GREAT PLAINS CO_2 SEQUESTRATION PROJECT MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Well

Reporting Number: 523812

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Within the text of this monitoring, reporting, and verification plan, Dakota Gasification Company's storage facility permit is designated as follows:

Reference 1: Great Plains CO_2 Sequestration Project, Mercer County, North Dakota

- Section 1 – Pore Space Access
- Section 2 – Geologic Exhibits
- Section 3 – Geologic Model Construction and Numerical Simulation of CO_2 Injection
- Section 4 – Area of Review
- Section 5 – Testing and Monitoring Plan
- Section 6 – Post-injection Site Care and Facility Closure Plan
- Section 7 – Emergency and Remedial Response Plan
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1.0 PROJECT DESCRIPTION

1.1 Project Characteristics

The Dakota Gasification Company's (DGC) Great Plains Synfuels Plant (GPSP), located 5 miles northwest of Beulah, North Dakota, is capable of gasifying 6 million tons of lignite coal per year (Figure 1-1). DGC, a wholly owned subsidiary of Basin Electric Power Cooperative (Basin), has owned and operated the facility since 1988. DGC has captured and transported more than 40 million tonnes (Mt) of carbon dioxide (CO_2) (>95% dry CO_2) from the gasification process for enhanced oil recovery purposes since 2000. The captured CO_2 is transported via a 205-mile pipeline that has successfully operated for the past 22 years. The CO_2 is first compressed to a pressure of ±2,500 pounds per square inch (psi), then transported north as a supercritical fluid. There currently exists excess compressor capacity, which makes the capture of an additional 1.0 Mt per year possible. DGC is currently constructing an additional 6.8 miles of pipeline to facilitate permanent sequestration of up to 2.7 Mt per year. The pipeline's design capacity is based on the total anticipated CO_2 output from the plant. Over the anticipated 12-year life of this project, sequestered volumes of CO_2 are expected to total 26 Mt. Four injection wells are anticipated initially (Coteau 1 through Coteau 4), with two additional wells planned (Coteau 5 and Coteau 6) as increased volumes in 2026 or beyond warrant (Figure 1-1). The injection wells will store the captured CO_2 stream in the porous and permeable Broom Creek Formation located below the GPSP.

DGC submitted its North Dakota CO_2 storage facility permit (SFP) to the North Dakota Industrial Commission (NDIC) on March 8, 2022, and an official hearing for DGC's Great Plains CO_2 Sequestration Project was held on July 20, 2022. North Dakota has the authority to regulate the geologic storage of CO_2 and primacy to administer the North Dakota Underground Injection Control (UIC) Class VI Program (83 Federal Register 17758, 40 Code of Federal Regulations [CFR] 147). If any material changes are made to the SFP after the hearing date that impact this MRV plan, DGC will notify EPA and submit an amended plan within 180 days.

No other geologic storage project exists or is planned within 18.2 miles of the Great Plains CO_2 Sequestration Project.

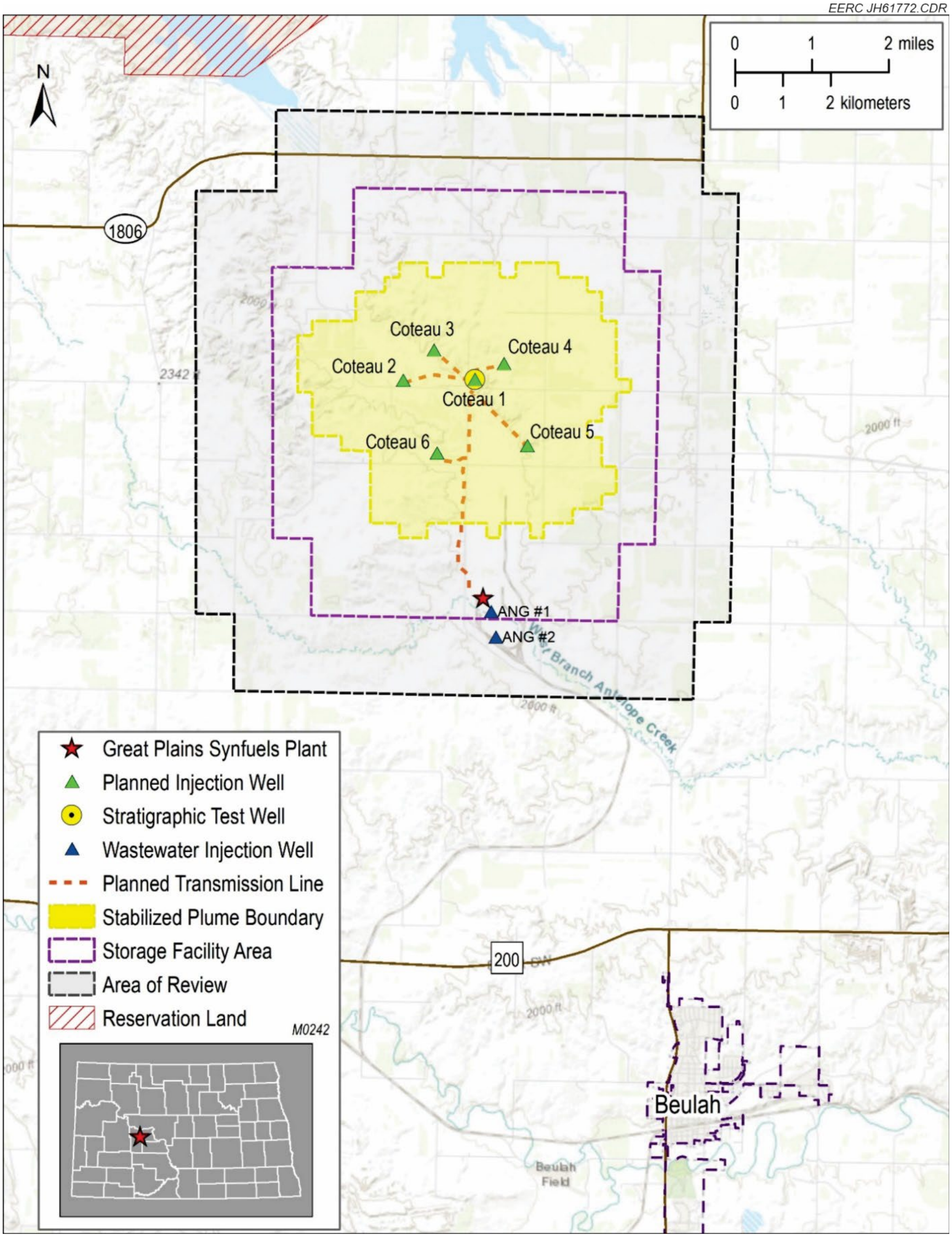

Figure 1-1. Location of the GPSP, Coteau 1 through Coteau 6 injection wells, and CO_2 transmission line. Also shown is the town of Beulah, with a population of about 3,200 people, the stabilized plume boundary, the storage facility area, and the area of review (AOR).

1.2 Environmental Setting

The Great Plains CO_2 Sequestration Project is located along the southern flank of the Williston Basin, a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. Figure 1-2 shows the geographic distribution of oil fields in North Dakota, demonstrating there has been no exploration for or development of hydrocarbon resources within the AOR (Reference 1, Section 2.6). The Herrmann 1 (NDIC File No. 4177), a dry hole drilled in 1966 to the Frobisher interval (stratigraphically equivalent to the Mission Canyon Formation of the Madison Group), falls just outside the southwestern edge of the AOR. See Section 3.2 of this MRV plan for more information about the Herrmann 1 well.

