capitalize on a supplemental market. Utilizing Section 45Q tax credits as a marketing tool would depend greatly on agreed-upon negotiating terms between the CO_2 supplier (e.g., NPPD) and the CO_2 purchaser. Although NPPD, as a public entity, does not qualify directly for Section 45Q, a pathway to market could exist where operator(s) for dedicated storage or EOR would be willing to purchase CO_2 from GGS2 and store in a saline formation or at an oil field(s) associated with EOR operations. In this case, the operator(s) would be responsible for claiming the tax credits as well as adhering to any CO_2 monitoring requirements in the subsurface.

The Section 45Q tax credit amounts are established by linear interpolation from \$12.83 to \$35 per tonne for EOR and from \$22.66 to \$50 per tonne for dedicated storage each calendar year after 2016 and before 2027 (115th Congress, 2018). These values are shown in Table 9. After 2026, the tax credits increase according to inflation as, presumably, would the cost of CCS. When this potential revenue is compared with the minimum estimated cost of \$67/tonne for a CCS project (shown in Table 8), it can be seen that tax credits alone are not a sufficient resource for CCS investment. This is particularly true for a dedicated storage scenario at GGS2 where NPPD could not qualify directly for Section 45Q. However, depending on the transferability of the 45Q tax credits, NPPD could still take advantage of them to offset the cost of capture. In the case of dedicated storage, even at \$50/tonne, there would still be at least a \$20/tonne shortfall between the potential capture cost and revenue. This result indicates that additional new market or incentive program(s) could be needed to attract investment for dedicated storage.

Table 9. Values of 45Q Tax Credits over Time

Storage Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026+
EOR, $/tonne	12.83	15.29	17.76	20.22	22.68	25.15	27.61	30.07	32.54	35[a]
Dedicated Storage, $/tonne	22.66	25.70	28.74	31.77	34.81	37.85	40.89	43.92	46.96	50[a]

[a] To remain constant in value for 2027 and thereafter (adjusted for inflation).

Further revenue assessment focused on potential EOR markets. At the typical current price of CO_2 of $25/tonne to $35/tonne, the combined value of the Section 45Q tax credit and the direct sale price of the CO_2 could range from $60 to $70/tonne. At a $70/tonne value, the estimated CCS cost may be offset, assuming that NPPD elected to allow the tax credit to pass to another allowable entity. In this case, perhaps NPPD could negotiate a price for the CO_2 on the higher end of the CO_2 price range in return for electing the credits to pass to the oil company using the CO_2 for EOR or to another part of the value chain such as a pipeline company transporting the CO_2, etc.

Note that the total CO_2 needed for EOR in the Nebraska oil fields near GGS2 is estimated as 10 million tonnes (Plains CO_2 Reduction Partnership, 2016). The quantity of CO_2 produced by GGS2 would meet this need in a relatively short period of time. Therefore, if EOR is to be a viable use for CO_2 produced by GGS2, additional target oil fields will need to be located potentially in Kansas, Oklahoma, Colorado, New Mexico, or Texas.

3.3 State and Federal Incentives and Challenges

As mentioned previously, the state of Nebraska has not contemplated or promulgated statutes regarding carbon capture, utilization, and storage (CCUS). To date, no academic, public, private, or commercial entity has developed a proposed CCUS project that would initiate the statutory development process through the Nebraska Legislature. For such interests considering CCUS and evaluating carbon capture technologies, statutory and regulatory certainty is necessary to commit the large capital investments and associated escalating operating costs. State regulatory agencies in Nebraska do not have the statutory authority for CCUS rule making; therefore, there is no guidance in place for regulatory certainty. The Legislature would need to promulgate CCUS statutes and subsequently delegate and empower regulatory authority to the appropriate state agencies for rule making, permitting, inspection, and oversight.

As of this date, no regulatory environment exists in Nebraska to address pore space ownership or long-term liability related to potential CCUS efforts. All permitting currently falls under EPA UIC regulation. Should the regulatory environment change, and/or if an academic, public, private, or commercial entity proposes a CCUS project, expect regulatory certainty to be a multiyear process in order for the Legislative statutes and state agencies rulemaking.

4.0 SUBBASINAL ANALYSIS

4.1 Reservoir and Seal Characteristics

Three potential CO_2 storage resource complexes in the subsurface of western Nebraska were identified and characterized to varying degrees. In order of increasing depth, the potential reservoirs investigated are the Lower Cretaceous Cloverly Formation (fluvial depositional environment), the Lower Permian Cedar Hills Sandstone (nearshore evaporate depositional environment), and the Middle Pennsylvanian Cherokee Group (interbedded lacustrine and nearshore marine depositional environments) (Figure 13). These formations are continuous within the Nebraska–Colorado study area shown in Figures 14 and 15, thicken and deepen to the southwest into the Denver–Julesburg Basin, and thin and shallow to the east.

Uncertainty and Data Availability

Where applicable and where data were available, the extent of each potential reservoir was limited to areas where the top of the reservoir is greater than 3000 ft deep with a salinity greater than 10,000 ppm. All potential reservoirs are capped by vertical sealing formations. Structural data were retrieved from publicly available state databases and used to create structural surfaces after the removal of erroneous data points and smoothing. Because stratigraphic data collection in Nebraska is geographically clustered according to oil and gas production, structural uncertainty is larger across the middle of the study area where there are fewer wells. Likewise, petrophysical properties used to populate geologic models were extrapolated from a limited number of digital well logs and core measurements, increasing the amount of uncertainty.

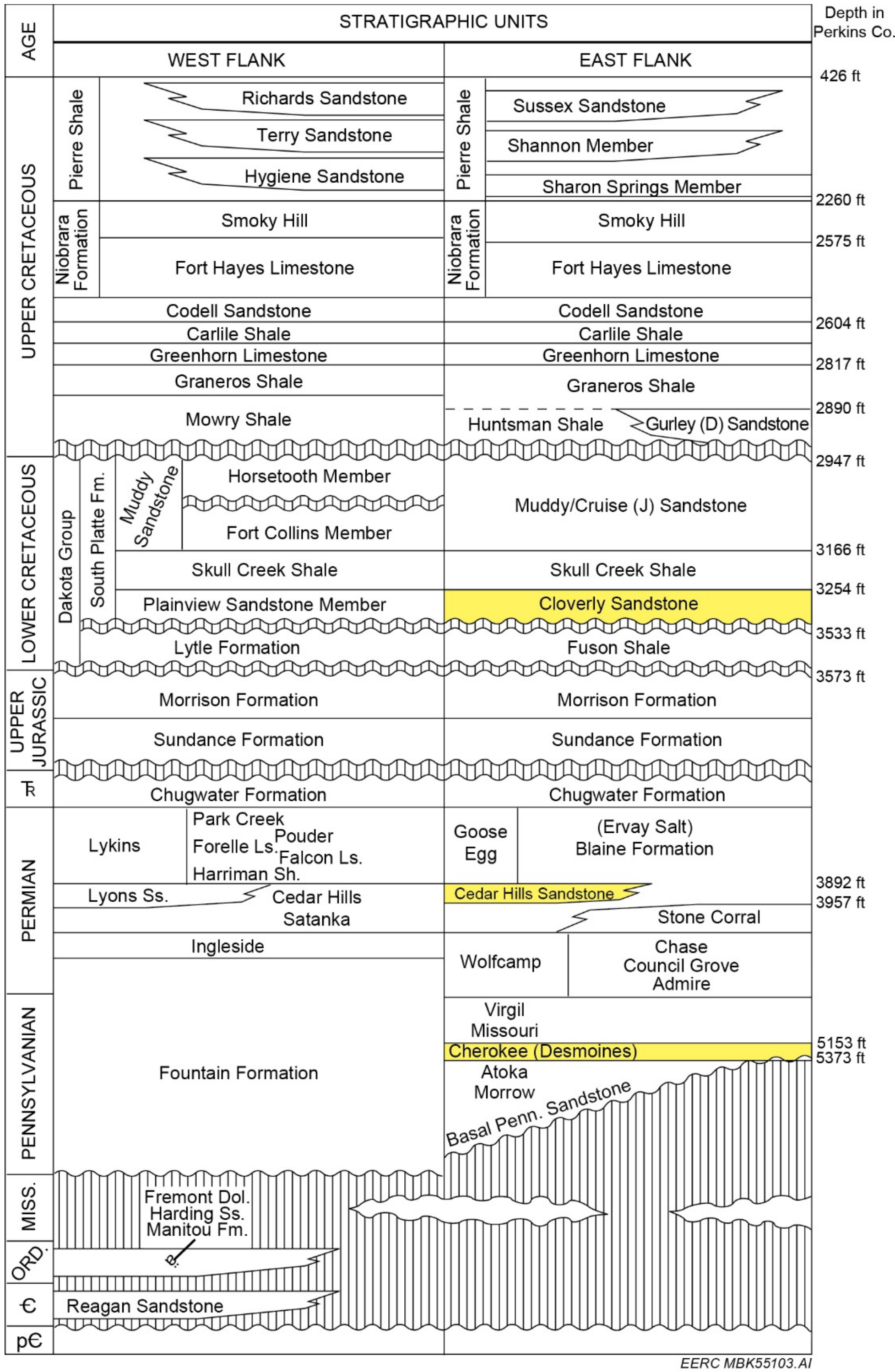

Figure 13. Stratigraphic column of the Denver–Julesburg Basin (modified from Higley and others, 1995). Colored intervals represent prospective CO_2 storage reservoirs discussed herein. Depths are approximate in Perkins County, Nebraska. The stratigraphic package thins to the east; near GGS in western Lincoln County, the Precambrian basement is about 4700 ft deep.

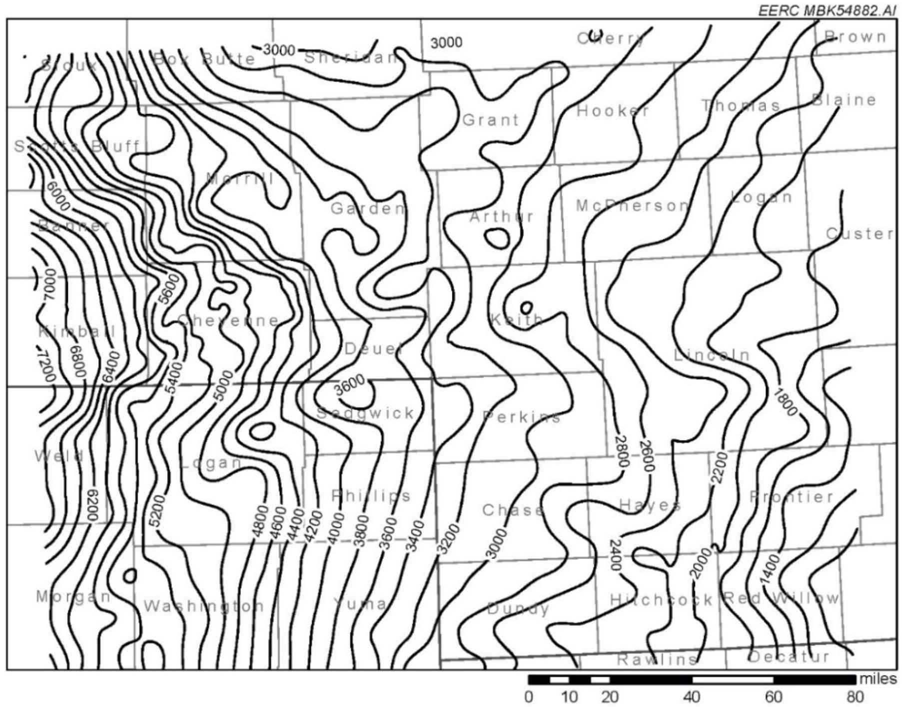

Figure 14. Depth to the top of the Cloverly Formation in western Nebraska and northeastern Colorado. The contour interval is 200 ft.

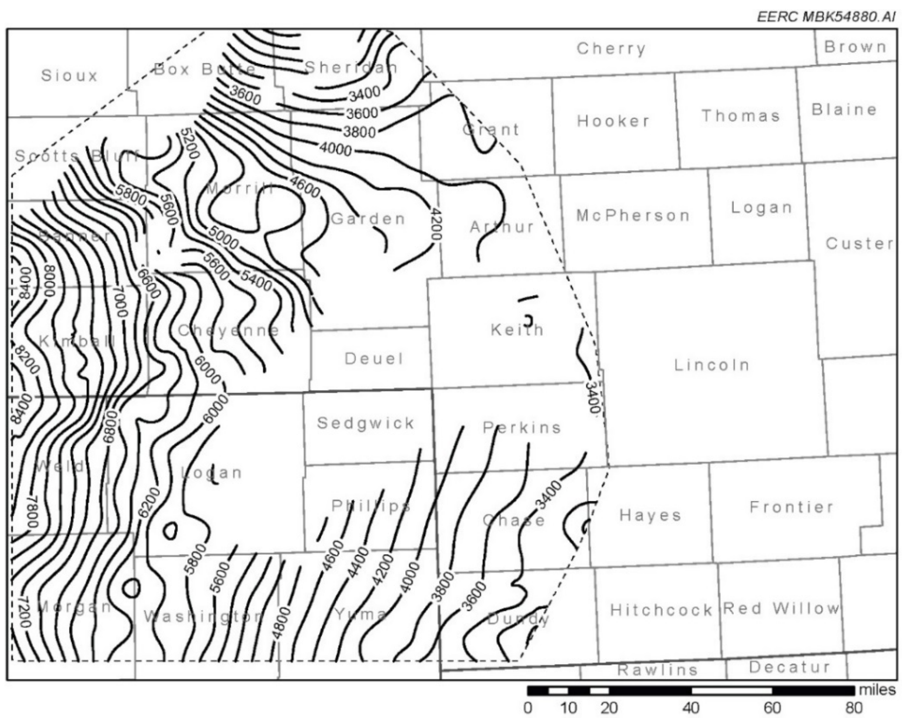

Figure 15. Depth to the top of the Cedar Hills Formation in western Nebraska and northeastern Colorado. Missing contours represent the presence of the salt and anhydrite Blaine Formation. The dashed line shows the extent of the area used to estimate storage potential.

Cloverly Formation

The Lower Cretaceous Cloverly Formation (“M” Sandstone of Bass [1958]) is the lower sandstone unit of the Dakota Group (Figure 16). It is capped by the Skull Creek Shale within the study area, although this seal thins to the east, away from the center of the Denver–Julesburg Basin. The upper sandstone unit, comprising the “D” and “J” Sandstones (aka “Gurley” and “Cruise”), is too shallow within the study area to hold CO_2 in a supercritical state. The entire Dakota Group is capped by multiple shale units, including the Graneros and Pierre Shales. The Cloverly is represented by northeast to southwest trending, often isolated, sand bodies surrounded by shale that were deposited in a fluvial system. The rivers were meandering, sinuous, and usually narrow, frequently less than one-half mile in width, but can often be traced over a length of several miles (Harms, 1966; Miller, 1963). Both the Cloverly and Skull Creek are conformable and occur throughout the extent of the model.

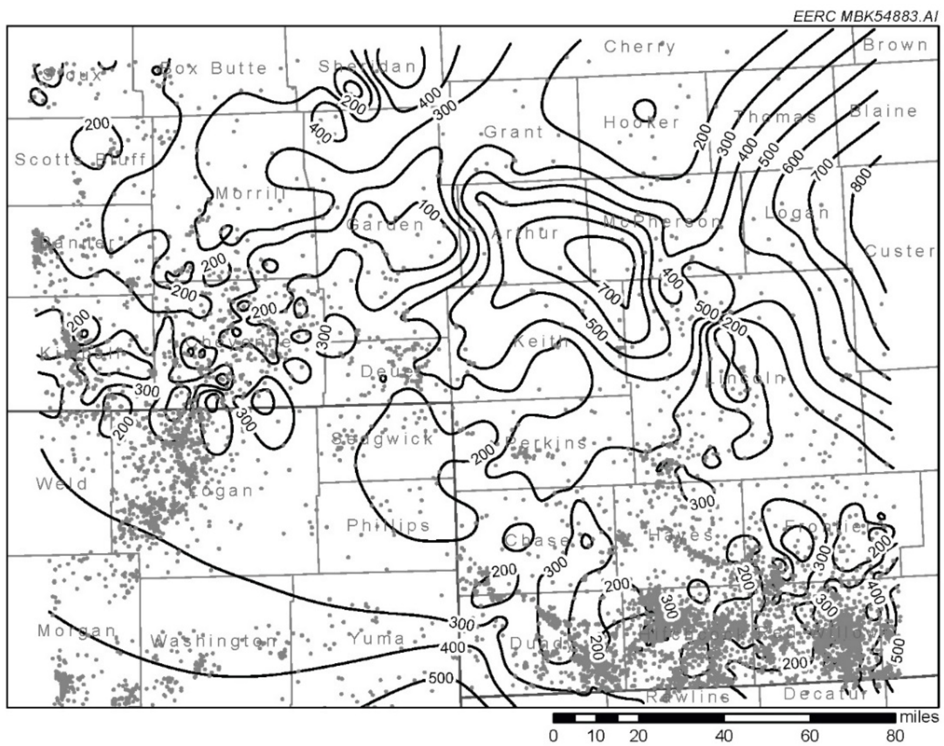

Figure 16. Thickness of the Cloverly Formation in western Nebraska and northeastern Colorado and wells that intersect the top of the formation.

The Cloverly Formation has been identified as a secondary (poor-quality, salinity > 10,000 ppm) aquifer named the Apishapa. The upper Dakota Group D and J Sandstones are of similar quality and termed the Maha, although the easternmost extent of this interval has better quality. The next-highest aquifers are the Codell and Niobrara aquifers, which contain good-quality water but are not primary USDW targets. The primary aquifer in the study area is the High Plains Aquifer (which includes the Ogallala) above the Pierre Shale (Korus and Joeckel, 2011).

Cedar Hills Formation

The Cedar Hills Formation is made up of interbedded red sandstone, sandy siltstone, and shale and is part of geographically extensive Permian eolian and evaporate deposits (Macfarlane and others, 1988; Oldham, 1997). It is vertically sealed by the Blaine (anhydrite) and Flowerpot (shale) Formations. Within the study area, the depth to the top of the Cedar Hills Formation ranges from less than 1600 ft in the east to greater than 8200 ft in the west but thins substantially east of Keith County, Nebraska (Figures 15 and 17). An area in Garden, Deuel, western Keith, and northern Perkins Counties (Nebraska) and Sedgwick, eastern Logan, and northwestern Phillips counties (Colorado) is filled with salts and anhydrite of the overlying Blaine Formation.

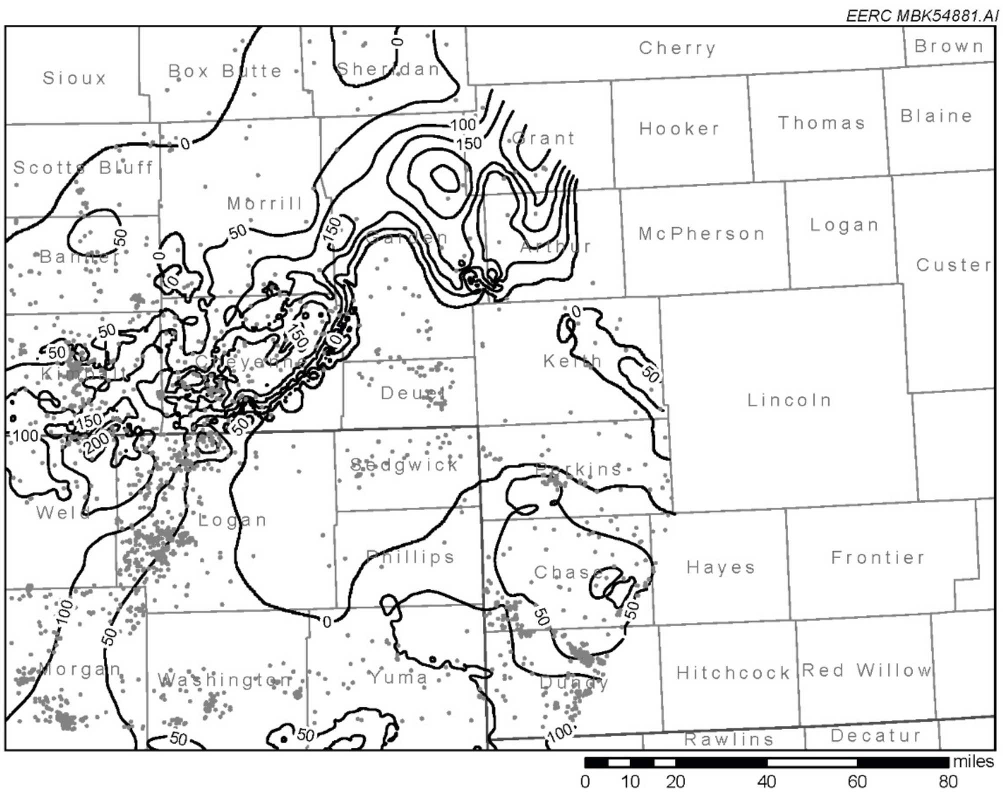

Figure 17. Thickness of the Cedar Hills Formation (Oldham, 1997; derived from Oldham's Figure 8-7) and intersecting wells in western Nebraska and northeastern Colorado. Zero-thickness area in Garden, Deuel, western Keith, and northern Perkins counties (Nebraska) and Sedgwick, eastern Logan, and northwestern Phillips counties (Colorado) is filled with salts and anhydrite of the overlying Blaine Formation.

Cherokee Group

A regional structural model areally equivalent to that of the Cloverly Formation of the Pennsylvanian Cherokee Group was constructed using well tops from Nebraska and Colorado state oil and gas databases. Petrophysical analysis of 65 wells in the study area suggest that the Cherokee Group would be a poorer CO_2 storage unit than the Cloverly or the Cedar Hills. In the areas of best well control, the potential reservoir in the lower Cherokee Group is too thin and shaly (about 86%) to provide much storage potential, and the thickness of the uppermost shale is too low to provide assurance between wells that leakage would not occur. Because of these factors, further pre-feasibility screening was not pursued.

4.2 Prospective Storage Resource Assessment

Varying degrees of precision were used to assess the amount of storage resource in each of the potential storage complexes, depending on the amount of data available. Regional storage resource estimates were calculated for the area of the Nebraska panhandle and the northeastern corner of Colorado (Figures 14 and 15). The eastern extent of the storage resource models was dictated by the shallowest part of each reservoir greater than 3000 ft in depth. Because of the low data availability in the study area for the current pre-feasibility study, these storage resource assessments were conducted at the play level according to the SPE (2016) CO_2 storage resources management system (SRMS) (Figure 18). This SRMS classifies storage resources according to project maturity, where an increasing amount of data increases the chance of eventual commercialization and screens out those resources that do not meet technical, economic, or regulatory standards.

Three distinct geologic model variations were constructed using Schlumberger Petrel to assess volumetric CO_2 storage potential: one for the Cedar Hills Formation and two for the Cloverly Formation (Table 10). Of the Cloverly models, B was built at a regional scale, and A was a smaller area clipped out for separate simulation work. The Cloverly A simulation model was used for both dynamic simulation and volumetric storage potential estimation.

A modified DOE method of calculating CO_2 storage potential in saline formations was used for each model (Peck and others, 2014). Storage resource potential was estimated on a per cell basis in the reservoir facies of each model using Equation 2.

$$M_{CO_2} = A \times h \times \varphi \times \rho_{CO_2} \times E_{saline} \qquad \text{[Eq. 2]}$$

where

A	=	cell area
h	=	cell height
φ	=	cell porosity
ρ_{CO_2}	=	CO_2 density based on cell pressure and temperature
E_{saline}	=	saline storage efficiency factor

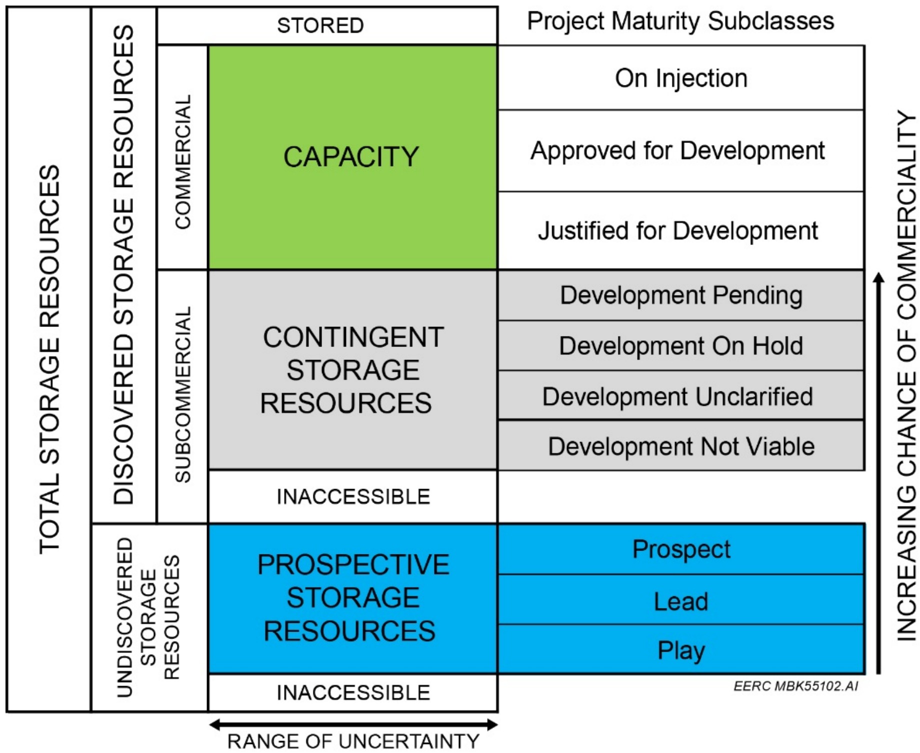

Figure 18. Subclasses of CO_2 storage resources based on project maturity (SPE 2016, Figure 2.1). The current project assesses Nebraska's prospective storage resources at the play level.

Table 10. Cloverly and Cedar Hills Formation Volumetric Storage Estimates for Western Nebraska and Northeastern Colorado Using E_{saline} Values from Peck and others (2014), millions of metric tonnes

		E_{saline}, %[2]			Potential Storage Estimate, millions of tonnes		
Model	**Known Factors[1]**	**P10**	**P50**	**P90**	**P10**	**P50**	**P90**
Regional Models							
Cloverly Formation B[3]	Net area Net thickness Net porosity	7.4	14	24	20,800	39,300	67,400
Cedar Hills Formation A[4]	Net area	1.62	4.41	9.53	510	1400	3000
Subarea Model							
Cloverly Formation A[3]	Net area Net thickness Net porosity	7.4	14	24	586	1110	1900

1 Known factors listed are those that were taken into account when applying potential E_{saline}.
2 E_{saline} is the efficiency factor applied to the total porosity to produce storage potential estimates (discussed below).
3 Storage potential was calculated for two variations of the Cloverly Formation model based on two model sizes (regional [Figure 19] and the geographically limited simulation model [Figure 20]). Net area, net thickness, and net porosity were known factors.
4 Model extent shown in Figure 20. Net area was the only known factor.

This method applies different E_{saline} values to total porosity estimates based on known factors incorporated into a model: net area, net thickness, and net porosity (Figure 19). “Net” terms refer to the formation volume remaining after screening out volumes that are too shallow at less than 3000 ft depth (net area), with porosity too low according to permeability (net porosity), or with facies that are not amenable to storage (e.g., shales, salts) (net thickness). As knowledge about the potential storage complex increases, the estimated total pore volume likely decreases, but the remaining pore volume is more amenable to CO_2 storage. For example, when total thickness, total porosity (including both reservoir and non-reservoir facies), and only net area of a saline formation are known, only 4.41% of the total pore volume (net area × total thickness × average porosity) is estimated to be available for storage. When net rather than total thickness is used for total pore volume (net area × net thickness × average porosity), the pore volume estimated to be available for storage is estimated to be 9.88% of the total pore volume (in this case, average porosity is derived from another source according to depositional environment).

For the Cedar Hills A regional model (Figure 20), the total pore volume for net area × total thickness × average porosity derived from literature based on depositional environment (Table 11) was multiplied by P10, P50, and P90 E_{saline} to estimate CO_2 storage potential (Table 10). The Cloverly B regional model (Figure 21) was populated with lithofacies and geostatistical porosity and permeability (net area × net thickness × distributed porosity based on core data). The Cloverly A simulation model was clipped from the geostatistical Cloverly B regional model. Petrophysical data were calculated based on legacy core data. The major and minor influence ranges of the geostatistical Cloverly models were determined from the literature for fluvial channel sands (IEA GHG, 2009a). Appendix D contains additional modeling details.

Table 11. Model Parameters Used for Volumetric Storage Estimates

Model	**Area, mi²**	**Cell Size, ft**	**Average Net Reservoir Porosity, %**	**Reservoir Temperature, °C[a]**	**Pressure Gradient, psi/ft[b]**
Regional Models					
Cloverly Formation B	30,600	1000 × 1000	18.6	45.7	0.6
Cedar Hills Formation A	32,800	2000 × 2000	5.3	44.4	0.6
Subarea Models					
Cloverly Formation A[c]	839	1000 × 1000	18.6	45.7	0.6

[a] Average temperature does not increase with stratigraphic depth because of the difference in model extents relative to the edge of the Denver–Julesburg Basin.
[b] Pressure gradient was chosen to estimate storage resource potential at the end of the injection period.
[c] The Cloverly A simulation model was clipped out of the Cloverly B regional model, resulting in a smaller area but the same property distributions within that area.

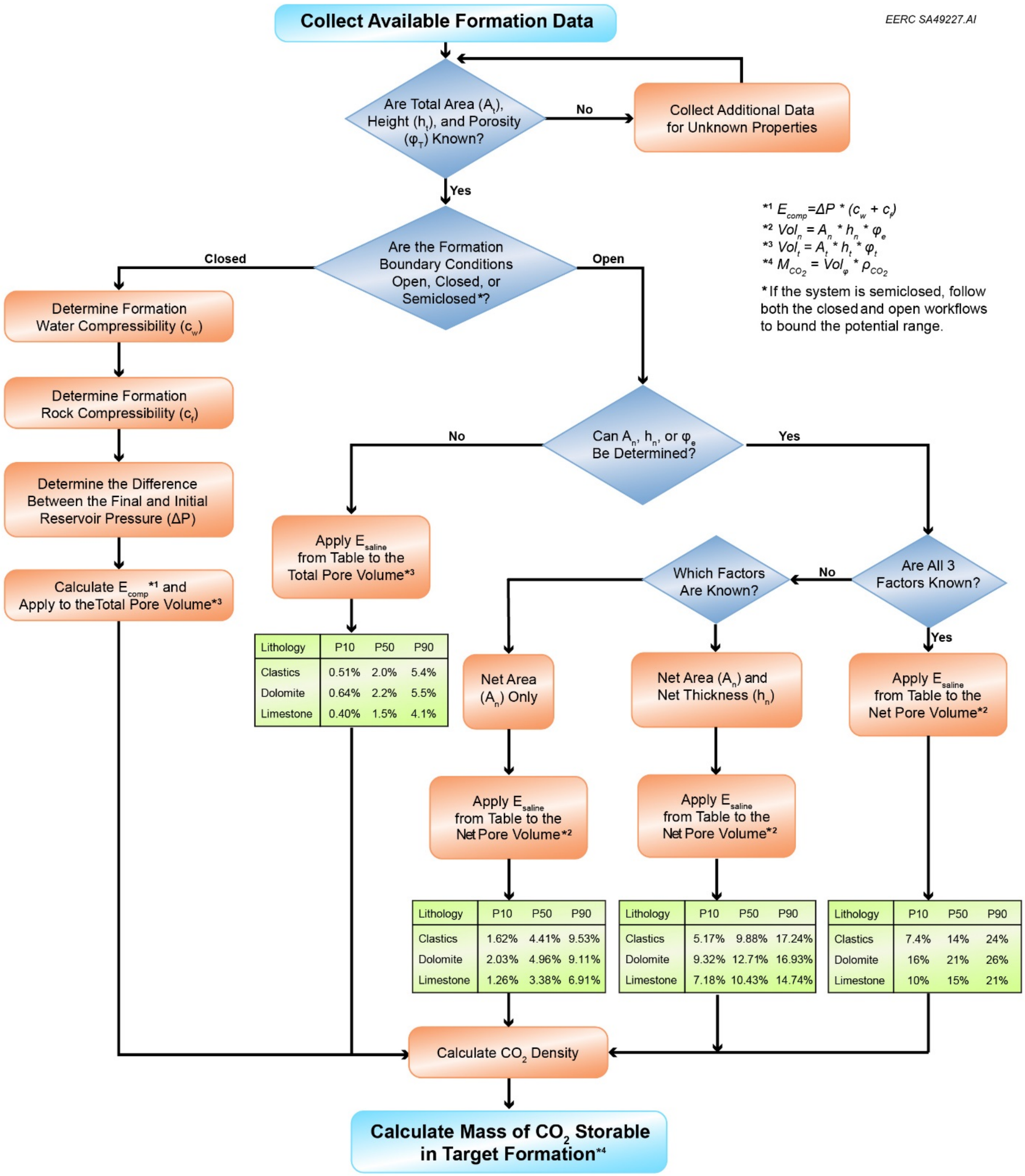

Figure 19. A workflow to estimate CO_2 storage resource in deep saline formations from Peck and others (2014).

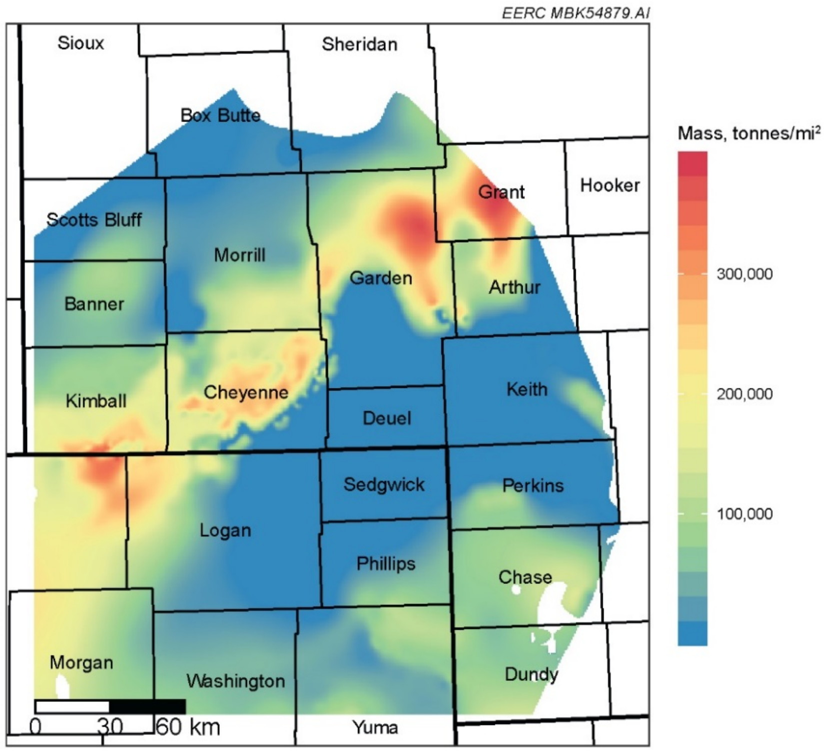

Figure 20. Cedar Hills A prospective CO_2 storage potential estimate, summed vertically.

4.3 Dynamic Simulation of CO_2 Storage in the Cloverly Formation

Objectives

Dynamic flow simulation was conducted to assess the pre-feasibility of storing 50 Mt of CO_2 over 25 years in the Cloverly Formation in Nebraska. An area in Perkins and Chase Counties, Nebraska, was chosen because this location is relatively close to GGS, still in Nebraska, and on the south side of the Platte River. Given the high degree of uncertainty in the geologic heterogeneity of the sandstone, three probability distributions of formation properties (optimistic [P90], average [P50], and conservative [P10]) were considered for numerical simulations (Table 12). The main goals of the simulation study were to investigate the following for each distribution (model):

- Potential locations and number of injection wells required to inject 50 Mt of CO_2 over 25 years in the Cloverly Formation.
- Wellhead pressure (WHP) ranges for injection wells and the associated parameter impact on WHP via a sensitivity analysis.
- An optimum WHP as a required injection (operation) pressure to inform infrastructure design.
- AOR which is determined by the extent of CO_2 plume and pressure plume as a result of CO_2 injection into the formation.
- Postinjection CO_2 plume migration and pressure stabilization.

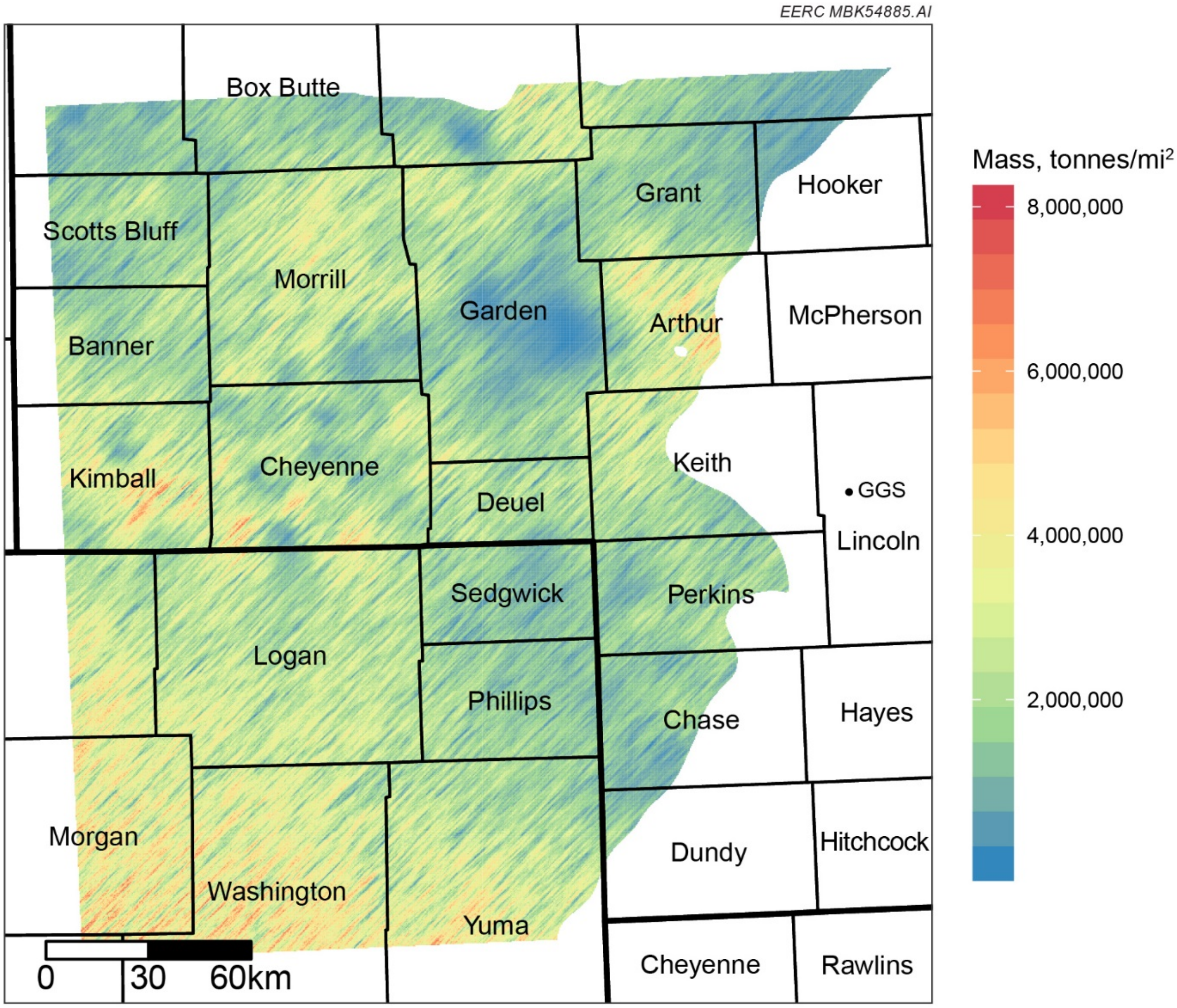

Figure 21. Cloverly B prospective CO_2 storage potential P50 estimate, summed vertically. Dot represents GGS.

Table 12. Arithmetic Mean Values for Porosity and Permeability of Sand and Shale in the Three Models

	Model					
Property	**P90**		**P50**		**P10**	
Facies	**Porosity, %**	**Permeability, mD**	**Porosity, %**	**Permeability, mD**	**Porosity, %**	**Permeability, mD**
Sandstone	25.0	425	18.6	211	16.0	161
Shale	12.1	0.00001	9.72	0.00001	7.95	0.00001

* Values are averages for the simulated area (orange rectangle in Figure 2).

Simulation Model Development

Computer Modelling Group's (CMG's) GEM simulator and CMG's CMOST, a sensitivity analysis tool, were used to simulate CO_2 injection into the Cloverly Formation and the subsequent postinjection scenario and perform a sensitivity study on wellhead pressure. The simulation fluid model includes two components: CO_2 and brine. The solubility of CO_2 in brine is modeled via Harvey's correlation for Henry's Law constants (Harvey, 1996). Correlations from Rowe and Chou (1970) and Kestin and others (1981) were used for the density and viscosity, respectively, of the aqueous fluids. The CO_2–brine relative permeability table used for model simulation was taken from the studies of Bennion and Bachu (2005 and 2007). The primary constraint for injection was a maximum daily total injection of 5500 tonnes of CO_2 based on the capture target of the facility (2 Mt of CO_2 annually). A secondary constraint of a maximum bottomhole pressure (BHP) of 2100 psi was also used in the model to ensure injection would not exceed the fracture pressure during the injection period. The 2100 psi value is 90% of the fracturing pressure of the formation at a depth of 3350 ft, using a fracture pressure gradient of 0.7 psi/ft.

Identification of Potential Location for CO_2 Injection

Numerical simulation was conducted, at first, to determine the potential locations for CO_2 injection into the Cloverly Sandstone and the number of wells required to inject and store 50 Mt of CO_2 over 25 years. The results from the numerical simulation efforts indicated that two, four, and 14 injection wells are required for the respective P90, P50, and P10 models to store 50 Mt of CO_2 (annually 2 Mt or daily, on average, 5500 tonnes of CO_2). The number of injection wells required for 50 Mt of CO_2 storage intrinsically increases with poorer formation properties as gas injectivity per well decreases from P90 wells to P10 wells. Figure 22 shows the potential injection wells and their locations with the porosity distribution for the corresponding models. Injection wells were placed in the clean, larger, and thicker sand bodies in the model. Extra effort was made to reduce the distance between the injection wells to have a smaller surface footprint of CO_2 injection and place them in a more uniform spacing. However, because of the extensive presence of shales in the model and the pressure interference from the very high injected volume of CO_2, this was challenging to achieve. The well spacing between two injection wells in the P90 model is about 2.5 miles. The well spacing (between two adjacent wells) for the P50 and P10 models approximately ranges from 6 to 13.5 and from 3.5 to 8 miles, respectively.

Sensitivity Analysis on Wellhead Pressure

Following the base simulation work of determining the number of wells required and their potential locations for CO_2 injection, a sensitivity analysis was conducted using CMG/CMOST to determine the relative effects of parameters greatly impacting WHP, ranges of predicted or simulated WHP values, and an optimum wellhead injection pressure to inform infrastructure design and corresponding economic analysis. The parameters included the wellhead temperature (whtemp), bottomhole temperature (bhtemp), tubing size (wradius), and tubing relative roughness (rel_rough).

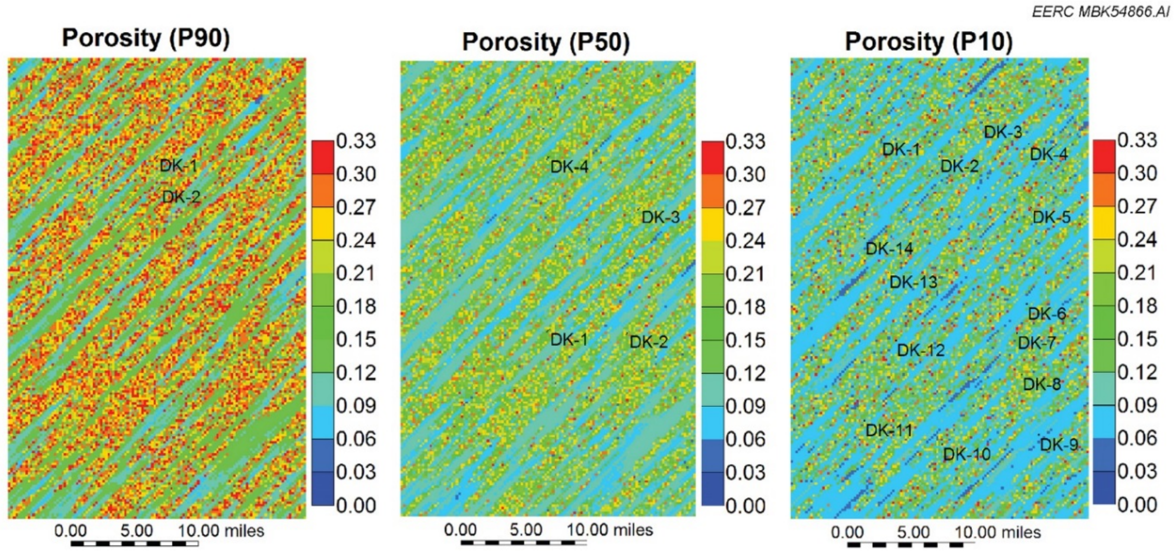

Figure 22. Porosity distributions (in plan view) with the potential well locations for CO_2 injection for P90, P50, and P10 models (from left to right). The injection wells are labeled "DK" (Dakota). The Cloverly Formation is the lower Dakota Group.

Figure 23 shows the relative effects of the parameters on WHP for the average, the P50 model. The sensitivity analysis indicated the parameter that most affects WHP varied for the P90, P50, and P10 models. For the P90 and P50 models of better porosity and permeability of the sandstone, injection tubing size is most impactful on WHP (inversely, i.e., using larger tubing for injection can significantly reduce the required WHP) as the injection rates considered per well are higher in both models. The other most influential parameters are tubing relative roughness and wellhead injection temperature following the tubing size in both models. Smaller tubing roughness is related to lower injection pressure because of the lower pressure loss (friction) in the tubing during injection. Higher injection pressure is required to compress CO_2 at a higher injection temperature because CO_2 is less dense at a higher temperature. As for the P10 model, where a considerably lower injection rate per well is applied because of the lower injectivity of the model, the wellhead temperature has the greatest effect on WHP, rather than the size of the injection tubing.

The sensitivity analysis also revealed the significantly wide ranges of simulated WHP values. The ranges of the WHP are 800–2600, 700–1750, and 650–1250 psia for the corresponding models. Figure 24 shows the simulated WHP for the average, the P50 model. WHP increases over the injection period as the formation pressure builds up. The curves in dotted gray represent the multiple sensitivity simulation cases executed by CMOST/GEM. The curve in black indicates the base simulation case, with typical values for the parameters including wellhead injection temperature and injection tubing size. The curves in red represent the cases that yielded the upper and lower limits of the WHP range. On a per injection well basis, the higher values of a WHP range are associated with smaller tubing size, greater tubing relative roughness, and warmer wellhead and bottomhole temperatures. On the other hand, the lower WHP values for a specific

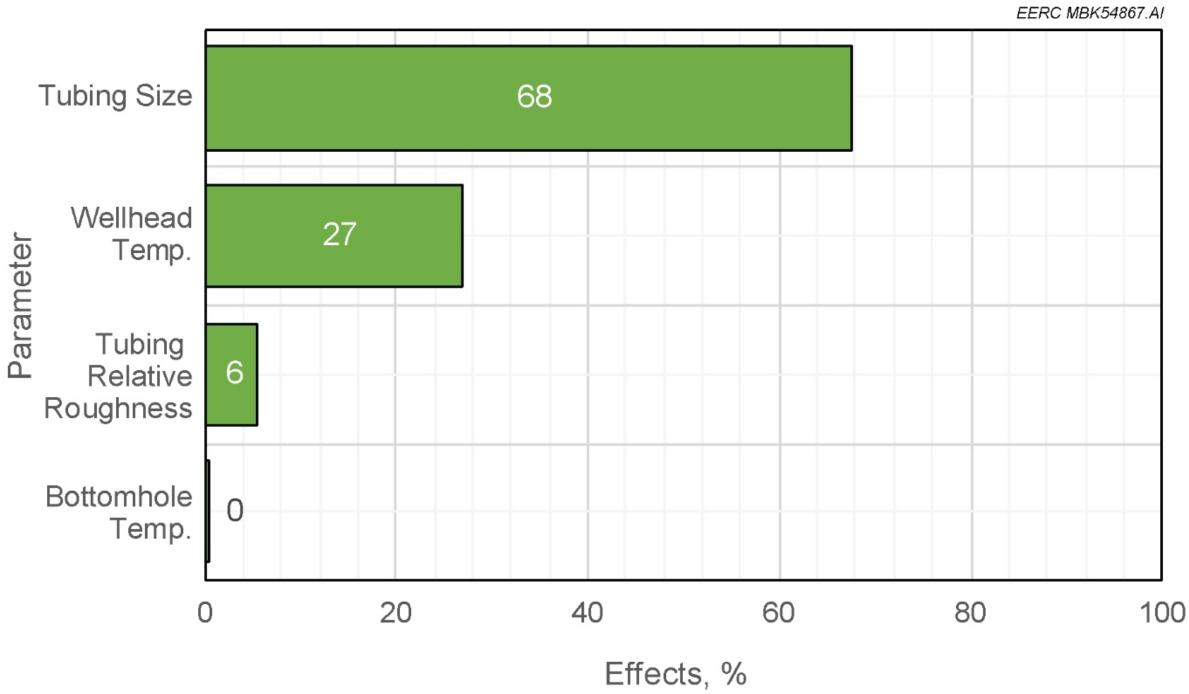

Figure 23. Parameter relative effects (%) on WHP for a P50 and well.

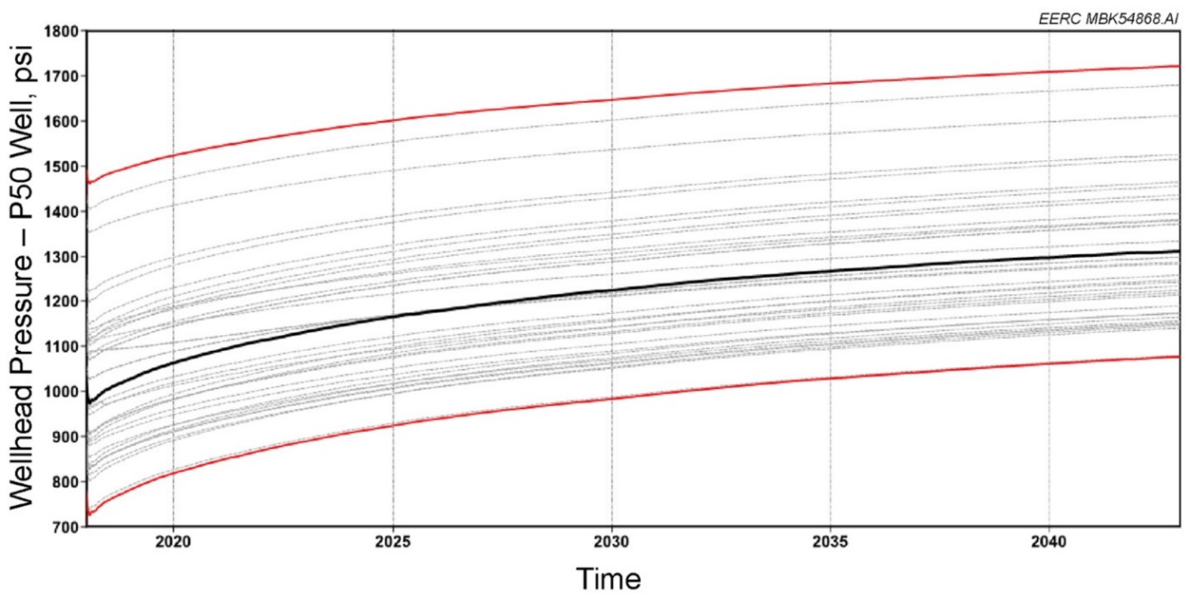

Figure 24. The simulated WHP for a P50 well. The curves in red represent the cases that yielded the upper and lower limits of the WHP range. The curves in dotted gray represent the multiple sensitivity simulation cases executed by CMOST/GEM. The curve in black indicates the base simulation case with typical values for the WHP associated parameters.

well are correlated to larger tubing size, smaller tubing relative roughness, and cooler wellhead and bottomhole temperatures.

On a per model basis, the P90 model has noticeably higher simulated WHP values (max. of 2600 psi) because of the corresponding higher injection rate per well in the P90 model where only two wells are required to inject 50 Mt of CO_2. Contrary to the P90 model, the P10 model has relatively smaller simulated WHP values (max 1250 psi) associated with the considerably lower injectivity of the P10 model where 14 wells are required to inject 50 Mt of CO_2.

Based on the information obtained from the sensitivity analysis, CO_2 injection at an optimum WHP was investigated to inform infrastructure design and associated economic study. Two different tubing sizes (3.5- and 4.5-inch diameters) were selected to investigate the required maximum WHP. A higher wellhead temperature of 90°F was used in this investigation to determine an optimum WHP for CO_2 injection. Table 13 gives the simulated WHP values for 3.5- and 4.5-inch tubings for the respective models. Based on this investigation, a WHP of 1300 psi using a larger tubing size of 4.5 inches was suggested for the required injection pressure because maintaining injection at a lower pressure is a cost-effective decision for the infrastructure design (gas compression system).

Table 13. Simulated Maximum WHPs with Different Tubing Sizes

Model	WHP (psi), 3.5-inch Tubing	WHP (psi), 4.5-inchTubing
P90	1900	1300
P50	1500	1260
P10	1250	1240

AOR Determination

The extents of CO_2 plume (lateral distribution of CO_2 saturation) and pressure plume (pressure buildup in the formation) were evaluated at the end of 25 years of injection into the Cloverly Sandstone to determine the size of AOR that will be necessary for planning a MVA (monitoring, verification, and accounting) program for CO_2 storage.

CO_2 Plume

The predicted CO_2 plume extent was quantified in gas per unit area in total, which is a product of CO_2 saturation, porosity, and thickness, as shown in Eq. 2:

$$CO_2 \text{ per Unit Area – Total (ft)} = CO_2 \text{ Saturation} \times \text{Porosity} \times \text{Thickness} \qquad \text{[Eq. 2]}$$

Figure 25 shows the CO_2 plume extents for all three models after 50 Mt of CO_2 is injected over 25 years. The plume diameters were up to approximately 3.5, 3, and 2 miles around each injection well, respectively, for the P90, P50, and P10 models.

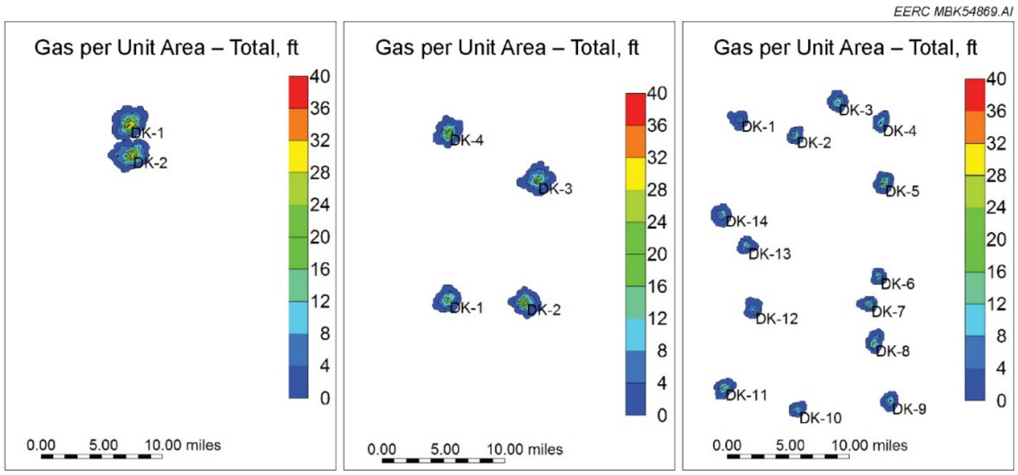

Figure 25. Simulated CO_2 plumes (in plan view) for the P90, P50, and P10 models (from left to right) at the end of a 25-year CO_2 injection operation.

Pressure Plume

The pressure front or threshold was calculated using the EPA's pressure front equation (U.S. Environmental Protection Agency, 2011). The pressure threshold (the pressure, within the injection zone, great enough to force fluids from within the injection zone through a hypothetical open conduit into any overlying USDW) was calculated at 138 psi for the region modeled for this project. Figure 26 shows the pressure increase and extent in each model as a result of 25 years of injection for the layer with the highest and largest (laterally) pressure extent. The maximum increase in the pore pressure after 50 Mt of CO_2 are stored in the Cloverly Sandstone was approximately 640, 700, and 720 psi for the respective models. The pressure increase is the greatest in the P10 model (poorest porosity and permeability among the models investigated). The extent of the simulated pressure plume was extensive in all three models because the high shale content in the model did not allow pressure to dissipate uniformly, resulting in directional and larger pressure plume extents, as shown in Figure 26. The size of the pressure plume extent for the P90 model was the smallest, covering an area of about 20 × 20 miles (west-east and north-south) at the end of the 25-year injection period. As for the P50 model, the pressure plume extent was considerably larger relative to the P90 plume, spreading out about 21 × 30 miles. The predicted pressure plume extent in the P10 model is largest, covering an area of about 22 × 32 miles.

As shown in Figures 25 and 26, the pressure plume extent was much greater than the extent of the CO_2 plume; hence the presume plume will dictate the AOR size for CO_2 injection in the Cloverly Formation. The simulated extent of the AOR in the formation for potentially storing 50 Mt of CO_2 would be approximately 20 × 20 (smallest) and 22 × 32 (largest) miles.

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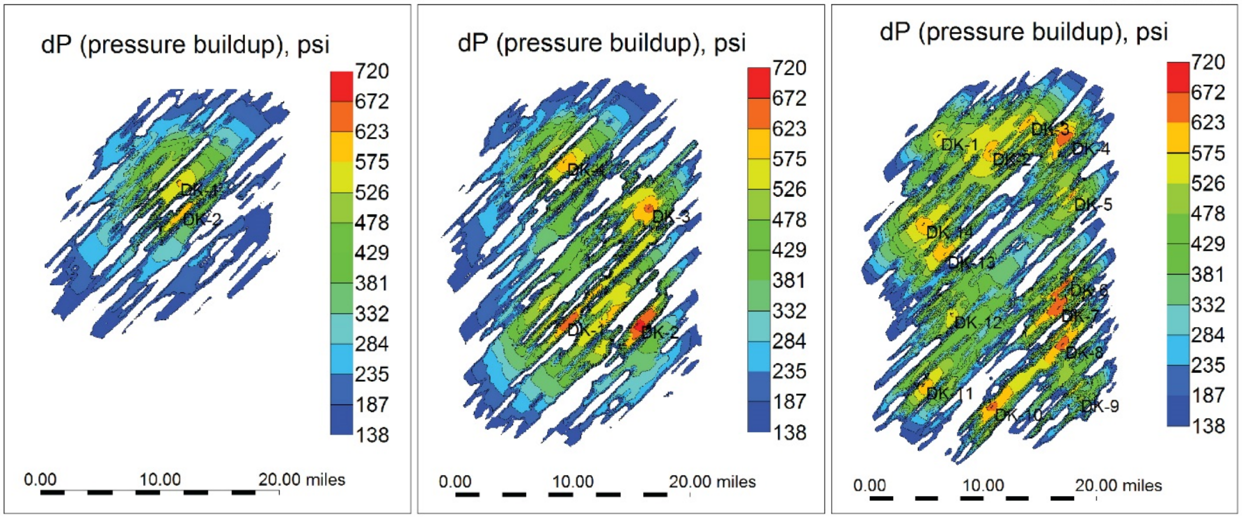

Figure 26. Simulated pressure plumes for the layer with the highest and largest (laterally) pressure extent (in plan view) for the P90, P50, and P10 models (from left to right) at the end of a simulated 25-year CO_2 injection operation. The lower limit in pressure scale is bounded by the pressure threshold value of 138 psi.

Postinjection

As part of numerical simulation efforts for this project, postinjection was also investigated using the P50 (moderate) model, after the 25-year CO_2 injection halted to understand CO_2 plume migration and evolution and pressure stabilization. CO_2 containment, plume evolution, and migration involve different processes according to the physical, chemical, and hydrodynamic conditions of the formation and are dependent on a variety of parameters. Those parameters include rock–fluid characteristic relative permeability end points (particularly residual CO_2 gas saturation) and CO_2 solubility in the formation brine that is dependent on formation temperature, pressure, and salinity of the brine and grid cell dimension (Pekot and others, 2016). A separate, individual study is required to fully and accurately address all those aspects. However, for this study, two scenarios with residual CO_2 gas saturation values of 0.2 and 0.3 were considered and simulated for 100 years of postinjection to predict the CO_2 plume migration and pressure stabilization.

