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May 31, 2017

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Dear Ms. Fine:

Subject: Final Report for Integrated Carbon Capture and Storage for North Dakota Ethanol Production; EERC Fund 21525

Attached is the final report for the subject project. If you have any questions, please contact me by phone at (701) 777-5013, by fax at (701) 777-5181, or by e-mail at kleroux@undeerc.org.

Sincerely,

100lue

Kerryanne M. Leroux Senior Chemical Engineer, Oilfield Operations Team Lead

KML/kal

Attachment



INTEGRATED CARBON CAPTURE AND STORAGE FOR NORTH DAKOTA ETHANOL PRODUCTION

Final Report

(for the period of November 1, 2016, through May 31, 2017)

Prepared for:

Karlene Fine

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INTEGRATED CARBON CAPTURE AND STORAGE FOR NORTH DAKOTA ETHANOL PRODUCTION

EXECUTIVE SUMMARY

The Energy & Environmental Research Center (EERC) and Red Trail Energy, LLC, (RTE) conducted an economic and technical feasibility study for integrating carbon capture and storage (CCS) with ethanol fuel production at the RTE facility near Richardton, North Dakota. Results of this study indicate that commercial CCS is a technically viable option for the significant reduction of CO_2 emissions from ethanol production at the RTE site. In addition, CCS may also be economically viable for RTE should pathways emerge for low-carbon-intensity (CI) ethanol-CCS in developing low-carbon fuels programs.

The RTE site offers an extremely favorable case study. RTE currently has ethanol distribution to low-carbon fuel markets in California and Oregon, and the facility overlies ideal geologic formations, which could store all of RTE's fermentation-generated CO₂ emissions for decades. Carbon markets such as California's Low Carbon Fuel Standard (LCFS) Program and Oregon's Clean Fuels Program provide a current economic incentive through which the ethanol industry could profit from CCS implementation. The Broom Creek Formation and accompanying sealing formations, which are present directly below RTE's facility, are expected to make an ideal storage complex for the proposed injection. If ultimately implemented, the resulting RTE CCS effort could store approximately 3.2 million tonnes of CO₂ in a 20-year period of injection.

A technical evaluation of CCS implementation at the RTE site provided the necessary inputs required for development of a provisional FIP (field implementation plan), with conceptual designs and permitting/pathway requirements. The following list summarizes the results from these efforts:

- The CO₂ generated at the RTE facility contains minimal impurities (>99% CO₂), requiring nominal processing for injection, such as dehydration of the CO₂ stream and compression up to 1500 psi. A 4-inch pipeline is recommended to transport CO₂ to the injection site within 1 mile of the RTE facility. Specific flow rates and composition of the CO₂ stream at the RTE facility will be needed to refine engineering designs.
- Site-specific geologic characterization data are imperative for the successful deployment of CCS at the RTE site. Geologic modeling and subsequent simulation estimated the average lateral extent of potential CO₂ storage to be about 1.8 miles in diameter after a 20-year injection period and 10-year postinjection monitoring period. Well logging, core acquisition and testing, and downhole testing at the RTE site are recommended for improved modeling and simulation estimates, as well as acquiring pertinent preinjection data.
- A programmatic risk analysis of CCS implementation at the RTE site determined the highest-ranking potential risks are external or commercial (i.e., not technical risks) due to uncertainty surrounding carbon storage policies currently under development. The North Dakota Class VI permitting process for a CO₂ storage facility is time- and data-intensive and will require coordination with regulators to ensure all designs and plans are compliant prior to submittal. Approval pathways for low-carbon fuel programs to include CCS are still in the development stages and will also require coordination with officials to ensure compliance for acquiring credits.
- A provisional monitoring, verification, and accounting (MVA) program and preliminary designs for monitoring and injection wells were derived based on permitting requirements to demonstrate secure CO₂ injection and long-term stability of potentially stored CO₂ at the RTE site. Refinement of the MVA program and well designs will depend greatly on

data attained to meet permitting regulations (e.g., geologic core analysis) and pathway requirements for obtaining carbon credits.

• A life cycle analysis showed >40% potential net reduction of CO₂ emissions for ethanol-CCS at RTE. A significant reduction in CI value may thus be achieved for ethanol production with CCS implementation, a required pathway parameter for designating carbon credits through low-carbon fuel programs.

Table ES-1 shows the estimated costs for integration of CCS at the RTE facility, based on execution of the developed FIP. Average estimated capital costs were \$29.0 million for installed infrastructure and implementing preinjection plans. Annual expenses for energy requirements and continued execution of operational plans were estimated to be about \$1.9 million on average. These preliminary values contain many site-specific uncertainties, such as permitting and pathway requirements (including related data needs), investment interest rates, escalation in construction or energy prices, land or pore space purchase, etc. Estimates for potential revenue that could be generated from low-carbon fuel programs suggest a considerable economic benefit from ethanol-CCS; however, results are proprietary because of the business-sensitive nature of the assessment, including additional uncertainties such as market stability. Alternate markets such as enhanced oil recovery and food/chemical-grade CO_2 may also be viable but require more detailed investigation. Therefore, RTE intends to move forward to the next phase of assessment for CCS implementation.

Item	Value, millions	Notes
Capital Expenses	\$29.0	Installed capture system, pipeline, and monitoring and injection wells; execution of permitting, characterization, and preinjection MVA plans
Annual Operating Expenses	\$1.9	Capture system energy requirements and execution of the MVA plan

Table ES-1. Estimated Costs for CCS Implementation at the RTE Site

The favorable technical and economic results of this feasibility study support continuation of the CCS research effort at the RTE site. The next steps toward implementation include a detailed examination of the storage complex beneath the facility, accomplished by drilling to collect core samples from the target formation and overlying seal. In addition, preliminary engineering designs will be refined and an in-depth economic analysis will be conducted. Dialogue will also continue during these efforts to ensure compliance with guidelines and requirements from North Dakota permitting regulators and low-carbon fuel program authorities.

This subtask was funded through the EERC–DOE Joint Program on Research and Development for Fossil Energy-Related Resources Cooperative Agreement No. DE-FE0024233. Nonfederal funding was provided by the North Dakota Industrial Commission and Red Trail Energy, LLC.

INTEGRATED CARBON CAPTURE AND STORAGE FOR NORTH DAKOTA ETHANOL PRODUCTION

INTRODUCTION

The Energy & Environmental Research Center (EERC), in partnership with Red Trail Energy, LLC, (RTE), a North Dakota ethanol producer; the North Dakota Industrial Commission (NDIC); and the U.S. Department of Energy (DOE), conducted a study to determine the technical and economic feasibility of implementing commercial carbon capture and storage (CCS) at a North Dakota ethanol production facility and proximal geologic injection site. Figure 1 provides a simplified block diagram of this ethanol-CCS process. Validation of the use of CCS to reduce the carbon intensity (CI) value of ethanol production may allow producers to maintain and/or expand marketability of their fuel within developing low-carbon fuel programs in California and Oregon.



Figure 1. Block diagram of ethanol-CCS process.

North Dakota is well-situated to demonstrate the implementation of CCS for small- to medium-scale CO_2 emitters. North Dakota has significant ethanol production as well as suitable geology for carbon storage. The ethanol industry is also often cited as falling below the threshold for large-scale CO_2 production (>1,000,000 tonnes/year) (1), meaning the challenges associated with developing CCS for small- to mid-scale CO_2 emitters are not well studied. In addition, emerging carbon markets in California and Oregon, such as California's Low Carbon Fuel Standard (LCFS) Program and Oregon's Clean Fuels Program (CFP), provide a current economic incentive through which small- to medium-scale CO_2 emitters in the fuel production industry could pursue carbon incentives and potentially offset the costs of CCS implementation.

The RTE site represents an extremely favorable case study. RTE currently has ethanol distribution to California and Oregon, and the facility directly overlies ideal geologic formations which have the potential to storage all of RTE's fermentation-generated CO₂ emissions for decades. The Broom Creek Formation, present in southwestern North Dakota, and the overlying

shales and salts of the Opeche, Piper, and Swift Formations are expected to make an ideal storage complex for the proposed CO_2 injection (2, 3). The Broom Creek target injection horizon is situated at a depth of approximately 6400 ft below the RTE facility. The RTE facility, located near Richardton, North Dakota, produces approximately 163,000 tonnes of CO_2 annually from the fermentation process. If a CCS project is implemented, the RTE site could store approximately 3.2 million tonnes of CO_2 during a 20-year period of injection.

The specific objectives of this project were to 1) assess the technical feasibility of carbon capture at a North Dakota ethanol facility and subsequent geologic CO_2 storage at a proximate site; 2) develop a field implementation plan (FIP) determining the design and implementation steps needed to install a CCS system; and 3) evaluate the economic feasibility of CCS deployment, including installation and operating costs as well as potential low-carbon fuel markets and other carbon markets to assess the benefits to North Dakota ethanol producers.

TECHNICAL EVALUATION

The technical aspects of carbon capture at the RTE ethanol facility in western North Dakota and its subsequent geologic storage were evaluated to verify the feasibility of reducing CO_2 emissions from ethanol production. Considerations included design criteria for CO_2 capture and transport, characterization of the surface and subsurface at the RTE site, geologic modeling and simulation of CO_2 storage in the Broom Creek Formation, a risk assessment of ethanol-CCS implementation, and a life cycle analysis (LCA) of the ethanol-CCS carbon footprint at the RTE site. The following section details the results of this technical viability evaluation.

CO₂ Capture and Transport

The high purity of CO_2 generated during the fermentation process at an ethanol plant requires limited postprocessing to generate a CO_2 product. Three options for CO_2 capture at the RTE site were investigated to generate 1) an injection-grade CO_2 , 2) an enhanced oil recovery (EOR) product, or 3) a food/chemical-grade product. The latter two product options were investigated to provide alternative or complementary market opportunities in addition to the geologic storage of the CO_2 for low-carbon fuel programs. The evaluations that follow examine the composition of the CO_2 stream produced at the RTE facility and determine the processing steps required to generate each product stream.

Each of the three potential CO₂ product streams investigated has different purity specifications, as shown in Table 1. Injection-grade quality is based on a combination of specifications for injection into a saline aquifer for geologic storage and transport in a carbon steel pipeline to minimize corrosiveness of the stream. Together, these place a restriction on a number of constituents, most notably being water content of $\leq 0.05\%$ by weight and O₂ $\leq 0.001\%$ by volume (4). It should be noted that the oxygen limit is provided as a range in literature, 0.001%–4%, with the lower limit dictated by the use of carbon steel pipes for the CO₂ transport. Further investigation of the impact of these limits on the system design will be conducted during the next project phase.

Component (max., unless noted)	Unit (unless noted)	Saline Reservoir/ Carbon Steel Pipeline	EOR/ Commercial Pipeline	Food/Beverage/ Chemical Grade
CO ₂ (min.)	vol%	95	95	≥99.9
H ₂ O	ppmv	500	500	≤20 ppmv
N_2	vol%	4	1	NRL^*
O_2	vol%	0.001^{\dagger}	0.001	≤30 ppmv (total
Ar	vol%	4	1	O ₂ and Ar)
CH_4	vol%	4	1	≤50 ppmv [‡]
H_2	vol%	4	1	NRL
CO	ppmv	35	35	≤10
H_2S	vol%	0.01	0.01	≤0.1 ppmv
SO_2	ppmv	100	100	≤1 ppmv
NO _x	ppmv	100	100	\leq 2.5 each for NO and NO ₂
Dissolved O ₂	ppmv	NRL	NRL	<5

 Table 1. CO2 Stream Compositional Specifications for Various End Uses (4–6)

* No requirement listed.

[†] This value can range up to 4 vol% for the saline formation but is 0.001 vol% for carbon steel pipelines.

[‡] Part of total volatile hydrocarbons.

Commercial CO₂ pipeline specifications were the design criteria for a potential EOR-grade CO₂ product. Kinder-Morgan pipeline specifications require \geq 95 mol% CO₂, \leq 0.05% H₂O, and \leq 0.001% O₂ (4). As expected, specifications for food/chemical-grade CO₂ are the most stringent, with \geq 99.9 vol% CO₂, \leq 20 ppm H₂O, and <30 ppm O₂ limitations for product quality (5, 6). The specifications presented in Table 1 suggest that each potential CO₂ product requires an independent assessment of the processing requirements for the CO₂ stream of the ethanol production facility, discussed further in the Plant Infrastructure Design section.

As shown in Table 2, available data indicate that a nearly pure stream of CO_2 is generated from the fermentation process at the RTE facility (>99% CO₂). The composition of the RTE CO₂ stream is based on two sampling events, one in 2014 and one in 2017. In January 2014, the CO₂ stream averaged approximately 99.8% CO₂, and 0.03% O₂ on a dry volume basis. Water content was measured at 0.78 vol%. The CO₂ stream was sampled again in February 2017, and the composition of the CO₂ stream was measured to be 99.987 mol% CO₂ and 0.013 mol% O₂ on a dry basis.

Comparison of Tables 1 and 2 indicate that the RTE CO_2 stream can be used for all of the above-referenced products with specific processing steps incorporated. For example, only water removal and compression (i.e., without O_2 removal) would be required for injection into a saline

Component	January 2014	February 2017	Unit
CO ₂	99.78	99.99	vol%, dry
H ₂ O	780	_*	ppmv
O ₂	300	130	ppmv, dry

Table 2. Average Analysis of RTE CO₂ Stream

*Not measured

formation. Given the purity of the stream, both conventional dehydration and compression equipment can be used to prepare the CO_2 for geologic injection. Production of EOR- or food/chemical-grade CO_2 would require significant water and O_2 removal through the use of conventional equipment, albeit with additional processing steps. Although the O_2 content exceeds commercial pipeline requirements, potential corrosion issues can be mitigated through judicious pipeline design, also described further in the Plant Infrastructure Design section.

Site Characterization

Existing site characterization data for both the surface and subsurface environment in the vicinity of the RTE ethanol facility were evaluated for use in geologic modeling for CO_2 storage design, siting of potential injection well locations, and the development of a groundwatermonitoring program. Surface structures and features were identified, such as existing wells and water resources. Property boundaries were also identified, specifically to distinguish between public and private lands. Based on previous research completed by the EERC (3, 7), the Broom Creek Formation, a sandstone formation saturated with a high-saline water (>100,000 ppm) directly underlying the RTE site, was determined to be highly suitable for CO_2 injection and storage, exhibiting good porosity and permeability, sufficient thickness, depth, and the presence of multiple upper and lower sealing formations.

The surface environment was assessed to identify land use, sensitive areas, and local population within a 2-mile radius of the RTE facility (Figure 2). In addition, five wells were identified, consisting of three domestic/groundwater, one municipal, and one oil and gas well. The site is located near the town of Richardton, North Dakota (population 524 [U.S. Census Bureau, 2014]) and is surrounded mainly by agricultural land. Interstate 94 is immediately adjacent to the site and federal grasslands owned by the Bureau of Land Management (BLM) are located a few miles to the north. The proximity of these areas is an important factor influencing the potential pipeline route, placement of monitoring and CO_2 injection wells, and development of a monitoring, verification, and accounting (MVA) program.

Review and interpretation of available literature and data further supports the suitability of the Broom Creek and associated sealing formations for CO₂ storage at the RTE site. Data collection was focused on regional wells that penetrate the Broom Creek Formation. Types of data included well, depth, formation tops, well logs, and core analyses. Lithologies and facies specific to the Broom Creek and associated formations were also assessed to determine regional petrophysics for porosity and permeability distributions. Based on these data, the estimated thickness of the Broom Creek Formation ranges from 243 to 312 feet and its permeability ranges from 71 to 490 mD. See Appendix D for further discussion of the geologic characteristics of this target formation.



Figure 2. Surface features at the RTE site.

Geologic Setting

Understanding the geologic characteristics of the storage complex is an essential aspect for the successful storage of CO_2 for any site. A storage complex refers to a geologic system comprising a storage unit and primary (and sometimes secondary) seal(s), extending laterally to the defined limits of the CO_2 storage operation(s) (8). The following sections discuss relevant characteristics of the CO_2 storage complex identified at the RTE site.

The RTE site is located in the southern portion of the Williston Basin in western North Dakota and overlies thousands of feet of sedimentary rock. The Williston Basin is a large, intracratonic basin covering approximately 150,000 square miles of eastern Montana, western North Dakota, northwestern South Dakota, and southern Saskatchewan and Manitoba, containing in excess of 16,000 feet of sediment near the depocenter in western North Dakota (Figure 3).

	Age Units	Rock Units	Hydrogeologic	Saskatchewan			
	Age onits	ROCK OTHES	Systems	Manitoba			
	Quaternary						
zoic		White River Grp		Williston			
oue	Tertiary		AQ5	· · · · · · · · · · · · · · · · · · ·			
ő	lordary	Fort Union Grp	Aquifer	Basin `,			
		Hell Creek Fm		North Dakota			
		Fox Hills Fm		``\ ☆ _{RTE} /			
		Pierre Fm					
		Judith River Fm					
	Cretaceous	Niobrara Fm	I K5 Aquitard	Whoming			
<u>.</u>		Carlile Fm		South Dakota			
0Z0		Greenhorn Fm ල් ල්					
les		Mowry Fm					
2		Skull Creek Fm	Dakota				
		Inyan Kara Fm	Aquifer				
	Jurassic	Swift Fm	тка				
		Rierdon Fm Piper Fm					
	Triassic	Spearfish Fm	Aquitard				
	Permian	Minnekahta Fm Opeche Fm					
		Broom Creek Fm	AQ3	Minnelusa Group			
	Pennsylvanian	Amsden Fm ຊີອິດ Tyler Fm ຊີ	Aquifer	Mininelusa Oroup			
		Otter Fm Kibbey Fm	TK2				
	Mississinnian	Charles Fm	Aquitard				
oic	Mississippian	Mission Canyon	AQ2 or Madison Aquifer				
ZO		Bakken Fm					
ale	Devenion	Three Forks Birdbear Duperow	тк1				
	Devonian	Dawson Bay Prairie Winnipegosis	Aquitard				
	Silurian	Ashern Interlake Fm					
	Siluitati	Stonewall Fm					
	Ordovision	Stony Mountain Fm					
	Ordovician	Red River Fm Roughlock Fm	AQ1 Aquifer				
		Black Island Fm					
	Cambrian	Deadwood Fm					

Figure 3. Williston Basin stratigraphic and hydrogeologic column (2 [modified])

The reservoir interval of the RTE site storage complex is the Permian Broom Creek Formation, the uppermost formation of the Minnelusa Group (Figure 3), and is composed of eolian and nearshore marine sandstone–carbonate cycles (9). At the RTE site, the Broom Creek Formation is approximately 6400 feet below the land surface and is about 280 feet thick. The formation in the study area is composed predominantly of sandstone (i.e., permeable storage intervals) with interbedded dolostone and anhydrite (impermeable layers).

The primary seals of the RTE storage complex include the Amsden and Opeche Formations. The Amsden Formation, which directly underlies the Broom Creek Formation, is mainly composed of dolostone and anhydrite, forming the underlying seal for the storage interval. Overlying the Broom Creek Formation is the Opeche Formation (primary upper seal), which is approximately 100 feet thick. Many additional low-permeability formations are present above the primary seal of the Opeche Formation, creating secondary barriers to prevent vertical CO₂ migration from the storage formation (Figure 3). These barriers also provide isolation from shallow aquifers that may be designated as underground sources of drinking water (USDW) and thus protected by U.S. Environmental Protection Agency (EPA).

The Williston Basin is considered tectonically stable, with a gentle structural character (10, 11). Structural features within the basin show a north- and northwest trend which include the Nesson, Billings, Cedar Creek, and Antelope Anticlines, and the Heart River Fault. The Heart River Fault is located approximately 3 miles southwest of the RTE plant (Figure 4). Well and seismic data acquired in the search for petroleum in the deeper formations in the area has led to some understanding of this fault. It is a high-angle reverse fault, seated in the Precambrian crystalline basement, with the upthrust block to the east. Fault offset is interpreted to be less than 400 feet in rocks up through the Upper Ordovician to Lower Silurian age, well below the Broom Creek Formation as shown in Figure 3. Formations above the Lower Silurian show flexure from the fault but do not appear to be offset (12). Available data and knowledge indicate the Heart River Fault system does not penetrate the Broom Creek; therefore, the risk of vertical fluid migration due to any potential fault activation is negligible.

Scientific investigations, to this point, indicate most cases of induced seismicity are associated with fluid injection directly into granitic basement rock or into overlying formations with hydraulic conductivity to such basement rock (13). Thousands of feet of sedimentary rock separate the Broom Creek Formation (i.e., planned injection horizon) from Precambrian crystalline basement rock, with seismic data showing no direct fluid communication between them. North Dakota also has an extensive history with injection of water produced from oil and gas operations. As of 2015, nearly 440 million barrels of water have been injected into North Dakota disposal wells (14), including but not limited to wells in the Broom Creek Formation, without a notable increase in seismic events.

In fact, there are very few recorded seismic events for North Dakota in general. A 1-year seismic forecast (including both induced and natural seismic events) released by the United States Geologic Survey in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (15). No events with a magnitude greater than 3.3 on the Modified Mercalli Intensity (MMI) scale have been recorded within 100 miles of the RTE site (Figure 5). This indicates relatively stable geologic conditions in the region surrounding the potential injection site.



Figure 4. Map of the Heart River Fault near the RTE plant; blue line labeled 3022 is a 2-D seismic line interpretation along the Heart River Fault (see Appendix D for details).

Geologic Modeling and Simulation

Geologic modeling integrated the identified geologic site characterization data and generated a digital representation of the Broom Creek Formation at the RTE site, serving as the basis for dynamic reservoir simulations and performance forecasts of CO_2 injection. These simulations predict how CO_2 may be distributed in the storage complex, under a variety of scenarios, and the effectiveness of the sealing formations in containing the stored CO_2 in the formation over the lifetime of the ethanol-CCS operations. Simulation results also provide key inputs for other project activities such as the capture-to-injection infrastructure design, an assessment of the technical risks of storage operations, and the determination of an area of review (AOR) for permitting and the development of an MVA program. The following section provides discussion of pertinent results from modeling and simulation activities, with full details provided in Appendix E.



Figure 5. Recorded seismic events in North Dakota from the year 1900 to present with magnitudes on the MMI scale greater than 2.5. Numerical values indicate the magnitudes associated with events (16).

Geologic Modeling

Geologic models were developed with publicly available data, obtained primarily from the NDIC Oil and Gas Division database. These data included well logs, formation top depths, well elevation values, and core sample analyses and descriptions. The models of the RTE study site were approximately 100 mi² in aerial extent (red box in Figure 4), focusing on potential storage in the Broom Creek Formation. The modeling effort indicates that the Broom Creek Formation is likely a suitable injection target with thick zones of favorable porosity and permeability and with competent upper and lower sealing formations suitable for successful CO₂ storage at the RTE site.

Model development was challenging, with only limited data available in close proximity to the RTE site, e.g., the closest Broom Creek well penetration is located approximately 2 miles south of the facility. As such, a rigorous set of analyses were undertaken to address the uncertainty of the formation structure, facies proportions/connectivity, and petrophysical properties. The outcome of this effort resulted in 18 models generated to investigate the effects of varying thickness, permeability (71–490 mD), porosity (0.6–0.23) and connectivity (low–high), based on the ranges in available data found for the region. Table 3 provides a summary of these properties for each model, where P10 indicates the low end of the data set, P50 denotes the average, and P90 represents the high end of the data set.

Reservoir Simulation

Reservoir simulations developed from each model were used to estimate the CO_2 injection pressure requirements (i.e., to inject CO_2 into the storage reservoir), the extent of pressure buildup within the reservoir (pressure plume), and the lateral distribution of CO_2 saturation extent (CO_2 plume). Pressure and CO_2 plumes were forecasted upon completion of a 20-year injection period and when stabilization occurs after injection has ceased. Injection pressures are needed for infrastructure designs, and the extent of the estimated pressure and CO_2 plumes factor into the AOR determination. Simulations were derived from each of the models developed (Table 3) to provide a range of potential pressure and plume results, accounting for the uncertainty in the original data parameters.

Note that simulations also require additional inputs such as operational conditions (CO₂ flow rate, temperature, etc.) and well design and completions for accurate prediction of CO₂ behavior in the reservoir. About 163,000 tonnes CO₂ are generated annually at the RTE facility for an average of 19.1 tonnes/hr potential injection rate. Well design and completions are detailed in the Well Design section. See Appendix E for details.

A maximum of 1450 psi was estimated for wellhead pressure (WHP) or injection pressure requirements for potential CO₂ storage within the Broom Creek Formation at the RTE site. Initial WHP estimates ranged 745–1305 psi for the simulation cases studied. A sensitivity analysis was conducted to identify which parameters have the most impact on the WHP estimate within the simulation model. Parameters included wellhead temperature (WHT), bottomhole temperature, injection rates, tubing roughness, and vertical/horizontal permeability ratio. WHT was found to have the most significant impact, e.g., increasing the WHT from 40° to 100°F was predicted to increase the required WHP by about 470 psi. This was an important finding, as the ambient temperatures in North Dakota can vary significantly, often surpassing 90°F in summer months. The WHP estimate was therefore reassessed for a WHT up to 100° F for all simulation cases, generating results ranging 1380–1450 psi. These results were then used to establish a target output pressure of 1500 psi for the design of the RTE compression equipment to ensure sufficient pressure at the wellhead for sustainable injection.

The maximum diameter for an AOR based on the estimated pressure plume was estimated for potential CO_2 storage at the RTE site. The AOR, based on extent of the pressure plume for stored CO_2 , is defined by EPA as "pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW" (17). That threshold is a pressure differential of 95 psi for the RTE site. Analytical tools available from both EPA and DOE were used to evaluate the pressure plume for CO_2 injection and storage at the RTE site under anticipated operating conditions. The maximum estimated pressure differential ranged 98–128 psi for all simulation cases. The estimated diameter for an AOR based on these results was less than 1 mile.

Simulation results suggest an average potential lateral CO_2 plume diameter of approximately 1.7 miles after 20 years of injection at the RTE site. CO_2 plume evolution was determined for the P10, P50, and P90 cases using the reservoir petrophysical properties indicated in Table 3. Figure 6 shows the simulated results of the estimated CO_2 plume extent ranging 1.4–2.0 miles in diameter, using RTE's average annual production rate of 163,000 tonnes CO_2 and a 20-year

Facies	Low Conne	ectivity/Sand	Proportion	Mid Connectivity/Sand Proportion			High Connectivity/Sand Proportion		
Porosity (PHI), Permeability (K)	P10*	P50	P90	P10	P50	P90	P10	P50	P90
Thin Structure	0.06, 72	0.14, 227	0.17, 349	0.07, 84	0.15, 264	0.19, 406	0.08, 101	0.17, 316	0.23, 488
Mid Structure	0.07, 71	0.14, 225	0.18, 315	0.07, 84	0.15, 266	0.2, 408	0.08, 100	0.18, 318	0.23, 490

Table 3. Geologic Modeling and Simulation Case Matrix

*Highlighted P10, P50, and P90 cases were the focus for further evaluations of simulation results.



Figure 6. Simulated CO₂ plume expansion after a 20-yr injection period, showing P10, P50, and P90 (left, middle, and right) simulation results generated from the highlighted regional properties shown in Table 3.

injection period. Since the AOR is determined by using the plume estimate with the greatest extent (CO_2 vs. pressure), these results indicate that the extent of the CO_2 plume will dictate the size of the AOR.

Another important consideration is the final stabilization state of the stored CO_2 after injection ceases, which is necessary for monitoring efforts to meet permitting requirements (see the MVA Plan section for details). An average lateral CO_2 plume diameter of 1.8 miles was estimated after simulating 10 years of postinjection migration (Figure 7). This is an expansion of only 0.1 miles from injection conditions, predominantly moving in a southeast, structural updip direction. Simulation results also indicate that reservoir pressures may return to preinjection conditions within this time frame (i.e., differential pressure <10 psi). Taken together, these factors define stable or near-stable conditions of stored CO_2 , appropriate for initiating site closure activities at that time in the project's life cycle (see Permitting Plan section). However, the previously discussed uncertainties present in the models and simulations remain and therefore will need to be confirmed after the collection of additional site-specific geologic data. See Appendix E for more details and discussion.

Risk Assessment

A risk assessment was conducted to evaluate potential project risks related to CCS implementation at the RTE facility. The risk management process followed the international standard presented in ISO-31000 (18), detailed in Appendix F. A project-specific risk register was created containing potential risks across several categories, including technical risks, ethanol or CCS policy-related risks, and other risks related to external or commercial aspects of CCS implementation, summarized below:

- Potential Technical Risks
 - Continuity of CO₂ supply, injectivity, and storage capacity
 - Subsurface containment
 - Lateral migration of CO₂ or formation water brine
 - Propagation of subsurface pressure plume
 - Vertical migration of CO₂ or formation water brine
 - Induced seismicity
- Policy-Related Risks
 - Ethanol policy
 - CCS policy
- External, Commercial, or Other Risks
 - Market forces
 - Accidents/unplanned events
 - Project management



Figure 7. Simulated CO₂ plume expansion 10 years after a 20-year injection period.

Impact categories were considered for evaluation of each risk: cost, schedule, health and safety, legal/regulatory compliance, permitting compliance, and corporate image/public relations. The probability of a potential risk occurring and the severity of its potential impact across these categories were assigned for each individual risk using a five-point scale: 1–very low, 2–low, 3– moderate, 4–high, and 5–very high. For example, disruption to the CO₂ supply may have a high impact to the cost or economics of the project (a score of 4) but a low probability of occurrence, especially if spare replacements for the capture system are on-site (a score of 1). Appendix F provides additional details on the risk assessment process.

The risk probability and impact scores for each individual risk were plotted onto a risk map. The risk maps provide a relative ranking of the project risks, with the individual risk scores providing a basis for comparing each risk to the others. Figure 8 shows a summary of all results for assessment of the cost impact category. Appendix F contains results for the other five impact categories.



Figure 8. Risk maps showing the cost impact score (x-axis) versus probability score (y-axis) for identified potential risks. Note: the solid circles represent the average score results, while the hollow circles represent conservative, upper-end estimates; the three hollow circles in the red area under "Other Risks" represent project management risks (e.g., equipment/materials delays, installation schedule, or cost for construction materials or services).

The risk assessment results indicate that technical risks associated with CO₂ supply, injectivity, storage capacity, subsurface containment, and induced seismicity are low, i.e., low-probability, low- to moderate-impact. The highest-ranking risks were policy-related or external/commercial risks associated with ethanol and CCS policy and other risks associated with construction activities that included the following:

- If North Dakota does not receive primacy from EPA for Class VI injection well regulations (see the Permitting Plan section for details), or RTE is not able to get a Class VI permit for the CO₂ storage operations.
- If California or Oregon policies become difficult or impossible for RTE to qualify for the carbon credits.
- If state or federal administration change overarching climate change policies resulting in the withdrawal of low-carbon fuel programs.
- If unexpected increases occur related to lead time for equipment/materials, construction schedule (wells, pipelines, capture facilities), or cost for construction materials or services.

The results of the risk assessment performed during this stage of the project indicate that there are no risks which would preclude the project from advancing toward implementing CCS at the RTE facility. The highest-ranked risks are not technical in nature, but rather are due to uncertainty surrounding policies that are under development and a change in federal administration, both of which are beyond the project team's immediate control. This assessment will be conducted again in future phases to prioritize project activities, including additional data collection, analysis, and monitoring.

Life Cycle Assessment

An LCA was completed to estimate reduction of net CO_2 emissions for ethanol production with potential CCS implementation at the RTE facility. CI values are used to estimate carbon credits and CO_2 market value through the California LCFS Program. The California LCFS Program targets fuels such as ethanol that demonstrate a lower CI value than standard fuels such as gasoline, with incentives through the program's CO_2 credit market. The model used by the LCFS Program to derive CI values for alternative fuels is referred to as CA-GREET (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation). The GREET model was created by Argonne National Laboratory using the LCA approach to determine the net carbon emissions from producing a particular fuel. The model was modified by the California LCFS Program to generate CI values for direct comparison between fuels and producers. The CA-GREET functional unit for the CI value is grams of CO_2 equivalent per megajoule (gCO₂e/MJ) of a produced ethanol.

Although the current CA-GREET model is only applicable for traditional ethanol production, its method can be applied to the operations of a CCS system to estimate CI reduction for an ethanol-CCS process (Figure 9). For a given ethanol producer, the CA-GREET model derives CO_2 emissions associated with corn farming and transportation (ethanol feedstock) and ethanol fuel production, transportation, and distribution. The blue dashed box in Figure 9 represents the boundary of the current CA-GREET model for deriving CI values associated with ethanol production. This technical evaluation appended CA-GREET to include additional emissions associated with CO_2 capture ("Capture System") and emissions reduction associated with CO_2 storage in the Broom Creek Formation, where the CO_2 will be isolated from contact with



Figure 9. Block diagram showing key elements of ethanol production with CCS.

the atmosphere ("Geologic Storage"). Appendix G provides a more detailed summary of the CA-GREET model, default assumptions, and calculations.

Results suggest that implementing CCS could significantly reduce the net CO₂ emissions for ethanol production by 40%–50%. The RTE facility produces both modified distillers' grain solubles (MDGS) and dry distillers' grain solubles (DDGS) as coproducts of ethanol production. There are greater energy inputs, and therefore greater CO₂ emissions, associated with producing DDGS because of the additional energy required to more completely dry the coproduct for DDGS compared to MDGS production. Consequently, ethanol produced with MDGS as the co-product has a lower CI value than ethanol produced with DDGS as the coproduct. These two processes to generate MDGS vs DDGS were thus considered to bracket the lower and upper bounds, respectively, for estimating reduction for ethanol-CCS at the RTE facility. The specific quantities of CI reduction are proprietary because of the business-sensitive nature of assessment.

FIELD IMPLEMENTATION PLAN DEVELOPMENT

The FIP describes the steps necessary to design and install infrastructure for the capture and secure storage of CO_2 at the RTE site. It includes infrastructure designs for CO_2 capture and transport; plans for CO_2 injection permitting and ethanol-CCS pathways for low-carbon fuel programs; a MVA program for geologic storage; designs for monitoring and injection wells; and well characterization and testing plans. This section summarizes the FIP development with detailed designs and plans provided in Appendix A.

Plant Infrastructure Design

As summarized in the CO₂ Capture and Transport section, capture system design options for generating three CO₂ product streams at the RTE site were investigated: injection-grade, EOR-grade, and food/chemical-grade products. Injection into a saline formation requires only that the CO₂ stream be dehydrated, whereas use in EOR requires dehydration as well as some O₂ removal, and food/chemical-grade requires dehydration and removal of virtually all impurities. Details of all three designs and considerations are available in Appendix B. Design options for a CO₂ pipeline were only considered for a CCS scenario at the RTE site.

Should RTE elect to produce injection-grade CO_2 to take advantage of carbon markets through low-carbon fuel programs, general processing requirements will consist of dehydration and compression (i.e., with no O_2 removal). This design, shown in Figure 10, consists primarily of a blower, initial CO_2 compression to about 620 psi with liquid water removal, a dehydration unit, high-pressure compression of the CO_2 to a dense phase up to about 1500 psi, and dense-phase pumps that transport the CO_2 to the injection site through the pipeline. The CO_2 will be dehydrated to a typical pipeline specification for water content so that the product stream is not corrosive to equipment constructed of carbon steel under normal operating conditions. An outline for implementation of this approach is provided in Appendix A.1.

Spares of the major rotating equipment such as the blower and compressors could be purchased as part of this effort to keep downtime from the capture system within 10 days per year of operation, i.e., without spares the system could be operational about 90% or 330 days per year. Spares for minor higher-maintenance equipment such as glycol pumps and cooling water pumps are recommended. Critical instrumentation may also be spared as required but should be a minor cost for this project and thus was not included at this early phase of design. Additional information about the planned downtime for the RTE facility can be found in Appendix B.

From the compression facility discharge, the CO₂ product would flow through a short (<1 mile) underground pipeline to the injection well located on RTE property. The exact length of the pipeline is dependent upon final selection of an injection well location. A 4-in.-diameter pipeline would be sufficient to carry the estimated 163,000 tonnes CO₂ generated annually by the RTE facility to the injection site. Because the O₂ concentration is likely to be greater than is typically transported by carbon steel pipeline, alternative materials of construction, such as thickerwall pipe or the addition of an impervious liner sleeve, could be revaluated following collection of additional CO₂ compositional data. Details regarding the estimation of pipeline diameter and materials of construction are available in Appendix C.

Figure 11 shows the processing required to produce EOR-grade CO₂. In this case, the CO₂ is compressed and liquid water is removed. The CO₂ passes through molecular sieve dehydration and is refrigerated, liquefied, and distilled to remove O₂ to commercial pipeline standards (Table 1). About a 10% loss of the CO₂ product stream can be expected from molecular sieve dehydration and liquefaction due to the nature of these separation processes. Recycling can be implemented to reduce losses but is not always economical for small flow rates such as that generated at the RTE facility (e.g., < 1000 tonnes/hr). Dense-phase pumps would bring the CO₂ above critical pressure for transport through a pipeline to the oil field.



Figure 10. Draft conceptual design for generation of an injection-grade CO₂ product at the RTE site (image courtesy of Trimeric Corporation). LP and HP refer to low- and high-pressure, respectively.



Figure 11. Draft conceptual design for generation of an EOR-grade CO₂ product at the RTE site (image courtesy of Trimeric Corporation).

The most extensive processing is for food/chemical-grade CO_2 , which is shown in Figure 12. To produce the ultrapure CO_2 required for ingestion in food or beverages, the CO_2 is compressed and liquid water is removed, after which the CO_2 stream is scrubbed in a water wash tower to remove any remaining water-soluble impurities. The CO_2 stream then flows through guard beds containing adsorbents for removal of any trace sulfur compounds and the activated carbon beds to remove any trace hydrocarbons. Following dehydration using molecular sieves, the CO_2 is refrigerated, liquefied, and distilled to remove O_2 , after which it is stored prior to transport via tanker truck to the end-use facility. Similar to the EOR-grade process, about 10% CO_2 product stream loss is possible from molecular sieve dehydration and liquefaction processes. Vapors generated in liquid CO_2 storage tanks can also be a source of product loss.

Permitting Plan

Requirements for the commercial deployment of CCS in North Dakota were identified. Theses requirements are embodied in the North Dakota Class VI permitting regulations for geologic CO_2 storage and in the evolving low-carbon fuel programs. These requirements can dictate or influence future site characterization activities, subsequent modeling and simulation needs, and compliant well designs and monitoring program. Full details regarding the North Dakota permitting and California LCFS pathway approval processes are provided in Appendix A.2. The Oregon CFP is still in development, particularly for CCS applications, and thus is not included in this discussion.

Class VI Permitting Requirements

North Dakota has promogulated a comprehensive set of carbon storage regulations for all aspects of CO₂ injection and storage operations within an Underground Injection Control (UIC) Class VI Program (19). Currently, EPA regulates all Class VI permits; however, the North Dakota regulations meet or exceed EPA Class VI requirements and address some factors that EPA is not able to address (e.g., pore space ownership, site certification, comprehensive program enforcement authority, etc.). NDIC thus submitted an application to EPA for Class VI Primacy in June 2013 (see Appendix H for details). On May 9, 2017, EPA signed a proposed federal rule to approve the State of North Dakota's application for regulatory primacy over Class VI injection wells. North Dakota's application will be published in the federal register and open to a 60-day public comment period before being finalized later this year (20). After finalization, the NDIC Department of Mineral Resources Division of Oil and Gas would be the permitting authority for Class VI wells in North Dakota (19).

In general, the North Dakota Class VI program requires all owners or operators applying to inject CO_2 for the purpose of geologic storage to obtain a storage facility permit, a permit to drill, and a permit to operate prior to commencement of injection activities. The storage facility permitting requirements include, but are not limited to, a technical evaluation, an AOR and corrective action plan, a demonstration of financial responsibility, an emergency and remedial response plan, a proposed casing and cementing program, a testing and monitoring plan, a plugging plan, and a postinjection site care and facility closure plan. A permit to drill the injection well must then be obtained, followed by a permit to operate (i.e., inject CO_2); the latter permit also requires proof that the well casing is cemented adequately so that injected CO_2 is confined to the storage reservoir.



Figure 12. Draft conceptual design for generation of a food/chemical-grade CO₂ product at the RTE site (image courtesy of Trimeric Corporation).

When injection operations and the final assessment specified by the approved postinjection site care and facility closure plan have concluded, the storage operator may apply for a Certificate of Project Completion (see Appendix A.2). This certification is only issued if the operator shows that the storage reservoir is reasonably expected to retain the stored CO_2 and that the CO_2 in the storage reservoir is stable. The stored CO_2 is considered stable if it is essentially stationary, or if it is migrating or may migrate, that any migration will be unlikely to cross the storage reservoir boundary. Upon certification, the state becomes responsible for the long-term monitoring and management of the storage site.

Low-Carbon Fuel Program Requirements

Although CCS is not yet included in the California LCFS Program or the Oregon CFP, efforts are being made by both states to incorporate pathway approvals to account for carbon storage, particularly via saline formation injection (21, 22). For example, the California Air Resources Board (ARB) has recently released (May 2017) summary and concept papers outlining their preliminary guidance for how CCS can be integrated into the existing initiatives such as the LCFS program. Specifically, ARB has committed to developing a CCS Quantification Methodology (QM) and Permanence Protocol (PP). The QM would include the calculation methodology and assumptions, including different methods of accounting to accommodate the LCA approach of the LCFS program. The QM is expected to focus on the following main areas: eligible activities, CCS project system boundary, project emission accounting, and storage reservoir type.

The PP would establish the requirements to ensure that a CCS project achieves the objective of permanent geologic CO_2 storage. The PP is expected to focus primarily on risk-based site analysis, injection or production well construction materials and structural integrity, operating requirements, and monitoring, reporting, and verification of storage permanence. Consequently, approval pathways through California's LCFS program have the potential to require more stringent monitoring requirements than required by North Dakota regulations to validate CO_2 storage amounts and permanence.

Continued engagement with the respective regulatory bodies to closely follow, and potentially impact the development of these programs is recommended. Although North Dakota primacy may allow for a less complicated and more timely permitting process, it is still a complex process, and RTE would likely be one of the first applicants. Furthermore, inclusion of CCS processes by California's LCFS program and Oregon's CFP into pathway approvals for low-carbon fuel programs is still undergoing development. California ARB's anticipated schedule is to release final drafts of the QM and PP in the latter half of 2017, which will then be presented to the ARB for approval through a set of hearings in the beginning half of 2018. Therefore, it is currently unknown what will be incorporated into the final programs and whether the pathway provisions to secure economic incentives will conflict with North Dakota regulations.

MVA Plan

A provisional MVA program has been developed for the RTE CCS project that addresses site uncertainties and anticipated regulatory compliance (assuming North Dakota Class VI primacy), thus informing site operations. The MVA program includes techniques to monitor designated areas of sensitivity and to track the storage and performance of CO₂ injection, including rates, pressure, and fluid saturation. Baseline data collection will be required for several MVA techniques to establish preinjection conditions. Additional data collected in subsequent project phases will allow for further refinement and optimization of this provisional MVA program. Uncertainties also remain with respect to compliance and approval of the MVA program by the various regulatory and storage accounting agencies in North Dakota, California, and Oregon. As a first-of-its-kind project, it is anticipated that RTE and project stakeholders will need to work closely with regulators and storage accounting agencies to assume a mutually agreeable MVA program that appropriately satisfies required project criteria. Ultimately, the MVA program will necessitate data appropriate to establishing long-term site stability and facilitate the transfer of long-term liability.

MVA Program Overview

The provisional monitoring program for the RTE CCS effort was developed based on previous EERC experience (23–25) and to meet North Dakota Class VI regulations (see Appendices A.2 and A.3). North Dakota regulations require monitoring of 1) all aspects of CO_2 injection operations, 2) the local groundwater system, 3) the subsurface environment through multiple methodologies, and 4) engineered systems for competency. Table 4 summarizes the developed MVA program to meet these requirements, and Figure 13 provides an illustration of the regions monitored. Furthermore, North Dakota regulations require regular assessment of the MVA program (minimum every 5 years) to ensure that systems are performing as designed to track the project's performance to date. If needed, alterations to the program (i.e., technologies applied, frequency of testing, etc.) can be submitted for approval. Results of pertinent analyses and data evaluations conducted as part of the MVA program are to be compiled and reported to the regulator.