A generalized stratigraphic column of the Williston Basin for the area of Beulah is provided in Figure 1-3. The target CO_2 storage reservoir for the Great Plains CO_2 Sequestration Project is the Broom Creek Formation, a predominantly sandstone interval lying about 5,900 feet below the GPSP (Reference 1, Section 2.3). Silty mudstones and interbedded evaporites of the Opeche Formation unconformably overlie the Broom Creek and serve as the primary confining zone (Reference 1, Section 2.4.1). Mixed layers of dolostone, mudstone, and anhydrite of the Amsden Formation unconformably underlie the Broom Creek Formation and serve as the lower confining zone (Reference 1, Section 2.4.3). From stratigraphic bottom to top, the Amsden, Broom Creek, and Opeche comprise the CO_2 storage complex. In addition to the Opeche Formation, there is about 1,100 feet of impermeable rock formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation (Reference 1, Section 2.4.2). An additional 2,660 feet of impermeable rocks separate the Inyan Kara and the lowest underground source of drinking water (USDW): the Fox Hills Formation.

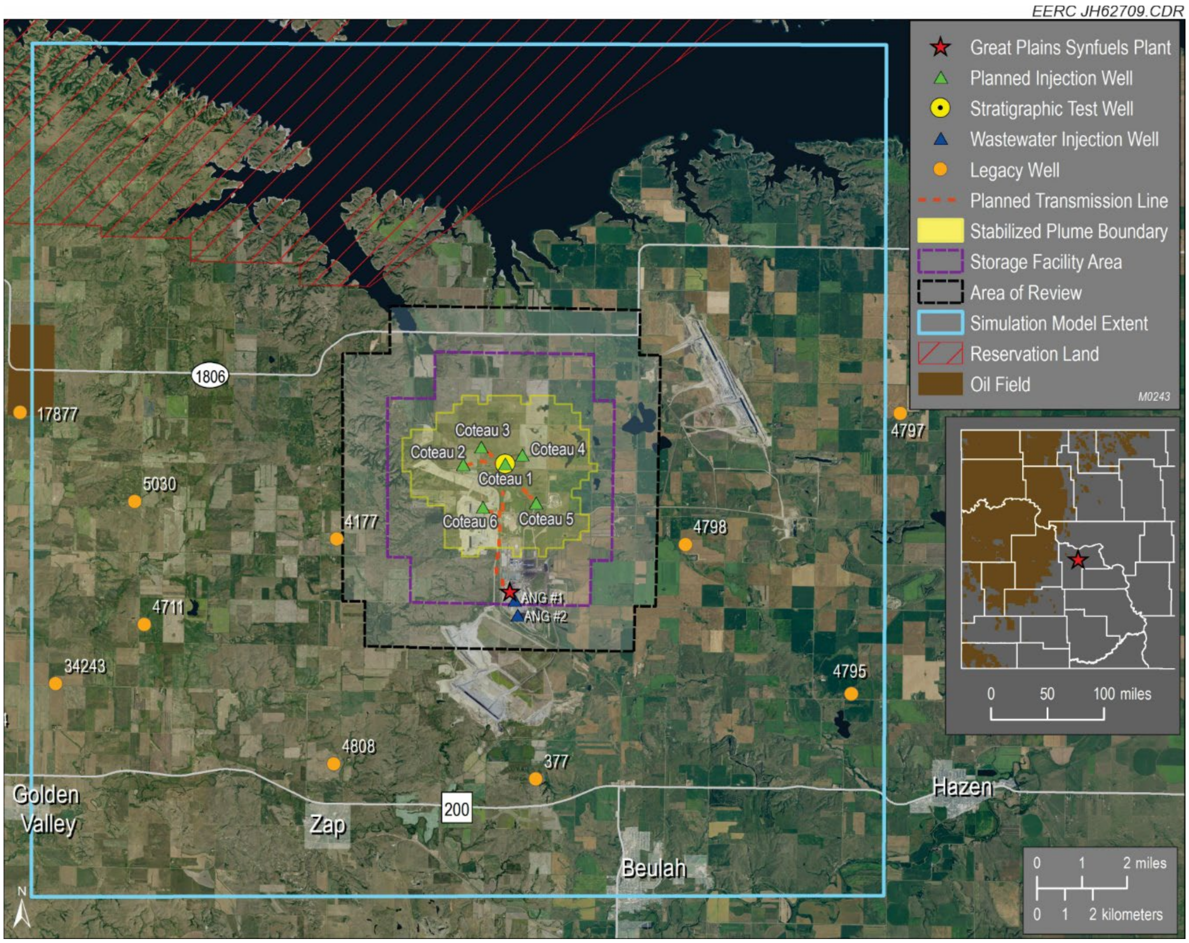

Figure 1-2. Map showing the simulation model extents of the Great Plains CO_2 Sequestration Project, legacy oil and gas wells, and geographic distribution of oil fields in North Dakota (i.e., western portion of the Williston Basin).

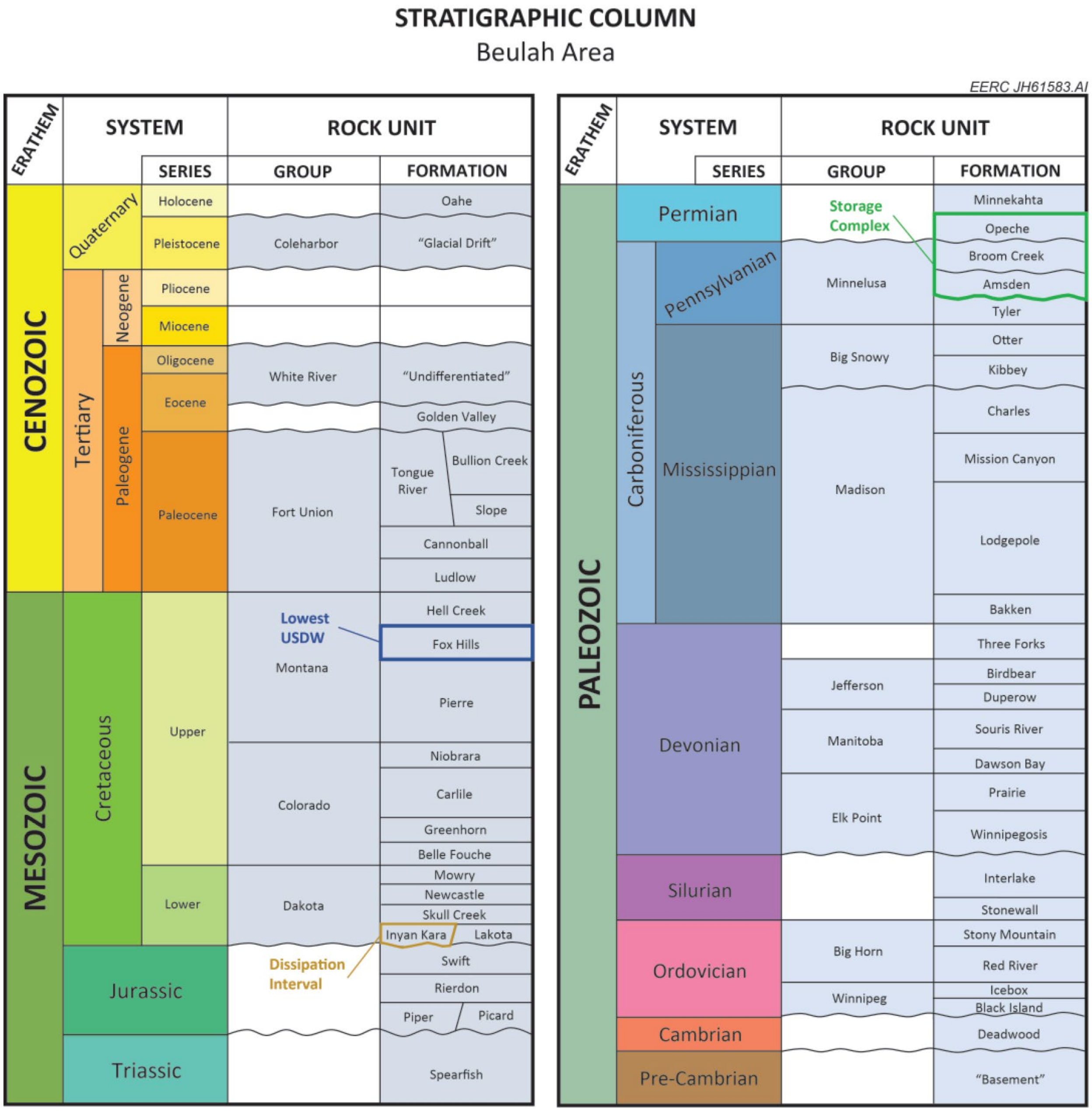

Figure 1-3. Generalized stratigraphic column of the Williston Basin for the Beulah area, identifying the storage complex (i.e., storage reservoir and primary confining zones) as well as the dissipation interval and lowest USDW underlying the Great Plains CO_2 Sequestration Project area. Figure modified after Murphy and others (2009) and Bluemle and others (1981).