The simulation results indicated that the CO_2 plume per around each injection well is slightly larger (by 0.1 mile in diameter) with a smaller residual CO_2 saturation value of 0.2 because less CO_2 is trapped and immobilized in the pores compared to the scenario with a higher CO_2 residual gas saturation of 0.3. Figure 27 shows the CO_2 and pressure plumes for only one scenario (the CO_2 residual gas saturation is 0.2) because the plumes in the two scenarios were not significantly different when plotted on the scale of the simulated area. The CO_2 plume per a well grew by 1 mile in diameter to approximately 4.0 miles in diameter at the end of the 100-year postinjection, indicating that the CO_2 is moving at a rate of approximately 50-ft radius per year within the

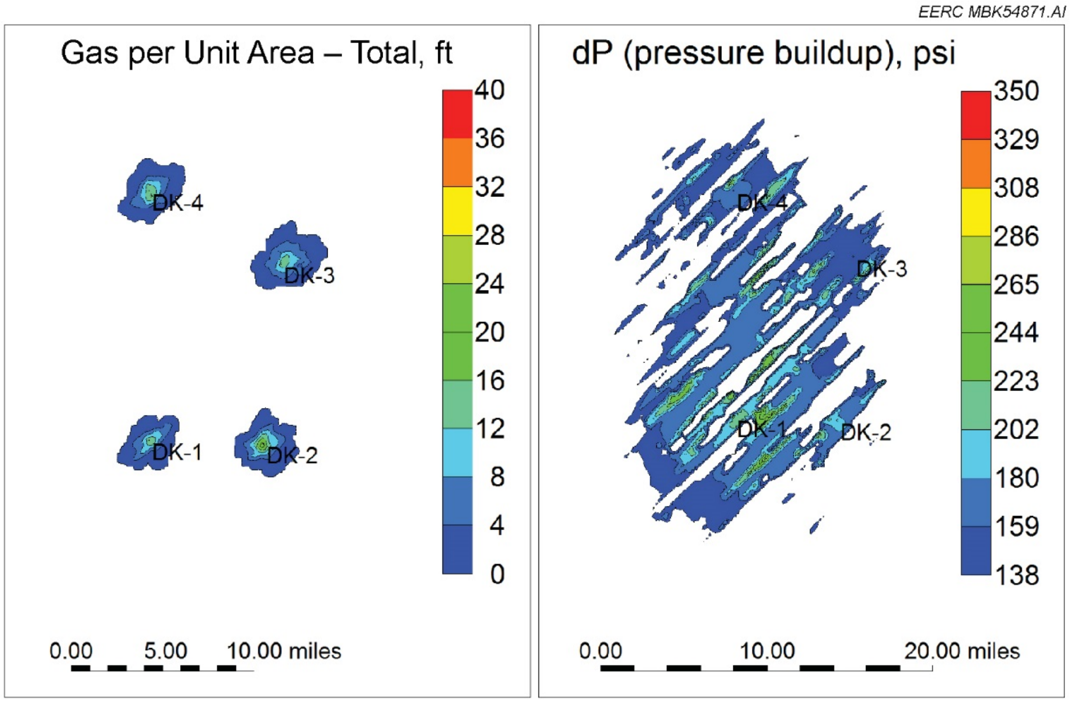

Figure 27. The postinjection CO_2 plume (in plan view) after 100 years of postinjection (left) and pressure plume extent after 40 years of postinjection (right). The lower limit in pressure scale is bounded by the pressure threshold value of 138 psi.

formation. As per the pressure plume in the formation, the remaining pressure buildup was not significant compared to the estimated pressure threshold, almost completely disappearing at the end of 100 years of postinjection. To demonstrate how small the pressure plume became during the postinjection period, the remaining pressure buildup (maximum value of 350 psi) at the end of 40 years of postinjection was shown in Figure 27, compared to the pressure plume at the end of the 25-year injection period shown in Figure 26 (the middle image, P50 model). The pressure plume at 40 years postinjection was selected to show because the pressure plume became significantly smaller after 40 years.

At the end of the 100-year postinjection, the fate of the injected CO_2 (how the injected CO_2 is stored in the sandstone) was also assessed. CO_2 storage involves four different trapping mechanisms: hydrodynamic trapping, residual trapping, solubility trapping, and mineral trapping (Gunter and others, 1997). Injected CO_2 will reside in the storage formation in the free-gas phase (through hydrodynamic and residual trapping), as dissolved in formation brine (through solubility trapping) and in immobile solid phase (through mineral trapping). The effects of mineral trapping were not included in the numerical simulations conducted in this study, as modeling mineral reactions adds to computational intensity.

Figure 28 indicates the cumulative injected CO_2, the dissolved CO_2, and hydrodynamically trapped (mobile, free) CO_2 and residually trapped (immobile, free) CO_2 in the Cloverly Sandstone

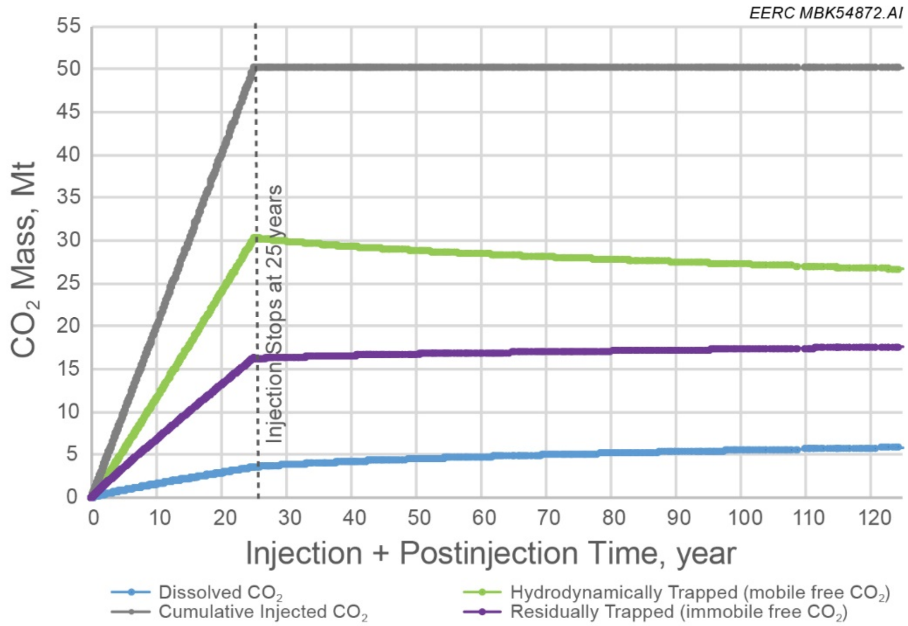

Figure 28. The cumulative injected, dissolved, and hydrodynamically and residually trapped CO_2 in the Cloverly Sandstone.

over the injection and postinjection periods. During the postinjection period after the 25-year injection was halted, the amount of the dissolved CO_2 gradually appears to increase with the decreasing free CO_2 during the postinjection period because the free CO_2 encounters the new (non-CO_2 saturated) formation brine and dissolves in the brine as free CO_2 migrates out in the sandstone, increasing the amount of aqueous (dissolved) CO_2 and decreasing the free CO_2 in the formation. However, the majority of the injected CO_2 (approximately 90%) will be stored as free CO_2 in the formation at the end of the 100-year postinjection period. Approximately, 60% of the free CO_2 would be mobile (hydrodynamically trapped), and 40% of the free CO_2 would be immobile (residually trapped), assuming a residual CO_2 saturation value of 0.2.

Dynamic Simulation Conclusions

Numerical simulation work was conducted to determine potential locations for injection, the number of injection wells required to inject and store 50 Mt of CO_2 over 25 years in the Cloverly Sandstone, the required wellhead injection pressure to inform infrastructure design and subsequent economic analyses, and the extent of AOR dictated by CO_2 and pressure plumes resulting from injection operation. Considering the high degree of uncertainty in the geologic heterogeneity of the storage sandstone, three probability distributions (models) of formation properties (optimistic [P90], average [P50], and conservative [P10]) were used in the numerical simulation efforts. CO_2 injection into the Cloverly Formation in Nebraska, a sensitivity study on injection pressure, and the subsequent postinjection scenario were dynamically simulated using CMG's GEM simulator and CMG's CMOST, a sensitivity analysis tool.

The simulation results indicated that two, four, and 14 injection wells will be potentially required for the respective P90, P50, and P10 models for sequestrating 50 Mt of CO_2 over a time period of 25 years. Wide ranges of WHP were predicted under different operating conditions. The sensitivity analysis showed that tubing size is the most influential factor on WHP and using larger tubings for injection can significantly reduce the required WHP. Based on the information obtained from the sensitivity study, a WHP of 1300 psi (with a larger tubing of 4.5 inch) is recommended for the infrastructure design as a required injection pressure.

The plume extents of injected CO_2 and the resulting pore pressure buildup in the Cloverly Sandstone at the end of the 25-year injection period were also investigated. The simulated CO_2 plumes were up to approximately 3.5, 3, and 2 miles in diameter around each injection well, respectively, for the P90, P50, and P10 models. The extent of the pressure plume was relatively large in all three models because the high shale content does not allow pressure to dissipate uniformly, resulting in extensive pressure plumes. The simulated AOR size dictated by the presume plume extent in the modeled area (because the pressure plume was much greater than the CO_2 plume) would vary between 20 × 20 (P90) and 22 × 32 (P10) miles, respectively, after sequestrating 50 Mt of CO_2 in the Cloverly Sandstone.

Simulation of long-term CO_2 migration and pressure stabilization was also conducted using the P50 (average) model. The simulation results indicated that the CO_2 plume around each injection well was approximately 4.0 miles (growing by 1 mile since injection halted) in diameter at the end of the 100 years of postinjection. During this postinjection scenario, CO_2 plume appears to be moving at a rate of approximately 50 ft per year in the formation. The pressure plume dissipated and was not significant after 100 years of postinjection, compared to the estimated pressure threshold. Most of the injected CO_2 will be stored as a free phase in the sandstone at the end of the 100-year postinjection.

The simulation results achieved in this pre-feasibility study show the potential of the Cloverly Sandstone to sequester 50 Mt of CO_2 over 25 years. However, the resulting AOR dictated by the pressure plume would be relatively large for a monitoring program because of the high shale content in the sandstone. The models and simulations conducted here have a relatively high degree of uncertainty, relying heavily on generalized subsurface characteristics as a result of a lack of site-specific data. Acquisition of site-specific data, including well log and core data, would provide opportunity to refine the models discussed here, enable more accurate predictive simulations, and decrease subsurface technical risks posed by geologic uncertainty.

4.4 Preliminary Evaluation of CO_2 Enhanced Oil Recovery in Nebraska

CO_2 EOR is an alternative to saline storage as a way to dispose of CO_2 generated by industrial sources such as fossil fuel power plants. CO_2 EOR provides an economic incentive for capture because oil producers can purchase CO_2 to use as an EOR injection fluid. We have produced a preliminary screening and ranking process for Nebraskan unitized oil and gas pools currently under waterflood (secondary recovery) to identify which geographic areas and stratigraphic intervals may be best served by a CO_2 pipeline from GGS.

The methods described here are derived from Burton-Kelly and others (2013), with additional insight from IEA GHG (2009a) and Taber and others (1997). Based on data gathered from the Nebraska Oil and Gas Conservation Commission (NOGCC) online database, a table was generated of 234 unitized pools that exist or previously existed in Nebraska (Appendix D). A total of 149 units were screened out based on failing to meet one or more of the following criteria (Table 14).

Table 14. Screening Criteria Used for Unitized Pools under Waterflood in Nebraska

Screening Criterion	Included Units	Excluded Units
Measured Depth	MD > 3000 ft	MD < 3000 ft
Oil Gravity	API > 17.5	API < 17.5
Status	Production	All other statuses
Oil Produced	Oil units	Gas units
Date of First Unitized Production	Date < 2018-01-01	Date > 2018-01-01
Missing Criteria Values	Not missing	Missing one or more

The 85 units remaining after the screening process were ranked according to three criteria (Table 15). These three rank scores were then summed with equal weights for each unit, and the summed rank score was ranked to create a final ranked score that estimates the likelihood of CO_2 EOR being successful in each unit. Units with equal values for a given criterion were given equal rank scores, and the next rank score was skipped.

Table 15. Ranking Criteria Used for Unitized Pools That Passed the Screening Process

Ranking Criterion	Rank Order
Average Well Spacing, acres	1 (lowest) to 85 (highest)
Estimated Ultimate Recovery, bbl	1 (highest) to 85 (lowest)
Distance to GGS, km	1 (lowest) to 85 (highest)

Each of the three ranking criteria was automatically calculated for this study rather than being drawn from the literature. The average well spacing was calculated by calculating the average distance between each well listed on the unit (NOGCC database) and its nearest neighbor (e.g., Figure 29), squaring that value and converting to acres. This method for calculating spacing assumes that the number of wells (both active and inactive) on the unit is appropriate to the OOIP of the pool. The distance from GGS to the nearest corner of each unit was calculated using the function st_distance() from the R package sf (Pebesma, 2017).

Estimated ultimate recovery (EUR) for each unit was calculated from waterflood production data because OOIP estimates were likely too low due to cumulative production approaching or exceeding existing OOIP values. EUR was estimated from unsupervised decline curve analysis (DCA) using the R package aRpsDCA (Turk, 2017), beginning with the year of greatest oil production (after ramp-up) and ending in 2017, the last year for which complete production data were available. The functions fit.best(), arps.q(), and arps.eur() were used to estimate the EUR of each unit based on a cutoff of 2000 bbl/year.

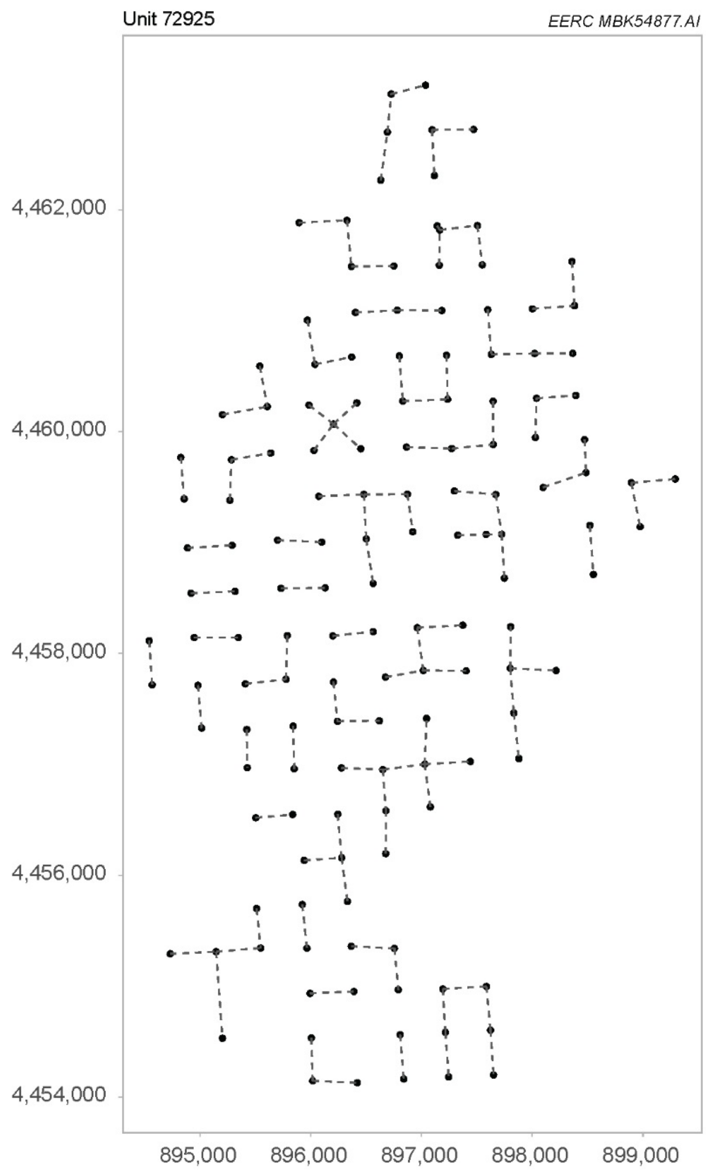

Figure 29. Example map of the Sleepy Hollow Reagan unit showing the nearest neighbor for each well. Distances marked by lines were used to calculate the average well spacing for the unit. Coordinates are shown in meters.

Because of the variability of fit between the production data and the best-fit decline curves, OOIP was not calculated from EUR, and incremental oil and CO_2 storage potential were not estimated. EUR was used as a ranking proxy for the size of the pool rather than an explicit value.

Figure 30 shows final ranking of each unit. Unitized fields south of GGS generally rank higher, and screened-in units are in close proximity to each other, which would prove beneficial to efficient pipeline design. These units are near the border with Kansas and form the northern tip of clustered Kansas fields that extend across the western portion of the state. Screened-in units west of GGS are smaller, farther away, and more scattered.

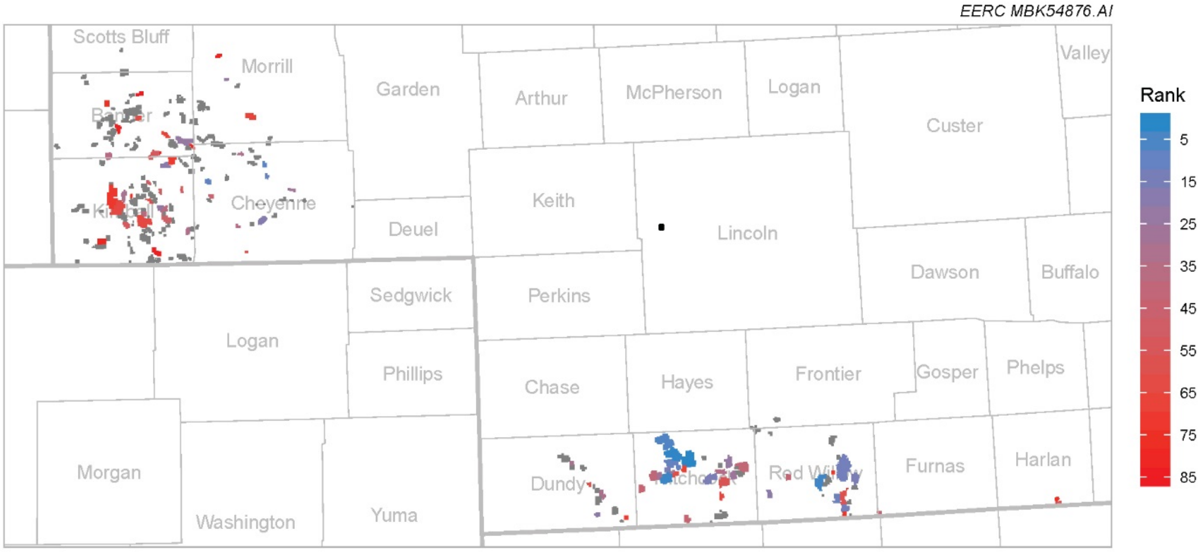

Figure 30. Nebraska unitized fields colored by final CO_2 EOR rank.

In separate analyses, Advanced Resources International (2006), Smith and others (2009), and Ferguson (2009) estimated CO_2 EOR potential for the largest unitized fields in Nebraska. Their combined storage potential estimates range from 8 to 25 Mt of CO_2 needed to produce 25 million to 150 million barrels of oil. Although only addressing a subset of the unitized fields in the state, there are not so many small producing fields that their combined storage potential will substantially increase the total for the state.

To confirm storage potential for the remaining units, OOIP values will be needed to improve the unit ranking as an improvement on the EUR method used here and allow incremental oil and CO_2 storage potential to be estimated. These values will allow more informed decisions to be made about the future of CO_2 EOR in Nebraska, but storage of commercial-scale amounts of CO_2 via EOR in Nebraska alone seems unlikely at this time.

4.5 Risk Assessment for the Nebraska Integrated Carbon Capture and Storage Pre-Feasibility Study

Introduction

This section provides a summary of an initial risk assessment that was conducted as part of the Nebraska Integrated Carbon Capture and Storage Pre-Feasibility Study (hereafter referred to as the "Phase 1 RA"). These results were generated from a workgroup session that was held via WebEx at the EERC in Grand Forks, North Dakota, on February 13, 2018.

The Phase 1 RA indicates that there are currently no potential constraints that would prevent the candidate storage units within the storage complex from serving as commercial storage sites. The available data and information suggest that the identified Cloverly Formation storage complex has the potential to accommodate commercial-scale storage of at least 50 Mt of CO_2 and would be a suitable candidate for further investigation.

The remainder of this memo summarizes the Phase 1 RA process that was used and the risk-scoring results.

Risk Management Process Overview

The risk management process used for the Phase 1 RA followed the international standard presented in International Organization for Standardization (ISO) 31000 (2009), with adaptations specific to conducting subsurface technical risk assessments of geologic CO_2 storage projects (Azzolina and others, 2017) (Figure 31).

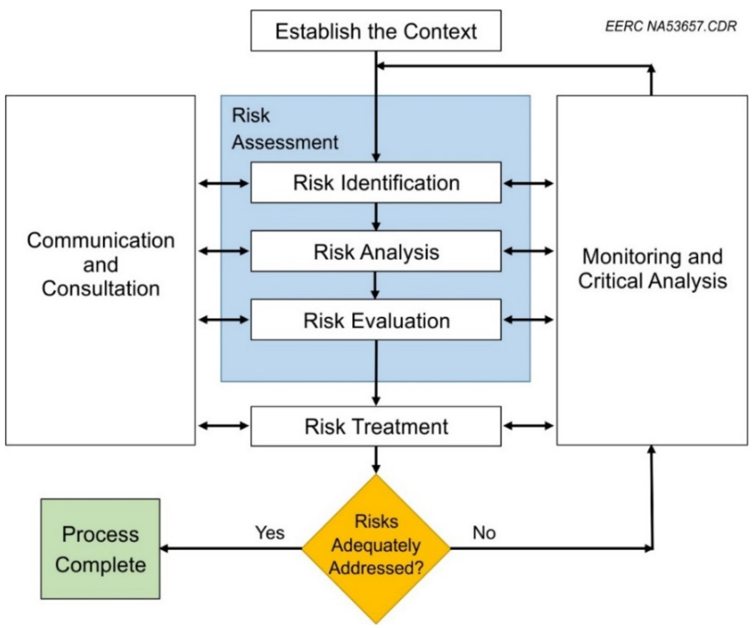

Figure 31. Risk management process adapted from the ISO 31000 (2009) standard (Azzolina and others, 2017).

The Phase 1 RA risk management process began with an initial set of meetings where members of the project team established the context for the Phase 1 RA (top box in Figure 31). This step included defining the storage complex boundaries and developing risk probability- and impact-scoring matrices for the risk evaluation. The risk probability- and impact-scoring matrices are provided in Appendix D.

The risk management process continued in a workgroup session held via WebEx on February 13, 2018. The session began with the project team reviewing a preliminary risk register developed based on the EERC's experience with other geologic CO_2 storage projects. The project team identified pertinent risks that were not yet included, as well as those risks not relevant to the Phase 1 RA, and finalized the current risk register. The individual project team members then assigned risk probability and risk impact scores for each individual risk using a standardized worksheet and the risk-scoring matrices from the initial meeting (Appendix D). Finally, the project team evaluated the risk scores to rank the individual risks and assess whether there were any higher-ranking risks that warranted risk treatment (mitigation). These risk identification, risk analysis, and risk evaluation steps constituted the risk assessment (blue box in Figure 32).

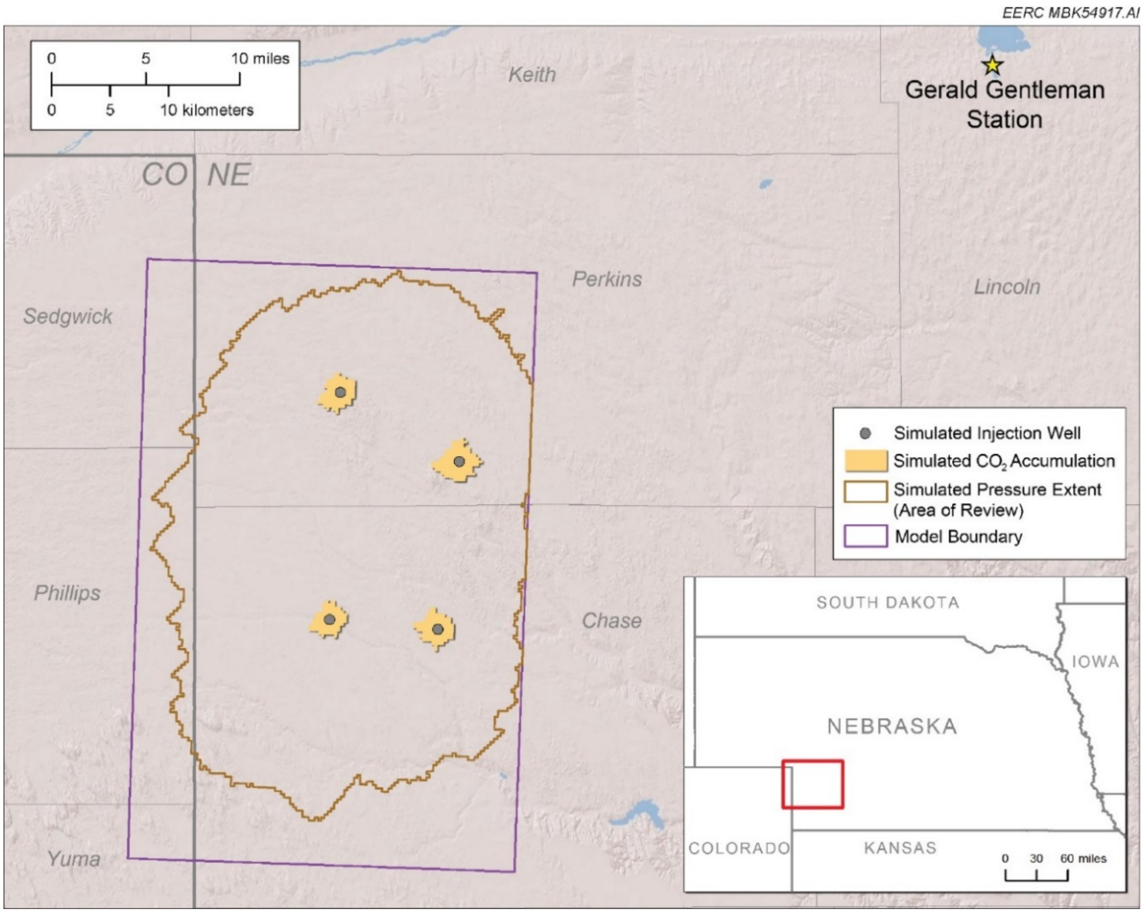

Figure 32. Map of the pre-feasibility study area showing the location of NPPD's GGS, Nebraska's largest coal-fired electricity-generating station, and the approximate extent of the AOR as determined through modeling and simulation.

Establish the Context

The pre-feasibility study evaluated a potential geologic CO_2 storage complex with storage sites near NPPD's GGS, Nebraska's largest coal-fired electricity-generating station. The focus of the Phase 1 RA was *technical subsurface* risks, which could prevent the candidate reservoirs in the subbasin from serving as commercial storage sites. As with any large industrial project, nontechnical risks (e.g., public acceptance issues, state and federal regulation changes) which could negatively affect its development exist. Should this project advance from the current pre-feasibility stage to subsequent stages of project development, nontechnical risks would likely be incorporated into the risk assessment.

For the purpose of the Phase 1 RA, CO_2 was assumed to be captured from GGS, transported via pipeline, and injected into the storage complex. The Phase 1 RA study region examined the extent of saline formations (DSFs) within the study region, focusing on those DSFs deeper than 800 meters (m) and a TDS greater than 10,000 parts per million (ppm). The depth criterion of 800 m ensures that CO_2 stays in a supercritical state within the reservoir, and the 10,000-ppm criterion is from the definition of a USDW as defined in the Code of Federal Regulations (40 CFR 144.3). The Phase 1 RA specifically focused on the storage complex within the anticipated AOR, as determined through modeling and simulation (Figure 32). See Sections 4.1 to 4.4 for a description of the modeling and simulation activities.

Three potential geologic storage units within the Denver–Julesburg Basin of western Nebraska were investigated through the course of the pre-feasibility study: 1) the Lower Cretaceous Cloverly Formation (also known as the Apishapa aquifer), 2) the Lower Permian Cedar Hills Sandstone, and 3) the Middle Pennsylvanian Cherokee Group Cloverly Formation (Figure 33). Based on initial analyses, the Cloverly Formation demonstrated the most promise for commercial CO_2 storage. As a result, the focus of the Phase 1 RA was on the storage resource potential and subsurface technical risks associated with the Cloverly Formation. The storage complex for this storage unit includes both the Cloverly Formation and the overlying primary and secondary seals, extending laterally to the defined limits of the CO_2 storage operation (Canadian Standards Association, 2012). The Cloverly Formation has been designated as a poor-quality aquifer with salinity >10,000 ppm, with the potential to be used for wastewater injection. The primary drinking-water aquifer in the study area is the High Plains aquifer (which includes the Ogallala) located above the Pierre Shale (Korus and Joeckel, 2011).

Risk Identification

Appendix D provides the current risk register for the Phase 1 RA, which includes 16 potential subsurface technical risks. These potential risks were grouped into five principal risk categories:

1) CO_2 injectivity and storage capacity (two risks).
2) Containment – lateral migration of CO_2 (three risks).
3) Containment – lateral propagation of the pressure plume (three risks).
4) Containment – vertical migration of CO_2 or formation brine via wells, faults/fractures, or inadequate seals (seven risks).
5) Induced seismicity (one risk).

Each participant in the workgroup session provided an independent set of risk probability and impact scores for each of the 16 individual risks, as described in the next section.

Risk Analysis and Evaluation

The risk analysis and evaluation consisted of two components: 1) assessing the uncertainty in the risk scores provided by the workgroup participants and 2) plotting the risk probability and impact scores onto risk maps to identify potential high-ranking risks.

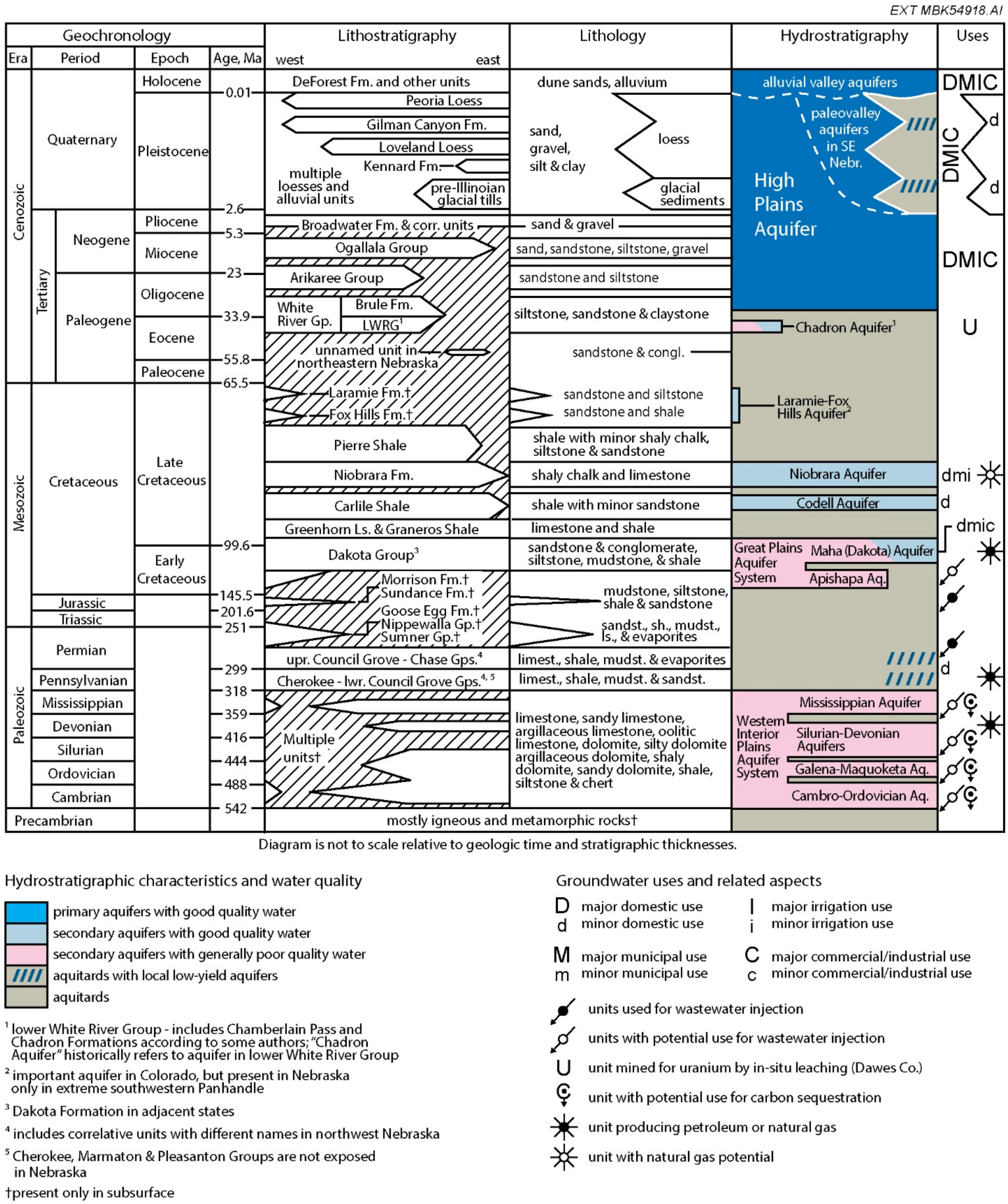

Figure 33. Generalized geochronology and hydrostratigraphic framework of Nebraska (modified from Korus and Joeckel, 2011).

Risk Score Uncertainty Assessment

As is typical for these types of initial assessments, the risk probability and impact scores varied across participants, resulting in uncertainty in the risk scores. This uncertainty was evaluated visually using heat maps. This visual assessment tool assigns darker coloring to the scores that had a greater proportion of responses and lighter coloring to scores that had a lesser proportion of responses. The heat map approach, therefore, provides a visual assessment of the score density or the region within the scoring range that had the greatest number of responses. Figure 34 provides heat maps of the risk scores for each of the 16 risks in the current risk register. As shown in the figure, while there was relative consensus about the risk probability scores, with most risks scoring less than or equal to “3” (possible), the risk impact scores showed a high degree of variability and included scores across the entire five-point-scale range. The higher variability for the risk impact scores is largely a function of the lack of detailed site- and stakeholder-specific knowledge commensurate with the pre-feasibility stage of the project and resultant conservative scoring by the workgroup participants.

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Risk No.	Principal Risk Category	Probability					Cost Impact					Schedule Impact				
		1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
1	Injectivity	0	0	1	0	0	0	0	0	0.3	0.8	0	0	0.5	0	0.5
2	Capacity	0	0.5	0.5	0	0	0	0	0	0.3	0.8	0	0	0.3	0	0.8
3	Containment - Lateral Migration of CO_2	0.2	0.5	0.3	0	0	0	0.3	0.7	0	0	0	0.7	0.3	0	0
4	Containment - Lateral Migration of CO_2	0.3	0.5	0.2	0	0	0	0	0.7	0.3	0	0	0.7	0	0.3	0
5	Containment - Lateral Migration of CO_2	0.5	0.5	0	0	0	0	0	0.3	0.7	0	0	0.7	0	0.3	0
6	Containment - Propagation of Pressure Plume	0.2	0.3	0.5	0	0	0	0.3	0.7	0	0	0	0.3	0.7	0	0
7	Containment - Propagation of Pressure Plume	0.2	0.8	0	0	0	0	0	0.7	0.3	0	0	0.3	0.7	0	0
8	Containment - Propagation of Pressure Plume	0.5	0.5	0	0	0	0	0	0.7	0.3	0	0	0.7	0	0.3	0
9	Containment - Vertical Migration of CO_2/Brine	0.7	0.3	0	0	0	0	0.3	0.7	0	0	0	0.3	0.7	0	0
10	Containment - Vertical Migration of CO_2/Brine	0.3	0.7	0	0	0	0	0	0.7	0.3	0	0	0	1	0	0
11	Containment - Vertical Migration of CO_2/Brine	0.8	0.2	0	0	0	0	0.3	0.3	0.3	0	0	0.3	0.7	0	0
12	Containment - Vertical Migration of CO_2/Brine	0.3	0.7	0	0	0	0	0.7	0	0.3	0	0	0.3	0.3	0.3	0
13	Containment - Vertical Migration of CO_2/Brine	0.3	0.5	0.2	0	0	0	0	0.3	0.7	0	0	0	0.7	0.3	0
14	Containment - Vertical Migration of CO_2/Brine	0.5	0.5	0	0	0	0	0.3	0	0.7	0	0	0.3	0.3	0.3	0
15	Containment - Vertical Migration of CO_2/Brine	0.3	0.7	0	0	0	0	0	0.3	0.7	0	0	0	0.3	0.3	0.3
16	Induced seismicity	0.7	0.3	0	0	0	0	0	0.3	0.7	0	0	0	0.7	0	0.3

Risk No.	Principal Risk Category	Permitting Impact					Corporate Image Impact				
		1	2	3	4	5	1	2	3	4	5
1	Injectivity	0.5	0.3	0.2	0	0	0.5	0.2	0.2	0	0.2
2	Capacity	0.5	0.2	0.2	0	0.2	0.3	0.2	0.2	0	0.3
3	Containment - Lateral Migration of CO_2	0	0.3	0.5	0.2	0	0.2	0.6	0.2	0	0
4	Containment - Lateral Migration of CO_2	0	0	0.3	0.7	0	0	0.6	0.4	0	0
5	Containment - Lateral Migration of CO_2	0	0	0.2	0.7	0.2	0	0.2	0.4	0.2	0.2
6	Containment - Propagation of Pressure Plume	0	0.7	0.3	0	0	0.2	0.8	0	0	0
7	Containment - Propagation of Pressure Plume	0	0.2	0.2	0.7	0	0	0.6	0.4	0	0
8	Containment - Propagation of Pressure Plume	0	0	0.5	0.5	0	0	0.2	0.8	0	0
9	Containment - Vertical Migration of CO_2/Brine	0	0.3	0.3	0.2	0.2	0.2	0.2	0.4	0.2	0
10	Containment - Vertical Migration of CO_2/Brine	0	0.2	0.3	0.3	0.2	0	0.2	0.4	0.2	0.2
11	Containment - Vertical Migration of CO_2/Brine	0	0.2	0.7	0	0.2	0	0.2	0.6	0	0.2
12	Containment - Vertical Migration of CO_2/Brine	0	0.3	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.2
13	Containment - Vertical Migration of CO_2/Brine	0	0.2	0.2	0.5	0.2	0	0.2	0.4	0	0.4
14	Containment - Vertical Migration of CO_2/Brine	0	0.2	0.5	0.2	0.2	0	0.2	0.4	0	0.4
15	Containment - Vertical Migration of CO_2/Brine	0	0	0.5	0	0.5	0	0	0.4	0.2	0.4
16	Induced seismicity	0	0	0.4	0.2	0.4	0	0	0.2	0.2	0.7

Figure 34. Heat map of risk scores for the 16 risks in the current risk register. Dark coloring represents the greatest proportion of responses, whereas lighter coloring to white (no color) represents the smaller proportion of responses. For example, Risk 1 scores for “Probability” had 100% of participants who scored a “3” (possible), while Risk 2 scores for “Probability” had 50% of participants who scored a “2” (unlikely) and 50% of participants who scored a “3.” Heat maps were used to visually assess uncertainty and evaluate the average response.

Recognizing the significant amount of uncertainty in the risk impact scores, the risk mapping (see below) used an average value to represent the most likely score among the participants and error bars of ±2 standard deviation across the responses to illustrate the uncertainty. In addition, many of the participants found the five-point scoring scale to be overly granular (i.e., too high-resolution) at this stage of analysis. Therefore, the original scores were translated onto a three-point scale of low, medium, and high. These changes resulted in a more tractable set of risk maps for evaluation.

Risk Mapping

The risk probability and impact scores for each individual risk were plotted onto a risk map, with impact on the *x*-axis and probability on the *y*-axis. Lower-probability, lower-impact risks, therefore, plot in the lower left-hand corner, while higher-probability, higher-impact risks plot in the upper right-hand corner of the risk map. A color-ramp from green to yellow to orange to red was used to illustrate the continuum from lower- to higher-ranking risks. Risks mapping into the green zone risks represent low or negligible risks with no immediate action required. The yellow and orange fields represent a transition zone where risks should continue to be monitored and, if warranted, risk treatment applied. Lastly, risks mapping into the red zone are the highest-ranking risks where immediate risk treatment is warranted. The risk maps provide a relative ranking of the project risks, with the assignment of individual risk scores providing a basis for comparing an individual risk to the others. In addition, the risk maps provide a means to prioritize further investigation, analysis, and monitoring.

Risk maps for each of the 16 risks and four different impact categories are shown in Figure 35. The risks are grouped by injectivity/capacity (solid circles), containment – lateral migration (hollow squares), containment – vertical migration (hollow triangles), and induced seismicity (solid square). The symbols show the expected-value ±2 standard deviation in the *x*- and *y*-direction, which illustrates the greater uncertainty for the impact scores (*x*-axis).

The probability scores for all risks were low-to-medium, with the highest score assigned to Risk 1 – "Injectivity into the storage unit (Cloverly Fm.) is insufficient to accept 2 million tonnes of captured CO_2 per year from the GGS and/or other identified facilities over the 25-year period." Six of six participants provided identical scores; therefore, there are no error bars in the *y*-direction for this risk.

As previously noted, the impact scores varied. While the average values generally fell into the medium impact category, the impact scores assigned by the project team ranged from low to high. In particular, the impacts associated with injectivity and capacity were the highest scores, since these risks, if they occurred, could prevent the Cloverly Formation from serving as a commercial storage site.

The combined probability and impact scores resulted in most risks mapping into the low-to-medium risk fields. The risks associated with lateral and vertical migration of CO_2 and other fluids had comparable risk scores and overlapped on the risk maps. The risk of induced seismicity, while having a low probability of occurrence, had a medium-to-high risk impact score if the risk were to occur. Lastly, the two risks associated with injectivity and storage capacity had the highest rank on the risk maps. At this time, none of the risks mapped into the red region where immediate risk treatment is warranted.

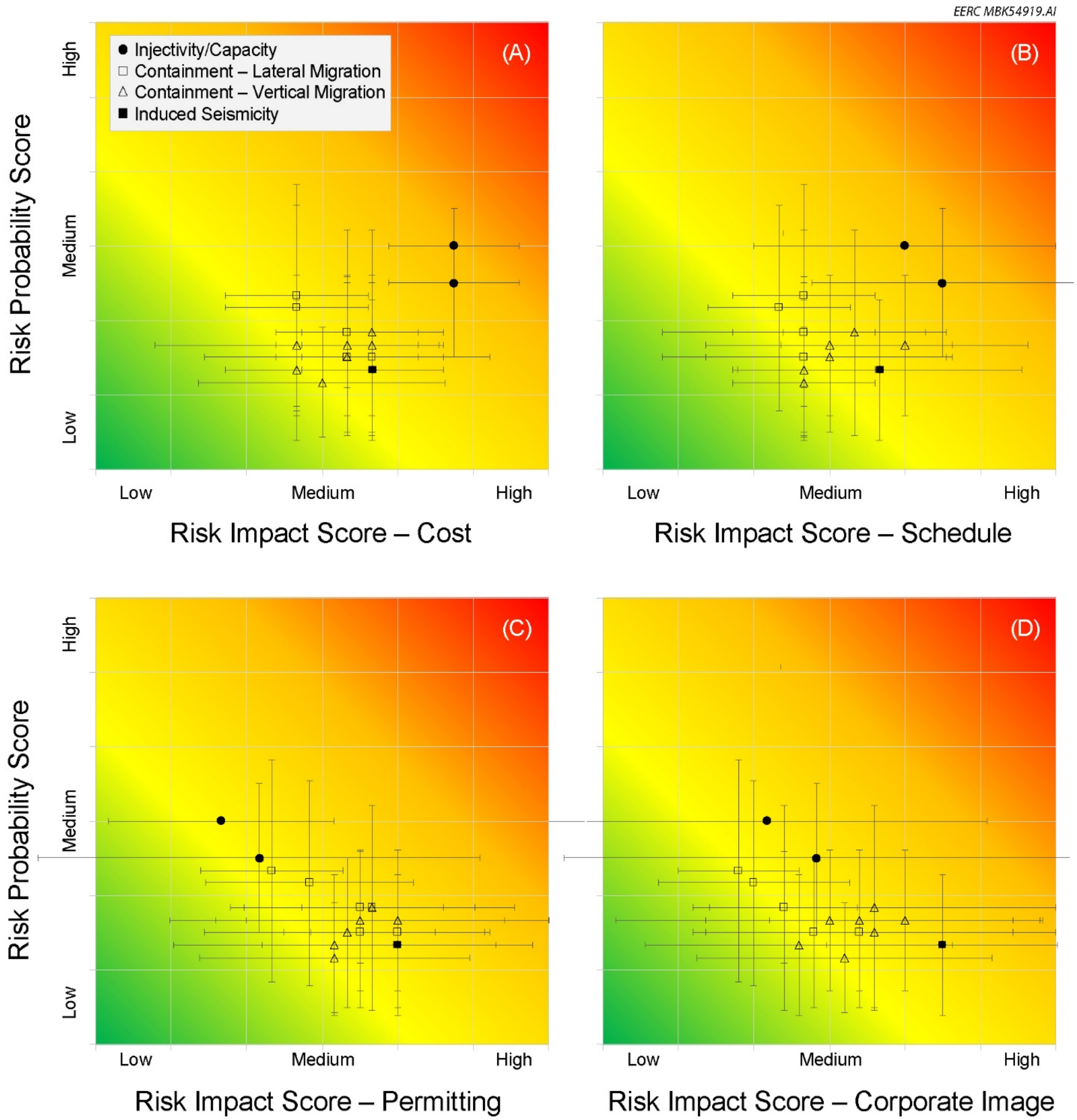

Figure 35. Risk maps for each of the 16 risks in the current risk register for the risk impacts of A) cost/finance, B) project schedule, C) permitting compliance, and D) corporate image/public relations. The symbols show the average value ±1 standard deviation in the *x*- and *y*-direction.

Summary and Conclusions

The risk assessment, conducted as part of the Nebraska Integrated Carbon Capture and Storage Pre-Feasibility Study, indicates that there are currently no potential constraints that would prevent the candidate reservoirs in the storage complex from serving as commercial storage sites. The available information suggests that the identified storage complex will likely accommodate commercial-scale storage of at least 50 Mt of CO_2, and would be a suitable candidate for further investigation.

These results provide a preliminary assessment of subsurface technical risks based on the available site characterization data for the target storage unit, the Cloverly Formation, and overlying seals. Risk assessment is an iterative process of identifying, analyzing, and evaluating individual project risks. This iterative process enables the evaluation of potential risks that may evolve because of changing site conditions, plans, or designs; operational factors; and/or policy and regulatory developments (Azzolina and others, 2017). Should this project advance from the current pre-feasibility stage to subsequent stages of project development, these risks will be reevaluated using the most currently available site data. In addition, nontechnical risks, which were outside the scope of the Phase 1 RA, would likely be included.

5.0 NATIONAL RISK ASSESSMENT PARTNERSHIP (NRAP) VALIDATION

5.1 Introduction

This section presents a summary of the results obtained under the NRAP Validation task. The goal was testing the validity of applicable tools developed through the DOE's NRAP. Three main objectives were delineated for the testing efforts: 1) select NRAP tools compatible with data collected from the Nebraska Integrated Carbon Capture and Storage Pre-Feasibility Study, 2) simulate long-term leakage and calculate CO_2 and pressure plumes through time, and 3) use other NRAP tools if applicable.

Four NRAP tools were selected for their greatest applicability to the data collected under Subbasinal Analysis task. Both the Reservoir Reduced-Order Model Generator (RROM-Gen) and the Reservoir Evaluation and Visualization (REV) were used to calculate CO_2 and pressure plumes. The Well Leakage Analysis Tool (WLAT) was used for the estimation of long-term leakage potential. Finally, the NRAP Integrated Assessment Model – Carbon Storage (NRAP-IAM-CS) Tool was used in performance and quantitative risk assessment of geologic sequestration of CO_2.

While a comprehensive validation work of the NRAP suite is beyond the scope of this work, the NRAP tools listed above were tested in the project context, i.e., using data and models generated as part of a Phase 1, pre-feasibility study. Data collected in the subbasinal analysis, more closely related with reservoir modeling and simulation workflows, was used with the purpose of calculating the spatial distribution of CO_2 and pressure plumes through time. The area under consideration includes a limited number of legacy wells, although detailed records of well condition are not available in this pre-feasibility study. Similarly, detailed design of proposed injection wells is beyond the scope of the study. ***Therefore, risks associated with any potential wellbore leakage have been assessed using an entirely theoretical migration pathway through a notional well(s) within the study area.***

Geologic information and reservoir simulation results were the key inputs used for the NRAP tools. Characterization data for the stratigraphic sequence above the storage formation were collected for an assessment of theoretical CO_2 leakage and potential impacts on aquifers with WLAT and NRAP-IAM-CS. Five shale intervals and five aquifers were found above storage formation (Table 1). Reservoir simulation results obtained in the subbasinal analysis, conducted to assess the pre-feasibility of storing 50 Mt of CO_2 over 25 years in the Cloverly Formation (Dakota Group) in Nebraska, were used to for testing both RROM-Gen and REV tools. While the RROM-Gen and REV tools were tested with three different simulation models (P90, P50, and P10), each of them with their respective 3-D properties distributions, only a key subset of results will be presented in the following sections.

5.2 Tool Validation Tests

RROM-Gen Tool Testing

RROM-Gen extracts the simulation results from the reservoir–seal interface layer and, using piecewise bilinear interpolation, maps the simulation results onto a new grid, formatted as required by other NRAP tools (e.g., NRAP-IAM-CS). RROM-Gen maps the CMG results using a new grid spacing. The new grid size was 100 × 100 cells, which is the only format compatible with the NRAP-IAM-CS.

Figure 36 shows one example of the RROM-Gen results in terms of the pressure plume after 25 years of injection. Additional results from RROM-Gen are shown in Appendix E. The RROM-Gen results with the 100 × 100 grid were found to be in reasonable agreement with CMG's visualization tool Results 3D. While some local differences may appear, they could be attributed to differences in the interpolation algorithms and/or the visualization utility settings (color bar scale settings, plot type settings, etc.).

Attempts to generate maps of the pressure and CO_2 plumes, using the original CMG grid spacing, were not successful. Some examples are shown in Appendix E.

REV Tool Testing

The REV tool provides insight on the evolution of the long-term CO_2 and pressure plumes through time, being the key REV metrics defined as differential values above a specified threshold. Pressure and saturation results from the CMG's GEM reservoir simulation models were used as input. REV automatically extracted the plume sizes metrics of performance. Key metrics are the size of CO_2 plume injection, the size of pressure plume, and the maximum pressure at specific locations.

Results obtained with REV are explained in detail in Appendix E. The output map created by the REV tool presented similar anomalies as noted previously with the "original" maps created

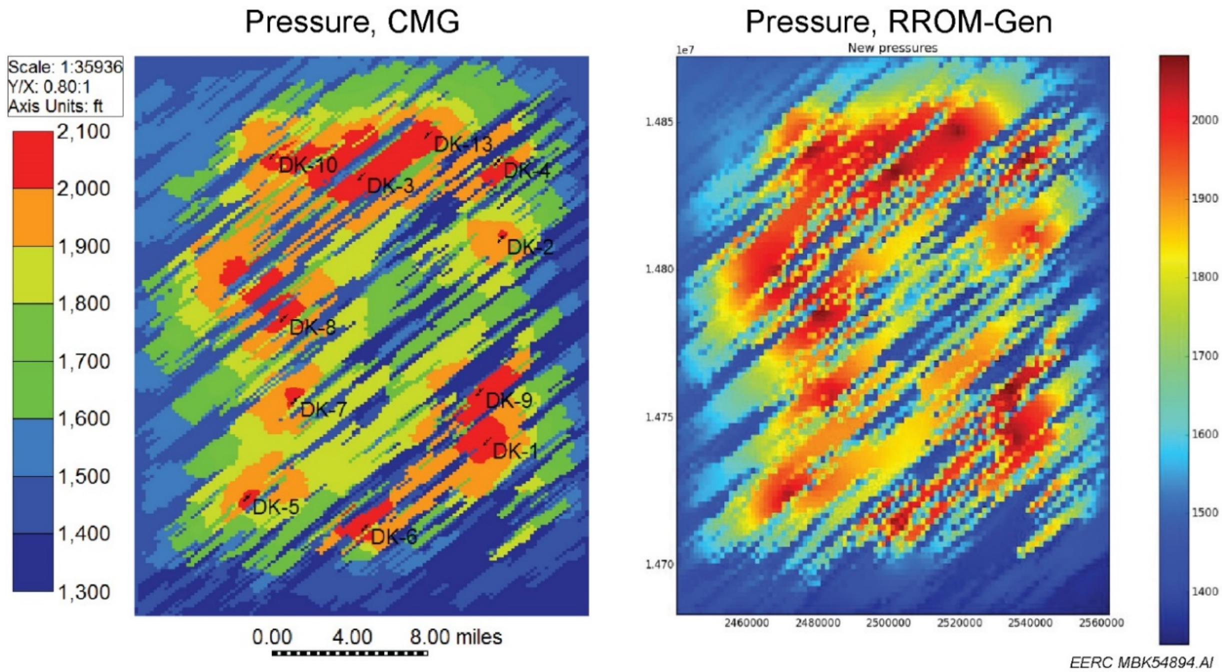

Figure 36. Maps showing a top view (XY plane) of the pressure plume with RROM-Gen outputs (right) compared against the CMG results (left) for Geologic Realization 1 (P10) after 25 years of injection.

with the RROM-Gen tool. These anomalies were considered anecdotic (most likely attributed to the interpolation algorithm and/or the visualization utility settings), and it was assumed that they did not influence the NRAP-IAM-CS results.

WLAT Testing

The area under consideration includes a limited number of legacy wells, although detailed records of well condition are not available in this pre-feasibility study. Similarly, detailed design of proposed injection wells is beyond the scope of the study. Therefore risks associated with any potential wellbore leakage have been assessed using an entirely theoretical migration pathway through a notional well(s) within the study area.

The WLAT tools contain a collection of Reduced Order Models (ROMs) to estimate the rate of CO_2 and brine leakage for different types of wells. Such models are built based on two approaches: 1) full-physics simulations with the results compiled into ROMs based on given input conditions and 2) physical models based on first principles that are simplified based on assumptions, mathematical tools, and empirical observations. WLAT comprises four types of models: the Cemented Wellbore Model, the Multisegmented Wellbore Model, the Open Wellbore Model, and the Brine Leakage Model. In this work, the Cemented Wellbore and the Multisegmented Well Models were selected. As no historical records of wells exhibiting CO_2 leakage existed in the area under study, the models results should be seen as a theoretical exercise that could not be validated using any field data.

Results from WLAT are fully explained in Appendix E. Worst-case scenario corresponds to a cement having a fracture (i.e., cement having an effective permeability of 101 Darcies) along the complete well length. Worst-case scenario resulted in less than 2 tons per day leaking into the thief zone, at depth of 683.1 meters. For the rest of the cases, CO_2 leakage to the thief and aquifers zones was negligible. CO_2 leakage to the atmosphere is negligible for all of the cases studied. Further investigations are needed to confirm that the ROM assumptions are plausible, despite the fact that the input data differ significantly from the user data. In particular, the differences observed in zone thickness are expected to have a pronounced effect on the Cemented Wellbore Model leakage results.

NRAP-IAM-CS Testing

The NRAP-IAM-CS Tool is an integrated model for use in performance and quantitative risk assessment. This tool is a hybrid system; i.e., links together ROMs for simulation of different processes, such as subsurface injection of CO_2, CO_2 migration, leakage, and shallow aquifer impacts. NRAP-IAM-CS can generate probabilistic simulations related to the long-term fate of CO_2 on different geologic sequestration scenarios.

Results from the NRAP-IAM-CS Tool are explained in detail in Appendix E. The base case scenario corresponds to the "*Leakage to groundwater through wells*" scenario (Figure 37). An effective wellbore permeability of 1 mD was arbitrarily chosen as a basis of calculation, and a sensitivity analysis based on this parameter allowed studying a larger range of values. The reason to choose a value as high as 1 mD is merely out of convenience. In reality, such a high value is very unlikely in real operations. However, values that are closer to realistic permeability measurements tend to provide leakage rates that are too small to analyze as part of the tool-testing exercise. As a reminder, the goal of this work is to test the NRAP tools, and realistic parameters may not serve this overarching purpose well.

Figure 37 shows that the maximum CO_2 leakage rate occurs during the first year of operation. For the aquifer, leakage rate ranges between 5 to 120 kg per day (depending on the model realization). For the groundwater, leakage rate varies from 0.5 to 2.5 kg day. All other things being equal, it was expected that the leakage rates were proportional to the number of wells in each model. However, different reservoir behaviors, such as local pressure increase around the near wellbore region (e.g., due to solids precipitation) or changing injection rates (e.g., modifying operational schedule) could complicate this kind of simplistic analysis. The leakage rates drop after the first year and, at later times, reach values as low as 0.3 kg per day for the groundwater or 3.7 kg per day for the aquifer. In the worst-case scenario, after 25 years of injection, the total mass leaked to the aquifer was 90 tons, while the total mass leaked to the groundwater was 4 tons.

Results of brine leakage to the groundwater aquifer resulted negligible for all three geologic realizations. The maximum brine leakage rate for the shallow aquifer occurs at the beginning of the second year of operation. For the worst-case scenario (P10), the brine leakage rate stabilizes around 25 kg per day, while with the best-case scenario, the rate stabilizes around 3.2 kg per day. Brine leakage rates stabilize around the second-year values. After 25 years of injection, the total mass leaked to the aquifer ranged from 27 tons to 213 tons (see Appendix E).

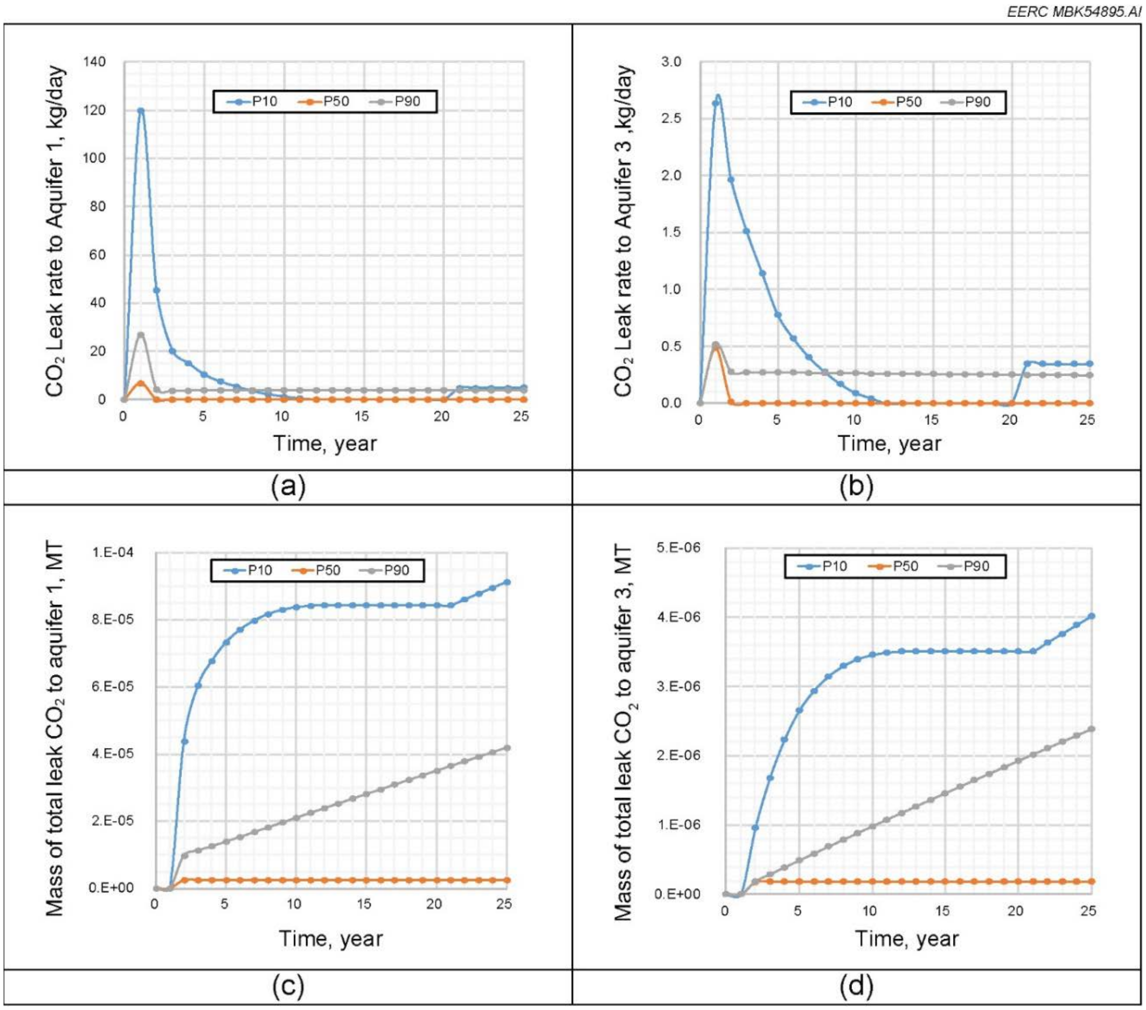

Figure 37. Plots obtained with the "Leakage to groundwater through wells" scenario showing time-dependent estimations for CO_2 leakage. CO_2 leakage to an intermediate aquifer (Aquifer 1) is shown in terms of leakage rate (a) and total mass (c). Also, CO_2 leakage to groundwater aquifers (Aquifer 3) is displayed in terms of Leakage rate (d) and total mass (b). Results of CO_2 leakage to the atmosphere resulted in negligible values for all three geologic realizations (P10, P50, P90).

5.3 Summary and Recommendations

- Four NRAP tools were selected RROM, REV, WLAT, and NRAP-IAM-CS and tested. When possible, site-specific data collected from the Nebraska Integrated Carbon Capture and Storage Pre-Feasibility Study were used. The NRAP tools listed above were tested in the project context.