Monitoring of the near-surface (USDWs) and deep subsurface environments will be accomplished through a variety of techniques applied within the determined AOR. The AOR as defined by North Dakota regulations is the extent of the estimated pressure or CO₂ plume, following stabilization after injection has ceased, plus an additional mile buffer. Results from modeling and simulation activities described in previous sections indicate the CO₂ plume could reach a maximum extent of 1 mile in radius from the injection location (after 10 years following a 20-year injection period), resulting in an estimated 2-mile-radius AOR. Figure 2 shows a sufficient number of groundwater wells present in this preliminary AOR to initiate a groundwater monitoring program. However, it is expected that the AOR will be modified in subsequent project phases as more data become available for analysis.

Monitoring Type	RTE MVA Program	Region Monitored
Analysis of injected CO ₂	Annual sampling and compositional analysis of the injected CO ₂ stream	Surface and storage reservoir
Continuous recording of injection pressure, rate, and volume	Instrumentation for continuous wellhead monitoring	Surface-to-reservoir
Near-surface monitoring	Groundwater sampling and analyses (existing groundwater wells in the AOR and dedicated water well)	Near-surface; USDWs
Direct reservoir monitoring	Sampling, logging, and pressure/temperature measurements via a reservoir monitoring well	Storage reservoir and primary sealing formation
Indirect reservoir monitoring	3-D seismic surveys, passive seismic measurements	Entire storage complex
Well annulus pressure between tubing and casing	Instrumentation for continuous annulus monitoring	Surface-to-reservoir
Mechanical integrity testing and pressure fall-off testing	Well testing every 1 and 5 years, respectively, as required	Well infrastructure
Corrosion monitoring	Well materials corrosion well logging	Well infrastructure

Table 4.	Provisiona	al MVA	Program	for	Potential	Geologic	Storage	at the	RTE Site

Monitoring Techniques

 CO_2 injection operations at the RTE site can be monitored both at the wellhead and at the reservoir level through the use of installed sensors that continuously record pressure, temperature, and flow. These sensors will permit the EERC and RTE to confirm that injection is occurring as expected, to account for CO_2 movement from the capture systems to the reservoir environment, and to allow for immediate mitigation if anomalous observations are made. In addition, annual sampling of CO_2 at the wellhead will undergo compositional analysis to ensure the quality of the injected CO_2 is as expected.

Groundwater monitoring can occur through sampling of existing wells within the AOR and/or from a dedicated groundwater-monitoring well installed on RTE property (Appendix A.3). Water sampling is recommended 2–4 times per year to account for seasonal variability and to document the water composition including alkalinity, major cations, major anions, organic carbon, dissolved solids, as well as isotopic analysis (¹⁸O, ¹⁴C, ¹³C, ²H). Surface water samples from a wastewater pond located on RTE's facility and the nearby Abbey Lake should also be collected at the same frequency and undergo the same analyses. Baseline or regional analyses at these locations should also occur prior to the start of injection operations or outside the AOR to establish the background conditions of the site until the first revaluation period.



Figure 13. Stratigraphic column illustrating provisional near-surface and deep subsurface regions monitored, as well as individual MVA techniques, for geologic CO₂ storage at the RTE site.

Deep subsurface monitoring of the storage complex is required by the NDIC Class VI program to occur through both direct and indirect methods. To directly monitor and track the extent of the CO₂ plume within the storage reservoir, a dedicated monitoring well allows regular sampling and analysis of reservoir fluids and for continuous measurement of pressure and temperature in the reservoir environment. In addition, the monitoring well will enable continuous monitoring of these parameters within the sandstone of the overlying Inyan Kara Formation, the first highly permeable unit above the reservoir and main sealing formations (see Figures 3 and 13). Furthermore, continuous pressure and temperature monitoring of the reservoir at the injection site also provides important data for monitoring the performance of the storage complex. Pulsed-

neutron logging (PNL) is recommended on an annual basis to evaluate fluids in the storage reservoir and show that fluids are not moving beyond the sealing formations. Baseline data should be collected from these downhole systems prior to operation of the injection well. Indirect monitoring tracks the extent of the CO₂ plume within the storage reservoir and can be accomplished via regular 3-D seismic surveys (known as 4-D seismic) of the AOR and continuous monitoring for any induced seismicity. If implemented, 3-D seismic surveys should be conducted once prior to injection to establish baseline conditions, 2 years after injection start to evaluate early performance of the storage complex, and on 5-year intervals during the remainder of the operational phase. Monitoring for any induced seismicity can be performed through the use of surface-installed sensors on the RTE site. These sensors are capable of continuous and wireless data reporting and should be installed prior to injection for collection of baseline data. Additional details of these activities can be found in Appendix A.3.

Injection and storage infrastructure installed on the site are also required by NDIC to be monitored for competency throughout the project life cycle via regular testing and inspections. Continuous annular pressure monitoring of the injection well and monitoring well must be performed, and these wells must undergo annual mechanical integrity testing and pressure fall-off testing every 5 years. Corrosion monitoring is also required, which could be accomplished by installing coupon monitoring in the wells and pipeline infrastructure. The various installed monitoring sensors must also undergo regular inspections and testing as required by regulations (or as recommended by the manufacturers if more frequent) to ensure continual and optimal system performance. Records of all testing results and any required maintenance must be maintained and reported to the regulator.

The long-term goal of the MVA program is to provide an assessment of the storage complex for the long-term containment and stability of the injected CO_2 for the purpose of achieving a Certificate of Project Completion (see Permitting Plan section). Once injection is completed, monitoring of the storage complex will continue until it can be established that the injected CO_2 plume has stabilized. This may include postinjection seismic survey(s), continued monitoring at the injection and monitoring wells, and continued groundwater monitoring. Once site stability is established, RTE can apply for Project Completion which will allow for the transfer of long-term liability to the state of North Dakota and the cessation of monitoring by RTE.

Well Design

The well design and completion plan scenario recommends the installation of a monitoring well and an injection well, completed in the Broom Creek Formation along with wellhead CO₂ handling and support infrastructure to meet North Dakota Class VI regulations. All the design and implementation activities for the drilling and completion of the monitoring and injection wells have been created to maximize efficiency while minimizing the construction time and costs. A summary of the well specifications is provided in Table 5; for more detailed information on drilling and completion plans, see Appendix A.4.

	Monitoring Well	Injection Well
Monitoring Tool(s) ^a	Digital pressure and temperature, fluid sampling	Digital pressure and temperature
Monitoring Horizon(s) ^b	Inyan Kara, Broom Creek Formations	Broom Creek Formation
Total Depth	6900 ft	6900 ft
Surface Casing ^c	9 ⁵ / ₈ -in., 40-lb/ft, J-55	13 ³ / ₈ -in., 72-lb/ft, L-80
Production Casing	5½-in., 17-lb/ft, L-80 ^d 5½-in., 17-lb/ft, 13Cr ^{e,f}	7-in., 26-lb/ft, L-80 ^d 7-in., 26-lb/ft, 13Cr ^{e,f}
Tubing	2 ⁷ / ₈ -in., 6.5ppf, 13Cr	3 ¹ /2-in., 9.2 ppf, 13Cr
Estimated Completion	26 days	27 days

Table 5. Summary of Well Specifications (see Appendix A.4 or Appendix I for details)

^a Fiber optic cable may also be considered for such applications as distributed acoustic sensing and temperature profile monitoring.

^b See Figure 13.

^c Outside diameter, weight of alloy, grade of steel.

^d Installed depth is estimated 0 to 6300 ft (from surface to above the cap rock of injection zone).

^e Chrome alloy with specific grade.

^f Installed depth is estimated 6300 to 6900 ft (from above the cap rock of injection zone to well total depth).

The monitoring well should be drilled first to allow additional time for characterization of the subsurface as needed to meet the permitting requirements, prescribed in the Well Characterization and Testing Design section below. Drilling the monitoring well first ensures the availability of cores and wireline logs in case they are not successfully acquired later when the injection well is drilled. Completion of the monitoring well would then be carried out once the log and core analysis have been completed (see Appendix I for details).

Monitoring equipment as described in the MVA Plan section will be installed in the monitoring and injection wells. Casing-conveyed pressure/temperature gauges are recommended to monitor subsurface conditions. The sampling of in situ formation fluids for subsequent analysis can be conducted through the use of two U-tube samplers installed in the monitoring well (see Appendix I for details).

The final locations of the monitoring and injection wells will depend on several factors such as land ownership, direction from NDIC, and updated simulation results via new characterization data. For example, both wells will be located on RTE land holdings. Well locations are also based on potential CO_2 pipeline placement, influenced by Interstate 94 to the south, railroad tracks to the north and east, and the city of Richardton to the west (Figure 2). However, site-specific characterization data gathered from the monitoring well will improve modeling and simulation results that indicate the size and extent of the CO_2 plume, pertinent information required for proper injection well placement. The permitting process for the project may also require changes to the well designs and locations, with potential specific direction from NDIC. Final monitoring and injection well locations will therefore be determined upon a completed assessment of all the aforementioned variables.

Well Characterization and Testing Design

The well characterization and testing design (site characterization plan) will address technical uncertainties in the geologic, geochemical, and geomechanical characteristics of the site. Site-specific data regarding the subsurface enabled by this characterization effort will 1) better inform the definition of a proper AOR (via expected CO_2 and pressure plume extents), 2) reduce uncertainty related to the injection program, 3) provide evidence and support needed to obtain a Class VI well permit, and 4) identify and/or clarify any technical risks which may have potential to affect the project's overall financial feasibility.

A site characterization plan was developed to reduce uncertainty in preliminary modeling and simulation results for successful CCS implementation at the RTE site. As mentioned previously in the Geologic Modeling section, this uncertainty was mainly due to limited characterization and injection data available in proximity to the RTE site. This newly collected characterization data, detailed below, will provide site-specific porosity and permeability correlations, allowing improvement of the initial modeling and simulation activities conducted during this preliminary assessment. Improved results for estimated CO_2 plume and injection pressure requirements will also lead to more accurate AOR determination and a subsequently improved MVA program. In addition, these characterization efforts will augment the MVA program by generating baseline data to which operational monitoring results can be compared to ensure conformance and CO_2 containment. These updated results will also be beneficial for precisely locating the injection well and properly designing the CO_2 capture system and pipeline, as well as construction planning and cost estimates.

Downhole Subsurface Characterization

The site characterization plan developed includes discussion of well logging, core acquisition and testing, and downhole testing. The completion of the initial site characterization well as a monitoring well is recommended for the RTE site, as it would be the best use of RTE's financial resources. Additional subsurface characterization efforts will be possible, and this is recommended when drilling the injection well, as mentioned in the Well Design section. Complete details of the plan are provided in Appendix A.5.

A program of well logging will be conducted for both the monitoring and injection wells. Well logging measurements are typically taken by depth, conducted via a wireline-connected sensor passed through the well. The logging techniques recommended include triple combination (resistivity, gamma ray, and spontaneous potential), dipole sonic, nuclear magnetic resonance, spectral gamma ray (or capture spectroscopy), PNL, and cement bond log (see Appendix A.5 for details). These industry-established techniques were chosen for their ability to generate the pertinent data needed reduce any identified technical risks and ensure injectivity is properly interpreted in the Broom Creek Formation at the scale necessary for project success at the RTE site.

Geologic core samples (~350 feet) will also be collected from both the monitoring and injection wells. These samples will contain approximately 50 feet of the Opeche Formation above the Broom Creek, continuing through the entirety of the Broom Creek Formation, and possibly a
portion of the underlying Amsden Formation, depending on specific depths at the well location. Analysis of this new core will include a suite of petrographic, petrophysical, geomechanical, and geochemical analyses performed on samples from both the reservoir and sealing formations. These analyses are also crucial to generating the pertinent data needed for improved knowledge and evaluation of the Broom Creek Formation specific to the RTE site.

As discussed in the MVA Plan section, fluid samples from the Broom Creek Formation will be collected to determine the specific fluid chemistry at the RTE site and other relevant parameters (i.e., salinity, CO₂ solubility, viscosity). In addition to updating simulation inputs, this information will be used to help identify and predict potential geochemical reactivity between the formation fluid, minerals present in the Broom Creek and Opeche Formations, and the RTE CO₂ product stream being injected (including any trace impurities present). Once sampling and logging processes are completed, this well would be completed as a monitoring well, following the procedures established by NDIC regulations.

ECONOMIC ANALYSIS

This preliminary economic assessment quantifies the costs and benefits of integrating commercial CO_2 capture with ethanol production at the RTE site. Considerations included potential revenue through low-carbon fuel programs or from generation of other CO_2 products (e.g., EOR- and food/chemical-grade) through alternative CO_2 markets. Estimated installed capital and operating expenses were based on execution of the detailed FIP (Appendix A). Evaluation of the investigated CO_2 market scenarios supports ethanol-CCS as an economically viable option for the RTE facility.

CO₂ Markets

Low-Carbon Fuel Programs

Significant revenue from CCS implementation at the RTE site may be possible assuming approvals for the California LCFS Program are attainable and CO₂ credits from the LCFS market could be realized. CO₂ credits are calculated using the difference between the contracted CI value (generated via LCA by the CA-GREET model) of the fuel generated (ethanol in this case) and the CI value of the conventional petroleum fuel replaced (i.e., gasoline). The LCFS Program has set the gasoline compliance CI value at 88.62 gCO₂e/MJ for the year 2020 and all subsequent years (26); however, this value could be lowered when the program is revaluated for continuation beyond 2020 (27).

RTE may apply for pathway approvals to the California LCFS Program and/or the emerging Oregon's CFP; however, only LCFS market data were available at the time of this study. The LCFS market is fairly new and somewhat volatile. Figure 14 shows the monthly volume of credits and average price for the California LCFS carbon market since 2013. The dip in the market around 2014–2015 was due to a freeze during legal challenges (27). It is also currently unknown how incorporation of CCS into pathway approvals for the California LCFS Program or the Oregon CFP will affect the market.



Figure 14. LCFS market variation for carbon credit prices, January 2013 – April 2017 (27).

Estimated potential revenue from low-carbon fuel programs suggests a considerable economic benefit from ethanol-CCS. Specific results are proprietary because of the business-sensitive nature of this assessment. However, RTE intends to move forward with subsequent project phases to further evaluate the LCFS and CFP markets, as well as other project components, in more detail.

Alternative Markets

Revenue from alternative CO_2 products potentially generated at the RTE site and related markets (EOR-grade and food/chemical-grade) was also investigated. As mentioned previously in the Plant Infrastructure Design section, a 10% loss is assumed due to the dehydration and liquefaction processing required to generate these CO_2 product streams. About 147,000 tonnes/yr EOR- or food/chemical-grade CO_2 product is thus estimated based on the average rate of 163,000 tonnes/yr CO_2 currently generated at the RTE facility. The revenue estimates for these alternative markets are very preliminary and were generated to provide a focus for future efforts should CCS pathway approvals for low-carbon fuel programs not be achievable or economical. As mentioned in the previous section, specific results are proprietary because of the business-sensitive nature of this assessment.

The closest operating oil fields in the vicinity of the RTE facility are located about 25 miles west, in the southwestern region of North Dakota. Many uncertainties need to be addressed before RTE can make an informed decision to pursue an EOR market. These include but are not limited to transportation methods (pipeline or trucking), anticipated CO_2 utilization (i.e., amount of CO_2 required to produce a barrel of oil), interest of oilfield operators in purchasing CO_2 for EOR and/or making EOR investments, and potential fluctuations in the CO_2 market due to changes in oil prices.

A food/chemical-grade CO₂ product generated at the RTE facility could provide product to a niche regional market. CO₂ can be used for various applications in the region, including cooling

while grinding powders such as spices and dry ice for freezing meats to prevent spoilage. While the specific market for food/chemical-grade CO_2 throughout North Dakota was not determined, several distributors confirmed that all food/chemical-grade CO_2 is imported into the state. At least one regional distributor confirmed that estimated RTE CO_2 product generation rates of ~150,000 tonnes/yr would not impede marketability.

Estimated Costs

One-time capital expenses (CAPEX) and annual operating expenses (OPEX) were estimated for installation of major equipment and infrastructure, as well as energy and monitoring needs, to implement CCS or alternative CO₂ product generation at the RTE facility. These preliminary costs were generated to guide future efforts for implementation and not absolute, stand-alone cost estimates. As such, several common cost elements were not included, such as electrical upgrades, land purchases, accounting for escalation or interest, etc. The average estimated costs are presented as a range to reflect the many uncertainties associated with the lack of available site-specific data and the cost of any identified contingencies. A summary of these estimated expenses are described below with a breakdown of costs provided in Appendix J.

Ethanol-CCS Costs

CAPEX and OPEX were estimated for implementation of CCS at the RTE facility based on the execution of the FIP (detailed in Appendix A). Expenses considered to be one-time capital costs are major equipment and infrastructure for the capture system and CO_2 pipeline, acquiring necessary permits and pathway approvals, drilling and completion of the monitoring and injection wells, and execution of the MVA (baseline only) and site characterization plans. Additional science and engineering was also considered to update geologic models and simulations, the MVA program, and the compilation and reporting of results for permitting and pathway requirements following the collection of site-specific data from the characterization efforts. Expenses considered to be repetitive or annual operating costs included energy and labor requirements for the capture system and continuation of the MVA program following the onset of CO_2 injection.

CAPEX was estimated to range \$27.6–\$33.0 million for installation of the capture system, pipeline, and monitoring and injection wells, as well as implementation of the permitting, MVA, and characterization plans and required technical support. A breakdown of these costs is summarized in Table 6, which shows the average total capital investment for implementing CCS at the RTE facility to be about \$29.0 million, with the potential for contingencies to add an additional \$17.4 million in a worst-case scenario. A brief discussion of each of the cost items is provided below (see Appendix J for details):

• The cost of infrastructure for CO₂ capture and transport to a potential injection site is estimated at about \$13.2-\$13.8 million. An additional \$8.0 million would be required for equipment spares (e.g., blowers and compressors) to ensure 10 days or fewer of downtime from the capture system (see Appendix B). Pipeline costs could increase by about \$0.3 million if the injection site is >1 mile from the RTE facility.

CAPEX (\$M)	Average	Range	Notes	Contingency	Notes
Capture System and Pipeline	13.5	13.2–13.8	Varying pipeline cost models	+8.3	Costs for spares ensuring <10 days downtime/yr; pipeline up to 1.2 miles.
Permitting	3.0	2.5–3.5	Based on varying required iterations	+1.8	Based on potential for additional iterations, public reviews
MVA Plan	2.3	2.0–2.5	Based on suggested baseline activities	+0.7	Based on potential for additional baseline monitoring activities
Monitoring and Injection Wells	8.4	8.4–11.0	Potential for 30% increase in construction costs	+5.5	Based on potential for additional monitoring well
Characterization Plan	0.8	0.9	Base on variation in quotes	+0.4	Based on potential analyses from additional monitoring well
Science and Engineering	1.0	0.7–1.3	Based on variations listed above	+0.7	Based on variations listed above
TOTAL	29.0	27.6-33.0		+17.4	

Table 6. Estimated CAPEX for CCS Implementation at RTE

- Permitting costs could range \$2.5–\$3.5 million depending on the number of iterations required by NDIC following initial submission and public review, with potential for an added \$1.8 million if several iterations are required.
- The cost of baseline activities included in the MVA program, such as installation of monitoring equipment and baseline data collection (detailed in Appendix A.3) is estimated at about \$2.0-\$2.5 million. This could increase by \$0.7 million if more extensive baseline and/or regional monitoring is required for permitting/pathway approval.
- The monitoring and injection wells could range \$8.4–\$11.0 million for drilling and completions. This wide range in estimated expenses is due to the high volatility in construction costs in western North Dakota, an area heavily influenced by the oil and gas industry. Well costs could increase by \$5.5 million should an additional monitoring well be required for permitting/pathway approval.
- The site characterization plan is estimated to cost about \$0.9 million for logging, testing and analyses for both the monitoring and injection wells as detailed in the FIP (Appendix A.5), which could increase by \$0.4 million if it became necessary to characterize another monitoring well.
- Science and engineering related to data collection/recording, processing, and interpretation, as well as the revaluation of designs and plans, is estimated to range \$0.7-\$1.3 million, with another \$0.7 million possible for technical support in response to the contingencies discussed.

OPEX was estimated to range \$1.7–\$2.7 million annually for capture system and pipeline operating requirements and continued execution of the MVA program following injection start. Table 7 shows the average total operating cost for implementing CCS at the RTE facility to be about \$1.9 million annually with the potential for contingencies to contribute, on average, an additional \$0.7 million a year in a worst-case scenario. In summary (see Appendix J for details):

- The annual cost for process energy, power charge, natural gas, and plant labor for the capture system (see Appendix B) and pipeline is estimated at about \$1.4 million. An additional \$0.4 million a year could be required with increased electrical rates due to increased power demand from the capture system.
- Monitoring activities outlined in the MVA Plan section to occur during the operational phase of the CCS effort, such as groundwater sampling and 4-D seismic surveys (detailed in Appendix A.3), is estimated to average \$0.5 million annually. This average is based on an estimated \$0.3 million a year to execute the MVA program when no seismic survey is conducted and \$1.3 million for years when a seismic survey is conducted (assuming every 5 years). The average could increase by \$0.3 million a year if more extensive or frequent monitoring is required for permitting/pathway approval (e.g., repeat seismic surveys every 2 years).

OPEX (\$M/yr)	Average	Range	Notes	Contingency	Notes
Capture System and	1.4	1.4	Range less than	+0.4	Based on potential for higher electric
Pipeline			±\$0.1M/yr		rates and/or pipeline up to 1.2 miles.
MVA Plan (average	0.5	0.3–1.3	Estimated annual	+0.3	Increase to average annual cost based
annual cost based on			cost with and		on potential for more frequent
repeat seismic survey			without a seismic		seismic surveys (e.g., every 2 years).
every 5 years)			survey, respectively		
TOTAL	1.9	1.7–2.7		+0.7	

 Table 7. Estimated OPEX for CCS Implementation at RTE

Alternative Market Costs

CAPEX and OPEX were estimated for production of EOR-grade or food/chemical-grade CO₂ at the RTE facility based on the designs presented in the Plant Infrastructure Design section (detailed in Appendix B). Expenses considered to be one-time capital costs were major equipment and infrastructure for a capture system to process the plant CO₂ emissions to generate these higherquality product streams. Transportation costs such as a CO₂ pipeline to an oil field for EOR or trucking to a distributor was not included in these cost estimates as they are highly variable depending on distance and quantity. Expenses considered to be repetitive or annual operating costs included energy and labor requirements for the capture systems.

CAPEX was estimated to be about \$14.7 million and \$15.7 million for installation of the capture system to produce EOR-grade or food/chemical-grade CO_2 , respectively (Table 8). These increased costs compared to a system to produce injection-grade CO_2 are due to the additional equipment required for greater water and O_2 removal. This includes refrigeration, liquefaction, distillation, etc., which are required for both product alternatives and the further removal of trace impurities to produce food/chemical-grade CO_2 . Also, note that these estimates do not include transportation expenses. Also, an additional \$8.0 million would be required for equipment spares (e.g., blowers and compressors) to mitigate downtime from the capture system (see Appendix B).

OPEX was estimated to be about \$1.6 million annually for operating requirements of both capture systems. This considers the annual cost for process energy, power charge, natural gas, and plant labor (see Appendix B). An additional \$0.6 million a year could be required with increased electrical rates due to increased power demand from the capture system (see Appendix J for details).

	Expense	Contingency	
Capture Facility	(\$M)	(\$M)	Contingency Notes
		Esti	mated CAPEX
EOR-Grade	14.7	+8.0	Includes dehydration, compression, refrigeration, liquefaction and distillation (Note: <i>does not</i> include pipeline costs); contingency includes estimated cost spares for major rotating equipment.
Food/Chemical- Grade	15.7	+8.0	Includes dehydration, compression, sulfur/hydrocarbon removal, refrigeration, liquefaction, distillation, and storage (Note: <i>does not</i> include transportation costs); contingency includes estimated cost spares for major rotating equipment.
Estimated OPEX			
EOR/Chemical	1.6/yr	+0.6/yr	Based on potential for higher electric rates

 Table 8. Estimated Carbon Capture Expenses at the RTE Facility for Potential

 Alternative CO2 Markets

In the event that RTE wishes to start with generating an injection-grade CO_2 for geologic storage first and later switch to an alternative CO_2 product such as EOR-grade or food/chemical-grade, there would still be an estimated CAPEX of \$12–\$13 million. Nearly the entire capture system would require replacement with only a small select portion of it being salvageable. This would equate to a potential savings of ~\$3.0 million in estimated CAPEX to retrofit the system. Hence, this replacement of the capture system would require a majority of the full capital investment.

Evaluation

A comparison of determined economics was performed for the three CO_2 product options: injection-, EOR-, and food/chemical-grade. The injection- and food/chemical-grade scenarios appear to provide the most potential for economic benefit. However, this preliminary assessment contains many site-specific uncertainties, particularly for an ethanol-CCS scenario. Uncertainties comprise permitting and pathway requirements (including related data needs), investment interest rates, escalation in construction or energy prices, market stability, land purchase or pore space leasing, etc. Therefore, sensitivity analyses were conducted to ascertain the impact of variable economic estimations.

Sensitivity analyses continued to support the economic feasibility of CCS implementation at the RTE site despite variability in final CAPEX, OPEX, and market estimates. Three sensitivity analyses were conducted to investigate factors with the most impact to the overall project economics for this preliminary assessment: 1) increased CAPEX from construction prices or additional monitoring wells, 2) increased OPEX from increased energy prices or additional monitoring surveys, and 3) decreased revenue due to fluctuations in the market or increased CI values. The greatest impact to the overall project economics currently appears to be the variability in the LCFS carbon market. Again, specific results are proprietary because of the businesssensitive nature of this assessment.

CONCLUSIONS

Commercial implementation of CCS at the RTE facility is a technically viable option to significantly reduce net CO₂ emissions associated with ethanol production and may also be economically viable should pathways for credits through low-carbon fuel programs in California and Oregon be developed to include CCS. A technical assessment and LCA of capture and subsequent geologic CO₂ storage at the RTE facility indicate that CCS can be used to meet low-carbon fuel standards as currently formulated. On this basis, a FIP was developed for small-scale CCS to determine the designs and implementation steps needed to install a CCS system at the RTE facility. Ethanol producers with access to secure storage targets could economically benefit from CCS deployment and potential revenue from low-carbon fuel markets.

Results of the technical evaluation, which considered CO_2 capture and transport, site characterization, geologic modeling and simulation, project risk assessment, and an ethanol-CCS LCA, verify the feasibility of CCS for significant reduction of CO_2 emissions from ethanol production to produce an ethanol fuel with reduced CI. Three potential CO_2 product streams were

investigated (i.e., injection-, EOR-, and food/chemical-grade); the desired stream dictates the extent of water, O_2 and other impurities that must be removed. Sufficient existing site characterization data was identified for both the surface and subsurface environment at the RTE ethanol facility to provide input for initial geologic modeling and subsequent simulation, injection well and infrastructure designs, and the MVA program; however, more site-specific data will be needed to generate detailed models, designs, and plans. The modeling and simulation efforts support the Broom Creek Formation as a suitable injection target for successful CO_2 storage at the RTE site. The highest-ranking potential risks to CCS implementation were external or commercial risks due to uncertainty surrounding carbon storage policies currently under development or in flux from the recent change in federal administration along with the uncertainties in the details of evolving California and Oregon low-carbon fuel programs. The LCA showed the CI of ethanol production can be significantly reduced should CCS be implemented at the RTE facility.

The FIP includes conceptual CO₂ capture system and pipeline designs, a permitting plan for CO₂ injection in North Dakota and ethanol-CCS approval for low-carbon fuel programs in California and Oregon, an MVA program, designs for monitoring and injection wells, and well characterization and testing design. The high purity of CO₂ generated from ethanol production allows for minimal processing (i.e., dehydration and compression) in a capture system. A 4-in. pipeline would be adequate to transport the CO₂ generated at the RTE site for injection, but specific design criteria (e.g. length, materials) will ultimately depend on well location and O₂ content. The North Dakota Class VI permitting process is extensive, is data-intensive, and will require coordination with regulators to ensure required design and implementation plans are compliant prior to submittal. Approval pathways for low-carbon fuel programs to include CCS are still in the planning stages and will also require coordination with officials to potentially impact the requirements of the final program and ensure compliance for acquiring credits. Final MVA program and well designs will depend greatly on data results attained during the permitting process (e.g. geologic core analysis at the site) and pathway requirements for attaining carbon credits. Thus, a comprehensive set of geologic characterization data is imperative for the successful deployment of the ethanol-CCS facility of RTE in Richardton, North Dakota.

Commercial CCS may be economically viable at the RTE facility, depending on the specific approval requirements to acquire carbon credits through the low-carbon fuel programs. Average estimated capital costs as detailed in the FIP are \$29.0 million for installed capture system and CO_2 pipeline, monitoring and injection wells, and execution of permitting, site characterization, and a baseline MVA program. Average expenses for energy requirements to operate the capture system and execution of the operational MVA program are estimated to be about \$1.9 million annually. Although the carbon credit market was determined to be the most impactful factor in assessing the economics, analyses support economic viability despite uncertainty in final costs, market stability, etc. Alternate markets such as food/chemical-grade CO_2 may also be viable but will require more detailed investigation.

INTERIM STEPS TO CCS IMPLEMENTATION

Several interim steps are necessary to complete the commercial assessment of CCS at the RTE site prior to execution of the FIP. The provisional FIP summarized in the FIP Development

section and detailed in Appendix A provides a concise process for installation of equipment and infrastructure specific to the RTE site; describes the requirements for permitting and monitoring of a Class VI well, including the technical requirements to gather and generate the necessary data for attaining and maintaining related permits; and summarizes what is currently known and required to attain pathway approvals from low-carbon fuel programs. These interim steps include but may not be limited to the following:

- Ongoing communication with California and Oregon regarding development of pathway approvals to include CCS in their respective low-carbon fuel programs; plans for attaining approvals and an update of the LCA model may require revaluation as these pathways continue to develop and details become publically available.
- Ongoing communication with NDIC regarding the permitting process once North Dakota primacy becomes official to ensure required design and implementation plans meet regulations prior to submittal; the permitting plan, MVA program, well designs, and site characterization plan may require revaluation to incorporate any new information provided by NDIC.
- Collect pertinent data needed to refine engineering designs for the capture system and pipeline, i.e., current flow rates and composition of the CO₂ stream generated at the RTE facility, specifically where the stream would tie into the capture system.
- Acquire land and/or contract with potential pore space owners within the AOR once determined.
- Begin any permitting and/or landowner discussions/agreements required to execute baseline monitoring, such as groundwater sample collection or seismic surveys.
- Develop and execute a community outreach plan to educate/inform the public, public opinion leaders, and decision makers.
- An in-depth economic analysis is recommended following the refinement of designs and plans to incorporate any changes, as well as financial details not included in this feasibility study (e.g., interest rates, market changes, electrical upgrades, landowner purchases or pore space payments, storage permitting fees, etc.).
- Secure financing for the above steps and capital expenditures to implement CCS at the RTE site.

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APPENDIX A

RED TRAIL ENERGY CARBON CAPTURE AND STORAGE FIELD IMPLEMENTATION PLAN

RED TRAIL ENERGY CARBON CAPTURE AND STORAGE FIELD IMPLEMENTATION PLAN

INTRODUCTION

The Energy & Environmental Research Center (EERC), in partnership with the U.S. Department of Energy (DOE); Red Trail Energy (RTE), a North Dakota ethanol producer; and the North Dakota Industrial Commission (NDIC), conducted a study to determine the technical and economic feasibility of implementing commercial carbon capture and storage (CCS) at a North Dakota ethanol production facility and proximal geologic injection site. Validation of the use of CCS to reduce the carbon intensity (CI) value of ethanol production may allow producers to maintain and/or expand marketability of their fuel within developing markets such as low-carbon fuel programs in California and Oregon.

North Dakota is well-situated to demonstrate the implementation of CCS for small- to medium-scale CO₂ emitters. The ethanol industry is often cited as falling below the threshold for large-scale CO₂ production (>1,000,000 tonnes),¹ and North Dakota has significant ethanol production as well as suitable geology for carbon storage. In addition, emerging carbon markets in California and Oregon, such as California's Low Carbon Fuel Standard (LCFS) and Oregon's Clean Fuels Program (CFP), provide a current economic incentive through which CO₂ emitters in the fuel production industry could pursue carbon incentives and potentially offset the costs of CCS implementation.

The RTE site represents an extremely favorable case study location with existing distribution to California and Oregon and directly overlies ideal geologic formations which have the potential to storage all of RTE's CO₂ emissions for decades. The Broom Creek Formation, present in southwestern North Dakota, and the overlying shales and salts of the Opeche, Piper, and Swift Formations are expected to make an ideal storage complex for the proposed CO₂ injection.^{2,3} The Broom Creek target injection horizon is situated at a depth of approximately 6400 ft below the RTE facility. The RTE facility, located near Richardton, North Dakota, produces approximately 163,000 tonnes of CO₂ annually from the fermentation process. If an ethanol-CCS project is implemented, the RTE site could store approximately 3.2 million tonnes of CO₂ during an assumed 20-year period of injection.

² Glazewski, K.A., Grove, M.M., Peck, W.D., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2015,

¹ Fischer, D.W., LeFever, J.A., LeFever, R.D., Helms, L.D., Sorensen, J.A., Smith, S.A., Steadman, E.N., and Harju, J.A., 2008, Broom Creek Formation outline: Plains CO₂ Reduction (PCOR) Partnership Value-Added Topical Report for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, Grand Forks, North Dakota, Energy & Environmental Research Center, March.

Characterization of the PCOR Partnership region: Plains CO₂ Reduction (PCOR) Partnership Value-Added Report for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2015-EERC-02-14, Grand Forks, North Dakota, Energy & Environmental Research Center, January.

³ Sorensen, J., Bailey, T., Dobroskok, A., Gorecki, C., Smith, S., Fisher, D., Peck, W., Steadman, E., and Harju, J., 2009, Characterization and modeling of the Broom Creek Formation for potential storage of CO₂ from coal-fired power plants in North Dakota: Search and Discovery Article 80046.

On this basis, an initial FIP was developed for small-scale CCS to determine the designs and implementation steps needed to install a CCS system at the RTE facility. This plan includes conceptual CO₂ capture system and pipeline designs; permitting plan for CO₂ injection in North Dakota and ethanol-CCS approval for low-carbon fuel programs in California and Oregon; monitoring, verification, and accounting (MVA) plan; designs for monitoring and injection wells; and well characterization and testing design.

- 1. *Plant Infrastructure Design*: The capture system will include dehydration of the CO₂ stream and compression up to 1500 psi. A 4-inch pipeline is recommended to transport CO₂ to the injection site within 1 mile of the RTE facility.
- 2. *Permitting Plan*: The North Dakota Class VI permitting process for an injection well is time- and data-intensive and will require coordinating with regulators to ensure all designs and plans meet regulations prior to submittal. Approval pathways for low-carbon fuel programs to include CCS are still in the planning stages and will also require coordinating with officials to ensure compliance for acquiring credits.
- 3. *MVA Plan*: The provisional MVA program was derived based on permitting requirements to demonstrate secure CO₂ injection and long-term stability of the potentially stored CO₂ at the RTE site.
- 4. *Well Designs*: The well design and completion plan scenario recommends the installation of a monitoring and an injection well that meets North Dakota Class VI regulations, with final locations dependent on several factors such as updated simulation results, land ownership, and any specific directions given by NDIC.
- 5. *Well Characterization and Testing Design*: The site characterization plan addresses technical uncertainties in the geologic, geochemical, geomechanical, and hydrogeologic characteristics of the site, improving modeling and simulation results, which influence the designs and plans above.

APPENDIX A-1

PLANT INFRASTRUCTURE DESIGN

PLANT INFRASTRUCTURE DESIGN

A nearly pure stream of CO_2 is generated during fermentation at an ethanol facility, requiring limited postprocessing, which depends upon the intended end use of the CO_2 . In RTE's case, only compression and dehydration will be required, as RTE is currently planning to generate injection-grade CO_2 for geologic storage. Dehydration is of particular importance to ensure that the CO_2 stream is not corrosive to equipment constructed of carbon steel.

CO2 CAPTURE APPROACH

A CO₂ capture system that produces CO₂ suitable for injection into a geologic formation near the RTE facility was preliminarily designed. Figure A.1-1 shows a block diagram of the general process design unit, including a blower, low-pressure CO₂ compression with liquid water removal, a dehydration unit, high-pressure compression of the CO₂ to a dense phase, and densephase pumps that transport the CO₂ to the injection site through the pipeline.

Design Basis

The design for the capture system began with identifying the feed stream characteristics, which are presented in Table A.1-1. The composition of the feed stream was also defined and is shown in Table A.1-2. Product characteristics and composition are given in Tables A.1-3 and A.1-4, respectively.

Equipment Required

The major compression equipment for the facility is expected to be a multistage centrifugal blower, which will pull CO_2 from the existing CO_2 scrubber and compress it to approximately 15 psig. The blower will be followed by a four-stage reciprocating compressor which will further compress the CO_2 to the required injection pressure of 1500 psig. Between the third and fourth stages of the reciprocating compressor, the CO_2 will be dehydrated with a dehydration unit. In a pressure range of nominally 500–600 psig, the water content in the CO_2 is at a minimum, and the pressure is still low enough to use a solvent such as triethylene glycol (TEG) without significant evaporation of the solvent into the CO_2 . Dehydration downstream of the reciprocating compressor would require use of a solvent such as glycerol, which generally has higher capital and operating costs than TEG.

The TEG dehydrator will reduce the water concentration to less than 30 lb H₂O/MMscf to avoid downstream corrosion issues. If operating above a water content of 30 lb/MMscf, a separate liquid water phase may condense out of the CO_2 stream under some conditions and could then corrode wetted surfaces. A target of 7–10 lb/MMscf is readily achievable with TEG dehydration units.



Figure A.1-1. Conceptual design for the generation of an injection-grade CO₂ product at the RTE site (image courtesy of Trimeric Corporation).

Parameter	Minimum	Maximum	Normal	Units
Flow Rate	294	587	495	Mtd
Flow Rate	5.6	11.2	9.4	MMscfd
Pressure	3	24	10	in. H ₂ O
Temperature	37	80	43	°F
PK-3801 Scrubber DP			5.84	in. H ₂ O

Table A.1-1. Feed Stream Characteristics

Table A.1-2. Feed Stream CompositionSpeciesMole%, dry basisCO299.9865O20.0135N20.0

Table A.1-3. CO2 Product Characteristics

Delivery Parameter	Project Design Requirement
Maximum Flow Rate	587 Mtd (11.2 MMscfd) at plant inlet.
Minimum Flow Rate	294 Mtd (5.6 MMscfd) at plant inlet.
Normal Pressure	1500 psig (maximum at injection wellhead at normal delivery temperature.
Maximum Temperature	100°F (maximum) at inlet to pipeline assuming cooling water available for process cooling.
Minimum Temperature	No minimum temperature at injection wellhead specification and cannot be controlled without insulation and/or additional unit operations.

Table A.1-4.	CO ₂ Stream	Component	Purity S	Specifications
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Component	Purity Specification
Water	Typical operation 7–10 lb/MMscf (147–211 ppmv).
	Alarm at 15 lb/MMscf (316 ppmv).
	Shut down at 30 lb/MMscf (633 ppmv).

The compressor and high-pressure pump and associated equipment (such as separators and heat exchangers) will be located indoors. Dehydration equipment may be located indoors or outdoors, depending upon RTE's preference, but all liquid-containing vessels and lines outdoors will require heat-tracing and insulation. Electrical equipment classification requirements will be confirmed, but it is expected that the facility will be a nonclassified area.

A complete description of the capture, dehydration, and compression equipment is provided in Appendix B of the main report.

Process Control and Monitoring

The compression and dehydration units will be controlled by the existing control system in the RTE facility and monitored by operations staff around the clock. No additional control systems, data historians, or human–machine interface (HMI) systems are envisioned at this time for the facility. It is likely that a custody transfer quality flowmeter will be required on the outlet of the facility. A moisture analyzer at the outlet of the dehydration unit is suggested to verify that the CO_2 is adequately dried. Standard pressure, temperature, and flow instruments will also be needed. Flow or pressure tests at certain conditions will not be required, and the facility will compress and dehydrate the CO_2 available from the fermenters during normal operations.

Spare Equipment

Spares of the compressor and high-pressure pump will be included as part of this project and, as a result, the planned downtime for the compression and dehydration facility will be a maximum of 10 days of operation a year. Minor higher-maintenance equipment such as glycol pumps and cooling water pumps will also include spare equipment. Critical instrumentation may also be spared as required but should be a minor cost for this project and was not included at this early phase of design.

Additional information about the planned downtime for the RTE facility can be found in Appendix B of the main report.

Operations

The compression and dehydration equipment will be designed to operate unattended and should only require monitoring from RTE personnel and occasional intervention from plant personnel. Routine maintenance items may include filter changeouts on rotating equipment and the dehydration unit, addition of oil to the cylinder lubrication system, and periodic sampling and replenishment of the circulating glycol solution.

The compression and dehydration unit will have several vents to atmosphere. A new atmospheric vent stack will need to be designed and installed by the capture facility to direct regular process venting and emergency relief process venting to a safe location and elevation. The TEG dehydration unit will also have a vent to the atmosphere on the discharge of the fired heater to vent the combustion gases. Another vent to atmosphere will be located on the discharge of the glycol still to vent water vapor that is removed from the glycol.

Operating energy and water requirements for the system in its entirety are estimated as the following:

- Electricity: 112 kWh/tonne of CO₂ injected
- Natural gas: 7 scf/tonne of CO₂ injected
- Cooling water circulation rate: 2370 gpm
- Cooling water makeup rate: 40 gpm

Additional information about system operations can be found in Appendix B of the main report.

Process Design Uncertainties

The uncertainties associated with the CO_2 capture process at the RTE facility are summarized in Table A.1-5, along with options for addressing them. A building permit may also be required through Stark County prior to construction of the CO_2 capture system.

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Uncertainty	Potential Consequence	Recommendation				
Existing electrical infrastructure not adequate.	Installation of extra electrical infrastructure and increased capital cost.	Assess excess electrical system capacity in next phase of project.				
Makeup cooling water not available.	Pursue alternate cooling technology, possible increase in cost.	Perform economic analysis of cooling tower versus air-cooled exchangers, if necessary.				
Facility capital and operating costs outweigh benefit of higher ethanol prices.	Facility construction delayed or not approved.	Do not include installed spares of rotating equipment or consider alternate compression technology.				
Using proven dehydration technology may not be lowest-cost option.	TEG is proven, reliable technology. Alternate technology might have lower capital/operating costs.	Research in next phase of project.				
Noncondensable gas concentrations in feed stream increase (O_2/N_2) .	Higher discharge pressure required at wellhead. Leads to higher operating costs.	Build additional compression capacity in last stage of compression.				

	Table A.1-5.	CO ₂ C	apture	Process	Uncertainties
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PIPELINE REQUIREMENTS

From the compression facility discharge, the CO_2 will flow through a short (roughly 0.5–1 mile) pipeline to the injection well, which will be located on RTE property. Although the exact length of the pipeline is dependent upon final selection of an injection location, it was estimated that a 4-in.-diameter pipeline would be sufficient to carry the RTE CO_2 to the injection site. Because the O_2 concentration is likely to be greater than is typically transported by carbon steel pipeline, alternative materials of construction, such as thicker-wall pipe or the addition of an impervious liner sleeve, could be evaluated.

The pipeline will most likely run underground. If not, it will be insulated to ensure a more consistent CO_2 delivery temperature to the wellhead.

Details regarding the estimation of pipeline diameter and materials of construction are presented in Appendix C of the main report.

Construction and Installation

Generally, several phases are involved in the standard construction and installation of a CO_2 pipeline. These include the following⁴:

- Survey and staking
- Clearing
- Front-end grading
- Right-of-way topsoil stripping
- Restaking centerline of trench
- Stringing pipe
- Lineup of pipe, initial welding
- Fill and cap, final welding
- As-built footage
- X-ray inspection, weld repair
- Coating of field welds
- Trenching
- Inspection and repair of coating
- Lowering pipe into the trench
- As-built survey
- Pad, backfill, rough grade
- Hydrostatic testing, final tie-in
- Replacement of topsoil, final cleanup, and full restoration

Pipeline Design

Estimates of the pipeline to be 4 inches in diameter are rudimentary. The work required for actual design and construction of the RTE pipeline will be contracted to pipeline construction experts.