1.3 Description of CO_2 Project Facilities and Injection Process

DGC plans to capture and store 1.0 to 2.7 Mt of CO_2 per year over the course of 12 years of injection, followed by at least 10 years of post-injection site care. Figure 1-4 shows integration

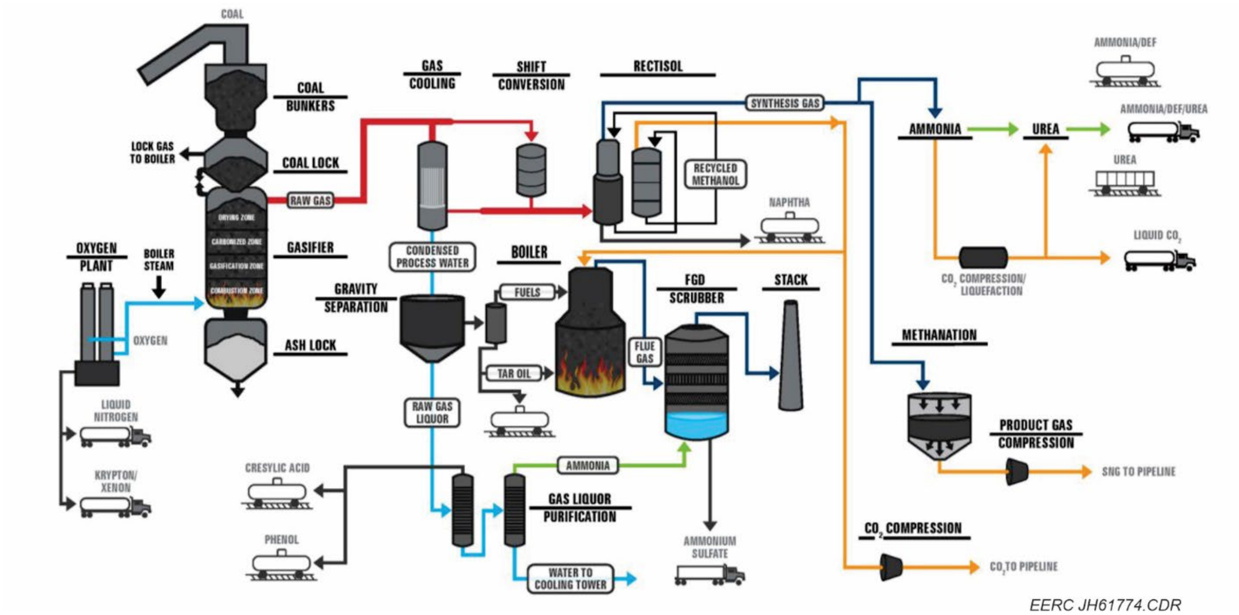

Figure 1-4a. Flow diagram of the CO_2 capture process at GPSP. The main metering station will be located downstream of the CO_2 compressors but upstream of the lateral for the Coteau 6 well, as shown in Figure 1-4b.

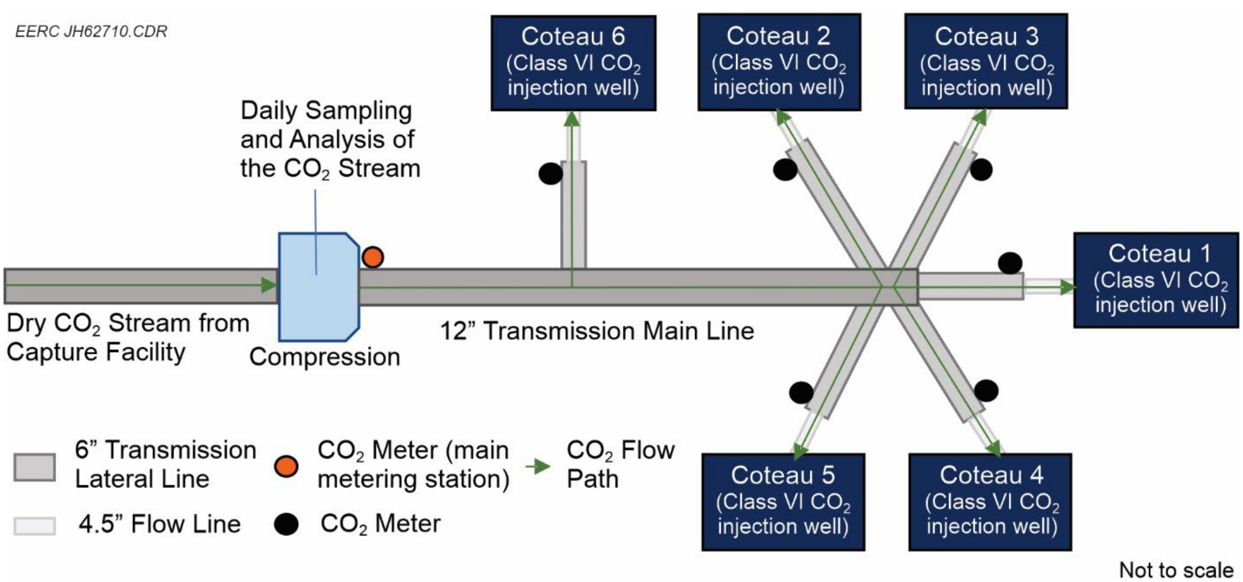

Figure 1-4b. Flow diagram illustrating major carbon capture and storage (CCS) components and the path of the CO_2 stream from the capture facility to the CO_2 injection wells.

of major CCS components with the capture facility at GPSP. The facility was designed to capture the CO_2 produced during the acid gas removal step of DGC's gasification process and compress the gaseous CO_2 stream to approximately 2,500 psi. The final compressed CO_2 stream would flow to the Coteau 1 through Coteau 6 injection wells for geologic storage into the Broom Creek Formation; an underground transmission pipeline permitted through the North Dakota Public Service Commission (NDPSC) Case No. PU-21-150 is installed on Basin, DGC, and Coteau Properties Company (CPC) property to connect the capture facility to the Coteau 1 through Coteau 6 injection wells. CPC, a wholly owned subsidiary of North American Coal Corporation, operates the Freedom Mine near the GPSP, supplying lignite coal feedstock to the plant.

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area: DGC AOR Delineation in Accordance with U.S. Environmental Protection Agency and North Dakota Rules

DGC proposes that because the AOR, as delineated in Reference 1, Section 4, exceeds the requirements of the active monitoring area (AMA) under Title 40, CFR § 98.449 (Subpart RR), the AOR will serve as the AMA for the Great Plains CO_2 Sequestration Project (Figure 2-1).

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). Therefore, DGC elected to permit the storage facility area boundaries based on the reservoir model output discussed in Reference 1, Section 4, and then, added a 1-mile buffer, rounding out to the nearest 40-acre tract.

