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15 North 23rd Street, Stop 9018 • Grand Forks, ND 58202-9018 • P. 701.777.5000 • F. 701.777.5181
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May 31, 2017

Ms. Karlene Fine
Executive Director
North Dakota Industrial Commission
State Capitol, 10th Floor
600 East Boulevard Avenue
Bismarck, ND 58505-0310

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,

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

KML/kal

Attachment

Energy & Environmental Research Center

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

North Dakota Industrial Commission
600 East Boulevard Avenue
Bismarck, ND 58505

Prepared by:

Kerryanne M. Leroux
Ryan J. Klapperich
Nicholas A. Azzolina
Melanie D. Jensen
Nicholas S. Kalenze
Nicholas W. Bosshart
José A. Torres Rivero
Lonny L. Jacobson
Scott C. Ayash
David V. Nakles
Tao Jiang
Benjamin S. Oster
Ian K. Feole
Nathan J. Fiala
Steven M. Schlasner
William I. Wilson IV
Thomas E. Doll
John A. Hamling
Charles D. Gorecki
Lawrence J. Pekot
Wesley D. Peck
John A. Harju
Shaughn A. Burnison
Bradley G. Stevens
Steven A. Smith
Shane K. Butler
Kyle A. Glazewski

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

Brad Piggott, P.E.
Austyn Emily Vance, P.E.
Trimeric Corporation
PO Box 826
Buda, TX 78610

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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 CO_2 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 CO_2 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 CO_2 generated at the RTE facility contains minimal impurities (>99% CO_2), requiring nominal processing for injection, such as dehydration of the CO_2 stream and compression up to 1500 psi. A 4-inch pipeline is recommended to transport CO_2 to the injection site within 1 mile of the RTE facility. Specific flow rates and composition of the CO_2 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 CO_2 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 CO_2 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 CO_2 injection and long-term stability of potentially stored CO_2 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 CO_2 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.

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

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

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.

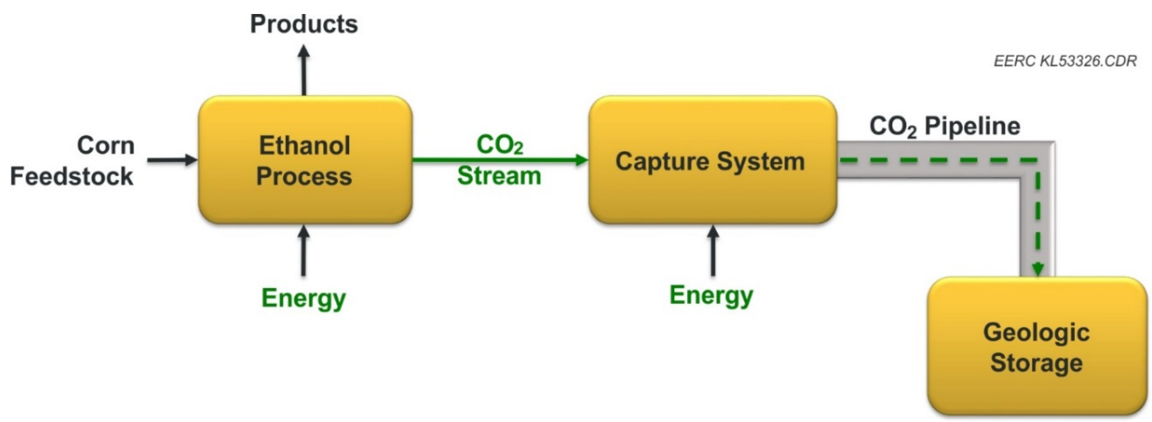

Figure 1. Block diagram of ethanol-CCS process.

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 CO_2 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.

CO_2 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 CO_2 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 O_2 $\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 CO_2 transport. Further investigation of the impact of these limits on the system design will be conducted during the next project phase.

Table 1. CO_2 Stream Compositional Specifications for Various End Uses (4–6)

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_2O	ppmv	500	500	≤20 ppmv
N_2	vol%	4	1	NRL*
O_2	vol%	0.001†	0.001	≤30 ppmv (total O_2 and Ar)
Ar	vol%	4	1	
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	≤2.5 each for NO and NO_2
Dissolved O_2	ppmv	NRL	NRL	<5

* 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 CO_2 pipeline specifications were the design criteria for a potential EOR-grade CO_2 product. Kinder-Morgan pipeline specifications require ≥95 mol% CO_2, ≤0.05% H_2O, and ≤0.001% O_2 (4). As expected, specifications for food/chemical-grade CO_2 are the most stringent, with ≥99.9 vol% CO_2, ≤20 ppm H_2O, and <30 ppm O_2 limitations for product quality (5, 6). The specifications presented in Table 1 suggest that each potential CO_2 product requires an independent assessment of the processing requirements for the CO_2 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% CO_2). The composition of the RTE CO_2 stream is based on two sampling events, one in 2014 and one in 2017. In January 2014, the CO_2 stream averaged approximately 99.8% CO_2, and 0.03% O_2 on a dry volume basis. Water content was measured at 0.78 vol%. The CO_2 stream was sampled again in February 2017, and the composition of the CO_2 stream was measured to be 99.987 mol% CO_2 and 0.013 mol% O_2 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

Table 2. Average Analysis of RTE CO_2 Stream

Component	January 2014	February 2017	Unit
CO_2	99.78	99.99	vol%, dry
H_2O	780	–*	ppmv
O_2	300	130	ppmv, dry

*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 groundwater-monitoring 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 CO_2 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.