⁴ Jensen, M.D., Hamling, J.A., and Gorecki, C.D., 2015, Bell Creek test site – transportation and injection operations report: Report prepared for U.S. Department of Energy National Energy Technology Laboratory, Grand Forks, North Dakota, Energy & Environmental Research Center.

APPENDIX A-2

PERMITTING PLAN

PERMITTING PLAN

All requirements for the commercial deployment of the ethanol-CCS process embodied in the North Dakota Class VI permitting regulations for a CO_2 injection well and in the evolving low-carbon fuel programs were identified. These requirements inform future site characterization activities, subsequent modeling and simulation needs, and compliant well designs and monitoring program. This section provides details regarding the North Dakota permitting process and current knowledge of approval processes for California's LCFS program and Oregon's CFP.

NORTH DAKOTA CLASS VI PERMITTING REQUIREMENTS

Assuming North Dakota primacy becomes official (see Appendix H), the NDIC Department of Mineral Resources Division of Oil and Gas would be the permitting authority under the Underground Injection Control (UIC) Class VI Program.⁵ The North Dakota permitting requirements for a Class VI injection well are described by North Dakota Administrative Code (NDAC) Chapter 43-05-01 and North Dakota Century Code (NDCC) Chapter 38-22. In general, the North Dakota UIC Class VI program requires all applicants applying for a CO₂ injection permit, for the purpose of geologic storage, to obtain a storage facility permit, a permit to drill, and a permit to operate prior to commencement of injection activities. The storage facility permitting requirements (listed below) include, but are not limited to, a technical evaluation, an area of review and corrective action plan, a demonstration of financial responsibility, an emergency and remedial response plan, a proposed casing and cementing program, a testing and monitoring plan, a plugging plan, and a postinjection site care and facility closure plan. If an appropriate injection well is not available, a permit to drill the injection well must then be obtained, followed by a permit to operate (i.e., inject CO₂); the latter permit also requires proof that the well casing is cemented adequately so that CO₂ injected is confined to the storage reservoir.

Communication with NDIC regarding the permitting process once North Dakota primacy becomes official is recommended to ensure required design and implementation plans meet regulations prior to submittal. Table A.2-1 provides a summary of the application requirements, current status, and plan for execution.

⁵ North Dakota Industrial Commission, 2013, North Dakota Class VI underground injection control program (1422) description: June 2013.

Requirement	Regulatory Requirement	Status
	• Name, description, and average depth of the storage reservoirs.	Initial assessment complete
	• A geologic and hydrogeologic evaluation of the facility area.	Initial assessment complete
	• A review of the data of public record for all wells within at least one mile of the facility.	Initial assessment complete
	• The proposed calculated injection rates of the carbon dioxide stream.	Initial assessment complete
Tashaisal Euclustian	• The proposed average and maximum bottomhole injection pressure to be utilized at the reservoir.	Initial modeling done
Technical Evaluation	• The proposed preoperational formation testing program.	To be completed by S/E ¹ contractor
	• The proposed stimulation program.	To be completed by S/E contractor
	• The proposed procedure to outline steps necessary to conduct injection operations.	To be completed by S/E contractor
Emergency and Remedial Response Plan	• A description of the actions to address movement of the injection or formation fluids that may endanger a USDW ² during construction, operation, and postinjection site care periods.	To be completed by S/E contractor
	• Use of automated and integrated wellhead leak detection systems on all reservoir wells.	To be completed by RTE
Lask Datastion and	• Regular equipment inspection.	To be completed by RTE
Reporting Plan	• Any detected leaks must be immediately reported.	To be completed by RTE
	• Any unexpected downhole readings which may indicate a subsurface leak must be immediately reported.	To be completed by S/E contractor, RTE
	• A description of the casing or the proposed casing program, including a full description of cement as proposed, and the proposed method of testing casing before use of the injection well.	Initial assessment complete
Well Casing and Cementing Program	• A final diagram of the well depicting the casing, cementing, perforation, tubing, and plug and packer records associated with the construction of the well.	Initial assessment complete
	• Proof that the long string of casing of the well is cemented adequately so that the carbon dioxide is confined to the storage reservoirs.	To be completed by S/E contractor
Area of Review (AOR) and Corrective Action	• Delineate the AOR: Project the final extent of the injected plume (horizontal and vertical) through computational modeling and extend an additional mile	To be completed by S/E contractor, RTE
	• Identify hazards requiring corrective action within the AOR (e.g. improperly abandoned wells).	To be completed by S/E contractor, RTE
Plan (CAP)	• Develop a CAP to address identified hazards.	To be completed by S/E contractor
	• Reevaluate the AOR and CAP every 5 years using operational and monitoring data.	To be completed by RTE

Table A.2-1. Summary of ND Class VI Regulatory Requirements and Current Status for Permitting CO₂ Injection and Storage at the RTE site. Facility Downit C4 -

S/E= Science/Engineering.
 ² Underground source of drinking water.

Storage Facility Permit Requirement	Regulatory Requirement	Status
	• The storage operator shall demonstrate and maintain financial responsibility.	To be completed by RTE
	• A detailed cost estimate to perform corrective action on wells in the AOR, plugging the injection well, postinjection site care and facility closure, and emergency and remedial response.	To be completed by S/E contractor, RTE
Demonstration of Financial Responsibility	• Notify the commission of adverse financial conditions that may affect the operator's ability to carry out its obligations.	To be completed by RTE
	• Provide an adjustment of the cost estimate if the commission determines during the annual evaluation of the qualifying instrument that it is no longer adequate to cover the operator's obligations.	To be completed by RTE
	• Analysis of injected CO ₂ .	To be completed by RTE
	• Continuous recording of injection pressure, rate, and volume; well annulus pressure between tubing and casing; and annulus fluid volume added.	To be completed by RTE
Testing and Monitoring	Corrosion monitoring of well materials.	To be completed by RTE
Plan	Groundwater monitoring.	To be completed by RTE
	• Mechanical integrity testing once per year and pressure fall-off testing every 5 years.	To be completed by RTE
	Direct injection plume tracking.	To be completed by RTE
	Indirect injection plume tracking.	To be completed by RTE
	• Well preparation procedures.	To be completed by S/E contractor
Well-Plugging Plan	• Test(s) for bottomhole pressure.	To be completed by S/E contractor
	Mechanical integrity testing.	To be completed by RTE
	• Direct injection plume tracking.	To be completed by RTE
	• Indirect injection plume tracking.	To be completed by RTE
	• Types, number of plugs, and placement method(s).	To be completed by S/E contractor, RTE
	• Material used in plugging.	To be completed by S/E contractor, RTE
	Notifications, pre- and postplugging.	To be completed by S/E contractor, RTE

¹ S/E= Science/Engineering. ² Underground source of drinking water.

Storage Facility Permit Requirement	Regulatory Requirement	Status
	• Expected status of reservoir and CO ₂ plume at end of injection phase.	To be completed by S/E contractor, RTE
	• Postinjection monitoring methodology, duration, and reporting.	To be completed by S/E contractor, RTE
	• Required reevaluation of plan at cessation of injection.	To be completed by S/E contractor, RTE
Postinjection Site Care and Facility Closure	• Minimum 10-year postinjection monitoring period.	To be completed by S/E contractor, RTE
Plan	• Well closure plans including well abandonment and site reclamation after injection cessation.	To be completed by S/E contractor, RTE
	• Final assessment of CO ₂ plume and project site submitted at completion of postinjection site care.	To be completed by S/E contractor, RTE
	• Reporting of project completion to U.S. Environmental Protection Agency regional office and recorded on affected property's deed.	To be completed by NDIC, RTE
Other Permits	Regulatory Requirement	Status
	• Injection well permits must be issued for the operating life of the storage facility and the closure period.	To be completed by RTE
Inigation Wall Dommit	• The commission shall review each issued injection well permit at least once every 5 years.	To be completed by RTE
Injection well Permit	• Injection is prohibited until construction is complete.	To be completed by RTE
	• Establish any maximum injection volumes and pressures necessary to assure compliance with NDAC Section 43-05-01-11.3 (injection well operating requirements).	To be completed by S/E contractor
Certificate of Project Completion	• After carbon dioxide injections into a reservoir end and upon application by the storage operator, the commission shall consider issuing a certificate of project completion.	To be completed by RTE
	• The certificate may only be issued after public notice and hearing and NDIC consultation with the North Dakota Department of Health.	To be completed by RTE
Determining Storage Amount	• Upon application by an operator or a storage operator, the commission will determine the amount of injected carbon dioxide stored in the reservoir.	To be completed by RTE

¹ S/E= Science/Engineering. ² Underground source of drinking water.

A.2-4

LOW-CARBON FUEL PROGRAM REQUIREMENTS

RTE is pursuing two separate approval pathways for low-carbon fuels programs with CCS: 1) California's LCFS program and 2) Oregon's CFP.⁶ Plans for attaining approvals and an update of the LCA model may require revaluation as these pathways continue to develop program and details become publically available. Ongoing communication with California and Oregon regarding development of their respective approval pathways to include CCS in their low-carbon fuel programs is recommended.

California's LCFS Program

The LCFS program was originally adopted in 2009, amended in 2011, and readopted in 2015. The overarching goal is to reduce the CI of transportation fuels used in California by at least 10% by 2020. Although CCS is not yet included in the LCFS program, efforts are being made to incorporate pathway approvals to account for CCS.

California Air Resources Board (ARB) has recently released (May 2017) summary and concept papers outlining preliminary guidance for how CCS may integrate into the existing initiatives such as the LCFS program.^{7,8} Specifically, ARB has committed to developing a CCS Quantification Methodology (QM) and Permanence Protocol (PP). The QM would lay out the calculation methodology and assumptions, including different methods of accounting to accommodate the life cycle analysis (LCA) approach of the LCFS program. The QM is expected to focus on the following main areas: eligible activities, CCS project system boundary, project emission accounting, and storage reservoir type. The PP would establish the requirements to ensure that a CCS project would achieve the objective of permanent geologic CO₂ storage. The PP is expected to focus primarily on risk-based site analysis, injection or production well material and structural integrity, operating requirements, and monitoring, reporting, and verification of storage permanence.

Figure A.2-1 provides an estimated time line of future CCS-related activities for ARB. ARB's anticipated schedule is to release final drafts of the QM and PP in Quarter 3 (Q3) 2017, which will then be presented to the ARB Board for approval through a set of hearings in Q1 and Q2 2018. Quarters reflect the calendar year.

www.arb.ca.gov/cc/ccs/meetings/CCS_Summary_Paper_April_2017.pdf (accessed May 2017).

⁶ The Pacific Coast Collaborative is a regional agreement between California, Oregon, Washington, and British Columbia that strategically aligns policies to reduce greenhouse gas emissions among the members. RTE may pursue additional pathway approvals within the Pacific Coast Collaborative; however, this section focuses on California and Oregon.

⁷ California Air Resources Board, 2017a, Air Resources Board's Carbon Capture and Sequestration Program—2016 progress and future plans: California Air Resources Board,

⁸ California Air Resources Board, 2017b. Air Resources Board Carbon Capture and Sequestration Program concept paper: California Air Resources Board, www.arb.ca.gov/cc/ccs/meetings/CCS_Concept_Paper_April_2017.pdf (accessed May 2017).



Figure A.2-1. Estimated time line of future CCS-related activities for ARB.⁸

Oregon's CFP

Analogous to California's LCFS program, Oregon's CFP is one component of its statewide plan to reduce greenhouse gas emissions in the transportation sector. The 2009 Oregon Legislature passed HB 2186 authorizing the Oregon Environmental Quality Commission to adopt rules to reduce the average CI of Oregon's transportation fuels by 10% over a 10-year period. The 2015 Oregon Legislature passed SB 324 allowing the Department of Environmental Quality (DEQ) to fully implement the CFP in 2016. The DEQ has set annual reduction targets to reach the overall goal between 2016 and 2025.⁹

Unlike California, Oregon has not yet put forth preliminary guidance for how CCS may integrate into the existing CFP.

⁹ Oregon, 2016, Oregon Clean Fuels Program—September 2016 program update, www.oregon.gov/deq/FilterDocs/cfp0916bulletin.pdf.

APPENDIX A-3

MVA PLAN

MVA PLAN

INTRODUCTION

A successful MVA program is site-specific, technical, goal-oriented, and risk-based to mitigate negative impacts and reduce uncertainties.¹⁰ Various components of a CCS project (site characterization, risk assessment, simulation, etc.) are thus integrated via an iterative process to produce comprehensive, broadly defensible MVA programs.¹¹ In addition, regulatory bodies at both the state and federal levels have developed regulations for CCS projects designed to ensure existing groundwater resources are protected during and after injection operations. With that in mind, the EERC has developed a risk-based, site-specific MVA program for the proposed RTE project which meets all regulations applicable in the state of North Dakota and is based on previous EERC experience with MVA planning.^{12,13,14} All plans developed at this time represent initial program plans that will be further developed with North Dakota regulators and RTE in subsequent project phases as new data become available; thus plans are subject to change.

NORTH DAKOTA CLASS VI REGULATIONS

The primary focus of the North Dakota UIC program¹⁵ and related regulations is the protection of USDWs. USDW is a federal designation that applies to any aquifer or any portion of an aquifer that has the capacity to supply the public with water or currently supplies a public source of water for human consumption, contains less than 10,000 mg/L of total dissolved solids, and is not an exempted aquifer. Therefore, the MVA program developed for the RTE project is designed with the protection of USDWs in mind.

North Dakota regulations require monitoring of 1) all aspects of CO_2 injection operations, 2) the local groundwater system, 3) the subsurface environment through multiple methodologies, and 4) engineered systems for competency (Table A.3-1; Figure A.3-1). Furthermore, the North

¹⁰ Canadian Standards Association, 2012, Standard SA Z741-12 geological storage of carbon dioxide: Mississuaga, Ontario, Canada, 62 p., October 2012.

¹¹ Gorecki, C.D., Hamling, J.A., Klapperich R.J., Steadman, E.N., and Harju, J.A., 2012, Integrating CO₂ EOR and CO₂ storage in the Bell Creek oil field: Carbon Management Technology Conference (CMTC) Paper 157476, February 2012.

¹² Hamling, J.A., Gorecki, C.D., Klapperich, R.J., Saini, D., and Steadman, E.N., 2013, Overview of the Bell Creek combined CO₂ storage and CO₂ enhanced oil recovery project: Energy Procedia, v. 37, p. 6402–6411.

¹³ Gorecki, C.D., Hamling, J.A., Pu, H., Braunberger, J.R., Gao, P., Liu, G., Steadman, E.N., and Harju, J.A., 2014, Modeling and monitoring associated CO₂ storage at the Bell Creek Field: Presented at the IEAGHG Combined Monitoring and Modelling Network Meeting, Morgantown, West Virginia, August 4–8, 2014.

¹⁴ Sorensen, J.A., Botnen, L.S., Smith, S.A., Liu, G., Bailey, T.P., Gorecki C.D., Steadman, E.N., and Harju, J.A., 2014, Fort Nelson carbon capture and storage feasibility study – a best practices manual for storage in a deep carbonate saline formation: Plains CO₂ Reduction (PCOR) Partnership Phase III Task 9 Deliverable D100 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication No. 2014-EERC-11-08, Grand Forks, North Dakota, Energy & Environmental Research Center, September.

¹⁵ North Dakota Industrial Commission, 2013, North Dakota Class VI underground injection control program (1422) description: June 2013.

Dakota regulations require regular assessment of the MVA program (minimum every 5 years) to ensure that systems are performing as designed to track the development of stored CO_2 and that the MVA program remains appropriate for the site given the project's performance to date. If needed, alterations to the program (technology applied, frequency of testing, etc.) can be submitted for approval at that time. Results of pertinent analyses and data evaluations conducted as part of the MVA program will be complied and reported to the regulator.

Monitoring Type	RTE Program Plan	Region Monitored
Analysis of injected CO ₂	Annual sampling and compositional analysis of the injected CO ₂ stream.	Surface and storage reservoir
Continuous recording of injection pressure, rate, and volume	Instrumentation for continuous wellhead monitoring.	Surface-to-reservoir
Near-surface monitoring	Groundwater sampling and analyses (existing groundwater wells in the AOR and dedicated water well).	Near surface; USDWs
Direct reservoir monitoring	Sampling, logging, and pressure/temperature measurements via a reservoir monitoring well.	Storage reservoir and primary sealing formation
Indirect reservoir monitoring	3-D seismic surveys, passive seismic measurements.	Entire storage complex
Well annulus pressure between tubing and casing	Instrumentation for continuous annulus monitoring.	Surface-to-reservoir
Mechanical integrity testing and pressure fall-off testing	Well testing every 1 and 5 years, respectively, as required.	Well infrastructure
Corrosion monitoring	Well materials corrosion well logging.	Well infrastructure

Table A.3-1. Provisional MVA Program for Potential Geologic Storage at the RTE Site.

 CO_2 injection operations at the RTE site will be monitored both at the wellhead and at the reservoir level through the use of installed sensors that continuously record pressure, temperature, and flow. These sensors will permit the EERC and RTE to confirm that injection is occurring as expected, to account for CO_2 movement from the capture systems to the reservoir environment, and to allow for immediate mitigation if anomalous observations are made. In addition, annual sampling of CO_2 at the wellhead will undergo compositional analysis to ensure the quality of the injected CO_2 is as expected.

SITE MONITORING

Monitoring of the near-surface (USDWs) and deep subsurface environments will be accomplished through a variety of techniques applied within the determined AOR. The AOR as defined by North Dakota regulations is the extent of the estimated pressure or CO_2 plume, following stabilization after injection has ceased, plus an additional mile buffer. Results from modeling and simulation activities (see Appendix E in the main report) indicated the CO_2 plume will reach a maximum extent of 1 mile in radius from the injection location (after 10 years following a 20-year injection period), resulting in an AOR of a 2-mile radius surrounding the project site (Figure A.3-2). However, the AOR is expected to be modified in subsequent project phases as more data become available for analysis.



Figure A.3-1. Stratigraphic column illustrating provisional near-surface and deep subsurface regions monitored, as well as individual MVA techniques, for geologic CO₂ storage at the RTE site.



Figure A.3-2. Preliminary AOR of the RTE site.

Groundwater Monitoring

Groundwater monitoring can occur through sampling of all existing wells within the AOR and/or from a dedicated groundwater monitoring well installed on RTE property. Water sampling is recommended 2–4 times a year to account for seasonal variability and to document the water composition, including alkalinity, major cations, major anions, dissolved organic carbon (DOC), total organic carbon (TOC), total dissolved solids (TDS), as well as isotopic analysis (¹⁸O, ¹⁴C, ¹³C, ²H). Surface water samples from a wastewater pond located on RTE's facility and nearby Abbey Lake will also be collected at the same frequency and undergo the same analysis. Baseline or regional analyses at these locations should also occur prior to the start of injection operations outside the AOR to establish the background conditions of the site until the first revaluation period.

The dedicated groundwater-monitoring well will be sited within RTE property and screened to monitor the lowest regional USDW, the Fox Hills Formation. The Fox Hills Formation is a regionally extensive sandstone unit which is a common source of groundwater in

the area. The exact depth of the Fox Hills at the RTE site is not currently known, but will be determined during future site characterization activities. It is expected that the dedicated monitoring well will need to be between 600 and 800 feet deep to intersect the Fox Hills Formation, based upon evaluation of nearby water wells (Figure A.3-2). The well would be designed with 4-in. PVC (polyvinyl chloride) casing to allow for proper access by water-sampling equipment, drilled through to the underlying Pierre Shale, and topped with a section of 8-in. surface casing to protect and stabilize the surface environment (Figure A.3-3). This well will be sampled and evaluated on the same schedule and in the same manner as the other nearby water wells.



Figure A.3-3. Example schematic of a groundwater-monitoring well illustrating a general design for sampling the Fox Hills Formation below the RTE site.
Deep Subsurface Monitoring

Deep subsurface monitoring of the storage complex is required by the NDIC Class VI program to occur through both direct and indirect methods. To directly monitor the extent of the CO₂ plume within the storage reservoir, a dedicated monitoring well allows regular sampling and analysis of reservoir fluids and for continuous measurement pressure and temperature in the reservoir environment. In addition, the monitoring well will enable continuous monitoring of these parameters within the sandstone of the overlying Inyan Kara Formation, the first highly permeable unit above the reservoir and main sealing formations (see Figure A.3-1). A fiber optic cable system for monitoring the distributed acoustic and temperature profile may also be considered in future project phases. The monitoring well will be located at a distance from the injection well appropriate to detect the presence of CO₂ at the approximate midway point of the operational phase, assuming a 20-year injection period. Pulsed-neutron logging (PNL) is recommended on an annual basis to evaluate fluids in the storage complex and show fluids are not moving beyond the sealing formations. Furthermore, continuous pressure and temperature monitoring of the reservoir at the injection site also provides important information for monitoring the performance of the storage complex. (The designs of the monitoring well and the injection well are discussed in more detail in Appendix A.4.)

Indirect monitoring of the storage complex can be accomplished via regular 3-D and 4-D seismic surveys of the AOR and continuous monitoring for any induced seismicity. 4-D seismic surveys consist of a series of 3-D seismic surveys that are assessed together in a time series to develop a four-dimensional interpretation of the movement of fluids within the target reservoir. If implemented, 3-D seismic surveys should be conducted once prior to injection to establish baseline conditions, 2 years after injection start to evaluate early performance of the storage complex, and on 5-year intervals during the remainder of the operational phase. The baseline 3-D survey and subsequent surveys would use the same pattern and distribution of seismic sensors to ensure the proper repeatability of the surveys. The survey area is anticipated to cover a surface radial area with a radius of approximately 1.75 miles to ensure that the entire effected reservoir can be imaged by the survey (Figure A.3-4). It is also anticipated that these surveys would occur in the fall season, after harvest, to ensure proper land access for personnel and minimize disturbances for impacted landowners.

Monitoring for any induced seismicity can be performed through the use of surface installed sensors on the RTE site. These sensors are capable of continuous and wireless data reporting and should be installed prior to injection for collection of baseline data. There is no significant danger of induced seismicity by injection of the planned volume of CO₂ into Broom Creek known at this time.¹⁶ The system would involve three broadband seismometers installed in drilled "post holes" that are linked by satellite or other means to a central reporting system (Figure A.3-5). Detected events would be located and their magnitude computed within minutes of occurrence and reported to RTE management by e-mail or text. This service would continue through the first MVA evaluation period (5 years), after which its continued use would be reviewed. Any changes in induced seismicity monitoring would require approval by the

¹⁶ Frohlich, C., Walter, J.I., and Gale, J.F.W., 2015, Analysis of transportable array (USArray) data show earthquakes are scarce near injection wells in the Williston Basin, 2008-2011: Seismological Research Letters, v. 86, no. 2A, p. 1–8.



Figure A.3-4. Approximate area of potential 3-D and 4-D seismic surveys (black) centered on the RTE injection site.

regulator, e.g., it is possible that there may be either none or some number of very small events detected in the early phases of the project that pose no danger to person or property. Although not explicitly required, induced seismicity monitoring may be an initial requirement as part of a site operating permit.

Infrastructure Monitoring

Injection and storage infrastructure systems installed on the site are also required by NDIC to be monitored for competency throughout the project life cycle via regular testing and inspections. Continuous annular pressure monitoring of the injection well and monitoring well must be performed, and these wells must undergo annual mechanical integrity testing and pressure falloff testing every 5 years. Corrosion monitoring is also required, which could be accomplished by installing coupon monitoring in the wells and pipeline infrastructure. The various installed monitoring sensors must also undergo regular inspections and testing as required by regulations (or as recommended by the manufacturers if more frequent) to ensure optimal and continual system performance. Records of all testing results and any required maintenance must be maintained and reported to the regulator.





Flowmeters

Flowmeters will be installed on the injection pump and the injection well. These flowmeters, distributed throughout the CO_2 -handling infrastructure, will provide a means of monitoring for leaks across the entire pipeline and flowline system. The flowmeters also provide detailed accounting of fluid injected to the injection well. This accounting is necessary as part of the monthly report to regulators. All flowmeters will also be integrated into a remote sensing system.

Pump Pressure Management

The injection pump will be fitted with high-pressure and low-pressure kill systems with battery backup motor control valves in the event of a power failure. This will ensure the safety of personnel, equipment, and the environment. It will minimize the risk of exceeding injection pressure limitations set by the state. It will also minimize the risk of damage to equipment because of overpressures. Injection pump will also include mechanical pressure relief valves as a secondary means of shutting down operations before the injection pressure limit is reached.

Digital Tubing and Casing Pressure

Digital pressure gauges will be installed in the tubing and casing of both wells. The casing pressure will record the pressure profile of the annulus and work as an alert to the operator that no CO_2 leakage occurs into the annulus. The tubing pressure will record the CO_2 injection pressure and work as an alert to the operator if a leakage occurs in the piping system. These data will be reported monthly. All pressure gauges will also be integrated into a remote sensing system.

Corrosion Coupon

A corrosion coupon feature will be permanently installed in the flowline to the injection well, while the coupon will be installed quarterly as part of regulation requirements to monitor the corrosion rate in the entire injection system. The monitoring result should be reported annually or as prescribed by the NDIC.

The U-Tube Sampler System

The U-tube sampler system will accommodate the fluid sampling in monitoring well. There will be two systems installed in monitoring well for fluid sampling Broom Creek and Inyan Kara Formations separately. The U-tube sampler system will include a U-tube system (downhole) and a mini separation unit (surface). The mini separation unit will provide nitrogen (N₂) as a carrier gas and multistages separator to separate sampled-fluid with nitrogen (Figure A.3-6). (See Appendix A.4 for more details on the U-tube sampler system and installation.)



Figure A.3-6. Example schematic for the type of U-tube sampler system that may be deployed at the RTE site (modified from Freifeld and others, 2005).¹⁷

¹⁷ Freifeld, B.M., Trautz, R.C., Kharaka, Y.K., and Collins, D.J., 2005, The u-tube: a novel system for acquiring borehole fluid samples from a deep geologic CO₂ sequestration experiment: *in* Journal of Geophysical Research Atmospheres, October, v. 110 p. 10.

Emergency Shut-Down System

Emergency shut-down valve (ESDV) is a system that will isolate the injection pipe if a leakage or failure occurs. ESDV will be installed adjacent to the injection pump and will be automatically closed if sudden pressure drop occurs in the pipeline system. This will ensure the safety of personnel, equipment, and the environment. This ESDV will be operated directly through the SCADA monitoring system and also will directly turn off the injection pump.

Remote Sensing System

All digital data (casing pressure, tubing pressure, flowmeter data, bottomhole pressure/temperature, pipeline and flowline monitoring data, injection pressure, etc.) will be tied into a real-time remote monitoring and data-logging system. This system will be used to 1) improve site operations and planning efficiency, 2) mitigate environmental, health, and safety risks by providing a snapshot of system conditions and allowing minimal response times to any operational deviation, and 3) provide automated control and shutdown of key systems in the event of an unanticipated deviation in performance.

LONG-TERM MONITORING

A long-term goal of the MVA program is to provide an assessment of the storage complex for long-term containment and stability of the injected CO₂ for the purpose of achieving a Certificate of Project Completion (see Appendix A.2). Once injection is completed, monitoring of the storage complex will continue until it can be established that the injected CO₂ plume has stabilized. This may include postinjection seismic survey(s), continued monitoring at the injection and monitoring wells, and continued groundwater monitoring. The postinjection monitoring phase is expected to use the same sampling and interpretation protocols established for the baseline and operational phases. These criteria and specific MVA steps will be defined as part of a larger postinjection plan, which is required by North Dakota regulations to be developed for CCS operation. The postinjection plan is subject to approval by NDIC as part of the sitepermitting process and can be reevaluated during the postinjection phase. A minimum of 10 years of postinjection monitoring is required by North Dakota's regulations.

Long-term monitoring data from these efforts will also be used to evaluate the stability of the injected CO_2 . Measurements and samples from the reservoir interval will be combined with other project activities, such as simulation to evaluate the conditions in the reservoir and collect evidence that the CO_2 remains secure and its movement is being retarded by various trapping mechanisms. Eventually, the injected CO_2 plume will stabilize within the reservoir. This process is expected to occur relatively rapidly because of the small volume of CO_2 expected to be injected relative to the size of the storage reservoir. Once site stability is established, RTE can apply for Project Completion) which will allow for the transfer of long-term liability to the state of North Dakota and the cessation of monitoring by RTE.

CONCLUSIONS

A provisional MVA program has been developed for the RTE CCS project which addresses site uncertainties and anticipated regulatory compliance (assuming North Dakota Class VI primacy), and informs site operations. The MVA program includes techniques to monitor designated areas of sensitivity and to track the storage and performance of CO₂ injection, including rates, pressure, and fluid saturation. Baseline data collection will be required for several MVA techniques to establish preinjection conditions. Additional data collected in subsequent project phases will allow for further refinement and optimization of this provisional MVA program. Uncertainties also remain with respect to compliance and approval of the MVA program by the various regulatory and storage accounting agencies in North Dakota, California, and Oregon. As a first-of-its-kind project, it is anticipated that RTE and project stakeholders will need to work closely with regulators and storage accounting agencies to assume a mutually agreeable MVA program that appropriately satisfies required project criteria. Ultimately, the MVA program will necessitate data appropriate to establishing long-term site stability and facilitate the transfer of long-term liability.

APPENDIX A-4

WELL DESIGNS

WELL DESIGNS

RTE IMPLEMENTATION PLAN

The well design and completion plan scenario recommends the installation of a monitoring well and an injection well, completed to the Broom Creek and a Class VI injection well in the Broom Creek Formation along with CO₂-handling equipment (e.g., storage tanks, pipeline, etc.), and support infrastructure (e.g., additional power lines, access roads, etc.) to meet North Dakota Class VI regulations.

Installation of these project elements will require several permits from the state of North Dakota (see Appendix A.2). Should the permits be approved, NDIC will assign a dedicated UIC Director to the project. All design and implementation activities have been created to maximize efficiency and minimize construction time and cost. During drilling and completion operations, the RTE monitoring and injection wells will be drilled and completed in stages, as will installation of the CO₂ -handling infrastructure to improve cost-efficiency of resources deployed on-site.

The monitoring well should be drilled first to allow additional time for characterization of the subsurface as needed to meet the permitting requirements, such as geochemical and geomechanical testing of core and log data (see Appendix A.5). Drilling the monitoring well ensures the availability of cores and wireline logs on the monitoring well in case they are not successfully acquired later when the injection well is drilled. Completion of the monitoring well will be carried out once the final perforation intervals and core analysis have been completed. This assumes the characterization of the subsurface proves sufficient for the RTE and regulators to continue.

MONITORING WELL INSTALLATION

Prior to permitting, a survey will be conducted to delineate the well pad placement boundaries for the monitoring well and the location of the wellhead. A potential location of the monitoring well is shown in Figure A.4-1. The final location of the monitoring well will be determined in subsequent project phases and depend on several factors such as results of any future site characterization activities, land ownership, and direction from the UIC Director.

The proposed well pad size is approximately 300 feet by 300 feet, which is the minimum surface footprint that will provide sufficient space for drilling operations. The survey package will include a cut-and-fill and grading plan, associated elevation maps, and identification of existing utility lines. Once completed, the information will be submitted with the permit package. Upon receiving a permit to drill, a contractor will be used to construct the drilling and facilities pad for the monitoring wellsite. The pad will be constructed by excavating and stockpiling the original topsoil and then performing the necessary cut-and-fill and grading for the pad and access road. It will then be topped with a native material known as scoria, which is analogous to gravel, to provide a firm top base and to reduce rutting and improve drainage on location.



Figure A.4-1. Map showing possible location of monitoring and injection wells and approximate size of well pad.

To provide access to the monitoring well location, a road will be constructed to connect with an existing road. The new road will be approximately 16 ft wide and excavated, graded, and topped with approximately 4 in. of scoria. The construction of the road and monitoring well pad is designed to provide consistent all-season access for industrial equipment and operations (e.g., drilling rig, workover rig, roustabout, etc.) for the duration of the project with minimal need for maintenance. The monitoring well pad will have a constructed basin for collection and disposal of any runoff. It is anticipated that the site pad and road will require approximately 10 days to complete after the design has been approved and the permits are finalized.

After the pad is constructed, a cellar will be dug, and a small top-hole drilling rig will be used to install and cement 90 ft of 16-in. conductor casing to surface to isolate unconsolidated sediments and protect a shallow water zone (as required by permit). The well will have casing and tubing installed that will be CO₂ resistant [Class VI Codes: 40 CFR 146.86(b)(2), 40 CFR 146.86(c)(1), 40 CFR 146.87(b)]. This 90 feet of conductor casing also allows appropriate room for the primary drilling rig to operate. After the conductor casing is installed, a primary drilling

rig will be mobilized to the site and begin drilling operations. A closed-loop system will be used with no reserve or cutting pits on location (as state law requires). Following state regulations, the NDIC will be informed of spudding within 24 hr. The surface hole will be drilled to 1925 ft with freshwater gel mud using a 12¹/₄ -in. bit, after which openhole logging, as described in Appendix I.4 of the main report, will be completed and surface casing will be installed and cemented to surface to protect USDWs [Class VI Code: 40 CFR 146.86(b)(2)]. After surface casing operations are completed, a blowout preventer will be installed and pressure-tested.

Apart from coring activities, the remainder of the well will be drilled with an 8½-in. bit and saltwater gel mud. Saltwater gel mud is used to minimize potential interaction with subsurface strata by balancing the mud chemistry with the native formation fluids. A saltwater mud is also used to prevent hole enlargement.

Summarized in Table A.4-1, taking either whole core and/or sidewall core from the confining system and injection zone will be required [Class VI Code: 40 CFR 146.87(b)]. Four-inch-diameter core will be collected from an estimated depth interval of 6455 to 6805 ft (350 ft), 50 ft in the Opeche and 300 ft in the Broom Creek Formation and possibly the underlying Amsden Formation. Drilling will recommence beginning with the reaming of the cored interval and then proceeding to an estimated total depth (TD) of 6900 ft. An 8½-in. PDC (polycrystalline diamond compact) bit and saltwater gel mud will be used for drilling. After reaching TD, the hole will be conditioned, and well logging will be conducted following the geophysical logging program described in Appendix I.4 of the main report.

 Table A.4-1 Anticipated Coring Intervals.

	P	<u> </u>	
Depth, ft*	Total, ft	Size, in.	Formation
6455–6505	50	4	Opeche (upper confining zone)
6505-6805	300	4	Broom Creek (injection zone)
*			

* All depths are approximate.

After logging is completed, the hole will be conditioned for casing and cement. An example schematic of the monitoring well is shown in Figure A.4-2. Sage Rider "SageWatch" casing-conveyed pressure and temperature gauges will be set on the production casing, one at each depth of 4930 ft and 6515 ft. These gauges will record pressure and temperature externally, into the formation, as well as record the pressure and temperature inside the casing. A summary of these recommended gauges for the monitoring well is provided in Table A.4-2. A 5½-in. production casing will be run and cemented from TD to surface casing to ensure wellbore integrity [40 CFR 146.86(b)(2)]. After casing is completed, a 5000-psi night cap will be installed for pressure control, and the drilling rig will be rigged down and released. The estimated drilling time for the monitoring well is 26 days. A summary of the drilling and completions casing plan for the monitoring well is shown in Table A.4-3, and detailed drilling prognosis for the monitoring well can be found in Appendix I.1.4 of the main report.



Figure A.4-2. Example monitoring well schematic.

	Depth,			
Gauge/System*	ft**	Model	Size, in.	Purpose
Pressure &	4930	Casing	7.75 OD***	Monitor the Inyan Kara
Temperature		conveyed,		Formation
Gauge No. 1		SageWatch		
Fluid Sampling	4930	U-tube system		Collect fluid samples from
No. 1				the Inyan Kara Formation
Pressure &	6515	Casing	7.75 OD	Monitor the Broom Creek
Temperature		conveyed,		Formation
Gauge No. 2		SageWatch		
Fluid Sampling	6425	U-tube system		Collect fluid samples from
No. 2				the Broom Creek Formation

Table A.4-2. Anticipated Gauges and Sampling Systems for the Monitoring Well

* Fiber optic cable may also be considered for applications such as distributed acoustic sensing and temperature profile monitoring.

** All depths are approximate.

*** Outer diameter.

			Outside			
	Depth		Casing			
	Interval,	Bit Size,	Diameter,	Mud	Weight, API	Cement
String	\mathbf{ft}^*	in.	in.	Туре	Grade/Type	Interval, ft
Conductor	0–90	26	16	Freshwater	84 lb/ft,	0–90
					J-55	
Surface	0-1925	121⁄4	9 ⁵ /8	Freshwater	40 lb/ft,	0–1925
					J-55	
Production	0–6300	81⁄2	51/2	Saltwater	17 lb/ft,	
				gel	L-80	
Production	6300-	81⁄2	51/2	Saltwater	17 lb/ft, 13Cr	0 6000
	6900			gel		0-0900
Tubing	0–6470		21/8		6.5 lb/ft,	
					13Cr	
Perforated	6555-					
Interval ^{**}	6775					

Table A.4-3. Anticipated Drilling and Completions Summary for Monitoring Well

* All depths are approximate.

** 4 spf [shot per foot], 90 deg, min 0.46" exit hole diameter (EHD); 23" penetration.

After the primary drilling rig is finished, RTE will notify NDIC of its intent to complete the well as stipulated by permit requirements. A workover rig will be mobilized to location, rigged up, and the wellbore will be cleaned out to prepare for completion work. To provide assurance of a quality cement job and secure connections between lengths of casing, a casing integrity pressure test (~2000 psi) will be conducted on the production casing [Class VI Code: 40 CFR 146.89(a)(4)(i)]. If the casing fails or the pressure test fails, the primary engineer will be consulted and solutions employed, followed by retesting.

Upon a successful casing integrity pressure test, a wireline cement bond log (CBL), variable-density log (VDL), casing collar locator (CCL), gamma ray (GR) will be run from TD (6900 ft) to surface to evaluate cement integrity and satisfy regulations [Class VI Code: 40 CFR 146.87(a)(2)]. These logs are required by state regulation (NDIC) and will be used to depth-correlate the perforating interval. If CBLs indicate issues with the top of cement used for organic carbons or cement bond quality, the primary engineer will be consulted and solutions employed, followed by retesting.

The production casing will be perforated into the Broom Creek Formation at an interval of 4 spf and a 90° phasing providing a 0.46-in. entry hole diameter and ~23-in. penetration. Specific perforating intervals in the Broom Creek will be determined based on interpretation of the logging results and core anlaysis. The top of the perforating interval will be located a minimum of one casing joint below the casing-conveyed pressure temperature gauge as correlated via the GR log to minimize potential damage to the external gauge system.

Injection tests with multiple rates and associated falloff pressure measurements will be used to assess the level of fluid communication with the formation. Based on calculations using results from the injection test, an acid stimulation will be performed to ensure the perforations are open. A packer will be set a maximum of 100 ft above the top perforation following NDIC requirements using 2-7/8 in., 6.5-lb/ft 13Cr tubing. Two U-tube sampling systems will be installed to allow for the sampling of formation fluids as required [Class VI Code: 40 CFR 146.90(d)]. A summary of these recommended sampling systems for the monitoring well is included in Table A.4-2. Corrosion-inhibiting fluids will be employed to minimize wear of the packer and to provide additional casing protection. A mechanical integrity test (MIT) will be performed on the well to a pressure of 1500 psi unless otherwise recommended by NDIC. Following state protocol, NDIC will be contacted to witness the MIT. Upon approval from NDIC, the well will be ready for installation of surface equipment.

The entire completion program for the monitoring well can be found in Appendix I of the main report.

INJECTION WELL INSTALLATION

Prior to permitting, a survey will be conducted to delineate the well pad placement boundaries for the injection well and the location of the wellhead. Potential location of the injection well is shown in Figure A.4-3. The final location of the injection well will be determined in subsequent project phases and depend on several factors such as results of any future site characterization activities, land ownership, and direction from the UIC Director.

The proposed well pad size is approximately 300 feet by 300 feet, which is the minimum surface footprint that will provide sufficient space for drilling operations. The survey package will include a cut-and-fill and grading plan, associated elevation maps, and identification of existing utility lines. Once completed, the information will be submitted with the permit package. Upon receiving a permit to drill, a contractor will be used to construct the drilling and facilities pad for the monitoring wellsite. The pad will be constructed by excavating and stockpiling the



Figure A.4-3. Example injection well schematic.

original topsoil, and then performing the necessary cut-and-fill and grading for the pad and access road. It will then be topped with a native material known as scoria, which is analogous to gravel, to provide a firm top base and to reduce rutting and improve drainage on location.

To provide access to the injection well location, a road will be constructed to connect with an existing road. The road will be approximately 16 ft wide and excavated, graded, and topped with approximately 4 in. of scoria. The construction of the road and injection well pad is designed to provide consistent all-season access for industrial equipment and operations (e.g., drilling rig, workover rig, roustabout, etc.) for the duration of the project with minimal need for maintenance. The injection well pad will have a constructed basin for collection and disposal of any runoff. It is anticipated that the construction of the site pad and road will require approximately 10 days to complete after the design has been approved and the permits are finalized.

After the pad is constructed, a cellar will be dug, and a small top-hole drilling rig will be used to install and cement 90 ft of 16-in. conductor casing to surface to isolate unconsolidated sediments and protect shallow water zone (as required by permit). The well will have casing and tubing installed that will be CO₂ resistant [Class VI Codes: 40 CFR 146.86(b)(2), 40 CFR 146.86(c)(1), 40 CFR 146.87(b)]. This 90 feet of conductor casing also allows appropriate room for the primary drilling rig to operate. After the conductor casing is installed, a primary drilling rig will be mobilized to the site and begin drilling operations. A closed-loop system will be used with no reserve or cutting pits on location (as state law requires). Following state regulations, NDIC will be informed of spudding within 24 hr. The surface hole will be drilled to 1925 ft with freshwater gel mud using a 14³/₄-in. bit, after which openhole logging as described in Appendix I.4 in the main text will be completed, and surface casing will be installed and cemented to surface to protect USDWs [40 CFR 146.86(b)(2)]. After surface casing operations are completed, a blowout preventer will be installed and pressure-tested.

Apart from coring activities, the remainder of the well will be drilled with a 12¼-in. bit and saltwater gel mud. Saltwater gel mud is used to minimize potential interaction with subsurface strata by balancing the mud chemistry with the native formation fluids. A saltwater mud is also used to prevent hole enlargement. Similar to core collection from the monitoring well summarized in Table A.4-1, taking either whole core and/or sidewall core from the confining system and injection zone will be required [Class VI Code: 40 CFR 146.87(b)]. Four-inch-diameter core will be collected from an estimated depth interval of 6455–6805 ft (total length is 350 ft), 50 ft in the Opeche and 300 ft in the Broom Creek Formation and possibly the underlying Amsden Formation. Drilling will recommence beginning with the reaming of the cored interval and then proceeding to an estimated TD of 6900 ft. A 12¼-in. PDC bit and saltwater gel mud will be used for drilling. After reaching TD, the hole will be conditioned, and well logging will be conducted following the logging program described in Appendix I.4 of the main text.

After logging is completed, the hole will be conditioned for casing and cementing operations. An example schematic of the injection well is shown in Figure A.4-3. A casing-conveyed pressure/temperature gauge will be installed approximately 385 ft above the casing shoe. The required downhole pressure and temperature gauges will be at 6375 ft and 6515 ft to

monitor the Broom Creek and Spearfish Formations [Class VI Code: 40 CFR 146.87(c)]. These sensors will record pressure and temperature conditions externally into the casing as well as record the pressure and temperature inside the casing. A summary of these recommended gauges for the injection well is provided in Table A.4-4. The casing will be cemented from TD to the surface, 1925 ft into surface casing, to ensure wellbore integrity [Class VI Code: 40 CFR 146.86(b)(2)]. After casing is completed, a 5000-psi night cap will be installed for pressure control, and the drilling rig will be rigged down and released. A summary of the drilling and completions casing plan for the injection well is shown in Table A.4-5. The estimated time from moving the drilling rig onto the site to final rig release is estimated to be 27 days. A detailed drilling prognosis and drilling procedure for the injection well can be found in Appendix I.2.4 of the main text.