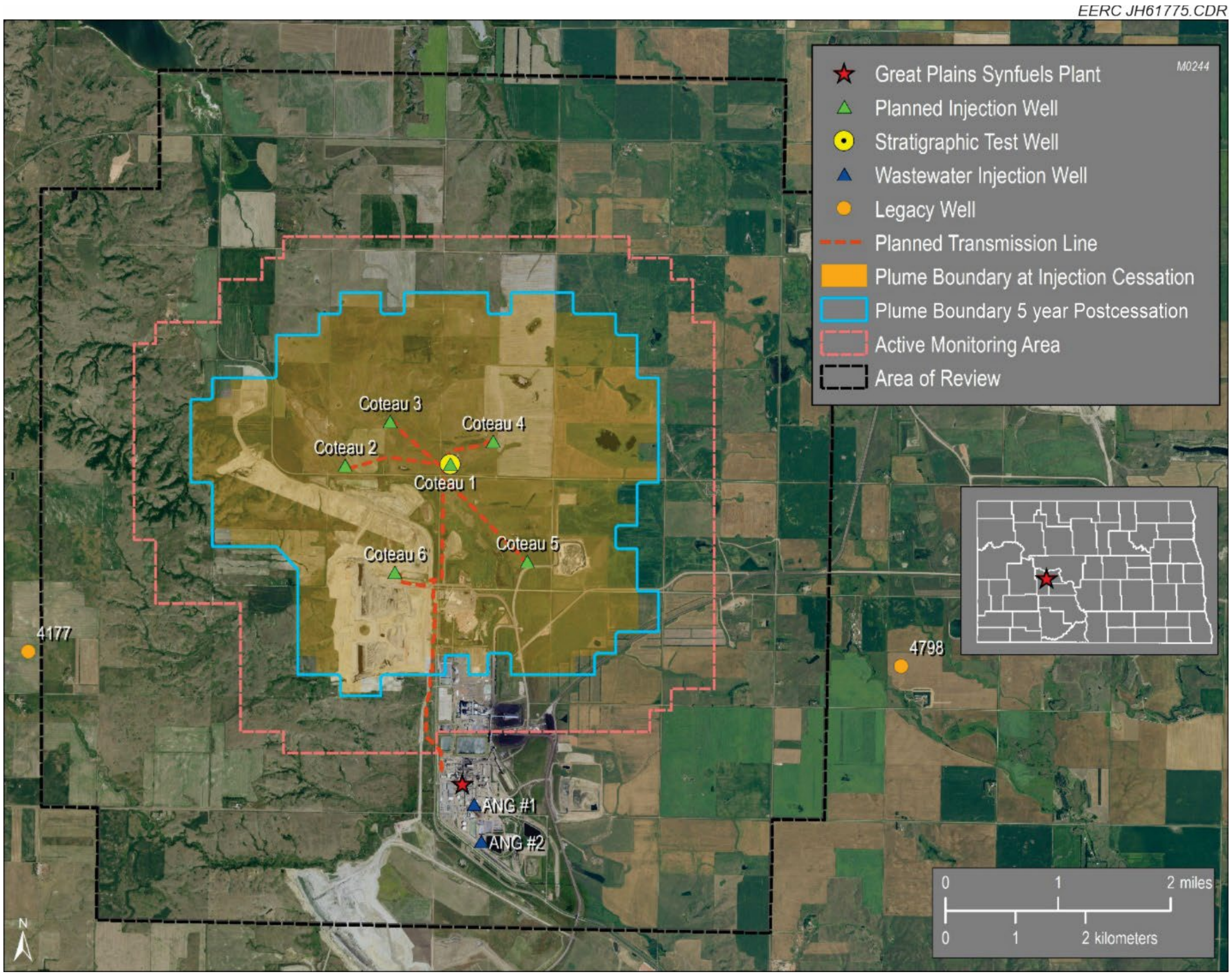

Figure 2-1. Map showing the AOR relative to the AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR), with "t" set equal to injection cessation (12 years). The AOR subsumes the AMA and exceeds requirements for the AMA; therefore, the AOR serves as the AMA for the Great Plains CO_2 Sequestration Project.

2.2 Maximum Monitoring Area

DGC proposes that the delineated AOR and proposed AMA from Figure 2-1 also serve as the maximum monitoring area (MMA) for the Great Plains CO_2 Sequestration Project (Figure 2-2), as it also exceeds the requirements for delineating the MMA under 40 CFR § 98.449 (Subpart RR).

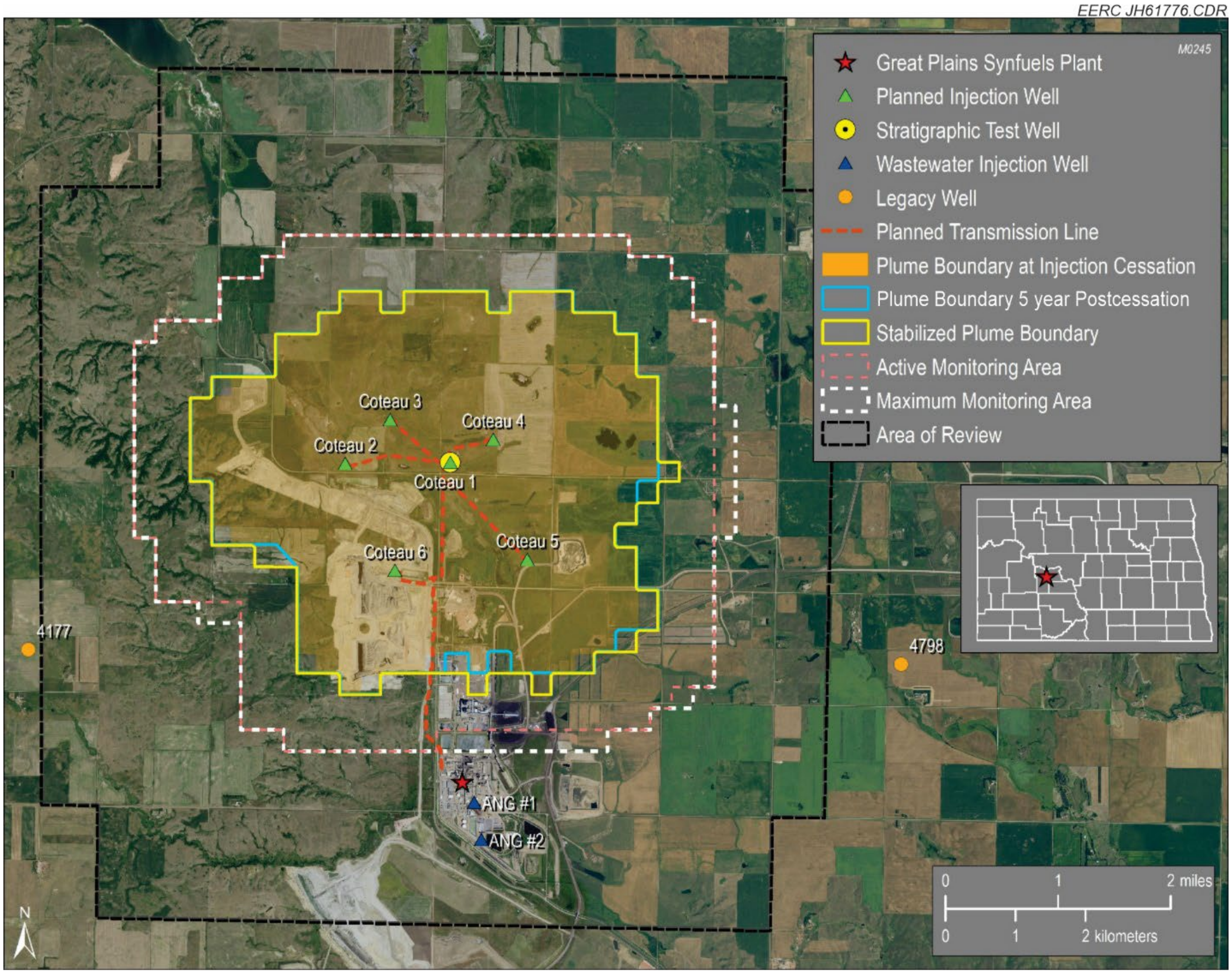

Figure 2-2. Map showing the AOR relative to the calculated MMA and AMA boundaries, calculated as prescribed under 40 CFR § 98.449 (Subpart RR). The AOR subsumes the calculated AMA and MMA and exceeds requirements for both AMA and MMA; therefore, the AOR serves as both the AMA and MMA for the Great Plains CO_2 Sequestration Project.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2 (Reference 1, Section 5) comprises three distinct periods: 1) pre-operational (pre-injection of CO_2) baseline monitoring, 2) operational (CO_2 injection) monitoring, and 3) post-operational (post-injection of CO_2) monitoring. These monitoring periods, therefore, encompass the entire life cycle of the project. For purposes of this MRV plan, it is expected that reporting will be initiated during the operational period and continue through the post-injection period.