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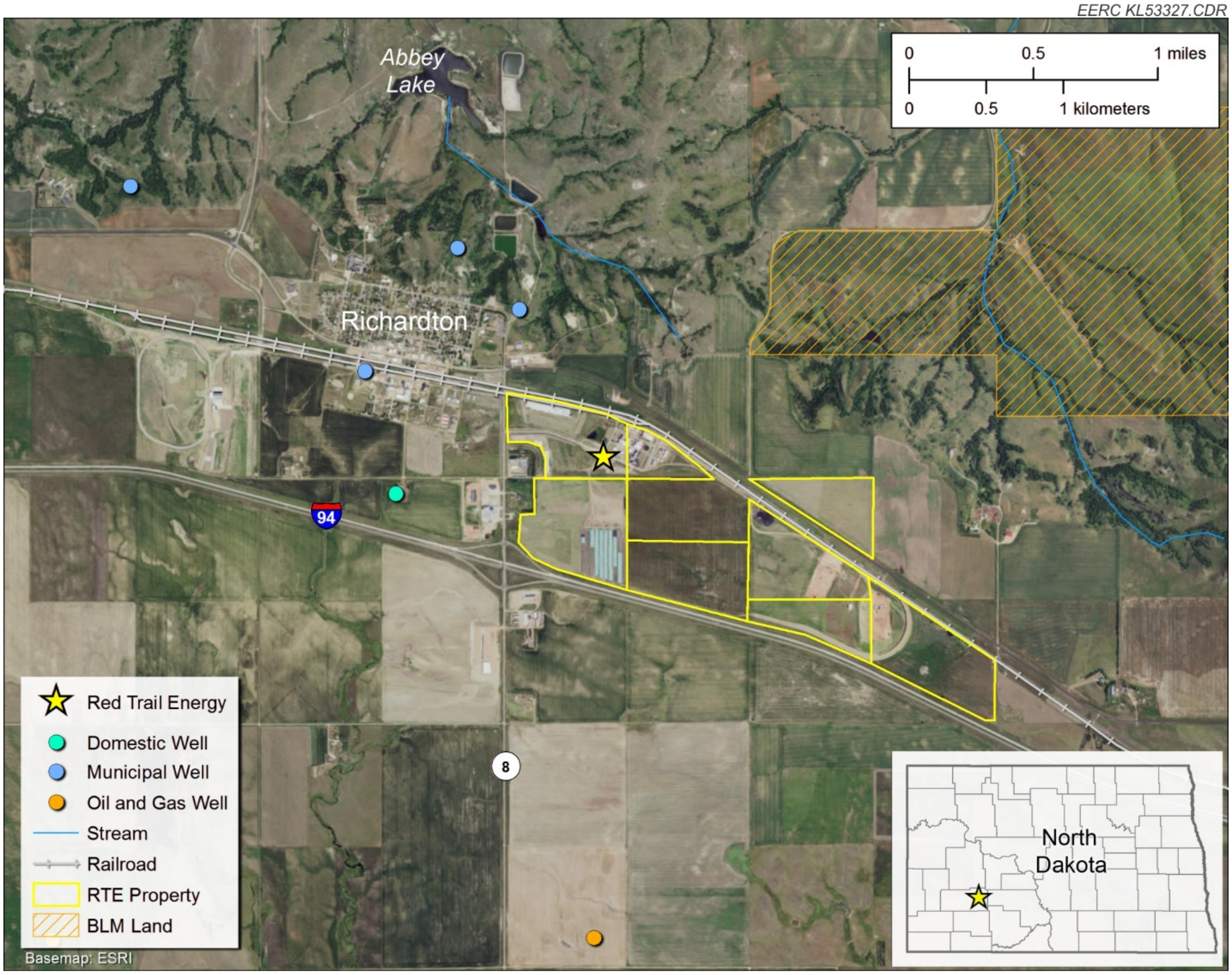

Figure 2. Surface features at the RTE site.

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).

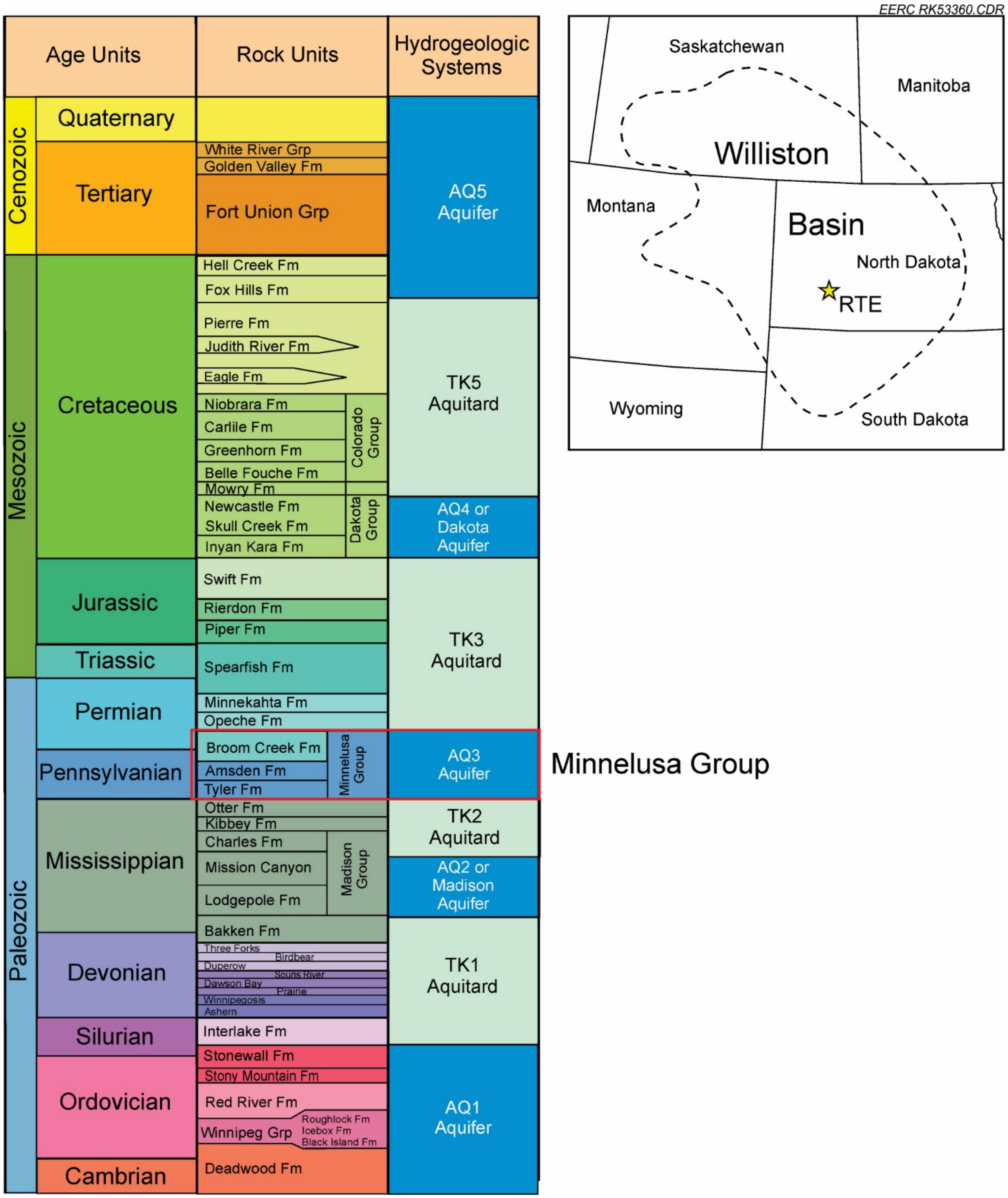

Figure 3. Williston Basin stratigraphic and hydrogeologic column (2 [modified])