1 abic A. . Ai	Table A.4-4. Anticipated Gauges for the injection wen					
Gauge*	Depth, ft**	Model	Size, in.	Purpose		
Pressure &	6375	Casing	9.25 OD	Monitor the formation directly		
Temperature		conveyed,		above the Opeche Formation		
Gauge No. 1		SageWatch				
Pressure &	6515	Casing	9.25 OD	Monitor the Broom Creek		
Temperature		conveyed,		Formation		
Gauge No. 2		SageWatch				

Table A.4-4. Anticipated Gauges for the Injection Well

* Fiber optic cable may also be considered for applications such as distributed acoustic sensing and temperature profile monitoring.

** All depths are approximate.

1 abic A. - -3.	Anticipateu D	i ning a	inu Compicuo	Jiis Suillillai y	injection wen	
			Outside			
	Depth	Bit	Casing			Cement
	Interval,	Size,	Diameter,		Weight, API	Interval,
String	\mathbf{ft}^*	in.	in.	Mud Type	Grade/Type	ft
Conductor	0–90	26	16	Freshwater	85 lb/ft,	0–90
Surface	0–1925	14¾	133/8	Freshwater	72 lb/ft, J-55	0–1925
Production	0–6300	121⁄4	7	Saltwater gel	26 lb/ft, L-80	
Production	6300–6900	12¼	7	Saltwater gel	26 lb/ft, 13Cr	0–6900
Tubing	0-6470		31/2		9.2 lb/ft, 13Cr	
Perforated Interval ^{**}	6555–6775					

Table A.4-5. Anticipated Drilling and Completions Summary Injection Well

* All depths are approximate.

** 4 spf, 90 deg, min 0.46" EHD; 23" penetration

After the primary drilling rig is finished, RTE will notify NDIC of its intent to complete the well as stipulated by permit requirements. A workover rig will be mobilized to location, rigged up, and the wellbore will be cleaned out to prepare for completion work. To provide assurance of a quality cement job and secure connections between lengths of casing, a casing integrity pressure test (~2000 psi) on the production casing will be conducted [Class VI Code: 40 CFR 146.89(a)(4)(i)]. If the casing fails or the pressure test fails, the primary engineer will be consulted and solutions employed, followed by retesting.

Upon a successful casing integrity pressure test, a wireline CBL with GR and VDL, and a CCL will be run from TD to surface to evaluate cement integrity and satisfy Class VI regulations [Class VI Code: 40 CFR 146.87(a)(2)]. GR will be run from TD to surface. These logs are required by state regulation (NDIC) and will be used to depth-correlate the perforating interval. If CBL logs indicate issues with the top of cement or cement bond quality, the primary engineer will be consulted and solutions employed, followed by retesting.

The production casing will be perforated into the Broom Creek Formation at an interval of 4 spf and a 90° phasing providing a 0.46-in. entry hole diameter and ~23-in. penetration. Specific perforating intervals in the Broom Creek will be determined based on interpretation of the logging results and core anlaysis. The top of the perforating interval will be located a minimum of one casing joint below the casing-conveyed pressure temperature gauge as correlated via the GR log to minimize potential damage to the external gauge system.

Injection tests with multiple rates and associated falloff pressure measurements will be used to assess the level of fluid communication with the formation. Based on calculations using results from the injection test, an acid stimulation will be performed to ensure the perforations are open. A packer will be set a maximum of 100 ft above the top perforation following NDIC requirements using 3½-in., 6.5-lb/ft 13Cr tubing. Corrosion-inhibiting fluids will be employed to minimize wear of the packer and to provide additional casing protection. A MIT will be performed on the well to a pressure of 1500 psi unless otherwise recommended by NDIC. Following state protocol, NDIC will be contacted to witness the MIT. Upon approval from NDIC, the well will be ready for installation of surface equipment.

A detailed completion program and operating procedure for the injection well can be found in Appendix I of the main report.

APPENDIX A-5

WELL CHARACTERIZATION AND TESTING DESIGN

APPENDIX A.5 WELL CHARACTERIZATION AND TESTING PLAN

GOALS

The geologic data interpretation, modeling, and simulation efforts of this feasibility study have preliminarily indicated the geology at the RTE site is suitable for long-term CO_2 injection at the scale required of the operation. However, these efforts were based on limited site-specific subsurface data, thus there is some uncertainty in the results. To further reduce this uncertainty a site characterization plan was developed for implementation at the conclusion of this feasibility study (pending endorsement by RTE). The site characterization efforts detailed in the following sections of this report will provide site-specific data to build upon the preliminary findings of this study and optimize injection well placement. These site characterization efforts will also augment the MVA program by generating baseline data to which operational monitoring technology measurements may be compared to ensure conformance and CO_2 containment.

The site characterization and MVA plans outlined here are designed to address technical uncertainties in geologic, geochemical, and geomechanical and flux baseline characteristics. Additional data regarding these technical aspects will 1) better inform the definition of a proper AOR (via expected CO_2 and pressure plume extents), 2) reduce uncertainty related to the injection program, 3) provide evidence and support needed to obtain a Class VI well permit, 4) identify and/or clarify any technical risks which may have potential to affect the project's overall financial feasibility, and 5) minimize the potential for legal concerns which may arise during and following CO_2 injection operations.

CHARACTERIZATION OF THE BROOM CREEK AND OPECHE FORMATIONS

The Broom Creek Formation is not known to contain or enable production of commercial amounts of hydrocarbons, has native brine with salinities generally greater than 100,000 ppm TDS (much too high to be considered for beneficial use), and is deep enough in most parts of the Williston Basin that it is not widely targeted for saltwater disposal purposes. Thus, limited characterization and injection data exist for the Broom Creek in proximity to the RTE location. Although available regional data (e.g., injection rates, core analysis, well logs) suggest that injectivity into this formation is likely sufficient for the amount of CO₂ which will be generated and captured at RTE, lack of nearby offset data leads to an elevated degree of uncertainty regarding the mineralogy, porosity, permeability, and injectivity into the Broom Creek Formation. There is also a risk of geochemical reactivity between the injected CO₂, the native brine, and the minerals present in the Broom Creek Formation which could reduce injectivity or create other adverse consequences.

To reduce uncertainty and mitigate the (potential) risk of limited Broom Creek injectivity, it is critical that this formation at the RTE site be thoroughly characterized. A program of well logging focused on the Broom Creek and Opeche Formations will be conducted. Geologic core samples will be collected and analyzed to determine mineralogy (with an emphasis on clay typing to determine the potential for clay swelling), porosity, and permeability. Fluid samples

from the Broom Creek Formation will be collected to determine the fluid chemistry and other relevant parameters (i.e., salinity, CO_2 solubility, viscosity). This information will be used to update numerical simulation inputs and to help identify and predict potential geochemical reactivity between the native formation fluid, minerals present in the Broom Creek Formation, and RTE gas effluent (CO_2 and any impurities present). If geochemical reactions (such as mineral precipitation or clay swelling) are found to pose significant risk of impairment to injection, several mitigation measures may be investigated as the project moves from the feasibility study into the development/operational phase.

Modeling and simulation efforts will use these characterization data to adjust and update static models for increased accuracy. Predictive simulations using updated models will further reduce uncertainty in comparison to the results reported in this feasibility study, including expected plume extent (both CO₂ and pressure) and the resulting AOR. These derivatives will provide evidence to be furnished in the Class VI well-permitting process. It is, therefore, critical for the geologic model of the injection and containment intervals at the RTE site to be finely detailed and an accurate representation of the subsurface. With the closest Broom Creek Formation well penetration at a distance of approximately 3 miles from the RTE site, it will be necessary to perform a comprehensive characterization of the Broom Creek in the proposed well location. It is important to have a quantitative understanding of the rock properties of the reservoir. It is also necessary to quantitatively understand the correlations between the corederived properties and the porosity and permeability interpretations from the geophysical logs. Furthermore, these data may provide important information which may be used to guide the design and operation of site equipment and infrastructure.

SITE CHARACTERIZATION PLAN

Baseline characterization includes activities to determine the initial compositions and qualities of the CO₂ injection target formation (Broom Creek) and the primary sealing formation (Opeche). Characterization is also a key component of the MVA plan for the RTE site, as improved characterization will aid in effective collection and interpretation of MVA data, guide the timing and frequency of MVA data collection, and reduce risk associated with the overall project.

A well must be drilled to acquire the site-specific subsurface data. Concerning the drilling of such a well, three options are available to RTE:

- 1. Design, permit, and construct the well as a stratigraphic test well.
- 2. Design, permit, and construct the well as an observation/monitoring well.
- 3. Design, permit, and construct the well as a <u>Class VI injection well</u>.

In the first scenario, a well will be sited at a location near where a future Class VI injection well would likely be placed. The well would be drilled, characterization data would be acquired, documents conveying intent to abandon would be filed with the NDIC, and the well would then be plugged back with cement and abandoned.

In the second scenario, the well would be sited at a distance of 400–800 m from where a future potential Class VI injection well would be located. Well casing would be set during drilling, characterization data would be acquired, the well would be completed (perforated) within the Broom Creek Formation, and the well would be outfitted with MVA technology (i.e., pressure, temperature, and/or acoustic monitoring technology) with which to conduct reservoir surveillance during future potential CO₂ injection activities.

With regard to the third scenario, the plan would be to construct and complete the well to Class VI injection well standards (i.e., corrosion-resistant casing and cement). A Class VI permit would need to be acquired, issued from NDIC. Characterization data would be acquired, the well would be completed (perforated) in the Broom Creek, mechanical integrity tests would be conducted, and a successful mechanical integrity test result would be followed by connection to CO₂ capture and compression infrastructure to begin injection operations.

In weighing the benefits and detractions from each of the options, the completion of the initial site characterization well as an observation/monitoring well is believed to best represent the financial interests of RTE. Although the other two options would satisfy the objectives of collecting additional site-specific characterization data, Option 1 would be the least expensive but would exhibit the lowest benefit-to-investment ratio, as the well would be plugged and abandoned after characterization data acquisition, offering no further usefulness to the overall project. Option 3 would have significantly higher costs associated with drilling, construction, and completion than either Option 1 or 2. This investment would be achieved or recoverable should the project not proceed because of regulatory/permitting or other technical or nontechnical complications that may arise. The decision will ultimately be left to RTE as to which of the above options will be undertaken.

Regardless of which well drilling and completion option is chosen, the characterization well will be located on property owned by RTE. The precise location of this well will be determined from numerical simulation results discussed in this report and with input from RTE. Schlumberger Carbon Services can be retained to provide drilling, coring, and logging services. Additionally, the well completion plan will have no effect on the recommended types of site characterization data to be collected, although the plans for acquiring these types of data may vary slightly. The rock and fluid properties of the Broom Creek Formation at the RTE site will be thoroughly quantified to demonstrate the reservoir's ability to support the goals of the project. Four-inch-diameter core will be taken from the cap rock (Opeche Formation) and the Broom Creek Formation. A comprehensive logging suite will be collected. Fluid samples will be acquired from the Broom Creek, and downhole testing (pressure, flow, and mechanical) will be conducted. Once sampling and logging processes are completed, this well will be transitioned according to RTE's decision regarding the options mentioned above (either plugged and abandoned, completed as an observation/monitoring well, or completed as a Class VI injection well) following the procedures established by NDIC.

GEOLOGIC CORE SAMPLE COLLECTION

Geologic core samples will be collected and analyzed from the Broom Creek and Opeche Formations. It is recommended that 350 ft of core be collected (approximately 50 ft from the Opeche Formation and the remainder from the entirety of the Broom Creek Formation). Analysis of this new core will allow for:

- 1) Development of more comprehensive porosity and permeability correlations to update the geologic model and enable more accurate predictive simulations of fluid flow and pressure response.
- 2) Investigation of potential geochemical reactions of both formations catalyzed by injection of CO₂, the occurrence of which may reduce injection capacity.
- 3) Investigation of geomechanical strength properties of the Opeche Formation (cap rock) to determine the formation's competency in acting as a seal.

A suite of petrographic, petrophysical, geomechanical, and geochemical analyses will be performed on core samples from both the target formation and the seal formation to better understand factors that influence the long-term containment of CO₂, to aid in the calibration and correlation of well logs, and to improve the accuracy of geologic and simulation models. Specific analytical techniques will include:

- Thin-section analysis to assess mineralogy, grain size, sorting, and morphology; diagenetic effects, and to assist understanding of facies interpretations, rock fabric, depositional trends, and diagenetic history.
- X-ray fluorescence (XRF) to give insight into sample chemistry and dynamics with CO₂/brine/rock interaction.
- X-ray diffraction (XRD) coupled with Rietveld refinement to assess bulk mineralogy and clay mineralogy via clay fraction isolation to understand cap integrity issues and reservoir dynamics in relation to clay types present.
- Field emission scanning electron microscopy (FE SEM) to gain visibility of fine-scale mineral and pore space relationships and to serve as a validation technique for XRD.
- Coupling of new FE SEM analysis mineral identification and classification system (AMICS) software to compare with original images acquired with the FE SEM will allow for visual inspection of the AMICS-derived pore and fracture characterization results for comparison to other acquired porosity measurements and also allow for coupled comparison of elemental and mineral content with XRF and XRD, improving reservoir and cap rock characterization.
- Porosity and permeability testing to establish baseline data.
- Geochemical analyses with gas compositions representative of RTE's effluent stream and the formation fluid to investigate chemical reactions, including mineral dissolution and precipitation reactions, which may impact injection activities.
- Nuclear magnetic resonance (NMR) to assess total versus effective porosity with representative brine/CO₂ compositions for relative permeability predictions.
- CO₂/brine relative permeability testing to determine the ease with which CO₂ will flow in the presence of the high-salinity brine of the reservoir.
- Geomechanical studies to conduct mechanical strength testing and determine the maximum injection integrity of the cap rock.

• Mercury injection capillary pressure (MICP) tests to provide data regarding the poresize distribution available and capillary pressure range in reservoir and cap rock samples.

The resulting data will be used in subsequent project phases to update both estimates of storage capacity and simulations of injected CO_2 behavior with respect to two-phase fluid flow.

WELL LOGGING AND DOWNHOLE TESTING

Geophysical logging data will be acquired and downhole formation testing will be conducted in the planned characterization well. The following well logs are planned: spectral GR, triple combination, dipole sonic, NMR, PNL/PNX, and CBL (if the well is planned to be completed as either an observation/monitoring or Class VI injection well). Downhole testing will include modular formation dynamics testing (MDT).

- Spectral GR logging will provide passive measurements of natural radioactivity in the subsurface and separate determinations of the contributions of potassium, thorium, and uranium to the overall measured radioactivity. A similar measurement will be made on the entire length of the core acquired, enabling an accurate core-to-log depth correlation. This correlation will be important when integrating core-measured properties in modeling activities.
- The triple combination ("triple combo") logging will provide a wide variety of physical property measurements of the openhole environment. Data produced from this tool will include GR, neutron porosity, density, photoelectric factor, spontaneous potential, temperature, and resistivity logs. These logs will provide the ability to assess formation top depths (previously estimated from nearby wells), lithology, and petrophysical characteristics (porosity, water resistivity, water saturation, and the presence/absence of gas), which will be important in identifying well test and completion intervals and correlating core data to offset wells.
- Dipole sonic logging will provide a means for derivation of sonic porosity (a metric of connected, fluid-filled pore space), which will prove useful in zones characterized with complex lithologies. Dipole sonic logging will provide shear wave data necessary to assess stress anisotropy and investigate the presence of natural fractures. Sonic logging will also provide a means to tie seismic data to the well, should it be collected as part of the baseline characterization in the following proposed/recommended MVA plan, assisting in seismic time-to-depth conversion.
- NMR logging, acquired with Schlumberger's combinable magnetic resonance (CMR) tool, will provide estimates of pore-size distribution, total porosity, effective porosity, bound fluid (irreducible water saturation), free fluid, and calculated permeability.
- PNL/PNX will provide mineralogic, porosity, and fluid saturations (water, oil, and gas). If the characterization well is completed as an observation/monitoring well, this data may be used in

comparison with repeat/monitor PNL/PNX surveys to identify changes in reservoir fluid saturation during injection (monitor CO₂ breakthrough), as well as monitoring of the strata overlying the reservoir for unexpected vertical migration of CO₂.

- CBL and CCL logs will provide an assessment of cement quality and identify any associated remedial cementing operations that are required. A measurement of cement top and a depth correlation for perforation and installing downhole equipment in relation to geology will also be provided.
- MDT technology will be implemented to conduct pressure testing and native formation fluid sampling, as well as injection tests to estimate downhole permeability and formation parting pressure. Formation fluid samples will be used to test for potential fluid and mineralogical reaction with mixtures of the native brine and RTE's gas effluent (CO₂ and any impurities present), which could affect injectivity.

These specific logging techniques were selected to reduce uncertainty in subsurface characteristics at the RTE site. Some data redundancy is planned for key parameters, such as porosity and permeability, as these parameters are of utmost importance in reducing the technical risks associated with the Broom Creek Formation's ability to receive injection at the scale necessary for the project's success. Injectivity assessment will rely upon permeabilities calculated from NMR logging, measured from core samples, and measured by MDT. Should inferences of downhole injectivity potential be too low (or simply inconclusive), additional downhole testing (such as a pump test or CO_2 injection test) may be recommended.

APPENDIX B

TRIMERIC FINAL REPORT



RED TRAIL ENERGY CO₂ CAPTURE AND SEQUESTRATION PROJECT

CO₂ SURFACE FACILITY DESIGN REPORT

This document has been revised as indicated below and described in the revision record on the following page. Please destroy all previous revisions.

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1 Executive Summary and Conclusions

The Red Trail Energy (RTE) ethanol facility in Richardton, ND produces ethanol through the fermentation of corn. In addition to ethanol, the fermentation process produces a large quantity of carbon dioxide (CO₂). RTE produces a maximum amount of 587 metric tonnes (11.2 MMSCF) of CO₂ per day in the fermentation process. The CO₂ from the fermentation process is normally vented to the atmosphere after it is scrubbed with water to remove any entrained ethanol and other chemicals. RTE is working with the University of North Dakota's Energy and Environmental Research Center (EERC) to develop a basic CO₂ recovery facility design and injection well design for capturing the CO₂ that is vented to atmosphere. Trimeric contracted with EERC to develop a concept-phase estimate for the surface equipment for the CO₂ recovery facility. This report details the work completed by Trimeric to estimate the size, capital cost, and operating costs for the surface equipment.

Trimeric presented three initial designs for the CO_2 recovery facility; each facility produced CO_2 at different purification levels so that the CO_2 could be used in different ways. The most basic facility produced CO_2 that was suitable for injection, a second design produced CO_2 that was suitable for enhanced oil recovery (EOR) operations, and the final design produced CO_2 that met established specifications for food and beverage grade CO_2 . Table 1 below shows the estimated capital and operating costs for each facility design. Block flow diagrams for each facility design are provided in Appendix A.



Facility Design	Total Installed Capital Cost	Power Requirement
	(Millions)	(kWh/Tonne)
Facility to Inject CO ₂ in	\$13.1	111.8
Sequestration Well		
EOR CO ₂ Facility	\$14.7	152.1
Food/Beverage Grade CO ₂	\$15.7	152.5
Facility		

Table 1.	Estimated Total Installed Capital and Power Requirements for CO ₂ Recovery
	Facilities.

The costs in Table 1 assume no sparing of major rotating equipment, that the process will be cooled with cooling water from a new cooling tower, and that the CO_2 , if injected into the ground, would be injected on RTE's existing property (pipeline distance would be minimized). These costs are based on scaling of costs for completed projects elsewhere in the United States and from Trimeric internal resources.

The project team decided to move forward with a design and cost estimate for a CO_2 recovery facility that produced CO_2 intended for injection only. As a result, the facility is only designed to compress and dehydrate the source CO_2 . Water is the only component that will be removed from the source CO_2 . The project team also decided to install spare equipment for the major rotating equipment, which has a large impact on the overall facility cost. The decision to spare major rotating equipment did not impact the facility design chosen for this project, but the total installed cost is estimated to be much higher than what is shown in Table 1.

The facility will compress the CO_2 with two different compression technologies. Primary compression will occur in a multistage centrifugal blower located next to the existing fermentation tanks at the RTE facility. This equipment will compress the CO_2 from the PK-3801 CO_2 Scrubber from near atmospheric pressure up to a nominal pressure of 17 psig.



The compressed CO_2 is cooled and condensed water is separated from the gas stream before it flows to a four stage reciprocating compressor. Between each stage of compression the gas stream is cooled and any condensed liquid water is separated from the gas stream. After the 3rd stage of compression, the gas stream flows through a tower where it is contacted with triethylene glycol (TEG) and nearly all of the remaining water vapor in the gas stream is absorbed into the TEG. Rich TEG from the bottom of the tower is regenerated in a small natural gas-fired or electric reboiler that drives water out of the rich TEG as a vapor that is then vented to the atmosphere. Dry CO_2 from the leaves the reciprocating compressor at a pressure of 1,511 psig and travels through a pipeline for a half mile to arrive at the injection wellhead at 1,502 psig. A process flow diagram for this process is provided in Appendix B and a heat and material balance for this process is provided in Appendix C.

Trimeric requested budgetary quotations from vendors for the rotating equipment and the TEG dehydration unit for this project and utilized internal resources to estimate the cost of the cooling tower. Table 2 shows the equipment costs for the compression and dehydration CO_2 recovery facility based on budgetary vendor quotes and Trimeric in-house data as well as the total installed cost for the facility assuming a scaling factor of 2.3 to get from purchased equipment costs to total installed capital costs. The costs shown in Table 2 assume that the blower and reciprocating compressor have installed spares.



Equipment Description	Purchased Equipment Cost	Total Installed Cost
Blower B-101 Skid	\$1,360,000	\$3,128,000
Blower B-102 Skid (Spare)	\$1,360,000	\$3,128,000
CO ₂ Compressor C-201 Skid	\$2,680,000	\$6,164,000
CO ₂ Compressor C-202 Skid (Spare)	\$2,680,000	\$6,164,000
TEG Dehydration Unit	\$625,000	\$1,438,000
Cooling Tower	\$292,000	\$584,000
Total	\$8,997,000	\$20,606,000

Table 2. Estimated Purchased Equipment Costs and Total Installed Capital Costs for CO2 Recovery Facility.

2 Facility Designs Considered

Three different CO_2 recovery facility designs were considered for this project. Each design captured most of the CO_2 but treated the CO_2 to remove varying levels of impurities in order to meet different product CO_2 requirements. A brief description of each facility design follows with some discussion on the reasons for accepting or rejecting the design from consideration. The facility design ultimately chosen for this project is a compression and dehydration facility, which removes only water from the feed stream for CO_2 intended for injection into a subsurface formation for permanent storage.



2.1 Food and Beverage Grade Facility

The first design considered for recovering the CO_2 emitted from the RTE ethanol facility was a food and beverage grade CO_2 plant. This plant design produces the highest value CO_2 in the form of a pressurized and refrigerated liquid that is typically transported from the plant by truck to customers. The CO_2 produced from this plant is suitable for human consumption and as a result, must meet stringent purity requirements that necessitate the installation of additional unit operations to remove trace impurities. A block flow diagram of a typical food grade facility is shown in Appendix A.

In the food grade plant design, CO_2 from the PK-3801 CO_2 Scrubber is compressed by a blower and then in a 2-stage oil-flooded screw compressor from approximately 17 psig to approximately 400 psig. The compressed gas stream is cooled and condensed water is removed from the gas stream before flowing to a series of unit operations designed to remove trace levels of impurities from the CO_2 . These unit operations vary depending upon the impurities in the source CO_2 but for an ethanol facility the typical unit operations include:

- Water Wash Column to remove any residual alcohols and aldehydes in the gas stream. The water supplied to this column is usually once-through water to prevent impurities from concentrating in the water.
- Sulfur Guard Beds to remove any trace sulfur compounds from the gas stream.
- Carbon Beds to remove trace large hydrocarbons (C5 and greater) from the gas stream.
- Molecular Sieve Beds to remove essentially all of the water vapor remaining in the gas stream.

Downstream of the Molecular Sieve Beds, the gas stream is condensed to a liquid in a heat exchanger that utilizes a refrigeration unit (typically ammonia, propane, or some other refrigerant) as the medium to liquefy the gas. Liquid CO_2 flows into a distillation column where the remaining inert light gases such as oxygen and nitrogen are stripped out of the liquid and vented to the atmosphere. The purified, liquid CO_2 flows into storage tanks for eventual trucking to customers.



Anticipated total installed capital costs and operating power estimate for the food grade CO_2 recovery plant design are shown in Table 3.

 Table 3. Food and Beverage Grade CO2 Recovery Facility Estimated Total Installed

 Capital Cost and Power Requirements.

Facility Design	Total Installed Capital Cost (Millions)	Power Requirement (kWh/Tonne)
Food/Beverage Grade CO ₂ Facility	\$15.7	152.5

The food grade CO₂ recovery plant design was not selected for this project for the following reasons:

- Uncertain market conditions. The food/beverage grade CO₂ market is highly regional and seasonal. The saleable price for the product CO₂ depends heavily on local demand and the proximity of other surrounding food and beverage grade CO₂ plants. The logistical costs for transporting the liquid CO₂ from the source to customers factors heavily into the anticipated profitability of the facility and no major efforts were undertaken to identify a market for food or beverage grade CO₂ in proximity to the RTE facility.
- High capital costs. The beverage and food grade CO₂ recovery facility has the highest capital cost of the options considered.
- High operating power costs. The compression requirements for the CO₂ are less than other facility designs because the final product is only compressed to approximately 400 psig, but the compression required for the refrigeration unit that liquefies the CO₂ is significant and drives the electrical costs upwards.

2.2 EOR / Pipeline Grade Facility

The second design considered for recovering CO_2 emitted from the RTE facility was an enhanced oil recovery CO_2 plant (EOR plant). The EOR plant produces a middle grade of CO_2 that is suitable for injection into oil producing formations and transportation by common carrier



pipelines in the U.S. The CO₂ acts as a solvent in the formation, pressurizing the oil field and allowing for deeper extraction of the residual oil in the formation after water-flood operations. EOR is a widely-practiced method for extracting crude oil from the ground in the United States and is typically delivered to the oil field via pipeline with the CO₂ at dense phase conditions, which is above the critical pressure of 1,070 psia. CO₂ needs to have some impurities removed from it in order to be suitable for injection into oil formations for EOR and common carrier CO₂ pipelines typically impose limits on water content, oxygen, and other components, but these limits are less stringent than for food and beverage grade CO₂. A block flow diagram of a typical EOR grade CO₂ recovery facility is shown in Appendix A.

In the EOR grade plant design, CO_2 from the PK-3801 CO_2 Scrubber is compressed by a blower and then a 2 stage oil-flooded screw compressor from nearly ambient pressure up to approximately 400 psig. The compressed gas stream is cooled and condensed water is removed from the gas stream before flowing to Molecular Sieve Beds to remove essentially all of the remaining water vapor in the gas stream. Downstream of the Molecular Sieve Beds, the gas stream is cooled to the liquefaction point by a heat exchanger that utilizes a refrigeration unit (typically ammonia, propane, or some other refrigerant) as the medium to liquefy the gas. Liquid CO_2 flows into a distillation column where the remaining inert light gases such as oxygen and nitrogen are stripped out of the liquid and vented to the atmosphere. The liquid CO_2 from the bottom of the distillation column is pumped up to delivery pressure and may be slightly heated before entering the EOR pipeline.

Anticipated total installed capital cost and operating power estimates for the EOR grade CO₂ recovery plant design are shown in Table 4.

Table 4.	EOR Grade CO ₂ Recovery Facility Total Installed Capital Cost and Power
	Requirement Estimates.

Facility Design	Total Installed Capital Cost (Millions)	Power Requirement (kWh/Tonne)
EOR CO ₂ Facility	\$14.7	152.1



The EOR grade CO₂ recovery plant design was not selected for this project for the following reasons:

- Insufficient pipeline infrastructure and low CO₂ product volumes. EOR grade CO₂ is typically transported to the oil field by pipeline in large volumes at high pressures. While North Dakota has significant oil reserves, not many of those reserves are currently at a point where EOR is an attractive option and the existing CO₂ pipeline networks in this area of the country coming into the North Dakota/Montana area such as Denbury's Greencore pipeline travel northwards from Wyoming into the Bell Creek area or head north from the Dakota Gasification Company facility into Canada. As a result, the RTE CO₂ is somewhat isolated from current infrastructure and justifying an additional investment in pipelines would likely require a larger CO₂ source than RTE.
- High capital costs. The EOR grade CO₂ recovery facility has a higher capital cost than the facility that produces CO₂ suitable for injection and produces a product that has less value than the food/beverage grade CO₂.
- High operating power costs. Similar to the food and beverage grade CO₂ recovery facility, the power required for the refrigeration circuit that liquefies the CO₂ in the EOR grade facility is significant and drives the electrical costs upwards.

2.3 Facility for Producing Injection Grade CO₂

The third and final design considered for recovering the CO_2 emitted by the RTE facility was a facility designed to produce CO_2 suitable for injection into an underground storage formation. The CO_2 produced in this process is not suitable for further use beyond injection and other than water, retains most of the impurities present in the source CO_2 . This type of facility is what is currently installed at the ethanol plant operated by Archer Daniels Midland in their Decatur, IL complex. A block flow diagram of the facility producing CO_2 suitable for injection can be found in Appendix A.

In this process, CO_2 from the PK-3801 CO_2 Scrubber is compressed by a blower and then further compressed by a four-stage reciprocating compressor to the required injection pressure.



Between stages of the reciprocating compressor, the gas stream is cooled and condensed water is removed from the gas stream. After the 3^{rd} stage of compression, the gas stream flows through a packed tower that contacts the gas with TEG. At this pressure, water content in CO₂ is at a natural minimum which reduces capital and operating costs of the dehydration unit, but solubility of TEG in CO₂ is still low enough for economic operation. TEG losses would be too high in the CO₂ at the outlet of the fourth stage. The TEG absorbs water vapor present in the gas stream and dehydrates the gas to an extent that it is suitable for downstream equipment to be constructed from carbon steel.

Anticipated capital costs and operating power estimate for the CO_2 recovery plant design producing CO_2 for injection are shown in Table 5.

Table 5.	Total Installed C	apital and Power	· Requirement	Estimates for	CO ₂ f	or Injection.
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Facility Design	Total Installed Capital Cost (Millions)	Power Requirement (kWh/Tonne)
Facility to Inject CO ₂ to Sequestration Well	\$13.1	111.8

The CO_2 recovery facility design that produces CO_2 for injection was selected for this project for the following reasons:

- 1. Low capital costs and operating cost requirements. The facility design has the lowest capital and operating power requirements of the designs considered for this project.
- 2. This approach has been proven on several other projects.
- Limited exposure to additional markets. In this design, RTE benefits from the CO₂ injection through incentives tied to the sale of their ethanol in markets that encourage minimizing CO₂ production. There is no need to sell the produced CO₂ itself.
- 4. Limited infrastructure requirements. The CO₂ injection well will likely be located on RTE's existing property, which will minimize the distance for a pipeline and limit the costs required to route a pipeline through private or public land that RTE does not control. Similarly, there will be no costs associated with trucking liquid CO₂ product off


site for this design. The CO_2 will be captured, processed, measured, and disposed of on RTE's property limits.

3 Facility Design Requirements

The capture facility will receive CO_2 that is currently vented to the atmosphere from the PK-3801 CO_2 Scrubber. This is the only tie-point to the existing RTE facility's process stream. Further details regarding the utilities required and the ambient conditions for the CO_2 recovery facility can be found in the Process Design Basis, issued on March 9, 2017.

3.1 Inlet CO₂ Conditions

The inlet composition for the feed stream to the CO_2 recovery facility is shown in Table 6.

Species	Mole Percent (Dry Basis)
Carbon Dioxide	99.9865
Oxygen	0.0135
Nitrogen	0

Table 6. Inlet Composition for Feed Stream to CO₂ Recovery Facility.

The compositions shown in Table 6 are based upon earlier stack sampling analyses completed by RTE and by efforts to characterize the feed stream during this project. This composition is on a dry basis, but the stream is saturated with water vapor. This stream is not considered fully characterized at this point and further work would be necessary to identify all species present in the inlet gas stream if this project moves forward. However, this information is adequate for the current stage of the project.

The conditions and flow rate for the inlet feed stream to the CO_2 recovery facility are shown in Table 7.



Parameter	Min	Max	Normal	Units
Flow Rate	294	587	495	MTD
Flow Rate	5.6	11.2	9.4	MMSCFD
Pressure	3	24	10	in. H ₂ O
Temperature	37	80	43	°F
PK-3801 Scrubber DP			5.84	in. H ₂ O

 Table 7. Inlet Conditions for CO2 Recovery Facility

The inlet flow rate, temperature, and Scrubber differential pressure are based upon historical operating data from the RTE facility. The minimum flow rate is the assumed turndown of the facility (approximately 50%), which is based upon the ability to deactivate the reciprocating compressor's head ends and reduce the energy consumption of the compressor. The minimum and maximum pressures are based on the set points of the PV/RV valves on the RTE fermenter tanks.

3.2 <u>Product CO₂ Specifications</u>

The specifications for the CO_2 produced by the facility will depend upon the use of the CO_2 . For this project, the CO_2 for injection has minimal purity requirements and as a result, the only component removed from the inlet gas stream is water. Table 8 shows the CO_2 purity specification at the discharge of the CO_2 recovery facility.

Component	Purity Specification
Water	Typical Operation 7-10 lb/MMSCF (147-211 ppmv)
	Alarm at 15 lb/MMSCF (316 ppmv)
	Shut Down at 30 lb/MMSCF (633 ppmv)

Table 8. CO₂ Purity Specifications at the CO₂ Recovery Facility Discharge.

The conditions and flow rate for the product from the CO_2 recovery facility are shown in Table 9.



Delivery Parameter	Project Design Requirement
Maximum Flow Rate ¹	Maximum total flow at plant inlet 587 MTD (11.2 MMSCFD)
Minimum Flow Rate ^{1,2}	Minimum total flow rate at plant inlet 294 MTD (5.6 MMSCFD)
Normal Pressure at	1,500 psig (maximum) at normal delivery temperature
Injection Wellhead	
Maximum Temperature	100 °F (maximum) Assuming cooling water available for process
at Inlet to Pipeline	cooling
Minimum Temperature at	No minimum temperature specification and cannot be controlled
Injection Wellhead	without additional unit operations.

Table 9.	CO ₂ Recovery	v Facility	Deliverv	Require	ments Duri	ng Normal	Operation.
I unic 71		' i acmey	Denvery	nequire	mento Duri	ing i wi mai	operation

1. Maximum and minimum flow rates based on the total inlet stream containing CO₂, water, and any trace contaminants.

2. Minimum flow rate assumes reciprocating compressor head end deactivation. Lower rates may be possible but could result in recycle and/or local venting with higher than normal injection electricity costs on a kWh/tonne basis.

4 Design of Chosen Facility

The CO_2 recovery facility that produces CO_2 for injection is a straight-forward design that has been implemented successfully in several different locations in the United States. The main equipment for the facility includes a multistage centrifugal blower, a four-stage reciprocating compressor, and a dehydration unit. This equipment configuration yields a facility that is easy to operate, easy to start up and shut down, and has a low operating cost relative to the other facility designs considered for this project.

Trimeric completed an early phase process simulation of this facility in VMGSim, utilizing the APR for Natural Gas equation of state, which has been shown to accurately predict CO_2 behavior above and below the critical point. A process flow diagram of this simulation is shown in Appendix B and the accompanying heat and material balance for this simulation can be found in Appendix C.

4.1 Major Equipment Design

This section details some of the high level design considerations for the major equipment in the CO_2 recovery facility that produces CO_2 suitable for injection. Trimeric obtained budgetary



quotes from some vendors as part of this initial design effort in order to bolster the confidence in the overall cost estimate for the CO_2 recovery facility.

4.1.1 Blower, B-101

The Blower B-101 is a multistage centrifugal blower that compresses CO_2 from the PK-3801 CO_2 Scrubber from near-ambient pressure up to approximately 17 psig. The blower is a skidmounted piece of rotating equipment that has an inlet separator, aftercooler, and discharge separator associated with it. The inlet separator operates at or near ambient pressure so disposing of liquid that collects in the bottom of the separator requires a small pump to generate enough head to drain the vessel. The gas stream heats up as it is compressed by the blower and the aftercooler cools the gas stream down by exchanging heat with cooling water. Any water condensed out of the gas stream as it cools is removed in the discharge separator. Table 10 shows some key parameters of the blower and associated equipment.

Parameter	Value
Blower B-101 Brake Horsepower	642 hp
Blower B-101 Discharge Pressure	17 psig
Blower B-101 Discharge Temperature	220 °F
Blower Aftercooler E-101-01 Cooling Water	158 gpm
Required	

 Table 10.
 Blower B-101 Operating Details.

4.1.2 CO₂ Compressor, C-201

From the Blower skid, the gas stream flows into the CO_2 Compressor, C-201 and its associated equipment. The CO_2 Compressor is a four-stage reciprocating compressor that is a skid-mounted



piece of equipment that has associated separators and heat exchangers for each stage of compression. The separators may or may not be mounted on the compressor skid, depending upon their size while the heat exchangers are typically shipped loose. After each stage of compression, the hot discharge gas is cooled in a heat exchanger and any condensed water is removed in a separator before the gas stream is compressed by the next stage. Table 11 shows some key process parameters of the CO_2 Compressor and its associated equipment; the total estimated brake horsepower for the compressor is 2,465 hp.

As shown in Table 11, the CO2 leaving each stage of compression is very hot. It is well above the water dew point, which often allows use of carbon steel from the outlet of the compression stage to the inlet of the cooler. Stainless steel or other corrosion resistant materials are typical on the process side of the cooler up to the inlet of the next stage of compression until the CO_2 goes through the dehydration unit. Proper purging following shutdowns is important for management of corrosion issues. Reciprocating compressor skids require sturdy foundations and adequate supporting of piping and other components in order to avoid vibration and stress issues. A pulsation study and a torsional analysis are often required to properly design and construct these units.

Parameter	Stage 1	Stage 2	Stage 3	Stage 4
Inlet Pressure (psia)	35.5	88	243	608
Inlet Temperature (°F)	85	85	85	85
Outlet Pressure (psia)	90	245	620	1527
Outlet Temperature (°F)	243	244	237	241
Stage Brake Horsepower (hp)	706	678	586	495
Cooling Water Required (gpm)	179	202	180	452

Table 11.	CO ₂ Compressor	C-201	Operating Details.
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4.1.3 TEG Dehydration Unit

The dehydration unit included in the design for this project is a triethylene glycol (TEG) dehydration unit that brings the wet gas stream into the bottom of a countercurrent absorber and a stream of lean (low water content) TEG into the top of the absorber. The liquid TEG flows down the absorber and absorbs water vapor from the gas as it flows up through the absorber, thereby drying the gas stream well below its saturation point. The TEG that has absorbed the water from the gas stream (referred to as rich TEG) flows from the bottom of the contactor to a regeneration system where the pressure is reduced and the TEG is heated to about 375 °F to liberate the water from the TEG. Water vapor from the regeneration system is vented to atmosphere. A process flow diagram for a typical TEG dehydration unit is provided in Appendix D. The regeneration equipment is skid-mounted while the contactor and, if necessary, an inlet separator would be shipped loose and mounted on their own foundations. Table 12 shows some key process parameters of the TEG dehydration unit.



Parameter	Value
TEG Circulation Rate	1.85 gpm
Required Reboiler Duty	78,000 Btu/hr
Required Reboiler Energy	175 SCFH (Natural Gas for Fired Heater)
	50 kW (Electric Heater, Technology
	Recommended by Vendor)
Outlet Gas Water Content	10 lb/MMSCF

 Table 12. TEG Dehydration Unit Operating Details.

4.1.4 Cooling Tower

The RTE facility has an existing cooling tower for the ethanol process, but after discussion with RTE personnel, it was determined that the existing cooling tower does not have excess water flow or heat capacity to handle the additional cooling requirements of the CO_2 recovery facility. As a result, this project assumes that a new cooling tower and cooling water pumps will be required for the CO_2 recovery facility. The cooling tower details shown below assume that the blower and CO_2 compressor will have installed spares with cooling water available for them. See Section 4.3 for the discussion regarding sparing of major rotating equipment. Table 13 shows some key operating parameters for the cooling tower.



Parameter	Value
Cooling Water Circulation Rate	2,370 gpm
Cooling Water Make Up Rate	40 gpm
Cooling Water Temperature Rise	13 °F

Table 13. Cooling Tower Operating Details.

4.2 Equipment Location

Due to the low operating pressure of the fermenter tanks (typically less than 1 psig), it will be necessary to locate at least a part of the CO_2 recovery facility close to the fermenter tanks and CO_2 Scrubber PK-3801. There is sufficient space at the RTE site directly to the west for the entire CO_2 recovery facility, but RTE is saving this space for additional fermentation tanks if the facility decides to expand in the future. As a result, only the blower skid will be located by the fermentation tanks. The reciprocating compressor skid and the dehydration unit will be located to the east of the heat medium building, in the area between the coal processing building and the existing cooling tower. The new cooling tower may be located next to the existing cooling tower; however a final location for this equipment is not known at this time, nor is it critical at this stage of the project.

The estimated piping distance between the blower skid and the reciprocating compressor skid is 1,000 feet. A new, 16" Sch. 10S pipe will be run through the RTE facility's existing main east/west pipe rack between the two skids. Additional cooling water lines may be run through this pipe rack as well, or buried underground. The suitability of the existing pipe rack for this new line will be assessed in a later phase of the project.

The estimated piping distance between the CO_2 recovery facility and the injection well is 0.5 miles, or 2,640 feet. A new, 4" Sch. 80 carbon steel pipe will be run from the facility to the injection wellhead to transport the compressed, dehydrated CO_2 . This pipe can be installed



aboveground or underground, as RTE prefers but Trimeric would recommend insulating the pipeline if it is installed aboveground. CO_2 at 1,500 psig will be very sensitive to ambient temperature changes since the density of the high pressure CO_2 fluid is strongly influenced by the temperature of the fluid. Pressure variations in the well from the surface to the point of injection could otherwise result from CO_2 density changes in an uninsulated above-ground pipeline and these pressure variations may be detrimental to the long-term stability of well casing cement.

Trimeric recommends that the CO_2 recovery facility be installed indoors in a building that can maintain a temperature of at least 60 °F in the winter months. Any equipment installed outdoors should be insulated and heat-traced. The formation of hydrates in the process or even liquid CO_2 is a possibility at cold ambient temperatures, and formation of these compounds or liquids can lead to plugging or even catastrophic equipment damage.

4.3 Sparing of Major Equipment

RTE has requested that the CO₂ recovery facility be designed for less than 10 days of downtime per year. This corresponds to an equipment uptime of 97% and this will be difficult to achieve, particularly for the reciprocating compressor, C-201. Planned maintenance for the compressor exceeds seven days of downtime annually and additional unplanned shutdowns and maintenance requirements make it unlikely that the compressor could reach that level of reliability year after year of operation. The B-101 Blower may also have difficulty achieving this level of reliability if a major component (like the impeller or the electric motor) suffers a catastrophic failure. As a result, Trimeric recommends installing spare equipment for the B-101 Blower and C-201 CO₂ Compressor. Other small pieces of rotating equipment like cooling tower pumps, TEG pumps, and water disposal pumps should be spared as well but this will be a minimal cost.

