BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 29450
(CONTINUED)
ORDER NO. 32250

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE APPLICATION OF DAKOTA GASIFICATION COMPANY REQUESTING CONSIDERATION FOR THE GEOLOGIC STORAGE OF CARBON DIOXIDE FROM THE GREAT PLAINS SYNFUELS PLANT LOCATED IN SECTIONS 5, 6, 7, 8, 17, 18, 19, TOWNSHIP 145 NORTH, RANGE 87 WEST, SECTIONS 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, TOWNSHIP 145 NORTH, RANGE 88 WEST, SECTIONS 30, 31, 32, TOWNSHIP 146 NORTH, RANGE 87 WEST, SECTIONS 25, 26, 27, 33, 34, 35, 36, TOWNSHIP 146 NORTH, RANGE 88 WEST, MERCER COUNTY, NORTH DAKOTA PURSUANT TO NORTH DAKOTA ADMINISTRATIVE CODE SECTION 43-05-01.

ORDER OF THE COMMISSION

THE COMMISSION FINDS:

(1) This cause originally came on for hearing at 9:00 a.m. on the 20th day of July, 2022. The Commission entered Order No. 32020 on October 5, 2022 continuing this matter for one hundred and seventy (170) days or until further order of the Commission.

(2) Dakota Gasification Company (DGC) made application to the Commission for an order requesting consideration for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, pursuant to North Dakota Administrative Code (NDAC) Section 43-05-01.

(3) DGC submitted an application for a Storage Facility Permit and necessary attachments pursuant to NDAC Section 43-05-01-05 and all other provisions of NDAC Chapter 43-05-01 as necessary.

(4) Case Nos. 29450, 29451, and 29452 were combined for the purposes of hearing.

(5) Case No. 29451, also on today's docket, is a motion of the Commission to determine the amalgamation of storage reservoir pore space, pursuant to a Storage Agreement by DGC for use of pore space falling within portions of Sections 25, 26, 27, 33, 34, 35, and 36, Township 146 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, and Sections 5, 6, 7, 8, 17, 18, and 19, Township 145 North, Range 87 West, Mercer County, North Dakota, in the Broom Creek Formation, has been signed, ratified, or approved by owners of interest owning at least sixty percent of the pore space interest within said lands pursuant to North Dakota Century Code (NDCC) 38-22-10.

(6) Case No. 29452, also on today's docket, is a motion of the Commission to determine the amount of financial responsibility for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in portions of Sections 25, 26, 27, 33, 34, 35, and 36, Township 146 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, Sections 5, 6, 7, 8, 17, 18, and 19, Township 145 North, Range 87 West, Mercer County, North Dakota in the Broom Creek Formation, pursuant to NDAC Section 43-05-01-09.1.

(7) The record in these matters were left open to receive additional information from DGC. Such information was received on August 8, 2022, and the record was closed.

(8) Pursuant to NDCC Section 38-22-06 and NDAC Section 43-05-01-08, the notice of filing of the application and petition and the time and place of hearing thereof was given, and that at least 45 days prior to the hearing, DGC, as the applicant, did give notice of the time and place of said hearing and the Commission has accepted the notice as adequate, and that the applicant did, at least 45 days prior to the hearing, file with the Commission engineering, geological, and other technical exhibits to be used and which were used at said hearing, and that the notice so given did specify that such material was filed with the Commission; that due public notice having been given, as required by law, the Commission has jurisdiction of this cause and the subject matter.

(9) The Commission gave at least a thirty-day public notice and comment period for the draft storage facility permit and issued all notices using methods required of all entities under NDCC Section 38-22-06 and NDAC Section 43-05-01-08. Publication was made June 8, 2022, and the comment period for written comments ended at 5:00 PM CDT July 19, 2022. The hearing was open to the public to appear and provide comments.

(10) The Commission received an email from Perry Anderson on June 26, 2022, asking if the applicant was to become Bakken Energy LLC, a subsidiary of Basin Electric Power

Cooperative. The Commission assumes this was intended for Dakota Gasification Company. The Commission finds the information included in the letter to be either inapplicable or irrelevant to this case.

(11) The Commission received a letter from Allen Eisenbeis (A. Eisenbeis) on June 27, 2022 indicating ownership of farmland in the N/2 NW/4 and S/2 NW/4 of Section 34, Township 146 North, Range 88 West, and mineral rights in Lot 1, Lot 2, the S/2 NE/4, and SE/4 of Section 3, Township 145 North, Range 88 West, the S/2 N/2 of Section 10, Township 145 North, Range 88 West, the NW/4 of Section 11, Township 145 North, Range 88 West, the SE/4 and SW/4 of Section 27, Township 146 North, Range 88 West, and the N/2 SE/4 of Section 36, Township 146 North, Range 88 West, Mercer County, North Dakota. The Commission notes A. Eisenbeis is identified as a mineral owner and surface owner requiring notification. A. Eisenbeis indicates that DGC sent him a letter offering $500 to sign an agreement to store carbon dioxide on his property. A. Eisenbeis considers the amount to not be worth the loss of the oil on his property. A. Eisenbeis states the land belongs to the property owners and not the state of North Dakota nor DGC, and that DGC should store the carbon dioxide on property that they own. A. Eisenbeis states that pressurized carbon dioxide is cryogenic, and questions why anyone would want to make North Dakota colder. A. Eisenbeis questions how the government or corporations can seize property that belongs to private citizens without paying fair market value for the land and oil.

(12) DGC testified the $500 dollar offer was for surface access to gather seismic data, and that nonconsenting pore space owners would receive the same compensation as consenting owners.

(13) NDCC Section 38-22-10 states, "If a storage operator does not obtain the consent of all persons who own the storage reservoir's pore space, the commission may require that the pore space owned by nonconsenting owners be included in a storage facility and subject to geologic storage." If oil and gas was displaced from the Bakken Formation, unitization of minerals would be required under NDCC Chapter 38-08. The atmosphere will not be exposed to cryogenic temperature impacts of pressurized carbon dioxide.

(14) The Commission received a letter from the Dakota Resource Council (DRC) on July 12, 2022, indicating concern with this project. DRC states the applicant should be required to conduct modeling regarding lithofacies and petrophysical properties that are specific to the site. DRC states to ensure the success and longevity of this project it would be prudent to require site specific data as geologic formations are not entirely uniform.

DRC states that the applicant should explain in more specific detail their plans to work with Mercer County LEPC. DRC states a leak from a Class VI injection well would be a new event for local first responders, and that there could be severe consequences for environmental and human health if local emergency crews are not equipped and educated for such an event.

(15) DGC's application discusses 3D seismic surveys in section 2.2.2.6 of their application. The application states placement of a seismic source and receiver locations required for a seismic survey would be restricted because of the active coal mine and industrial facilities. Due to the

inability to acquire site-specific 3D seismic data within the area, localized variograms distributing lithofacies and petrophysical properties are not viable.

(16) DGC testified to having a protection services group. The group takes care of security, hazmat, fire protection, and medical and are the first responders for any emergency in the event of a leak. DGC testified to having a reverse 911 system that contacts all people within the area of impact corridor that will be notified with an evacuation order. DGC testified that they meet with local emergency responders every two years to provide them with plans and training. Local responders are informed what the hazards of carbon dioxide and natural gas pipelines are. DGC stated they are a member of the emergency local planning commission where mock drills and tabletop drills are performed for the event of a leak. DGC testified that local law enforcement would be used to block roads since DGC has the staff to take care of an emergency response.

(17) The Commission received a letter from Bruce and Gail Bitterman (Bittermans) on July 11, 2022, indicating they are not in favor of this application. The Bittermans state science does not agree that the storage is permanent or forever. The Commission did not receive additional information from the Bittermans supporting this statement.

(18) The Commission received a letter from Clyde Eisenbeis (C. Eisenbeis) on June 9, 2022 indicating ownership of farmland and mineral rights in Lot 1, Lot 2, the S/2 NE/4, and SE/4 of Section 3, Township 145 North, Range 88 West, the S/2 N/2 of Section 10, Township 145 North, Range 88 West, the NW/4 of Section 11, Township 145 North, Range 88 West, the SE/4 and SW/4 of Section 27, Township 146 North, Range 88 West, the N/2 NW/4 and S/2 NW/4 of Section 34, Township 146 North, Range 88 West, and the N/2 SE/4 of Section 36, Township 146 North, Range 88 West, Mercer County, North Dakota. The Commission notes C. Eisenbeis is identified as a mineral owner and surface owner requiring notification. C. Eisenbeis is concerned with injected carbon dioxide displacing oil and gas in the Bakken Formation. C. Eisenbeis questioned if Basin Electric will reimburse farmland owners and mineral rights owners for potential future loss of oil and gas income. C. Eisenbeis provided North Dakota Geological Survey geologic investigation number 59 by Julie A. LeFever 2008.

(19) C. Eisenbeis appeared on July 20, 2022 to provide testimony, and submitted emails supplemental to his testimony. The first email was received July 21, 2022 and clarified his ownership from his letter received June 9, 2022. C. Eisenbeis indicated ownership of farmland in the N/2 NW/4 and S/2 NW/4 of Section 34, Township 146 North, Range 88 West, and mineral rights in Lot 1, Lot 2, the S/2 NE/4, and SE/4 of Section 3, Township 145 North, Range 88 West, the S/2 N/2 of Section 10, Township 145 North, Range 88 West, the NW/4 of Section 11, Township 145 North, Range 88 West, the SE/4 and SW/4 of Section 27, Township 146 North, Range 88 West, the N/2 NW/4 and S/2 NW/4 of Section 34, Township 146 North, Range 88 West, and the N/2 SE/4 of Section 36, Township 146 North, Range 88 West, Mercer County, North Dakota. C. Eisenbeis asks if all mineral rights owners have been informed that the carbon dioxide could displace oil and gas under their land. C. Eisenbeis asks if all mineral owners have been given a Bakken and Broom Creek Formation elevation map, and asks if all mineral rights owners have been informed that this could cost them, their children, and their grandchildren millions of

dollars in the future. C. Eisenbeis asks the following: 1.) if it is possible there is an opening between the Broom Creek and Bakken Formation that could allow carbon dioxide to displace oil and gas in the Bakken Formation, 2.) if it is possible that pressurizing the carbon dioxide in the Broom Creek Formation could rupture the gap between the Broom Creek and Bakken Formations that could allow carbon dioxide to displace oil and gas, 3.) if it is possible that an earthquake could allow carbon dioxide to displace oil and gas in the Bakken Formation, and 4.) if Basin Electric will reimburse mineral rights owners for potential future loss of oil and gas income.

C. Eisenbeis states he heard during the hearing, North Dakota legislature created a law that allows others to remove minerals under mineral rights land. C. Eisenbeis asks if the state can remove minerals that are the owner's property with no just cause and states that Industrial Commission should take this to the federal court and US Supreme Court if necessary.

C. Eisenbeis questions why the Bakken Formation was not mentioned in the hearing until he brought it up and if the Bakken Formation is in the reports submitted to the Industrial Commission. C. Eisenbeis states the Bakken Formation could be affected by carbon dioxide injection into the Broom Creek, could result in millions of dollars of losses to the mineral rights owners, and should be included in the reports.

C. Eisenbeis referenced models mentioned in the hearing, and states models are often inaccurate and referenced global warming models being incorrect. C. Eisenbeis states that code writers who write the code for models can produce any result they want, and that it can be modified until producing the result they want. C. Eisenbeis interprets the applicant's mention of several models in the hearing as the initial model producing a result the applicant did not like and switched to a model that produced a result it liked.

C. Eisenbeis referenced that he heard there is no Broom Creek 3D map, and states he is concerned with the 1,000-foot distance between the Broom Creek and Bakken Formations as being too little. C. Eisenbeis asks how the applicant knows the distance between the formations is 1,000 feet without a 3D map and asks if it is 1,000 feet from the top of the Broom Creek to the top of the Bakken. C. Eisenbeis questions if this thickness varies and if the formations are as close as one foot in some places, or already connected. C. Eisenbeis questions if the formations were drilled through vertically, and states there is already a breach between the formations if so. C. Eisenbeis states that the depth and thickness of the Bakken Formation varies and asks how the applicant's models accurately determine the distance between the formations. C. Eisenbeis states oil companies do not know the exact depth and thickness of the Bakken in various locations.

C. Eisenbeis states that there is an aquifer 80 to 100 feet below the surface of his farmland valley, and that there is another aquifer 180 to 200 feet below the surface. C. Eisenbeis states that a well was dug in that valley for the carbon dioxide project, asks if there are protections in place to prevent contaminating the aquifer, and states the water's color is changing. C. Eisenbeis states DGC puts sulfur into the ground and that there is a lot of sulfur in lignite coal. C. Eisenbeis is concerned with fly ash pits, loss of cattle due to sulfide, and that sulfur can kill people. C. Eisenbeis asks if DGC should be shut down and remove the fly ash and all sulfur from the ground.

C. Eisenbeis referenced that it was mentioned in the hearing that no one lives on the land. C. Eisenbeis states that Lucille Sailer (Sailer), Lyle Eisenbeis, and Karen Waltz do live on the land in the area at various times of the year and there may be others. C. Eisenbeis states that coal mining pond water discharges into a farmland creek which floods Sailer's farmhouse basement and farmland. C. Eisenbeis states Sailer was not given a Bakken Formation or Broom Creek Formation map and was not told it could displace oil or gas under her land, nor that it could affect her water. C. Eisenbeis states all contracts should be invalidated as they did not provide adequate information.

C. Eisenbeis referenced the hearing and the applicant testimony that it is not economically feasible to extract oil or gas under his farmland. C. Eisenbeis states the same was said years ago in the Williston area, and that new technology of horizontal drilling made it feasible as evidenced by the current oil and gas extraction in the Williston area. C. Eisenbeis questions if future technology could heat the gas present to convert it to oil.

C. Eisenbeis asks if a leak is detected by the applicant, how they would find and fix the location of the leak, and how they would ensure it does not displace oil or gas.

C. Eisenbeis is concerned that the permit also grants access to the surface of farmland without any restrictions, and that the applicant could build a variety of infrastructures, including buildings, on the farmland. C. Eisenbeis asks what authority grants access to someone else's farmland.

C. Eisenbeis states that proponents of carbon dioxide injection supposedly know there is no risk of displacing oil or gas. C. Eisenbeis states if the proponents know, they should sign a legal contract that gives all of their assets to the mineral rights owner if there is a problem. C. Eisenbeis states that if displacing oil and gas does occur then the proponents lose money rather than the mineral rights owners. C. Eisenbeis states that if the proponents do not sign these types of legal documents, that they do not know if displacement will occur and are guessing.

C. Eisenbeis states Mary Ricker's (Ricker) attorney said oil companies will not drill where carbon dioxide is stored. C. Eisenbeis agrees with the statement saying there is too much of a risk which could have many complications. C. Eisenbeis states carbon dioxide storage should not be placed within a hundred miles of the Bakken Formation.

C. Eisenbeis states there should be another hearing to include the property owners which discusses responses from the applicant. C. Eisenbeis states this would give the opportunity to discuss responses and ask more questions, and that there is a lot of money at stake.

(20) C. Eisenbeis submitted a second email received by the Commission on July 25, 2022 as an addendum to his July 21, 2022 email. C. Eisenbeis states that after the well was dug in the valley for the carbon dioxide project that there is sand in the water, that the water's color changed, that it is unknown what contaminates changed the water's color, and that these contaminants could harm people. C. Eisenbeis states that it is unknown if it is possible to completely seal well holes and that over time water penetrates almost everything. C. Eisenbeis states steel cannot be welded to rocks, and that filling the area around a well pipe with concrete may delay the penetration, but

the odds are quite high that water and some gasses will eventually bypass the filling around the pipes.

C. Eisenbeis states if carbon dioxide escaped from the Broom Creek, it could kill people and that the injection puts people at risk. C. Eisenbeis states carbon dioxide is heavier than air and references carbon dioxide killing close to 2,000 people living near Lake Nyos in Cameron, Africa in 1986.

C. Eisenbeis asks if sulfur killed some cattle, are residents drinking well water that has sulfur. C. Eisenbeis asks if sulfur contamination has occurred in rural water, Lake Sakakawea, and for fish in the area.

C. Eisenbeis states Sailer did not sign the document that allowed seismic testing on the farmland, and that she did not know there were two documents. C. Eisenbeis states that flooding of her basement occurred when deep holes were dug for the Dakota Gasification Company and or Antelope Valley Coal Power Plant.

C. Eisenbeis states carbon dioxide is heavier than air, that storing it under the valley may not be safe, and that it could kill people who live in the valley if it escaped. C. Eisenbeis states that storing carbon dioxide on a mountain may not be safe as it could sink to lower levels and kill people. C. Eisenbeis states the safest place to store carbon dioxide appears to be the ocean.

(21) Pursuant to NDAC 43-05-01-08(2), the notice given by the applicant to mineral owners within one half mile of the facility boundary must contain a legal description of the land within the facility area; the date, time, and place that the Commission will hold a hearing on the permit application; a statement that a copy of the permit application and draft permit may be obtained from the Commission; a statement that all comments regarding the storage facility permit application must be in writing and submitted to the Commission prior to the hearing or presented at the hearing; a statement that amalgamation of the storage reservoir pore space is required to operate the storage facility, that the commission may require the pore space owned by nonconsenting owners be included in the storage facility and subject to geologic storage, and the amalgamation of pore space will be considered at the hearing.

(22) Using a conservative 6,500-foot subsea contour from the map provided by C. Eisenbeis, that would place the Bakken Formation at approximately 8,500 feet true vertical depth at the location of the Coteau #1 (File No. 38379). The top of the injection formation, the Broom Creek Formation, is 5,907 feet true vertical depth and the base of the formation is 6,166 feet true vertical depth at the location of the Coteau # 1 (File No. 38379). The approximate 2,300 feet of underlying formations include the Amsden, Tyler, Otter, Kibbey, Charles, Mission Canyon, and Lodgepole Formations. Beds of impermeable shales as well as hydraulically isolated porous formations separate the injection formation from the Bakken Formation. If an existing transmissive conduit existed connecting the Broom Creek and Bakken Formations, gas or oil shows would be expected. Carbon dioxide is buoyant and would not behave in a manner conducive to downward migration. If fluids were displaced downward, various porous formations that would intercept fluid exist

between the injection formation and the Bakken Formation. For an earthquake to occur, there would need to be a fault present and testimony indicated there are no faults present within the storage reservoir or upper or lower confining zones. Microseismic events caused by injection created fractures will not be created due to the regulatory bottom hole pressure constraint of ninety percent of fracture pressure. Migration of carbon dioxide outside of the injection formation would be detected in seismic data. If oil and gas was displaced from the Bakken Formation, unitization of minerals would be required under NDCC 38-08.

(23) NDCC 38-22-10 states that if a storage operator does not obtain the consent of all persons who own the storage reservoir's pore space, the commission may require that the pore space owned by nonconsenting owners be included in a storage facility and subject to geologic storage. Removal or displacement of oil and gas is not the subject of this application as it is not applying for storage in a hydrocarbon bearing reservoir.

(24) The Bakken Formation is addressed in Section 2.6 of the application. It indicates there has been no historic hydrocarbon exploration in, or production from, formations below the Broom Creek Formation in the storage facility area. It includes that in the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a horizontal well could be used to produce the hydrocarbons while avoiding drilling through the carbon dioxide 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.

(25) The equation of state reservoir simulator used by DGC is GEM, an EPA acknowledged existing code used for the development of geologic sequestration models. Commission staff reviewed all inputs for the reservoir model and used Computer Modelling Group LTD.'s software with GEM to verify outputs given by DGC. DGC updated and submitted the model based on a request by the Department of Environmental Quality in the review process. Reference to an alternate model was made based on DGC using publicly available relative permeability and capillary entry pressure data that allowed for a greater extent of carbon dioxide migration than site specific core data. This provides for a more conservative storage facility boundary. Formations considered in the model included the Opeche, Broom Creek, and Amsden Formations. DGC has performed baseline 2D seismic over the storage facility area. Time-lapse seismic surveys will be repeated 1, 3, 5, and 10 years after initial injection. Time-lapse 2D seismic will show the vertical and lateral extents of the carbon dioxide independent of the model.

(26) All stratigraphic test wells drilled in the storage facility were subject to NDAC 43-02-03-32, stating, in part, stratigraphic test and core holes shall be permitted the same as oil and gas wells. NDAC 43-02-03-21 states, in part, drilling of the surface hole shall be with freshwater-based drilling mud or other method approved by the director which will protect all freshwater-bearing strata. This includes water used during the cementing of surface casing for displacement. The surface casing for stratigraphic wells is set into the Pierre Formation, below

the deepest underground source of drinking water within the facility area, cemented to surface, and verified by radial cement bond log.

(27) The Commission notes three residential occupancies within figure 4-2 of the application, and various others within the area of review. DGC testified to the safety procedures concerning the facility and residential and public land use within one mile of the facility area as required in NDAC 43-05-01-13.

(28) The application indicates leak detection at the wellbore will be monitored using temperature and pulse neutron logging. In the event of out of zone migration through the upper confining zone, the Inyan Kara Formation above exists as a porous trap. The location of a confining zone leak can be detected with time-lapse seismic. DGC identifies installing a system to intercept brine or carbon dioxide or to pump and treat to air-strip carbon dioxide from the impacted water in the event of an underground source of drinking water being impacted.

(29) Article 8 of the Storage Agreement, section 8.1 "Grant of Easement" states the storage operator shall have the right to use as much of the surface of the land within the Facility Area as reasonably necessary for Storage Operations and the injection of Storage Substances. DGC testified that the surface access would be for monitoring activities by means of seismic surveys. NDCC 38-22-09 states the commission may include in a permit or order all things necessary to carry out this chapter's objectives and to protect and adjust the respective rights and obligations of persons affected by geologic storage. Seismic surveys are required to monitor the migration, lateral, and vertical extent of the plume. If an applicant proposed to build a variety of infrastructures, including buildings, as C. Eisenbeis states, an application can be filed for hearing by an impacted party under NDAC 43-05-01-12(1), which states in part that any interested person (i.e., the storage operator, local governments having jurisdiction over land within the area of review, any person who has suffered or will suffer actual injury or economic damage) may request that the commission review permits issued under this chapter for one of the reasons set forth below. NDAC 43-05-01-12(1)(k), "The commission receives information that was not available at the time of the permit issuance. Permits may be modified during their terms for this cause only if the information was not available at the time of permit issuance (other than revised regulations, guidance, or test methods) and would have justified the application of different permit conditions at the time of issuance). Building infrastructure or buildings without a separate surface agreement would not be considered reasonably necessary to carry out the objectives of NDCC 38-22.

(30) The Commission has rules and regulations in place to safeguard against tubing leaks or blowouts. NDAC Section 43-05-01-11(10) requires all tubing strings must meet the standards contained in subsection 6. All tubing must be new tubing or reconditioned tubing of a quality equivalent to new tubing and that has been pressure-tested. For new tubing, the pressure test conducted at the manufacturing mill or fabrication plant may be used to fulfill this requirement. NDAC Section 43-05-01-11(11) requires all wellhead components, including the casinghead and tubing head, valves, and fittings, must be made of steel having operating pressure ratings sufficient to exceed the maximum injection pressures computed at the wellhead and to withstand the corrosive nature of carbon dioxide. Each flow line connected to the wellhead must be equipped

with a manually operated positive shutoff valve located on or near the wellhead. NDAC Section 43-05-01-11(12) requires all packers, packer elements, or similar equipment critical to the containment of carbon dioxide must be of a quality to withstand exposure to carbon dioxide. NDAC 43-05-01-11(14) requires all newly drilled wells must establish internal and external mechanical integrity as specified by the Commission and demonstrate continued mechanical integrity through periodic testing as determined by the Commission. All other wells to be used as injection wells must demonstrate mechanical integrity as specified by the Commission prior to use for injection and be tested on an ongoing basis as determined by the Commission. NDAC 43-05-01-11(17) requires all injection wells must be equipped with shutoff systems designed to alert the operator and shut-in wells when necessary.

(31) The Commission has rules and regulations in place requiring the operator to demonstrate seismicity will not interfere with containment and prohibiting fracturing of the injection zone. NDAC Section 43-05-01-05(1)(b)(2)(m) requires the applicant must provide information on the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment. NDAC Section 43-05-01-11.3(1) requires except during stimulation, the storage operator shall ensure that injection pressure does not exceed ninety percent of the fracture pressure of the injection zone so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone. Injection pressure must never initiate fractures in the confining zone or cause the movement of injection or formation fluids that endanger an underground source of drinking water. All stimulation programs are subject to the Commission's approval as part of the storage facility permit application and incorporated into the permit.

(32) Pursuant to NDAC 43-05-01-05 (1)(b)(2)(j) the application is required to provide the location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone in the area of review, and a determination that they would not interfere with containment. Pursuant to NDAC 43-05-01-05 (1)(b)(2)(k) the application must include data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions. Pursuant to NDAC 43-05-01-05 (1)(b)(2)(l) the application is required to provide geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream. Pursuant to NDAC 43-05-01-05 (1)(b)(2)(o) the application is required to identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement, are free of transmissive faults or fractures, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.

(33) DGC's application provides adequate data to show suitability of the Broom Creek Formation for geologic storage of carbon dioxide in the facility area.

(34) DGC's application provides adequate modeling of the storage reservoir for delineation of the facility area, and adequate monitoring to detect if carbon dioxide is migrating into properties outside of the facility area pursuant to NDAC Section 43-05-01-11.4. Vertical release of carbon dioxide is addressed by the application pursuant to NDAC Section 43-05-01-13, and lateral release of carbon dioxide from the facility area is addressed by the application pursuant to NDAC Section 43-05-01-05.

(35) The Commission finds the information and opinions included in C. Eisenbeis's letters that were not addressed, to be either inapplicable or irrelevant to this case.

(36) Ricker appeared on July 20, 2022 to provide testimony. Ricker testified to owning mineral rights within the storage facility in the N/2 Section 10 and NW/4 Section 11, Township 145 North, Range 88 West. Ricker testified to seeking legal advice and their lawyer stated their mineral rights will be condemned or made null by this operation. Ricker is concerned about what may be in the Bakken Formation, and how any retrieval of those minerals will be made more difficult because of the actions being taken here. Ricker states that even if you can drill through or around it, these actions would be more costly than direct retrieval, and that there will be a real economic impact to mineral rights.

(37) There has been no historic hydrocarbon exploration, production, or studies suggesting there is an economically profitable supply of hydrocarbons from formations above or below the Broom Creek Formation within the proposed storage facility area. There has been historic production approximately 11 miles to the west of the storage facility from the Traxel 1-31H well (File No. 17877). The lateral extent of the stabilized plume and the pressure differential are minor enough to allow for horizontal drilling for hydrocarbon exploration, under the Broom Creek Formation, without penetrating the stored carbon dioxide. DGC testified that 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. DGC testified that a vertical well could be drilled using proper controls.

(38) The Commission received no compelling information to indicate underlying minerals would be stranded.

(39) DGC's Great Plains Synfuels Plant is a gasification plant located in Mercer County, North Dakota, near the city of Beulah. The lignite used for natural gas generation is the source of the carbon dioxide.

(40) Up to 2,700,000 metric tons of carbon dioxide will be captured annually from the Great Plains Synfuels Plant. The captured carbon dioxide will be compressed, transported to a Class VI well by a transmission and flow line, and then injected. Up to 2,700,000 metric tons of carbon dioxide will be injected into the Broom Creek Formation annually.

(41) DGC permitted a 6.8-mile transmission line through the North Dakota Public Service Commission (PSC) and implements their approved corrosion monitoring and prevention strategy. Transition from the PSC jurisdiction transmission line to injection well flow line will be at the flow meter on each injection well pad.

(42) The projected composition of the carbon dioxide stream is 95.9% carbon dioxide, 1.8% C_2^+ and hydrocarbons, 1.2% hydrogen sulfide, 0.6% methane, and 0.5% nitrogen.

(43) The flow line will be equipped with pressure gauges and a Supervisory Control and Data Acquisition (SCADA) system to detect leaks. Hydrogen sulfide detection stations will also be utilized for detection of leaks.

(44) The Coteau #1 well (File No. 38379) is stratigraphic test well that was used for reservoir characterization and constructed to Class VI requirements, located 555 feet from the south line and 460 feet from the west line of Section 1, Township 145 North, Range 88 West, Mercer County, North Dakota. This well is to be converted to a Class VI injection well.

(45) The Coteau #2 well (File No. 38916) is stratigraphic test well that is constructed to Class VI requirements, located 424 feet from the south line and 805 feet from the west line of Section 2, Township 145 North, Range 88 West, Mercer County, North Dakota. This well is to be converted to a Class VI injection well.

(46) The Coteau #3 well (File No. 38917) is stratigraphic test well that is constructed to Class VI requirements, located 2,462 feet from the south line and 2,391 feet from the east line of Section 2, Township 145 North, Range 88 West, Mercer County, North Dakota. This well is to be converted to a Class VI injection well.

(47) The Coteau #4 well (File No. 38918) is stratigraphic test well that is constructed to Class VI requirements, located 1,641 feet from the south line and 2,421 feet from the west line of Section 1, Township 145 North, Range 88 West, Mercer County, North Dakota. This well is to be converted to a Class VI injection well.

(48) The Coteau #5 well (File No. 39418) is a stratigraphic test well that will be tested, logged, and constructed to Class VI requirements, located 1,408 feet from the south line and 1,138 feet from the east line of Section 12, Township 145 North, Range 88 West, Mercer County, North Dakota. This well is to be converted to a Class VI injection well.

(49) The proposed Coteau #6 well will be tested, logged, and constructed to Class VI requirements, to be located approximately 688 feet from the south line and 2,037 feet from the east line of Section 12, Township 145 North, Range 88 West, Mercer County, North Dakota. This proposed well is to be a Class VI injection well.

(50) DGC created a geologic model based on site characterization as required by NDAC Section 43-05-01-05.1 to delineate the area of review. Data utilized included seismic survey data,

geophysical logs from nearby wells, and core data. Structural surfaces were interpolated with Schlumberger's Petrel software, and included formation tops, data collected from the Coteau #1 (File No. 38379), the Flemmer #1 (File No. 34243), the BNI #1 (File No. 34244), the J-LOC #1 (File No. 37380), the Liberty #1 (File No. 37672), the ANG #1 (Class I well), as well as 3D seismic surveys conducted at the Flemmer #1 and Liberty #1 locations. Due to low well control and difficulties with obtaining 3D seismic data on reclaimed mine land, publicly available variograms from the Minnkota Center MRYS Broom Creek Storage Facility #1 were used to inform lithofacies and petrophysical properties in the geologic model. The variograms were selected as they provided a generalized representation of property distributions expected in the Broom Creek Formation. Based on the reservoir pressure obtained from the Coteau #1 (File No. 37380), critical threshold pressure for this storage facility exists in the Broom Creek Formation prior to injection. Critical threshold pressure has the same meaning as pressure front, defined in NDAC Section 43-05-01-01, for area of review delineation purposes. EPA's "UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance" lists several methods to estimate an acceptable pressure increase for over-pressurized reservoirs, including a multiphase numerical model designed to model leakage through a single well bore, or through multiple well bores in the formation. DGC has used this method to determine cumulative leakage potential along a hypothetical leaky wellbore without injection occurring is estimated to be 0.01 cubic meters over 20 years. Incremental leakage with injection occurring was determined to be a maximum of 0.011 cubic meters over 20 years. A value of 1 cubic meter is the lowest meaningful value that can be produced by the ASLMA model as smaller values likely represent statistical noise. An actual leaky wellbore or transmissive conduit would likely communicate with the Inyan Kara Formation. DGC's application noted no indications of communication between the Broom Creek Formation and Inyan Kara Formation were observed, and that nothing in fluid samples indicated communication to USDWs. The predicted extent of the carbon dioxide plume from beginning to end of life of the project, at the time that the carbon dioxide plume ceases to migrate into adjacent cells of the geologic model, was used to define the area of review in this case. Pursuant to NDAC 43-05-01-05(1)(b)(2) the area of review was proposed as a one-mile buffer around the storage facility boundaries. Time lapse seismic surveys will be used for monitoring the extent of the carbon dioxide plume.

(51) The area proposed to be included within the storage facility is as follows:

<u>TOWNSHIP 146 NORTH, RANGE 88 WEST</u>
ALL OF SECTIONS 35 AND 36, THE S/2 OF SECTION 25, THE S/2 OF SECTION 26, THE SE/4 OF SECTION 27, THE SE/4 OF SECTION 33, AND THE S/2, AND NE/4 OF SECTION 34,

<u>TOWNSHIP 146 NORTH, RANGE 87 WEST</u>
ALL OF SECTION 31, THE S/2 OF SECTION 30, AND THE SW/4 OF SECTION 32,

<u>TOWNSHIP 145 NORTH, RANGE 88 WEST</u>
ALL OF SECTIONS 1, 2, 3, 10, 11, 12, 13, 14, 15, 22, 23 AND 24, THE E/2 OF SECTION 4, THE E/2 OF SECTION 9, AND THE E/2 OF SECTION 16,

<u>TOWNSHIP 145 NORTH, RANGE 87 WEST</u>
ALL OF SECTIONS 6, 7, 18 AND 19, THE W/2 OF SECTION 5, THE W/2 OF SECTION 8, AND THE W/2 OF SECTION 17.

ALL IN MERCER COUNTY AND COMPRISING OF 15,979.20 ACRES, MORE OR LESS.

(52) The Broom Creek Formation, the upper confining Opeche Formation, and the lower confining Amsden Formation are laterally extensive through the area of review.

(53) Core analysis of the Broom Creek Formation shows sufficient permeability to be suitable for the desired injection rates and pressures without risk of creating fractures in the injection zone. Thin-section investigation shows the Broom Creek Formation's sandstone intervals are comprised primarily of quartz, with minor occurrences of feldspar, dolomite, and anhydrite as cement. Within the Broom Creek, carbonate intervals are present consisting of dolostone, dolomite, anhydrite, quartz, dolosparite, feldspar, and clay. Anhydrite is present crystallized between quartz grains, as well as in the form of clasts and veins within carbonate intervals. Microfracture testing in the Flemmer #1 (Well No. 34243) well, near, but outside of the delineated facility area, at a depth of 6,358 feet determined the breakdown pressure of the formation to be 4,950 psi bottom hole pressure, with a fracture propagation pressure of 4,384 psi bottom hole pressure, and a fracture closure pressure of 4,195 psi bottom hole pressure. Microfracture in situ tests were not attempted in the Coteau #1 (File No. 38379) well due to unstable wellbore conditions. A one-dimensional mechanical earth model (1D MEM) was used to compensate for the lack of microfracture data within the storage facility area. Average fracture propagation pressure gradient at the Coteau #1 was assigned at 0.71 psi/ft, comparable to the 0.69 psi/ft gradient of the Flemmer #1.

Core analysis of the overlying Opeche Formation shows sufficiently low permeability to stratigraphically trap carbon dioxide and displaced fluids. Thin-section investigation shows the Opeche Formation is comprised of alternating intervals of silty mudstone and mudstone. Microfracture testing in the Flemmer #1 (Well No. 34243) well, near, but outside of the delineated facility area, at a depth of 6,262 feet observed formation breakdown at 8,157 psi bottom hole pressure and fracture propagation pressures of 4,879 psi bottom hole pressure and 5,085 psi bottom hole pressure, or a 0.78 psi/ft and 0.81 psi/ft gradient respectively. Microfracture in situ tests were not attempted in the Coteau #1 (File No. 38379) well due to unstable wellbore conditions. Injection pressure is limited to ninety percent of the fracture pressure of the injection zone. Injection formation breakdown would be observed and recorded if permitted operational pressures were exceeded before compromising the confining zone.

Core analysis of the underlying Amsden Formation shows sufficiently low permeability to stratigraphically contain carbon dioxide and displaced fluids. Thin-section investigation shows the Amsden Formation is comprised of dolomite, sandy dolomite, shaly sand, and anhydrite.

(54) The in situ fluid of the Broom Creek Formation in this area is in excess of 10,000 parts per million of total dissolved solids.

(55) Investigation of wells within the area of review found no vertical penetrations of the confining or injection zones requiring corrective action. The area of review will be reevaluated at a period not to exceed five years from beginning of injection operations.

(56) The Fox Hills Formation is the deepest underground source of drinking water (USDW) within the area of review. Its base is situated at a depth of 1,749 feet at the location of the proposed injection wells, leaving approximately 4,158 feet between the base of the Fox Hills Formation and the top of the Broom Creek Formation.

(57) Fluid sampling of shallow USDWs has been performed to establish a geochemical baseline, with additional baseline sampling proposed for the Fox Hills Formation and other shallow wells under investigation. Future sampling is proposed in DGC's application pursuant to NDAC Section 43-05-01-11.4.

(58) Soil sampling is proposed pursuant to NDAC Section 43-05-01-11.4. A baseline of soil gas concentrations has been established and was submitted to the Commission as part of this application. Six soil gas profile stations are located where the six injection wells will be, as well as five additional stations within the proposed storage facility area boundary.

(59) The top of the Inyan Kara Formation is at 4,404 feet, approximately 2,655 feet below the base of the Fox Hills Formation and it provides an additional zone of monitoring between the Fox Hills Formation and the Broom Creek Formation to detect vertical carbon dioxide or fluid movement.

(60) No known or suspected regional faults or fractures with transmissibility have been identified during the site-specific characterization. Formation imaging logs run showed the section of the Opeche Formation closest to the Broom Creek Formation to be dominant in litho-bound fractures and microfaults which are electrically conductive likely due to the presence of clay. The mid-region of the Opeche Formation notes the presence of electrically conductive and resistive features. The resistive features are interpreted as minor anhydrite filled fractures. Conductive features and microfaults are interpreted as clay filled due to electric conductivity.

(61) Fluid samples from the Inyan Kara Formation and Broom Creek Formation suggest that they are hydraulically isolated from each other, supporting that the confining formations above the Broom Creek Formation are not compromised by migration pathways.

(62) Geochemical simulation performed with the injection stream and data obtained from the confining and injection zones determined no observable change in injection rate or pressure. Conservatively high carbon dioxide exposure simulations to the cap rock determined that geochemical changes will be minor and will not cause substantive deterioration compromising confinement.

(63) Risk of induced seismicity is not a concern based on existing studies of major faults within the area of review, tectonic boundaries, and relatively stable geologic conditions surrounding the proposed injection site.

(64) The six injection wells are proposed to be temperature logged annually to demonstrate external mechanical integrity.

(65) The approval of this application is in the public interest by promoting the policy stated in NDCC Section 38-22-01.

IT IS THEREFORE ORDERED:

(1) The creation of the DGC Beulah Broom Creek Storage Facility #1 in Mercer County, North Dakota, is hereby authorized and approved.

(2) Dakota Gasification Company, its assigns and successors, is hereby authorized to store carbon dioxide in the Broom Creek Formation in the DGC Beulah Broom Creek Storage Facility #1.

(3) The DGC Beulah Broom Creek Storage Facility #1 shall extend to and include the following lands in Mercer County, North Dakota:

<u>TOWNSHIP 146 NORTH, RANGE 88 WEST</u>
ALL OF SECTIONS 35 AND 36, THE S/2 OF SECTION 25, THE S/2 OF SECTION 26, THE SE/4 OF SECTION 27, THE SE/4 OF SECTION 33, AND THE S/2, AND NE/4 OF SECTION 34,

<u>TOWNSHIP 146 NORTH, RANGE 87 WEST</u>
ALL OF SECTION 31, THE S/2 OF SECTION 30, AND THE SW/4 OF SECTION 32,

<u>TOWNSHIP 145 NORTH, RANGE 88 WEST</u>
ALL OF SECTIONS 1, 2, 3, 10, 11, 12, 13, 14, 15, 22, 23 AND 24, THE E/2 OF SECTION 4, THE E/2 OF SECTION 9, AND THE E/2 OF SECTION 16,

<u>TOWNSHIP 145 NORTH, RANGE 87 WEST</u>
ALL OF SECTIONS 6, 7, 18 AND 19, THE W/2 OF SECTION 5, THE W/2 OF SECTION 8, AND THE W/2 OF SECTION 17.

ALL IN MERCER COUNTY AND COMPRISING OF 15,979.20 ACRES, MORE OR LESS.

(4) Injection into the DGC Beulah Broom Creek Storage Facility #1 shall not occur until Dakota Gasification Company has met the financial responsibility demonstration pursuant to Order No. 32252.

(5) This authorization does not convey authority to inject carbon dioxide into the DGC Beulah Broom Creek Storage Facility #1; approved permits to inject for the Coteau #1 well (File No. 38379), the Coteau #2 well (File No. 38916), the Coteau #3 well (File No. 38917), the Coteau #4 well (File No. 38918), the Coteau #5 (File No. 39418), and the proposed Coteau #6 shall be issued by the Commission prior to injection operations commencing.

(6) The authorization granted herein is conditioned on the operator receiving and complying with all provisions of the injection permit issued by the Oil and Gas Division of the Industrial Commission and complying with all provisions of NDAC Chapter 43-05-01 where applicable, and this order.

(7) Definitions**.**

"Area of review" in this case means an area encompassing a radius around the facility area of one mile.

"Cell" in this case means individual cell blocks of the geologic model; each cell is approximately 1,000 feet by 1,000 feet.

"Facility area" means the areal extent of the storage reservoir as defined in paragraph (3) above, that includes lands within the lateral boundary of the carbon dioxide plume from beginning of injection to the time the carbon dioxide plume ceases to migrate into adjacent geologic model cells.

"Storage facility" means the reservoir, underground equipment, and surface facilities and equipment used or proposed to be used in the geologic storage operation. It does not include pipelines used to transport carbon dioxide to the storage facility under NDCC Section 38-22-02.

(8) The storage facility operator shall comply with all conditions of this order, the permit to inject, and NDAC Chapter 43-05-01, where applicable. Any noncompliance constitutes a violation and is grounds for enforcement action, including but not limited to termination, revocation, or modification of this order pursuant to NDAC Section 43-05-01-12.

(9) In an administrative action, it shall not be a defense that it would have been necessary for the storage facility operator to halt or reduce the permitted activity in order to maintain compliance with this order, the permit to inject, and NDAC 43-05-01, where applicable.

(10) The storage facility operator shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this order, the permit to inject, and NDAC 43-05-01, where applicable.

(11) The storage facility operator shall implement and maintain the provided emergency and remedial response plan pursuant to NDAC Section 43-05-01-13.

(12) Pursuant to NDAC 43-05-01-13, subsection 1, subdivision a, the Commission requests DGC submit the documentation of the training efforts with Mercer County LEPC after the exercises are performed.

(13) The storage facility operator shall cease injection immediately, take all steps reasonably necessary to identify and characterize any release, implement the emergency and remedial response plan approved by the Commission, and notify the Commission within 24 hours of carbon dioxide detected above the confining zone.

(14) The storage facility operator shall at all times properly operate and maintain all storage facilities which are installed or used by the storage facility operator to achieve compliance with the conditions this order, the permit to inject, and NDAC 43-05-01, where applicable. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems only when necessary to achieve compliance.

(15) This order may be modified, revoked and reissued, or terminated pursuant to NDAC Section 43-05-01-12. The filing of a request by the storage facility operator for and order modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any condition contained therein.

(16) The injection well permit or the permit to operate an injection well does not convey any property rights of any sort of any exclusive privilege.

(17) The storage facility operator shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this order, or to determine compliance thereof. The storage facility operator shall also furnish to the Director, upon request, copies of records required to be kept by this order, the permit to inject, and NDAC 43-05-01, where applicable.

(18) The storage facility operator shall allow the Director, or an authorized representative, upon presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the storage facility premises where records must be kept pursuant to this order and NDAC Chapter 43-05-01.

(b) At reasonable times, have access to and copy any records that must be kept pursuant to this order and NDAC Chapter 43-05-01.

(c) At reasonable times, inspect any facilities, equipment, including monitoring and control equipment, practices, or operations regulated or required pursuant to this order, the permit to inject, and NDAC Chapter 43-05-01.

(d) At reasonable times, sample or monitor for the purposes of assuring compliance, any substances or parameters at any location.

(19) The storage facility operator shall maintain and comply with the proposed testing and monitoring plan pursuant to NDAC Section 43-05-01-11.4

(20) The storage facility operator shall comply with the reporting requirements provided in NDAC Section 43-05-01-18. The volume of carbon dioxide injected, the average injection rate, surface injection pressure, and down-hole temperature and pressure data shall be reported monthly to the Director on or before the fifth day of the second succeeding month once injection commences regardless of the status of operations, until the injection well is properly plugged and abandoned.

(21) The storage facility operator must obtain an injection well permit under NDAC Section 43-05-01-10 and injection wells must meet the construction and completion requirements in NDAC Section 43-05-01-11.

(22) The storage facility operator shall notify the Director at least 48 hours in advance to witness a mechanical integrity test of the tubing-casing annulus in the injection well. The packer must be set within 100 feet of the upper most perforation and in the 13CR-80 casing, as an exception to NDAC Section 43-05-01-11. However, the packer must also be set within confining zone lithology, and within carbon dioxide resistant cement.

(23) The storage facility operator shall maintain and comply with the prepared plugging plan pursuant to NDAC Section 43-05-01-11.5.

(24) The storage facility operator shall establish mechanical integrity prior to commencing injection and maintain mechanical integrity pursuant to NDAC Section 43-05-01-11.1.

(25) The storage facility operator shall implement the worker safety plan pursuant to NDAC Section 43-05-01-13.

(26) The storage facility operator shall comply with leak detection and reporting requirements pursuant to NDAC Section 43-05-01-14.

(27) The storage facility operator shall implement the proposed corrosion monitoring and prevention program pursuant to NDAC Section 43-05-01-05.1.

(28) The storage facility operator shall maintain financial responsibility pursuant to NDAC Section 43-05-01-09.1.

(29) The storage facility operator shall maintain and comply with the proposed post-injection site care and facility closure plan pursuant to NDAC Section 43-05-01-19.

(30) The storage facility operator shall notify the Director within 24 hours of failure or malfunction of surface gauges in the Coteau #1 (File No. 38379), the Coteau #2 (File No. 38916), the Coteau #3 (File No. 38917), the Coteau #4 (File No. 38918), the Coteau #5 (File No. 39418), and the proposed Coteau #6 injectors.

(31) The storage facility operator shall implement surface air and soil gas monitoring as proposed.

(32) This storage facility authorization and permit shall be reviewed at least once every five years from commencement of injection to determine whether it should be modified, revoked, or minor modification made, pursuant to NDAC Section 43-05-01-05.1(4).

(33) The storage facility operator shall pay fees pursuant to NDAC Section 43-05-01-17 annually, no more than thirty days after the receipt of 26 U.S. Code § 45Q tax credits, unless otherwise approved by the Director.

(34) This order shall remain in full force and effect until further order of the Commission.

Dated this 24th day of January, 2023.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Doug Burgum, Governor

/s/ Drew H. Wrigley, Attorney General

/s/ Doug Goehring, Agriculture Commissioner

SFN 5729

STATE OF NORTH DAKOTA

AFFIDAVIT OF MAILING

COUNTY OF BURLEIGH

I, Jeanette Bean, being duly sworn upon oath, depose and say: That on 1/26/2023 enclosed in separate envelopes true and correct copies of the attached Order No. 32250 of the North Dakota Industrial Commission, and deposited the same with the United States Postal Service in Bismarck, North Dakota, with postage thereon fully paid, directed to the following persons by the Industrial Commission in Case No. 29450:

Scott Skokos
Dakota Resource Council
1720 Burnt Boat Road Suite 104
Bismarck, ND 58503

Allen Eisenbeis
2979 Mesquite Drive
Idaho Falls, ID 83404

Clyde Eisenbeis
2819 Hogan Drive
Bismarck, ND 58503

Lawrence Bender
FREDRIKSON & BYRON
PO BOX 1855
Bismarck, ND 58502-1855

Bruce and Gail Bitterman
6480 Hwy 1806
Zap, ND 58580-9618

Perry Anderson
309 3rd Ave NW Apt 4
Mandan, ND 58554

Mary Ricker
12916 Mohawk Drive
Piedmont, SD 57769

Jeanette Bean
Oil & Gas Division

On this 1/26/2023 before me personally appeared Jeanette Bean to me known as the person described in and who executed the foregoing instrument and acknowledged that she executed the same as her free act and deed.

NOTARY PUBLIC NAME
DAVID TABOR
STATE OF NORTH DAKOTA
MY COMMISSION EXPIRES MAR. 18, 2026

Notary Public
State of North Dakota,
County of Burleigh

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 29450
ORDER NO. 32020

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE APPLICATION OF DAKOTA GASIFICATION COMPANY REQUESTING CONSIDERATION FOR THE GEOLOGIC STORAGE OF CARBON DIOXIDE FROM THE GREAT PLAINS SYNFUELS PLANT LOCATED IN SECTIONS 5, 6, 7, 8, 17, 18, 19, TOWNSHIP 145 NORTH, RANGE 87 WEST, SECTIONS 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, TOWNSHIP 145 NORTH, RANGE 88 WEST, SECTIONS 30, 31, 32, TOWNSHIP 146 NORTH, RANGE 87 WEST, SECTIONS 25, 26, 27, 33, 34, 35, 36, TOWNSHIP 146 NORTH, RANGE 88 WEST, MERCER COUNTY, NORTH DAKOTA PURSUANT TO NORTH DAKOTA ADMINISTRATIVE CODE SECTION 43-05-01.

ORDER OF THE COMMISSION

THE COMMISSION FINDS:

(1) This cause came on for hearing at 9:00 a.m. on the 20th day of July, 2022.

(2) The Commission received an application from Dakota Gasification Company requesting consideration for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in Sections 5, 6, 7, 8, 17, 18, and 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, and 36, Township 146 North, Range 88 West, Mercer County, North Dakota pursuant to North Dakota Administrative Code (NDAC) Section 43-05-01. (Case No. 29450)

(3) In the matter of a hearing called on a motion of the Commission to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Dakota Gasification Company storage facility located in Sections 5, 6, 7, 8, 17, 18, and 19, Township 145 North, Range 87 West, Sections 1, 2,

3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, and 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code (NDCC) Section 38-22-10. (Case No. 29451)

(4) In the matter of a hearing called on a motion of the Commission for an order determining the amount of financial responsibility for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant in the storage facility located in Sections 5, 6, 7, 8, 17, 18, and 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, and 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to NDAC Section 43-05-01-09.1. (Case No. 29452)

(5) The Commission consolidated Case Nos. 29450, 29451, and 29452 at the hearing on July 20, 2022.

(6) Evidence and testimony in these matters were taken on July 20, 2022. The record in these cases was left open to receive additional exhibits from Dakota Gasification Company. Supplemental exhibits were received on August 8, 2022 and the record was closed.

(7) NDCC Sections 38-08-11 and 28-32-39 provide that upon the filing of a petition of any interested party, the Commission must enter its order within thirty (30) days after the evidence has been received, briefs filed, and arguments closed, or as soon thereafter as possible.

(8) The issues in these cases are of such complexity that additional time is necessary for the Commission to render a decision, therefore, this matter should be continued.

IT IS THEREFORE ORDERED:

(1) This matter is hereby continued for one hundred and seventy (170) days or until further order of the Commission.

Dated this 5th day of October, 2022.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

By the Director, on behalf of the Commission

/s/ Lynn D. Helms, Director

SFN 5729

STATE OF NORTH DAKOTA

AFFIDAVIT OF MAILING

COUNTY OF BURLEIGH

I, Jeanette Bean, being duly sworn upon oath, depose and say: That on 10/12/2022 enclosed in separate envelopes true and correct copies of the attached Order No. 32020 of the North Dakota Industrial Commission, and deposited the same with the United States Postal Service in Bismarck, North Dakota, with postage thereon fully paid, directed to the following persons by the Industrial Commission in Case No. 29450:

Scott Skokos
Dakota Resource Council
1720 Burnt Boat Road Suite 104
Bismarck, ND 58503

Allen Eisenbeis
2979 Mesquite Drive
Idaho Falls, ID 83404

Clyde Eisenbeis
2819 Hogan Drive
Bismarck, ND 58503

Lawrence Bender
FREDRIKSON & BYRON
PO BOX 1855
Bismarck, ND 58502-1855

Bruce and Gail Bitterman
6480 Hwy 1806
Zap, ND 58580-9618

Perry Anderson
309 3rd Ave NW Apt 4
Mandan, ND 58554

Mary Ricker
12916 Mohawk Drive
Piedmont, SD 57769

Jeanette Bean
Oil & Gas Division

On this 10/12/2022 before me personally appeared Jeanette Bean to me known as the person described in and who executed the foregoing instrument and acknowledged that she executed the same as her free act and deed.

NOTARY PUBLIC NAME
DAVID TABOR
STATE OF NORTH DAKOTA
MY COMMISSION EXPIRES MAR. 18, 2026

Notary Public
State of North Dakota,
County of Burleigh

Hamilton, Melissa J.

From:	Hamilton, Melissa J.
Sent:	Monday, November 21, 2022 11:09 AM
To:	Bender, Lawrence; 'cte677@gmail.com'; 'perryanderson_55@q.com'; 'SCOTT@DRCINFO.COM'
Cc:	Nelson, Steve
Subject:	Email on Behalf of Hearing Examiner Steven B. Nelson in NDIC Case No. 29450

Please see the email below from Hearing Examiner Steven B. Nelson in the above referenced matter.

Thank you.

Melissa

Melissa J. Hamilton, ACP
Advanced Certified Paralegal
North Dakota Office of Attorney General-
Bismarck, ND 58501-4509
Telephone: (701) 328-3640
Fax: (701) 328-4300

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Counsel and Interested Parties - On October 5, 2022 the Commission entered Order No. 32020 in the above referenced case. The Commission ordered the matter was continued for one hundred and seventy (170) days or until further order from the Commission. The matter remains under advisement; however it appears that parties may have anticipated an earlier decision date from the Commission. For example, Article 14 of the June 1, 2022 Storage Agreement appears to anticipate an Effective Date determination by the Commission on or before December 31, 2022. Please be advised that the determination in this matter may take more time than parties originally anticipated as indicated in Order No. 32020.

Thank you.

Steven B. Nelson
Assistant Attorney General
500 North 9th Street
Bismarck, ND 58501-4509
Office: (701) 328-3640
stnelson@nd.gov

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE APPLICATION OF DAKOTA GASIFICATION COMPANY REQUESTING CONSIDERATION FOR THE GEOLOGIC STORAGE OF CARBON DIOXIDE FROM THE GREAT PLAINS SYNFUELS PLANT LOCATED IN SECTIONS 5, 6, 7, 8, 17, 18, 19, TOWNSHIP 145 NORTH, RANGE 87 WEST, SECTIONS 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, TOWNSHIP 145 NORTH, RANGE 88 WEST, SECTIONS 30, 31, 32, TOWNSHIP 146 NORTH, RANGE 87 WEST, SECTIONS 25, 26, 27, 33, 34, 35, 36, TOWNSHIP 146 NORTH, RANGE 88 WEST, MERCER COUNTY, NORTH DAKOTA PURSUANT TO NORTH DAKOTA ADMINISTRATIVE CODE SECTION 43-05-01.	**UNSWORN DECLARATION OF SERVICE BY ELECTRONIC MAIL, BY U.S. MAIL, AND RETENTION OF DOCUMENTS** **CASE NO. 29450**

[¶1] Melissa J. Hamilton states as follows:

[¶2] I am of legal age and on the 21st day of November, 2022, I served the following **NOVEMBER 21, 2022 EMAIL ON BEHALF OF HEARING EXAMINER STEVEN B. NELSON IN NDIC CASE NO. 29450** upon the following by emailing thereof as follows:

Lawrence Bender - LBender@fredlaw.com;
Clyde Eisenbeis - cte677@gmail.com;
Perry Anderson - perryanderson_55@q.com;
Scott Skokos - SCOTT@DRCINFO.COM.

[¶3] I also served the document upon the following by placing a true and correct copy thereof in an envelope addressed as follows:

Scott Skokos
Dakota Resource Council
1720 Burnt Boat Road Suite 104
Bismarck, ND 58503

Bruce and Gail Bitterman
6480 Hwy 1806
Zap, ND 58580-9618

Allen Eisenbeis
2979 Mesquite Drive
Idaho Falls, ID 83404

Perry Anderson
309 3rd Ave NW Apt 4
Mandan, ND 58554

Clyde Eisenbeis
2819 Hogan Drive
Bismarck, ND 58503

Mary Ricker
12916 Mohawk Drive
Piedmont, SD 57769

Lawrence Bender
FREDRICKSON & BYRON
PO BOX 1855
Bismarck, ND 58502-1855

and depositing the same, with postage prepaid, in the United States mail at Bismarck, North Dakota. The original documents shall be retained at the North Dakota Industrial Commission, 600 E. Boulevard Ave. – Dept. 405, Bismarck, ND 58505-0840.

[¶3] I declare, under penalty of perjury under the law of North Dakota, that the foregoing is true and correct.

Signed on the 21st day of November, 2022, at Bismarck, North Dakota, United States.

Melissa J. Hamilton

NORTH
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June 1, 2023

DGC Beulah Broom Creek Storage Facility #1
Mercer County, North Dakota
Order No. 32250
STORAGE FACILITY PERMIT
CERTIFICATE OF ISSUANCE

Dakota Gasification Company made application to the Commission, on March 10, 2022, for an order authorizing geologic storage of carbon dioxide from the Great Plains Synfuels Plant in the amalgamated storage reservoir pore space of the Broom Creek Formation, in portions of Sections 25, 26, 27, 33, 34, 35, and 36, Township 146 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, and Sections 5, 6, 7, 8, 17, 18, and 19, Township 145 North, Range 87 West, Mercer County, North Dakota, pursuant to North Dakota Administrative Code (NDAC) Chapter 43-05-01, and such other relief as is appropriate.

The Commission approved this application January 24, 2023.

Order No. 32250 attached establishes the DGC Beulah Broom Creek Storage Facility #1 to include the following lands:

TOWNSHIP 146 NORTH, RANGE 88 WEST
ALL OF SECTIONS 35 AND 36, THE S/2 OF SECTION 25, THE S/2 OF SECTION 26, THE SE/4 OF SECTION 27, THE SE/4 OF SECTION 33, AND THE S/2, AND NE/4 OF SECTION 34,

TOWNSHIP 146 NORTH, RANGE 87 WEST
ALL OF SECTION 31, THE S/2 OF SECTION 30, AND THE SW/4 OF SECTION 32,

TOWNSHIP 145 NORTH, RANGE 88 WEST
ALL OF SECTIONS 1, 2, 3, 10, 11, 12, 13, 14, 15, 22, 23 AND 24, THE E/2 OF SECTION 4, THE E/2 OF SECTION 9, AND THE E/2 OF SECTION 16,

TOWNSHIP 145 NORTH, RANGE 87 WEST
ALL OF SECTIONS 6, 7, 18 AND 19, THE W/2 OF SECTION 5, THE W/2 OF SECTION 8, AND THE W/2 OF SECTION 17.

Bruce E. Hicks
ASSISTANT DIRECTOR
OIL AND GAS DIVISION

Lynn D. Helms
DIRECTOR
DEPT. OF MINERAL RESOURCES

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Order No. 32251 attached establishes amalgamation of the storage reservoir pore space.

Order No. 32252 attached establishes financial responsibility for the storage facility permit.

Director's Order No. 557 attached establishes the effective date of the amalgamation of the storage reservoir pore space.

Pursuant to North Dakota Century Code Section 38-22-11, this certificate of issuance is to be filed with the county recorder in Mercer County.

Sincerely,

Lynn D. Helms
North Dakota Industrial Commission
Department of Mineral Resources
Oil and Gas Division

Bruce E. Hicks
ASSISTANT DIRECTOR
OIL AND GAS DIVISION

Lynn D. Helms
DIRECTOR
DEPT. OF MINERAL RESOURCES

600 E Boulevard Ave – Dept 405 | Bismarck ND 58505-0840 | PHONE 701-328-8020 | FAX 701-328-8022 | dmr.nd.gov/oilgas

INDUSTRIAL COMMISSION OF NORTH DAKOTA

Doug Burgum
Governor

Drew H. Wrigley
Attorney General

Doug Goehring
Agriculture Commissioner

I, Karen Tyler, Interim Executive Director for the Industrial Commission of North Dakota, do hereby certify that the attached documents are true and correct copies of the following records on file in the Office of the Industrial Commission, Department of Mineral Resources, Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota.

- Dakota Gasification Company – Permit Certificate
- Order No. 32250 issued in Case No. 29450
- Order No. 32251 issued in Case No. 29451
- Order No. 32252 issued in Case No. 29452
- Director's Order No. 557

STATE OF NORTH DAKOTA SEAL INDUSTRIAL COMMISSION

Karen Tyler
Interim Executive Director to the Commission
May 31, 2023

Karen Tyler, Interim Executive Director and Secretary
Reice Haase, Deputy Executive Director
State Capitol, 14th Floor - 600 E Boulevard Ave Dept 405 - Bismarck, ND 58505-0840
E-Mail: ktyler@nd.gov
E-Mail: rhaase@nd.gov
Phone: (701) 328-3726
www.nd.gov

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 29450
(CONTINUED)
ORDER NO. 32250

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE APPLICATION OF DAKOTA GASIFICATION COMPANY REQUESTING CONSIDERATION FOR THE GEOLOGIC STORAGE OF CARBON DIOXIDE FROM THE GREAT PLAINS SYNFUELS PLANT LOCATED IN SECTIONS 5, 6, 7, 8, 17, 18, 19, TOWNSHIP 145 NORTH, RANGE 87 WEST, SECTIONS 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, TOWNSHIP 145 NORTH, RANGE 88 WEST, SECTIONS 30, 31, 32, TOWNSHIP 146 NORTH, RANGE 87 WEST, SECTIONS 25, 26, 27, 33, 34, 35, 36, TOWNSHIP 146 NORTH, RANGE 88 WEST, MERCER COUNTY, NORTH DAKOTA PURSUANT TO NORTH DAKOTA ADMINISTRATIVE CODE SECTION 43-05-01.

ORDER OF THE COMMISSION

THE COMMISSION FINDS:

(1) This cause originally came on for hearing at 9:00 a.m. on the 20th day of July, 2022. The Commission entered Order No. 32020 on October 5, 2022 continuing this matter for one hundred and seventy (170) days or until further order of the Commission.

(2) Dakota Gasification Company (DGC) made application to the Commission for an order requesting consideration for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, pursuant to North Dakota Administrative Code (NDAC) Section 43-05-01.

(3) DGC submitted an application for a Storage Facility Permit and necessary attachments pursuant to NDAC Section 43-05-01-05 and all other provisions of NDAC Chapter 43-05-01 as necessary.

(4) Case Nos. 29450, 29451, and 29452 were combined for the purposes of hearing.

(5) Case No. 29451, also on today's docket, is a motion of the Commission to determine the amalgamation of storage reservoir pore space, pursuant to a Storage Agreement by DGC for use of pore space falling within portions of Sections 25, 26, 27, 33, 34, 35, and 36, Township 146 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, and Sections 5, 6, 7, 8, 17, 18, and 19, Township 145 North, Range 87 West, Mercer County, North Dakota, in the Broom Creek Formation, has been signed, ratified, or approved by owners of interest owning at least sixty percent of the pore space interest within said lands pursuant to North Dakota Century Code (NDCC) 38-22-10.

(6) Case No. 29452, also on today's docket, is a motion of the Commission to determine the amount of financial responsibility for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in portions of Sections 25, 26, 27, 33, 34, 35, and 36, Township 146 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, Sections 5, 6, 7, 8, 17, 18, and 19, Township 145 North, Range 87 West, Mercer County, North Dakota in the Broom Creek Formation, pursuant to NDAC Section 43-05-01-09.1.

(7) The record in these matters were left open to receive additional information from DGC. Such information was received on August 8, 2022, and the record was closed.

(8) Pursuant to NDCC Section 38-22-06 and NDAC Section 43-05-01-08, the notice of filing of the application and petition and the time and place of hearing thereof was given, and that at least 45 days prior to the hearing, DGC, as the applicant, did give notice of the time and place of said hearing and the Commission has accepted the notice as adequate, and that the applicant did, at least 45 days prior to the hearing, file with the Commission engineering, geological, and other technical exhibits to be used and which were used at said hearing, and that the notice so given did specify that such material was filed with the Commission; that due public notice having been given, as required by law, the Commission has jurisdiction of this cause and the subject matter.

(9) The Commission gave at least a thirty-day public notice and comment period for the draft storage facility permit and issued all notices using methods required of all entities under NDCC Section 38-22-06 and NDAC Section 43-05-01-08. Publication was made June 8, 2022, and the comment period for written comments ended at 5:00 PM CDT July 19, 2022. The hearing was open to the public to appear and provide comments.

(10) The Commission received an email from Perry Anderson on June 26, 2022, asking if the applicant was to become Bakken Energy LLC, a subsidiary of Basin Electric Power

Cooperative. The Commission assumes this was intended for Dakota Gasification Company. The Commission finds the information included in the letter to be either inapplicable or irrelevant to this case.

(11) The Commission received a letter from Allen Eisenbeis (A. Eisenbeis) on June 27, 2022 indicating ownership of farmland in the N/2 NW/4 and S/2 NW/4 of Section 34, Township 146 North, Range 88 West, and mineral rights in Lot 1, Lot 2, the S/2 NE/4, and SE/4 of Section 3, Township 145 North, Range 88 West, the S/2 N/2 of Section 10, Township 145 North, Range 88 West, the NW/4 of Section 11, Township 145 North, Range 88 West, the SE/4 and SW/4 of Section 27, Township 146 North, Range 88 West, and the N/2 SE/4 of Section 36, Township 146 North, Range 88 West, Mercer County, North Dakota. The Commission notes A. Eisenbeis is identified as a mineral owner and surface owner requiring notification. A. Eisenbeis indicates that DGC sent him a letter offering $500 to sign an agreement to store carbon dioxide on his property. A. Eisenbeis considers the amount to not be worth the loss of the oil on his property. A. Eisenbeis states the land belongs to the property owners and not the state of North Dakota nor DGC, and that DGC should store the carbon dioxide on property that they own. A. Eisenbeis states that pressurized carbon dioxide is cryogenic, and questions why anyone would want to make North Dakota colder. A. Eisenbeis questions how the government or corporations can seize property that belongs to private citizens without paying fair market value for the land and oil.

(12) DGC testified the $500 dollar offer was for surface access to gather seismic data, and that nonconsenting pore space owners would receive the same compensation as consenting owners.

(13) NDCC Section 38-22-10 states, "If a storage operator does not obtain the consent of all persons who own the storage reservoir's pore space, the commission may require that the pore space owned by nonconsenting owners be included in a storage facility and subject to geologic storage." If oil and gas was displaced from the Bakken Formation, unitization of minerals would be required under NDCC Chapter 38-08. The atmosphere will not be exposed to cryogenic temperature impacts of pressurized carbon dioxide.

(14) The Commission received a letter from the Dakota Resource Council (DRC) on July 12, 2022, indicating concern with this project. DRC states the applicant should be required to conduct modeling regarding lithofacies and petrophysical properties that are specific to the site. DRC states to ensure the success and longevity of this project it would be prudent to require site specific data as geologic formations are not entirely uniform.

DRC states that the applicant should explain in more specific detail their plans to work with Mercer County LEPC. DRC states a leak from a Class VI injection well would be a new event for local first responders, and that there could be severe consequences for environmental and human health if local emergency crews are not equipped and educated for such an event.

(15) DGC's application discusses 3D seismic surveys in section 2.2.2.6 of their application. The application states placement of a seismic source and receiver locations required for a seismic survey would be restricted because of the active coal mine and industrial facilities. Due to the

inability to acquire site-specific 3D seismic data within the area, localized variograms distributing lithofacies and petrophysical properties are not viable.

(16) DGC testified to having a protection services group. The group takes care of security, hazmat, fire protection, and medical and are the first responders for any emergency in the event of a leak. DGC testified to having a reverse 911 system that contacts all people within the area of impact corridor that will be notified with an evacuation order. DGC testified that they meet with local emergency responders every two years to provide them with plans and training. Local responders are informed what the hazards of carbon dioxide and natural gas pipelines are. DGC stated they are a member of the emergency local planning commission where mock drills and tabletop drills are performed for the event of a leak. DGC testified that local law enforcement would be used to block roads since DGC has the staff to take care of an emergency response.

(17) The Commission received a letter from Bruce and Gail Bitterman (Bittermans) on July 11, 2022, indicating they are not in favor of this application. The Bittermans state science does not agree that the storage is permanent or forever. The Commission did not receive additional information from the Bittermans supporting this statement.

(18) The Commission received a letter from Clyde Eisenbeis (C. Eisenbeis) on June 9, 2022 indicating ownership of farmland and mineral rights in Lot 1, Lot 2, the S/2 NE/4, and SE/4 of Section 3, Township 145 North, Range 88 West, the S/2 N/2 of Section 10, Township 145 North, Range 88 West, the NW/4 of Section 11, Township 145 North, Range 88 West, the SE/4 and SW/4 of Section 27, Township 146 North, Range 88 West, the N/2 NW/4 and S/2 NW/4 of Section 34, Township 146 North, Range 88 West, and the N/2 SE/4 of Section 36, Township 146 North, Range 88 West, Mercer County, North Dakota. The Commission notes C. Eisenbeis is identified as a mineral owner and surface owner requiring notification. C. Eisenbeis is concerned with injected carbon dioxide displacing oil and gas in the Bakken Formation. C. Eisenbeis questioned if Basin Electric will reimburse farmland owners and mineral rights owners for potential future loss of oil and gas income. C. Eisenbeis provided North Dakota Geological Survey geologic investigation number 59 by Julie A. LeFever 2008.