The storage system parameters that are monitored during each period are essentially identical; however, the duration of the monitoring period of the measurements performed varies. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

The pre-operational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and uncertainty associated with the measurement of each of the key storage system parameters. An understanding of the repeatability and variability of each measurement is key to successfully determining the movement of CO_2 that is contained in the formation at any given time.

The operational injection period is focused on validating and updating numerical models of the storage system to ensure that the geologic storage project is operating safely and protecting all USDWs. Lastly, the purpose of the post-operational monitoring is to verify the stability of the CO_2 plume location and assess the integrity of all decommissioned wells. The duration of these monitoring periods is a minimum of 12 and 10 years, respectively.

3.0 EVALUATION OF POTENTIAL LEAKAGE PATHWAYS

The potential leakage pathways for CO_2 arriving at the surface after injection or from surface equipment failures during operations were evaluated. Factors and equipment that could lead to leakage pathways were identified and placed into the following six categories:

1. Class I nonhazardous disposal wells
2. Abandoned oil and gas wells
3. Class VI injection wells
4. Surface components
5. Confining zone limitations
6. Faults, fractures, bedding plane partings, and seismicity

This leakage assessment determined none of the pathways required corrective action and the probability of leakage is unlikely. However, a robust monitoring program, described in Reference 1, Section 5, and summarized in Table 5-1, was developed to form the basis of this MRV plan.

3.1 Class I Nonhazardous Disposal Wells

Two Class I disposal wells are active in the Great Plains CO_2 Sequestration Project area. Both wells were drilled in the 1980s to dispose of nonhazardous wastewater produced from GPSP operations in the Minnelusa Group (Broom Creek Formation) and Kibbey Formation under North Dakota Department of Health (NDDH) Permit Nos. ND-UIC-101 and ND-UIC-102. In 2018, both permits were renewed under NDDH Permit No. ND-UIC-101-1. In 2019, the North Dakota Department of Environmental Quality (NDDEQ) separated from the NDDH, and both Class I disposal wells were given well numbers by the NDDEQ.

3.1.1 ANG #1 (NDDEQ Well No. 11308)

The American Natural Gas No. 1 Disposal Well (ANG #1) spudded in April 1982 (NDDEQ Well No. 11308), reaching a total depth of 6,784 feet in the Kibbey Formation. Drillstem test data and core collected from porous and permeable intervals of the Dakota, Minnelusa, and Kibbey saw no evidence of hydrocarbons. Injectivity tests demonstrated the Minnelusa (Broom Creek Formation) and Kibbey were the most viable for receiving wastewater at the injection rates and volumes specified in NDDH Permit No. ND-UIC-101. The well was completed in the Minnelusa in July 1982, and additional perforations were added to the Kibbey Formation in 1983. The ANG #1 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure, and a seal pot system on the annulus to detect annulus leaks. The ANG #1 is also monitored with temperature logs or tracer surveys about once every 5 years.

The ANG #1 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project, and it was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-4).

The risk of leakage via the ANG #1 is unlikely and is mitigated through the wellbore leak detection plan described hereto. The simulation work (presented in Reference 1, Section 2.3.3) also illustrates that the CO_2 plume does not come into contact with the well and suggests there is little interaction between the CO_2 plume and the injected disposal water, even after 10 years post-injection. Because the CO_2 plume does not come into contact with the well, the anticipated magnitude of leakage from the ANG #1 in terms of volume of CO_2 or associated fluids over the life of the project is extremely low.

3.1.2 ANG #2 (NDDEQ Well No. 11309)

The American Natural Gas No. 2 Disposal Well (ANG #2) spudded in September 1983 (NDDEQ Well No. 11309), reaching a total depth of 6,911 feet in the Kibbey Formation. The well was completed in both the Minnelusa (Broom Creek Formation) and Kibbey sands (NDDH Permit No. ND-UIC-102). The ANG #2 is equipped with pressure gauges on the tubing and annulus, continuous recorders that measure flow rate, injection volume, and injection pressure in the tubing-casing annulus, and a seal pot system on the annulus to detect annulus leaks. The ANG #2 is also monitored with temperature logs or tracer surveys about once every 5 years.

The ANG #2 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project, and it was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-5).

The risk of leakage via the ANG #2 is unlikely and is mitigated through the wellbore leak detection plan described hereto. The simulation work presented in Reference 1, Section 2.3.3, also illustrates that the CO_2 plume does not come into contact with the well and suggests there is little interaction between the CO_2 plume and the injected disposal water, even after 10 years post-injection. Because the CO_2 plume does not come into contact with the well, the anticipated magnitude of leakage from the ANG #2 in terms of volume of CO_2 or associated fluids over the life of the project is extremely low.

3.2 Abandoned Oil and Gas Wells

The Herrmann 1 (NDIC File No. 4177) well spudded in November 1966. The well was drilled to a depth of 8,057 feet into the Frobisher interval (stratigraphically equivalent to the Mission Canyon Formation of the Madison Group) and was plugged and abandoned in December of the same year. A drillstem test was conducted in the Frobisher interval, but the well encountered no commercial accumulations of hydrocarbons.

The Herrmann 1 was reviewed as part of the corrective action evaluation for the Great Plains CO_2 Sequestration Project and is the only oil and gas well within 0.5 miles outside of the AOR. It was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 4.2, Tables 4-2 and 4-3).

The risk of leakage via the Herrmann 1 of any magnitude and at any time over the life of the project is extremely low, as the well 1) never comes into contact with the CO_2 plume, 2) experiences a pressure increase of less than 100 psi over the life of the project (Reference 1, Section 6.1.1, Figures 6-1 and 6-2), and 3) has multiple cement plugs to prevent vertical migration of pressure or fluids outside the storage reservoir (Reference 1, Section 4.2, Figure 4-6).

3.3 Surface Components

Surface equipment components present potential leakage pathways during the operational injection period for the Great Plains CO_2 Sequestration Project site. Surface equipment can be subject to deterioration due to normal aging throughout its functional life. Corrosion, lack of maintenance, and deviation from operational parameters may cause loss of mechanical integrity in these assets.

The DGC CCS system includes a 6.8-mile-long transmission pipeline (NDPSC Case No. PU-21-150), six flowlines, and six injection wellheads (Figure 1-4b). The transmission line consists of a 12-inch main line and six 6-inch lateral lines that branch off and connect with 4.5-inch flowlines near each well pad. The flowlines will be connected to metering stations and located contiguous with the well pads (Reference 1, Section 5, Figures 5-1 and 5-2). Flowmeters will be installed at each metering station. The chemical composition of the CO_2 stream that will flow through the surface equipment is given in Reference 1, Section 5.1.1, Table 5-2.

Surface components of the injection system, including the flowlines and wellheads, will be monitored using leak detection equipment. The wellsite flowlines will be monitored continuously via multiple pressure gauges and H_2S detection stations located between the transmission line and the individual wellheads. This leak detection equipment will be integrated with automated warning systems that notify the pipeline control center at DGC, giving the operator the ability to remotely close the valves in the event of an anomalous reading. Further details of the surface leak detection system are given in Reference 1, Section 5.3.