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 CO_2 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.

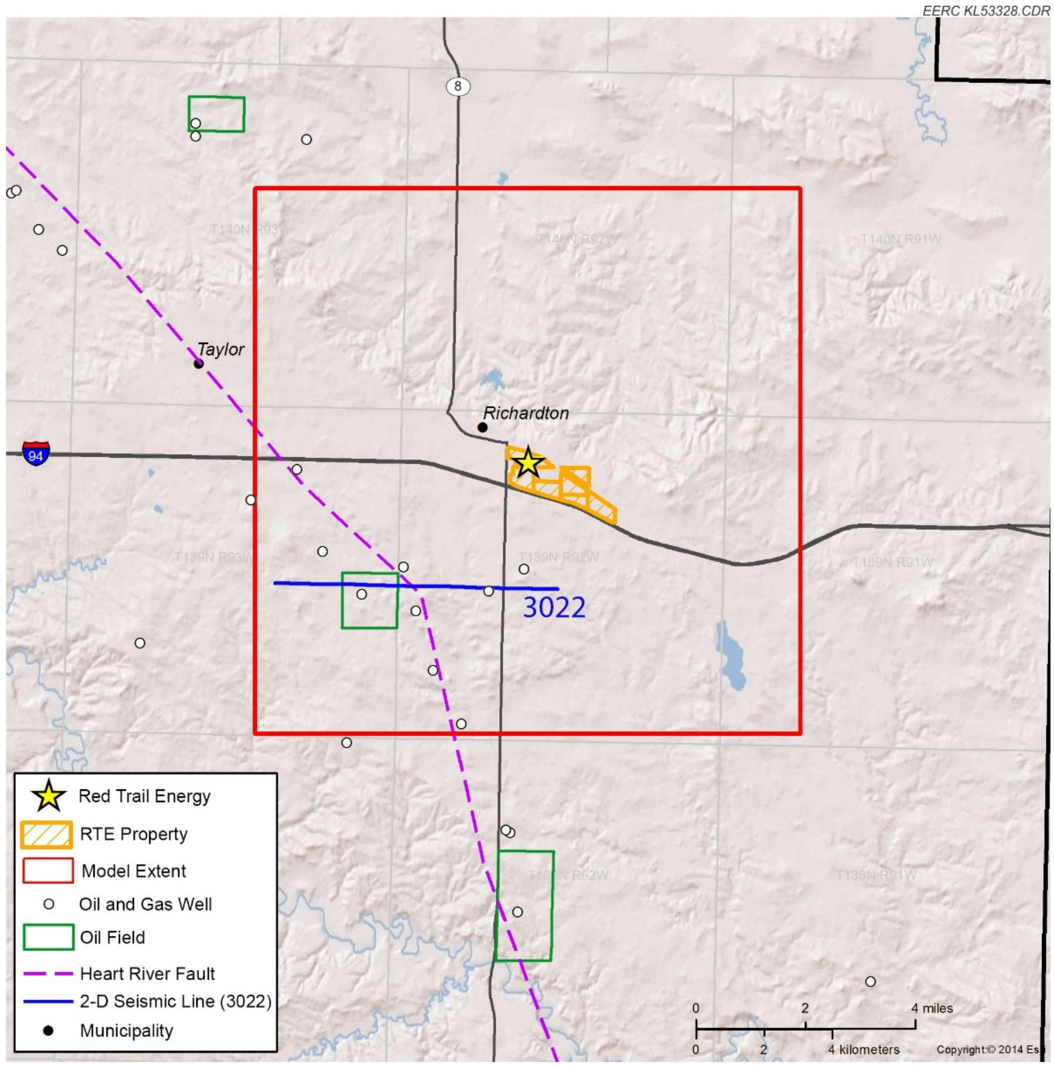

Figure 4. Map of the Heart River Fault near the RTE plant; blue line labeled 3022 is a 2-D seismic line interpretation along the Heart River Fault (see Appendix D for details).

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.