- Data collected under the subbasinal analysis were used with the purpose of calculating the spatial distribution of CO_2 and pressure plumes through time. As no historical records of CO_2 injection operations existed in the area under study, potential leakage from wells and risk assessment of geologic sequestration of CO_2 remained a theoretical exercise that could not be validated using any field data.

- The test included identifying the model options that could be adapted with the data. The model options that were less suitable for the data set were not explored.

- The RROM-Gen was used as part of the testing. This tool could utilize the CMG results generated in the project. While the CMG grid results look fuzzy, the tool could properly show the values of the lookup table (the 100 × 100 grid) to be used together with IAM.

- The REV tool was also used as part of the testing. This tool could utilize the CMG results generated in the project. The REV tool only plots the CMG grid results, which look fuzzy. It is recommendable to the tool could properly show the values of the lookup table (100 × 100 grid) to be used together with IAM.

- Two modules of the WLAT tool were used in the testing, the Cemented Well Model and the Multisegment Model. The latter was found to have a lower number of restrictions. Also, the former tool has a significant number of parameters that are hard-wired or restricted; as a result, some important inputs accepted by the tool differ significantly from the data collected from the project. The consequences of such limitations are uncertain. Results suggest that leakage to the atmosphere is negligible under the studied conditions, i.e., injecting 2 Mt per year during 25 years.

- The NRAP-IAM-CS tool was also tested. The key parameter required to predict the wellbore leakage is the effective wellbore cement permeability. One disadvantage of this approach is that, in reality, a single factor would largely influence, even dictate, the model results and the uncertainty analysis outcomes, while many others parameters would end up having a modest or negligible contribution.

6.0 FINAL REPORT SUMMARY AND CONCLUSIONS

6.1 Regional and Stakeholder Analysis

A review of geographic and socioeconomic characteristics, in combination with geologic characterization in the subbasinal analysis described below, identified an area to the southwest and within a 75-mile radius of GGS as the most prospective for development of a storage site. This area largely avoided lands with protected status such as wetlands.

A public outreach plan has also been developed for implementation in any further phases of CCS assessment in western Nebraska, for example, a CarbonSAFE Phase 2 feasibility study.

6.2 Scenario Analysis

GGS is the only single major source of CO_2 emissions capable of satisfying the CarbonSAFE 50-Mt scale requirement within the study region. Chemical absorption using amines was identified as the most viable technology for postcombustion CO_2 capture at GGS. The total cost of a CCS project at GGS was estimated to be between \$67/tonne CO_2 for capture + auxiliary boiler to minimize parasitic load and \$70/tonne CO_2 avoided cost, using the Carnegie-Mellon University IECM. The total avoided cost included the capture facility and parasitic load, a flue gas desulfurization plant required for the use of amine solvent technology, transport via pipeline, and dedicated storage infrastructure.

Nebraska has no legislation in place to address typical CCS-specific issues, for example, pore space ownership for storage. Long-term liability, therefore, falls under EPA's UIC Program regulations.

6.3 Subbasinal Analysis

Modeling and simulation studies identified an area to the southwest of GGS with the potential for storage of 50 Mt CO_2 in the Cloverly Formation, comprising sandstones with shales. The AOR that would be required for monitoring under a Class VI operating permit was estimated to range from 400 to 700 square miles. The viability of this storage option is subject to significant uncertainty because of the relatively limited amount of existing characterization data available to the pre-feasibility study; for example, dynamic simulation indicated that the proposed storage rate might require as little as 2 or as many as 14 injection wells. A key uncertainty is the relative proportion and distribution of sandstone and shale within the Cloverly Formation.

A preliminary, semiquantitative risk assessment also suggested uncertainty over storage capacity and injectivity constitute the most significant project risks at this pre-feasibility stage. No assessed risks were considered to rule out the possibility of a project moving to deployment.

6.4 National Risk Assessment Partnership Validation

NRAP tools were used to assess hypothetical leakage scenarios. Results broadly supported the conclusion of the semiquantitative risk analysis – for example, even worst-case analysis of theoretical leakage scenarios found limited migration rates and impacts.

6.5 Overall Conclusions

In summary, the work undertaken in this Phase 1 pre-feasibility study has shown that western Nebraska has potential to host a commercial-scale CCS project, including a dedicated storage container for 50 Mt of CO_2. However, the following key challenges would need to be overcome:

- The business case for deploying CCS projects is uncertain; recently announced federal tax credits may not compensate for the cost of CCS deployment at a coal-fired power station such as GGS. Sales of CO_2 for EOR could provide additional revenue, but the combined benefits of tax credits plus EOR sales would still might not cover the cost of a CCS project at GGS, as estimated by this pre-feasibility study.

- The potential 50 Mt CO_2 dedicated storage container defined in this pre-feasibility study should be regarded as having a relatively low level of readiness to support a CCS project.

Significant further work, including exploratory drilling and geophysical surveys, would be required to provide sufficient certainty to support an investment decision in a Nebraska CCS effort.

- Public outreach would be a vital element in western Nebraska, where sensitivities around such environmental issues as water resource protection and pipeline construction would need to be carefully addressed.

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APPENDIX A

PUBLIC OUTREACH PLAN

DRAFT

CARBONSAFE-NEBRASKA OUTREACH PLAN

Phase I Milestone 5

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CARBONSAFE-NEBRASKA OUTREACH PLAN

EXECUTIVE SUMMARY

In collaboration with the Nebraska Public Power District (NPPD), the Energy & Environmental Research Center (EERC) has conducted a prefeasibility study for a commercial-scale carbon dioxide (CO_2) geologic storage complex in western Nebraska, integrated with potential CO_2 capture at Gerald Gentleman Station (GGS). GGS is the largest coal-fired electricity-generating station in Nebraska, emitting 8.5 million metric tons of CO_2 annually, and is located near the town of Sutherland. This prefeasibility ("Phase 1") project has been executed as part of the U.S. Department of Energy (DOE) CarbonSAFE Program, a multiphase initiative to support the deployment of large-scale carbon capture and storage (CCS) projects. Each CarbonSAFE project is required to demonstrate the potential to capture and store at least 50 million tonnes (Mt) of CO_2 over a 25-year operational period.

The *Community Outreach Plan* fulfills a key goal of the CarbonSAFE-Nebraska (CS-NE) prefeasibility investigation (January 2017 through June 2018), by providing a foundation for constructive public engagement related to potential commercial-scale CCS featuring dedicated CO_2 storage in the area of southwestern Nebraska. This outreach plan, based on input from project partners and key stakeholders and in accordance with DOE's best practice manual for geologic storage project outreach features sections covering outreach goals, roles, approach and guidelines, audiences, project narrative, outreach considerations, strategies, toolkit, time line, and tracking and assessment.

CARBONSAFE-NEBRASKA OUTREACH PLAN

INTRODUCTION

In collaboration with the Nebraska Public Power District (NPPD), the Energy & Environmental Research Center (EERC) has conducted a prefeasibility study for a commercial-scale CO_2 geologic storage complex in western Nebraska, integrated with potential carbon dioxide (CO_2) capture at Gerald Gentleman Station (GGS). GGS is the largest coal-fired electricity-generating station in Nebraska, emitting 8.5 million metric tons of CO_2 annually, and is located near the town of Sutherland. This prefeasibility ("Phase 1") project has been executed as part of the U.S. Department of Energy (DOE) CarbonSAFE Program, a multiphase initiative to support the deployment of large-scale carbon capture and storage (CCS) projects. Each CarbonSAFE project is required to demonstrate the potential to capture and store at least 50 million tonnes (Mt) of CO_2 over a 25-year operational period. As part of this effort, a *Community Outreach Plan* was developed to educate/inform the public, public opinion leaders, and decision makers, incorporating methods to evaluate public perception of a potential CCS effort in Nebraska and mitigation approaches to any identified potential conflicts. The 18-month prefeasibility study was performed January 2017 through June 2018.

Outreach is an integral part of any overall project and encompasses all project-related activities that have public contact or exposure. The overall goal for implementing outreach is to develop and implement a strategy to engage with stakeholders and to create an environment that allows them to make an informed decision regarding the project within their community and the region. Internal outreach efforts create an effective, informed team that can act as knowledgeable spokespeople for the project. External outreach is triggered by any project-related activity that has public contact or exposure. This includes actions by the outreach team on behalf of the project, by project management, the technical team, or partners.

The CarbonSAFE-Nebraska (CS-NE) outreach plan lays a foundation for public engagement related to a potential permanent CO_2 storage effort in southwestern Nebraska. The plan's various components answer five key questions that the outreach team needs to know to create and implement a comprehensive and successful outreach campaign (Table 0-1). The outreach plan provides a starting point for NPPD and/or other parties for any potential CCS effort in southwestern Nebraska.

Table 0-1. Relating Outreach Plan Content to Key Project Story Questions

Questions to Answer		Plan Content
1	What are we trying to achieve, and how do we best work together to achieve it?	• Goal, approach, and success measures • Partner roles • Audiences • Implementation considerations and guidelines
2	What is our story?	• Outreach narrative, themes, and messages
3	How will audiences hear our story?	• Strategies • Outreach toolkit
4	When do we need to tell the story?	• Preliminary outreach time line matched to technical time line and partner considerations
5	Who heard the story, and what do they think about it?	• Tracking and assessment

GOAL AND APPROACH

The goal when implementing CCS-related outreach is to raise awareness to key audiences and audiences in the vicinity of potential CCS efforts in the region in collaboration with CS-NE partners. Outreach encompasses any project-related activity that has public contact or exposure. The CS-NE outreach plan, developed by the EERC in collaboration with NPPD, is designed to provide a conceptual and temporal framework for delivering timely, accurate information to key stakeholder audiences regarding CCS, CCS-specific activities, and activities in the region and beyond. The outreach time line is keyed to a potential CCS implementation time line. The time line also has outreach actions that precede any public phase of outreach and proceeds through the end of the potential CCS effort.

The plan is designed to mesh with the time lines and activities of a potential CCS technical program as well as the commercial development program. The plan is designed to function within the local context, provide roles for the project participants, and build on the foundation of DOE's *Best Practices: Public Outreach and Education for Geologic Storage Projects* and on the team's knowledge of the region's social characterization, as well as its outreach experience, expertise, and capabilities. The plan is a living document that will be updated periodically. Components of the plan include:

- Outreach Management (Section 1) suggests a framework for decision making and implementation for outreach in the area.
- Regional Analysis (Section 2) describes the assessment of geographic and socioeconomic characteristics specific to the study region in relation to CCS.
- Audiences (Section 3) contains a listing of outreach audiences.
- Narrative, Themes, and Messages (Section 4) contains a sample sentence, summary paragraph, and a one-page detailed project description as well as themes and messages.

- Audience Engagement Strategies (Section 5) lays out strategies to engage each of the audiences identified in Section 3.

- Outreach Tool Kit (Section 6) contains a list of outreach materials that could be used in support of the outreach strategies described in Section 5. The toolkit materials incorporate the narrative, themes, and messages from Section 4 and are geared as appropriate to fit individual audiences.

- Outreach Time Line (Section 7) contains a sample outreach time line for drilling a hole to collect geologic information (stratigraphic test) as a model for a suite of time lines that could be prepared for key activities in a future project time line.

- Outreach Tracking and Evaluation Process (Section 8) contains suggestions for tracking and assessment actions as well as suggestions on measuring success for the outreach activities.

SECTION 1. OUTREACH MANAGEMENT

CS-NE outreach would have oversight by an advisory board comprising members of the CCS coordination team, listed in Table 1-1. Given the organization’s history and prominence in the region, NPPD is the natural choice for lead organization with respect to outreach on a future CCS project involving GGS in the region. NPPD would likely proceed with the aid of this outreach plan and draw on its own capabilities. Within this NPPD-led environment, provisions would be made to support the development of outreach materials; outreach and team communication; and outreach tracking, planning, and assessment. Following DOE’s *Best Practices: Public Outreach and Education for Geologic Storage Projects* and EERC experience in CCS outreach, the following general guidelines are suggested for future activities:

- Outreach is an integral part of project management and planning.

- Outreach is proactive and is operational from the planning stages of the project through the end of operations and through postproject monitoring activities.

- All partners will work from a single narrative on goals, activities, outcomes, and benefits (consensus-based content approved by NPPD and the CS-NE Coordination Team).

- Partners are free to stress different individual talking points around benefits consistent with individual company goals/objectives but need to accommodate these within and maintain the integrity of the central consensus-based narrative.

- The outreach team will develop and regularly update consistent talking points regarding the project itself and our partnership to ensure a consistent narrative/message.

- All press releases and public statements will come from materials that have been reviewed and approved by the outreach team, NPPD, and CS-NE partners; statements/products will be shared on a timely basis.

- Outreach will be augmented by an outreach toolkit (Section 6) consisting of items that include a Talking Points Document (project explanation, dates, time frame, scope of work, objectives, benefits, next steps, etc.), fact sheets, FAQs (frequently asked questions), and other aids such as approved PowerPoint slides for partner use in public and internal presentations.

- Basic information will be online (and tracked and assessed) on the CS-NE Web page on the EERC's PCOR Partnership Web site as well as pages for NPPD Web site.

- Periodic internal review and assessment of the outreach program in light of measures of success (Section 9).

- Regular progress updates to partners and customers, members, and regulators in addition to outreach to broader audiences.

Table 1-1. Project Coordination Team Members

Organization	Position
Nebraska Energy Office	Director
Nebraska Department of Environmental Quality	Director Deputy Director, Air and Land Division
Southwest Public Power District	General Manager
Lincoln Electric System	Vice President, Power Supply
Omaha Public Power District	Manager, Environmental and Regulatory Affairs
University of Nebraska – Lincoln Department of Earth & Atmospheric Sciences	Assistant Professor
Berexco LLC	Vice President
ION Engineering	Senior Product Manager
Nebraska Oil and Gas Conservation Commission	Director
Nebraska Public Power District	Vice President and COO General Manager
EERC	Project Manager Outreach Team

SECTION 2. REGIONAL ANALYSIS

A regional analysis was conducted to determine geographic and socioeconomic characteristics of the prefeasibility study area to identify any potential CCS-related concerns. The geographic component of the analysis revealed environmentally sensitive areas, potential impacts on current and future resource development, and the regulatory situation. The stakeholder analysis identified avenues to initiate public outreach and to gain local public acceptance of future potential CCS efforts. The data, collected from a variety of sources such as the U.S. Department of Agriculture's Natural Resources Conservation Service (USDA NRCS) and the state of Nebraska, were incorporated into an internal geographic information system (GIS) database. Data visualization in the GIS system allowed team members to simultaneously evaluate a myriad of relevant data sets and fostered communication between various teams involved in the project.

2.1 Project Area

GGS is located in Lincoln County in western Nebraska on the eastern edge of the Denver sedimentary basin and just south of the Platte River system (North and South Platte Rivers). Initial analysis of surface features such as environmentally sensitive or protected areas and subsurface geologic formations within a 50- and 75-mile radius around GGS suggested closer evaluation of the five-county area to the west and south. The five counties included are Lincoln, Keith, Perkins, Chase, and Hayes Counties (Figure 2-1).

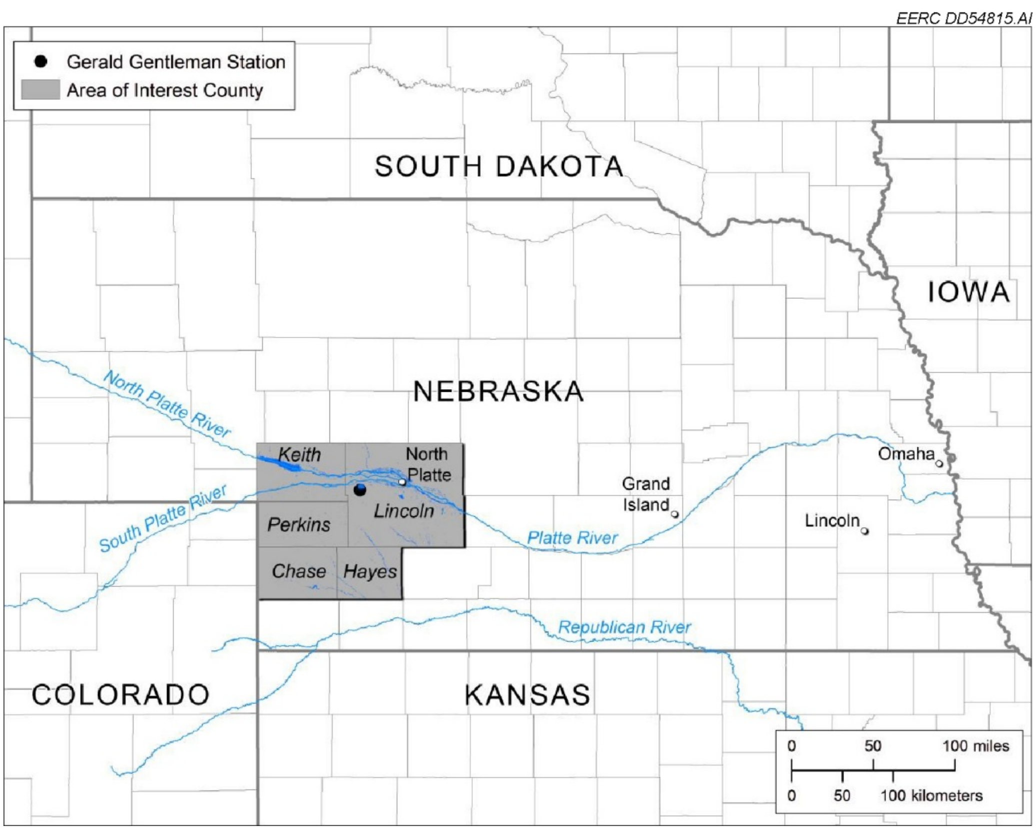

Figure 2-1. State of Nebraska showing the five counties of interest and GGS.

2.2 Environmentally Sensitive Areas

An essential part in planning any potential CCS effort is to evaluate for environmentally sensitive or protected areas in the proposed project area. These areas may be legally protected, such as underground sources of drinking water (USDWs), state or federal refuge systems, or they may be of importance to local stakeholders such as agricultural lands. Protected and sensitive areas for the proposed project area are described in the following subsections.

2.2.1 Land Use

The five-county study area is a rural, sparsely populated region heavily influenced by agriculture. Land cover in this region, shown in Figure 2-2, is primarily grasslands and cropland, with cropland covering almost 33% of the land. For the general public, the sensitive land cover types consist of wetlands and open water areas as these types are environmentally important to wildlife and for human use. Cropland and pasture will be of local interest, but CCS-related impacts are limited to individual landowners.

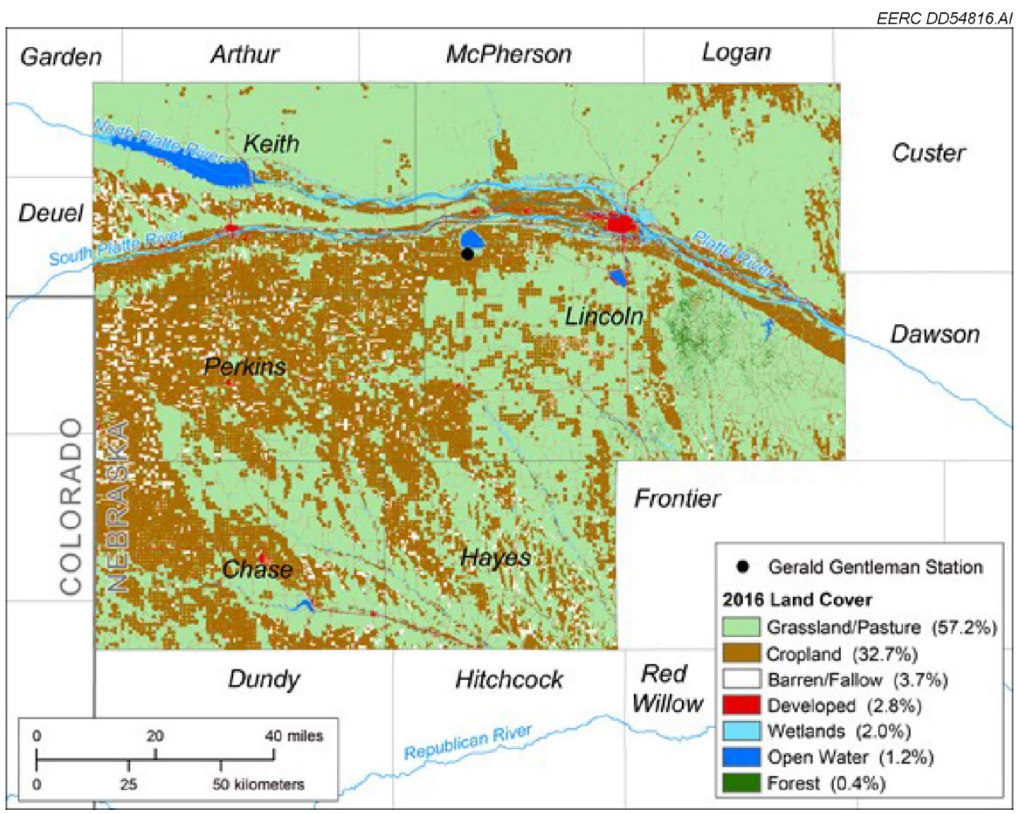

Figure 2-2. Land cover for a five-county regional analysis (source: U.S. Department of Agriculture Natural Resources Conservation Service, 2016).

2.2.2 Water Resources

Water is one of Nebraska's most valuable resources. The state has one of the world's largest freshwater aquifers and numerous surface water resources that are vital for agriculture, industry, energy production, domestic use, and recreation. The aquifer in the five-county study area is the High Plains (aka, Ogallala) aquifer, found in the upper Tertiary sediments extending from the surface to a depth of about 300 feet (U.S. Geological Survey, 2018). Major stream systems in this area include the North and South Platte Rivers (north of GGS), which join to form the Platte River just east of the city of North Platte. The Republican River flows just to the south of the study area. The five-county area also includes temporary, seasonal, semipermanent, and permanent wetlands. Areas containing larger semipermanent and permanent wetlands will be avoided during project operations.

The primary use of groundwater in the study area is for agricultural irrigation, which accounts for over 95% of daily groundwater withdrawals in the five-county area (Maupin and others, 2014) (Figure 2-3 and Table 2-1). Groundwater is the source of about 80% of the publicly supplied drinking water for the entire state of Nebraska (Johnson and others, 2011), and the reliance on the Ogallala aquifer has greatly impacted water levels. In the proposed project area, Chase and Perkins County groundwater levels have significantly declined, while Lincoln and Keith County groundwater levels have risen because of recharge from the Platte River system (Figure 2-4).

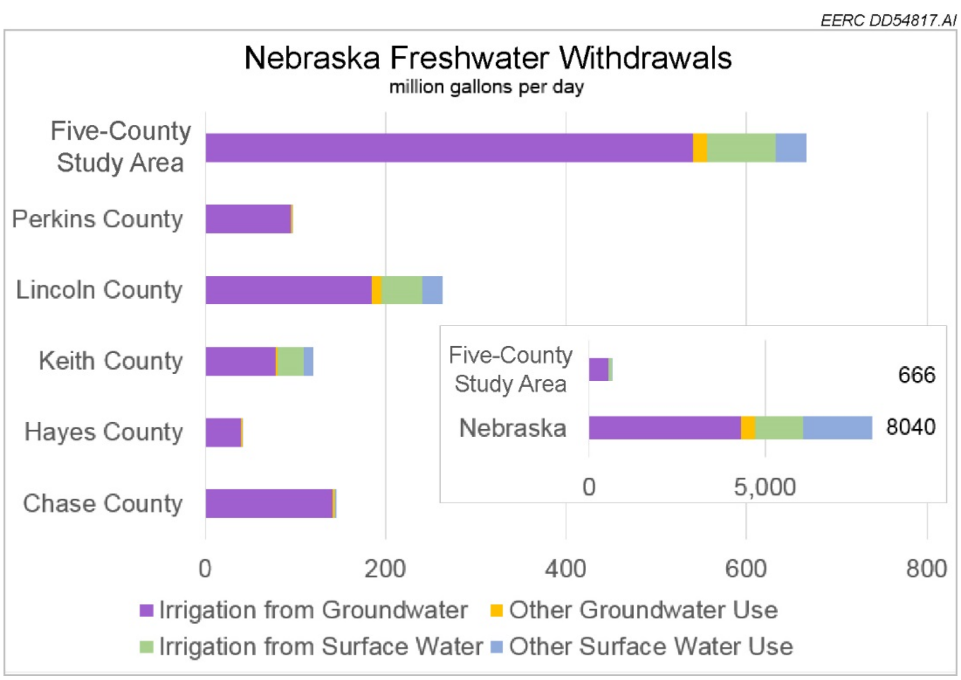

Figure 2-3. Comparison of freshwater withdrawals shows that a higher percentage of water use is for irrigation of agricultural crops in the counties of the study area rather than statewide withdrawals.

Table 2-1. Water Withdrawals by Source, 2010 (Maupin and others, 2014)

	Population, thousands		Groundwater, million gal/day				Surface Water, million gal/day				Total Withdrawals, million gal/day		Acres Irrigated, thousands	
		% State Total	For Irrigation		Total Withdrawals		For Irrigation		Total Withdrawals			% State Total		% State Total
Nebraska	1830	100	4300	100%	4710	100%	1360	100%	3320	100%	8040	100	8730	100
Chase County	4.0	0.22	140	3.3%	140	3.0%	0.54	0.04%	0.8	0.02%	140	1.8	182	2.1
Hayes County	1.0	0.05	40	0.9%	41	0.9%	0.36	0.03%	0.5	0.02%	41.6	0.5	76	0.9
Keith County	8.4	0.46	79	1.8%	81	1.7%	28	2.07%	39	1.17%	120	1.5	110	1.3
Lincoln County	36.3	1.98	180	4.3%	195	4.1%	46	3.39%	68	2.06%	260	3.3	260	3.0
Perkins County	3.0	0.16	95	2.2%	96	2.0%	0	0.00%	0.1	0.00%	96	1.2	130	1.5
Total Five-County Study Area	52.6	2.87	540	12.6%	560	11.8%	75	5.53%	108	3.27%	666	8.3	770	8.8

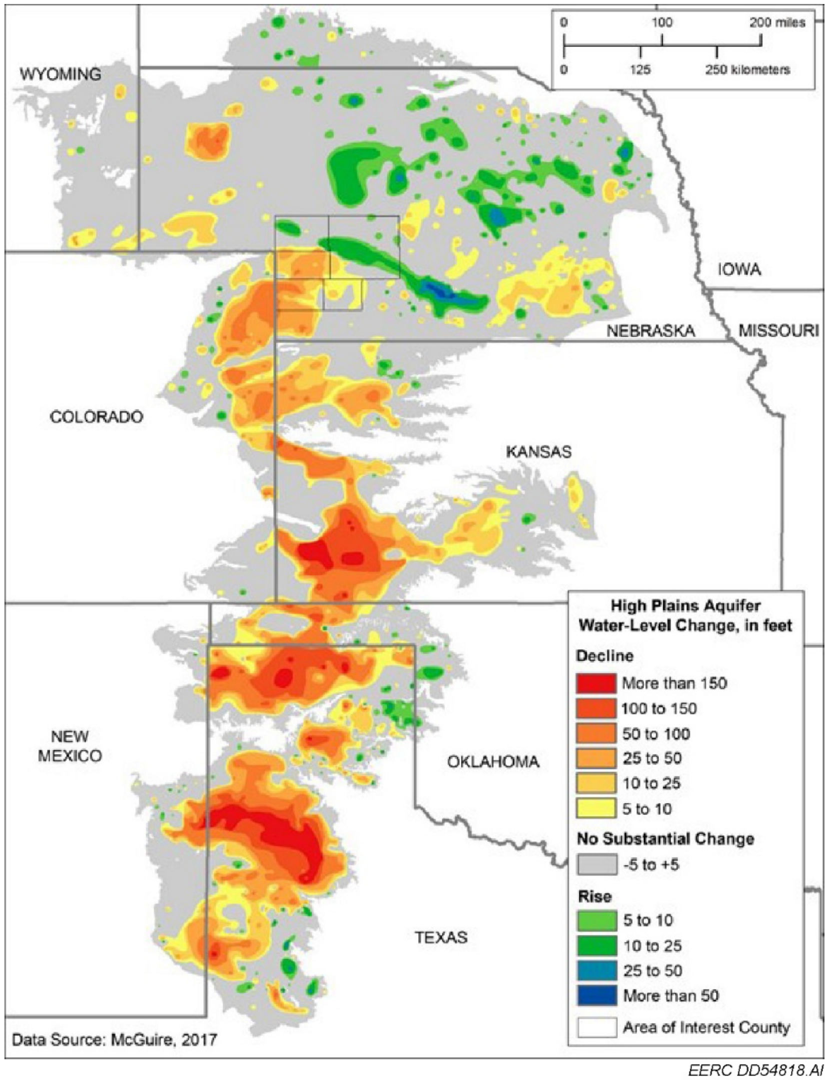

Figure 2-4. Water-level change in the High Plains aquifer (McGuire, 2017).

Any potential CCS projects must take appropriate steps to ensure the protection of the USDWs (U.S. Environmental Protection Agency, 1974). In addition to the federal guidelines set by the U.S. Environmental Protection Agency (EPA), state water decisions are governed by 23 Natural Resources Districts (NRDs). The five-county study area includes all or part of four NRDs: Twin Platte NRD, Middle Republican NRD, Upper Republican, Twin Platte NRD, and Upper Loup NRD (Chase, Perkins, and Lincoln Counties).

2.2.3 Wildlife/Habitat

The study area contains multiple state and federal wildlife management areas, wildlife refuges, and other protected environmental habitats, particularly along the North and South Platte Rivers. As shown in Figure 2-5, relatively few areas of concern are located to the west and south of GGS. Any project activities must avoid these wildlife habitats and account for the conservation of any threatened or endangered species that may require special management or protection.

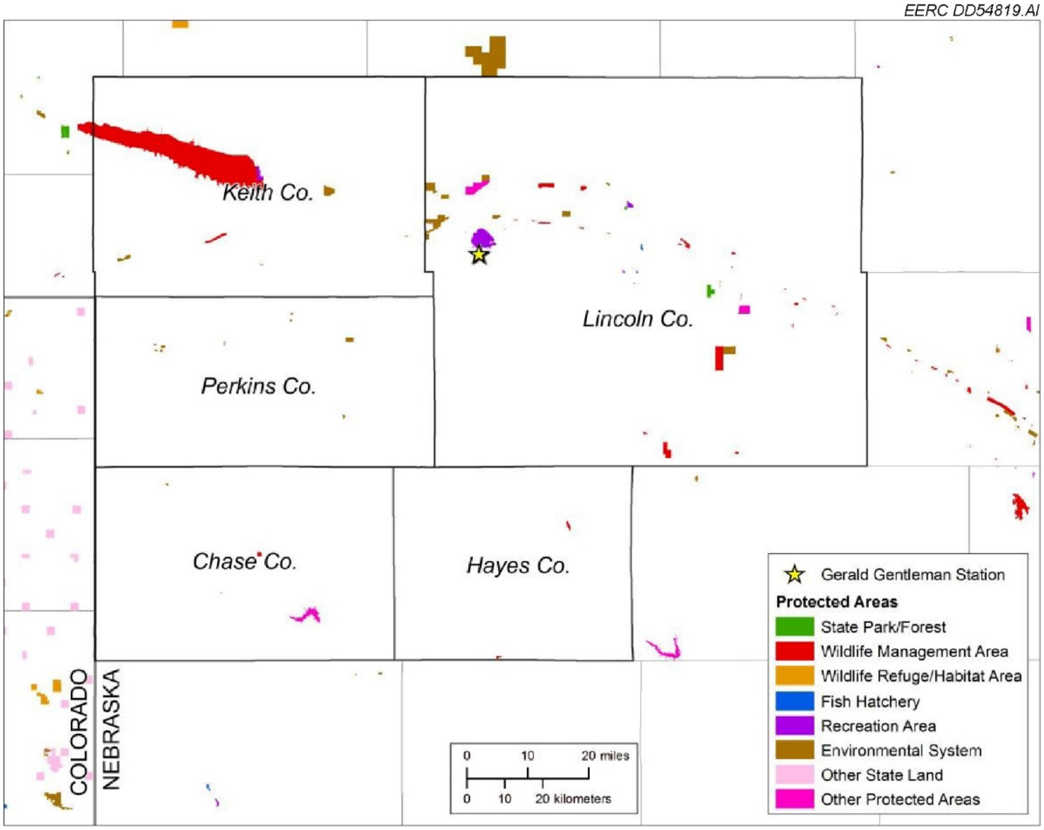

Figure 2-5. Protected areas in the study area.

2.3 Existing and Future Resource Development

One concern with respect to the implementation of CCS projects is the potential to negatively impact mineral or other resource development. Although there has been past exploration for hydrocarbons in the five-county study area, most existing exploration and production wells are no longer in operation and have been plugged and abandoned (Figure 2-6).

Renewable energy development, primarily wind energy such as the proposed wind project in Keith County (Kansas Energy Information Network, 2018), could potentially occur in the area. Most wind energy development, however, occurs in northern and eastern Nebraska. Any future CCS activity would likely be able to avoid these oil/gas or wind energy development areas, thus limiting impacts on resource development.

Energy, particularly electricity, is critical to supplying water for agriculture in the area. The pumps for Ogallala-based irrigation are run by electricity, and water wells supply the great majority of water for this part of Nebraska. With that said, GGS has supplied low-cost energy to farmers for water supply. GGS is also a coal-fired power station, and some environmental nongovernment organizations (NGOs) have called attention to the conventional pollutants as well as CO_2 emissions from the power plant. With respect to electricity generation, Nebraska is unique in that all power comes from publicly owned utilities: municipal utilities, cooperatives, and power districts.

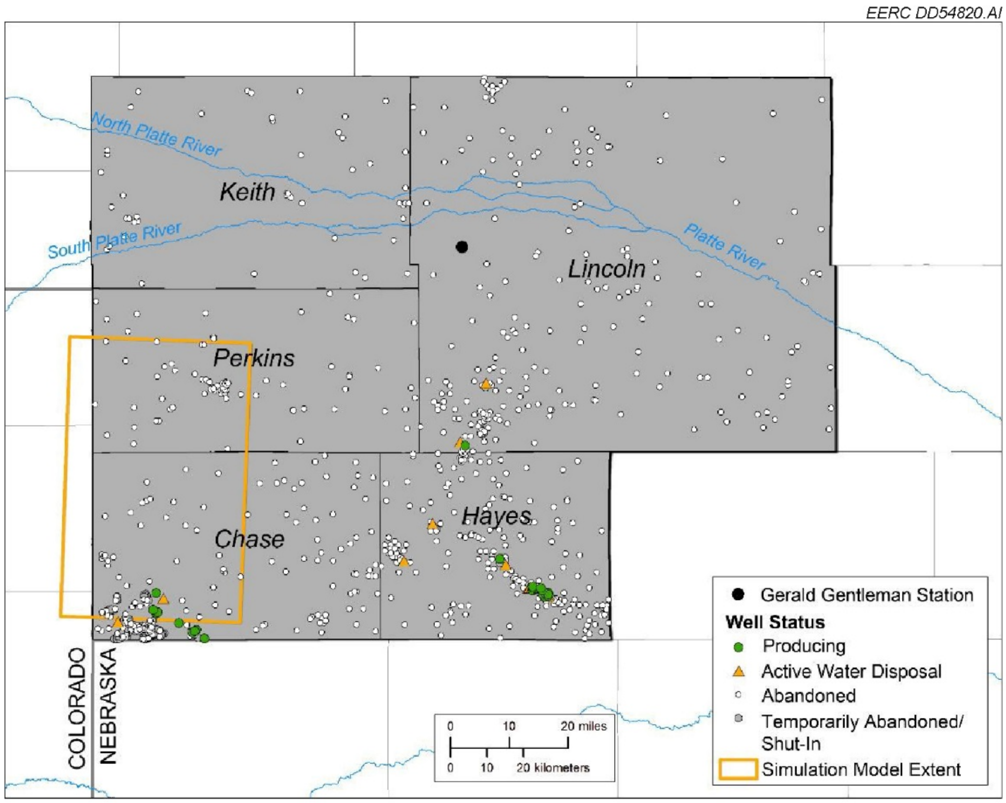

Figure 2-6. Oil and gas activity in the study area.

2.4 Community Impact Analysis

2.4.1 Regional Demographics

The study area is a rural, sparsely populated region with an economy based on agriculture. Anglo settlement began in the 1870s. Population plateaued in the region from the period 1920 to 1970. Over the past 50 years, population has grown by a third in Lincoln County, mainly due to the growth of the city of North Platte. The five-county study area has a population of 51,947 (2015 census). Population centers in this rural area of the state are the towns of North Platte (population 24,420), Ogallala (4605), Imperial (1917), Sutherland (1446), and Grant (1250). Together, these communities account for about 65% of the combined populations of these five counties. Racial makeup in this area is predominantly white, averaging 97%. The other 3% include American Indian, African American, Asian, and Hispanic. An average of 90% of the population has a high school diploma or higher. Only 20% have a bachelor's degree or higher.

In the five-county area, there are 22,341 households of which 25.1% had children under the age of 18 living with them, 58.1% were married couples living together, 5.4% had a female householder with no husband present, 33.3% were nonfamilies, and 26.6% of all households were made up of individuals. The average household size was 2.24, and the average family size was 2.74. The average median age of the five-county study area was 45.2.

The average household income for the five-county study area is $48,958, 10% less than for the state of Nebraska ($54,996). The per capita income was $27,755. About 6.8% of families and 9.5% were below the poverty line. Table 2-2 summarizes some of the regional demographic and economic data for the study area.

Table 2-2. Demographic Data

	Population	Median Age	Household	Poverty Rate, %	Median Household Income	Number of Employees	Median Property Value
Chase	3897	44.9	1701	8.88	$52,422	2073	$91,200
Hayes	1084	48	485	6.27	$44,500	549	$73,500
Keith	8146	49.1	3905	11.60	$41,781	4116	$99,700
Lincoln	35,896	40.1	15,010	12.80	$50,194	17,360	$114,200
Perkins	2924	44.1	1243	6.89	$55,893	1499	$97,700

2.4.2 Local Economic and Industrial Trends

The state of Nebraska is recognized as having significant agricultural activity, which represents nearly a quarter of the state's workforce, generates 25% of the state's labor income, and accounts for over 40% of the state's economic output (Thompson and others, 2012).

The local workforce occupations in the five-county study area are shown in Table 2-3. The largest portion of workers are employed in educational services, health care, and social assistance at 22.8%, followed by transportation, retail trade, and agriculture. Interestingly, excluding Lincoln County and the city of North Platte raises agriculture to the second most popular field with 17.2% (in the remaining four counties), slightly behind education and health care. More to the point, Thompson and others (2012) analyzed the southwest region, which includes the five-county study area plus four additional rural counties (Frontier, Dundy, Hitchcock, and Red Willow) and found that the economic output for the region from agriculture is 46.1% and agriculture-related workforce employment is 34%. The difference in employment numbers is explained by their inclusion of agriculture-related work in other industries such as transportation, manufacturing, research/education, and tourism.

The takeaway from the analysis of the local economy is that agriculture is a significant factor in the lives of people in the potential CCS project area, and as such, planning of CCS-related activities must ensure minimal impact to the resources (e.g., groundwater, agricultural land, etc.) that are perceived as paramount to the local economy.

Table 2-3. Number of Workers over 16 years of Age by Industry

	Counties									Statewide	
Industries	**Keith**	**Perkins**	**Hayes**	**Chase**	**Subtotal**	**%**	**Lincoln**	**Total**	**%**	**Total**	**%**
Agriculture, Forestry, Fishing and Hunting, and Mining	474	301	205	440	1420	17.2	769	2189	8.6	44,287	4.6
Construction	244	177	46	165	632	7.7	839	1471	5.7	64,837	6.7
Manufacturing	312	37	11	110	470	5.7	628	1098	4.3	105,135	10.9
Wholesale Trade	110	89	3	61	263	3.2	410	673	2.6	26,947	2.8
Retail Trade	531	112	42	328	1013	12.3	2512	3525	13.8	112,767	11.6
Transportation and Warehousing and Utilities	274	113	63	113	563	6.8	3231	3794	14.8	54,194	5.6
Information	76	10	6	78	170	2.1	275	445	1.7	18,590	1.9
Finance and Insurance, and Real Estate and Rental and Leasing	143	78	13	108	342	4.2	650	992	3.9	71,684	7.4
Professional, Scientific, and Management, and Administrative and Waste Management Services	290	30	6	80	406	4.9	763	1169	4.6	79,427	8.2
Educational Services and Health Care and Social Assistance	743	374	108	308	1533	18.6	4315	5848	22.8	230,596	23.8
Arts, Entertainment, and Recreation, and Accommodation and Food Services	469	31	21	102	623	7.6	1539	2162	8.4	76,206	7.9
Other Services, Except Public Administration	258	71	6	102	437	5.3	774	1211	4.7	43,102	4.5
Public Administration	192	76	19	78	365	4.4	655	1020	4.0	40,362	4.2
Total	**4116**	**1499**	**549**	**2073**	**8237**		**17,360**	**25,597**		**968,134**	

Source: 2015 American Community Survey 5-year Estimate, (U.S. Census Bureau, 2015).

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2.4.3 *Perceptions of Carbon and Climate Change*

Local stakeholder support is vital for any CCS project as access to private land is essential for the installation and operation of well pad infrastructure, pipeline routing, and monitoring activities. Prior to engaging local stakeholders, some knowledge of their values and perceptions of climate change is critical to provide direction for public engagement. The "Yale Survey on Climate Change" provides insight into regional attitudes and can help predict the public's perceptions and attitudes toward climate mitigation strategies. Key details from the Yale survey for the five-county study area are provided in Table 2-4.

Table 2-4. Yale Survey on Climate Change Responses

		Five Counties	Nebraska	USA
Beliefs	Believe global warming is happening	56%	64%	69%
	Believe global warming is caused mostly by human activities	42%	48%	52%
	Trust climate scientists about global warming	61%	66%	70%
Risk Perception	Worried about global warming	47%	51%	56%
	Believe global warming is already harming people in the U.S.	37%	44%	50%
	Global warming will harm me personally	32%	33%	38%
	Global warming will harm people in the U.S.	50%	51%	56%
	Global warming will harm people in developing countries	54%	57%	61%
	Global warming will harm future generations	62%	65%	69%
	Global warming will harm plants and animals a great deal	59%	63%	68%
Policy Support	Support funded research into renewable energy sources	77%	81%	80%
	Support the regulation of CO_2 as a pollutant	66%	71%	74%
	Support strict CO_2 limits on existing coal-fired power plants	46%	63%	68%
	Support the requirement of utilities to produce 20% electricity from renewable sources	56%	62%	65%
Behaviors	Never discuss global warming	74%	70%	64%

SECTION 3. AUDIENCES

The CS-NE outreach plan defines eight basic audiences: potential project partners, landowners, media, officials, educators, general public, technical groups, and environmental NGOs. A preliminary breakdown for audiences and subgroups is presented in Table 3-1. This list is a starting point for determining the amount and type of outreach for each of the potential stakeholder audiences.

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Table 3-1. Description of Major Stakeholder Groups

Stakeholder	Description	Identification Strategies
Project Partners	• Managers working with projects on outreach and board members of the partner company • Current and retired employees • Partner customer/members (cooperative) or customer base arranged by category of relationship, method of engagement • Industry sector peers (e.g., other ethanol plants, grower associations, advocacy groups)	• State, county, and community Web sites • Local phone books • Interviews with stakeholders in this category • Local newspapers
Landowners	• Local	• Local outreach team members • Town or county clerks, surveyors • Industry partners
Media	• Print media – national, regional, and local • Radio – national, regional, and local • Television media – national, regional, and local • Web media – project partners, commercial media, Facebook, and independent bloggers	• Federal and state Web sites or directories • Stakeholder interviews
Officials	• Elected – national, state, county, and municipal • Nonelected/regulatory – federal, state, county, and local	• Federal, state, county, and community Web sites or directories • Local phone books • Interviews with stakeholders in this category • Local newspapers
Educators	• Regional, state, local, and project area	• State and local boards of education • Community colleges • National Center for Education Statistics
General Public	• Regional, state, local, and project area	• State, county, and community Web sites • Local phone books • Interviews with stakeholders in this category • Local newspapers
Technical Groups	• DOE Regional Carbon Sequestration Partnerships (RCSPs) such as the EERC's Plains CO_2 Regional (PCOR) Partnership • International Energy Agency Greenhouse Gas R&D Programme (IEAGHG) • Other energy and/or carbon capture and storage groups	• Federal and state Web sites or directories • Web site reviews
Environmental NGOs	• International, national, regional, state, and local	• Stakeholder interviews at local level • Web site reviews • Local newspapers • Local outreach team members

SECTION 4. NARRATIVE, THEMES, AND MESSAGES

Having a single coherent story is essential to create an effective, informed team that can act as knowledgeable spokespeople for a potential CCS project. The story needs to be consistent whether presented as a one-sentence sound bite, a paragraph synopsis, or a project fact sheet. As shown in the examples below, the messages are intended as a foundation for expansion and customization as needed over the course of the project.

4.1 Product 1 – CS-NE Sound Bite Sentence (Version 001; DRAFT EXAMPLE)

The CarbonSAFE-Nebraska research project is investigating the potential for the capture and safe, permanent, geologic storage of carbon dioxide from Nebraska Public Power District's coal-fired Gerald Gentleman electricity generation station.

4.2 Product 2 – CS-NE One-Paragraph Description (Version 001; DRAFT EXAMPLE)

The CarbonSAFE-Nebraska research project is assessing the technical and economic feasibility of integrating carbon capture and storage with Nebraska Public Power's coal-fired Gerald Gentleman Station in Sutherland, Nebraska. The study is investigating the feasibility of carbon capture and the suitability of injection and safe, permanent storage of the captured CO_2 *in deep rock layers in southwestern Nebraska. The _______, a _________ rock layer located approximately ____ feet below the surface in the area, has shown the most promise as a storage layer. The project is funded by _________and managed by the Energy & Environmental Research Center (EERC) in collaboration with Nebraska Public Power. The project coordination team includes a number of Nebraska entities, including … For more information, contact Neil Wildgust, Project Manager, EERC, nwildgust@undeerc.org, 701-777-5000, or John Swanson, Nebraska Public Power.*

4.3 Product 3 – CS-NE One-Page Detailed (Version 001; DRAFT EXAMPLE)

1. *The CarbonSAFE-Nebraska research project is assessing the technical and economic feasibility of integrating carbon capture and storage with Nebraska Public Power's coal-fired Gerald Gentleman Station in Sutherland, Nebraska.*

2. *Carbon capture and storage (CCS) is the practice of capturing* CO_2 *emissions from an industrial facility before the emissions are released to the atmosphere and then transporting the* CO_2 *to a site for safe, permanent storage deep underground. Commercial technologies to capture and separate* CO_2 *emissions already exist, and* CO_2 *injection is currently practiced in 150 locations in the United States alone.*

3. *The CarbonSAFE Nebraska research project is looking at the technical case and the business case for implementing CCS in western Nebraska. Previous general assessments showed promising results of technical and economic viability. The current phase of research will further refine the regulatory, processing, and financial requirements for CCS implementation, improving the pathway toward commercial success.*

4. *The technical case investigation is focused an determining the compatibility of the Gerald Gentleman facility to CO_2 capture technology and an initial assessment of the geology deep underground in the region for the safe, permanent storage of CO_2 captured from the station. To be successful, the business case must show that the capital and operation costs are acceptable and balance against the potential environmental gains and the bottom line costs to Nebraska consumers.*

5. *Geologic CO_2 storage requires a deep porous rock layer to hold the CO_2 and overlying impermeable rock layers as a seal. According to regional studies conducted by the Energy & Environmental Center (EERC), the ___________, a ________ rock layer located approximately ___ feet deep in southwestern Nebraska, is promising as a storage target. This is the rock layer that is the focus of investigation in the CarbonSAFE-Nebraska project.*

6. *Funding for the project is from _________. The Energy & Environmental Research Center in Grand Forks, North Dakota, manages the project in collaboration with Nebraska Public Power. The advisory group includes representatives of _________.*

7. *The project will run from ___ to ___. If results are promising, the next phase of research would include ________________.*

8. *For more information, contact Neil Wildgust, Project Manager, Energy & Environmental Research Center, nwildgust@undeerc.org, 701-777-5000, or John Swanson, Nebraska Public Power District.*

Based on the regional socioeconomic and environmental analysis of the five-county study area (Figure 2-1), the outreach team developed themes and relevant messages and responses, which are organized in the following tables:

- Table 4-1. Example: Societal Concerns and Outreach Attributes
- Table 4-2. Example: Land Considerations and Outreach Attributes
- Table 4-3. Example: Water and Outreach Attributes
- Table 4-4. Example: Energy and Outreach Attributes
- Table 4-5. Example: General Considerations and Outreach Attributes

Table 4-1. EXAMPLE: Societal Concerns and Outreach Attributes

	Character/Concern	Attribute/Response
1	Close-knit society, local focus, long-standing relationships	NPPD is a publically owned company dedicated to service Nebraska communities and stakeholders and with long ties to region and community Consistent, clear, concise, accurate narrative told in the same way to all people in the community over time, officials to landowners to students to general public; narrative features: project highlights, goal, time line, cost/benefit Proactive, early, respectful, open, transparent process in keeping with RCSP best practices Landowner interactions using best practices (introductions, personal visits, follow-up)
2	Available and known in the community	NPPD is a homegrown company dedicated to service to Nebraska stakeholders and with long ties to community First impression is the impression: proactive, early, respectful, open, transparent communication in keeping with RCSP best practices Work with key regional and local officials (county commission, metro, planning groups, chamber, local organizations) in keeping with RCSP best practices Be physically present in the community on a regular basis to provide opportunities for constructive interaction Landowner interactions using best practices (introductions, personal visits, follow-up)
3	Components of CCS technology infrastructure are unfamiliar and new to stakeholders	NPPD is a homegrown company dedicated to service to Nebraska stakeholders and with long ties to region and community CS-NE is committed to a proactive, respectful, open, transparent engagement process in keeping with RCSP best practices CS-NE is committed to understanding and responding to concerns, both in informal settings and in formal hearings for permits and actions, should we reach that step

Table 4-2. EXAMPLE: Land Considerations and Outreach Attributes

	Character/Concern	Attribute/Response
1	Land is the basis of the local, state, and regional economy.	Accurate statements on the impacts/benefits to land • Pipeline and other infrastructure right of way will affect land use (compensation). • Pipeline will disturb land during construction (compensation). • Monitoring, verification, and accounting (MVA) reduces risk for leaks and failures and is thus required for obtaining permits for injection wells and their operation. • If leaks and failures happen, no permanent impact to land (compensation).
2	County and municipal plans have provided general development guidelines.	• Review and assess attributes in relation to state, county, and municipal plans/permits.
3	Concerns about land damage have been exacerbated by the Keystone Pipeline.	• NPPD is a homegrown company dedicated to service to Nebraska stakeholders. • No infrastructure at this investigation phase. • CO_2 pipelines are not oil pipelines; if leaks and failures happen with CO_2, the CO_2 enters the air, and there are no permanent impacts to air, land, or water. There will be compensation for landowner inconvenience. • State-of-the-art MVA techniques minimize risk of leaks/failures. • If we reach that step, CS-NE is committed to working with landowners to minimize inconvenience from periodic operation needs and issues.

Table 4-3. EXAMPLE: Water and Outreach Attributes

	Character/Concern	Attribute/Response
1	Nebraska agriculture, especially in the west, depends on irrigation.	• NPPD is required by law to supply lowest-cost power possible to consumers. • CS-NE supports coal-fired power; this is dispatchable, dependable, and affordable. • Dispatchable, dependable, affordable power is critical to irrigation and other agricultural needs. • NPPD is investigating all possible options for dependable affordable power to fulfill its mandate to Nebraska consumers. • NPPD has history of working with stakeholders, including irrigation customers, to ensure dependable affordable power.
2	Ogallala is exposed at the surface – so “the land is the aquifer” in Nebraska.	If we reach that step, CS-NE is committed to working with landowners to minimize inconvenience from installation and operation. • Pipeline and other infrastructure right of way will affect land use (compensation). • Pipeline will disturb land during construction (compensation). • MVA reduces risk for leaks and failures. CO_2 pipelines are not oil pipelines; if leaks and failures happen with CO_2, the CO_2 enters the air and there are no permanent impacts to air, land, or water. There will be compensation for landowner inconvenience during pipe repair and maintenance.

Table 4-4. EXAMPLE: Energy and Outreach Attributes

	Character/Concern	Attribute/Response
1	Dependable, affordable electricity is critical for irrigation.	• NPPD is required by law to supply lowest-cost power possible to consumers. • CS-NE supports coal-fired power; this is dispatchable, dependable, affordable. • Dispatchable, dependable, affordable power is critical to irrigation and other agricultural needs. • NPPD is investigating all possible options for dependable affordable power to fulfill its mandate to Nebraska consumers. • NPPD has history of working with stakeholders, including irrigation customers, to ensure dependable affordable power.
2	CS-NE is supporting the continued use of polluting coal, a fossil fuel, for electricity generation. Nebraska should support renewable sources like wind and solar not fossil energy like coal.	• NPPD is required by law to supply lowest-cost power possible to consumers. • CS-NE supports coal-fired power; this is dispatchable, dependable, and affordable. • Dispatchable, dependable, affordable power is critical to irrigation and other agricultural needs. • NPPD is investigating all possible options for dependable affordable power to fulfill its mandate to Nebraska consumers. • NPPD has history of working with stakeholders, including irrigation customers, to ensure dependable affordable power.
3	GGS is emitting conventional pollutants and CO_2 (largest point source for CO_2 in Nebraska).	CS-NE is investigating a safe, permanent, and practical deep storage of CO_2 emissions for GGS. This will allow Nebraska to have the benefits of dependable affordable power and improved air quality, reduced climate emissions, and a cleaner environment.

Table 4-5. EXAMPLE: General Considerations and Outreach Attributes

	Issue	CS-NE Outreach Attribute
1	Funding agency (DOE) has national-level policy goals, program goals, and legal and technical requirements.	Outreach strategy and communication plan put project in global and regional context of CCS, outreach program based on DOE RCSP outreach best practices, seamless outreach continuum from DOE's RCSP program into DOE's multiyear CarbonSAFE Program.
2	Industry partners have stakeholders, legal requirements, and business interests.	Strategy and plan reflect industry partner considerations, positions, and intentions through central consensus-based outreach model featuring collaboration between core EERC outreach project team (Task 2) and Outreach Advisory Board (project partner representatives).
3	Public stakeholders have personal and community-based concerns over economics, safety, and quality of life.	Community-based concerns addressed in outreach strategy and communication plan informed by social characterization research of published data and information augmented with audience focus groups and interviews (TBD) and interviews with partner and EERC outreach and technical personnel.
4	Audiences have differences in geographic distribution, relation to project, concerns, and engagement styles.	The outreach strategy and communication plan is designed to address concerns for each group using timing, formats, language, and approaches that optimize the potential for exposure to, and uptake of, project information.
5	The transportation and storage parts of CCS projects often occur in greenfield areas	The outreach plan is designed to be proactive and to establish and maintain relationships with partners and public stakeholder audiences from project inception, through field activities, and through the announcement of results.
6	Feasibility project may be the first step in a multiyear process leading to a commercial-scale venture (or not).	The outreach plan provides a foundation for follow-on outreach related to future CCS project phases, if warranted.
7	CCS projects have a number of components that occur in the public sphere and call for public input (e.g., permits, infrastructure installation, sampling, infrastructure operations)	The outreach plan is designed to be proactive and to establish and maintain relationships with partners and public stakeholder audiences from project inception, through field activities, and through the announcement of results.

SECTION 5. AUDIENCE ENGAGEMENT STRATEGIES

Approximately 20 outreach strategies were identified for the CS-NE effort. The strategies cover seven audiences and offer opportunities for engagement over the course of a potentially multiphase effort. The audiences represented in Tables 5-1–7 (see Section 3) include the following:

- Table 5-1. Example: Project Partner and Peer Audiences vs. Engagement Methods and Partner Roles
- Table 5-2. Example: Media vs. Engagement Methods and Partner Roles
- Table 5-3. Example: Officials vs. Engagement Methods and Partner Roles
- Table 5-4. Example: Educators/Students vs. Engagement Methods and Partner Roles
- Table 5-5. Example: General Public (including Project Area Landowners) vs. Engagement Methods and Partner Roles
- Table 5-6. Example: CCS and Other Technical Groups vs. Engagement Methods and Partner Roles
- Table 5-7. Example: Environmental Nongovernmental Organizations vs. Engagement Methods and Partner Roles

These strategies would be used as a basis to populate the outreach time line. *Note: more detailed description for select strategies and individual campaigns related to specific activities on the time line would be developed in future phases based on this framework.*

Table 5-1. EXAMPLE: Project Partners and Peer Audiences vs. Engagement Methods and Partner Roles

Strategy	Internal Working Group/ Advisory Session	Presentation to Internal Partner Audiences	Partner-Based Social Media, Newsletter, Web Site, or Trade Publication	External Meetings
Project Outreach Advisors	• Internal project kickoff meeting • Planned Outreach Advisory Board Webinars and meetings over course of the project	–	–	–
Senior Managers	• Internal project kickoff meeting • Planned Outreach Advisory Board Webinars and meetings over course of the project	–	–	–
Board Members	–	• Presentation by project technical team member at partners' annual meetings	–	–
Active Employees	–	• Presentation by project technical team member or partner managers using outreach presentation for internal meetings	• Community open house invitations and information blurbs on employee-targeted social media	–
Retired Employees	–	–	• Community open house invitations and information blurbs on social media	–
Cooperative Member and/ or Consumers	–	• Presentation by project technical team member at partner annual meetings	• Partner project summary to members using newsletter or social media • Community open house invitations and information blurbs on internal and external social media	–
Industry Peers	–	–	• Monthly social media updates to industry peers by partner or outreach team	• Internal project kickoff meeting • Planned Outreach Advisory Board Webinars and meetings over course of the project

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Table 5-2. EXAMPLE: Media vs. Engagement Methods and Partner Roles

Strategy	Outbound from Project EERC Press Release, Media Advisory	Response/Inbound from Media Interview with Media; Media Site Visit, Media News Story	Outbound from Project EERC/Partner News Article, Announcement, Op Ed
Print News Media	• EERC press release or media advisory for CS-NE funding • EERC press release or media advisory for CS-NE project milestones (e.g., field activity, permit, government action, project announcement) over course of the project	EERC/partner response to inquiry (press kit materials)	For example, community open house, paid announcement
Radio News Media	• EERC press release or media advisory for CS-NE funding • EERC press release or media advisory for CS-NE project milestones (e.g., field activity, permit, government action, project announcement) over course of the project	EERC/partner response to inquiry (press kit materials)	–
Television News Media	• EERC press release or media advisory for CS-NE funding • EERC press release or media advisory for CS-NE project milestones (e.g., field activity, permit, government action, project announcement) over course of the project	EERC/partner response to inquiry (press kit materials)	–
Web	• Post content on the Web page as appropriate	–	• Update the CS-NE Phase I project page in the PCOR Partnership Public Web site. • Weekly EERC blurbs on EERC social media, e.g., Facebook, Twitter, Instagram, YouTube • Partner Web posts, e.g., Web site, Facebook, Twitter, YouTube
Trade Press	• Partner or EERC articles in industry trade publications, as appropriate	–	–

Table 5-3. EXAMPLE: Officials vs. Engagement Methods and Partner Roles

Strategy	One on One, Individual	Testify or Present to Board, Small Group	Presentations to Conferences, Meetings
National Elected	• Letter invitations to project event like community open houses, groundbreaking, announcement	–	–
State Elected	• Letter invitations to project event like community open houses, groundbreaking, announcement	–	• Attendance and/or booth or presentation at Western Governors Association
County Elected	• Letter invitations to project event like community open houses, groundbreaking, announcement	• Project introduction and periodic project updates	–
Municipal Elected	• Letter invitations to project event like community open houses, groundbreaking, announcement	• Project introduction and periodic project updates	• Update the CS-NE Phase I project page in the PCOR Partnership public Web site. • Weekly EERC blurbs on EERC social media, e.g., Facebook, Twitter, Instagram, YouTube • Partner Web posts, e.g., Web site, Facebook, Twitter, YouTube
National Regulatory	–	–	–
State Regulatory	• Inquiries on seismic permits • Inquiries on drilling permits	• Hearing/testimony/presentation of permit application for seismic • Hearing/testimony/presentation of permit application for drilling/coring	–
County Regulatory	• County permit forms	• Permit applications and approvals from counties (drilling)	–
Municipal Regulatory	• Municipal permit forms	–	• Attendance and/or presentation Nebraska League of Municipalities

Table 5-4. EXAMPLE: Educators/Students[1,2] vs. Engagement Methods and Partner Roles

Strategy	One on One, Individual	Educator Conference Presentations	Classroom Presentations, Site Tours, Displays	Curricula, Classroom Materials
Regional	–	• Include project materials in presentation at regional teacher workshops	–	–
State	–	–	–	–
District	• Invitation to community open house event	–	–	–
Local	• Invitation to community open house event • Contact with local principals and teachers to discuss possible activities	• Provide a breakout session at a state teacher conference	• Presentations, workshops, site tours for classes or individual students	• Develop local curricula or classroom activity related to the project and involving project personnel as mentors • Student projects mentored by project personnel
Extension	–	–	–	–

[1] Additional primary through EERC blog blurbs sent monthly (includes government officials).
[2] Secondary through news media (radio, television, and print and their Web sites).