The risk of leakage via surface equipment is mitigated through:

- Adhering to regulatory requirements for construction and operation of the site.

- Implementing the highest standards on material selection and construction processes for the flowlines and wells.
- Applying best practices and a robust mechanical integrity program as well as operating procedures.
- Monitoring continuously via an automated system and integrated databases.

The risk of leakage through surface equipment (under normal operating conditions) is unlikely, and the magnitude will vary according to the failure observed. A potential leakage event from instrumentation or valves could represent a few pounds of CO_2 released during several hours, while a puncture in the flowline could represent several tons of CO_2 released underground until the operator ceases the CO_2 supply. Note that should a shutoff situation occur, the CO_2 stream can be looped back to the DGC capture facility, passed through the burners, and be vented to the atmosphere.

This risk of leakage through surface equipment reduces to almost zero during the post-injection site care period. At cessation of the injection period, the injection wells will be properly plugged and abandoned following NDIC protocols and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the Class I wastewater injection wells, ANG #1 and ANG #2, identified as potential leakage pathways at the wellhead valves or in the instrumentation as discussed in Section 3.1.

3.4 Faults, Fractures, Bedding Plane Partings, and Seismicity

No known or suspected regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations have been identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration activities (Reference 1, Section 2.5).

3.4.1 Natural or Induced Seismicity

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment (Reference 1 Section 2.5). Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Anderson, 2016). The two closest recorded seismic events to the Great Plains CO_2 Sequestration Project occurred 29.6 miles to the northwest and 36.8 miles southwest of the Coteau 1 injection wellsite, with estimated magnitudes of 1.9 and 3.2, respectively (Reference 1, Section 2.5).

A 1-year seismic forecast (including both induced and natural seismic events) released by the U.S. Geological Survey (USGS) in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (U.S. Geological Survey, 2016). Frohlich and others (2015) state there is very little seismic activity near injection wells in the Williston Basin. They noted only two historic earthquake events in North Dakota (both were magnitude 2.6 or lower events) that could be associated with oil and gas activities. This indicates relatively stable geologic conditions in the region surrounding the potential injection site.

The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the absence of known or suspected local or regional faults suggest the probability that seismicity would interfere with CO_2 containment is low. In the event a seismic event occurs (natural or induced) near the project site, the magnitude of any seismic event would be expected to be less than 3.2 based on the historical record and would expected to cause little to no damage to subsurface or downhole equipment. In addition, DGC will operate below the maximum allowable injection pressure (Reference 1, Section 11, Table 11-1) to maintain safe operations throughout the injection period.

Through the geologic site characterization and corrective action review processes, leakage resulting from natural or induced seismicity was shown to be very unlikely.

3.5 Class VI Injection Wells

3.5.1 Coteau 1 (NDIC File No. 38379)

The Coteau 1 well spudded in June 2021 as a stratigraphic test well to a depth of 6,483 feet into the Amsden Formation. This well was drilled to gather geologic data to support the development of a CO_2 SFP and to later be converted into a Class VI injection well for the Great Plains CO_2 Sequestration Project. The Coteau 1 will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues.

The risk of leakage via the Coteau 1 is mitigated through:

- Preventing corrosion of well materials, following the preemptive measures in Reference 1, Section 5.2.2.
- Monitoring operations with a surface leak detection plan, as described in Reference 1, Section 5.3.
- Monitoring the storage reservoir with a subsurface leak detection plan, as described in Reference 1, Section 5.4.
- Performing wellbore mechanical integrity testing, as described in Reference 1, Section 5.1.2, and summarized in Reference 1, Section 5.7, Table 5-7.

The risk of leakage via the Coteau 1 during injection is low. The magnitude of any leakage during injection may vary according to the failure observed and could potentially represent a few pounds of CO_2 to several metric tons per hour released until operations are shut in and emergency protocols activated, as described in Reference 1, Section 7.4. Once the injection period ceases, the Coteau 1 will be properly plugged and abandoned following NDIC protocols, thereby reducing the risk for leakage from the well to almost zero.

3.5.2 Coteau 2 Through Coteau 6 Planned CO_2 Injection Wells

The Coteau 2 (NDIC File No. 38916), Coteau 3 (NDIC File No. 38917), and Coteau 4 (NDIC File No. 38918) wells are planned to spud in the summer of 2022 as stratigraphic test wells for the Great Plains CO_2 Sequestration Project. The wells will be drilled to the Amsden Formation at planned depths of 6,345, 6,339, and 6,301 feet, respectively. Once the SFP is issued, all stratigraphic test wells will be converted to Class VI injection wells. Like the Coteau 1, the wells will be monitored with periodic bottomhole pressure tests and temperature logs to detect any potential mechanical integrity issues. The Coteau 5 and Coteau 6 wells are planned to spud in 2026 and are conditional upon additional injection volumes of CO_2 becoming available from the capture facility. The Coteau 5 and Coteau 6 wells will be monitored after the same manner as the Coteau 1 through Coteau 4 wells. Once the injection period ceases, the Coteau 2 through Coteau 6 wells will be properly plugged and abandoned following NDIC protocols.

The discussion for assessing the risk of leakage via the Coteau 2 through Coteau 6 is the same as presented in Section 3.5.1 of this MRV plan. Once the injection period ceases, the Coteau 2 through Coteau 6 will be properly plugged and abandoned following NDIC protocols, thereby reducing the risk for leakage from the wells to almost zero.

3.6 Confining Zone Limitations

3.6.1 Lateral Migration

For the Great Plains CO_2 Sequestration Project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure (Reference 1, Section 2.3.2). The Opeche Formation is a laterally extensive formation that is 5,763 feet below the surface and 143 feet thick at the Coteau 1 wellsite (Reference 1, Section 2.4.1). Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine), as discussed in Reference 1, Section 3.4.

The risk of leakage via lateral migration is extremely unlikely, as demonstrated by the geologic characteristics of the storage reservoir (Reference 1, Section 2.3) and upper confining zone (Reference 1, Section 2.4.1) (e.g., mineralogy, permeability/sealing capacity, and lateral continuity) coupled with the modeling and simulation work (Reference 1, Section 3) that was performed for the Great Plains CO_2 Sequestration Project. In the event that the monitoring data or models and simulations predict any part of the CO_2 plume may migrate beyond the anticipated stabilized plume boundary over the project's life because of a previously unidentified permeability pathway in the storage reservoir, the storage facility area and AOR will be recalculated, and the MRV plan, including the testing and monitoring strategy, will be updated as necessary.

3.6.2 Seal Diffusivity

Several other formations provide additional confinement above the Opeche Formation (Reference 1, Section 2.4.2). Impermeable rocks above the primary seal, the Opeche Formation, include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations. Together with the Opeche, these formations are 1,106 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 2,657 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation.

Confining layers above the Inyan Kara include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (see Figure 1-3 for stratigraphic reference).

The risk of leakage via the Herrmann 1 of any magnitude and at any time over the life of the project is extremely low, as there is a total of 3,763 feet of overlying confining layers, which presents a very low risk to the Great Plains CO_2 Sequestration Project. The presence of multiple thick impermeable layers and laterally extensive formations drastically reduces potential leakage pathways through geologic formations.

3.6.3 Drilling Through the CO_2 Area

There has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the AOR. Although there was a historical oil and gas production well test from the Madison Group just outside the AOR (i.e., Herrmann 1), there are no known commercial accumulations of hydrocarbons in the AOR (Reference 1, Section 2.6). With no known commercial ventures drilling near the Great Plains CO_2 Sequestration Project area, there is very little chance of drilling through the storage complex.