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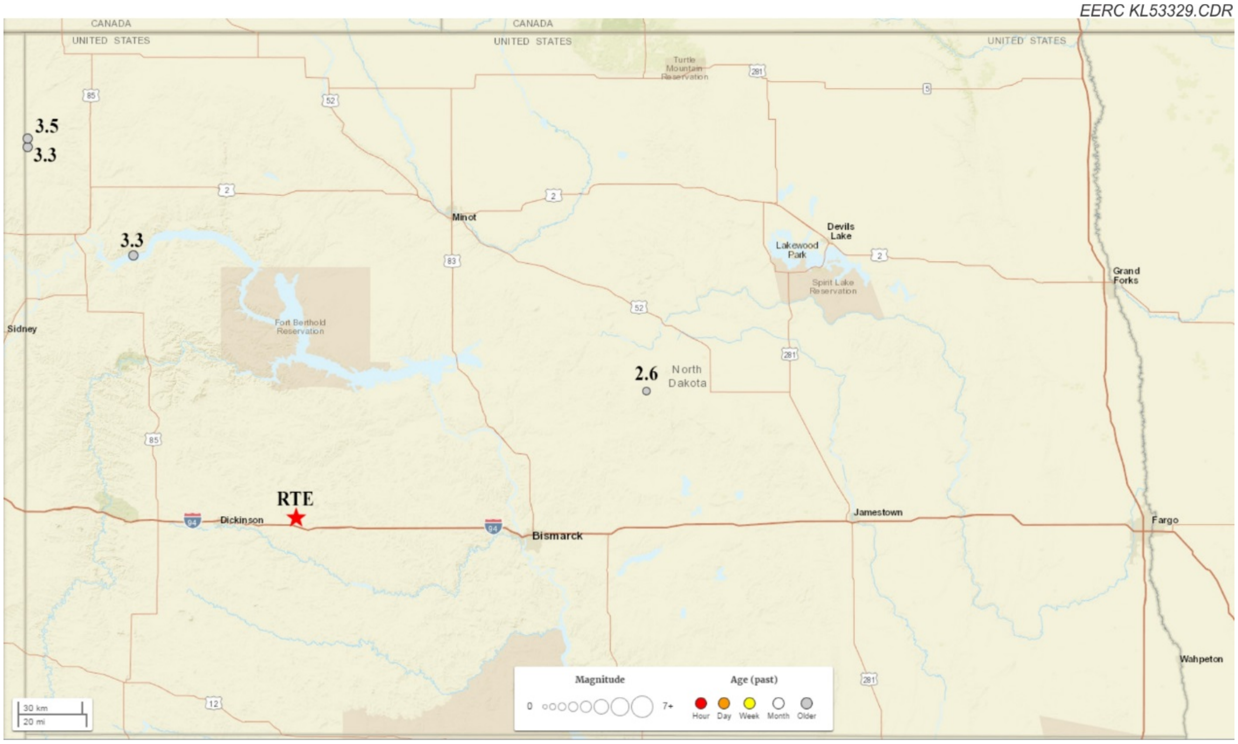

Figure 5. Recorded seismic events in North Dakota from the year 1900 to present with magnitudes on the MMI scale greater than 2.5. Numerical values indicate the magnitudes associated with events (16).

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 mi^2 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 CO_2 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 (CO_2 flow rate, temperature, etc.) and well design and completions for accurate prediction of CO_2 behavior in the reservoir. About 163,000 tonnes CO_2 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 CO_2 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

Table 3. Geologic Modeling and Simulation Case Matrix

Facies	*Low Connectivity/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**

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

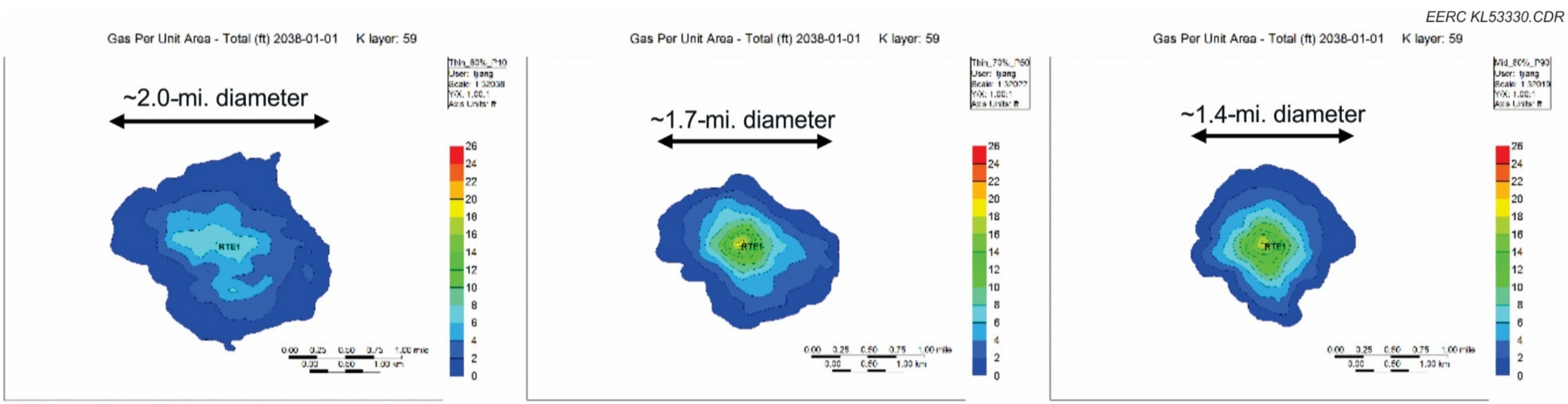

Figure 6. Simulated CO_2 plume expansion after a 20-yr injection period, showing P10, P50, and P90 (left, middle, and right) simulation results generated from the highlighted regional properties shown in Table 3.

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 CO_2 supply, injectivity, and storage capacity
  - Subsurface containment
    - Lateral migration of CO_2 or formation water brine
    - Propagation of subsurface pressure plume
    - Vertical migration of CO_2 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