Table 5-5. EXAMPLE: General Public (including Project Area Landowners)[1,2] vs. Engagement Methods and Partner Roles

Strategy	Media, Web Pages, Announcements, Invitations, Local Displays	Community Open House	Presentations to Groups and Social Clubs	Focus Groups
Regional[2]	• Web pages and news media coverage[2]	–	–	–
State[2]	• Web pages and news media coverage[2]	–	–	–
Local[2]	• Individual contact with landowners in association with project technical activities • Paid announcement in the local papers regarding community open house; Facebook-boosted invitations to local residents • Web pages and news media coverage[2]	• Community open house event announcements, event, follow-up news media coverage.	TBD	TBD
Project Area Landowners	• Focused statements or pieces in news media, Web, etc.	• Targeted meetings for landowners involved in project activities	–	–

[1] Additional primary through EERC blog blurbs on social media, signage on fieldwork sites.
[2] Secondary through news media (radio, television, print, and their Web sites)

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Table 5-6. EXAMPLE: CCS and Other Technical Groups[1,2] vs. Engagement Methods and Partner Roles

Strategy	Contractor Meeting	Presentation or Poster at Technical Conference, Proceedings	Refereed Journal Article	Working Group or Task Force
DOE	• Periodic contractor meetings	TBD	–	TBD
IEAGHG	–	• IEAGHG, GHGT,[3] other, TBD	TBD	–
State Regulators	TBD	TBD		

[1] Additional primary through EERC blog blurbs sent monthly (includes government officials).
[2] Secondary through news media (radio, television, print, and their Web sites)
[3] Greenhouses gas technologies.

Table 5-7. EXAMPLE: Environmental Nongovernmental Organizations[1,2] vs. Engagement Methods and Partner Roles

Strategy	Presentation or Poster at Technical Conference, Proceedings	Working Group or Task Force	Direct Contact/Discussions/ Dialogue	Other
International	TBD	–	–	–
National	TBD	• Discussion with NGOs through the DOE RCSP Outreach Working Group	–	–
Regional	TBD	TBD	TBD	–
State	TBD	• Targeted meetings for landowners involved in project activities	TBD	–
Local	TBD	–	TBD	–

[1] Additional primary through EERC blog blurbs sent monthly (includes government officials).
[2] Secondary through news media (radio, television, print, and their Web sites).

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SECTION 6. OUTREACH TOOL KIT

The table below contains a list of the types of materials that would be developed in consultation with the project managers, NPPD, the core outreach team, and advisors. These materials would incorporate the outreach themes and messages to an appropriate degree and be tailored to the target audience identified in the strategy section.

Table 6-1. EXAMPLE: Summary Listing of Materials in CS-NE CCS Outreach Tool Kit

Category	Item	Status[1]
	Outreach Components	
Approved Language	Project summary sentence	DE
	Project summary paragraph	DE
	Two-page project summary	DE
Building Blocks	Project logo (TBD)	TBD
	Standard header and footer	TBD
	2-D simplified geologic column graphic	TBD
	Study area map graphic	TBD
	Seismic survey graphic	TBD
	3-D simplified geologic column graphic	TBD
	Casing layers graphic (characterization well)	TBD
	Drilling, coring, and logging photographs (characterization well)	TBD
	Before and after site photographs (characterization well)	TBD
	Capture equipment images/schematic	TBD
	CO_2 generation to injection/storage schematic	TBD
	Formal Products	
Fact Sheets	CarbonSAFE-Nebraska – A Feasibility Study	TBD[a]
	CarbonSAFE-Nebraska (future phase updates)	TBD
Activity FAQs	TBD	TBD
Web Content[2]	"CarbonSAFE-Nebraska" Web page http://undeerc.org/PCOR/CO2SequestrationProjects/CarbonSAFE-NE.aspx	Final
	Project location map with project fast facts text http://undeerc.org/PCOR/CO2SequestrationProjects/	Final
	Future blog/newsletter articles	TBD
Project Presentations	Technical audience presentation	TBD
	Partner employee/general audience presentation slide deck	TBD
	Partner employee/general audience presentation script	TBD
	Secondary classroom presentation	TBD
Community Events	Event welcome banner	TBD[a]
	Event station title signs	TBD[a]
	Event directional signs	TBD[a]
	Sign-in sheet	TBD[a]

[1] Definition of status categories:
- DE – draft example
- Final: item has been completed and approved; if appropriate, item may be updated in future phases.
- TBD: content would be determined based on needs of future phases.
  - TBD[a]: templates developed under other projects are available.

[2] Items housed on PCOR Partnership public Web site.
[3] This is a possibility for consideration.
[4] Media kit is customized to fit the request, contains images and background.

Continued . . .

Table 6-1. EXAMPLE: Summary Listing of Materials in CS-NE CCS Outreach Tool Kit (continued)

Category	Item	Status[1]
Community Events (cont.)	Outreach posters, example topics: • Energy with a Smaller Carbon Footprint • Reasons to Investigate Carbon Capture and Storage • Investigating Geology for CO_2 Storage Potential • Geologic Feasibility – Evaluating the Character and Performance of the Storage Zone • CCS – Investigating Dedicated CO_2 Storage for Nebraska CarbonSAFE-Nebraska – *Local Project with National Implications*	TBD[a]
	CarbonSAFE-Nebraska event handout; example topic: *Investigating Dedicated CO_2 Storage for Nebraska*	TBD[a]
Feedback Forms	School classroom and field activities feedback form	TBD[a]
	Event comment card	TBD[a]
Fieldwork	Site signage (sample)	TBD[a]
	Landowner letter (sample)	TBD[a]
Social Media	Social media posts to drive content to Web site information about the project	TBD[a]
	Open house Facebook events	TBD[a]
	EERC channels: Facebook, Twitter, Instagram, YouTube	TBD[a]
	Partner channels	TBD
Video[3]	Video short(s) (examples available in clip library on PCOR Web site)	TBD
Media Kit[4]	Items from the above Outreach Tool Kit contents selected as appropriate for the request; typically include news releases, project fact sheets, and photos.	TBD

[1] Definition of status categories:
- DE – draft example
- Final: item has been completed and approved; if appropriate, item may be updated in future phases.
- TBD: content would be determined based on needs of future phases.
  – TBD[a]: templates developed under other projects are available.

[2] Items housed on PCOR Partnership public Web site.
[3] This is a possibility for consideration.
[4] Media kit is customized to fit the request, contains images and background.

SECTION 7. OUTREACH TIME LINE

Outreach activities should coordinate with and, in most cases, precede technical activities (ideally by 3–4 months) in order to provide timely information, maintain transparency, and establish trust with target audiences. Outreach should also anticipate and continually prepare to meet the information needs of target audiences.

The outreach time line shown in Table 7-1 is an example. The actual time line for any future project activities would be populated based on an assessment of the particular project phase in consultation with NPPD, the project's coordination team, and the project technical leads. Where appropriate, the outreach time line would be organized into campaigns that match key technical project, regulatory, market, or business actions. A continuous time line over the three phases of CarbonSAFE program as well as CCS operations is recommended. The time line is, therefore, a living or open document that would be revised and updated as needed in consultation with project managers, advisors, and partners.

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Table 7-1. EXAMPLE: Sample Time Line for Outreach Activities Related to Drilling a Stratigraphic Test Well (strat-test)

Month	Technical/Project Actions	Example Outreach Actions
1	Planning meeting(s)	• Hold stratigraphic characterization test well (strat-test) planning session: – Review the technical time line. – Present draft outreach time line. • Discuss and come to agreement on initial plan and time line for strat-test outreach campaign. • Implement agreed upon outreach plan and time line for the campaign featuring fact sheet(s), slide deck(s), public presentation(s), press release(s), social media updates, a community open house, and drill site tours for select audiences. • Initiate contact with school district to invite teachers to participate in classroom activities and/or drill site tour; prepare a schedule for developing classroom activities that add value to the experience. • Finalize/approve 1-page strat-test fact sheet describing related activities. • Update CS-NE fact sheet as needed to reflect current project phase for public audiences.
2	State drilling permit prepared	• Schedule presentations: – County commission – NRDs – Municipal government – School principal or school board • Commence community open house preparations: – Logistics – Content for posters, handouts, comment sheets – Designated project personnel (scheduling and travel) • Prepare initial draft materials for open house and drill site signage. • Brief partner employees (partners assisted by project team as needed); use approved slide deck, project fact sheet, and strat-test fact sheet. • Continue to engage teachers interested in classroom activities/drill site tour.

Continued . . .

Actual time lines would be populated based on assessment of the particular project phase in consultation with the CarbonSAFE-NE coordination team, outreach task team, and project management.

Table 7-1. EXAMPLE: Sample Time Line for Outreach Activities Related to Drilling a Stratigraphic Test Well (strat-test) (continued)

Month	Technical/Project Actions	Example Outreach Actions
3	State drilling permit (minimum of 30 days for approval) submitted	• Give initial presentation (possible invite to drill site): – County commission – NRDs – Municipal government – School board/schools • Disseminate press release on the project, the strat-test, presentations, time line, and upcoming community open house. • Finalize open house logistics and materials and drill site signage. • Collaborate with teachers on classroom activities to be carried out in conjunction with the open house and/or drill site tour.
4	State drilling permit process proceedings	• Send community open house invitations: – By letter to key groups (government officials, school officials, community leaders) – Partner employee invitations – Advertisement in the paper • Print final open house materials and drill site signage. • Continue to engage teachers interested in classroom activities/drill site tour.
5	State drilling permit approved Drill site preparation (dirt work, pad installed, equipment installed)	• Hold community open house event: – Materials: posters, handouts, signage, comment sheets – Refreshments – CS-NE project personnel/partners at open house stations • Debrief on the event with project personnel and review written comment sheets. • Send out press releases on open house, upcoming drilling, and sampling. • Install site drilling signage.
6	Rig setup, active drilling, geologic sampling, and geophysical logs Drilled hole plugged and pad removed	• Update drill site signage as drilling progresses. • Provide drill site tours for community leaders, decision makers, and school classes. • Implement classroom activity related to project; debrief project personnel and teachers. • Schedule presentations to county and municipal government. • Disseminate press story on tours and/or school activities; time line for project and when results expected.
7	Results evaluation and reporting	• Schedule update presentation: – County commission – NRDs – Municipal government

SECTION 8. OUTREACH TRACKING AND EVALUATION PROCESS

Assessing the effectiveness of communication to reach the targeted audience and generate a positive response is critical to the success of any outreach campaign. The assessment attempts to determine whether the target audience heard the message, how the message was perceived, and what changes in the audience resulted. Evaluation also facilitates continued improvement to materials and guidance for ongoing and/or future activity development.

For the CS-NE outreach effort, all outreach activities and materials will be conceived of, developed, distributed or implemented, and evaluated within the formal evaluation process. The components of strategies (Section 5) and products (Section 6) will be individually documented, characterized, and evaluated against defined measures of success. Feedback and lessons learned will be incorporated into product updates and/or subsequent events and activities and laid against the measures of success.

As shown in Table 8-1, the process would involve three stages (Macnamara, 2016):

- Inputs – What happens before and during the activity by the project team?
- Outputs – What is delivered, when/where/how, and to whom (target audience)?
- Outcomes – What are the results of outreach on target audiences?

Table 8-1. EXAMPLE: Future Project Outreach Process Framework

Stage	Item	Method/Action	CS-NE Phase II
Inputs	Product(s)/material(s) development and production, activity conception and execution	Research audience(s), create and produce materials, develop and implement activities (incorporating any lessons learned from previous campaigns)	Social characterization; discussions with team, advisors, and stakeholders (including program experience); data management of material/activity versions
Outputs	Product distribution, activity reach	Track number and location of products/activities, types of audiences exposed and reached, etc.	Track Web visits, news stories, product distribution, presentations, etc.; record feedback; quarterly review and reporting
Outcomes	Impact on audience knowledge or outlook	Evaluate changes in knowledge/outlook	Assess knowledge level and nature (positive/negative) of news stories, feedback, etc.; develop lessons learned for future outreach

8.1 Inputs – Outreach Planning and Production

Inputs cover all the pertinent information and action required to create materials and/or develop activities for a particular outreach campaign (e.g., planning materials for an open house and holding the open house). Inputs thus take the form of any discussions within the EERC team, as well as with CS-NE project partners/Coordination Team. They include the research and development of materials and/or an activity concept. The manner in which materials are disseminated and activities executed is also an important component of the Inputs step.

Once public outreach is initiated, the Inputs step will incorporate a feedback element. Feedback solicited during and following presentations and for individual outreach products as part of the Outputs step and assessed in the Outcomes step (discussed further in the sections below) will be used as Inputs for subsequent campaigns. These inputs are evaluated with other lessons learned and may be used to update materials and/or improve activities and overall messages. Proper record keeping and data management at this step is imperative to reference decisions made on research results, discussions, and lessons learned from previous outreach campaigns.

8.2 Outputs – Tracking and Documentation

The Outputs step involves documenting and categorizing all strategies to reach and educate the intended audience. Categories include documenting the development path, update history, distribution or degree of visibility and, in select cases, outcomes. The EERC outreach team has an established three-pronged system of tracking outreach responses: direct feedback from target audiences during or following a campaign, external media occurrences, and online social media activities. The breadth and depth of tracking will be determined in discussion with CS-NE project partners/Coordination Team during the Inputs step.

Direct outreach tracking uses standardized forms that describe the action, event, or activity of an outreach campaign; list the products distributed; characterize the audiences; and compile any immediate feedback received. All data collected are stored in an isolated outreach-tracking database that produces standardized reports. The tracking software has a GIS component to generate thematic maps that display outreach activities by region. If deemed appropriate by the project partners/Coordination Team, results could also be placed within the regional context developed during the PCOR Partnership project.

Media coverage is defined as reports or articles related to the CS-NE effort covered on external outlets such as television or radio or found in newspapers or magazines, including both print and online news sources. Nikki Massmann, EERC Director of Communications, will track information on media releases, inquiries, stories, and interviews and gather information on the character of the response.

A CS-NE project Web page is currently hosted on the EERC's PCOR Partnership Web site. For the EERC's Web pages, Google Analytics Universal is used to track and assess Web activity. This free Google product provides standardized data analysis on user interaction and is capable of limited customized research. Social media posts from the EERC and project partners will also be incorporated in the database.

8.3 Outcomes – Assessment of Impacts on Audience Attitudes or Behaviors

The final step of the outreach evaluation process is the Outcomes stage, which assesses the Outputs tracked and, therefore, the success of the outreach campaign. Outcomes consider the target audience's frequency and level of engagement, as well as the quality of interaction and feedback. These results are then evaluated against established measures of success, as shown below:

- Neutral to positive public results among stakeholder groups based on qualitative and semiquantitative feedback obtained from the Outputs step.
- Overall neutral to positive coverage by media based on content assessment of published stories and radio/television pieces.
- Maintaining a continual level of communication about the project through primary (direct interaction with audiences) and secondary pathways (e.g., number, content, and frequency of news media print stories).
- Positive assessment of outreach performance during period reviews from the project partners, managers, and advisors.

Lessons learned will be generated from the results of this assessment by the outreach team, to be shared and discussed with the project partners/Coordination Team. As mentioned previously, these findings will then be used to improve materials, activities, and/or overall messages for subsequent outreach campaigns. All results will be stored in the isolated outreach data management system.

It is important to note that the EERC's outreach approach is focused on exposing stakeholders to information, characterizing the distribution of the information and using qualitative informal measures to assess the state of outreach. In keeping with this approach, the EERC currently does not plan to define an opinion baseline and assess attempts at information transfer overall or for an audience segment within a particular stakeholder group or area. If it is deemed pertinent by the project partners/Coordination Team to establish a formal baseline through surveys or focus groups to measure impact, that will be discussed by the team during the Input step of an outreach campaign.

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APPENDIX B

COORDINATION TEAM MEETINGS

CarbonSAFE-Nebraska Project Kickoff Meeting

Chancellor Meeting Room – Embassy Suites
Lincoln, Nebraska
Tuesday, July 18, 2017

Presented by:

Energy & Environmental Research Center (EERC)
Nebraska Public Power District (NPPD)

Time	Presentation/Activity	Presenter
10:00 a.m.	Welcome Introductions Meeting Goal Agenda Preview	John Swanson, NPPD Kerryanne Leroux, EERC Joe Citta, NPPD
10:20 a.m.	Introduction to Carbon Capture and Storage (CCS)	Neil Wildgust, EERC
10:45 a.m.	CarbonSAFE-Nebraska Project Overview	Kerryanne Leroux, EERC John Meacham, NPPD
11:20 a.m.	BREAK	
11:30 a.m.	NPPD and CCS: What We Have Done and Why	Joe Citta, NPPD John Swanson, NPPD
12:15 p.m.	LUNCH	
1:00 p.m.	Your Point of View – Facilitated Discussion	Dan Daly, EERC
2:20 p.m.	Next Steps and Action Items	Kerryanne Leroux, EERC John Swanson, NPPD
2:30 p.m.	ADJOURN	

CarbonSAFE-Nebraska
Coordination Team Meeting

Regents C Meeting Room – Embassy Suites
Lincoln, Nebraska
Thursday, May 3, 2018

Presented by:
Energy & Environmental Research Center (EERC)

TIME	PRESENTATION/ACTIVITY	DISCUSSION LEADER
10:00 a.m.	Welcome Introductions Meeting Goal Agenda Preview	Neil Wildgust, EERC John Swanson, NPPD
10:15 a.m.	CarbonSAFE-Nebraska Phase 1: Task 2 Update Task 3 Update Task 4 Update	 Charlene Crocker, EERC Melanie Jensen, Nick Kalenze, EERC Matt Burton-Kelly, EERC
11.15 a.m.	**BREAK**	
11:30 a.m.	Summary of Phase 1: Key Findings and Conclusions	Neil Wildgust, EERC
12:00 Noon	CCS Update	John Swanson, NPPD
12:30 p.m.	**LUNCH**	
1:30 p.m.	CarbonSAFE Phase 2 Activities: CarbonSAFE North Dakota – Active Project Midcontinent – Proposal	Neil Wildgust, EERC
2:00 p.m.	Discussion, Questions, Feedback	All
2:50 p.m.	Wrap-Up	Neil Wildgust, EERC John Swanson, NPPD
3:00 p.m.	**ADJOURN**	John Swanson, NPPD

CarbonSAFE-Nebraska

Integrated Carbon Capture and Storage Pre-Feasibility Study

Coordination Team Meeting
May 3, 2018
Lincoln, Nebraska

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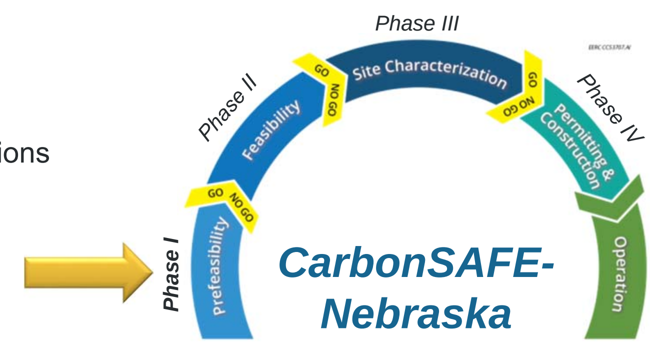
Critical Challenges. **Practical Solutions.**

Pre-Feasibility: Does geologic storage of CO_2 emissions have the potential to be practicable in Nebraska?

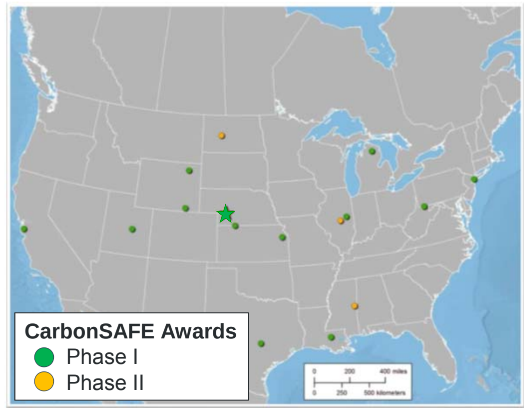
- Geology
- Economics
- Regulations and policy
- Social and environmental considerations



Critical Challenges. **Practical Solutions.**

CarbonSAFE Projects

- First proposal round: August 2016
  - 13 Phase I (pre-feasibility) awards
  - Three Phase II (feasibility) awards
- Second proposal round: February 2018
  - Three additional Phase II awards
- Future proposal rounds: TBD
  - Phases III and IV



CarbonSAFE-Nebraska Phase I

- Goal: Determine the conceptual feasibility of CO_2 capture from NPPD's Gerald Gentlemen Station (GGS) with subsequent geologic storage
- Objectives
  - Establish a CCS coordination team
  - Identify challenges to commercial-scale CCS in western Nebraska, and develop potential solutions
  - Conduct conceptual evaluations:
    - ♦ Western Nebraska subsurface for geologic storage
    - ♦ CO_2 emissions from GGS for potential capture

Assessment of existing data and information.
No fieldwork. No injection. No public engagement.

Regional and Stakeholder Analysis

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Critical Challenges. **Practical Solutions.**

Accomplishment 1
Engaged and Involved Key Stakeholders*

1

- Project Kickoff Meeting (July 2017)
- Project Coordination Team formed (August 2017)
- Coordination Team update Webinars
  - November 2017
  - February 2018
- Coordination Team Project Results Meeting (today)

** Representatives of the organizations that provided letters of support to the Phase 1 CS-NE project proposal*

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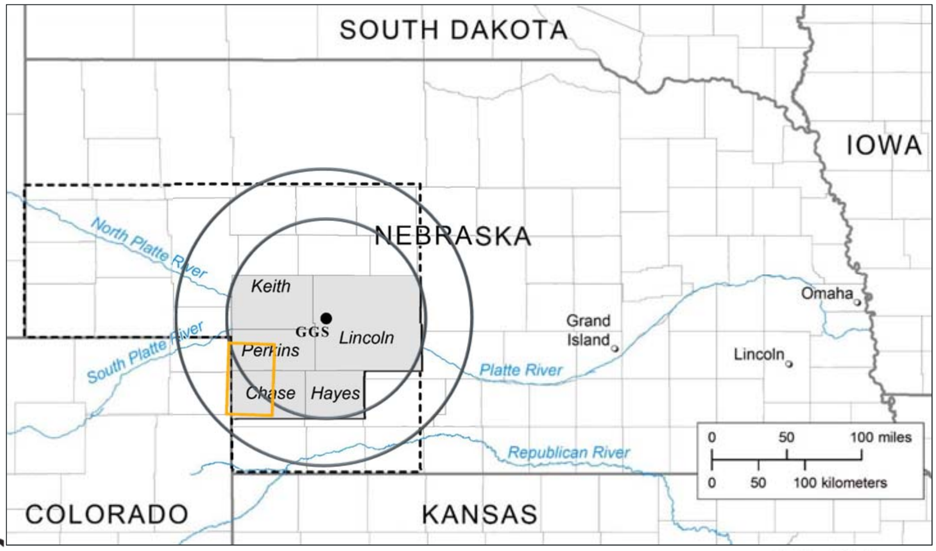
Critical Challenges. **Practical Solutions.**

Accomplishment 2
Defined the Area of Interest

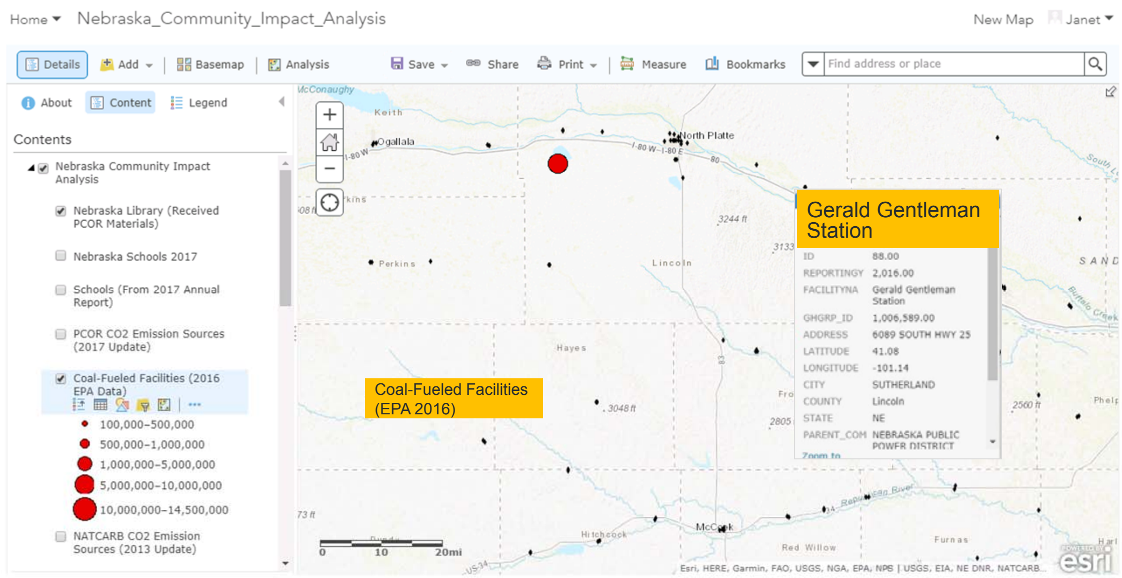
2



Accomplishment 3
ArcGIS Database for Surface Data

ArcGIS – Geographic Data

3

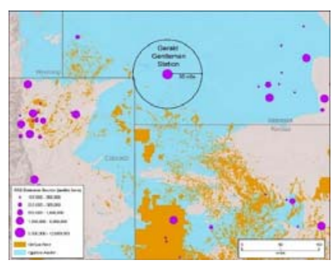


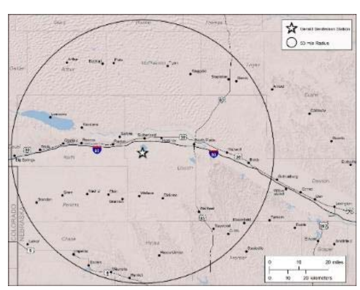
Regional Analysis

3

Assessment of geographic and socioeconomic characteristics specific to the study region in relation to CCS.

- **Analysis of Environmentally Sensitive Areas**
- **Investigation of Potential Impact on Current and Future Resource Development**
- **Community Impact Analysis**





Accomplishment 4
Delineated Environmentally Sensitive Surface Areas

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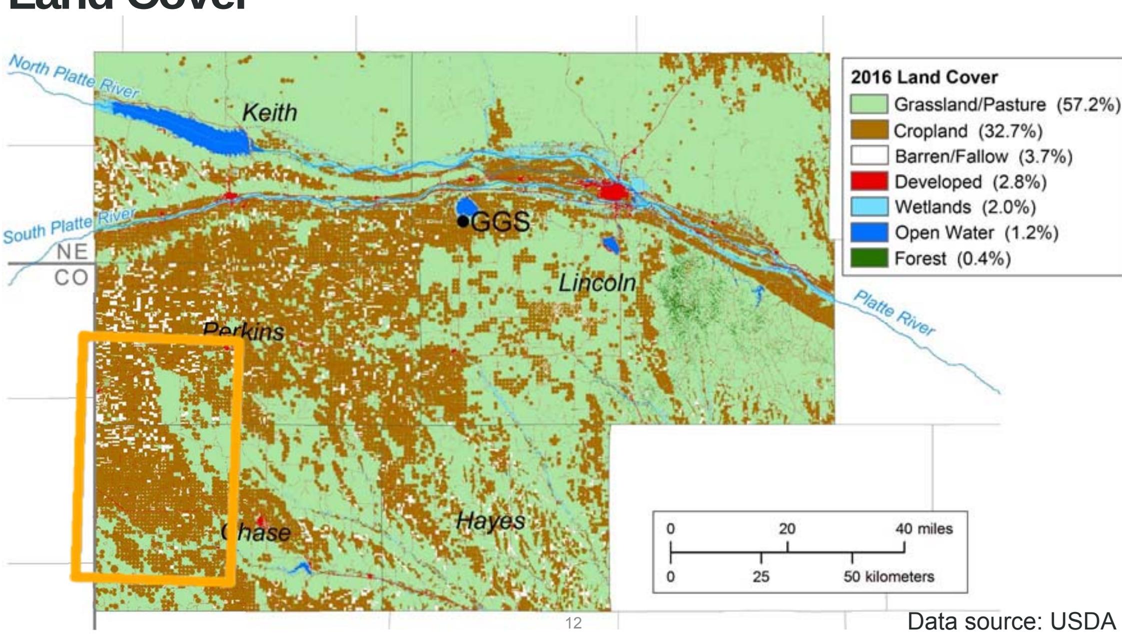
Critical Challenges. **Practical Solutions.**

Land Cover

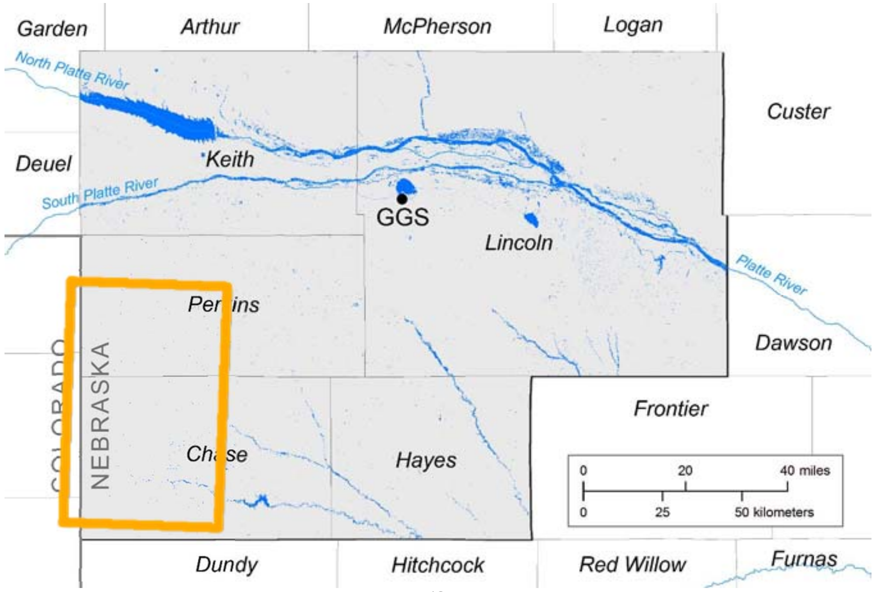
4



12

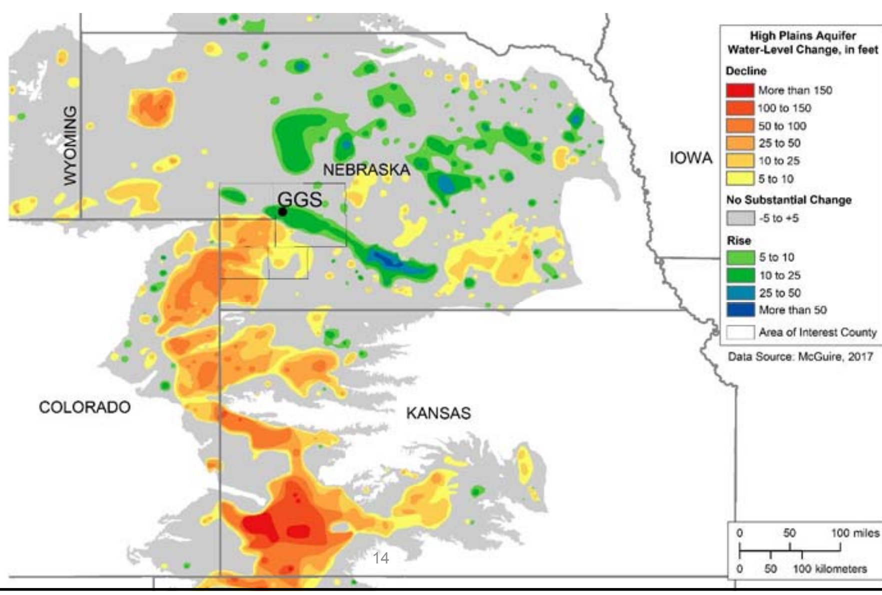
Data source: USDA NRCS

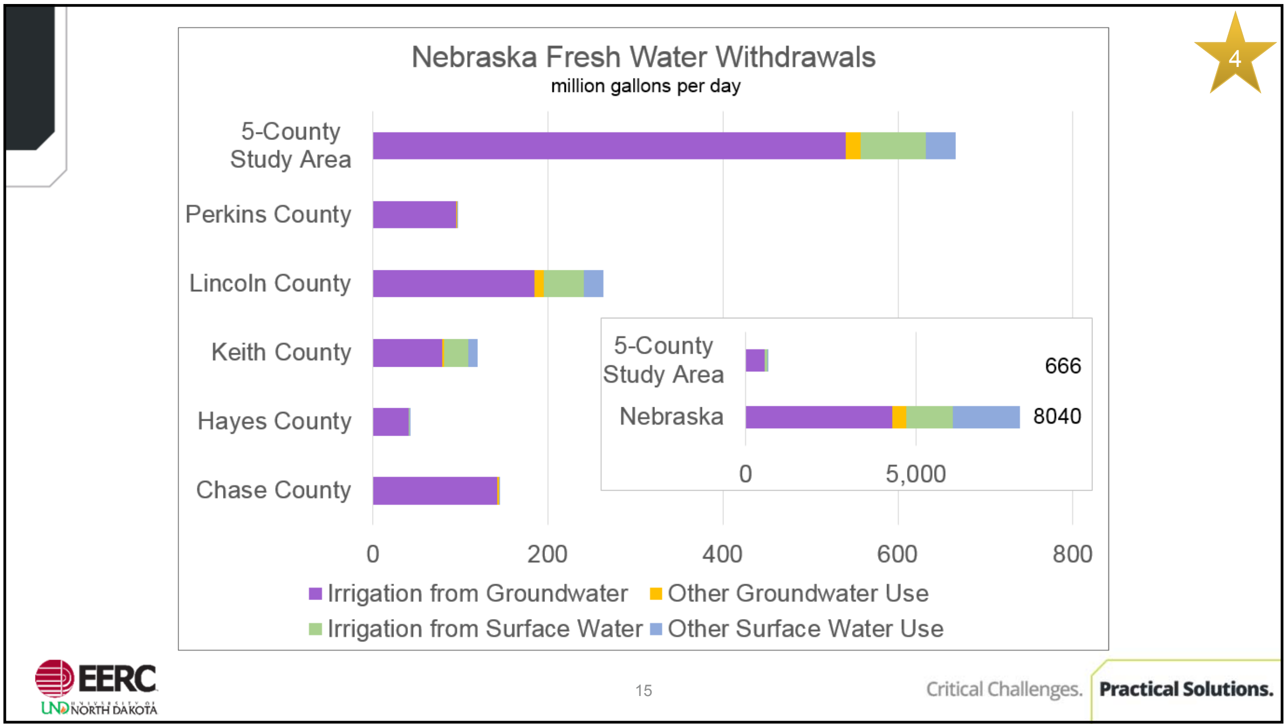
Major Surface Water Resources



Data source: USDA NRCS

Major Groundwater Resources – High Plains Aquifer




Nebraska Fresh Water Withdrawals
million gallons per day
5-County Study Area
Perkins County
Lincoln County
Keith County
Hayes County
Chase County
0
200
400
600
800
5-County Study Area
Nebraska
666
8040
0
5,000
Irrigation from Groundwater
Other Groundwater Use
Irrigation from Surface Water
Other Surface Water Use
4
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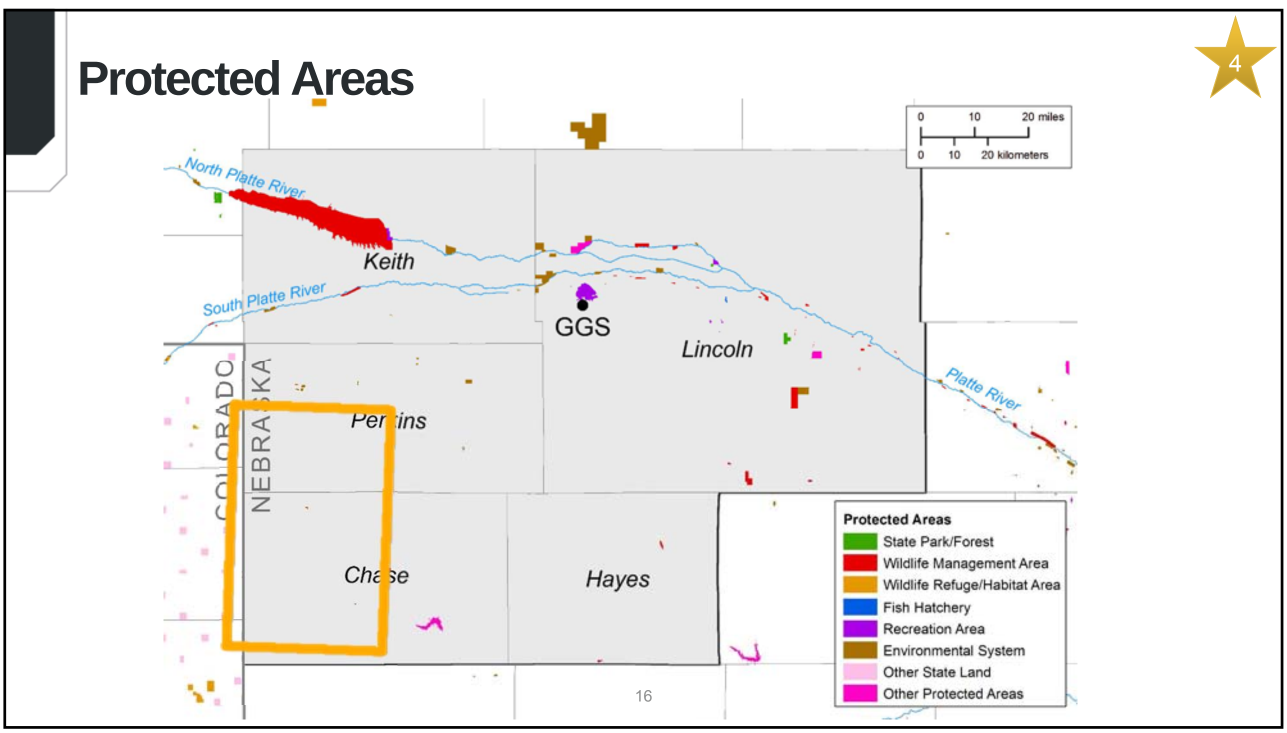
15
Critical Challenges. Practical Solutions.


Protected Areas
4
North Platte River
South Platte River
Platte River
Keith
GGS
Lincoln
Perkins
Chase
Hayes
COLORADO
NEBRASKA
0 10 20 miles
0 10 20 kilometers
Protected Areas
State Park/Forest
Wildlife Management Area
Wildlife Refuge/Habitat Area
Fish Hatchery
Recreation Area
Environmental System
Other State Land
Other Protected Areas
16

Accomplishment 5
Determined Impacts on Resource Development

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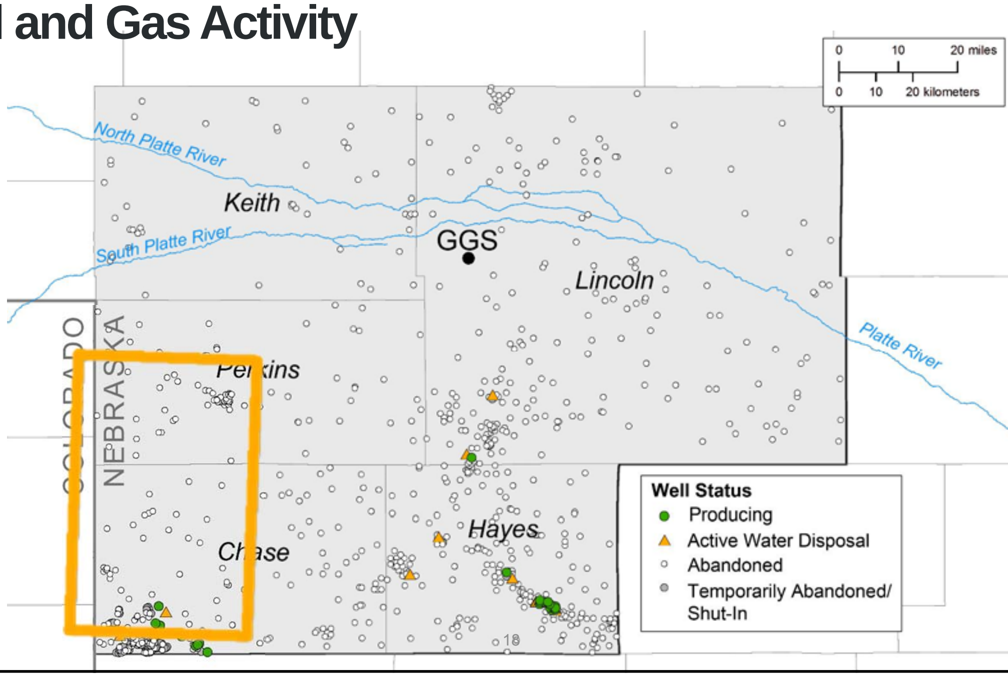
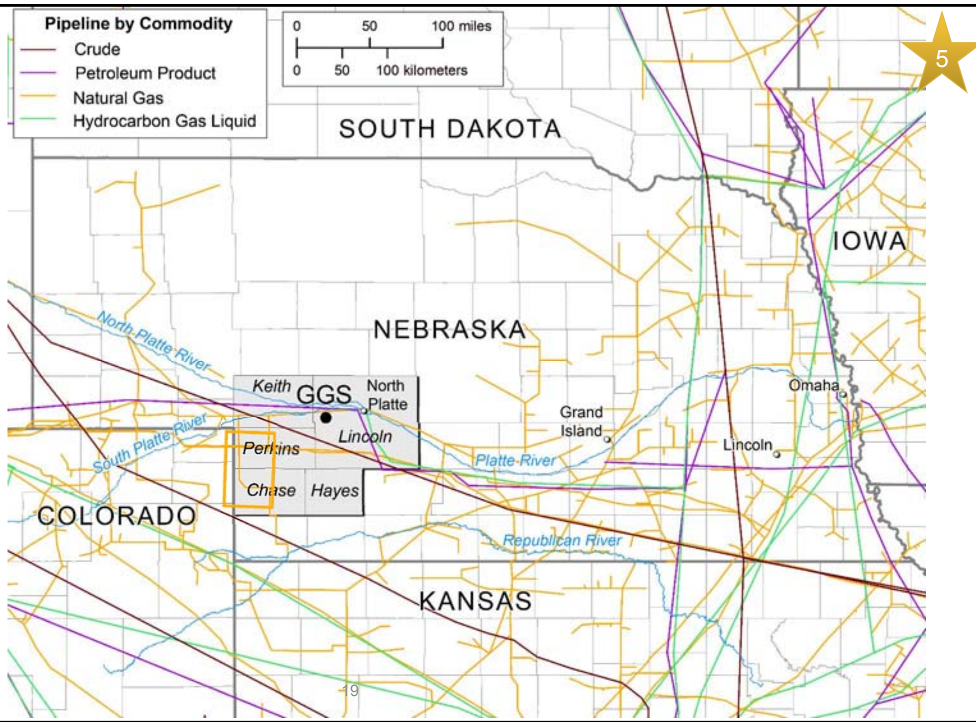
Critical Challenges. **Practical Solutions.**

Oil and Gas Activity

5



Existing Pipelines



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Accomplishment 6
Completed Basic Socioeconomic Characterization

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Critical Challenges. **Practical Solutions.**

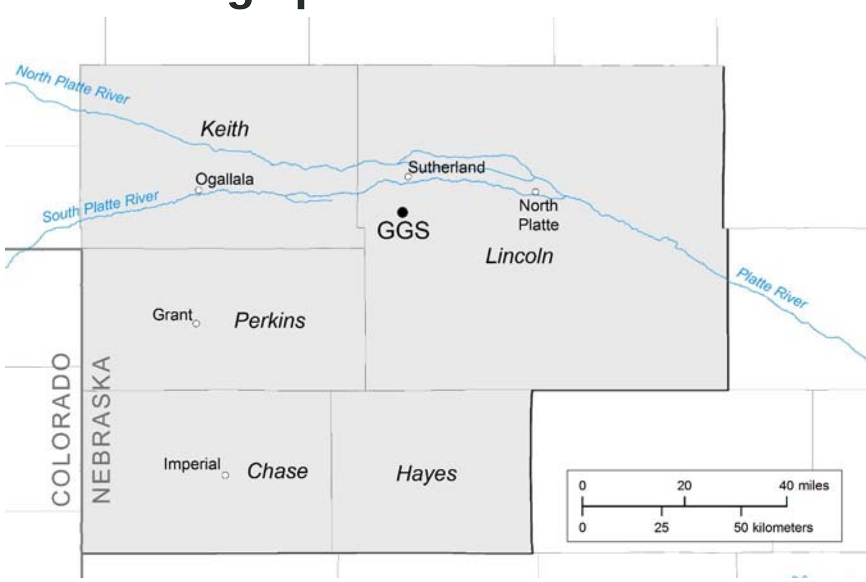
Community Impact Analysis

6

- Community impact analysis identifies:
  - Regional demographics.
  - Local economic and industrial trends.
  - Public perception/understanding of CCS-related issues.

Regional Demographics

6



Agriculture-Dominated Region

6

- In-depth investigation by University of Nebraska analyzed impact of agriculture.
- Agriculture contributes:
  - Nearly a quarter of the state's workforce.
  - 25% of the state's labor income.
  - Over 40% of the state's economic output.
- In the five-county area of interest, agriculture contributes:
  - 34% of the workforce.
  - 46% of the economic output.

Reference: Thompson, E., Johnson, B., and Giri, A., 2012, The 2010 Economic Impact of the Nebraska Agricultural Production Complex, Department of Agricultural Economics at University of Nebraska Lincoln, Report No. 192, June 2012.

Yale Climate Opinion Study – 2016

6

BELIEFS	AOI	NE	US
Believe global warming is happening	56%	64%	69%
Believe global warming is caused mostly by human activities	42%	48%	52%
RISK PERCEPTION			
Worried about global warming	47%	51%	56%
Believe global warming is already harming people in the U.S. now	37%	44%	50%
Global warming will harm me personally	32%	33%	38%
Global warming will harm future generations	62%	65%	69%
POLICY SUPPORT			
Support the regulation of CO_2 as a pollutant	66%	71%	74%
Support strict CO_2 limits on existing coal-fired power plants	46%	63%	68%
Support fund research into renewable energy sources	77%	81%	80%
Support the requirement of utilities to produce 20% electricity from renewable sources	56%	62%	65%
BEHAVIORS			
Never discuss global warming	74%	70%	67%

Accomplishment 7
Public and Stakeholder Outreach Plan in AOI

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Critical Challenges. **Practical Solutions.**

Approach for Outreach in AOI*

7

- Community outreach plan:
  - Identifies stakeholder audiences
  - Identifies key stakeholder issues based on social characterization
  - Describes strategies to appeal to each audience segment
  - Delineates project partner roles
- Plan designed to supplement NPPD efforts.
- Activation of plan requires NPPD and Coordination Team approval.

*Completed and submitted as Project Milestone 5, April 30, 2018.

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Critical Challenges. **Practical Solutions.**

Outreach Plan Content

	Questions to Answer	Plan Content
1	What are we trying to achieve, and how do we best work together to achieve it?	• Goal, approach, and success measures • Partner roles • Audiences • Implementation considerations and guidelines
2	What is our story?	• Outreach narrative, themes, and messages
3	How will audiences hear our story?	• Strategies • Outreach tool kit
4	When do we need to tell the story?	• Preliminary outreach time line matched to technical time line and partner considerations
5	Who heard the story, and what do they think about it?	• Tracking and assessment

Regulatory Assessment

State and Federal Incentives and Challenges

- **State of Nebraska**
  - The state of Nebraska has not promulgated statutes regarding CCS.
  - Should statutes related to CCS be introduced, no state regulatory agency has been selected for primacy, rule making, and oversight.
- **Federal**
  - U.S. EPA administers the Underground Injection Control Program to ensure that underground sources of drinking water are protected.
  - A dedicated CO_2 storage project would require installation of a Class VI well.
  - If EOR is viable, the Class II regulations would be followed.

Regulations Needed for CCS

- Should Nebraska wish to pursue CCS, it would need to:
  - Promulgate statutes regarding CCS.
  - Establish a state regulatory environment for pore space ownership, financial assurance, closure, or long-term liability.
  - Select a state regulatory agency for primacy, rule making, and oversight.
- Reliance on existing federal regulations.
  - Class II wells for EOR.
  - Class VI wells for dedicated CO_2 storage.

Storage Resource Ownership and Long-Term Liability

- The Legislature would need to promulgate CCS statutes and subsequently delegate and empower regulatory authority to the appropriate state agencies for rule making, permitting, inspection, and oversight.

EERC UND UNIVERSITY OF NORTH DAKOTA 31 Critical Challenges. **Practical Solutions.**

Scenario Analysis

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Scenario Analysis Topics

- **CO_2 resource assessment**
  – CO_2 sources
  – Technologies and infrastructure required for capture, dehydration and compression, transport, and injection
  – Rights of way
  – Monitoring
- **Financial and economic evaluation**
- **State and federal incentives and challenges**
- **Storage resource ownership evaluation**
- **Long-term liability**

Image from CO_2CRC

Source and Capture Technology Assessment

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Images from NPPD and USEA

- No competing large CO_2 sources within 75 mi of GGS.
- Potential capture technologies:
  – Solvent scrubbing
    - Chemical solvents (Amines – Fluor Econamine FG+, Cansolv, MHI KS-1, ION, etc.)
    - Physical solvents (Rectisol, Selexol) – require higher pressures
  – Membranes – not proven for flue gas containing any particulate
  – **Amine scrubbing is the clear choice.**

Dehydration, Compression, and Pipeline Transport Infrastructure

Images from QB Johnson (top), NIST (middle), and Casper [WY] Star Tribune (bottom)

- Glycol dehydration system
- Integrally geared centrifugal compressor
- 18-inch, 75-mile, carbon-steel CO_2 pipeline

Pipeline Rights-of-Way

- No CO_2 pipelines in study region.
- Significant petroleum and natural gas pipelines in the vicinity of GGS.
- Use of existing pipeline corridors minimizes impacts to landowners.

Image from K2 Radio

CO_2 Injection, Monitoring, and Storage Infrastructure

Infield Injection Infrastructure:

- CO_2 supply system
- Injection well(s) with associated instruments
- SCADA system for monitor and control of systems

Potential Monitoring Infrastructure:

- Near-surface sampling
- Wellhead gauges
- Wellbore (core analysis, etc.)
- Corrosion coupon
- Emergency shutdown system
- Downhole gauges and sampling
- Seismic
- Electrical techniques
- InSAR/LIDAR
- Other novel/innovative technologies

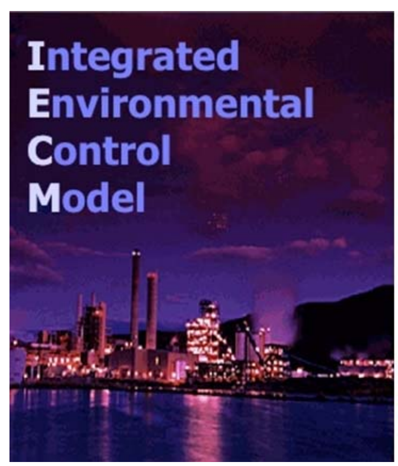
Financial and Economic Evaluation

The Carnegie-Mellon University IECM was used to model GGS Unit 2 with amine scrubbing for estimating capital and operating costs.

Major Assumptions:

- Capture at GGS Unit 2 as a retrofit on NPPD-owned property.
- Installation of wet flue gas desulfurization with a demister.
- Pipeline would be 75 mi in length.
- CO_2 pressure at plant = 1500 psia (minimum allowed by IECM); pressure at injection site ≈ 1300 psi.
- Use of a flue gas bypass and a 65% overall CO_2 removal efficiency produces roughly 2 million tonnes of CO_2 for injection each year.

➢ Check: modeled CO_2 output within 1% of actual 2016 values.



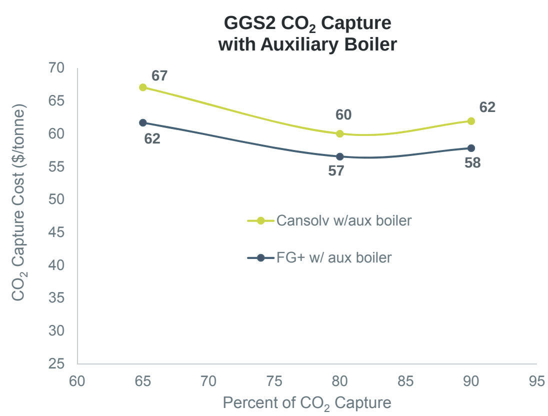
IECM Modeling

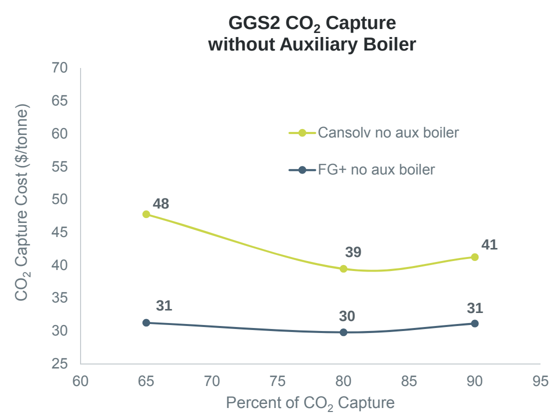
Solvent	Econamine FG+ and Cansolv					
Capture, %	65	80	90	65	80	90
Auxiliary Boiler	Yes			No		

Several IECM model runs were performed for economic sensitivity analyses, varying:

- Capture levels (65%, 80%, and 90%).
- Solvents (Fluor Econamine FG+, Cansolv).
- Use of a natural gas-fired auxiliary boiler to provide steam for solvent regeneration.

IECM GGS Unit 2 CO_2 Capture Cost Estimates





Impact of an Auxiliary Boiler

- Increases estimated capture investment.
- Prevents parasitic load on the power plant from steam requirement by the capture process.
- Economic viability depends on required revenue from power sales.

Solvent:	Cansolv	FG+
Capture, %	% Increase of CO_2 Capture Cost with Auxiliary Boiler	
65	40	97
80	52	90
90	50	86

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Critical Challenges. **Practical Solutions.**

Pipeline Modeling Assumptions

- IECM and DOE NETL CO_2 Pipeline Cost Model
- Pipeline length = 75 mi
- Inlet pressure (at GGS Unit 2) = 1500 psia
- Outlet pressure (at injection site) ≈ 1300 psia
- 30-year pipeline operating lifetime
- All values converted to 2014$
- Included in CAPEX model estimates:
  – Materials
  – Labor
  – ROW
  – Miscellaneous

Image from American Oil & Gas Reporter

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Critical Challenges. **Practical Solutions.**

Preliminary Pipeline Economics – 90% Capture (3 million tonnes/yr)

Pipe Diameter, in.	20[a]	18	
Model	DOE	DOE	IECM
CAPEX, $million	96	86	70
OPEX, $million	22	22	11
Total, $million	**120**	**110**	**81**
CO_2 Cost, $/tonne	*1.3*	*1.2*	*0.9*

[a] Not applicable for IECM model

- Assumes >30-yr pipeline lifetime
- 89 million tonnes CO_2 transported

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Critical Challenges. **Practical Solutions.**

Preliminary Pipeline Economics – 80% Capture (2.6 million tonnes/yr)

Pipe Diameter, in.	18	
Model	DOE	IECM
CAPEX, $million	86	70
OPEX, $million	22	11
Total, $million	**108**	**81**
CO_2 Cost, $/tonne	*1.4*	*1.0*

[a] Not applicable for IECM model

- Assumes >30-yr pipeline lifetime
- 79 million tonnes CO_2 transported

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Critical Challenges. **Practical Solutions.**

Preliminary Pipeline Economics – 65% Capture (2.1 million tonnes/yr)

Pipe Diameter, in.	18	
Model	DOE	IECM
CAPEX, $million	75	65
OPEX, $million	22	11
Total, $million	**97**	**76**
CO_2 Cost, $/tonne	*1.5*	*1.2*

[a] Not applicable for IECM model

- Assumes >30-yr pipeline lifetime
- 64 million tonnes CO_2 transported

Estimated Well Drilling and Seismic Costs

Item	CAPEX, $million	Notes
Well Type		Costs were acquired through Schlumberger Carbon Services.
Class VI Injection AFE*	4.2	
Stratigraphic Test Well AFE	3.0	
Monitor Well AFE	4.9	
Seismic		
3-D Seismic Survey, 12.3 mi^2	0.7 (range 0.5–1.2)	

* Authorization for Expenditure

Modeled Scenario Costs

Component	$/tonne	Notes/Assumptions
FG+ 80% Capture	30	FG+ solvent without auxiliary boiler
Pipeline	1.3	DOE Model for 80% capture, 18-inch, 75-mile, 1300 psi. delivered, 30-yr lifetime, 2014$
Class VI Injection Wells	0.32	Assumes four Class VI injection wells;
Stratigraphic Test Well	0.06	Calculated from Schlumberger estimate.
Monitoring Well	0.1	Calculated from Schlumberger estimate.
3-D Seismic Survey (12.25 mi^2)	0.01	Costs for a single 3-D survey; does not include repeat surveys.
Permitting	0.24	Assumes permitting four Class VI injection wells
Total Estimated Cost	**32**	

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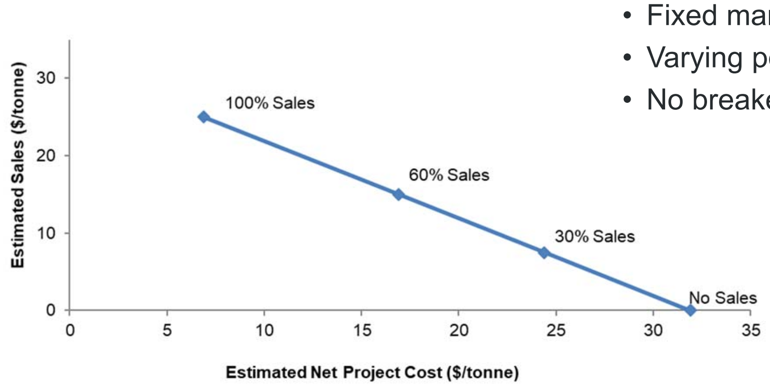
Critical Challenges. **Practical Solutions.**

Enhanced Oil Recovery (EOR) Sensitivity Market



Case Study 1

- Overall net project cost ~$32/tonne
- Fixed market price for EOR ~$25/tonne
- Varying percentage of EOR sales
- No breakeven point

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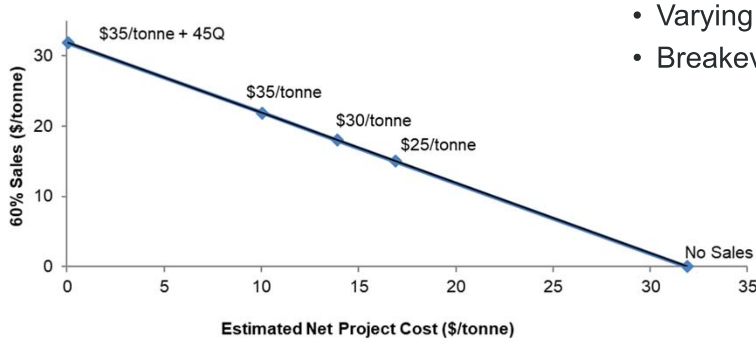
Critical Challenges. **Practical Solutions.**

EOR Sensitivity Market with 45Q

Case Study 2

- Overall net project cost ~$32/tonne
- Fixed EOR sales at 60%
- Varying market value for CO_2
- Breakeven at high market value + 45Q



Section 45Q Impressions

- Bipartisan Budget Act of 2018 expands value, time window, and cap on tax credits for CO_2 sequestration.

Storage	Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
EOR	$/tonne	12.83	15.29	17.76	20.22	22.68	25.15	27.61	30.07	32.54	35[a]
Dedicated Storage	$/tonne	22.66	25.70	28.74	31.77	34.81	37.85	40.89	43.92	46.96	50[a]

[a] To remain constant in value for 2027 and thereafter (adjusted for inflation).

- Uncertainty exists with regard to potential private investors and actual CO_2 values for suppliers.
- Main challenges associated with specific monitoring and reporting required by *EPA's Greenhouse Gas Reporting*.

Subbasinal Analysis

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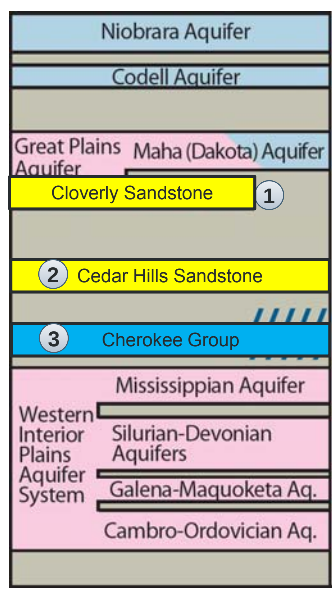
Critical Challenges. **Practical Solutions.**

Evaluation of Reservoir and Seal Characteristics

- CO_2 storage resource is being estimated for three potential geologic storage complexes, all in the Denver–Julesburg Basin of western Nebraska
  - Salinity >10,000 ppm dissolved solids
  - Overlain by a regional seal
  - Wholly or partially >3000 ft deep

No.	Formation	Seal(s)	Available Information
1	Cloverly Formation	Skull Creek Shale	Salinity varies regionally but high in target area
2	Cedar Hills Formation	Opeche and Flower Pot Shales and the Blaine Anhydrite	Parent Nippewalla Group contains multiple evaporite beds that contribute to high salinity
~~3~~	~~Cherokee Group~~	~~Intermediate shales~~	~~Interbedded shales, sandstones, and carbonates~~



Paleozoic and Mesozoic Aquifers in Nebraska (Korus and Joeckel, 2011; mod.)

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52

Critical Challenges. **Practical Solutions.**

Storage Estimation – Two Parts

Static storage estimate based on volume

- DOE method based on:
  – Formation area.
  – Formation thickness.
  – Formation porosity.

- Gives a rough estimate of storage potential at the end of an injection campaign.