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a deviated or horizontal well could be used to produce the hydrocarbon while avoiding drilling through the CO_2 plume or a vertical well could be drilled using proper controls. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available, which will allow prospective operators to design an appropriate well control strategy via increased drilling mud weight. The maximum pressure increase in the center of the injection area is projected by computer modeling to be 400–450 psi, with lesser impacts extending radially (Reference 1, Section 3, Figure 3-20). Pressure increases will relax post-injection as the area returns to its pre-injection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the CO_2 should be designed to include an intermediate casing string made of CO_2-resistant material and placed across the storage reservoir, with CO_2-resistant cement used to anchor the casing in place.

3.7 Monitoring, Response, and Reporting Plan for CO_2 Loss

DGC proposes a robust monitoring program for the SFP (Reference 1, Section 5). The program covers a corrosion and mechanical integrity protocol (Reference 1, Section 5.2), surveillance of injection performance (Reference 1, Sections 5.3 and 5.4), monitoring of near-surface conditions (Reference 1, Sections 5.5 and 5.6), and direct and indirect monitoring of the CO_2 plume (Reference 1, Section 5.7). To compliment the monitoring program, DGC proposes a detailed emergency remedial and response plan (Reference 1, Section 7) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting in the event of an unplanned loss of CO_2 from the Great Plains CO_2 Sequestration Project area.

3.8 Summary

In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the emergency and remedial response plan. Estimating volumetric losses of CO_2 would require consideration of the leakage event facts and circumstances, e.g., magnitude and timing of the CO_2 leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based upon the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

Table 4-1 summarizes the monitoring strategy for each of the three project periods, and Table 4-2 summarizes the strategy for detecting leakage pathways associated with CO_2 injection. These methodologies target early detection of any abnormalities in operating parameters or deviations from baselines and equipment detection thresholds established for the Great Plains CO_2 Sequestration Project. These methodologies will lead to a verification process to validate if a leak has occurred or if the system has lost mechanical integrity. The data collected during monitoring are also used to calibrate the numerical model and improve the prediction for the injectivity, CO_2 plume, and pressure front.

Table 4-1. Summary of DGC's CCS Monitoring Strategy

Method (target area/structure)	**Pre-injection (Baseline – 1 year)**	**Injection Period (12 years)**	**Post-injection (10 years)**
CO_2 Stream Analysis (capture)	Start-up	Daily	NA[1]
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	Start-up	Real time	NA
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	Start-up	Real time	NA
H_2S Detection Stations (flowlines, wellheads, and well pads)	Start-up	Real time	NA
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	Start-up	Monthly in the first quarter, then quarterly in the next 2 years	NA
Platform Multifinger Imaging Tool (PMIT) or Ultrasonic Imaging Tool (USIT) (CO_2 injection wells)	NA	Starting in Year 2, a PMIT or USIT will be run during well workovers but not more frequently than once every 5 years	NA
SCADA[2] Automated Remote System (surface facilities)	Start-up	Real time	NA
Soil Gas Analysis (11 soil gas profile stations)	Three to four seasonal samples	Three to four seasonal samples each year	Three to four seasonal samples each year
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)	Provide historical water sampling results	NA	NA
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)	Baseline	NA	NA
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	Baseline	Three to four seasonal samples	Three to four seasonal samples
Cement Bond Logs (CO_2 injection wells)	After cementing	If needed	Prior to P&A[3]
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	Baseline	Perform during workovers but not less than once every 5 years	Perform during workovers but not less than once every 5 years
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	Start-up	Real time	NA
Pulsed-Neutron Logs with Temperature and Bottomhole Pressure Readings (CO_2 injection wells)	Baseline	Quarterly using phased approach described in Reference 1, Section 5.1.2	NA
USIT Logs (CO_2 injection wells)	Baseline	Perform during workovers but not less than once every 5 years	Perform during workovers but not less than once every 5 years
Pressure Falloff Test (CO_2 injection wells)	Baseline	Every 5 years	NA
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	Baseline	Repeat survey 1 year after injection begins, then in Years 3, 5, and 10	Repeat survey 1 year after injection ceases, then in Years 3, 5, and 10
Vertical Seismic Profiles (VSP) (CO_2 plume)	Baseline	Repeat VSP 1 year after injection begins, then (if deemed beneficial) in Years 3, 5, and 10	NA

[1] Not applicable
[2] Supervisory control and data acquisition
[3] Plugging and abandonment

Table 4-2. Monitoring Strategies for Detecting Leakage Pathways Associated with CO_2 Injection

Monitoring Strategy (target area/structure) / Potential Leakage Pathway	Wellbores*	Faults and Fractures	Flowline and Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis (capture)			X			
Surface Pressure Gauges (ANG #1, ANG #2, and flowlines)	X		X			X
Mass/Volume Flowmeters (CO_2 injection wells and flowlines)	X		X	X		
H_2S Detection Stations (flowlines, wellheads, and well pads)	X		X	X		X
Ultrasonic Testing of Tubing Test Sections (flowlines at wellheads)	X		X	X		
PMIT or USIT (CO_2 injection wells)	X			X		
SCADA Automated Remote System (surface facilities)	X		X	X		
Soil Gas Analysis (11 soil gas profile stations)	X			X	X	X
Water Analysis: Shallow Aquifers (19 wells operated by Coteau Properties Company) (Reference 1, Appendix B)				X	X	X
Water Analysis: Lowest USDW (Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells)		X		X	X	X
Water Analysis: Lowest USDW (groundwater monitoring wells at CO_2 injection wells and Herrmann 1 well)	X	X		X	X	X
Cement Bond Logs (CO_2 injection wells)	X			X		X
Tubing–Casing Annulus Pressure Tests (CO_2 injection wells)	X			X		
200 psi Kept on Annulus, Between Tubing and Long-String and Digital Annular Pressure Gauges (CO_2 injection wells)	X			X	X	
Pulsed-Neutron Logs with Temperature and Bottomhole Readings (CO_2 injection wells)	X			X	X	X
USIT Logs (CO_2 injection wells)	X			X		
Pressure Falloff Test (CO_2 injection wells)	X			X	X	
Time-Lapse 2D Radial Seismic Surveys (CO_2 plume)	X	X		X	X	X
VSP (CO_2 plume)*	X	X		X	X	X

* Applies to all wellbores in project area if not otherwise specified under the monitoring strategy target area/structure column.

4.1 Leak Verification

DGC's strategy to detect and verify leakage pathways is summarized in Table 4-2.

As part of the surveillance protocol, DGC will use reservoir simulation modeling, based on history-matched data obtained from the monitoring program, to compare the initial numerical model with the real development of the plume and pressure front. The model will be continuously calibrated with the acquisition of real-time data. Every 5 years, a formal AOR will be submitted, and the monitoring plan will be revised, if needed.

The model history match allows the project operator and owner to identify conditions that differ from those proposed by the numerical model and deviations in the operating conditions from the originals. For example, the injection well will be monitored, and if the injection pressure, temperature, or rate measurements deviate significantly from the specified set points, then a data flag will be automatically triggered by the automated system and field personnel will investigate the excursion. These excursions will be reviewed to determine if CO_2 leakage is occurring. Excursions are not necessarily indicators of leaks; rather, they indicate that injection rates, temperatures, and pressures are not conforming to the expected pattern of the injection plan. In many cases, problems are straightforward and easy to fix (e.g., a meter needs to be recalibrated), and there is no indication that CO_2 leakage has occurred. In the case of issues that are not readily resolved, a more detailed investigation will be initiated. If further investigation indicates a leak has occurred, efforts will be made to quantify its magnitude.

The model history-matching in combination with the mechanical integrity data, geophysical surveys, and near-surface monitoring form a powerful tool to appropriately follow changes in CO_2 concentration at the surface. Many variations of CO_2 concentration detected on the surface are the result of natural processes or external events not related to the CO_2 storage complex.

Because a CO_2 surface leak is of lower temperature than ambient conditions, it will often lead to the formation of bright white clouds and ice that are easily visually observed. With this understanding, DGC will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the Great Plains CO_2 Sequestration Project.