(19) C. Eisenbeis appeared on July 20, 2022 to provide testimony, and submitted emails supplemental to his testimony. The first email was received July 21, 2022 and clarified his ownership from his letter received June 9, 2022. C. Eisenbeis indicated ownership of farmland in the N/2 NW/4 and S/2 NW/4 of Section 34, Township 146 North, Range 88 West, and mineral rights in Lot 1, Lot 2, the S/2 NE/4, and SE/4 of Section 3, Township 145 North, Range 88 West, the S/2 N/2 of Section 10, Township 145 North, Range 88 West, the NW/4 of Section 11, Township 145 North, Range 88 West, the SE/4 and SW/4 of Section 27, Township 146 North, Range 88 West, the N/2 NW/4 and S/2 NW/4 of Section 34, Township 146 North, Range 88 West, and the N/2 SE/4 of Section 36, Township 146 North, Range 88 West, Mercer County, North Dakota. C. Eisenbeis asks if all mineral rights owners have been informed that the carbon dioxide could displace oil and gas under their land. C. Eisenbeis asks if all mineral owners have been given a Bakken and Broom Creek Formation elevation map, and asks if all mineral rights owners have been informed that this could cost them, their children, and their grandchildren millions of

dollars in the future. C. Eisenbeis asks the following: 1.) if it is possible there is an opening between the Broom Creek and Bakken Formation that could allow carbon dioxide to displace oil and gas in the Bakken Formation, 2.) if it is possible that pressurizing the carbon dioxide in the Broom Creek Formation could rupture the gap between the Broom Creek and Bakken Formations that could allow carbon dioxide to displace oil and gas, 3.) if it is possible that an earthquake could allow carbon dioxide to displace oil and gas in the Bakken Formation, and 4.) if Basin Electric will reimburse mineral rights owners for potential future loss of oil and gas income.

C. Eisenbeis states he heard during the hearing, North Dakota legislature created a law that allows others to remove minerals under mineral rights land. C. Eisenbeis asks if the state can remove minerals that are the owner's property with no just cause and states that Industrial Commission should take this to the federal court and US Supreme Court if necessary.

C. Eisenbeis questions why the Bakken Formation was not mentioned in the hearing until he brought it up and if the Bakken Formation is in the reports submitted to the Industrial Commission. C. Eisenbeis states the Bakken Formation could be affected by carbon dioxide injection into the Broom Creek, could result in millions of dollars of losses to the mineral rights owners, and should be included in the reports.

C. Eisenbeis referenced models mentioned in the hearing, and states models are often inaccurate and referenced global warming models being incorrect. C. Eisenbeis states that code writers who write the code for models can produce any result they want, and that it can be modified until producing the result they want. C. Eisenbeis interprets the applicant's mention of several models in the hearing as the initial model producing a result the applicant did not like and switched to a model that produced a result it liked.

C. Eisenbeis referenced that he heard there is no Broom Creek 3D map, and states he is concerned with the 1,000-foot distance between the Broom Creek and Bakken Formations as being too little. C. Eisenbeis asks how the applicant knows the distance between the formations is 1,000 feet without a 3D map and asks if it is 1,000 feet from the top of the Broom Creek to the top of the Bakken. C. Eisenbeis questions if this thickness varies and if the formations are as close as one foot in some places, or already connected. C. Eisenbeis questions if the formations were drilled through vertically, and states there is already a breach between the formations if so. C. Eisenbeis states that the depth and thickness of the Bakken Formation varies and asks how the applicant's models accurately determine the distance between the formations. C. Eisenbeis states oil companies do not know the exact depth and thickness of the Bakken in various locations.

C. Eisenbeis states that there is an aquifer 80 to 100 feet below the surface of his farmland valley, and that there is another aquifer 180 to 200 feet below the surface. C. Eisenbeis states that a well was dug in that valley for the carbon dioxide project, asks if there are protections in place to prevent contaminating the aquifer, and states the water's color is changing. C. Eisenbeis states DGC puts sulfur into the ground and that there is a lot of sulfur in lignite coal. C. Eisenbeis is concerned with fly ash pits, loss of cattle due to sulfide, and that sulfur can kill people. C. Eisenbeis asks if DGC should be shut down and remove the fly ash and all sulfur from the ground.

C. Eisenbeis referenced that it was mentioned in the hearing that no one lives on the land. C. Eisenbeis states that Lucille Sailer (Sailer), Lyle Eisenbeis, and Karen Waltz do live on the land in the area at various times of the year and there may be others. C. Eisenbeis states that coal mining pond water discharges into a farmland creek which floods Sailer's farmhouse basement and farmland. C. Eisenbeis states Sailer was not given a Bakken Formation or Broom Creek Formation map and was not told it could displace oil or gas under her land, nor that it could affect her water. C. Eisenbeis states all contracts should be invalidated as they did not provide adequate information.

C. Eisenbeis referenced the hearing and the applicant testimony that it is not economically feasible to extract oil or gas under his farmland. C. Eisenbeis states the same was said years ago in the Williston area, and that new technology of horizontal drilling made it feasible as evidenced by the current oil and gas extraction in the Williston area. C. Eisenbeis questions if future technology could heat the gas present to convert it to oil.

C. Eisenbeis asks if a leak is detected by the applicant, how they would find and fix the location of the leak, and how they would ensure it does not displace oil or gas.

C. Eisenbeis is concerned that the permit also grants access to the surface of farmland without any restrictions, and that the applicant could build a variety of infrastructures, including buildings, on the farmland. C. Eisenbeis asks what authority grants access to someone else's farmland.

C. Eisenbeis states that proponents of carbon dioxide injection supposedly know there is no risk of displacing oil or gas. C. Eisenbeis states if the proponents know, they should sign a legal contract that gives all of their assets to the mineral rights owner if there is a problem. C. Eisenbeis states that if displacing oil and gas does occur then the proponents lose money rather than the mineral rights owners. C. Eisenbeis states that if the proponents do not sign these types of legal documents, that they do not know if displacement will occur and are guessing.

C. Eisenbeis states Mary Ricker's (Ricker) attorney said oil companies will not drill where carbon dioxide is stored. C. Eisenbeis agrees with the statement saying there is too much of a risk which could have many complications. C. Eisenbeis states carbon dioxide storage should not be placed within a hundred miles of the Bakken Formation.

C. Eisenbeis states there should be another hearing to include the property owners which discusses responses from the applicant. C. Eisenbeis states this would give the opportunity to discuss responses and ask more questions, and that there is a lot of money at stake.

(20) C. Eisenbeis submitted a second email received by the Commission on July 25, 2022 as an addendum to his July 21, 2022 email. C. Eisenbeis states that after the well was dug in the valley for the carbon dioxide project that there is sand in the water, that the water's color changed, that it is unknown what contaminates changed the water's color, and that these contaminants could harm people. C. Eisenbeis states that it is unknown if it is possible to completely seal well holes and that over time water penetrates almost everything. C. Eisenbeis states steel cannot be welded to rocks, and that filling the area around a well pipe with concrete may delay the penetration, but

the odds are quite high that water and some gasses will eventually bypass the filling around the pipes.

C. Eisenbeis states if carbon dioxide escaped from the Broom Creek, it could kill people and that the injection puts people at risk. C. Eisenbeis states carbon dioxide is heavier than air and references carbon dioxide killing close to 2,000 people living near Lake Nyos in Cameron, Africa in 1986.

C. Eisenbeis asks if sulfur killed some cattle, are residents drinking well water that has sulfur. C. Eisenbeis asks if sulfur contamination has occurred in rural water, Lake Sakakawea, and for fish in the area.

C. Eisenbeis states Sailer did not sign the document that allowed seismic testing on the farmland, and that she did not know there were two documents. C. Eisenbeis states that flooding of her basement occurred when deep holes were dug for the Dakota Gasification Company and or Antelope Valley Coal Power Plant.

C. Eisenbeis states carbon dioxide is heavier than air, that storing it under the valley may not be safe, and that it could kill people who live in the valley if it escaped. C. Eisenbeis states that storing carbon dioxide on a mountain may not be safe as it could sink to lower levels and kill people. C. Eisenbeis states the safest place to store carbon dioxide appears to be the ocean.

(21) Pursuant to NDAC 43-05-01-08(2), the notice given by the applicant to mineral owners within one half mile of the facility boundary must contain a legal description of the land within the facility area; the date, time, and place that the Commission will hold a hearing on the permit application; a statement that a copy of the permit application and draft permit may be obtained from the Commission; a statement that all comments regarding the storage facility permit application must be in writing and submitted to the Commission prior to the hearing or presented at the hearing; a statement that amalgamation of the storage reservoir pore space is required to operate the storage facility, that the commission may require the pore space owned by nonconsenting owners be included in the storage facility and subject to geologic storage, and the amalgamation of pore space will be considered at the hearing.

(22) Using a conservative 6,500-foot subsea contour from the map provided by C. Eisenbeis, that would place the Bakken Formation at approximately 8,500 feet true vertical depth at the location of the Coteau #1 (File No. 38379). The top of the injection formation, the Broom Creek Formation, is 5,907 feet true vertical depth and the base of the formation is 6,166 feet true vertical depth at the location of the Coteau # 1 (File No. 38379). The approximate 2,300 feet of underlying formations include the Amsden, Tyler, Otter, Kibbey, Charles, Mission Canyon, and Lodgepole Formations. Beds of impermeable shales as well as hydraulically isolated porous formations separate the injection formation from the Bakken Formation. If an existing transmissive conduit existed connecting the Broom Creek and Bakken Formations, gas or oil shows would be expected. Carbon dioxide is buoyant and would not behave in a manner conducive to downward migration. If fluids were displaced downward, various porous formations that would intercept fluid exist

between the injection formation and the Bakken Formation. For an earthquake to occur, there would need to be a fault present and testimony indicated there are no faults present within the storage reservoir or upper or lower confining zones. Microseismic events caused by injection created fractures will not be created due to the regulatory bottom hole pressure constraint of ninety percent of fracture pressure. Migration of carbon dioxide outside of the injection formation would be detected in seismic data. If oil and gas was displaced from the Bakken Formation, unitization of minerals would be required under NDCC 38-08.

(23) NDCC 38-22-10 states that if a storage operator does not obtain the consent of all persons who own the storage reservoir's pore space, the commission may require that the pore space owned by nonconsenting owners be included in a storage facility and subject to geologic storage. Removal or displacement of oil and gas is not the subject of this application as it is not applying for storage in a hydrocarbon bearing reservoir.

(24) The Bakken Formation is addressed in Section 2.6 of the application. It indicates there has been no historic hydrocarbon exploration in, or production from, formations below the Broom Creek Formation in the storage facility area. It includes that in the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a horizontal well could be used to produce the hydrocarbons while avoiding drilling through the carbon dioxide 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.

(25) The equation of state reservoir simulator used by DGC is GEM, an EPA acknowledged existing code used for the development of geologic sequestration models. Commission staff reviewed all inputs for the reservoir model and used Computer Modelling Group LTD.'s software with GEM to verify outputs given by DGC. DGC updated and submitted the model based on a request by the Department of Environmental Quality in the review process. Reference to an alternate model was made based on DGC using publicly available relative permeability and capillary entry pressure data that allowed for a greater extent of carbon dioxide migration than site specific core data. This provides for a more conservative storage facility boundary. Formations considered in the model included the Opeche, Broom Creek, and Amsden Formations. DGC has performed baseline 2D seismic over the storage facility area. Time-lapse seismic surveys will be repeated 1, 3, 5, and 10 years after initial injection. Time-lapse 2D seismic will show the vertical and lateral extents of the carbon dioxide independent of the model.

(26) All stratigraphic test wells drilled in the storage facility were subject to NDAC 43-02-03-32, stating, in part, stratigraphic test and core holes shall be permitted the same as oil and gas wells. NDAC 43-02-03-21 states, in part, drilling of the surface hole shall be with freshwater-based drilling mud or other method approved by the director which will protect all freshwater-bearing strata. This includes water used during the cementing of surface casing for displacement. The surface casing for stratigraphic wells is set into the Pierre Formation, below

the deepest underground source of drinking water within the facility area, cemented to surface, and verified by radial cement bond log.

(27) The Commission notes three residential occupancies within figure 4-2 of the application, and various others within the area of review. DGC testified to the safety procedures concerning the facility and residential and public land use within one mile of the facility area as required in NDAC 43-05-01-13.

(28) The application indicates leak detection at the wellbore will be monitored using temperature and pulse neutron logging. In the event of out of zone migration through the upper confining zone, the Inyan Kara Formation above exists as a porous trap. The location of a confining zone leak can be detected with time-lapse seismic. DGC identifies installing a system to intercept brine or carbon dioxide or to pump and treat to air-strip carbon dioxide from the impacted water in the event of an underground source of drinking water being impacted.

(29) Article 8 of the Storage Agreement, section 8.1 "Grant of Easement" states the storage operator shall have the right to use as much of the surface of the land within the Facility Area as reasonably necessary for Storage Operations and the injection of Storage Substances. DGC testified that the surface access would be for monitoring activities by means of seismic surveys. NDCC 38-22-09 states the commission may include in a permit or order all things necessary to carry out this chapter's objectives and to protect and adjust the respective rights and obligations of persons affected by geologic storage. Seismic surveys are required to monitor the migration, lateral, and vertical extent of the plume. If an applicant proposed to build a variety of infrastructures, including buildings, as C. Eisenbeis states, an application can be filed for hearing by an impacted party under NDAC 43-05-01-12(1), which states in part that any interested person (i.e., the storage operator, local governments having jurisdiction over land within the area of review, any person who has suffered or will suffer actual injury or economic damage) may request that the commission review permits issued under this chapter for one of the reasons set forth below. NDAC 43-05-01-12(1)(k), "The commission receives information that was not available at the time of the permit issuance. Permits may be modified during their terms for this cause only if the information was not available at the time of permit issuance (other than revised regulations, guidance, or test methods) and would have justified the application of different permit conditions at the time of issuance). Building infrastructure or buildings without a separate surface agreement would not be considered reasonably necessary to carry out the objectives of NDCC 38-22.

(30) The Commission has rules and regulations in place to safeguard against tubing leaks or blowouts. NDAC Section 43-05-01-11(10) requires all tubing strings must meet the standards contained in subsection 6. All tubing must be new tubing or reconditioned tubing of a quality equivalent to new tubing and that has been pressure-tested. For new tubing, the pressure test conducted at the manufacturing mill or fabrication plant may be used to fulfill this requirement. NDAC Section 43-05-01-11(11) requires all wellhead components, including the casinghead and tubing head, valves, and fittings, must be made of steel having operating pressure ratings sufficient to exceed the maximum injection pressures computed at the wellhead and to withstand the corrosive nature of carbon dioxide. Each flow line connected to the wellhead must be equipped

with a manually operated positive shutoff valve located on or near the wellhead. NDAC Section 43-05-01-11(12) requires all packers, packer elements, or similar equipment critical to the containment of carbon dioxide must be of a quality to withstand exposure to carbon dioxide. NDAC 43-05-01-11(14) requires all newly drilled wells must establish internal and external mechanical integrity as specified by the Commission and demonstrate continued mechanical integrity through periodic testing as determined by the Commission. All other wells to be used as injection wells must demonstrate mechanical integrity as specified by the Commission prior to use for injection and be tested on an ongoing basis as determined by the Commission. NDAC 43-05-01-11(17) requires all injection wells must be equipped with shutoff systems designed to alert the operator and shut-in wells when necessary.

(31) The Commission has rules and regulations in place requiring the operator to demonstrate seismicity will not interfere with containment and prohibiting fracturing of the injection zone. NDAC Section 43-05-01-05(1)(b)(2)(m) requires the applicant must provide information on the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment. NDAC Section 43-05-01-11.3(1) requires except during stimulation, the storage operator shall ensure that injection pressure does not exceed ninety percent of the fracture pressure of the injection zone so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone. Injection pressure must never initiate fractures in the confining zone or cause the movement of injection or formation fluids that endanger an underground source of drinking water. All stimulation programs are subject to the Commission's approval as part of the storage facility permit application and incorporated into the permit.

(32) Pursuant to NDAC 43-05-01-05 (1)(b)(2)(j) the application is required to provide the location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone in the area of review, and a determination that they would not interfere with containment. Pursuant to NDAC 43-05-01-05 (1)(b)(2)(k) the application must include data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions. Pursuant to NDAC 43-05-01-05 (1)(b)(2)(l) the application is required to provide geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream. Pursuant to NDAC 43-05-01-05 (1)(b)(2)(o) the application is required to identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement, are free of transmissive faults or fractures, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.

(33) DGC's application provides adequate data to show suitability of the Broom Creek Formation for geologic storage of carbon dioxide in the facility area.

(34) DGC's application provides adequate modeling of the storage reservoir for delineation of the facility area, and adequate monitoring to detect if carbon dioxide is migrating into properties outside of the facility area pursuant to NDAC Section 43-05-01-11.4. Vertical release of carbon dioxide is addressed by the application pursuant to NDAC Section 43-05-01-13, and lateral release of carbon dioxide from the facility area is addressed by the application pursuant to NDAC Section 43-05-01-05.

(35) The Commission finds the information and opinions included in C. Eisenbeis's letters that were not addressed, to be either inapplicable or irrelevant to this case.

(36) Ricker appeared on July 20, 2022 to provide testimony. Ricker testified to owning mineral rights within the storage facility in the N/2 Section 10 and NW/4 Section 11, Township 145 North, Range 88 West. Ricker testified to seeking legal advice and their lawyer stated their mineral rights will be condemned or made null by this operation. Ricker is concerned about what may be in the Bakken Formation, and how any retrieval of those minerals will be made more difficult because of the actions being taken here. Ricker states that even if you can drill through or around it, these actions would be more costly than direct retrieval, and that there will be a real economic impact to mineral rights.

(37) There has been no historic hydrocarbon exploration, production, or studies suggesting there is an economically profitable supply of hydrocarbons from formations above or below the Broom Creek Formation within the proposed storage facility area. There has been historic production approximately 11 miles to the west of the storage facility from the Traxel 1-31H well (File No. 17877). The lateral extent of the stabilized plume and the pressure differential are minor enough to allow for horizontal drilling for hydrocarbon exploration, under the Broom Creek Formation, without penetrating the stored carbon dioxide. DGC testified that 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. DGC testified that a vertical well could be drilled using proper controls.

(38) The Commission received no compelling information to indicate underlying minerals would be stranded.

(39) DGC's Great Plains Synfuels Plant is a gasification plant located in Mercer County, North Dakota, near the city of Beulah. The lignite used for natural gas generation is the source of the carbon dioxide.

(40) Up to 2,700,000 metric tons of carbon dioxide will be captured annually from the Great Plains Synfuels Plant. The captured carbon dioxide will be compressed, transported to a Class VI well by a transmission and flow line, and then injected. Up to 2,700,000 metric tons of carbon dioxide will be injected into the Broom Creek Formation annually.

(41) DGC permitted a 6.8-mile transmission line through the North Dakota Public Service Commission (PSC) and implements their approved corrosion monitoring and prevention strategy. Transition from the PSC jurisdiction transmission line to injection well flow line will be at the flow meter on each injection well pad.

(42) The projected composition of the carbon dioxide stream is 95.9% carbon dioxide, 1.8% C_2^+ and hydrocarbons, 1.2% hydrogen sulfide, 0.6% methane, and 0.5% nitrogen.

(43) The flow line will be equipped with pressure gauges and a Supervisory Control and Data Acquisition (SCADA) system to detect leaks. Hydrogen sulfide detection stations will also be utilized for detection of leaks.

(44) The Coteau #1 well (File No. 38379) is stratigraphic test well that was used for reservoir characterization and constructed to Class VI requirements, located 555 feet from the south line and 460 feet from the west line of Section 1, Township 145 North, Range 88 West, Mercer County, North Dakota. This well is to be converted to a Class VI injection well.

(45) The Coteau #2 well (File No. 38916) is stratigraphic test well that is constructed to Class VI requirements, located 424 feet from the south line and 805 feet from the west line of Section 2, Township 145 North, Range 88 West, Mercer County, North Dakota. This well is to be converted to a Class VI injection well.

(46) The Coteau #3 well (File No. 38917) is stratigraphic test well that is constructed to Class VI requirements, located 2,462 feet from the south line and 2,391 feet from the east line of Section 2, Township 145 North, Range 88 West, Mercer County, North Dakota. This well is to be converted to a Class VI injection well.

(47) The Coteau #4 well (File No. 38918) is stratigraphic test well that is constructed to Class VI requirements, located 1,641 feet from the south line and 2,421 feet from the west line of Section 1, Township 145 North, Range 88 West, Mercer County, North Dakota. This well is to be converted to a Class VI injection well.

(48) The Coteau #5 well (File No. 39418) is a stratigraphic test well that will be tested, logged, and constructed to Class VI requirements, located 1,408 feet from the south line and 1,138 feet from the east line of Section 12, Township 145 North, Range 88 West, Mercer County, North Dakota. This well is to be converted to a Class VI injection well.

(49) The proposed Coteau #6 well will be tested, logged, and constructed to Class VI requirements, to be located approximately 688 feet from the south line and 2,037 feet from the east line of Section 12, Township 145 North, Range 88 West, Mercer County, North Dakota. This proposed well is to be a Class VI injection well.

(50) DGC created a geologic model based on site characterization as required by NDAC Section 43-05-01-05.1 to delineate the area of review. Data utilized included seismic survey data,

geophysical logs from nearby wells, and core data. Structural surfaces were interpolated with Schlumberger's Petrel software, and included formation tops, data collected from the Coteau #1 (File No. 38379), the Flemmer #1 (File No. 34243), the BNI #1 (File No. 34244), the J-LOC #1 (File No. 37380), the Liberty #1 (File No. 37672), the ANG #1 (Class I well), as well as 3D seismic surveys conducted at the Flemmer #1 and Liberty #1 locations. Due to low well control and difficulties with obtaining 3D seismic data on reclaimed mine land, publicly available variograms from the Minnkota Center MRYS Broom Creek Storage Facility #1 were used to inform lithofacies and petrophysical properties in the geologic model. The variograms were selected as they provided a generalized representation of property distributions expected in the Broom Creek Formation. Based on the reservoir pressure obtained from the Coteau #1 (File No. 37380), critical threshold pressure for this storage facility exists in the Broom Creek Formation prior to injection. Critical threshold pressure has the same meaning as pressure front, defined in NDAC Section 43-05-01-01, for area of review delineation purposes. EPA's "UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance" lists several methods to estimate an acceptable pressure increase for over-pressurized reservoirs, including a multiphase numerical model designed to model leakage through a single well bore, or through multiple well bores in the formation. DGC has used this method to determine cumulative leakage potential along a hypothetical leaky wellbore without injection occurring is estimated to be 0.01 cubic meters over 20 years. Incremental leakage with injection occurring was determined to be a maximum of 0.011 cubic meters over 20 years. A value of 1 cubic meter is the lowest meaningful value that can be produced by the ASLMA model as smaller values likely represent statistical noise. An actual leaky wellbore or transmissive conduit would likely communicate with the Inyan Kara Formation. DGC's application noted no indications of communication between the Broom Creek Formation and Inyan Kara Formation were observed, and that nothing in fluid samples indicated communication to USDWs. The predicted extent of the carbon dioxide plume from beginning to end of life of the project, at the time that the carbon dioxide plume ceases to migrate into adjacent cells of the geologic model, was used to define the area of review in this case. Pursuant to NDAC 43-05-01-05(1)(b)(2) the area of review was proposed as a one-mile buffer around the storage facility boundaries. Time lapse seismic surveys will be used for monitoring the extent of the carbon dioxide plume.

(51) The area proposed to be included within the storage facility is as follows:

<u>TOWNSHIP 146 NORTH, RANGE 88 WEST</u>
ALL OF SECTIONS 35 AND 36, THE S/2 OF SECTION 25, THE S/2 OF SECTION 26, THE SE/4 OF SECTION 27, THE SE/4 OF SECTION 33, AND THE S/2, AND NE/4 OF SECTION 34,

<u>TOWNSHIP 146 NORTH, RANGE 87 WEST</u>
ALL OF SECTION 31, THE S/2 OF SECTION 30, AND THE SW/4 OF SECTION 32,

<u>TOWNSHIP 145 NORTH, RANGE 88 WEST</u>
ALL OF SECTIONS 1, 2, 3, 10, 11, 12, 13, 14, 15, 22, 23 AND 24, THE E/2 OF SECTION 4, THE E/2 OF SECTION 9, AND THE E/2 OF SECTION 16,

TOWNSHIP 145 NORTH, RANGE 87 WEST
ALL OF SECTIONS 6, 7, 18 AND 19, THE W/2 OF SECTION 5, THE W/2 OF SECTION 8, AND THE W/2 OF SECTION 17.

ALL IN MERCER COUNTY AND COMPRISING OF 15,979.20 ACRES, MORE OR LESS.

(52) The Broom Creek Formation, the upper confining Opeche Formation, and the lower confining Amsden Formation are laterally extensive through the area of review.

(53) Core analysis of the Broom Creek Formation shows sufficient permeability to be suitable for the desired injection rates and pressures without risk of creating fractures in the injection zone. Thin-section investigation shows the Broom Creek Formation's sandstone intervals are comprised primarily of quartz, with minor occurrences of feldspar, dolomite, and anhydrite as cement. Within the Broom Creek, carbonate intervals are present consisting of dolostone, dolomite, anhydrite, quartz, dolosparite, feldspar, and clay. Anhydrite is present crystallized between quartz grains, as well as in the form of clasts and veins within carbonate intervals. Microfracture testing in the Flemmer #1 (Well No. 34243) well, near, but outside of the delineated facility area, at a depth of 6,358 feet determined the breakdown pressure of the formation to be 4,950 psi bottom hole pressure, with a fracture propagation pressure of 4,384 psi bottom hole pressure, and a fracture closure pressure of 4,195 psi bottom hole pressure. Microfracture in situ tests were not attempted in the Coteau #1 (File No. 38379) well due to unstable wellbore conditions. A one-dimensional mechanical earth model (1D MEM) was used to compensate for the lack of microfracture data within the storage facility area. Average fracture propagation pressure gradient at the Coteau #1 was assigned at 0.71 psi/ft, comparable to the 0.69 psi/ft gradient of the Flemmer #1.

Core analysis of the overlying Opeche Formation shows sufficiently low permeability to stratigraphically trap carbon dioxide and displaced fluids. Thin-section investigation shows the Opeche Formation is comprised of alternating intervals of silty mudstone and mudstone. Microfracture testing in the Flemmer #1 (Well No. 34243) well, near, but outside of the delineated facility area, at a depth of 6,262 feet observed formation breakdown at 8,157 psi bottom hole pressure and fracture propagation pressures of 4,879 psi bottom hole pressure and 5,085 psi bottom hole pressure, or a 0.78 psi/ft and 0.81 psi/ft gradient respectively. Microfracture in situ tests were not attempted in the Coteau #1 (File No. 38379) well due to unstable wellbore conditions. Injection pressure is limited to ninety percent of the fracture pressure of the injection zone. Injection formation breakdown would be observed and recorded if permitted operational pressures were exceeded before compromising the confining zone.

Core analysis of the underlying Amsden Formation shows sufficiently low permeability to stratigraphically contain carbon dioxide and displaced fluids. Thin-section investigation shows the Amsden Formation is comprised of dolomite, sandy dolomite, shaly sand, and anhydrite.

(54) The in situ fluid of the Broom Creek Formation in this area is in excess of 10,000 parts per million of total dissolved solids.

(55) Investigation of wells within the area of review found no vertical penetrations of the confining or injection zones requiring corrective action. The area of review will be reevaluated at a period not to exceed five years from beginning of injection operations.

(56) The Fox Hills Formation is the deepest underground source of drinking water (USDW) within the area of review. Its base is situated at a depth of 1,749 feet at the location of the proposed injection wells, leaving approximately 4,158 feet between the base of the Fox Hills Formation and the top of the Broom Creek Formation.

(57) Fluid sampling of shallow USDWs has been performed to establish a geochemical baseline, with additional baseline sampling proposed for the Fox Hills Formation and other shallow wells under investigation. Future sampling is proposed in DGC's application pursuant to NDAC Section 43-05-01-11.4.

(58) Soil sampling is proposed pursuant to NDAC Section 43-05-01-11.4. A baseline of soil gas concentrations has been established and was submitted to the Commission as part of this application. Six soil gas profile stations are located where the six injection wells will be, as well as five additional stations within the proposed storage facility area boundary.

(59) The top of the Inyan Kara Formation is at 4,404 feet, approximately 2,655 feet below the base of the Fox Hills Formation and it provides an additional zone of monitoring between the Fox Hills Formation and the Broom Creek Formation to detect vertical carbon dioxide or fluid movement.

(60) No known or suspected regional faults or fractures with transmissibility have been identified during the site-specific characterization. Formation imaging logs run showed the section of the Opeche Formation closest to the Broom Creek Formation to be dominant in litho-bound fractures and microfaults which are electrically conductive likely due to the presence of clay. The mid-region of the Opeche Formation notes the presence of electrically conductive and resistive features. The resistive features are interpreted as minor anhydrite filled fractures. Conductive features and microfaults are interpreted as clay filled due to electric conductivity.

(61) Fluid samples from the Inyan Kara Formation and Broom Creek Formation suggest that they are hydraulically isolated from each other, supporting that the confining formations above the Broom Creek Formation are not compromised by migration pathways.

(62) Geochemical simulation performed with the injection stream and data obtained from the confining and injection zones determined no observable change in injection rate or pressure. Conservatively high carbon dioxide exposure simulations to the cap rock determined that geochemical changes will be minor and will not cause substantive deterioration compromising confinement.

(63) Risk of induced seismicity is not a concern based on existing studies of major faults within the area of review, tectonic boundaries, and relatively stable geologic conditions surrounding the proposed injection site.

(64) The six injection wells are proposed to be temperature logged annually to demonstrate external mechanical integrity.

(65) The approval of this application is in the public interest by promoting the policy stated in NDCC Section 38-22-01.

IT IS THEREFORE ORDERED:

(1) The creation of the DGC Beulah Broom Creek Storage Facility #1 in Mercer County, North Dakota, is hereby authorized and approved.

(2) Dakota Gasification Company, its assigns and successors, is hereby authorized to store carbon dioxide in the Broom Creek Formation in the DGC Beulah Broom Creek Storage Facility #1.

(3) The DGC Beulah Broom Creek Storage Facility #1 shall extend to and include the following lands in Mercer County, North Dakota:

TOWNSHIP 146 NORTH, RANGE 88 WEST
ALL OF SECTIONS 35 AND 36, THE S/2 OF SECTION 25, THE S/2 OF SECTION 26, THE SE/4 OF SECTION 27, THE SE/4 OF SECTION 33, AND THE S/2, AND NE/4 OF SECTION 34,

TOWNSHIP 146 NORTH, RANGE 87 WEST
ALL OF SECTION 31, THE S/2 OF SECTION 30, AND THE SW/4 OF SECTION 32,

TOWNSHIP 145 NORTH, RANGE 88 WEST
ALL OF SECTIONS 1, 2, 3, 10, 11, 12, 13, 14, 15, 22, 23 AND 24, THE E/2 OF SECTION 4, THE E/2 OF SECTION 9, AND THE E/2 OF SECTION 16,

TOWNSHIP 145 NORTH, RANGE 87 WEST
ALL OF SECTIONS 6, 7, 18 AND 19, THE W/2 OF SECTION 5, THE W/2 OF SECTION 8, AND THE W/2 OF SECTION 17.

ALL IN MERCER COUNTY AND COMPRISING OF 15,979.20 ACRES, MORE OR LESS.

(4) Injection into the DGC Beulah Broom Creek Storage Facility #1 shall not occur until Dakota Gasification Company has met the financial responsibility demonstration pursuant to Order No. 32252.

(5) This authorization does not convey authority to inject carbon dioxide into the DGC Beulah Broom Creek Storage Facility #1; approved permits to inject for the Coteau #1 well (File No. 38379), the Coteau #2 well (File No. 38916), the Coteau #3 well (File No. 38917), the Coteau #4 well (File No. 38918), the Coteau #5 (File No. 39418), and the proposed Coteau #6 shall be issued by the Commission prior to injection operations commencing.

(6) The authorization granted herein is conditioned on the operator receiving and complying with all provisions of the injection permit issued by the Oil and Gas Division of the Industrial Commission and complying with all provisions of NDAC Chapter 43-05-01 where applicable, and this order.

(7) Definitions.

"Area of review" in this case means an area encompassing a radius around the facility area of one mile.

"Cell" in this case means individual cell blocks of the geologic model; each cell is approximately 1,000 feet by 1,000 feet.

"Facility area" means the areal extent of the storage reservoir as defined in paragraph (3) above, that includes lands within the lateral boundary of the carbon dioxide plume from beginning of injection to the time the carbon dioxide plume ceases to migrate into adjacent geologic model cells.

"Storage facility" means the reservoir, underground equipment, and surface facilities and equipment used or proposed to be used in the geologic storage operation. It does not include pipelines used to transport carbon dioxide to the storage facility under NDCC Section 38-22-02.

(8) The storage facility operator shall comply with all conditions of this order, the permit to inject, and NDAC Chapter 43-05-01, where applicable. Any noncompliance constitutes a violation and is grounds for enforcement action, including but not limited to termination, revocation, or modification of this order pursuant to NDAC Section 43-05-01-12.

(9) In an administrative action, it shall not be a defense that it would have been necessary for the storage facility operator to halt or reduce the permitted activity in order to maintain compliance with this order, the permit to inject, and NDAC 43-05-01, where applicable.

(10) The storage facility operator shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this order, the permit to inject, and NDAC 43-05-01, where applicable.

(11) The storage facility operator shall implement and maintain the provided emergency and remedial response plan pursuant to NDAC Section 43-05-01-13.

(12) Pursuant to NDAC 43-05-01-13, subsection 1, subdivision a, the Commission requests DGC submit the documentation of the training efforts with Mercer County LEPC after the exercises are performed.

(13) The storage facility operator shall cease injection immediately, take all steps reasonably necessary to identify and characterize any release, implement the emergency and remedial response plan approved by the Commission, and notify the Commission within 24 hours of carbon dioxide detected above the confining zone.

(14) The storage facility operator shall at all times properly operate and maintain all storage facilities which are installed or used by the storage facility operator to achieve compliance with the conditions this order, the permit to inject, and NDAC 43-05-01, where applicable. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems only when necessary to achieve compliance.

(15) This order may be modified, revoked and reissued, or terminated pursuant to NDAC Section 43-05-01-12. The filing of a request by the storage facility operator for and order modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any condition contained therein.

(16) The injection well permit or the permit to operate an injection well does not convey any property rights of any sort of any exclusive privilege.

(17) The storage facility operator shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this order, or to determine compliance thereof. The storage facility operator shall also furnish to the Director, upon request, copies of records required to be kept by this order, the permit to inject, and NDAC 43-05-01, where applicable.

(18) The storage facility operator shall allow the Director, or an authorized representative, upon presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the storage facility premises where records must be kept pursuant to this order and NDAC Chapter 43-05-01.

(b) At reasonable times, have access to and copy any records that must be kept pursuant to this order and NDAC Chapter 43-05-01.

(c) At reasonable times, inspect any facilities, equipment, including monitoring and control equipment, practices, or operations regulated or required pursuant to this order, the permit to inject, and NDAC Chapter 43-05-01.

(d) At reasonable times, sample or monitor for the purposes of assuring compliance, any substances or parameters at any location.

(19) The storage facility operator shall maintain and comply with the proposed testing and monitoring plan pursuant to NDAC Section 43-05-01-11.4

(20) The storage facility operator shall comply with the reporting requirements provided in NDAC Section 43-05-01-18. The volume of carbon dioxide injected, the average injection rate, surface injection pressure, and down-hole temperature and pressure data shall be reported monthly to the Director on or before the fifth day of the second succeeding month once injection commences regardless of the status of operations, until the injection well is properly plugged and abandoned.

(21) The storage facility operator must obtain an injection well permit under NDAC Section 43-05-01-10 and injection wells must meet the construction and completion requirements in NDAC Section 43-05-01-11.

(22) The storage facility operator shall notify the Director at least 48 hours in advance to witness a mechanical integrity test of the tubing-casing annulus in the injection well. The packer must be set within 100 feet of the upper most perforation and in the 13CR-80 casing, as an exception to NDAC Section 43-05-01-11. However, the packer must also be set within confining zone lithology, and within carbon dioxide resistant cement.

(23) The storage facility operator shall maintain and comply with the prepared plugging plan pursuant to NDAC Section 43-05-01-11.5.

(24) The storage facility operator shall establish mechanical integrity prior to commencing injection and maintain mechanical integrity pursuant to NDAC Section 43-05-01-11.1.

(25) The storage facility operator shall implement the worker safety plan pursuant to NDAC Section 43-05-01-13.

(26) The storage facility operator shall comply with leak detection and reporting requirements pursuant to NDAC Section 43-05-01-14.

(27) The storage facility operator shall implement the proposed corrosion monitoring and prevention program pursuant to NDAC Section 43-05-01-05.1.

(28) The storage facility operator shall maintain financial responsibility pursuant to NDAC Section 43-05-01-09.1.

(29) The storage facility operator shall maintain and comply with the proposed post-injection site care and facility closure plan pursuant to NDAC Section 43-05-01-19.

(30) The storage facility operator shall notify the Director within 24 hours of failure or malfunction of surface gauges in the Coteau #1 (File No. 38379), the Coteau #2 (File No. 38916), the Coteau #3 (File No. 38917), the Coteau #4 (File No. 38918), the Coteau #5 (File No. 39418), and the proposed Coteau #6 injectors.

(31) The storage facility operator shall implement surface air and soil gas monitoring as proposed.

(32) This storage facility authorization and permit shall be reviewed at least once every five years from commencement of injection to determine whether it should be modified, revoked, or minor modification made, pursuant to NDAC Section 43-05-01-05.1(4).

(33) The storage facility operator shall pay fees pursuant to NDAC Section 43-05-01-17 annually, no more than thirty days after the receipt of 26 U.S. Code § 45Q tax credits, unless otherwise approved by the Director.

(34) This order shall remain in full force and effect until further order of the Commission.

Dated this 24th day of January, 2023.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Doug Burgum, Governor

/s/ Drew H. Wrigley, Attorney General

/s/ Doug Goehring, Agriculture Commissioner

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 29451
(CONTINUED)
ORDER NO. 32251

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE APPLICATION OF DAKOTA GASIFICATION COMPANY TO CONSIDER THE AMALGAMATION OF THE STORAGE RESERVOIR PORE SPACE, IN WHICH THE COMMISSION MAY REQUIRE THAT THE PORE SPACE OWNED BY NONCONSENTING OWNERS BE INCLUDED IN THE GEOLOGIC STORAGE FACILITY AND SUBJECT TO GEOLOGIC STORAGE, AS REQUIRED TO OPERATE THE DAKOTA GASIFICATION COMPANY STORAGE FACILITY LOCATED IN SECTIONS 5, 6, 7, 8, 17, 18, 19, TOWNSHIP 145 NORTH, RANGE 87 WEST, SECTIONS 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, TOWNSHIP 145 NORTH, RANGE 88 WEST, SECTIONS 30, 31, 32, TOWNSHIP 146 NORTH, RANGE 87 WEST, SECTIONS 25, 26, 27, 33, 34, 35, 36, TOWNSHIP 146 NORTH, RANGE 88 WEST, MERCER COUNTY, NORTH DAKOTA, IN THE BROOM CREEK FORMATION, PURSUANT TO NORTH DAKOTA CENTURY CODE SECTION 38-22-10.

ORDER OF THE COMMISSION

THE COMMISSION FINDS:

(1) This cause originally came on for hearing at 9:00 a.m. on the 20th day of July, 2022. The Commission entered Order No. 32021 on October 5, 2022 continuing this matter for one hundred and seventy (170) days or until further order of the Commission.

(2) Case No. 29451 is a motion of the Commission determining the amalgamation of storage reservoir pore space, pursuant to a Storage Agreement by Dakota Gasification Company (DGC) for use of pore space falling within portions of Sections 25, 26, 27, 33, 34, 35, and 36, Township

146 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, and Sections 5, 6, 7, 8, 17, 18, and 19, Township 145 North, Range 87 West, Mercer County, North Dakota, in the Broom Creek Formation, has been signed, ratified, or approved by owners of interest owning at least sixty percent of the pore space interest within said lands, pursuant to North Dakota Century Code (NDCC) 38-22-10.

(3) Case Nos. 29451, 29450, and 29452 were combined for the purposes of hearing.

(4) Case No. 29450, also on today's docket, is an application by DGC for an order authorizing geologic storage of carbon dioxide from the Great Plains Synfuels Plant in the amalgamated pore space of the Broom Creek Formation in portions of Sections 25, 26, 27, 33, 34, 35, and 36, Township 146 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, and Sections 5, 6, 7, 8, 17, 18, and 19, Township 145 North, Range 87 West, Mercer County, North Dakota, pursuant to North Dakota Administrative Code (NDAC) Chapter 43-05-01.

(5) Case No. 29452, also on today's docket, is a motion of the Commission to determine the amount of financial responsibility for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in portions of Sections 25, 26, 27, 33, 34, 35, and 36, Township 146 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, and Sections 5, 6, 7, 8, 17, 18, and 19, Township 145 North, Range 87 West, Mercer County, North Dakota in the Broom Creek Formation, pursuant to NDAC Section 43-05-01-09.1.

(6) The record in these matters was left open to receive additional information from DGC. Such information was received on August 8, 2022 and the record was closed.

(7) Pursuant to NDCC Section 38-22-06 and NDAC Section 43-05-01-08, the notice of filing of the application and petition and the time and place of hearing thereof was given, and that at least 45 days prior to the hearing, DGC, as the applicant, did give notice of the time and place of said hearing and the Commission has accepted the notice as adequate, and that the applicant did, at least 45 days prior to the hearing, file with the Commission engineering, geological, and other technical exhibits to be used and which were used at said hearing, and that the notice so given did specify that such material was filed with the Commission; that due public notice having been given, as required by law, the Commission has jurisdiction of this cause and the subject matter.

(8) The Commission gave at least a thirty-day public notice and comment period for the draft storage facility permit and issued all notices using methods required of all entities under NDCC Section 38-22-06 and NDAC Section 43-05-01-08. Publication was made June 8, 2022, and the comment period for written comments ended at 5:00 PM CDT July 19, 2022. The hearing was open to the public to appear and provide comments.

(9) Order No. 32250 entered in Case No. 29450 created the DGC Beulah Broom Creek Storage Facility #1.

(10) The plan for amalgamation proposed by DGC includes a Storage Agreement for the Broom Creek Formation for certain lands in Mercer County, North Dakota.

(11) The area proposed to be included within the amalgamation area of the storage facility is as follows:

TOWNSHIP 146 NORTH, RANGE 88 WEST
ALL OF SECTIONS 35 AND 36, THE S/2 OF SECTION 25, THE S/2 OF SECTION 26, THE SE/4 OF SECTION 27, THE SE/4 OF SECTION 33, AND THE S/2, AND NE/4 OF SECTION 34,

TOWNSHIP 146 NORTH, RANGE 87 WEST
ALL OF SECTION 31, THE S/2 OF SECTION 30, AND THE SW/4 OF SECTION 32,

TOWNSHIP 145 NORTH, RANGE 88 WEST
ALL OF SECTIONS 1, 2, 3, 10, 11, 12, 13, 14, 15, 22, 23 AND 24, THE E/2 OF SECTION 4, THE E/2 OF SECTION 9, AND THE E/2 OF SECTION 16,

TOWNSHIP 145 NORTH, RANGE 87 WEST
ALL OF SECTIONS 6, 7, 18 AND 19, THE W/2 OF SECTION 5, THE W/2 OF SECTION 8, AND THE W/2 OF SECTION 17.

ALL IN MERCER COUNTY AND COMPRISING OF 15,979.20 ACRES, MORE OR LESS.

(12) DGC is proposing a one-phase formula for the calculation of tract participation, allocating 100% to surface acres.

"Surface acres" means the number of acres within each respective tract.

(13) Pursuant to NDCC Section 47-31-03, title to pore space in all strata underlying surface lands and waters is vested in the owner of the overlying surface estate.

No pore space has been leased out by pore space owners prior to this agreement. DGC did not find instances of pore space being severed from the surface estate that was allowed prior to April 9, 2009.

(14) A one-phase formula based on surface acres will fairly compensate owners farther away from the injection well that will eventually have pore space occupied by carbon dioxide. DGC testified Coteau Properties and DGC own the pore space where the injection wells are to be located. DGC indicates that the majority of carbon dioxide stored will remain in close proximity to the well

bores for an extended period of time, making Coteau Properties and DGC the primary beneficiary of a pore volume formula. Computational modeling performed by DGC and the Commission supports DGC's assessment.

The Commission believes capillary trapping, relative permeability hysteresis, and a lack of local area history matching data from injection of carbon dioxide into the saline Broom Creek Formation reservoir provides reasonable doubt for the utility of a pore volume formula. The Commission believes the 100% weighting on surface acreage is acceptable and that the one-phase formula is protective of correlative rights and should not be modified.

(15) DGC delineated the tracts to be utilized through computational modeling based on site characterization as required by NDAC Section 43-05-01-05.1. The data acquired during site characterization as well as the reservoir model and all inputs were provided to the Commission. The Commission evaluated the storage reservoir utilizing data acquired during site characterization and other publicly available data before performing computational simulation. The Commission concludes that DGC's inclusion of pore space that will be affected by the project has been adequately delineated.

(16) The Storage Agreement contains fair, reasonable, and equitable provisions for:

(a) The amalgamation of pore space interests for the storage of carbon dioxide within said pore spaces of the storage reservoir.

(b) The division of interest or formula for the apportionment and allocation of carbon dioxide to be stored.

(c) The measurement of quantity of carbon dioxide injected into the pore spaces underlying the delineated storage facility.

(d) The enlargement or reduction of the delineation of pore space utilized for geologic storage of carbon dioxide which may be warranted by review pursuant to NDAC Section 43-05-01-05.1(4).

(e) The time when the Storage Agreement shall become effective.

(f) The time when, conditions under, and the method by which the Storage Agreement shall be or may be terminated and its affairs wound up.

(17) Such amalgamation of the storage reservoir's pore space and the Storage Agreement are in the public interest, and require procedures that promote, in a manner fair to all interested, cooperative management, thereby ensuring the maximum use of natural resources, and that said Storage Agreement, as contained therein, appears to conform and comply with the provisions and requirements of NDCC Section 38-22-08.

(18) NDCC Section 38-22-10 provides that the Commission may require that the pore space owned by nonconsenting owners be included in a storage facility and subject to geological storage, if a storage operator does not obtain the consent of all persons who own the storage reservoir's pore space.

(19) Pursuant to NDAC Section 43-05-01-08(2)(e), the required notice given by DGC included a statement that amalgamation of the storage reservoir's pore space is required to operate the storage facility, that the Commission may require that the pore space owned by nonconsenting owners be included in the storage facility and subject to geologic storage, and that the amalgamation of pore space will be considered at the hearing.

(20) The approval of this application is in the public interest by promoting the policy stated in NDCC Section 38-22-01.

IT IS THEREFORE ORDERED:

(1) The amalgamation of pore space in the DGC Beulah Broom Creek Storage Facility #1 in Mercer County, North Dakota, is hereby approved.

(2) The Storage Agreement for the Broom Creek Formation is hereby incorporated in this order by reference insofar as the Commission has jurisdiction and said Storage Agreement for the amalgamated pore space therein is approved; and that if said Storage Agreement does not in all respects conform to and comply with the provisions and requirements under NDCC Chapter 38-22, the statute shall prevail.

(3) The amalgamated pore space is hereby defined as the following described tracts of land in Mercer County, North Dakota:

TOWNSHIP 146 NORTH, RANGE 88 WEST
ALL OF SECTIONS 35 AND 36, THE S/2 OF SECTION 25, THE S/2 OF SECTION 26, THE SE/4 OF SECTION 27, THE SE/4 OF SECTION 33, AND THE S/2, AND NE/4 OF SECTION 34,

TOWNSHIP 146 NORTH, RANGE 87 WEST
ALL OF SECTION 31, THE S/2 OF SECTION 30, AND THE SW/4 OF SECTION 32,

TOWNSHIP 145 NORTH, RANGE 88 WEST
ALL OF SECTIONS 1, 2, 3, 10, 11, 12, 13, 14, 15, 22, 23 AND 24, THE E/2 OF SECTION 4, THE E/2 OF SECTION 9, AND THE E/2 OF SECTION 16,

TOWNSHIP 145 NORTH, RANGE 87 WEST
ALL OF SECTIONS 6, 7, 18 AND 19, THE W/2 OF SECTION 5, THE W/2 OF SECTION 8, AND THE W/2 OF SECTION 17.

ALL IN MERCER COUNTY AND COMPRISING OF 15,979.20 ACRES, MORE OR LESS.

(4) The storage reservoir containing the amalgamated pore space is hereby defined as the stratigraphic interval from below the top of the Opeche Formation, found at a depth of 6,132 feet below the Kelly Bushing, to above the base of the Amsden Formation, found at a depth of 6,839 feet below the Kelly Bushing, as identified by the laterolog gamma ray log run in the Herrmann #1 well (File No. 4177), located in the NE/4 SW/4 of Section 17, Township 145 North, Range 88 West, Mercer County, North Dakota.

(5) The injection of carbon dioxide into the amalgamated pore space by the operator for the purpose of storage of carbon dioxide is authorized through the Coteau #1 well (File No. 38379), located 555 feet from the south line and 460 feet from the west line of Section 1, Township 145 North, Range 88 West, Mercer County, North Dakota; the Coteau #2 well (File No. 38916), located 424 feet from the south line and 805 feet from the west line of Section 2, Township 145 North, Range 88 West, Mercer County, North Dakota; the Coteau #3 well (File No. 38917), located 2,462 feet from the south line and 2,391 feet from the east line of Section 2, Township 145 North, Range 88 West, Mercer County, North Dakota; the Coteau #4 well (File No. 38918), located 1,641 feet from the south line and 2,421 feet from the west line of Section 1, Township 145 North, Range 88 West, Mercer County, North Dakota; the Coteau #5 well (File No. 39418), located 1,408 feet from the south line and 1,138 feet from the east line of Section 12, Township 145 North, Range 88 West, Mercer County, North Dakota; and the proposed Coteau #6 well, to be located approximately 688 feet from the south line and 2,037 feet from the east line of Section 11, Township 145 North, Range 88 West, Mercer County, North Dakota; provided, however, that prior to the commencement of such injection the operator shall obtain such permits as are required under NDAC Chapter 43-05-01.

(6) The termination of the amalgamation of lands hereinbefore described in paragraph (3) above shall be as prescribed in the Storage Agreement or at project completion as provided by NDCC Section 38-22-17; and that notwithstanding any provisions to the contrary, in the event that the operator fails to commence or ceases storage operations, the Commission, upon its own motion, after notice and hearing, may consider rescinding this order, or any portion thereof, so that this order of amalgamation will terminate and cease to exist.

(7) DGC shall provide an affidavit affirming it has complied with Article 14.2 of the Storage Agreement and the Storage Agreement has not been terminated. The effective date of the amalgamation of pore space in the lands hereinbefore described in paragraph (3) above shall be provided by order of the Director of the North Dakota Oil and Gas Division after said affidavit is received by the Commission.

(8) No well, other than those proposed in Case No. 29450, shall be hereafter drilled and completed in or injected into in the amalgamated pore space, as defined herein, without order of the Commission after due notice and hearing.

(9) This order shall be reviewed when a review of Order No. 32250 is conducted.

(10) This order shall cover all of the amalgamated pore space, as defined herein, and continues in full force and effect until further order of the Commission.

Dated this 24th day of January 2023.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Doug Burgum, Governor

/s/ Drew H. Wrigley, Attorney General

/s/ Doug Goehring, Agriculture Commissioner

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 29452
(CONTINUED)
ORDER NO. 32252

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE APPLICATION OF DAKOTA GASIFICATION COMPANY FOR AN ORDER OF THE COMMISSION DETERMINING THE AMOUNT OF FINANCIAL RESPONSIBILITY FOR THE GEOLOGIC STORAGE OF CARBON DIOXIDE FROM THE GREAT PLAINS SYNFUELS PLANT IN THE STORAGE FACILITY LOCATED IN SECTIONS 5, 6, 7, 8, 17, 18, 19, TOWNSHIP 145 NORTH, RANGE 87 WEST, SECTIONS 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, TOWNSHIP 145 NORTH, RANGE 88 WEST, SECTIONS 30, 31, 32, TOWNSHIP 146 NORTH, RANGE 87 WEST, SECTIONS 25, 26, 27, 33, 34, 35, 36, TOWNSHIP 146 NORTH, RANGE 88 WEST, MERCER COUNTY, NORTH DAKOTA, IN THE BROOM CREEK FORMATION, PURSUANT TO NORTH DAKOTA ADMINISTRATIVE CODE SECTION 43-05-01-09.1.

ORDER OF THE COMMISSION

THE COMMISSION FINDS:

(1) This cause originally came on for hearing at 9:00 a.m. on the 20th day of July, 2022. The Commission entered Order No. 32022 on October 5, 2022 continuing this matter for one hundred and seventy (170) days or until further order of the Commission.

(2) This case is a motion of the Commission to determine the amount of financial responsibility to be required of Dakota Gasification Company (DGC) for geologic storage of carbon dioxide in the amalgamated storage reservoir pore space of the Broom Creek Formation within Sections 25, 26, 27, 33, 34, 35, and 36, Township 146 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, and Sections 5, 6, 7, 8, 17, 18, and 19,

Township 145 North, Range 87 West, Mercer County, North Dakota, pursuant to North Dakota Administrative Code (NDAC) Section 43-05-01-09.1, and such relief as is appropriate.

(3) Case Nos. 29452, 29450, and 29451 were combined for the purposes of hearing.

(4) Case No. 29450, also on today's docket, is an application by DGC for an order authorizing geologic storage of carbon dioxide from the Great Plains Synfuels Plant in the amalgamated pore space of the Broom Creek Formation in portions of Sections 25, 26, 27, 33, 34, 35, and 36, Township 146 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, and Sections 5, 6, 7, 8, 17, 18, and 19, Township 145 North, Range 87 West, Mercer County, North Dakota, pursuant to North Dakota Administrative Code (NDAC) Chapter 43-05-01.

(5) Case No. 29451, also on today's docket, is a motion of the Commission to determine the amalgamation of storage reservoir pore space, pursuant to a Storage Agreement by DGC for use of pore space falling within portions of Sections 25, 26, 27, 33, 34, 35, and 36, Township 146 North, Range 88 West, Sections 30, 31, and 32, Township 146 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, and 24, Township 145 North, Range 88 West, and Sections 5, 6, 7, 8, 17, 18, and 19, Township 145 North, Range 87 West, Mercer County, North Dakota, in the Broom Creek Formation, has been signed, ratified, or approved by owners of interest owning at least sixty percent of the pore space interest within said lands pursuant to North Dakota Century Code (NDCC) 38-22-10.

(6) The record in these matters was left open to receive additional information from DGC. Such information was received on August 8, 2022, and the record was closed.

(7) Order No. 32250 entered in Case No. 29450 created the DGC Beulah Broom Creek Storage Facility #1; and Order No. 32251 entered in Case No. 29451 determined said storage facility will become effective as provided by subsequent order of the Director of the North Dakota Oil and Gas Division.

(8) DGC outlined its proposed qualifying financial responsibility instruments to be utilized to demonstrate financial responsibility pursuant to NDAC Section 43-05-01-09.1.

(9) Pursuant to NDAC Section 43-05-01-09.1 the qualifying financial responsibility instruments must cover the cost of:

(a) Corrective action that meets the requirements of NDAC Section 43-05-01-05.1.

(b) Injection well plugging that meets the requirements of NDAC Section 43-05-01-11.5.

(c) Postinjection site care and facility closure that meets the requirements of NDAC Section 43-05-01-19.

(d) Emergency and remedial response that meets the requirements of NDAC Section 43-05-01-13.

(10) DGC demonstrated that corrective action pursuant to NDAC Section 43-05-01-05.1 is not necessary within the delineated area of review. The Commission agrees with DGC's demonstration.

(11) DGC estimates the injection well plugging cost pursuant to NDAC Section 43-05-01-11.5 to be $1,000,000 total for six wells. The Commission accepts this as a conservative estimate.

(12) The DGC Beulah Broom Creek Storage Facility #1 will have six injection wells, the Coteau #1 well (File No. 38379), located 555 feet from the south line and 460 feet from the west line of Section 1, Township 145 North, Range 88 West, Mercer County, North Dakota; the Coteau #2 well (File No. 38916), located 424 feet from the south line and 805 feet from the west line of Section 2, Township 145 North, Range 88 West, Mercer County, North Dakota; the Coteau #3 well (File No. 38917), located 2,462 feet from the south line and 2,391 feet from the east line of Section 2, Township 145 North, Range 88 West, Mercer County, North Dakota; the Coteau #4 well (File No. 38918), located 1,641 feet from the south line and 2,421 feet from the west line of Section 1, Township 145 North, Range 88 West, Mercer County, North Dakota; the Coteau #5 well (File No. 39418), located 1,408 feet from the south line and 1,138 feet from the east line of Section 12, Township 145 North, Range 88 West, Mercer County, North Dakota; and the proposed Coteau #6 well, to be located approximately 688 feet from the south line and 2,037 feet from the east line of Section 11, Township 145 North, Range 88 West, Mercer County, North Dakota. DGC proposes covering the plugging of injection wells with an escrow account with initial funding of $1,000,000, paid in prior to injection, and paying in an additional $3,000,000 over three annual payments, with the final payment occurring in 2025, totaling $4,000,000. Escrow accounts are a qualifying financial responsibility instrument under NDAC Section 43-05-01-09.1

(13) DGC estimates the postinjection site care and facility closure financial responsibility pursuant to NDAC Section 43-05-01-19 is $3,000,000 and is proposed to be covered by the aforementioned $4,000,000 escrow account, that is deemed a qualifying financial responsibility instrument under NDAC Section 43-05-01-09.1.

(14) DGC estimates the emergency and remedial response costs pursuant to NDAC Section 43-05-01-13 by considering a conservative scenario there is carbon dioxide migration to the surface combined with groundwater interferences. Technical manuscripts by Manceau and others (2014) and Bielicki and others (2014) were used to identify and estimate the costs of mitigation and remediation technologies to address undesired migration of carbon dioxide from a geological storage reservoir. DGC's estimate for the emergency and remedial response actions is $16,000,000 and is proposed to be covered by a $16,000,000 third-party pollution liability

insurance policy, that is deemed a qualifying financial responsibility instrument under NDAC Section 43-05-01-09.1.

(15) The Commission should set minimum amounts of qualifying financial responsibility for injection well plugging, postinjection site care and facility closure, and emergency and remedial response.

IT IS THEREFORE ORDERED:

(1) Dakota Gasification Company, its assigns and successors, is hereby required to maintain financial responsibility with qualifying instruments in the minimum amounts specified in paragraph (2) below, pursuant to NDAC Section 43-05-01-09.1, covering the DGC Beulah Broom Creek Storage Facility #1 in Mercer County, North Dakota.

(2) The minimum amount for injection well plugging that meets the requirements of NDAC Section 43-05-01-11.5 is a $1,000,000 for 6 injection wells.

The minimum amount for postinjection site care and facility closure that meets the requirements of NDAC Section 43-05-01-19 is $3,000,000.

The minimum amount for emergency and remedial response that meets the requirements of NDAC Section 43-05-01-13 is $16,000,000.

(3) This order shall be reviewed when a review of Order No. 32250 is conducted.

(4) This order shall remain in full force and effect until further order of the Commission.

Dated this 24th day of January, 2023.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Doug Burgum, Governor

/s/ Drew H. Wrigley, Attorney General

/s/ Doug Goehring, Agriculture Commissioner

NORTH DAKOTA INDUSTRIAL COMMISSION

DIRECTOR'S
ORDER NO. 557

APPLICATION OF DAKOTA GASIFICATION COMPANY TO CONSIDER THE AMALGAMATION OF THE STORAGE RESERVOIR PORE SPACE, IN WHICH THE COMMISSION MAY REQUIRE THAT THE PORE SPACE OWNED BY NONCONSENTING OWNERS BE INCLUDED IN THE GEOLOGIC STORAGE FACILITY AND SUBJECT TO GEOLOGIC STORAGE, AS REQUIRED TO OPERATE THE DAKOTA GASIFICATION COMPANY STORAGE FACILITY LOCATED IN SECTIONS 35 AND 36, THE S/2 OF SECTIONS 25 AND 26, THE SE/4 OF SECTION 27, THE SE/4 OF SECTION 33, AND THE S/2 AND NE/4 OF SECTION 34, TOWNSHIP 146 NORTH, RANGE 88 WEST; SECTION 31, THE S/2 OF SECTION 30, AND THE SW/4 OF SECTION 32, TOWNSHIP 146 NORTH, RANGE 87 WEST; SECTIONS 1, 2, 3, 10, 11, 12, 13, 14, 15, 22, 23 AND 24, AND THE E/2 OF SECTIONS 4, 9 AND 16, TOWNSHIP 145 NORTH, RANGE 88 WEST; AND SECTIONS 6, 7, 18 AND 19, AND THE W/2 OF SECTIONS 5, 8 AND 17, TOWNSHIP 145 NORTH, RANGE 87 WEST, MERCER COUNTY, NORTH DAKOTA, IN THE BROOM CREEK FORMATION, PURSUANT TO NORTH DAKOTA CENTURY CODE SECTION 38-22-10.

ADMINISTRATIVE ORDER OF THE DIRECTOR

Under the provisions of North Dakota Century Code (NDCC) Chapter 38-22 and Order No. 32251, Dakota Gasification Company has provided an affidavit affirming it has complied with Article 14.2 of the Storage Agreement and said agreement has not terminated.

THE DIRECTOR FINDS:

(1) Order No. 32251 entered in Case No. 29451 on January 24, 2023 approved the amalgamation of the pore space in the DGC Beulah Broom Creek Storage Facility #1.

(2) The amalgamated pore space in the DGC Beulah Broom Creek Storage Facility #1 is defined as the following described tracts of land in Mercer County, North Dakota:

TOWNSHIP 146 NORTH, RANGE 88 WEST
ALL OF SECTIONS 35 AND 36, THE S/2 OF SECTIONS 25 AND 26, THE SE/4 OF SECTION 27, THE SE/4 OF SECTION 33, AND THE S/2, AND NE/4 OF SECTION 34,

TOWNSHIP 146 NORTH, RANGE 87 WEST
ALL OF SECTION 31, THE S/2 OF SECTION 30, AND THE SW/4 OF SECTION 32,

TOWNSHIP 145 NORTH, RANGE 88 WEST
ALL OF SECTIONS 1, 2, 3, 10, 11, 12, 13, 14, 15, 22, 23 AND 24, AND THE E/2 OF SECTIONS 4, 9 AND 16,

TOWNSHIP 145 NORTH, RANGE 87 WEST
ALL OF SECTIONS 6, 7, 18 AND 19, AND THE W/2 OF SECTIONS 5, 8 AND 17.

ALL IN MERCER COUNTY AND COMPRISING OF 15,979.20 ACRES, MORE OR LESS.

(3) The DGC Beulah Broom Creek Storage Facility #1 storage reservoir containing the amalgamated pore space is defined as the stratigraphic interval from below the top of the Opeche Formation, found at a depth of 6,132 feet below the Kelly Bushing, to above the base of the Amsden Formation, found at a depth of 6,839 feet below the Kelly Bushing, as identified by the laterolog gamma ray log run in the Herrmann #1 well (File No. 4177), located in the NE/4 SW/4 of Section 17, Township 145 North, Range 88 West, Mercer County, North Dakota.

(4) Order No. 32251 required Dakota Gasification Company to provide an affidavit affirming it has complied with Article 14.2 of the Storage Agreement and the Storage Agreement has not been terminated. Upon receipt of such affidavit, the Director of the North Dakota Oil and Gas Division was authorized to issue a Director's Order setting the effective date of the amalgamation of pore space in the lands hereinbefore described in paragraph (2) above.

(5) Dakota Gasification Company filed an affidavit on May 15, 2023, executed on May 11, 2023, that affirms Dakota Gasification Company has complied with Article 14.2 of the Storage Agreement and said agreement has not been terminated.

(6) The statutory requirements under NDCC Chapter 38-22 and the requirements under Order No. 32251 have been met.

(7) In order to promote the policy stated on NDCC Section 38-22-01, the DGC Beulah Broom Creek Storage Facility #1 should become effective.

IT IS THEREFORE ORDERED:

(1) The effective date of the amalgamation of pore space in the lands described above in paragraph (2) of the Findings in the DGC Beulah Broom Creek Storage Facility #1 shall become effective at 7:00 a.m. on the first day of June, 2023.

(2) This order shall remain in full force and effect until further order of the Commission.

Dated this 17th day of May, 2023.

/s/ Lynn D. Helms
Lynn D. Helms, Director

MORTGAGEE
MORTGAGOR
INDEXED ✓

COUNTY RECORDER
SEAL
MERCER COUNTY, N. DAK

226480

STATE OF NORTH DAKOTA
COUNTY OF MERCER

OFFICE OF
COUNTY RECORDER

I hereby certify that the within instrument was filed in this office for record this 7/20/2023 at 9:00 AM, and was duly recorded as Book 235 MISC on Page 555 Fee: $126.00

County Recorder Shannan Senger

By Deputy Amber Gabert

Return To: OFFICE OF ATTORNEY GENERAL, 500 NORTH 9TH STR
BISMARCK, ND 58501-4509

Office of Attorney General
RECEIVED
JUL 27 2023
BISMARCK, NORTH DAKOTA

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Shawna Senger
Mercer County Recorder
P.O. Box 39
Stanton, ND 58571-0039

9590 9402 7877 2234 0854 10

Article Number *(Transfer from service label)*

7021 0350 0001 1027 0601

S Form 3811, July 2020 PSN 7530-02-000-9053

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Jim Albers
☐ Agent
☐ Addressee

B. Received by *(Printed Name)* Jim Albers

C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Adult Signature
☐ Adult Signature Restricted Delivery
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☐ Certified Mail Restricted Delivery
☐ Collect on Delivery
☐ Collect on Delivery Restricted Delivery
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Office of Attorney General
500 N. 9th St.
Bismarck ND 58501-4509
Official Mail
State of North Dakota

JH
AK

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Shanna Senger
Mercer County Recorder
P.O. Box 39
Stanton, ND 58571 - 0039

9590 9402 7877 2234 0854 41

2. Article Number *(Transfer from service label)*

7021 0350 0001 1027 0618

PS Form 3811, July 2020 PSN 7530-02-000-9053

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Jim Albers
☐ Agent
☐ Addressee

B. Received by *(Printed Name)* Jim Albers

C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☐ Adult Signature
☐ Adult Signature Restricted Delivery
☒ Certified Mail®
☐ Certified Mail Restricted Delivery
☐ Collect on Delivery
☐ Collect on Delivery Restricted Delivery
Mail
Mail Restricted Delivery
00)
☐ Priority Mail Express®
☐ Registered Mail™
☐ Registered Mail Restricted Delivery
☐ Signature Confirmation™
☐ Signature Confirmation Restricted Delivery

Domestic Return Receipt

DGC Beulah Broom Creek

Received
AUG 08 2022
. . Gas Division

Fredrikson
& BYRON, P.A.

August 8, 2022

HAND DELIVERED

Mr. Bruce Hicks
Assistant Director
North Dakota Industrial Commission
Oil and Gas Division
600 East Boulevard
Bismarck, North Dakota 58505-0310

RE: Case Nos. 29450, 29451 and 29452
Dakota Gasification Company

Dear Mr. Hicks:

As requested by Commission staff at the hearing held on July 20, 2022 for the captioned matters, please find attached herewith for filing four copies of corrections to the exhibits presented at the hearings and four copies of supplemental exhibits.

Should you have any questions or require additional information, please advise.

Sincerely,

/s/ Lawrence Bender
LAWRENCE BENDER

LB/leo

Enclosure

cc: Ms. Casey Jacobson – (w/o enc.) *Via Email*
Ms. Amanda Livers – (w/o enc.) *Via Email*
Mr. Kevin Connors – (w/o enc.) *Via Email*

76857480 v1

Dakota Gasification Company

Case No. 29450

Application of Dakota Gasification Company requesting consideration for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Dakota Gasification Company intends to capture carbon dioxide from the Great Plains Synfuels Plant and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT July 19, 2022. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Steve Fried, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Dakota Gasification Company, 1717 East Interstate Avenue, Bismarck, ND 58503.

Case No. 29451

Application of Dakota Gasification Company to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Dakota Gasification Company storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code Section 38-22-10.

Case No. 29452

Application of Dakota Gasification Company for an order of the Commission determining the amount of financial responsibility for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant in the storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.

July 20, 2022

CORRECTIONS

Correction No.	Section	Correction Needed	Notes
1	4.0	**Noted during hearing**: Figure 4-2, page 4-3, caption mentions teal squares representing vacant buildings and blue squares representing commercial buildings, but these are not on legend or on map only in figure caption	Figure updated.
2	6.0	**Noted during hearing**: Page 6-4; geophysical monitoring (center box) minimum of 10 years, frequency states perform 2D radial seismic surveys at cessation of injection "1 year after injection begins", ...should be 1-year after injection ceases?	Yes; correction made.
3	7.0	**Noted during hearing**: Page 7-12, correct DMR phone number (not needed for DMR records). Should be "328" not "327"	Corrected; also verified all numbers on the list and corrected those in error.
4	5.0	**Noted during hearing**: Frequency performed during well workovers, but not more frequently than once every 5 years ... should that say not less frequently? not going to test if after pull packer Correction to be made in three places; correction also needed to USIT occurrences.	Corrections to workover and USIT wording made in several different places in Section 5 and 6.
5	2.4.3.2	**Typo:** Table 3-2, correct Opeche Average Porosity from 25.7 to 2.57.	Correction made.
6	2.0	**Typo:** Figure 2-5, incorrect file number listed for Coteau 1 (NDIC File No. 30570) – correct to No. 38379	File number corrected.
7	12.3.3	**Correction:** Section 12.3.3, language in paragraph "b) formation monitoring (i.e., downhole pressure and temperature surveys, pulsed-neutron logs) and mechanical integrity well tests (i.e., injection well annulus pressure, ultrasonic logs)" should be deleted as the wells will be plugged during the PISC period.	Language deleted and following items renumbered.
8	3	**Correction/Typo:** Paragraph beginning "A PHIE property..." changed "random function simulation *conditioning* to the..." to "random function simulation *conditioned* to the..."	Updated.
9	3	**Correction**: Delete text describing stabalization as time when CO2 does not migrate to the adjacent cell.	Text deleted.
10	2	**Correction**: Table 2-14, PHREEQC pH should be 7.04 (taken from in field report). Data in the text was updated, missed the occurrence in the table.	pH in Table 2-14 updated.

Correction No.	Section	Correction Needed	Notes
11	2.4.3.2	**Clarification**: Section 2.4.3.2, sentence beginning "The Amsden Formation temperature…" Clarify that temperature was not derived from the 1D MEM.	Clarification added.