4.4 **Options**

There are several options that could be considered if the project moves into the next phase of development. In previous projects, Trimeric has found that the equipment configuration presented above results in a reliable and cost-efficient facility but there are other options to



consider if the equipment price increases beyond that anticipated by RTE or if some other sitespecific factor dictates that the project make an alternate decision. These options include:

- 1. Alternative process cooling technology. If make up water is limited or unavailable, it is feasible to change the heat exchangers from water-cooled shell and tube exchangers to air-cooled exchangers. In general, air cooled exchangers require more surface area for heat transfer and more space in the facility than shell and tube heat exchangers and since the tubes for the exchangers and at least some of the interconnecting piping need to be constructed of stainless steel, it is typically more economical to minimize the size of the exchangers. Another option to consider would be to install wet surface air coolers, which can realize better heat transfer than air cooled exchangers alone. Wet surface air coolers can reduce water circulation rates relative to shell and tube heat exchangers and can sometimes operate with lower quality water than in a typical cooling tower.
- 2. Alternative dehydration unit technology. TEG dehydration units are used in a multitude of applications and have been used with success by Trimeric in previous CO₂ recovery facilities. An emerging alternative to TEG dehydration in some applications similar to the proposed RTE CO₂ recovery facility is a DexProTM unit, which recycles some of the CO₂ around one or more of the stages of compression to take advantage of the Joule-Thomson effect to cool the recycled CO₂ to a relatively cold temperature and sub cool the main CO₂ gas stream to condense additional water from the gas stream in order to meet a target moisture specification. There are limits to how far the DexPro unit can dehydrate the gas stream, but the DexPro technology may be more cost-competitive than TEG dehydration. Trimeric is aware of at least one commercial application of DexPro technology.
- 3. Alternative compression technology to increase rotating equipment reliability. Sparing of the major rotating equipment is a major cost in this project. A different compression technology, such as a centrifugal compressor, may have higher reliability than the reciprocating compressor and avoid the need for an installed spare compressor. The flow rate of CO_2 for this project is somewhat smaller than what would usually dictate the



selection of a centrifugal compressor, but the large installed cost of the spare reciprocating compressor may make a centrifugal compressor an option if the project moves forward. On a single machine basis, it is unlikely that the centrifugal compressor would be less expensive than a reciprocating compressor and the centrifugal compressor would likely not be able to turn down as far as a reciprocating compressor.

4. Limit blower installed spare cost. This project's cost estimate includes a full installed spare blower skid for the B-101 Blower, including the associated separators and aftercooler. To limit capital costs, it may be feasible to spare only the blower and blower motor and store them in a local warehouse for quick installation should the operating blower or blower motor have a problem that requires significant maintenance. Assuming that a relatively small crane is either on-site or could be brought to site quickly, it would likely only take 1-2 days to replace the blower and/or blower motor.

4.5 Estimated Facility Costs

The total installed cost of the CO₂ recovery facility, including spares of the major rotating equipment, is estimated to be \$20.6 million +/- 30%. The cost range of +/- 30% incorporates any contingencies and as a result the \$20.6 million is a total installed cost for the equipment only. Most of the equipment for the facility would be constructed off-site on skids and then the completed units would be shipped to the site. Table 14 shows the cost breakdown for the facility. The installed cost assumes that the cost installation factor for the skidded equipment would be 2.3, except for the cooling tower, which would be mostly constructed at site and has an installed cost factor of 2.



Equipment	Purchased	Total Installed
Description	Equipment Cost	Cost
Blower B-101 Skid	\$1,360,000	\$3,128,000
Blower B-102 Skid (Spare)	\$1,360,000	\$3,128,000
CO ₂ Compressor C-201 Skid	\$2,680,000	\$6,164,000
CO ₂ Compressor C-202 Skid (Spare)	\$2,680,000	\$6,164,000
TEG Dehydration Unit	\$625,000	\$1,438,000
Cooling Tower	\$292,000	\$584,000
Total	\$8,997,000	\$20,606,000

Table 14. Estimated Purchased Equipment and Total Installed Costs for CO2 Recovery Facility.

APPENDIX A

BLOCK FLOW DIAGRAMS OF CO2 RECOVERY FACILITIES







>INJECTION

N	CONCEPTUAL INJECTI CO2 PLANT SCHE	ON GRADE MATIC
	CLIENT/SITE	JOB NUMBER
	EERC – RTE FACILITY	50168.01
	DRAWING NUMBER	SCALE
	DWG-003	NONE

APPENDIX B

PROCESS FLOW DIAGRAM FOR CO2 RECOVERY FACILITY



APPENDIX C

HEAT AND MATERIAL BALANCE FOR CO_2 RECOVERY FACILITY



Name	1		2		3		4		5		6		
	CO ₂ from I	PK-3801	Liquid from	Liquid from Blower				CO ₂ Blower		CO ₂ Blower		Liquid from Blower	
Description	Scrub	ber	Inlet Sepa	arator	CO ₂ Blower Feed		Discharge		Aftrcooler Outlet		Discharge Separator		
VapFrac	1.00		0.00		1.00		1.00	-	0.98413		0.00	_	
T [F]	80.0		80.0		80.0		220.2		85.0		85.0		
P [psia]	13.80		13.80		13.80		30.80		28.80		28.80		
MoleFlow/Composition	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h	
WATER	0.03607	45.85	0.99958	0.00	0.03607	45.85	0.03607	45.85	0.03607	45.85	0.99917	20.15	
CARBON DIOXIDE	0.9638	1225.09	0.00042	0.00	0.9638	1225.09	0.9638	1225.09	0.9638	1225.09	0.00083	0.02	
OXYGEN	0.00013	0.17	0.00	0.00	0.00013	0.17	0.00013	0.17	0.00013	0.17	0.00	0.00	
Total	1.00	1271.11	1.00	0.00	1.00	1271.11	1.00	1271.11	1.00	1271.11	1.00	20.17	
Mass Flow [lb/h]	54747		0		54747		54747		54747		364		
Metric Tonnes per day [MTD]	596		0		596		596		596		4		
Volume Flow [gal(US)/min]	66152		0		66152		37324		31314		1		
Std Liq Volume Flow [gal(US)/min]	133.631		0.000		133.631		133.631		133.631		0.728		
Std Gas Volume Flow [SCFD]	1.1577E+7		2.0079E-36		1.1577E+7		1.1577E+7		1.1577E+7		1.8372E+5		
Energy [Btu/h]	4.991E+6		-3.257E-36		4.991E+6		6.624E+6		4.642E+6		-2.960E+5		
H [Btu/lbmol]	3926.6		-14771.9		3926.6		5211.0		3651.9		-14675.6		
S [Btu/lbmol-F]	35.614		17.003		35.614		36.141		33.670		17.172		
MW	43.07		18.03		43.07		43.07		43.07		18.04		
Mass Density [lb/ft3]	0.1032		62.1763		0.1032		0.1829		0.2180		62.1356		
Cp [Btu/lbmol-F]	8.933		18.172		8.933		9.631		9.171		18.184		
Thermal Conductivity [Btu/h-ft-F]	0.0097		0.3521		0.0097		0.0137		0.0122		0.3541		
Viscosity [cP]	1.4948E-2		8.5812E-1		1.4948E-2		1.8238E-2		1.6900E-2		8.0836E-1		
Molar Volume [ft3/lbmol]	417.428		0.290		417.428		235.521		197.592		0.290		
Z Factor	0.9947		0.0008		0.9947		0.9944		0.9738		0.0017		



Name	7	1	8		9		10		11		12	
	GO G	G.	GO G		CO ₂ Com	pressor			60. G		00 G	
	CO_2 Compr	essor Stage	$CO_2 Com$	CO_2 Compressor		Stage I Intercooler		Stage 1	CO_2 Compressor		CO_2 Compressor	
Description	1 Fe	eed	Stage 1 Di	scharge	Outl	et	Separa	tor	Stage 2 Feed		Stage 2 Discharge	
VapFrac	1.00		1.00		0.98778		0.00		1.00		1.00	
T [F]	84.9		249.2		85.0		85.0		85.0		277.9	
P [psia]	28.20753		74.00		72.00		72.00		72.00		245.00	
MoleFlow/Composition	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h
WATER	0.02054	25.70	0.02054	25.70	0.02054	25.70	0.99791	15.26	0.00845	10.44	0.00845	10.44
CARBON DIOXIDE	0.97933	1225.08	0.97933	1225.08	0.97933	1225.08	0.00209	0.03	0.99142	1225.04	0.99142	1225.04
OXYGEN	0.00013	0.17	0.00013	0.17	0.00013	0.17	0.00	0.00	0.00013	0.17	0.00013	0.17
Total	1.00	1250.94	1.00	1250.94	1.00	1250.94	1.00	15.29	1.00	1235.65	1.00	1235.65
Mass Flow [lb/h]	54383		54383		54383		276		54107		54107	
Metric Tonnes per day [MTD]	592		592		592		3		589		589	
Volume Flow [gal(US)/min]	31972		15844		12171		1		12171		4812	
Std Liq Volume Flow [gal(US)/min]	132.904		132.904		132.904		0.553		132.351		132.351	
Std Gas Volume Flow [SCFD]	1.1393E+7		1.1393E+7		1.1393E+7		1.3924E+5		1.1254E+7		1.1254E+7	
Energy [Btu/h]	4.938E+6		6.825E+6		4.583E+6		-2.241E+5		4.807E+6		6.938E+6	
H [Btu/lbmol]	3947.4		5455.9		3663.5		-14659.0		3890.2		5614.8	
S [Btu/lbmol-F]	33.977		34.499		31.639		17.174		31.818		32.163	
MW	43.47		43.47		43.47		18.07		43.79		43.79	
Mass Density [lb/ft3]	0.2121		0.4279		0.5571		62.1812		0.5543		1.4018	
Cp [Btu/lbmol-F]	9.023		9.868		9.311		18.227		9.201		10.332	
Thermal Conductivity [Btu/h-ft-F]	0.0099		0.0146		0.0118		0.3534		0.0101		0.0160	
Viscosity [cP]	1.5189E-2		1.9068E-2		1.6663E-2		8.1061E-1		1.5350E-2		2.0040E-2	
Molar Volume [ft3/lbmol]	205.001		101.592		78.039		0.291		79.001		31.237	
Z Factor	0.9896		0.9886		0.9617		0.0042		0.9736		0.9681	



Name	13		14		15		16		17		18		19	
	CO ₂ Com	pressor							CO ₂ Com	pressor				
	Stage 2 Int	ercooler	Liquid from	Stage 2	$CO_2 Com$	pressor	CO ₂ Compr	ressor Stg	Stage 3 Int	ercooler	Liquid from	Stage 3	Dehydrati	on Unit
Description	Outl	et	Separa	tor	Stage 3	Feed	3 Disch	narge	Outl	et	Separa	ıtor	Fee	d
VapFrac	0.99431		0.00		1.00		1.00		0.99865		0.00		1.00	
T [F]	85.0		85.0		85.0		237.0		85.0		85.0		85.0	
P [psia]	243.00		243.00		243.00		620.00		618.00		618.00		618.00	
MoleFlow/Composition	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h
WATER	0.00845	10.44	0.99311	6.99	0.00281	3.45	0.00281	3.45	0.00281	3.45	0.98398	1.63	0.00149	1.82
CARBON DIOXIDE	0.99142	1225.04	0.00689	0.05	0.99706	1225.00	0.99706	1225.00	0.99706	1225.00	0.01602	0.03	0.99838	1224.97
OXYGEN	0.00013	0.17	0.00	0.00	0.00013	0.17	0.00013	0.17	0.00013	0.17	0.00	0.00	0.00013	0.17
Total	1.00	1235.65	1.00	7.04	1.00	1228.61	1.00	1228.61	1.00	1228.61	1.00	1.66	1.00	1226.96
Mass Flow [lb/h]	54107		128		53979		53979		53979		31		53948	
Metric Tonnes per day [MTD]	589		1		588		588		588		0		587	
Volume Flow [gal(US)/min]	3340		0		3340		1659		1063		0		1063	
Std Liq Volume Flow [gal(US)/min]	132.351		0.257		132.094		132.094		132.094		0.062		132.032	
Std Gas Volume Flow [SCFD]	1.1254E+7		6.4081E+4		1.119E+7		1.119E+7		1.119E+7		1.5083E+4		1.1175E+7	
Energy [Btu/h]	4.401E+6		-1.027E+5		4.504E+6		5.995E+6		3.736E+6		-2.397E+4		3.760E+6	
H [Btu/lbmol]	3562.0		-14595.2		3666.0		4879.1		3041.2		-14471.0		3064.9	
S [Btu/lbmol-F]	28.934		17.170		29.001		29.283		26.296		17.146		26.309	
MW	43.79		18.19		43.93		43.93		43.93		18.43		43.97	
Mass Density [lb/ft3]	2.0197		62.3543		2.0151		4.0576		6.3291		62.6820		6.3259	
Cp [Btu/lbmol-F]	10.061		18.389		10.014		11.251		13.764		18.690		13.757	
Thermal Conductivity [Btu/h-ft-F]	0.0118		0.3507		0.0110		0.0165		0.0138		0.3457		0.0136	
Viscosity [cP]	1.6385E-2		8.1908E-1		1.5771E-2		1.9951E-2		1.7399E-2		8.3476E-1		1.7246E-2	
Molar Volume [ft3/lbmol]	21.680		0.292		21.803		10.828		6.942		0.294		6.951	
Z Factor	0.9031		0.0143		0.9082		0.9015		0.7407		0.0364		0.7417	



Name	20		21		22		23		24	
	Steam	rom	$CO_2 Com$	pressor	$CO_2 Com$	pressor	Stage 4 Aft	ercooler		
Description	Dehydrati	on Unit	Stage 4 Feed		Stage 4 Discharge		Outlet		At Injection	
VapFrac	1.00		1.00		1.00	<u> </u>	0.00		0.00	
T [F]	220.0		85.4		240.9		85.0		84.8	
P [psia]	13.80		608.00		1527.00		1525.00		1516.09272	
MoleFlow/Composition	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h	Fraction	lbmol/h
WATER	1.00	1.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CARBON DIOXIDE	0.00	0.00	0.99986	1224.97	0.99986	1224.97	0.99986	1224.97	0.99986	1224.97
OXYGEN	0.00	0.00	0.00014	0.17	0.00014	0.17	0.00014	0.17	0.00014	0.17
Total	1.00	1.82	1.00	1225.13	1.00	1225.13	1.00	1225.13	1.00	1225.13
Mass Flow [lb/h]	33		53916		53916		53916		53916	
Metric Tonnes per day [MTD]	0		587		587		587		587	
Volume Flow [gal(US)/min]	0		1090		577		136		136	
Std Liq Volume Flow [gal(US)/min]	0.066		131.967		131.967		131.967		131.967	
Std Gas Volume Flow [SCFD]	1.6597E+4		1.1158E+7		1.1158E+7		1.1158E+7		1.1158E+7	
Energy [Btu/h]	-2.671E+4		3.787E+6		5.047E+6		-6.067E+5		-6.067E+5	
H [Btu/lbmol]	-14655.9		3091.2		4119.8		-495.2		-495.2	
S [Btu/lbmol-F]	17.154		26.343		26.613		18.924		18.927	
MW	18.02		44.01		44.01		44.01		44.01	
Mass Density [lb/ft3]	62.1416		6.1691		11.6569		49.3292		49.2995	
Cp [Btu/lbmol-F]	18.134		13.540		14.864		36.632		36.798	
Thermal Conductivity [Btu/h-ft-F]	0.3549		0.0135		0.0217		0.0528		0.0528	
Viscosity [cP]	8.0644E-1		1.7207E-2		2.3410E-2		7.2548E-2		7.2459E-2	
Molar Volume [ft3/lbmol]	0.290		7.134		3.775		0.892		0.893	
Z Factor	0.0355		0.7480		0.7778		0.2470		0.2459	

APPENDIX D

PROCESS FLOW DIAGRAM FOR TYPICAL TEG DEHYDRATION UNIT



APPENDIX C

CO₂ PIPELINE

PIPELINE INFRASTRUCTURE

PIPELINE SIZING

The Red Trail Energy, LLC (RTE) facility produces about 180,000 short tons (163,300 tonnes) of CO₂ annually. Geologic modeling results have indicated that the CO₂ pressure at the target injection site should be about 1500 psi. RTE plans to transport the dried and compressed CO₂ to the injection site on its property through a pipeline. At this time, the exact distance between the capture, dehydration, and compression facility and the injection point is unknown, thus it was assumed that the pipeline will be about 1 mi in length. Pipeline diameter was estimated using the U.S. Department of Energy (DOE) Fossil Energy/National Energy Technology Laboratory (FE/NETL) CO₂ Transport Cost Model.¹ The model calculates the net present value for a project that transports liquid CO₂ by carbon steel pipeline. The user provides a variety of inputs, including the annual mass of CO₂ to be transported, the pipeline length, and the inlet and delivery pressures as well as the years of operation and financial parameters.

While very useful for estimating the cost of pipeline transport for large volumes of CO_2 at supercritical conditions, the model is not set up to estimate the costs as they would apply to RTE because the model cannot assume the use of pipe that is less than 8 in. in diameter. For the smaller quantity of CO_2 produced by RTE, this is likely too large a pipe.

The Carnegie Mellon Integrated Environmental Control Model (IECM) was used to verify that a 4-in.-diameter pipe would be sufficient for the RTE CO_2 stream. The IECM is typically employed to model power plants both with and without the addition of CO_2 capture and to model the transport of a compressed CO_2 stream. The IECM was configured to provide a CO_2 stream that was about the same mass as that of the RTE stream. The pressure was set at 1100 psi, the lowest pressure at which the IECM models are accurate. This pressure is slightly below the minimum pressure at which CO_2 becomes supercritical, meaning that it would still be in the gas phase. The IECM showed that 4-in.-diameter would be the preferred size for transport of the RTE CO_2 .

PIPELINE COSTS

The FE/NETL model was then used to provide a rough estimate of the capital expenses and operating costs associated with the RTE pipeline. Four different pipeline inlet pressures were modeled in order to get an understanding of the variation that could be expected in the cost. Pressures of 850, 1250, 1450, and 2050 psi were modeled, with corresponding delivery pressures of 800, 1200, 1400, and 2000 psi, respectively. In all four cases, the model estimated that the smallest size pipe (8 in.) would be sufficient, meaning that the costs were the same. Because the IECM had shown that a 4-in. pipe would be appropriate, the FE/NETL model pipe diameter was overridden to show the cost results of using 4-in.-diameter pipe operating at 1500 psi. The pipeline costs estimated by the FE/NETL model are shown in Table C-1.

¹ www.netl.doe.gov/research/energy-analysis/analytical-tools-and-data/co2-transport.

Component	Cost	
Installed Pipeline ^b	\$1,187,000	
Control System	\$112,000	
Total Capital Expenses	\$1,299,000	
Pipe O&M ^c	\$8,500	
Related Equipment O&M	\$54,300	
Total Operating Expenses	\$62,800	

 Table C-1. Estimated 4-inch Pipeline Costs (in 2011 dollars)
 for the RTE CO₂ Stream^a

^a Assuming a booster pump is not required to maintain pressure within the pipeline.

^b Includes material, labor, ROW (right-of-way)-damages, and miscellaneous costs.

^c Operating and maintenance costs.

A second approach was taken to estimate the pipeline costs using Oil & Gas Journal (OGJ) data from 2015. Because no CO₂ pipelines were included in the OGJ data set, natural gas pipeline information was utilized. Thirty-three pipelines constructed in the United States in 2015 were evaluated. They ranged from 4 in. to 42 in. in diameter and were 1.2 to 292.8 mi in length. A cost in \$/in. diameter per mi in length was determined for materials and labor costs only for each pipeline. An average cost was determined for smaller-diameter pipelines that were not located in high-population areas. The average cost for materials and labor was \$79,850/in.-mi. For a pipeline at the RTE site, the expected cost for materials and labor for a 4-in., 1-mi pipeline would be an estimated \$324,000 using this method. Table C-2 shows the capital costs as estimated by three different methods available within the DOE cost model.

Table C-2. DOE Pipeline Cost Model Results										
Estimation Method	Parker	McCoy and Rubin	Rui and others							
Installed Pipeline ^a	\$1,187,000	\$569,000	\$324,000							
Control System	\$99,000	\$99,000	\$99,000							
Total Capital Expenses	\$1,286,000	\$668,000	\$423,000							
Pipe O&M ^b	\$8,500	\$8,500	\$8,500							
Equipment O&M	\$46,900	\$46,900	\$46,900							
Total Operating Expenses	\$55,400	\$55,400	\$55,400							

^a Materials, labor, ROW-damages, and miscellaneous costs in 2016 dollars.

^b Annual operating and maintenance costs.

Sampling of the CO₂ stream at the RTE facility showed that the stream may contain about 218 ppmw of oxygen. Oxygen can corrode carbon steel (particularly in the presence of small amounts of water), so oxygen limits for carbon steel pipelines have generally been set at about 10 ppmw. It is very expensive to remove oxygen from a CO_2 stream, so it is assumed that the

oxygen will be present in the CO_2 that is transported through the pipeline to the injection site. Possible pipeline options for mitigation include:

- Use of a thicker-walled carbon steel pipe.
- Coating the interior of the pipeline with Teflon or other material.
- Adding an impervious liner sleeve to the pipeline.
- Using nonsteel pipe material, such as fiberglass (produced by Fiberspar) or a highdensity polyethylene and steel combination such as is produced by FlexSteel.

APPENDIX D

SITE CHARACTERIZATION

CHARACTERIZATION

SITE CHARACTERIZATION

Existing site characterization data for both the surface and subsurface environment near the Red Trail Energy (RTE) ethanol facility were evaluated for use in geologic modeling for CO_2 storage design, siting of potential injection well locations, and the development of a groundwater monitoring program. Surface structures and features were identified, such as existing wells, water resources, and property boundaries. Based on previous research completed by the Energy & Environmental Research Center (EERC) (Sorensen and others, 2009; Peck and others, 2014), the Broom Creek Formation, a sandstone formation saturated with highly saline water (> 100,000 ppm) located directly underneath the RTE site, was determined to be the most suitable reservoir for CO_2 injection and storage. The Broom Creek Formation exhibits geologic characteristics necessary for permanent CO_2 injection and storage, such as good porosity and permeability, sufficient thickness, depth, and the presence of upper and lower sealing formations.

The surface environment was assessed to identify land use, sensitive areas, and local population characteristics within a 2-mile radius of the RTE facility (Figure D-1). Within the 2-mile radius, five wells were identified, consisting of three domestic/groundwater wells, one municipal well, and one oil and gas well. The RTE facility is located near the town of Richardton, North Dakota (population 524) and is surrounded mainly by agricultural land. Interstate 94 is immediately adjacent to the site, and federal grasslands are located a few miles to the north. The proximity of these features is an important factor influencing the determination of a pipeline route; placement of monitoring and CO₂ injection wells; and development of the monitoring, verification, and accounting (MVA) plan.

Review and interpretation of available literature and data further support the suitability of the Broom Creek and associated sealing formations for CO₂ storage at the RTE site. Data collection was focused on regional wells that penetrate the Broom Creek Formation. Types of data included well depth, formation tops, well logs, and core analyses. Lithologies and facies specific to the Broom Creek and associated formations were also assessed to determine regional petrophysical properties for porosity and permeability distributions. Based on these data, the estimated thickness of the Broom Creek Formation in this region ranges from 243 to 312 feet, and its permeability ranges from 71 to 490 mD.

GEOLOGIC SETTING

Understanding the geologic characteristics of the storage complex is an essential aspect for the successful storage of CO₂ for any site. A storage complex refers to a geologic system comprising a storage unit and primary (and sometimes secondary) seal(s), extending laterally to the defined limits of the CO₂ storage operation(s) (Canadian Standards Association, 2012). The following sections discuss relevant characteristics of the CO₂ storage complex identified at the RTE site.



Figure D-1. Surface features at the RTE site.

The RTE facility is located in western North Dakota in the central portion of the Willison Basin, a large, roughly circular, intracratonic basin. This basin covers approximately 150,000 square miles of eastern Montana, western North Dakota, northwestern South Dakota, and southern Saskatchewan and Manitoba. The Williston Basin contains in excess of 16,000 feet of sediment near the depocenter in western North Dakota (Figure D-2).

Based on previous regional research completed by the EERC (Sorensen and others, 2009; Peck and others, 2014), the Broom Creek Formation was determined to be the most suitable storage complex reservoir for the RTE site. The Broom Creek Formation exhibits geologic characteristics necessary for successful CO₂ injection and storage, including appropriate porosity and permeability, sufficient thickness and depth, and the presence of upper and lower sealing formations. Regionally, the Broom Creek Formation consists of eolian and nearshore marine sandstone-carbonate cycles and constitutes the uppermost formation of the Minnelusa Group (Figure D-1) in the Williston Basin (Willis, 1959). At the RTE site, the Broom Creek Formation is approximately 6400 feet below the land surface, is approximately 280 feet thick (Figure D-2),



Figure D-2. Williston Basin stratigraphic and hydrogeologic column (modified from Glazewski and others, 2015)

and is composed predominantly of sandstone with interbedded dolostone and anhydrite. Overlying the Broom Creek Formation is the Opeche Formation (Figure D-2), a shale formation that is approximately 100 feet thick and forms the storage complex's primary seal. Many additional low-permeability formations are present above the primary seal which create secondary barriers to protect overlying underground sources of drinking water (USDW) in the region. The Amsden Formation forms the underlying seal for the site and is composed of dolostone and anhydrite.

STRUCTURAL FEATURES

The Williston Basin is considered tectonically stable, with a gentle structural character (Gerhard and others, 1982; Fischer and others, 2005). A north and northwest structural trend is known within the basin and includes structures of the Nesson, Billings, and Antelope Anticlines and the Heart River Fault (Figure D-3). The Heart River Fault is located approximately 3 miles to the southwest of the RTE plant (Figure D-4), and its proximity to the RTE site makes it a feature of particular note.

Existing well and seismic data provide some context for understanding the Heart River Fault. The Heart River Fault is a northwest-southeast trending sinuous feature located in the southeastern portion of the Williston Basin in North Dakota. A published 2-D seismic survey (Figures D-4 and D-5), located south of the RTE plant, gives some information about the fault in the RTE study area. The fault is a high-angle reverse fault, seated in the Precambrian crystalline basement, with the upward block being on the east. Fault offset is interpreted to be less than 400 feet in rocks up through the Upper Ordovician to Lower Silurian age, well below the Broom Creek Formation. Formations above the Lower Silurian show flexure from the fault but do not appear to be offset (Chimney and others, 1992). Available data and knowledge indicate the Heart River Fault system does not penetrate the Broom Creek; therefore, the risk of vertical fluid migration due to any potential fault activation is negligible.

Scientific investigations, to this point, indicate most cases of induced seismicity are associated with fluid injection directly into granitic basement rock or into overlying formations with hydraulic conductivity to such basement rock (Ground Water Protection Council and Interstate Oil and Gas Compact Commission, 2015). Thousands of feet of sedimentary rock separate the Broom Creek Formation (i.e., planned injection horizon) from Precambrian crystalline basement rock, with seismic data showing no means for direct fluid communication (faults) between them. North Dakota also has an extensive history with injection of water produced from oil and gas operations. As of 2015, nearly 440 million barrels of water has been injected into North Dakota disposal wells (mostly in a different formation) (Kurz and others, 2016), without a notable increase in seismic events.

In fact, there are very few recorded seismic events for North Dakota in general. A 1-year seismic forecast (including both induced and natural seismic events) released by the U.S. Geological Survey in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (Petersen and others, 2016). No events with a magnitude greater than 3.3 on the Modified Mercalli Intensity (MMI) scale have been recorded within 100 miles of the RTE site (Figure D-6). This indicates relatively stable geologic conditions in the region surrounding the potential injection site.



Figure D-3. RTE location in relation to the extent of the Broom Creek Formation and structural features of the Williston Basin.



Figure D-4. Map of the Heart River Fault near the RTE plant. Blue line labeled 3022 is a published 2-D seismic line interpretation along the Heart River Fault.


Figure D-5. 2-D seismic line 3022 intersecting the Heart River Fault (Chimney and others, 1992). Identified formations: Ordovician Winnipeg (OWP: yellow), Mississippian Mission Canyon (MMC: red), Jurassic Piper Lime (JPL: blue), Cretaceous Green Horn (KGH: green), and Cretaceous Niobrara (KN: orange). The Broom Creek Formation, not interpreted in the diagram, is approximately halfway between the MMC and JPL horizons. Faulting offset is observed in the OWP horizon, but only slight flexure is observed in other overlying interpreted horizons.



Figure D-6. Recorded seismic events from the year 1900 to present with magnitudes on the MMI scale greater than 2.5 in North Dakota. Numerical values indicate the magnitudes associated with events. (U.S. Geological Survey, 2017).

HYDROGEOLOGY

Downey and others (1987) divided the stratigraphy of the Williston Basin into five regional aquifers with four regional aquitards (Figure D-2). The Minnelusa Group, including the Broom Creek Formation, comprises the AQ3 Aquifer system of the Williston Basin (Figure D-7). This aquifer system is overlain by the TK3 aquitard and underlain by the TK2 aquitard. Hydrodynamic flow withing the formation is exceedingly slow and moves toward the northeast with recharge occurring in the Black Hills to the south (Hoda, 1977). The Broom Creek Formation salinity ranges from fresh near recharge areas to in excess of 300,000 mg/L total dissolved solids (TDS) in the center of the Williston Basin. In the proximity of the RTE site, Broom Creek salinity is estimated at approximately 145,000 mg/L TDS (Hoda, 1977).



Figure D-7. A cross section of the Williston Basin illustrating the five major aquifer systems. The Minnelusa Group is highlighted in yellow (modified from Downey and others, 1987).

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APPENDIX E

MODELING AND SIMULATION

MODELING AND SIMULATION

INTRODUCTION

Geologic (or static) models were created to support numerical simulations of CO₂ injection and evaluation of dynamic CO₂ storage potential, as well as assessment of geologic uncertainty. The basis for these models' construction was a combination of measured subsurface characteristics and geologic interpretation. Modeling efforts were also used to assess the current availability and quality of data available for the site and to identify key data acquisitions during future activities.

The modeling efforts resulted in the creation of visual representations of subsurface geologic/stratigraphic characteristics, including structure, heterogeneity, pressure, temperature, and petrophysical properties (porosity, permeability, and fluid saturations). These efforts were focused on the Broom Creek Formation at the Red Trail Energy (RTE) site.

The purposes of numerical simulation were to achieve predictive results of CO₂ and pressure plume evolution, estimate wellhead pressure, and predict CO₂ plume stabilization (postinjection). Simulations were carried out using Computer Modelling Group's GEM, a compositional reservoir simulation module, and CMOST, a sensitivity analysis tool.

Predictive simulation results achieved from these models enabled visibility of migration and accumulation of injected CO₂ and the associated reservoir pressure response. The simulation results also provided a means to assess the long-term fate of injected CO₂ (thereby assisting in estimating potential AOR [area of review]); verifying containment/conformity; and informing well placement, completion, and financial assessments.

MODELING

The geologic model construction workflow followed in these efforts included 1) literature review and data compilation; 2) data review (quality assurance and control), formatting, and input to modeling software; 3) well data interpretation; 4) structural framework and geocellular grid construction; 5) property distribution and uncertainty analysis; and 6) grid upscaling and preparation for numerical simulation.

Geologic models of the Broom Creek Formation developed for the RTE site were built in Schlumberger's Petrel E&P software platform using publicly available data, mostly from the North Dakota Industrial Commission (NDIC) databases. These data included well logs, formation top depths, well datum values (i.e., kelly bushing [KB]), and core sample analyses and descriptions.

Existing well penetrations and their associated data sets comprise the primary source of information for the geologic models. A limited number of wells penetrating the Broom Creek

surround the RTE site, with especially low concentrations to the north and east (Figure E-1). The closest well to the RTE plant was located approximately 2 miles to the south. Thus a large initial study area was delineated (1100 mi²; 35.6 miles by 30.9 miles), which included 37 wells. A smaller subset of this region served as the basis for simulation model extent (100 mi²; 10 miles by 10 miles), centered on the RTE plant.



Figure E-1. Map showing the larger extent (1100 mi²) used to create the geologic model along with the smaller simulation model extent (100 mi²).

STRUCTURAL MODELING

Broom Creek and Amsden Formation top depths were picked based on well log signatures (Figure E-2) using standards described in Sorensen and others (2009), Peck and others (2014), and Murphy and others (2009). These tops were then interpolated across the study area, creating structural surfaces for the Broom Creek Formation top and the top of the underlying Amsden Formation.



Figure E-2. Type log of the Broom Creek Formation near the RTE study site (NDIC Well 9796). Curves shown are caliper (CALI), gamma ray (GR), sonic porosity (SPHI), sonic travel time (DT), density porosity (DPHI), neutron porosity (NPHI), flushed zone resistivity (RXO), shallow resistivity (LLS), deep resistivity (LLD), and lithology.

STRUCTURAL UNCERTAINTY

There is an inherit degree of uncertainty with regard to the formation's structural configuration because of the relatively low density of well penetrations into the Broom Creek Formation in the model area. A structural uncertainty analysis was conducted in order to quantify the degree of uncertainty and gain an understanding of the potential range in formation thickness. This process involved the development of multiple Broom Creek Formation top structural surfaces, each representing varying interpretations of overall formation thickness.

To create these multiple structural uncertainty surfaces, the interpolation method of Broom Creek structural data was varied away from the control points (wells), relying on spatial uncertainty (distance from control points), standard deviation of the input structural data, and the confidence intervals of interest (P10/P50/P90 in this case). The underlying Amsden Formation top surface remained unchanged (Figure E-3). Three structural models of differing thickness were developed which characterized a thin (P10), mid (P50), and thick (P90) Broom Creek reservoir. The "P10" nomenclature designated a Broom Creek top surface in which there was a 10% chance of the surface being lower, creating a thinner reservoir. The "P90" nomenclature designated a surface in which there was a 10% chance of the surface being higher, resulting in a thicker reservoir.



Figure E-3. Structural uncertainty illustration showing the thin (P10), mid (P50), and thick (P90) thicknesses of the Broom Creek Formation at a pseudowell used in simulation efforts.

Average depth and thickness for each structural uncertainty case are found in Table E-1. Structure and isopach maps created in the structural uncertainty analyses are illustrated in Figures E-4, E-5, and E-6. These surfaces were each used to create model grids composed of 300-ft \times 300-ft cells with a vertical thickness of 7 feet. A pseudowell was created on RTE property for simulation of CO₂ injection.

100-square mile Model							
		Average					
	Average Depth	Thickness,					
Case	TVDSS,* feet	feet					
P10	4040	228					
P50	3985	282					
P90	3932	336					

Table E-1. Structural Uncertainty Values for100-square mile Model

* Total vertical depth subsea (below mean sea level).



Figure E-4. Top: Structure contour map of the Broom Creek P10 within the RTE study area. Datum: mean sea level. Bottom: isopach map of the Broom Creek Formation P10 (thin) within the RTE study area. In both images, the RTE plant location is displayed in red, with RTE property limits displayed in black.



Figure E-5. Top: structure contour map of the Broom Creek P50 within the RTE study area. Datum: mean sea level. Bottom: isopach map of the Broom Creek Formation P50 (mid) within the RTE study area. In both images, RTE plant is displayed in red, with RTE property limits displayed in black.

2 miles



Figure E-6. Top: structure contour map of the Broom Creek P90 within the RTE study area. Datum: mean sea level. Bottom: isopach map of the Broom Creek Formation P90 (thick) within the RTE study area. In both images, RTE plant is displayed in red with RTE property limits displayed in black.

FACIES MODELING

Willis (1959) interpreted the depositional environment of the Broom Creek Formation as eolian (wind-blown) and nearshore marine sandstone-carbonate cycles. Facies logs were created based on well log signatures at each well location within the study area. The facies logs divided the formation into sandstone (reservoir) and dolostone (nonreservoir) intervals, based upon Willis's (1959) interpretation. An object modeling method using dune-shaped geobodies was then used to distribute facies between the well control points. Sandstone geobodies were modeled as dunes, and carbonate geobodies were modeled as intradune environments. Dimensions of the dune and intradune geobodies were derived from a study completed of a modern eolian environment in the Saudi Arabian desert, which is a potential modern analogue to the Broom Creek Formation (Al-Masrahy and Mountney, 2013).

FACIES UNCERTAINTY

The Broom Creek Formation in North Dakota has a relatively small number of core samples available for lithologic description and petrophysical property measurement. Thus facies uncertainty analyses were carried out to create multiple realizations of reservoir sand proportions and connectivity in the RTE model extent. Facies proportions and connectivity both have implications for CO₂ injectivity, pressure response, storage capacity, and storage efficiency.

Three facies distributions were achieved with varying facies proportions and resulting connectivity of reservoir sandstone and nonreservoir dolostone. Facies logs calculated at the study onset resulted in the assignment of relative proportions of 70% sandstone with 30% dolostone, hereafter described as the "mid case" facies distribution. A variability of $\pm 10\%$ in the sandstone component was applied to create "low case" and "high case" facies distributions. Table E-2 displays facies proportion values for these distributions. Figure E-7 displays cross sections of the final facies distributions.

Facies Uncertainty Analyses								
Proportions/Connectivity	% Sandstone	% Dolostone						
Low Case	60%	40%						
Mid Case	70%	30%						
High Case	80%	20%						

Table E-2.	Relative	Facies	Proportions	used to) Guide
Facies Und	certainty .	Analys	es		



Figure E-7. Facies distribution cross sections used to account for facies uncertainty, representing the low, mid, and high case (top to bottom, respectively).

PETROPHYSICAL PROPERTY MODELING

Petrophysical properties (porosity and permeability) were distributed using a variogrambased geostatistical method and with conditioning to the previously developed facies models. Variogram parameters used in these distributions were adapted from generalized variogram ranges described in Deutsch (2008). Variograms were oriented with the major axis east-west, perpendicular to interpreted paleowind direction at the time of deposition (Willis, 1959). A major variogram range of 1735 feet, minor variogram range of 470 feet, and vertical variogram of 10 feet were applied in the distribution of petrophysical properties. Properties for the sandstone intervals were derived from a crossplot of all available Broom Creek core sample porosity and permeability measurements (Figure E-8). Dolostone interval properties, modeled as nonreservoir, were populated from a generic crossplot.



Figure E-8. Broom Creek porosity/permeability crossplot derived from all core data available from the Broom Creek in North Dakota.

PETROPHYSICAL PROPERTY UNCERTAINTY

As mentioned previously, a relatively small number of geologic core data exist for the Broom Creek Formation in the Williston Basin. Poor sample resolution contributed to a relatively high degree of uncertainty in petrophysical property distributions. To address the uncertainty related to petrophysical properties, multiple property distributions were developed. Properties were distributed which represented P10, P50, and P90 cases within each previously developed facies model. The P10 distribution represented a generally conservative case, with a 10% chance that the actual values were lower. The P50 distribution represented a median value, and the P90 distribution represented a more optimistic case, with a 10% chance that the values were higher.

Porosity

Core sample-derived Broom Creek sandstone porosity values ranged from 3% to 28.4% (Figure E-8). These core-measured porosity values were used to determine the P10, P50, and P90 values and the standard deviation used in petrophysical modeling (Table E-3).

The porosity of the dolostone intervals ranged from 1.0% to 7.0%. Figure E-9 displays cross sections of the final porosity distributions.

Table E-3. Petrophysical Uncertainty Values from100-square mile Model

Case	Average Porosity, %	Standard Deviation
P10	9.0	6.14
P50	22.4	6.14
P90	27.9	6.14



Figure E-9. Cross-section comparison of the P10, P50, and P90 porosity distributions. Histograms show the frequency of modeled porosity values.

Permeability

Permeability values used in modeling efforts for the Broom Creek Formation were based on core-measured values. Sandstone permeability values ranged from 36 to 1164 mD, with a geometric mean of 316 mD (Figure E-8). Sandstone permeability was bivariately distributed using the previously modeled porosity property and a relationship derived from a porosity/permeability crossplot of Broom Creek core measurements.

Permeability distributions of the dolostone facies were completed similar to sandstone methods using a generic porosity/permeability crossplot. Permeability values of the dolostone intervals ranged from 0.000001 to 0.0001 mD

Other Reservoir Properties

Pressure and temperature were modeled throughout the area to aid in dynamic simulation efforts. A drillstem test completed within the study area was used for estimating pressure and temperature of the Broom Creek Formation. This test was conducted in offset well (NDIC Well 6797) within the underlying Mission Canyon Formation. A pressure gradient of 0.45 psi/ft was used in modeling pressure within the formation. A temperature gradient of 0.015 °F/ft was used to determine temperature within the geologic model, using a surface annual average temperature of 43.9°F.

UNCERTAINTY CASE MATRIX

The uncertainty case matrix resulting from the different uncertainty analyses is shown in Table E-4. The three modes of uncertainty assessment that were conducted (structural, facies, and petrophysical property uncertainty analyses) created a matrix of twenty-seven geologic model realizations. Three structural models were developed to account for uncertainty associated with reservoir thickness and depth. Three facies distributions representing P10, P50, and P90 proportions/connectivity were developed to account for uncertainty in facies proportions and connectivity. Three petrophysical property distributions (P10, P50, and P90) were created within each facies model to address uncertainty in the porosity and permeability of the reservoir.

However, only 18 of these cases were subject to subsequent numerical simulation (marked by "X" in Table E-4). The focus was given to expected and conservative cases, as opposed to optimistic cases, as successful outcomes of CO_2 injection simulations based upon expected and conservative cases would provide support for the likelihood of the project's success. Simulation cases based upon optimistic model parameters would provide little extra benefit in this stage of the project feasibility study.

		Red Trail Uncertainty Case Matrix								
		Facies								
		Low Connectivity/Sand Proportion			Mid Connectivity/Sand Proportion			High Connectivity/Sand Proportion		
		Petrophysical Properties		Petrophysical Properties			Petrophysical Properties			
		P10	P50	P90	P10	P50	P90	P10	P50	P90
	Thin	Х	Х	Х	Х	Х	Х	Х	Х	Х
Structure	Mid	Х	Х	Х	Х	Х	Х	Х	Х	Х
	Thick									

Table E-4. Model Uncertainty Case Matrix

SIMULATION

A base case was simulated initially to obtain predictive results for the target formation under assumed operating conditions. A sensitivity analysis, which delineated factors and their impact to the simulated CO₂ injection operation, were evaluated using CMOST. These activities were followed by predictive simulations under various operating conditions.

As described in the above modeling section, a total of 18 cases were subjected to numerical simulation. Table E-5 depicts the average porosity (arithmetic mean: red) and average permeability (geometric mean: blue) for each of the models simulated. The models had total cell counts ranging from 1 million to 1.23 million. Each model assumed open boundary conditions, which allowed lateral water flow through the simulation model boundary without pressure buildup. This is thought to be representative of the Broom Creek Formation throughout the region. Of the 18 cases subjected to numerical simulation, three select case simulation results will be discussed in the following sections (highlighted yellow in Table E-5):

- 1. Structurally thin, low connectivity/sand proportion facies (60% sand), P10 petrophysical properties; hereafter referred to as the "P10 (conservative)" case.
- 2. Structurally thin, mid connectivity/sand proportion facies (70% sand), P50 petrophysical properties; hereafter referred to as the "P50 (moderate)" case.
- 3. Mid case structure, high connectivity/sand proportion facies (80% sand), P90 petrophysical properties; hereafter referred to as the "P90 (optimistic)" case.

	Red Trail Simulation Case Matrix									
	Facies									
	Low Conne	ectivity/Sand P	roportion	Mid Connectivity/Sand Proportion			High Connectivity/Sand Proportion			
	Petrophysical Properties			Petrophysical Properties			Petrophysical Properties			
	P10 (PHI; K)	P50 (PHI; K)	Р90 (РНІ; К)	P10 (<mark>PHI; K</mark>)	P50 (PHI; K)	Р90 (РНІ; К)	P10 (<mark>PHI; K</mark>)	P50 (PHI; K)	P90 (PHI; K)	
Thin	0.06; <mark>72</mark>	0.14; 227	0.17; 349	0.07; <mark>84</mark>	0.15; <mark>26</mark> 4	0.19; <mark>406</mark>	0.08; <mark>101</mark>	0.17; <mark>316</mark>	0.23; 488	
Mid	0.07; 71	0.14; 225	0.18; 315	0.07; 84	0.15; 266	0.2; 408	0.08; 100	0.18; 318	0.23 <mark>; 490</mark>	
Thick	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	

 Table E-5. Simulation Case Matrix (PHI = porosity; K = permeability)

Previous studies indicated the water salinity in this region of Stark County, North Dakota, ranges from 150,000 to 200,000 ppm (Peck and others, 2014). The water saturation in the simulation model was specified as 100%, as there were no indications of the presence of oil or gas in the Broom Creek Formation in the vicinity of the RTE site. The fluid model used Henry's solubility model, which allowed CO₂ to dissolve into the native formation brine. The CO₂-brine relative permeability table was based upon a previous study by Bennion and Bachu (2005), representing CO₂-brine flow characteristics in high-permeability sandstone.