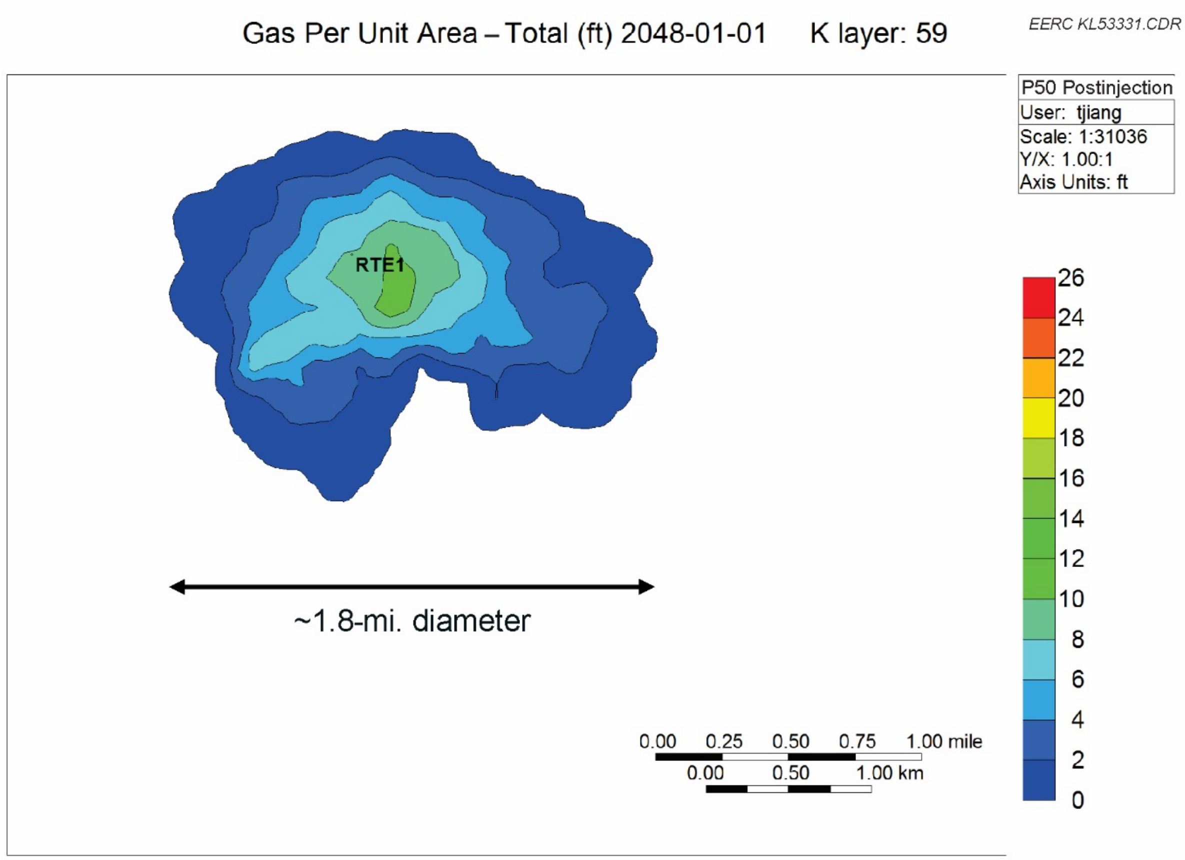

Figure 7. Simulated CO_2 plume expansion 10 years after a 20-year injection period.

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 CO_2 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.

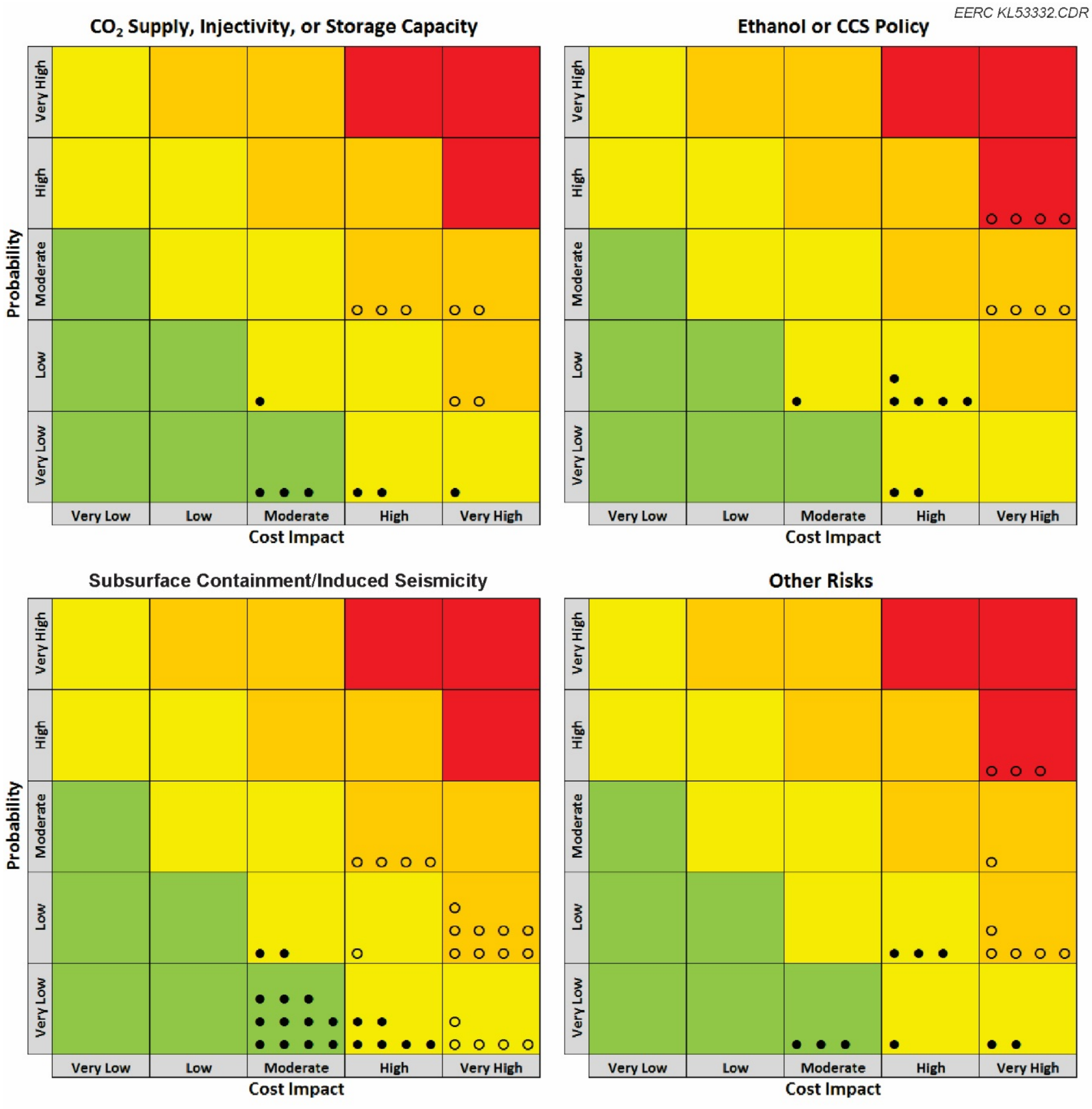

Figure 8. Risk maps showing the cost impact score (x-axis) versus probability score (y-axis) for identified potential risks. Note: the solid circles represent the average score results, while the hollow circles represent conservative, upper-end estimates; the three hollow circles in the red area under "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 CO_2 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 CO_2 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 (gCO_2e/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