Correction 1
Section 4.0

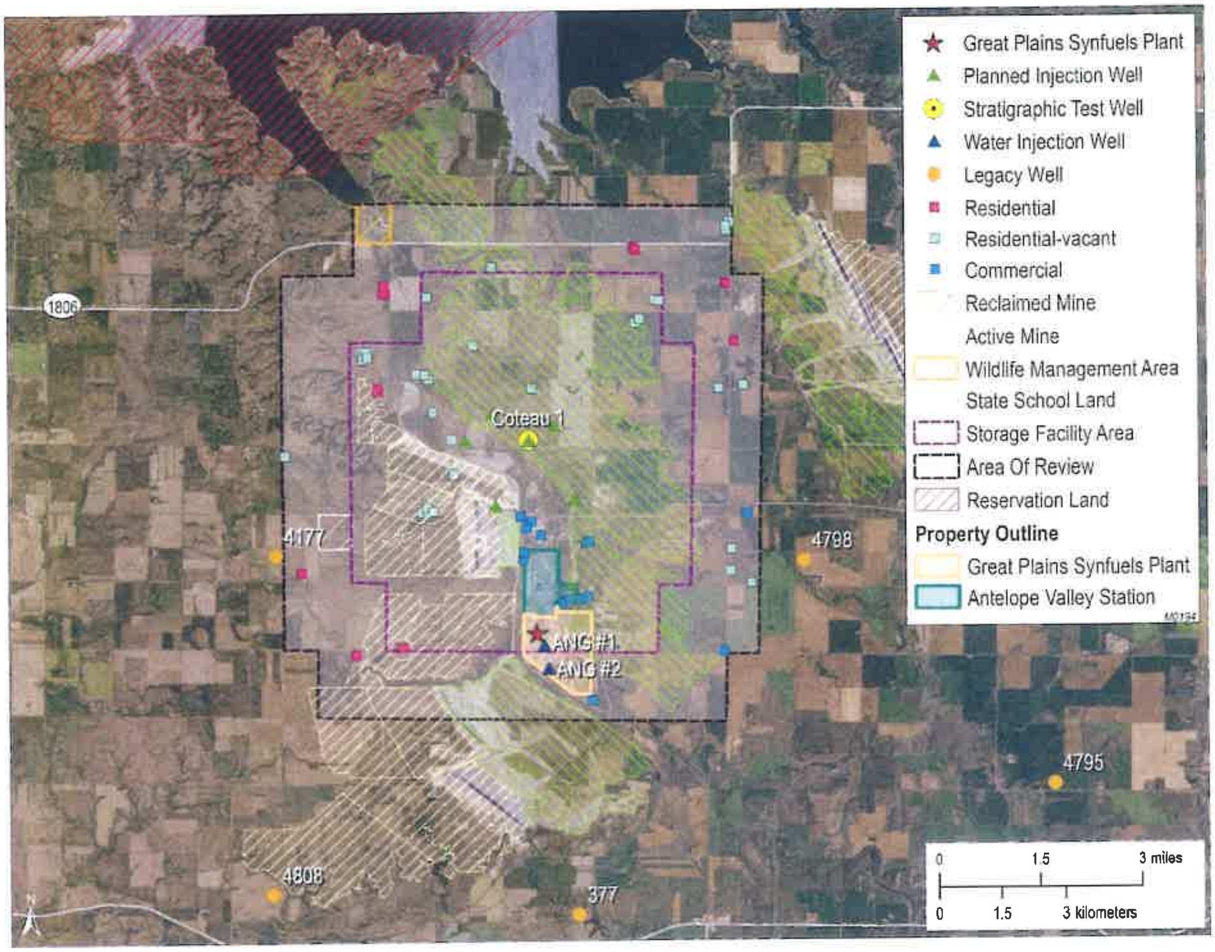


Figure 4-2. Final AOR map showing the Great Plains CO_2 Sequestration Project storage facility area, the storage facility area (dashed purple boundary), and the AOR (dashed black boundary). Pink squares represent occupied dwellings, teal squares represent vacant buildings, and blue squares represent commercial buildings.

Correction 2
Section 6.0

6.1.3 Postinjection Monitoring Plan

A summary of the postinjection monitoring plan that will be implemented during the 10-year postinjection period is provided in Table 6-1. The plan includes a combination of soil gas and groundwater/USDW monitoring as well as downhole and geophysical monitoring of the CO_2 plume in the storage reservoir.

Table 6-1. Summary of 10-year Postinjection Site Care Monitoring Plan

Type of Monitoring	Duration and Frequency	Justification
	Near-Surface Monitoring	
Soil Gas Profile Stations (SG01 to SG11) (Figure 6-3)	Duration: minimum 10 years Frequency: 3–4 seasonal sample events at soil gas stations SG01 to SG11	The sampling and analysis program will monitor the vadose zone for any signs of potential CO_2 leaks within the storage facility area.
Dedicated Fox Hills (lowest USDW) Monitoring Wells (Figure 6-3)	Duration: minimum 10 years Frequency: 3–4 seasonal sample events at each dedicated Fox Hills monitoring well	The sampling and analysis program will monitor the Fox Hills Formation at each injection well pad to ensure the USDW is not impacted by operations.
	Storage Reservoir Monitoring	
Surface Pressure Gauges on the ANG #1 and ANG #2 Wells (if WHP:BHP method is not satisfactory, DGC will perform a BHP survey in the first year of the PISC period)	Duration: minimum 10 years postinjection Frequency: continuous	Surface pressures will monitor the pressure decrease in the Broom Creek and history-match model predictions.
	Geophysical Monitoring	
Time-Lapse Seismic	Duration: minimum 10 years postinjection Frequency: perform 2D radial seismic surveys at the cessation of injection, 1 year after injection ceases, then in Years 3, 5, and 10	Time-lapse seismic surveys will continue as part of the 10-year postinjection period to support a stabilization assessment of the CO_2 plume.

6.2 Groundwater and Soil Gas Monitoring

Eleven soil gas profile stations and six dedicated monitoring wells in the Fox Hills Formation (i.e., lowest USDW) will be sampled during the proposed 10-year PISC period. Figure 6-3 identifies the locations of the soil gas profile stations and dedicated Fox Hills Formation monitoring wells that will be included. It is proposed that these samples will be analyzed for the same list of parameters as described in the testing and monitoring plan (Section 5); however, it is anticipated

Correction 3
Section 7.0

In addition to DGC personnel, the IC is responsible for establishing and maintaining communications with appropriate off-site persons and/or agencies, including, but not limited to, the following:

Beulah Police Department	**701.873.5252**
Beulah Fire Department	701.873.2121
Mercer County Ambulance	**701.747.5558**
Mercer County Emergency Manager	701.745.3302 or 701.745.3695
Mercer County Sheriff's Office	**701.745.3333**
Hazen Police Department	701.748.2414
North Dakota Highway Patrol	**701.328.2447**
North Dakota Highway Department	701.328.2500
North Dakota Poison Control	**800.222.1222**
Hazen Fire Department	701.745.3332
Sakakawea Medical Center	**701.748.2225**
NDIC DMR UIC Program Director	701.328.8020
North Dakota Department of Emergency Services	**701.328.8100**

Lastly, the DGC plant emergency plan contains addresses and contact information for approximately 58 neighboring facilities and residences located within 4.5 miles of the GPSP. This information is based on DGC's latest population density survey. DGC will update this information to document any changes that may occur by conducting semi-annual surveys. DGC will utilize an emergency out call system which is designed to notify residents in the area if an emergency occurs.

7.7 ERRP Review and Updates

This ERRP shall be reviewed:

- At least annually following its approval by NDIC DMR.
- Within 1 year of an area of review (AOR) reevaluation.
- Within a prescribed period (to be determined by NDIC DMR) following any significant changes to the project, e.g., injection process, injection rate, etc.
- As required by NDIC DMR.

Should the operational monitoring (see Section 5.0, Testing and Monitoring Plan) of the geologic storage operations identify trends that warrant a modification to the ERRP prior to the scheduled annual review, DGC will move forward with revising the plan and submitting a revised ERRP to NDIC DMR within 6 months of that determination.

If the annual review indicates that no amendments to the ERRP are necessary, DGC will provide NDIC DMR with the documentation supporting a no-amendment-necessary determination. If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to NDIC DMR within 6 months following their identification.

Correction 4
Section 5.0

1.0 QUALITY ASSURANCE AND SURVEILLANCE PLAN

The primary goal of the testing and monitoring plan of this storage facility permit application is to ensure that the geologic sequestration project is operating as permitted and is not endangering USDWs. In compliance with North Dakota Administrative Code (NDAC) § 43-05-01-11.4 (Testing and Monitoring Requirements), this Quality Assurance and Surveillance Plan (QASP) was developed and is being provided as part of the testing and monitoring program.

The testing and monitoring program for the project includes the analysis of the injected CO_2 stream, periodic testing of the injection wells, a corrosion monitoring plan for the CO_2 injection well components and surface facilities, a leak detection and monitoring plan for surface components of the CO_2 injection system, and a leak detection plan to monitor any movement of the CO_2 outside of the storage reservoir (see Table 5-1). The latter consists of a combination of soil gas and groundwater monitoring, storage reservoir monitoring, downhole monitoring, and geophysical monitoring. The quality assurance and surveillance procedures for this testing and monitoring plan are provided in the remainder of this QASP.

1.1 CO_2 Stream Analysis and Injection Well Mechanical Integrity Testing

1.1.1 CO_2 Stream Analysis

NDAC § 43-05-01-11.4(1a) requires analysis of the CO_2 stream in compliance with applicable analytical methods and standards generally accepted by industry and with sufficient frequency to yield data representative of its chemical and physical characteristics. DGC will collect samples of the injected CO_2 stream daily at the capture facility and analyze them to determine the concentrations of CO_2, nitrogen, oxygen, hydrogen, water, hydrogen sulfide, carbon monoxide, and a suite of hydrocarbons (e.g., ethane, propane, n-butane, and methane). This is consistent with the daily analysis DGC has performed on volumes delivered to Canadian oil fields since 1998. DGC uses an Agilent gas chromatograph with flame ionization and thermal conductivity detectors and complies with American Society for Testing and Materials Standards D7833, D1946, D2163, and UOP 539. Selected stable and radiogenic isotopes (i.e., isotopes of carbon dioxide [^{13}C and ^{14}C], methane [^{13}C and ^{14}C], and deuterium [^{2}H]) will also be sampled three to four times in the first year to establish a baseline. The isotopic analyses will be outsourced to commercial laboratories that will employ standard analytical quality assurance/quality control (QA/QC) protocols used in the industry.

1.1.2 Injection Well Mechanical Integrity Testing

The external mechanical integrity of the injection wells will be established prior to injection with a USIT (ultrasonic imager tool) in combination with variable density (VDL) and cement bond logs (CBL). The USIT (includes the VDL and CBL) will be performed during well workovers not less frequently than once every 5 years. It will also be useful for assessing the internal mechanical integrity of the injection wells. In addition, the injection wells will be monitored with a pulsed neutron log tool (PNX), to include temperature and pressure readings, using the phased approach described in Section 5.1.2 of this storage facility permit. The tool specifications of the USIT and the PNX are provided in Attachments A-1 and A-2, respectively.

Internal mechanical integrity of the injection wells will be demonstrated via tubing-casing annulus pressure tests prior to injection and during well workovers but at least once every 5 years.

A detailed description of this test is provided in Attachment A-3. Pressure falloff tests will be performed in the injection wells prior to injection. During injection operations, pressure falloff testing will be carried out via surface pressure monitoring at least once every 5 years to demonstrate storage reservoir injectivity. In addition, the injection wells will be continuously monitored for surface and annular pressure anomalies by maintaining a consistent 200 pounds per square inch (psi) on the annulus with a nitrogen cushion that will be added on top of the packer fluid.

1.2 Corrosion Monitoring and Prevention Plan

1.2.1 Corrosion Monitoring

DGC will install a 3-foot test section of 4½-inch L-80 tubing in the flowlines near each wellhead for regular testing and corrosion monitoring of the well material (Figure 5-1 or the storage facility permit). The tubing joints will be inspected monthly via ultrasound equipment during the first quarter, then quarterly thereafter for the first 2 years. If the well materials (i.e., tubing) show no sign of corrosion within the first 2 years of the injection period, future internal monitoring of the tubing will be accomplished through a platform multifinger imaging tool (PMIT), or in the event a downhole tubing string is pulled for any reason, it will be inspected at the surface for corrosion and mechanical integrity. Wireline monitoring using the USIT, which will be run during workovers (including when tubing is pulled) but not less frequently than once every 5 years, will also be considered for assessing the corrosion of the casing in the injection wells. Details related to the PMIT and Tuboscope wellsite injection services are provided as Attachments A-4 and A-5, respectively.

1.2.2 Corrosion Prevention

To prevent corrosion of the well materials, the following preemptive measures will be taken: 1) cement in the injection wells opposite the injection interval and extending more than 2,000 feet uphole, will be CO_2-resistant, 2) the well casing (L-80 13Cr) will also be CO_2-resistant from the bottomhole to a depth just above the Opeche Formation, and 3) the packer fluid will be an industry standard corrosion inhibitor. In addition, the chemical composition of the CO_2 stream is highly pure (Table 5-2) and dry, with a moisture level for the CO_2 stream typically less than 2.00 parts per million by volume, both of which help prevent corrosion of the surface and well materials.

1.3 Surface Leak Detection and Monitoring Plan

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 (Attachment A-6) located inside each gas meter and wellhead enclosure. Another H_2S detection station will be installed on the exterior of each wellhead enclosure to monitor atmospheric conditions on the pad. This leak detection equipment will be integrated with automated warning systems capable of immediately notifying personnel in DGC's pipeline control center in the event of an anomalous reading. As an added measure for safety, field personnel will have multi gas detectors with them to monitor for H_2S (Attachment A-7). Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

5.1 CO_2 Stream Analysis and Injection Well Mechanical Integrity Testing

5.1.1 CO_2 Stream Analysis

The CO_2 stream is analyzed daily at the capture facility, using methods and standards generally accepted by industry. The chemical content of the captured gas is 95.9 by volume percent CO_2 and 4.1 by volume percent other chemical components, as summarized in Table 5-2. The physical characteristics of the CO_2 stream, including its corrosiveness, temperature, and density are also measured daily at the capture facility.

Table 5-2. Chemical Content of the CO_2 Stream

Chemical Content	Volume Percent
Carbon Dioxide	95.9
C_2^+ and Hydrocarbons	1.8
Hydrogen Sulfide	1.2
Methane	0.6
Nitrogen	0.5
Total	100.0

5.1.2 Injection Well Mechanical Integrity Testing

A USIT, in combination with variable density and cement bond logs, was used to establish the baseline external mechanical integrity in the Coteau 1 well. The same suite of logging tools will also establish baseline conditions in the other injection wells, and the USIT will be run during well workovers but not less frequently than once every 5 years. Baseline temperature data will also be collected prior to operations and will be regularly performed using a phased approach (described in the following paragraph) to verify external mechanical integrity in the injection wells.

DGC's phased approach: pulsed-neutron logs (PNLs), which include a temperature log and bottomhole pressure (BHP) readings, will be run in an individual injection well quarterly. Each injection well will be placed on a rotating schedule to gather these downhole data, starting with Coteau 1 in the first quarter, Coteau 2 in the second quarter, Coteau 3 in the third quarter, and Coteau 4 in the fourth quarter, at which point the rotation will be repeated. Once drilled, the Coteau 5 and Coteau 6 wells will be added to the rotating schedule and the frequency adjusted to a bimonthly basis.

A BHP survey will be acquired each month during the first quarter of operations to supplement the phased approach described above. These supplemental BHP readings will confirm that the wellhead pressure (WHP):BHP correlation (pressure gradient) is accurate and reliable. If the WHP:BHP correlation is reconciled with the BHP data in the first quarter, BHP surveys will continue to be acquired at the frequency and schedule described in the phased approach.

Internal mechanical integrity of the injection wells will be demonstrated via tubing-casing annulus pressure tests prior to injection and during well workovers but at least once every 5 years.

Pressure falloff tests will be performed in the injection wells prior to injection. During injection operations, pressure falloff testing will be carried out via surface pressure monitoring at least once every 5 years to demonstrate storage reservoir injectivity. In addition, the injection wells will be continuously monitored for surface and annular pressure anomalies by maintaining a consistent 200 pounds per square inch on the annulus with a nitrogen cushion that will be placed and maintained on top of the packer fluid. USITs may be run during workovers (including when tubing is pulled) but not less frequently than once every 5 years, to further assess the internal mechanical integrity of the injection wells.

5.2 Corrosion Monitoring and Prevention Plan

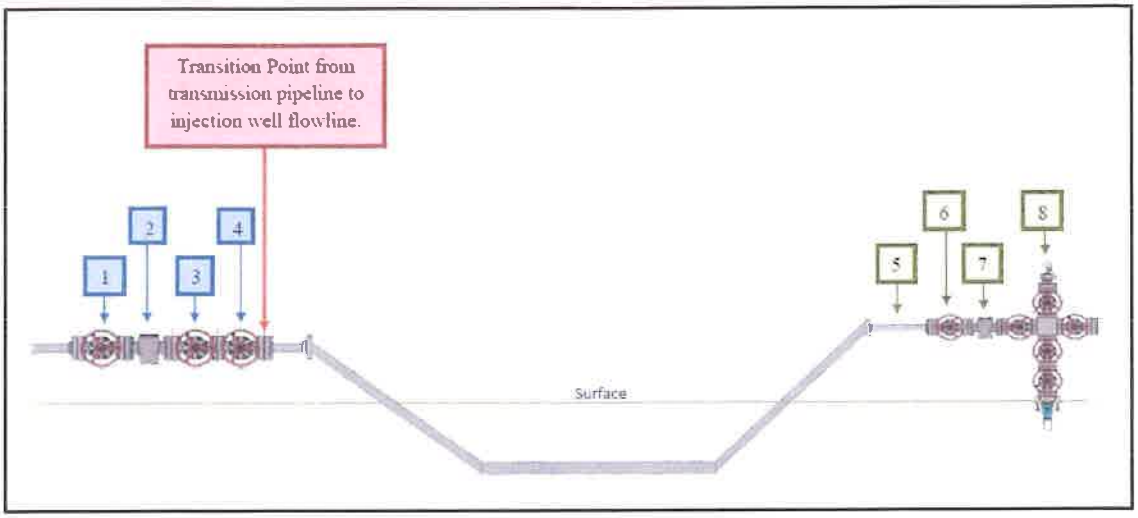
The purpose of the corrosion monitoring and prevention plan is to monitor the surface facilities and injection well components during the operational phase of the Great Plains CO_2 Sequestration Project to ensure that the materials meet the minimum standards for material strength and performance. Figure 5-1 illustrates the pad drawings for the Coteau 1 through Coteau 4 wells.

DGC permitted a new 6.8-mile-long transmission line through the North Dakota Public Service Commission (PSC) in July 2021 (PU-21-150). The transmission line implements a corrosion monitoring and prevention strategy that was approved by PSC and is not discussed in this storage facility permit application. At the transition from transmission line to flowline (Figure 5-2), DGC's efforts to monitor and prevent corrosion of the flowline and well materials at the injection wellsites are presented in Sections 5.2.1 and 5.2.2.

5.2.1 Corrosion Monitoring

DGC will install a 3-foot test section of 4½-inch L-80 tubing in the flowlines near each wellhead for regular testing and corrosion monitoring of the well material. The tubing joints will be

Great Plains CO2 Sequestration Project
Coteau No. 1 Surface Connections



1. Block valve (capable of remote operation) - this valve will shut down CO_2 to the flowline in the event of a leak or other issue.
2. Flow Meter.
3. Pressure control valve.
4. Block valve (capable of remote operation) - this valve will shut off CO_2 to the well if for some reason the control valve outlet pressure approaches the maximum well head pressure.

5. 4 1/2" L-80 Tubing test section
6. 4 1/16" 5M isolation wing valve
7. One-way check valve to prevent backflow of CO2 from the reservoir in the event of an emergency shutdown
8. 4 1/6" 5M Tree with 200 psi of static operating pressure held on the tubing-casing annulus. A deviation of 20% in either direction will trigger closure of the remote block valve, as will an alarm condition from the surface H2S monitors

Figure 5-2. Diagram of surface connections at the Coteau 1 wellsite. The Coteau 2 through 5 wells will connect to a common gathering system at the Coteau 1 well pad. The Coteau 6 will be similarly equipped but will connect to a separate gathering system. The primary block valve (item 1 above) will be located at the Coteau 1 well while the rest of the equipment (items 2 through 8 above) will be located on the well pads of each of the injection wells.

inspected monthly via ultrasound equipment during the first quarter, then quarterly thereafter for the first 2 years. If the well materials (i.e., tubing) show no sign of corrosion within the first 2 years of the injection period, future internal monitoring of the tubing will be accomplished through a platform multifinger imaging tool (PMIT), or in the event a downhole tubing string is pulled for any reason, it will be inspected at the surface for corrosion and mechanical integrity. USITs may also be run during workovers (including when tubing is pulled), but not less frequently than once every 5 years, to further assess any corrosion of the injection string.

5.2.2 Corrosion Prevention

To prevent corrosion of the well materials, the following preemptive measures will be taken: 1) cement in the injection wells opposite the injection interval and extending more than 2,000 feet uphole will be CO_2-resistant, 2) the well casing (L-80 13Cr) will also be CO_2-resistant from the bottomhole to a depth just above the Opeche Formation in the injection wells, and 3) the packer fluid will be an industry standard corrosion inhibitor. In addition, the chemical composition of the CO_2 stream is highly pure (Table 5-2) and dry, with a moisture level for the CO_2 stream typically

Table 5-7. Description of DGC's Deep Subsurface Monitoring Program

Monitoring Type	Preoperational (baseline)	Operational	Postoperational
Mechanical Integrity Testing (MIT)			
USIT (external MIT)	Prior to injection	Duration: 12 years Frequency: Perform when tubing is pulled but not less frequently than once every 5 years.	None Injection wells will be plugged.
Temperature Logs Run with PNL (external MIT)	Prior to injection	Duration: 12 years Frequency: Quarterly using phased approach described in Section 5.1.2	None Injection wells will be plugged.
200 psi Kept on Annulus, Between Tubing and Long-String (multifinger imaging tool [internal MIT])	Prior to injection Initial volume of packer fluid (corrosion inhibitor) and nitrogen cushion to fill casing	Duration: 12 years Frequency: Continuous Nitrogen cushion will be used to maintain a consistent pressure.	None Injection wells will be plugged.
Tubing-Casing Annulus Pressure Testing (internal MIT)	Prior to injection	Duration: 12 years Frequency: Perform during well workovers but at least once every 5 years.	None Tubing will be pulled from the injection wells, and the injection wells will be plugged.
Pressure Falloff Test in the Injection Zone (internal MIT)	Prior to injection	Duration: 12 years Frequency: Once every 5 years	None Injection wells will be plugged.
Storage Reservoir (Direct) Monitoring			
Flow Rate and Volume, Surface Injection Pressure, and Surface Injectate Temperature	At start of injection operations	Duration: 12 years Frequency: Continuous monitoring	None Injection operations will have ceased.
PNLs with Temperature Logs and Pressure Recording Devices Attached	Prior to injection	Duration: 12 years Frequency: Quarterly, using phased approach described in Section 5.1.2	None Injection wells will be plugged.

Continued…

Correction 5
Section 2.4.3.2

Temperature and pressure data recorded from a pressure test in the Coteau 1 were used to derive a temperature and pressure gradient to initialize the numerical simulation model for the proposed injection site. In combination with depth, this temperature gradient of 0.02°F/ft was used to calculate subsurface temperatures throughout the study area. A pressure reading recorded from the Broom Creek Formation was used to derive a pore pressure gradient of 0.49 psi/ft (Table 3-1). Table 3-2 shows the general properties used for numerical simulation analysis in this study.

Table 3-1. Pressure Measurement Recorded from the Coteau 1 Well and Derived Pressure Gradient

Test Depth, ft MD*	Formation Pressure, psi	Pressure Gradient, psi/ft
5,975.00	2,937.09	0.49

* Measured depth.

Table 3-2. Summary of Reservoir Properties in the Simulation Model

Formation	Average Permeability, mD	Average Porosity, %	Initial Pressure, P_i, psi	Salinity, ppm	Boundary Condition
Opeche	0.034	2.57	~2,937.1 (at 3,960.6 ft)	42,800	Partially closed
Broom Creek	241.2	14.5			
Amsden	2.55	4.4			

The CMG fluid property characterization tool, WinProp, was used to generate the fluid property input data for the simulation model. Only the major constituents in the gas stream were included for computational efficiency. After all the constituents were normalized to sum 100% mole fraction, the CO_2 composition in the gas stream was 96.45% CO_2. Other constituents represent 3.55% of the stream, including 1.23% hydrogen sulfide (H_2S) and 2.32% for methane, ethane, propane, and nitrogen.

The numerical simulation model was history-matched using the field injection data from the Class I injector wells located in the area of study, ANG #1 and ANG #2. The field injection data consisted of daily field data from Dakota Gasification Company (DGC) water injection into the ANG wells throughout December 1983 for ANG#1 and November 1984 for ANG #2 to August 2021. The field data provided were averaged per month and included in the numerical model for the history matching. The well skin factor was the parameter used to history-match the model based on data from a monitoring study conducted in the ANG wells in 2016. Figures 3-13 and 3-14 show a comparison between the WHP and water injection rate from the field data set and the predicted values from the history-matched model.

Six CO_2 injection wells, Coteau 1, Coteau 2, Coteau 3, Coteau 4, Coteau 5, and Coteau 6, were simulated as perforated across the entire Broom Creek Formation interval (Figure 2-2). The CO_2 injection well constraints and wellbore model inputs for the simulation model are shown in

Correction 6
Section 2.0

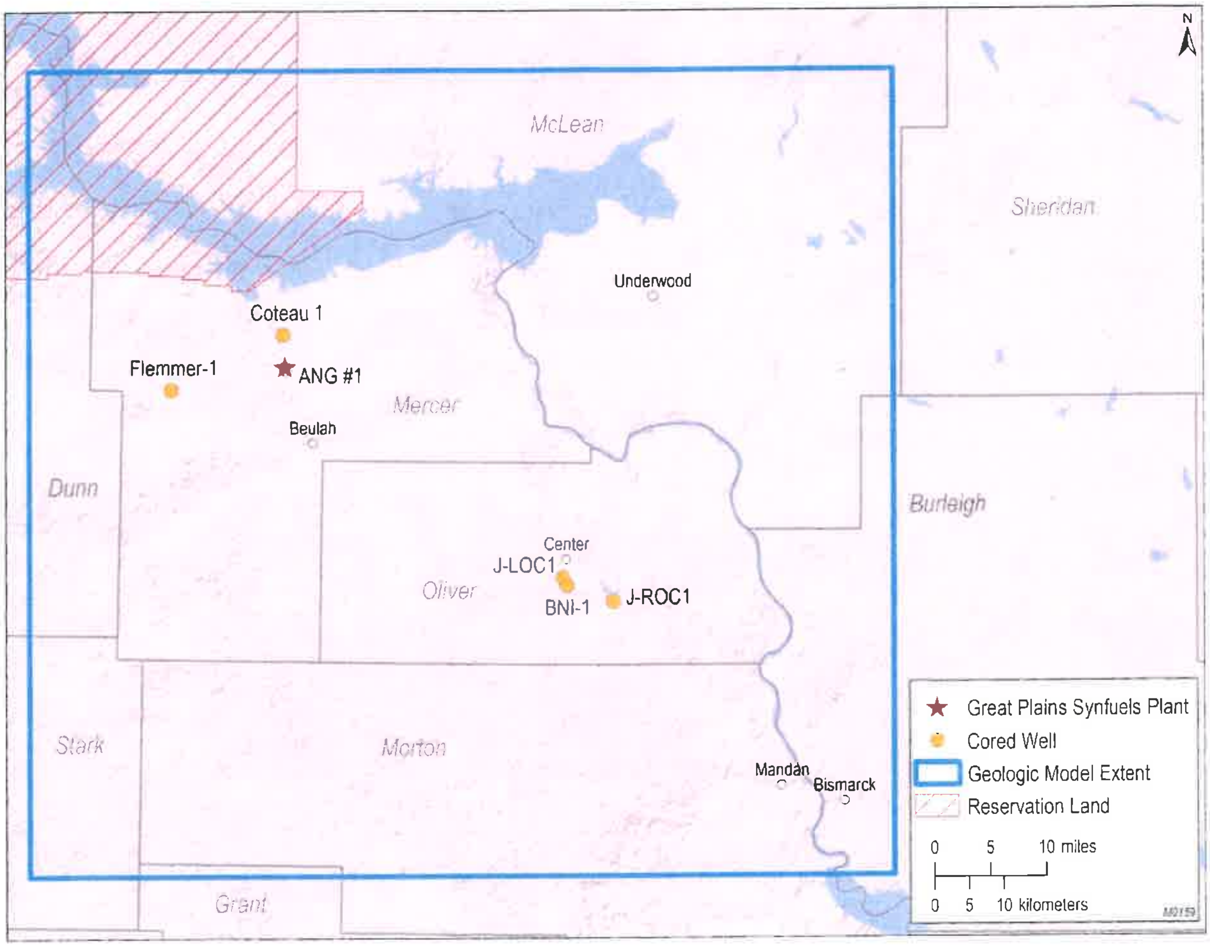


Figure 2-5. Map showing the spatial relationship between the Great Plains CO_2 Sequestration Project area and wells where the Broom Creek Formation core samples were collected. Wells with core data include the Coteau 1 (NDIC File No. 38379), Flemmer 1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), ANG #1 (NDEQ No. 11308), J-LOC1 (NDIC File No. 37380), and J-ROC1 (NDIC File No. 37672).

Ten square miles of legacy 3D seismic data from Mercer County, encompassing the Flemmer 1 wellsite, and twenty-eight miles of legacy 2D seismic data were licensed and examined to understand the heterogeneity and geologic structure of the Broom Creek Formation interval. Additionally, publicly available seismic interpretation products for the Broom Creek from a 3D seismic survey in Oliver County were used to inform structure and variogram distributions (Section 3.2). The structural configurations of the formations of interest generated from the interpretation of the two 3D seismic data sets along with formation tops interpreted from well log data were used to construct the geologic model. Variogram distributions derived from inversion volumes generated using the 3D seismic data were used to inform property distribution in the geologic model which was, in turn, used to simulate migration of the CO_2 plume (Section 3). These simulated CO_2 plumes were used to inform the testing and monitoring plan (Section 5).

12.3.3 Implementation of PISC and Facility Closure Activities

The breakdown of estimated costs totaling $3 million for implementing the PISC as described in the PISC and facility closure plan is provided in Table 12-2, which includes the following: a) near-surface monitoring (i.e., soil gas and Fox Hills Formation testing), b) coordinated repeat 2D seismic, and c) estimated cost of site closure activities, which has been estimated at $100K based on the integrated environmental control.

Table 12-2. Cost Estimates for 10-year PISC Monitoring Efforts

Monitoring Type	Comments	Total Estimated Cost
Near-Surface Monitoring		
Soil Gas Sampling and Analysis	10 years at $25,000 per year	$250,000
Fox Hills Sampling and Analysis	10 years at $25,000 per year plus $300,000 for site closure activities	$550,000
Geophysical Monitoring		
2D Seismic Data Acquisition	Perform four 2D seismic surveys (PISC years 1, 3, 5, and 10) at $550,000 per survey	$2,200,000
	Total	**$3,000,000**

12.3.4 Implementation of Emergency and Remedial Response Actions

12.3.4.1 Emergency Response Actions

A review of the technical risk categories for DGC's Great Plains CO_2 Sequestration Project identified a list of events that could potentially result in the movement of injected CO_2 or formation fluids in a manner that may endanger a USDW and require an emergency response. These events are as follows:

- Failure of the surface equipment
- Integrity failure of injection well
- Injection well-monitoring equipment failure
- Storage reservoir is unable to contain the formation fluid or stored CO_2
- Natural disasters

If it is determined that one or more of these events have occurred, the emergency response actions that will be implemented are described in the ERRP (Section 7). These response actions are summarized in Table 12-3.

Correction 8
Section 3

A PHIE property (effective porosity; total porosity less occupied or isolated pore space) was distributed using calculated PHIE well logs upscaled to the resolution of the 3D model as control points and variogram structures described previously with Gaussian random function simulation and conditioned to the distributed lithofacies. A permeability property was distributed using the same variables and algorithm, but cokriged to the PHIE volume (Figures 3-4 and 3-5).

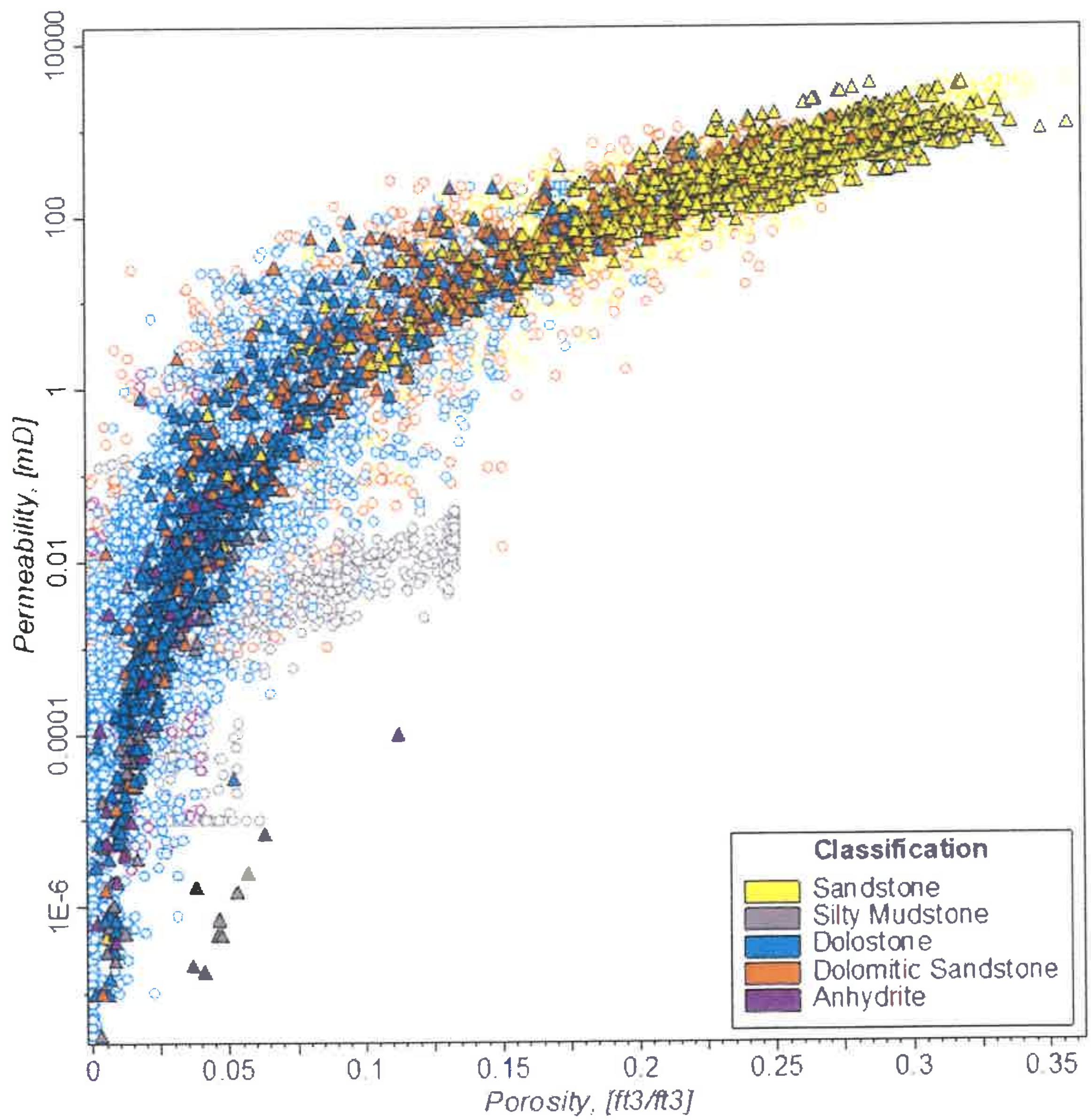


Figure 3-4. Illustration of the relationship between the modeled porosity and permeability. Upscaled well log values are represented by triangles, while circles represent distributed values. Values are colored according to lithofacies classification, as seen in Figure 3-3.

Correction 9
Section 3

3.4.2 Stabilized Plume

Movement of the injected CO_2 plume is driven by the potential energy found in the buoyant force of the injected CO_2. As the plume spreads out within the reservoir and CO_2 is trapped residually through the effects of relative permeability and dissolution, the potential energy of the buoyant CO_2 is gradually lost. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized. The extent of the stabilized plume is important for determining the project's AOR and the corresponding scale and scope of the project's monitoring plans.

Plume stabilization can be visualized at the microscale as CO_2 being unable to exit its current pore space and enter the neighboring pore space, but at the macroscale, these interactions cannot be measured. Instead, plume stabilization may be estimated using the tools available to predict the CO_2 plume's extent.

The CO_2 plume was simulated in 5-year time steps until the rate of total areal extent change slowed to less than 0.25 square miles per 5-year time step to define the stabilized plume extent boundary and the associated buffers and boundaries (Figure 3-20). This estimate is anticipated to be regularly updated during the CO_2 storage operation as data collected from the site are used to update predictions made about the behavior of the injected CO_2.

3.5 Delineation of the Area of Review

The North Dakota Administrative Code (NDAC) defines the AOR as the region surrounding the geologic storage project where USDWs may be endangered by CO_2 injection activity (NDAC § 43-05-01-05). The primary endangerment risk is the potential for vertical migration of CO_2 and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the CO_2 plume within the storage reservoir.

However, the CO_2 plume has an associated pressure front where CO_2 injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the CO_2 plume. Therefore, the AOR encompasses both the areal extent of the CO_2 plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the CO_2 plume, AOR delineation focuses on the pressure front.

The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. U.S. Environmental Protection Agency (EPA) guidance for AOR delineation under the Underground Injection Control (UIC) Program for Class VI wells provides several methods for estimating the critical threshold pressure increase and resulting critical threshold pressure.

In this document, "storage reservoir" refers to the Broom Creek Formation (the injection zone), and the "lowest USDW" refers to the Fox Hills Formation.

Correction 10
Section 2

2.4.1.2 Geochemical Interaction

Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected CO_2 stream on the Opeche Formation, the primary confining zone. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to CO_2 and minor amounts of H_2S at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Opeche by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the Opeche Formation. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock –CO_2/H_2S exposure boundary. The mineralogical composition of the Opeche Formation was honored (Table 2-13). The XRD data used to define mineral composition in the model correspond to a mudstone sample from the Opeche Formation. Formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone below (Table 2-14). The CO_2 stream composition was as described in Table 2-15. 96.45 mol% of the stream is CO_2, and the rest represents other components, including H_2S, the second major component of the stream. 96 mol% of CO_2 was used in the simulation instead of 96.45 mol% to keep the model input simple (Table 2.15). The 4 mol% H_2S used for this simulation represents the sum of all other components (CH_4, C_2H_6, C_3H_8, N_2) and thus overstates the actual H_2S fraction of 1.23 mol% (Table 2-15). The exposure level, expressed in moles per year, of the CO_2 stream to the cap rock used was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/year (Espinoza and Santamarina, 2017). This overestimate was done to ensure that the degree and pace of geochemical change would not be underestimated. This geochemical simulation was run for 37 years to match the reservoir injection zone geochemical model and represent 12 years of injection plus 25 years of postinjection. The simulation was performed at reservoir pressure and temperature conditions.

Table 2-13. Mineral Composition of the Opeche Derived from XRD Analysis of Coteau 1 Core Samples

Minerals, wt%	
Illite	32.3
K-Feldspar	12.7
Albite	7.6
Quartz	24.0
Dolomite	13.1
Anhydrite	5.1

Table 2-14. Formation Water Chemistry from Broom Creek Fluid Samples from Coteau 1

pH	7.04	TDS	42,800 mg/L
Total Alkalinity	853 mg/L $CaCO_3$	Calcium	1,860 mg/L
Bicarbonate	853 mg/L $CaCO_3$	Magnesium	212 mg/L
Carbonate	<20 mg/L $CaCO_3$	Sodium	12,800 mg/L
Hydroxide	<20 mg/L $CaCO_3$	Potassium	516 mg/L
Sulfate	469 mg/L	Strontium	70.8 mg/L
Chloride	24,900 mg/L	Iron	392 mg/L

Correction 11
Section 2.4.3.2

2.4.3.2 Geochemical Interaction

The Broom Creek's underlying confining layer, the Amsden Formation, was investigated using PHREEQC geochemical software. A vertically oriented 1D simulation was created using a stack of six cells, each cell 1 meter in thickness. The formation was exposed to CO_2 and a minor amount of H_2S at the top boundary of the simulation which were allowed to enter the system by advection and dispersion processes. Direct contact between the Amsden and free-phase saturation from the injection stream is not expected to occur. Results were calculated at the center of each cell below the confining layer–CO_2/H_2S exposure boundary. The mineralogical composition of the Amsden was honored (Table 2-18). The Amsden formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone above. The CO_2 stream composition used is described in Section 2.4.1.2. The Amsden Formation pressure was determined from the 1D MEM and the temperature was calculated using the temperature gradient. Two different pressure levels, 2,755 and 3,447 psi, were applied to the CO_2/H_2S saturated brine at the base of the Broom Creek Formation. These values represent the initial and potential maximum pore pressure levels. The higher-pressure results are shown here to represent a potentially more rapid pace of geochemical change.

Table 2-18. Mineral Composition of the Amsden Derived from XRD Analysis of Coteau 1 Core Samples at a Depth of 6,183 ft MD

	Sample Depth
	6,183 ft
Mineral	**wt%**
Illite/Muscovite	13.8
Fe Minerals	3.5
K-Feldspar	18.3
Albite	9.3
Quartz	40.1
Dolomite	14.3

Results show geochemical processes at work. Figures 2-51 through 2-56 show results from the geochemical modeling.

Figure 2-51 shows change in fluid pH over 37 years of simulation time as CO_2/H_2S enters the system. Initial change in pH in all of the cells from 7.04 to 7 is related to initial equilibration of the model. For the cell at the CO_2/H_2S interface, C1, the pH begins to decline after Year 7, declines to a level of 6.3 after 12 years of injection, and slowly declines further to 5.5 after an additional 25 years of post-injection. Progressively less or slower pH change occurs for each cell that is more distant from the CO_2/H_2S interface. The pH for Cells 5–6 did not decline over the 37 years of simulation time.

Figure 2-52 shows that CO_2 does not penetrate more than 4 meters (represented by Cells C5–C6) within the 37 years simulated.

Dakota Gasification Company

Case No. 29450

Application of Dakota Gasification Company requesting consideration for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Dakota Gasification Company intends to capture carbon dioxide from the Great Plains Synfuels Plant and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT July 19, 2022. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Steve Fried, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Dakota Gasification Company, 1717 East Interstate Avenue, Bismarck, ND 58503.

Case No. 29451

Application of Dakota Gasification Company to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Dakota Gasification Company storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code Section 38-22-10.

Case No. 29452

Application of Dakota Gasification Company for an order of the Commission determining the amount of financial responsibility for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant in the storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.

July 20, 2022

SUPPLEMENTAL EXHIBITS

Supplement Request	Section	Details	Comments
1	2.0	Page 2-36: Anhydrite precipitation; explained that calcium and sulfate ions present in water; but those are present in prior cases too… any other explanation for precipitation of anhydrite?	Explanation added.
2	2.0	Provide figure to show molar mass change of anhydrite like you did with other minerals at 2-37 to 2-40.	Figure provided.
3	2.0	Page 2-81: 1500ft cutoff for density data, but it does appear that density logs were run on the surface for Coteau 1 … • describe why the 1500ft cutoff was chosen? And what it is from? • Also address where did 1180 psi number comes from	Explanation included.
4	2.0	Table 2-8 on page 2-23: provide supplement showing your inputs into the equation for the tabled outcomes and source of those inputs (Coteau or Flemmer)?	Explanation and data included.
5		Address why: • Both rel perm and cap entry pressures are different for anhydrite and siltstone. • Cap pressures different (but rel perm the same) for dolomitic sandstone and dolostone. • Both curves were the same for the sandstone.	Explanation included.
6	4.0	Section 4-4: large number of observational monitoring wells, but only have lab analyses provided for some of these; a summary of critical elements would be good, or an explanation for why the sample set was chosen for what was submitted. For the ones that were chosen for the baseline: • Provide a lab analysis report	Provided an explanation of data used.
7	6.0	Page 6-1: pre/post injection pressure differential, discussion that when CO2 injections stop, insufficient pressure to move fluids to deepest USDWs, isn't that pressure existing already in the Broom Creek, even prior to injection ops?	Question addressed in supplement.
8	9.0	Section 9: Validate the surface locations of Coteau 2-4… SFP application numbers differed from the APDs.	Updated Coteau 2–4 coordinates in the table and figures with as-constructed information. Schematics updated in Section 11 also.

Supplement 1

Figure 2-26 shows the mass of mineral dissolution and precipitation due to geochemical reaction in the Broom Creek Formation. Anorthite is the most prominent dissolution mineral. Illite starts to dissolve and then precipitate after Year 2034, the year in which injection ends. Dolomite, albite, and pyrite are the primary precipitation minerals. Pyrite (FeS_2) precipitation is favored by the presence of dissolved H_2S in the gas stream injected and aqueous iron in the Broom Creek Formation water. There is a small amount of precipitation for quartz and anhydrite during the simulation period possibly due to the additional SiO_2 released by anorthite dissolution and the presence of Ca^{2+} and SO_4^{2-} ions in the water formation, respectively. Precipitation of anhydrite in the geochemical model is likely associated with the H_2S in the CO_2 stream interacting with the formation brine and forming SO_4^{2-} and the brine being saturated by Ca^{2+} produced from the dissolution of anorthite.

Figures 2-27 through 2-30 provide an indication of the change in distribution of the mineral that experienced the most dissolution, anorthite, and the minerals that have experienced significant precipitation: dolomite, albite, and pyrite.

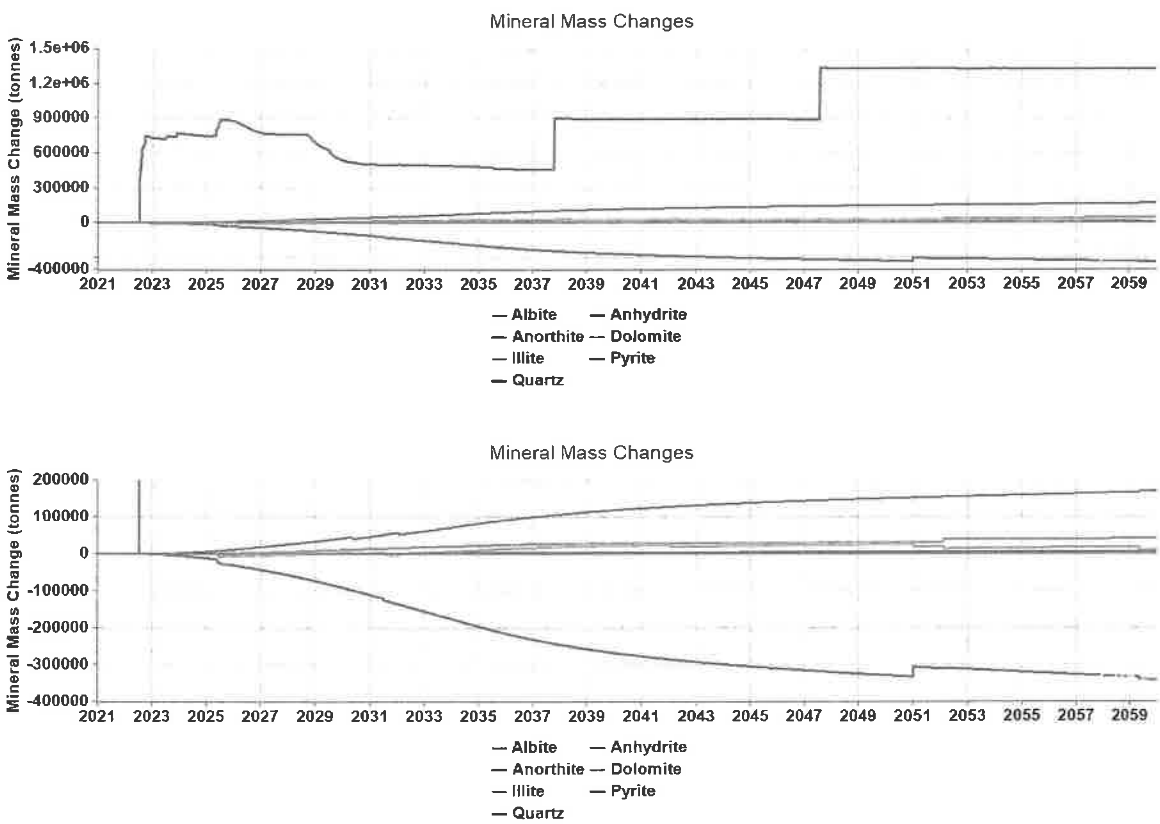
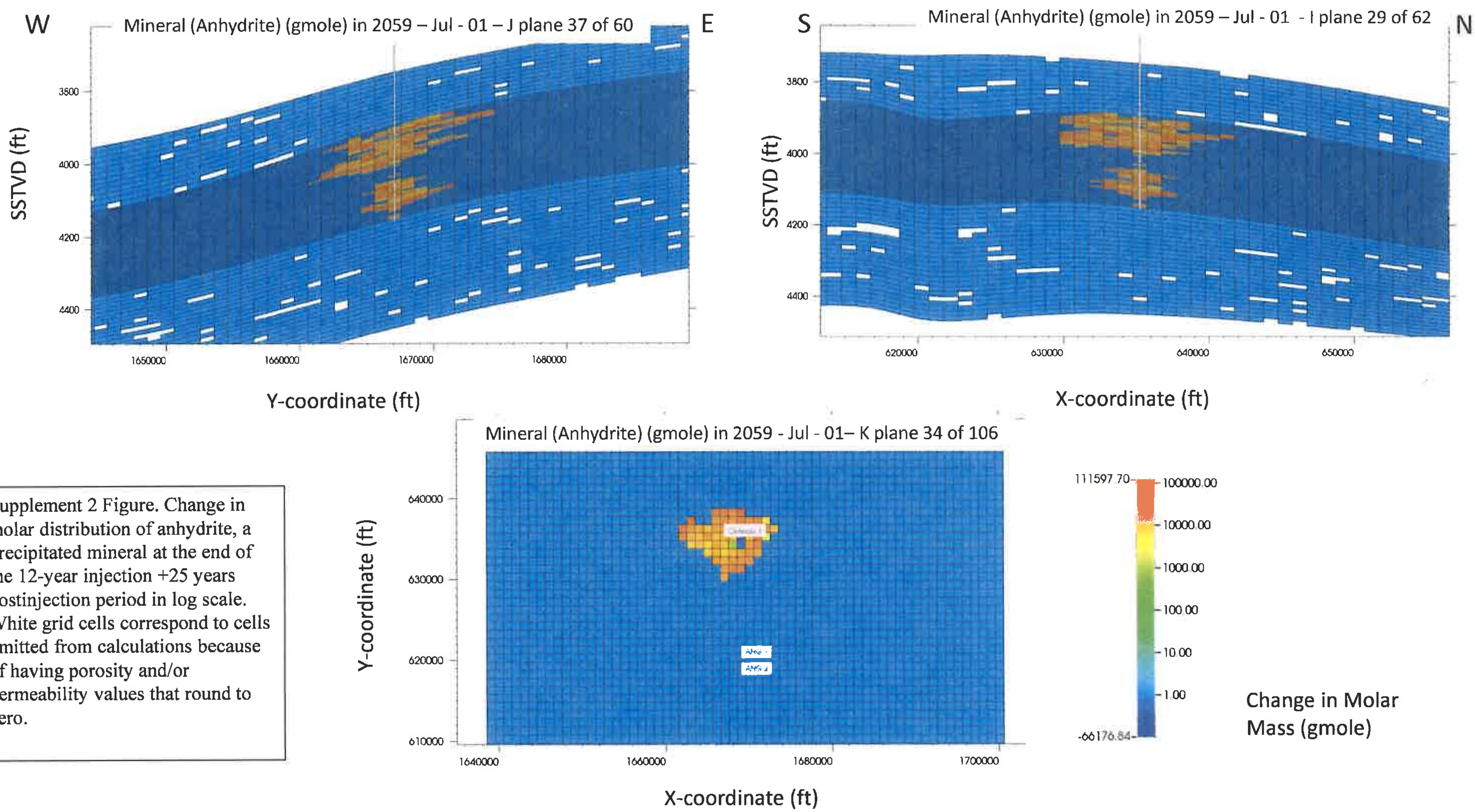


Figure 2-25. Dissolution and precipitation quantities of reservoir minerals because of CO_2 injection. Dissolution of anorthite with precipitation of pyrite, albite, and dolomite was observed. Upper figure shows all the minerals; the lower figure is rescaled for better view of the minerals mass change except pyrite.

Supplement 2



Supplement 2 Figure. Change in molar distribution of anhydrite, a precipitated mineral at the end of the 12-year injection +25 years postinjection period in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

Supplement 3

1) Reason why available RHOB data wasn't utilized above 1,500' in the Coteau-1 Well 1D MEM for calculation of Sv/vertical stress (page 2-81 of SFP)?

Overburden stress or vertical stress (Sv) was estimated using the RHOB log. The RHOB log is available from the top to the bottom throughout the wellbore.

$$S_v = \int_0^z \rho(z) g dz \approx \overline{\rho} g z$$

Core laboratory did generate the vertical stress curve (CLB_Sv) based on RHOB and assumed 1 psi/ft above the 1,500 ft. This was due to significant washouts observed in the wellbore combined with the large diameter of the surface casing. Each of these factors impacted the determination of density; therefore, a known gradient was used.

2) Source of triaxial tests confining pressure of 1,180 psi (page 2-81 of SFP)?

Core laboratories acquired the laboratory's ultrasonic acoustic velocities for Opeche, Broom Creek, and Amsden samples under conditions that they estimate to be in situ stress conditions in the field. The axial stress in the laboratory is analogous to vertical effective stress in the field, and the confining pressure in the laboratory is analogous to horizontal stress in the field. The vertical stress is determined simply from the mass of the overlying material. If ρd represents the density of the rocks, the vertical stress is expressed as σv = ρd gz.

The effective stress equals the vertical stress minus pore pressure multiplied to Biot's coefficient σ' = σv - αPp. For the performed laboratory tests, Poisson's ratio is assumed to be 0.26, pore pressure gradient 0.49 psi/ft, vertical stress gradient 1.0 psi/ft, and Biot's constant 0.9 at average sample depth ~6,010 ft.

The vertical stress and pore pressure equal to average depth (6,010 ft) multiplied to the vertical stress gradient (1.0 psi/ft) and pore pressure gradient (0.49 psi/ft), respectively. The lateral earth pressure coefficient K'o is expressed K'o = v/1-v, which indicates that K'o varies from 0 to 1.0 as the Poisson's ratio varies from 0 to 0.5.

The applied confining pressure which equals to the effective stress multiplied to the lateral earth pressure coefficient (0.35) is 1,180 psi. The latter value is used in the triaxial test and applied to all samples. Values captured are presented in the table below (Table 1).

Table 1. The Triaxial Test Parameters Used to Estimate the Vertical Stress, Pore Pressure, Effective Vertical Stress, and the Confining Pressure in the Opeche, Broom Creek, and Amsden Formations

Vertical stress gradient (psi/ft)	1
Pore pressure gradient (psi/ft)	0.49
Poisson's ratio	0.26
Lateral earth pressure coefficient K0	0.35
Biot's coefficient	0.9

Samples Info					**Reservoir conditions**			**Triaxial test conditions**
Sample ID	Formation	Lithology / rock type	Depth (ft)	Average Depth (ft)	Vertical stress (psi)	Pore pressure (psi)	Effective vertical stress (psi)	Applied confining pressure (psi)
1V	Opeche	Silty-shale	5872.8	6010	6010	2945	3360	1180
2V	Opeche	Silty-shale with anhydrite	5884.75	6010	6010	2945	3360	1180
3V	Opeche	Shale with anhydrite	5901.6	6010	6010	2945	3360	1180
4V	Broom Creek	Anhydrite	5908.3	6010	6010	2945	3360	1180
5V	Broom Creek	Anhydritic-dolostone	5920.4	6010	6010	2945	3360	1180
6V	Broom Creek	Sandy-dolostone	5924.8	6010	6010	2945	3360	1180
7V	Broom Creek	Dolo-sandstone	5928.7	6010	6010	2945	3360	1180
8V	Broom Creek	Sandstone	5941.1	6010	6010	2945	3360	1180
9V	Broom Creek	Sandstone	5951.75	6010	6010	2945	3360	1180
10V	Broom Creek	Sandstone	5989.6	6010	6010	2945	3360	1180
11V	Broom Creek	Anhydritic-sandstone	6146.3	6010	6010	2945	3360	1180
12V	Broom Creek	Sandy-dolomite	6160.1	6010	6010	2945	3360	1180
13V	Amsden	Dolostone	6169.6	6010	6010	2945	3360	1180
14V	Amsden	Dolostone	6183.2	6010	6010	2945	3360	1180
15V	Amsden	Anhydritic-sandstone	6190	6010	6010	2945	3360	1180

Supplement 4

1. Compile a list of input data values that were used to calculate the pressures in Table 2-8 (Page 2-23 of SFP application):

Coteau-1 well calculations used the 1D MEM approach; assumptions and methods summarized here:

1) Leak-off or formation breakdown tests from a minifrac were not performed because of poor hole conditions in the Broom Creek Formation.

2) Formation pore pressure calculated based on sonic log and calibrated with MDT and published regional DFIT data. Normal compaction curve based on regional shale data; formation pressure gradient derived from difference in normal compaction curve and calibrated sonic log. Formation pore pressure summarized to averages in each zone of the storage complex.

3) A continuous dynamic Poisson's Ratio and Young's Modulus curve was generated from the wireline logs DTS/DTC and then calibrated to laboratory-based triaxial test data to transform the rock properties to static conditions. This approach is a best practice and better represents the constitutive properties of the rocks in the subsurface.

4) Closure pressure, propagation pressure, and breakdown pressure parameters were estimated using the available well log data in combination with other assumptions as outlined above. Fracture gradient is obtained by dividing the true vertical depth and calculated fracture pressure.

5) The fracture closure pressure and minimum horizontal stress (Shmin) are assumed to be equal (Table 1). Typically, Shmin, which was estimated from a modified Eaton calculation (MEC) method, is viewed as a lower bound for fracture closure pressure with the knowledge that fracture closure pressure will be slightly higher because of rock strength and other factors. MEC_Pressure = $(v/(1-v))*(Sv-a_V*Pp) + a_H*Pp$ where v: Poisson's ratio; Sv: vertical stress; a_V: vertical Biot's constant; a_V: horizontal Biot's constant; Pp: pore pressure (Table 4).

6) The fracture propagation is assumed to be the same as the fracture pressure and the estimated fracture pressure is closure pressure plus process zone stress. Process zone stress is a function of porosity with a couple of factors. In this case, a set of default values are applied which will have less confidence (Table 2).

7) Breakdown pressure is more complicated as it is related to wellbore stability. Breakdown is computed by setting the minimum tangential stress around the circumference of the well to zero. Breakdown pressure is estimated using the Kirsch (1898), Aadnoy and others (2008), and Grandi and others (2002) equations (Table 3).

Table 1. Closure Pressure and Closure Pressure Gradient in the Upper and Lower Sand Bodies of the Broom Creek Formation

	Upper Sand Body		Lower Sand Body	
	Closure pressure (psi)	Closure pressure gradient (psi/ft)	Closure pressure (psi)	Closure pressure gradient (psi/ft)
Min	3526.13	0.63	3393.37	0.59
Max	4502.34	0.79	4475.38	0.77
Average	4014.23	0.71	3934.37	0.68

Table 2. Propagation Pressure and Propagation Pressure Gradient in the Upper and Lower Sand Bodies of the Broom Creek Formation

	Upper Sand Body		Lower Sand Body	
	Propagation pressure (psi)	Propagation presure gradient (psi/ft)	Propagation pressure (psi)	Propagation presure gradient (psi/ft)
Min	3695.61	0.62	3687.07	0.60
Max	4622.12	0.78	4851.91	0.80
Average	4263.48	0.71	4287.66	0.70

Table 3. Breakdown Pressure and Breakdown Pressure Gradient in the Upper and Lower Sand Bodies of the Broom Creek Formation

	Upper Sand Body		Lower Sand Body	
	Breakdown presure (psi)	Breakdown presure gradient (psi/ft)	Breakdown presure (psi)	Breakdown presure gradient (psi/ft)
Min	3664.46	0.62	4209.30	0.69
Max	6406.59	1.07	6185.97	1.01
Average	5865.99	0.98	5193.35	0.85

References

Aadnoy, B.S., Belayneh, M., Arriado, M., and Roar, F., 2008, Design of well barriers to combat circulation losses: SPE Drill & Compl, v. 23, p. 295–300. doi: https://doi.org/10.2118/105449-PA.

Grandi, S., Rao, R.V.N., and Toksoz, M.N., 2002, Geomechanical modeling of in-situ stresses around a borehole: Massachusetts Institute of Technology, Earth Resources Laboratory.

Kirsch, G., 1898, Die Theorie der Elastizitat and die Bediirfnisse der Festigkeitslehre: Z. Vereines Deutscher Ing., v. 42, p. 797–807.