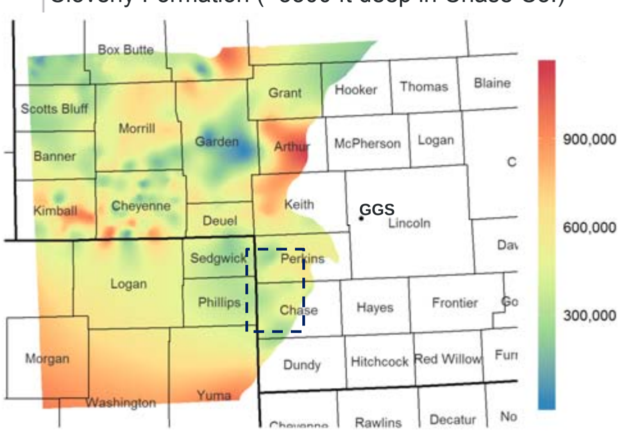
Dynamic CO_2 and pressure plume estimate

- Simulation method based on a detailed geologic model of:
  – Lithofacies (rock types).
  – Porosity (space in the rock).
  – Permeability (injection potential).

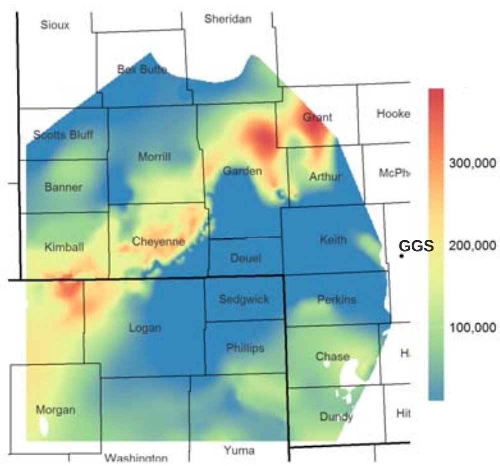
- Gives an estimate of storage potential including pressure effects during injection.

Volumetric Estimated Storage Potential

Cloverly Formation (~3300 ft deep in Chase Co.)



Cedar Hills Formation (~3700 ft deep in Chase Co.)



Mass shown in tonnes/mi^2.

Volumetric Estimated Storage Potential

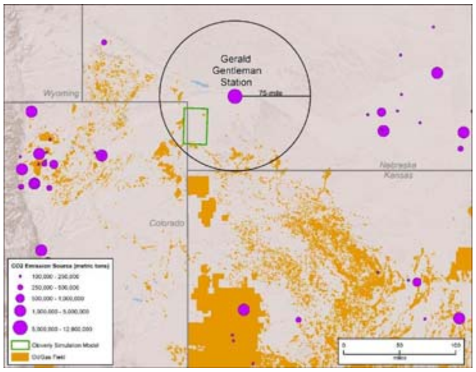
Model	Potential Storage Estimate, tonnes		
	Optimistic	Moderate	Conservative
Cloverly Formation, regional model	Tens of billions	Tens of billions	Billions to tens of billions
Cedar Hills Formation, regional model	Billions	Billions	Hundreds of millions
Cloverly Formation, simulation model (moderate)	Billions	Hundreds of millions	Hundreds of millions

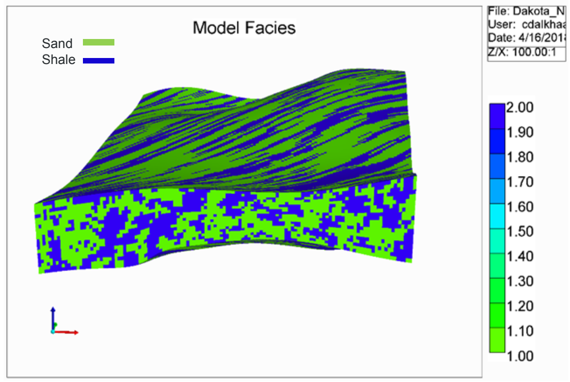
- Estimated CO_2 storage potential for the Cloverly regional model is larger than that of the Cedar Hills.
- Volumetric estimates of the Cloverly simulation model are greater than estimates from the simulations because pressure effects are not taken into account.

Summary of Dynamic Simulation Work

- CO_2 injection is simulated for the Cloverly Formation to store 50 Mt of CO_2 over 25 years to determine:
  - ✓ The number of injection wells required.
  - ✓ A maximum wellhead pressure (WHP) for injection.
  - ✓ The size of the AOR for CO_2 injection.
- Simulations were continued for 100 years after the end of injection to investigate the CO_2 plume migration and pressure stabilization.

Cloverly Formation Simulation Model





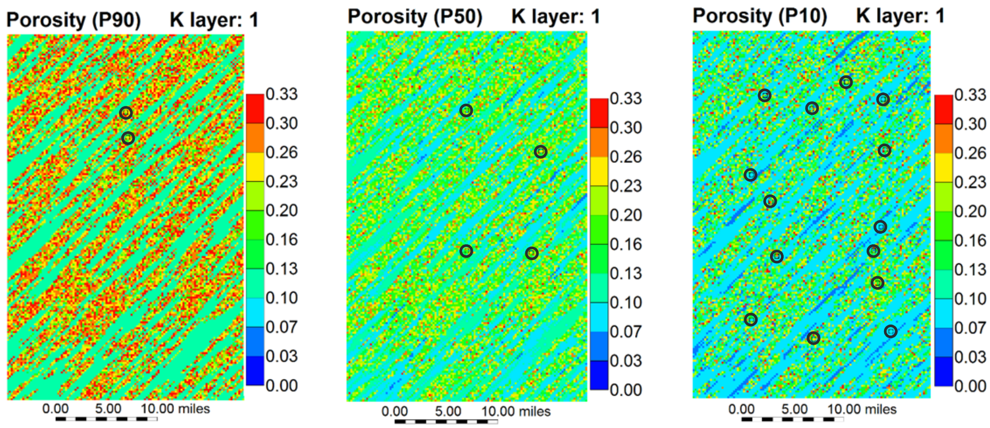
- Model extent is ~24 x 36 miles (850 square miles).
- Average thickness of the Cloverly Formation is 280 ft.
- Average depth of the Cloverly Formation is 3350 ft.

Cloverly Formation Model Properties

Model	Optimistic (P90)		Moderate (P50)		Conservative (P10)	
Facies	Poro. (%)	Perm. (mD)	Poro. (%)	Perm. (mD)	Poro. (%)	Perm. (mD)
Sand	25.02	425.97	18.62	210.85	16.03	161.42
Shale	12.10	0.00001	9.72	0.00001	7.95	0.00001

- Three models of different properties (P90, P50, and P10) are considered for simulation.

Potential Locations for Injection



	Optimistic	Moderate	Conservative
No. of injection wells	2	4	14

- 2 Mt of CO_2 is injected annually (5500 tonnes per day).
- Injection period: 25 years.
- Total amount of CO_2 injected: 50 Mt.
- Simulator: CMG GEM.

Sensitivity Analysis on WHP

- A sensitivity study is conducted to determine a WHP range with varying values of the parameters (such as wellhead injection and bottomhole temperatures and injection tubing size and roughness) and the relative effects of the parameters on WHP.

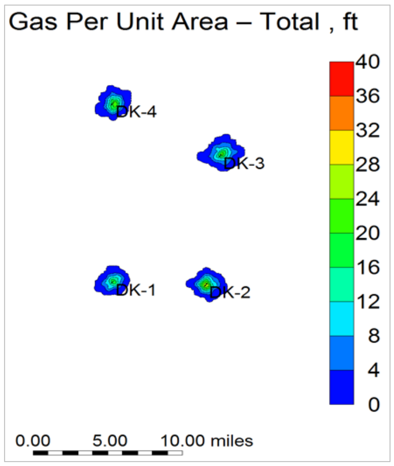
Model	Simulated WHP Range (psi)
Optimistic	800–2600
Moderate	700–1750
Conservative	650–1250

- The sensitivity analysis indicated that WHP is most sensitive to:
  - Injection tubing size.
  - Wellhead injection temperature.
  - Tubing roughness.

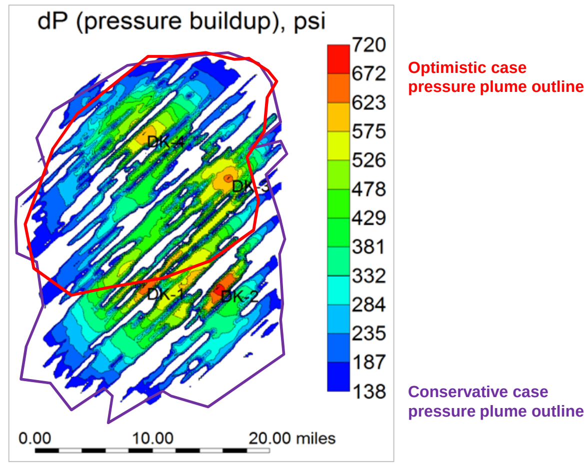
- A maximum WHP of 1300 psi (with a 4.5 inch injection tubing) is recommended as an injection pressure for the infrastructure design.

Area of Review (AOR) Investigation

P50 CO_2 Plume



P50 Pressure Plume



- The CO_2 plume size is about ~3 miles in diameter.
- The pressure plume size is about 21 x 30 miles.
- The pressure plume dictates the AOR size, as its extent is greater.

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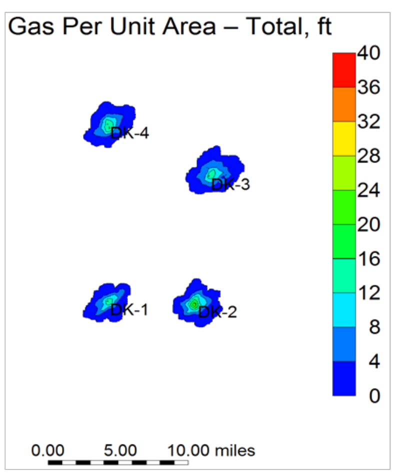
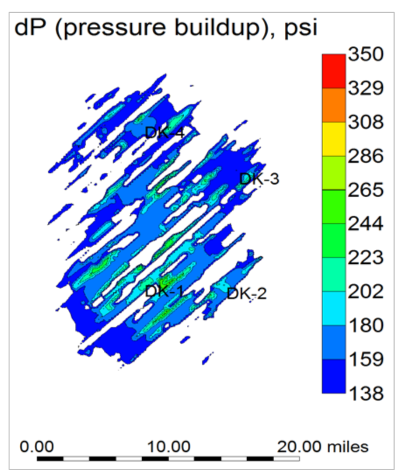
Investigation of Postinjection (100 years)

CO_2 plume after 100 years of postinjection



Pressure plume after 40 years of postinjection



- The CO_2 plume size is about ~4 miles in diameter.
- The pressure plume size is approximately 12 x 20 miles.

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Recap

Regional and Stakeholder Analysis Summary

- Based on environmental sensitivity and resource development analysis, the area to the west and south of GGS is the most promising for development of a CCS project.
- The community impact analysis suggests that the local sparsely populated region would have concerns about protection of the freshwater resources, especially groundwater, and potential impacts on agriculture.
- A CCS project would need to incorporate outreach messages that describe the risk, regulatory requirements to protect groundwater, and procedures in place to mitigate potential risk of groundwater contamination.
- The local population is likely to be more familiar with land leases related to farming and ranching than pore space or mineral rights.

Scenario Analysis Summary

- CCS in the study area is technically feasible for the capture and pipeline transport of CO_2 to a potential injection site.
- Economics may not support a CCS project if incentives such as the 45Q tax credits are not available.
- Nebraska currently has no statutes or programs specific to CCS regulation.

Subbasinal Analysis Summary

- Regional CO_2 storage resource potential in two formations:
  – Cloverly Formation
  – Cedar Hills Formation
- Geologic storage resource increases to the southwest into the Denver–Julesburg Basin.
- Dynamic simulation results support the possibility of 50 million tonnes of storage in 25 years in the Cloverly Formation.

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Energy & Environmental Research Center

NORTH DAKOTA INTEGRATED CARBON CAPTURE AND STORAGE COMPLEX FEASIBILITY STUDY

Carbon Capture, Utilization & Storage (CCUS) Conference
Nashville, Tennessee
March 21, 2018

Wes Peck
Principal Geologist

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NORTH DAKOTA CARBONSAFE

- Address technical and nontechnical challenges specific to commercial-scale deployment of a CO_2 storage project in central North Dakota.

- Long-term goal: develop a certified (permitted) geologic storage opportunity should a business case for CO_2 storage emerge.

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PROJECT OBJECTIVES

- Evaluate two ideal geologic storage complexes located adjacent to separate coal-fired facilities.
  - One has readily available CO_2 and an existing CO_2 pipeline.
  - The other is associated with a planned integrated CO_2 capture and storage project with a time line coincident with the CarbonSAFE Program.
- Gauge public support.
- Conduct a regulatory and economic analysis.

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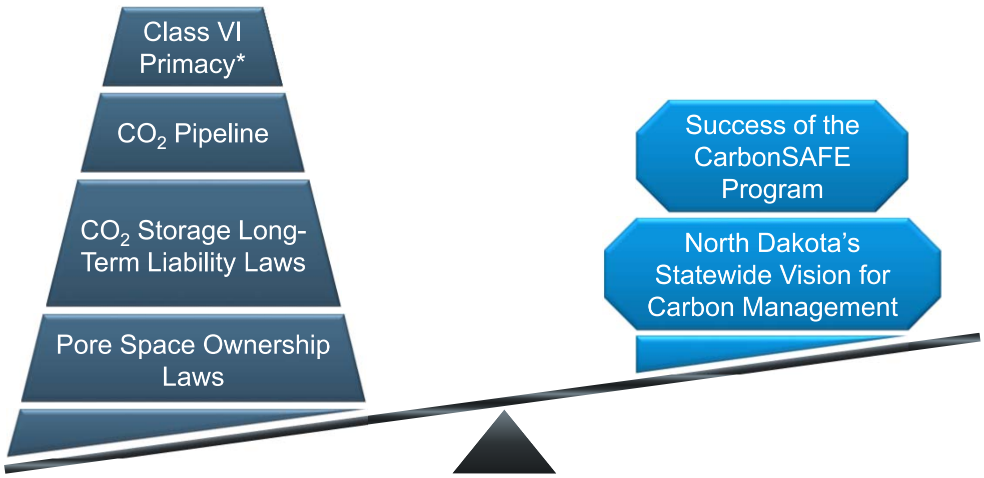
NORTH DAKOTA'S LEVERAGE



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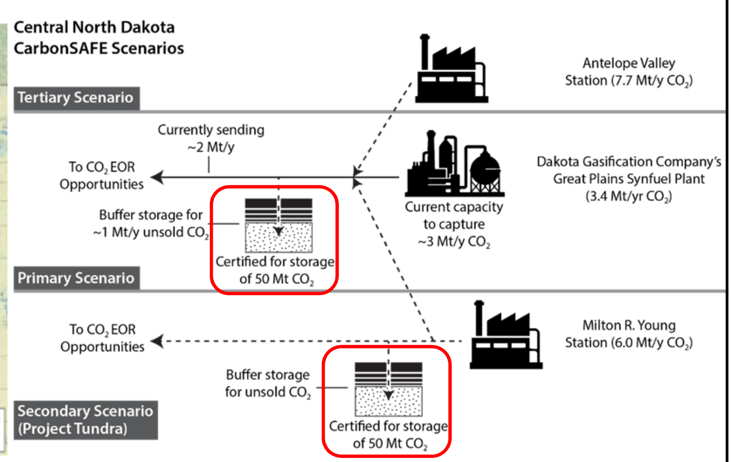
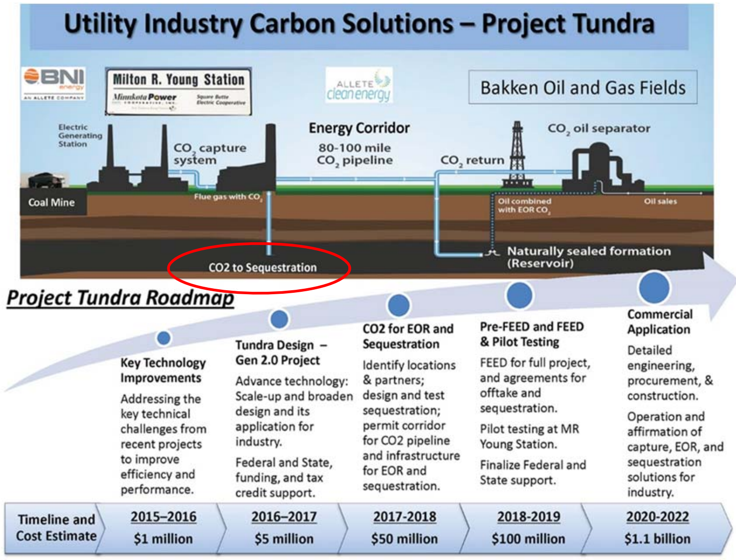
NORTH DAKOTA CARBONSAFE CO_2 SOURCE OPTIONS



PROJECT TUNDRA: A NICE FIT



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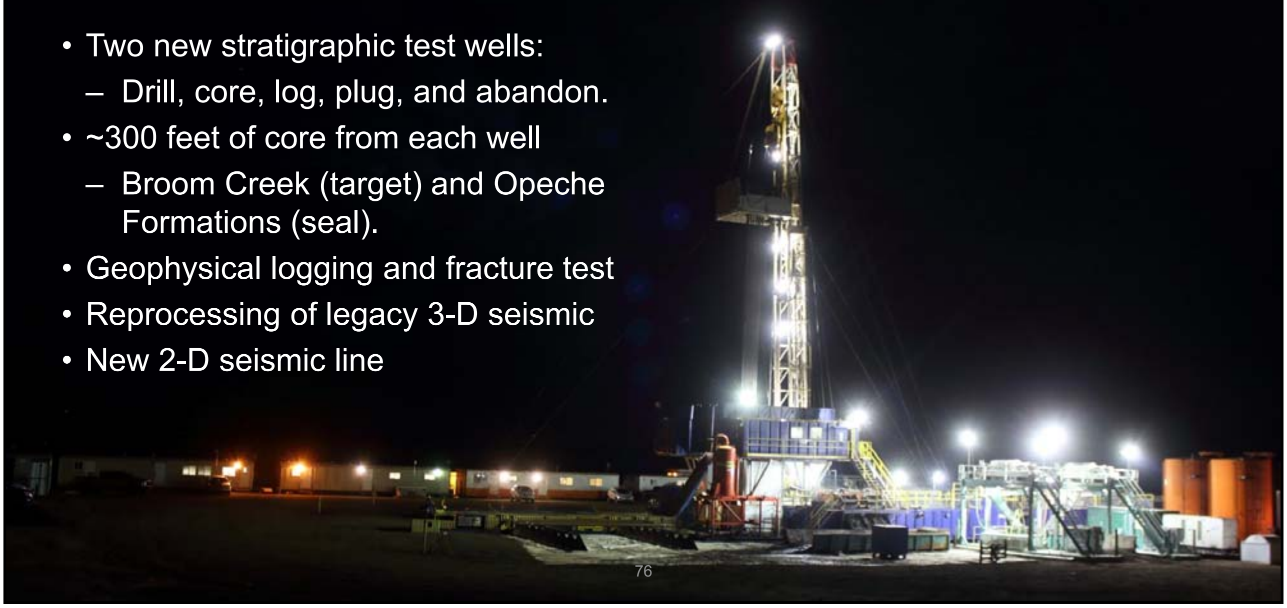
GEOLOGIC CHARACTERIZATION

- Two new stratigraphic test wells:
  - Drill, core, log, plug, and abandon.
- ~300 feet of core from each well
  - Broom Creek (target) and Opeche Formations (seal).
- Geophysical logging and fracture test
- Reprocessing of legacy 3-D seismic
- New 2-D seismic line



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PUBLIC OUTREACH

Gauge local public acceptance of a potential CO_2 storage project.

- Formed a collaborative outreach advisory group.
- Developed a tailored set of outreach materials.
- Implemented outreach:
  - Stakeholder meetings
  - Open house meetings
- Develop a public engagement plan for Phase III.

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REGULATORY AND ECONOMIC ANALYSIS

- Evaluating permitting requirements needed for future implementation of Class VI injection wells.
- Exploring site access agreement options, pore space acquisition, and short-term project liability.
- Examining specific economic needs and the incentives in place to make the proposed scenarios economically feasible for the project partners.

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EXPECTED OUTCOMES

- Develop 3-D geologic models to:
  - Predict the extent of CO_2 and pressure plumes and future monitoring activities.
  - Determine pore space-leasing requirements, and develop business case scenarios.
- Identify technical and nontechnical challenges specific to establishing commercial-scale CO_2 storage site.
- Develop mitigation strategies to address identified challenges.
- Develop a detailed plan for the Site Characterization phase of CarbonSAFE.

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DISCLAIMER


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APPENDIX C

SCENARIO ANALYSIS SUPPORTING INFORMATION

SCENARIO ANALYSIS SUPPORTING INFORMATION

MONITORING TECHNOLOGIES

A preliminary well design was developed for the Nebraska carbon capture and storage (CCS) scenario with two goals in mind: 1) to ascertain that the project technical target of permanently storing at least 50 million tonnes of CO_2 safely is possible and 2) to realize risk reduction and mitigation objectives for the CO_2 storage. The approaches and technologies described in this appendix are under consideration for helping to meeting these two goals.

Initially, geologic core and formation fluid samples will be collected from the injection location to determine mineralogy, porosity, permeability, and geochemical reactivity to CO_2 at the injection site. Next, cement bond and variable density logs would provide cement bond quality information to ensure the protection of drinking water and reduce the risk of CO_2 migration to the shallow subsurface or the surface. Finally, reservoir surveillance would be implemented to observe and quantify the CO_2 plume movement and injection profile.

Fluid Sampling While Drilling (precompletion)

1. **Saturn Probe**
   Saturn Probe is the largest probe, with total flow area of 79.44 in.^{2}. Saturn system consists of four (4) elliptical suction ports which establish and maintain circumferential flow in the formation around the borehole, enabling downhole fluid analysis and sampling, permeability estimation, and highly accurate pressure measurement. Saturn probe is equipped with:

   1.1. A self-seal system that increases fluid sampling efficiency by eliminating stationary mud mixing and minimizing storage effect.

   1.2. Different storage options which provide flexibility in a number of samples per sampling point and a number of sampling points per run. There are two (2) options for storage size, 1 × 3-L bottle or 6 × 450-mL bottle. Being deployed with wireline also increases the fluid sampling efficiency by reducing the running time of fluid sampling and rig days.

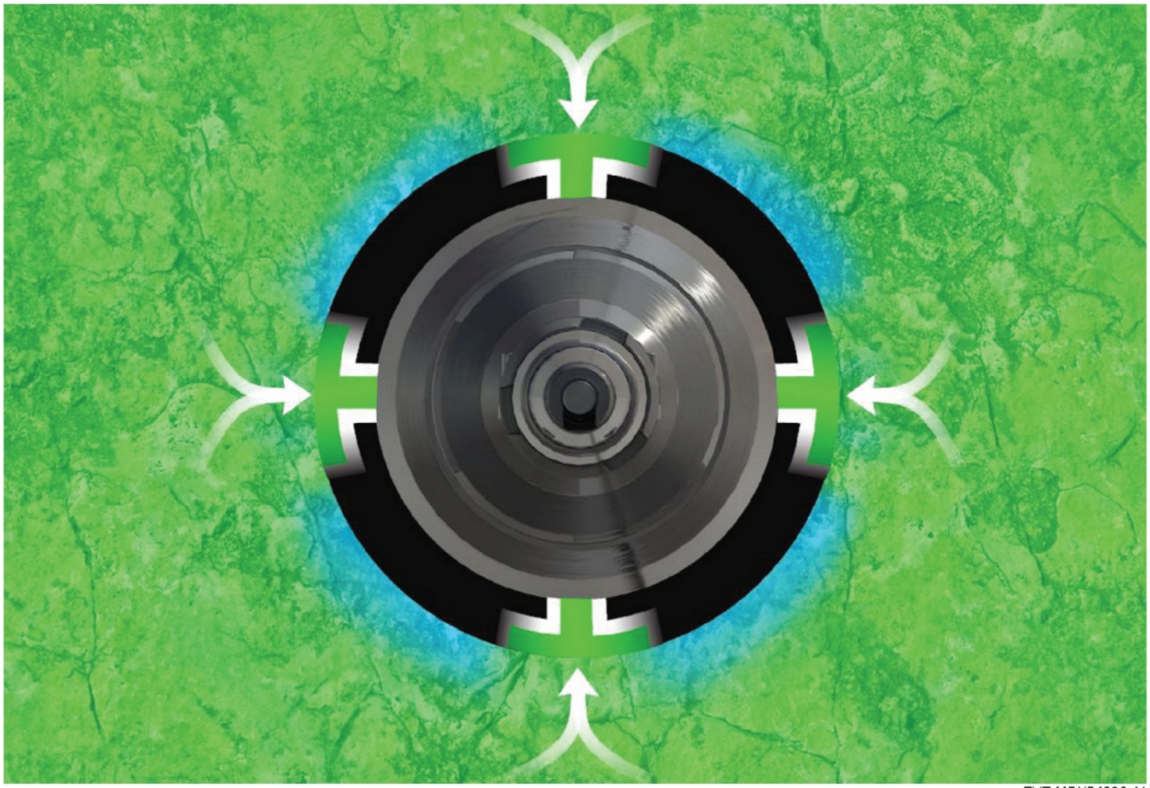

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Figure C-1. The four Saturn ports (courtesy of Schlumberger – Saturn 3-D radial probe).

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Saturn

Specifications	
	Saturn 3D Radial Probe
Measurement	
Output	Ultralow-contamination formation fluids, formation pressure, fluid mobility, downhole fluid analysis, permeability anisotropy
Logging speed	Stationary
Mud type or weight limitations	None
Combinability	Fully integrates with MDT modular formation dynamics tester and InSitu Family* sensors
Special applications	Low-permeability formations, heavy oil, near-critical fluids, unconsolidated formations, rugose boreholes, large-diameter boreholes, high temperatures
Mechanical	
Temperature rating	7- and 9-in versions: 350 degF [177 degC] High-temperature 7-in version: 400 degF [204 degC]
Pressure rating	20,000 psi [138 MPa] High-pressure version: 30,000 psi [207 MPa]
Borehole size—min.	7-in version: 7.875 in [20.0 cm] 9-in version: 9.875 in [25.08 cm]
Borehole size—max.	7-in version: 9.5 in [24.13 cm] 9-in version: 14.5 in [36.83 cm]
Max. hole ovality	20%
Outside diameter	Tool body: 4.75 in [12.06 cm] 7-in version drain assembly: 7 in [17.78 cm] 9-in version drain assembly: 8.75 in [22.23 cm]
Length	5.7 ft [1.74 m] With Modular Reservoir Sonde and Electronics (MRSE): 12.4 ft [3.78 m]
Weight (in air)	7-in version: 385 lbm [175 kg] 9-in version: 485 lbm [220 kg]

Figure C-2. Saturn probe specification (courtesy of Schlumberger – Saturn 3-D radial probe).

2. DST

A drillstem test (DST) is a temporary completion that provides information on the target formations. DST obtains reservoir characteristics, including reservoir pressure, formation properties (permeability, skin, and radius of investigation), and productivity estimates. DST is deployed on drill pipes and consists of the following main parts:

2.1. Perforated sub as the fluid intake
2.2. Packers to provide zonal isolation to contain the tested formation
2.3. Recorders to record downhole pressure, temperature, and flow rate of the entire test processes
2.4. Fluid sample chambers to store collected sample at downhole condition (in situ sample)

One advantage of DST for fluid sampling is the sample can be collected in two different environments: in situ and surface sampling. The in situ sample is limited by the size of sample chambers, while the surface sample has unlimited amount only if the fluid can flow naturally to the surface.

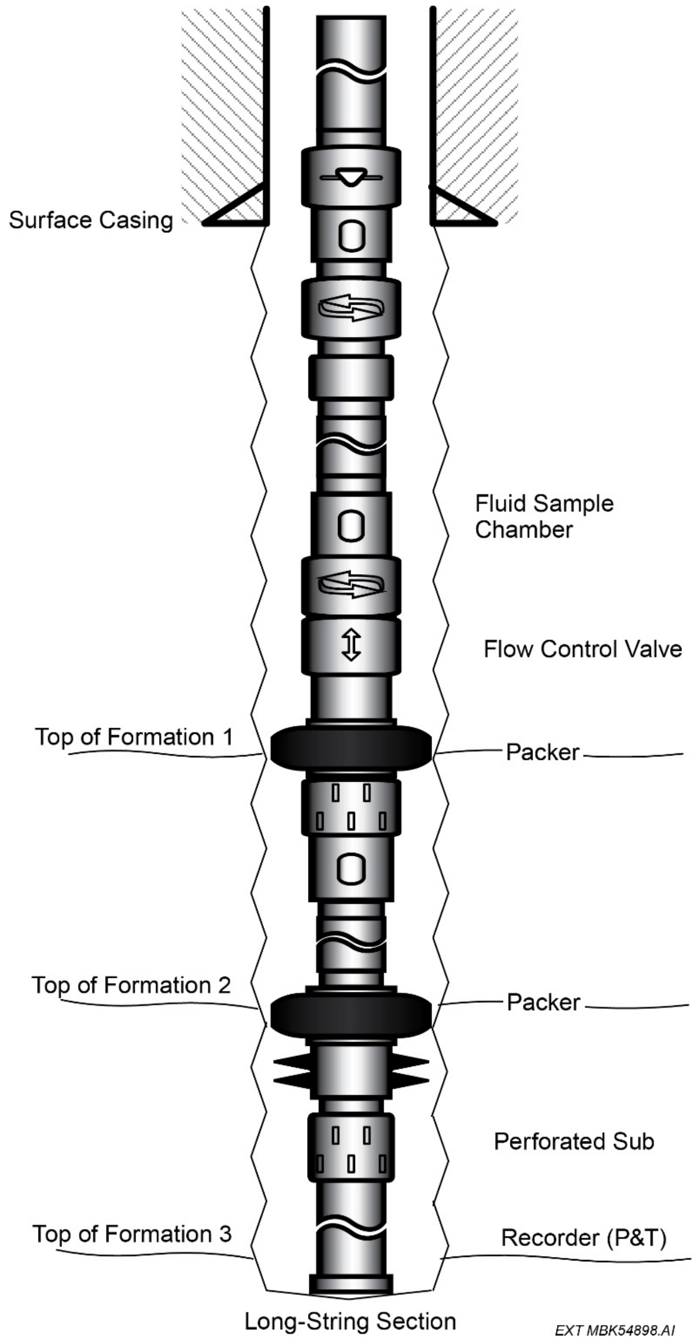


Figure C-3. Illustration of DST equipment.

3. Fluid-Sampling System (postcompletion)

3.1. U-Tube Sampler. Figure C-4 illustrates the configuration of the U-tube sampler that provides minimally contaminated aliquots of multiphase fluids from reservoirs and allows for an in situ sample with accurate determination of dissolved gas composition.

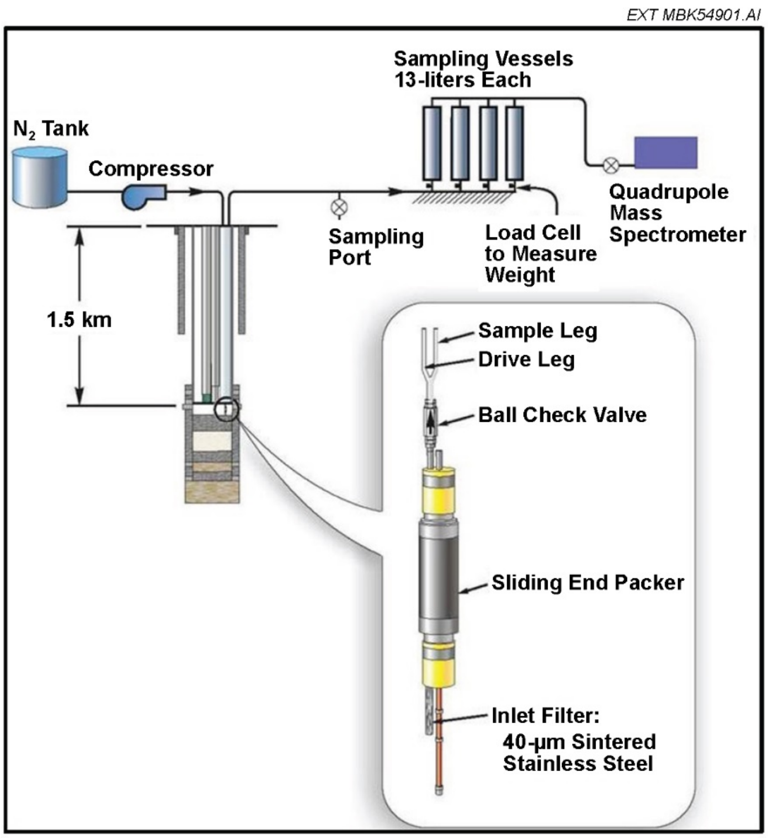


Figure C-4. Schematic of the U-tube fluid sampling system (adopted from Freifeld and others, 2009, not to scale).

4. **IntelliZone**. Figure C-5 illustrates IntelliZone configuration once installed into the well. IntelliZone provides zonal isolations and allows surface fluid samplings. The sealing system for zonal isolation is utilizing packers while the access for fluid sampling is controlled with surface control line to open/close the sliding sleeves. IntelliZone ensures minimally contaminated aliquots of multiphase fluid from each zone.

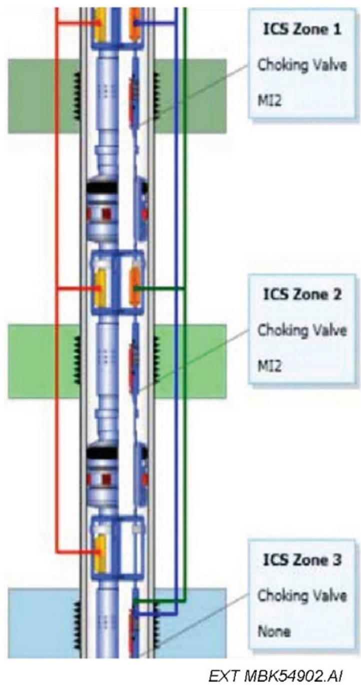


Figure C-5. Configuration of IntelliZone for three (3) perforated zones.

5. **Pressure and Temperature Gauge**

   5.1. **SageWatch** is a gauge system that provides both tubing and annulus (or reservoir) pressure and temperature monitoring. It can be run either as a casing- or tubing-conveyed system. As an additional tool to SageWatch, EasyRider provides an ability to create their own connection to the reservoir without affecting wellbore integrity. This system is usually attached to a casing-conveyed SageWatch system to monitor reservoir pressure and temperature. Figures A-16 to A-18 in Appendix A illustrate the SageWatch and EasyRider.

   5.2. **PROMORE** is a gauge system that is able to monitor pressure and temperature. There are three ways to run this gauge: casing-, tubing-, and wireline-conveyed (or through tubing gauge). Figures A-19 to A-21 in Appendix A illustrate the PROMORE gauges.

6. **Borehole-to-Surface Electromagnetic (BSEM)**
BSEM consists of two parts, the transmitting electrodes, that are installed in the wellbore, and the receiving electrodes, that are placed on the surface. The transmitting electrodes are stationed at different depths, typically at the top and the bottom of the reservoir layer under investigation. It is deployed through a classic wireline operation. The receiving electrodes are placed on the surface within an area of survey. Figures A-22 to A-23 in Appendix A illustrate the placement of the electrodes (Citation: SPE 146348). The data acquisition mode was analogous to reverse vertical seismic profiling (VSP) configuration used for seismic measurements. BSEM generates a signal that will be interpreted as CO_2 plume growth.

7. **Coring**

7.1. Core Barrel Systems

The thin-sleeve system (TSS) three-barrel system is an innovative system compared to traditional inner/outer barrel systems. TSS eliminates thermal expansion issues, improves core quality through ease of handling, and provides a platform to enhance wellsite processes and core analysis. The TSS includes two components: a threaded steel jacket and a disposable liner in which the core is housed. The presence of two independent tubes allows the disconnection process to take place without transmitting the torque to the core, therefore without inducing any rotation core damage.

The liners are made of aluminum or fiberglass and can be upgraded for enhanced coring services. The liners ease the core entry due to lower friction compared to conventional steel inner barrels. Each material offers the best compromise between structural integrity, temperature rating, friction coefficients, and cost.

7.2. Full-Barrel Liner

There are two (2) material options for a full-barrel liner.

7.2.1. Aluminum liners

Aluminum liners offer a lower friction coefficient compared to steel while maintaining integrity to avoid structural damage and ample benefit at an economic value which makes this liner the most widely used disposable liner. The aluminum liner can be dry-cut with the use of special blades to avoid unnecessary core contamination.

7.2.2. Fiberglass Liners

Fiberglass liners offer higher core recovery and reduce core jamming. Fiberglass has limitations such as cannot be used above 180°C and cannot be used in all drilling fluids. Special care and PPE (personal protective equipment) are required while cutting the core at the surface because of the toxicity of the fiberglass and resin.

In order to view the core, the full-barrel liner needs to include manually sliding the core out of the inner tube or cutting the entire length of the inner tube with a longitudinal saw. These techniques are destructive and expose the core to damage.

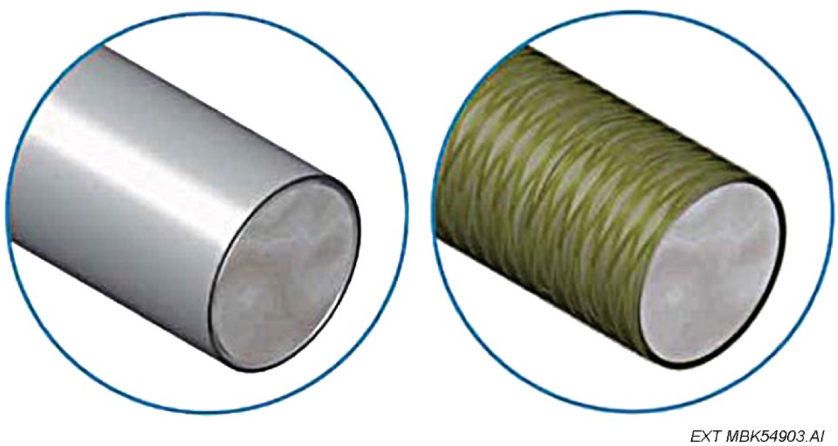


Figure C-6. Full-barrel aluminum liners (left) and fiberglass liners (right) (courtesy of Reservoir Group).

7.3. Half-Moon Liner

Half-moon liner consists of two half-cylinder liners made of aluminum. Half-moon liner technology is the only TSS system that provides a quick and easy way to visually examine the core on the rig site without affecting the quality and characteristics of the core. By viewing the core at the rig site, real-time decisions can be made concerning subsequent operations associated with coring, drilling ahead, core preservation, and future analysis. The ability to view the core also provides valuable information in terms of cutting the core for preservation and transport and to avoid cutting the core in any critical sections, such as at a fracture where damage would be possibly induced into the core itself.

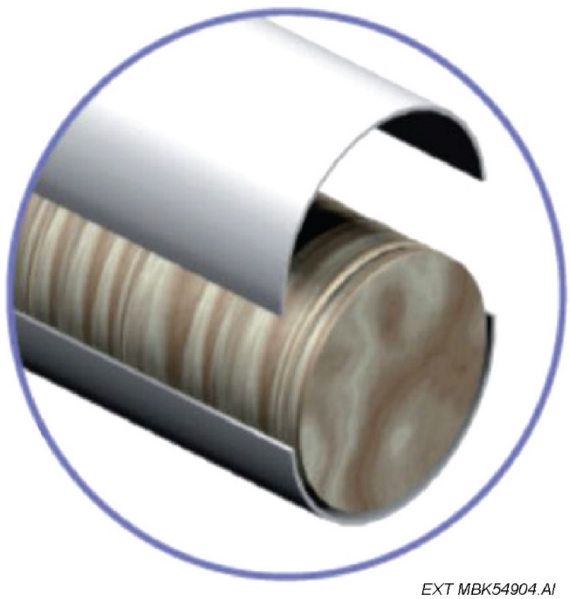


Figure C-7. Half-moon liner (courtesy of Reservoir Group).

PRELIMINARY WELL DESIGN

Two types of wells will be designed and drilled: a stratigraphic well and injection wells. A stratigraphic well will be used to characterize the Cloverly Formation, which is the primary target and the Cherokee Formation, which is the secondary target formation. Following the characterization activities, the stratigraphic well will be converted to a monitoring well to track CO_2 plume inside the formation in an updip direction. Modeling has indicated that four injection wells may be needed to inject the CO_2 from GGS2 (Gerald Gentleman Station Unit 2).

Formation Tops

Formation	MD,[1] ft	TVD,[2] ft	Remarks
Pierre	426	426	A bottom confining layer of drinking water source
Gurley D	2890	2890	
Huntsman	2903	2903	
Cruise	2947	2947	
Skull Creek	3166	3166	
Cloverly	**3254**	**3254**	Primary target formation
Morrison	3573	3573	
Marmaton	5018	5018	
Cherokee	**5153**	**5153**	Secondary target formation
Cherokee Base	5373	5373	

[1] Measured depth.
[2] True vertical depth.

Stratigraphic Well

1. This well will be drilled to 5473’ with two target formations, Cloverly and Cherokee. Schlumberger estimates 23 days required for well drilling and P&A (plug & abandon), which is shown in Figure C-8 and C-9. The cost estimate for well drilling and P&A is shown in Figure B-24 in Appendix B.

2. The objective of a stratigraphic well is to collect formation data through coring and particular logs. The core and log data will be analyzed to identify formation capability to store CO_2.

3. Planned coring intervals are 3204’ – 3604’ (Core Point 1) and 5103’ – 5403’ (Core Point 2). It consists of the following:
   a. Core Point 1 with total core length of 400’
      i. 50’ of Skull Creek (top confining layer)
      ii. 319’ of Cloverly (primary target zone)
      iii. 31’ of Morrison (bottom confining layer)
   b. Core Point 2 with total core length of 300’
      i. 50’ of Marmaton (top confining layer)
      ii. 220’ of Cherokee (secondary target zone)
      iii. 30’ of Cherokee base (bottom confining layer)

Coring will be done in multiple runs with various core lengths per run. The formation characteristic determines the length of core per run, which varies from 40’ to 120’ per run.

4. Logging
   Besides coring, logging data are necessary to have comprehensive information on Cloverly and Cherokee Formations, including their sealing systems. Triple combo, consisting of gamma ray (GR), resistivity, porosity, density, and caliper log, will be running along with Spectral GR, fracture finder, and modular formation dynamics tester (MDT) in openhole section. Cement bond (CBL), variable density (VDL), temperature, GR, and casing collar locator (CCL) log will be running in cased hole section. The measured data from each logging tool are listed in Table C-1.

Table C-1 Logging Tools and Its Description

No.	Logging Tools	Objectives
1	**Resistivity**	Identify fluid type in the reservoir
2	**Spontaneous potential (SP)**	Detect permeable beds and estimate formation water salinity and formation clay content
3	**Caliper**	Identify wellbore size, reference for cement volume calculation
4	**GR**	Lithology, identify clays that could affect injectivity, core/log correlations.
5	Porosity	Identify porosity, the presence of hydrocarbon in the reservoir
6	Borehole compensated sonic	It measures the elastic compressional wave velocity of the formation surrounding the borehole. It is considered as a miniature seismic refraction experiment carried out within the cylindrical borehole.
7	**Fracture finder**	Identify fractures in reservoir
8	**CBL**	Cement top, cement bond quality, zonal isolation.
9	**VDL**	Cement top, cement bond quality, zonal isolation.
10	**Temperature log**	Identify reservoir temperature and gradient
11	CCL	To locate casing collars, for correlation

5. Other Tests
   Fluid samplings will be performed in Cloverly, Cherokee, and Cruise as the next permeable zone above the Cloverly. Fluid samples from Cloverly and Cherokee will be analyzed for fluid compatibility prior to injecting CO_2 into the formation.

   Injectivity testing will be implemented in Cloverly and Cherokee to identify formation capability in accepting CO_2 injection.

6. P&A Program
   Once the characterization process is complete, the stratigraphic well will be plugged and abandoned. Multiple cement plugs will be placed to isolate Cloverly and Cherokee Formations

and isolate the well to the surface. The cement plug placement will prevent any fluid vertical movement or any USDW (underground sources of drinking water) contamination in the future.

7. Hole and Casing Plan of the Stratigraphic Well

Section	Bit Size	Casing Size	Casing Type	Depth
Conductor		16		0–90’
Surface	12-½”	9-5/8”	36#, J-55	0–526’
Long-String	8-¾”	No casing		

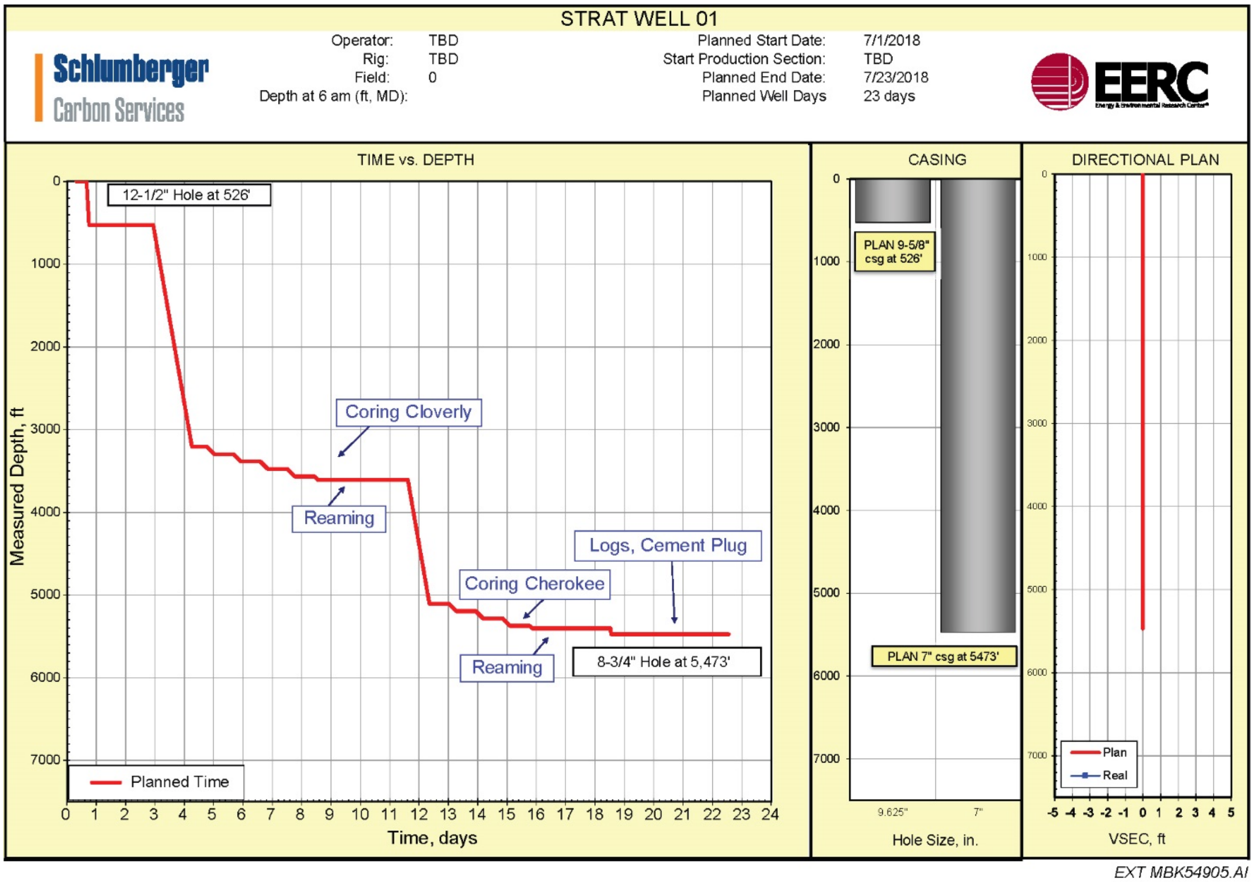
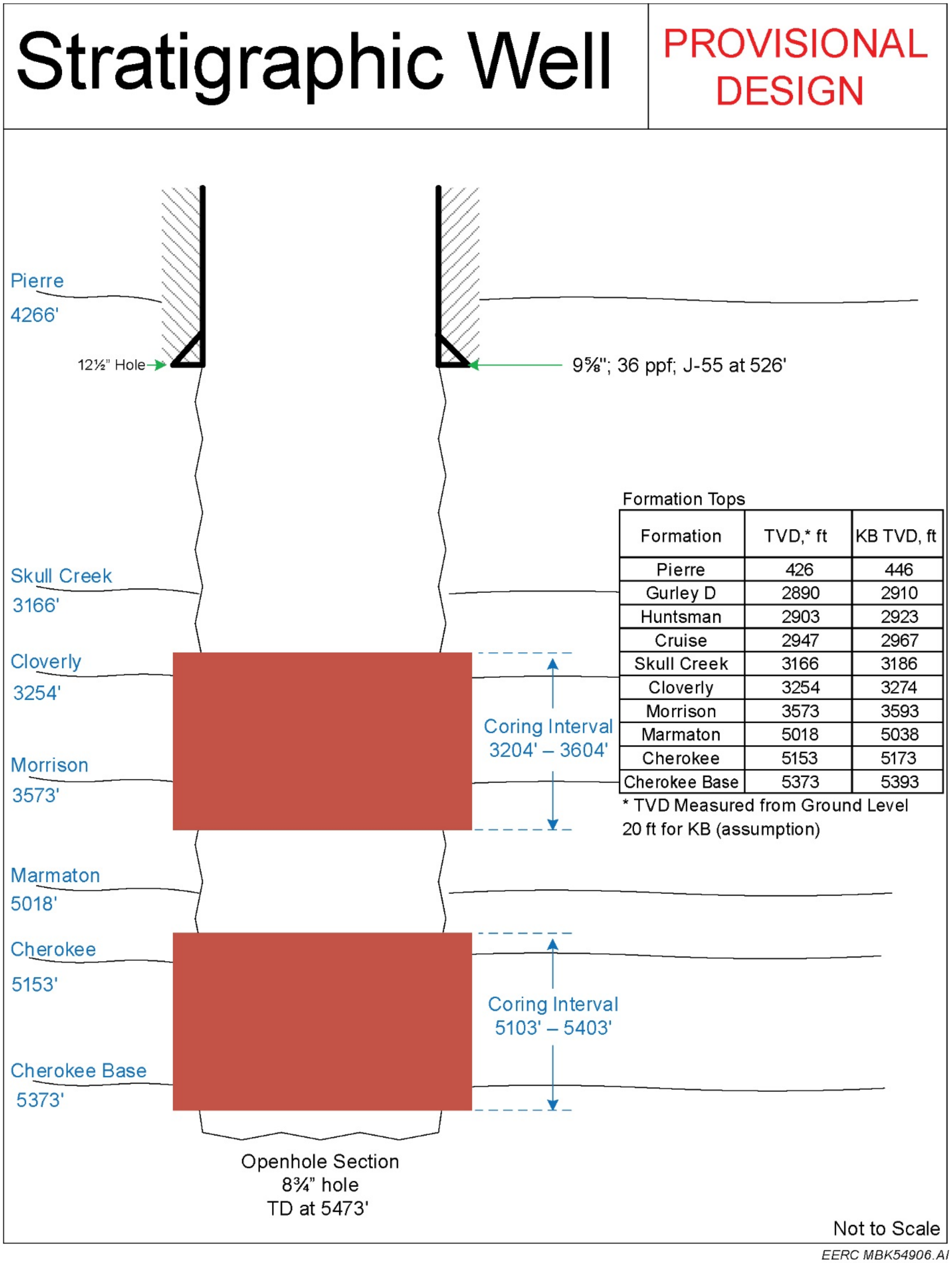


Figure C-8. Well drilling plan of Nebraska stratigraphic well.



Formation	TVD,* ft	KB TVD, ft
Pierre	426	446
Gurley D	2890	2910
Huntsman	2903	2923
Cruise	2947	2967
Skull Creek	3166	3186
Cloverly	3254	3274
Morrison	3573	3593
Marmaton	5018	5038
Cherokee	5153	5173
Cherokee Base	5373	5393

Figure C-9. Well schematic of stratigraphic well.

Monitoring Well

1. This well will be drilled to 5473’ with two target formations: Cloverly and Cherokee. Schlumberger estimates 25 days required for well drilling, which is shown in Figure C-10 and C-11, and 14 days required for well construction. The cost estimate for well drilling and construction cost is shown in Figure B-25 in Appendix B.

2. The main objective of the monitoring well is to monitor the plume growth in a particular direction. The location of the monitoring well will be in the updip direction of the injection well. Another objective is to collect fluid samples from the target formations and the next permeable formation.

3. Planned coring intervals are 3204’–3604’ (Core Point 1) and 5103’–5403’ (Core Point 2). It consists of the following:
   a. Core Point 1 with total core length of 400’
      i. 50’ of Skull Creek (top confining layer)
      ii. 319’ of Cloverly (primary target zone)
      iii. 31’ of Morrison (bottom confining layer)
   b. Core Point 2 with total core length of 300’
      i. 50’ of Marmaton (top confining layer)
      ii. 220’ of Cherokee (secondary target zone)
      iii. 30’ of Cherokee base (bottom confining layer)

      Coring will be done in multiple runs with various core lengths per run. The formation characteristic determines the length of core per run, which varies from 40’ to 120’ per run.

4. Logging
   Besides coring, logging data are necessary to have comprehensive information on Cloverly and Cherokee Formations, including their sealing systems. Triple combo, consisting of GR, resistivity, porosity, density, and caliper log, will be running along with Spectral GR, fracture finder, and MDT in an openhole section. CBL, VDL, temperature, GR, and CCL log will be running in a cased-hole section. The measured data from each logging tool are listed in Table C-1.

5. Other Tests
   Fluid sampling will be performed in Cloverly, Cherokee, and Cruise as the next permeable zone above the Cloverly. Fluid samples from Cloverly and Cherokee will be analyzed for fluid compatibility prior to injecting CO_2 into the formation.

   Injectivity testing will be implemented in Cloverly and Cherokee to identify formation capability in accepting CO_2 injection.

6. Completion
   In addition to the logging mentioned in Section 4, a cased-hole log (CBL–VDL–CCL–GR–temperature logs) will be run to observe the cement bonding quality of the long-string section. Good cement bonding will diminish the possibility of any CO_2 cross-flow.

   The monitoring well will be completed with the following equipment:
   a. Tubing and casing with the compatible material (13Cr or IPC – internal plastic coating)
   b. Gauges (pressure and temperature) at the following:
      i. Injection zone
      ii. Next permeable zone above confining layer of the injection zone
   c. CO_2-resistant cement with additives
   d. Mechanical integrity test
   e. Formation fluid samplers at the following:
      i. Interest zone
      ii. The permeable zone above the confining layer
      It is mainly used to sample fluid from the reservoir. It can also be used to confirm the predicted breakthrough time from the reservoir model by tracking CO_2 content in the reservoir during the project lifetime.

7. Casing Plan of the Monitoring Well

Section	Bit Size	Casing Size	Casing Type	Depth
Conductor		16		0–90’
Surface	12-½”	9-5/8”	36#, J-55	0–526’
Long-String	8-¾”	7”	26#, L-80 26#, 13Cr	0–5473’

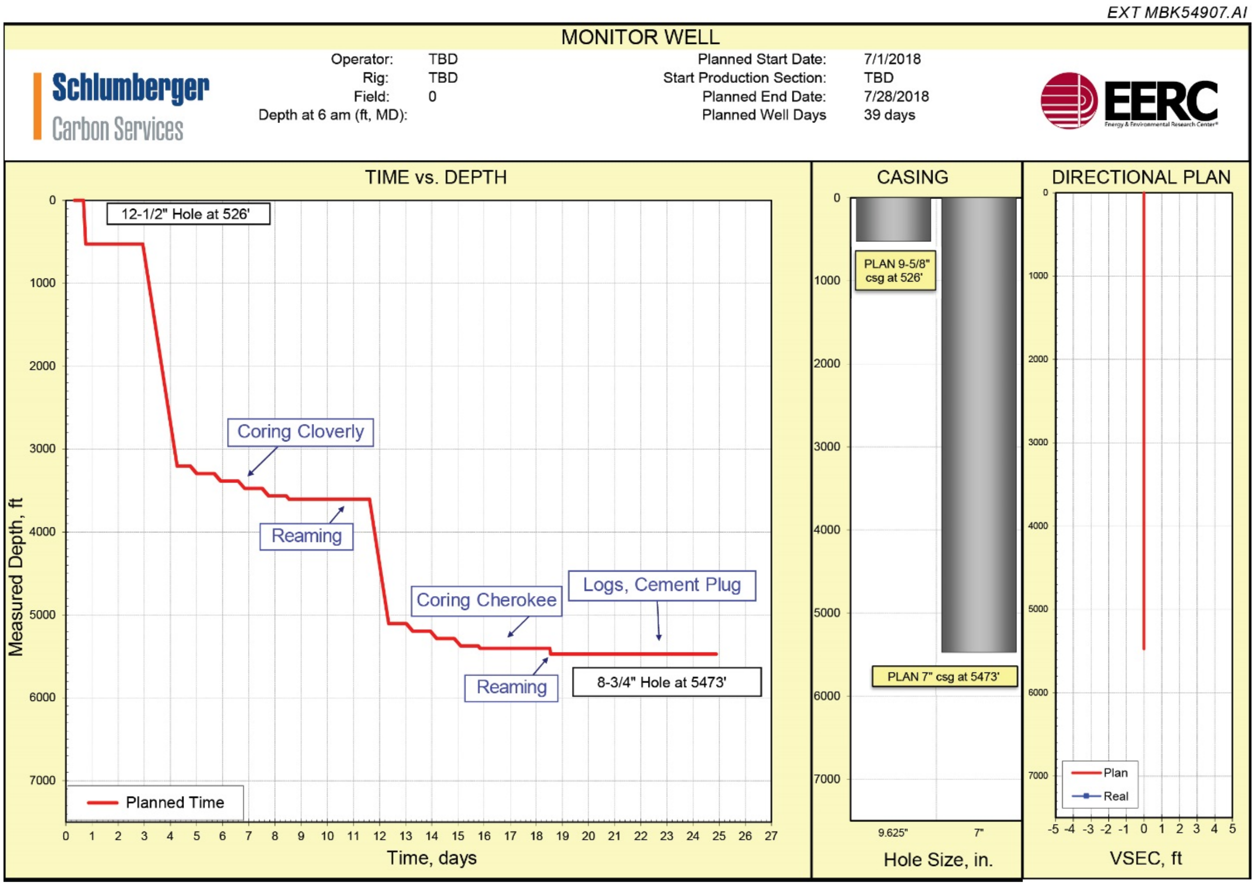


Figure C-10. Well drilling plan of Nebraska monitoring well.

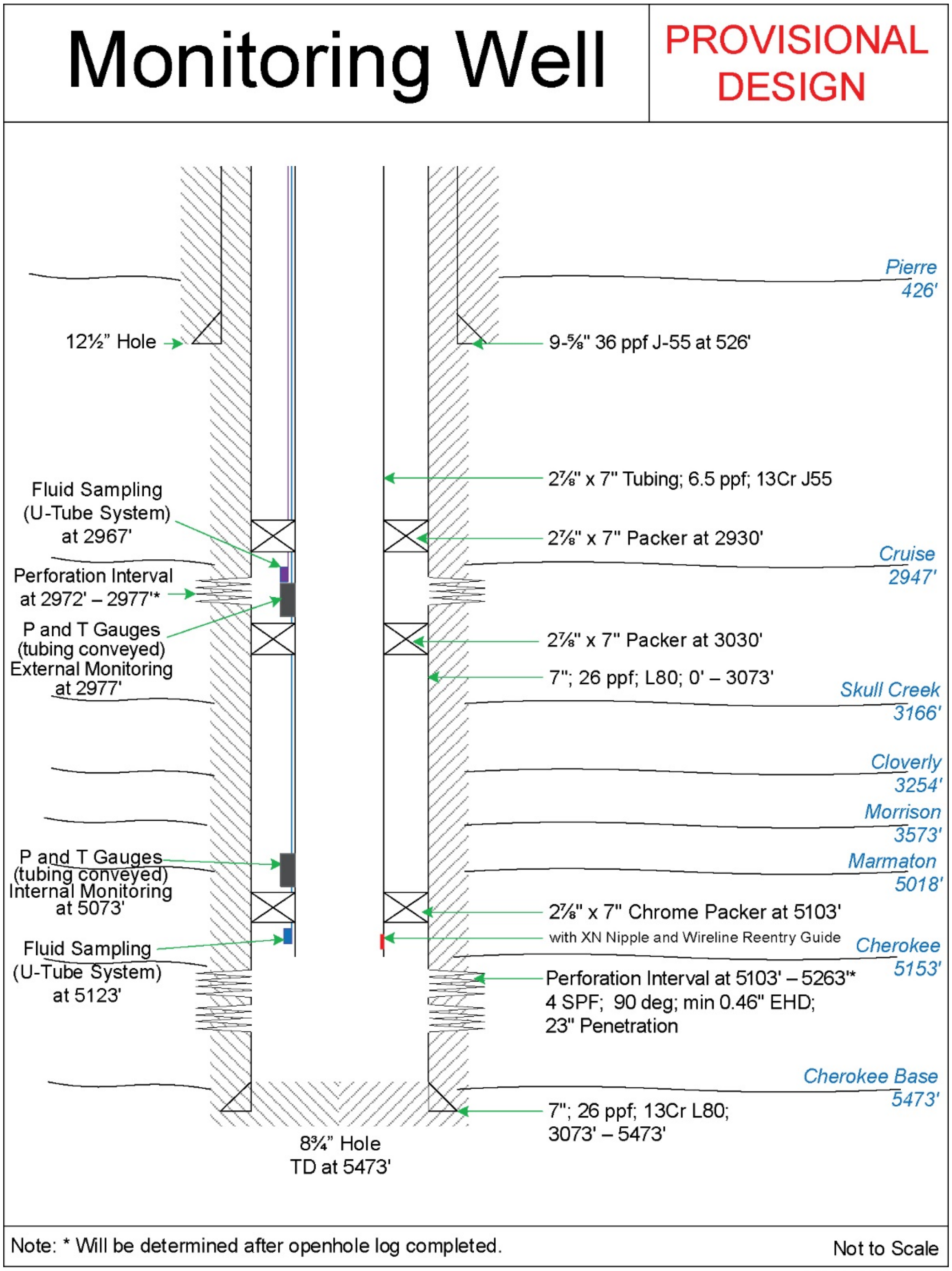


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Figure C-11. Well schematic of monitoring well.