SENSITIVITY ANALYSIS

A sensitivity analysis was conducted to identify parameters impacting simulated wellhead pressure (WHP) and determine the relative importance of each. This was conducted to provide estimates of maximum WHP, which were needed to inform infrastructure design and the associated financial/economic considerations. The parameters investigated included petrophysical characteristics (Inc_KPhi), wellhead temperature (WHTemp), bottomhole temperature (BHTemp), injection rate, tubing roughness, vertical/horizontal permeability ratio (Kv/Kh), and salinity. The sensitivity analysis suggested WHTemp had the greatest effect on the pressure response (Figure E-10). The results also suggested that increasing WHTemp from 40°F to 100°F would increase WHP about 472 psi (Figure E-11). The predicted WHP range was 745 to 1305 psi.



Figure E-10. Sensitivity analysis for WHP. The result indicates WHTemp had the most significant impact on WHP.



Figure E-11. Tornado plot showing how WHP would change by varying impacting parameters in a given value range.

A sensitivity analysis was also conducted for bottomhole pressure (BHP). A thorough understanding of the sensitivity of the pressure response of the reservoir is necessary because reservoir pressure response is a key component for AOR determination. The most influential parameter for BHP was the petrophysical characteristics (Inc_KPhi) of the model, which varied between the different petrophysical property uncertainty cases (Figure E-12).

Two different tools were used to evaluate the pressure elevation threshold determining the pressure plume AOR, including the Environmental Protection Agency's (EPA) pressure front equation (EPA, 2011), and the National Risk Assessment Partnership Reservoir Evaluation and Visualization tool (NRAP REV, 2015). The pressure threshold calculated from both tools was 98 and 120 psi, respectively. However, the P10 (conservative) case showed a maximum potential change in pressure (ΔP) of 128 psi at the injection well location, and the radius for the area of pressure change greater than 98 psi was about 0.43 mi (Figure E-13). The pressure responses simulated in the other 17 cases did not exceed the threshold values calculated from both the EPA and NRAP tools. This indicates that elevated pressure will not determine the AOR; rather the areal extent of the free-phase CO₂ plume will determine AOR extent. The pressure responses generated by the models are shown in Figure E-14.



Figure E-12. Sensitivity analysis for BHP response.



Figure E-13. Map view of the pressure response (ΔP) at the top the P10 (conservative) case at the end of a simulated 20-year CO₂ injection operation. Only the area in the immediate vicinity of the injection wellbore exceeds the ΔP threshold values calculate for this site. The model size is 10 mi ×10 mi.



Figure E-14. Simulated wellhead and bottomhole pressure responses.

CO₂ Plume (AOR)

As mentioned above, it was determined the CO₂ plume would likely dictate AOR. Thus the plume evolution for select simulation cases was evaluated, including the P10 (conservative), P50 (moderate), and P90 (optimistic) cases. The predicted plume extents (map view) were quantified in gas per unit area in total (feet), using the following equation:

Gas Per Unit Area-Total (Ft) = CO_2 Saturation (%) × Porosity (Frac) × Net Pay Thickness (Ft) [Eq. 1]

The CO₂ plume diameters after 20 years of continuous injection were approximately 2 miles, 1.7 miles, and 1.4 miles for the P10 (conservative), P50 (moderate), and P90 (optimistic) cases, respectively. Figures E-15–E-17 show the plume extents for each case at 5, 10, 15, and 20 years.



Figure E-15. Plume evolution for the P10 (conservative) case after 5, 10, 15, and 20 years.



Figure E-16. Plume evolution for the P50 (moderate) case after 5, 10, 15, and 20 years.



Figure E-17. Plume evolution for the P90 (optimistic) case after 5, 10, 15, and 20 years.

As mentioned above, the CO₂ plume extent (map view) was evaluated by calculating gas per unit in total, where CO₂ saturation was the dynamic factor resulting in observed differences. Cross-section views of CO₂ saturation are shown in Figure E-18 to illustrate how CO₂ migrated laterally from the simulated injection well.





Figure E-18. Cross-section views of CO2 saturation for P10 (conservative), P50 (moderate), and P90 (optimistic) cases after 20 years of simulated CO₂ injection.

Figure E-18 indicates that an increase in the modeled porosity and permeability (e.g., the P90 [optimistic] case) results in greater gravity segregation, under the effect of buoyancy, between CO₂ and native formation brine, meaning the injected CO₂ is more concentrated at the top of the injection interval. Lower porosity and permeability (e.g., the P10 [conservative] case) results in CO₂ migrating laterally rather than vertically, and the decreased amount of pore space available to injected CO₂ results in a greater areal extent of the CO₂ plume (i.e., a greater areal extent is needed to provide storage for a quantity of injected CO₂ in a formation with generally lower porosity than a formation with generally higher porosity). Additionally, the P10 (conservative) case contained a greater percentage of nonreservoir facies, which acted as baffling, inhibiting vertical CO₂ migration.

Postinjection Plume Expansion

Long-term CO₂ migration and the implications for storage security were also investigated in numerical simulation efforts. Postinjection CO₂ plume expansion was evaluated for the P50 (moderate) case (Figure E-19). This work considered the role of the relative permeability on the postinjection plume expansion in order to reduce computational time. This assessment required assumptions of irreducible ("connate" or "residual") CO₂ saturation. As CO₂ disperses, CO₂ saturation decreases until reaching this irreducible saturation, at which point the remaining CO₂ is effectively immobilized. Figures E-20 and E-21 show postinjection CO₂ migration after 50 and 100 years while considering irreducible CO₂ saturation endpoints of 0.2 and 0.3, respectively).

However, CO₂ plume expansion is also sensitive to CO₂ solubility, which, in turn, is affected by a number of factors such as grid cell size, brine salinity, and temperature (Pekot and others, 2017). While CO₂ solubility was included in these simulations, there is some uncertainty in the accuracy of the results related to the characteristics of the aforementioned variables (the appropriate grid cell size, salinity, and temperature). A separate study would be required to fully address those aspects.

Additionally, injected CO_2 may be converted into carbonate minerals (i.e., calcite – $CaCO_3$) through a process known as "mineralization" or "mineral trapping." This process is commonly postulated to occur over a very long time frame (e.g., hundreds to thousands of years). However, examples of mineralization occurring over short period (e.g., 1–2 years) are known (Matter and others, 2016). This process is likely to have some implications against long-term CO_2 migration potential, but it has not been considered in the simulations discussed here.

Figure E-19 shows the simulated CO₂ plume extent after 20 years of simulated injection for the P50 (moderate) case. The postinjection CO₂ plume extent (Figures E-21 and E-22) shows CO₂ migrating generally to the southeast because of the effects of buoyancy in the structural updip direction.



Figure E-19. CO₂ plume extent for P50 (moderate) case after 20 years of simulation injection.



Figure E-20. Postinjection CO₂ plume extent after 50 years (left) and 100 years (right) assuming an irreducible CO₂ saturation of 0.2.



Figure E-21. Postinjection CO₂ plume extent after 50 years (left) and 100 years (right) assuming an irreducible CO₂ saturation of 0.3.

Figures E-20 and E-21 show that increasing irreducible CO_2 saturation results in decreased lateral CO_2 migration and containment of CO_2 within a smaller area. With an irreducible CO_2 saturation of 0.2, the CO_2 plume would extend from the injection well approximately 1.5 miles towards the southeast after 200 years postinjection, whereas assuming 0.3 for irreducible CO_2 saturation results in a CO_2 plume extending approximately 1.3 miles from the injection well. During this postinjection assessment, the CO_2 plume expanded at a rate of approximately 30 feet a year with the current structural setting.

Figure E-22 indicates both the injected CO₂ mass and dissolved CO₂ mass during the 20 years of simulated injection and 100 years of postinjection simulation.



Figure E-22. Total CO₂ injected, dissolved CO₂ in brine, and free-phase CO₂.

CONCLUSION

Sensitivity analyses conducted in the exercises described here show that WHP may show significant variability with WHTemp. These simulation efforts are important for well and infrastructure design; indicated WHPs may be as high as 1400 psi.

The numerical simulation activities discussed here have shown that the CO₂ plume, rather than elevated pressure plume, is likely to govern AOR under current regulation. The CO₂ plume extents from predictive simulations ranged from 1.4 to 2 miles in diameter, varying with uncertainty in the reservoir's petrophysical property characteristics. Better petrophysical properties appear to result in a (generally) more consolidated CO₂ plume, whereas the presence of poorer porosity and permeability characteristics tends to result in a CO₂ plume with greater areal extent. This effect is related to pore volume, as the necessary amount of pore space to store the injected CO₂ spans a greater areal extent in a formation characterized by relatively lower porosity than in a formation with relatively higher porosity. Additionally, an increase in nonreservoir facies content may create more barriers to vertical CO₂, causing a CO₂ plume to grow further outward.

Postinjection CO₂ migration simulations assuming irreducible CO₂ saturations of 0.2 and 0.3 may result in a CO₂ plume radius of approximately 1.3–1.5 miles after 100 years. However, there is a high degree of uncertainty in such long-term forecasts, as the geologic heterogeneity at the RTE site is not well understood; calculated dissolved CO₂ may vary significantly as a function of the model's grid cell size, brine salinity, and temperature; mineralization of dissolved CO₂ has not been taken into account; generalized relative permeability curves and assumed irreducible CO₂ saturation inputs may be different than actual characteristics; and there is a relatively high degree of structural uncertainty in the vicinity of the RTE site. The presence of local structural features may have significant impact on the long-term migration potential of injected CO₂. But while there is a high degree of uncertainty in the results of long-term CO₂ migration simulations, the worst-case scenario has illustrated that 100 years of migration has relatively minor consequences in terms of plume growth. These data, combined with the knowledge of low external risks (faults, seismic events, wellbore penetrations, etc.) indicate that the plume will not pose a threat of unintended vertical migration potential once CO₂ injection operations are complete.

The simulation results achieved in this preliminary study support the potential for success in implementing CCS (carbon capture and storage) at the RTE site. However, the models and simulations conducted here rely heavily on generalized subsurface characteristics, stemming from a lack of site-specific data and resulting in a relatively high degree of uncertainty. The acquisition of site-specific data, such as core sample-measured petrophysical characteristics, would provide data necessary to refine the models discussed here, enable more accurate predictive simulations, and decrease subsurface technical risks posed by geologic uncertainty. This will be the focus of further modeling and simulation activities to be conducted in the future phases of research related to potential CCS activities at RTE.

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APPENDIX F

RISK ASSESSMENT
RISK ASSESSMENT

This appendix provides a summary of the risk assessments that were conducted to evaluate potential risks related to the geologic storage of CO₂, including their potential to threaten success for carbon capture and storage (CCS) at the Red Trail Energy, LLC (RTE) ethanol production facility in North Dakota (hereafter referred to as the "Project").

RISK ASSESSMENT PROCESS OVERVIEW

The risk assessments conducted for this project were performed through a series of webinar meetings and workgroup sessions involving subject matter experts from among the Energy & Environmental Research Center (EERC) technical staff and the RTE management team (hereafter referred to as the "Group").¹ The risk management process that the Group used followed the international standard presented in ISO 31000,² as illustrated below in Figure F-1.



Figure F-1. Risk management process adapted from the ISO 31000 standard.²

¹ Gerald Bachmeier and Dustin Willett of RTE participated in the risk assessment sessions along with the following technical experts from the EERC: Scott Ayash, Nick Azzolina, Nick Bosshart, Nate Fiala, Charlie Gorecki, John Hamling, Lonny Jacobson, Melanie Jensen, Todd Jiang, Nick Kalenze, Ryan Klapperich, Kerryanne Leroux, Dave Nakles, Larry Pekot, Jim Sorensen, and José Torres.

² International Organization for Standardization [ISO], 2009, Risk management —principles and guidelines: ISO. 31000:2009(E).

The Group initiated the risk management process during a meeting held via Webinar on January 12, 2017, where the Group began by establishing the context for the Project risk assessment (top box in Figure F-1). This included defining the geologic CO₂ storage system boundaries and developing risk probability- and impact-scoring matrices for the risk evaluation.

The risk management process continued in a work group session on January 18, beginning with the review of a preliminary risk register that the EERC developed based on experience with other geologic CO₂ storage sites. Figure F-2 provides a conceptual block model of the Project to identify the various system components that may be impacted should a risk occur. The Group used this system block diagram to help identify potential risks and to constrain the physical limits (boundaries) of the risk assessment. The Group identified pertinent risks that were not yet included, as well as those not relevant to the Project, and finalized the risk register.



Figure F-2. System block diagram illustrating the target storage horizon (orange block showing the Broom Creek Formation), overlying seal formations (Opeche, Piper, and Swift Formations), and potential leakage pathways to overlying formations and the surface environment (e.g., injection wells, plugged and abandoned [P&A] wells, monitoring wells, other wells, and faults/fractures).

The individual participants then assigned probability and impact scores for each individual risk using the risk-scoring matrices from the initial meeting (Figures F-3 and F-4). A low and high probability score was assigned to each risk, representing the most likely and worst-case scenarios. Impact scores were given for each of six different categories of potential impacts: 1) cost, 2) schedule, 3) health and safety, 4) legal/regulatory compliance, 5) permitting compliance, and 6) corporate image/public relations.

The results of this January 18 evaluation represented the screening-level risk assessment for the Project. Following the completion of the site characterization and modeling/simulation tasks, EERC's team of technical experts reevaluated the risk probability scores associated with the subsurface technical risks. These risk probability scores were revised as necessary based on the knowledge gained regarding the expected behavior of the subsurface CO₂ plume and pressure propagation over the lifetime of the Project. These revised risk scores were used to complete the final, quantitative risk assessment for the feasibility study. All subsequent discussions in the remainder of this appendix summarize the results of the quantitative risk assessment, which represents the Group's current understanding of potential Project risks.

Probability Score	Description
1	Very low
2	Low
3	Moderate
4	High
5	Very high

Figure F-3. Project risk probability scoring matrix. Participants provided a low-estimate and a high-estimate probability score for each risk.

Impact Score	Cost/Finance	Project Schedule	Legal/Regulatory Compliance (economic/market)	Permitting Compliance (operational)	Corporate Image/Public Relations	Health and Safety
1 – Very						
Low						
2 – Low						
3 –						
Moderate						
4 – High						
5 – Very						
High						

Figure F-4. Project risk impact scoring matrix for six different categories of impacts: cost/finance, project schedule, legal/regulatory compliance, permitting compliance, corporate image/public relations, and health and safety.

PROJECT RISK REGISTER SUMMARY

The current Project risk register includes 43 potential risks. These potential risks were divided between 26 technical risks, eight policy-related risks, and nine external, commercial, or other risks, which were further grouped into ten different risk categories, as summarized below.

Technical Risks

- 1. CO₂ supply, injectivity, and storage capacity (7 risks)
- 2. Subsurface containment lateral migration of CO₂ or formation water brine (3 risks)
- 3. Subsurface containment propagation of subsurface pressure plume (3 risks)
- 4. Subsurface containment vertical migration of CO₂ or formation water brine via injection wells, P&A wells, monitoring wells, or faults/fractures (12 risks)
- 5. Induced seismicity (1 risk)

Policy-Related Risks

- 6. Ethanol policy (3 risks)
- 7. CCS policy (5 risks)

External, Commercial, or Other Risks

- 8. Market forces (1 risk)
- 9. Accidents/unplanned events (2 risks)
- 10. Project management (6 risks)

RISK SCORING RESULTS

Risk-Mapping Framework

Both risk probability and each of the six risk impacts were scored on a five-point scale: 1) very low, 2) low, 3) moderate, 4) high, and 5) very high (Figures F-3 and F-4). 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. Figure F-5 provides a generic example of the risk map format that was used. Lower-probability, lower-impact risks plot in the lower left-hand corner, while higher-probability, higher-impact risks plot in the upper right-hand corner of the risk map.

Those risks that fall into the upper-right region of the risk maps represent risks that may be higher-priority for further investigation, as they represent higher-probability events with moderate to very high risk impacts. Conversely, risks in the lower-left region of the risk maps are of lesser concern since they represent lower-probability events with low to minor risk impacts. The remaining risks, which are located in the upper left and lower right regions of the risk maps,



Figure F-5. Generic risk map showing impact on the *x*-axis and probability on the *y*-axis. Lowerprobability, lower-impact risks will plot in the lower left-hand region, while higher-probability, higher-impact risks will plot in the upper right-hand region.

may warrant further investigation as they are either higher-probability risks, albeit with low to minor risk impacts, or lower-probability events with moderate to very high risk impacts. The risk-mapping framework therefore provides a relative ranking of the project risks, with the individual risk scores providing a basis for comparing each risk to the others. In addition, these maps provide a risk-based means to prioritize future activities, including additional data collection, analysis, and monitoring.

Uncertainty Assessment

As expected, the risk probability and impact scores varied across participants, resulting in a level of uncertainty in the risk scores. This uncertainty was evaluated using several tools to identify "outliers" (i.e., risk scores outside the normal range of scores by Group respondents) and derive a set of most likely and worst-case scenarios. The most likely risk scores represent the average Group response for the probability and impact of a particular risk. The worst-case scenarios represent a conservative estimate of the risk scores for a particular risk, and reflect an upper bound estimate for both the risk probability and risk impact.

Project-Specific Risk Maps

Figures F-6 through F-11 show the Project-specific risk maps for the impacts on cost, schedule, health and safety, legal/regulatory compliance, permitting compliance, and corporate image/public relations, respectively. Two sets of risk scores are presented: solid circles are used to represent the most likely scenario scores and hollow circles are used to represent the worst-case scenario scores.

In general, only the scores of select external/commercial/other risks under the worst-case scenario were plotted into the upper right-hand region of the risk maps. These scores are likely due to the current uncertainty regarding ethanol policies in California and Oregon and their potential impacts on the Project. Also reflected in these scores was uncertainty about the status of North Dakota's primacy of Class VI regulations, the ability to secure a Class VI permit, and federal policy changes regarding CCS under a new Administration. Many of these same risks plot in the lower-right region of the risk maps when considering the most likely scenario.

For the most likely scenario, the Group scored technical risks as low-probability, low-tomoderate-impact events, placing them in the lower-left and lower-right regions of the risk maps. These results are not surprising and are consistent with the current physical understanding of the Project and the key features of the site that make it an attractive geologic CO_2 storage site, including the following:

- A target horizon with sufficient capacity to store 180,000 tons of CO₂ a year.
- A series of over- and underlying low-permeability sealing formations to prevent vertical fluid migration.
- A predicted radial extent of the CO₂ plume of less than 1 mile from the injection well after 20 years of CO₂ injection.
- Very few existing wells within 2 miles of the planned CO₂ injection well.



Figure F-6. Risk maps showing the *cost impact score* (x-axis) versus probability score (y-axis) for risks related to CO₂ supply, injectivity, or storage capacity (top left); ethanol or CCS policy (top right); subsurface containment or induced seismicity (bottom left); and other risks related to

markets, accidents, project management, and construction (bottom right). The solid circles represent the average score across the Group, while the hollow circles represent a conservative, upper-end estimate for both probability and impact. The three hollow circles plotting into the red area under "Other Risks" represent construction-related risk associated with unexpected increases in lead-time for equipment/materials, construction schedule (wells, pipelines, capture facilities), or cost for construction materials or services.



Figure F-7. Risk maps showing the *schedule impact score* (x-axis) versus probability score (y-axis) for risks related to CO₂ supply, injectivity, or storage capacity (top left); ethanol or CCS policy (top right); subsurface containment or induced seismicity (bottom left); and other risks related to markets, accidents, project management, and construction (bottom right). The solid circles represent the average score across the Group, while the hollow circles represent a conservative, upper-end estimate for both probability and impact.



Figure F-8. Risk maps showing the *health and safety impact score* (x-axis) versus probability score (y-axis) for risks related to CO₂ supply, injectivity, or storage capacity (top left); ethanol or CCS policy (top right); subsurface containment or induced seismicity (bottom left); and other risks related to markets, accidents, project management, and construction (bottom right). The solid circles represent the average score across the Group, while the hollow circles represent a conservative, upper-end estimate for both probability and impact.



Figure F-9. Risk maps showing the *legal/regulatory impact score* (x-axis) versus probability score (y-axis) for risks related to CO₂ supply, injectivity, or storage capacity (top left); ethanol or CCS policy (top right); subsurface containment or induced seismicity (bottom left); and other risks related to markets, accidents, project management, and construction (bottom right). The solid circles represent the average score across the Group, while the hollow circles represent a conservative, upper-end estimate for both probability and impact.



Figure F-10. Risk maps showing the *permitting compliance impact score* (x-axis) versus probability score (y-axis) for risks related to CO₂ supply, injectivity, or storage capacity (top left); ethanol or CCS policy (top right); subsurface containment or induced seismicity (bottom left); and other risks related to markets, accidents, project management, and construction (bottom right). The solid circles represent the average score across the Group, while the hollow circles represent a conservative, upper-end estimate for both probability and impact.



Figure F-11. Risk maps showing the *corporate image/public relations impact score* (x-axis) versus probability score (y-axis) for risks related to CO₂ supply, injectivity, or storage capacity (top left); ethanol or CCS policy (top right); subsurface containment or induced seismicity (bottom left); and other risks related to markets, accidents, project management, and construction (bottom right). The solid circles represent the average score across the Group, while the hollow circles represent a conservative, upper-end estimate for both probability and impact.

SUMMARY AND CONCLUSION

As part of this feasibility study, a site-specific screening-level risk assessment and subsequent quantitative risk assessment were conducted to evaluate potential risks related to the geologic storage of CO₂ for the purpose of assessing their potential to threaten the success for proposed Project.

The risk assessment results indicate that technical risks associated with CO₂ supply, injectivity, storage capacity, subsurface containment, and induced seismicity are low, i.e., low-probability, low- to moderate-impact events. The highest-ranking risks were policy-related or external/commercial risks associated with ethanol and CCS policy and other risks associated with construction activities. Currently the highest-ranking risks include the following:

- North Dakota does not receive primacy of the U.S. Environmental Protection Agency (EPA) Class VI regulations from EPA Region 8, or RTE is not able to get a Class VI permit for the CO₂ storage operations.
- California or Oregon ethanol policies change, making it difficult or impossible for RTE to qualify for the emission credits.
- State or federal administration changes overarching climate change policies resulting in the withdrawal of low-carbon fuel standard or emission credits.
- Unexpected increases in lead time for equipment/materials, construction schedule (wells, pipelines, capture facilities), or cost for construction materials or services.

The results of the screening-level and quantitative risk assessments performed during this stage of the Project indicate that there are no risks that would preclude the Project from advancing to the next phase. The highest-ranked risks are not technical in nature but rather are due to the uncertainty of developing legislative and regulatory policies and a change in federal administration, all of which are beyond the Group's immediate control. Since the likelihood of these risks occurring and/or the severity of their impact will likely change as time progresses, the risk management framework used in this study allows for active, iterative risk management over the lifetime of a project. As such, these project risks will be reevaluated in future phases to assess whether the existing risk scores have changed or additional risks should be evaluated.

APPENDIX G

LCA

LIFE CYCLE ANALYSIS

INTRODUCTION

As part of this feasibility study, a site-specific life-cycle analysis (LCA) was completed to estimate carbon intensity (CI) reduction for ethanol produced at the Red Trail Energy (RTE) facility, modified with carbon capture and storage (CCS). These CI values are a required pathway parameter for designating carbon credits through low-carbon fuel programs. This appendix describes the data and methods used, including:

- A description of the CA-GREET model used by California's LCFS Program.
- A summary of the derived CI reductions for ethanol produced at RTE's facility with CCS.

This appendix does not include specific results related to potential CI values for the RTE facility, as these are proprietary due to the business sensitive nature of the assessment. Nor does it contain a detailed analysis of the resulting CI reductions that may be incurred by RTE as that information is also considered business sensitive.

CA-GREET

California's LCFS Program currently uses the California-modified CA-GREET model to calculate CI values for ethanol generated at a specified facility. CA-GREET version 2.0 was released on September 29, 2015, and that was the version used in this feasibility study (hereafter referred to as "CA-GREET"). The CA-GREET model is a modified version of Argonne National Laboratory's 2013 GREET model, and derives CO₂ emissions associated with corn farming and transportation (ethanol feedstock) and ethanol fuel production, transportation, and distribution. The CA-GREET functional unit for the CI value is grams of CO₂ equivalent per megajoule (gCO₂e/MJ) of produced ethanol, which provides the basis for comparing one fuel to another under the LCFS system.¹

CA-GREET is a spreadsheet model developed in Microsoft Excel[®]. There are three datainput tabs related to ethanol production from fermentation of dry-milled corn: a high-level data

¹ While CO₂ is the most commonly produced greenhouse gas (GHG), methane (CH₄) and nitrous oxide (N₂O) also act as GHGs in the atmosphere. GHG emissions are expressed in units of "CO₂ equivalents" (CO₂e) using the 100-year global warming potential (GWP) coefficients of 25 for CH₄ and 298 for N₂O.* The GWP coefficient for CO₂ is one. Expressing GHGs in units of CO₂e allows a summation of all three values (CO₂ + CH₄ + N₂O) into a single number, i.e., CO₂e.

^{*} Forster, P., Ramaswamy, V., Artaxo, P., Berntsen, T., Betts, R., Fahey, D.W., Haywood, J., Lean, J., Lowe, D.C., Myhre, G., Nganga, J., Prinn, R., Raga, G., Schulz, M., and Van Dorland, R., 2007, Changes in atmospheric constituents and in radiative forcing, *in* climate change 2007—the physical science basis: Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, Solomon, S., Qin, D., Manning, M., Chen, Z., Marquis, M., Averyt, K.B., Tignor, M., and Miller, H.L., eds., Cambridge University Press, Cambridge, United Kingdom and New York, New York.

entry and results-display page ("T1 Calculator"), a more detailed data input tab ("Inputs"), and a tab that contains and collects ethanol-specific data ("EtOH"). CA-GREET employs standard spreadsheet functions supported by custom Visual Basic routines to accomplish its calculations. The approach adopted by this study was to identify and input RTE facility-specific data into the necessary cells of the T1 Calculator tab.

Although the current CA-GREET model is only applicable for traditional ethanol production, its method can be applied to the operations of a CCS system to estimate CI values for ethanol produced with CCS (Figure G-1). This section describes the specific components of the current CA-GREET model. Subsequent sections describe how this model was appended to incorporate CCS.



Figure G-1. Block diagram showing key elements of ethanol production with CCS. The blue dashed box represents the boundary of the current CA-GREET model for deriving CI values associated with ethanol production without CCS. This technical evaluation appended CA-GREET to include additional emissions associated with CO₂ capture ("Capture System") and emission credits associated with CO₂ storage in the Broom Creek Formation ("Geologic Storage").

Ethanol Feedstock

Corn farming and transportation are referred to as "ethanol feedstock." In the T1 Calculator tab, the inputs related to ethanol feedstock include the following:

- Ethanol yield (gallons of anhydrous ethanol per bushel of corn, gal anh-EtOH/bu).
- Corn farming energy intensity (British thermal unit per bushel of corn, Btu/bu).
- Fertilizer, herbicide, and insecticide use (grams per bushel, g/bu).
- Nitrous oxide (N₂O) in soil (%).

• Corn transportation distances (miles).

This study uses the default CA-GREET input values and calculations for ethanol feedstock with the exception of ethanol yield.

The default CA-GREET input value for corn farming energy intensity is 9608 Btu/bu, and the default fertilizer, herbicide, and insecticide use and N₂O in soil are as follows:

- Fertilizer:
 - Nitrogen: 423.30 g/bu
 - P2O5: 145.80 g/bu
 - K₂O: 151.30 g/bu
 - CaCO₃: 1,149.87 g/bu
- Herbicide: 7.00 g/bu
- Insecticide: 0.06 g/bu
- N₂O in soil:
 - N in N₂O as % of N in N fertilizer: 1.325%
 - N in N₂O as % of N in biomass: 1.225%
 - N above and below ground biomass: 141.6 g/bu.

In estimating emissions associated with corn transportation, CA-GREET applies emission factors to the miles transported by medium-duty truck (10 miles) and heavy-duty truck (40 miles), which are the default inputs.

Distillers's Grain Solubles (DGS)

The primary product to which the LCA assigns emissions is ethanol. However, the RTE facility produces both modified distillers' grain solubles (MDGS) and dry distillers' grain solubles (DDGS) as coproducts of ethanol production. These coproducts earn an emission credit for the ethanol.

Greater energy inputs, and therefore commensurately greater CO₂ emissions, are associated with producing DDGS because of the additional drying steps. Consequently, ethanol produced with MDGS as the coproduct has a lower CI value than ethanol produced with DDGS as the coproduct. This technical evaluation considers two end members, 100% MDGS and 100% DDGS, to bracket the lower and upper bounds, respectively, for RTE's ethanol production with CCS.

While disposition and related emissions of corn oil and syrup are different from MDGS and DDGS, their weights were included in DGS coproduct displacement calculations. The error introduced by this simplification is small—especially in light of the alternative which was, since there is no appropriate disposition for these coproducts in the model, to ignore the products.

Ethanol Fuel Production and Transportation

In the T1 Calculator tab, the inputs related to ethanol fuel production and transportation include the following:

- Volume of anhydrous ethanol produced (gal anh-EtOH)
- Facility electricity consumption (kWh/gal anh-EtOH)
- Facility natural gas consumption (Btu/gal anh-EtOH)
- Enzyme use (g/gal anh-EtOH)
- Ethanol fuel transportation and distribution distances (miles).

This study uses RTE facility-specific inputs for the *amounts* of each of these ethanol fuel production and transportation inputs (gal, kWh/gal, Btu/gal, g/gal, and miles), and the default CA-GREET calculations for estimating the *emissions* associated with each input.

Analogous to corn transportation, in estimating emissions associated with ethanol transportation and distribution, CA-GREET applies emission factors to the miles transported by rail from the ethanol facility to a California rail yard (2000 miles), by heavy-duty truck from a California rail yard to the blending terminal (100 miles), and by heavy-duty truck from the blending terminal to fuel stations (71 miles). The 2000 miles transported by rail from the ethanol facility to a California rail yard is specific to the RTE facility; the other inputs of 100 miles and 71 miles by heavy-duty truck are the default values in CA-GREET.

Denaturant and Indirect Land Use

CA-GREET assumes a denaturant content of *denatured ethanol* (D-EtOH) of 2.5% (volume per volume, v/v). This study therefore used RTE facility-specific inputs for *anhydrous ethanol* (anh-EtOH) and the default CA-GREET assumptions to estimate the CI increse associated with adding denaturant.

The final component added to the life cycle emissions of D-EtOH is indirect land use. These are indirect emissions associated with the expansion of land used for corn production. CA-GREET uses a default value of 19.8 gCO₂e/MJ of D-EtOH.

CI REDUCTION FOR ETHANOL PRODUCED AT RTE'S FACILITY WITH CCS

The baseline CA-GREET results for ethanol produced without CCS were appended to include the additional emissions associated with CO₂ capture and compression and the emissions reduction for geologic CO₂ storage to estimate net CI reduction for ethanol produced at RTE's facility with CCS. A range of CI reduction values were first derived for RTE's existing ethanol production based on higher or lower operating efficiency with respect to energy usage per gallon of ethanol and annual ethanol production. These CI values represent RTE's baseline without CCS.

The emissions associated with operation of a CO₂ capture facility (e.g., energy usage for dehydration and compression), based on the design described in Appendix B, were estimated to add 3-4% to the net CO₂ emissions. Geologic storage of the captured CO₂ stream could then reduce CO₂ emissions by an estimated 43-54% because this CO₂ would be safely stored in the Broom Creek Formation and therefore isolated from contact with the atmosphere. The resulting net CO₂ emissions reduction for RTE ethanol production with CCS was determined to be 40%-50%.

SUMMARY AND CONCLUSIONS

A site-specific LCA was completed to estimate reduction of CO₂ emissions for ethanol produced at the RTE facility modified with CCS. This LCA used the CA-GREET model, RTE facility-specific inputs, and supplemental calculations to include additional emissions associated with CO₂ capture and compression and emissions credit for geologic CO₂ storage. The estimated percent reduction in net CO₂ emissions ranges approximately 40%–50%. These results suggest that amending RTE's ethanol facility with CCS will generate a significant reduction in life-cycle CO₂ emissions as compared to their baseline CI values.

APPENDIX H

PERMITTING HISTORY

PERMITTING HISTORY

NORTH DAKOTA CARBON CAPTURE AND STORAGE (CCS) REGULATORY PERSPECTIVE

Historical Context

The United Nations Framework Convention on Climate Change (UNFCCC) is the main international treaty of climate change. It is a Rio Convention, i.e., one of three adopted at the Rio Earth Summit in 1992. UNFCCC took effect on March 21, 1994, with the ultimate objective of "stabilizing greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous human interference with the climate system."¹

Beginning in 1995, yearly conferences have been held under the auspices of UNFCCC. They serve as the formal meeting of the UNFCCC parties (i.e., the Conference of the Parties, or COP) to assess the progress in dealing with climate change and, beginning in the mid-1990s, to negotiate the Kyoto Protocol, which establishes legally binding obligations for developed countries to reduce their greenhouse gas emissions. As such, since 2005, the conferences of UNFCCC have served as the Conference of the Parties Serving as the Meeting of the Parties to the Kyoto Protocol, or CMP. To date, there have been 22 meetings of COP and 12 meetings of CMP.¹

In 1997, during COP 3 in Kyoto, Japan, the Kyoto Protocol was adopted, which outlined greenhouse gas emission reduction obligations for developed nations and nations with economies in transition (Annex I countries). Most Annex I countries agreed to legally binding reductions of an average of 6% to 8% below 1990 levels between the years 2008 to 2012; the United States and Canada were required to reduce their greenhouse gas emissions by 6% and 7% below 1990 levels, respectively. The Kyoto Protocol also included what came to be known as Kyoto mechanisms, which included emission trading. Emission trading, commonly referred to as a "cap-and-trade system," sets a maximum level of allowed CO₂ emissions for individual entities. An entity is permitted to exceed its maximum allowable CO₂ emissions it plans to emit in excess of its allowable limit. However, the Congress of the United States did not ratify the Kyoto treaty after it was signed by President Clinton, and the administration of G.W. Bush explicitly rejected the protocol in 2001. Ratification of the Kyoto Protocol required ratification by 55 countries, including those accounting for 55% of developed-country emissions of CO₂ in 1990.

In 2005, at CMP, an agreement ("The Montreal Action Plan") was made to extend the life of the Kyoto Protocol beyond its 2012 expiration date and to negotiate greater reductions in greenhouse gas emissions. Multiple attempts to develop a post-2012 framework were made in subsequent COP/CMP meetings but with no success. Finally, at COP 18/CMP 8, which was held in Doha, Qatar, in 2012, the Doha amendment to the Kyoto Protocol was produced and featured

¹ United Nations Framework Convention on Climate Change, 2017, http://newsroom.unfccc.int (accessed May 2017).

a second commitment period running from 2012 until 2020, which was limited in scope to 15% of the global CO_2 emissions because of the lack of commitments from Japan, Russia, Belarus, Ukraine, and New Zealand (as well as the United States and Canada, who are not parties to the protocol in that period) and because of the fact that developing countries like China, India, and Brazil are not subject to emission reductions under the Kyoto Protocol.

The last meeting of COP/CMP that addressed climate change was held in Paris, France, in 2015. Negotiations at this conference resulted in the adoption of the Paris Agreement, which governs climate change reduction measures from 2020. This effort ended the work initiated in COP 17/CMP 7 in Durban, South Africa, which began the process to negotiate a legally binding agreement comprising all countries by 2015 and governing the period post-2020.

Canada ratified the Kyoto Protocol in 2002, while the United States, a signatory to the Kyoto Protocol, has neither ratified nor withdrawn from the protocol as of the writing of this report. Until such time that the protocol is ratified, it is nonbinding on the United States.

Even though the Kyoto Protocol is nonbinding, the United States has proceeded to move forward with efforts to reduce greenhouse gas emissions in the country by establishing compliance-related carbon markets, which include cap-and-trade systems as well as a carbon tax (i.e., a set price per ton for emitting CO₂ into the atmosphere) and developing greenhouse gas reduction strategies involving both carbon capture and storage (CCS) and carbon capture, utilization, and storage (CCUS). Carbon taxes have yet to be applied in the United States, but mandatory market-based cap-and-trade systems have been implemented elsewhere in the country, e.g., the Regional Greenhouse Gas Initiative, which was formed in 2009 and comprises a cooperative of states, including Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

U.S. Environmental Protection Agency (EPA) CCS Regulation

Beginning in 2010, several key federal and state statutory and/or regulatory developments related to the geologic storage of CO_2 occurred in the United States. In December 2010, EPA issued a rule establishing a new well class (Class VI) in the Underground Injection Control (UIC) Program. The new rule specified the minimum technical criteria to protect underground sources of drinking water (USDWs) from the long-term subsurface storage of CO_2 .² In September 2011, EPA became the acting authority for Class VI injection wells requiring all states to conform to the standards set forth in the UIC Class VI rules for all long-term subsurface CO_2 storage projects.

However, this created significant uncertainty regarding the applicability of these rules to previously permitted UIC Class II injection wells should a CO₂ enhanced oil or gas recovery

² U.S. Environmental Protection Agency, 2010, Underground injection control (UIC) Class VI program—research and analysis in support of UIC Class VI Program financial responsibility requirements and guidance: December 2010, www.epa.gov/sites/production/files/2015-07/documents/uicclass6reasearchandanalysisupdatedpg84.pdf (accessed May 2017).

project (CO₂ EOR) ever transition to a geologic storage project.³ At issue is the determination of if, and when, such a transition occurs. EPA Class VI rules specify that such a transition shall be determined at the discretion of the EPA Regional Director based on a determination that the continued subsurface injection of CO₂ will result in an increased risk to USDW compared to Class II operations. Nine specific criteria, or factors, must be considered in making this determination, one of which is the totally open-ended criterion, "as well as any additional site-specific factors as determined by the Director." To address this uncertainty, EPA's Office of Groundwater and Drinking Water, within the Office of Water, issued a technical memorandum on April 23, 2015, to all Regional Water Division Directors entitled "Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI." In that memorandum, EPA stated that "the best implementation approach is for states to administer both the Class II and the Class VI UIC programs." The memorandum further encouraged states to "apply for primacy for all well classes, including Class VI" and simultaneously requested that the Regional Directors "assist states in submitting primacy applications for all well classes."

In June 2013, prior to the issuance of this EPA technical memorandum, but consistent with its recommendations, the State of North Dakota applied to Region 8 of EPA for primacy of the Class VI regulations. Nearly 4 years after that submission, North Dakota had not yet received a decision regarding its application. In recognition of the delay of EPA in responding to the North Dakota primacy application, as well as the inconsistency of this delay with the spirit of EPA's technical memorandum, the Interstate Oil and Gas Compact Commission (IOGCC) passed a resolution in September 2015 (Resolution 15.091 – "Clarifying Issues Related to the Transitioning of Class II Carbon Dioxide Enhanced Oil or Gas Recovery Projects to a Class VI Geologic Storage Project") which requested that "EPA ensure that states have the right to administer injection of CO_2 for EOR under Class II UIC" and:

- 1. "The states and owner/operators have the right to regulatory certainty that injection of CO₂ for EOR is managed as Class II UIC throughout the commercial life of each project."
- 2. "The Class II UIC program director has the right to determine if and when transition from Class II UIC to Class VI UIC is required to address risk."

These key elements of the IOGCC resolution are consistent with the recommendations in the IOGCC guidance documents as well as in the 2015 technical memorandum of the EPA Office of Water, both of which encourage states to secure Class VI primacy jurisdiction from EPA. The IOGCC resolution also recognizes that the Class VI rules of EPA include neither the regulation of the pore space of the state nor provide protection of the state from associated liability from what would otherwise be nonregulated CO₂ storage-related activity. As such, IOGCC is a strong proponent of the states determining if and when transition from Class II UIC to Class VI UIC occurs, acknowledging that it is the states that are best positioned to administer

³ U.S. Environmental Protection Agency, 2017, Code of Federal Regulations—Title 40 – protection of environment, www.gpo.gov/fdsys/pkg/CFR-2015-title40-vol23/xml/CFR-2015-title40-vol23-sec144-19.xml (accessed May 2017).

a regulatory approach that meets the stringent requirements necessary to obtain Class VI primacy while at the same time implementing a resource management philosophy.

Most recently in 2015, EPA finalized New Source Performance Standards (NSPS) under Clean Air Act (CAA) Section 111(b) that, for the first time, established standards for emissions of CO_2 for newly constructed, modified, and reconstructed affected fossil fuel-fired electric utility generating units (EGUs).⁴ The rule essentially mandates the use of partial CCS by including it as part of the Best System of Emission Reduction (BSER). The implementation of this rule was delayed by a federal lawsuit that challenged EPA's conclusion that CCS is "adequately demonstrated and achievable," as is required by the CAA. It should be noted that EPA also concluded that a highly efficient new steam generating unit implementing full CCS is not the BSER at this time because the costs were predicted to be significantly more than the costs for implementation of partial CCS and significantly more than the costs for competing non-NGCC (natural gas combined cycle) base load, dispatchable technologies—primarily new nuclear generation. While this rule has been delayed, it is clear that EPA believes CCS is critical to achieving reductions in greenhouse gas from fossil fuel EGUs and that is will likely be a part of this or any future NSPS established for CO₂ emissions.

The large-scale deployment of CO_2 geologic storage (CCS), which includes dedicated storage in both deep saline aquifers and in depleted oil and gas reservoirs as well as associated storage occurring during active CO_2 EOR (CCUS), will require compliance with a formal regulatory process for individual storage sites. With a new federal administration in place January 2017 and a new EPA Director, philosophies, programs, and policies are coming under review. The nature and extent of the regulatory process that will continue to be dictated by EPA and impact to the various regulatory agencies of the individual states have not been determined as of the date of this report.

In summary, 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. 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 CO₂, lack of geologically suitable storage sites, and/or the lack of long-term financial drivers), and maintain a reliance upon existing regulatory frameworks. In the absence of obtaining primacy of the Class VI rules, the regulation of a commercial CCS project will be led by EPA. North Dakota is the only state to submit an Application for UIC Class VI Primacy.

⁴ U.S. Environmental Protection Agency, 2015, Standards of performance for greenhouse gas emissions from new, modified, and reconstructed stationary sources—electric utility generating units: October 2015, www.federalregister.gov/documents/2015/10/23/2015-22837/standards-of-performance-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed-stationary (accessed May 2017).

State and Federal Regulatory Uncertainties

In general, three legal/regulatory obstacles have inhibited the commercial deployment of CCS technology to varying degrees: 1) access to and use of pore space, 2) the permitting of CCS/CCUS projects, and 3) site closure and management of long-term, postoperational liability.

In developing legislation and rule making, North Dakota adopted two basic principles: 1) it is in the public interest to promote the geologic storage of CO_2 to reduce anthropogenic CO_2 emissions, and 2) the pore space of the state or province should be regulated and managed as a resource under a resource management philosophy. A resource management philosophy ensures that pore space ownership and postoperational liability are incorporated into the CCS/CCUS regulatory process. EPA's waste management philosophy is embodied in the UIC Class VI regulations, which do not adequately address pore space ownership and, consequently, cannot effectively manage the efficient use of the pore space resource.

Concurrent evolution of the technology and regulations for the geologic storage technology for CO_2 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 EOR operations; 3) the storage of natural gas in geologic reservoirs; and 4) the injection of acid gas (a combination of hydrogen sulfide [H₂S] 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.

The state of legislative and regulatory affairs related to the geologic storage of CO_2 provides a stark contrast in regulatory approaches. On the one hand, Canada has deferred to the provinces, which have relied heavily upon the existing provincial regulatory frameworks of the oil and gas industry (Saskatchewan and British Columbia) or developed consensus CCS regulatory frameworks (Alberta). This has resulted in the construction and operation of several commercial-scale CO_2 geologic storage projects, e.g., Shell Quest, Alberta Carbon Trunk Line, SaskPower Boundary Dam/Aquistore, and the Weyburn–Midale Project.