Table 4. Modified Eaton Equation (MEC) Fracture Gradient Calculation Data Input in Broom Creek Formation (Column 1: well tops, Column 2: depth (ft), Column 3: Poisson's ratio, Column 4: vertical stress (Sv), Column 5: Biot's coefficient, Column 6: pore pressure (psi), Column 7: modified Eaton calculation pressure, Column 8: modified Eaton calculation pressure gradient)

Tops	Depth, ft	PR Corrected, unitless	Sv, psi	Gohfer Biot's, unitless	PP, psi	MEC Pressure, psi	MEC Pressure Grad., psi/ft
Top_Upr_Sand	5906.0	0.329	6076.4	0.73	2640.0	3960.9	0.70
Upr Sand Body	5906.5	0.319	6077.0	0.67	2640.2	3787.8	0.67
Upr Sand Body	5907.0	0.315	6077.6	0.64	2640.4	3708.6	0.66
Upr Sand Body	5907.5	0.290	6078.2	0.63	2640.7	3472.3	0.62
Upr Sand Body	5908.0	0.272	6078.8	0.68	2640.9	3397.4	0.61
Upr Sand Body	5908.5	0.302	6079.3	0.70	2641.1	3688.3	0.66
Upr Sand Body	5909.0	0.312	6079.9	0.72	2641.3	3790.9	0.67
Upr Sand Body	5909.5	0.291	6080.5	0.71	2641.5	3605.0	0.64
Upr Sand Body	5910.0	0.297	6081.0	0.71	2641.8	3655.1	0.65
Upr Sand Body	5910.5	0.315	6081.6	0.70	2642.0	3804.5	0.68
Upr Sand Body	5911.0	0.327	6082.2	0.69	2642.2	3893.4	0.69
Upr Sand Body	5911.5	0.337	6082.8	0.68	2642.4	3981.4	0.70
Upr Sand Body	5912.0	0.328	6083.5	0.67	2642.7	3870.5	0.68
Upr Sand Body	5912.5	0.307	6084.1	0.66	2642.9	3667.3	0.65
Upr Sand Body	5913.0	0.303	6084.7	0.66	2643.1	3641.6	0.65
Upr Sand Body	5913.5	0.307	6085.3	0.68	2643.3	3691.5	0.65
Upr Sand Body	5914.0	0.327	6085.9	0.68	2643.6	3886.5	0.69
Upr Sand Body	5914.5	0.325	6086.5	0.69	2643.8	3875.6	0.69
Upr Sand Body	5915.0	0.307	6087.1	0.68	2644.0	3701.5	0.66
Upr Sand Body	5915.5	0.276	6087.7	0.69	2644.2	3452.1	0.61
Upr Sand Body	5916.0	0.286	6088.3	0.70	2644.5	3554.1	0.63
Upr Sand Body	5916.5	0.318	6088.8	0.71	2644.7	3842.7	0.68
Upr Sand Body	5917.0	0.327	6089.4	0.71	2644.9	3924.0	0.70
Upr Sand Body	5917.5	0.335	6090.0	0.70	2645.1	3997.9	0.71
Upr Sand Body	5918.0	0.302	6090.6	0.71	2645.3	3699.9	0.66
Upr Sand Body	5918.5	0.293	6091.2	0.72	2645.6	3636.7	0.65
Upr Sand Body	5919.0	0.327	6091.8	0.73	2645.8	3952.1	0.70
Upr Sand Body	5919.5	0.313	6092.3	0.73	2646.0	3832.0	0.68

Upr Sand Body	**5920.0**	**0.296**	**6092.9**	**0.73**	**2646.2**	**3678.0**	**0.65**
Upr Sand Body	5920.5	0.297	6093.5	0.73	2646.5	3692.6	0.66
Upr Sand Body	**5921.0**	**0.302**	**6094.0**	**0.74**	**2646.7**	**3754.2**	**0.67**
Upr Sand Body	5921.5	0.310	6094.6	0.75	2646.9	3832.1	0.68
Upr Sand Body	**5922.0**		**6095.2**	**0.77**	**2647.1**		
Upr Sand Body	5922.5	0.300	6095.7	0.79	2647.4	3805.2	0.68
Upr Sand Body	**5923.0**	**0.307**	**6096.2**	**0.80**	**2647.6**	**3890.3**	**0.69**
Upr Sand Body	5923.5	0.300	6096.8	0.80	2647.8	3830.0	0.68
Upr Sand Body	**5924.0**	**0.311**	**6097.3**	**0.78**	**2648.0**	**3894.9**	**0.69**
Upr Sand Body	5924.5	0.317	6097.9	0.76	2648.3	3910.8	0.69
Upr Sand Body	**5925.0**	**0.319**	**6098.5**	**0.73**	**2648.5**	**3890.5**	**0.69**
Upr Sand Body	5925.5	0.313	6099.1	0.71	2648.7	3805.1	0.67
Upr Sand Body	**5926.0**	**0.317**	**6099.7**	**0.69**	**2648.9**	**3819.1**	**0.68**
Upr Sand Body	5926.5	0.330	6100.2	0.68	2649.1	3924.5	0.69
Upr Sand Body	**5927.0**	**0.329**	**6100.8**	**0.69**	**2649.4**	**3922.8**	**0.69**
Upr Sand Body	5927.5	0.318	6101.4	0.70	2649.6	3830.1	0.68
Upr Sand Body	**5928.0**	**0.292**	**6102.0**	**0.71**	**2649.8**	**3615.9**	**0.64**
Upr Sand Body	5928.5	0.284	6102.6	0.71	2650.0	3566.2	0.63
Upr Sand Body	**5929.0**	**0.288**	**6103.1**	**0.72**	**2650.3**	**3602.4**	**0.64**
Upr Sand Body	5929.5	0.278	6103.7	0.72	2650.5	3526.1	0.63
Upr Sand Body	**5930.0**	**0.279**	**6104.3**	**0.74**	**2897.4**	**3674.7**	**0.66**
Upr Sand Body	5930.5	0.293	6104.8	0.77	2897.7	3828.9	0.68
Upr Sand Body	**5931.0**	**0.318**	**6105.3**	**0.80**	**2897.9**	**4080.7**	**0.73**
Upr Sand Body	5931.5	0.330	6105.8	0.81	2898.2	4205.3	0.75
Upr Sand Body	**5932.0**	**0.339**	**6106.2**	**0.82**	**2898.4**	**4295.4**	**0.76**
Upr Sand Body	5932.5	0.337	6106.7	0.83	2898.6	4280.4	0.76
Upr Sand Body	**5933.0**	**0.340**	**6107.2**	**0.83**	**2898.9**	**4307.2**	**0.77**
Upr Sand Body	5933.5	0.341	6107.6	0.83	2899.1	4317.9	0.77
Upr Sand Body	**5934.0**	**0.341**	**6108.1**	**0.82**	**2899.4**	**4313.6**	**0.77**
Upr Sand Body	5934.5	0.340	6108.6	0.82	2899.6	4303.2	0.77
Upr Sand Body	**5935.0**	**0.337**	**6109.0**	**0.83**	**2899.9**	**4288.4**	**0.76**
Upr Sand Body	5935.5	0.337	6109.5	0.83	2900.1	4288.7	0.76

Upr Sand Body	**5936.0**	**0.336**	**6110.0**	**0.83**	**2900.4**	**4282.3**	**0.76**
Upr Sand Body	5936.5	0.334	6110.4	0.83	2900.6	4259.9	0.76
Upr Sand Body	**5937.0**	**0.338**	**6110.9**	**0.82**	**2900.8**	**4282.2**	**0.76**
Upr Sand Body	5937.5	0.295	6111.5	0.79	2901.1	3899.3	0.70
Upr Sand Body	**5938.0**	**0.317**	**6112.0**	**0.76**	**2901.3**	**4019.3**	**0.71**
Upr Sand Body	5938.5	0.277	6112.6	0.74	2901.6	3668.0	0.65
Upr Sand Body	**5939.0**	**0.309**	**6113.1**	**0.77**	**2901.8**	**3958.8**	**0.70**
Upr Sand Body	5939.5	0.318	6113.6	0.80	2902.1	4091.7	0.73
Upr Sand Body	**5940.0**	**0.337**	**6114.1**	**0.82**	**2902.3**	**4277.6**	**0.76**
Upr Sand Body	5940.5	0.342	6114.6	0.82	2902.6	4321.4	0.77
Upr Sand Body	**5941.0**	**0.341**	**6115.0**	**0.82**	**2902.8**	**4312.3**	**0.77**
Upr Sand Body	5941.5	0.342	6115.5	0.82	2903.0	4324.0	0.77
Upr Sand Body	**5942.0**	**0.343**	**6116.0**	**0.82**	**2903.3**	**4333.3**	**0.77**
Upr Sand Body	5942.5	0.346	6116.5	0.82	2903.5	4355.4	0.77
Upr Sand Body	**5943.0**	**0.350**	**6117.0**	**0.81**	**2903.8**	**4383.2**	**0.78**
Upr Sand Body	5943.5	0.348	6117.4	0.81	2904.0	4361.5	0.77
Upr Sand Body	**5944.0**	**0.346**	**6117.9**	**0.81**	**2904.3**	**4349.5**	**0.77**
Upr Sand Body	5944.5	0.343	6118.4	0.81	2904.5	4326.2	0.77
Upr Sand Body	**5945.0**	**0.339**	**6118.9**	**0.81**	**2904.8**	**4281.0**	**0.76**
Upr Sand Body	5945.5	0.340	6119.4	0.81	2905.0	4295.9	0.76
Upr Sand Body	**5946.0**	**0.342**	**6119.9**	**0.81**	**2905.2**	**4314.7**	**0.77**
Upr Sand Body	5946.5	0.347	6120.3	0.82	2905.5	4363.0	0.77
Upr Sand Body	**5947.0**	**0.348**	**6120.8**	**0.82**	**2905.7**	**4377.8**	**0.78**
Upr Sand Body	5947.5	0.343	6121.3	0.82	2906.0	4332.7	0.77
Upr Sand Body	**5948.0**	**0.338**	**6121.8**	**0.82**	**2906.2**	**4292.7**	**0.76**
Upr Sand Body	5948.5	0.336	6122.2	0.82	2906.5	4273.3	0.76
Upr Sand Body	**5949.0**	**0.338**	**6122.7**	**0.82**	**2906.7**	**4285.8**	**0.76**
Upr Sand Body	5949.5	0.338	6123.2	0.82	2906.9	4288.6	0.76
Upr Sand Body	**5950.0**	**0.333**	**6123.7**	**0.82**	**2907.2**	**4246.0**	**0.75**
Upr Sand Body	5950.5	0.325	6124.2	0.81	2907.4	4172.6	0.74
Upr Sand Body	**5951.0**	**0.298**	**6124.7**	**0.80**	**2907.7**	**3934.6**	**0.70**
Upr Sand Body	5951.5	0.301	6125.2	0.79	2907.9	3945.3	0.70

Upr Sand Body	5952.0	0.315	6125.7	0.79	2908.2	4056.8	0.72
Upr Sand Body	5952.5	0.331	6126.1	0.81	2908.4	4219.9	0.75
Upr Sand Body	5953.0	0.346	6126.6	0.82	2908.7	4364.1	0.77
Upr Sand Body	5953.5	0.345	6127.1	0.82	2908.9	4366.7	0.77
Upr Sand Body	5954.0	0.340	6127.6	0.82	2909.1	4321.3	0.77
Upr Sand Body	5954.5	0.331	6128.0	0.82	2909.4	4238.9	0.75
Upr Sand Body	5955.0	0.326	6128.5	0.82	2909.6	4194.9	0.74
Upr Sand Body	5955.5	0.323	6129.0	0.81	2909.9	4167.7	0.74
Upr Sand Body	5956.0	0.322	6129.5	0.81	2910.1	4152.8	0.74
Upr Sand Body	5956.5	0.315	6130.0	0.81	2910.4	4095.3	0.73
Upr Sand Body	5957.0	0.310	6130.5	0.81	2910.6	4053.2	0.72
Upr Sand Body	5957.5	0.312	6130.9	0.81	2910.9	4074.6	0.72
Upr Sand Body	5958.0	0.317	6131.4	0.80	2911.1	4105.2	0.73
Upr Sand Body	5958.5	0.295	6132.0	0.79	2911.3	3903.6	0.69
Upr Sand Body	5959.0	0.297	6132.5	0.78	2911.6	3903.0	0.69
Upr Sand Body	5959.5	0.300	6133.0	0.79	2911.8	3943.4	0.70
Upr Sand Body	5960.0	0.322	6133.5	0.80	2912.1	4140.7	0.73
Upr Sand Body	5960.5	0.335	6134.0	0.81	2912.3	4266.2	0.76
Upr Sand Body	5961.0	0.345	6134.4	0.82	2912.6	4359.4	0.77
Upr Sand Body	5961.5	0.349	6134.9	0.82	2912.8	4400.1	0.78
Upr Sand Body	5962.0	0.346	6135.4	0.82	2913.1	4375.6	0.77
Upr Sand Body	5962.5	0.344	6135.9	0.82	2913.3	4362.3	0.77
Upr Sand Body	5963.0	0.343	6136.3	0.82	2913.5	4349.3	0.77
Upr Sand Body	5963.5	0.343	6136.8	0.83	2913.8	4357.1	0.77
Upr Sand Body	5964.0	0.343	6137.3	0.83	2914.0	4364.5	0.77
Upr Sand Body	5964.5	0.342	6137.7	0.83	2914.3	4357.9	0.77
Upr Sand Body	5965.0	0.338	6138.2	0.83	2914.5	4319.9	0.76
Upr Sand Body	5965.5	0.332	6138.7	0.82	2914.8	4255.7	0.75
Upr Sand Body	5966.0	0.329	6139.2	0.82	2915.0	4228.9	0.75
Upr Sand Body	5966.5	0.334	6139.6	0.82	2915.3	4268.1	0.76
Upr Sand Body	5967.0	0.337	6140.1	0.82	2915.5	4297.5	0.76
Upr Sand Body	5967.5	0.334	6140.6	0.82	2915.7	4267.7	0.76

Upr Sand Body	5968.0	0.333	6141.1	0.82	2916.0	4265.8	0.75
Upr Sand Body	5968.5	0.334	6141.5	0.82	2916.2	4275.2	0.76
Upr Sand Body	5969.0	0.339	6142.0	0.82	2916.5	4316.2	0.76
Upr Sand Body	5969.5	0.344	6142.5	0.82	2916.7	4361.7	0.77
Upr Sand Body	5970.0	0.344	6143.0	0.83	2917.0	4368.7	0.77
Upr Sand Body	5970.5	0.344	6143.4	0.83	2917.2	4376.8	0.77
Upr Sand Body	5971.0	0.343	6143.9	0.83	2917.5	4365.8	0.77
Upr Sand Body	5971.5	0.342	6144.4	0.83	2917.7	4359.8	0.77
Upr Sand Body	5972.0	0.345	6144.9	0.82	2917.9	4374.5	0.77
Upr Sand Body	5972.5	0.349	6145.3	0.82	2918.2	4410.3	0.78
Upr Sand Body	5973.0	0.349	6145.8	0.82	2918.4	4407.5	0.78
Upr Sand Body	5973.5	0.349	6146.3	0.82	2918.7	4411.0	0.78
Upr Sand Body	5974.0	0.349	6146.7	0.82	2918.9	4408.5	0.78
Upr Sand Body	5974.5	0.349	6147.2	0.82	2919.2	4407.8	0.78
Upr Sand Body	5975.0	0.354	6147.7	0.83	2919.4	4467.1	0.79
Upr Sand Body	5975.5	0.355	6148.1	0.83	2919.7	4470.1	0.79
Upr Sand Body	5976.0	0.353	6148.6	0.83	2919.9	4457.0	0.79
Upr Sand Body	5976.5	0.354	6149.1	0.83	2920.1	4462.8	0.79
Upr Sand Body	5977.0	0.356	6149.5	0.83	2920.4	4483.9	0.79
Upr Sand Body	5977.5	0.358	6150.0	0.83	2920.6	4502.3	0.79
Upr Sand Body	5978.0	0.356	6150.5	0.83	2920.9	4489.3	0.79
Upr Sand Body	5978.5	0.351	6150.9	0.83	2921.1	4445.7	0.78
Upr Sand Body	5979.0	0.349	6151.4	0.83	2921.4	4422.2	0.78
Upr Sand Body	5979.5	0.345	6151.9	0.82	2921.6	4382.9	0.77
Upr Sand Body	5980.0	0.354	6152.4	0.81	2921.9	4445.4	0.78
Upr Sand Body	5980.5	0.358	6152.9	0.80	2922.1	4469.0	0.79
Upr Sand Body	5981.0	0.352	6153.4	0.80	2922.3	4413.9	0.78
Upr Sand Body	5981.5	0.329	6153.8	0.81	2922.6	4231.3	0.75
Upr Sand Body	5982.0	0.318	6154.3	0.82	2922.8	4156.7	0.74
Upr Sand Body	5982.5	0.335	6154.8	0.82	2923.1	4297.8	0.76
Upr Sand Body	5983.0	0.334	6155.3	0.83	2923.3	4296.7	0.76
Upr Sand Body	5983.5	0.346	6155.7	0.83	2923.6	4402.2	0.78

Upr Sand Body	5984.0	0.350	6156.2	0.83	2923.8	4436.1	0.78
Upr Sand Body	5984.5	0.352	6156.7	0.83	2924.1	4450.0	0.78
Upr Sand Body	5985.0	0.347	6157.1	0.83	2924.3	4405.4	0.78
Upr Sand Body	5985.5	0.340	6157.6	0.83	2924.5	4348.8	0.77
Upr Sand Body	5986.0	0.338	6158.1	0.82	2924.8	4326.1	0.76
Upr Sand Body	5986.5	0.340	6158.5	0.83	2925.0	4346.4	0.77
Upr Sand Body	5987.0	0.335	6159.0	0.82	2925.3	4295.2	0.76
Upr Sand Body	5987.5	0.335	6159.5	0.81	2925.5	4282.7	0.76
Upr Sand Body	5988.0	0.337	6160.0	0.81	2925.8	4297.6	0.76
Upr Sand Body	5988.5	0.342	6160.5	0.81	2926.0	4346.0	0.77
Upr Sand Body	5989.0	0.349	6160.9	0.83	2926.2	4429.1	0.78
Upr Sand Body	5989.5	0.350	6161.4	0.83	2926.5	4445.8	0.78
Upr Sand Body	5990.0	0.347	6161.9	0.83	2926.7	4415.5	0.78
Upr Sand Body	5990.5	0.346	6162.3	0.83	2927.0	4406.1	0.78
Upr Sand Body	5991.0	0.347	6162.8	0.83	2927.2	4415.6	0.78
Upr Sand Body	5991.5	0.347	6163.3	0.84	2927.5	4431.4	0.78
Upr Sand Body	5992.0	0.344	6163.7	0.84	2927.7	4403.8	0.78
Upr Sand Body	5992.5	0.341	6164.2	0.84	2928.0	4372.1	0.77
Upr Sand Body	5993.0	0.338	6164.7	0.83	2928.2	4339.8	0.76
Upr Sand Body	5993.5	0.341	6165.1	0.82	2928.4	4356.6	0.77
Upr Sand Body	5994.0	0.343	6165.6	0.82	2928.7	4378.0	0.77
Upr Sand Body	5994.5	0.346	6166.1	0.83	2928.9	4402.2	0.77
Upr Sand Body	5995.0	0.346	6166.5	0.83	2929.2	4407.8	0.78
Upr Sand Body	5995.5	0.341	6167.0	0.84	2929.4	4377.8	0.77
Upr Sand Body	5996.0	0.339	6167.5	0.84	2929.7	4363.0	0.77
Upr Sand Body	5996.5	0.340	6167.9	0.83	2929.9	4365.8	0.77
Upr Sand Body	5997.0	0.342	6168.4	0.83	2930.2	4379.5	0.77
Upr Sand Body	5997.5	0.342	6168.9	0.83	2930.4	4376.0	0.77
Upr Sand Body	5998.0	0.342	6169.3	0.83	2930.6	4376.4	0.77
Upr Sand Body	5998.5	0.341	6169.8	0.83	2930.9	4367.2	0.77
Upr Sand Body	5999.0	0.341	6170.3	0.83	2931.1	4371.3	0.77
Upr Sand Body	5999.5	0.338	6170.7	0.83	2931.4	4343.5	0.76

Upr Sand Body	**6000.0**	**0.340**	**6171.2**	**0.82**	**2931.6**	**4350.7**	**0.77**
Upr Sand Body	6000.5	0.342	6171.7	0.82	2931.9	4370.6	0.77
Upr Sand Body	**6001.0**	**0.345**	**6172.1**	**0.83**	**2932.1**	**4399.4**	**0.77**
Upr Sand Body	6001.5	0.345	6172.6	0.83	2932.4	4400.7	0.77
Upr Sand Body	**6002.0**	**0.341**	**6173.1**	**0.82**	**2932.6**	**4366.3**	**0.77**
Upr Sand Body	6002.5	0.334	6173.5	0.82	2932.8	4304.3	0.76
Upr Sand Body	**6003.0**	**0.330**	**6174.0**	**0.82**	**2933.1**	**4268.2**	**0.75**
Upr Sand Body	6003.5	0.334	6174.5	0.83	2933.3	4310.0	0.76
Upr Sand Body	**6004.0**	**0.336**	**6175.0**	**0.84**	**2933.6**	**4341.5**	**0.76**
Upr Sand Body	6004.5	0.332	6175.4	0.84	2933.8	4310.8	0.76
Upr Sand Body	**6005.0**	**0.309**	**6175.9**	**0.83**	**2934.1**	**4112.1**	**0.73**
Upr Sand Body	6005.5	0.294	6176.4	0.81	2934.3	3958.8	0.70
Upr Sand Body	**6006.0**	**0.300**	**6176.9**	**0.80**	**2934.6**	**3987.8**	**0.70**
Upr Sand Body	6006.5	0.313	6177.4	0.80	2934.8	4094.3	0.72
Upr Sand Body	**6007.0**	**0.314**	**6177.9**	**0.80**	**2935.0**	**4101.0**	**0.72**
Upr Sand Body	6007.5	0.287	6178.4	0.80	2935.3	3897.6	0.69
Upr Sand Body	**6008.0**	**0.278**	**6178.9**	**0.81**	**2935.5**	**3838.4**	**0.68**
Upr Sand Body	6008.5	0.295	6179.4	0.79	2935.8	3943.4	0.70
Upr Sand Body	**6009.0**	**0.314**	**6179.9**	**0.75**	**2936.0**	**4034.3**	**0.71**
Upr Sand Body	6009.5	0.319	6180.5	0.69	2936.3	3968.5	0.69
Base Upr Sand	**6010.0**	**0.302**	**6181.1**	**0.62**	**2920.8**	**3716.1**	**0.65**
Dolomite-Prone	6010.5	0.285	6181.8	0.61	2905.2	3532.0	0.62
Dolomite-Prone	6011.0	0.281	6182.4	0.63	2889.6	3523.4	0.62
Dolomite-Prone	6011.5	0.292	6183.0	0.65	2873.8	3653.2	0.64
Dolomite-Prone	6012.0	0.282	6183.6	0.67	2858.0	3588.8	0.63
Dolomite-Prone	6012.5	0.282	6184.2	0.68	2842.2	3614.3	0.63
Dolomite-Prone	6013.0	0.292	6184.8	0.69	2826.2	3703.3	0.65
Dolomite-Prone	6013.5	0.291	6185.4	0.70	2810.2	3704.2	0.65
Dolomite-Prone	6014.0	0.319	6186.0	0.71	2688.3	3906.5	0.68
Dolomite-Prone	6014.5	0.321	6186.5	0.71	2688.5	3929.2	0.69
Dolomite-Prone	6015.0	0.334	6187.1	0.71	2688.7	4061.3	0.71
Dolomite-Prone	6015.5	0.341	6187.7	0.71	2688.9	4117.8	0.72

Dolomite-Prone	6016.0	0.330	6188.3	0.70	2689.2	4006.2	0.70
Dolomite-Prone	6016.5	0.328	6188.9	0.70	2689.4	3984.3	0.69
Dolomite-Prone	6017.0	0.333	6189.5	0.70	2689.6	4032.5	0.70
Dolomite-Prone	6017.5	0.337	6190.1	0.70	2689.8	4065.9	0.71
Dolomite-Prone	6018.0	0.310	6190.7	0.69	2690.0	3805.1	0.66
Dolomite-Prone	6018.5	0.288	6191.3	0.69	2690.3	3615.9	0.63
Dolomite-Prone	6019.0	0.264	6191.8	0.71	2690.5	3448.5	0.60
Dolomite-Prone	6019.5	0.302	6192.4	0.74	2690.7	3813.2	0.67
Dolomite-Prone	6020.0	0.323	6192.9	0.77	2690.9	4040.5	0.71
Dolomite-Prone	6020.5	0.349	6193.5	0.79	2691.2	4310.9	0.75
Dolomite-Prone	6021.0	0.337	6194.0	0.78	2691.4	4178.4	0.73
Dolomite-Prone	6021.5	0.332	6194.6	0.75	2691.6	4092.9	0.71
Dolomite-Prone	6022.0	0.325	6195.1	0.73	2691.8	4001.2	0.70
Dolomite-Prone	6022.5	0.323	6195.7	0.72	2692.1	3969.9	0.69
Dolomite-Prone	6023.0	0.342	6196.3	0.72	2692.3	4149.9	0.72
Dolomite-Prone	6023.5	0.353	6196.9	0.71	2692.5	4250.3	0.74
Dolomite-Prone	6024.0	0.319	6197.5	0.70	2692.7	3901.9	0.68
Dolomite-Prone	6024.5	0.309	6198.1	0.70	2693.0	3807.9	0.66
Dolomite-Prone	6025.0	0.311	6198.7	0.71	2693.2	3854.5	0.67
Dolomite-Prone	6025.5	0.317	6199.2	0.73	2693.4	3928.9	0.68
Dolomite-Prone	6026.0	0.332	6199.8	0.72	2693.6	4064.8	0.71
Dolomite-Prone	6026.5	0.313	6200.4	0.70	2693.8	3851.0	0.67
Dolomite-Prone	6027.0	0.314	6201.0	0.68	2694.1	3838.6	0.67
Dolomite-Prone	6027.5	0.318	6201.6	0.67	2694.3	3858.9	0.67
Dolomite-Prone	6028.0	0.314	6202.2	0.67	2694.5	3821.2	0.66
Dolomite-Prone	6028.5	0.315	6202.8	0.67	2694.7	3836.4	0.67
Dolomite-Prone	6029.0	0.314	6203.4	0.67	2695.0	3817.0	0.66
Dolomite-Prone	6029.5	0.308	6204.0	0.67	2695.2	3773.1	0.66
Dolomite-Prone	6030.0	0.295	6204.6	0.67	2695.4	3659.3	0.64
Dolomite-Prone	6030.5	0.297	6205.2	0.70	2695.6	3708.9	0.65
Dolomite-Prone	6031.0	0.295	6205.8	0.70	2695.9	3705.7	0.65
Dolomite-Prone	6031.5	0.273	6206.4	0.70	2696.1	3519.4	0.62

Dolomite-Prone	6032.0	0.287	6206.9	0.70	2696.3	3625.0	0.63
Dolomite-Prone	6032.5	0.313	6207.5	0.69	2696.5	3836.1	0.67
Dolomite-Prone	6033.0	0.317	6208.1	0.66	2696.8	3840.6	0.67
Dolomite-Prone	6033.5	0.315	6208.7	0.66	2697.0	3815.8	0.66
Dolomite-Prone	6034.0	0.313	6209.3	0.66	2697.2	3807.7	0.66
Dolomite-Prone	6034.5	0.326	6210.0	0.68	2697.4	3957.8	0.69
Dolomite-Prone	6035.0	0.339	6210.6	0.68	2697.6	4074.2	0.71
Dolomite-Prone	6035.5	0.334	6211.2	0.67	2697.9	4018.8	0.70
Dolomite-Prone	6036.0	0.329	6211.8	0.67	2698.1	3972.4	0.69
Dolomite-Prone	6036.5	0.317	6212.4	0.67	2698.3	3857.6	0.67
Dolomite-Prone	6037.0	0.314	6213.0	0.70	2698.5	3875.3	0.67
Dolomite-Prone	6037.5	0.307	6213.6	0.71	2698.8	3810.5	0.66
Dolomite-Prone	6038.0	0.307	6214.1	0.70	2699.0	3808.3	0.66
Dolomite-Prone	6038.5	0.308	6214.7	0.70	2699.2	3821.1	0.66
Dolomite-Prone	6039.0	0.306	6215.3	0.71	2699.4	3810.4	0.66
Dolomite-Prone	6039.5	0.305	6215.9	0.73	2699.7	3829.3	0.67
Dolomite-Prone	6040.0	0.308	6216.4	0.73	2699.9	3870.2	0.67
Dolomite-Prone	6040.5	0.315	6217.0	0.73	2700.1	3933.4	0.68
Dolomite-Prone	6041.0	0.317	6217.6	0.73	2700.3	3936.4	0.68
Dolomite-Prone	6041.5	0.300	6218.2	0.72	2700.6	3780.6	0.66
Dolomite-Prone	6042.0	0.291	6218.8	0.72	2700.8	3697.8	0.64
Dolomite-Prone	6042.5	0.287	6219.3	0.73	2701.0	3678.4	0.64
Dolomite-Prone	6043.0	0.289	6219.9	0.73	2701.2	3706.1	0.65
Dolomite-Prone	6043.5	0.306	6220.4	0.73	2701.4	3841.0	0.67
Dolomite-Prone	6044.0	0.288	6221.0	0.71	2701.7	3657.3	0.64
Dolomite-Prone	6044.5	0.299	6221.6	0.70	2701.9	3736.1	0.65
Dolomite-Prone	6045.0	0.316	6222.1	0.72	2702.1	3917.0	0.68
Dolomite-Prone	6045.5	0.317	6222.6	0.75	2702.3	3972.4	0.69
Dolomite-Prone	6046.0	0.328	6223.2	0.77	2702.6	4096.4	0.71
Dolomite-Prone	6046.5	0.317	6223.7	0.77	2702.8	4003.8	0.70
Dolomite-Prone	6047.0	0.327	6224.2	0.77	2703.0	4092.5	0.71
Dolomite-Prone	6047.5	0.334	6224.8	0.76	2703.2	4142.8	0.72

Dolomite-Prone	6048.0	0.319	6225.4	0.76	2703.5	4005.9	0.70
Dolomite-Prone	6048.5	0.314	6225.9	0.75	2703.7	3952.7	0.69
Dolomite-Prone	6049.0	0.313	6226.5	0.74	2703.9	3934.9	0.68
Dolomite-Prone	6049.5	0.319	6227.1	0.73	2704.1	3965.1	0.69
Dolomite-Prone	6050.0	0.319	6227.7	0.72	2704.4	3957.9	0.69
Dolomite-Prone	6050.5	0.311	6228.2	0.72	2704.6	3883.8	0.67
Dolomite-Prone	6051.0	0.308	6228.8	0.72	2704.8	3856.8	0.67
Dolomite-Prone	6051.5	0.308	6229.4	0.73	2705.0	3859.3	0.67
Dolomite-Prone	6052.0	0.306	6230.0	0.72	2705.2	3839.0	0.67
Dolomite-Prone	6052.5	0.315	6230.6	0.72	2705.5	3911.2	0.68
Dolomite-Prone	6053.0	0.318	6231.2	0.71	2705.7	3933.0	0.68
Dolomite-Prone	6053.5	0.312	6231.8	0.71	2705.9	3878.7	0.67
Dolomite-Prone	6054.0	0.312	6232.3	0.71	2706.1	3878.4	0.67
Dolomite-Prone	6054.5	0.314	6232.9	0.71	2706.4	3892.4	0.67
Dolomite-Prone	6055.0	0.317	6233.5	0.71	2706.6	3920.4	0.68
Dolomite-Prone	6055.5	0.317	6234.1	0.71	2706.8	3915.0	0.68
Dolomite-Prone	6056.0	0.322	6234.7	0.71	2707.0	3969.5	0.69
Dolomite-Prone	6056.5	0.322	6235.3	0.71	2707.3	3964.8	0.69
Dolomite-Prone	6057.0	0.316	6235.9	0.72	2707.5	3927.8	0.68
Dolomite-Prone	6057.5	0.323	6236.4	0.73	2707.7	4009.3	0.69
Dolomite-Prone	6058.0	0.325	6237.0	0.73	2707.9	4028.1	0.70
Dolomite-Prone	6058.5	0.331	6237.6	0.72	2708.1	4074.0	0.70
Dolomite-Prone	6059.0	0.336	6238.1	0.71	2708.4	4102.4	0.71
Dolomite-Prone	6059.5	0.326	6238.7	0.70	2708.6	3999.1	0.69
Dolomite-Prone	6060.0	0.302	6239.3	0.70	2960.9	3875.8	0.67
Dolomite-Prone	6060.5	0.310	6239.9	0.71	2961.2	3962.8	0.69
Dolomite-Prone	6061.0	0.300	6240.4	0.71	2961.4	3867.4	0.67
Dolomite-Prone	6061.5	0.285	6241.0	0.70	2961.7	3729.6	0.65
Dolomite-Prone	6062.0	0.254	6241.6	0.69	2961.9	3476.0	0.61
Dolomite-Prone	6062.5	0.243	6242.2	0.70	2962.2	3415.7	0.60
Dolomite-Prone	6063.0	0.264	6242.7	0.73	2962.4	3621.7	0.63
Dolomite-Prone	6063.5	0.285	6243.3	0.74	2962.7	3815.8	0.67

Dolomite-Prone	6064.0	0.280	6243.9	0.74	2962.9	3766.6	0.66
Dolomite-Prone	6064.5	0.288	6244.5	0.72	2963.1	3796.5	0.66
Dolomite-Prone	6065.0	0.289	6245.0	0.70	2963.4	3778.8	0.66
Dolomite-Prone	6065.5	0.273	6245.6	0.70	2963.6	3636.0	0.63
Top Lwr Sand	6066.0	0.267	6246.2	0.70	2963.9	3593.7	0.63
Lwr Sand Body	6066.5	0.249	6246.7	0.72	2964.1	3492.9	0.61
Lwr Sand Body	6067.0	0.246	6247.3	0.75	2964.4	3530.4	0.62
Lwr Sand Body	6067.5	0.275	6247.8	0.77	2964.6	3786.0	0.66
Lwr Sand Body	6068.0	0.279	6248.3	0.78	2964.8	3833.2	0.67
Lwr Sand Body	6068.5	0.282	6248.8	0.78	2965.1	3866.5	0.68
Lwr Sand Body	6069.0	0.282	6249.3	0.78	2965.3	3861.1	0.67
Lwr Sand Body	6069.5	0.287	6249.8	0.79	2965.6	3910.4	0.68
Lwr Sand Body	6070.0	0.303	6250.3	0.79	2965.8	4042.5	0.70
Lwr Sand Body	6070.5	0.312	6250.8	0.80	2966.1	4132.2	0.72
Lwr Sand Body	6071.0	0.309	6251.3	0.80	2966.3	4116.4	0.72
Lwr Sand Body	6071.5	0.308	6251.8	0.81	2966.6	4114.9	0.72
Lwr Sand Body	6072.0	0.301	6252.3	0.81	2966.8	4066.2	0.71
Lwr Sand Body	6072.5	0.287	6252.8	0.81	2967.0	3953.7	0.69
Lwr Sand Body	6073.0	0.278	6253.3	0.80	2967.3	3867.7	0.68
Lwr Sand Body	6073.5	0.273	6253.8	0.80	2967.5	3821.5	0.67
Lwr Sand Body	6074.0	0.301	6254.3	0.79	2967.8	4037.5	0.70
Lwr Sand Body	6074.5	0.325	6254.8	0.79	2968.0	4225.1	0.73
Lwr Sand Body	6075.0	0.303	6255.4	0.77	2968.3	4009.6	0.70
Lwr Sand Body	6075.5	0.269	6256.0	0.74	2968.5	3691.9	0.64
Lwr Sand Body	6076.0	0.243	6256.5	0.74	2968.8	3496.1	0.61
Lwr Sand Body	6076.5	0.265	6257.1	0.75	2969.0	3679.5	0.64
Lwr Sand Body	6077.0	0.288	6257.6	0.77	2969.2	3888.5	0.68
Lwr Sand Body	6077.5	0.297	6258.1	0.78	2969.5	3986.5	0.69
Lwr Sand Body	6078.0	0.298	6258.6	0.80	2969.7	4014.2	0.70
Lwr Sand Body	6078.5	0.311	6259.1	0.80	2970.0	4122.3	0.72
Lwr Sand Body	6079.0	0.307	6259.6	0.80	2970.2	4100.3	0.71
Lwr Sand Body	6079.5	0.303	6260.1	0.80	2970.5	4065.1	0.71

Lwr Sand Body	6080.0	0.307	6260.6	0.81	2970.7	4113.8	0.72
Lwr Sand Body	6080.5	0.306	6261.1	0.81	2971.0	4106.7	0.72
Lwr Sand Body	6081.0	0.303	6261.6	0.81	2971.2	4073.9	0.71
Lwr Sand Body	6081.5	0.296	6262.1	0.80	2971.4	4000.8	0.70
Lwr Sand Body	6082.0	0.283	6262.6	0.79	2971.7	3889.3	0.68
Lwr Sand Body	6082.5	0.283	6263.1	0.79	2971.9	3895.5	0.68
Lwr Sand Body	6083.0	0.292	6263.6	0.79	2972.2	3961.9	0.69
Lwr Sand Body	6083.5	0.299	6264.1	0.80	2972.4	4026.9	0.70
Lwr Sand Body	6084.0	0.305	6264.6	0.80	2972.7	4088.9	0.71
Lwr Sand Body	6084.5	0.301	6265.1	0.81	2972.9	4061.8	0.71
Lwr Sand Body	6085.0	0.294	6265.6	0.81	2973.2	4009.2	0.70
Lwr Sand Body	6085.5	0.291	6266.1	0.80	2973.4	3982.4	0.69
Lwr Sand Body	6086.0	0.279	6266.6	0.80	2973.6	3877.3	0.68
Lwr Sand Body	6086.5	0.268	6267.1	0.79	2973.9	3783.8	0.66
Lwr Sand Body	6087.0	0.276	6267.6	0.77	2974.1	3811.2	0.66
Lwr Sand Body	6087.5	0.311	6268.1	0.77	2974.4	4084.2	0.71
Lwr Sand Body	6088.0	0.323	6268.6	0.79	2974.6	4216.6	0.73
Lwr Sand Body	6088.5	0.338	6269.1	0.81	2974.9	4390.0	0.76
Lwr Sand Body	6089.0	0.330	6269.6	0.83	2975.1	4338.2	0.75
Lwr Sand Body	6089.5	0.304	6270.1	0.82	2975.4	4114.2	0.72
Lwr Sand Body	6090.0	0.261	6270.6	0.81	2975.6	3765.2	0.66
Lwr Sand Body	6090.5	0.269	6271.1	0.79	2975.8	3797.8	0.66
Lwr Sand Body	6091.0	0.287	6271.7	0.78	2976.1	3911.6	0.68
Lwr Sand Body	6091.5	0.297	6272.2	0.78	2976.3	3988.5	0.69
Lwr Sand Body	6092.0	0.292	6272.7	0.78	2976.6	3959.9	0.69
Lwr Sand Body	6092.5	0.290	6273.2	0.79	2976.8	3950.6	0.69
Lwr Sand Body	6093.0	0.301	6273.7	0.79	2977.1	4040.2	0.70
Lwr Sand Body	6093.5	0.315	6274.2	0.80	2977.3	4181.5	0.73
Lwr Sand Body	6094.0	0.323	6274.7	0.82	2977.6	4271.3	0.74
Lwr Sand Body	6094.5	0.335	6275.1	0.82	2977.8	4378.6	0.76
Lwr Sand Body	6095.0	0.334	6275.6	0.81	2978.0	4350.7	0.75
Lwr Sand Body	6095.5	0.334	6276.1	0.81	2978.3	4346.5	0.75

Lwr Sand Body	**6096.0**	**0.330**	**6276.6**	**0.80**	**2978.5**	**4304.3**	**0.75**
Lwr Sand Body	6096.5	0.328	6277.1	0.81	2978.8	4296.5	0.74
Lwr Sand Body	**6097.0**	**0.326**	**6277.6**	**0.80**	**2979.0**	**4267.0**	**0.74**
Lwr Sand Body	6097.5	0.311	6278.1	0.80	2979.3	4141.4	0.72
Lwr Sand Body	**6098.0**	**0.286**	**6278.6**	**0.80**	**2979.5**	**3944.5**	**0.69**
Lwr Sand Body	6098.5	0.276	6279.1	0.80	2979.8	3859.3	0.67
Lwr Sand Body	**6099.0**	**0.285**	**6279.6**	**0.79**	**2980.0**	**3923.3**	**0.68**
Lwr Sand Body	6099.5	0.305	6280.1	0.79	2980.2	4076.9	0.71
Lwr Sand Body	**6100.0**	**0.334**	**6280.6**	**0.80**	**2980.5**	**4328.6**	**0.75**
Lwr Sand Body	6100.5	0.346	6281.1	0.81	2980.7	4452.8	0.77
Lwr Sand Body	**6101.0**	**0.347**	**6281.6**	**0.82**	**2981.0**	**4475.4**	**0.77**
Lwr Sand Body	6101.5	0.342	6282.1	0.82	2981.2	4439.5	0.77
Lwr Sand Body	**6102.0**	**0.324**	**6282.5**	**0.83**	**2981.5**	**4301.0**	**0.75**
Lwr Sand Body	6102.5	0.315	6283.0	0.83	2981.7	4226.9	0.73
Lwr Sand Body	**6103.0**	**0.309**	**6283.5**	**0.83**	**2982.0**	**4180.1**	**0.73**
Lwr Sand Body	6103.5	0.302	6284.0	0.82	2982.2	4112.1	0.71
Lwr Sand Body	**6104.0**	**0.220**	**6284.5**	**0.81**	**2982.4**	**3504.7**	**0.61**
Lwr Sand Body	6104.5	0.240	6285.0	0.78	2982.7	3582.6	0.63
Lwr Sand Body	**6105.0**	**0.256**	**6285.6**	**0.76**	**2982.9**	**3656.2**	**0.64**
Lwr Sand Body	6105.5	0.318	6286.1	0.77	2983.2	4159.7	0.72
Lwr Sand Body	**6106.0**	**0.329**	**6286.6**	**0.80**	**2983.4**	**4297.0**	**0.74**
Lwr Sand Body	6106.5	0.336	6287.1	0.82	2983.7	4387.5	0.76
Lwr Sand Body	**6107.0**	**0.335**	**6287.5**	**0.82**	**2983.9**	**4390.3**	**0.76**
Lwr Sand Body	6107.5	0.315	6288.0	0.82	2984.1	4205.3	0.73
Lwr Sand Body	**6108.0**	**0.291**	**6288.5**	**0.81**	**2984.4**	**4002.8**	**0.69**
Lwr Sand Body	6108.5	0.292	6289.0	0.79	2984.6	3984.6	0.69
Lwr Sand Body	**6109.0**	**0.292**	**6289.6**	**0.77**	**2984.9**	**3941.9**	**0.68**
Lwr Sand Body	6109.5	0.289	6290.1	0.74	2985.1	3873.6	0.67
Lwr Sand Body	**6110.0**	**0.286**	**6290.7**	**0.72**	**2985.4**	**3807.9**	**0.66**
Lwr Sand Body	6110.5	0.262	6291.3	0.71	2985.6	3609.6	0.63
Lwr Sand Body	**6111.0**	**0.255**	**6291.8**	**0.71**	**2985.9**	**3547.5**	**0.62**
Lwr Sand Body	6111.5	0.280	6292.4	0.71	2986.1	3741.6	0.65

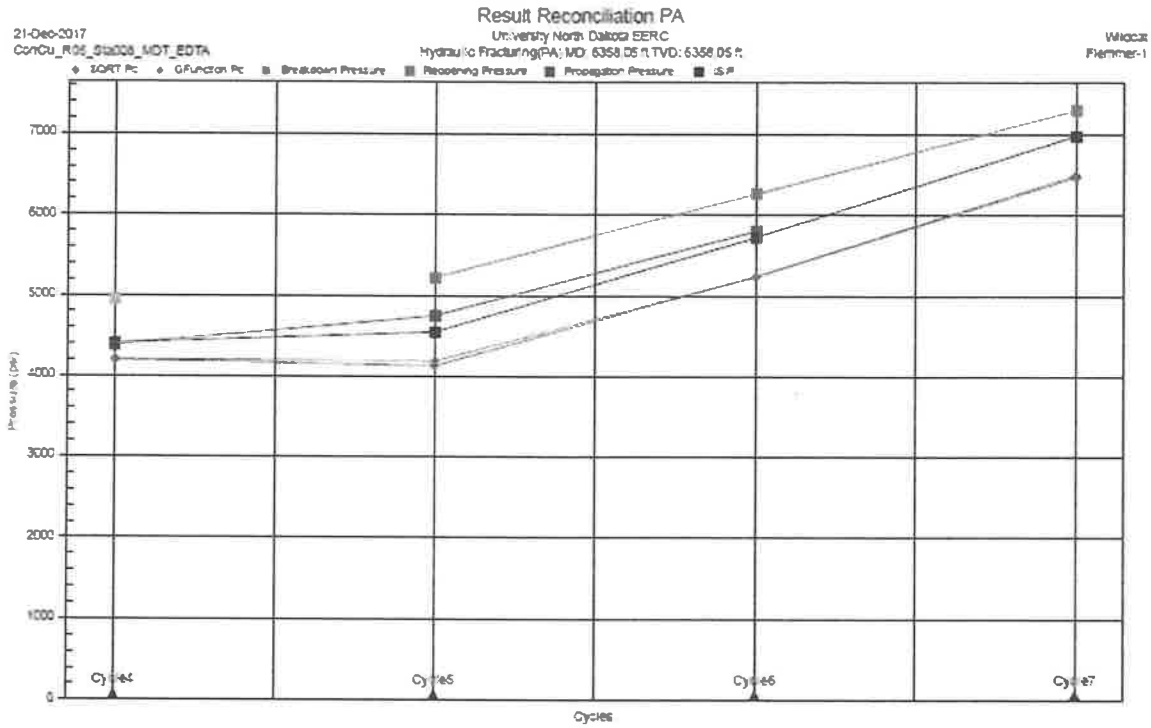
Lwr Sand Body	**6112.0**	**0.305**	**6293.0**	**0.70**	**2986.3**	**3934.4**	**0.68**
Lwr Sand Body	6112.5	0.326	6293.6	0.69	2986.6	4101.0	0.70
Lwr Sand Body	**6113.0**	**0.329**	**6294.2**	**0.67**	**2986.8**	**4109.3**	**0.71**
Lwr Sand Body	6113.5	0.255	6294.8	0.67	2987.1	3482.4	0.60
Lwr Sand Body	**6114.0**	**0.242**	**6295.4**	**0.68**	**2987.3**	**3393.4**	**0.59**
Lwr Sand Body	6114.5	0.298	6295.9	0.71	2987.6	3887.7	0.67
Lwr Sand Body	**6115.0**	**0.318**	**6296.5**	**0.75**	**2987.8**	**4125.1**	**0.71**
Lwr Sand Body	6115.5	0.333	6297.0	0.78	2988.1	4312.6	0.74
Lwr Sand Body	**6116.0**	**0.337**	**6297.5**	**0.81**	**2988.3**	**4386.1**	**0.76**
Lwr Sand Body	6116.5	0.331	6297.9	0.82	2988.5	4349.7	0.75
Lwr Sand Body	**6117.0**	**0.326**	**6298.4**	**0.83**	**2988.8**	**4323.5**	**0.75**
Lwr Sand Body	6117.5	0.322	6298.9	0.83	2989.0	4293.3	0.74
Lwr Sand Body	**6118.0**	**0.327**	**6299.4**	**0.83**	**2989.3**	**4329.1**	**0.75**
Lwr Sand Body	6118.5	0.331	6299.8	0.82	2989.5	4360.8	0.75
Lwr Sand Body	**6119.0**	**0.328**	**6300.3**	**0.82**	**2989.8**	**4338.6**	**0.75**
Lwr Sand Body	6119.5	0.308	6300.8	0.82	2990.0	4166.9	0.72
Lwr Sand Body	**6120.0**	**0.313**	**6301.3**	**0.81**	**2990.3**	**4195.4**	**0.73**
Lwr Sand Body	6120.5	0.313	6301.8	0.81	2990.5	4187.5	0.72
Lwr Sand Body	**6121.0**	**0.311**	**6302.3**	**0.81**	**2990.7**	**4180.1**	**0.72**
Lwr Sand Body	6121.5	0.302	6302.8	0.82	2991.0	4117.0	0.71
Lwr Sand Body	**6122.0**	**0.300**	**6303.3**	**0.81**	**2991.2**	**4091.3**	**0.71**
Lwr Sand Body	6122.5	0.303	6303.7	0.81	2991.5	4114.5	0.71
Lwr Sand Body	**6123.0**	**0.323**	**6304.2**	**0.81**	**2991.7**	**4279.1**	**0.74**
Lwr Sand Body	6123.5	0.333	6304.7	0.82	2992.0	4371.9	0.75
Lwr Sand Body	**6124.0**	**0.337**	**6305.2**	**0.82**	**2992.2**	**4410.5**	**0.76**
Lwr Sand Body	6124.5	0.339	6305.7	0.82	2992.5	4430.8	0.76
Lwr Sand Body	**6125.0**	**0.339**	**6306.1**	**0.82**	**2992.7**	**4436.3**	**0.76**
Lwr Sand Body	6125.5	0.335	6306.6	0.82	2992.9	4402.5	0.76
Lwr Sand Body	**6126.0**	**0.317**	**6307.1**	**0.82**	**2993.2**	**4246.3**	**0.73**
Lwr Sand Body	6126.5	0.296	6307.6	0.82	2993.4	4074.2	0.71
Lwr Sand Body	**6127.0**	**0.285**	**6308.0**	**0.82**	**2993.7**	**3987.2**	**0.69**
Lwr Sand Body	6127.5	0.285	6308.5	0.81	2993.9	3971.4	0.69

Lwr Sand Body	**6128.0**	**0.277**	**6309.0**	**0.80**	**2994.2**	**3888.9**	**0.67**
Lwr Sand Body	6128.5	0.262	6309.6	0.79	2994.4	3757.2	0.65
Lwr Sand Body	**6129.0**	**0.269**	**6310.1**	**0.78**	**2994.7**	**3805.4**	**0.66**
Lwr Sand Body	6129.5	0.278	6310.6	0.78	2994.9	3871.7	0.67
Lwr Sand Body	**6130.0**	**0.271**	**6311.1**	**0.77**	**2995.1**	**3797.1**	**0.66**
Lwr Sand Body	6130.5	0.295	6311.6	0.75	2740.3	3844.0	0.66
Lwr Sand Body	**6131.0**	**0.284**	**6312.2**	**0.75**	**2740.6**	**3750.0**	**0.65**
Lwr Sand Body	6131.5	0.296	6312.7	0.76	2740.8	3864.0	0.66
Lwr Sand Body	**6132.0**	**0.304**	**6313.2**	**0.77**	**2741.0**	**3948.1**	**0.68**
Lwr Sand Body	6132.5	0.306	6313.7	0.78	2741.2	3976.0	0.68
Lwr Sand Body	**6133.0**	**0.317**	**6314.3**	**0.78**	**2741.5**	**4080.0**	**0.70**
Lwr Sand Body	6133.5	0.329	6314.8	0.78	2741.7	4185.6	0.72
Lwr Sand Body	**6134.0**	**0.334**	**6315.3**	**0.78**	**2741.9**	**4230.6**	**0.72**
Lwr Sand Body	6134.5	0.324	6315.8	0.76	2742.1	4113.0	0.70
Lwr Sand Body	**6135.0**	**0.310**	**6316.3**	**0.74**	**2742.3**	**3948.2**	**0.68**
Lwr Sand Body	6135.5	0.298	6316.9	0.73	2742.6	3845.7	0.66
Lwr Sand Body	**6136.0**	**0.305**	**6317.4**	**0.74**	**2742.8**	**3921.1**	**0.67**
Lwr Sand Body	6136.5	0.307	6317.9	0.76	2743.0	3957.7	0.68
Lwr Sand Body	**6137.0**	**0.310**	**6318.5**	**0.76**	**2743.2**	**3994.6**	**0.69**
Lwr Sand Body	6137.5	0.318	6319.0	0.77	2743.5	4076.9	0.70
Lwr Sand Body	**6138.0**	**0.302**	**6319.5**	**0.77**	**2743.7**	**3925.6**	**0.67**
Lwr Sand Body	6138.5	0.306	6320.1	0.76	2743.9	3955.3	0.68
Lwr Sand Body	**6139.0**	**0.309**	**6320.6**	**0.76**	**2744.1**	**3984.6**	**0.68**
Lwr Sand Body	6139.5	0.289	6321.1	0.77	2744.4	3813.3	0.66
Lwr Sand Body	**6140.0**	**0.293**	**6321.6**	**0.77**	**2744.6**	**3853.6**	**0.66**
Lwr Sand Body	6140.5	0.285	6322.2	0.77	2744.8	3786.7	0.65
Lwr Sand Body	**6141.0**	**0.291**	**6322.7**	**0.77**	**2745.0**	**3837.8**	**0.66**
Lwr Sand Body	6141.5	0.311	6323.2	0.76	2745.3	3998.5	0.69
Lwr Sand Body	**6142.0**	**0.291**	**6323.8**	**0.74**	**2745.5**	**3800.4**	**0.65**
Lwr Sand Body	6142.5	0.289	6324.3	0.71	2745.7	3722.1	0.64
Lwr Sand Body	**6143.0**	**0.305**	**6324.9**	**0.66**	**2745.9**	**3791.4**	**0.65**
Lwr Sand Body	6143.5	0.318	6325.6	0.61	2746.1	3844.9	0.65

Lwr Sand Body	6144.0	0.325	6326.2	0.61	2746.4	3912.5	0.66
Lwr Sand Body	6144.5	0.326	6326.8	0.63	2746.6	3947.7	0.67
Lwr Sand Body	6145.0	0.326	6327.5	0.63	2746.8	3959.7	0.67
Lwr Sand Body	6145.5	0.305	6328.1	0.63	2747.0	3745.7	0.64
Lwr Sand Body	6146.0	0.268	6328.8	0.60	2747.3	3366.9	0.57
Lwr Sand Body	6146.5	0.256	6329.4	0.60	2747.5	3229.7	0.56
Lwr Sand Body	6147.0	0.272	6329.9	0.63	2747.7	3451.6	0.59
Lwr Sand Body	6147.5	0.279	6330.5	0.62	2747.9	3484.9	0.59
Lwr Sand Body	6148.0	0.265	6331.1	0.60	2748.2	3347.7	0.57
Lwr Sand Body	6148.5	0.259	6331.7	0.62	2748.4	3317.4	0.57
Lwr Sand Body	6149.0	0.269	6332.3	0.67	2748.6	3487.7	0.60
Lwr Sand Body	6149.5	0.288	6332.8	0.69	2748.8	3692.7	0.63
Lwr Sand Body	6150.0	0.293	6333.4	0.70	2749.1	3750.5	0.64
Lwr Sand Body	6150.5	0.270	6334.0	0.69	2749.3	3543.6	0.61
Lwr Sand Body	6151.0	0.265	6334.5	0.69	2749.5	3497.7	0.60
Lwr Sand Body	6151.5	0.290	6335.1	0.70	2749.7	3730.3	0.64
Lwr Sand Body	6152.0	0.311	6335.6	0.72	2749.9	3940.3	0.67
Lwr Sand Body	6152.5	0.312	6336.2	0.72	2750.2	3950.7	0.67
Lwr Sand Body	6153.0	0.312	6336.7	0.71	2750.4	3938.1	0.67
Lwr Sand Body	6153.5	0.326	6337.3	0.73	2750.6	4100.0	0.70
Lwr Sand Body	6154.0	0.321	6337.8	0.76	2750.8	4094.4	0.70
Lwr Sand Body	6154.5	0.321	6338.4	0.78	2751.1	4126.9	0.71
Lwr Sand Body	6155.0	0.293	6338.9	0.77	2751.3	3867.8	0.66
Lwr Sand Body	6155.5	0.277	6339.4	0.75	2751.5	3693.7	0.63
Lwr Sand Body	6156.0	0.278	6340.0	0.74	2751.7	3690.9	0.63
Lwr Sand Body	6156.5	0.287	6340.5	0.75	2752.0	3778.0	0.65
Lwr Sand Body	6157.0	0.293	6341.1	0.76	2752.2	3850.9	0.66
Lwr Sand Body	6157.5	0.317	6341.6	0.76	2752.4	4060.1	0.69
Lwr Sand Body	6158.0	0.313	6342.1	0.76	2752.6	4038.9	0.69
Lwr Sand Body	6158.5	0.316	6342.6	0.77	2752.8	4076.3	0.70
Lwr Sand Body	6159.0	0.330	6343.1	0.78	2753.1	4213.6	0.72
Lwr Sand Body	6159.5	0.323	6343.7	0.78	2753.3	4153.6	0.71

Lwr Sand Body	**6160.0**	**0.324**	**6344.2**	**0.78**	**2753.5**	**4155.3**	**0.71**
Lwr Sand Body	6160.5	0.313	6344.7	0.78	2753.7	4055.1	0.69
Lwr Sand Body	**6161.0**	**0.317**	**6345.2**	**0.78**	**2754.0**	**4089.6**	**0.70**
Lwr Sand Body	6161.5	0.319	6345.7	0.77	2754.2	4104.2	0.70
Lwr Sand Body	**6162.0**	**0.313**	**6346.3**	**0.77**	**2754.4**	**4038.8**	**0.69**
Lwr Sand Body	6162.5	0.303	6346.8	0.76	2754.6	3933.2	0.67
Lwr Sand Body	**6163.0**	**0.302**	**6347.4**	**0.74**	**2754.9**	**3899.2**	**0.67**
Lwr Sand Body	6163.5	0.307	6347.9	0.72	2755.1	3918.1	0.67
Lwr Sand Body	**6164.0**	**0.307**	**6348.5**	**0.71**	**2755.3**	**3904.2**	**0.67**
Lwr Sand Body	6164.5	0.309	6349.1	0.71	2755.5	3911.6	0.67
Base Lwr Sand	**6165.0**	**0.322**	**6349.6**	**0.70**	**2755.8**	**4026.7**	**0.68**
AVG. UPR + LWR SANDS -->	**0.315**	**6211.8**		**2875.8**	**4072.6**	**0.71**	

Flemmer #1 Frac Test



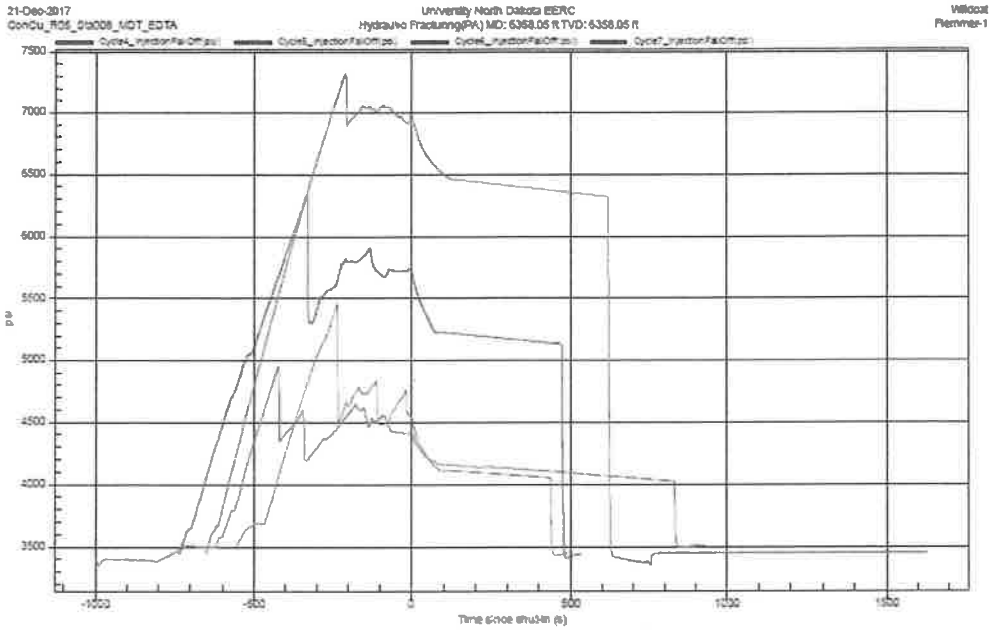
Tests/Cycles	Cycle4	Cycle5	Cycle6	Cycle7
Type	InjectionFallOff	InjectionFallOff	InjectionFallOff	InjectionFallOff
Interval (s)	6546.9 - 8477.1	8477.4 - 9527.7	9528 - 10797.3	10797.6 - 13080.6
Breakdown Pressure (psi)	4950.589			
Reopening Pressure (psi)		5214.212	6255.856	7293.515
Propagation Pressure (psi)	4384.225	4746.564	5795.598	
ISIP (psi)	4407.587	4542.987	5721.316	6983.199
Closure Pressure(SQRT) (psi)	4195.888	4125.801	5240.428	6488.475
Closure Pressure(G-plot) (psi)	4200.639	4189.797	5238.812	6470.688

Break down occurred on the third cycle

Closure in agreement between cycles three and four

Cycles five and six show steady rise in measured closure pressure indication possible formation pore space plugging.

Cycle Comparison



Supplement 5

A multiplication factor was applied to the capillary entry pressure data to correlate the properties from the core to the properties in the numerical model. This multiplication factor was calculated by dividing the rock quality index from the core sample by the rock quality index from the model for each lithofacies (Tables S-1).

The relative permeability used in the model is the same for anhydrite and siltstone; however, the capillary pressure curves for the two lithofacies are different because of the difference in the multiplication factors used.

Dolomitic sandstone values were derived from two different core samples that had similar porosity and permeability, resulting in similar relative permeability curves (Figure S-1). The capillary entry pressure curves are different for dolomitic sandstone and dolostone because of the multiplication factors used to derive them (Table S-1).

The dolomitic sandstone and sandstone values were derived from two different core samples, and the capillary entry pressure and relative permeability curves look similar but have small differences (Figure S-2).

Table S-1. Core Sample Properties and Rock Quality Index Used to Assign Capillary Entry Pressure Curve to the Model Lithofacies

Formation	Rock Type	Porosity, %	Swanson Permeability, mD	Rock Quality Index from Samples, RQI	Rock Quality Index from Model, RQI	Entry Pressure A/Hg System, psi	Entry Pressure Brine/CO_2 System, psi
Broom Creek	**Anhydrite**	**1.7**	**0.00002**	**0.133**	**3.50**	**2,630**	**168**
Broom Creek	Silty-mudstone	1.7	0.00002	0.133	1.39	2,630	168
Broom Creek	**Dolomitic-sandstone**	**8.7**	**0.00683**	**0.758**	**30.35**	**312**	**20**
Broom Creek	Sandstone	26.7	1147	65.54	49.35	3.04	0.2
Broom Creek	**Dolomitic-dolostone**	**4.8**	**0.00478**	**0.289**	**11.88**	**274**	**18**

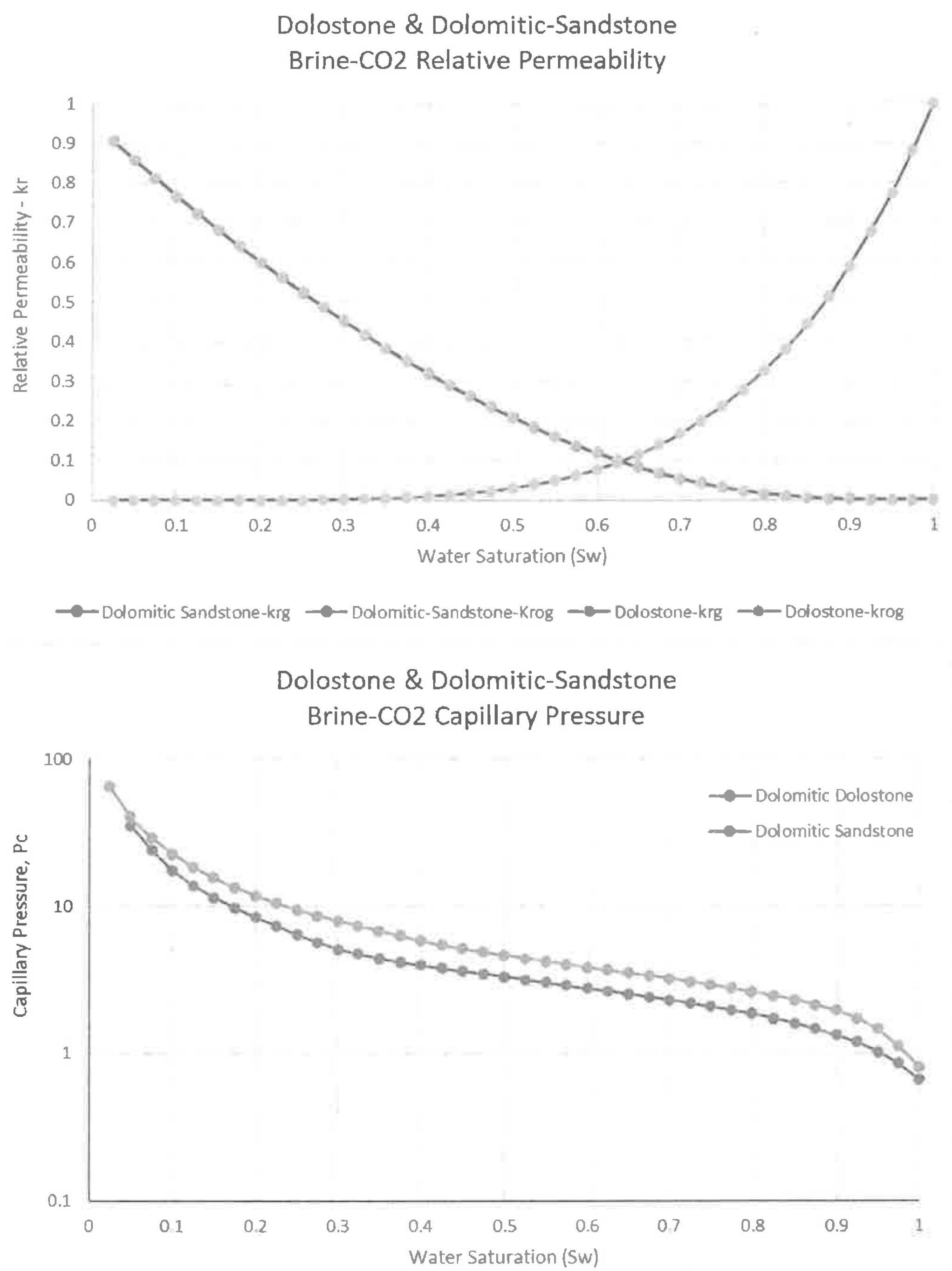
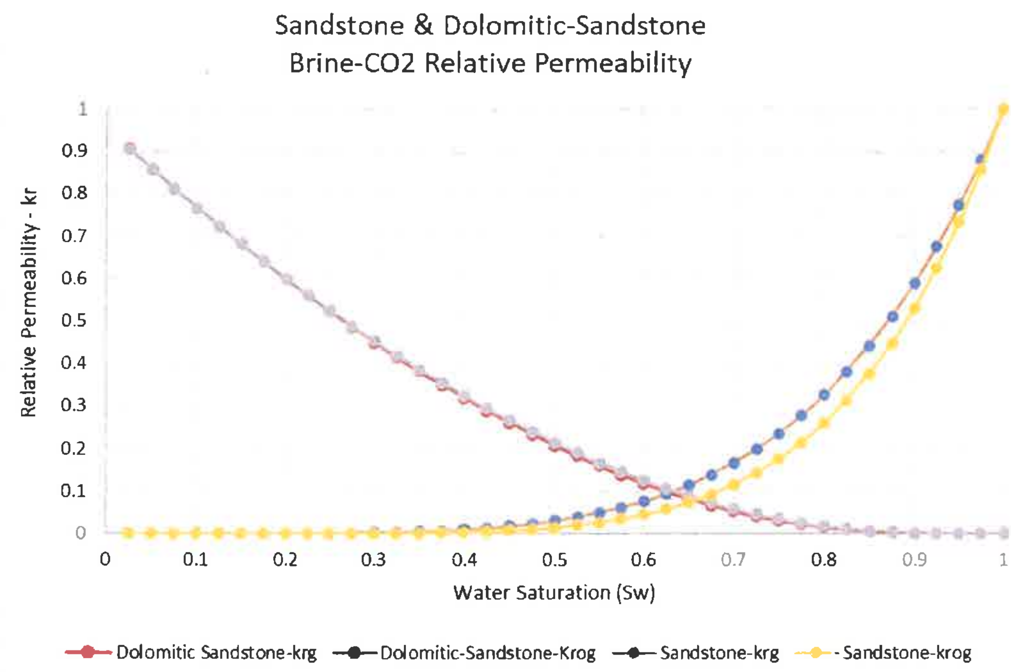


Figure S-1. Relative permeability (top) and capillary pressure curves (bottom) for dolostone and dolomitic sandstone.



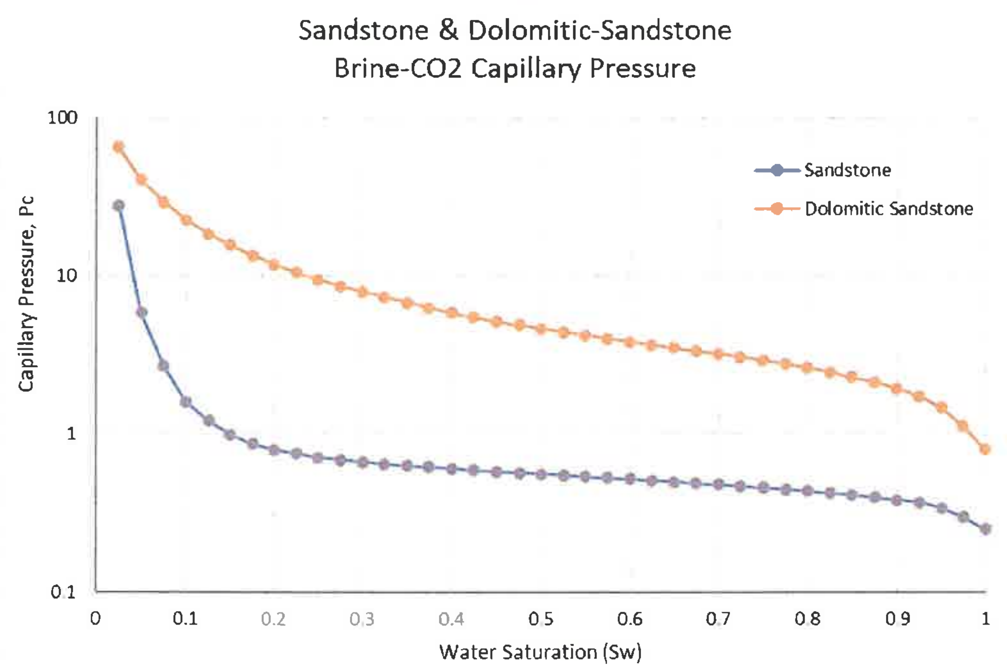


Figure S-2. Relative permeability (top) and capillary pressure curves (bottom) for sandstone and dolomitic sandstone.

Supplement 6

Request: Provide a lab analysis reports for and justification for why each of the 19 monitoring wells operated by Coteau Properties (Coteau) were chosen in Appendix B.

Response: The 19 monitoring wells presented in Appendix B were selected to serve as a baseline data set using the criteria presented on Page B-12 in Appendix B. Appendix B, includes a summary of the critical elements evaluated in each well from a data set provided by Coteau Properties Company, the operators of the wells, and three example laboratory reports. Additional laboratory reports for each well are available through open records request from the Public Service Commission.

Supplement 7

6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

This postinjection site care (PISC) and facility closure plan describes the activities that DGC will perform following the cessation of CO_2 injection to achieve final closure of the site. A primary component of this plan is a postinjection monitoring program that will provide evidence that the injected CO_2 plume is stable (i.e., CO_2 migration will be unlikely to move beyond the boundary of the storage facility area). Based on simulations of the predicted CO_2 plume movement following the cessation of CO_2 injection, it is projected that the CO_2 plume will stabilize within the storage facility area boundary (Section 3). Based on these observations, a minimum postinjection monitoring period of 10 years is planned to confirm these current predictions of the CO_2 plume extent and postinjection stabilization. However, monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable CO_2 plume. The nature and duration of that extension will be determined based on an update of this plan and NDIC approval.

In addition to DGC executing the postinjection monitoring program, the Class VI injection wells will be plugged as described in the plugging plan of this permit application (Section 10), all surface equipment not associated with long-term monitoring will be removed, and the surface land of the site will be reclaimed to as close as is practical to its original condition. Following the plume stability demonstration, a final assessment will be prepared to document the status of the site and submitted as part of a site closure report.

6.1 Predicted Postinjection Subsurface Conditions

6.1.1 Pre- and Postinjection Pressure Differential

Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of CO_2 injection. The simulations were conducted for 12 years of CO_2 injection at rates between 1.0 and 2.7 million metric tons per year, followed by a postinjection period of 10 years. Figure 6-1 illustrates the predicted pressure differential at the conclusion of 12 years of CO_2 injection. At the time that CO_2 injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of 400 to 450 psi at the location of the injection wells. There is insufficient pressure increase caused by CO_2 injection to move more than 1 cubic meter of formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the area of review (AOR) delineation of this permit application (Section 3). An illustration of the predicted decrease in this pressure profile over the 10-year postinjection period is provided in Figure 6-2. The pressure in the reservoir gradually decreases over time following the cessation of CO_2 injection, with the pressure at the injection well after 10 years of postinjection predicted to decrease 300 to 350 psi as compared to the pressure at the time CO_2 injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions.

Supplement 8

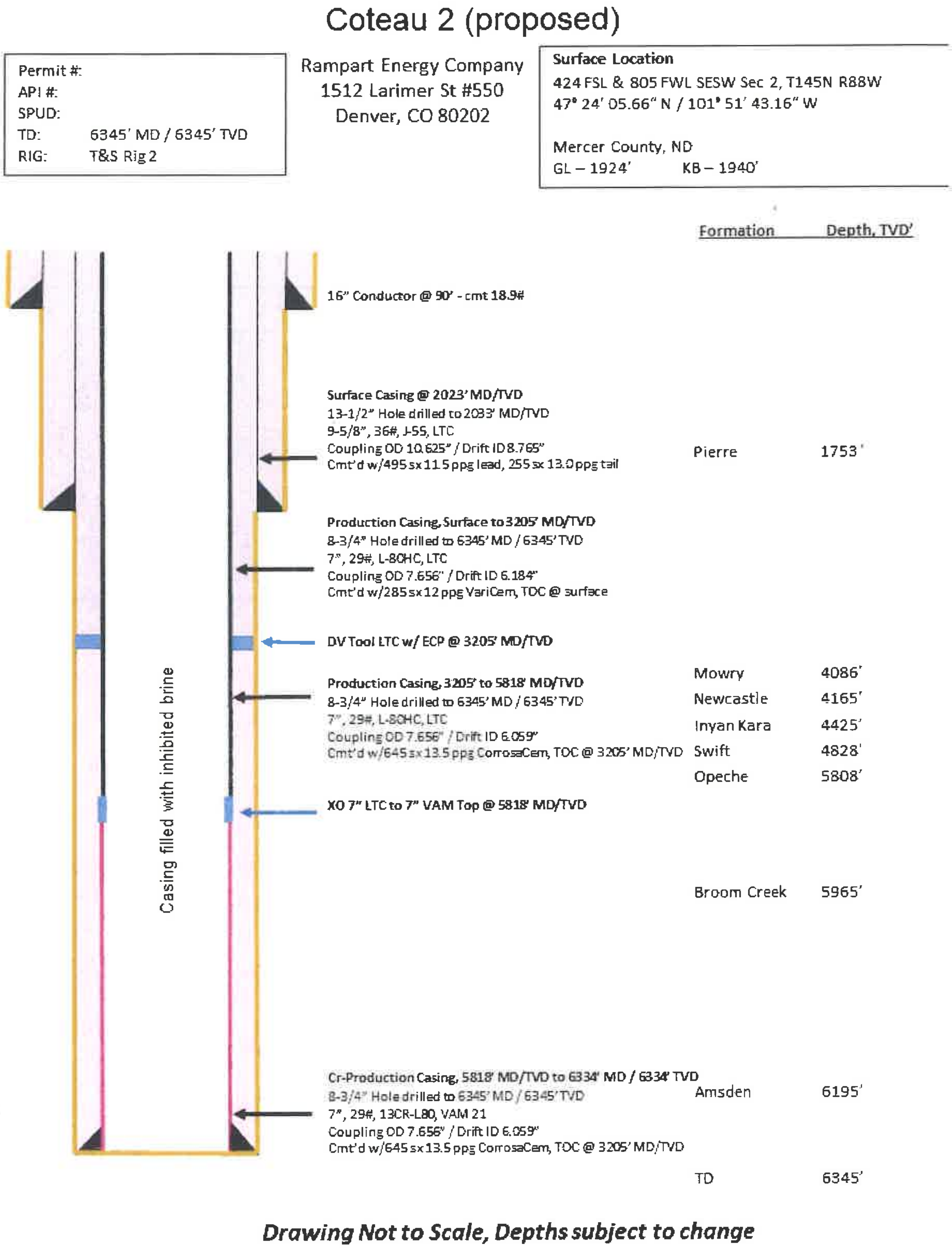


Figure 9-3. Coteau 2 proposed wellbore schematic.

Table 9-5. Coteau 2 As-Constructed Well Information

Well Name:	**Coteau 2**	**NDIC No.:**	**38916**	**API No.:**	**33-057-00043**
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.2 T145N R88W	**Footages:**	424 S 805 W	**Total Depth, ft:**	6345 MD

Table 9-6. Coteau 2 As-Constructed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5829	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5829	6360	CO_2-resistant production casing

Table 9-7. Coteau 2 As-Constructed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7.717	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-8. Coteau 2 As-Constructed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6360–3205	100	625
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft.

9.3 Coteau 3: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 3 well is expected to be drilled and completed in the second quarter of 2022. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-4.