Injection Well

1. This well will be drilled to 5473’ with two target formations: Cloverly and Cherokee. Schlumberger estimates 25 days required for well drilling, which is shown in Figure C-12 and Figure 13, and 8 days required for well construction. The cost estimate for well drilling and construction cost is shown in Figure B-26 in Appendix B.

2. The main objective of the injection well is to inject the CO_2 into a particular formation. The injection well is designed to comply the Class VI well standard.

3. Planned coring intervals are 3204’–3604’ (Core Point 1) and 5103’–5403’ (Core Point 2). It consists of the following:
   a. Core Point 1 with total core length of 400’
      i. 50’ of Skull Creek (top confining layer)
      ii. 319’ of Cloverly (primary target zone)
      iii. 31’ of Morrison (bottom confining layer)
   b. Core Point 2 with total core length of 300’
      i. 50’ of Marmaton (top confining layer)
      ii. 220’ of Cherokee (secondary target zone)
      iii. 30’ of Cherokee Base (bottom confining layer)

      Coring will be done in multiple runs with various core lengths per run. The formation characteristic determines the length of core per run, which varies from 40’ to 120’ per run.

4. Logging
   Besides coring, logging data are necessary to have comprehensive information on Cloverly and Cherokee Formations, including their sealing systems. Triple combo, consisting of GR, resistivity, porosity, density, and caliper log, will be running along with Spectral GR, fracture finder, and MDT in an openhole section. CBL, VDL, temperature, GR, and CCL log will be running in a cased-hole section. The measured data from each logging tool are listed in Table C-1.

5. Other Tests
   Fluid samplings will be performed in Cloverly, Cherokee, and Cruise as the next permeable zone above the Cloverly. Fluid samples from Cloverly and Cherokee will be analyzed for fluid compatibility prior to injecting CO_2 into the formation.

   Injectivity testing will be implemented in Cloverly and Cherokee to identify formation capability in accepting CO_2 injection.

6. Completion
   In addition to the logging mentioned in Section 4, a cased-hole log (CBL–VDL–CCL–GR–temperature logs) will be running to observe the cement bonding quality of the long-string section. Good cement bonding will diminish the possibility of any CO_2 crossflow.

The injection well will be completed with the following equipment:

a. Tubing and casing with the compatible material (13Cr or IPC)
b. Gauges (pressure and temperature) at the injection zone
c. CO_2-resistant cement with additives
d. Mechanical integrity test

7. Casing Plan of the Monitoring Well

Section	Bit Size	Casing Size	Casing Type	Depth
Conductor		16		0–90’
Surface	12-½”	9-5/8”	36#, J-55	0–526’
Long-String	8-¾”	7”	26#, L-80 26#, 13Cr	0–5473’

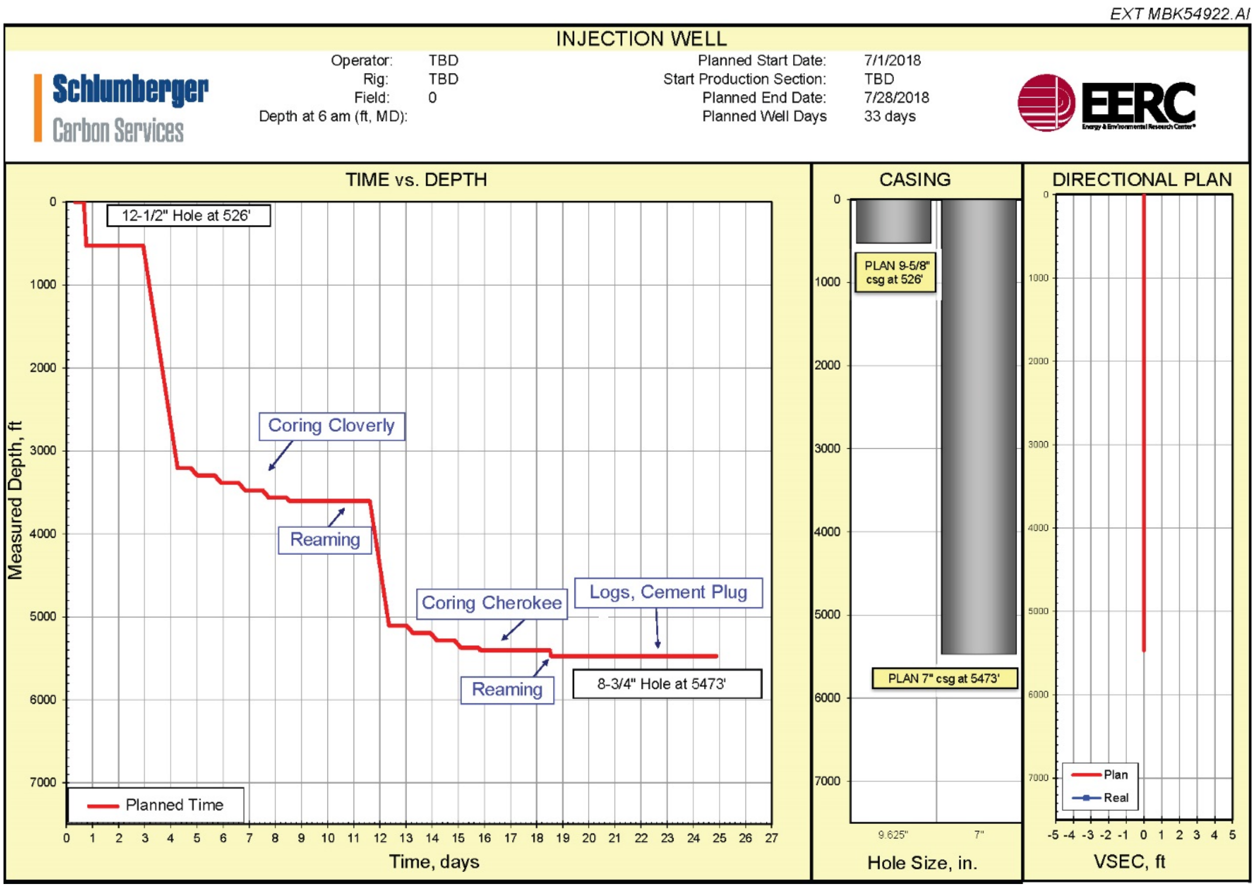

Figure C-12. Well drilling plan of Nebraska injection well.

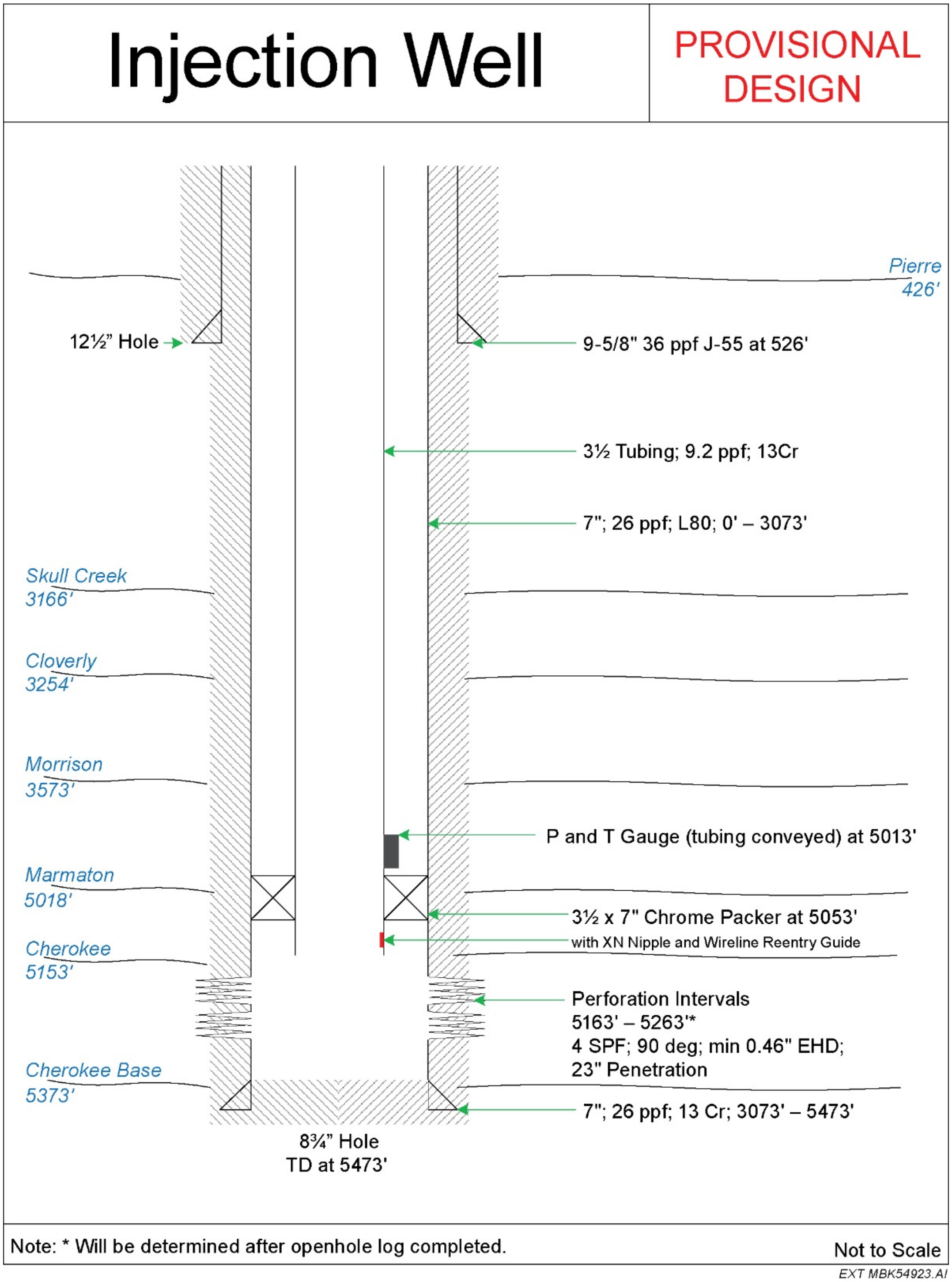

Figure C-13 Well schematic of injection well.

Infrastructure

1. Surface Monitoring
   a. Injection pressure with a digital pressure gauge
   b. Injection rate with flowmeter/Coriolis
   c. Injection volume with flowmeter/Coriolis
   d. Annulus pressure with a digital pressure gauge
   e. Annulus fluid volume with a flowmeter
   f. Corrosion coupon. It is a corrosion monitoring system that is installed in the pipe near the wellhead. The coupon will be periodically installed and analyzed.
   g. Emergency shutdown system or ESD which is used to shut down the system when any problem occurs, such as leaks or overpressure due to an obstructed system
   h. Pipeline pressure with the pressure sensor
   i. Pipeline flowmeters to track rates and volumes (mass balancing)

2. Supporting Infrastructure
   a. SCADA (supervisory control and data acquisition) is used to monitor and control all attached systems. It is able to shut down or turn on the system or adjust operation parameters.
   b. Processing facility of U-tube supporting system. It will be used to provide compressed N_2 as a lifting fluid and separate the reservoir fluid and the lifting fluid.
   c. Surface monitoring unit for IntelliZone. It will open/close the sliding sleeve at the sampled zone.

CO_2 Plume Growth

1. Monitoring well. It will monitor the plume growth in formation updip direction (direction of monitoring well to injection well).
2. Reservoir simulation model. It generates a predicted plume growth but does not report actual growth.
3. Seismic. It identifies the CO_2 plume growth at a specific area in a specific time. Preinjection seismic should be done as a baseline.
4. Geophones. It can identify the CO_2 plume growth at a specific area in a specific time. Preinjection seismic should be done as a baseline.
5. BSEM. This technology can leverage the resistivity contrast between the brine character of the target formations at the beginning of the project and at the end (or post-CO_2 injection). The resistivity changing can be processed to identify the growth of the CO_2 plume in the formation.

ADDITIONAL DETAIL ABOUT TECHNOLOGIES

IntelliZone by Schlumberger

Figure C-14. IntelliZone compact system for fluid sampling.

SageWatch and EasyRider

SAGE Watch™
Subsurface Surveillance Systems

SAGE RIDER

The SageRider SageWatch™ Subsurface Surveillance System is an innovative Permanent Monitoring system designed to provide continuous real-time Pressure/Temperature data for a variety of valuable reservoir applications. The system design allows for simultaneous monitoring of as many points/zones as desired within a single wellbore, vertical or horizontal, with any size casing. There are two distinct installation methods that provide a wide variety of wellbore configurations and monitoring options. The SageWatch™ system can be installed on the outside of the casing from where it can monitor reservoir activity only, internal casing activity only, or a combination of external and internal activity. This method is cemented in place to provide isolation between zones. The SageWatch™ system can also be installed into an existing cased wellbore to monitor individual sections within the wellbore, isolation for this method is accomplished through the use of hydraulic or swellable packers.

The SageWatch™ Subsurface Surveillance System installed permanently behind pipe is conveyed as an integral part of the casing string with all communication/power lines running along the outside of the casing to surface. Once cemented in place the P/T gauges are connected to the reservoir through perforations directed into the formation (only). This allows for continuous real-time undisturbed reservoir data that can be monitored during all subsequent drilling, stimulation, and production in the area. Each individual monitoring point up and down the wellbore is isolated from each other by cement to give true individual points of data from as many zones as desired. This method, powered from surface, collects data at surface which can be accessed locally or transmitted wirelessly via any typical field SCADA type system.

Applications for the external casing SageWatch™ system have rapidly progressed beyond “monitor only” wells. The system can also be installed for completion wells and those completions monitored with the real-time downhole P/T gauges in place. As an added benefit multiple monitoring points can be ported to read internal pressure at any point along the wellbore during these operations.

Benefits of this system include:

- Reservoir Definition , Establishing True Perm, Identifying Crossflow
- Well Spacing Optimization
- Verifying Injection Pressures, Migration
- Identification of Unusual Geology
- Modeling Verification and Calibration
- Offset Fracturing
- Downhole Fracture Monitoring
- Ability to Run in Conjunction with Fiber Optics

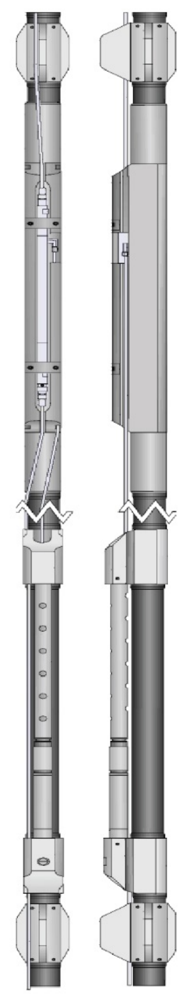

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Figure C-15. SageWatch systems.

SageWatch™ System Size Chart – Casing Integrated

Casing Size	2.875"	3.50"	4.50"	5.00"	5.50"	7.00"	7.625"	9.625"
System OD	5.130"	6.00"	6.75"	7.25"	7.75"	9.25"	9.875"	11.875"

SageWatch™ Gauge Specifications

Measurement Method	Quartz Transducer
Pressure Rating Temperature Rating	20,000 psi 392 deg F
Pressure Resolution Temperature Resolution	0.01 psi 0.01 deg F
Pressure Accuracy Temperature Accuracy Hysteresis	+/- 0.02 % of Calibration +/- 0.90% of Calibration +/- 0.02 % of Calibration
Data Polling	1 Sample/Second/Gauge

The SageWatch™ Subsurface Surveillance System installed into an existing wellbore provides the same continuous real-time data only it is monitoring each area of the wellbore between isolation points. As with the previous method, as many monitoring points as desired can be installed. This method can be run in conjunction with the perforating aspect, or without in the case of wells that have already been perforated. Isolation for this system can be accomplished through the use of multiple hydraulic or swellable packers. Additional benefits of this system include:

- Can be run in Small or Large Casing
- Can take Advantage of Old Vertical Wells
- Can be installed above areas of Collapsed Casing
- Provides Data to Monitor Close Proximity New Wells

The SageWatch™ Subsurface Surveillance System is a unique proven effective method for gathering long term and/or short term data for a wide base of applications. Data supplied by SageWatch™ creates high level value through a better understanding of reservoir parameters, connectivity, field drainage, and stimulation processes. We at SageRider pride ourselves on project managing all aspects of every SageWatch™ installation, this turnkey approach has built our reputation and ultimately lead to our Clients long term success.

For more information contact us at info@sageriderinc.com

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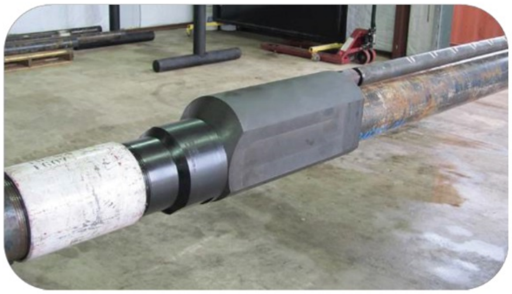
Figure C-16. SageWatch specification.

EasyRider™ Multi-Zone Completion System

- Perforating guns integrated on the outside of the casing fire into the casing and into the formation
- Toe guns are initiated by internal casing pressure
- Subsequent stages are initiated and isolated through reliable ball/ball seat technology
- Additional cluster gun sections initiated through pressure transfer line simultaneous to stage section initiation



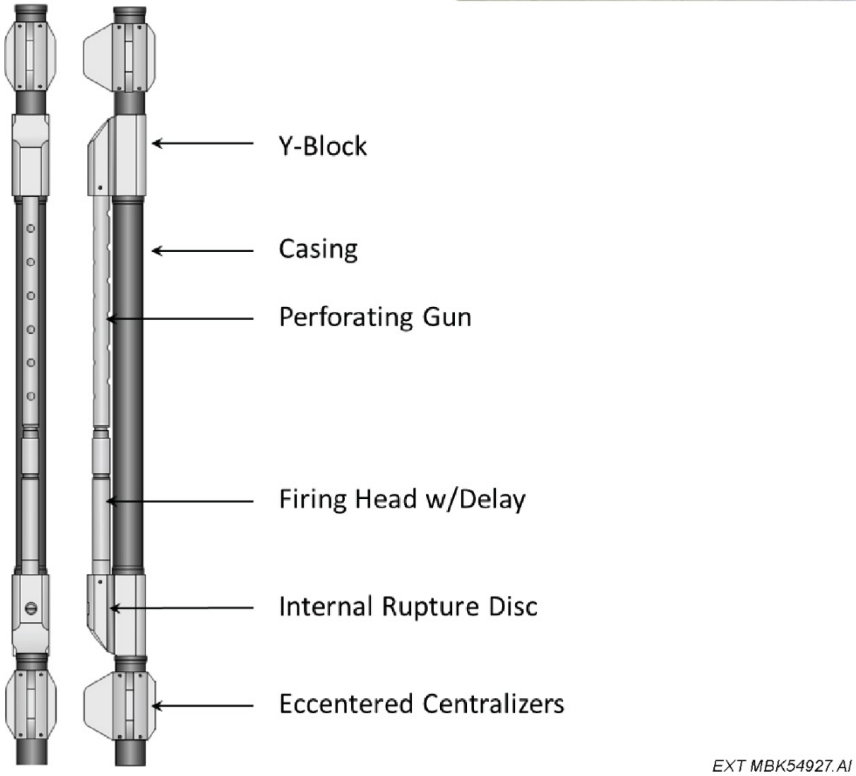


Figure C-17. EasyRider system.

PROMORE

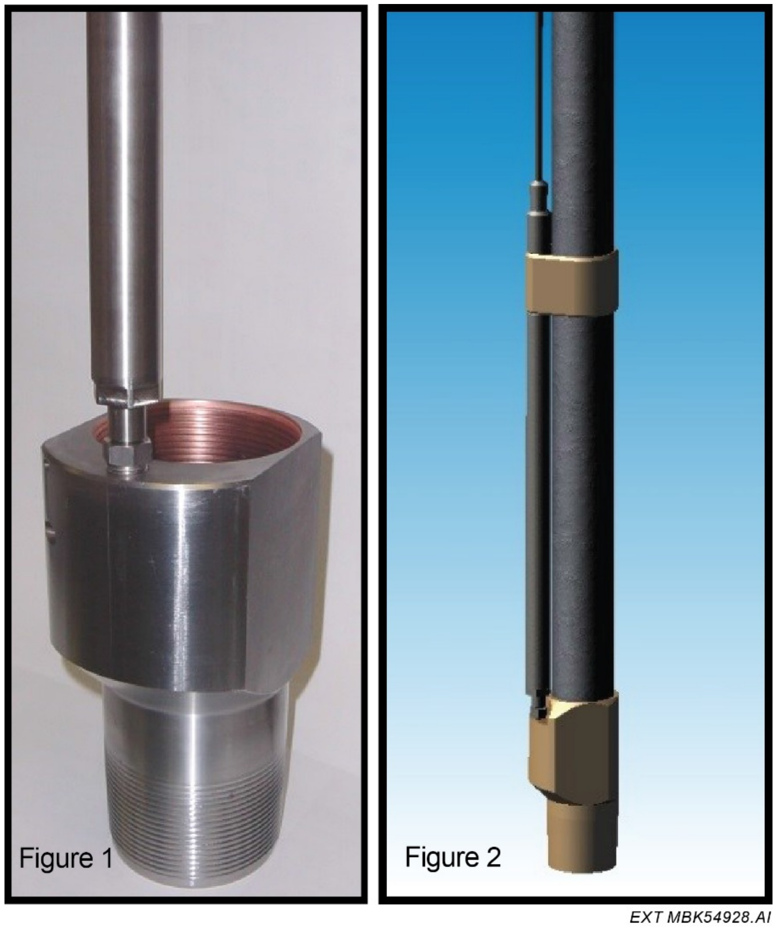
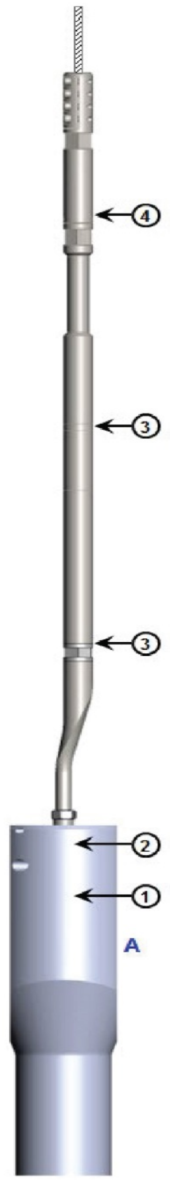


Figure C-18. PROMORE casing-conveyed system.

Design Specifications and Manufacturing Notes

QF-24, Rev. 0, Nov. 2004			Page 1 of 1
Description:	*Pressure Gauge - MT1-MT-5000-1.000*	*Part Number:*	*FG-100118*
Description:	*Tubing Mandrel - YB-API-7.000-L80-1*	*Part Number:*	*FG-102042*



	OVERALL DIMENSIONAL DATA
Overall Length	51 inch
Maximum Running Outside Diameter	8.630 inch
Overall Weight	Approximately 70 lbs

	MANDREL DIMENSIONAL DATA
Length	22 inch
Mandrel Weight	Approximately 60 lbs
Maximum Outside Diameter	8.630 inch
Coupling Outside Diameter	7.656 inch
Inside Diameter	6.276 inch
Drift Diameter	6.151 inch
Tubing Weight	26.0 lb/ft
Connection Type	API - LT&C
Thread 1	7.000 inch - Box
Thread 2	7.000 inch - Pin

	MANDREL PERFORMANCE DATA
Service Conditions	Mild H2S, Mild CO2
Material Grade	L80
Internal Yield Pressure	7,240 psi
Collapse Pressure	5,410 psi
Minimum Material Yield Strength	80,000 psi
Maximum Material Yield Strength	95,000 psi
Minimum Material Tensile Strength	95,000 psi
Joint Yield Strength	519,000 lbs

	GAUGE DIMENSIONAL DATA
Length	29 inch
Maximum Outside Diameter	1.000 inch
Gauge Weight	Approximately 10 lbs

	GAUGE SPECIFICATIONS
Gauge Type	ERD™ (Electrical Resonating Diaphragm)
Service Conditions	H_2S, CO_2
Wetted Part Material	Incoloy 925
Non-Wetted Material	Hasteloy C-276
Non-Critical Material	4140 QT NACE MR01-75
Sensor Count	1 Pressure and 1 Temperature
A	Internal Casing Pressure / BHT
Temperature Rating (Sensor)	300 Fahrenheit
Pressure Rating (Sensor)	5,000 psi
Minimum Collapse Pressure (Sensor Housing)	20,000 psi
Vibration Rating	35 G - 10 to 70 Hz
Shock Rating	500 G - 1/2 Sine Wave of 2 ms on 3 Axis
	50 G - 1/2 Sine Wave of 10 ms on 3 Axis
Sensor Housing Cable Head	1.000" OD Clamp Style Cable Head (DAC)
Primary Internal Seal [1]	20,000 psi Metal-to-Metal
Secondary Internal Seal [2]	Dual Viton 90 Durometer O-Rings
Primary External Seal [3]	Hermetically Sealed (Welded)
Secondary External Seal [4]	20,000 psi, 4-Pin, Welded Inconel Connector

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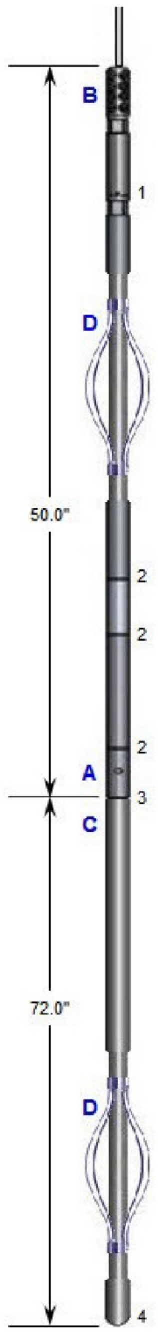
Figure C-19. PROMORE casing-conveyed specification.

Design Specifications and Manufacturing Notes

QF-24, Rev. 0, Nov. 2004	Page 1 of 1
Description: ***Pressure Gauge - MS1-MT-5000-1.375***	***Part Number:*** ***FG-103053***



	OVERALL DIMENSIONAL DATA
Overall Length	122 inch
Maximum Running Outside Diameter	1.375 inch
Overall Weight	Approximately 56 lbs

	GAUGE DIMENSIONAL DATA
Length	50 inch
Maximum Outside Diameter	1.375 inch
Gauge Weight	Approximately 20 lbs

	GAUGE SPECIFICATIONS [B]
Gauge Type	ERD™ (Electrical Resonating Diaphragm)
Service Conditions	H_2S, CO_2
Wetted Part Material	Incoloy 925
Non-Wetted Material	Hasteloy C-276
Non-Critical Material	4140 QT NACE MR01-75
Sensor Count	1 Pressure and 1 Temperature
A - Pressure Access Port	Casing Annulus Pressure / BHT
Temperature Rating (Sensor)	300 Fahrenheit
Pressure Rating (Sensor)	5,000 psi
Minimum Collapse Pressure (Sensor Housing)	20,000 psi
Vibration Rating	35 G - 10 to 70 Hz
Shock Rating	500 G - 1/2 Sine Wave of 2 ms on 3 Axis
	50 G - 1/2 Sine Wave of 10 ms on 3 Axis
Sensor Housing Cable Head	1.375" OD TEC Cable Head
Primary Internal Seals [1]	Metal-to-Metal (Autoclave)
Primary External Seals [2]	Hermetically Sealed (Welded)

	SINKER BAR SPECIFICATIONS [C]
Length	72 inch
Weight	30 lbs
Maximum Outside Diameter	1.375 inch
Bullnose [4]	1/2 Round
Thread Connection [3]	Stub ACME - 0.375" OD
Service Conditions	Mild H_2S, Mild CO_2
Metallurgy	AISI 4130 Q&T

	CENTRALIZER SPECIFICATIONS [D]
Length (Each)	16 inch
Weight (Each)	3 lbs
Maximum Outside Diameter	1.375 inch
Minimum Running Restriction	1.560 inch
Maximum Bow Spring Expansion	7.000 inch
Service Conditions	Mild H_2S, Mild CO_2
Metallurgy	AISI 4130 Q&T

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Figure C-20. PROMORE suspended-gauge specification.

BSEM

BSEM analysis is used to measure the salinity contrast between the injected CO_2 and native formation fluid. When mapped, this information provides an image of the CO_2 plume around the injector well. It is often performed at both the beginning and the end of a project.

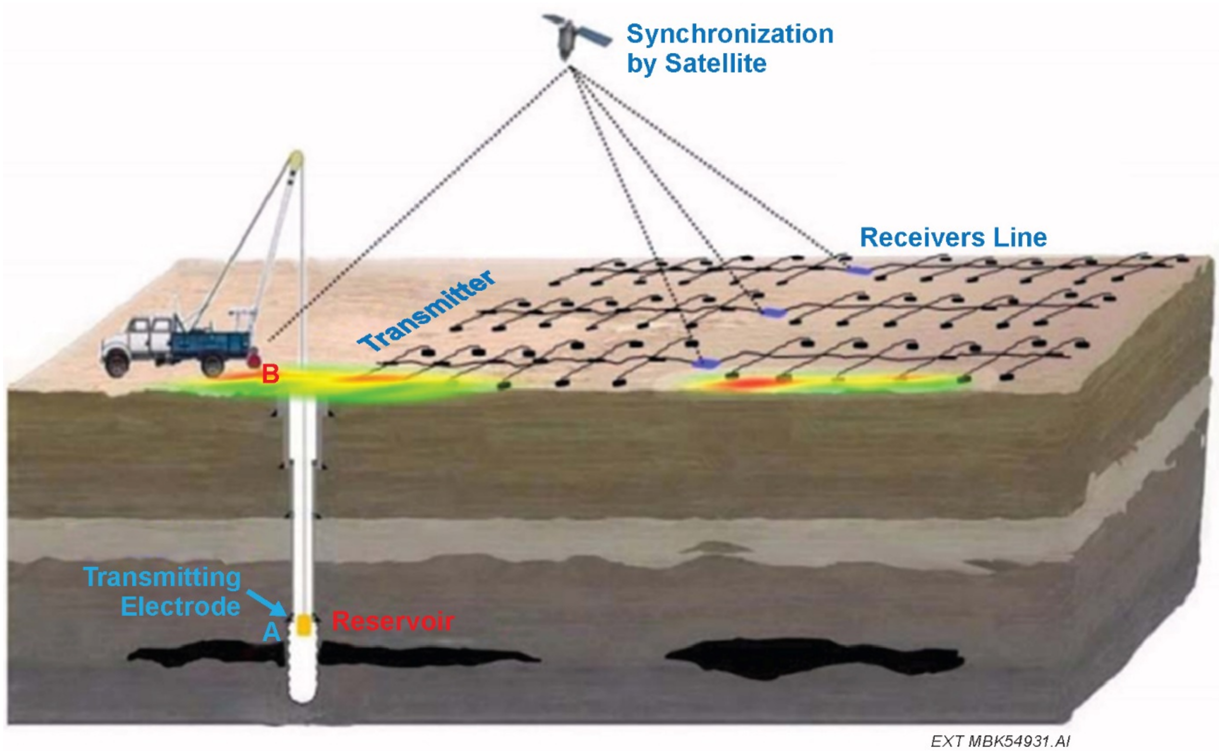

Figure C-21. Schematic of BSEM layout.

Logging

Technique/Well/Interval		Quantity	Justification
Well Logging			
	Surface Section		
OH[1]	Triple combo (resistivity, gamma ray [GR], caliper, and SP)	Surface section	Regulatory requirement, quantify variability in reservoir properties such as resistivity, lithology, and core/log correlations. Identify the wellbore volume to calculate required cement volume.
CH[2]	CBL-VDL-temperature log-CCL	Surface casing section	Regulatory requirement, identify cement bond quality, cement top, and zonal isolation.
	Long-String Section		
OH	Triple combo (resistivity, GR, caliper, and SP)	Long-string section	Regulatory requirement, quantify variability in reservoir properties at the target formations. Provide an input for enhanced geomodeling and predictive simulation of CO_2 injection into target formations. Generate core/log correlations that can be extrapolated to surrounding areas. Select well test intervals and well completion intervals.
OH	Capture spectroscopy/spectral GR	Long-string section	Lithology, identify clays that could affect injectivity, core/log correlations.
OH	Fracture finder logs (acoustic log)	Long-string section	Regulatory requirement, quantify fracture in the target formations and confining layers to ensure the safety aspect of injecting CO_2 into target formations, especially in protecting groundwater, and quantify sealing quality of confining layers.
OH	Fluid sampling	Injection zones/ target zones/ interest zones	Collect reservoir fluid sample for testing of potential fluid and mineralogical reactions between injected fluid chemistry, formation fluid chemistry, and formation mineralogy that could affect injectivity.
CH	CCL–CBL–VDL–temperature log–CCL	Long-string casing section	Regulatory requirement, identify cement bond quality, cement top, and zonal isolation.

[1] Openhole.
[2] Cased hole.

Cost Estimate for Well Drilling and Completion

A cost estimate for well drilling and completion was performed by Schlumberger Carbon Services. The details are presented in the following pages.

EXT MBK54933.AI

EERC

CarbonSAFE Stratigrphic Test Well - Nebraska

AUTHORIZATION FOR EXPENDITURES - Est Cost

Schlumberger Carbon Services

In US $

Operator:	EERC	Project Type :	C02 Sequestration		
Contract Area:	Nebraska	Well Name :	Stratigrphic Test Well		
Contract Area #:		Well Type :	Exploration		
Prepared by	WR, GV, JK, NM	Platform/Tripod :		AFE #:	1 of 3
		Field/Structure :		Date:	10-Jan-18
		Basin :			

Location ____________ Surface Coordinate ____________

Surface Elev. ____________ Elevation ____________

	PROGRAM	ACTUAL
Spud Date		
Compl Date		
In Service		
Drilling Days		

	PROGRAM	ACTUAL
Rig Days	20	
Total Depth	5473	
Well Cost $/Ft.	$0.00	
Well Cost $/Day	$0.00	

Close Out Date: ________ Completion Type: Cased Hole ________ Well Status: Pre Permit

	Description	Dry Hole Budget	Completed Budget	Total Budget	Actual Expenditure	Actual Over/Under	% Over/Under
1	TANGIBLE COSTS						
2	Casing	18,150	0	18,150	$0	18,150	100%
3	Casing Accessories; Float Equip & Liners	3,000	0	3,000	$0	3,000	100%
4	Tubing		0	0	$0	0	
5	Well Equipment - Surface	5,000	0	5,000	$0	5,000	100%
6	Well Equipment - Subsurface	0	0	0	$0	0	
7	Other Tangible Costs	0	0	0	$0	0	
8	Contingency	2,615	0	2,615	$0	2,615	100%
9	Total Tangible Costs	$28,765	$0	$28,765	$0	28,765	100%
10	INTANGIBLE COSTS						
11	PREPARATION & TERMINATION						
12	Surveys	7,000	0	7,000	$0	7,000	100%
13	Location Staking & Positioning	4,500	0	4,500	$0	4,500	100%
14	Wellsite & Access Road Preparation	120,000	0	120,000	$0	120,000	100%
15	Service Lines & Communications	25,500	0	25,500	$0	25,500	100%
16	Water Systems	0	0	0	$0	0	
17	Rigging Up/Rigging Down/ Mob/Demob	400,000	0	400,000	$0	400,000	100%
19	Total Preparations/MOB	$557,000	$0	$557,000	$0	557,000	100%
20	DRILLING - W/O OPERATIONS						
21	Contract Rig	595,640	0	595,640	$0	595,640	100%
22	Drlg Rig Crew/Contract Rig Crew/Catering	0	0	0	$0	0	
23	Mud, Chem & Engineering Servs	69,208	0	69,208	$0	69,208	100%
24	Water	15,000	0	15,000	$0	15,000	100%
25	Bits, Reamers & Coreheads	12,415	0	12,415	$0	12,415	100%
26	Equipment Rentals	73,270	0	73,270	$0	73,270	100%
27	Directional Drlg & Surveys	172,548	0	172,548	$0	172,548	100%
28	Closed Loop and Disposal	98,898	0	98,898	$0	98,898	100%
29	Casing & Wellhead Installation & Inspection	52,641	0	52,641	$0	52,641	100%
30	Cement, Cementing & Pump Fees	90,000	0	90,000	$0	90,000	100%
31	Misc. H2S Services	0	0	0	$0	0	
32	Total Drilling Operations	$1,179,620	$0	$1,179,620	$0	1,179,620	100%
33	FORMATION EVALUATION						
34	Coring	280,000	0	280,000	$0	280,000	100%
35	Mud Logging Services	0	0	0	$0	0	
36	Drillstem Tests	0	0	0	$0	0	
37	Open Hole Elec Logging Services	284,522	0	284,522	$0	284,522	100%
39	Total Formation Evaluation	$564,522	$0	$564,522	$0	564,522	100%
40	COMPLETION						
41	Casing, Liner, Wellhead & Tubing Installation	0	0	0	$0	0	
42	Remedial Cementing and Fees	0	0	0	$0	0	
43	Cased Hole Elec Logging Services	10,000	0	10,000	$0	10,000	100%
44	Perforating & Wireline Services	0	0	0	$0	0	
45	Stimulation Treatment	0	0	0	$0	0	
46	Production Tests	0	0	0	$0	0	
48	Total Completion Costs	$10,000	$0	$10,000	$0	10,000	100%
49	GENERAL						
50	Supervision	170,300	0	170,300	$0	170,300	100%
51	Insurance	50,000	0	50,000	$0	50,000	100%
52	Permits & Fees	45,000	0	45,000	$0	45,000	100%
53	Marine Rental & Charters	0	0	0	$0	0	
54	Helicopter & Aviation Charges	0	0	0	$0	0	
55	Land Transportation	23,000	0	23,000	$0	23,000	100%
56	Other Transportation	0	0	0	$0	0	
57	Fuel & Lubricants Non Rig	3,900	0	3,900	$0	3,900	100%
58	Camp Facilities	20,000	0	20,000	$0	20,000	100%
59	Allocated Overhead - Schlumberger	89,435	0	89,435	$0	89,435	100%
60	Allocated Overhead - Main Office	0	0	0	$0	0	
61	Allocated Overhead - Overseas	0	0	0	$0	0	
62	Contingency Intangibles	271,278	0	271,278	$0	271,278	100%
64	Total General Costs	$672,912	$0	$672,912	$0	672,912	100%
65	TOTAL INTANGIBLE COSTS	$2,984,054	$0	$2,984,054	$0	2,984,054	100%
	TOTAL TANGIBLE COSTS	$28,765	$0	$28,765	$0	28,765	100%
66	TOTAL WELL COST			$3,012,819	$0	3,012,819	100%
67							
68							
69							
70							

Operator	Approved By:			Remarks
	Position			
	Date			
Operator Approval	Approved By;			
	Position			
	Date			

Figure C-22. Cost estimate for Nebraska stratigraphic well.

EXT MBK54934.AI

EERC

CarbonSAFE Monitor Well - Nebraska

AUTHORIZATION FOR EXPENDITURES - Est Cost

Schlumberger Carbon Services

In US $

Operator:	EERC	Project Type :	C02 Sequestration		
Contract Area:	Nebreska	Well Name :	Monitor Well		
Contract Area #:		Well Type :	MMV		
Prepared by	WR, GV, JK, NM	Platform/Tripod :		AFE #:	2 of 3
		Field/Structure :		Date:	10-Jan-18
		Basin :			

Location ______ Surface Coordinate ______

Surface Elev. ______ Elevation ______

	PROGRAM	ACTUAL
Spud Date		
Compl Date		
In Service		
Drilling Days		

	PROGRAM	ACTUAL
Rig Days	20	
Total Depth	5473	
Well Cost $/Ft.	$0.00	
Well Cost $/Day	$0.00	

Close Out Date: ______ Completion Type: Cased Hole ______ Well Status: Pre Permit

	Description	Dry Hole Budget	Completed Budget	Total Budget	Actual Expenditure	Actual Over/Under	% Over/Under
1	TANGIBLE COSTS						
2	Casing	18,150	142,853	161,003	$0	161,003	100%
3	Casing Accessories; Float Equip & Liners	3,000	15,482	18,482	$0	18,482	100%
4	Tubing		124,980	124,980	$0	124,980	100%
5	Well Equipment - Surface	5,000	134,000	139,000	$0	139,000	100%
6	Well Equipment - Subsurface	0	835,000	835,000	$0	835,000	100%
7	Other Tangible Costs	0	0	0	$0	0	
8	Contingency	2,615	125,232	127,847	$0	127,847	100%
9	Total Tangible Costs	$28,765	$1,377,547	$1,406,312	$0	1,406,312	100%
10	INTANGIBLE COSTS						
11	PREPARATION & TERMINATION						
12	Surveys	7,000	0	7,000	$0	7,000	100%
13	Location Staking & Positioning	4,500	0	4,500	$0	4,500	100%
14	Wellsite & Access Road Preparation	120,000	0	120,000	$0	120,000	100%
15	Service Lines & Communications	25,500	0	25,500	$0	25,500	100%
16	Water Systems	0	0	0	$0	0	
17	Rigging Up/Rigging Down/ Mob/Demob	400,000	0	400,000	$0	400,000	100%
19	Total Preparations/MOB	$557,000	$0	$557,000	$0	557,000	100%
20	DRILLING - W/O OPERATIONS						
21	Contract Rig	615,780	180,000	795,780	$0	795,780	100%
22	Drlg Rig Crew/Contract Rig Crew/Catering	0	0	0	$0	0	
23	Mud, Chem & Engineering Servs	69,208	20,000	89,208	$0	89,208	100%
24	Water	15,000	24,000	39,000	$0	39,000	100%
25	Bits, Reamers & Coreheads	13,405	0	13,405	$0	13,405	100%
26	Equipment Rentals	73,270	6,769	80,039	$0	80,039	100%
27	Directional Drlg & Surveys	172,548	0	172,548	$0	172,548	100%
28	Closed Loop and Disposal	98,898	0	98,898	$0	98,898	100%
29	Casing & Wellhead Installation & Inspection	52,641	10,000	62,641	$0	62,641	100%
30	Cement, Cementing & Pump Fees	30,000	80,000	110,000	$0	110,000	100%
31	Misc. H2S Services	0	0	0	$0	0	
32	Total Drilling Operations	$1,140,750	$320,769	$1,461,518	$0	1,461,518	100%
33	FORMATION EVALUATION						
34	Coring	280,000	0	280,000	$0	280,000	100%
35	Mud Logging Services	0	0	0	$0	0	
36	Drillstem Tests	0	0	0	$0	0	
37	Open Hole Elec Logging Services	284,522	0	284,522	$0	284,522	100%
39	Total Formation Evaluation	$564,522	$0	$564,522	$0	564,522	100%
40	COMPLETION						
41	Casing, Liner, Wellhead & Tubing Installation	0	0	0	$0	0	
42	Remedial Cementing and Fees	0	0	0	$0	0	
43	Cased Hole Elec Logging Services	0	53,947	53,947	$0	53,947	100%
44	Perforating & Wireline Services	0	33,716	33,716	$0	33,716	100%
45	Stimulation Treatment	0	50,000	50,000	$0	50,000	100%
46	Production Tests	0	0	0	$0	0	
48	Total Completion Costs	$0	$137,663	$137,663	$0	137,663	100%
49	GENERAL						
50	Supervision	176,100	23,000	199,100	$0	199,100	100%
51	Insurance	50,000	0	50,000	$0	50,000	100%
52	Permits & Fees	45,000	0	45,000	$0	45,000	100%
53	Marine Rental & Charters	0	0	0	$0	0	
54	Helicopter & Aviation Charges	0	0	0	$0	0	
55	Land Transportation	23,000	0	23,000	$0	23,000	100%
56	Other Transportation	0	0	0	$0	0	
57	Fuel & Lubricants Non Rig	4,050	0	4,050	$0	4,050	100%
58	Camp Facilities	20,000	0	20,000	$0	20,000	100%
59	Allocated Overhead - Schlumberger	86,484	49,750	136,234	$0	136,234	100%
60	Allocated Overhead - Main Office	0	0	0	$0	0	
61	Allocated Overhead - Overseas	0	0	0	$0	0	
62	Contingency Intangibles	266,691	53,118	319,809	$0	319,809	100%
64	Total General Costs	$671,325	$125,868	$797,193	$0	797,193	100%
65	TOTAL INTANGIBLE COSTS	$2,933,596	$584,300	$3,517,896	$0	3,517,896	100%
	TOTAL TANGIBLE COSTS	$28,765	$1,377,547	$1,406,312	$0	1,406,312	100%
66	TOTAL WELL COST			$4,924,208	$0	4,924,208	100%
67							
68							
69							
70							

Operator

Approved By:

Position

Date

Operator Approval

Approved By;

Position

Date

Remarks

Downhole intelligent packer system to isolate injection interval and deepest USDW above sealing formation. Includes Blowout insurance estimation. If well is specifically drilled to be a monitor well it can be downsized to 7 7/8" borehole, 5 1/2" casing and 2 7/8" tubing to reduce cost.

Figure C-23. Cost estimate for Nebraska monitoring well.

EXT MBK54935.AI

CarbonSAFE Class VI Injection Well - Nebraska

AUTHORIZATION FOR EXPENDITURES - Est Cost

Schlumberger Carbon Services

In US $

Operator:	EERC	Project Type :	C02 Sequestration		
Contract Area:	Nebreska	Well Name :	Class VI Injection Well		
Contract Area #:		Well Type :	CO2 Injection		
Prepared by	WR, GV, JK, NM	Platform/Tripod :		AFE #:	3 of 3
		Field/Structure :		Date:	10-Jan-18
		Basin :			

Location ______ Surface Coordinate ______

Surface Elev. ______ Elevation ______

	PROGRAM	ACTUAL
Spud Date		
Compl Date		
In Service		
Drilling Days		

	PROGRAM	ACTUAL
Rig Days	20	
Total Depth	5473	
Well Cost $/Ft.	$0.00	
Well Cost $/Day	$0.00	

Close Out Date: ______ Completion Type: Cased Hole ______ Well Status: Pre Permit

	Description	Dry Hole Budget	Completed Budget	Total Budget	Actual Expenditure	Actual Over/Under	% Over/Under
1	TANGIBLE COSTS						
2	Casing	18,150	142,853	161,003	$0	161,003	100%
3	Casing Accessories; Float Equip & Liners	3,000	15,482	18,482	$0	18,482	100%
4	Tubing		124,980	124,980	$0	124,980	100%
5	Well Equipment - Surface	5,000	109,000	114,000	$0	114,000	100%
6	Well Equipment - Subsurface	0	131,500	131,500	$0	131,500	100%
7	Other Tangible Costs	0	0	0	$0	0	
8	Contingency	2,615	52,382	54,997	$0	54,997	100%
9	Total Tangible Costs	$28,765	$576,197	$604,962	$0	604,962	100%
10	INTANGIBLE COSTS						
11	PREPARATION & TERMINATION						
12	Surveys	7,000	0	7,000	$0	7,000	100%
13	Location Staking & Positioning	4,500	0	4,500	$0	4,500	100%
14	Wellsite & Access Road Preparation	120,000	0	120,000	$0	120,000	100%
15	Service Lines & Communications	25,500	0	25,500	$0	25,500	100%
16	Water Systems	0	0	0	$0	0	
17	Rigging Up/Rigging Down/ Mob/Demob	400,000	0	400,000	$0	400,000	100%
19	Total Preparations/MOB	$557,000	$0	$557,000	$0	557,000	100%
20	DRILLING - W/O OPERATIONS						
21	Contract Rig	615,780	60,000	675,780	$0	675,780	100%
22	Drlg Rig Crew/Contract Rig Crew/Catering	0	0	0	$0	0	
23	Mud, Chem & Engineering Servs	69,208	20,000	89,208	$0	89,208	100%
24	Water	15,000	24,000	39,000	$0	39,000	100%
25	Bits, Reamers & Coreheads	13,405	0	13,405	$0	13,405	100%
26	Equipment Rentals	73,270	6,769	80,039	$0	80,039	100%
27	Directional Drlg & Surveys	172,548	0	172,548	$0	172,548	100%
28	Closed Loop and Disposal	98,898	0	98,898	$0	98,898	100%
29	Casing & Wellhead Installation & Inspection	52,641	10,000	62,641	$0	62,641	100%
30	Cement, Cementing & Pump Fees	30,000	80,000	110,000	$0	110,000	100%
31	Misc. H2S Services	0	0	0	$0	0	
32	Total Drilling Operations	$1,140,750	$200,769	$1,341,518	$0	1,341,518	100%
33	FORMATION EVALUATION						
34	Coring	280,000	0	280,000	$0	280,000	100%
35	Mud Logging Services	0	0	0	$0	0	
36	Drillstem Tests	0	0	0	$0	0	
37	Open Hole Elec Logging Services	284,522	0	284,522	$0	284,522	100%
39	Total Formation Evaluation	$564,522	$0	$564,522	$0	564,522	100%
40	COMPLETION						
41	Casing, Liner, Wellhead & Tubing Installation	0	0	0	$0	0	
42	Remedial Cementing and Fees	0	0	0	$0	0	
43	Cased Hole Elec Logging Services	0	53,947	53,947	$0	53,947	100%
44	Perforating & Wireline Services	0	33,716	33,716	$0	33,716	100%
45	Stimulation Treatment	0	50,000	50,000	$0	50,000	100%
46	Production Tests	0	0	0	$0	0	
48	Total Completion Costs	$0	$137,663	$137,663	$0	137,663	100%
49	GENERAL						
50	Supervision	176,850	12,250	189,100	$0	189,100	100%
51	Insurance	50,000	0	50,000	$0	50,000	100%
52	Permits & Fees	45,000	200,000	245,000	$0	245,000	100%
53	Marine Rental & Charters	0	0	0	$0	0	
54	Helicopter & Aviation Charges	0	0	0	$0	0	
55	Land Transportation	23,000	0	23,000	$0	23,000	100%
56	Other Transportation	0	0	0	$0	0	
57	Fuel & Lubricants Non Rig	3,900	0	3,900	$0	3,900	100%
58	Camp Facilities	20,000	0	20,000	$0	20,000	100%
59	Allocated Overhead - Schlumberger	86,484	14,575	101,059	$0	101,059	100%
60	Allocated Overhead - Main Office	0	0	0	$0	0	
61	Allocated Overhead - Overseas	0	0	0	$0	0	
62	Contingency Intangibles	266,751	56,526	323,276	$0	323,276	100%
64	Total General Costs	$671,985	$283,351	$955,335	$0	955,335	100%
65	TOTAL INTANGIBLE COSTS	$2,934,256	$621,783	$3,556,039	$0	3,556,039	100%
	TOTAL TANGIBLE COSTS	$28,765	$576,197	$604,962	$0	604,962	100%
66	TOTAL WELL COST			$4,161,001	$0	4,161,001	100%
67							
68							
69							
70							

Operator	Approved By:			Remarks
	Position			Includes estimated cost to obtain Class VI license.
	Date			Includes Blowout insurance estimation.
Operator Approval	Approved By;			
	Position			
	Date			

Figure C-24. Cost estimate for Nebraska injection well.

REGULATORY FRAMEWORKS

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

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

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

Most state and provincial legislative action related to CCS occurred on the order of 15 to 20 years ago in reaction to the initial actions of the federal governments, beginning with the Kyoto Protocol in 1997, which introduced legally binding emission reduction targets for developed countries. Nevertheless, some state and provincial agencies delayed legislative and regulatory actions because of a lack of potential CCS/CCUS projects (e.g., lack of candidate sources of anthropogenic CO_2, lack of geologically suitable storage sites, and/or the lack of long-term financial drivers), a reliance upon existing regulatory frameworks for oil and natural gas activity, and/or uncertainty related to developing federal regulations (e.g., EPA UIC Class VI rules). North Dakota submitted an application for primacy of the Class VI rules in June 2013 and received primacy for UIC Class VI on April 10, 2018. The UIC Class VI rules establish minimum federal requirements under the SDWA (Safe Drinking Water Act) for the underground injection and geologic storage of CO_2.[1] Wyoming submitted an application for primacy at the end of January 2018. In the absence of obtaining primacy of the Class VI rules (such as is the case for Wyoming), the regulation of a commercial CCS project in the states of the PCOR Partnership region will be led by one of three EPA Regions, Regions 5, 7, or 8, each with its own interpretation of the Class VI rules. At the same time, the provinces of Alberta and Saskatchewan have built and operated commercial CCS and CCUS projects using their current oil and gas regulatory frameworks; no similar commercial activity has occurred in either British Columbia or Manitoba.

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

However, the ability to take advantage of this existing CO_2 EOR industry and its infrastructure for the geologic storage of CO_2 is being threatened by the potential applicability of the Class VI rules of EPA. In particular, the threat of having a CO_2 EOR operation, with its permitted Class II injection wells, arbitrarily transitioned to a CO_2 storage operation by EPA and subjected to the requirements of the Class VI rule has virtually ensured that such a transition of

[1] The state of North Dakota submitted an application for primacy of the Class VI rules to EPA Region 8 in June 2013 and received Primacy for Class VI UIC on April 10, 2018. The state of Wyoming submitted an application for primacy of the Class VI rules to EPA Region 8 at the end of January 2018.

this nature will not be pursued.[2] One issue of particular concern is the long-term postoperational liability that is associated with the containment of the "stored" CO_2. While five of the states in the PCOR Partnership region (i.e., Montana, Nebraska, North Dakota, South Dakota, and Wyoming) have primacy over UIC Class II wells, only two (North Dakota and Wyoming) have applied for primacy over the Class VI rule. The transition determination remains in the hands of EPA.

North Dakota

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

Legislative Action Time Line

- Senate Bill No. 2139 (effective April 2009) – This bill assigned the title of pore space to the owner of the overlying surface estate and prohibited the severance of the leasing of pore space.

- Senate Bill No. 2095 (effective July 2009) – This bill granted authority to the North Dakota Industrial Commission (NDIC) to address the geologic storage of CO_2.

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

Administrative Rule Making Time Line

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

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

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

With the ultimate goal of achieving primacy of the UIC Class VI regulations, and following extensive interaction with EPA Region 8, the state submitted a formal primacy application to EPA on June 21, 2013. On April 10, 2018, EPA Headquarters (Washington, D.C.) granted primacy to North Dakota.

Based on this legislative and regulatory framework, the state of North Dakota developed a permitting process (Figure C-27) for the geologic storage of CO_2. This permitting process requires separate permits for drilling the injection well, injecting CO_2 into the subsurface, and activities related to underground gathering pipelines.

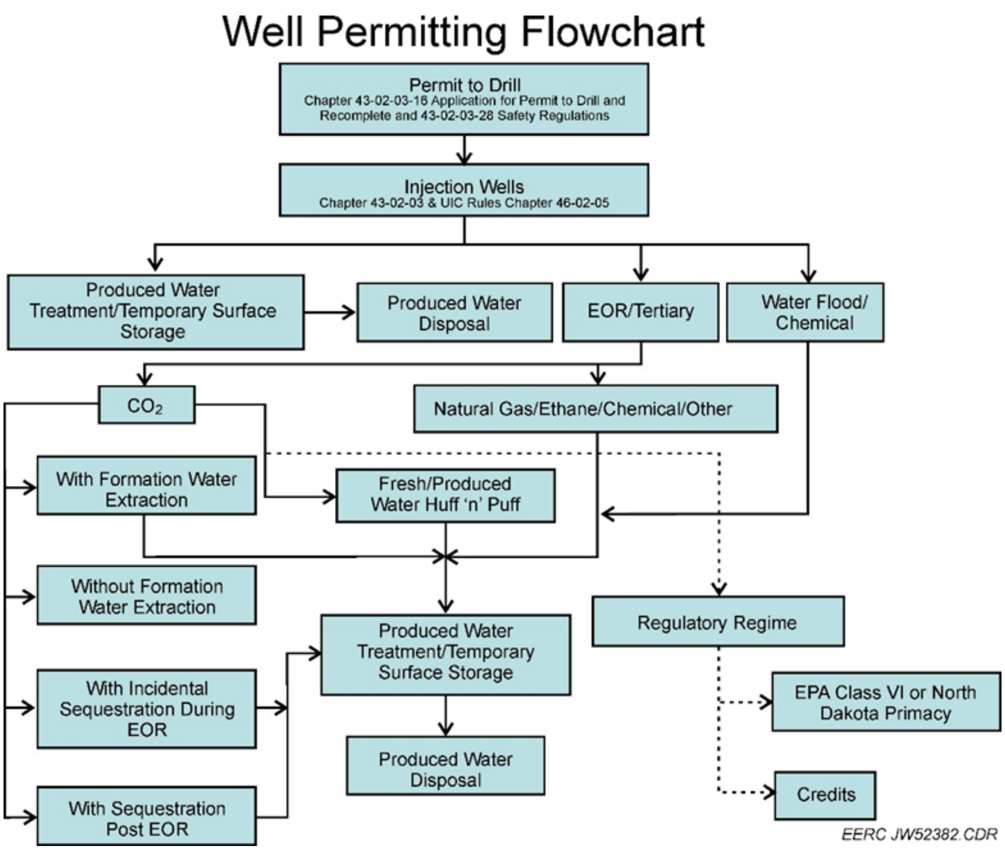

Figure C-25. Flowchart for the permitting of a CO_2 injection well for a CCS operation in North Dakota. Critical to this process are two permits: 1) Permit to Drill a CO_2 Injection Well and 2) Permit to Inject CO_2.

Wyoming

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

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

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

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

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

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

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

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

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

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

Wyoming filed a primacy application for UIC Class VI wells on January 31, 2018. Pending granting of the application, EPA Region 8 remains responsible for issuing Class VI permits for CCS/CCUS projects in Wyoming. At the same time, the WOGCC currently has primacy for UIC Class II wells, and the Wyoming DEQ has primacy for UIC Class I wells.

Nebraska

The state of Nebraska has not contemplated or promulgated statutes regarding CCUS. To date, no academic, public, private, or commercial entity has developed a proposed CCUS project that would initiate the statutory development process through the Nebraska Legislature. For such interests considering CCUS and evaluating carbon capture technologies, statutory and regulatory certainty is necessary to commit the large capital investments and associated escalating operating costs. State regulatory agencies in Nebraska do not have the statutory authority for CCUS rule making; therefore, there is no guidance in place for regulatory certainty. The Legislature would need to promulgate CCUS statutes and subsequently delegate and empower regulatory authority to the appropriate state agencies for rule making, permitting, inspection, and oversight. As of this reporting, no regulatory environment exists in Nebraska to address the multitude of legal issues related to CCUS, for example, carbon pore space ownership, financial assurance, site closure, or long-term liability, to name a few. Should the regulatory environment change, and/or if an academic, public, private, or commercial entity propose a CCUS project, expect regulatory certainty to be a multiyear process in order for the Legislative statutes and state agency rule making. EPA Region 7 regulates all UIC well classes in Nebraska.

OUTSTANDING CHALLENGES AND BARRIERS

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

1. Access to and Use of Pore Space

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

Three states within the PCOR Partnership region, Montana, North Dakota, and Wyoming, have acted on the pore space issues and have established that pore space is tied to the surface estate (Montana – SB 498, North Dakota – SB 2139, and Wyoming – HB 89); however, both North Dakota and Wyoming prohibit the severance of pore space from the surface estate, while Montana permits severance if it is provided for by deed or severance documents. In addition, compulsory unitization, similar to that used in oilfield development, has also been adopted. In all three states, landowners are compelled to be part of a sequestration unit once a certain percentage of the landowners have voluntarily committed their pore space to be developed and used for sequestration. Threshold percentages of 60% (Montana and North Dakota) and 80% (Wyoming) have been specified for this purpose.

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

2. Permitting of Geologic Storage Projects

As indicated previously, Montana, North Dakota, and Wyoming have promulgated regulations for the permitting of CCS projects. Each of these states has elected to delegate the permitting responsibilities to different agencies. Specifically, both North Dakota and Montana delegated permitting authority to their oil and gas regulatory authorities: NDIC and the Montana Board of Oil and Gas Conservation, respectively. However, Montana also incorporated environmental input into the permitting process (i.e., air emissions and water quality through the Montana DEQ) by adopting the administrative procedural rules as specified in Rule 36.22.202 of the Environmental Policy Act. On the other hand, Wyoming delegated the permitting of CCS projects to its environmental agency, DEQ, through HB 90. The permitting requirements are presented in Wyoming Statute Section 35-11-313.

Regardless of current state regulations, effective with the promulgation of the EPA Class VI rules in December 2010, the permitting of CCS projects within the PCOR Partnership states will be under EPA control and will be governed by the requirements of that federal regulation until such time that a primacy application has been filed by the state and approved by EPA. To secure this primacy, each state must promulgate state regulations that are at least as stringent as the requirements of the EPA Class VI rule. To date in the PCOR Partnership region, only North Dakota and Wyoming have filed for primacy of these rules. North Dakota received primacy for Class VI UIC on April 10, 2018. As of March 2018, Wyoming's application had not yet been approved. Consequently, any entity seeking to permit a CCS project in Wyoming must comply with the Class VI rules, as written, and must receive approval for its permit from EPA.