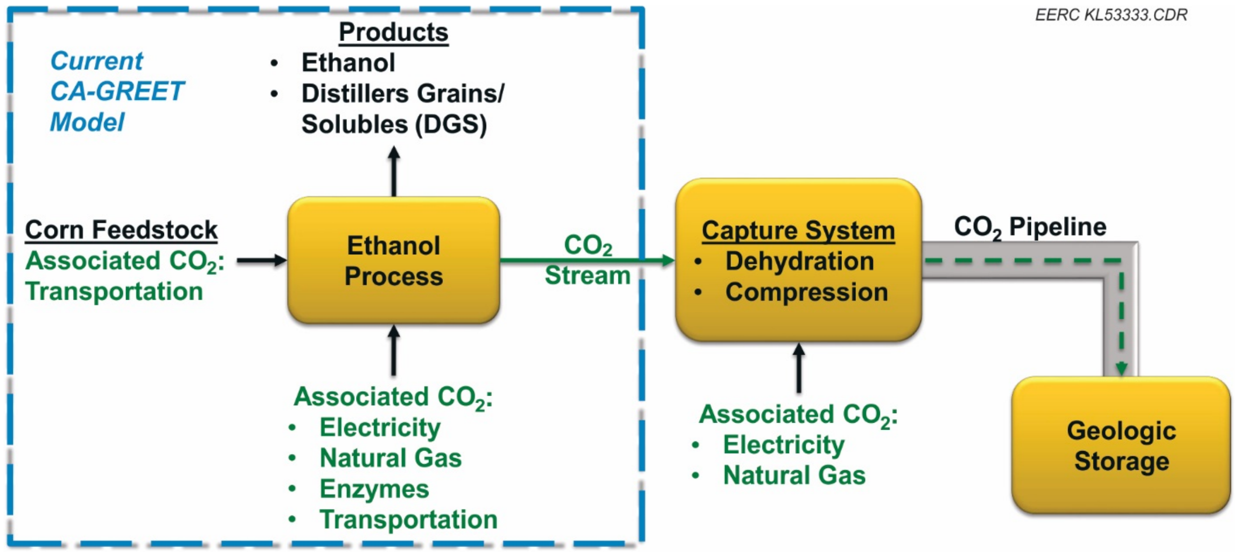

Figure 9. Block diagram showing key elements of ethanol production with CCS.

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 CO_2 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 CO_2 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 CO_2 Capture and Transport section, capture system design options for generating three CO_2 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 CO_2 stream be dehydrated, whereas use in EOR requires dehydration as well as some O_2 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 CO_2 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 CO_2 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 CO_2 generated annually by the RTE facility 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 revaluated following collection of additional CO_2 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 CO_2. In this case, the CO_2 is compressed and liquid water is removed. The CO_2 passes through molecular sieve dehydration and is refrigerated, liquefied, and distilled to remove O_2 to commercial pipeline standards (Table 1). About a 10% loss of the CO_2 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 CO_2 above critical pressure for transport through a pipeline to the oil field.

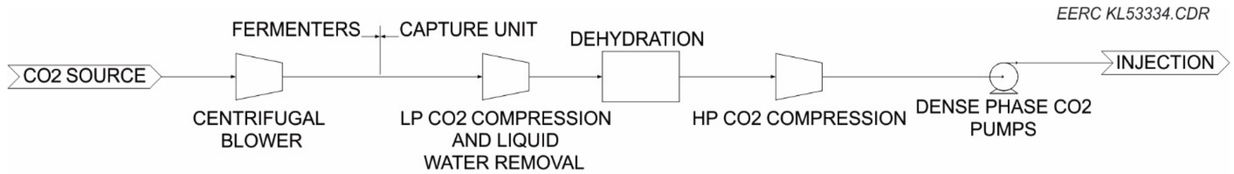

Figure 10. Draft conceptual design for generation of an injection-grade CO_2 product at the RTE site (image courtesy of Trimeric Corporation). LP and HP refer to low- and high-pressure, respectively.

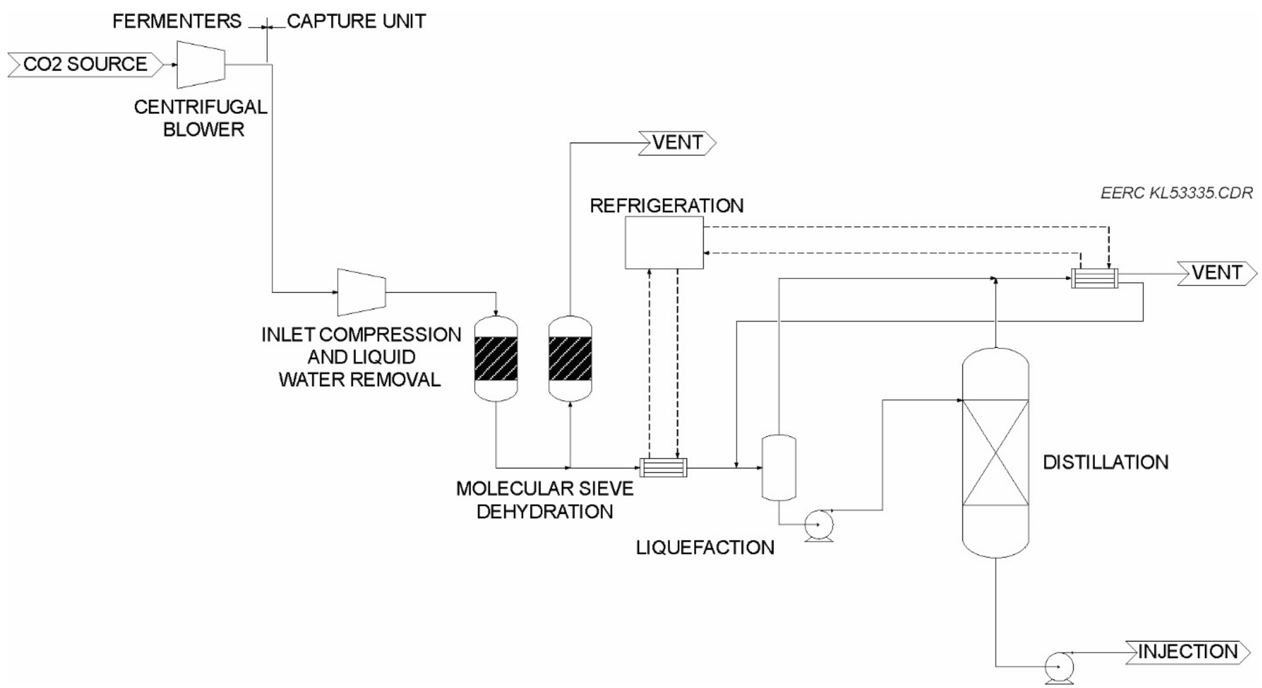

Figure 11. Draft conceptual design for generation of an EOR-grade CO_2 product at the RTE site (image courtesy of Trimeric Corporation).