Tables 9-9 through 9-12 include the proposed casing and cement programs for the Coteau 3 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

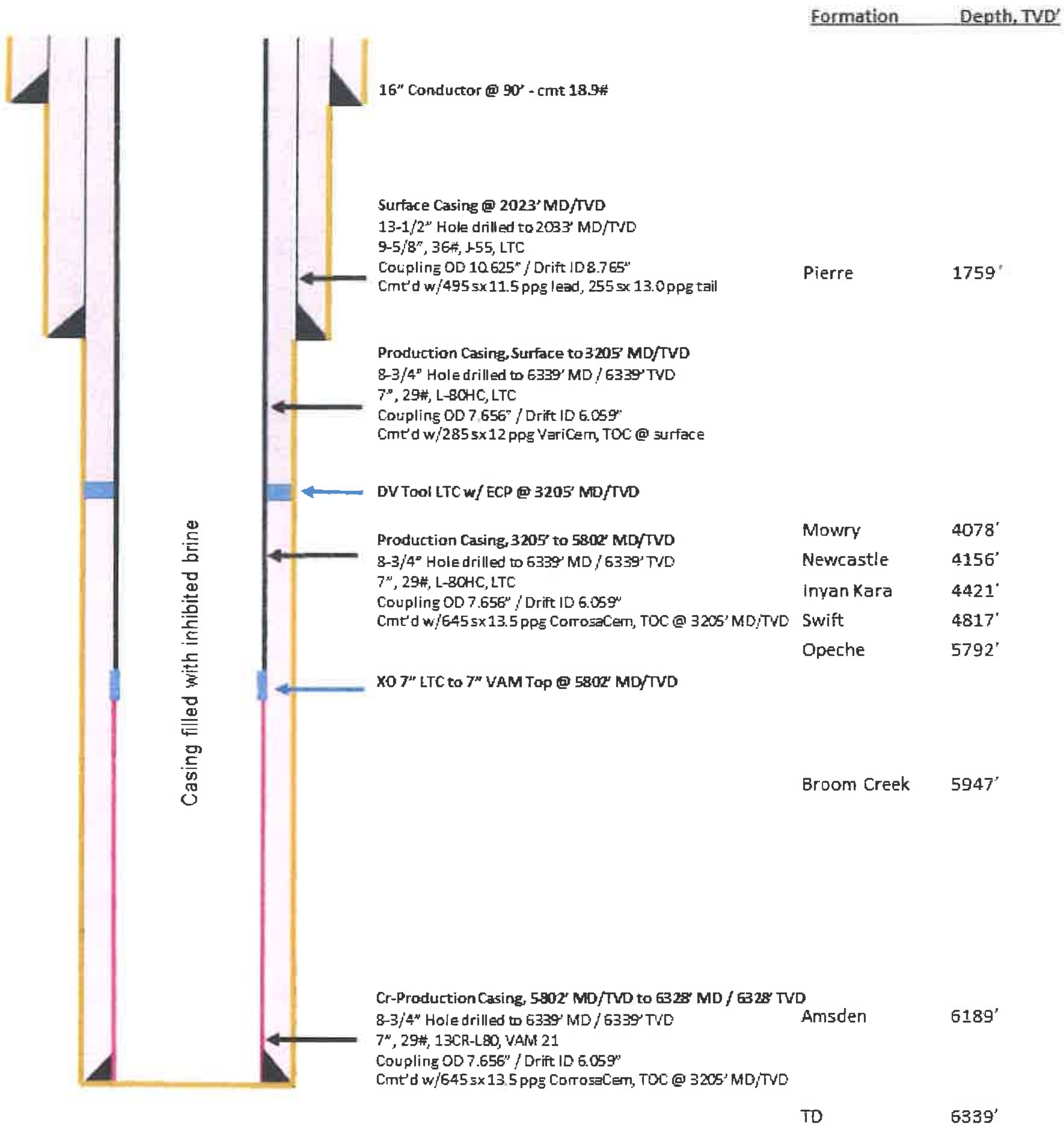
Coteau 3 (proposed)

Permit #:
API #:
SPUD:
TD: 6339' MD / 6339' TVD
RIG: T&S Rig 2

Rampart Energy Company
1512 Larimer St #550
Denver, CO 80202

Surface Location
2462 FSL & 2391 FEL SWNE Sec 2, T145N R88W
47° 24' 26.31" N / 101° 51' 13.02" W

Mercer County, ND
GL – 1988' KB – 2004'



Drawing Not to Scale, Depths subject to change

Figure 9-4. Coteau 3 proposed wellbore schematic.

Table 9-9. Coteau 3 As-Constructed Well Information

Well Name:	**Coteau 3**	**NDIC No.:**	**38917**	**API No.:**	**33-057-00044**
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.2 T145N R88W	**Footages:**	2462 S, 2391 E	**Total Depth, ft:**	6339 MD

* FEL: from the east line.

Table 9-10. Coteau 3 As-Constructed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5815	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5815	6350	CO_2-resistant production casing

Table 9-11. Coteau 3 As-Constructed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7.717	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-12. Coteau 3 As-Constructed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6350–3205	100	620
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft.

9.4 Coteau 4: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 4 well is expected to be drilled and completed in the second quarter of 2022. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-5.

Tables 9-13 through 9-16 include the proposed casing and cement programs for the Coteau 4 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

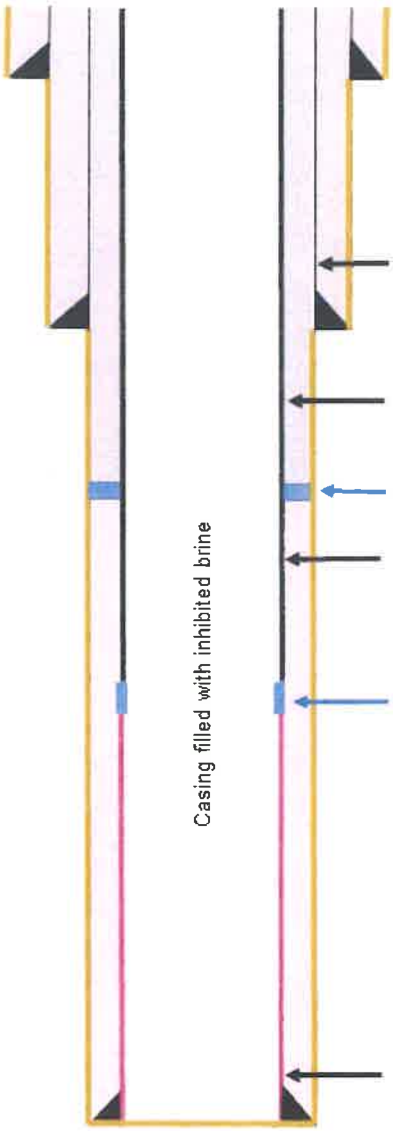
Coteau 4 (proposed)

Permit #:
API #:
SPUD:
TD: 6301' MD / 6301' TVD
RIG: T&S Rig 2

Rampart Energy Company
1512 Larimer St #550
Denver, CO 80202

Surface Location
1641 FSL & 2421 FWL NESW Sec 1, T145N R88W
47° 24' 18.00" N / 101° 50' 02.72" W

Mercer County, ND
GL – 2061' KB – 2077'



16" Conductor @ 90' - cmt 18.9#

Surface Casing @ 2023' MD/TVD
13-1/2" Hole drilled to 2033' MD/TVD
9-5/8", 36#, J-55, LTC
Coupling OD 10.625" / Drift ID 8.765"
Cmt'd w/495 sx 11.5 ppg lead, 255 sx 13.0 ppg tail

Production Casing, Surface to 3205' MD/TVD
8-3/4" Hole drilled to 6301' MD / 6301' TVD
7", 29#, L-80HC, LTC
Coupling OD 7.656" / Drift ID 6.059"
Cmt'd w/285 sx 12 ppg VariCem, TOC @ surface

DV Tool LTC w/ ECP @ 3205' MD/TVD

Production Casing, 3205' to 5757' MD/TVD
8-3/4" Hole drilled to 6301' MD / 6301' TVD
7", 29#, L-80HC, LTC
Coupling OD 7.656" / Drift ID 6.059"
Cmt'd w/645 sx 13.5 ppg CorrosaCem, TOC @ 3205' MD/TVD

XO 7" LTC to 7" VAM Top @ 5757' MD/TVD

Cr-Production Casing, 5757' MD/TVD to 6290' MD / 6290' TVD
8-3/4" Hole drilled to 6301' MD / 6301' TVD
7", 29#, 13CR-L80, VAM 21
Coupling OD 7.656" / Drift ID 6.059"
Cmt'd w/645 sx 13.5 ppg CorrosaCem, TOC @ 3205' MD/TVD

Formation	Depth, TVD'
Pierre	1754'
Mowry	4049'
Newcastle	4129'
Inyan Kara	4404'
Swift	4789'
Opeche	5747'
Broom Creek	5886'
Amsden	6151'
TD	6301'

Drawing Not to Scale, Depths subject to change

Figure 9-5. Coteau 4 proposed wellbore schematic.

Table 9-13. Coteau 4 As-Constructed Well Information

Well Name:	**Coteau 4**	**NDIC No.:**	**38918**	**API No.:**	**33-057-00045**
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.1 T145N R88W	**Footages:**	1641 S, 2421 W	**Total Depth, ft:**	6301 MD

Table 9-14. Coteau 4 As-Constructed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5769	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5769	6298	CO_2-resistant production casing

Table 9-15. Coteau 4 As-Constructed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-16. Coteau 4 As-Constructed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6298–3205	100	610
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft

11.2 Coteau 2 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 2 (Figure 9-3 and Tables 9-5 through 9-8) prior to project start-up in 2022, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 2 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 2 completed wellbore is shown in Figure 11-3.

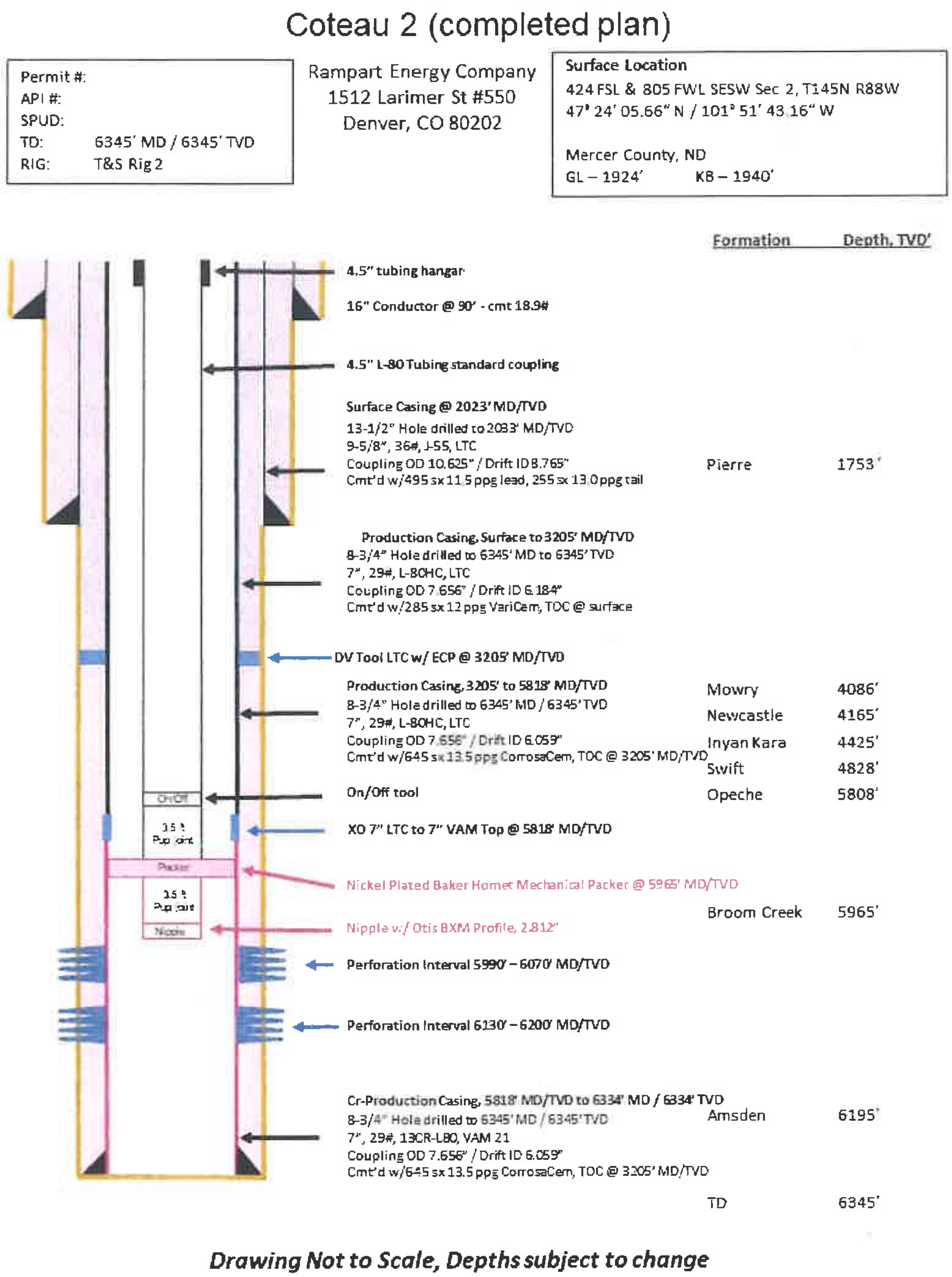


Figure 11-3. Coteau 2 proposed completed wellbore schematic.

11.3 Coteau 3 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 3 (Figure 9-4 and Tables 9-9 through 9-12) prior to project start-up in 2022, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 3 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 3 completed wellbore is shown in Figure 11-4.

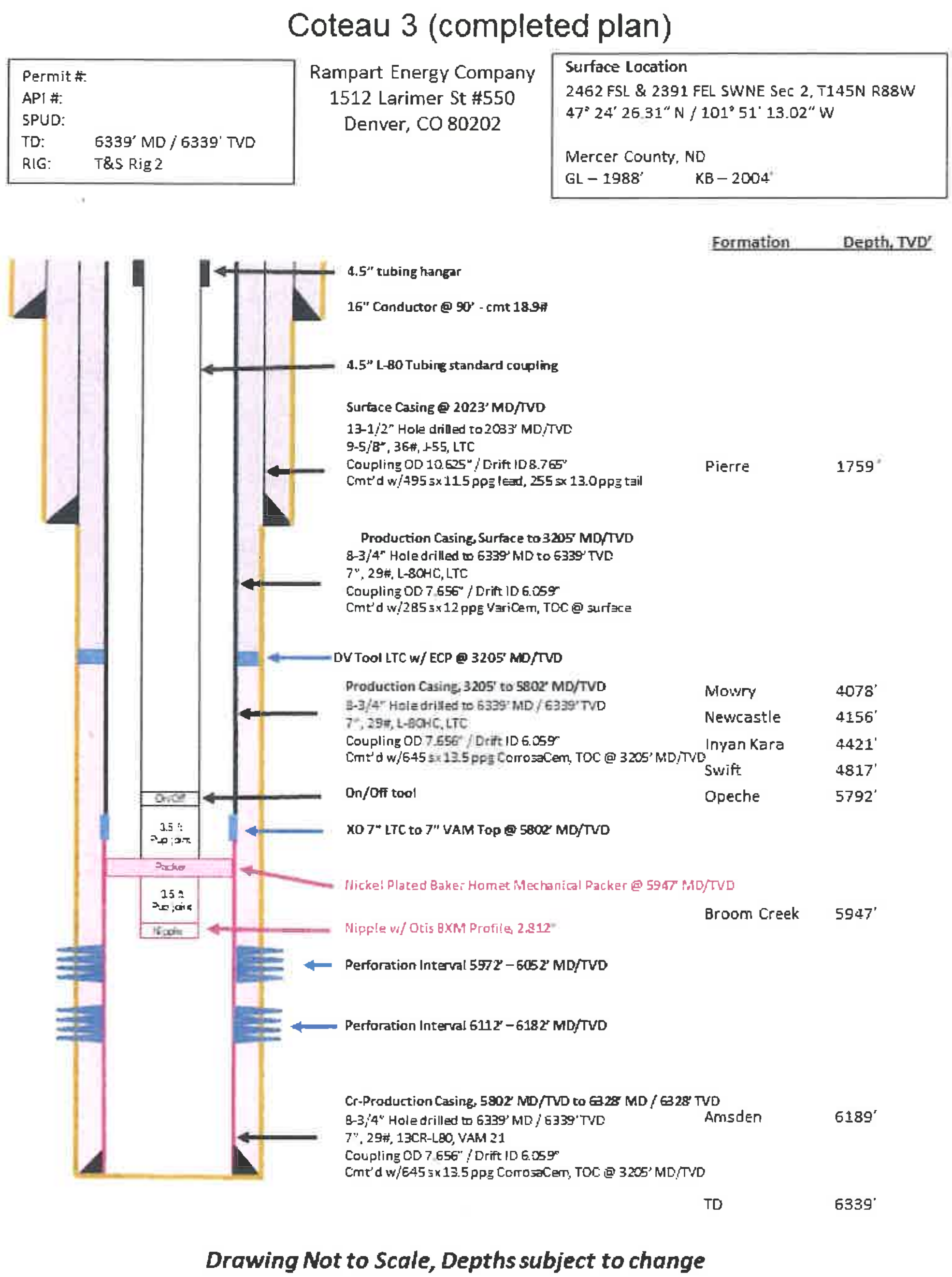


Figure 11-4. Coteau 3 proposed completed wellbore schematic.

11.4 Coteau 4 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 4 (Figure 9-5 and Tables 9-13 through 9-16) prior to project start-up in 2022, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 4 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 4 completed wellbore is shown in Figure 11-5.

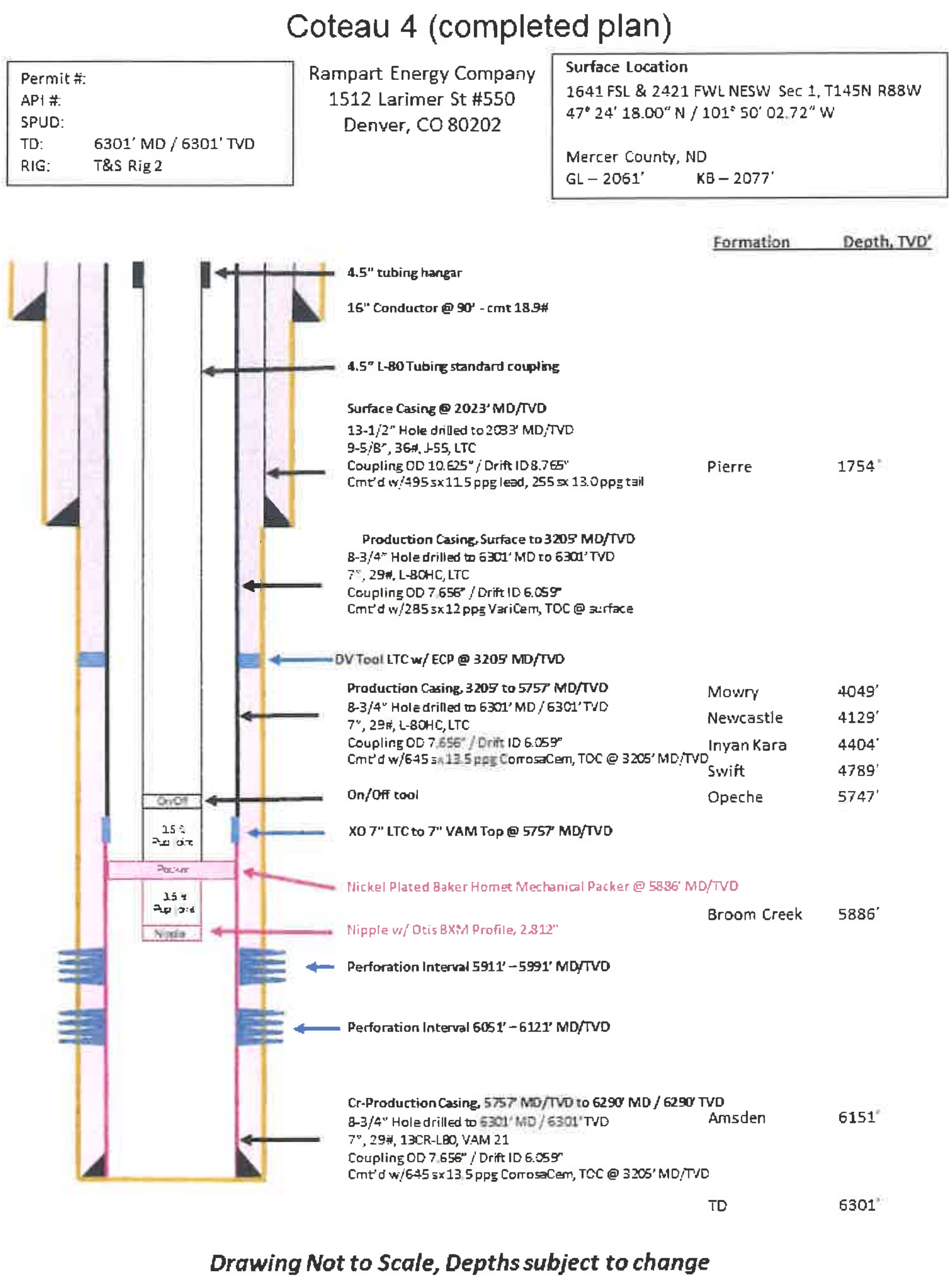


Figure 11-5. Coteau 4 proposed completed wellbore schematic.

Kadrmas, Bethany R.

From: McPherson, Madie <MMcPherson@fredlaw.com>
Sent: Friday, July 22, 2022 9:20 AM
To: Kadrmas, Bethany R.
Cc: Entzi-Odden, Lyn
Subject: Dakota Gasification Company - Telephonic Communication Affidavit - NDIC Case Nos. 29450 ,29451, & 29452
Attachments: DGC - Hicks ltr flg Tel Aff - NDIC Case Nos. 29450, 29451, & 29452_76680377(1).PDF

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Good morning, Bethany –

Please see the attached Telephonic Communication Affidavit for filing in NDIC Case Nos. 29450, 29451, and 29452.

Thank you,

Madie McPherson | Legal Administrative Assistant | Fredrikson & Byron, P.A.
1133 College Drive, Suite 1000 | Bismarck, North Dakota 58501
Main: 701.221.8700 | Direct: 701.221.8654 | mmcpherson@fredlaw.com

****This is a transmission from the law firm of Fredrikson & Byron, P.A. and may contain information which is privileged, confidential, and protected by the attorney-client or attorney work product privileges. If you are not the addressee, note that any disclosure, copying, distribution, or use of the contents of this message is prohibited. If you have received this transmission in error, please destroy it and notify us immediately at our telephone number (612) 492-7000. The name and biographical data provided above are for informational purposes only and are not intended to be a signature or other indication of an intent by the sender to authenticate the contents of this electronic message.****

Fredrikson & BYRON, P.A.

July 22, 2022

VIA EMAIL
Mr. Bruce Hicks
North Dakota Industrial Commission
Oil and Gas Division
600 East Boulevard
Bismarck, ND 58505

RE: CASE NO. 29450
CASE NO. 29451
CASE NO. 29452
Dakota Gasification Company

Dear Mr. Hicks:

Enclosed please find herewith for filing the original TELEPHONIC COMMUNICATION AFFIDAVIT with regard to the above-captioned matters.

Should you have any questions, please advise.

Sincerely,

LAWRENCE BENDER

LB:mlm

Enclosure

cc: Bret Fossum (w/encl.) – *via email*

76674973 v1

BEFORE THE NORTH DAKOTA INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 29450: **Application of Dakota Gasification Company requesting consideration for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Dakota Gasification Company intends to capture carbon dioxide from the Great Plains Synfuels Plant and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT July 19, 2022. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information mayobtained from Steve Fried, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Dakota Gasification Company, 1717 East Interstate Avenue, Bismarck, ND 58503.**

CASE NO. 29451: **Application of Dakota Gasification Company to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Dakota Gasification Company storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code Section 38-22-10.**

CASE NO. 29452: **Application of Dakota Gasification Company for an order of the Commission determining the amount of financial responsibility for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant in the storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36,Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.**

TELEPHONIC COMMUNICATION AFFIDAVIT

Bret Fossum being first duly sworn deposes and states as follows: That on Wednesday, July 20, 2022, I testified under oath before the North Dakota Industrial Commission in Case Nos. 29450, 29451, and 29452. My testimony was presented by telephone from 281-650-5979, at the offices of and on behalf of the Energy and Environmental Research Center, 15 North 23rd Street, Stop 9018, Grand Forks, North Dakota 58202-9018.

BRET FOSSUM

STATE OF TEXAS)
) ss.
COUNTY OF HAYS)

On July 21, 2022, Bret Fossum of the Energy and Environmental Research Center, known to me to be the person described in and who executed the foregoing instrument, personally appeared before me and acknowledged that he executed the same as a free act and deed.

Notary Public

76659271 v1

CAROLINE E ADAMS
Notary Public, State of Texas
Comm. Expires 02-23-2024
Notary ID 12483220-8

Kadrmas, Bethany R.

From: Clyde Eisenbeis <cte677@gmail.com>
Sent: Monday, July 25, 2022 10:00 AM
To: Kadrmas, Bethany R.
Subject: Case 29450 29452 - Addendum
Attachments: Industrial Commission 220725 Addendum CO2 signed.pdf

***** CAUTION: This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Attached is an addendum letter.

Let me know if you received the letter. Thanks!

Clyde

Clyde Eisenbeis
cte677@gmail.com
https://gcc02.safelinks.protection.outlook.com/?url=https%3A%2F%2Fndacademy.foxping.com%2F&data=05%7C01%7Cbrkadrmas%40nd.gov%7C53aaf4baadd0467cea3608da6e4e6efe%7C2dea0464da514a88bae2b3db94bc0c54%7C0%7C0%7C637943580543981029%7CUnknown%7CTWFpbGZsb3d8eyJWIjoiMC4wLjAwMDAiLCJQIjoiV2luMzIiLCJBTiI6Ik1haWwiLCJXVCI6Mn0%3D%7C3000%7C%7C%7C&sdata=IfPOQoaRfNUil9C0EBSJQ7M2HkhoA1aijsgSmgp9PfA%3D&reserved=0
641-691-0110

~~~~~~

On Thu, Jul 21, 2022 at 5:09 PM Clyde Eisenbeis <cte677@gmail.com> wrote:
>
> Attached is a signed letter. Thanks!
>
> ~~~~~~
>
> On Thu, Jul 21, 2022 at 5:04 PM Clyde Eisenbeis <cte677@gmail.com> wrote:
> >
> > The letter to the Industrial Commissioners is attached. Let me know
> > if you received it and can read it. Thanks!
> >
> > Clyde
> >
> > -----------------------------
> > Clyde Eisenbeis
> > cte677@gmail.com
> > https://gcc02.safelinks.protection.outlook.com/?url=https%3A%2F%2Fnd
> > academy.foxping.com%2F&data=05%7C01%7Cbrkadrmas%40nd.gov%7C53aaf
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> > =0
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Clyde Eisenbeis
2819 Hogan Dr
Bismarck, ND 58503
641-691-0110
cte677@gmail.com

25-Jul-2022 ------------------------- **Addendum** ---------------------------

Department of Mineral Resources
Oil & Gas Division
1016 East Calgary Avenue
Bismarck, North Dakota 58503

RE: Application for Geologic Storage of Carbon Dioxide
Hearing to consider application. 9am, 20 Jul 2022,
Dept. of Mineral Resources Conference Room

Addendum to 20-Jul-2022 Letter

Drilling?

After the well was dug in that valley for the CO_2 project

- There is sand in the water.
- The water color changed:
  - It is unknown what contaminates changed the water color.
  - The contaminates, that changed the water color, could harm people.
  - Future contaminates, could harm people.

It is unknown if it is possible to completely seal well holes. Over time, water penetrates almost everything.

Steel cannot be welded to rocks. Filling the area around a well pipe, with concrete, may delay the penetration. The odds are quite high that water, and some gasses, will eventually bypass the filling around the pipes.

If CO_2 escaped from Broom Creek, it could kill people. Injecting CO_2 puts people at risk.

- CO_2 is heavier than air.
- In 1986, CO_2 killed close to 2,000 people living near Lake Nyos in Cameron, Africa.

If sulfur killed some cattle, are residents drinking well water that has sulfur? Is rural water contaminated with sulfur? Is Lake Sakakawea, in that area, contaminated with sulfur? Are the fish, in that area, contaminated with sulfur?

No one living on the land?

To clarify further, Lucille Sailer did “not” sign the doc that allowed “seismic” testing on her farmland. I did not know there were two docs.

The coal mining pond water discharge into a farmland creek did flood her farmland.

The flooding of her farmhouse basement occurred when deep holes were dug for the Dakota Gasification Company (Basin Electric) and / or Antelope Valley Coal Power Plant (Basin Electric).

While the coal mining pond water discharge into a farmland creek resulted in cattails on her farmland, those cattails are no longer there.

“Know” there is zero risk?

CO2 is heavier than air.

Storing CO2 under that valley may not be safe. If CO2 escaped, it could kill people who live in that valley.

In addition, storing CO2 on a mountain may not be safe. If CO2 escaped on a mountain, it would sink to lower levels, which could kill people.

The safest place to store CO2 appears to be the ocean.

Best Regards,

Kadrmas, Bethany R.

From: Clyde Eisenbeis <cte677@gmail.com>
Sent: Thursday, July 21, 2022 5:10 PM
To: Kadrmas, Bethany R.
Subject: Re: Case 29450 29452
Attachments: Industrial Commission 220720 CO2.pdf

***** CAUTION: This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Attached is a signed letter. Thanks!

~~~~~~

On Thu, Jul 21, 2022 at 5:04 PM Clyde Eisenbeis <cte677@gmail.com> wrote:
>
> The letter to the Industrial Commissioners is attached. Let me know
> if you received it and can read it. Thanks!
>
> Clyde
>
> -----------------------------
> Clyde Eisenbeis
> cte677@gmail.com
> https://gcc02.safelinks.protection.outlook.com/?url=https%3A%2F%2Fndac
> ademy.foxping.com%2F&data=05%7C01%7Cbrkadrmas%40nd.gov%7Cc79392f7d
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> 641-691-0110
> -----------------------------
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Clyde Eisenbeis
2819 Hogan Dr
Bismarck, ND 58503
641-691-0110
cte677@gmail.com

20-Jul-2022 ------------------------ Updated on 20 Jul 2022 --------------------------

Department of Mineral Resources
Oil & Gas Division
1016 East Calgary Avenue
Bismarck, North Dakota 58503

RE: Application for Geologic Storage of Carbon Dioxide
Hearing to consider application. 9am, 20 Jul 2022,
Dept. of Mineral Resources Conference Room

My siblings and I own farmland

T146N R88W S34 N1/2 of NW1/4
T146N R88W S34 S1/2 of NW1/4

and mineral rights north of Beulah.

T145N R88W S3 Lot 1, Lot 2, and S1/2 of NE1/4
T145N R88W S3 SE1/4
T146N R88W S27 SE1/4
T146N R88W S27 SW1/4
T146N R88W S34 N1/2 of NW1/4
T146N R88W S34 S1/2 of NW1/4
T146N R88W S36 N1/2 of SE1/4
T145N R88W S10 S1/2 of N1/2
T145N R88W S11 NW1/4

On 15 Oct 2021, Shauna Laber [Basin Electric] and Kevin Solie [Basin Electric] approached me to sign a seismic permit. I would not sign that permit until it was modified.

Shauna Laber invited me to meet again on 4 Nov 2021. Bruce Fulker [Cougar Land Services] was there too. They wanted me to sign the "unmodified" permit. I said that would not happen until it was modified.

I asked Bruce Fulker if Carbon Dioxide Injection would affect the Bakken Formation. Bruce Fulker said no. The Bakken Formation is 2 to 3 miles below the surface. I responded that I thought Bakken is 1 to 2 miles below the surface in Mercer County.

Bruce Fulker said that I was wrong. The Carbon Dioxide Injection would be between 1 and 2 miles below the surface. Bruce Fulker said that the Bakken Formation is 2 to 3 miles below the surface.

I received the Bakken Formation elevation map from Kevin Solie [Basin Electric]. I added more numbers to put it into perspective (see enclosed maps). If injected, the Carbon Dioxide Injection could displace oil and gas in the Bakken Formation. All mineral rights owners should be told this.

Bruce Fulker lied to me. I wonder to whom else did Bruce Fulker and his cohorts lie?

I asked Shauna Laber if Bruce Fulker's lie was reported to Todd Telesz, Basin Electric CEO? She did not respond.

I asked Shauna Laber if Todd Telesz knew that the Carbon Dioxide Injection could displace oil and gas in the Bakken Formation, which could eliminate future income for farmers? She did not respond.

I asked Shauna Laber if Basin Electric will reimburse land owners for the future loss of oil and gas income? She did not respond.

I called my cousins Wayne Eisenbeis and Lyle Eisenbeis. They signed the permit. Lyle said he knew they would do it anyway with eminent domain, so he signed it to get rid of them.

Recently Shauna Laber emailed that the Carbon Dioxide Injection would be into the Broom Creek Formation.

I requested a Broom Creek Formation elevation map similar to the Bakken Formation elevation map. There has been no response.

After my meeting with Bruce Fulker [Cougar Land Services], I don’t trust what they say.

If oil and gas were displaced, by accident, there is no way to fix that. It would be too late.

The CO2 should be put in a location where there is no potential problem. Zero chance is the best.

---

1) Have all mineral rights owners been informed that the CO2 could displace oil and gas under their land?
2) Have all mineral rights owners been given the Bakken Formation elevations map?
3) Have all mineral rights owners been given a Broom Creek Formation elevations map?
4) Have all mineral rights owners been informed that this could cost them, their children, and / or their grandchildren millions of dollars in the future?
5) Is it possible there is an opening between the Broom Creek Formation and the Bakken Formation that could allow CO2 to displace oil and gas in the Bakken Formation?
6) Is it possible that pressurizing the CO2 in the Broom Creek Formation could rupture the gap between the Broom Creek Formation and the Bakken Formation that could allow CO2 to displace oil and gas?
7) Is it possible that an earthquake could allow CO2 to displace oil and gas in the Bakken Formation?
8) Will Basin Electric reimburse mineral rights owners for potential future loss of oil and gas income?

~~~~~~

During the hearing, it is difficult to listen to others speak, and, simultaneously, compile my thoughts.

Below are my thoughts that occurred throughout the hearing. I don't recall which ones I verbally stated.

North Dakota Century Code

I heard yesterday that the ND legislature created a law that allows "others" to remove minerals under your mineral rights land.

Can the state remove minerals, that are your property, with no just cause? The Industrial Commission should take this to a federal court, and if necessary to the US Supreme Court.

Bakken Formation

Why was the Bakken Formation not mentioned today until I mentioned it? I do not recall hearing the name Bakken (unless that happened when I went to the rest room).

Is the Bakken Formation in the reports submitted to the Industrial Commission? If not, why not?

The Bakken Formation could be affected by CO2 injection into Broom Creek. This could result in millions of dollar losses to the mineral right owners. This should be included in the reports.
~~~~~~

Models

Today I heard the word “model” multiple times. Models are often inaccurate.

A good example is the global warming models which supposedly proved, many years ago, that parts of the US would be underwater by now. This did not happen. That model was incorrect.

Code writers, who write code for models, can produce any result they want. If the model result is not what they want, they can keep modifying the code until the model produces the result they want.

Today I heard that that EERC, at one point, switched to a different model. I interpret this as meaning that the first model produced a result that EERC did not like, so they switched to a different model that did produce a model result they did like.

As an example, the global warming folks identify areas where there is new water on top of the land. This is misleading.

A good example is Florida / sink holes. The land elevation is dropping. The ocean is not rising.

The ocean cannot be higher in some places and not higher in other places. Higher ocean levels would affect “all” land throughout the world, not just some parts of the world.

Broom Creek 3D map

Today I heard the there is no Broom Creek 3D map. I also heard that the spacing between Bakken and Broom Creek is 1,000 feet. A distance of 1,000 feet may seem like a lot, but that is less than the length of three football fields including end zones. That is very close.

How does EERC know the distance between is 1,000 feet, without a 3D map?

Is that 1,000 feet from the “top” of Broom Creek to the “top” of Bakken? Or is it 1,000 feet from the “bottom” of Broom Creek to the “top” of Bakken?

Is it 1,000 feet over the entire area of the CO2 storage? Or does the distance vary? Maybe it is as close as one foot in some places? Or maybe they are already connected?

Did they drill vertically through Broom Creek until they hit Bakken? If so, there is already a breach between Broom Creek and Bakken.

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When I visit with her, she provides a lengthy list which includes coal mining pond water discharge into a farmland creek that floods her farm house basement, and floods her farmland. Some of her farmland is covered with cattails.

In addition, when she signed the contract, she was not told that CO2 injection could displace the oil / gas under her land, was not given a Bakken Formation map, was not given a Broom Creek Formation map, was not told that this could affect her water.

“All” contracts should be invalidated as they did not provide adequate information.

Technology

I heard the comment that it is not economically feasible to extract oil / gas under our farmland.

The same was said years ago in the Williston area. Oil / gas extraction “was not” economically feasible.

The new technology of horizontal drilling has made it economically feasible, as is evidenced by the current oil / gas extraction in the Williston area.

It is possible that future new technology could make it economically feasible to extract oil / gas underneath our farmland.

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If the testing discovers a leak:

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This includes things such as earthquakes. Today, I heard that the odds of an earthquake are little. This means the odds are not zero. If an earthquake does occur, the mineral rights owners should not lose money. The proponents should lose money.

If the proponents do not sign these types of legal documents, this indicates they "do not" know. They are guessing.

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This makes complete sense. If I were an oil company, I would NOT drill where CO_2 was injected. That is too much of a risk that could have many complications.

CO_2 storage should not be placed within a hundred miles of the Bakken Formation. Otherwise we, and our descendants, could lose a lot of money

Another hearing

There should be another hearing, that includes us, which discusses the responses from Basin Electric and EERC.

This would give us the opportunity to discuss those responses and ask more questions. There is a lot of money at stake.

Best Regards,

BTW Enclosed are the Bakken Formation elevation maps.

Kadrmas, Bethany R.

From: Clyde Eisenbeis <cte677@gmail.com>
Sent: Thursday, July 21, 2022 5:05 PM
To: Kadrmas, Bethany R.
Subject: Case 29450 29452
Attachments: Industrial Commission 220720 CO2.pdf; Bakken Formation Elevation large and zoomed.pdf

***** CAUTION: This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

The letter to the Industrial Commissioners is attached. Let me know if you received it and can read it. Thanks!

Clyde

Clyde Eisenbeis
cte677@gmail.com
https://gcc02.safelinks.protection.outlook.com/?url=https%3A%2F%2Fndacademy.foxping.com%2F&data=05%7C01%7Cbrkadrmas%40nd.gov%7Cabe1f99bbb3e4bd5b41308da6b651ccc%7C2dea0464da514a88bae2b3db94bc0c54%7C0%7C0%7C637940379402089623%7CUnknown%7CTWFpbGZsb3d8eyJWIjoiMC4wLjAwMDAiLCJQIjoiV2luMzIiLCJBTiI6Ik1haWwiLCJXVCI6Mn0%3D%7C3000%7C%7C%7C&sdata=m6uzJFOaa%2B3dEU2aVy3sGQx15Qe8NwoRVupmQPAHuvE%3D&reserved=0
641-691-0110

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Clyde Eisenbeis
2819 Hogan Dr
Bismarck, ND 58503
641-691-0110
cte677@gmail.com

20-Jul-2022 ------------------------- Updated on 20 Jul 2022 ---------------------------

Department of Mineral Resources
Oil & Gas Division
1016 East Calgary Avenue
Bismarck, North Dakota 58503

RE: Application for Geologic Storage of Carbon Dioxide
Hearing to consider application. 9am, 20 Jul 2022,
Dept. of Mineral Resources Conference Room

My siblings and I own farmland

T146N R88W S34 N1/2 of NW1/4
T146N R88W S34 S1/2 of NW1/4

and mineral rights north of Beulah.

T145N R88W S3 Lot 1, Lot 2, and S1/2 of NE1/4
T145N R88W S3 SE1/4
T146N R88W S27 SE1/4
T146N R88W S27 SW1/4
T146N R88W S34 N1/2 of NW1/4
T146N R88W S34 S1/2 of NW1/4
T146N R88W S36 N1/2 of SE1/4
T145N R88W S10 S1/2 of N1/2
T145N R88W S11 NW1/4

On 15 Oct 2021, Shauna Laber [Basin Electric] and Kevin Solie [Basin Electric] approached me to sign a seismic permit. I would not sign that permit until it was modified.

Shauna Laber invited me to meet again on 4 Nov 2021. Bruce Fulker [Cougar Land Services] was there too. They wanted me to sign the "unmodified" permit. I said that would not happen until it was modified.

I asked Bruce Fulker if Carbon Dioxide Injection would affect the Bakken Formation. Bruce Fulker said no. The Bakken Formation is 2 to 3 miles below the surface. I responded that I thought Bakken is 1 to 2 miles below the surface in Mercer County.

Bruce Fulker said that I was wrong. The Carbon Dioxide Injection would be between 1 and 2 miles below the surface. Bruce Fulker said that the Bakken Formation is 2 to 3 miles below the surface.

I received the Bakken Formation elevation map from Kevin Solie [Basin Electric]. I added more numbers to put it into perspective (see enclosed maps). If injected, the Carbon Dioxide Injection could displace oil and gas in the Bakken Formation. All mineral rights owners should be told this.

Bruce Fulker lied to me. I wonder to whom else did Bruce Fulker and his cohorts lie?

I asked Shauna Laber if Bruce Fulker's lie was reported to Todd Telesz, Basin Electric CEO? She did not respond.

I asked Shauna Laber if Todd Telesz knew that the Carbon Dioxide Injection could displace oil and gas in the Bakken Formation, which could eliminate future income for farmers? She did not respond.

I asked Shauna Laber if Basin Electric will reimburse land owners for the future loss of oil and gas income? She did not respond.

I called my cousins Wayne Eisenbeis and Lyle Eisenbeis. They signed the permit. Lyle said he knew they would do it anyway with eminent domain, so he signed it to get rid of them.

Recently Shauna Laber emailed that the Carbon Dioxide Injection would be into the Broom Creek Formation.

I requested a Broom Creek Formation elevation map similar to the Bakken Formation elevation map. There has been no response.

After my meeting with Bruce Fulker [Cougar Land Services], I don't trust what they say.

If oil and gas were displaced, by accident, there is no way to fix that. It would be too late.

The CO2 should be put in a location where there is no potential problem. Zero chance is the best.

---

1) Have all mineral rights owners been informed that the CO_2 could displace oil and gas under their land?
2) Have all mineral rights owners been given the Bakken Formation elevations map?
3) Have all mineral rights owners been given a Broom Creek Formation elevations map?
4) Have all mineral rights owners been informed that this could cost them, their children, and / or their grandchildren millions of dollars in the future?
5) Is it possible there is an opening between the Broom Creek Formation and the Bakken Formation that could allow CO_2 to displace oil and gas in the Bakken Formation?
6) Is it possible that pressurizing the CO_2 in the Broom Creek Formation could rupture the gap between the Broom Creek Formation and the Bakken Formation that could allow CO_2 to displace oil and gas?
7) Is it possible that an earthquake could allow CO_2 to displace oil and gas in the Bakken Formation?
8) Will Basin Electric reimburse mineral rights owners for potential future loss of oil and gas income?

~~~~~~

During the hearing, it is difficult to listen to others speak, and, simultaneously, compile my thoughts.

Below are my thoughts that occurred throughout the hearing. I don't recall which ones I verbally stated.

North Dakota Century Code

I heard yesterday that the ND legislature created a law that allows "others" to remove minerals under your mineral rights land.

Can the state remove minerals, that are your property, with no just cause? The Industrial Commission should take this to a federal court, and if necessary to the US Supreme Court.

Bakken Formation

Why was the Bakken Formation not mentioned today until I mentioned it? I do not recall hearing the name Bakken (unless that happened when I went to the rest room).

Is the Bakken Formation in the reports submitted to the Industrial Commission? If not, why not?

The Bakken Formation could be affected by CO_2 injection into Broom Creek. This could result in millions of dollar losses to the mineral right owners. This should be included in the reports.
~~~~~~

Models

Today I heard the word “model” multiple times. Models are often inaccurate.

A good example is the global warming models which supposedly proved, many years ago, that parts of the US would be underwater by now. This did not happen. That model was incorrect.

Code writers, who write code for models, can produce any result they want. If the model result is not what they want, they can keep modifying the code until the model produces the result they want.

Today I heard that that EERC, at one point, switched to a different model. I interpret this as meaning that the first model produced a result that EERC did not like, so they switched to a different model that did produce a model result they did like.

As an example, the global warming folks identify areas where there is new water on top of the land. This is misleading.

A good example is Florida / sink holes. The land elevation is dropping. The ocean is not rising.

The ocean cannot be higher in some places and not higher in other places. Higher ocean levels would affect “all” land throughout the world, not just some parts of the world.

Broom Creek 3D map

Today I heard the there is no Broom Creek 3D map. I also heard that the spacing between Bakken and Broom Creek is 1,000 feet. A distance of 1,000 feet may seem like a lot, but that is less than the length of three football fields including end zones. That is very close.

How does EERC know the distance between is 1,000 feet, without a 3D map?

Is that 1,000 feet from the “top” of Broom Creek to the “top” of Bakken? Or is it 1,000 feet from the “bottom” of Broom Creek to the “top” of Bakken?

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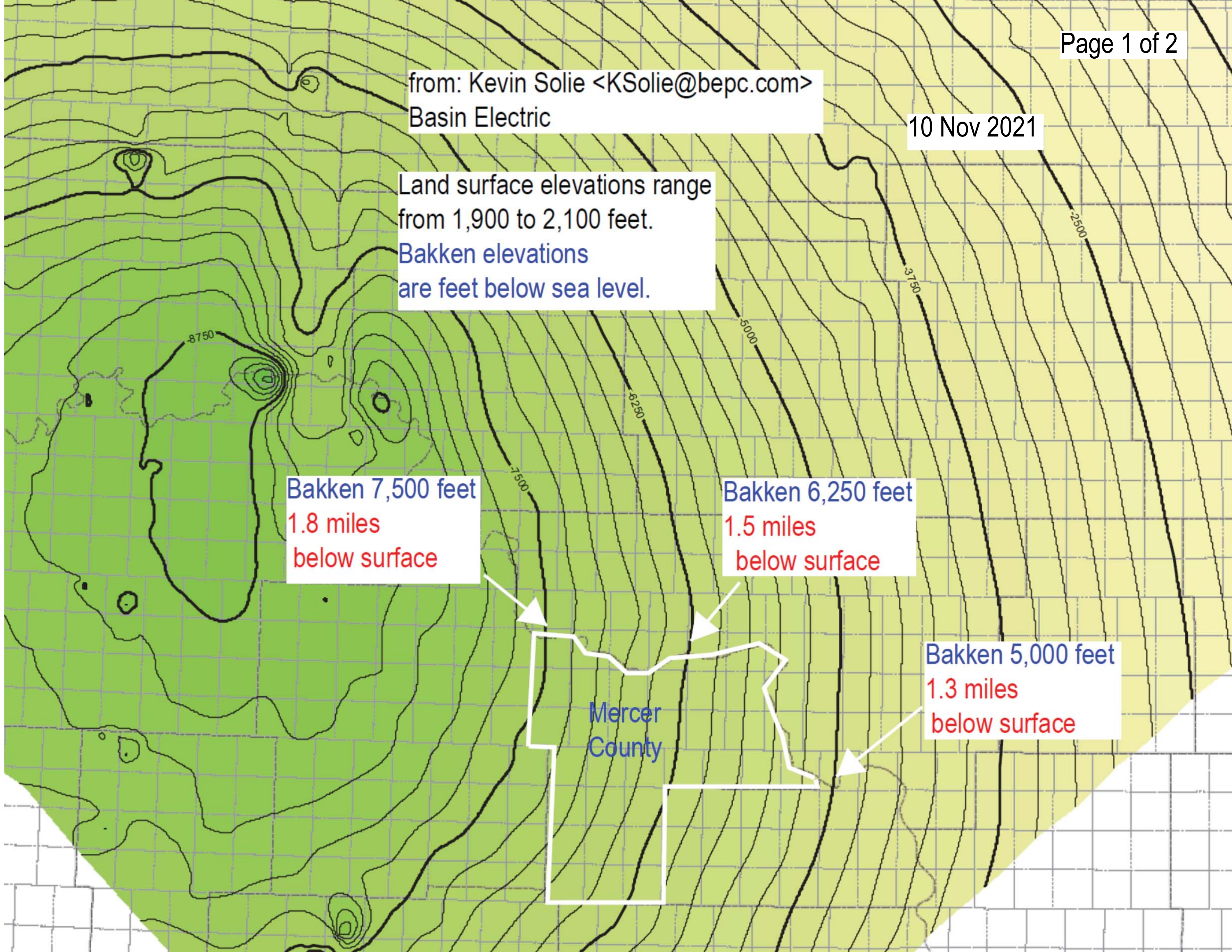
Best Regards,

BTW Enclosed are the Bakken Formation elevation maps.

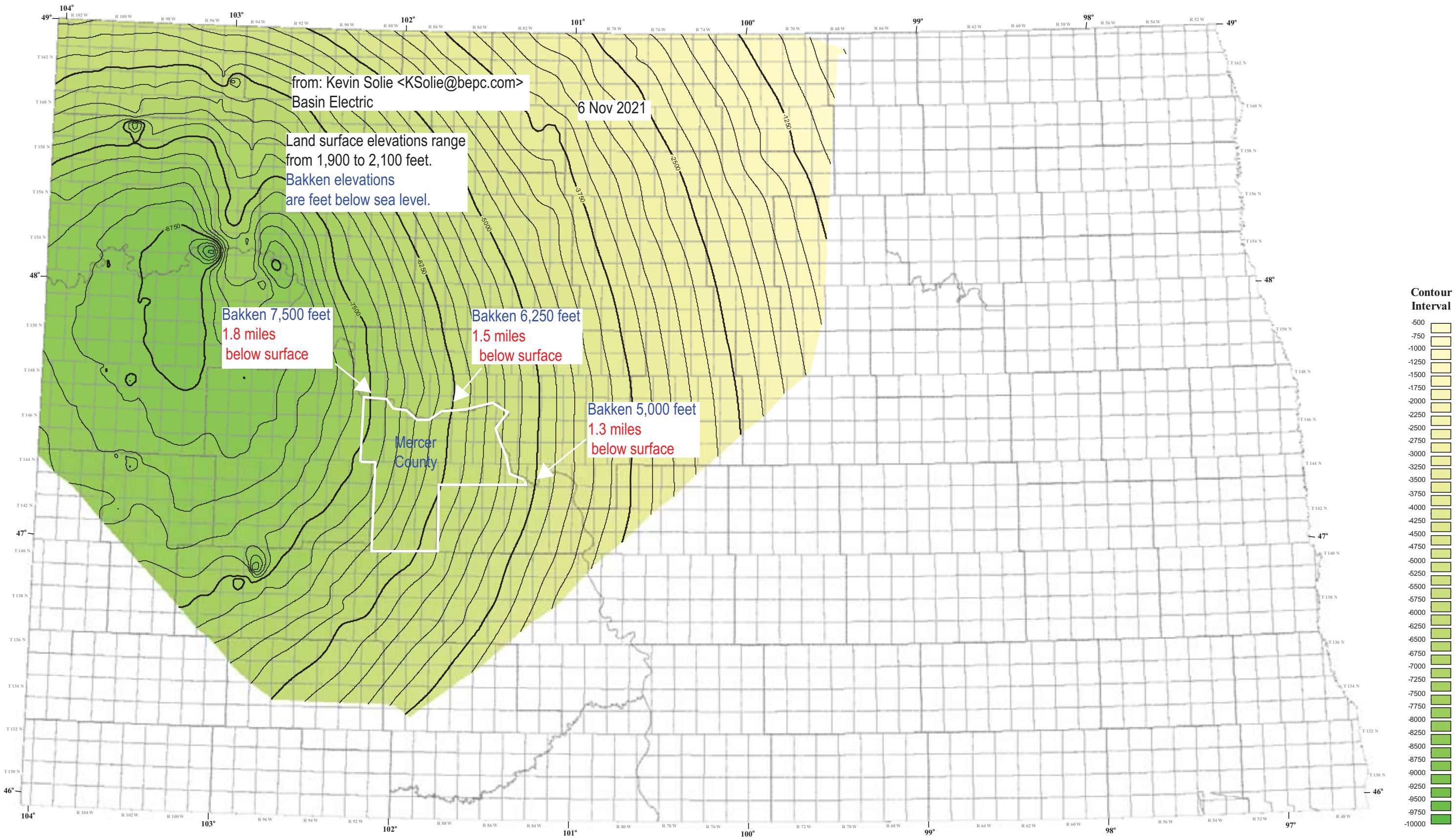

from: Kevin Solie <KSolie@bepc.com>
Basin Electric
10 Nov 2021
Land surface elevations range from 1,900 to 2,100 feet.
Bakken elevations are feet below sea level.
-8750
-7500
-6250
-5000
-3750
-2500
Bakken 7,500 feet
1.8 miles below surface
Bakken 6,250 feet
1.5 miles below surface
Bakken 5,000 feet
1.3 miles below surface
Mercer County

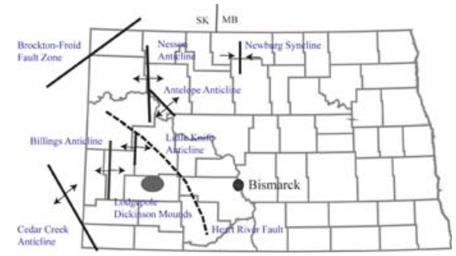
North Dakota Geological Survey
Geologic Investigations No. 59
Bakken Formation Map Series: Sheet 5
2008

Edward C. Murphy, State Geologist
Lynn D. Helms, Director Dept. of Mineral Reources

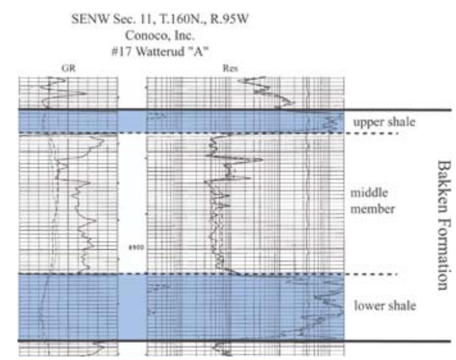
Structure on the Top of the Bakken Formation

Julie A. LeFever





Index Map



Typical Log

Explanation

Top of Bakken Formation (in feet below sea level)

Township Boundaries

County Boundaries

Scale 1:1,000,000

0 20 40 60 80 Miles

0 20 40 60 80 Kilometers

North American Datum 1927 Lambert Conformal Conic

This letter was not received before the deadline for written comments. Therefore, it is not part of the evidentiary record of this case.

Kadrmas, Bethany R.

From: Perry Anderson <perryanderson_55@q.com>
Sent: Sunday, July 24, 2022 4:00 AM
To: Kadrmas, Bethany R.

Subject: 7/20/2022 NDIC hearing on DGC Carbon Pipeline Project

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

This should be entered into the record, as it answers many of the questions posed to your experts which they could not or would not answer!!! (Such as the current CO2 line going to Canada and what's to be done with it) PLEASE UNDERSTAND TRANSPARENCY IS CRITICAL IN MATTERS LIKE THIS??? MY QUESTION WAS SIMPLE - SIX WELLS 2 APPLICATIONS one from Bakken Energy LLC and one from DGC?? WHY??

At the close of the meeting there seemed to be confusion about my Questions and it was stated BASIN and DGC had nothing to do with Bakken Energy LLC's Application!! Still Agree????

"This proposes a use for the DGC plant that we heard today was not going to continue in its current use."

-01 – Dakota H2 Hub; Submitted by Bakken Energy LLC; Project Duration: 2021-2027; Total Project Costs: $1.75 billion; Amount Requested: $10 million (grant) – a letter has been received to increase the grant amount to $20 million based on recent legislative action; $100 million (loan). The purpose of the Dakota H2 Hub is to establish one of the largest and the lowest cost clean hydrogen production hubs in the country in the shortest amount of time, continue employment of the Synfuels Plant jobs, become a center of innovation and economic development, reduce site CO2 emissions by 6 million tons/yr. and put ND on a path to permanently solving its natural gas flaring problem. The use of an existing site at the Synfuels plant is a strong positive aspect with regards to costs, the proposed technology is well known, and the project was viewed as technically sound. The quality and clarity of the methodology was average and could have scored higher with additional information around the carbon capture and storage facility plans. The facilities and equipment available were notably or exceptionally good due to the repurposing of an existing facility. The budget was most likely sufficient, and the strategic partnerships are adequate to exceptional. There would be a significant impact to ND's economy, not only in avoiding the potential shuttering of the DGC facility but in the development of a major hub of clean hydrogen production regionally, and even nationally. As carbon intensive energy production is declining in the state and around the nation, this would be a transformative response to the demand for cleaner energy production solutions. The lack of a concrete offtake purchase agreement and the unknowns associated with a new energy source do pose a significant risk. The size of the facility will impact the overall oil and gas industry with it's significant use of natural gas in the future as the state's GOR increases. This project is expected to result in one of the lowest cost single sources of clean hydrogen production in the country due to the low cost of redevelopment of the Synfuels Plant, which is unique, and shorter conversion time that provides a competitive advantage. The size and complexity of this project makes it have a 6-year timeframe. The $10M grant request is 1% of the project ($1754M) cost. The applicants' intention is to spend the grant on a 1:1 basis (matched with private funding) during the Pre-FEED and FEED stage ($29.8M). The loan ($100M) will be in addition to a DOE loan ($1149.7M) and $493.9M of private equity. The competition for the Federal loan also is a risk. Two conditions were identified: (1) that the CSEA grant funding comes from SB 2345 (hydrogen allocation) dollars and (2) that the sale of DGC to Bakken Energy LLC be completed. Presentation was made by Mr. Steven LeBow, Mr. Mike Hopkins, Mr. Shane Goettle, Curt Launer with Bakken Energy LLC, Jacek Szyszkowski, ATCO, and Mr. Paul Sukut with Basin Electric Cooperative for C-01-01 – Dakota H2 Hub. A copy of their handout responding to the Technical Reviewers' comments is available in the Industrial Commission files. DRAFT Clean Sustainable Energy Authority Page 12 December 14, 2021 After the presentation the CSEA members had a discussion with the applicant and Mr. Sukut on the following points: • In response to question, it was stated that the production of fertilizer will continue after the development of the clean hydrogen at the plant and the ammonia will also be decarbonized. • Review of the breakdown of the processed natural gas and the capture of the carbon and the making of the hydrogen and the input and the output. • Role of Mitsubishi Power Americas as a partner in the project. • Status of the Department of Energy loan application. • How the CO2 pipeline that goes from the SynFuels Plant into Canada will be utilized in this project. Response was that the input gas would not come from the Northern Border Pipeline; CO2 pipeline will be a 50/50 ownership with Basin Electric. 100 miles of the pipeline from Tioga to Beulah will be repurposed. The rest of the pipeline will remain a CO2 pipeline to Weyburn. • Discussions have been ongoing with North American Coal regarding the status of the mine and the impact on the employees • It was clarified that there could be a DOE loan guarantee which they are currently applying for; a separate piece is the availability of $8 billion infrastructure grants that were recently appropriated by Congress – rules and allocations for those grants are still being developed. The applicant will be pursuing all grants, loans, tax credits, etc. • Sale of the SynFuels Plant from Basin Electric to Bakken Energy LLC and the commitment to continue the employment of the current SynFuels employees (525 employees) from the period of the acquisition of the SynFuels Plant through the redevelopment of the plant as these highly qualified employees will be doing similar work and they are employees they want to have on staff. • Discussion of the EOR potential using CO2 to the Bakken and the importance of having a CO2 pipeline available for that purpose. • Discussions that had been taking place with Basin identifying the type of equipment that would be beneficial to this project so a determination could be made whether it would be beneficial to this project. • Usage of the grant and loan funding if awarded – pre-engineering, pre-FEED will be the predominant usage; will not be for operations. Design work, assessing the state of the equipment at the SynFuels plant, etc. • It is hoped that as the project expands there will be opportunities for more employees to be hired. • The amount of private equity that has already been raised for this project and how the support from the State through this funding would be advantageous as the federal government looks at grant and loan guarantee opportunities. • A review of the current work that is being done regarding CO2 capture. • In response to a question, if the federal funding does not become available the project will continue to move forward. It was moved by Christianson and seconded by Goerger that under the authority of North Dakota Century Code Sections 54-63.1-06 and 44-04-19.2(1) the Clean Sustainable Energy Authority enter into executive session for the purpose of considering Clean Sustainable Energy Authority confidential information. On a roll call vote Arthaud, Brown, Christianson, Friez, Goerger, McLennan, Neset, Lt. Governor Sanford voted aye. The motion carried unanimously. Lt. Governor Sanford stated that The Clean Sustainable Energy Authority is meeting in executive session to consider confidential information. Only CSEA members and Industrial Commission staff will be present during the executive session unless an applicant is requested to appear before the Authority to clarify their confidential information. Any formal action will occur after reconvening in open session. I remind those present in the executive session that the discussion must be limited to the announced purpose which is DRAFT Clean Sustainable Energy Authority Page 13 December 14, 2021 anticipated to last approximately 1.5 hours. The CSEA members that are joining by Teams must rejoin in the confidential session Teams link. The executive session will begin at 3:00 p.m. The following CSEA members present in executive session were: Lt. Governor Sanford Jim Arthaud Joel Brown Al Christianson Christopher Friez Terry Goerger Robert (Mac) McLennan Kathy Neset Tom Erickson Lynn Helms Justin Kringstad James Leiman Rachel Retterath Todd

Steinwand Kelvin Hullet, BND staff and designee for Mr. Steinwand John Weeda Others present including Industrial Commission staff and Industrial Commission members staff: Al Anderson CSEA Director Karlene Fine, Industrial Commission staff Katie Haarsager, Industrial Commission staff Reise Haase, Governor's Office Andrea Pfenning, Industrial Commission staff (remote) for a portion of the meeting. During the Executive Session the CSEA took up the following agenda items: Review of Confidential Information Report on Economic Review Results The CSEA meeting reconvened in open session at 5:00 p.m. The CSEA took up each of the applications that had been heard for Grant Round 1. C001-01 – Dakota H2 Hub; Submitted by Bakken Energy LLC; Total Project Costs: $1.75 billion; Amount Requested: $10 million (grant) $100 million (loan) It was moved by Goerger and seconded by McLennan that the Clean Sustainable Energy Authority recommends that the Industrial Commission provide financial assistance for the Dakota H2 Hub project submitted by Bakken Energy LLC as a grant in the amount of $10,000,000 with the grant funding coming from the SB 2345 Hydrogen Projects allocation on a 1:1 basis and a loan in the amount of $80,000,000 with the following terms: • Loan funds be released when the purchase agreement between Basin Electric and Bakken Energy for the purchase of the Dakota Gasification Company is signed. DRAFT Clean Sustainable Energy Authority Page 14 December 14, 2021 • Bakken Energy may draw the $80 million loan in two $40 million segments. The first segment is January 1, 2022 to December 31, 2023. The second is from January 1, 2024 to December 31, 2026. • Loans will be interest only for 2-years from the date when the total amount of $40 million is drawn from each segment. • P&I payments at 2% with a 15-year amortization starting in 2027. • BND noted its preference for the $80 million be repaid to the CSEA when the project goes to permanent financing if possible. Mr. Friez stated that this might be a great project and it may have merit and may solve some problems for the State of North Dakota. It clearly has a lot of smart people and a great team behind it but when I read the CSEA statute and look at the intent of what it is for and look at the timing and the number of unanswered questions that the project brings up, I don't think it fits the purpose of the statute at this time. It might at some future date but just not today. Mr. Goerger stated he was excited about the project as it includes the production of some anhydrous for agriculture – the costs of which has doubled over the last six months. To have it made right here and all the other things that go with it including zero carbon, everything about it sounds right plus trying to keep people employed and moving ahead into the future long term. I think it is a great project and a lot of the people that are on the other side of it are ND people that are trying to improve things here in North Dakota. Mr. Brown stated that on the merits of this project that when we were given the directive and the color from the legislators who helped to draft this legislation, we were told to focus on A+ projects that have a chance of making significant meaningful impact--to move the needle for energy in North /Dakota. Of all the projects that we have seen today I think this classifies for that. It is going to use approximately 5% of the natural gas that is produced in the state. We have a big problem of what we are going to do with the growth in the natural gas production. We are moving the needle with this project. Additionally, it is going to sequester approximately 10% of the ND CO2 emissions and I think that is meaningful. This proposes a use for the DGC plant that we heard today was not going to continue in its current use and can save the jobs for the people that work there. For those reasons I think this project applies to the statute and should be supported by the CSEA. Mr. Christianson stated that Paul Sukut said Dakota Gasification would no longer be operating under Basin Electric's ownership and I have to believe Paul. I believe that this project could be good for North Dakota. I also have some reservations because we are in the middle of the United States and we have to move products out of North Dakota. The product is hydrogen and there are no hydrogen pipelines. There will also be anhydrous which we can use some in North /Dakota. I have some concerns about reactions politically to this because we are using State money to change the fuel source. However, I believe that Mr. Sukut gave us his best information so I will support the project. Lt. Governor Sanford restated the conditions that the grant funds will come from those grant funds that were appropriated for hydrogen grants and the loan funding is contingent upon the purchase agreement with Basin Electric. On a roll call vote Arthaud, Brown, Christianson, Goerger, McLennan, Neset, Lt. Governor Sanford voted aye. Friez voted no. The motion carried.

Perry L Anderson
309 3rd Ave NW Apt 4
Mandan, ND
perryanderson_55@q.com

This letter was not received before the deadline for written comments. Therefore, it is not part of the evidentiary record of this case.

Kadrmas, Bethany R.

From: Perry Anderson <perryanderson_55@q.com>
Sent: Wednesday, July 20, 2022 2:21 PM
To: Kadrmas, Bethany R.
Subject: Fwd: BEPC Deal to purchase DGC assets Confidential info
Attachments: News-CSEAawards.pdf

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

I am not upset about the grants made, as you implied on 7/20/2022!!! I,m concerned about North Dakota losing out on a blue hydrogen Plant and you not mentioning the same six wells are included in both DGC's and Bakken Energy LLC's aplications to the NDIC and CSEA respectively! You do realize transparency is a big issue and something that is lacking in ND! This same letter was sent to Bakken Energy LLC, along with others over a 3 month period and have received no reply!! Are they a shell Co. set up to get around BEPC members voting not to suppport the H2 Hub due to it's risk!! MYSELF I BELIEVE ND SHOULD BE LEADING THE H2 HUB?? Bring The Dakota Gas Company and Dakota Coal into North Dakota's future by using GASIFICATION OF COAL and CCUSS technology along with Hydrogen production on a large scale and convert our coal powered generation to Gas generated power!! Dakota Gas generated 16 million in profits in the 1st quarter of 2022?? And you can stick a feather in your cap by DOING EXACTLY WHAT THE DOE is requiring for funding and can open private investments into ND's H2 HUB owned and operated by The Bank of ND,The DOE and EERC!! Hydrogen projects need to be addressed now in ND not later!! DON'T MISS THE BOAT ON H2 fuel cells!!! Thank you Perry L Anderson (We could be the 1st CCUSS project in America and provide for our state's future in Green Energy and curb climate change.)

BAKKEN ENERGY REACHES AGREEMENT TO PURCHASE DAKOTA GASIFICATION COMPANY ASSETS

Transformational plan to develop $2 billion North Dakota Hydrogen Hub and make Bakken Energy the largest and lowest-cost clean hydrogen producer in the USA.

ARE YOU THE SUBSIDARY MENTIONED IN THE DAKOTA GASIFICATION COMPANIES APPLICATION FOR A CO2 STORAGE FACILITY DATED 6/6/2022 AND TO BE HEARD ON 7/20/2022 BEFORE THE NDIC??? YOUR APPLICATION FOR THE DAKOTA H2 HUB BEFORE THE CSEA (WHICH GRANTED YOU 10 MILLION DOLLARS AND A LOAN OF 80 MILLION) SEEKS APPROVAL FOR THE SAME SIX INJECTION WELLS??? BASIN ELECTRIC POWER COOPERATIVE MEMBERS VOTED AGAINST FUNDING THE H2 HUB!!! ARE YOU TO BECOME BAKKEN ENERGY LLC A SUBSIDARY OF BASIN ELECTRIC POWER COOPERATIVE??

A SIMPLE YES OR NO QUESTION!!! Mr. Christianson stated that Paul Sukut said Dakota Gasification would no longer be operating under Basin Electric's ownership and I have to believe Paul. I believe that this project could be good for North Dakota. I also have some reservations because we are in the middle of the United States and we have to move products out of North Dakota. The product is hydrogen and there are no hydrogen pipelines. There will also be anhydrous which we can use some in North /Dakota. I have some concerns about reactions politically to this because we are using State money to change the fuel source. However, I believe that Mr. Sukut gave us his best information so I will support the project.(CSEA MINUTES !st ROUND AWARDS)

Perry L Anderson
309 3rd Ave NW Apt 4
Mandan, ND
perryanderson_55@q.com

INDUSTRIAL COMMISSION OF NORTH DAKOTA

Doug Burgum	Wayne Stenehjem	Doug Goehring
Governor	Attorney General	Agriculture Commissioner

NEWS December 20, 2021

INDUSTRIAL COMMISSION AWARDS FUNDING FOR CLEAN SUSTAINABLE ENERGY PROJECTS

BISMARCK, N.D. – The North Dakota Industrial Commission awarded funding today from the Clean Sustainable Energy Fund in the amount of $28 million in grants and $135 million in loans for six projects.

"We are excited about the quality and quantity of the projects that were presented today after going through an extensive review process. These projects have the potential of capturing over 30% of the annual carbon dioxide production in North Dakota, capturing natural gas that would otherwise be flared, and identifying opportunities that will diversify North Dakota's economy," the Industrial Commission said in a joint statement. "Each of these awards will be matched by other funds and result in over $4.5 billion in investment in North Dakota."