Of particular importance to the PCOR Partnership region is the regulatory handling of CO_2 EOR projects, which are currently operating with Class II permits that have been issued either by the state (i.e., Missouri, Nebraska, North Dakota, Wisconsin, and Wyoming) or EPA (Iowa, Minnesota, Montana, and South Dakota) (see Table C-2). Although Montana, North Dakota, and Wyoming have excluded CO_2 EOR from their current legislative and regulatory CCS initiatives, the lack of primacy of the Class VI rules will ultimately leave the decision regarding the transition of CO_2 EOR operations to geologic storage of CO_2 to the discretion of the EPA Directors, either at the regional or headquarter's level or both. This reclassification of CO_2 EOR operations will introduce additional long-term liability and carbon credit issues that will likely eliminate the use of CO_2 EOR as a CO_2 emissions reduction strategy; i.e., CO_2 EOR operations will likely be terminated rather than be used for CO_2 storage under the Class VI rules. To address this obstacle, the IOGCC has made it clear (Interstate Oil and Gas Compact Commission, 2007: Appendix I – Model Statute, Section 10), and the EPA Office of Ground Water and Drinking Water has confirmed (U.S. Environmental Protection Agency, 2015) that it would be best if the states administered both the Class II and the Class VI UIC programs. EPA's Office of Water further acknowledged that it expects that states approved for primacy for the Class VI program will administer the program through their oil and gas programs.

3. Site Closure and Management of Long-Term Liability

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

North Dakota and Wyoming have embraced the guidance of IOGCC to address the liabilities associated with closing a site and its long-term management following closure. Specifically, financial assurance mechanisms have been put in place to ensure that CCS projects are properly

Table C-2. Status of Primacy for UIC Well Classes in States of the PCOR Partnership Region

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

closed. North Dakota requires performance bonds for the CO_2 injection and observation wells and the surface facility, the amounts to be determined by NDIC. Wyoming requires public liability insurance or self-insurance for the CCS operations and bonds or other financial assurance to cover the costs of meeting permit requirements, including monitoring, remediation, and site closure. To determine when closure has been successfully attained, both states have established site closure criteria:

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

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

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

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

NEBRASKA

Nebraska Oil and Gas Conservation Commission — www.nogcc.ne.gov
(308) 254-6919

Nebraska Department of Environmental Quality — www.deq.state.ne.us
(402) 471-2186
Toll Free: (877) 253-2603
Fax: (402) 471-2909

EPA in Nebraska – U.S. Environmental Protection Agency — https://www.epa.gov/ne
Region 7
(913) 551-7003

NORTH DAKOTA

North Dakota Industrial Commission — www.nd.gov/ndic
(701) 328-3722
Fax: (701) 328-2820

NDIC Department of Mineral Resources Oil and Gas Division — www.dmr.nd.gov/oilgas
(701) 328-8020
Fax: (701) 328-8022

North Dakota Department of Health — www.ndhealth.gov
Environmental Health Section — www.ndhealth.gov/ehs
(701) 328-5150
Fax: (701) 328-5200

EPA in North Dakota – U.S. Environmental Protection Agency Region 8 — https://www.epa.gov/nd
(303) 312-6312 or in the Region 8 states (800) 227-8917

WYOMING

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

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

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

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U.S. Environmental Protection Agency, 2015, Standards of performance for greenhouse gas emissions from new, modified, and reconstructed stationary sources: electric utility generating units, Federal Register, v. 89, no. 205, p. 64510–64660, October 23.

APPENDIX D

SUBBASINAL ANALYSIS SUPPORTING INFORMATION

SUBBASINAL ANALYSIS SUPPORTING INFORMATION

GEOLOGIC MODELING

The purpose of the Cloverly C model (clipped from the regional model) was to capture geologic properties to conduct dynamic simulations for history matching and predictive simulation of CO_2 migration and storage potential. A geologic model was developed from 41 wells in the Gerald Gentleman Station area. Formation tops were imported from the Nebraska Oil and Gas Conservation Commission (NE OGCC) online database. In the model, the Cloverly was divided into 20 layers to better capture the lithologic heterogeneity in the field. The overlying Skull Creek Formation was modeled as two layers to keep the simulation cell count as low as possible. The resulting model contains 514,140 cells at a cell size of 1000 feet by 1000 feet, with a grid that is 123 cells by 190 cells and 22 layers. The average cell thickness of the reservoir is 12.21 feet and varies from 6.48 feet to 17.97 feet.

RESERVOIR PROPERTIES

The lithofacies percentages obtained for the Cloverly C model were 57.70% for sand and 42.30% for shale. Cloverly facies were defined from normalized gamma ray logs in the 41 wells as two facies, sand and shale, using a cutoff of 40 API (American Petroleum Institute) units. There were no reports of radioactive sands in the reservoirs, thereby enabling the use of gamma ray cutoffs to define the facies.

Modeling provides a geologically realistic distribution of facies that agreed with the depositional interpretation of the reservoir. The facies that were assigned to the Skull Creek Formation consisted entirely of shale. The variograms used to distribute the facies were based on information from the literature, with the variogram major orientation having a northeast to southwest orientation.

Petrophysical properties were modeled for porosity and permeability and were conditioned to the distributed facies using a variogram-based geostatistical distribution. The good quality facies (sandstone) was generally modeled with higher porosity and higher permeability. Shales within the reservoir were modeled with an arithmetic mean of approximately 50% of the reservoir porosity of sand for each of the P10, P50, and P90 models (Table M4).

Water saturation was modeled as a constant property equal to 1.0 in the model, indicating it is fully saturated. Temperature was also modeled as a constant property at 45.7°C, based on data from the National Geothermal Data System ("SMU Heat Flow Database from BHT Data"; NGDS, 2018), and pressure was computed as 0.433 psi/ft (normal hydrostatic pressure gradient for fresh water) multiplied by the measured depth from the ground surface.

ADDITIONAL FIGURES

Screening and ranking results for unitized fields in Nebraska. NA = not applicable. Unit IDs beginning with 9999xx represent units for which a unit ID could not be derived from state data.

CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
1	79800	Bush Creek	Bush Creek	Lansing – Kansas City	Berexco LLC	17	23	4	NA
2	9625	Boevau Canyon	Boevau Canyon	Lansing – Kansas City	Berexco LLC	32	10	3	NA
3	38275	Dry Creek	Dry Creek (Exeter)	Lansing – Kansas City	Citation Oil & Gas Corp. Inc.	28	8	11	NA
4	65400	Ackman	Ackman	Lansing – Kansas City	Central Operating Inc.	14	5	31	NA
5	72900	Sleepy Hollow	Sleepy Hollow LKC	Lansing – Kansas City	Central Operating Inc.	20	4	27	NA
6	79200	Bishop	Bishop	Lansing – Kansas City	Berexco LLC	53	7	1	NA
6	40300	Husker	Husker	Lansing – Kansas City	Berexco LLC	41	18	2	NA
8	29075	Reimers	Reimers	J Sand	Coral Production Corp.	2	20	44	NA
9	24725	Ittner	Ittner	J Sand	3 RP Operating	8	9	50	NA
10	78950	Dry Creek North	Dry Creek, North	Lansing – Kansas City	Berexco LLC	42	22	5	NA
11	25200	Jormar	Jormar	J Sand	Coral Production Corp	3	24	43	NA
12	67150	Danbury	Danbury	Lansing – Kansas City	Gore Oil Company	21	16	34	NA
13	72925	Sleepy Hollow	Sleepy Hollow Reagan	Reagan Sand	Central Operating Inc.	44	1	27	NA
14	68750	Midway	Midway	Lansing – Kansas City	Bach oil production	21	16	38	NA
15	38300	Dry Creek	Dry Creek (GKM)	Lansing – Kansas City	Bach oil production	39	37	7	NA

* Asterisks in field names are reproduced as they appear in the NOGCC database.

CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
15	80675	Meeker Canal	Meeker Canal	Lansing – Kansas City	Gore Oil Company	52	14	17	NA
15	71175	Silver Creek	Silver Creek (Texaco)	Lansing – Kansas City	Bach Oil Production	25	25	33	NA
18	20300	Doran	Doran Farm	D Sand	Coral Production Corp.	30	12	42	NA
19	52375	Jacinto	Jacinto	J Sand	Smith Red Plains Production	12	13	62	NA
20	88825	Jones	Jones Foraker	Foraker	Great Plains Energy, Inc.	11	47	30	NA
20	79325	Suess	Suess	Lansing – Kansas City	Bellaire Oil Co.	34	29	25	NA
22	51600	Houtby	Houtby	J Sand	Warner Ventures Inc.	6	21	64	NA
23	4775	Dunlap	Dunlap	D Sand	RTA Petroleum, LLC	18	27	51	NA
23	39750	Frenchman Creek	Frenchman Creek	Lansing – Kansas City	Gore Oil Company	54	36	6	NA
23	18225	Willson Ranch	Willson Ranch	J Sand	Rampart Energy Company	38	3	55	NA
26	80175	Culbertson	Culbertson, SW	Lansing – Kansas City	Water Flood Operations, LLC	45	35	18	NA
27	81025	Spearow	Spearow	D Sand	Coral Production Corp.	1	57	41	NA
28	79275	Dry Creek	Dry Canyon	Lansing – Kansas City	Gore Oil Company	31	63	9	NA
29	41450	Mitch	Mitch	Lansing – Kansas City	Berexco LLC	63	28	13	NA
30	50600	Heidemann	Heidemann	J Sand	LLC	15	15	79	NA

* Asterisks in field names are reproduced as they appear in the NOGCC database.

CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
31	87075	Hoover	Stamm	Lansing – Kansas City	Kaler Oil Company	43	53	16	NA
32	82625	Kame	Kame	J Sand	Wieser Oil LLC	13	54	48	NA
32	35125	Twin Lakes	Twin Lakes	Oread-Lansing-Kansas City	Berexco LLC	50	43	22	NA
34	58475	Potter Southwest*	Potter, SW (western)	D & J Sand	Wind River Exploration Inc.	9	55	52	NA
35	79975	Republican River	Republican River	Lansing – Kansas City	Gore Oil Company	58	45	15	NA
36	51625	Houtby	Houtby, South	J Sand	Chaco Energy Company	5	51	63	NA
37	1325	Barrett*	Barrett	J Sand	Wieser Oil LLC	27	19	83	NA
37	82400	Bird	Bird	Virgil-Missouri	Bellaire Oil Co.	51	31	47	NA
39	52925	Kenton	Kenton	J Sand	Coral Production Corp.	10	59	61	NA
39	62525	Swearingen	Swearingen, South	J Sand	Z & S Construction Co.	4	52	74	NA
41	88650	Mitch	Stratton	Lansing – Kansas City	Berexco LLC	81	41	10	NA
42	37275	Culbertson	Culbertson	Lansing – Kansas City	Central Operating Inc.	36	83	14	NA
43	85225	McCartney	McCartney	Lansing – Kansas City	Bach Oil Production	26	85	24	NA
44	88075	Camstone	Camstone	Lansing – Kansas City	Berexco LLC	69	48	20	NA
44	82850	Driftwood	Driftwood Creek	Lansing – Kansas City	Berexco LLC	46	65	26	NA

* Asterisks in field names are reproduced as they appear in the NOGCC database.

CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
44	80925	Slama	Slama	J Sand	Smith Oil Properties Inc.	24	64	49	NA
44	7775	Wilsonville SW	Wilsonville, SW	Lansing – Kansas City	Platte valley Oil Co Inc.	29	68	40	NA
48	62300	Susan	Susan	J Sand	Eagle Creek Resources, LLC	48	30	60	NA
49	44850	Barkhoff	Barkhoff	J Sand	Timka Resources, Ltd.	7	60	72	NA
50	82875	Bean	Bean	J Sand	Mtarri, Inc.	16	67	58	NA
50	60925	Simpson East	Simpson, East	J Sand	Cardinal Oil Company, Inc.	37	38	66	NA
52	63800	Torgeson	Torgeson, South	J Sand	Coral production Corp.	23	42	77	NA
52	17650	Vowers	Vowers	J Sand	Tri family Oil Co.	67	6	69	NA
54	68800	Midway	Midway, North (Gore)	Lansing – Kansas City	Gore Oil Company	59	49	37	NA
55	56825	Ostgren*	Ostgren	J Sand	Tri family Oil Co.	47	26	73	NA
56	85025	Upton	Upton	Lansing – Kansas City	Berexco LLC	75	56	19	NA
57	8100	Alma South	Fischer	Lansing – Kansas City	Bruce Oil Co. LLC	62	33	57	NA
58	34900	Southwick	Southwick	Lansing – Kansas City	Murfin DRLG Co. Inc.	57	77	21	NA
59	68775	Midway	Midway, North (Gemini)	Lansing – Kansas City	Bach Oil Production	71	50	36	NA
59	84600	Sidney Southwest	Sidney "J," SW	J Sand	Wieser Oil LLC	40	72	45	NA
61	85000	Dry Creek	Macklin	Lansing – Kansas City	Berexco LLC	78	69	12	NA

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CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
62	57000	Owasco	Owasco	J Sand	Evertson Operating Co. Inc.	61	34	70	NA
62	16600	Stauffer	Stauffer	J Sand	Warner Ventures Inc.	49	40	76	NA
64	87925	Eagle	Eagle	Lansing – Kansas City	Berexco LLC	64	79	23	NA
64	84550	Kleinholz	Kleinholz	Wolfcamp	Evertson Operating Co. Inc.	84	2	80	NA
64	61550	Sloss	Sloss	J Sand	Rampart Energy Company	19	76	71	NA
67	84050	Duggers Springs	Duggers Springs	J Sand	C & M Oil Inc.	79	46	46	NA
67	84575	Elm Creek Southeast	Elm Creek, SE	Lansing – Kansas City	Berexco LLC	83	80	8	NA
67	14975	Raymond	Raymond	J Sand	Coral Production Corp.	74	32	65	NA
70	81375	Montie	Montie	Lansing – Kansas City	Eland Energy, Inc.	70	73	29	NA
71	82425	Pound	Pound/ Schmid	J Sand	Eagle Creek Resources, LLC	73	44	59	NA
72	88300	Terrestrial	Terrestrial	Wolfcamp	Evertson Operating Co. Inc.	85	11	81	NA
73	88100	School Creek	Quigley	Lansing – Kansas City	Bach Oil Production	65	81	32	NA
74	71450	Sink	Sink	Lansing – Kansas City	Bach Oil Production	82	58	39	NA
75	84900	Cross	Cross	J Sand	Evertson Operating Co. Inc.	35	66	85	NA
76	7875	Alma South	Alma South (Kauk)	Lansing – Kansas City	Bach Oil Production	72	62	56	NA

* Asterisks in field names are reproduced as they appear in the NOGCC database.

CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
77	82900	Kimball	Morton	J Sand	Wieser Oil LLC	55	61	75	NA
78	87950	Silver Creek	Brakhahn Murphy	Lansing – Kansas City	Bach Oil Production	77	82	35	NA
78	84075	Willson Ranch South*	Willson Ranch, South	J Sand	Centerra Energy Corp.	56	84	54	NA
80	84125	Baltensperger	Roma Baltensperger, North	J Sand	Hesperus Energy LLC	33	78	84	NA
81	84375	Nike	Nike	J Sand	Wieser Oil LLC	76	71	53	NA
82	15050	Rocky Hollow	Rocky Hollow	D & J Sand	Smith Oil Properties Inc.	80	39	82	NA
83	17400	Vowers	Peterson	D Sand	Tri Family Oil Co.	60	74	68	NA
84	81350	Allely	Reep/Allely	J Sand	DNR Oil and Gas, Inc.	66	75	67	NA
85	11275	Joyce	Joyce	D Sand	Wind River Exploration Inc.	68	70	78	NA
NA	65450	Ackman	Ackman, East	Lansing – Kansas City	Central Operating Inc.	NA	NA	NA	Not producing
NA	999999	Airport	Airport Project	Na	Na	NA	NA	NA	Not producing
NA	43575	Allely	Allely	J Sand	Atlantic Richfield Co.	NA	NA	NA	Not oil-producing
NA	44150	Aue-Griffith	Aue	J Sand	Chandler & Assoc. Inc.	NA	NA	NA	Not producing
NA	999998	Baltensperger	Baltensperger Project	Na	Na	NA	NA	NA	Not producing
NA	44525	Baltensperger	Baltensperger, North	J Sand	Soper	NA	NA	NA	Not producing
NA	44550	Baltensperger	Baltensperger, South	J Sand	Quality Supply Co.	NA	NA	NA	Not oil-producing

* Asterisks in field names are reproduced as they appear in the NOGCC database.

CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
NA	66575	Barger	Barger	Lansing – Kansas City	Central Operating Inc.	NA	NA	NA	Not producing
NA	45075	Bartow	Bartow	J Sand	Texota Oil Co.	NA	NA	NA	Not oil-producing
NA	999997	Base	Base project	NA	NA	NA	NA	NA	Not producing
NA	76625	Casey	Bead Mountain Ranch	J Sand	Stanco Petroleum Inc.	NA	NA	NA	Not producing
NA	92555	Bed Canyon*	Bed Canyon, North	Basal sand	Bellaire Oil Co.	NA	NA	NA	Unit too new
NA	45450	Benziger	Benziger	J Sand	High	NA	NA	NA	Not oil-producing
NA	1575	Blake	Blake	J Sand	Petroleum Inc.	NA	NA	NA	Not oil-producing
NA	46250	Bourlier	Bourlier	J Sand	Coral Production Corp.	NA	NA	NA	Not producing
NA	81325	Bridgeport	Bridgeport, South	D Sand	Coral Production Corp.	NA	NA	NA	Not producing
NA	1675	Brinkerhoff	Brinkerhoff	J Sand	Okmar Oil Co.	NA	NA	NA	Not oil-producing
NA	46475	Brook	Brook	J Sand	Pan American Petroleum Corp.	NA	NA	NA	Not oil-producing
NA	47000	Bukin state	Bukin state	J Sand	National Coop. Refinery Assoc.	NA	NA	NA	Not oil-producing
NA	999996	Cedar Valley	Cedar Valley Project	NA	NA	NA	NA	NA	Not producing
NA	47325	Chaney	Chaney "D" Sand	D Sand	Soper Production	NA	NA	NA	Not producing

* Asterisks in field names are reproduced as they appear in the NOGCC database.

CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
NA	47475	Chaney East	Chaney, East	J Sand	Coral Production Corp.	NA	NA	NA	Not producing
NA	84100	Claude	Claude	J Sand	Evertson	NA	NA	NA	Not producing
NA	87225	Slama	Cliff Farms	J Sand	Coral Production Corp.	NA	NA	NA	Not producing
NA	37300	Culbertson	Culbertson, South	Lansing – Kansas City	Central Operating Inc.	NA	NA	NA	Not producing
NA	83400	Culbertson	Culbertson, West	Lansing – Kansas City	Central Operating Inc.	NA	NA	NA	Not producing
NA	999995	Darnall	Darnall Project	NA	NA	NA	NA	NA	Not producing
NA	2925	Davis	Davis	D Sand	Franks Well Service	NA	NA	NA	Not oil-producing
NA	48150	Dietz	Dietz	J Sand	Raymond Oil Co. Inc.	NA	NA	NA	Not oil-producing
NA	48450	Divoky	Divoky	J Sand	Skaer	NA	NA	NA	Not oil-producing
NA	3475	Downer West	Downer, West	D Sand	Basin Pipe & Supply Co.	NA	NA	NA	Not oil-producing
NA	48575	Draw*	Draw	D Sand	Beren Corp.	NA	NA	NA	Not producing
NA	21100	Eddy	Eddy	J Sand	Timka Resources, Ltd.	NA	NA	NA	Not producing
NA	3725	Edwards	Edwards	J Sand	Stanco Petroleum Inc.	NA	NA	NA	Not oil-producing
NA	48825	Enders	Enders	D & J Sand	Stanco Petroleum Inc.	NA	NA	NA	Not producing
NA	82650	Endo	Endo	J Sand	Ashby Andrew M	NA	NA	NA	Not producing

* Asterisks in field names are reproduced as they appear in the NOGCC database.

CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
NA	999994	Engelland	Engelland Project	NA	NA	NA	NA	NA	Not producing
NA	49200	Evertson	Evertson	J Sand	Stanco Petroleum Inc.	NA	NA	NA	Not oil-producing
NA	999993	Idler	Farmer Project	NA	NA	NA	NA	NA	Not producing
NA	49500	Fernquist	Fernquist	J Sand	Gregory, JD	NA	NA	NA	Not producing
NA	91020	Fondo	Fondo	Lansing – Kansas City	Bach Oil Production	NA	NA	NA	Unit too new
NA	22175	Foreland	Foreland	J Sand	Petroleum Inc.	NA	NA	NA	Not producing
NA	999992	Frederick	Frederick Project	NA	NA	NA	NA	NA	Not producing
NA	50000	Gehrke	Gehrke	D & J Sand	Tipps	NA	NA	NA	Not oil-producing
NA	50100	Goodwin	Goodwin, F L B	J Sand	Coral Production Corp.	NA	NA	NA	Not producing
NA	999991	Graff*	Graff Project	NA	NA	NA	NA	NA	Not producing
NA	8050	Grant	Grant	D Sand	Kimbark Expl	NA	NA	NA	Not oil-producing
NA	999990	Huntsman	Gurschke Project	NA	NA	NA	NA	NA	Not producing
NA	999989	Hafeman	Hafeman Project	NA	NA	NA	NA	NA	Not producing
NA	10425	Harrisburg	Harrisburg, East	D & J Sand	Z & S Construction Co.	NA	NA	NA	Not producing
NA	10400	Harrisburg	Harrisburg, West	D & J Sand	Silvertip Oil Inc.	NA	NA	NA	Not oil-producing

* Asterisks in field names are reproduced as they appear in the NOGCC database.

CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
NA	61350	Sloss	Haug	J Sand	C & M Oil Inc.	NA	NA	NA	Not producing
NA	23300	Heider*	Heider	J Sand	Cannon Dale	NA	NA	NA	Not producing
NA	23650	Henry	Henry	J Sand	Hickman Oil Operating Inc.	NA	NA	NA	Not producing
NA	50950	Hill	Hill (Madden)	J Sand	Gregory, JD	NA	NA	NA	Not producing
NA	78475	Hilltop	Hilltop	J Sand	Stanco Petroleum Inc.	NA	NA	NA	Not producing
NA	79900	Hinshaw	Hinshaw Project	J Sand	Western Operating Co.	NA	NA	NA	Not producing
NA	91310	Hoover	Hoover Extension	Lansing – Kansas City	Kaler Oil Company	NA	NA	NA	Unit too new
NA	999988	Hoover	Hoover Project	NA	NA	NA	NA	NA	Not producing
NA	51850	Hruska	Hruska	J Sand	Chain Oil Inc.	NA	NA	NA	Not oil-producing
NA	52075	Ibex	Ibex	D Sand	Stanco Petroleum Inc.	NA	NA	NA	Not producing
NA	10950	Idle Acres	Idle Acres	J Sand	Coral Production Corp.	NA	NA	NA	Not producing
NA	999987	Johnson	Johnson Project	NA	NA	NA	NA	NA	Not producing
NA	25525	Juelfs-Gaylord*	Juelfs, East	J Sand	Raymond Oil Co. Inc.	NA	NA	NA	Not oil-producing
NA	25550	Juelfs-Gaylord*	Juelfs, West	J Sand	Raymond Oil Co. Inc.	NA	NA	NA	Not oil-producing
NA	52725	Keefer	Keefer	J Sand	Dowd, Gene	NA	NA	NA	Not producing

* Asterisks in field names are reproduced as they appear in the NOGCC database.

CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
NA	11425	Kenmac	Kenmac	J Sand	Raymond Oil Co. Inc.	NA	NA	NA	Not oil-producing
NA	85900	Kenton	Kenton, South	J Sand	Chaco Energy Company	NA	NA	NA	Not producing
NA	53550	Kimball	Kimball	J Sand	Z & S Construction Co.	NA	NA	NA	Missing data
NA	84275	KMA	KMA	J Sand	Wistrom	NA	NA	NA	Not producing
NA	91100	Sleepy Hollow	Kodiak Northwest Sleepy Hollow	Reagan Sand	Kodiak Petroleum Inc.	NA	NA	NA	Unit too new
NA	999986	Krueger	Krueger-Ladegard Project	NA	NA	NA	NA	NA	Not producing
NA	26175	Kugler	Kugler	J Sand	Briggs Energy LLC	NA	NA	NA	Not producing
NA	5400	Lane	Lane, West	J Sand	Marathon Oil Co.	NA	NA	NA	Not oil-producing
NA	26325	Leafdale*	Leafdale	J Sand	Coloco Minerals Inc.	NA	NA	NA	Not oil-producing
NA	11800	Lewis	Lewis	J Sand	Stanco Petroleum Inc.	NA	NA	NA	Not oil-producing
NA	5525	Lindberg	Lindberg	J Sand	Gregory, JD	NA	NA	NA	Not producing
NA	11925	Llano	Llano	J Sand	Stanco Petroleum Inc.	NA	NA	NA	Not producing
NA	55025	Long	Long	D Sand	Noble Energy, Inc.	NA	NA	NA	Not producing

* Asterisks in field names are reproduced as they appear in the NOGCC database.

CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
NA	12475	Lovercheck	Lovercheck	D & J Sand	Kewanee Oil Co.	NA	NA	NA	Not oil-producing
NA	84675	Lovercheck North	Lovercheck, North	J Sand	Diversified Operating Corp.	NA	NA	NA	Not producing
NA	12625	Ludden	Ludden	J Sand	Evertson Operating Co. Inc.	NA	NA	NA	Not producing
NA	999985	Maas	Maas Project	NA	NA	NA	NA	NA	Not producing
NA	26975	Marvel	Marvel	J Sand	Gregory, JD	NA	NA	NA	Not producing
NA	5675	Matador	Matador	J Sand	Cannon, Robert D.	NA	NA	NA	Not producing
NA	84475	Matador East	Matador East	J Sand	Cannon, Robert D.	NA	NA	NA	Not producing
NA	13000	McDaniel	McDaniel (Big Horn)	J Sand	Baney Well Service Inc.	NA	NA	NA	Not producing
NA	13075	McMurray	McMurray	J Sand	Chain Oil Inc.	NA	NA	NA	Not producing
NA	92735	McMurray	McMurray, East	J Sand	Lone Mountain Prod.	NA	NA	NA	Unit too new
NA	90640	Millennium	Millennium	Lansing – Kansas City	Berexco LLC	NA	NA	NA	Unit too new
NA	56050	Mintken	Mintken, North	J Sand	Sunray DX Oil Co.	NA	NA	NA	Not oil-producing
NA	56075	Mintken	Mintken, South	J Sand	Sunray DX Oil Co.	NA	NA	NA	Not oil-producing
NA	999984	Mosier	Mosier Project	Na	Na	NA	NA	NA	Not producing
NA	27675	Murfin	Murfin	J Sand	Stanco Petroleum Inc.	NA	NA	NA	Not oil-producing

* Asterisks in field names are reproduced as they appear in the NOGCC database.

CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
Na	999983	Midway	Nicholson Project	NA	NA	NA	NA	NA	Not producing
Na	999982	Harrisburg	Obering Project	NA	NA	NA	NA	NA	Not producing
Na	6300	Olsen*	Olsen	J Sand	Monahan	NA	NA	NA	Not producing
Na	14525	Petroleum State	Olsen “B” Waterflood	D Sand	Clinton Oil Co.	NA	NA	NA	Not producing
Na	14025	Omega	Omega	J Sand	Stanco Petroleum Inc.	NA	NA	NA	Not producing
Na	57100	Owl	Owl	J Sand	Hrbek, R.L.	NA	NA	NA	Not producing
Na	91410	Acorn	Palm	Lansing – Kansas City	Berexco LLC	NA	NA	NA	Unit too new
Na	92410	Albin West	Palm	Cruise “J” Sand	Bellaire Oil Co.	NA	NA	NA	Unit too new
Na	14200	Pan Am	Pan Am	D Sand	Chandler & Simpson	NA	NA	NA	Not oil-producing
Na	999981	Parman	Parman Project	NA	NA	NA	NA	NA	Not producing
Na	91070	Pawnee	Pawnee	Lansing – Kansas City	Baker Corporation	NA	NA	NA	Unit too new
Na	999980	Pecos	Pecos Project	NA	NA	NA	NA	NA	Not producing
Na	14575	Petroleum State	Petroleum State	D Sand	Clinton Oil Co.	NA	NA	NA	Not oil-producing
Na	999979	Phillips East	Phillips, East Project	NA	NA	NA	NA	NA	Not producing
Na	34700	Pierce Lake	Pierce Lake	Lansing – Kansas City	Braden-Deem Inc.	NA	NA	NA	Not oil-producing

* Asterisks in field names are reproduced as they appear in the NOGCC database.

CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
NA	999978	Pierce Lake	Pierce Lake Project	NA	NA	NA	NA	NA	Not producing
NA	999977	Pleasant View	Pleasant View “D” Sand Project	NA	NA	NA	NA	NA	Not producing
NA	28675	Potter Southwest*	Potter “J” Sand, SW	J Sand	J & L Oil Corp	NA	NA	NA	Not oil-producing
NA	999976	Potter Southwest*	Potter, SW Project	Na	Na	NA	NA	NA	Not producing
NA	58700	Prairie	Prairie	J Sand	Skaer	NA	NA	NA	Not oil-producing
NA	42450	Reiher	Reiher	Lansing – Kansas City	Texaco Exploration & Production Inc.	NA	NA	NA	Not producing
NA	42425	Reiher	Reiher, North (Hay)	Lansing – Kansas City	Platte Valley Oil Co. Inc.	NA	NA	NA	Not oil-producing
NA	59500	Rodman	Rodman	J Sand	Chandler & Simpson	NA	NA	NA	Not oil-producing
NA	91015	Republican River North	Roland	Lansing – Kansas City	Berexco LLC	NA	NA	NA	Unit too new
NA	999975	Kevil	Ryan Project	NA	NA	NA	NA	NA	Not producing
NA	84325	Sidney North	Sidney, North	J Sand	Centerra Energy Corp.	NA	NA	NA	Not producing
NA	71150	Silver Creek	Silver Creek (Oxford)	Lansing – Kansas City	Morgan, Mike	NA	NA	NA	Not producing
NA	60850	Simpson	Simpson	J Sand	Chandler & Assoc. Inc.	NA	NA	NA	Not producing
NA	16000	Singleton	Singleton	J Sand	Elk Operating Company LLC	NA	NA	NA	Not producing

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CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
NA	61175	Skiles	Skiles	J Sand	Chandler & Assoc. Inc.	NA	NA	NA	Not oil-producing
NA	73450	Sleepy Hollow NW	Sleepy Hollow, NW	Reagan Sand	Kodiak Petroleum Inc.	NA	NA	NA	Not producing
NA	16325	Soule	Soule	J Sand	Skaer	NA	NA	NA	Not oil-producing
NA	61900	Spath	Spath	J Sand	Stanco Petroleum Inc.	NA	NA	NA	Not oil-producing
NA	16450	Stage Hill*	Stage Hill	J Sand	Chandler & Assoc. Inc.	NA	NA	NA	Not producing
NA	63625	Torgeson	Stanco	J Sand	Tri Family Oil Co.	NA	NA	NA	Not producing
NA	6450	Stark	Stark	J Sand	Misco Industries Inc.	NA	NA	NA	Not oil-producing
NA	92750	Raichart	Stark	Lansing – Kansas City	Berexco LLC	NA	NA	NA	Unit too new
NA	92495	Stauffer	Stauffer D Sand	Gurley “D” Sand	Flatirons Resources LLC	NA	NA	NA	Missing data
NA	62025	Stevens	Stevens	J Sand	C & L Oil Co.	NA	NA	NA	Not oil-producing
NA	92660	Stolte	Stolte	Lansing – Kansas City	Berexco LLC	NA	NA	NA	Unit too new
NA	62200	Sulfide	Sulfide	J Sand	Wieser Oil LLC	NA	NA	NA	Not producing
NA	62500	Swearingen	Swearingen	J Sand	Nebraska Drillers Inc.	NA	NA	NA	Not oil-producing
NA	62800	Terrace	Terrace	J Sand	Soper	NA	NA	NA	Not producing
NA	63775	Torgeson	Torgeson	J Sand	Stanco Petroleum Inc.	NA	NA	NA	Not producing

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CO_2 EOR Rank	Unit ID	Field	Unit	Formation	Operator	Spacing Rank	EUR Rank	Distance Rank	Reason Screened Out
Na	17325	Vedene	Vedene	D & J Sand	Evertson Operating Co. Inc.	Na	Na	Na	Not producing
Na	64575	Vrtatko	Vrtatko	J Sand	Brew	Na	Na	Na	Not oil-producing
Na	7200	Waitman	Waitman	J Sand	Frerichs, Everett	Na	Na	Na	Not oil-producing
Na	17750	Warner Ranch	Warner Ranch	J Sand	Chain Oil Inc.	Na	Na	Na	Not producing
Na	17975	Weaver	Weaver	J Sand	Skaer	Na	Na	Na	Not oil-producing
Na	999974	Widget	Widget Project	NA	NA	Na	Na	Na	Not producing
Na	999973	Dill East	Wilke Project	NA	NA	Na	Na	Na	Not producing
Na	32900	Winkleman	Winkleman	J Sand	Raymond Oil Co. Inc.	Na	Na	Na	Not oil-producing
Na	999972	Allchin	Woolsey Project	NA	NA	Na	Na	Na	Not producing
Na	65075	Young	Young	J Sand	C & L Oil Co.	Na	Na	Na	Not oil-producing
Na	65275	Zoller State	Zoller State	J Sand	Braden-Deem Inc.	Na	Na	Na	Not oil-producing

* Asterisks in field names are reproduced as they appear in the NOGCC database.

Phase 1. RA Risk Probability Scoring Matrix

Probability Score	Description
5	Very likely (almost certain
4	Likely
3	Possible
2	Unlikely
1	Very unlikely (rare)

Phase 1 RA Risk Impact Scoring Matrix

Impact Score	Cost/Finance	Project Schedule	Permitting Compliance	Corporate Image/Public Relations
1 – Minor	<$10K	<1 month	Information requests	Negative local news event
2 – Low	$10K–$50K	1–4 months	Additional compliance checks	Local community disgruntled
3 – Moderate	$50K–$250K	4–8 months	Permit violation and fines	Negative national news event; protests
4 – High	$250K–$500K	8–12 months	Legal action	Violent protest
5 – Very High	>$500K	>1 year	Shutdown	Stakeholder confidence falls

Current Phase 1 RA Risk Register

Risk No.	Principal Risk Category	Risk Descriptions
Technical Risks		
01	**Injectivity**	Injectivity into the storage unit (Cloverly Fm.) is insufficient to accept 2 million tonnes of captured CO_2 per year from the GGS and/or other identified facilities over the 25-year period.
02	**Capacity**	Capacity of target storage unit (Cloverly Fm.) is insufficient to store the commercial-scale storage volume of at least 50 million metric tons of CO_2.
03	**Containment – Lateral migration of CO_2**	CO_2 moves laterally beyond permitted boundaries
04		CO_2 moves laterally and negatively influences existing natural gas well or other oil and gas wells.
05		CO_2 moves laterally and negatively influences existing water wells.
06	**Containment – Propagation of pressure plume**	Subsurface pressure impacts extend beyond the permitted area of review.
07		Subsurface pressure impacts negatively impact oil and gas fields.
08		Subsurface pressure negatively impact water wells.
09	**Containment – vertical migration of CO_2/formation brine via injection wells**	CO_2 moves vertically up the injection well resulting in migration to the atmosphere..
10		CO_2 or formation brine moves vertically up the injection well resulting in migration to USDWs.
11		CO_2 or formation brine moves vertically up the injection well resulting in migration to surface water bodies.
12	**Containment – vertical migration of CO_2/ formation brine via other wells**	CO_2 moves laterally and intercept existing wells resulting in vertical migration to the atmosphere.
13		CO_2 or formation brine move laterally and intercept existing wells resulting in vertical migration to USDWs.
14		CO_2 or formation brine move laterally and intercept existing wells resulting in vertical migration to surface water bodies.
15	**Containment –vertical migration of CO_2/formation brine via inadequate seals**	Out-of-zone migration of CO_2 to the near-surface/surface environment via inadequate sealing formation(s).

Risk No.	Principal Risk Category	Risk Descriptions
16	**Induced seismicity**	CO_2 injection induces seismicity resulting in an event that might be felt by local residents (e.g., 3.0 Richter scale magnitude).

APPENDIX E

DETAILS TO SUPPORT NATIONAL RISK ASSESSMENT PARTNERSHIP (NRAP) VALIDATION

DETAILS TO SUPPORT NATIONAL RISK ASSESSMENT PARTNERSHIP (NRAP) VALIDATION

Table E-1 provides stratigraphic information for the areas assessed.

Table E-1. Stratigraphic Information

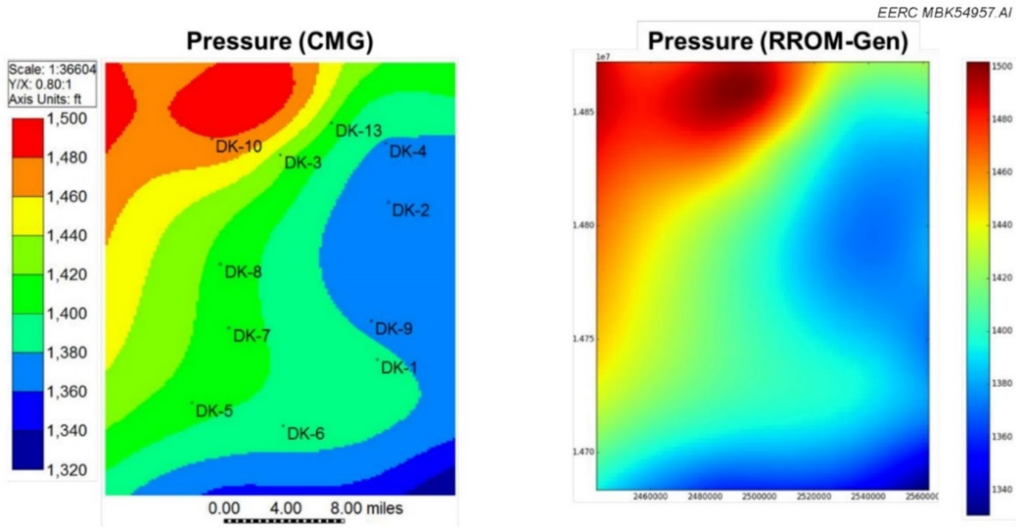
Formation	TVD,* m	Elevation, m	Thickness, m	Properties	Comment
High Plains Aquifer	0.00	1074.72	129.84	Aquifer	Ground surface aquifer
Pierre	129.84	944.88	559.00	Shale	
Niobrara	688.85	385.88	96.01	Aquifer	These two aquifers were counted as one for leakage calculation.
Fort Hays	784.86	289.86	8.84	Aquifer	
Carlile	793.70	281.03	47.55	Shale	
Greenhorn	841.25	233.48	17.37	Aquifer	
Belle Fourche	858.62	216.10	22.25	Shale	
Gurley D	880.87	193.85	3.96	Aquifer	
Huntsman	884.83	189.89	13.41	Shale	
Cruise	898.25	176.48	66.75	Aquifer	
Skull Creek	965.00	109.73	26.82	Shale	
Cloverly	991.82	82.91	97.23	Aquifer	Target formation

* True vertical depth.

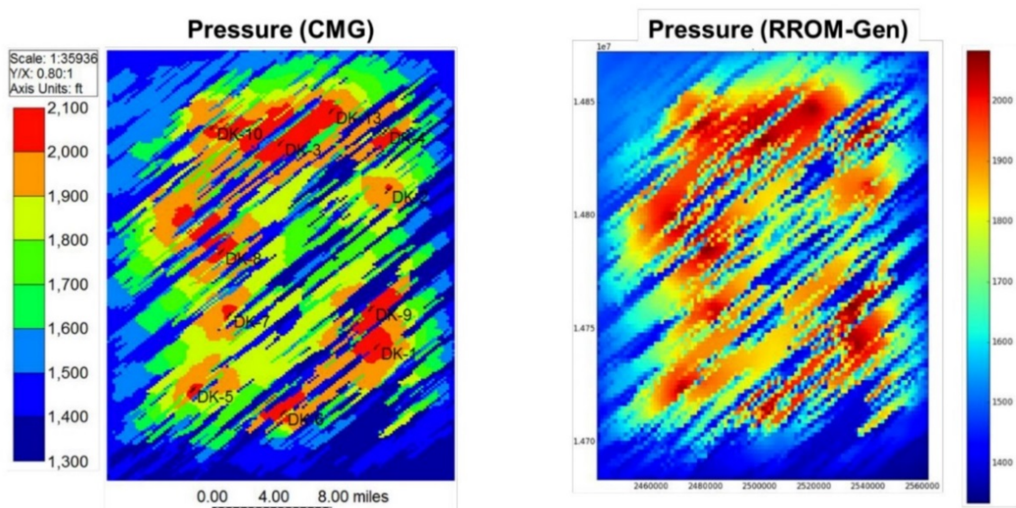
RROM-GEN TOOL TESTING

RROM-Gen extracts the simulation results from the reservoir–seal interface layer and, using piecewise bilinear interpolation, maps the simulation results onto a new grid, formatted as required by other NRAP tools (e.g., NRAP-IAM-CS [Integrated Assessment Model for Carbon Storage]). RROM-Gen maps the CMG (Computer Modelling Group) results using a new grid spacing that can be specified as either regular or relative grid. Regular grid spacing, which will make each grid block the same size, was chosen in this work. The new grid size is defined by default to be 100 × 100, which is the only compatible size with the NRAP-IAM-CS. The new grid information is stored into an ASCII file, which later on is used to link the CMG outputs with NRAP-IAM-CS.

Results from RROM-Gen are shown below (Figures E-1 and E-2) at selected times (before starting the injection and after 25 years of injection), with the GEM (Generalized Equation-of-State Model) outputs corresponding to the Geological Realization 1 (P10). Figure E-1 shows results in terms of the pressure plume. Figure E-2 shows results in terms of the CO_2 plume after 25 years of injection. RROM-Gen results were found to be in reasonable agreement with CMG's visualization tool Results 3-D. While some local differences may appear, they could be attributed to differences in the interpolation algorithms and/or the visualization utility settings (color bar scale settings, plot type settings, etc.).



a) Pressure Maps in Layer 1 Before Starting the CO_2 Injection



b) Pressure Maps in Layer 1 after 25 years of CO_2 Injection

Figure E-1. Maps showing a top view (XY plane) of the pressure plume with RROM-Gen outputs (right) compared against the CMG results (left) for the Geological Realization 1 (P10) at a) before starting the CO_2 injection and b) after 25 years of injection.

One important finding, in terms of the NRAP tools testing and validation, was that the RROM-Gen visualization tool showed anomalies with respect to the "original" map (i.e., plotting the map in RROM-Gen using the original CMG grid spacing). An example of this anomaly can be found in Figure E-3, which compares a CO_2 plume map (created with RROM-Gen) using the original CMG grid spacing (left) vs. a CO_2 plume map (created with RROM-Gen) using the new grid (100 × 100 grid later on used as input for NRAP-IAM-CS). While it is difficult to tell without having access to the source code, the differences observed in the map could be attributed to the

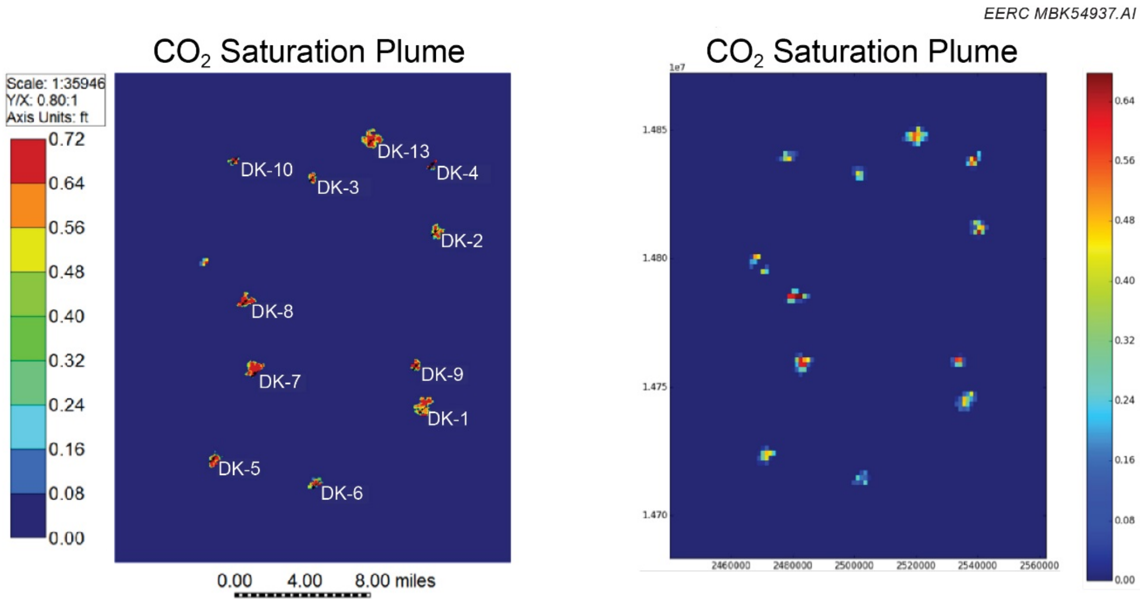


Figure E-2. Maps showing a top view (XY plane) of the CO_2 plume with RROM-Gen outputs (right) compared against the CMG results (left) for the Geological Realization 1 (P10) after 25 years of injection.

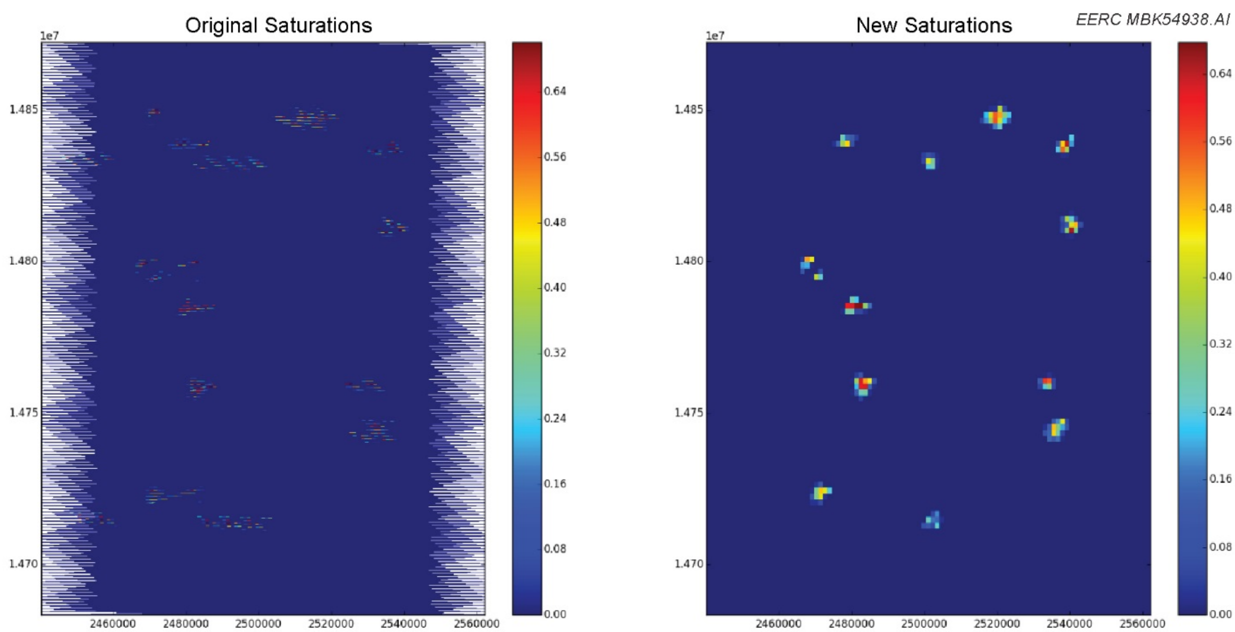


Figure E-3. CO_2 plume map (created with RROM-Gen) using the original CMG grid spacing (left) vs. a CO_2 plume map (created with RROM-Gen) using the new grid (100×100 grid used with NRAP-IAM-CS). Differences observed in the maps could be attributed to the interpolation algorithm and/or the visualization utility settings. Results correspond to the Geological Realization 1 after 25 years of injection.

interpolation algorithm and/or the visualization utility settings. In any case, the information is transmitted (from the CMG outputs to the NRAP-IAM-CS inputs) with the new grid (via ASCII files), and the new grid did not show any anomalies. Therefore, the anomalies observed in the "original" maps are anecdotic and are not expected to influence the NRAP-IAM-CS results.

Results with the Reservoir Reduced-Order Model-Generator Tool are shown in Figures E-4–E-9.

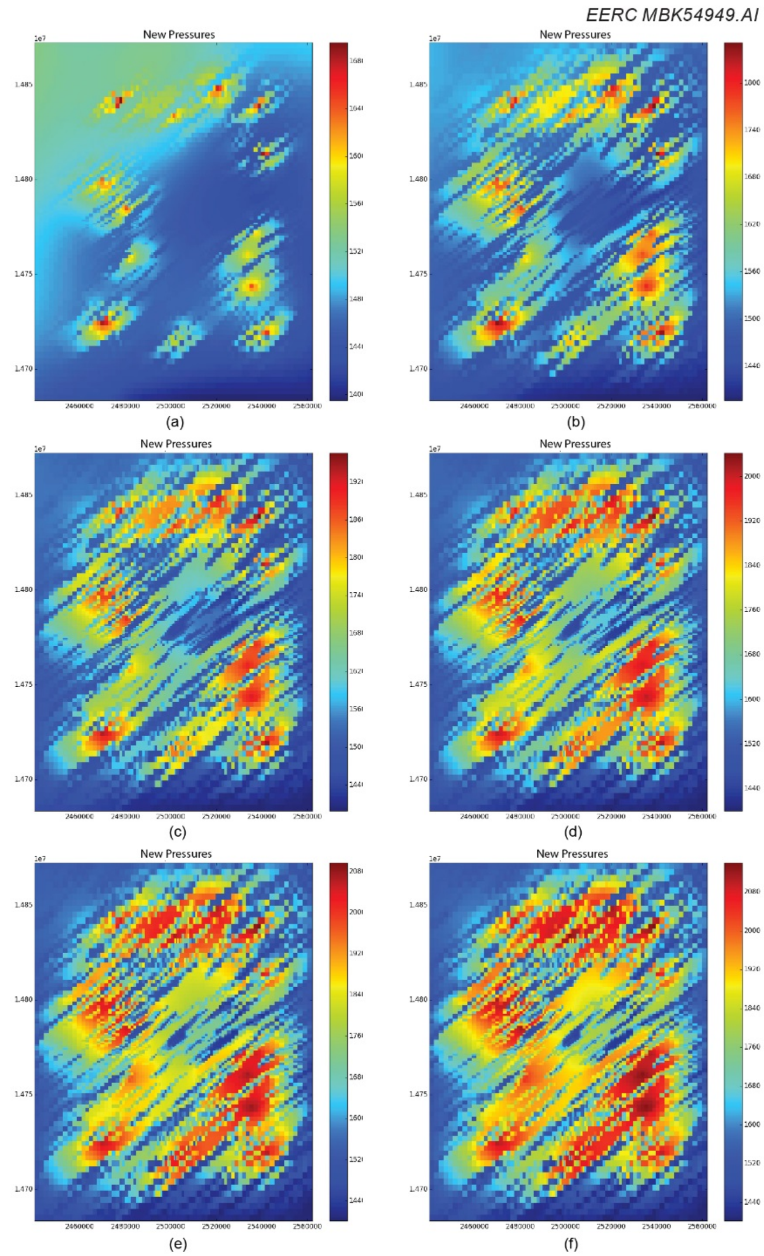


Figure E-4. Validation of the RROM-Gen output. Top view of the results for Geological Realization 1 (P10). Presure plume at (a) 1 year after injection, (b) 5 years, (c) 10 years, (d) 15 years, (e) 20 years, and (f) 25 years.

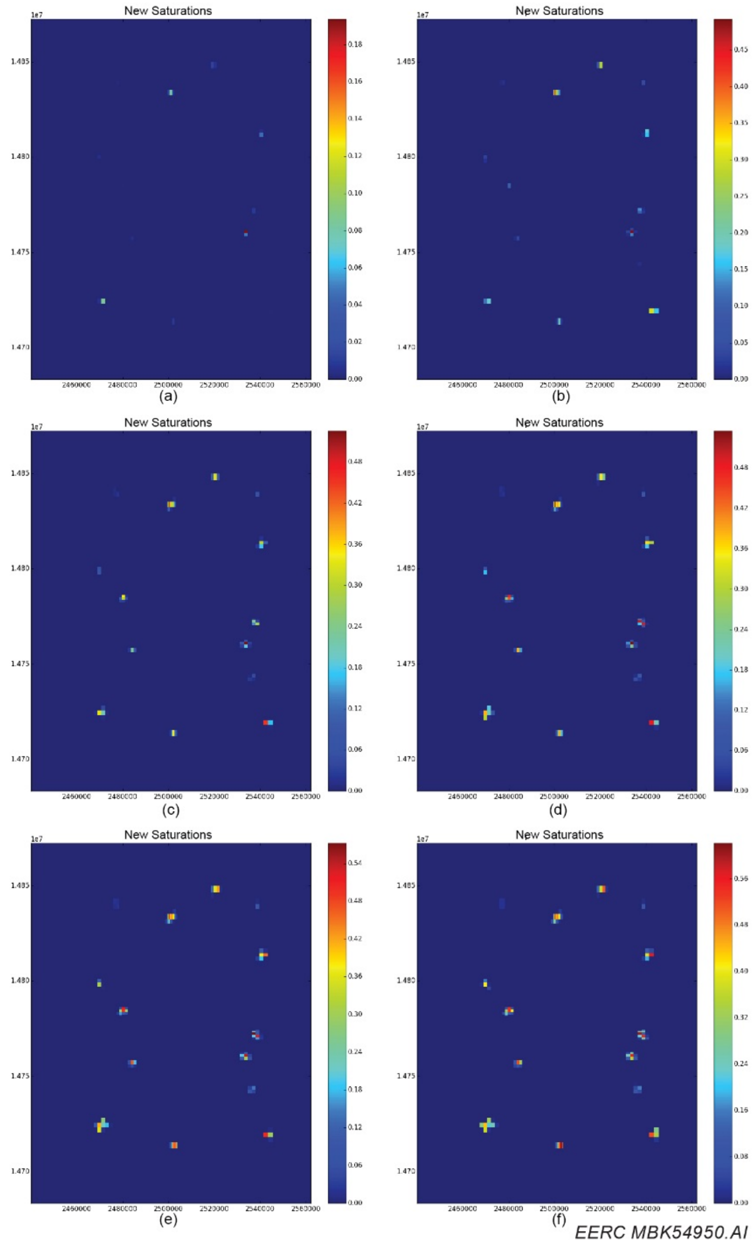


Figure E-5. Validation of the RROM-Gen output. Top view of the results for Geological Realization 1 (P10). Saturation plume at (a) 1 year after injection, (b) 5 years, (c) 10 years, (d) 15 years, (e) 20 years, and (f) 25 years.

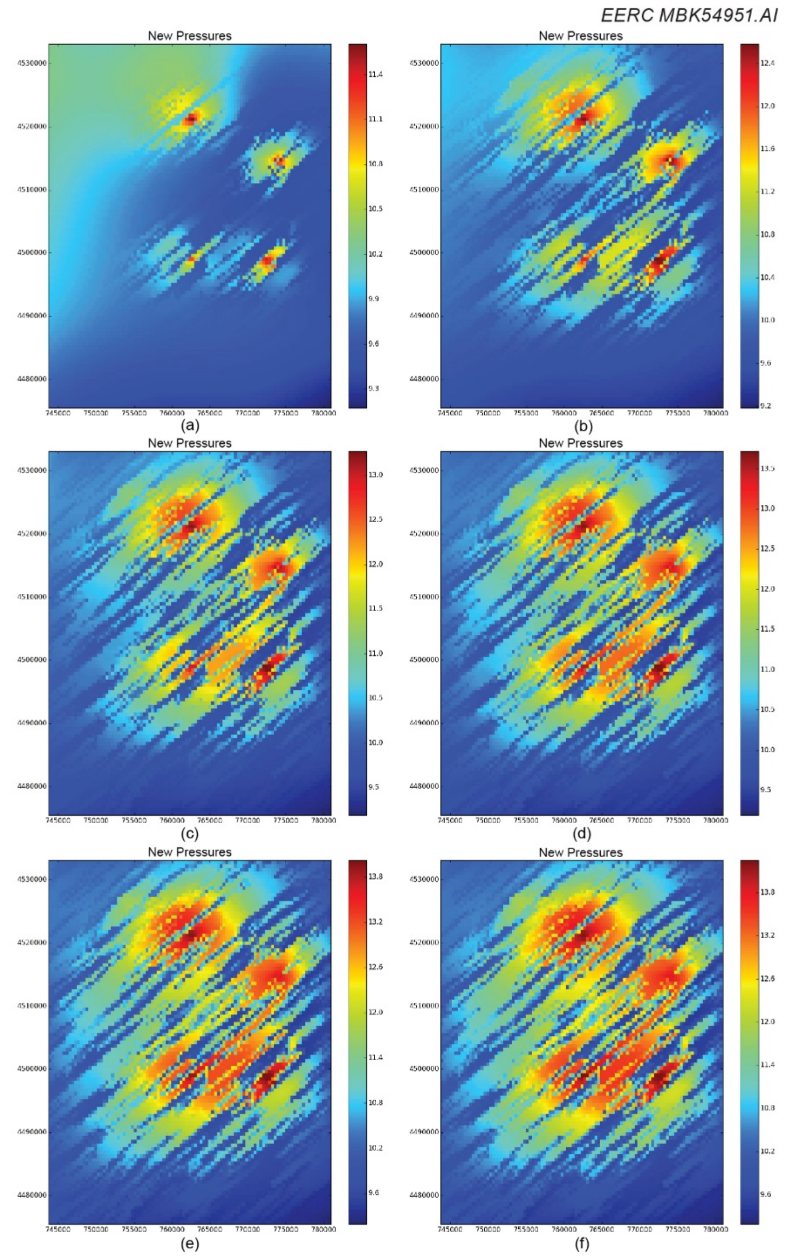


Figure E-6. Validation of the RROM-Gen output. Top view of the results for Geological Realization 2 (P50). Pressure plume at (a) 1 year after injection, (b) 5 years, (c) 10 years, (d) 15 years, (e) 20 years, and (f) 25 years.

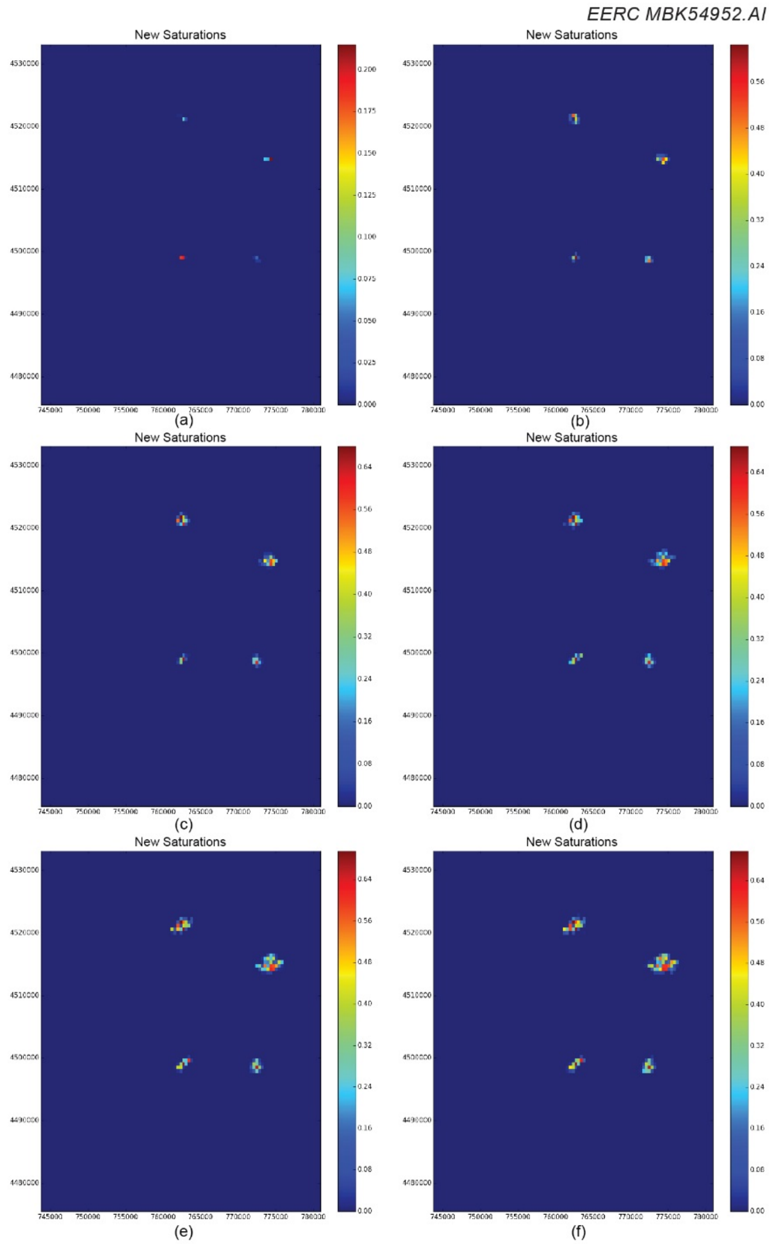


Figure E-7. Validation of the RROM-Gen output. Top view of the results for Geological Realization 2 (P50). Saturation plume at (a) 1 year after injection, (b) 5 years, (c)10 years, (d) 15 years, (e) 20 years, and (f) 25 years.