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 CO_2 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.

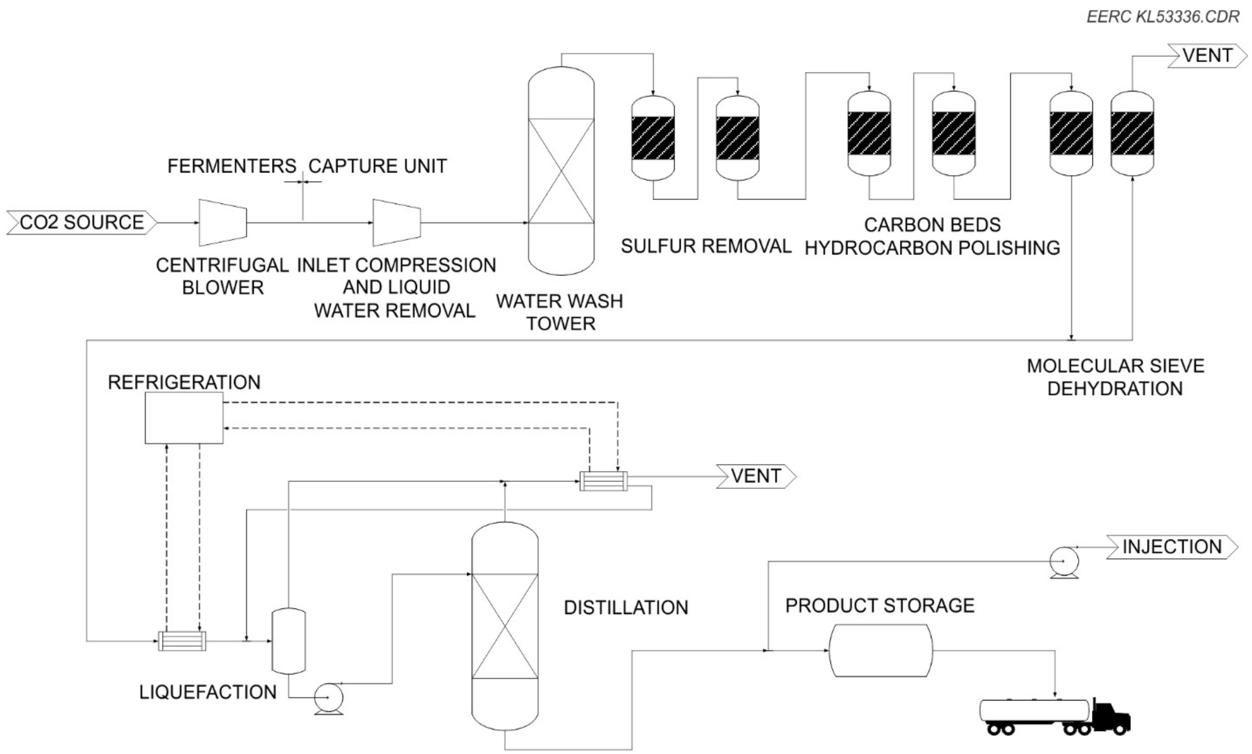

Figure 12. Draft conceptual design for generation of a food/chemical-grade CO_2 product at the RTE site (image courtesy of Trimeric Corporation).

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 CO_2 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 progression 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 (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 CO_2 plume, following stabilization after injection has ceased, plus an additional mile buffer. Results from modeling and simulation activities described in previous sections indicate the CO_2 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.

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

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

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 (^{18}O, ^{14}C, ^{13}C, ^{2}H). 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.