On the other hand, the United States has elected to promulgate federal regulations for the geologic storage of CO_2 distinct and separate from the regulatory frameworks of the oil and gas industry. Of particular significance is the fact that these regulations have created regulatory uncertainty that is threatening the only commercially viable approach that currently exists for the geologic storage of CO_2 in the United States: CO_2 EOR. The end result of this regulatory action has been the lack of implementation of large-scale, commercial CO_2 storage projects in the United States.

The regulatory uncertainties in the United States should be reduced as CCS/CCUS projects are implemented and the respective states and EPA regions focus on moving forward with the regulatory permitting of these projects.

North Dakota UIC Class VI Program Development

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 CO₂ storage work group, which was tasked with the development of a regulatory framework for the long-term geologic storage of CO₂. 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 in 2007.⁵ This model statute was later modified by the IOGCC following a biennial review conducted in 2010.⁶ Of particular importance was an emphasis on the treatment of geologically stored CO₂ 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 CO₂ (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 CO₂.
- House Bill No. 1014 Appropriations Committee (2011) A Carbon Dioxide Facility Administrative Fund was established from which NDIC 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.

⁵ IOGCC Task Force on Carbon Capture and Geologic Storage, 2007, Storage of carbon dioxide in geologic structures—a legal and regulatory guide for states and provinces: September 25,

http://iogcc.publishpath.com/Websites/iogcc/PDFS/2008-CO2-Storage-Legal-and-Regulatory-Guide-for-States-Full-Report.pdf (accessed May 2017).

⁶ IOGCC Task Force on Carbon Capture and Geologic Storage, 2010, Phase II biennial review of the legal and regulatory environment for the storage of carbon dioxide in geologic structures:

http://groundwork.iogcc.ok.gov/sites/default/files/Biennial%20Report_FINAL_09-30-2010_0.pdf (accessed May 2017).

• Rulemaking and amendments to Chapter 43-05-01 (effective April 2013) – The existing rule, which complemented the existing laws for CO₂ 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. To date, EPA headquarters (Washington, D.C.) has not yet made a determination regarding this application.

The state of North Dakota UIC Class VI Program⁷ developed a permitting process 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. Details regarding this permitting process and the information requirements of the drilling and injection permits are provided in this document.

OUTSTANDING CHALLENGES AND BARRIERS

Previous reviews have identified the regulatory and legal obstacles to the commercial deployment of CCS technology.^{8,9,10} Three main obstacles have been highlighted: 1) access to and use of pore space, 2) permitting of geologic storage projects, and 3) management of long-term liability. The manner in which each of these obstacles has been addressed by North Dakota is discussed below.

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. North Dakota has acted on the pore space issues and has established that:

• Pore space is tied to the surface estate (North Dakota SB2139).

⁷ North Dakota Industrial Commission, 2013, North Dakota Class VI underground injection control program (1422) description: June 2013.

⁸ Gresham, R.L., McCoy, S.T., Apt, J., and Morgan, M.G., 2010, Implications of compensating property owners for geologic sequestration of CO₂: Environmental Science Technology, v. 44, p. 2897–2903,

http://pubs.acs.org/doi/pdf/10.1021/es902948u (accessed May 2017)

⁹ Interstate Oil and Gas Compact Commission, 2008, CO₂ storage: a legal and regulatory guide for states, https://iogcc.myshopify.com/collections/frontpage/products/co2-storage-a-legal-and-regulatory-guide-for-states-2008 (accessed May 2017).

¹⁰ Interstate Oil and Gas Compact Commission, 2014, 2014 resolutions: http://iogcc.publishpath.com/2014-resolutions (accessed May 2017).

- Severance of pore space from the surface estate is prohibited in North Dakota.
- Compulsory unitization, similar to that used in oilfield development, has also been adopted; 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, establishing a threshold percentage of 55% for North Dakota.¹¹
- An alternative to unitization is the use of eminent domain; a prerequisite is the declaration that the geologic storage of CO₂ is in the public interest as adopted by North Dakota in its legislation, SB2095, which granted authority to NDIC to address the geologic storage of CO₂.

CCS Project Permitting

The NDIC Department of Mineral Resources Division of Oil and Gas is the permitting authority under the North Dakota UIC Class VI Program.⁶ Currently, EPA still regulates all Class VI permits; however, North Dakota has promogulated a comprehensive set of carbon storage regulations for all aspects of CO₂ injection and storage operations. These regulations meet or exceed the EPA Class VI requirements and address some factors that EPA is not able to address (e.g., pore space ownership, site certification, comprehensive program enforcement authority, etc.). On May 9, 2017, EPA signed a proposed federal rule to approve the State of North Dakota's application for regulatory primacy over Class VI injection wells. North Dakota's application will be published in the federal register and open to a 60-day public comment period before being finalized later this year.¹²

Site Closure and Management of Long-Term Liability

Under the Safe Water Drinking Act, 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.

North Dakota has addressed the liabilities associated with closing a site and its long-term management following closure:

• Financial assurance mechanisms have been put in place to ensure that CCS projects are properly closed. North Dakota requires performance bonds for the CO₂ injection and observation wells and the surface facility, the amounts to be determined by NDIC.

¹¹ Wilson, W.I., Doll, T.E., Wildgust, N., and Gorecki, C.D., 2017, Regulatory perspective regarding the geologic storage of carbon dioxide (CO₂) in the PCOR Partnership region: Plains CO₂ Reduction (PCOR) Partnership Phase III, Task 3 – Deliverable D76 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2017-EERC-03-14, Grand Forks, North Dakota, Energy & Environmental Research Center, August.

¹² Hoeven, U.S. Senator John, 2017, Hoeven: EPA signs proposed rule to approve ND application to regulate Class VI injection wells, will help advance CCS technologies [Press release].

- To determine when closure has been successfully attained, North Dakota regulations state that position and characteristics of the injected CO₂ must be provided along with a reasonable expectation that the mechanical integrity of the reservoir will be maintained.
- Upon achieving closure, 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 of North Dakota, and the costs of these liabilities will be covered by establishing long-term stewardship funds that will be developed during the CCS operations.

NORTH DAKOTA REGULATORY AUTHORITIES

North Dakota Industrial Commission (NDIC), www.nd.gov/ndic Phone: (701) 328-3722; Fax: (701) 328-2820

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

North Dakota Department of Health, www.ndhealth.gov

Environmental Health Section, www.ndhealth.gov/ehs Phone: (701) 328-5150; Fax: (701) 328-5200

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

APPENDIX I

WELL DESIGN DETAILS

WELL DESIGN

DRILLING AND COMPLETION RTE MONITORING WELL

Energy & Environmental Research Center (EERC) Drilling Plan

Developed drilling procedure for the Red Trail Energy, LLC, (RTE) monitoring well based on industry standards as well as North Dakota Industrial Commission (NDIC) and U.S. Environmental Protection Agency (EPA) requirements. Plan details geologic marker tops, well evaluation program, pressure control equipment, borehole size, casing programs, mud programs, and additional procedures for the proposed well.

Monitoring Well Location: Unknown (within RTE property) Stark County, North Dakota

Estimated Tops of Geologic Markers

Estimated depth and thickness of formations, members, or zones potentially containing usable water, oil, gas, or other valuable deposits. All prospectively valuable deposits will be within 9-5/8-in. casing or 5-1/2-in. production casing that will be cemented. Well will not be produced.

		Datum, ft	
Marker	Depth, ft (MD*)	(SS**)	Resources
Pierre	1875	645	
Greenhorn	4125	-1605	
Mowry	4565	-2045	
Dakota (Inyan Kara)	4910	-2390	Water
Swift	5310	-2790	
Spearfish	6245	-3725	Oil
Minnekata	6360	-3840	
Opeche	6405	-3885	
Broom Creek	6505	-3985	
Amsden	6775	-4255	
TD (total depth)	6900	-4380	
* Massurad denth			

* Measured depth.

** Subsea.

Evaluation Program

Mudlogging: A mud log will be run from 1925 ft to TD. The mudlog will include total gas chromatograph and sample cuttings—30-ft sample intervals in the vertical hole.

Logging: Openhole logging will be conducted by Schlumberger (SLB) upon completion of drilling. A borehole-compensated (BHC) sonic and triple combo will be run from TD to surface. Spectroscopy/spectral GR (gamma ray) from TD to surface. A cement bond log (CBL), variable-density log (VDL), and temperature log will be run as required by North Dakota Administrative Code (NDAC) and EPA Class VI regulation to determine the cement has set over the casing and established a good bond.

Cores: Cored intervals are 6455–6505 ft Opeche, 6505–6805 ft Broom Creek.

Pressure Control Equipment

- A. Type: 11-inch double-gate hydraulic BOP (blowout preventer) with 11-inch annular preventer with 5000-psi casing head.
- B. Testing Procedure

The annular preventer will be pressure-tested to 50% of stack-rated working pressure for 10 minutes or until provisions of the test are met, whichever is longer. The BOP, choke manifold, and related equipment will be pressure-tested to approved BOP stack working pressure (if isolated from surface casing by a test plug) or to 70% of surface casing internal yield strength (if BOP is not isolated by a test plug). Pressure will be maintained for 10 minutes or until the requirements of the test are met, whichever is longer. At a minimum, the annular and BOP pressure tests will be performed:

- 1. When the BOPE (BOP equipment) is initially installed.
- 2. Whenever any seal subject to test pressure is broken.
- 3. Following related repairs.
- 4. At 30-day intervals.

Annular will be function-tested weekly, and pipe and blind rams will be activated each trip. All BOP drills and tests will be recorded in the International Association of Drilling Contractors (IADC) driller's log.

C. Choke Manifold Equipment

All choke lines will be straight lines, unless turns use tee blocks or are targeted with running tees, and will be anchored to prevent whip and reduce vibration.

D. Accumulator

The fluid reservoir capacity will be double accumulator capacity, and the fluid level will be maintained at manufacturer recommendations. An accumulator precharge pressure test will be conducted prior to connecting the closing unit to the BOP stack.

Drilling Program

Estimated Surface Casing:	Surface to 1925'
Conductor:	16" set at 90'
Hole Size:	12¼"
Mud:	Freshwater, mud weight 9.0 ppg (pounds per gallon)
Bits:	Tricone, conventional assembly
Procedure:	Set 16" conductor pipe to 90'
	Drill to casing setting depth, 50' below Fox Hills
	Formation (per state and EPA requirements)
	Run casing with float shoe and collar and cement, weld on 5000M casing head. Install $11" \times 5000M$ drillstem adapter. Nipple up (NU) 5000M BOPE. Test to 5000 psi for 15 minutes, American Petroleum Institute (API) 16C
Casing:	9-5/8" 40# J-55 LTC (long thread casing) – new

Set at 1925 ft

Size	Weight	Grade	Conn	Collapse, psi	Burst, psi	Inner Diameter	Drift	Joint Strength, 1000 lb	Body Yield, 1000 lb
9- 5/8"	40 lb/ft	J-55	LT&C	2570	3950	8.835"	8.679"	452	630

Csg (casing) Torque (Tq): Centralizers: Cement: 9-5/8" Tq (ft-lb) Optimum 5200 Min. 3900 Max. 6500 TBD (to be determined) in field

Actual cement program will be designed by selected contractor. For surface casing, we may utilize CO₂ resistant cement or as proposed by the selected contractor. Note: volumes calculated assuming 75% excess over 12¹/4" hole size Monitor returns, and note cement volume to surface. Catch cement samples and mix water. If cement is not at surface after the job, state (and federal if applicable) authorities must be notified for "top job." Cement must achieve 500 psi compressive prior to drill out. Min. WOC (wait on cement) is 24 hours (WOC time includes all time not drilling).

Surface Casing to Core Point 1: Hole Size: Mud: Bits:

1925' to 6455' 8 1/2" Saltwater gel Polycrystalline diamond compact (PDC), 1.5 degree mud motor assembly

Procedure:	Before drilling: test casing for 5 min to 500 psi Drill up to 20' of new hole, perform 11.5 ppg or field- calculated ppg needed for estimated mud weight (EMW) formation integrity test (FIT) for 15 min Drill to Core Point 1 Condition hole. Trip out of hole (TOOH).
Core 1 Opeche Hole Size: Mud: Bits: Procedure:	6455' to 6545' 8" Saltwater gel Core head and 90' core barrel assembly Drill core TOOH.
Core 2 Broom Creek Hole Size: Mud: Bits: Procedure:	6545' to 6635' 8" Saltwater gel Core head and 90' core barrel assembly Drill core TOOH.
Core 3 Broom Creek Hole Size: Mud: Bits: Procedure:	6635' to 6725' 8" Saltwater gel Core head and 90' core barrel assembly Drill core TOOH.
Core 4 Broom Creek Hole Size: Mud: Bits: Procedure:	6725' to 6805' 8" Saltwater gel Core head and 90' core barrel assembly Drill core TOOH.
End of Core 4 to TD Hole Size: Mud: Bits: Procedure:	6805' to 6900' 8-1/2" Saltwater gel PDC, 1.5 degree mud motor assembly Ream cored interval Drill to TD of 7971' Condition hole. TOOH. Wireline log and test well. Condition mud for cement. Run casing and cement.

Casing: 5-1/2" 17# L-80 LTC – New

Set at: 6300 ft

Size	Weight	Grade	Conn.	Collapse, psi	Burst, psi	Inner Diameter	Drift	Joint Strength, 1000 lb	Body Yield, 1000 lb
5- 1/2"	17 lb/ft	L-80	LTC	6290	7740	4.892"	4.767"	338	397

Csg Torque: 5-1/2" Tq (ft-lb) Centralizers: TBD in field Optimum 3410 Min. 2557 Max. 4262

Casing: 5-1/2" 17# 13Cr LTC – New

Set at: 6900 ft

Size	Weight	Grade	Conn.	Collapse, psi	Burst, psi	Inner Diameter	Drift	Joint Strength, 1000 lb	Body Yield, 1000 lb
5- 1/2"	17 lb/ft	13Cr	LTC	6290	7740	4.892"	4.767"	338	397

Csg Torque: 5-1/2" Tq (ft-lb) Centralizers: TBD in field Optimum 3410 Min. 2557 Max. 4262

Cement:Actual cement program will be designed by selected
contractor. For production casing, we will utilize CO2
resistant cement as required by the regulation and/or as
proposed by the selected contractor.
Note: volumes calculated assuming 30% excess over
8-1/2" hole sizeFinalize Well:Rig down cementers. Install 5000-psi night-cap. Rig down
and release rig.

DRILLING TIME LINE

SLB estimates 27 days required for well drilling and construction, which is shown in Figure I-1.



Figure I-1 Proposed drilling time line for the RTE monitoring well.

WELL SCHEMATIC OF THE RTE MONITORING WELL DETAILING DEPTHS AND SPECIFICATIONS OF CASING, CEMENT, AND PERFORATIONS

Figure I-2 shows the well schematic and Figure I-3 shows the specififcations for the well.



Figure I-2. Monitoring well schematic by EERC.
EERC Monitoring Well



Wellhead Equipment

Section	Item	Description
"A"	Casing Head	9-5/8" SOW x 11" 5000 psi WP
"B"	Tubing Head	11" 5000 psi x 7-1/16" 5000 psi WP

Casing - Tubing Program

			Casing							
Section	Hole Size	OD	Weight	Grade	Conn	ID	Drift	Collapse	Burst	Joint
Conductor	14-3/4"	13-3/8"	68 lb/ft	B&C	PE	12.415"				
Surface	12-1/4"	9-5/8"	40 lb/ft	J-55	LT&C	8.835"	8.679"	2,570 psi	3,950 psi	452 klbs
Production	8-1/2"	5-1/2"	17 lb/ft	L-80 13Cr	LT&C	4.892"	4.767"	6,290 psi	7,740 psi	397 klbs
Section	Siz	5	Weight	Grade	Conn	ID	Drift	Collapse	Burst	Joint
Tubing	2-7/	2-7/8"		13Cr	LT&C	2.441"	2.347"	7,680 psi	7,260 psi	99.7 klbs

Mud Program

Liele Cestion	Interval	Туре	MW	VIS	PV	YP	WL	Cl
Hole Section			(lb/gal)	(sec/qt)	(cP)	(lb/100ft)	(cc/30 min)	(ppm)
Surface	80'-1,925'	Freshwater	8.6-9.0	30-35	n/a	n/a	NC	n/a
Production	1,925'-6,900'	SW gel	10.2-10.4	40-46			6-8	150,000 - 170,000

Formation Tops

Formation	TVD*	KB TVD
Formation	(ft)	(ft)
Pierre	1,875	1,895
Greenhorn	4,125	4,145
Mowry	4,565	4,585
Inyan kara	4,910	4,930
Swift	5,310	5,330
Minnekahta	6,360	6,380
Opeche	6,405	6,425
Broom Creek	6,505	6,525
Amsden	6,775	6,795
TD	6,900	6,920

*TVD measured from ground level 20 ft for KB (assumption)

Figure I-3. EERC's monitoring well specifications.

PROPOSED WELL DRILLING PLAN FOR THE RTE MONITORING WELL FROM SCHLUMBERGER.

RTE, EERC and SLB Monitor Well 1

LOCATION: (xxx) STARK COUNTY, NORTH DAKOTA

WELL PROGNOSIS GROUND ELEVATION: xxx ft

SURFACE SECTION

- 1. Drill well on paper/prespud safety meeting to be held within a week from spud date.
- 2. Rig up drilling rig and drill rat and mouse holes, make up 12-1/4" BHA (bottomhole assembly).
- 3. Have mud engineer provide a detailed inventory of all additives on location and provide to the project technical team prior to first mudding up.
- 4. Drill 1925' of 12-1/4" surface hole to accommodate approximately 1925' of 9-5/8" pipe.
- 5. Run openhole surface logs: Resistivity–SP–Caliper from TD to surface.
- 6. Run approximately 48 joints of 9-5/8", 40#/ft, J55 surface casing with a guide shoe and float collar on bottom joint.
- 7. Circulate casing to bottom of well and then pick up 2' off bottom to cement.
- 8. Cement well according to cement company design using 100% excess. Wait in cement for 24 hours or until 500-psi compressive strength is reached.

MAIN SECTION

- 1. NU BOP and flow stack. Function and pressure-test BOP.
- 2. Make up 8-1/2" BHA.
- 3. Drill 8-1/2" hole from 1925'– 6900' to accommodate approximately 4975' of 5-1/2" casing.
- 4. Cores will be cut in the well in the Opeche and Broom Creek Formations. A total of 350' of core will be cut. Prepare mud for coring and keep to mud engineer's specification. Core each interval at the direction of the coring tool operator. Carefully lay down core at each coring interval. A separate core plan will be provided.
- 5. At TD, circulate hole clean, and build mud to engineer's specifications. Short trip for minimum of 2000' and again circulate hole clean. TOOH, making sure hole is full at all times.
- 6. Run openhole logs: triple combo-spectral gamma ray–dipole sonic–fracture finder from TD to casing shoe.
- 7. Run cased-hole logs: CBL–VDL–GR–temperature from casing shoe to surface.
- 8. Run modular formation dynamic tester (MDT) sampling as per sampling program.

- 9. After logging, trip back in hole and circulate to bottom. Circulate and condition hole in preparation for running casing. TOOH laying down drill string.
- 10. Run 5-1/2", 17#/ft, L-80, casing to 6300' and 5-1/2", 13#/ft, 80 Ksi CR-13 chrome casing from 6300' to 6900'.
- 11. Insert: SageWatch installation, easy rider and marker join installation procedure.
- 12. Chrome casing requires special handling and care must be taken to not allow the chrome to become damaged by contact with other steel edges. The JFE Bear connection requires a different tong inserts and must be torqued to manufacturer's specification. Failure to do so could result in premature casing failure.
- 13. Run guide shoe on bottom joint and float collar on first joint. Run centralizers as per cementing company design. Once casing is on bottom circulate well to condition mud. Cement well as per cementing company design.
- 14. Displace well with freshwater. Bump plug to 1000 psi over final lift pressure. Check floats. Set casing slips and release rig.

COMPLETIONS

- 1. Move in completion unit and rig up. NU tubing head adapter and BOP, pump, tank and support equipment.
- 2. Pick up 3-1/2" 9.2 #/ft tubing with bit and scraper and trip in hole. Tag up PBTD (plug back total depth) and confirm that sufficient rat hole is available for production logging.
- 3. Log CBL–VDL–GR–temperature and Pulsed Neutron eXtreme (PNX) from TD to surface and perforate the Broom Creek Formation from 6555' to 6775' with 4" high shot density (HSD) 4SPF 90DEG. Be prepared for well to flow.
- 4. Pick up 2-7/8" 6.5 #/ft 13Cr tubing.
- 5. Insert: Packer completions procedure.
- 6. Rig up test separator and flow lines and frac tank. Swab well to kick off and flow until cleaned up.
- 7. Rig down completion unit and move out.

Figure I-4 shows the wellhead schematic of the RTE monitoring well.



Figure I-4. Wellhead schematic for monitoring well (image courtesy of SLB).

DRILLING AND COMPLETION RTE INJECTION WELL

EERC Drilling Plan

Developed drilling procedure for the RTE injection well based on industry standards as well as NDIC and EPA requirements. Plan details geologic marker tops, well evaluation program, pressure control equipment, borehole size, casing programs, mud programs, and additional procedures for the proposed well.

Injection Well Location: Unknown (within RTE property) Stark County, North Dakota

Estimated Tops of Geologic Markers

Estimated depth and thickness of formations, members, or zones potentially containing usable water, oil, gas or other valuable deposits. All prospectively valuable deposits will be within 13-3/8-in. casing or 7-in. production casing that will be cemented. Well will not be produced.

Marker	Depth, ft (MD*)	Datum, ft (SS**)	Resources
Pierre	1875	645	
Greenhorn	4125	-1605	
Mowry	4565	-2045	
Dakota (Inyan Kara)	4910	-2390	Water
Swift	5310	-2790	
Spearfish	6245	-3725	Oil
Minnekata	6360	-3840	
Opeche	6405	-3885	
Broom Creek	6505	-3985	
Amsden	6775	-4255	
TD (total depth)	6900	-4380	

* Measured depth.

** Subsea.

Evaluation Program

Mudlogging: A mud log will be run from 1925 ft to TD. The mudlog will include total gas chromatograph and sample cuttings – 30-ft sample intervals in the vertical hole.

Logging: Openhole logging will be conducted by SLB upon completion of drilling. A BHC sonic and triple combo will be run from TD to surface and spectroscopy/spectral GR from TD to surface. A CBL, VDL, and temperature log will be run as required by NDAC and EPA Class VI regulation to determine the cement has set over the casing and established a good bond.

Cores: Cored intervals are 6455–6505 ft Opeche, 6505–6805 ft Broom Creek.

Pressure Control Equipment

- E. Type: 11-in. double-gate hydraulic BOP with 11-in. annular preventer with 5000-psi casing head.
- F. Testing Procedure

The annular preventer will be pressure-tested to 50% of stack-rated working pressure for 10 minutes or until provisions of the test are met, whichever is longer. The BOP, choke manifold, and related equipment will be pressure-tested to approved BOP stack working pressure (if isolated from surface casing by a test plug) or to 70% of surface casing internal yield strength (if BOP is not isolated by a test plug). Pressure will be maintained for 10 minutes or until the requirements of the test are met, whichever is longer. At a minimum, the annular and BOP pressure tests will be performed:

- 1. When the BOPE (BOP equipment) is initially installed.
- 2. Whenever any seal subject to test pressure is broken.
- 3. Following related repairs.
- 4. At 30-day intervals.

Annular will be function-tested weekly, and pipe and blind rams will be activated each trip. All BOP drills and tests will be recorded in the IADC driller's log.

G. Choke Manifold Equipment

All choke lines will be straight lines unless turns use tee blocks or are targeted with running tees and will be anchored to prevent whip and reduce vibration.

H. Accumulator

The fluid reservoir capacity will be double accumulator capacity, and the fluid level will be maintained at manufacturer recommendations. An accumulator precharge pressure test will be conducted prior to connecting the closing unit to the BOP stack.

DRILLING PROGRAM

Surface Casing	Surface to 1925'
Conductor:	16" set at 90'
Hole Size:	14-3/4"
Mud:	Freshwater, mud weight 9.0 ppg (pounds per gallon)
Bits:	Tricone, conventional assembly
Procedure:	Set 16" conductor pipe to 90' Drill to casing setting depth, 50' below Fox Hills Formation (per state and EPA requirements)
Casing:	Run casing with float shoe and collar and cement, weld on 5000M casing head. Install 13-5/8" × 5000 M drill stem adapter. NU 5000M BOPE. Test to 5000 psi for 15 minutes, API 16C 13-3/8" 40# J-55 LTC (long thread casing) – new Set at 1925 ft

Size	Weight	Grade	Conn	Collapse, psi	Burst, psi	Inner Diameter	Drift	Joint Strength, 1000 lb	Body Yield, 1000 lb
13- 3/8"	72 lb/ft	L-80	STC	2670	5380	12.347"	12.191"	1029	1661

Csg (casing) Torque (Tq): 13-3/8" Tq (ft-lb) Optimum 10290 Min. 7700 Max. 12850 Centralizers: TBD (to be determined) in field

Centralizers:	IBD (to be determined) in field
Cement:	Actual cement program will be designed by selected
	contractor. For surface casing, we may utilize CO ₂ resistant
	cement or as proposed by the selected contractor.
	Note: volumes calculated assuming 75% excess over 14-3/4"
	hole size. Monitor returns, and note cement volume to surface.
	Catch cement samples and mix water. If cement is not at
	surface after the job, state (and federal if applicable)
	authorities must be notified for "top job." Cement must
	achieve 500 psi compressive prior to drill out. Min. WOC is
	24 hours (WOC time includes all time not drilling).
Surface Casing to Core Point 1	1925' to 6455'
Hole Size:	12-1/4"
Mud:	Saltwater gel
Bits:	PDC, 1.5 degree mud motor assembly

Procedure:	Before drilling: test casing for 5 min to 500 psi Drill up to 20' of new hole, perform 11.5 ppg or field- calculated ppg needed for estimated mud weight (EMW) formation integrity test (FIT) for 15 min Drill to Core Point 1 Condition hole. Trip out of hole (TOOH).
Core 1 Opeche/Broom Creek Hole Size: Mud: Bits: Procedure:	6455' to 6545' 8" Saltwater gel Core head and 90' core barrel assembly Drill core TOOH.
Core 2 Broom Creek Hole Size: Mud: Bits: Procedure:	6545' to 6635' 8" Saltwater gel Core head and 90' core barrel assembly Drill core TOOH.
Core 3 Broom Creek Hole Size: Mud: Bits: Procedure:	6635' to 6725' 8" Saltwater gel Core head and 90' core barrel assembly Drill core TOOH.
Core 4 Broom Creek/Amsden Hole Size: Mud: Bits: Procedure:	6725' to 6805' 8" Saltwater gel Core head and 90' core barrel assembly Drill core TOOH.
End of Core 4 to TD Hole Size: Mud: Bits: Procedure:	6805' to 6900' 12-1/4" Saltwater gel PDC, 1.5 degree mud motor assembly Ream cored interval Drill to TD of 6900' Condition hole. TOOH. Wireline log and test well. Condition mud for cement. Run casing and cement.

Size	Weight	Grade	Conn.	Collapse, psi	Burst, psi	Inner Diameter	Drift	Joint Strength, 1000 lb	Body Yield, 1000 lb
7"	26 lb/ft	L-80	LTC	5410	7240	6.276"	6.151"	511	604

Set at: 6300 ft

Csg Torque: Centr	7" Tq (ft-lb) calizers:	Optimum 4820 TBD in field	Min. 3615	Max. 6025
	Casing:	7" 26# 13Cr LTC	– New	Set at: 6900 ft

7" 26# L-80 LTC – New

Size	Weight	Grade	Conn.	Collapse, psi	Burst, psi	Inner Diameter	Drift	Joint Strength, 1000 lb	Body Yield, 1000 lb
7"	26 lb/ft	13Cr	LTC	5410	7240	6.276"	6.151"	511	604

7" Tq (ft-lb) Csg Torque: Centralizers:

Casing:

Optimum 4820 Min. 3615

Max. 6025

TBD in field

Cement: Actual cement program will be designed by selected contractor. For production casing, we will utilize CO₂ resistant cement as required by the regulation and/or as proposed by the selected contractor. Note: volumes calculated assuming 30% excess over 12-1/4" hole size

Rig down cementers. Install 5000-psi night-cap. Rig down release rig. **Finalize Well**

DRILLING TIME LINE

SLB estimates 27 days required for well drilling and construction, which is shown in Figure I-5.



Figure I-5 Injection well drilling and completion time line.

WELL SCHEMATIC OF THE RTE INJECTION WELL DETAILING DEPTHS AND SPECIFICATIONS OF CASING, CEMENT, AND PERFORATIONS

Figure I-6 shows the well schematic, and Figure I-7 shows the specifications for the well.







Injection Well



Wellhead Equipment

Section	ltem	Description						
"A"	Casing Head	13-3/8" SOW x 13-5/8" 5000 psi WP						
"B"	Tubing Head	13-5/8" 5000 psi x 7-1/16" 5000 psi WP						

Casing - Tubing Program

			Casing									
Section	Hole Size	OD	Weight	Grade	Conn	ID	Drift	Collapse	Burst	Joint		
Conductor	26"	16"	42 lb/ft	B&C	PE	15.5"						
Surface	14-3/4"	13-3/8"	72 lb/ft	L-80	ST&C	12.347"	12.191"	2,670 psi	5,380 psi	1,029 klbs		
Production	12-1/4" 7"		26 lb/ft	L-80 13Cr	LT&C	6.276"	6.151"	5,410 psi	7,240 psi	511 klbs		
Section	n Size		Weight	Grade	Conn	ID	Drift	Collapse	Burst	Joint		
Tubing	3-1/	' 2 "	92lh/ft	13Cr	17&C	2 992"	2 867"	7 400 nsi	6 990 nsi	142 5 klbs		

Mud Program

Hala Castian	Intorval	Tuno	MW	VIS	PV	YP	WL	Cl
Hole Section	Interval	туре	(Ib/gal)	(sec/qt)	(cP)	(lb/100ft)	(cc/30 min)	(ppm)
Surface	80'-1,925'	Freshwater	8.6-9.0	30-35	n/a	n/a	NC	n/a
Production	1,925'-6,900'	SW gel	10.2-10.4	40-46			6-8	150,000 - 170,000

Formation Tops

Formation	TVD*	KB TVD
Formation	(ft)	(ft)
Pierre	1,875	1,895
Greenhorn	4,125	4,145
Mowry	4,565	4,585
Inyan kara	4,910	4,930
Swift	5,310	5,330
Minnekahta	6,360	6,380
Opeche	6,405	6,425
Broom Creek	6,505	6,525
Amsden	6,775	6,795
TD	6,900	6,920

*TVD measured from ground level 20 ft for KB (assumption)

Figure I-7. EERC's monitoring well specifications.

PROPOSED WELL DRILLING PLAN FOR RTE INJECTION WELL FROM SCHLUMBERGER.

RTE, EERC and SLB Injector Well 1 LOCATION: (xxx) STARK COUNTY, NORTH DAKOTA WELL PROGNOSIS GROUND ELEVATION: (xxx)

SURFACE SECTION

- 1. Drill well on paper/prespud safety meeting to be held within a week from spud date.
- 2. Rig up drilling rig and drill rat and mouse holes, make up 14-3/4" BHA.
- 3. Have mud engineer provide a detailed inventory of all additives on location and provide to the project technical team prior to first mudding up.
- 4. Drill 1925' of 14-3/4" surface hole to accommodate approximately 1925' of 13-3/8" pipe.
- 5. Run openhole surface logs: resistivity-SP-Caliper, GR from TD to surface.
- 6. Run approximately 48 joints of 13-3/8", 72#/ft, J55 surface casing with a guide shoe and float collar on bottom joint.
- 7. Circulate casing to bottom of well and then pick up 2' off bottom to cement.
- 8. Cement well according to cement company design using 100% excess. Wait on cement for 24 hours or until 500 psi compressive strength is reached.

MAIN SECTION

- 1. NU BOP and flow stack. Function and pressure test BOP.
- 2. Make up 12-1/4" BHA.
- 3. Drill 12-1/4" hole from 1925'- 6900' to accommodate approximately 6900' of 7" casing.
- 4. Cores will be cut in the well in the Broom Creek formation. A total of 350 feet of core will be cut. Prepare mud for coring and keep to mud engineer's specification. Core each interval at the direction of the coring tool operator. Carefully lay down core at each coring interval. A separate core plan will be provided.
- 5. At TD, circulate hole clean and build mud to engineer's specifications. Short trip for minimum of 2000 feet and again circulate hole clean. TOOH to log making sure hole is full at all times.
- 6. Run openhole logs: triple combo–spectral gamma ray–dipole sonic–fracture finder from TD to casing shoe.
- 7. Run cased-hole logs: CBL–VDL–GR–temperature from casing shoe to surface.
- 8. Run MDT sampling as per sampling program.
- 9. After logging, trip back in hole and circulate to bottom. Circulate and condition hole in preparation for running casing. TOOH laying down drill string.
- 10. Run 7", 26#/ft, L-80, casing to 6300' and 7", 26#/ft, 80 Ksi CR-13 chrome casing from 6300' to 6900'.
- 11. Insert: SageWatch installation, easy rider and marker joint installation procedure.

- 12. Chrome casing requires special handling and care must be taken to not allow the chrome to become damaged by contact with other steel edges. The JFE Bear connection requires a different tong insert and must be torqued to manufacturer's specification. Failure to do so could result in premature casing failure.
- 13. Run guide shoe on bottom joint and float collar on first joint. Run centralizers as per cementing company design. Once casing is on bottom, circulate well to condition mud. Cement well as per cementing company design.
- 14. Displace well with freshwater. Bump plug to 1000 psi over final lift pressure. Check floats. Set casing slips and release rig.

INJECTION WELL PROPOSED COMPLETION PROCEDURE

Before rig up:

- Notify NDIC as required.
- Work road, location, and pit as needed for safe operation; install rig anchors; and test to 20,000 lb (or as required).
- Confirm actual casing depths with engineer, and inspect casing heads/valves.
- Confirm hole is loaded with fluid.
- Confirm no completion string in hole.
- Production casing is 7" 26 ppf with combination L-80 and L-80 13Cr (ID is 6.276").
- 1. Move in and rig up (MIRU) workover rig. Install BOPs, and test low/high 250 psi/4500 psi. Move in rental tools: 2-7/8" 6.5 lb/ft L-80 work string and 3-1/2" 13-Chrome tubing.
- Run in hole (RIH) with 6-1/8" bit, four drill collars and 2-7/8" L-80 work string. Continue to clean out production casing to PBTD, circulate hole clean with clean produced saltwater. Pressure-test production casing to ±2000 psi.

a. If casing fails pressure test, contact primary EERC engineer for further instructions. b. Implement solutions.

c. Continue completion after successful production casing test.

- 3. TOOH with tubing, lay down bit, scraper, collars, and tubing.
- 4. MIRU SLB Wireline Services. Install lubricator and RIH with CBL–VDL–casing collar locator (CCL)–GR–temperature log. Log from PBTD to surface (note: top of cement should be at surface). Review CBL–VDL with EERC engineer. If necessary, apply 1000 psi pressure to production casing and repeat.
- 5. Make up perforating guns, loaded 4 spf (shots per foot), 90° phasing with charges providing a 0.46" exit hole and ± 23 " penetration. Perforate well depths as directed by geologist and engineer using lubricator, noting casing reaction after each firing (perforations, anticipated to be several runs). RDMO (rig down and move out) SLB Wireline. (note: be aware of casing conveyed gauge at depth 6515' – 6545')
- 6. RU (rig up) to establish pump in injection rate down work string. Make up and RIH treating string that consists of treating packer with work string to 50'–100' above perforation. Establish injection rate at 0.5, 1.0, 1.5, 2.0, 3.0, and 5.0 bpm (barrels per minute), and allow each to stabilize for 10 minutes prior to increasing to the next target injection rate. Shut down injection and record ISIP (initial shut-in pressure) and fall-off pressure with real-time data.

The injection procedure is subject to change based on the judgment of on-site engineer. POOH (pull out of hole) treating string.

- Evaluate data to develop a procedure to isolate and break down individual zones with 15% hydrochloric acid (with additives) to ensure proper communication with the reservoir. Overdisplace each treatment with 40+ bbl of lease water. (note: stimulation job should be conducted through treating string)
- Make up 3-1/2" wireline reentry guide, 13-Chrome 3-1/2" × 2.667" ID XN-Nipple, 7" × 3-1/2" 13-Chrome packer, 1-joint of 3-1/2" 13-Chrome tubing, and 13-Chrome 3-1/2" × 2.813" ID X-Nipple. RIH with remainder of 3-1/2" 13-Chrome tubing. Place packer ±50'-100' above top perforation (avoid setting packer in casing collar). Space out tubing to land with ±30,000 lb compression on tubing.
- 8. RU and pump ±185 bbl corrosion-inhibited packer fluid down 3-1/2" tubing, and displace with ±56 bbl clean saltwater (placing packer fluid between the 3-1/2" tubing and 7" casing).
- 9. Set packer with 1/4 right-hand turn and place $\pm 30,000$ lb compression on packer.
- 10. Land tubing with tubing head, lock down, and secure.
- 11. Nipple down (ND) BOP and NU wellhead. See Figure I-8 for injection well wellhead schematic.
- 12. Contact NDIC to witness MIT (mechanical integrity test) 24 hr prior to MIT test. MIT well to 1500 psi or as directed by NDIC, charting pressure test. NDIC must witness MIT in accordance with state regulations. Well is ready for injection upon MIT approval from NDIC.
- 13. Load out surplus equipment. RDMO workover rig, continuing to be careful of wellhead equipment.
- 14. Clear and clean location.

Well ready for installation of surface equipment to initiate injection.

Figure I-8 shows wellhead schematic of the RTE injection well.



Figure I-8. RTE Injection well wellhead schematic (image courtesy of SLB).

DRILLING SOLID HANDLING

As drilling project will produce cuttings, the cuttings handling will be specified as follows. The cuttings will first be stored in a three-sided container on location where they will be solidified for transportation. RTE will send a side dump truck to pickup the cuttings from the location and transport them to the permitted solid waste disposal that can handle drilling. Once at the permitted solid waste disposal, the driver will provide the scale operator with a waste manifest from the RTE injection and monitoring sites, the truck will be scaled in on a certified scale. The truck will proceed to the special waste landfill, then dump the drill cuttings at an assigned location and return back to the scale to be weighed empty.

RTE WELL LOGGING PLAN FOR MONITORING AND INJECTION WELLS

Well log data will be acquired in both monitoring and injection wells. The following well logs are planned: triple combination, BHC sonic, spectral GR, capture spectroscopy, CBL–VDL, and injection profiles. A unique logging program has been designed for each casing section (Table I-1).

- The triple combination ("triple combo") will provide a wide variety of physical property measurements of the openhole environment. Data produced from this tool will include GR, neutron porosity, density, photoelectric factor, spontaneous potential, temperature, and resistivity logs. These logs will provide the ability to assess formation top depths (previously estimated from nearby wells), lithology, and petrophysical characteristics (which will be important in identifying well test and completion intervals and correlating core test data to offset wells).
- Caliper log will provide actual borehole diameter. This data will be the reference in calculating required cement volume.
- BHC sonic will provide a means for derivation of sonic porosity (a metric of connected, fluid-filled pore space), which will prove useful in zones characterized with complex lithologies.
- Spectral GR logs provide a means by which lithology can be interpreted and aid in coreto-log correlation.
- Capture spectroscopy logs provide an assessment of mineralogy and lithology and enhance extrapolation of core/log correlations of geologic properties based on lithology profiles to offset wells.
- Reservoir temperature logs measure borehole fluid temperature to establish reservoir conditions and provide information needed to design safe, low-risk infrastructure (i.e., pipeline specifications).
- CBL, VDL, and CCL log will provide an assessment of cement quality (and any associated remedial cementing operations that are required), a measurement of cement top, and a depth correlation for perforation and installing downhole equipment in relation to geology.

Technic	que/Well/Interval	Quantity	Justification
Well Lo	ogging		
	Surface Casing		
ОН	Triple combo (resistivity, GR, caliper and spontaneous potential [SP])	1925'-0'	Quantify variability in reservoir properties such as resistivity, lithology and core/log correlations. Identify the wellbore volume to calculate required cement volume.
СН	CBL-VDL-Temperature log	1925'-0'	Regulatory requirement, identify cement bond quality, cement top, and zonal isolation.
	Production Casing		
он	Triple combo (resistivity, GR, caliper and spontaneous potential [SP]) and BHC sonic	6900'–1925'	Quantify variability in reservoir properties within the ARM (active reservoir management) test area (Broom Creek Formation). Provide an input for enhanced geomodeling and predictive simulation of CO ₂ injection into Broom Creek Formations to improve ARM test design and interpretations. Generate core/log correlations that can be extrapolated to surrounding areas and hypothetical ARM cases for investigating optimization based on ARM test results. Select well test intervals and well completion intervals.
ОН	Capture spectroscopy/spectral GR	6900'-1925'	Lithology, identify clays that could affect injectivity, core/log correlations.
ОН	Fracture finder logs (acoustic log)	6900'–1925'	Quantify fracture in the Broom Creek Formation and confining layers to ensure the safety aspect of injecting CO ₂ in Broom Creek Formation especially in protecting groundwater and quantify sealing quality of confining layers
ОН	Fluid sampling	Broom Creek	Collect reservoir fluid sample for testing of potential fluid and mineralogical reactions between injected fluid chemistry, formation fluid chemistry, select step rate test fluid chemistry, and formation mineralogy that could affect injectivity.
СН	CCL-CBL-VDL-temperature log	6900'–0'	Regulatory requirement, identify cement bond quality, cement top, and zonal isolation.

Table I-1 Monitoring and Injection Well Plan

Note: OH – openhole; CH – cased-hole.

RTE MONITORING AND INJECTION WELL COST, AUTHORIZATION FOR EXPENDITURES (AFE) BY SCHLUMBERGER

Tables I-2 and I-3 provide the estimated SLB quotes.