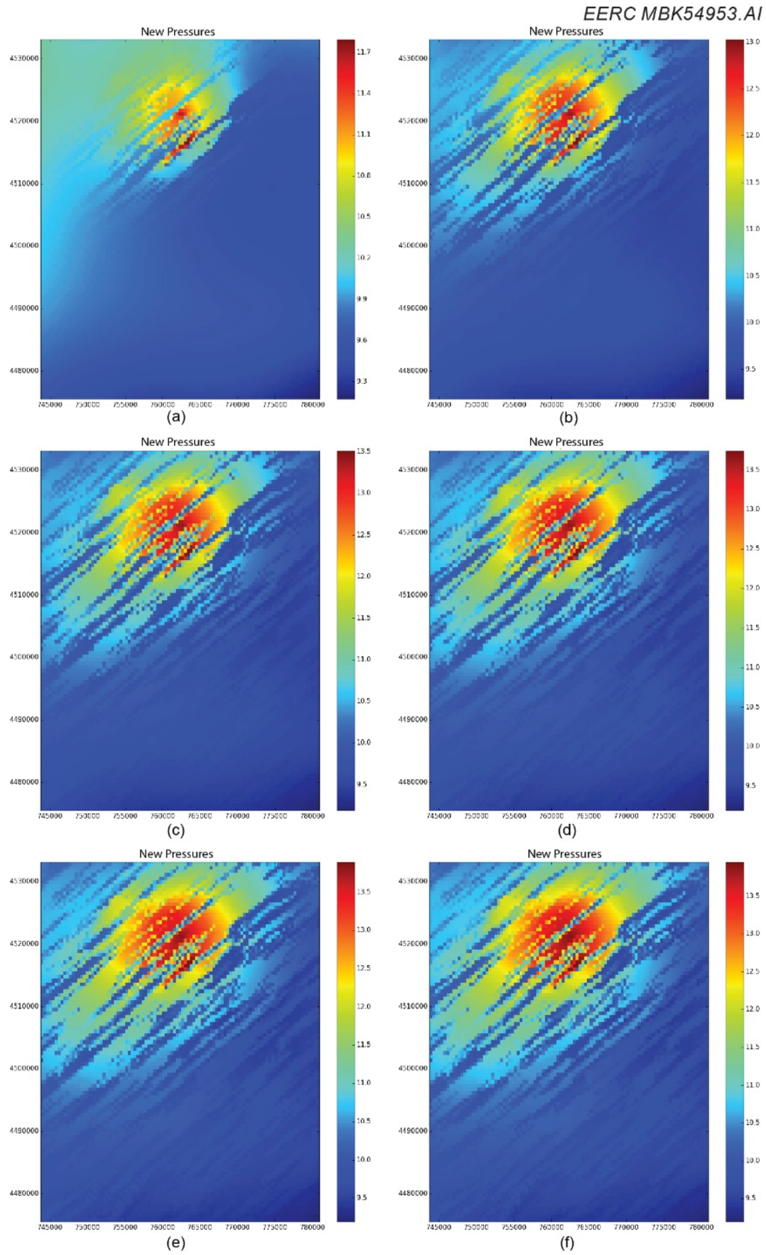


Figure E-8. Validation of the RROM-Gen output. Top view of the results for Geological Realization 3 (P90). Pressure plume at (a) 1 year after injection, (b) 5 years, (c) 10 years, (d) 15 years, (e) 20 years, and (f) 25 years.

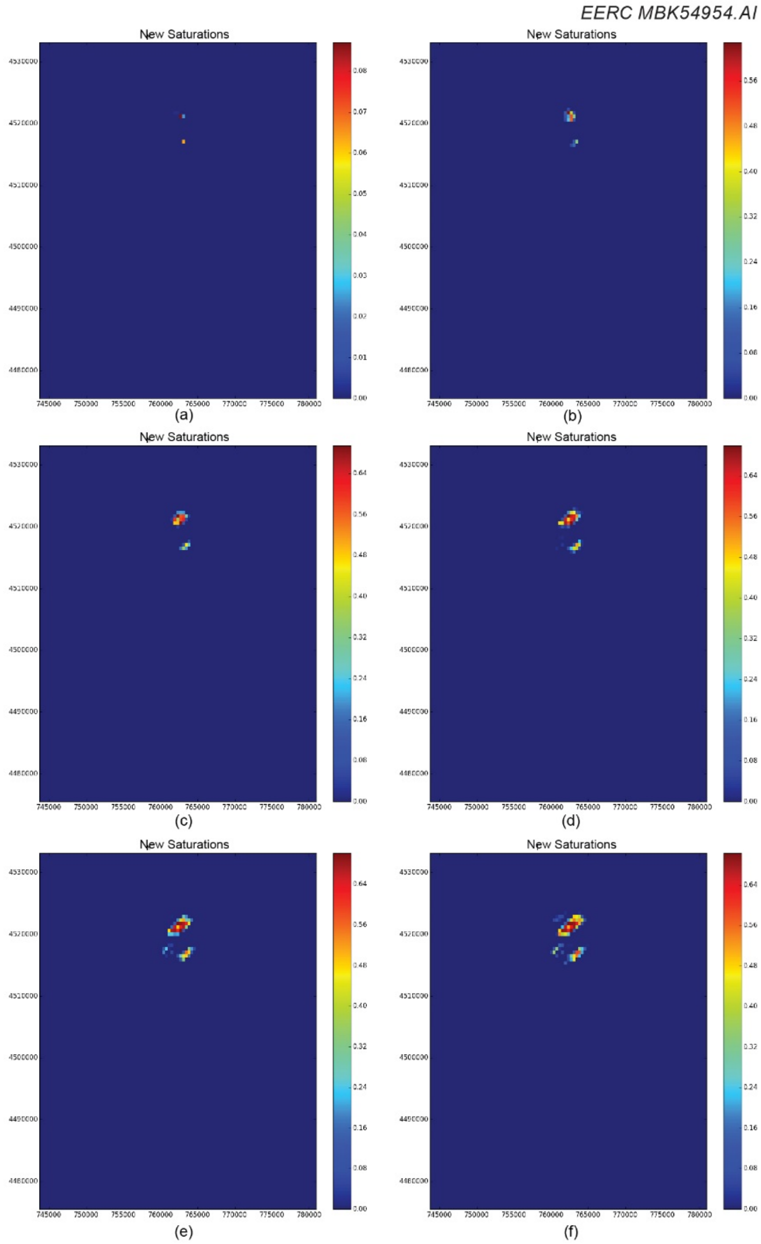


Figure E-9. Validation of the RROM-Gen output. Top view of the results for Geological Realization 3 (P90). Saturation plume at (a) 1 year after injection, (b) 5 years, (c) 10 years, (d) 15 years, (e) 20 years, and (f) 25 years.

REV TOOL TESTING

The Reservoir Evaluation and Visualization (REV) tool provides insight on the evolution of the long-term CO_2 and pressure plumes through time, being the key REV metrics defined as differential values above a specified threshold. Pressure and saturation results from CMG's GEM reservoir simulation models were used as input. REV automatically extracted the plume size metrics of performance. Key metrics are the size of CO_2 plume injection, the size of pressure plume, and the maximum pressure at specific locations.

Results from REV are shown after 25 years of injection, with the GEM outputs corresponding to Geological Realization 1 (P10). Figure E-10a shows maps with top views (XY plane) of the pressure plume at a threshold of 300 psi, and Figure E-10b shows maps of the CO_2 saturation plume at a threshold of 1%. The output map created by the REV tool presented similar anomalies as noted previously with the "original" maps created with the RROM-Gen tool. As discussed in the previous section, these anomalies are anecdotic (most likely attributed to the interpolation algorithm and/or the visualization utility settings) and are not expected to influence the NRAP-IAM-CS results.

Results with the REV tool are shown in Figures E-11 and E-12.

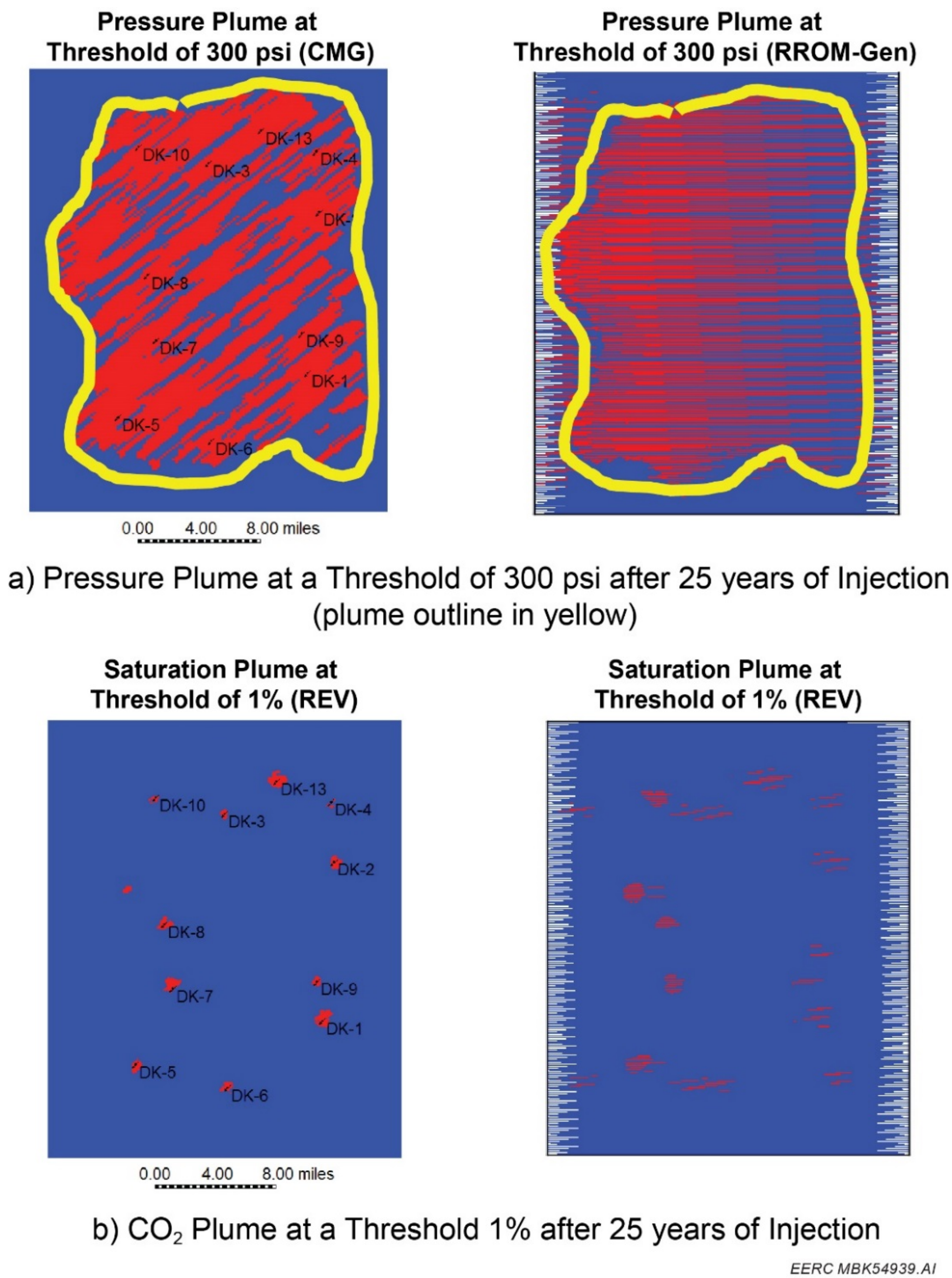


Figure E-10. Maps showing a top view (XY plane) of the pressure plume with REV outputs (right) compared against the CMG results (left) for Geological Realization 1 (P10) after 25 years of injection: a) pressure plume and b) CO_2 plume. A pressure plume outline (curve in yellow, created outside REV) was added for facilitating the comparison exercise.

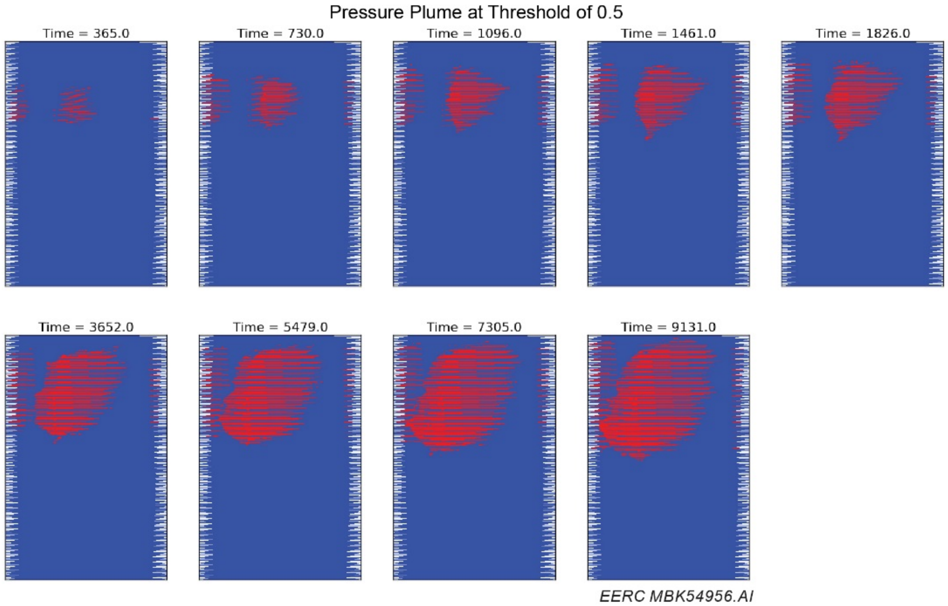


Figure E-11. Validation of the REV output. Maps show series time-dependent top views at a threshold of 200 psi for the CO_2 plume results for Geological Realization 3 (P90).

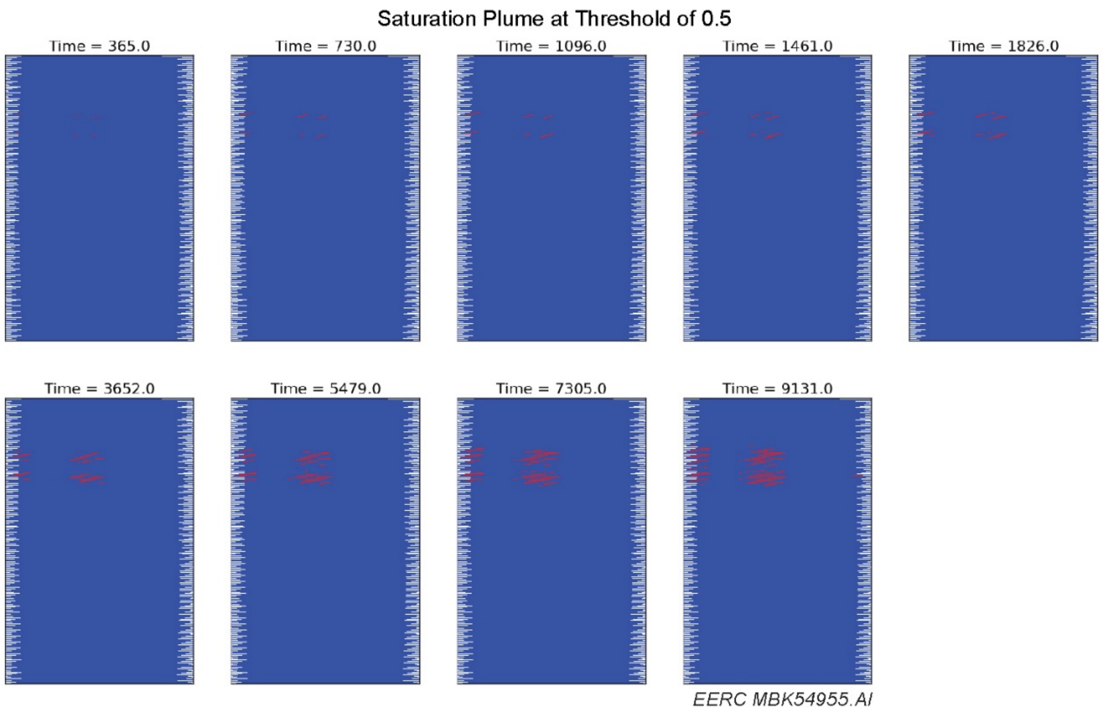


Figure E-12. Validation of the REV output. Maps show series time-dependent saturation plumes at a threshold of 0.5 for Geological Realization 3 (P90).

WLAT TESTING

The WLAT tools contain a collection of Reduced Order Models (ROMs) to estimate the rate of CO_2 and brine leakage for different types of wells. Such models are built based on two approaches: 1) full-physics simulations with the results compiled into ROMs based on given input conditions and 2) physical models based on first principles that are simplified based on assumptions, mathematical tools, and empirical observations. WLAT is composed of four types of models: the Cemented Wellbore Model, the Multisegmented Wellbore Model, the Open Wellbore Model, and the Brine Leakage Model. In this work, the Cemented Wellbore and the Multisegmented Well Models were selected because, when compared with the other models, their assumptions closely represent the projected well design. As no historical records of wells exhibiting CO_2 leakage existed in the area under study, the remainder of this section should be seen as a theoretical exercise that could not be validated using any field data.

Cemented Wellbore Model

The Cemented Wellbore Model ROM estimates the multiphase flow of CO_2 and brine along a cemented wellbore using polynomial functions, expressed in terms of input parameters, to estimate a leakage rate for wells (Huerta and Vasylkivska, 2016). This ROM can treat leakage to a thief zone, aquifer, or to the atmosphere. The model already has embedded preceding results from full-physics simulations, covering a certain range of values on key parameters. Figure E-13 shows a schematic illustration of a leaky well as defined by the WLAT User's Manual.

The model inputs are divided into three major categories: field properties, wellbore properties, and additional parameters. Field properties are classified into four groups: upper shale, shallow aquifer, thief zone, and reservoir, as shown in the input dashboard screenshot in Figure E-14. Some inputs are restricted to follow the original ROM assumptions. Table E-2 lists selected parameters from the project site characteristics (right column) and the actual parameters accepted by WLAT (central column). Hard-wired parameters (i.e., parameters that were subject to some kind of restriction) are displayed using light-gray cells. Parameters limited by an allowed range are displayed in light-gold cells. When the model imposed a specific boundary, the criteria followed was to use the closest value possible to comply with the requirements imposed by the tool. The cement permeability was used as a sensitivity parameter ranging from 10^{-14} to 10^{-10} m^2 (0.01 to 101 Darcy), with 0.01 being the minimum value accepted by WLAT and 101 representing the worst-case scenario: a fracture or high-permeability channel. The permeability of the thief zone used was 10^{-12} m^2 (0.01 Darcy). All of the four thicknesses and three out of four depth values are hard-wired. Reservoir pressure history, saturation history and time point values were exported from CMG's GEM results corresponding to Geological Realization 3 (P90) after 25 years of injection (Figure E-15).

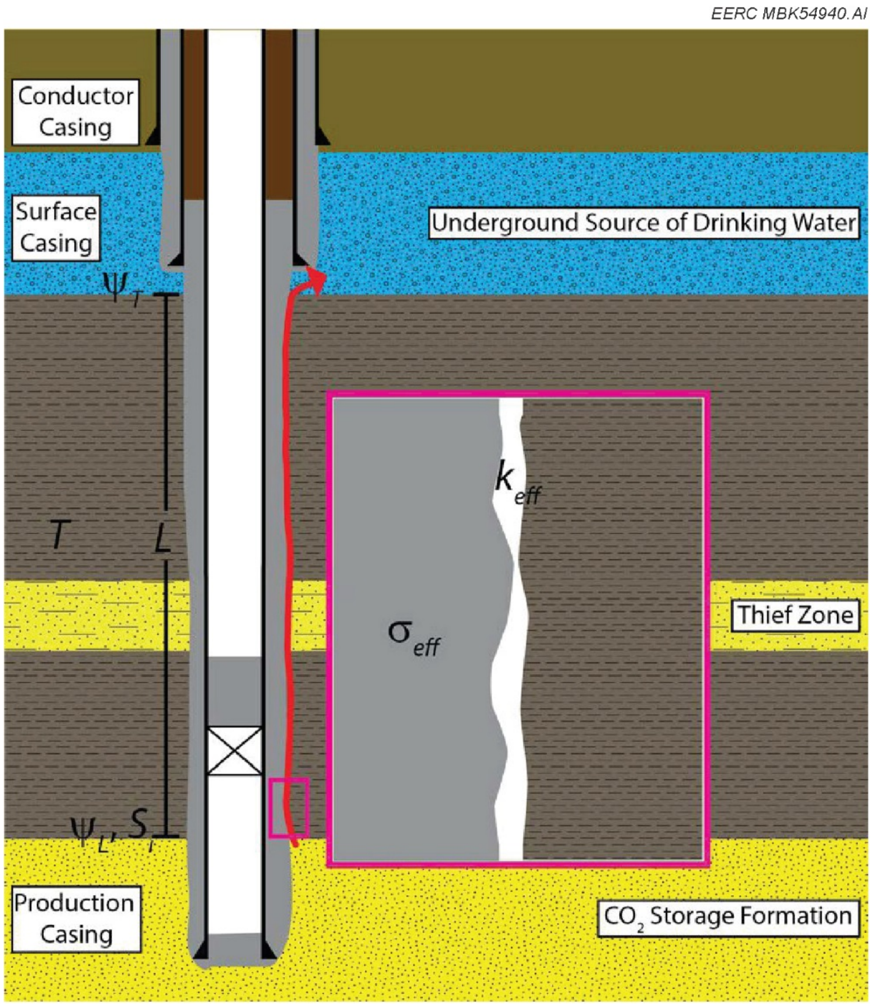


Figure E-13. Schematic of a leaky well, showing the relevant well configuration and lithological units assumed by WLAT. Image after the WLAT Tool User's Manual (Huerta and Vasylkivska, 2016).

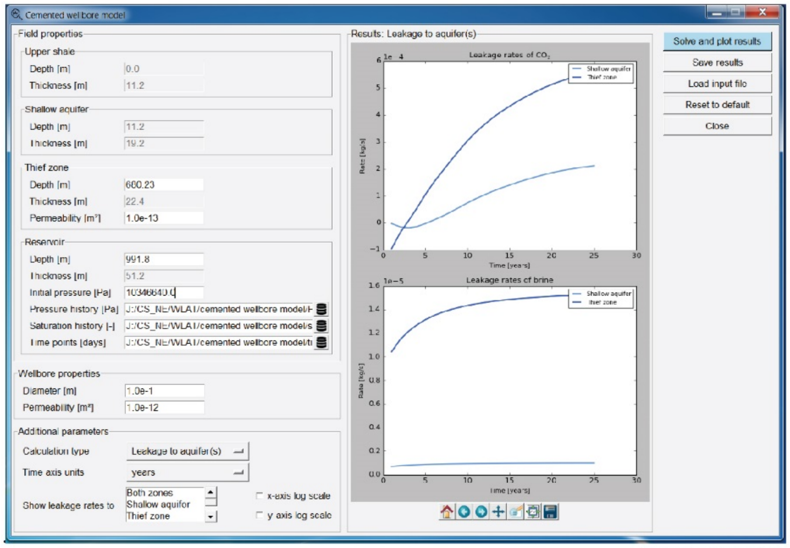


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Figure E-14. Input dashboard of cemented wellbore model.

Table E-2. Input Parameters Used for the Cemented Wellbore Model

	Model	Project
Zone	**Depth, m**	**TVD, m**
Upper Shale	0.0	0.0
Shallow Aquifer	11.2	129.8
Thief Zone	683.1	688.9
Reservoir	991.8	991.8
Zone	**Thickness, m**	**Thickness, m**
Upper Shale	11.2	559.0
Shallow Aquifer	19.2	129.8
Thief Zone	22.4	104.9
Reservoir	51.2	97.2
Cement Permeability	**Perm., m^2**	**Perm., m^2**
Average	1.00E-14	5.9E-17
Minimum	1.00E-14	8.9E-18
Maximum	1.00E-14	1.1E-16

Figure E-15 shows the pressure and saturation histories in the reservoir at the bottom of the leaking well with the Cemented Well Model. Worst-case scenario corresponds to a cement with a fracture (i.e., cement having an effective permeability of 101 Darcy), giving 2 tons per day leaking into the thief zone, at depth of 683.1 meters. For the rest of the cases, CO_2 leakage to the thieve and aquifers zones is negligible. CO_2 leakage to the atmosphere is negligible for all of the cases studied. Further investigations are needed to confirm that the ROM is still valid, despite the fact that the input data differ significantly from the user data. In particular, the differences observed in zone thickness are expected to have a pronounced effect on the Cemented Wellbore Model leakage results.

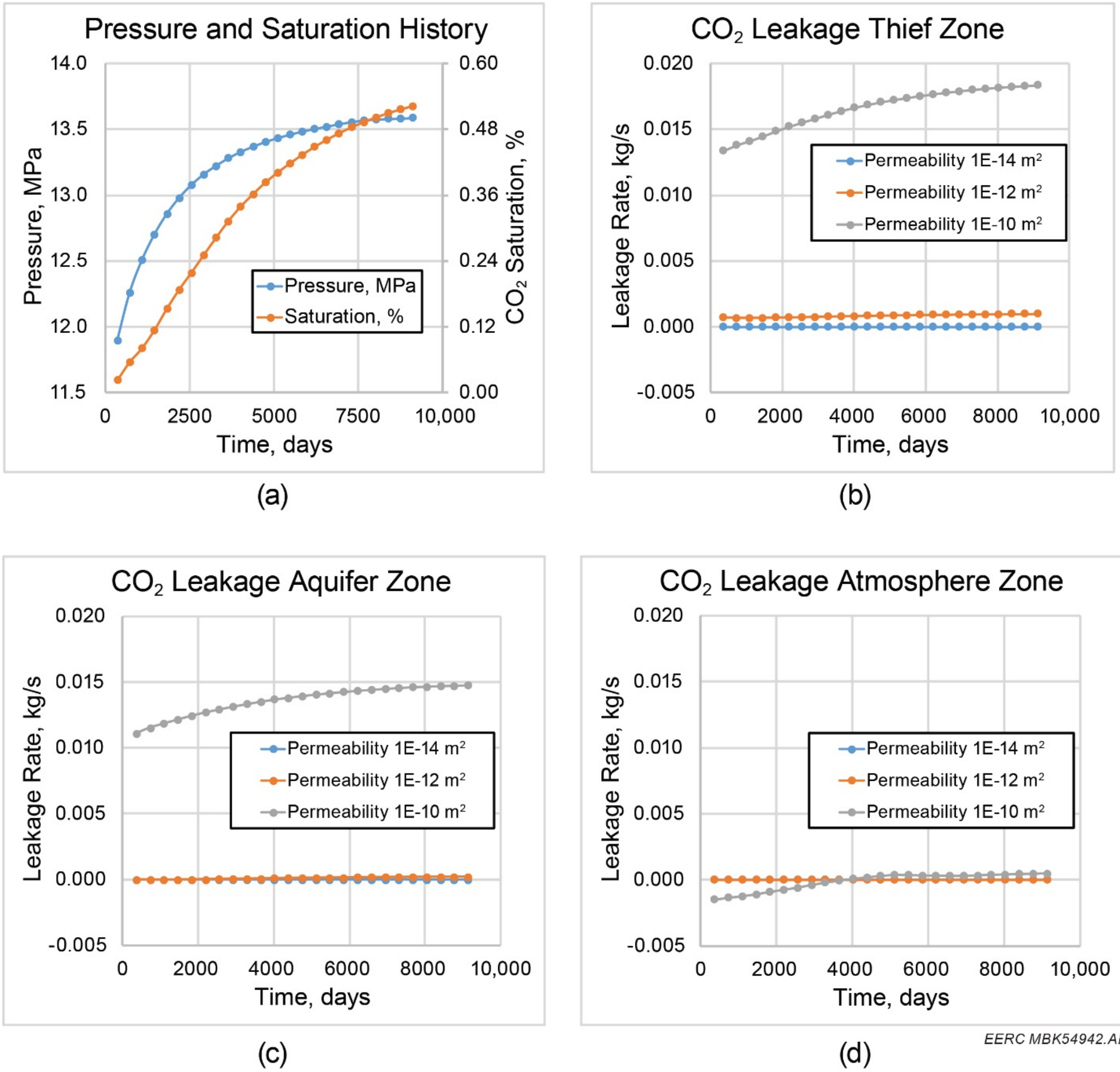

Figure E-15. Cemented Wellbore Model inputs and results: (a) pressure and saturation history from CMG results, (b) CO_2 leakage rate to the thief zone, (c) CO_2 leakage rate to the aquifer zone, and (d) CO_2 leakage rate to the atmosphere zone. Note that 1 kg/s is equivalent to 86.4 metric tons/day.

Multisegmented Well Model

The Multisegmented Well Model estimates the leakage rate of brine and CO_2 along wells with the presence of overlying aquifers or thief zones. The model assumes that there is multiphase flow of CO_2 and brine occurring through the well annulus, between the outside of the casing and the borehole. This leaky region is modeled with an "effective" permeability that emulates the presence of high permeability pathways. The permeability is applied over a length along the well, corresponding to the thickness of a shale formation (Huerta and Vasylkivska, 2016). The model inputs are classified into eight sections: shale layers, aquifers, reservoir, leaking well, injection, CO_2 properties, brine properties, and additional parameters. Figure E-16 shows a screenshot of the input dashboard for the Multisegmented Well Model. As opposed to the Cemented Wellbore Model, the users can define all of the input parameters.

The static geological parameters were obtained from existing well files. Specific input parameters, representative of some Nebraska wells, are shown in Table E-3. The injection rate is defined targeting 2 MM metric tons injected each year during 25 years. Figure E-17 shows the results obtained with the Multisegmented Well Model in terms of the CO_2 leakage rate to

Table E-3. Input Parameters for the Multisegment Well Model

Shale Layers	**Values**
Number of Shale Layers	5
Shale Thickness, m	26.8, 13.4, 22.3, 47.55, 559.0
Well Permeability along Shale, m^2	1.0E-14
Land Surface Pressure, MPa	0.0925
Aquifers	**Values**
Number of Aquifers	4
Aquifer Thickness, m	66.8, 4.0, 17.4, 104.8
Aquifer Permeability, m^2	1.0E-12, 1.0E-14, 1.0E-14, 1.0E-14
Reservoir	**Values**
Reservoir Thickness, m	97
Reservoir Permeability, m^2	1.0E-14
Reservoir Porosity	0.1
Leaking Well	**Values**
Well Diameter, m	1.0E-1
Injection Rate, m^2/day	0.1
Distance to Well, m	500
Injection Period, years	50
Time Step, days	30.0
CO_2 Properties	**Values**
CO_2 Density, kg/m^3	479.0
CO_2 Viscosity, Pa.s	3.95E-5
Brine Properties	**Values**
Brine Density, kg/m^3	1000.0
Brine Viscosity, Pa.s	2.5E-3
Residual Saturation	0.1
Compressibility, 1/Pa	4.6E-10

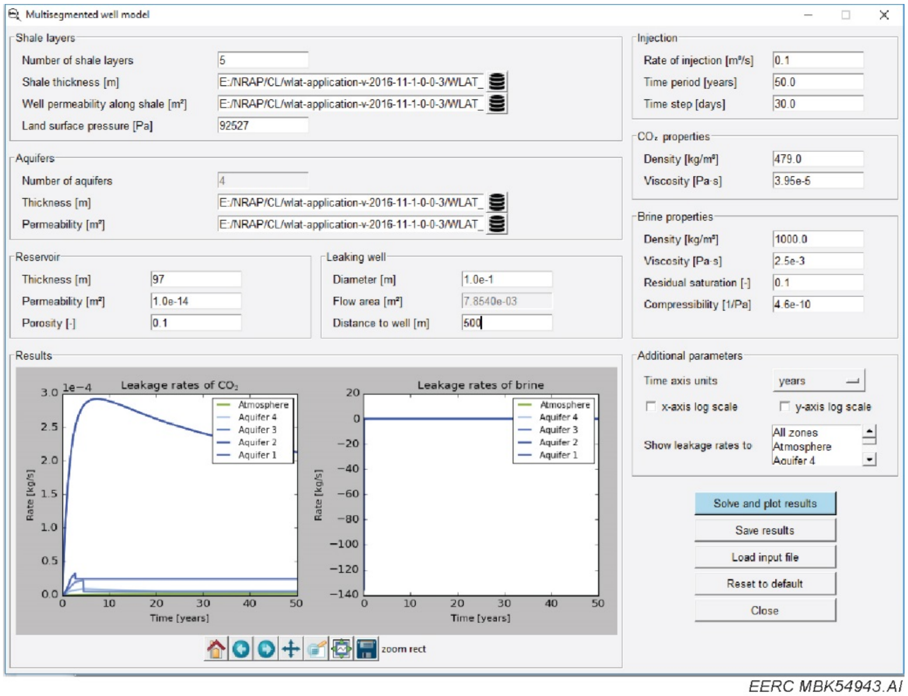

Figure E-16. Screenshot of the input dashboard for the Multisegmented Well Model.

aquifers vs. time (Figure E-17a) and the brine leakage rate to aquifers vs time (Figure E-17b). Leakage to the atmosphere (not shown here) was negligible (less than 0.001 tons per day). Note that the leakage rate of brine is a negative value during the first 35 minutes of injection (not shown in Figure E-17). This could indicate that some influx of brine occurs from the bottom aquifer to the reservoir, which could be interpreted as the reservoir pressure being not high enough to transport any fluids from the reservoir to the thief zone during the early stages of the injection.

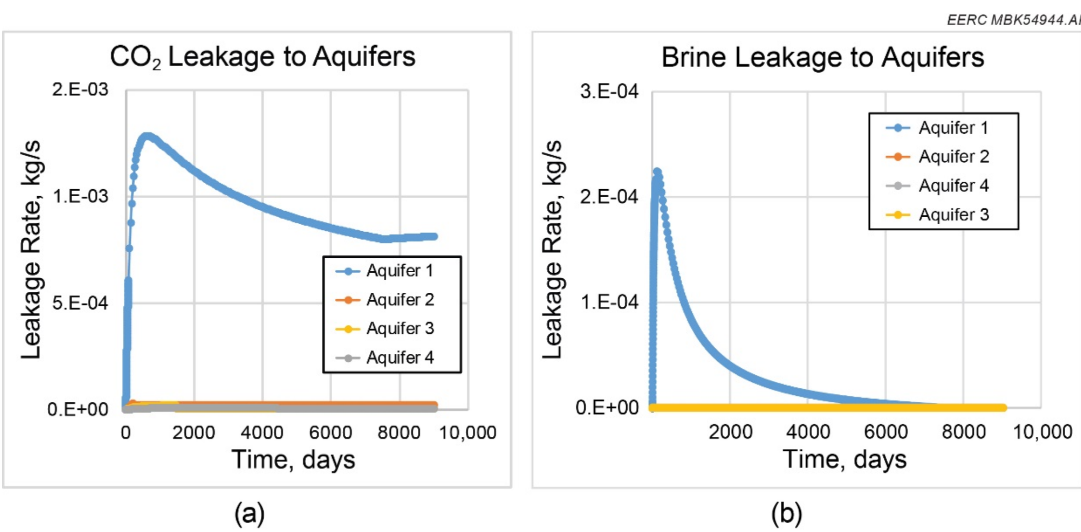

Figure E-17. Plots of the results obtained with the Multisegmented Well Model: (a) CO_2 leakage to aquifers vs. time and (b) brine leakage to aquifers vs. time.

NRAP-IAM-CS TESTING

Brief Introduction to the NRAP-IAM-CS Tool

The NRAP-IAM-CS tool is an integrated model for use in performance and quantitative risk assessment. This tool is a hybrid system, i.e., links together ROMs for simulation of different processes, such as subsurface injection of CO_2, CO_2 migration, leakage, and shallow aquifer impacts. NRAP-IAM-CS can generate probabilistic simulations related to the long-term fate of CO_2 on different geologic sequestration scenarios.

The ROMs incorporated into NRAP-IAM-CS can run in several ways, from analytical functions to direct incorporation of reservoir simulation results as look-up tables. Look-up tables are created by resampling the original CMG outputs into a compatible grid, created with the REV tool. The NRAP-IAM-CS compatible grid represents the model domain using 10,000 cells (100 in each Cartesian axis in the XY-plane), with the cell dimensions being calculated as even increments inside the model domain. Model features (e.g., wells) and processes (e.g., flow of CO_2 and brine) in the reservoir and overlying aquifers are mapped spatially into corresponding cells. CO_2 saturation and mass flow are computed with the 10,000-cell domain, providing the model with a comparable spatial distribution.

The NRAP-IAM-CS model is set up by means of a GoldSim project. GoldSim is a Monte Carlo (MC) simulation software platform, commonly used for modeling complex systems in engineering, science, and business (GoldSim, 2018). The NRAP-IAM-CS GoldSim project links the ROMs with the MC algorithms, which help to represent uncertainty using probabilistic simulations.

The NRAP-IAM-CS tool displays a dashboard that has a tree structure, with several layers of interfaces that give access to each system component. The tree structure provides a natural hierarchy where the user progressively chooses between a set of preexisting options. For instance, the first two levels of the dashboard are as follows:

1. Scenario type and (site-specific) inputs
   Direct leakage to atmosphere through wells
   Leakage to groundwater through wells
   Area of review (pressure and saturation)

2. MC settings
   Time
   MC
   Globals
   Information

3. Results
   CO_2 brine leakage
   Aquifer impact results
   CO_2 brine leakage: multivariate statistics
   Aquifer impact results: multivariate statistics

Figure E-18 illustrates a diagram showing the second-level components unfolded when opening the first-level option “Scenario Type & Inputs.” Red-colored components indicate components that are specific to certain components. Table E-4 shows the parameters, or site-specific data, per each second-level component belonging to the same first-level option. In this study, two scenario types (“Direct leakage to atmosphere through wells” and “Leakage to groundwater through wells”) were studied. The former scenario refers to estimated mass transfer rates because of leaking from the reservoir through leaky wellbores. The later scenario incorporates aquifer impacts, estimated as time-dependent changes in groundwater aquifers. The

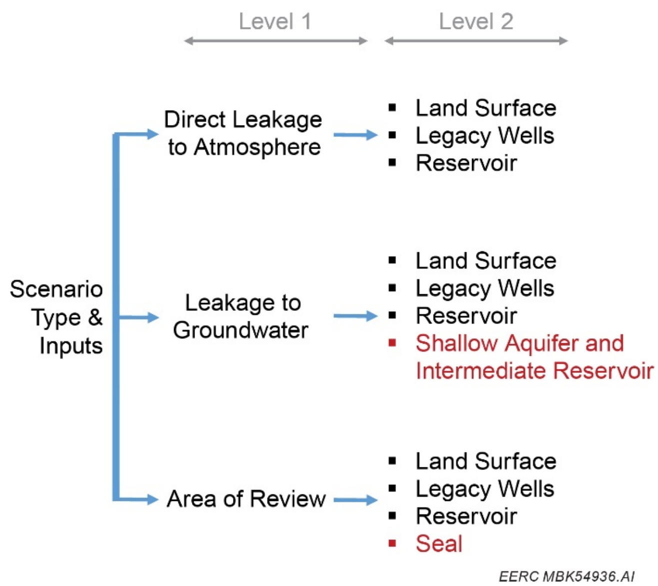

Figure E-18. Schema showing the options under “Scenario Type & Inputs.” Red-colored components indicate components that are unique to one of the Level 1 options.

Table E-4. List of the Parameters, or Site-Specific Data, per each Level 2 Component under the “Scenario Type & Inputs” Category

Component	Data
Reservoir	Can choose one out of two options: • Built-in ROM (semianalytical model) • User-supplied site-specific simulation results Specifications: spatial extent, permeability, thickness, porosity, injection parameters
Wellbore	Built-in ROM Location, type (cemented/open), spatial density, cement permeability
Shallow Aquifer	Built-in ROMs for carbonate and sandstone aquifers Aquifer hydrological and geochemical parameters
Intermediate Reservoir	Location, permeability, thickness
Atmosphere	Built-in ROM Elevation, wind speed, ambient temperature and pressure, leak temperature Detection threshold

third option, “Area of review (pressure and saturation),” was left out of the analysis because, after the geologic characterization results, sealing cap rock thickness is assumed to be sufficiently large to safely neglect potential risks due to CO_2 leakage though this impermeable layer. For the sake of simplicity, results presented in the following discussion refer to the “Leakage to groundwater through wells” scenario, as this model is more complete than the first scenario model.

Inputs for the Nebraska Model

NRAP-IAM-CS allows two ways for scoping a study: “General Scoping Case” and “Complex Calculations Case.” The General Scoping Case is a simpler approach as the user just provides constant or distributed values via the GoldSim dashboard. The Complex Calculation Case requires having look-up tables with site-specific data. In this study, the Complex Calculations Case scoping approach was used for taking advantage of the geologic and reservoir simulation models prepared in Task 4.

Based on the collected geologic data, constant values were defined for the parameters of the components “Land Surface” and “Shallow Aquifer and Intermediate Reservoir.” Table E-5 and Table E-6 show those values, which are based on site-specific information after the Nebraska site characterization effort. On the Land Surface dashboard, some parameters are hard-wired (gray-colored cells in Table E-4).

Table E-5. Input Parameters for Component “Land Surface”

Parameters	Input value	unit
Land Surface Temperature	Hard-wired	
Mass Fracture of CO_2 Leaving from Top Layer	Hard-wired	
Geothermal Gradient	Hard-wired	
Land Surface Elevation	1074.7	m
Wind Speed at 10 m above Land Surface	10	
Ambient Temperature	9.4	C
Ambient Pressure	1	atm
Leaked Gas Temperature	20	C
Threshold Concentration	0.002	
Number of Checking Point	1	

Table E-6. Input Parameters for Component “Aquifer”

	Shallow Aquifer Properties	Intermediate Aquifer Properties	Unit
Elevation	1074	385.8	m
Thickness	/	96	m
Pressure	1.27	6.75	MPa
Temperature	14.1	34.3	°C
Permeability	10E-12	1.0E-14	m^2
Porosity	0.25	0.1	

Inputs of the "Reservoir" and "Legacy wells" components are specified with external lookup files. First, a list with file names is written into a Master-file ("Lookup_tables_and_inputs.txt"), which sits into the root directory of the NRAP-IAM-CS tool. Six text files are needed, corresponding to various reservoir parameters (reservoir pressure, reservoir temperature, reservoir CO_2 saturation, reservoir dissolved CO_2 weight fraction, reservoir permeability, and reservoir elevation). Note that static parameters, permeability and elevation, are defined with a 2-D look-up table, while dynamic parameters are defined with a 3-D look-up table, with time-dependent being stacked with 100 × 100 cell values for each time step.

Inputs of the Legacy well component also use the external lookup files format. Two kinds of information are needed to characterize the leakage wells: i) well placement (i.e., number and location of wells) and ii) well settings (i.e., wellbore type and cement permeability). Multiple wells with known locations were defined via ASCII files. The well location coincides with the injection wells defined in the reservoir simulation models from Task 4. Table E-7 shows the well locations for different realizations. Note that the default format for the well location is prescribed in terms of a relative coordinate system. As the geologic model and reservoir simulation results are defined with a global coordinate system, a coordinate transformation function was needed to meet the tool requirements. Another parameter required to predict wellbore leakage is the effective wellbore cement permeability. The base case has a single value for wellbore cement permeability. Possible values for wellbore permeability can vary in a wide range from 1E-17 m^2 to 1E-13m^2 (i.e., 0.01 to 100 mD). The base case uses a value of 1 mD for all three realizations (P10, P50, P90). Later on, a sensitivity analysis on the effect of wellbore permeability on leakage results was performed to explore the effect of wellbore cement permeability on the leakage estimation.

Table E-7. Injection Well Locations for Different Realizations

Realization	Well Name	Global Coordinates		Relative Coordinates			
		X, ft	Y, ft	X, ft	Y, ft	X, m	Y, m
P10	DK-1	2535118	14742394.75	95500	59500	29108.401	18135.6
	DK-2	2539118	14811394.75	99500	128500	30327.601	39166.8
	DK-3	2501118	14832394.75	61500	149500	18745.201	45567.6
	DK-4	2450118	14841394.75	10500	158500	3200.4013	48310.8
	DK-5	2544118	14697394.75	104500	14500	31851.601	4419.599
	DK-6	2453118	14706394.75	13500	23500	4114.8013	7162.799
	DK-7	2463118	14697394.75	23500	14500	7162.8013	4419.599
	DK-8	2455118	14785394.75	15500	102500	4724.4013	31242
P50	DK-1	2470118	14724394.75	30500	41500	9296.4013	12649.2
	DK-2	2537118	14747394.75	97500	64500	29718.001	19659.6
	DK-3	2539118	14811394.75	99500	128500	30327.601	39166.8
	DK-4	2501118	14832394.75	61500	149500	18745.201	45567.6
P90	DK-1	2501118	14832394.75	61500	149500	18745.201	45567.6
	DK-2	2523118	14811394.75	83500	128500	25450.801	39166.8

Base Case Results

This section presents results from the Leakage to groundwater through wells scenario. An effective wellbore permeability of 1 mD was arbitrarily chosen as a basis of calculation. Sensitivity analysis based on this parameter is described in the next section. The reason to choose a value as high as 1 mD is merely out of convenience. In reality, such a high value is very unlikely in real operations. However, values that are closer to realistic permeability measurements tend to provide leakage rates that are too small to analyze as part of the tool-testing exercise. As a reminder, the goal of this work is to test the NRAP tools, and sometimes realistic parameters do not serve this overarching purpose.

The scoping scenario is the "Complex Case"; therefore, the CMG dynamic flow simulation results (from Task 4) were employed to generate the grids required by some of the model components. Dynamic flow simulation was conducted to assess the prefeasibility of storing 50 million tonnes of CO_2 over 25 years.

Figure E-19 shows results in terms of the CO_2 leakage, while Figure E-20 show results in terms of brine leakage. Results of both CO_2 and brine leakage to atmosphere were negligible for all of the geologic realizations (P10, P50, P90).

The maximum CO_2 leakage rate, to both the groundwater and the shallow aquifer, occurs at the beginning of the operations (Year 1). For the aquifer, leakage rate ranges between 5 to 120 kg per day (depending on the model realization). For the groundwater, leakage rate varies from 0.5 to 2.5 kg/day. All other things being equal, it was expected that the leakage rates were proportional to the number of wells in each model. The fact that P50 is an exception indicates that other factors (such as local pressure around the near wellbore region or well rates) could obscure this kind of simplistic analysis. The leakage rates drop after the first year and, at later times, reach values as low as 0.3 kg per day for the groundwater or 3.7 kg per day for the aquifer. In the worst-case scenario, after 25 years of injection, the total mass leaked to the aquifer was 90 tons, while the total mass leaked to the groundwater was 4 tons.

The maximum brine leakage rate for the shallow aquifer occurs at the beginning of the second year of operation. For the worst-case scenario (P10), the brine leakage rate stabilizes around 25 kg per day, while for the best-case scenario, it stabilizes around 3.2 kg per day. Brine leakage rates stabilize around the second-year values. After 25 years of injection, the total mass leaked to the aquifer ranged from 27 to 213 tons.

For the groundwater, leakage rate varies from 0.5 to 2.5 kg day. All other things being equal, it was expected that the leakage rates were proportional to the number of wells in each model. The fact that P50 is an exception indicates that other factors (such as local pressure around the near wellbore region or well rates) could obscure this kind of simplistic analysis. The leakage rates drop after the first year, and at later times, they reach values as low as 0.3 kg per day for the groundwater or 3.7 kg per day for the aquifer. In the worst-case scenario, after 25 years of injection, the total mass leaked to the aquifer was 90 tons, while the total mass leaked to the groundwater was 4 tons.

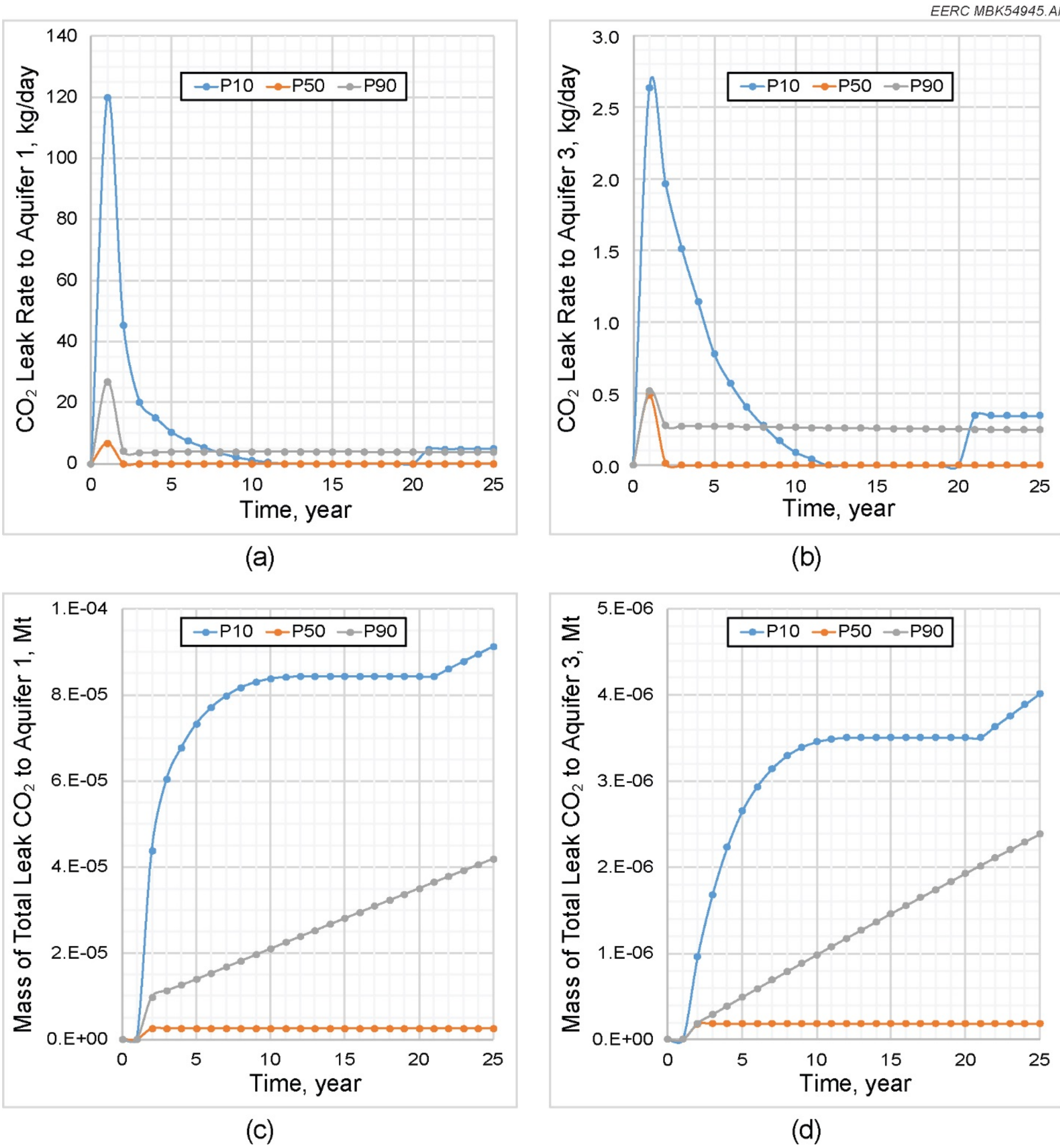

Figure E-19. Plots obtained with the Leakage to groundwater through wells scenario showing time-dependent estimations for CO_2 leakage. CO_2 leakage to an intermediate aquifer (Aquifer 1) is shown in terms of leakage rate (a) and total mass (c). Also, CO_2 leakage to groundwater aquifers (Aquifer 3) is displayed in terms of leakage rate (d) and total mass (b). Results of CO_2 leakage to atmosphere were negligible for all three geologic realizations (P10, P50, P90).

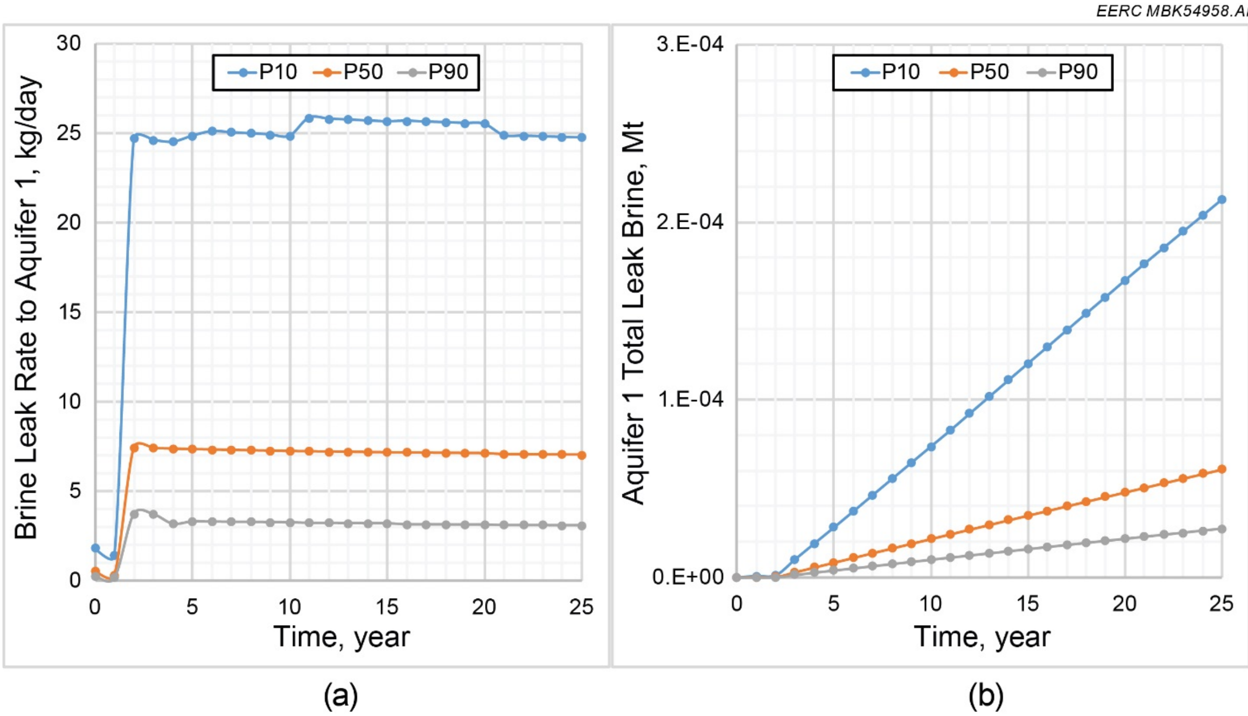

Figure E-20. Plots obtained with the Leakage to groundwater through wells scenario showing time-dependent estimations for brine leakage to an intermediate aquifer (Aquifer 1), is shown in terms of leakage rate (a) and total mass (b). Results of brine leakage to the groundwater aquifer were negligible for all three geologic realizations (P10, P50, P90).

Sensitive Analysis on Wellbore Cement Permeability

As mentioned before, a key parameter required to predict the wellbore leakage is the effective wellbore cement permeability. Geological realization P50 was selected to test the potential impacts of various wellbore cement permeability values on both CO_2 and brine leakage. To yield a sufficiently ample range of wellbore cement permeability values, a four order-of-magnitude variation range was used, from 1E-17 to 1E-13 m^2 (which is equivalent to about 0.01 up to 100 mD approximately). All of the other factors were kept equal. The range chosen for the effective wellbore cement permeability is based on reported values found in the open literature (Viswanathan and others, 2008; Um and others, 2011; Gasda and others, 2013).

Figures E-21 and E-22 show the results of the sensitivity analysis. Results include rate of CO_2 leakage to atmosphere (Figure E-21a) and the total mass of CO_2 leakage to the groundwater (Figure E-21b). As expected, the maximum values occur with the highest permeability (100 mD, equivalent to 1E-13 m^2). After 25 years, the values of the total mass of CO_2 leak observed were 2.5 tons for the shallow aquifer and 58 tons for the groundwater.

Figure E-22 shows results of the total mass of brine leakage to the shallow aquifer (Figure E-22a) and brine leakage to the groundwater (Figure 22b). Maximum values for the total mass of brine leakage were 60.9 tons reach into the shallow aquifer and 20.6 tons reach into the groundwater.

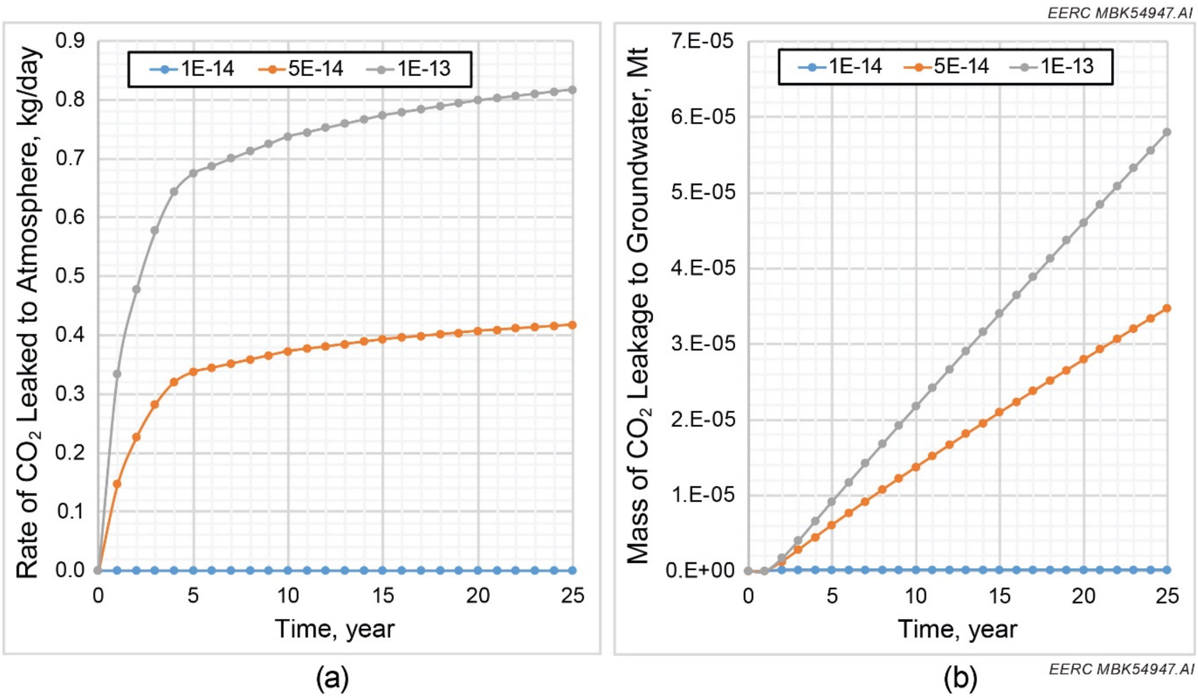

Figure E-21. Sensitive analysis of wellbore cement permeability on CO_2 leakage: (a) rate of CO_2 leakage to atmosphere and (b) total mass of CO_2 leakage to the groundwater.

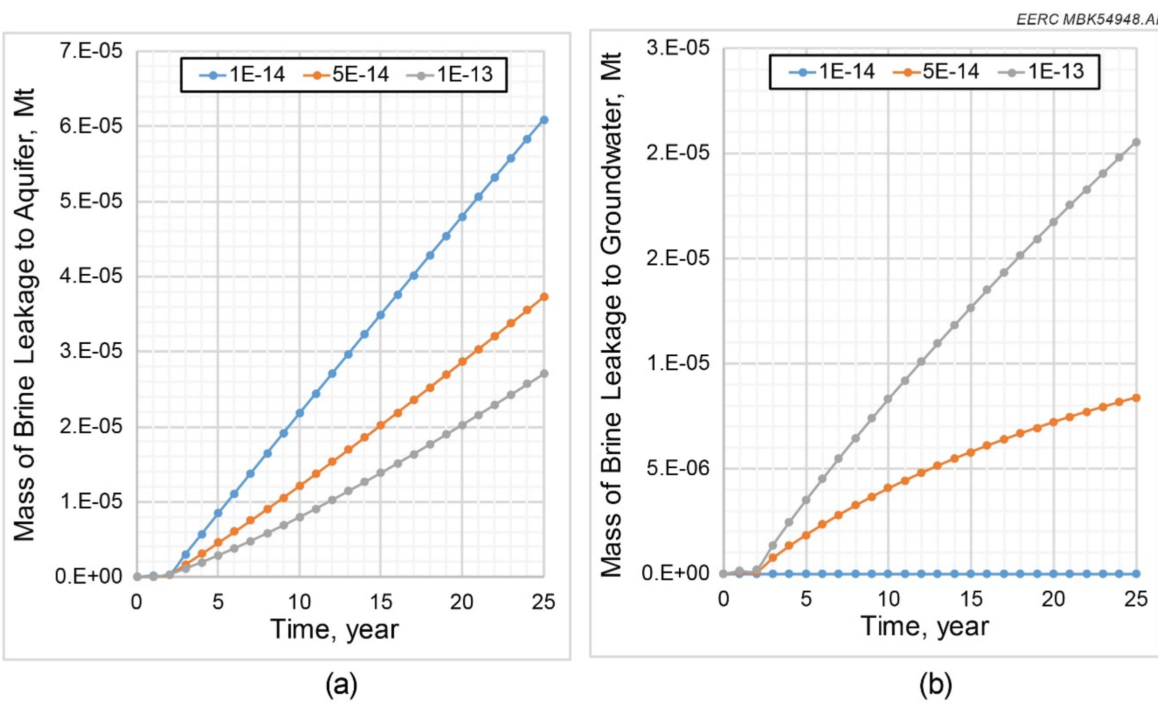

Figure E-22. Sensitive analysis of wellbore cement permeability on brine leakage: (a) rate of brine leakage to the shallow aquifer and (b) total mass of brine leakage to the groundwater.

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