The six projects and their funding awards are as follows:

- Production of Blue Hydrogen – Dakota H2 Hub – BakkenEnergy LLC - $10 million grant; $80 million loan
- Converting Gas to Value-Added Projects – Cerilon GTL – Cerilon GTL ND Inc. - $7 million grant; $40 million loan
- Unlocking the Full Potential of Produced Water as a Key Component of Clean Sustainable Energy – Wellspring Hydro - $1 million grant
- Commercial Deployment of Carbon Dioxide Capture & Geological Sequestration in McLean County – Midwest AgEnergy Group - $3 million grant
- Front-End Engineering and Design for CO2 Capture at Coal Creek Station – Energy & Environmental Research Center - $7 million grant
- Solving North Dakota Flaring: Mobile Flare Gas Capture & Fueling Platform Expansion – Valence Natural Gas Solutions - $15 million loan

"The Legislature established and funded the Clean Sustainable Energy program during the recent legislative sessions and directed that the projects selected be transformational in developing energy projects for North Dakota's future," said Lt. Gov. Brent Sanford, chairman of the Clean Sustainable Energy Authority. "The Authority believes these projects have met the goals of the program to enhance the production of clean sustainable energy and to make North Dakota a world leader in the production of clean sustainable energy."

"The program received applications totaling over $49 million in grant requests and $165 million in loan requests during this first grant round," said Al Anderson, director of the Clean Sustainable Energy Authority. "The Authority is appreciative of the work completed by all the reviewers and advisors."

The Industrial Commission, which oversees the Clean Sustainable Energy Authority, consists of Gov. Doug Burgum as chairman, Attorney General Wayne Stenehjem and Agriculture Commissioner Doug Goehring.

Karlene K. Fine, Executive Director and Secretary
State Capitol, 14th Floor - 600 E Boulevard Ave Dept 405 - Bismarck, ND 58505-0840
E-Mail: kfine@nd.gov
Phone: (701) 328-3722 FAX: (701) 328-2820
"Your Gateway to North Dakota": www.nd.gov

The next submission deadline for funding requests is March 1, 2022. More information about the program, including the application process, can be found on the CSEA website at http://www.nd.gov/ndic/csea-infopage.htm.

For more information, contact Al Anderson at 701-595-9668.

Karlene K. Fine, Executive Director and Secretary
State Capitol, 14th Floor - 600 E Boulevard Ave Dept 405 - Bismarck, ND 58505-0840
E-Mail: kfine@nd.gov
Phone: (701) 328-3722 FAX: (701) 328-2820
"Your Gateway to North Dakota": www.nd.gov

Dakota Gasification Company

Case No. 29450

Application of Dakota Gasification Company requesting consideration for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Dakota Gasification Company intends to capture carbon dioxide from the Great Plains Synfuels Plant and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT July 19, 2022. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Steve Fried, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Dakota Gasification Company, 1717 East Interstate Avenue, Bismarck, ND 58503.

Case No. 29451

Application of Dakota Gasification Company to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Dakota Gasification Company storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code Section 38-22-10.

Case No. 29452

Application of Dakota Gasification Company for an order of the Commission determining the amount of financial responsibility for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant in the storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.

July 20, 2022

EXHIBIT 1

Great Plains

SYNFUELS

DAKOTA GASIFICATION COMPANY

A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

GREAT PLAINS CO2 SEQUESTRATION PROJECT

MERCER COUNTY, NORTH DAKOTA

Case No.: 29450
Date Established: June 6, 2022

DRAFT STORAGE FACILITY PERMIT

STORAGE FACILITY FOR CARBON SEQUESTRATION UNDER THE NORTH DAKOTA UNDERGROUND INJECTION CONTROL PROGRAM

In compliance with North Dakota Century Code Chapter (NDCC) 38-22 (Carbon Dioxide Underground Storage) and North Dakota Administrative Code (NDAC) Chapter 43-05-01 (Geologic Storage of Carbon Dioxide), Dakota Gasification Company has applied for a carbon dioxide storage facility permit. A draft permit does not grant the authorization to inject. This is a document prepared under NDAC 43-05-01-07.2 indicating the Commission's tentative decision to issue a storage facility permit. Before preparing the draft permit, the Commission has consulted with the Department of Environmental Quality and determined the storage facility permit application to be complete. The draft permit contains permit conditions required under NDAC 43-05-01-07.3 and 43-05-01-07.4. A fact sheet is included and contains the following information:

1. A brief description of the type of facility or activity which is the subject of the draft permit.
2. The quantity and quality of the carbon dioxide which is proposed to be injected and stored.
3. A brief summary of the basis for the draft permit conditions, including references to applicable statutory or regulatory provisions.
4. The reasons why any requested variances or alternatives to required standards do or do not appear justified.
5. A description of the procedures for reaching a final decision of the draft permit, including:
    a. The beginning and ending dates of the comment period.
    b. The address where comments will be received.
    c. The date, time, and location of the storage facility permit hearing.
    d. Any other procedures by which the public may participate in the final decision.
6. The name and telephone number of a person to contact for additional information.

This draft permit has been established on June 6, 2022 and shall remain in effect until a storage facility permit is granted under NDAC 43-05-01-05, unless amended or terminated by the Department of Mineral Resources (commission).

Stephen Fried, CCUS Supervisor
Department of Mineral Resources
Date: June 6, 2022

I. APPLICANT

Dakota Gasification Company
1717 East Interstate Avenue
Bismarck, ND 58503

II. PERMIT CONDITIONS (NDAC 43-05-01-07.3)

1. The storage operator shall comply with all conditions of the permit. Any noncompliance with the permit constitutes a violation and is grounds for enforcement action, including permit termination, revocation, or modification pursuant to NDAC 43-05-01-12.

2. In an administrative action, it shall not be a defense that it would have been necessary for the storage operator to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

3. The storage operator shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with the storage facility permit.

4. The storage operator shall develop and implement an emergency and remedial response plan pursuant to section 43-05-01-13.

5. The storage operator shall at all times properly operate and maintain all storage facilities which are installed or used by the storage operator to achieve compliance with the conditions of the storage facility permit. Proper operation and maintenance include effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the storage facility permit.

6. The permit may be modified, revoked and reissued, or terminated pursuant to section 43-05-01-12. The filing of a request by the storage operator for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. The injection well permit or the permit to operate an injection well does not convey any property rights of any sort or any exclusive privilege.

8. The storage operator shall furnish to the commission, within a time specified by the commission, any information which the commission may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. The storage operator shall also

furnish to the commission, upon request, copies of records required to be kept by the storage facility permit.

9. The storage operator shall allow the commission, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

   a. Enter upon the storage facility premises where records must be kept under the conditions of the permit;
   b. At reasonable times, have access to and copy any records that must be kept under the conditions of the permit;
   c. At reasonable times, inspect any facilities, equipment, including monitoring and control equipment, practices, or operations regulated or required under the permit; and
   d. At reasonable times, sample or monitor for the purposes of assuring permit compliance, any substances or parameters at any location.

10. The storage operator shall prepare, maintain, and comply with a testing and monitoring plan pursuant to section 43-05-01-11.4.

11. The storage operator shall comply with the reporting requirements provided in section 43-05-01-18.

12. The storage operator must obtain an injection well permit under section 43-05-01-10 and injection wells must meet the construction and completion requirements in section 43-05-01-11.

13. The storage operator shall prepare, maintain, and comply with a plugging plan pursuant to section 43-05-01-11.5.

14. The storage operator shall establish mechanical integrity prior to commencing injection and maintain mechanical integrity pursuant to section 43-05-01-11.1.

15. The storage operator shall implement the worker safety plan pursuant to section 43-05-01.13.

16. The storage operator shall comply with leak detection and reporting requirements pursuant to section 43-05-01-14.

17. The storage operator shall conduct a corrosion monitoring and prevention program pursuant to section 43-05-01-15.

18. The storage operator shall prepare, maintain, and comply with the area of review and corrective action plan pursuant to section 43-05-01-05.1.

19. The storage operator shall maintain financial responsibility pursuant to section 43-05-01-09.1

20. The storage operator shall maintain and comply with post-injection site care and facility closure plan pursuant to section 43-05-01-19.

III. CASE SPECIFIC PERMIT CONDITIONS

1. NDAC 43-05-01-11.4, subsection 1, subdivision b; The operator shall notify the commission within 24 hours of failure or malfunction of the surface gauges in the Coteau 1 (File No. 38379 – SWSW 1-145N-88W) injector, and the proposed Coteau 2, Coteau 3, Coteau 4, Coteau 5, and Coteau 6 injectors.

2. NDAC 43-05-01-11.4, subsection 1, subdivision c and NDAC 43-05-01-11, subsection 14; The operator shall run an ultrasonic or other log capable of evaluating internal and external pipe condition to establish a baseline for corrosion monitoring for the proposed Coteau 2, Coteau 3, Coteau 4, Coteau 5, and Coteau 6 wells. The operator shall run logs with the same capabilities for the Coteau 1, Coteau 2, Coteau 3, Coteau 4, Coteau 5, and Coteau 6 wells on a 5 year schedule, unless analysis of corrosion coupons or subsequent logging necessitates a more frequent schedule.

3. NDAC 43-05-01-11.4, subsection 1, subdivision d and NDAC 43-05-01-13, subsection 2, The operator shall cease injection immediately, take all steps reasonably necessary to identify and characterize any release, implement the emergency and remedial response plan approved by the commission, and notify the commission within 24 hours of carbon dioxide detected above the confining zone.

4. NDAC 43-05-01-11.4, subsection 1, subdivision h, paragraph 1, Surface air and soil gas monitoring is required to be implemented as planned by the operator in Section 5.3 (Surface Leak Detection and Monitoring Plan) and Section 5.5 (Near-Surface Soil Gas and Groundwater Sampling and Monitoring) of its permit.

5. NDAC 43-05-01-10, subsection 9, subdivision c, NDAC 43-05-01-11, subsection 15, and NDAC 43-05-01-11.1, subsection 2, The operator shall notify the commission at least 48 hours in advance to witness a mechanical integrity test of the tubing-casing annulus. The packer must be set within 100' of the upper most perforation and in the 13CR-80 casing. Dependent on evaluation, the operator shall run the same test on a 5 year schedule for the Coteau 1, Coteau 2, Coteau 3, Coteau 4, Coteau 5, and Coteau 6 injection wells.

6. NDAC 43-05-01-11, subsections 3 and 5, The operator shall continuously monitor the surface casing-production casing annulus with a gauge not to exceed 300 psi. The commission must be notified in advance if there is pressure that needs to be bled off.

Fact Sheet

1. Description of Facility

The Dakota Gasification Company's (DGC) Great Plains Synfuels Plant is located 5 miles northwest of Beulah, North Dakota and has been in operation since 1984. The plant is capable of gasifying 6 million tons of lignite coal per year and generates approximately 150 million standard cubic feet of natural gas daily. Carbon dioxide is among the by-products of the gasification process.

2. Quantity and Quality of Carbon Dioxide Stream

DGC's plant will initially sequester 1 million metric tons of the captured carbon dioxide stream annually in the proposed storage facility. As additional compressed volumes become available over the next 4 years, annual sequestration is expected to be increased to 2.7 million metric tons. The carbon dioxide stream is analyzed daily at the capture facility and is 95.9% carbon dioxide, 1.8% C_2+ hydrocarbons, 1.2% hydrogen sulfide, 0.6% methane, and 0.5% nitrogen.

3. Summary of Basis of Draft Permit Conditions

The case specific permit conditions are unique to this storage facility, and not indicative of conditions for other storage facility permits. The conditions take into consideration the equipment proposed for this storage facility. Regulatory provisions for these conditions are all cited from NDAC Chapter 43-05-01 (Geologic Storage of Carbon Dioxide).

4. Reasons for Variances or Alternatives

No variances or alternatives.

5. Procedures Required for Final Decision

The beginning and ending dates of the comment period:
June 6, 2022 to 5:00 P.M. CDT July 19, 2022

The address where comments will be received:
Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov

Date, time, and location of the storage facility permit hearing:
July 20, 2022 9:00 A.M. CDT at 1000 East Calgary Avenue, Bismarck, North Dakota 58503

Any other procedures by which the public may participate in the final decision:
At the hearing, the Commission will receive testimony and exhibits of interested parties.
#

6. Contact for Additional Information

Draft Permit Information: Stephen Fried – sjfried@nd.gov – 701-328-8020
Hearing Information: Bethany Kadrmas – brkadrmas@nd.gov – 701-328-8020#

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

RECEIVED
MAR 1 4 2022
N.D. INDUSTRIAL COMMISSION

March 10, 2022

Mr. Lynn Helms
Director
North Dakota Industrial Commission (NDIC)
Department of Mineral Resources (DMR)
State Capitol, Department 405
600 East Boulevard Avenue
Bismarck, ND 58505-0840

Dear Mr. Helms:

Subject: Great Plains CO_2 Sequestration Project – Storage Facility Permit Application

Dakota Gasification Company, together with its partners and affiliates, respectfully submits a storage facility permit application for the dedicated geologic storage of carbon dioxide at Dakota Gasification Company's Great Plains Synfuels Plant in Mercer County, North Dakota.

Following is a link to the application: SFP Application - 3.8.22

Please find attached the permit application certification for filing.

If you have any questions, please contact me by phone at (701) 873-6635 or by e-mail at dalej@bepc.com.

Sincerely,

Dale A. Johnson
Vice President & Plant Manager
Dakota Gasification Company

Attachment
c/att: Stephen Fried, NDIC DMR

RECEIVED
MAR 14 2022
N.D. INDUSTRIAL COMMISSION

STORAGE FACILITY PERMIT APPLICATION CERTIFICATION

BEFORE ME, the undersigned authority, personally appeared Dale Johnson of Dakota Gasification Company, who being duly sworn upon oath stated and certifies that:

1. I, Dale Johnson, am over 18 years of age. I have personal knowledge of the information and facts stated by me in this Certification, and they are true and correct. I have never been convicted of any felony or of any crime involving moral turpitude and am fully competent to make these representations.

2. I hold the position of Vice President and Plant Manager for Dakota Gasification Company. As required in accordance with North Dakota Administrative Code 43-05-01-07.1 and by virtue of my position with Dakota Gasification Company, I am authorized to make the representations on behalf of Dakota Gasification Company.

3. Attached is the storage facility permit application requesting a permit under Chapter 38-22 of the North Dakota Century Code and in accordance with Article 43-05 of the North Dakota Administrative Code for the establishment of a carbon dioxide storage facility located in Mercer County, North Dakota.

4. Based upon information and reports provided by individuals immediately responsible for compiling and preparing the enclosed permit applications and supporting information, I have personal knowledge and am familiar with the information being submitted in the attached documents to the permit application. Based upon information and belief, the information contained herein is true, accurate, and complete.

5. I affirm under penalty of perjury that the representations contained in this affidavit are true to the best of my knowledge, information, and belief. I understand that there are significant penalties for submitting false information, including the possibility of a fine and imprisonment.

6. By my signature below, I hereby submit the attached application and supporting documentation and information on behalf of Dakota Gasification Company.

Executed this 10th day of March 2022.

Dale A. Johnson

STATE OF NORTH DAKOTA)
)
COUNTY OF BURLEIGH)

Subscribed and sworn to before me this 10th day of March 2022.

SHEILA E. WALD
Notary Public
State of North Dakota
My Commission Expires May 2, 2022

Sheila E. Wald
Notary Public

GREAT PLAINS CO_2 SEQUESTRATION PROJECT MERCER COUNTY, NORTH DAKOTA

North Dakota CO_2 Storage Facility Permit Application

Prepared for:

Stephen Fried

North Dakota Industrial Commission
Oil & Gas Division
600 East Boulevard Avenue
Department 405
Bismarck, ND 58505-0840

Prepared by:

Dakota Gasification Company
1717 East Interstate Avenue
Bismarck, ND 58503-0564

CarbonVault Great Plains LLC
1512 Larimer Street, Suite 550
Denver, CO 80202-1620

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

March 2022

TABLE OF CONTENTS

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TABLE OF CONTENTS (continued)

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TABLE OF CONTENTS (continued)

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TABLE OF CONTENTS (continued)

GREAT PLAINS CO_2 SEQUESTRATION PROJECT
MERCER COUNTY, NORTH DAKOTA

PERMIT APPLICATION SUMMARY

The Dakota Gasification Company (DGC), together with its partners and affiliates, requests consideration of this application for the dedicated geologic storage of carbon dioxide (CO_2) at DGC's Great Plains Synfuels Plant, located 5 miles northwest of Beulah, North Dakota.

Built in the 1970s as a response to America's quest for energy independence, the Great Plains Synfuels Plant has been owned and operated by DGC since 1988. Capable of gasifying 6 million tons of lignite coal per year, the facility generates approximately 150 million standard cubic feet (MMscf) of natural gas daily and is the only such plant of its kind in the country. Among the by-products of the gasification process is a nearly pure stream of CO_2 (95+% by volume).

The plant has captured and transported more than 40 million metric tons of CO_2 for enhanced oil recovery purposes since 2000. This is accomplished by means of a 205-mile pipeline that has operated without incident for the past 22 years. The CO_2 is first compressed to a pressure of ±2,500 psi, then transported north as a supercritical fluid. There currently exists excess compressor capacity which makes the capture of an additional 1.0 MMt/year possible. As additional compressed volumes become available over the next 4 years, on-site sequestration of 2.7 MMt/year is expected. Over the anticipated 12-year life of this project, sequestered volumes of CO_2 are expected to total 26 MMt. Four injection wells are anticipated initially, with two additional wells planned as increased volumes in 2026 or beyond warrant. Extensive reservoir simulations have been conducted to predict the full extent of the injected CO_2 plume in the subsurface over the life of the project, the results of which are displayed in Figure PS-1.

DGC is a wholly owned subsidiary of Basin Electric Power Cooperative (Basin), a consumer owned utility that serves over 3 million customers across nine states and is one of North Dakota's largest employers. Basin employees have played an integral role in the preparation of this application, as have representatives from the University of North Dakota's Energy & Environmental Research Center (EERC) and Denver's Carbon Vault Great Plains LLC (CV). The EERC has a 19-year history studying the CO_2 sequestration potential of North Dakota's Williston Basin in general and the Broom Creek sandstone formation specifically. The EERC also leads the Plains CO_2 Reduction (PCOR) Partnership, whose mission is "making safe practical carbon capture, utilization, and storage (CCUS) projects a reality." CV is a subsidiary of Rampart Energy Company (fka Duncan Energy Company), which has been a long-time oil and gas operator in the state and is lending its drilling, reservoir, operations, and injection well expertise to this project.

The target storage interval for the project is the Broom Creek sandstone formation, which underlies the synfuels plant and surrounding region. The Broom Creek Formation, and more specifically its CO_2 storage potential, has been the subject of numerous studies conducted by the North Dakota Geological Survey, the U.S. Geological Survey, and the EERC. It has been deemed an ideal storage candidate because of its superior reservoir quality, depth, impermeable upper and lower confining zones, and expansive areal extent. Preliminary estimates suggest a maximum storage capacity exceeding 10 billion metric tons of CO_2. The Coteau 1 stratigraphic test well was drilled in June 2021 and confirmed all expectations for the Broom Creek interval as the preferred sequestration zone at this location.

The operational plan calls for a 6.8-mile transmission line consisting of a 12" mainline and adjoining 6" lateral lines to the individual injection sites (permitted through the North Dakota Public Service Commission) to deliver CO_2 from the synfuels plant to the nearby sequestration area. Sequestration closer to the synfuels plant was originally considered but was ultimately adjusted northward because of possible interference with existing Class I Broom Creek water disposal wells associated with DGC plant operations. This transmission line will be operated and monitored in a manner consistent with the existing 205-mile CO_2 transmission line to Canada.

As the transmission lines dead-end at the individual wellsites, a pressure drop commensurate with anticipated injection conditions will take place, thus transitioning to the individual well flowlines included in this permit application.

The effluent from the synfuels plant operation includes other constituents beyond CO_2. Among these are ethane (1% by volume) and hydrogen sulfide (H_2S), 1.2% by volume. Exposure to H_2S can be harmful at very low concentrations. For that reason, continuous H_2S monitoring is planned, with automated alarms and emergency shutdown valves included. In addition, soil gas and Fox Hills water samples will be analyzed on a quarterly basis to detect any changes. The Fox Hills Formation represents the deepest subsurface formation that contains an underground source of drinking water (USDW). At this location, the base of the Fox Hills Formation is more than 4,500 feet above the Broom Creek injection interval, with both the Opeche Shale and the thousands of feet thick Pierre Shale in between.

The condition of downhole equipment will be monitored with multiple degrees of redundancy. Surface pressures will be tracked continuously for signs of anomalies, tubulars will be evaluated via ultrasonic electrical logs and/or caliper diagnoses, and regular mechanical integrity tests will be performed. Periodic pulse neutron logging will be conducted to monitor the near wellbore environment and confirm CO_2 is confined to the injection zone. As for the expansion of the CO_2 plume itself, periodic seismic surveys will be conducted, and compared to a preinjection baseline, to determine the extent of the plume's progression. Given the four to six injection wells anticipated with this project, sufficient operational flexibility will exist to maintain control of the stabilized plume within the anticipated project area.

Details of this sequestration opportunity are included in the pages to follow.

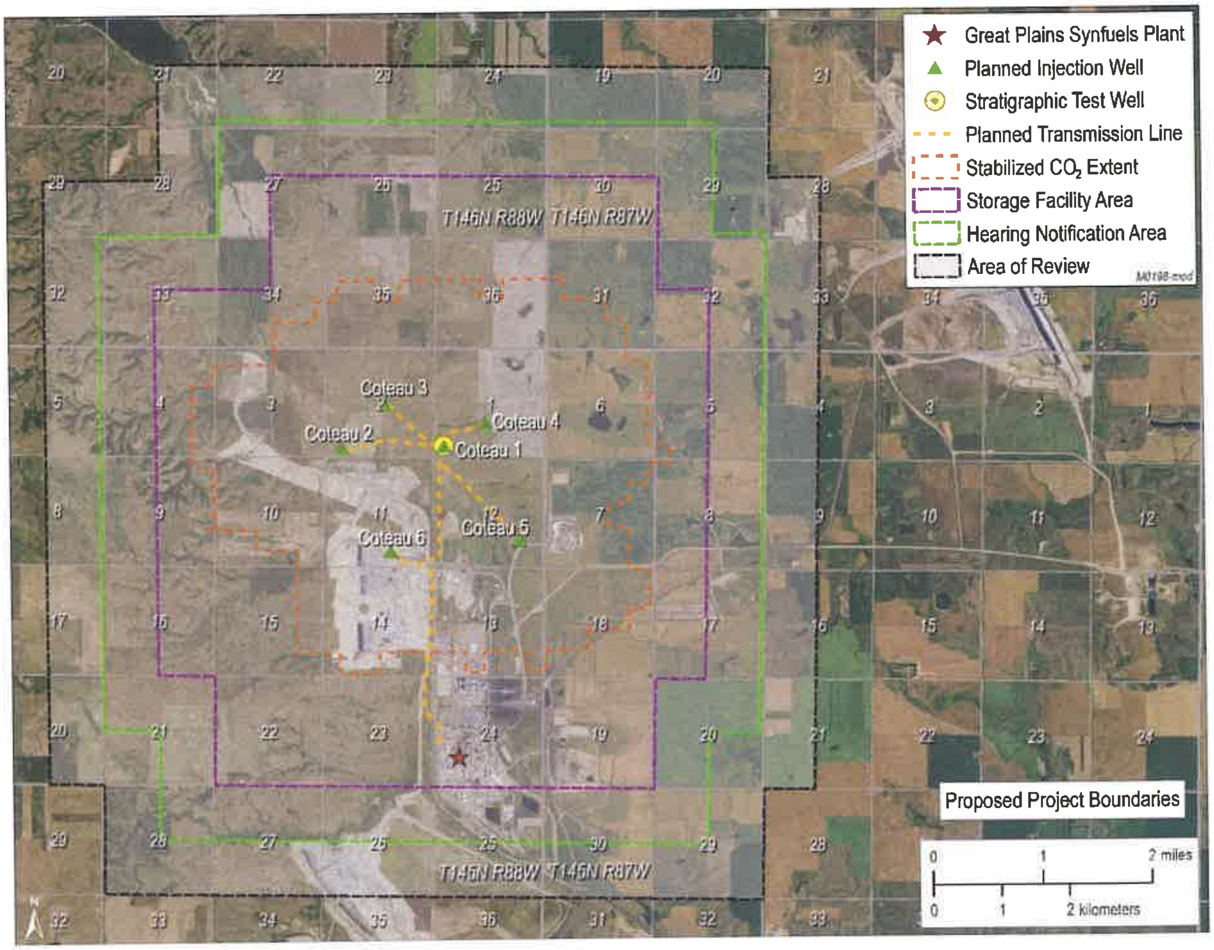


Figure PS-1. The projected stabilized CO_2 plume, storage facility area, notification area, and area of review.

1.0 PORE SPACE ACCESS

1.0 PORE SPACE ACCESS

North Dakota law explicitly grants title of the pore space in all strata underlying the surface of lands and waters to the overlying surface estate, i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] Chapter 47-31 – Subsurface Pore Space Policy). Prior to issuance of the storage facility permit (SFP), the storage operator is mandated by the North Dakota statute governing geologic storage of carbon dioxide (CO_2) to obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir. The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are or will be equitably compensated. North Dakota law grants the North Dakota Industrial Commission (NDIC) the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation. Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application (NDCC §§ 38-22-06[3] and 38-22-06[4] and North Dakota Administrative Code [NDAC] §§ 43-05-01-08[1] and 43-05-01-08[2]).

Dakota Gasification Company (DGC) has identified the owners (surface and mineral). In addition, with the exception of coal extraction, there are no mineral lessees or operators of mineral extraction activities within the facility area or within 0.5 miles of its outside boundary. DGC will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made.

All owners, lessees, and operators that require notification have been identified in accordance with North Dakota law, which vests the title to the pore space in all strata underlying the surface of lands and water to the owner of the overlying surface estate (NDCC Chapter 47-31). The identification of pore space owners indicates that there was no severance of pore space or leasing of pore space to a third-party from the surface estate prior to 2009.

Maps showing the extent of the pore space that will be occupied by CO_2 over the life of the project, including the storage reservoir boundary and 0.5 miles (0.8 kilometers) outside of the storage reservoir boundary with a description of pore space ownership, surface owner, and pore space lessees of record are illustrated in Figures 1-1 and 1-2.

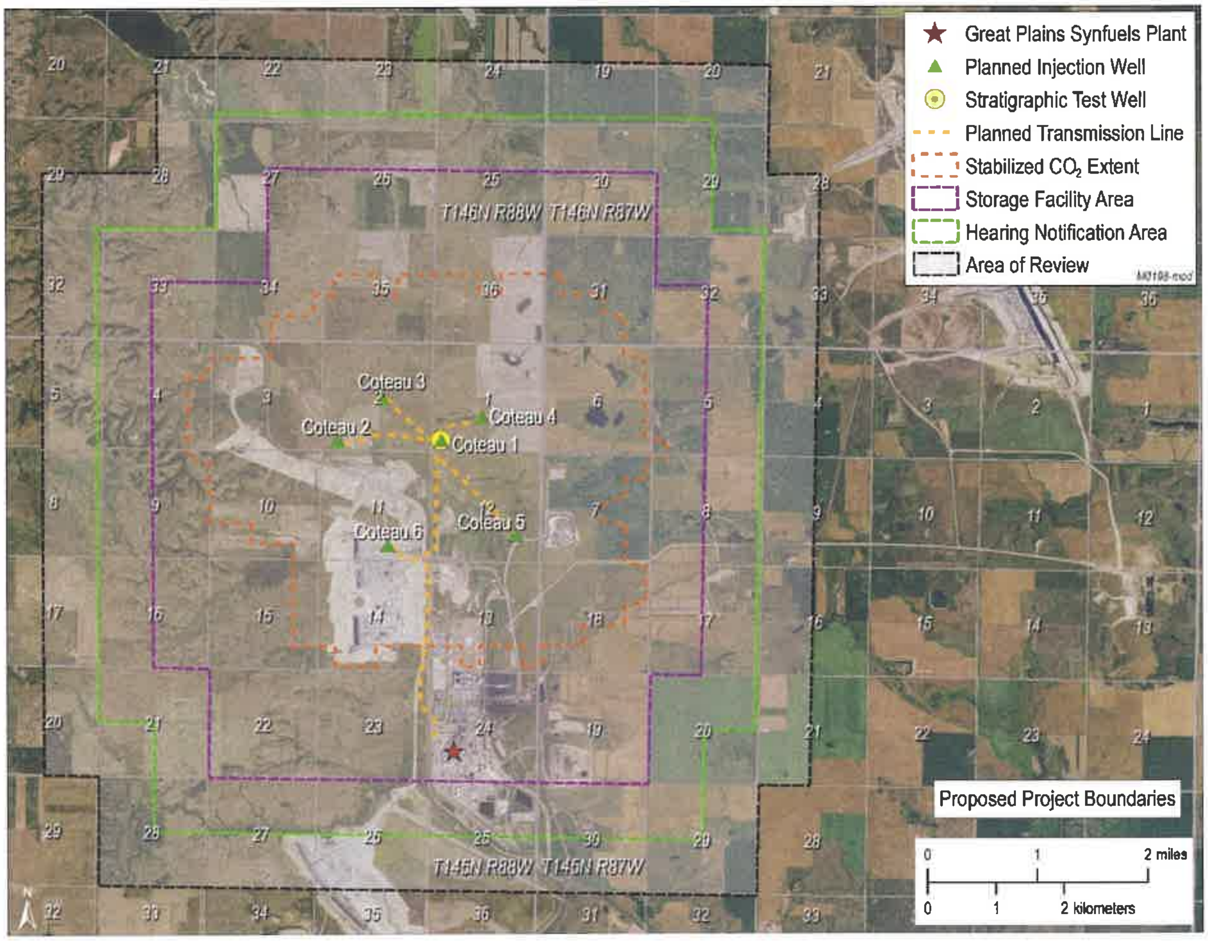


Figure 1-1. Storage facility area map.

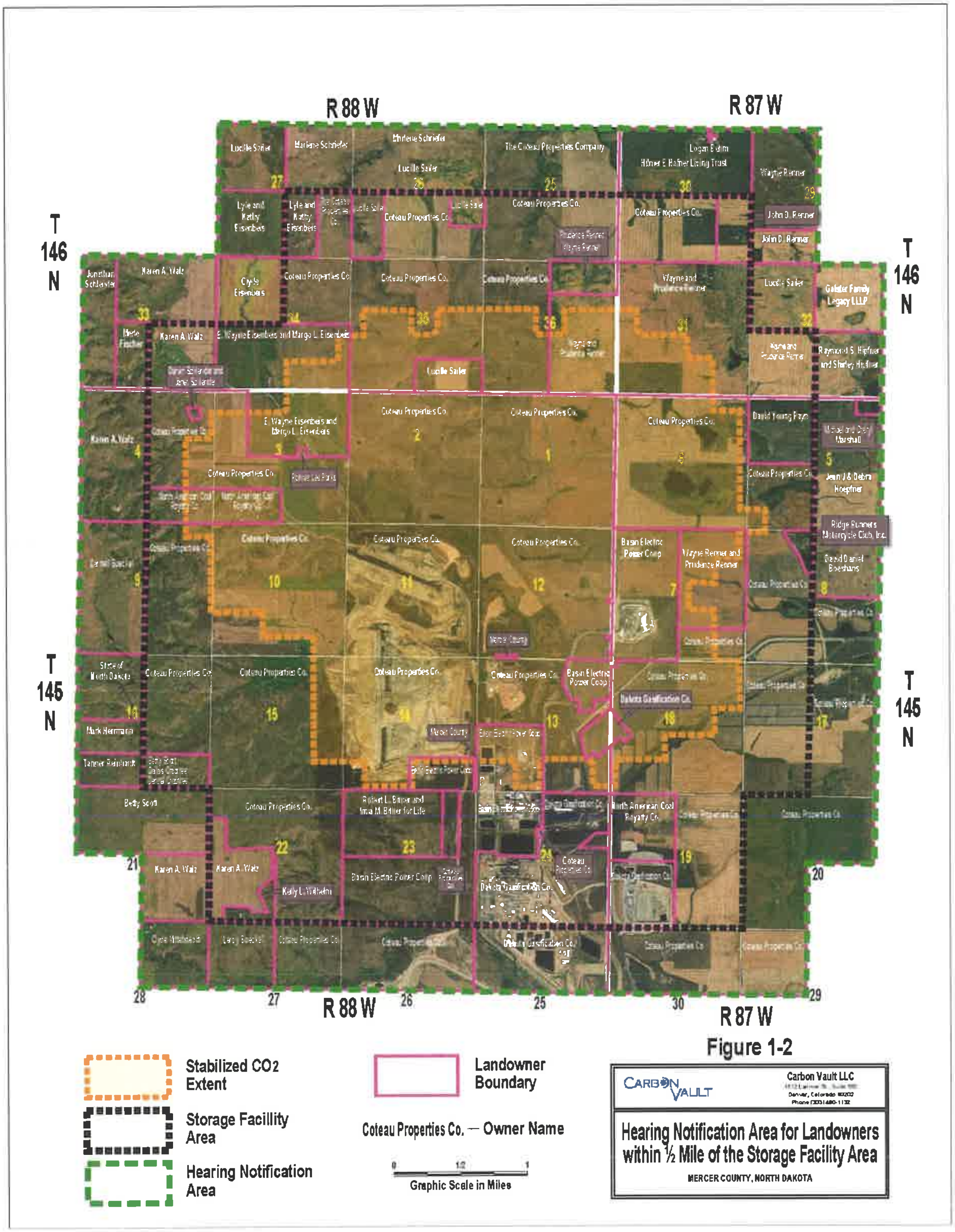


Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area.

RECEIVED

MAY - 3 2022

N.D. INDUSTRIAL COMMISSION

Fredrikson
& BYRON, P.A.

May 3, 2022

HAND DELIVERED

Mr. Bruce Hicks
Assistant Director
North Dakota Industrial Commission
Oil and Gas Division
600 East Boulevard
Bismarck, North Dakota 58505-0310

RE: Application of Dakota Gasification Company for an order of the Commission to consider a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.

Dear Mr. Hicks:

Please find enclosed herewith the following for filing:

1. STORAGE AGREEMENT, GREAT PLAINS CO2 SEQUESTRATION PROJECT. (BROOM CREEK FORMATION, MERCER COUNTY, NORTH DAKOTA)

Should you have any questions, please advise.

Sincerely,

LAWRENCE BENDER

LB/leo
Enclosure
cc: Ms. Casey Jacobson - (w/enc.) *Via Email*
75938438 v1

STORAGE AGREEMENT
GREAT PLAINS CO2 SEQUESTRATION PROJECT
(BROOM CREEK FORMATION,
MERCER COUNTY, NORTH DAKOTA)

STORAGE AGREEMENT
GREAT PLAINS CO2 SEQUESTRATION PROJECT
(BROOM CREEK FORMATION,
MERCER COUNTY, NORTH DAKOTA)

THIS AGREEMENT ("Agreement") is entered into as of the 1st day of June, 2022, by the parties who have signed the original of this instrument, a counterpart thereof, ratification and joinder or other instrument agreeing to become a Party hereto.

RECITALS:

A. It is in the public interest to promote the geologic storage of carbon dioxide in a manner which will benefit the state and the global environment by reducing greenhouse gas emissions and in a manner which will help ensure the viability of the state's coal and power industries, to the economic benefit of North Dakota and its citizens;

B. To further geologic storage of carbon dioxide, a potentially valuable commodity, may allow for its ready availability if needed for commercial, industrial, or other uses, including enhanced recovery of oil, gas, and other minerals; and

C. For geologic storage, however, to be practical and effective requires cooperative use of surface and subsurface property interests and the collaboration of property owners, which may require procedures that promote, in a manner fair to all interests, cooperative management, thereby ensuring the maximum use of natural resources.

AGREEMENT:

It is agreed as follows:

ARTICLE 1
DEFINITIONS

As used in this Agreement:

1.1 **Carbon Dioxide** means carbon dioxide in gaseous, liquid, or supercritical fluid state together with incidental associated substances derived from the source materials, capture process and any substances added or used to enable or improve the injection process.

1.2 **Commission** means the North Dakota Industrial Commission.

1.3 **Effective Date** is the time and date this Agreement becomes effective as provided in Article 14.

1.4 **Facility Area** is the land described by Tracts in Exhibit "B" and shown on Exhibit "A" containing 15,979.20 acres, more or less.

1.5 **Party** is any individual, corporation, limited liability company, partnership, association, receiver, trustee, curator, executor, administrator, guardian, tutor, fiduciary, or other representative of any kind, any department, agency, or instrumentality of the state, or any governmental subdivision thereof, or any other entity capable of holding an interest in the Storage Reservoir.

1.6 **Pore Space** means a cavity or void, whether natural or artificially created, in any subsurface stratum.

1.7 **Pore Space Interest** is a right to or interest in the Pore Space in any Tract within the boundaries of the Facility Area.

1.8 **Pore Space Owner** is a Party hereto who owns Pore Space Interest.

1.9 **Storage Equipment** is any personal property, lease and well equipment, plants and other facilities and equipment for use in Storage Operations.

1.10 **Storage Expense** is all costs, expense or indebtedness incurred by the Storage Operator pursuant to this Agreement for or on account of Storage Operations.

1.11 **Storage Facility** is the unitized or amalgamated Storage Reservoir created pursuant to an order of the Commission.

1.12 **Storage Facility Participation** is the percentage shown on Exhibit "C" for allocating payments for use of the Pore Space under each Tract identified in Exhibit "B".

1.13 **Storage Operations** are all operations conducted by the Storage Operator pursuant to this Agreement or otherwise authorized by any lease covering any Pore Space Interest.

1.14 **Storage Operator** is the person or entity named in Section 4.1 of this Agreement.

1.15 **Storage Reservoir** consists of the Pore Space and confining subsurface strata underlying the Facility Area described as the Broom Creek Formation and geologically confined by the Opeche Formation (upper confining zone) and the Amsden Formation (lower confining zone) identified by the laterolog gamma ray (LGR) log run in the Hermann #1 well (File No. 4177), located in the NE/4 SW/4 of Section 17, Township 145 North, Range 88 West, Mercer County, North Dakota, which encompasses the stratigraphic interval from a depth of 6132 feet to a depth of 6839 feet as measured from the Kelly Bushing elevation of 2203 feet, within the limits of the Facility Area.

1.16 **Storage Rights** are the rights to explore, develop, and operate lands within the Facility Area for the storage of Storage Substances.

1.17 **Storage Substances** are Carbon Dioxide and incidental associated substances, fluids, and minerals.

1.18 **Tract** is the land described as such and given a Tract number in Exhibit "B."

ARTICLE 2
EXHIBITS

2.1 **Exhibits.** The following exhibits, which are attached hereto, are incorporated herein by reference:

2.1.1 Exhibit "A" is a map that shows the boundary lines of the Great Plains Broom Creek Facility Area and the tracts therein;

2.1.2 Exhibit "B" is a schedule that describes the acres of each Tract in the Great Plains Broom Creek Facility Area;

2.1.3 Exhibit "C" is a schedule that shows the Storage Facility Participation of each Tract; and

2.1.4 Exhibit "D" is a form of Surface Use and Pore Space Lease.

2.2 **Reference to Exhibits.** When reference is made to an exhibit, it is to the exhibit as originally attached or, if revised, to the last revision.

2.3 **Exhibits Considered Correct.** Exhibits "A," "B," "C" and "D" shall be considered to be correct until revised as herein provided.

2.4 **Correcting Errors.** The shapes and descriptions of the respective Tracts have been established by using the best information available. If it subsequently appears that any Tract, mechanical miscalculation or clerical error has been made, Storage Operator, with the approval of Pore Space Owners whose interest is affected, shall correct the mistake by revising the exhibits to conform to the facts. The revision shall not include any re-evaluation of engineering or geological interpretations used in determining Storage Facility Participation. Each such revision of an exhibit made prior to thirty (30) days after the Effective Date shall be effective as of the Effective Date. Each such revision thereafter made shall be effective at 7:00 a.m. on the first day of the calendar month next following the filing for record of the revised exhibit or on such other date as may be determined by Storage Operator and set forth in the revised exhibit.

2.5 **Filing Revised Exhibits.** If an exhibit is revised, Storage Operator shall execute an appropriate instrument with the revised exhibit attached and file the same for record in the county or counties in which this Agreement or memorandum of the same is recorded and shall also file the amended changes with the Commission.

ARTICLE 3
CREATION AND EFFECT OF STORAGE FACILITY

3.1 **Unleased Pore Space Interests.** Any Pore Space Owner in the Storage Facility who owns a Pore Space Interest in the Storage Reservoir that is not leased for the purposes of this Agreement and during the term hereof, shall be treated as if it were subject to the Surface Use and Pore Space Lease attached hereto as Exhibit "D".

3.2 **Amalgamation of Pore Space.** All Pore Space Interests in and to the Tracts are hereby amalgamated and combined insofar as the respective Pore Space Interests pertain to the Storage Reservoir, so that Storage Operations may be conducted with respect to said Storage Reservoir as if all of the Pore Space Interests in the Facility Area had been included in a single lease executed by all Pore Space Owners, as lessors, in favor of Storage Operator, as lessee and as if the lease contained all of the provisions of this Agreement.

3.3 **Amendment of Leases and Other Agreements.** The provisions of the various leases, agreements, or other instruments pertaining to the respective Tracts or the storage of the Storage Substances therein, including the Surface Use and Pore Space Lease attached hereto as Exhibit "D", are amended to the extent necessary to make them conform to the provisions of this Agreement, but otherwise shall remain in effect.

3.4 **Continuation of Leases and Term Interests.** Injection in to any part of the Storage Reservoir, or other Storage Operations, shall be considered as injection in to or upon each Tract within said Storage Reservoir, and such injection or operations shall continue in effect as to each lease as to all lands and formations covered thereby just as if such operations were conducted on and as if a well were injecting in each Tract within said Storage Reservoir.

3.5 **Titles Unaffected by Storage.** Nothing herein shall be construed to result in the transfer of title of the Pore Space Interest of any Party hereto to any other Party or to Storage Operator.

3.6 **Injection Rights.** Storage Operator is hereby granted the right to inject into the Storage Reservoir any Storage Substances in whatever amounts Storage Operator may deem expedient for Storage Operations, together with the right to drill, use, and maintain injection wells in the Facility Area, and to use for injection purposes.

3.7 **Transfer of Storage Substances from Storage Facility.** Storage Operator may transfer from the Storage Facility any Storage Substances, in whatever amounts Storage Operator may deem expedient for Storage Operations, to any other reservoir, subsurface stratum or formation permitted by the Commission for the storage of carbon dioxide under Chapter 38-22 of the North Dakota Century Code. The transfer of such Storage Substances out of the Storage Facility shall be disregarded for the purposes of calculating the royalty under any lease covering a Pore Space Interest (including Exhibit "D") and shall not affect the allocation of Storage Substances injected into the Storage Facility through the surface of the Facility Area in accordance with Article 6 of this Agreement.

3.8 **Receipt of Storage Substances.** Storage Operator may accept and receive into the Storage Facility any Storage Substances, in whatever amounts Storage Operator may deem expedient for Storage Operations, being stored in any other reservoir, subsurface stratum or formation permitted by the Commission for the storage of carbon dioxide under Chapter 38-22 of the North

Dakota Century Code. The receipt of such Storage Substances into the Storage Facility shall be disregarded for the purposes of calculating the royalty under any lease covering a Pore Space Interest (including Exhibit "D") and shall not affect the allocation of Storage Substances injected into the Storage Facility through the surface of the Facility Area in accordance with Article 6 of this Agreement.

3.9 **Cooperative Agreements.** Storage Operator may enter into cooperative agreements with respect to lands adjacent to the Facility Area for the purpose of coordinating Storage Operations. Such cooperative agreements may include, but shall not be limited to, agreements regarding the transfer and receipt of Storage Substances pursuant to Sections 3.7 and 3.8 of this Agreement.

3.10 **Border Agreements.** Storage Operator may enter into an agreement or agreements with owners of adjacent lands with respect to operations which may enhance the injection of the Storage Substances in the Storage Reservoir in the Facility Area or which may otherwise be necessary for the conduct of Storage Operations.

ARTICLE 4
STORAGE OPERATIONS

4.1 **Storage Operator.** Dakota Gasification Company is hereby designated as the initial Storage Operator. Storage Operator shall have the exclusive right to conduct Storage Operations, which shall conform to the provisions of this Agreement and any lease covering a Pore Space Interest. If there is any conflict between such agreements, this Agreement shall govern.

4.2 **Successor Operators.** The initial Storage Operator and any subsequent operator may, at any time, transfer operatorship of the Storage Facility with and upon the approval of the Commission.

4.3 **Method of Operation.** Storage Operator shall engage in Storage Operations with diligence and in accordance with good engineering and injection practices.

4.4 **Change of Method of Operation.** As permitted by the Commission nothing herein shall prevent Storage Operator from discontinuing or changing in whole or in part any method of operation which, in its opinion, is no longer in accord with good engineering or injection practices. Other methods of operation may be conducted or changes may be made by Storage Operator from time to time if determined by it to be feasible, necessary or desirable to increase the injection or storage of Storage Substances.

ARTICLE 5
TRACT PARTICIPATIONS

5.1 **Tract Participations.** The Storage Facility Participation of each Tract is shown in Exhibit "C." The Storage Facility Participation of each Tract shall be based 100% upon the ratio of surface acres in each Tract to the total surface acres for all Tracts within the Facility Area.

5.2 **Relative Storage Facility Participations.** If the Facility Area is enlarged or reduced, the revised Storage Facility Participation of the Tracts remaining in the Facility Area and which were within the Facility Area prior to the enlargement or reduction shall remain in the same ratio to one another.

ARTICLE 6
ALLOCATION OF STORAGE SUBSTANCES

6.1 **Allocation of Tracts.** All Storage Substances injected shall be allocated to the several Tracts in accordance with the respective Storage Facility Participation effective during the period that the Storage Substances are injected. The amount of Storage Substances allocated to each tract, regardless of whether the amount is more or less than the actual injection of Storage Substances from the well or wells, if any, on such Tract, shall be deemed for all purposes to have been injected into such Tract. Storage Substances transferred or received pursuant to Sections 3.7 and 3.8 of this Agreement shall be disregarded for the purposes of this Section 6.1.

6.2 **Distribution within Tracts.** The Storage Substances injected and allocated to each Tract shall be distributed among, or accounted for to, the Pore Space Owners who own a Pore Space Interest in such Tract in accordance with each Pore Space Owner's Storage Facility Participation effective during the period that the Storage Substances were injected. If any Pore Space Interest in a Tract hereafter becomes divided and owned in severalty as to different parts of the Tract, the owners of the divided interests, in the absence of an agreement providing for a different division, shall be compensated for the storage of the Storage Substances in proportion to the surface acreage of their respective parts of the Tract. Storage Substances transferred or received pursuant to Sections 3.7 and 3.8 of this Agreement shall be disregarded for the purposes of this Section 6.2.

ARTICLE 7
TITLES

7.1 **Warranty and Indemnity.** Each Pore Space Owner who, by acceptance of revenue for the injection of Storage Substances into the Storage Reservoir, shall be deemed to have warranted title to its Pore Space Interest, and, upon receipt of the proceeds thereof to the credit of such interest, shall indemnify and hold harmless the Storage Operator and other Parties from any loss due to failure, in whole or in part, of its title to any such interest.

7.2 **Injection When Title Is in Dispute.** If the title or right of any Pore Space Owner claiming the right to receive all or any portion of the proceeds for the storage of any Storage Substances allocated to a Tract is in dispute, Storage Operator shall require that the Pore Space Owner to whom the proceeds thereof are paid furnish security for the proper accounting thereof to the rightful Pore Space Owner if the title or right of such Pore Space Owner fails in whole or in part.

7.3 **Payments of Taxes to Protect Title.** The owner of surface rights to lands within the Facility Area is responsible for the payment of any *ad valorem* taxes on all such rights, interests or property, unless such owner and the Storage Operator otherwise agree. If any *ad valorem* taxes are not paid by or for such owner when due, Storage Operator may at any time prior to tax sale or expiration of period of redemption after tax sale, pay the tax, redeem such rights, interests or property, and discharge the tax lien. Storage Operator shall, if possible, withhold from any proceeds derived from the storage of Storage Substances otherwise due any Pore Space Owner who is a delinquent taxpayer an amount sufficient to defray the costs of such payment or redemption, such withholding to be credited to the Storage Operator. Such withholding shall be without prejudice to any other remedy available to Storage Operator.

7.4 **Pore Space Interest Titles.** If title to a Pore Space Interest fails, but the tract to which it relates is not removed from the Facility Area, the Party whose title failed shall not be entitled to share under this Agreement with respect to that interest.

ARTICLE 8
EASEMENTS OR USE OF SURFACE

8.1 **Grant of Easement.** Storage Operator shall have the right to use as much of the surface of the land within the Facility Area as may be reasonably necessary for Storage Operations and the injection of Storage Substances.

8.2 **Use of Water.** Storage Operator shall have and is hereby granted free use of water from the Facility Area for Storage Operations, except water from any well, lake, pond or irrigation ditch of a Pore Space Owner; notwithstanding the foregoing, Storage Operator may access any well, lake, or pond as provided in Exhibit "D".

8.3 **Surface Damages.** Storage Operator shall pay surface owners for damage to growing crops, timber, fences, improvements and structures located on the Facility Area that result from Storage Operations.

8.4 **Surface and Sub-Surface Operating Rights.** Except to the extent modified in this Agreement, Storage Operator shall have the same rights to use the surface and sub-surface and use of water and any other rights granted to Storage Operator in any lease covering Pore Space Interests. Except to the extent expanded by this Agreement or the extent that such rights are common to the effected leases, the rights granted by a lease may be exercised only on the land covered by that lease. Storage Operator will to the extent possible minimize surface impacts.

ARTICLE 9
ENLARGEMENT OF STORAGE FACILITY

9.1 **Enlargement of Storage Facility.** The Storage Facility may be enlarged from time to time to include acreage and formations reasonably proven to be geologically capable of storing Storage Substances. Any expansion must be approved in accordance with the rules and regulations of the Commission.

9.2 **Determination of Tract Participation.** Storage Operator, subject to Section 5.2, shall determine the Storage Facility Participation of each Tract within the Storage Facility as enlarged, and shall revise Exhibits "A", "B" and "C" accordingly and in accordance with the rules, regulations and orders of the Commission.

9.3 **Effective Date.** The effective date of any enlargement of the Storage Facility shall be effective as determined by the Commission.

ARTICLE 10
TRANSFER OF TITLE PARTITION

10.1 **Transfer of Title.** Any conveyance of all or part of any interest owned by any Party hereto with respect to any Tract shall be made expressly subject to this Agreement. No change of title shall be binding upon Storage Operator, or any Party hereto other than the Party so transferring, until 7:00 a.m. on the first day of the calendar month following thirty (30) days from the date of receipt by Storage Operator of a photocopy, or a certified copy, of the recorded or filed instrument evidencing such a change in ownership.

10.2 **Waiver of Rights to Partition.** Each Party hereto agrees that, during the existence of this Agreement, it will not resort to any action to partition any Tract or parcel within the Facility Area or the facilities used in the development or operation thereof, and to that extent waives the benefits or laws authorizing such partition.

ARTICLE 11
RELATIONSHIP OF PARTIES

11.1 **No Partnership.** The duties, obligations and liabilities arising hereunder shall be several and not joint or collective. This Agreement is not intended to create, and shall not be construed to create, an association or trust, or to impose a partnership duty, obligation or liability with regard to any one or more of the Parties hereto. Each Party hereto shall be individually responsible for its own obligations as herein provided.

11.2 **No Joint Marketing.** This Agreement is not intended to provide, and shall not be construed to provide, directly or indirectly, for any joint marketing of Storage Substances.

11.3 **Pore Space Owners Free of Costs.** This Agreement is not intended to impose, and shall not be construed to impose, upon any Pore Space Owner any obligation to pay any Storage Expense unless such Pore Space Owner is otherwise so obligated.

11.4 **Information to Pore Space Owners.** Each Pore Space Owner shall be entitled to all information in possession of Storage Operator to which such Pore Space Owner is entitled by an existing lease or a lease imposed by this Agreement.

ARTICLE 12
LAWS AND REGULATIONS

12.1 **Laws and Regulations.** This Agreement shall be subject to all applicable federal, state and municipal laws, rules, regulations and orders.

ARTICLE 13
FORCE MAJEURE

13.1 **Force Majeure.** All obligations imposed by this Agreement on each Party, except for the payment of money, shall be suspended while compliance is prevented, in whole or in part, by a labor dispute, fire, war, civil disturbance, or act of God; by federal, state or municipal laws; by any rule, regulation or order of a governmental agency; by inability to secure materials; or by any other cause or causes, whether similar or dissimilar, beyond reasonable control of the Party. No Party shall be required against his will to adjust or settle any labor dispute. Neither this Agreement nor any lease or other instrument subject hereto shall be terminated by reason of suspension of Storage Operations due to any one or more of the causes set forth in this Article.

ARTICLE 14
EFFECTIVE DATE

14.1 **Effective Date.** This Agreement shall become effective as determined by the Commission.

14.2 **Ipso Facto Termination.** If the requirements of Section 14.1 are not accomplished on or before December 31, 2022 this Agreement shall *ipso facto* terminate on that date (hereinafter called "termination date") and thereafter be of no further effect, unless prior thereto Pore Space Owners owning a combined Storage Facility Participation of at least thirty percent (30%) of the Facility Area have become Parties to this Agreement and have decided to extend the termination date for a period not to exceed six (6) months. If the termination date is so extended and the requirements of Section 14.1 are not accomplished on or before the extended termination date this Agreement shall *ipso facto* terminate on the extended termination date and thereafter be of no further effect.

14.3 **Certificate of Effectiveness.** Storage Operator shall file for record in the county or counties in which the land affected is located a certificate stating the Effective Date of this Agreement.

ARTICLE 15
TERM

15.1 **Term.** Unless sooner terminated in the manner hereinafter provided or by order of the Commission, this Agreement shall remain in full force and effect until the Commission has issued a certificate of project completion with respect to the Storage Facility in accordance with § 38-22-17 of the North Dakota Century Code.

15.2 **Termination by Storage Operator.** This Agreement may be terminated at any time by the Storage Operator with the approval of the Commission.

15.3 **Effect of Termination.** Upon termination of this Agreement all Storage Operations shall cease. Each lease and other agreement covering Pore Space within the Facility Area shall remain in force for ninety (90) days after the date on which this Agreement terminates, and for such further period as is provided by Exhibit "C" or other agreement.

15.4 **Salvaging Equipment Upon Termination**. If not otherwise granted by Exhibit "C" or other instruments affecting each Tract, Pore Space Owners hereby grant Storage Operator a period of six (6) months after the date of termination of this Agreement within which to salvage and remove Storage Equipment.

15.5 **Certificate of Termination**. Upon termination of this Agreement, Storage Operator shall file for record in the county or counties in which the land affected is located a certificate that this Agreement has terminated, stating its termination date.

ARTICLE 16
APPROVAL

16.1 **Original, Counterpart or Other Instrument**. A Pore Space Owner may approve this Agreement by signing the original of this instrument, a counterpart thereof, ratification or joinder or other instrument approving this instrument hereto. The signing of any such instrument shall have the same effect as if all Parties had signed the same instrument.

16.2 **Joinder in Dual Capacity**. Execution as herein provided by any Party as either a Pore Space Owner or the Storage Operator shall commit all interests owned or controlled by such Party and any additional interest thereafter acquired in the Facility Area.

16.3 **Approval by the North Dakota Industrial Commission**.
Notwithstanding anything in this Article to the contrary, all Tracts within the Facility Area shall be deemed to be qualified for participation if this Agreement is duly approved by order of the Commission.

ARTICLE 17
GENERAL

17.1 **Amendments Affecting Pore Space Owners**. Amendments hereto relating wholly to Pore Space Owners may be made with approval by the Commission.

17.4 **Construction**. This agreement shall be construed according to the laws of the State of North Dakota.

ARTICLE 18
SUCCESSORS AND ASSIGNS

18.1 **Successors and Assigns**. This Agreement shall extend to, be binding upon, and inure to the benefit of the Parties hereto and their respective heirs, devisees, legal representatives, successors and assigns and shall constitute a covenant running with the lands, leases and interests covered hereby.

[*Remainder of page intentionally left blank. Signature page follows.*]

Executed the date set opposite each name below but effective for all purposes as provided by Article 14.

Dated: ____________, 2022/

STORAGE OPERATOR

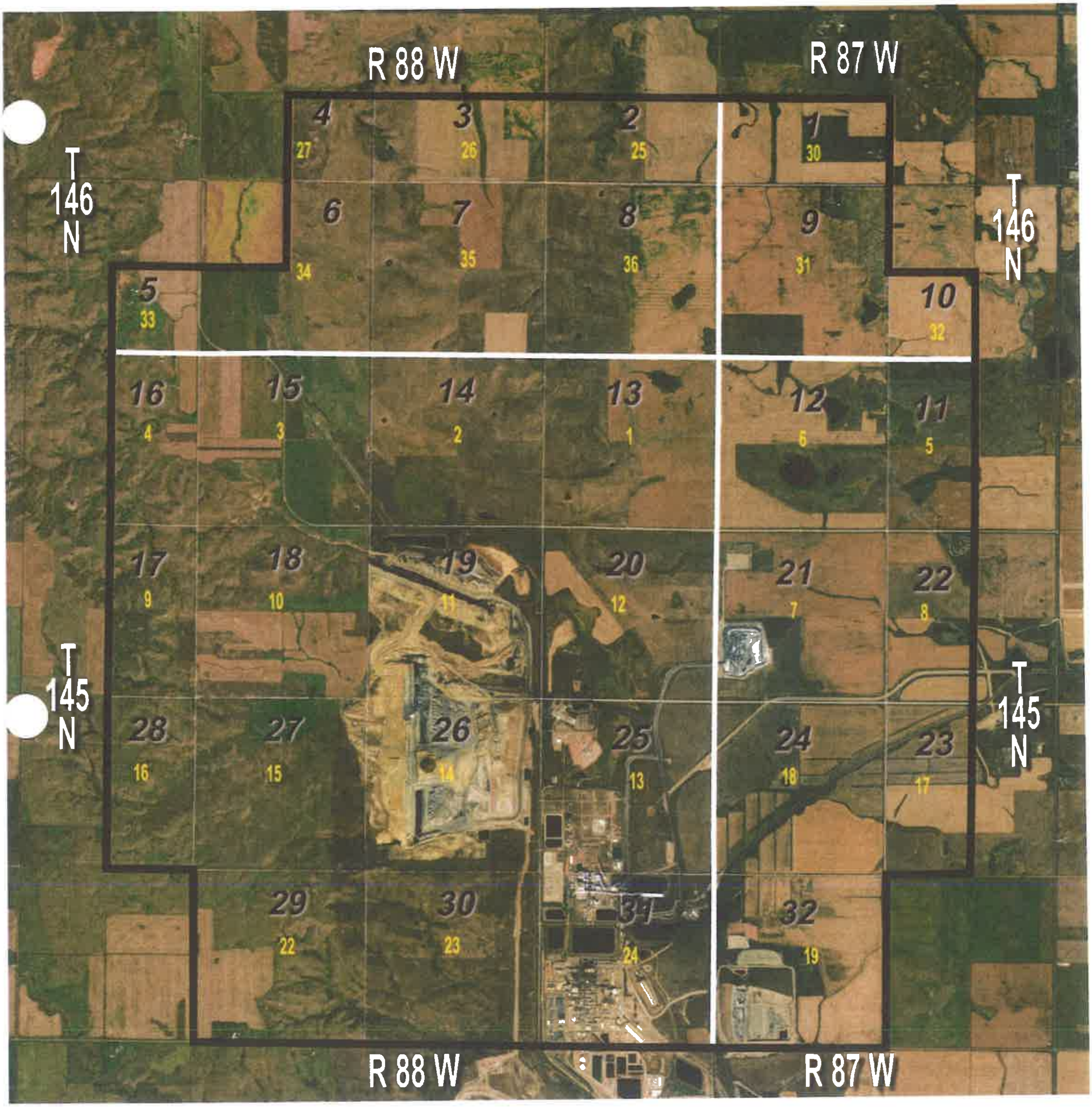
DAKOTA GASIFICATION COMPANY

By:___________________________________

[Name]

Its: [Title]

75907136 v1



Permit Boundary

27 Tract Number

0 1/2 1
Graphic Scale in Miles

75931620.1

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

Exhibit A

Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County,
North Dakota)

EXHIBIT B
Tract Summary
Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation
1	Section 30 - T146N-R87W	The Coteau Properties Co.	237.57	74.81%	1.48674499%
		John D. Renner	80.00	25.19%	0.50065075%
		Tract Total	**317.57**	100.00%	
2	Section 25 - R146N-R88W	The Coteau Properties Co.	**320.00**	100.00%	2.00260301%
3	Section 26 - R146N-R88W	The Coteau Properties Co.	200.00	62.50%	1.25162688%
		Lucille Sailer	120.00	37.50%	0.75097613%
		Tract Total	**320.00**	100.00%	
4	Section 27 - R146N-R88W	The Coteau Properties Co.	80.00	50.00%	0.50065075%
		Lyle Eisenbeis and Kathy Eisenbeis	80.00	50.00%	0.50065075%
		Tract Total	**160.00**	100.00%	
5	Section 33 - R146N-R88W	Karen A. Walz	**160.00**	100.00%	1.00130150%
6	Section 34 - R146N-R88W	E. Wayne Eisenbeis and Margo L. Eisenbeis	320.00	66.67%	2.00260301%
		The Coteau Properties Co.	160.00	33.33%	1.00130150%
		Tract Total	**480.00**	100.00%	
7	Section 35 - R146N-R88W	The Coteau Properties Co.	560.00	87.50%	3.50455526%
		Lucille Sailer	80.00	12.50%	0.50065075%
		Tract Total	**640.00**	100.00%	
8	Section 36 - R146N-R88W	The Coteau Properties Co.	320.00	50.00%	2.00260301%
		Wayne Renner and Prudence Renner	240.00	37.50%	1.50195226%
		Prudence Renner	40.00	6.25%	0.25032538%
		Wayne Renner	40.00	6.25%	0.25032538%
		Tract Total	**640.00**	100.00%	
9	Section 31 - T146N-R87W	Wayne Renner and Prudence Renner	**637.68**	100.00%	3.99068715%
10	Section 32 - T146N-R87W	Wayne Renner and Prudence Renner	**160.00**	100.00%	1.00130150%
11	Section 5 - T145N-R87W	David Young Payn	159.94	49.99%	1.00092602%
		The Coteau Properties Co.	160.00	50.01%	1.00130150%
		Tract Total	**319.94**	100.00%	
12	Section 6 - T145N-R87W	The Coteau Properties Co.	**639.31**	100.00%	4.00088790%
13	Section 1 - T145N-R88W	The Coteau Properties Co.	**636.40**	100.00%	3.98267673%
14	Section 2 - T145N-R88W	The Coteau Properties Co.	**634.96**	100.00%	3.97366502%

EXHIBIT B
Tract Summary
Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation
15	Section 3 - T145N-R88W	E. Wayne Eisenbeis and Margo L. Eisenbeis	235.47	36.93%	1.47362168%
		Ronnie Lee Parks	4.21	0.66%	0.02634675%
		The Coteau Properties Co.	317.90	49.86%	1.98946093%
		North American Coal Royalty Co.	80.00	12.55%	0.50065075%
		Tract Total	**637.58**	100.00%	
16	Section 4 - T145N-R88W	The Coteau Properties Co.	233.71	73.46%	1.46260737%
		Darvin Schlender and Janet Schlender	4.43	1.39%	0.02770476%
		North American Coal Royalty Co.	80.00	25.15%	0.50065075%
		Tract Total	**318.14**	100.00%	
17	Section 9 - T145N-R88W	The Coteau Properties Co.	**320.00**	100.00%	2.00260301%
18	Section 10 - T145N-R88W	The Coteau Properties Co.	**640.00**	100.00%	4.00520602%
19	Section 11 - T145N-R88W	The Coteau Properties Co.	**640.00**	100.00%	4.00520602%
20	Section 12 - T145N-R88W	The Coteau Properties Co.	636.71	99.49%	3.98461675%
		Mercer County	2.52	0.39%	0.01577050%
		Basin Electric Power Coop	0.77	0.12%	0.00481876%
		Tract Total	**640.00**	100.00%	
21	Section 7 - T145N-R87W	Wayne Renner and Prudence Renner	240.00	37.54%	1.50195226%
		Basin Electric Power Coop	319.30	49.95%	1.99822231%
		The Coteau Properties Co.	80.00	12.51%	0.50065075%
		Tract Total	**639.30**	100.00%	
22	Section 8 - T145N-R87W	The Coteau Properties Co.	293.43	91.70%	1.83632438%
		Ridge Runner Motorcycle Club, Inc.	26.57	8.30%	0.16627863%
		Tract Total	**320.00**	100.00%	
23	Section 17 - T145N-R87W	The Coteau Properties Co.	**320.00**	100.00%	2.00260301%
24	Section 18 - T145N-R87W	The Coteau Properties Co.	625.29	97.81%	3.91316138%
		Dakota Gasification Co.	13.45	2.10%	0.08415939%
		Basin Electric Power Coop	0.58	0.09%	0.00362972%
		Tract Total	**639.32**	100.00%	
25	Section 13 - T145N-R88W	Basin Electric Power Coop	233.09	36.42%	1.45867726%
		The Coteau Properties Co.	372.46	58.20%	2.33089848%
		Dakota Gasification Co.	34.46	5.38%	0.21563028%
		Tract Total	**640.00**	100.00%	
26	Section 14 - T145N-R88W	The Coteau Properties Co.	558.75	87.30%	3.49673260%

EXHIBIT B
Tract Summary
Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation
		Mercer County	1.25	0.20%	0.00782267%
		Basin Electric Power Coop	80.00	12.50%	0.50065075%
		Tract Total	**640.00**	100.00%	
27	Section 15 - T145N-R88W	The Coteau Properties Co.	**640.00**	100.00%	4.00520602%
28	Section 16 - T145N-R88W	The Coteau Properties Co.	240.00	75.00%	1.50195226%
		Betty Scott	40.00	12.50%	0.25032538%
		Dallas Crabtree	20.00	6.25%	0.12516269%
		Denzel Crabtree	20.00	6.25%	0.12516269%
		Tract Total	**320.00**	100.00%	
29	Section 22 - T145N-R88W	The Coteau Properties Co.	446.70	69.80%	2.79550864%
		Karen A. Walz	152.92	23.89%	0.95699391%
		Kelly L. Wilhelm	40.38	6.31%	0.25270347%
		Tract Total	**640.00**	100.00%	
30	Section 23 - T145N-R88W	Basin Electric Power Coop	360.00	56.25%	2.25292838%
		The Coteau Properties Co.	40.00	6.25%	0.25032538%
		Robert L. Bitner and Irma M Bitner for Life	240.00	37.50%	1.50195226%
		Tract Total	**640.00**	100.00%	
31	Section 24 - T145N-R88W	Dakota Gasification Co.	478.40	74.75%	2.99389150%
		Basin Electric Power Coop	147.58	23.06%	0.92356922%
		The Coteau Properties Co.	14.02	2.19%	0.08774530%
		Tract Total	**640.00**	100.00%	
32	Section 19 - T145N-R87W	The Coteau Properties Co.	320.00	50.08%	2.00260301%
		North American Coal Royalty Co.	159.45	24.95%	0.99785953%
		Dakota Gasification Co.	159.55	24.97%	0.99848534%
		Tract Total	**639.00**	100.00%	
		Total Acres	**15,979.20**	**Total Participation**	**100.00000000%**

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EXHIBIT C
Tract Participation
Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

Tract No.	Tract Acres	Tract Participation
1	317.57	1.98739611%
2	320.00	2.00260338%
3	320.00	2.00260338%
4	160.00	1.00130169%
5	160.00	1.00130169%
6	480.00	3.00390508%
7	640.00	4.00520677%
8	640.00	4.00520677%
9	637.68	3.99068789%
10	160.00	1.00130169%
11	319.94	2.00222790%
12	639.31	4.00088866%
13	636.40	3.98267748%
14	634.96	3.97366577%
15	637.58	3.99006208%
16	318.14	1.99096325%
17	320.00	2.00260338%
18	640.00	4.00520677%
19	640.00	4.00520677%
20	640.00	4.00520677%
21	639.30	4.00082607%
22	320.00	2.00260338%
23	320.00	2.00260338%
24	639.32	4.00095124%
25	640.00	4.00520677%
26	640.00	4.00520677%
27	640.00	4.00520677%
28	320.00	2.00260338%
29	640.00	4.00520677%
30	640.00	4.00520677%
31	640.00	4.00520677%
32	639.00	3.99894863%
	15,979.20	**100.00000000%**

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EXHIBIT D
Pore Space Lease
Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

THIS PORE SPACE LEASE (this "Lease") is made effective as of the Effective Date (as defined below), by and between «Surface_Owner», whose address is «Address», «City» «State» «Zip», (whether one or more, "Lessor"), and Dakota Gasification Company, a North Dakota corporation, whose address is 1717 East Interstate Avenue, Bismarck, North Dakota 58503 (whether one or more, "Lessee"). Lessor and Lessee may be individually referred to herein as a "Party" and collectively as the "Parties".

1. Leased Premises. Lessor, for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, does hereby grant, demise, lease and let unto Lessee for Lessee's geologic storage operations and other purposes set forth herein, the following-described lands situated in Mercer County, North Dakota:

Township [__] North, Range [___] West
Section [__]: [__]

containing «Acres» acres, more or less (the "Leased Premises"), subject to the terms and conditions set forth herein. The entire project area includes acres, more or less (the "Project Area").

2. Term.

(a) Primary Term. This Lease shall commence on the date Lessee executes this Lease ("Effective Date") and continue for an initial term of Fifteen (15) years ("Primary Term") unless sooner terminated in accordance with the terms of this Lease. On the Effective Date of this Lease and thereafter on or before each annual anniversary date of this Lease, Lessee shall pay to Lessor the sum of ($) per surface acre covered by this Lease. After the Primary Term, Lessee retains the right to extend this lease up to three (3) additional five (5) year terms by providing Lessor with at least a 60-day notice, as long as Lessee continues to pay to Lessor through any extension period, the annual lease rate provided for above and any royalty rates as set forth in Section 3 of this Lease.

(b) Operational Term. This Lease shall continue beyond the Initial Term for so long as any portion of the Leased Premises or Lessee's storage facilities located in, on or under the Leased Premises (including without limitation, any Reservoirs) are subject to a permit issued by the North Dakota Industrial Commission (the "Commission") (a "Permit") or under the ownership or control of the State of North Dakota; *provided, however*, that all of Lessee's obligations under this Lease shall terminate upon issuance of a certificate of project completion pursuant to Chapter 38-22 of the North Dakota Century Code (the "Operational Term"). If the Primary Term expires and no portion of the Leased Premises or Lessee's storage facilities located in, on or under the Leased Premises is subject to a Permit, this Lease shall terminate, and Lessee shall execute a document evidencing termination of this Lease in recordable form and shall record it in the official records of the county or counties in which any portion of the Leased Premises is located.