Response plan actions and activities will depend upon the circumstances and severity of the event. DGC will address an event immediately and, if warranted, communicate the event to the UIC program director within 24 hours of discovery.

If an event triggers cessation of injection and remedial actions, DGC will demonstrate the efficacy of the response/remedial actions to the satisfaction of the UIC program director before resuming injection operations. Injection operations will only resume upon receipt of written authorization of the UIC program director.

4.2 Quantification of Leakage

As discussed above, the potential pathways for leakage include failure or issue in surface equipment or subsurface equipment (wellbores), faults or induced fractures, and competency of the seal to contain the CO_2 in the storage reservoir.

Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods to quantify the volume of CO_2 will be determined on a case-by-case basis. Any volume of CO_2 detected as leaking to the surface will be quantified using acceptable emission factors, engineering estimates of leak amount based on subsurface measurements, numerical models, history-matching of the reservoir performance, detailed analysis of the collected monitoring parameters, and delineation of the affected area, among others. Leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in an electronic central database.

5.0 DETERMINATION OF BASELINES

DGC will establish pre-injection baselines by implementing a monitoring program prior to any CO_2 injection and during each of the four primary seasonal ranges. This baseline will be created by monitoring the targeted surface, near-surface, and deep subsurface. The baseline will contain information on the characteristics of a range of environmental media, such as surface water, soil gas in the vadose zone, shallow groundwater, and storage reservoir formation water.

These baselines provide a basis for determining if CO_2 leaks are occurring by providing a foundation against which characteristics of these same media during CO_2 injection can be compared and evaluated. For example, changes in concentrations or levels of certain parameters in these media during injection might suggest that they have been impacted by leaking CO_2.

Determinations of these baselines are a critical component of a Class VI SFP. A detailed description of these baselines for both the surface and subsurface for the Great Plains CO_2 Sequestration Project area is provided in Reference 1, Sections 5.3 through 5.7.

5.1 Surface and Near-Surface Baselines

A baseline surface and near-surface sampling program has been completed for the Great Plains CO_2 Sequestration Project. Baseline data gathering included measuring chemical concentrations of the soil gas (i.e., O_2, N_2, and CO_2) and groundwater (e.g., pH, total dissolved solids, alkalinity, major cations/anions and trace metals) as well as characterizing the naturally occurring stable and radiocarbon (^{14}C) isotopic signatures of the soil gas and groundwater for comparison with the isotopic signature of the CO_2 stream. The data were obtained from 11 soil gas-sampling locations and two existing groundwater wells from the northern and eastern portions of the AOR. Baseline water samples are also planned to be obtained from five new Fox Hills monitoring wells that will be drilled prior to the start of injection operations. One of the groundwater monitoring wells will be placed near the Herrmann 1 well and the others will be placed adjacent to the Coteau 1 through Coteau 4 injection wells (Reference 1, Section 5.6,

Figure 5-4). For additional information regarding surface and near-surface baselines, refer to Reference 1, Sections 5.5.1–5.5.2 and Section 5.6, paragraph 1.

5.2 Subsurface Baselines

Pre-operational baseline data will be collected in each of the six injection wells for the Great Plains CO_2 Sequestration Project, including ultrasonic imaging, pulsed-neutron, and temperature logs, bottomhole pressure surveys, tubing-casing annulus pressure tests, and pressure falloff tests (Reference 1, Section 5.7, Table 5-7). The data acquisition schedule for the pulsed-neutron and temperature logs with a pressure-recording device attached is presented in Reference 1, Section 5.1.2. The time-lapse saturation data will be used as an assurance-monitoring technique for CO_2 in the formation directly above the storage reservoir, otherwise known as the above-zone monitoring interval. The pressure and temperature data will be useful for informing the geologic model and simulations, monitoring conditions in the storage reservoir, and confirming wellbore mechanical integrity. The pressure testing in each of the wellbores will also help to confirm wellbore mechanical integrity.

Indirect monitoring methods will also track the extent of the CO_2 plume within the storage reservoir and can be accomplished by performing time-lapse geophysical surveys of the AOR. A 2D radial seismic survey was collected to establish baseline conditions in the storage reservoir. A baseline VSP was also collected to determine the feasibility of monitoring the CO_2 plume during the injection phase with this technology. For additional information regarding subsurface baselines, refer to Reference 1, Section 5.7.2.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The Great Plains CO_2 Sequestration Project area is a geologic CO_2 storage site in a saline aquifer with no production associated from the storage complex. A flowmeter will be placed downstream of the CO_2 compressor (start of the CO_2 transmission line) and near each of the injection wellheads (Figure 1-4b). The proposed main metering station for mass balance calculation is identified as the first metering station placed at the start of the CO_2 transmission main line. The use of a single metering station for the mass balance calculation (as opposed to using multiple metering stations near each wellhead) will help ensure accuracy of the measurements.

To calculate the annual mass of CO_2 that is stored in the storage complex, the project will use Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \quad \text{[Eq. 1]}$$

Where:

CO_2 = Total annual CO_2 mass stored in subsurface geologic formations (metric tons) at the facility.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage.
CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of Part 98.

Mass of CO_2 Injected (CO_{2I}):
DGC will use volumetric flow metering to measure the flow of the injected CO_2 stream and will calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5 from 40 CFR Part 98, Subpart RR (Equation 2):

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_2,p,u} \qquad \text{[Eq. 2]}$$

Where:
$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by Flowmeter u.
$Q_{p,u}$ = Quarterly volumetric flow rate measurement for Flowmeter u in Quarter p at standard conditions (standard cubic meters per quarter).
D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.
$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for Flowmeter u in Quarter p (weight percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flowmeter.

Mass of CO_2 Emitted by Surface Leakage (CO_{2E}):
DGC characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario. However, a detailed monitoring and surveillance plan is proposed in Reference 1, Section 5, to detect any leak and defined a baseline for monitoring.

If the monitoring and surveillance plan detects a deviation from the threshold established for each method, the project will conduct a detailed analysis based on technology available and type of leak to quantify the CO_2 volume to the best of its capabilities. The process for quantifying any leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the leak, and numerical and predictive models, among others.

DGC will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98-Subpart RR (Equation 3):

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \qquad \text{[Eq. 3]}$$

Where:
CO_{2E} = Total annual CO_2 mass emitted by any surface leakage (metric tons) in the reporting year.

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.
x = Leakage pathway.

<u>Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions</u>
Annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead (CO_{2FI}) will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan proposed in Reference 1, Section 5.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented starting September 2022 or within 90 days of EPA approval, whichever occurs later. Other greenhouse gas reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time. It is anticipated that the MRV program will be in effect from September 2022 to September 2036, during which time the Great Plains CO_2 Sequestration Project will be operated.

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for DGC monitoring techniques and data management is provided in the quality assurance and surveillance plan found in Reference 1, Appendix C.

DGC will ensure compliance with the quality assurance requirement in 40 CFR § 98.444:

<u>CO_2 received</u>:

- The quarterly flow rate of CO_2 will be reported from continuous measurement at the main metering station (identified in Figure 1-4b). In addition, the quarterly flow rate of CO_2 will be continuously measured by receiving meters at each of the injection well pads.

- The CO_2 concentration will be reported as an average from daily measurements obtained from the CO_2 compressors.

<u>Flowmeter provision</u>:

- Operated continuously, except as necessary for maintenance and calibration.

- Operated using calibration and accuracy requirements in 40 CFR § 98.3(i).

- Operated in conformance with consensus-based standards organizations including, but not limited to, American Society for Testing and Materials (ASTM) International, the American National Standards Institute, the American Gas Association, the American

Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.

9.0 RECORDS RETENTION

DGC will follow the record retention requirements specified by 40 CFR § 98.3(g). In addition, it will follow the requirements in Subpart RR 40 CFR § 98.447-Subpart RR by maintaining the following records for at least 3 years:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.

- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.

- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

These data will be collected, generated, and aggregated as required for reporting purposes.

10.0 REFERENCES

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