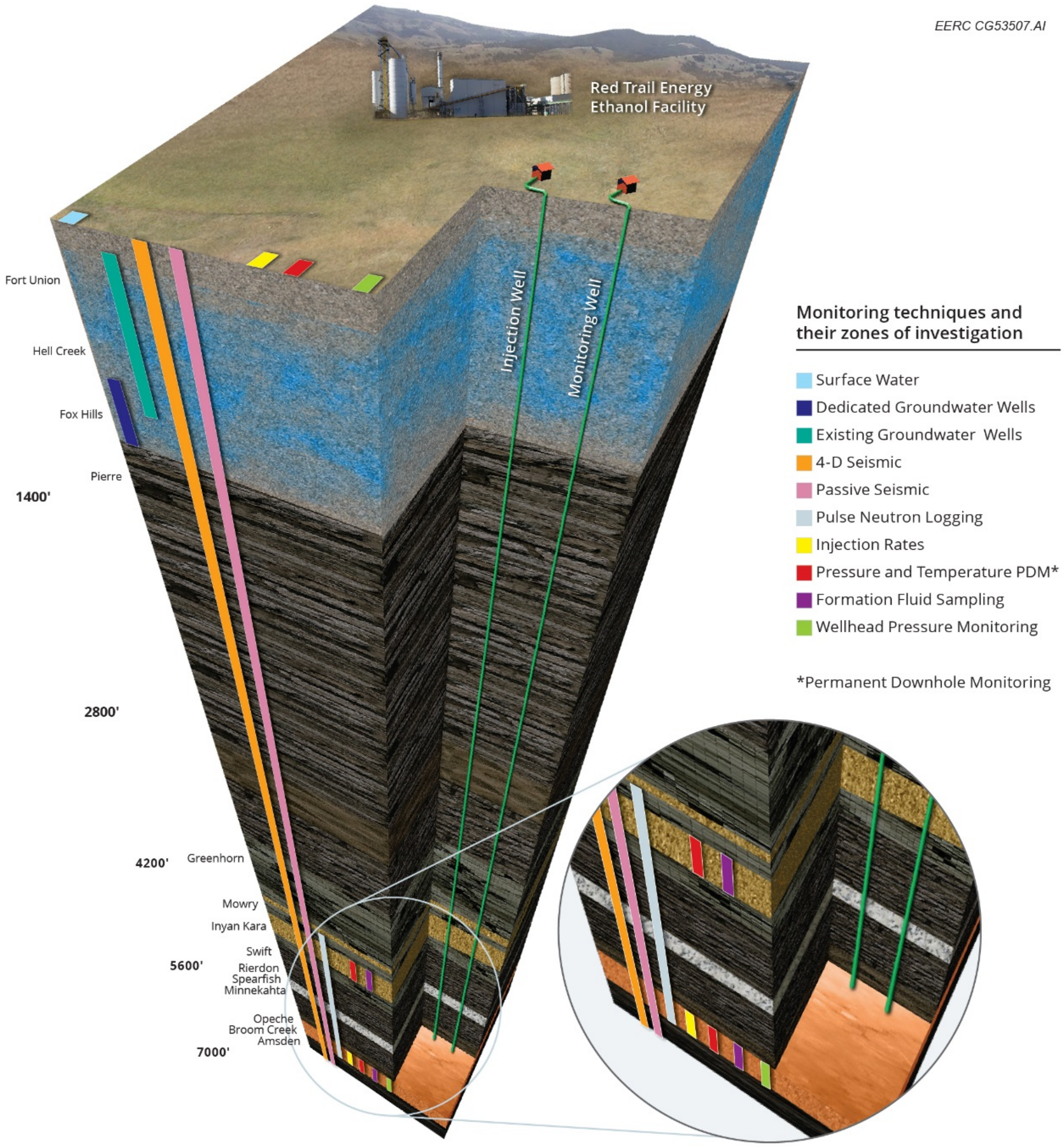

Figure 13. Stratigraphic column illustrating provisional near-surface and deep subsurface regions monitored, as well as individual MVA techniques, for geologic CO_2 storage at the RTE site.

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 CO_2 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. Pulsedneutron 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 CO_2 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 CO_2 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.

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

	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]	7-in., 26-lb/ft, L-80 [d]
	5½-in., 17-lb/ft, 13Cr [e,f]	7-in., 26-lb/ft, 13Cr [e,f]
Tubing	$2^{7}/_{8}$-in., 6.5ppf, 13Cr	3½-in., 9.2 ppf, 13Cr
Estimated Completion	26 days	27 days

[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, CO_2 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 CO_2 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.

CO_2 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 CO_2 credits from the LCFS market could be realized. CO_2 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 gCO_2e/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.

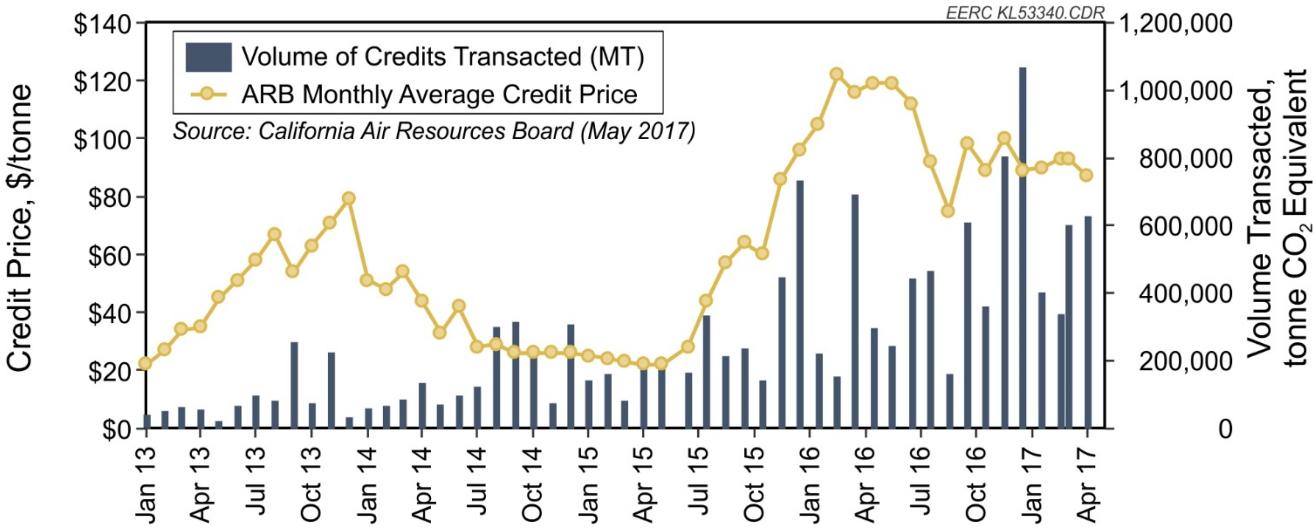

Figure 14. LCFS market variation for carbon credit prices, January 2013 – April 2017 (27).

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 CO_2 product generated at the RTE facility could provide product to a niche regional market. CO_2 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 CO_2 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 CO_2 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.

Table 6. Estimated CAPEX for CCS Implementation at RTE

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**	

- 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).

Table 7. Estimated OPEX for CCS Implementation at RTE

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

Alternative Market Costs

CAPEX and OPEX were estimated for production of EOR-grade or food/chemical-grade CO_2 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 CO_2 emissions to generate these higher-quality product streams. Transportation costs such as a CO_2 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).

Table 8. Estimated Carbon Capture Expenses at the RTE Facility for Potential Alternative CO_2 Markets

Capture Facility	Expense ($M)	Contingency ($M)	Contingency Notes
		Estimated CAPEX	
EOR-Grade	14.7	+8.0	Includes dehydration, compression, refrigeration, liquefaction and distillation (Note: ***does not*** 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: ***does not*** 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

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 business-sensitive nature of this assessment.

CONCLUSIONS

Commercial implementation of CCS at the RTE facility is a technically viable option to significantly reduce net CO_2 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 CO_2 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 CO_2 capture system and pipeline designs, a permitting plan for CO_2 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 CO_2 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 CO_2 generated at the RTE site for injection, but specific design criteria (e.g. length, materials) will ultimately depend on well location and O_2 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 CO_2 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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