3. Royalty. Lessee shall pay to Lessor its proportionate share of ($) per metric ton of carbon dioxide (CO_2) injected into the reservoirs and subsurface pore spaces (as used herein, such terms shall have the meanings set forth in Chapter 38-22 and Chapter 47-31 of the North Dakota Century Code), stratum or strata underlying the Leased Premises (collectively, "Reservoirs"), or reservoirs and subsurface pore spaces, stratum or strata unitized or amalgamated therewith (the "Amalgamated Reservoirs"). Lessor's "proportionate share" shall be determined on a net acre basis and the Parties hereby stipulate that the acreage set forth in Section 1 shall be used to calculate Lessor's proportionate share of the Project Area. The quantity of carbon dioxide injected into the Reservoirs or any Amalgamated Reservoirs shall be determined through the use of metering equipment installed and operated by Lessee at the injection site. All royalties due hereunder for carbon dioxide injected into the Reservoirs or any Amalgamated Reservoirs during any calendar year shall be paid to Lessor within sixty (60) days of the end of said year. Lessor and Lessee agree that this Lease shall continue as specified herein even in the absence of injection operations and the payment of royalties.

4. Right to Pore Space/Storage of Carbon Dioxide. Lessor grants to Lessee the exclusive right to inject and store carbon dioxide and other incidental gaseous substances into and in the Reservoirs, together with the right of reasonable use of the surface of the Leased Premises as set forth in Section 5. Lessor shall not grant to any other person the right to inject or store carbon dioxide or any other gases, liquids, solids or semi-solids into the Reservoirs underlying the Leased Premises.

5. Surface Access. Lessor grants Lessee the right of reasonable use of the surface of the Leased Premises, including without limitation, the rights of ingress and egress over the Leased Premises, for purposes of any surveys and/or ongoing testing activities related to this Lease provided, however, that Lessee shall compensate Lessor, or its tenants, for any physical damages to growing crops, livestock and improvements located on the Leased Premises, if such damages are caused by Lessee's use of the Leased Premises.

6. Amalgamation. Lessee, in its sole discretion, shall have the right and power, at any time and from time to time during the term of this Lease to pool, unitize, or amalgamate any reservoirs or subsurface pore spaces, stratum or strata underlying the Leased Premises with any other lands or interests into which such reservoirs or subsurface pore spaces extend and document such unit in accordance with applicable law or agency order. Amalgamated units shall be of such shape and dimensions as Lessee may elect and as are approved by the Commission. Amalgamated areas may include, but are not required to include, land upon which injection or extraction wells have been completed or upon which the injection and/or withdrawal of carbon dioxide and/or related gaseous substances has commenced prior to the effective date of amalgamation. In exercising its amalgamation rights under this Lease and if required by law, Lessee shall record or cause to be recorded a copy of the Commission's amalgamation order or other notice thereof in the county or counties in which any portion of the amalgamated unit is located. Amalgamating in one or more instances shall, if approved by the Commission, not exhaust the rights of Lessee to amalgamate Reservoirs or portions of Reservoirs into other amalgamation areas, and Lessee shall have the recurring right to revise any amalgamated area formed under this Lease by expansion or contraction or both. Lessee may dissolve any amalgamated area at any time and document such dissolution by recording an instrument in accordance with applicable law or agency order. Lessee shall have the right to negotiate, on behalf of and as agent for Lessor, any unit, amalgamation, storage or operating agreements with respect to amalgamation of reservoir or pore space interests

underlying the Leased Premises or the operation of any amalgamated areas formed under such agreements and Lessor shall ratify any such agreements upon Lessee's request. To the extent any of the terms of such agreements conflict with the terms of this Lease, the terms of such agreements shall control and the provisions of this Lease shall be deemed modified to conform to the terms, conditions, and provisions of any such agreements which are approved by the Commission.

7. Lessee Obligations. Lessee shall have no obligation, express or implied, to begin, prosecute or continue storage operations in, upon or under the Leased Premises, or store and/or sell or use all or any portion of the gaseous substances stored thereon. The timing, nature, manner and extent of Lessee's operations, if any, under this Lease shall be at the sole discretion of Lessee. All obligations of Lessee are expressed herein, and there shall be no covenants implied under this Lease, it being agreed that all amounts paid hereunder constitute full and adequate consideration for this Lease.

8. Ownership. Lessee shall at all times be the owner of (i) the carbon dioxide and other gaseous substances stored in the Reservoirs or any Amalgamated Reservoirs, and (ii) all Facilities constructed or installed by Lessee on the Leased Premises. Lessee shall have the right, but not the obligation, at any time during this Lease to remove all or any portion of the property or fixtures placed by Lessee on the Lease Premises. Notwithstanding the foregoing, title to the storage facility and to the stored carbon dioxide or other gaseous substances shall be transferred to the State of North Dakota upon issuance of a certificate of project completion by the Commission in accordance with Chapter 38-22 of the North Dakota Century Code.

9. Minerals, Oil and Gas. This lease is not intended to grant or convey, nor does it grant or convey, any right to or obligation for lessee to explore for or produce minerals, including oil and gas, that may exist on or under the leased premises.

10. Surrender of Leased Premises. Lessee shall have the right, but not the obligation, at any time from time to time to execute and deliver to Lessor a surrender and/or release covering all or any part of the Leased Premises for which the Reservoirs are not being utilized for storage as set forth herein, and upon delivery of such surrender and/or release to Lessor this Lease shall terminate as to such lands, and Lessee shall be released from all further obligations and duties as to the lands so surrendered and/or released, including, without limitation, any obligation to make payments provided for herein, except obligations accrued as of the date of the surrender and/or release. Lessee shall be able to surrender any and or all of the Leased Premises if not utilizing the Reservoirs located thereunder.

11. Hold Harmless and Indemnification. The Lessee agrees to defend, indemnify, and hold harmless Lessor from any claims by any person that are a direct result of the Lessee's use of the Leased Premises or Reservoirs. Notwithstanding the foregoing, such indemnity/hold harmless obligation excludes (i) any claim or cause of action, or alleged or threatened claim or cause of action, damage, judgment, interest, penalty or other loss arising or resulting from the negligence or intentional acts of Lessor or Lessor's agents, invitees, or licensees; or third parties, and (ii) any claim for exemplary, punitive, special or consequential damages claimed by Lessor. Lessee further accepts liability and indemnifies Lessor for reasonable costs, expenses and attorneys' fees incurred in establishing and litigating the indemnification coverage provided above. The legal defense provided by Lessee to the Lessor under this paragraph must be free of any conflicts of interest even if this requires Lessee to retain separate legal counsel for Lessor.

12. Hazardous Substances. Lessee shall have no liability for any regulated hazardous substances located on the Leased Premises prior to the Effective Date or placed in, on or about the Leased Premises by Lessor or any third-party on or after the Effective Date, and nothing in this Lease shall be construed to impose upon Lessee any obligation for the removal of such regulated hazardous substances. As used herein, "hazardous substances" shall have the meaning set forth in the Comprehensive Environmental Response Compensation and Liability Act (CERCLA) and any amendments thereto, or any other local, state or federal statutes.

13. Termination. A material violation or default of any terms of this Lease by Lessee shall be grounds for termination of the Lease. Lessor shall provide Lessee written notice of violation or default and Lessee shall have sixty (60) days after receipt of said notice to substantially cure such violations or defaults. If Lessee fails to substantially cure such violations or defaults within the 60-day cure period, Lessor may terminate the Lease; *provided that*, if it is not reasonably possible to cure such violations or defaults within the 60-day cure period, Lessee shall have additional time as is reasonably necessary to cure such violations or defaults provided Lessee has commenced its efforts to cure within the initial sixty (60) day period and thereafter diligently pursues such cure. Lessee may terminate the lease with thirty (30) days written notice to Lessor. Upon termination of this Lease, Lessee shall have one hundred eighty (180) days to remove all facilities and property (except for carbon dioxide or other incidental gaseous substances which have been injected into the Reservoirs) of Lessee located on the Leased Premises.

14. Taxes. Lessee shall pay all taxes, if any, levied against its personal property or on its improvements to the Leased Premises. Lessor shall pay for all real estate taxes and other assessments levied upon the Leased Premises. Lessee shall have the right to pay all taxes, assessments and other fees on behalf of Lessor and to deduct the amount so paid from other payments due to Lessor hereunder.

15. Conduct of Operations. In conducting its operations hereunder, Lessee shall use its best efforts to comply with all applicable laws, rules and regulations and ordinances pertaining thereto. Lessee reserves and shall have the right to challenge and/or appeal any law, ruling, regulation, order or other determination and to carry on its operations in accordance with Lessee's interpretation of the same, pending final determination.

16. Force Majeure. Should Lessee be prevented from complying with any express covenant of this Lease, from utilizing the Lease Premises for underground storage purposes by reason of scarcity of or an inability to obtain or to use equipment or material or failure or breakdown of equipment, or by operation of force majeure, any federal or state law or any order, rule or regulation of governmental authority, then while so prevented, Lessee's obligation to comply with such covenant shall be suspended and this Lease shall be extended while and so long as Lessee is prevented by any such cause from utilizing the property for underground storage purposes and the time while Lessee is so prevented shall not be counted against Lessee, anything in this Lease to the contrary notwithstanding.

17. Warranty of Title. Lessor represents and warrants to Lessee that Lessor is the owner of the surface of the Leased Premises and the pore space located thereunder. Lessor hereby warrants and agrees to defend title to the Leased Premises and the pore space located thereunder' and Lessor hereby agrees that Lessee, at its option, shall have the right to discharge any tax, mortgage, or other lien upon the Leased Premises, and in the event Lessee does so, Lessee shall be subrogated to such

lien with the right to enforce the same and apply royalty payments or any other payments due to Lessor toward satisfying the same.

18. Quiet Enjoyment. Lessor shall have the quiet use and enjoyment of the Leased Premises in accordance with the terms of this Lease. Lessor's activities and any grant of rights Lessor makes to any person or entity, whether located on the Leased Premises or elsewhere, shall not interfere with the rights granted to Lessee hereunder.

19. Environmental Incentives and Tax Credits. Lessee shall be the owner of (i) any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to Lessee's geologic storage operations, including any avoided emissions and the reporting rights related to these avoided emissions, such as 26 U.S.C. § 45Q Tax Credits, and any other attributes of Lessee's ownership of the Facilities and Lessee's geologic storage operations ("Environmental Attributes"), and (ii) any and all credits, rebates, subsidies, payments or other incentives that relate to the use of technology incorporated into Lessee's geologic storage operations, environmental benefits of such operations, or other similar programs available from any regulated entity or any governmental authority ("Environmental Incentives"). Lessee is further entitled to the benefit of any and all (a) investment tax credits, (b) production tax credits, (c) credits under 26 U.S.C. § 45Q credits, and (d) similar tax credits or grants under federal, state or local law relating to Lessee's geologic storage operations ("Tax Credits"). Lessor shall (i) cooperate with Lessee in obtaining, securing and transferring all Environmental Attributes and Environmental Incentives and the benefit of all Tax Credits, and (ii) shall allow Lessee to take any actions necessary to install additional equipment on the Facilities to comply with all monitoring and reporting obligations, and allow Lessee's personnel to enter the premises and collect any data Lessee requires to satisfy its obligations required in connection with obtaining Tax Credits and Environmental Attributes. Lessor shall not be obligated to incur any out-of-pocket costs or expenses in connection with such actions unless reimbursed by Lessee. If any Environmental Incentives are paid directly to Lessor, Lessor shall immediately pay such amounts over to Lessee.

20. Financing. Lessor acknowledges and agrees that Lessee may, at Lessee's own expense, seek equity or debt financing or refinancing in connection with Lessee's geologic storage operations, including any construction financing, whether on a project basis or a portfolio basis ("Financing"). In order to facilitate the Financing, Lessor agrees, at Lessee's expense, to cooperate and to execute all documents including, if applicable, any title policy affidavits reasonably necessary to obtain the Financing, provided that the foregoing shall not require Lessor to execute any documents that (a) result in Lessor incurring liabilities or obligations not contemplated in this Lease, or (b) encumber Lessor's fee interest in the Leased Premises, except to the extent any such interest is covered by this Lease. Lessor agrees that Lessor shall execute and deliver to Lessee any documents reasonably required by a financing party within five (5) business days after presentation of said documents by Lessee. Lessee shall have the absolute right in its sole and exclusive discretion, without obtaining the consent of Lessor, to mortgage, encumber, hypothecate, pledge, transfer, assign, or collateral assign, to one or more financing parties any or all of the rights granted to Lessee hereunder and/or any or all right or interest of Lessee in the Leased Premises or in any or all of the Facilities.

21. Assignment. The rights of either Party hereto may be assigned in whole or part. The assigning party shall provide written notice of any assignment within sixty (60) days after such assignment has become effective; *provided, however,* that an assigning party's failure to deliver written notice

of assignment within such 60-day period shall not be deemed a breach of this Lease unless such failure is willful and intentional. The Lessor's consent shall not be required for an assignment by the Lessee of this Lease, whether by way of a collateral assignment to its financiers or otherwise.

22. Change of Ownership. Lessee understands that this Lease runs with the land and transfers to any new owner of the surface acres. No change of ownership in the Leased Premises or assignment of Lessor's rights hereunder shall be binding on the Lessee for purpose of making payments to Lessor hereunder until the date Lessor, or Lessor's successors or assigns, furnishes Lessee the recorded original or a certified copy of the instrument evidencing the change in ownership or assignment.

23. Notices. All notices required to be given under this Lease shall be in writing and addressed to the respective Party at the addresses set forth at the beginning of this Lease unless otherwise directed by either Party.

24. No Waiver. The failure of either Party to insist in any one or more instances upon strict performance of any of the provisions of this Lease or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provision or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

25. Notice of Lease. This Lease shall not be recorded in the real property records. Lessee shall cause a memorandum of this Lease to be recorded in the real property records of the county or counties in which any portion of the Leased Premises are situated. A recorded copy of said memorandum shall be furnished to Lessor within thirty (30) days of recording.

26. Confidentiality. Lessor shall maintain in the strictest confidence, for the benefit of Lessee, all information pertaining to the compensation paid under this Lease, any information regarding Lessee and its business or operations on the Leased Premises or on any other lands, the capacity and suitability of any Reservoir or Amalgamated Reservoir, and any other information that is deemed proprietary or that Lessee requests or identifies to be held confidential, in each such case whether disclosed by Lessee or discovered by Lessor.

27. Counterparts. This Lease may be executed in any number of counterparts, each of which, when executed and delivered, shall be an original, but all of which shall collectively constitute one and the same instrument.

28. Severability. If any provision of this Lease is found to be invalid, illegal or unenforceable in any respect, such provision shall be deemed to be severed from this Agreement, and the validity, legality and enforceability of the remaining provisions contained herein shall not in any way be affected or impaired thereby.

29. Governing Law. This Lease shall be governed by, construed and enforced in accordance with the laws of the State of North Dakota and the Parties hereby submit to the jurisdiction of the state or federal courts located in the State of North Dakota.

30. Further Assurances. Each Party will execute and deliver all documents, provide all information, and take or forbear from all actions as may be necessary or appropriate to achieve the purposes of this Lease, including without limitation executing a memorandum of this Lease and all documents required to obtain any necessary government approvals.

31. Entire Agreement. This Lease constitutes the entire agreement between the Parties and supersedes all prior negotiations, undertakings, notices, memoranda and agreement between the Parties, whether oral or written, with respect to the subject matter hereof. This Lease may only be amended or modified by a written agreement duly executed by Lessor and Lessee.

32. Electronic Signatures. This Lease, and any amendments hereto, to the extent signed and delivered by means of electronic transmission in portable document format (pdf) or by DocuSign or similar electronic signature process, shall be treated in all manner and respects as an original contract and shall be considered to have the same binding legal effect as if it were the original signed version thereof delivered in person.

IN WITNESS WHEREOF, the Parties have executed this Lease effective for all purposes as of the Effective Date.

LESSOR:

By: ______________________________

Print: ______________________________

By: ______________________________

Print: ______________________________

Effective Date: ________________

LESSEE:

Dakota Gasification Company

By: ______________________________

Print: ______________________________

Its: ______________________________

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2.0 GEOLOGIC EXHIBITS

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2.1 Overview of Project Area Geology

The proposed DGC Great Plains CO_2 Sequestration Project will be situated near Beulah, North Dakota (Figure 2-1). This project site is on the central portion of the Williston Basin. The Williston Basin is an intracratonic sedimentary basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota.

Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted via the PCOR Partnership, the Williston Basin has been identified as an excellent candidate for long-term CO_2 storage because of, in part, the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structure character and tectonic stability (Peck and others, 2014; Glazewski and others, 2015).

The target CO_2 storage reservoir for the Great Plains CO_2 Sequestration Project is the Broom Creek Formation, a predominantly sandstone horizon lying about 5,900 ft below DGC's Great Plains Synfuels Plant (Figure 2-2). Mudstones, siltstones, and interbedded evaporites of the Opeche Formation unconformably overly the Broom Creek and serve as the primary confining zone (Figure 2-3). The Amsden Formation (dolostone, limestone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-3). Together, the Opeche, Broom Creek, and Amsden comprise the CO_2 storage complex for the Great Plains CO_2 Sequestration Project (Table 2-1).

Including the Opeche Formation, there is ~1,100 ft of impermeable formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation. An additional ~2,700 ft of impermeable intervals separates the Inyan Kara and the lowest USDW, the Fox Hills Formation (Figure 2-3).

2.2 Data and Information Sources

Several sets of data were used to characterize the injection and confining zones to establish their suitability for the storage and containment of injected CO_2. Data sets used for characterization included both existing data (sources and uses are discussed within Section 2.2) and site-specific data acquired by the applicant specifically to characterize the storage complex.

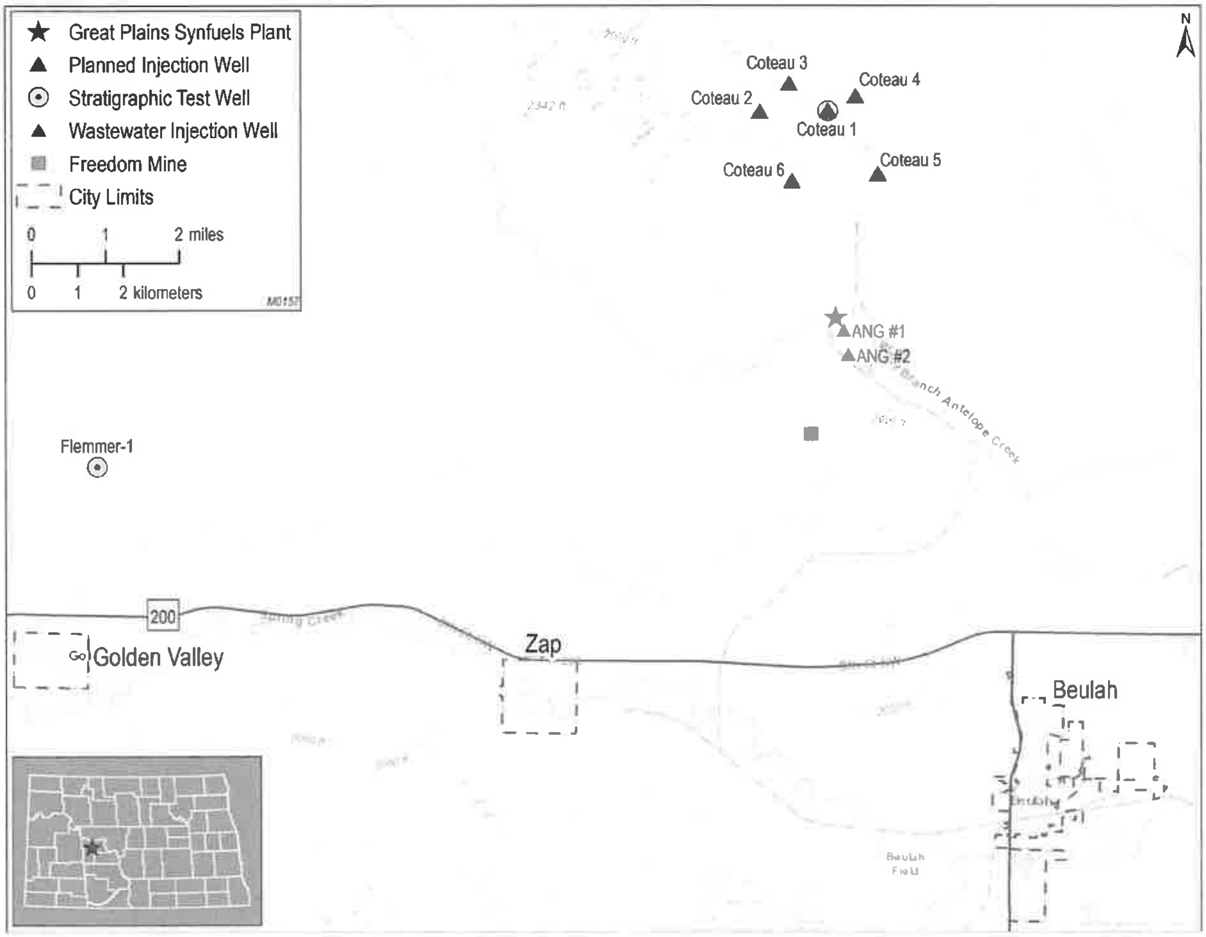

Figure 2-1. Topographic map of the Great Plains CO_2 Sequestration Project area showing well locations and the Great Plains Synfuels Plant.

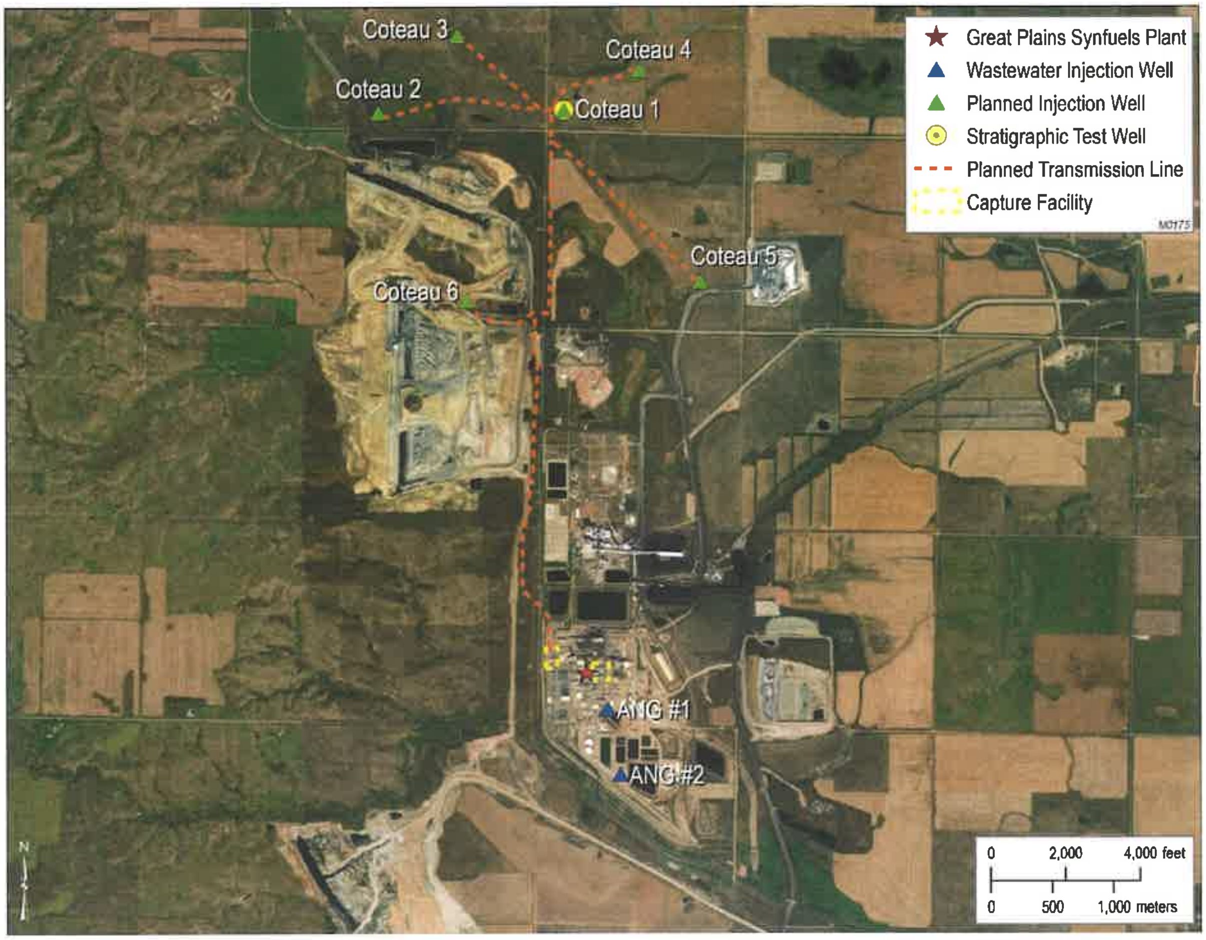

Figure 2-2. Map of the proposed CO_2 injection wells.

2.2.1 Existing Data

The existing data used to characterize the geology beneath the Great Plains CO_2 Sequestration Project site included publicly available well logs and formation top depths acquired from the NDIC online database. Well log data and interpreted formation top depths were acquired for 120 wellbores within a 5,472-mi^2 (72 × 76-mi) area centered on the proposed storage site (Figure 2-4). Well data were used to characterize the depth, thickness, and extent of the subsurface geologic formations.

Existing laboratory measurements from Broom Creek Formation core samples were available from five wells shown in Figure 2-5: Coteau 1 (NDIC File No. 38379), Flemmer 1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), J-LOC1 (NDIC File No. 37380), J-ROC1 (NDIC File No. 37672), and ANG #1 (North Dakota Department of Environmental Quality [NDEQ] No. 11308). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and integrated with newly acquired site-specific data.

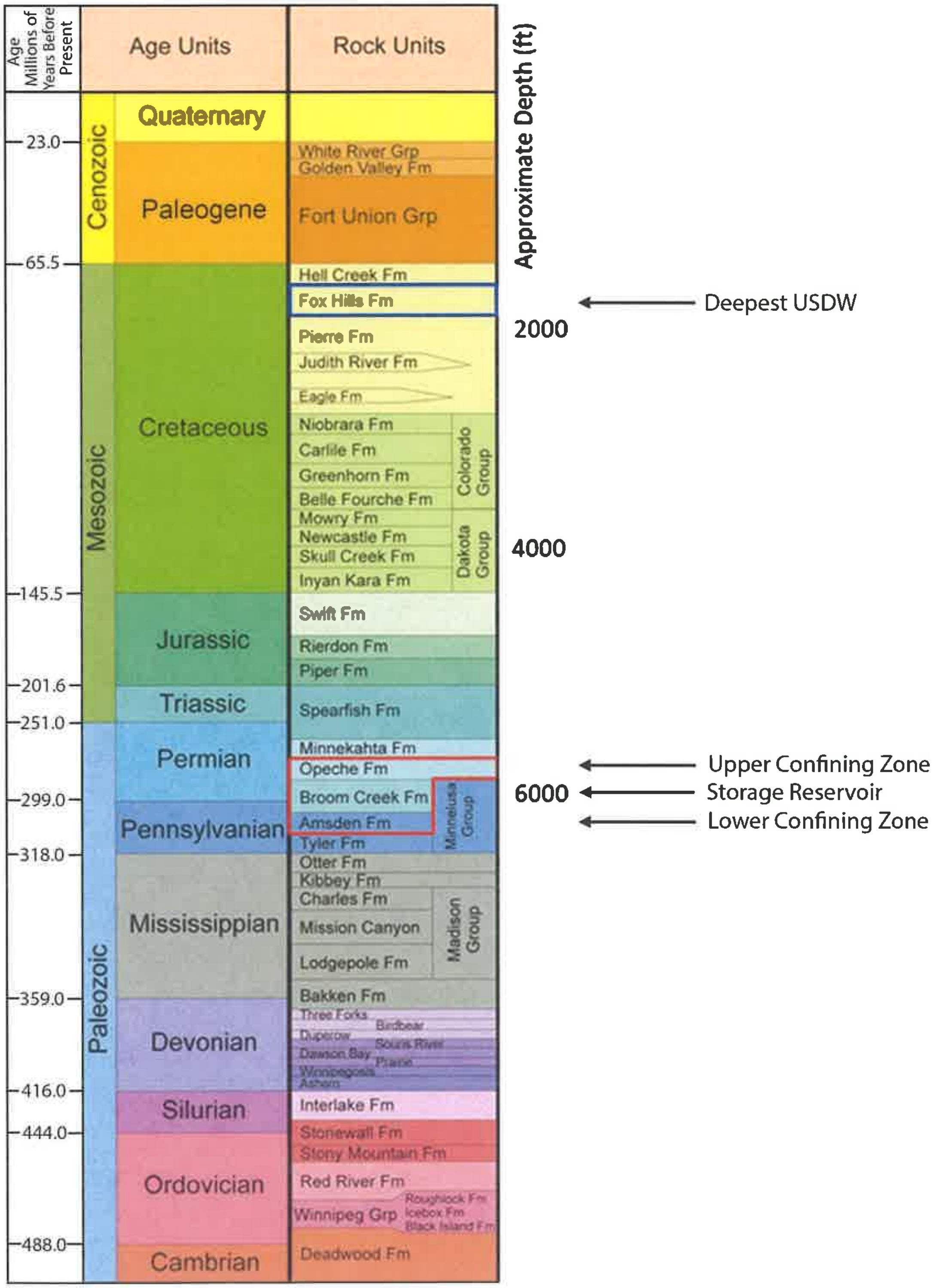

Figure 2-3. Stratigraphic column identifying the storage reservoir, confining zones, and lowest USDW addressed in this permit application for the Great Plains CO_2 Sequestration Project.

Table 2-1. Formations Comprising the Great Plains CO_2 Sequestration Project Storage Complex (average values calculated from the simulation model and well log data)

	Formation	Purpose	Average Thickness, ft	Average Measured Depth (MD), ft	Lithology
Storage Complex	**Opeche**	**Upper confining zone**	**150**	**4,887**	**Mudstone, siltstone, evaporites**
	Broom Creek	Storage reservoir (i.e., injection zone)	248	5,348	Sandstone, dolostone, dolomitic sandstone, anhydrite
	Amsden	**Lower confining zone**	**268**	**5,558**	**Dolostone, limestone, anhydrite**

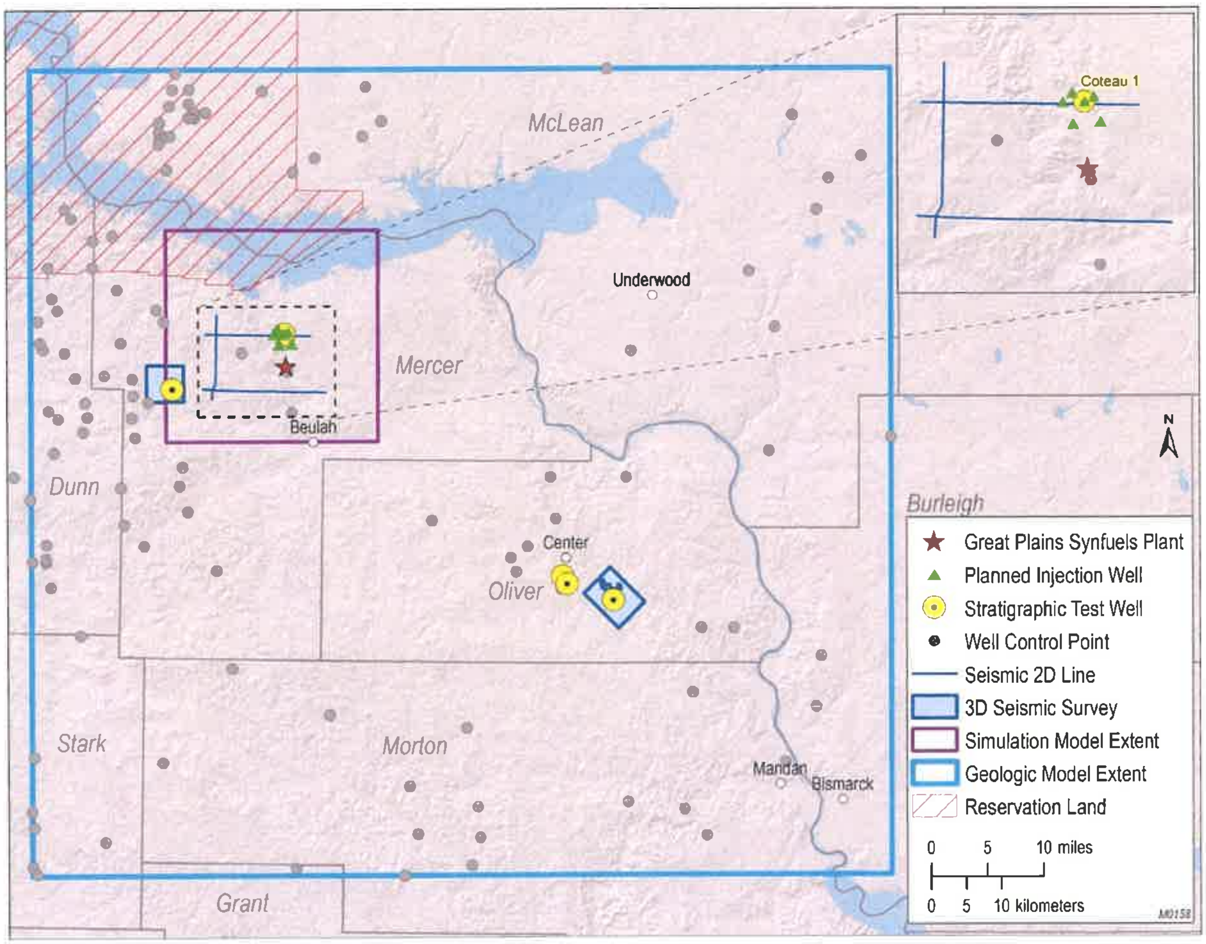

Figure 2-4. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones.

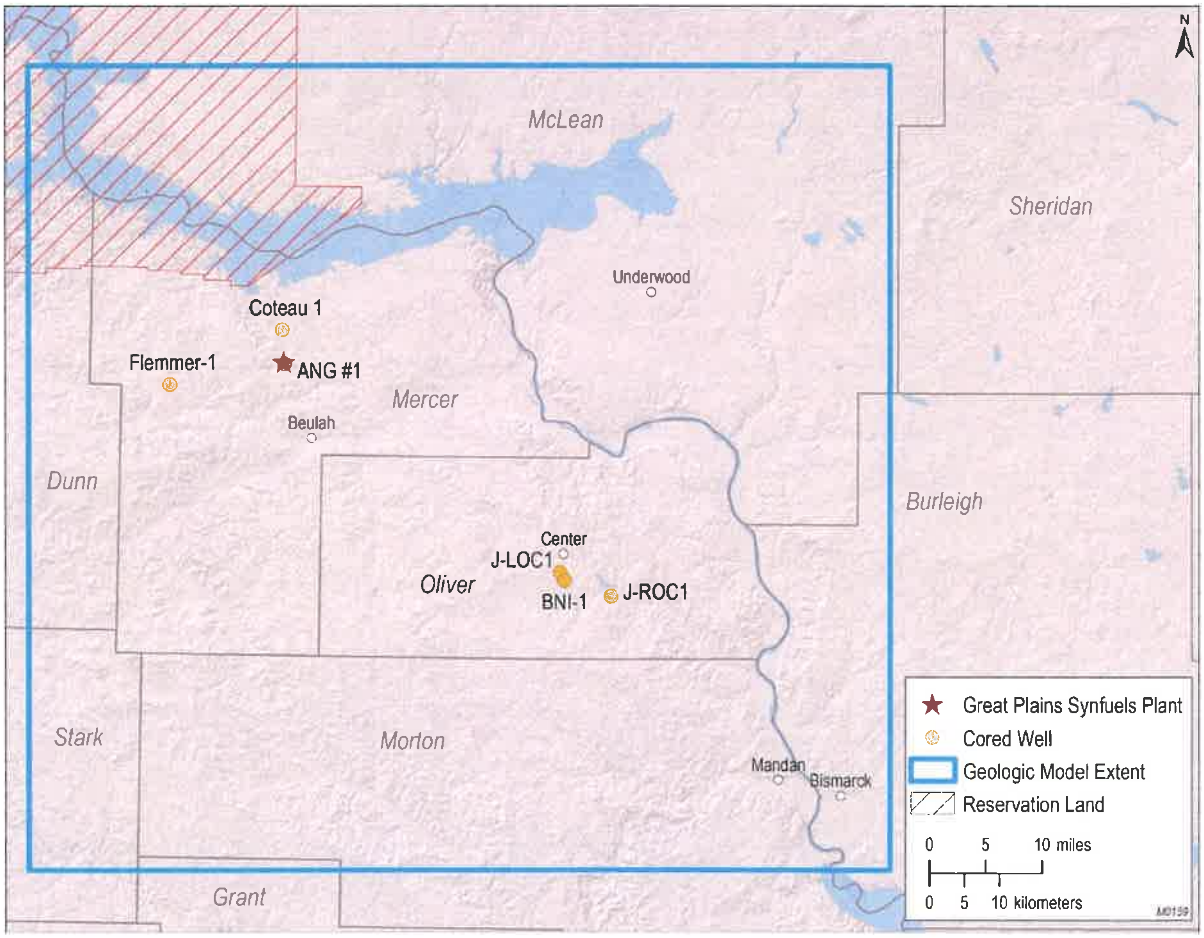

Figure 2-5. Map showing the spatial relationship between the Great Plains CO_2 Sequestration Project area and wells where the Broom Creek Formation core samples were collected. Wells with core data include the Coteau 1 (NDIC File No. 38379), Flemmer 1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), ANG #1 (NDEQ No. 11308), J-LOC1 (NDIC File No. 37380), and J-ROC1 (NDIC File No. 37672).

Ten square miles of legacy 3D seismic data from Mercer County, encompassing the Flemmer 1 wellsite, and twenty-eight miles of legacy 2D seismic data were licensed and examined to understand the heterogeneity and geologic structure of the Broom Creek Formation interval. Additionally, publicly available seismic interpretation products for the Broom Creek from a 3D seismic survey in Oliver County were used to inform structure and variogram distributions (Section 3.2). The structural configurations of the formations of interest generated from the interpretation of the two 3D seismic data sets along with formation tops interpreted from well log data were used to construct the geologic model. Variogram distributions derived from inversion volumes generated using the 3D seismic data were used to inform property distribution in the geologic model which was, in turn, used to simulate migration of the CO_2 plume (Section 3). These simulated CO_2 plumes were used to inform the testing and monitoring plan (Section 5).

2.2.2 Site-Specific Data

Site-specific efforts to characterize the proposed Broom Creek storage complex generated multiple data sets, including geophysical well logs, fluid analyses, and 2D seismic data. The Flemmer 1 well was drilled in 2017 to a depth of 6,790 ft in the Amsden Formation. The ANG #1 well was drilled in 1982 to a depth of 6,784 ft in the Amsden Formation. In 2021, the Coteau 1 well was drilled specifically to gather subsurface geologic data to support the development of a CO_2 storage facility permit. The Coteau 1 well was drilled to a depth of 6,484 ft. The downhole sampling and measurement program focused on the proposed storage complex (i.e., the Opeche, Broom Creek, and Amsden Formations) (Figure 2-6).

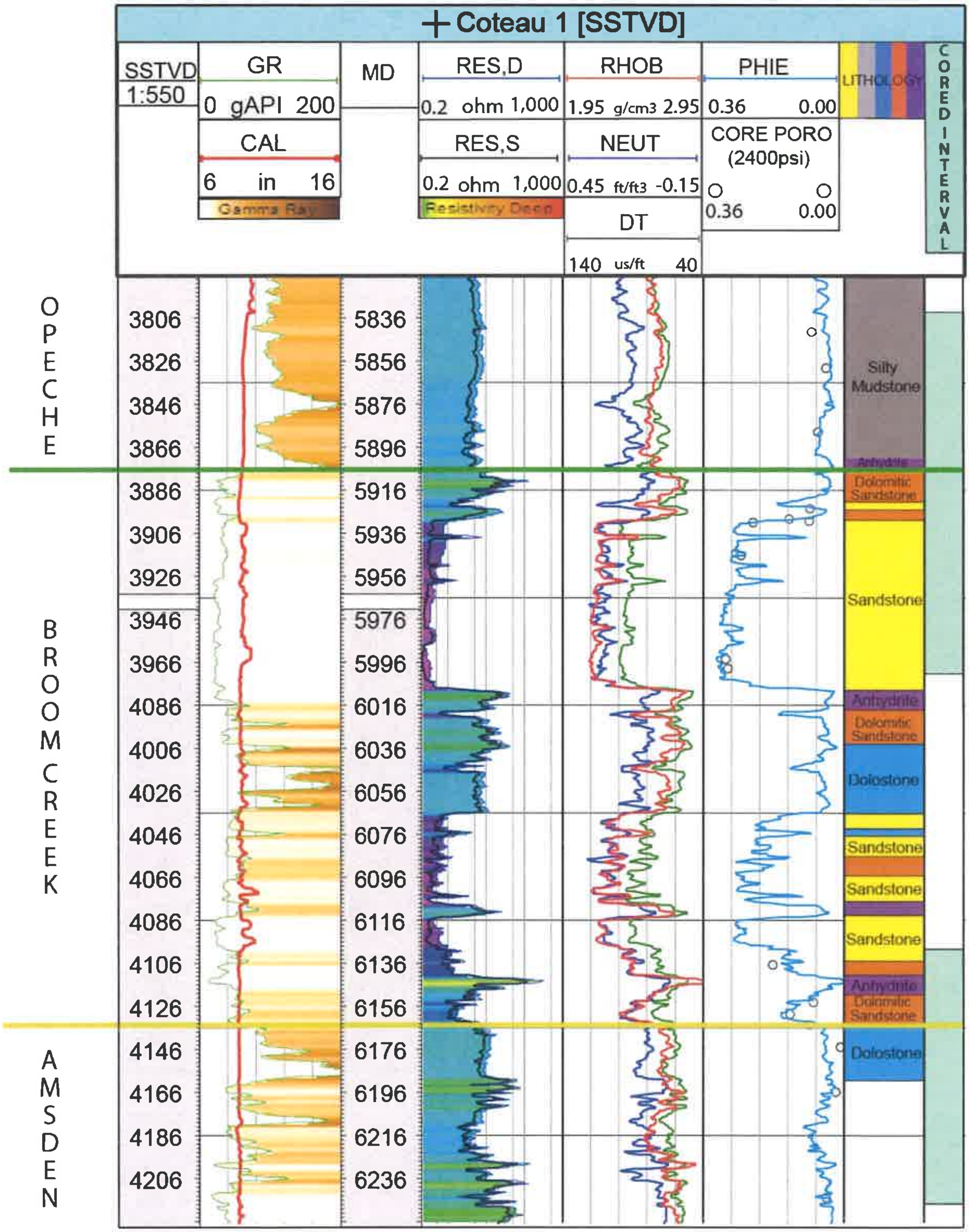

Figure 2-6. Schematic showing vertical relationship of coring (rightmost track) and core plug porosity (third track from right) intervals in the Opeche, Broom Creek, and Amsden Formations in the Coteau 1 well.

Site-specific data were used to assess the suitability of the storage complex for safe and permanent storage of CO_2. Site-specific data were also used as inputs for geologic model construction (Section 3.2), numerical simulations of CO_2 injection (Section 3.3.1), geochemical simulation (Sections 2.3.3, 2.4.1.2, and 2.4.3.2), and geomechanical analysis (Section 2.4.4). The site-specific data improved the understanding of the subsurface and directly informed the selection of monitoring technologies, development of the timing and frequency of collecting monitoring data, and interpretation of monitoring data with respect to potential subsurface risks. Furthermore, these data guided and influenced the design and operation of site equipment and infrastructure.

2.2.2.1 Geophysical Well Logs

Openhole wireline geophysical well logs were acquired in the Coteau 1 well along the entire open section of the wellbore. The logging suite included caliper, gamma ray (GR), density, porosity, dipole sonic, resistivity, combinable magnetic resonance (CMR) log, spectral GR, and fracture finder or image log. A similar logging suite was acquired from the Flemmer 1 well. The suite included caliper, GR, density, porosity, dipole sonic, spectroscopy, and spectral GR.

The acquired well logs were used to pick formation top depths, interpret lithology and petrophysical properties, and create synthetic seismic traces for tying depth to time. Formation top depths were picked from the top of the Pierre Formation to the top of the Amsden Formation. The site-specific formation top depths were added to the existing data of 120 wellbores within the 5472-mi^2 area covered by the model to understand the geologic extent, depth, and thickness of the subsurface geologic strata. The formation top depths were interpolated to create structural surfaces which served as inputs for geologic model construction.

2.2.2.2 Core Sample Analyses

Core (283 ft) was collected from the Broom Creek storage complex in the Coteau 1 well. This core was analyzed to characterize the lithologies of the Broom Creek, Opeche, and Amsden Formations and correlated to the well log data. Core analysis also included porosity and permeability measurements, x-ray diffraction (XRD), x-ray fluorescence (XRF), relative permeability testing, thin-section analysis, capillary entry pressure measurements, and triaxial geomechanics testing. The results were used to inform geologic modeling, predictive simulation inputs and assumptions, geochemical modeling, and geomechanical modeling.

2.2.2.3 Formation Temperature and Pressure

Temperature data recorded from logging the Coteau 1 and Flemmer 1 wellbores were used to derive a temperature gradient for the proposed injection site (Tables 2-2 and 2-3). In combination with depth, the temperature gradient was used to distribute a temperature property throughout the geologic model of the Great Plains CO_2 Sequestration Project area. The temperature property was used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for the geochemical modeling.

The formation pressure and temperature at Coteau 1 were collected with a bottomhole pressure (BHP) gauge. In the Coteau 1 well, the Broom Creek was perforated at 5975 ft (1 foot, 4 shots per foot). After perforating, the BHP gauge was run to the perforation depth where temperature and pressure measurements were collected (Appendix C, "Pressure Survey Report"). The pressure data recorded in the Coteau 1 well are shown in Table 2-4.

Table 2-2. Description of Coteau 1 Temperature Measurements and Calculated Temperature Gradients

Formation	Test Depth, ft	Temperature, °F
Broom Creek	5,975	151.85
Broom Creek Temperature Gradient, °F/ft	0.02*	

* The temperature gradient is the BHP measured temperature minus the average annual surface temperature of 40°F, divided by the associated test depth.

Table 2-3. Description of Flemmer 1 Temperature Measurements and Calculated Temperature Gradients

Formation	Test Depth, ft	Temperature, °F
Opeche/Spearfish	6,260	151.43
	6,261	151.83
Broom Creek	6,306	150.76
	6,308	149.46
	6,358	150.35
	6,367	149.31
	6,372	149.83
	6,402	149.87
	6,403	149.78
	6,426	149.24
	6,453	149.23
	6,454	149.36
	6,455	149.68
Mean Broom Creek Temp., °F	149.72	
Broom Creek Temperature Gradient, °F/ft	0.02*	

* The temperature gradient is an average of the MDT modular formation dynamics tester tool measured temperatures minus the average annual surface temperature of 40°F, divided by the associated test depth.

Flemmer 1 formation pressure and temperature measurements were performed with the Schlumberger MDT tool. The MDT tool is a wireline-conveyed tool assembly incorporated with a dual-packer module to isolate intervals, a large-diameter probe for formation pressure and temperature measurements, a pump-out module to pump unwanted mud filtrate, a flow control module, and sample chambers for formation fluid collection. The MDT tool formation pressure measurements from the Broom Creek Formation in the Flemmer 1 well are included in Table 2-5. The calculated pressure gradients from the Flemmer 1 and Coteau 1 wells were used to model formation pressure profiles for use in the numerical simulations of CO_2 injection.

Table 2-4. Description of Coteau 1 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Test Depth, ft	Formation Pressure, psi
Broom Creek	5,975	2,937.09
Broom Creek Pressure Gradient, psi/ft	0.49*	

* The pressure gradient is the BHP measured pressure minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.

Table 2-5. Description of Flemmer 1 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Test Depth, ft	Formation Pressure, psi
Broom Creek	6,306	3,093.67
Broom Creek	6,308	3,094.53
Broom Creek	6,367	3,125.21
Broom Creek	6,372	3,127.00
Broom Creek	6,454	3,168.26
Broom Creek	6,455	3,167.00
Mean Broom Creek Pressure, psi	3,129.28	
Broom Creek Pressure Gradient, psi/ft	0.49*	

* The pressure gradient is an average of the MDT tool measured pressures minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.

2.2.2.4 Microfracture In Situ Stress Tests

Microfracture in situ stress tests were not performed in the Coteau 1 well. The in situ stresses for Coteau 1 were estimated using a 1D Mechanical Earth Model (1D MEM) that was generated using laboratory-derived core data and well log data from the Coteau 1 well. Discussion of the 1D MEM can be found in Sections 2.3 and 2.4.4.4. The Flemmer 1 microfracture in situ stress test results can be found in Sections 2.3 and 2.4.

2.2.2.5 Fluid Samples

A fluid sample from the Broom Creek Formation was collected from the Coteau 1 wellbore by perforating 1 foot at 5,975 ft and then swabbing the well until formation fluid flowed back to surface for collection. Results were analyzed by Minnesota Valley Testing Laboratories (MVTL), a state-certified lab. The results from the Coteau 1 sample are shown in Table 2-6. Fluid sample analysis results were used as inputs for geochemical modeling and dynamic reservoir simulations. Fluid sample analysis reports can be found in Appendix A.

Table 2-6. Description of Fluid Sample Test and Corresponding Total Dissolved Solids (TDS) Value

Formation	Well	Test Depth, ft	MVTL TDS, mg/L	EERC Lab TDS, mg/L
Broom Creek	Coteau 1	5,976	42,800	NA

2.2.2.6 Seismic Survey

The proximity of the site to an active coal mine and industrial facilities makes acquisition of 3D seismic data problematic. Placement of seismic source and receiver locations required for a 3D seismic survey would be restricted because of these surface uses potentially resulting in insufficient data quality to image the subsurface for characterization and monitoring purposes. Interpretation of 2D seismic data provides a practical alternative to acquiring and interpreting 3D seismic data. 2D seismic surveys can be used to evaluate the subsurface across large tracts of land, can be oriented to avoid surface obstacles such as those found at this site, can be acquired more frequently for future site monitoring, and eliminates the need to overshoot areas that have already been swept with CO_2.

Twenty-eight miles of 2D seismic lines that traverse the storage facility area and intersect the Coteau 1 well were licensed and interpreted (Figure 2-4). The 2D seismic lines were tied to the Coteau 1 well and used to evaluate the thickness and structure of the Broom Creek and upper and lower confining zones within the storage facility area. The interpreted surfaces for the formations of interest derived from the 2D seismic lines were used to confirm that the geologic model is representative of the reservoir thickness and structure within the storage facility area.

The 2D seismic data suggest there are no major stratigraphic pinch-outs or structural features with associated spill points in the Great Plains CO_2 Sequestration Project area. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the lowest USDW, the Fox Hills Formation, were observed in the seismic data. Twenty-eight miles of new 2D seismic data centered around the Coteau 1 well was acquired in January 2022 and will be used to confirm these interpretations.

2.3 Storage Reservoir (Injection Zone)

Locally, the Broom Creek Formation is laterally extensive (Figure 2-7) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone, siltstones, and evaporites of the Opeche Formation (Figure 2-3).

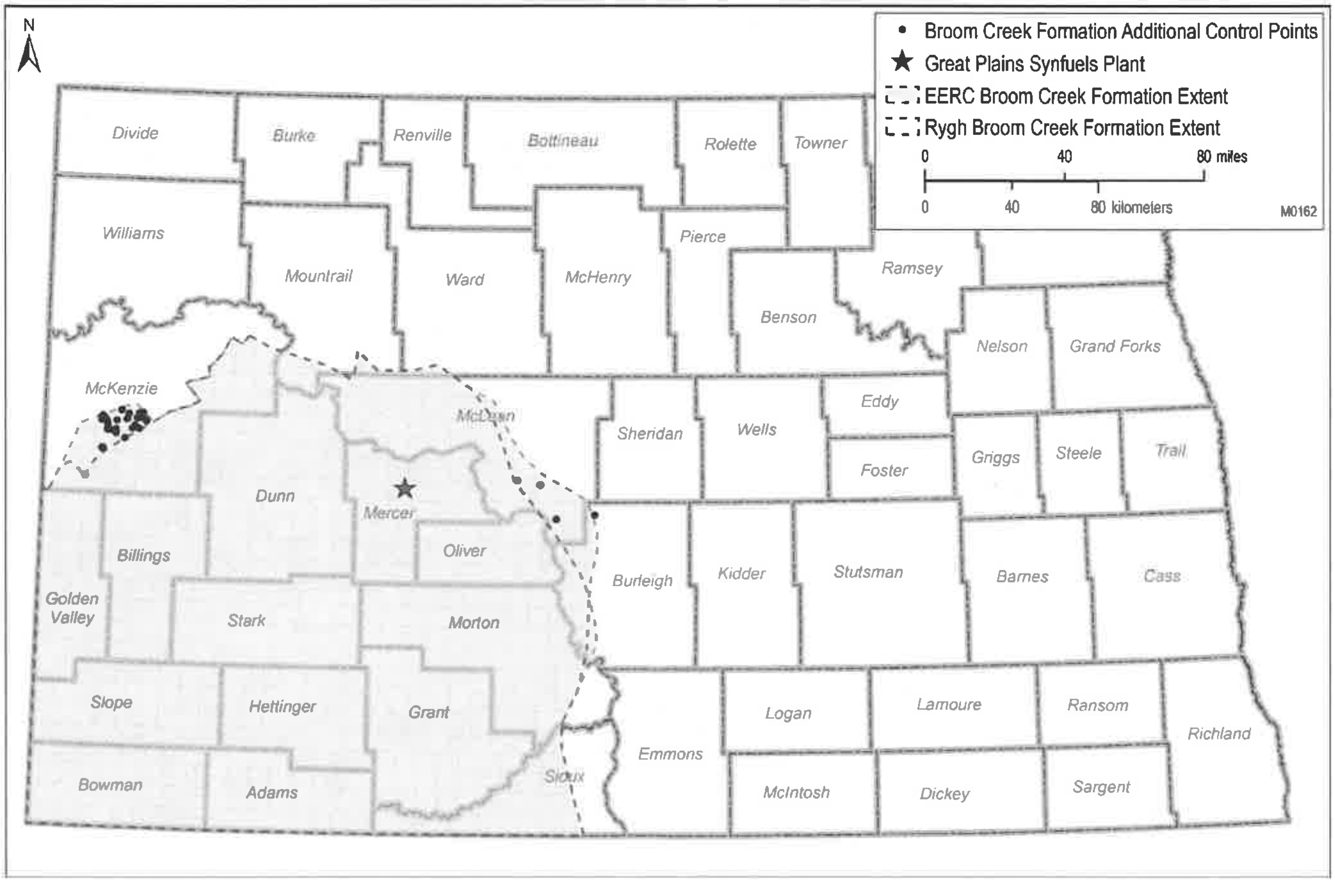

Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (modified from Rygh and others [1990]). Based on new well control shown outside of the green dashed line.

At Coteau 1, the Broom Creek Formation is 258 ft thick; is made up of 134 ft of sandstone, 35 ft of dolostone, 24 ft of anhydrite, and 65 ft of dolomitic sandstone; and is located at a depth of 5,906 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 163 to 322 ft (Figure 2-8), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 24 to 205 ft, with an average of 99 ft.

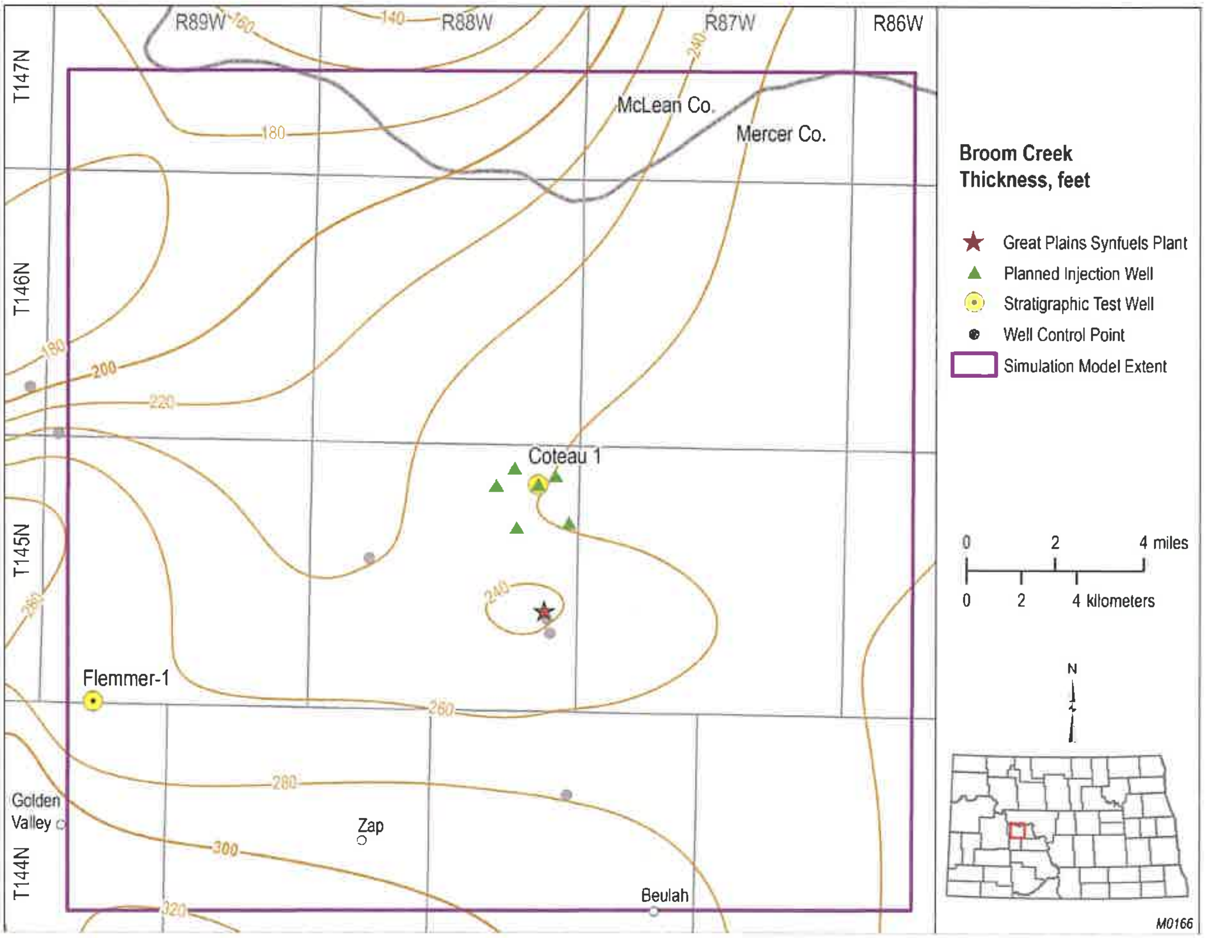

Figure 2-8. Isopach map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project area.

The top of the Broom Creek Formation was picked across the model area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-9). The top of the Amsden Formation was placed at the bottom of a relatively high GR signature representing an argillaceous dolostone that can be correlated across the entirety of the Great Plains CO_2 Sequestration Project area. 2D seismic data collected as part of site characterization efforts were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and analyses indicate that there should be few-to-no major reservoir stratigraphic discontinuities near the Coteau 1 well (Figures 2-10 and 2-11). The Broom Creek Formation is estimated to pinch out ~34 miles to the east of the Coteau 1 wellsite. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Great Plains CO_2 Sequestration Project area (Figure 2-12 and Figure 2-13).

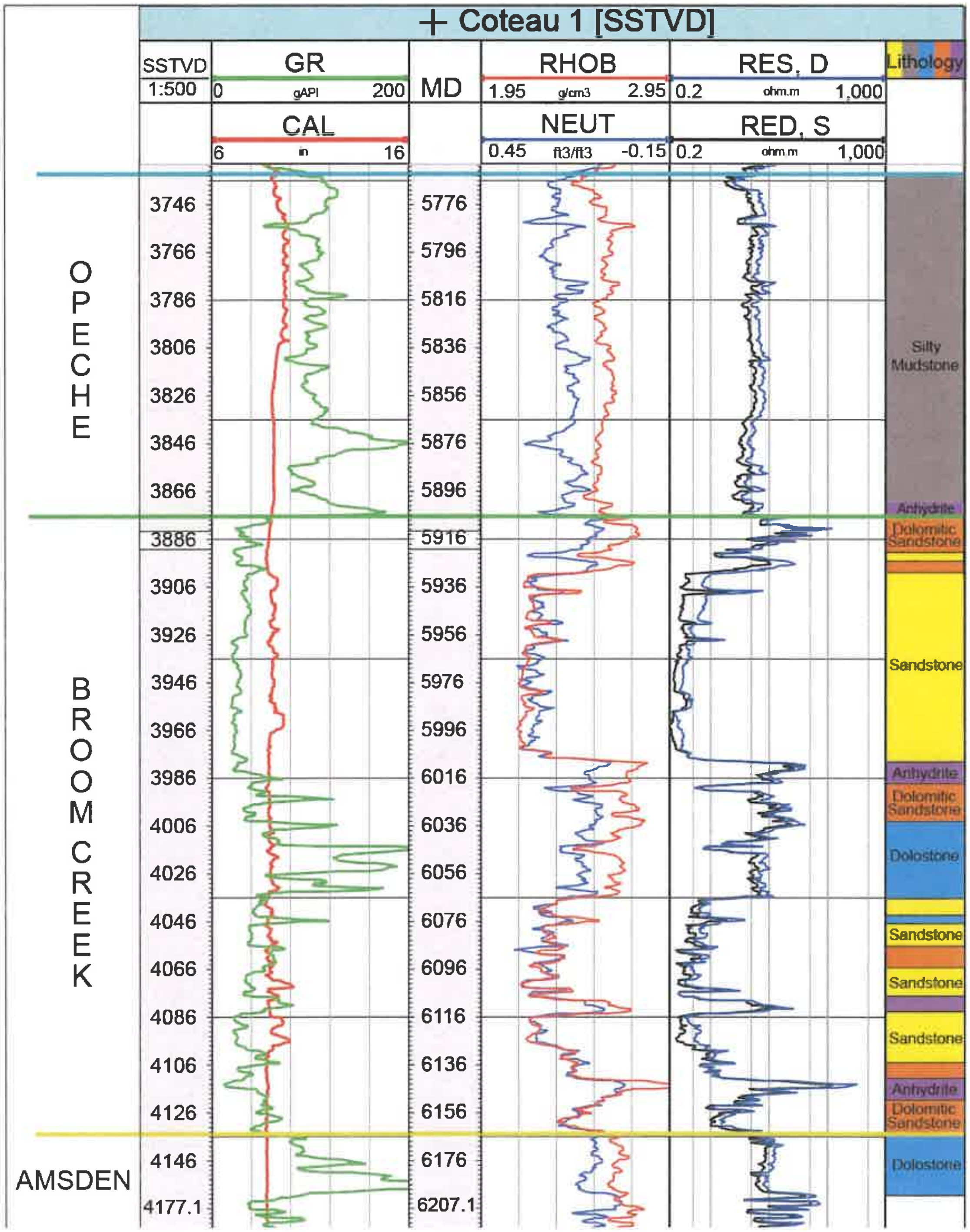

Figure 2-9. Well log display of the interpreted lithologies of the Opeche, Broom Creek, and upper Amsden Formations in the Coteau 1 well.

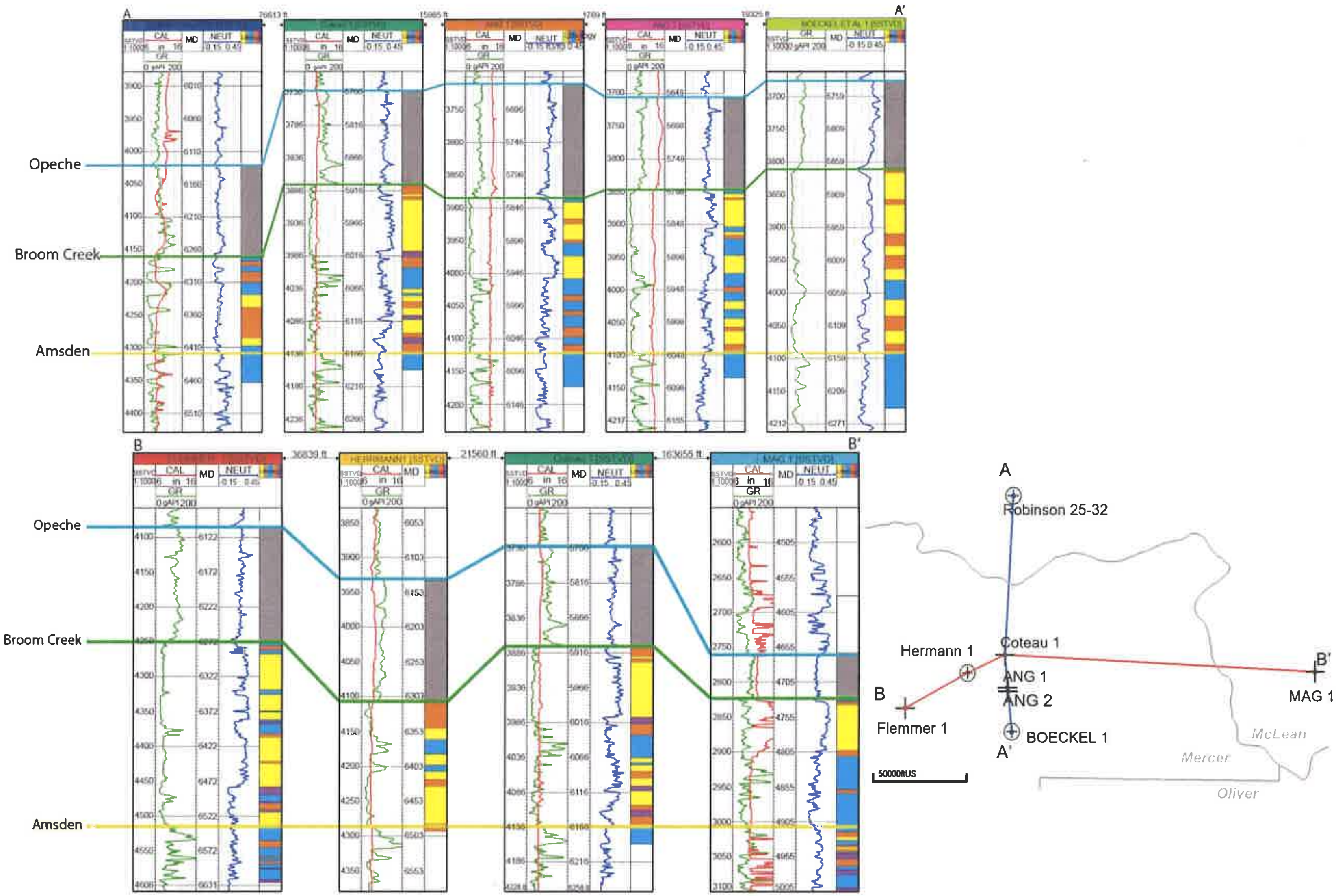

Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log.

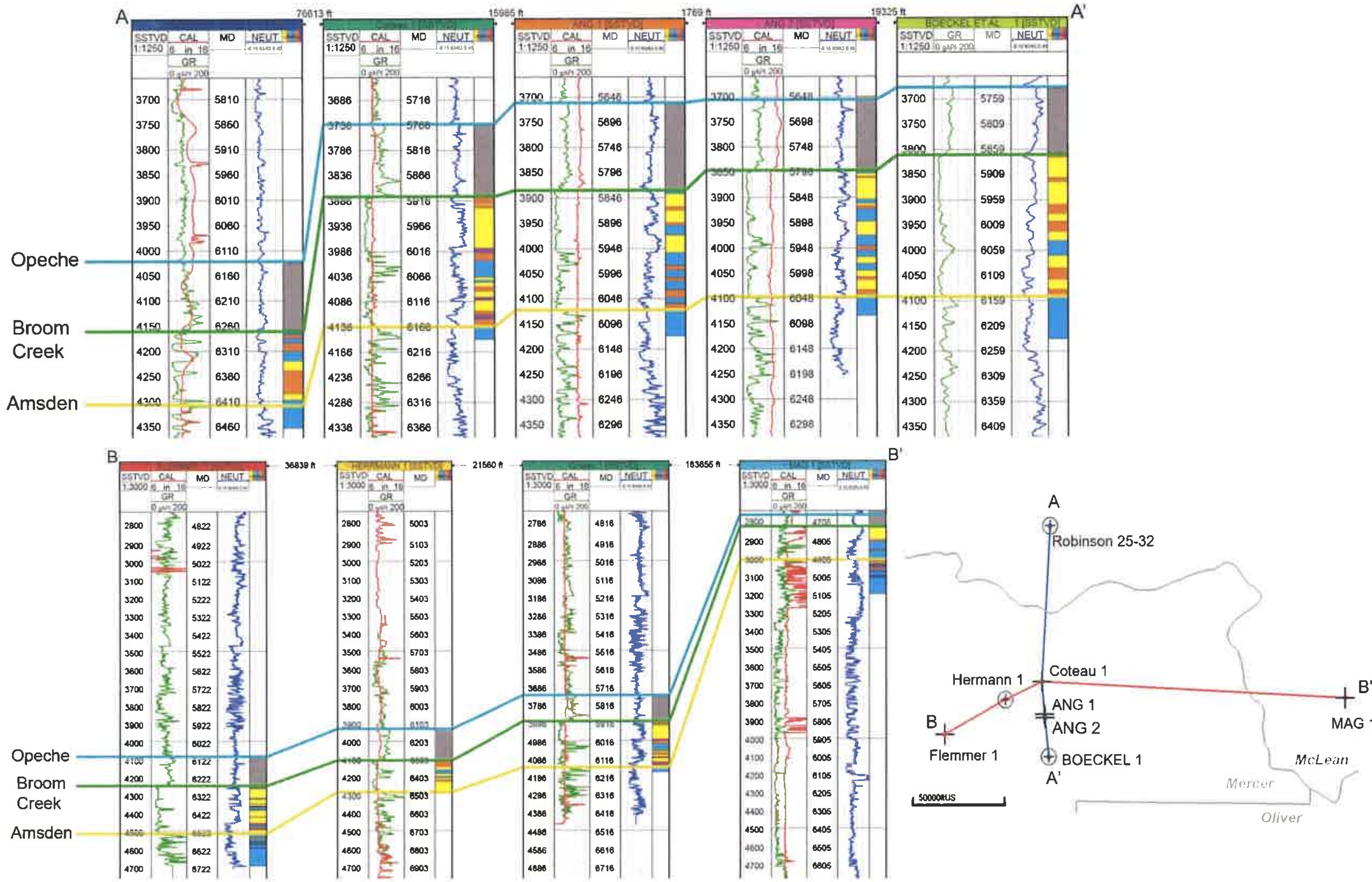

Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log.