				AUTH	ORIZAT	ION FOR		URES - Est	Cost	Carbo	an Services
In US \$											1007089/25897035
Operator:		EER	C-RTE		Project T	ype:	C02 Sequest	ration			
Contract A	vrea:				Well Nam	ne :	Monitor Well	1			
Contract A	vrea #:				Well Type	e :	Monitor				
Prepared I	by	GV,	JK, NM		Platform/	Tripod :			AFE #:	1	
					Field/Stru	icture :	Broom Creel	(Date:	22-Mar-17	
					Basin :		Williston				
	Location			Su	rface Coor	dinate					
	Surface Elev.			Ele	vation						
					2						
		PROC	SRAM	ACTUAL	8			PROGRAM	ACTUAL		
	Spud Date						Rig Days	20			
	Compl Date						Total Depth	6900			
	In Service						Well Cost \$/Pt.	\$0.00			
	Drilling Days						well Cost \$/Da	\$0.00			
	Close Out Dat	· ·			Completion	Tuno: Carod	Holo	Woll Status	Pro Pormit		
	olose out bu		-		Joinpiction	Type: Gasea		Wen Olatas.			
10000				i		Dry Hole	Completed	Total	Actual	Actual	%
	Descrip	tion				Budget	Budget	Budget	Expenditure	Over/Under	Over/Under
1	TANGIBLE C	OSTS	3								******
2	Casing					210.150	0	210.150	\$0	210,150	100
3	Casing Acce	ssori	es; Float	Equip & Line	ers	16.094	0	16.094	\$0	16.094	100
4	Tubina			1		10,004	115.638	115.638	\$0	115.638	100
5	Well Equipm	ent -	Surface			41.666	83.334	125.000	\$0	125.000	100
6	Well Equipm	ent -	Subsurfac	ce		0	179.050	179.050	\$0	179.050	100
7	Other Tanoih	le Co	osts			0	0	0	\$0 \$0	0	100
. 8	Contingency					26.791	37.802	64.593	\$0 \$0	64,593	100
9	Total Tan	gible	Costs			\$294.701	\$415.824	\$710.525	\$0	710.525	100
10	INTANGIBLE	cos	TS			,,	,	<i>,,.</i> 20			
11	PREPARATIO	N &	TERMINA	TION							1
12	Surveys					7.000	0	7.000	\$0	7.000	100
13	Location Sta	kina a	& Position	ning		4.500	0	4.500	\$0	4.500	100
14	Wellsite & A	ccess	s Road Pr	reparation		120,000	0	120,000	\$0	120,000	100
15	Service Lines	s & C	ommunica	ations		20,400	0	20,400	\$0	20,400	100
16	Water Syste	msĺ				0	0	0	\$0	0	
17	Riggina Un/F	Rigain	g Down/ N	Nob/Demoh		230.000	0	230.000	\$0	230.000	100
19	Total Pre	parat	ions/MO	3		\$381,900	\$0	\$381,900	\$0	381,900	100
20	DRILLING - V	//O C	PERATIC	ONS							
21	Contract Rig					656,060	155,000	811,060	\$0	811,060	100
22	Drlg Rig Crev	v/Cor	ntract Rig	Crew/Cateri	ng	0	0	0	\$0	0	
23	Mud, Chem	& End	gineerina	Servs		49,272	20,000	69,272	\$0	69,272	100
24	Water					15,000	24,000	39,000	\$0	39,000	100
25	Bits, Reame	rs & (Coreheads	S		30,500	0	30,500	\$0	30,500	100
26	Equipment F	ental	s			64,660	7,469	72,129	\$0	72,129	100
27	Directional D	rlg &	Surveys			194,398	0	194,398	\$0	194,398	100
28	Closed Loop	and [Disposal			98,898	0	98,898	\$0	98,898	100
29	Casing & We	ellhea	d Installat	tion & Inspec	ction	52,641	10,000	62,641	\$0	62,641	100
30	Cement, Cer	nentir	ng & Pum	p Fees		110,000	0	110,000	\$0	110,000	100
31	Misc. H2S S	Servic	es			0	0	0	\$0	0	
32	Total Drill	ing C	Operation	ıs		\$1,271,429	\$216,469	\$1,487,898	\$0	1,487,898	100
33	FORMATION	EVAL	LUATION								
34	Coring					113,750	0	113,750	\$0	113,750	100
35	Mud Logging	Serv	ices	-	-	0	0	0	\$0	0	ļ
36	Drillstem Tes	sts			-	40,000	0	40,000	\$0	40,000	100
37	Open Hole E	lec Lo	ogging Se	ervices	-	232,340	0	232,340	\$0	232,340	100
39	Total For	natio	on Evalua	ition	10000000000000000000000000000000000000	\$386,090	\$0	\$386,090	\$0	386,090	100
40	COMPLETIO	N III									
41	Casing, Line	r, We	Inead &	Lubing Instal	lation	0	0	0	\$0	0	ł
42	Remedial Ce	ment	ing and F	ees	-	0	0	0	\$0	0	l
43	Cased Hole	LIEC L	Logging S	ervices	-	0	57,232	57,232	\$0	57,232	100
44	Perforating 8	Wire	enne Servi	ces	-	0	22,884	22,884	\$0	22,884	100
45	Stimulation	reatn	nent			0	50,000	50,000	\$0	50,000	100
46	Production T	ests				0	0	0	\$0	0	
48	Total Con	pleti	ion Costs		0000000000	\$0	\$130,116	\$130,116	\$0	130,116	100
49	SUBSTITUT					045 400	104.000	250.000	6 0	250.000	4.00
50	Supervision	-			-	215,100	134,900	350,000	\$0	350,000	100
51	Insurance				-	0	0	0	\$0	0	<u> </u>
52	Permits & Fe	es	No. and a second		-	0	0	0	\$0	0	ł
53	Marine Renta	an & C	ion Charters		-	0	0	0	\$0	0	<u> </u>
54	Hencopter &	Avat	ion charg	US	-	0	0	0	\$0	0	
55	Other Transp	Junatio		-	-	23,000	0	23,000	\$0	23,000	100
56	Other Transp	ortati	Nex Di	-	-	0	0	0	\$0	0	
and the second se	Fuel & Lubrid	ants	NON RIG		-	3,600	0	3,600	\$0	3,600	100
57	Camp Facilit	ies	4 800		-	19,500	100.011	19,500	\$0	19,500	100
57	Allocated Ov	ernea	u - SCS	04	-	284,658	138,011	422,669	\$0	422,669	100
57 58 59		ernea	iu - Main (UITICE	-	0	0	0	\$0	0	ł
57 58 59 60	Allocated OV	ork -	· - ·	000		. 0	0	0	\$0	0	1
57 58 59 60 61	Allocated Ov Allocated Ov	erhea	ad - Overs	eas		050 500	C1 0.10	000 477	e e	200 477	100
57 58 59 60 61 62	Allocated Ov Allocated Ov Contingency	erhea Intan	ad - Oversi Igibles	eas		258,528	61,949	320,477	\$0	320,477	100
57 58 59 60 61 62 64	Allocated Ov Allocated Ov Contingency Total Gen	erhea Intan eral	ad - Overson Igibles Costs	eas		258,528 \$804,386	61,949 \$334,860	320,477 \$1,139,246	\$0 \$0	320,477 1,139,246	100
57 58 59 60 61 62 64	Allocated Ov Allocated Ov Contingency Total Gen	erhea Intan eral	ad - Oversi igibles Costs	eas		258,528 \$804,386	61,949 \$334,860	320,477 \$1,139,246	\$0 \$0	320,477 1,139,246	100
57 58 59 60 61 62 64 64	Allocated Ov Allocated Ov Contingency Total Gen	erhea Intan eral NGIBI	ad - Oversi ngibles Costs	s		258,528 \$804,386 \$2,843,805	61,949 \$334,860 \$681,444	320,477 \$1,139,246 \$3,525,249	\$0 \$0 \$0	320,477 1,139,246 3,525,249	100

Table I-2. Monitoring Well AFE

Table I-3. Injection Well AFE

				R	TE Injec	ction W	ell 1		Sch	lumberger
			AUTHO	RIZAT	ION FOR E		URES - Est	Cost	Carbi	on Services
In US \$ Operator:		FERC-RTE		Project T	vne ·	C02 Sequest	ration			
Contract	Area:	LERO-RIE		Well Nam	уре. 1е:	Injection We				
Contract /	Area #:			Well Type	e :	Injection				
Prepared	by	GV, JK, NM		Platform/	Tripod :		-	AFE #:	1	
				Field/Stru	icture :	Broom Creel	ĸ	Date:	12-Mar-17	
				Dasin :		winiston				
	Location		Sur	face Coor	dinate					
	Surface Elev.		Elev	ation						
	Cauld Date	PROGRAM	ACTUAL			Dia Dava	PROGRAM	ACTUAL		
	Spud Date		-			Rig Days	20			
	In Service					Well Cost \$/Ft.	\$0.00			*****
	Drilling Days					Well Cost \$/Day	\$0.00		l	
	Close Out Da	te:	C	ompletion	Type: Cased	Hole	Well Status:	Pre Permit		
0000					Dry Hole	Completed	Total	Actual	Actual	%
	Descrip	tion			Budget	Budget	Budget	Expenditure	Over/Under	Over/Under
1	TANGIBLE C	OSTS								
2	Casing				239,190	0	239,190	\$0	239,190	100%
3	Casing Acce	essories; Float E	quip & Liner	S	17,058	150.050	17,058	\$0	17,058	100%
4	Well Equipr	ent - Surface	-		41 666	100,252	150,252	\$0 ¢∩	125 000	100%
6	Well Equipri	nent - Subsurface	e		41,000	41.050	41.050	\$0	41.050	100%
7	Other Tangit	ble Costs			0	0	0	\$0	0	
8	Contingency	r			29,791	27,464	57,255	\$0	57,255	100%
9	Total Tan	gible Costs			\$327,705	\$302,100	\$629,805	\$0	629,805	100%
10		COSIS								
12	Surveys				7.000	0	7.000	\$0	7.000	100%
13	Location Sta	aking & Positioni	ng		4,500	0	4,500	\$0	4,500	100%
14	Wellsite & A	ccess Road Pre	eparation		120,000	0	120,000	\$0	120,000	100%
15	Service Line	s & Communica	tions		25,500	0	25,500	\$0	25,500	100%
16	Water Syste	ems Dissing Daws / M	ah/Damah		0	0	0	\$0	0	1000
10	Total Pre	narations/MOR	do/Demob		\$352,000	\$0	\$352,000	\$0 \$0	352,000	100%
20	DRILLING - W	V/O OPERATIO	NS		\$002,000	φ0	\$352,000	ΨŪ	002,000	1007
21	Contract Rig	1			676,200	155,000	831,200	\$0	831,200	100%
22	Drlg Rig Cre	w/Contract Rig 0	Crew/Caterin	g	0	0	0	\$0	0	
23	Mud, Chem	& Engineering S	ervs		50,352	20,000	70,352	\$0	70,352	100%
24	Water	ra 8 Carabaada			15,000	24,000	39,000	\$0	39,000	100%
20	Equipment F	Rentals			73 270	6 769	80,039	\$0	80,039	1007
27	Directional D	Orlg & Surveys			240,398	0,100	240,398	\$0	240,398	1009
28	Closed Loop	and Disposal			98,898	0	98,898	\$0	98,898	100%
29	Casing & W	ellhead Installati	on & Inspect	tion	52,641	10,000	62,641	\$0	62,641	100%
30	Cement, Ce	menting & Pump	Fees		110,000	0	110,000	\$0	110,000	100%
31	Total Dril	Services			\$1 347 259	\$215 769	\$1 563 028	\$0 \$0	1 563 028	100%
33	FORMATION	EVALUATION	•		ψ1,047,200	\$210,700	¥1,000,020	ψŪ	1,000,020	1007
34	Coring				113,750	0	113,750	\$0	113,750	100%
35	Mud Logging	Services			0	0	0	\$0	0	
36	Drillstem Te	sts	icon		40,000	0	40,000	\$0	40,000	100%
37	Upen Hole E	mation Evaluat	ion		232,340 \$386.000	0	232,340	\$0 ¢0	232,340	100%
40	COMPLETIO	N			¥300,090	- U	\$300,090	J	500,030	1307
41	Casing, Line	er, Wellhead & Te	ubing Installa	ation	0	0	0	\$0	0	
42	Remedial Ce	ementing and Fe	es		0	0	0	\$0	0	
43	Cased Hole	Elec Logging Se	ervices		0	57,232	57,232	\$0	57,232	100%
44	Stimulation	x vvireiirie SerMC	62		0	22,884	50,000	\$0 ¢0	50 000	100%
46	Production 1	Tests			0	0	0	\$0	0,000	100%
48	Total Cor	npletion Costs			\$0	\$130,116	\$130,116	\$0	130,116	100%
49	GENERAL									
50	Supervision				221,600	135,800	357,400	\$0	357,400	100%
51	Permits & F	ees			0	0	0	\$0 \$0	0	
53	Marine Rent	al & Charters			0	0	0	\$0	0	1
54	Helicopter &	Aviation Charge	s		0	0	0	\$0 \$0	0	
55	Land Transp	ortation			23,000	0	23,000	\$0	23,000	100%
56	Other Trans	ortation			0	0	0	\$0	0	
57	Fuel & Lubri	cants Non Rig			4,500	0	4,500	\$0	4,500	100%
59		verhead - SCS			20,000	128 652	438 328	\$U .\$0	438 328	100%
60	Allocated O	verhead - Main C	ffice		0	0	0	\$0	0	
61	Allocated O	verhead - Overse	as		0	0	0	\$0	0	
62	Contingency	Intangibles			266,413	61,034	327,446	\$0	327,446	100%
64	I otal Ger	neral Costs			\$845,189	\$325,486	\$1,170,674	\$0	1,170,674	100%
65		NGIBLE COSTS			\$2,930 538	\$671.370	\$3 601 908		3,601,908	100%
	TOTAL TANC	GIBLE COSTS			\$327,705	\$302,100	\$629,805	\$0	629,805	100%
66	тот	AL WELL CO	DST				\$4,231,712	\$0	4,231,712	100%

U-TUBE SYSTEM DESCRIPTION

Figure I-9 provides an example schematic of the U-tube system.



Figure I-9. Example U-tube system to be implemented on the monitoring well for fluid samples (figure courtesy of Freifeld and others, 2005¹).

¹ Freifeld, B.M., Trautz, R.C., Kharaka, Y.K., and Collins, D.J., 2005, The u-tube: a novel system for acquiring borehole fluid samples from a deep geologic CO₂ sequestration experiment: *in* Journal of Geophysical Research Atmospheres, October, v. 110 p. 10.

SAGERIDER PRESSURE – TEMPERATURE MONITORING EQUIPMENT





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 realtime 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





SageWatch	System S	Size Chart –	Casing	Integrated
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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	20,000 psi					
Temperature Rating	392 deg F					
Pressure Resolution	0.01 psi					
Temperature Resolution	0.01 deg F					
Pressure Accuracy	+/- 0.02 % of Calibration					
Temperature Accuracy	+/- 0.90% of Calibration					
Hysteresis	+/- 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





EASYRIDER PERFORATION GUN FOR MULTIZONE COMPLETION SYSTEM 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







PRESSURE SENSOR SPECIFICATIONS

NOSHOK pressure sensors will be used in the pipeline and in the casing and tubing of all new and existing wells to continuously monitor pressures. NOSHOK pressure sensors are the industry standard in pressure sensor technology. Technical information about the sensors is provided in Figures I-10 and I-11.



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Figure I-10. NOSHOK-provided 100 Series pressure sensor transmitters and transducers specification data sheet (page 1).



ORDERING INFORMATION DIMENSIONS

				ORDE	RING I	FORMATION				
SERIES	100									
PRESSURE	30vac	-30 inHg to 0 psig	5	0 psig to 5 psig	200	0 psig to 200 psig	3000	0 psig to 3,000 psig	15A	0 psia to 15 psia
RANGES	30/15	-30 inHg to 15 psig	10	0 psig to 10 psig	300	0 psig to 300 psig	4000	0 psig to 4,000 psig	30A	0 psia to 30 psia
	30/30	-30 inHg to 30 psig	15	0 psig to 15 psig	500	0 psig to 500 psig	5000	0 psig to 5,000 psig	60A	0 psia to 60 psia
	30/45	-30 inHg to 45 psig	25	0 psig to 25 psig	600	0 psigto 600 psig	6000	0 psig to 6,000 psig	100A	0 psia to 100 psia
	30/100	-30 inHg to 100 psig	30	0 psig to 30 psig	750	0 psigto 750 psig	7500	0 psig to 7,500 psig	150A	0 psia to 150 psia
	30/150	-30 inHg to 150 psig	60	0 psig to 60 psig	1000	0 psig to 1,000 psig	10000	0 psig to 10,000 psig	200A	0 psia to 200 psia
	30/200	-30 inHg to 200 psig	100	0 psig to 100 psig	1500	0 psig to 1,500 psig	15000	0 psig to 15,000 psig	300A	0 psia to 300 psia
	30/300	-30 inHg to 300 psig	150	0 psig to 150 psig	2000	0 psig to 2,000 psig				
				psig = gauge pressure	psia	= absolute pressure	Other ran	ges available on request		
ACCURACIES	1	±0.5%full scale (BFSL)			2	±0.25% full scale (Bl	FSL)			
OUTPUTSIGNAL	1	4 mA to 20 mA, 2-wire								
PROCESS	1	1/8"NPT male	3	SAE J1926-3:7/16-20	Adjusta	ble	9	SAE J1926-1:7/16-20		
CONNECTIONS	2	1/4" NPT male	4	1/8"NPT female			10	G1/4 male		
ELECTRICAL	1	36" cable (connected to o	ption 7)	6	1/2" NPT conduit (w	ith 36" ca	ble)	25	M12 x 1 (4-pin)
CONNECTIONS	2	4-pin Bendix			7	Mini-Hirschmann (DI	N EN 17	5301-803 Form C)	36	Integral cable 36"
	3	6-pin Bendix								
OPTION	ST8	Threaded Orifice								

Please consult your local NOSHOK Distributor or NOSHOK, Inc. for availability and delivery information.





DENSITY METER SPECIFICATIONS

Density meters provide the ability to measure fluid extraction and injection volumes and identify changes in fluid properties. Data obtained from density meters will be used for calibration of the reservoir simulation model, which will allow for more accurate results. Emerson FDM 7828 density meters were chosen for the project because of their accuracy, adaptability, and ease of integration into our proposed SCADA system (see Figures I-12 through I-17).



DISCOVER THE DIFFERENCE

Unparalleled real-world performance means delivering measurement stability and repeatability that stand up to even the most difficult application and process challenges. At Emerson, we design our products to do just that, and then we support them with a team of experts dedicated to helping you achieve incredible results.



Figure I-12. Emerson-provided density meter specification data sheet (page 1).



Emerson delivers outstanding results that ensure the success of your process and operation. We provide unmatched value with a wide breadth of products that include Coriolis Density & Viscosity, Magnetic and Vortex Meters. Our flow solutions deliver:

Leading technology- through our world-class research and development capabilities — driving product development solutions for your most challenging applications.

Product breadth- with our wide range of materials, configurations and electronics capabilities to enable flexible and easy installation for every operating environment.

Unparalleled value- through our application expertise that covers more than 35 years of experience and more than 1,000,000 devices installed worldwide.

Look closer to discover why Micro Motion[®] and Rosemount[®] flow technologies are unmatched in the industry and what they can do.

Figure I-13. Emerson-provided density meter specification data sheet (page 2).

SETTING YOU UP FOR

Emerson is dedicated to offering Micro Motion Coriolis products that deliver the three things that we believe are key to the success of your process.

Micro Motion offers a wide range of products for any application all of which are easy to install, configure and maintain. Not only do our products exhibit unparalleled real-world performance, but they also provide actionable insights that help you optimize your process and set you up for success.

SIMPLIFIED SOLUTIONS

We're committed to making your entire experience easier with our broad range of simple-to-use, high-performance products that excel under the widest range of conditions and applications.

MEASUREMENT CONFIDENCE

Confidence in your measurement is key to your process. That's why we are dedicated to the pursuit of ultimate real-world performance, even in the most critical and complex applications.

Whatever your measurement needs, you can trust our industry-leading products to deliver unparalleled accuracy.

PROCESS INSIGHTS

To optimize your process and ensure that it is running smoothly, you need to have the right insights. Our technology and experts provide you with just that.

Emerson technologies offer powerful integrated diagnostics that provide you with process data and actionable information, enabling you to make quick, effective decisions. With our meters, issues such as two-phase flow or corrosion can easily be detected and addressed.



MICRO MOTION[®]

Figure I-14. Emerson-provided density meter specification data sheet (page 3).

MICRO MOTION DENSITY & VISCOSITY



Compact Density Meter (CDM) The Compact Density Meter (CDM) is the next generation in fiscal custody transfer and precision process density and concentration measurement.



Fork Density Meter (FDM)

The Fork Density Meter (FDM) is the latest development in direct insertion density and concentration. This meter builds upon the success of the Micro Motion 7826 and 7828 density meters.



Fork Viscosity Meter (FVM)

The Fork Viscosity Meter (FVM) is the latest development in multivariable direct insertion viscosity meters. These unique meters provide unbeatable installation flexibility, robustness and market-leading communications flexibility.





The Gas Density Meter (GDM) is the next generation in fast response direct gas density measurement. It's designed for applications such as fiscal custody transfer where reliability and accuracy are critical.



Gas Specific Gravity Meter (SGM)

The Gas Specific Gravity Meter (SGM) is the industry standard for direct measurement of specific gravity, molecular weight, relative density, Calorific Value/BTU and Wobbe Index.



Heavy Fuel Viscosity Meter (HFVM)

The HFVM Viscomaster is a high performance, multivariable viscosity meter designed for the measurement and control of heavy fuel oil (HFO) that supply engines, turbines and burners in Marine and Power applications.



Figure I-15. Emerson-provided density meter specification data sheet (page 4).

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MICRO MOTION CORIOLIS SENSORS

	ELITE [®]	F-Series	H-Series	T-Series	R-Series	LF-Series
Application Type						
Continuous Control	•	•	•	•	•	•
Batching / Loading / Blending	•	•	•	•	•	•
Custody Transfer	٠	•				
Measurement Accuracy						
Liquid & Slurry - Flow	±0.05%	±0.10%	±0.10%	±0.15%	±0.4%%	±0.50%
Liquid & Slurry - Density	±0.0002 g/cm³ (±0.2 kg/m³)	±0.0005 g/cm ³ (±0.5 kg/m ³)	±0.0005 g/cm ³ (±0.5 kg/m ³)	±0.002 g/cm ³ (±2.0 kg/m ³)	±0.003 g/cm³ (± 3.0 kg/cm³)	±0.005 g/cm ³ (±5.0 kg/m ³)
Gas - Flow	±0.25%	±0.50%	±0.50%	±0.50%	±0.75%	±0.50%
Capabilities						
Self Draining	•	•	•	•	•	
Sanitary / Hygienic	•		•	•		
Two-Phase Flow / Entrained Gas	•	•	•			
Smart Meter Verification	•	•	•			
High Temperature *	•	•				
High Pressure **	•	•				
Cryogenic *	•	•				
Wetted Materials						
300-Series Stainless Steel	•	•	•		•	•
Super Duplex	•					
Nickel Alloy C22	•	•				
Nickel Alloy B3						
NI-Span-C*						
Titanium				•		
Monel€						
Zirconium						
Nominal Line Sizes						
Inches	1/2-16	1/4-4	1/4-4	1/4-2	1/4-2	1/32-1/4
Millimeters	2-406	6-100	6-100	6-50	6-75	0.8-6

Supported on all models Usupported on some models
 *Standard temperature is -148 to +400°F (-100 to +204°C) High temperature is above +400°F (+204°C) Cryogenic is below -148°F (-100°C)
 **Above 1494 PSI (103 bar)



Figure I-16. Emerson-provided density meter specification data sheet (page 5).

MICRO MOTION DENSITY & VISCOSITY

	CDM	FDM	FVM	HFVM	GDM	SGM
Application Type						
Cantinuous Contral	•	•	•	•	•	•
Batching / Loading / Blending	•	•	•	•	•	•
Custody Transfer	•				•	•
Measurement Accuracy						
Liquid & Slurry - Density	±0.0001 g/cm ³	±0.001 g/cm ³	±0.001 g/cm ³	±0.001 g/cm ³		
Liquid - Viscosity			±0.2 cP (for 0.5- 10 cP) ±1% of calibration range max	±0.2 cP (for 0.5-10 cP) ±1% of calibration range max		
Gas - Density					Up to ± 0.1 %	Up to ± 0.1%
Gas - Density / Specific Gravity						Up to ± 0.1%
Capabilities						
Self Draining	٠	٠	٠	٠		
Two-Phase Flow / Entrained Gas	•					
Known Density Verification (KDV)	•	•	•	•	•	•
High Pressure		•	•	•	•	
Wetted Materials						
300-Series Stainless Steel	•	٠	•	•	•	٠
Nickel Alloy C22	•	•	•			
Ni-Span-C*					•	•
Titanium		•				
Zirconium		•				
Nominal Line Sizes						
Inches	1	1 or Larger	1 or Larger	1 or Langer	% or Larger	1/4 or Larger
Millimeters	23	25 or Larger	25 or Larger	25 or Larger	6 or Larger	6 or Larger
Output Variables						
Density	•	•	•	•	•	•
Time Period	•	•			•	
Temperature	•	•	•	•	•	•
Drive Gain					-	
External Temperature Input		•	•	•	•	•
External Pressure Innut		-	-	-		
Einw Rate (Velocity)						
Palarad Vienceity	•		•			
Specific Craulty Malagular Walcht						•
Local Display						•
2 Line	•					
Outpute	•	•	•	•	•	•
4.20 mA						
4-20 mA						
4-20 mA + PART			•	•		
Time Period Signal (TPS)						
Discrete Output						
Modbus/KS-485	•	•	•	•	•	•
(Remote Mount Only)	•	•	•			
Transmitter Mounting						
Integral	•	•	•	•	•	•
Approvals						
ATEX	•	•	•	•	•	•
CSA	•	•	•	•	•	•
IECeX	•	•	•	•	•	•
Marine				•		

Figure I-17. Emerson-provided density meter specification data sheet (page 6).

EPA CLASS VI REGULATION CHECKLIST

WELL TESTING AND MONITORING

No.	Regulations	
	(refer to EPA – U.S. Environmental Protection Agency)	
1	Analysis of the CO2 stream - Chemical composition - Physical characteristic [40 CFR 146.90(a)] Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics	
	Monitoring of operational parameters	
2	Tubing (continuous recording) Injection pressure with digital pressure gauge Injection rate with flowmeter / Coriolis Injection volume with flowmeter / Coriolis 	
	<u>[40 CFR 140.90(b)]</u> Installation and use, except during well workovers as defined in § 146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added	
	[40 CFR 146.88(d)] (d) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	
	Note for external gauge: EPA recommends that the use of external gauges be determined in consultation with the underground injection control (UIC) Program Director, considering whether external gauges are a viable option for the given project and whether they pose an undue risk compared to downhole equipment. (UIC Program Class VI Well Testing and Monitoring Guidance page 60 - 3 rd paragraph)	

No.	Regulations	Checklist
	Monitoring of operational parameters	
	Annulus (continuous recording)	
3	 Annulus pressure (should be greater than injection pressure) with digital pressure gauge Annulus fluid volume with flowmeter 	
	[40 CFR 146.90(b)]	
	Installation and use, except during well workovers as defined in § 146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added	
	[40 CFR 146.88(d)]	
	(d) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	
	Corrosion monitoring	
	Quarterly basis	
	 Corrosion coupon will be installed in flowline and conducted on quarterly basis EPA may recommend Casing Inspection Logs on periodic basis (with caliper log) 	
	[40 CFR 146.90(c)]	
4	Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in § 146.86(b), by:	
	(1) Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	
	 (2) Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or (3) Using an alternative method approved by the Director 	
	[40 CFR 146.89(d)]	
	(d) If required by the <u>Director</u> , at a frequency specified in the testing and monitoring plan required at § 146.90, the <u>owner or operator</u> must run a <u>casing</u> inspection log to determine the presence or absence of corrosion in the long-string <u>casing</u> .	

No.	Regulations	Checklist
	Monitoring of groundwater quality at a site-specific frequency and spatial distribution	
5	- It should include the description of method sensitivities and monitoring strategy in detect deviations in project performance and/or any endangerment to an underground source of drinking water (USDW)	
	[40 CFR 146.90(d)]	
	 Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including: (1) The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other 	
	factors; and (2) The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under § 146.82(a)(6) and on any modeling results in the area of review evaluation required by § 146.84(c)	
	Monitoring of geochemical changes above the confining zone(s), at a site-specific frequency and spatial distribution which will be able to accommodate the U-tube sampler	
	[40 CFR 146.90(d)]	
6	 Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including: (1) The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and (2) The monitoring frequency and spatial distribution of monitoring wells 	
	based on baseline geochemical data that has been collected under § 146.82(a)(6) and on any modeling results in the area of review evaluation required by § 146.84(c)	
No.	Regulations	Checklist
-----	--	-----------
7	External mechanical integrity testing to ensure that there is an absence of any significant fluid movement into a USDW through channels adjacent to the wellbore, at least once a year until the injection well is plugged. Conducting pressure test by applying $\pm 2,000$ psi. [40 CFR 146.89(c): 40 CFR 146.90(e)] A demonstration of external mechanical integrity pursuant to § 146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at § 146.89(d) at a frequency established in the testing and monitoring plan	
8	Pressure fall-off testing, at least once every 5 years (or more frequentlyif required by the UIC Program Director)[40 CFR 146.90(f)]A pressure fall-off test at least once every five years unless more frequenttesting is required by the Director based on site-specific information	
9	Testing and monitoring to track the extent of the CO ₂ plume and the presence or absence of elevated pressure (e.g., the pressure front) by having monitoring well to monitor the breakthrough of either pressure or CO ₂ . [40 CFR 146.90(g)] Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using: (1) Direct methods in the injection zone(s); and, (2) Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate	

No.	Regulations	Checklist
	Surface air and/or soil gas monitoring (only if required by the UIC Program Director)	
	[40 CFR 146.90(h)]	
10	The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW. (1) Design of Class VI surface air and/or soil gas monitoring must be based	
	on potential risks to USDWs within the area of review; (2) The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or	
	compliance with standards under § 144.12 of this chapter; (3) If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 et seq.) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and	
	meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit	

No.	Regulations	Checklist
	Internal mechanical integrity testing, prior to injection	
	 By annulus pressure test (consult with the UIC Program Director for the required delta pressure between tubing and annulus) for 15 minutes to 1 hour 	
	[40 CFR 146.87(a)(4)(i)]	
11	 (4) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include: (i) A pressure test with liquid or gas; [other options] (ii) A tracer survey such as oxygen-activation logging; (iii) A temperature or noise log; (iv) A casing inspection log 	
	[40 CFR 146.89(a)(1) and 146.89(b)]	
	 (a) A Class VI well has mechanical integrity if: (1) There is no significant leak in the casing, tubing, or packer; (b) To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e) 	

LOGGING REQUIREMENT

No.	Regulations	Checklist
	(refer to EPA – U.S. Environmental Protection Agency)	
1	 Surface casing [OPENHOLE] Resistivity, spontaneous potential, caliper logs [CASED-HOLE] Cement bond, variable density, and temperature logs [40 CFR 146.87(a)(2)] At a minimum, such logs and tests must include: (2) Before and upon installation of the surface casing: (i) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and (ii) A cement bond and variable density log to evaluate cement 	
	quality radially, and a temperature log after the casing is set and cemented	
	 [OPENHOLE] Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs [CASED-HOLE] Cement bond, variable density, and temperature logs 	
2	<u>[40 CFR 146.87(a)(2)]</u> At a minimum, such logs and tests must include: (3) Before and upon installation of the long string casing: (i) Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and (ii) A cement bond and variable density log, and a temperature log after the casing is set and cemented.	

No.	Regulations	Checklist
	Coring	
3	 Take whole cores or sidewall cores of the injection zone and confining system – will use 4-in. whole-core drill bit with total core length 350 ft Formation fluid samples from the injection zone(s) – conducting drillstem test (DST) in Broom Creek Formation 	
	[40 CFR 146.87(b)]	
	(b) The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: Well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.	
	Additional information	
4	 Fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s) – conducting DST in Broom Creek Formation Fracture pressure of confining and injection zone(s) – conducting injectivity test from 0.5 bpm to 5 bpm 	
	[40 CFR 146.87(c) and d(d)]	
	 (c) The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s). (d) At a minimum, the owner or operator must determine or calculate the 	
	following information concerning the injection and confining zone(s):	
	 (1) Practine pressure, (2) Other physical and chemical characteristics of the injection and confining zone(s); and (2) Division and chemical characteristics of the form (in Childrich). 	
	(5) Physical and chemical characteristics of the formation fluids in the injection zone(s).	

WELL CONSTRUCTION

No.	Regulations	Checklist
	(refer to EPA – U.S. Environmental Protection Agency)	
1	 Surface casing Extend from the ground surface through the base of the lowermost USDW – surface casing will be installed from surface to 1925 ft or 50 ft below USDW Cemented up to the ground surface [40 CFR 146.86(b)(2)] (2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement. 	
2	 Long-string casing Extend from the ground surface down to the injection zone – production casing will be installed from surface to 6900 ft Cemented up to the ground surface [40 CFR 146.86(b)(2)] (3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages. 	
3	 Caliper logs will be conducted as part of openhole log (triple combo) Should be conducted before installation of the surface casing and the long-string casing [40 CFR 146.87(a)(2)(i): 40 CFR 146.87(a)(3)(i)]] (2) Before and upon installation of the surface casing: (i) Resistivity, spontaneous potential, and caliper logs before the casing is installed; (3) Before and upon installation of the long string casing: (i) Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; 	

No.	Regulations	Checklist
	Tubing – 13Cr tubing (CO ₂ resistant) will be run to 50–100 ft above perforation	
	 Run inside the long-string casing down to a point just below the packer Its annulus should be filled with a noncorrosive fluid – corrosion-inhibited fluid will be used as packer fluid 	
	[40 CFR 146.86(c)(1)]	
4	(1) Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.	
	[40 CFR 146.88(c)]	
	(c) The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	
	Cement – CO ₂ -resistant cement will be used, and the casings (surface and production) will be cemented from TD to surface	
	 Should provide zonal isolation Can be done in stages Should compatible with the CO₂ stream and formation fluid 	
5	[40 CFR 146.86(b)(5)]	
	(5) Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	

No.	Regulations	Checklist
	Cement bond and variable density log (CBL–VDL) will be conducted from TD of each casing to surface	
	 Required after setting and cementing the surface and long-string casing 	
	[40 CFR 146.87(a)(2)(ii) and 146.87(a)(3)(ii)]	
6	(2) Before and upon installation of the surface casing:	
0	(ii) A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented	
	(3) Before and upon installation of the long string casing:	
	(ii) A cement bond and variable density log, and a temperature log after the casing is set and cemented	
	Packer – will be set 50 ft above top of Broom Creek Formation	
7	 Consider the following aspects: mechanical integrity factor, logging requirement, plume monitoring, approved cemented interval Consult with the UIC Program Director to select the best location <u>(UIC Program Class VI Well Construction Guidance page 29 - last</u> paragraph) 	
	Placement of the packer can also be an important consideration, influenced by numerous factors. If the packer is placed above the confining layer, it will allow logs to be run next to the casing through the confining layer without having to pull the tubing. Alternatively, placing the packer close to the perforations may allow instruments used for carbon dioxide plume tracking, such as geophones, to be placed closer to the expected plume. Packer placement can also affect how mechanical integrity tests are conducted and may affect the stress placed on well components. The owner or operator should consider these factors, in consultation with the UIC Program Director, in order to select the best location for the packer according to project- and site-specific circumstances.	
	[40 CFR 146.86(c)(1)]	
	(1) Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director	

No.	Regulations	Checklist
8	 Permit application Information concerning the tubing and packer should include: Depth of setting. Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids. Maximum proposed injection pressure. Maximum proposed annular pressure. Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream. Size of tubing and casing. Tubing tensile, burst, and collapse strengths. 	
	 Surface safety system (onshore well) – monitoring alarm will be set in the injection pump and emergency shut-down valve will also be installed as a protection tool. All monitoring data will be tied up to the remote sensing system (SCADA) Installation of alarms and automatic surface shut-off system Installation of downhole shut-off systems (may be required) The system should be monitored and controlled by a system (like SCADA) Permit should be submitted along with schematics of the surface and subsurface construction detail of the well (include type and location to the safety valve(s) and any landing nipples if used) 	
9	 [40 CFR 146.88(e)(2)] (e) The owner or operator must install and use (2) Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and (3) Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit [40 CFR 146.82(a)(11) and 146.82(a)(12)] (11) Schematics or other appropriate drawings of the surface and subsurface construction details of the well; (12) Injection well construction procedures that meet the requirements of § 	

No.	Regulations	Checklist
	Injection pressure – tubing will be installed for injection purposes and injection pressure will be limited by injection pump pressure (or 90% of injection zone fracture pressure)	
	 Should not exceed 90% of the injection zone fracture pressure, except during stimulation Injection should be through tubing 	
	[40 CFR 146.88(a)]; [40 CFR 146.88(b)]	
10	 (a) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit. (b) Injection between the outermost casing protecting USDWs and the well bore is prohibited 	

EPA ATTACHMENT FOR WELL TESTING AND MONITORING

Sections of the Testing and Monitoring Guidance	Relevant Regulatory Citations		
2. Mechanical integrity testing			
2.1 Mechanical integrity definitions and mechanical integrity testing requirements	40 CFR 146.87(a)(4) 40 CFR 146.89 40 CFR 146.92(a)		
2.2 Internal MITs	40 CFR 146.87(a)(4) 40 CFR 146.89(a)(1) 40 CFR 146.89(b)		
2.3 External MITs	40 CFR 146.87(a)(4) 40 CFR 146.89(a)(2) 40 CFR 146.89(c) 40 CFR 146.92(a)		
2.4 Reporting results of MITs	40 CFR 146.91(a)(7) 40 CFR 146.91(b)(1)		
3. Operational testing and monitoring during injection			
3.1 Analysis of the carbon dioxide stream	40 CFR 146.90(a) 40 CFR 146.91(a)(1) 40 CFR 146.91(a)(7)		
3.2 Continuous monitoring of injection rate and volume	40 CFR 146.88(e)(1) 40 CFR 146.90(b) 40 CFR 146.91(a)(2)		
3.3 Continuous monitoring of injection pressure	40 CFR 146.88(e)(1) 40 CFR 146.90(b) 40 CFR 146.91(a)(2)		
3.4 Corrosion monitoring	40 CFR 146.89(d) 40 CFR 146.90(c) 40 CFR 146.91(a)(7)		
3.5 Pressure fall-off testing	40 CFR 146.90(f) 40 CFR 146.91(a)(7)		
4. Ground water quality and geochemical monitoring			
4.1 Design of the monitoring well network	40 CFR 146.90(d) 40 CFR 146.90(g)(1)		
4.2 Monitoring well construction	40 CFR 146.90(d)		
4.3 Collection and analysis of ground water samples	40 CFR 146.90(d) 40 CFR 146.90(g)(1) 40 CFR 146.91(a)(7)		
5. Plume and pressure-front tracking			
5.1 Class VI Rule requirements regarding plume and pressure-front tracking	40 CFR 146.90(g)		

Table 1-1. Crosswalk of guidance document sections and relevant Class VI Rule citations.

Sections of the Testing and Monitoring Guidance	Relevant Regulatory Citations	
5.2 Direct pressure-front tracking	40 CFR 146.90(g)(1) 40 CFR 146.91(a)(7)	
5.3 Plume and pressure-front tracking using indirect geophysical techniques	40 CFR 146.90(g)(2) 40 CFR 146.91(a)(7)	
5.4 Use of geochemical ground water monitoring in plume tracking	40 CFR 146.90(d) 40 CFR 146.90(g)(2)	
6. Surface air and soil gas monitoring		
6.1 Soil gas monitoring	40 CFR 146.90(h)(1)–(2) 40 CFR 146.91(a)(7)	
6.2 Surface air monitoring	40 CFR 146.90(h)(1)–(2) 40 CFR 146.91(a)(7)	

APPENDIX J

ECONOMICS BREAKDOWN

CAPEX ¹ (\$M)	Average	Range	Contingency	Notes		
Capture System and Pipeline						
CCS ² Facility Infrastructure	12.9	12.9	+8.0	Centrifugal blower, low-pressure compression and liquid water removal, dehydration, high-pressure compression, and dense phase CO ₂ pumps. See Appendix B in main report for individual installed costs. Range less than \pm \$0.1M. Contingency based on spare rotating equipment (e.g., blowers and compressors) for < 10 days downtime/yr.		
Pipeline	0.6	0.3–0.9	+0.3	Pipeline materials, assuming 0.7-mile length, and pipeline monitoring equipment (e.g., flowmeters, corrosion test coupons, etc.). Contingency based on highest cost estimations (see Appendix C of main report)		
Subtotal	13.5	13.2–13.8	+8.3			
Permitting						
Initial CO ₂ Storage Facility Permit Application	1.8	1.8	-	All required permit information and multiple discussions with regulatory to review drafts. Assumes third-party consultants for financial assurance, emergency/remedial response, worker safety, public outreach, and other requirements. Range and contingency less than \pm \$0.1M.		
Application Revision	0.5	0–1.0	+1.1	Variation based on 0–2 iterations assuming additional data requirements from the North Dakota Industrial Commission (NDIC) prior to issuance of draft permit. Contingency based on numerous iterations.		
Public Review Response and NDIC Hearing	0.7	0.7	+0.7	Assumes outreach will minimize substantive public comments, requiring only one iteration for response. Range less than \pm \$0.1M. Contingency based on additional review.		
Subtotal	3.0	2.5–3.5	+1.8			
MVA ³ Plan						
Near Surface	0.3	0.2–0.4	+0.3	Baseline sampling and analyses for up to 20 regional groundwater wells, 1 Fox Hills monitoring well (install/permit), 2 surface waters, and 3 soil gas profile stations (SGPS; install). Range based on 3–6 sampling events; contingency is based on 9 sampling events.		

Table J-1. CAPEX Detail for CCS Implementation at Red Trail Energy (RTE)

¹ Capital expenses.
 ² Carbon capture and storage.
 ³ Monitoring, verification, and accounting.
 ⁴ Soil gas profile stations.

Continued . . .

CAPEX (\$M)	Average	Range	Contingency	Notes
Seismic	1.0	0.8–1.1	+0.1	Design of 10.5 mi ² 3-D baseline survey, permitting, layout, survey
				equipment, processing, and contracted services (e.g., induced seismic
				monitoring and third-party consultant interpretation of survey results). Range
				and contingency based on variation/extremes in quotes for a 10.5 mi ² survey.
SCADA System	0.1	0.1	-	Tubing and casing for monitoring and injection wells, pressure monitoring
				for injection pump and pipe network, controlling, server, cables, data
				acquisition, shack, and utilities. Range and contingency less than \pm \$0.1M.
SAGE Rider	0.9	0.9	+0.3	Instrumentation and fluid-sampling system (monitoring well), depth-related
				equipment, surface equipment, watch stations (injection well), project
				management and engineering. Range less than \pm \$0.1M. Contingency based
0.11	• • •	20.25	. 0 7	on potential ~30% increase in installed costs.
Subtotal	2.3	2.0-2.5	+0.7	
Monitoring and Inject	ion Wells		4.0	
Monitoring Well	4.2	4.2–5.5	4.2	Casing, casing accessories, tubing, surface and subsurface well equipment,
Injection Well	4.2	4.2–5.5	1.3	site surveys, wellsite and access road preparation, drilling operations,
				formation evaluation, completion, etc. Range based on potential $\sim 30\%$
				increase in construction costs. Contingency based on an additional
	0.4	0.4.11.0		monitoring well.
Subtotal	8.4	8.4–11.0	+5.5	
Characterization Plan				
Monitoring Well Core	0.4	0.4–0.5	+0.4	Core analyses including x-ray diffraction, x-ray fluorescence, scanning
Injection Well Core	0.4	0.4	—	electron microscope morphology, thin section, geochemical/geomechanical,
				and core slabbing. Range based on variation in quotes. Contingency based
				on core analyses for an additional monitoring well.
Subtotal	0.8	0.8–0.9	+0.4	
Science and Engineering	ng			
	1.0	0.7–1.3	+0.7	Modeling, simulation, risk assessment and other research activities necessary
				for initial permitting activities. Range and contingency based on potential
~				variations in permitting requirements/iterations.
Subtotal	1.0	0.7–1.3	+0.7	
TOTAL	29.0	27.6-33.0	+17.4	

Table J-1. CAPEX Detail for CCS Implementation at RTE (Continued)

¹ Capital expenses.
² Carbon capture and storage
³ Monitoring, verification, and accounting.
⁴ Soil gas profile stations.

OPEX (\$M/yr)	Average	Range	Contingency	Detail Notes			
Capture S	System and	Pipeline					
CCS ² Facility	1.3	1.3	+0.4	Energy requirements, power charge, gas usage, and plant labor Range less than +\$0.1M/yr Contingency based on			
Dinalina	0.1	0.1		potential for higher electric rates.			
Pipeline	0.1	0.1	_	than \pm \$0.1M/yr.			
Subtotal	1.4	1.4	+0.4				
MVA ³ Plan							
Near Surface	0.1	0.1–0.2	_	Operational sampling and analyses for up to 20 regional groundwater wells, 1 Fox Hills monitoring well (install/permit), 2 surface waters, and 3 SGPSs ⁴ (install). Range based on varying sampling frequency per year. Contingency less than ±\$0.1M/yr.			
4-D Seismic (average annual cost based on repeat seismic survey every 5 years)	0.2	<0.1–0.8	+0.3	Design of 10.5 mi ² 4-D repeat survey, recurring fees for induced seismic monitoring, and third-party consultant interpretation of survey results. Range based on estimated annual cost with and without a seismic survey. Contingency based on increase to average cost for 10.5 mi ² 3-D seismic survey conducted every 2 years.			
Science and Engineering	0.2	0.2–0.3	_	Data processing, assessment, and management from monitoring activities to maintain compliance. Range based on updating models/simulations following repeat survey events. Contingency less than ±\$0.1M/yr.			
Subtotal	0.5	0.3–1.3	+0.3				
TOTAL	1.9	1.7–2.7	+0.7				

Table J-2. OPEX¹ Detail for CCS Implementation at RTE

¹ Operating expenses. ² Carbon capture and storage ³ Monitoring, verification, and accounting. ⁴ Soil gas profile stations.