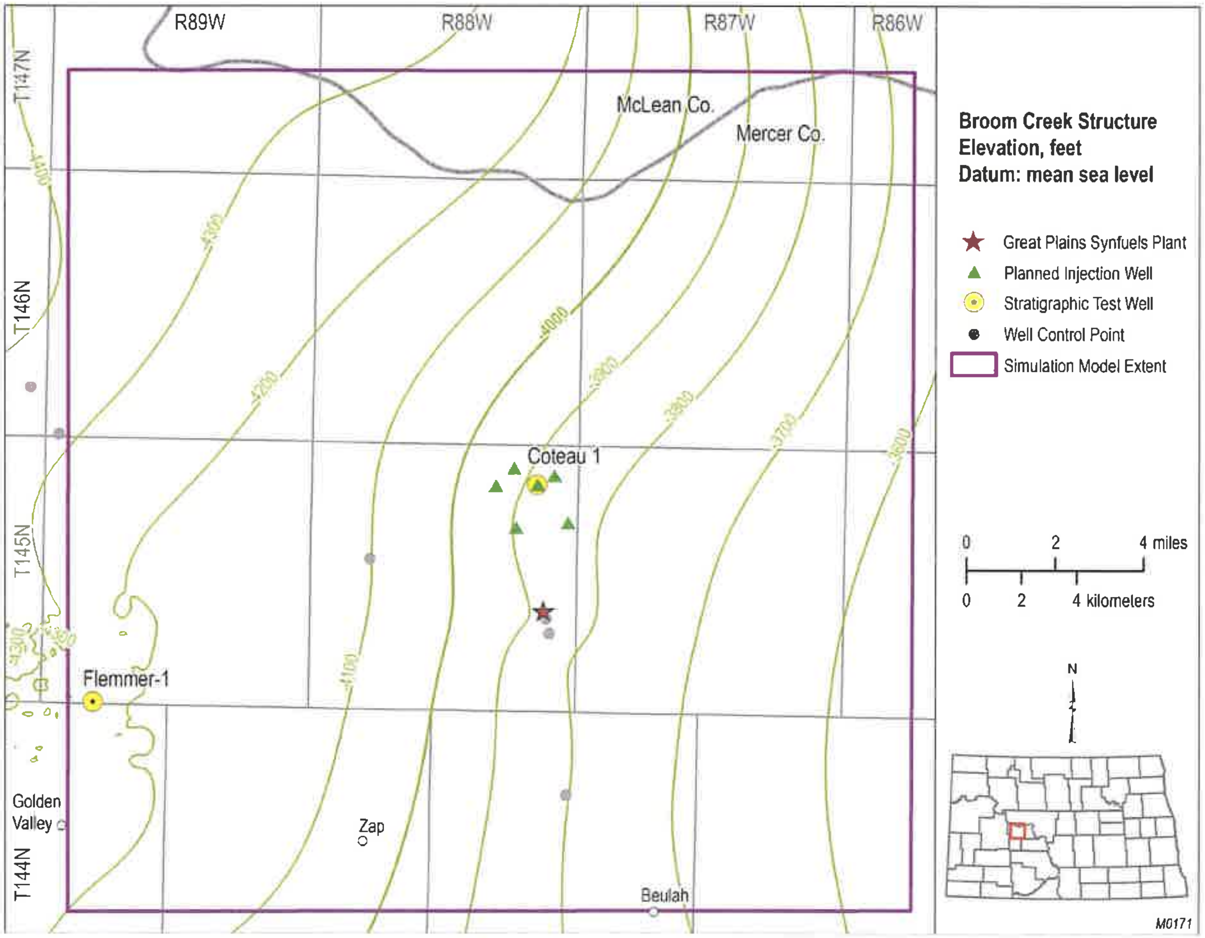

Figure 2-12. Structure map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops).

Twenty-two 1-inch-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the Coteau 1 well. From the twenty-two samples, three samples at 5,941.9', 5,969.9', and 5,994.4' were duplicated and oriented 90 degrees compared to the original core plug to investigate the possibility of any orientation-dependent permeability existing in the reservoir. The remaining nineteen core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the Coteau 1 Broom Creek Formation core samples have porosity values ranging from 1.41% to 34.39% at 800 psi and 7.88% to 30.34% at 2400 psi. Permeabilities range from 0.13 to 12,300 mD at 800 psi and 0.118 to 3,990 mD at 2,400 psi (Table 2-7). The wide range in porosity and permeability reflects the differences between the sandstone and dolostone lithofacies in the Broom Creek Formation. Portions of the Broom Creek Formation core revealed unconsolidated or poorly consolidated sandstone.

Table 2-7. Description of CO_2 Storage Reservoir (injection zone) at the Coteau 1 Well

Injection Zone Properties	
Property	**Description**
Formation Name	Broom Creek
Lithology	Sandstone, dolostone, dolomitic sandstone, anhydrite
Formation Top Depth, ft	5,906
Thickness, ft	Sandstone 134 Dolostone 35 Dolomitic sandstone 65 Anhydrite 24
Capillary Entry Pressure (CO_2/brine), psi	0.72

Geologic Properties

Formation	Property	Laboratory Analysis	Simulation Model Property Distribution
Broom Creek (sandstone)	Porosity, %*	21.28 (7.88–30.34)	23.64 (3.65–35.77)
	Permeability, mD**	221.84 (2.92–3,990)	246.74 (0.001–3,379)
Broom Creek (dolostone)	Porosity, %	8.79 (8.66–8.94)	5.68 (0.1–25.99)
	Permeability, mD	0.180 (0.118–0.361)	0.02 (0–220)

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses.
** Permeability values are reported as the geometric mean followed by the range of values in parentheses.

Analysis of thirteen core samples from the sandstone portion of the Broom Creek Formation core from the Coteau 1 well showed porosity values ranging from 8.73% to 34.39% at 800 psi and 7.88% to 30.34% at 2,400 psi, with an average of 25.10% and 21.28% respectively. Permeability of the sandstone samples ranged from 3.22 to 9,660 mD at 800 psi and 2.92 to 3,990 mD at 2,400 psi, with a geometric average of 728.35 mD and 221.84 mD, respectively. Porosity values of dolostone samples from the Broom Creek Formation core ranged from 1.41% to 12.31% at 800 psi and 8.66% to 8.94% at 2400 psi, with an average of 6.64% and 8.79%, respectively. Dolostone permeability values ranged from 0.001 to 1.62 mD at 800 psi and 0.118 to 0.361 mD at 2,400 psi, with a geometric average of 0.109 mD and 0.180 mD, respectively (Table 2-7 and Figure 2-14).

Core-derived measurements were used as the foundation for the generation of porosity and permeability properties within the 3D geologic model. The core sample measurements showed good agreement with the wireline logs collected from the Coteau 1 well. This agreement allowed for confident extrapolation of porosity and permeability from offset well logs, thus creating a spatially and computationally larger data set to populate the geologic model. The model property distribution statistics shown in Table 2-7 are derived from a combination of the core analysis and larger data set derived from offset well logs.

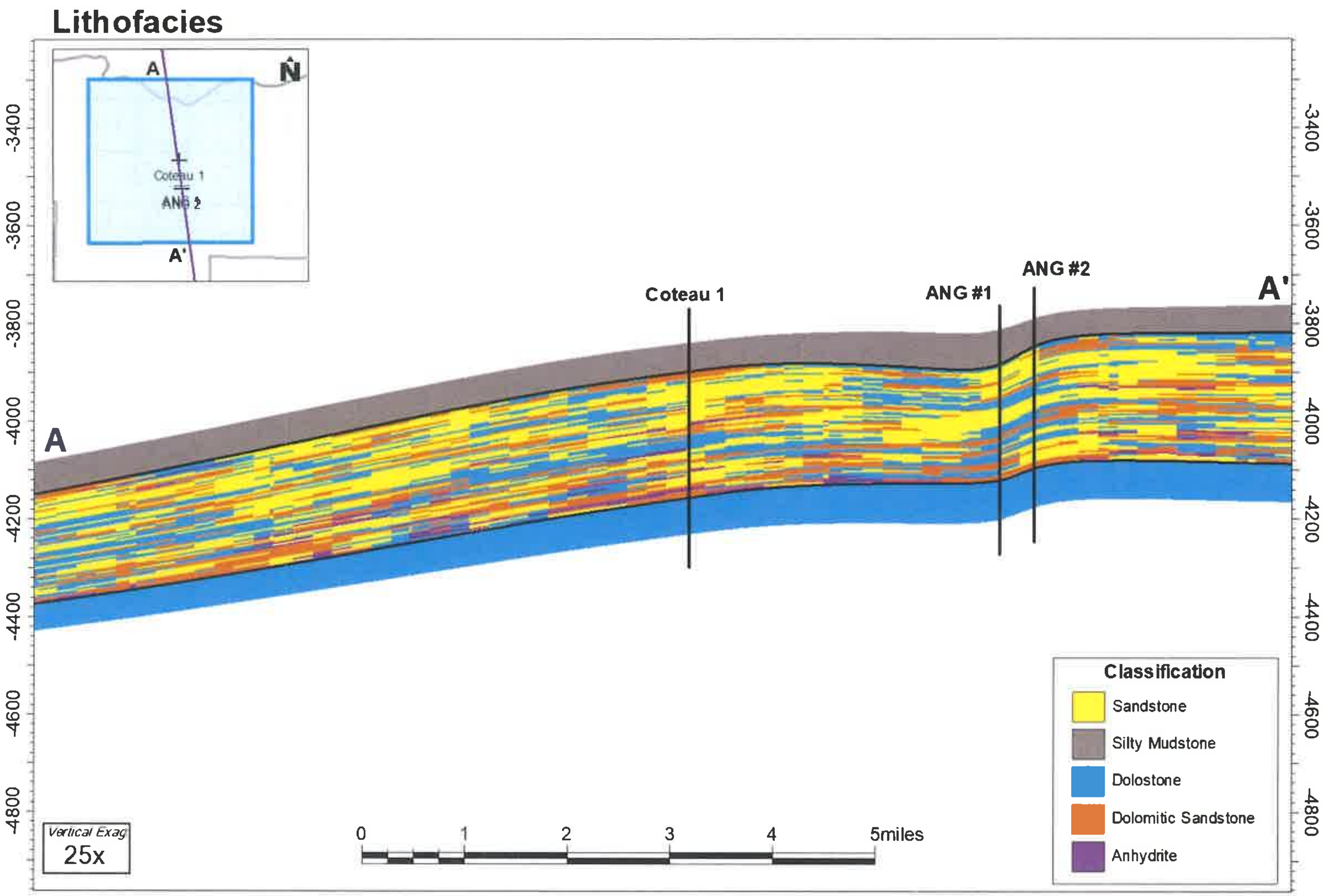

Figure 2-13. Cross section of the Great Plains CO_2 Sequestration Project storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level.

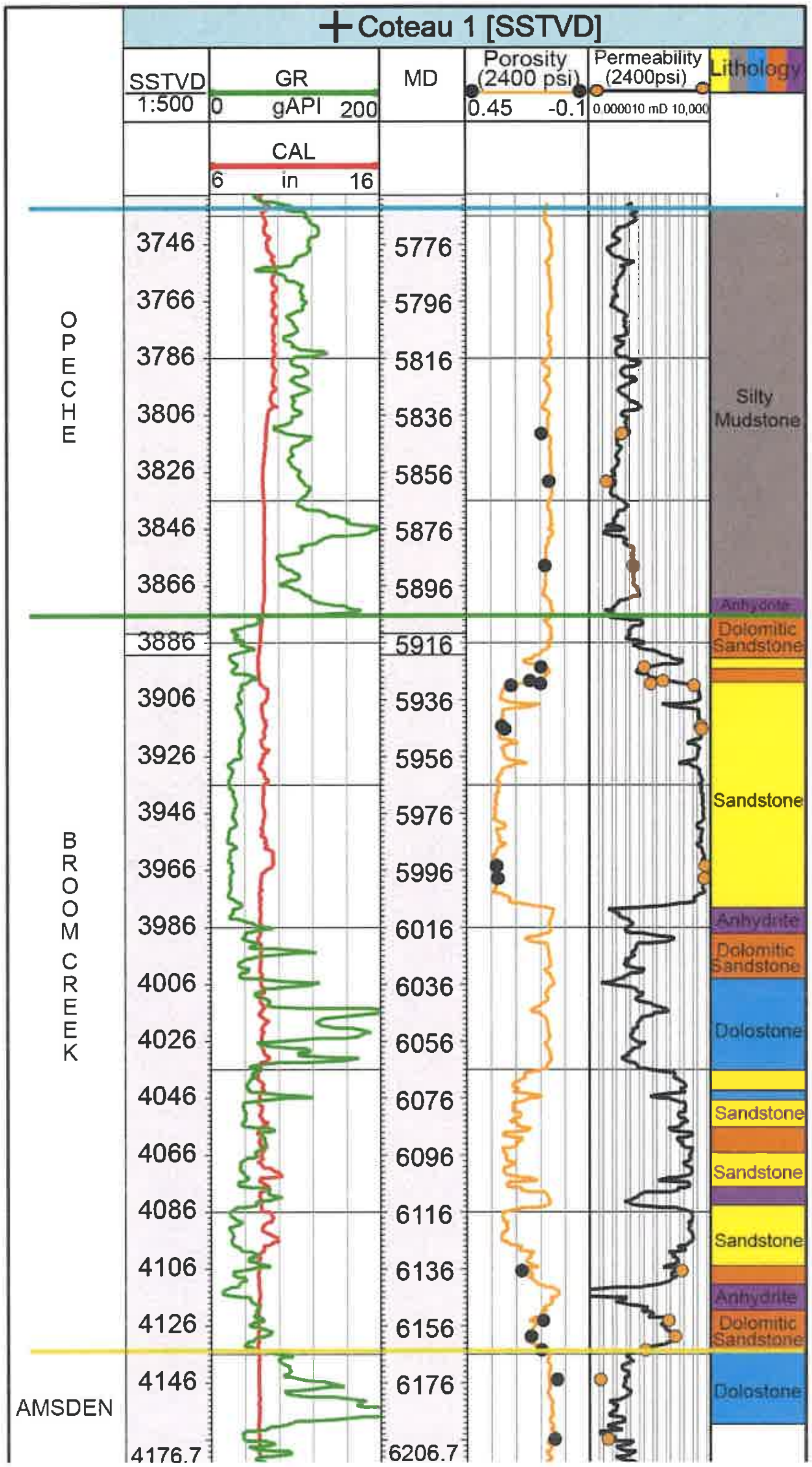

Figure 2-14. Vertical distribution of core-derived porosity and permeability values in the Great Plains CO_2 Sequestration Project storage complex.

Sandstone intervals in the Broom Creek Formation are associated with low GR, low density, high porosity (neutron, density, and sonic), low resistivity due to high porosity and brine salinity, and high sonic velocity measurements. The dolostone intervals in the formation are associated with an increase in GR measurements compared to the sandstone intervals, in addition to high density, low porosity (neutron, density, and sonic), high resistivity, and low sonic velocity measurements.

During drilling of the Coteau 1 well, the hole condition did not allow an openhole MDT microfracture in situ stress test to determine the formation breakdown pressure, fracture closure pressure, fracture propagation pressure, and minimum horizontal stress to be performed. To overcome this lack of data, a 1D MEM for Opeche, Broom Creek, and Amsden Formations was generated using laboratory-derived core data and well log data from the Coteau 1 well. A discussion of how the 1D MEM was generated can be found in Section 2.4.4.4.

The 1D MEM was used to determine the formation breakdown pressure, fracture closure pressure, and fracture propagation pressure for the Broom Creek Formation. The breakdown pressure was computed by setting the minimum tangential stress around the circumference of the well to zero and applying Kirsch (1898); Aadnoy (2008); and Grandi, Rao, and Toksoz (2002) equations. The fracture propagation pressure is assumed to be the same as the fracture pressure and allows the estimation of a maximum threshold whereby connected flow may be sustained. In this case, the estimated fracture pressure is considered to be the estimated fracture closure pressure. The fracture closure pressure was defined using the minimum horizontal stress (Shmin). Typically, Shmin, can be estimated from a modified Eaton calculation method and is viewed as a lower bound for the reservoir fracture closure pressure or the maximum stress prior to breakdown of the system competency. The modified Eaton formula used is shown in Equation 1. This equation has been widely used in the industry and has a good match with the field test data:

$$P = \frac{v}{1-v} * \left((S_v - \alpha_v) * P_p\right) + \alpha_H * P_p \qquad \text{[Eq. 1]}$$

Where:

P is pressure.
v is Poisson's ration.
S_v is the vertical stress.
α_V is the vertical Biot's constant.
α_H is the horizonal Biot's constant.
P_p is pore pressure.

The estimated pressures were compared to MDT-deployed microfracture in situ stress test results from Flemmer 1. The Flemmer 1 microfracture in situ stress test in the Broom Creek Formation (6,358 ft depth) was conducted over 7 cycles of injection and falloff. The first two cycles reached approximately 7,250 psi and 8,000 psi, respectively, without breakdown. The breakdown occurred on the third cycle, with an initial breakdown pressure of 4,950 psi. Fracture reopening pressures increased to 5,214 psi, 6,255 psi, and, finally, 7,293 psi in Cycles 5, 6, and 7. Fracture reopening pressures are generally lower than initial breakdown pressure; however, Cycles 5 and 6 show a steady rise in measured closure pressure, indicating the possible formation of pore space plugging. Propagation pressure recorded in Cycle 4 was 4,384 psi. The average pressures of the stress test from prior tests on the Flemmer 1 and estimates for the Coteau 1 well results are shown in Table 2-8.

The average fracture propagation pressure gradient of 0.71 psi/ft for the Coteau 1 well agrees with the average fracture propagation values determined from microfracture in situ stress tests in other regional wells: the J-LOC 1 and BNI-1 (NDIC, 2021b). Because of the confidence in the calculated value for fracture propagation pressure gradient and the predicted maximum BHP (Table 3-5), there are no plans to run an MDT test in one of the other injection wells.

Table 2-8. Broom Creek Microfracture Results from Flemmer 1 and Interpreted Results from Coteau 1

	Coteau 1		Flemmer 1	
Depth, ft	NA		6358	
Pressure/Gradient	**psi**	**psi/ft**	**psi**	**psi/ft**
Breakdown	5,193	0.85	4,950	0.77
Avg. Fracture Propagation	4,263	0.71	4,384	0.69
Avg. Closure	4,014	0.71	4,195	0.66

Note: Flemmer 1 average fracture propagation and closure pressure are representative of Cycle 4 because of possible plugging in the later cycles.

2.3.1 Mineralogy

The combined interpretation of core, well logs, and thin sections shows that the Broom Creek Formation is dominated by fine- to medium-grained sandstone with lesser amounts of carbonates and anhydrites. Twenty-two depth intervals across 131.25 ft of the Broom Creek Formation were sampled for XRD mineralogical determination and XRF bulk chemical analysis. Out of 22 samples, 18 samples were selected to create thin sections. For the assessment below, thin sections and XRD provide independent confirmation of the mineralogical constituents of the Broom Creek Formation. No core was acquired for the interval of 6,001' to 6,130' (the middle dolomite-rich section of the Broom Creek Formation) because of the low rate of penetration.

Thin-section analysis of the upper Broom Creek interval shows that quartz (84%) is the dominant mineral. Throughout these intervals are minor occurrences of feldspar (6%), dolomite (5%), and anhydrite as cement (5%). Where present, anhydrite is crystallized between quartz grains and obstructs the intercrystalline porosity. The quartz minerals sometimes show overgrowth and, occasionally, dissolution. The contact between grains is long (straight) to tangential. In most cases, grains are surrounded/rimmed by a thin red brown to dark red iron oxides. The porosity ranges between 15% to 34%, except for a sample at the depth of 6,146 ft with a porosity of 9% that is extensively cemented by anhydrite. Figure 2-15 shows the primary features observed in thin sections within the upper sand of the Broom Creek Formation.

Within the intervals of core collected, occurrences of carbonates are notable in the 5,903'–6,001' interval. The first occurrence at 5,908'–5,924' (Figure 2-16) is a relatively thick carbonate that comprises a very fine- to fine-grained dolostone (75%), with quartz of variable size and shape (7%) and anhydrite (18%). The porosity averages 8% and is mainly intercrystalline and moldic in

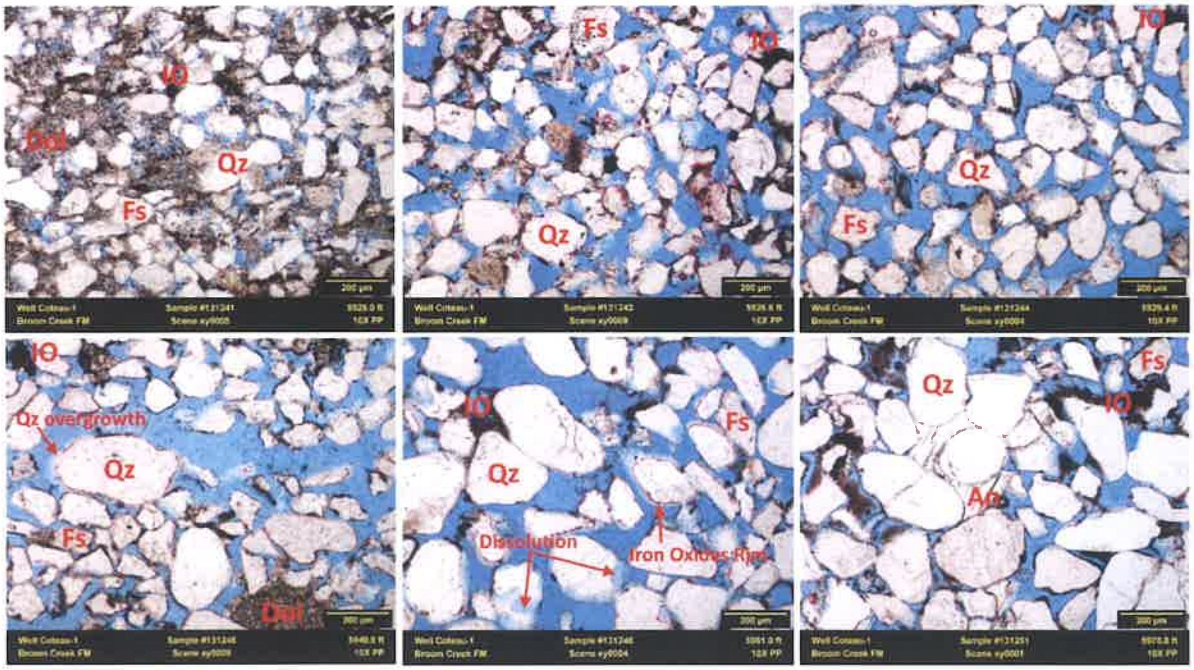

Figure 2-15. Thin sections from the upper sand interval of the Broom Creek Formation.

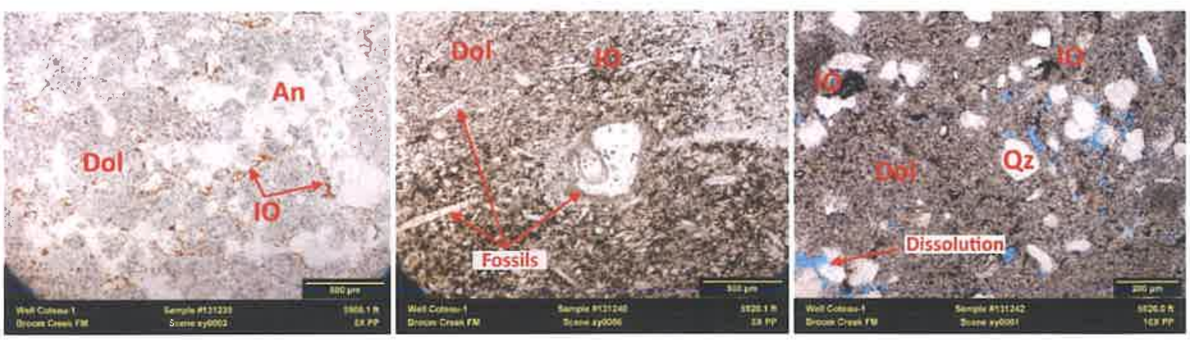

Figure 2-16. Thin sections from the three carbonate depth intervals of the upper Broom Creek Formation.

structure. Diagenesis is expressed by dolomitization of the original calcite grains. Fossils include some dolomitized bivalve shell fragments.

A small section of carbonate was penetrated at 5,999' to 6,001' prior to ceasing the first coring run. This bed is a pure dolomite (Figure 2-17) that comprises dolosparite/micro-dolosparite (78%). The presence of clay (11%) and iron oxides is noticeable in the rock matrix. Anhydrite as the clasts and veins is the other comprising mineral (7%). The quartz (very fine grains) presents in low content (4%). The observed thin-section porosity averages 7% and occurs as the dissolution of anhydrite and open fractures. It is noted that the scale of observed fractures in these carbonate intervals is on the micrometer scale and may be induced by the thin-section creation process.

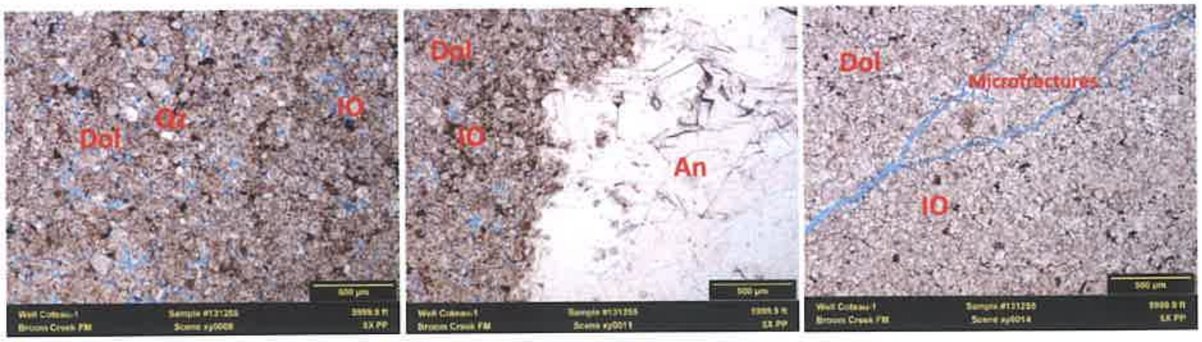

Figure 2-17. Thin section from the carbonate depth interval of the middle Broom Creek Formation.

The last occurrence of carbonates in the Broom Creek Formation is notable at the depth interval of 6,130'–6,163'. This occurrence of carbonate (6,160'–6,163.25') is much more quartz-rich dolomite (sandy dolomite) and comprises mainly micro-dolomite (54%), quartz (35%), feldspar (10%), and clay (1%). The presence of iron oxides is noticeable. The quartz minerals show some dissolution. The contact between grains is tangential and separated by a dolomitic matrix and locally by iron oxide cements. The observed porosity is due to the dissolution of feldspar and averages 9%. Figure 2-18 shows the characteristics observed within this carbonate.

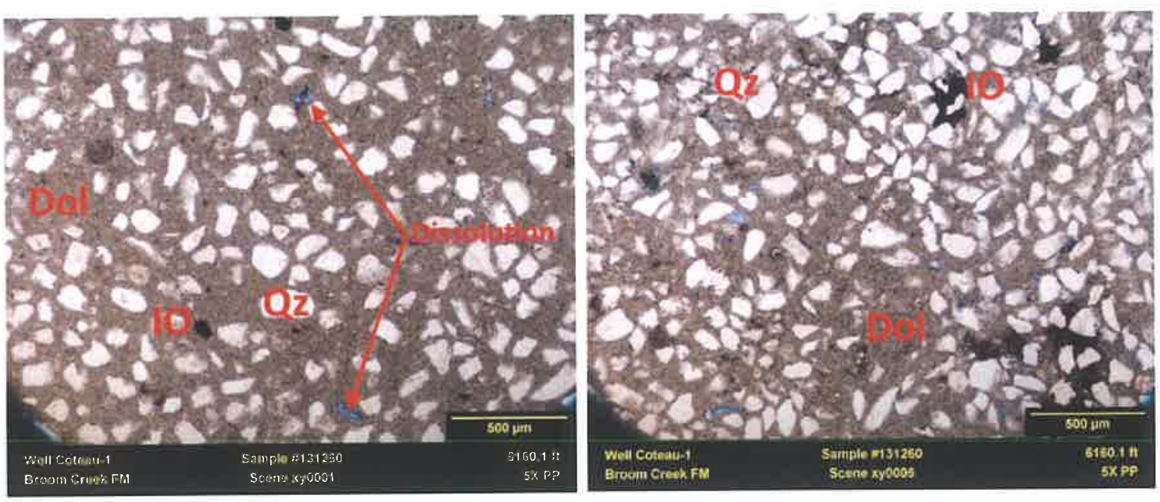

Figure 2-18. Thin section from a carbonate depth interval of the lower Broom Creek Formation.

XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek Formation core primarily comprises quartz, feldspar, carbonates, anhydrite, clay, and other minor minerals (Figure 2-19).

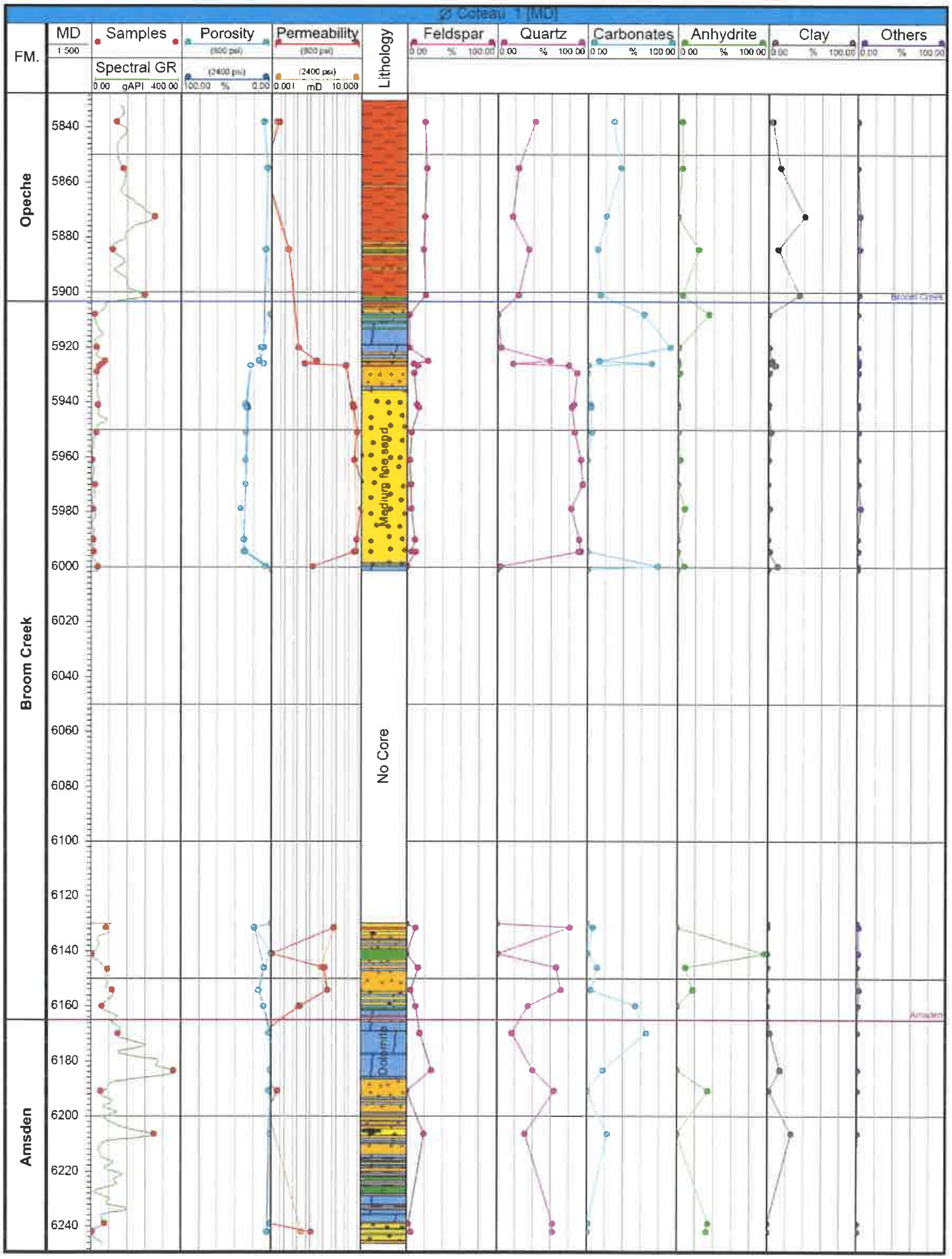

Figure 2-19. Described core and laboratory-derived mineralogic characteristics of the Opeche, Broom Creek, and Amsden Formations.

XRF data are shown in Figure 2-20 for the Broom Creek Formation. Sandstone and dolomite intervals are confirmed through the high percentages of SiO_2 (71%–98%), CaO (19%–36%), and MgO (13%–21%). The high percentage of CaO and SO_3 at 5,908, 6,141, and 6,154 ft indicate a presence of anhydrite beds. The formation shows little volumes of clay, with a range of 0.04% to 10.54% for all samples.

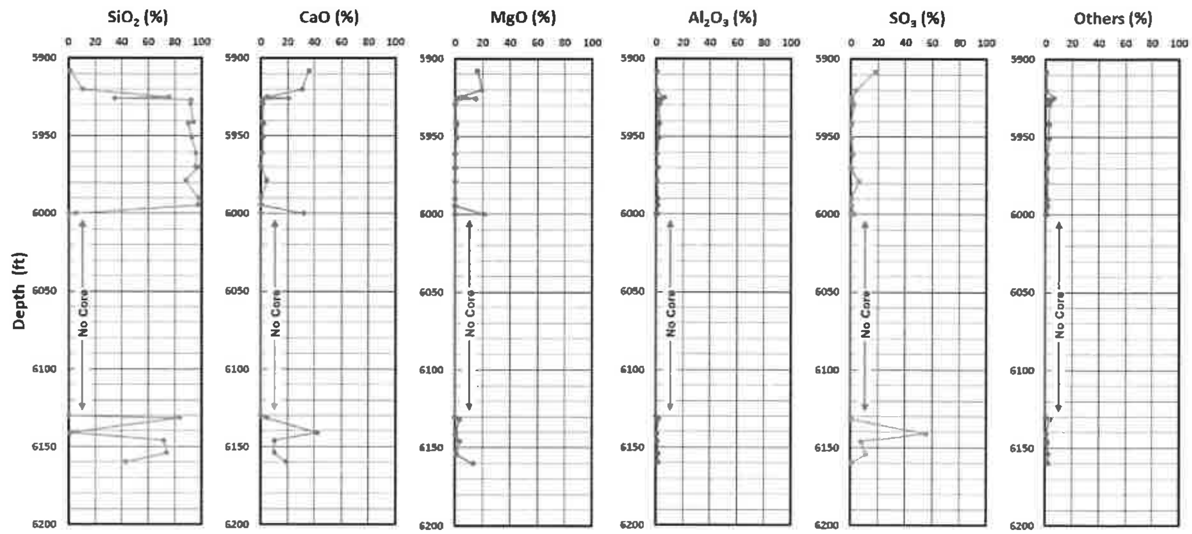

Figure 2-20. XRF data from the Broom Creek Formation from the Coteau 1.

2.3.2 Mechanism of Geologic Confinement

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. 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). After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period of time (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation and, therefore, is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.

2.3.3 Geochemical Information of Injection Zone

Geochemical simulation has been performed to calculate the effects of introducing the CO_2 stream to the injection zone.

The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in the Computer Modelling Group Ltd. (CMG) compositional simulation software package GEM. GEM is also the primary simulation software used for evaluation of the reservoir's dynamic behavior resulting from the expected CO_2 injection. For this geochemical modeling study, the injection scenario consisted of a single injection well injecting for a 12-year period with maximum BHP and maximum gas injection rate (STG) constraints of 3,833 psi and 25 MMcfd (468,000 tonnes/year), respectively. A postinjection period of 25 years was run in the model to evaluate any dynamic behavior and/or geochemical reaction after the CO_2 injection is stopped. This geochemical scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared (Figure 2-21).

Simulation results indicate that the low-salinity plume (TDS 8,050 ppm) associated with the ANG #1 and ANG #2 disposal water and the injected CO_2 plume for the six-well injection scenario discussed in Section 3 may have little interaction after 10 years of postinjection (Figure 2-22). Based on this limited interaction of the injected CO_2 and the injected disposal water and the chemical composition of the disposal water, the ANG disposal well injection was not included as part of the geochemical modeling for computational efficiency. The historical ANG well injection up to August 2021 was included during the modeling.

Geochemical alteration effects were seen in the geochemistry case, as described below. However, these effects were not significant enough to cause meaningful changes to the storage reservoir performance of the storage formation.

The scenario with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (86% of bulk reservoir volume) and average formation brine composition (14% of bulk reservoir volume). XRD data from the Coteau 1 well core samples were used to inform the mineralogical composition of the Broom Creek Formation (Table 2-9). Illite was chosen to represent clay for geochemical modeling as it was the most prominent type of clay identified in the XRD data. Kaolinite is the only other clay mineral that was identified in XRD data and was only identified in one of twenty-two samples analyzed. Ionic composition of the Broom Creek Formation water and the ANG disposal water chemistry are listed in Tables 2-10 and 2-11.

The injection stream is expected to be 95.9% CO_2. For input into CMG, this value was normalized along with the other constituents in the stream to sum to 100% mole fraction. The CO_2 composition in the gas stream used for the simulated injection stream was 96.45% CO_2. Other constituents represent 3.55% of the stream and are expected to include 1.23% hydrogen sulfide (H_2S) and 2.32% including methane, ethane, and propane. N_2, known to be an inert gas, was not included in the gas stream. Some of the other carbon constituents such as butane, ethylene, pentane, isobutane, isopentane, and n-pentane may also be present but in a negligible amount that would have no impact on geochemical reactions in the storage formation and were also not included. The simulated injection stream was 96.45% CO_2, 1.23 H_2S, and 2.32% CH_4. As in the model without geochemical reactions, the geochemistry case was run for the 12-year injection period followed by 25 years of postinjection monitoring.

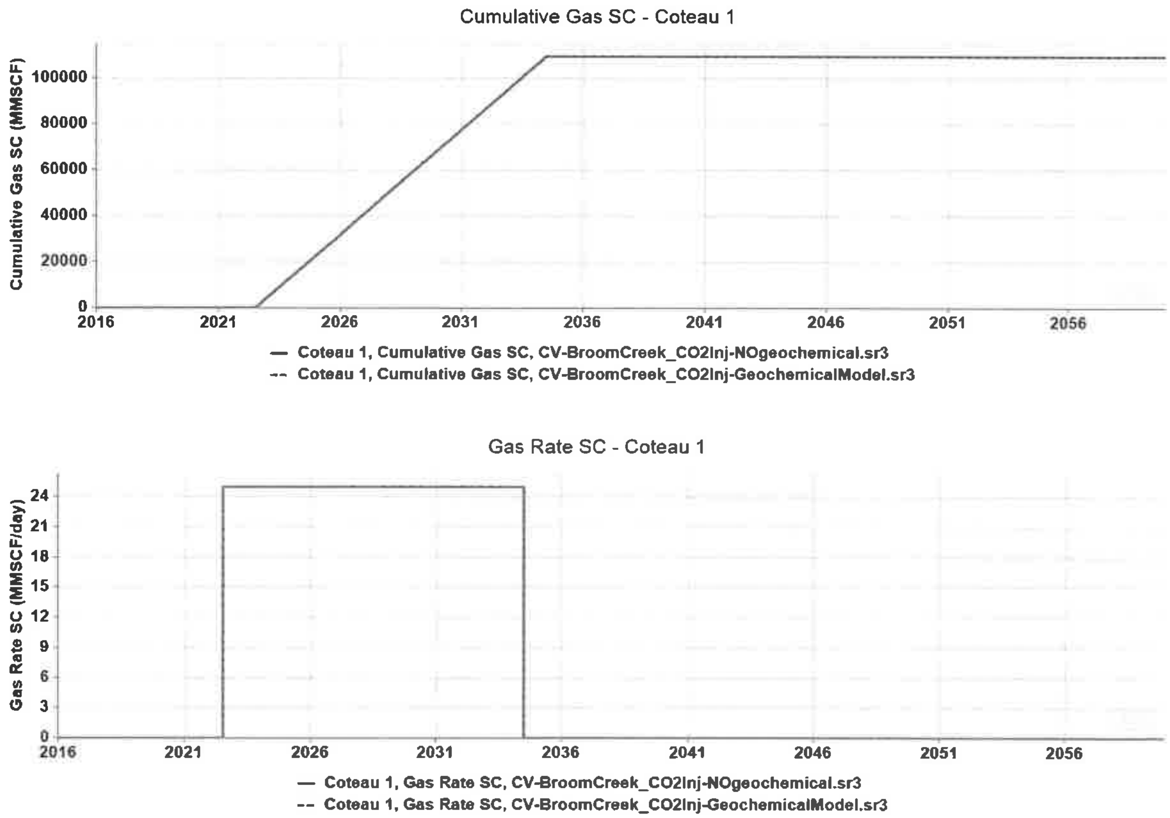

Figure 2-21. Upper graph shows cumulative injection vs. time; the bottom figure shows the gas injection rate vs. time. There is no observable difference in injection due to geochemical reactions.

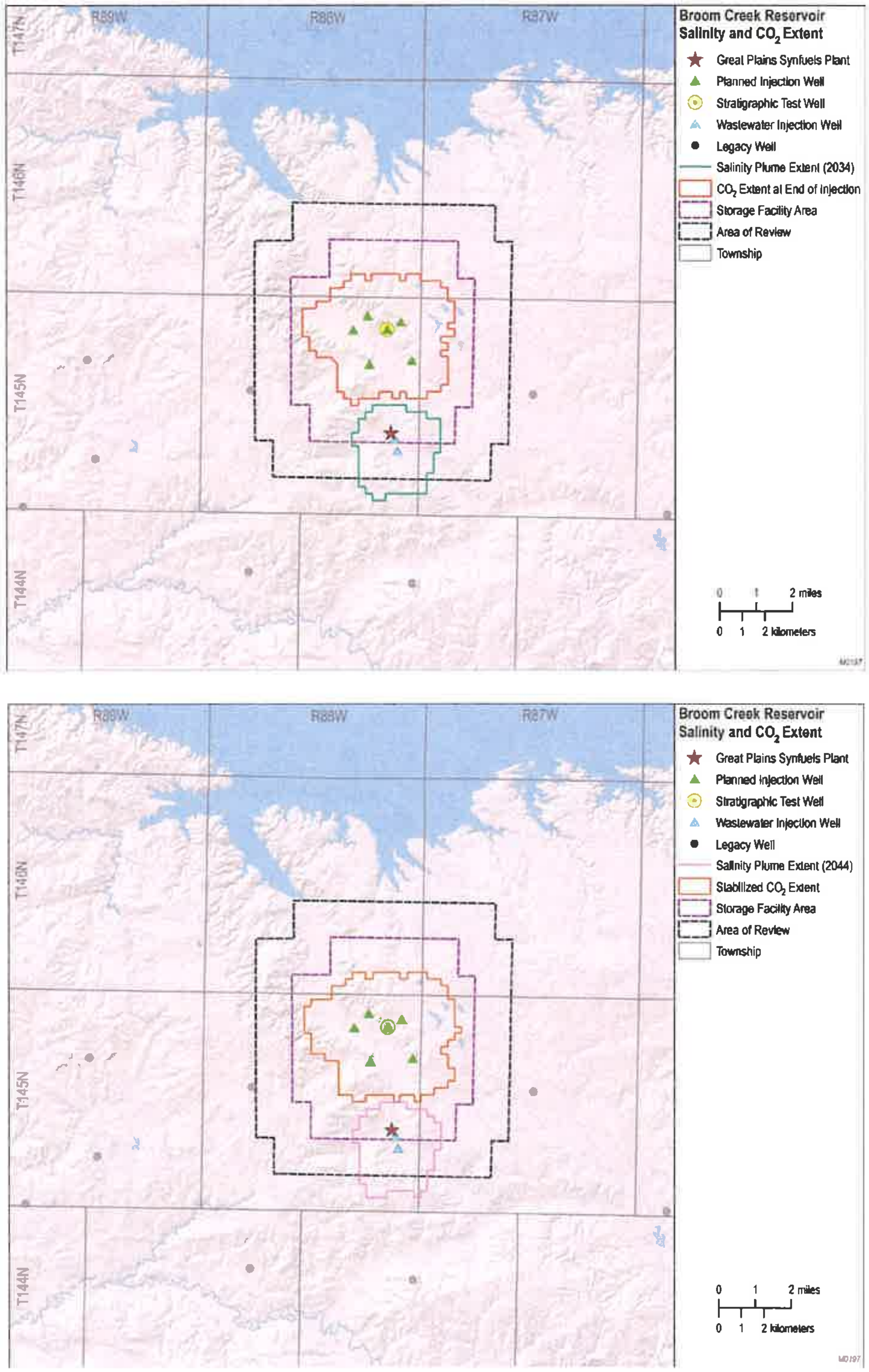

Figure 2-22. 2D map showing the water salinity plume from the disposal wells, ANG #1 and ANG #2, and the gas mole fraction (CO_2) for the expected injection scenario for this project described in Section 3 consisting of six CO_2 injection wells. The lower map shows the stabilized CO_2 plume vs. the salinity plume extent after 10 years postinjection, in July 2044.

Table 2-9. XRD Results for Coteau 1 Broom Creek Core Sample

Mineral Data	%
Albite	2.25
Anhydrite	15.17
Anorthite	1.96
Dolomite	23.91
Illite	2.85
Pyrite	0.13
Quartz	54.15

Table 2-10. Broom Creek Water Ionic Composition, expressed in molality

Component	mg/L, ppm	Molality
SO_4^{2-}	469	0.00474
K^+	516	0.01281
Na^+	12,800	0.54698
Ca^{2+}	1,860	0.04511
Mg^{2+}	212	0.00847
Fe^{3+}	392	0.00681
CO_3^{2-}	<20	0.00032
Cl^-	24,900	0.69829
HCO_3^-	853	0.01357
TDS, ppm	42,800	

Table 2-11. ANG #1 Water Ionic Composition, expressed in molality

Component	mg/L, ppm	Molality
SO_4^{2-}	2,280	0.02355
K^+	38.5	0.00098
Na^+	2,200	0.09495
Ca^{2+}	283	0.00699
Mg^{2+}	175	0.00713
Cl^-	2,880	0.08066
HCO_3^-	63	0.00102
TDS, ppm	8,050	

Figure 2-21 shows that reservoir performance results for the two cases are essentially identical. As a result of geochemical reactions in the reservoir, there is no observable difference in cumulative injection. The injection BHP and wellhead pressure (WHP) are shown in Figure 2-23. The two cases are also essentially the same, and no difference was appreciable between the case with and without geochemical modeling.

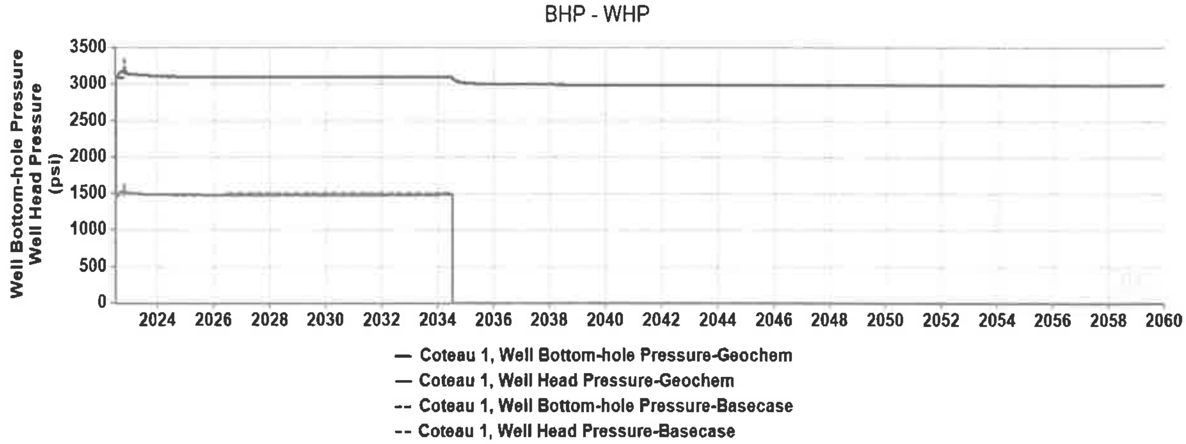

Figure 2-23. BHP and WHP vs. time. There is no observable difference in injection pressure due to geochemical reactions as compared to the results without the geochemical model.

Figures 2-24a and 2-24b show the concentration of CO_2, in molality, in the reservoir after 12 years of injection plus 25 years of postinjection for the geochemistry model case (upper figure) and for the non-geochemistry model (bottom figure) for comparisons. The results are not showing an evident difference in the CO_2 gas molality fraction between both cases as seen in the previous figures for volume injected and injection pressure simulation results.

The pH of the reservoir brine changes in the vicinity of the CO_2 accumulation, as shown in Figure 2-25. The pH of the Broom Creek native brine sample is 6.7 whereas the fluid pH declines to approximately 5.6 in the CO_2-flooded areas.

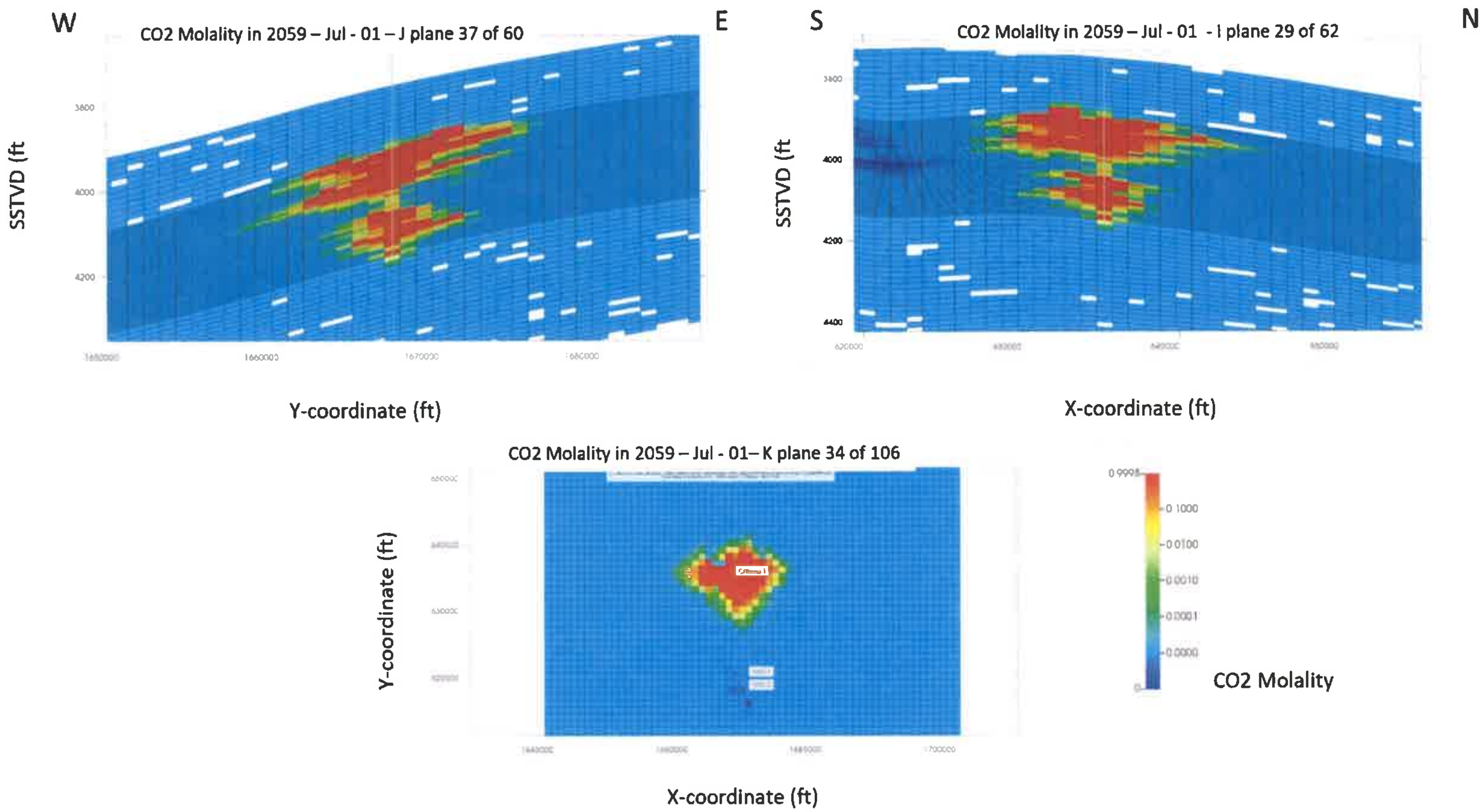

Figure 2-24a. CO_2 molality for the geochemistry case simulation results after 12 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east and right upper are north-south cross sections. Lower image is a planar view of simulation in layer k = 11. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

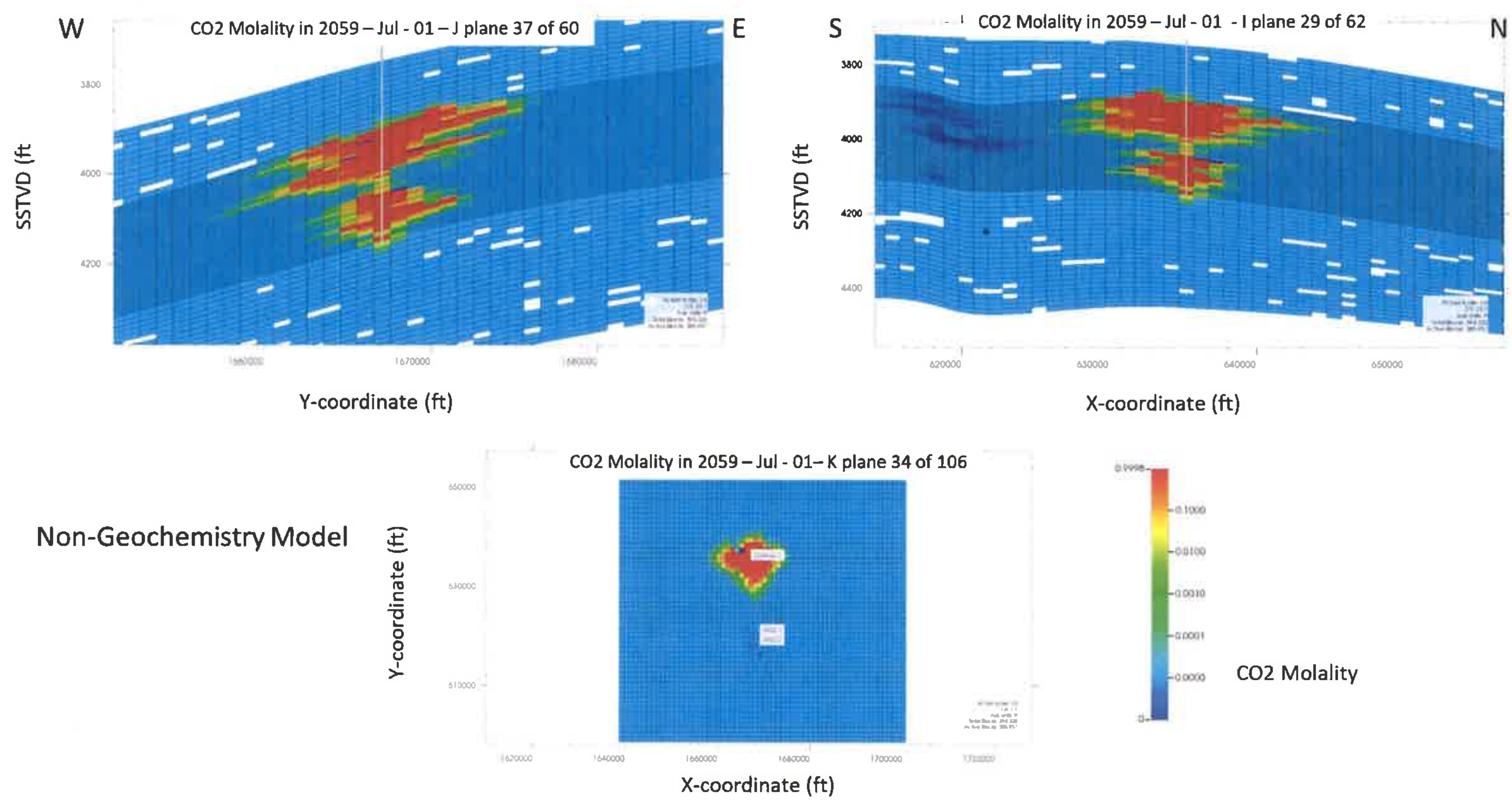

Figure 2-24b. CO_2 molality for the non-geochemistry model (bottom) results after 12 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east and right upper are north-south cross sections. Lower image is a planar view of simulation in layer k = 11. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

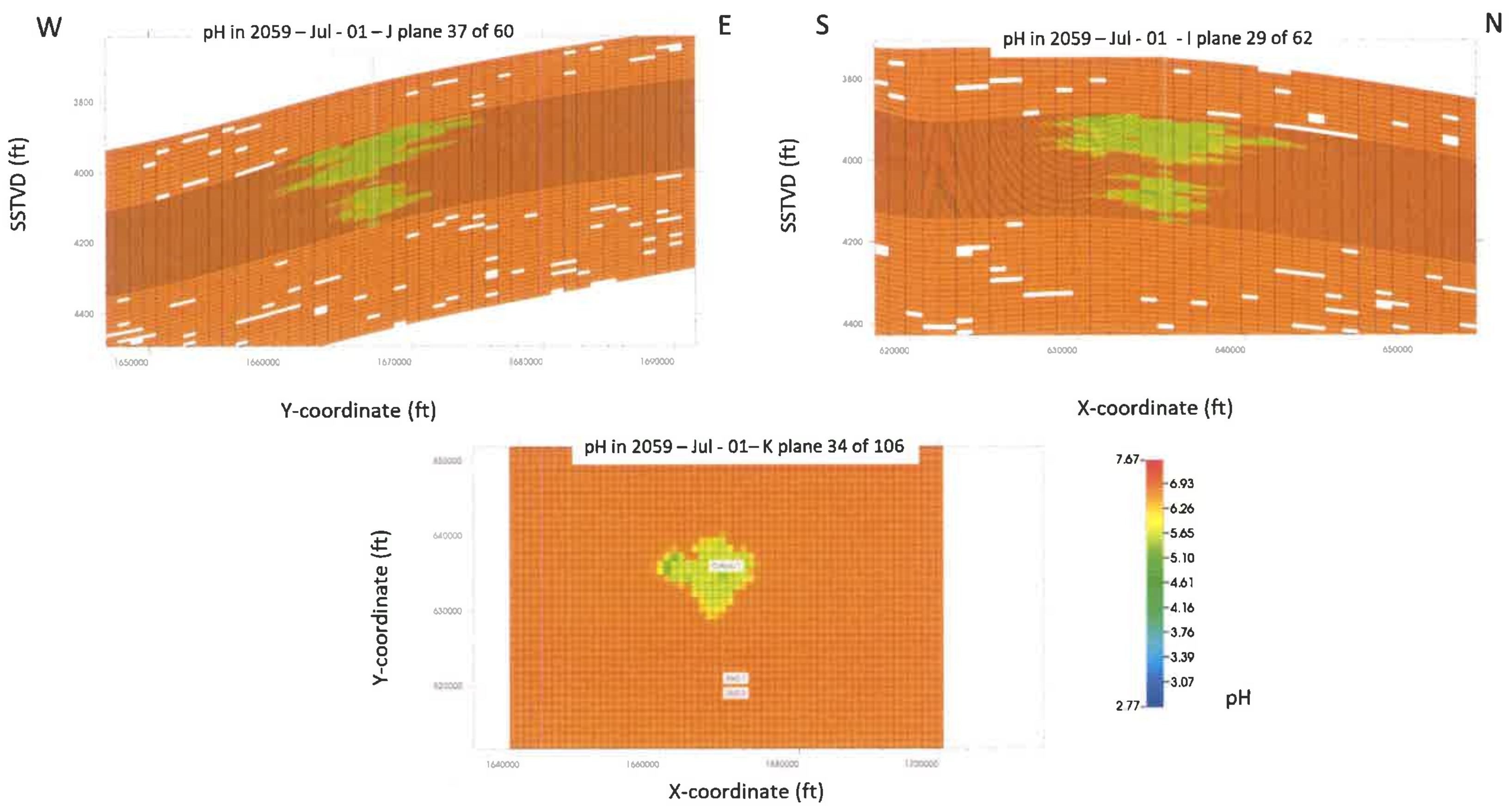

Figure 2-25. Geochemistry case simulation results after 12 years of injection + 25 years postinjection showing the pH of formation brine in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

Figure 2-26 shows the mass of mineral dissolution and precipitation due to geochemical reaction in the Broom Creek Formation. Anorthite is the most prominent dissolution mineral. Illite starts to dissolve and then precipitate after Year 2034, the year in which injection ends. Dolomite, albite, and pyrite are the primary precipitation minerals. Pyrite (FeS_2) precipitation is favored by the presence of dissolved H_2S in the gas stream injected and aqueous iron in the Broom Creek Formation water. There is a small amount of precipitation for quartz and anhydrite during the simulation period possibly due to the additional SiO_2 released by anorthite dissolution and the presence of Ca^{2+} and SO_4^{-2} ions in the water formation, respectively.

Figures 2-27 through 2-30 provide an indication of the change in distribution of the mineral that experienced the most dissolution, anorthite, and the minerals that have experienced significant precipitation: dolomite, albite, and pyrite.

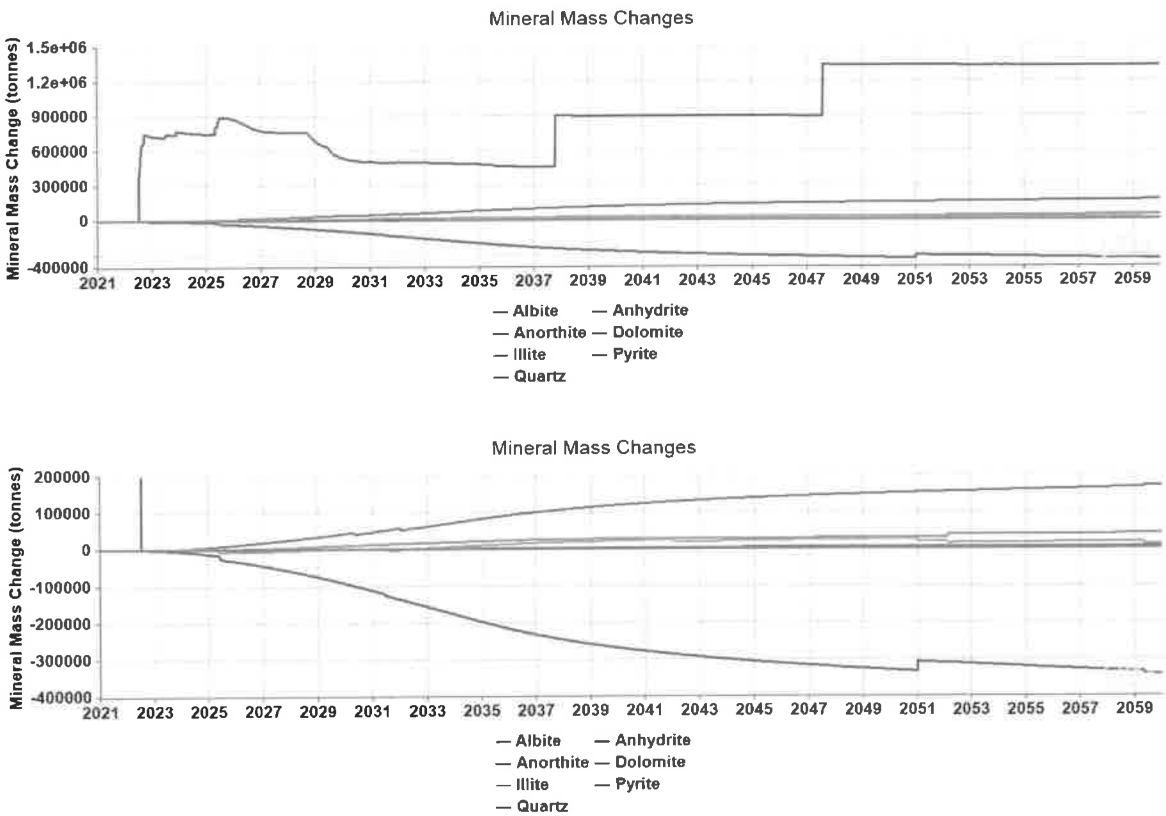

Figure 2-25. Dissolution and precipitation quantities of reservoir minerals because of CO_2 injection. Dissolution of anorthite with precipitation of pyrite, albite, and dolomite was observed. Upper figure shows all the minerals; the lower figure is rescaled for better view of the minerals mass change except pyrite.

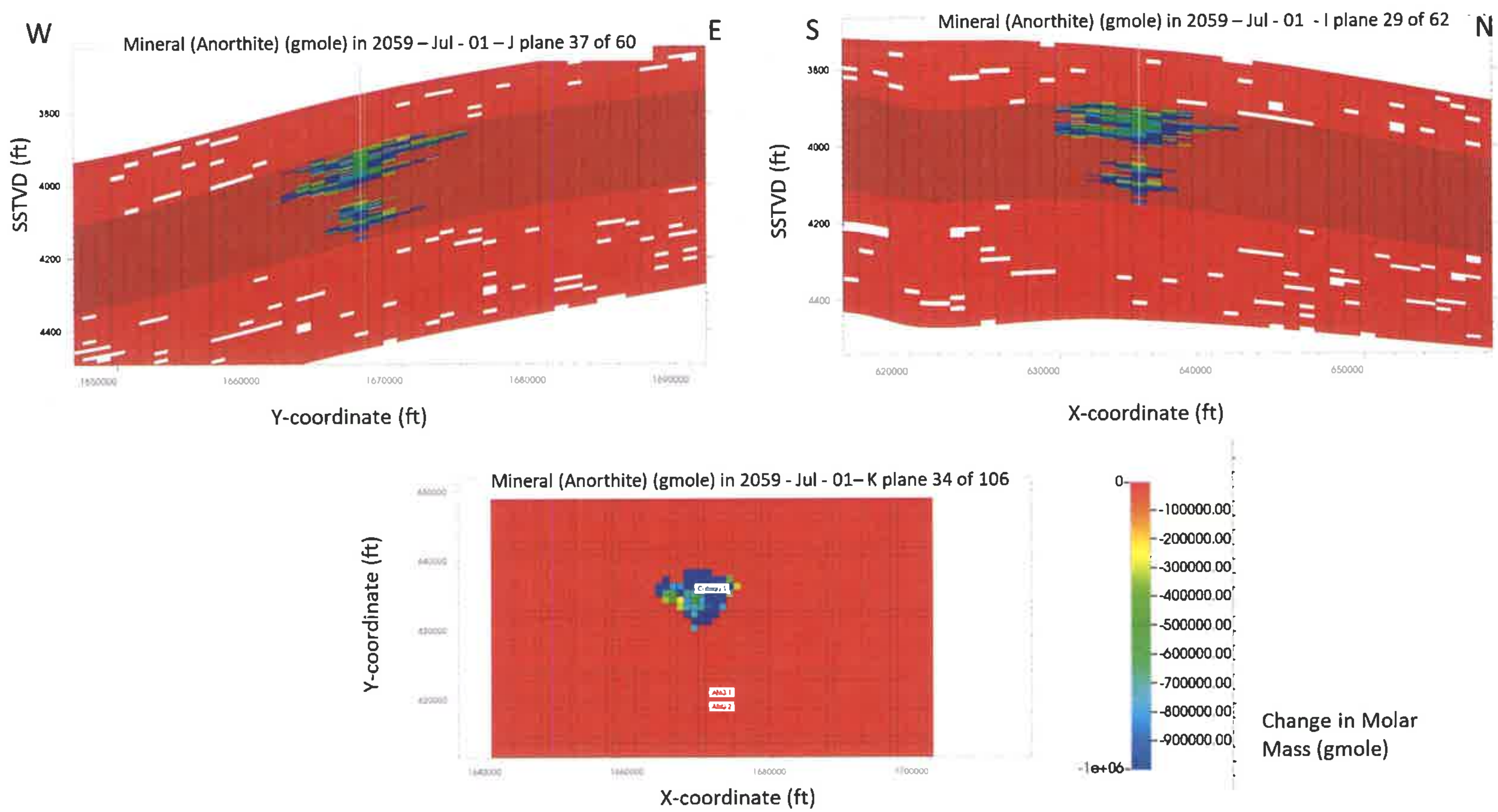

Figure 2-26. Change in molar distribution of anorthite, the most prominent dissolved mineral at the end of the 12-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

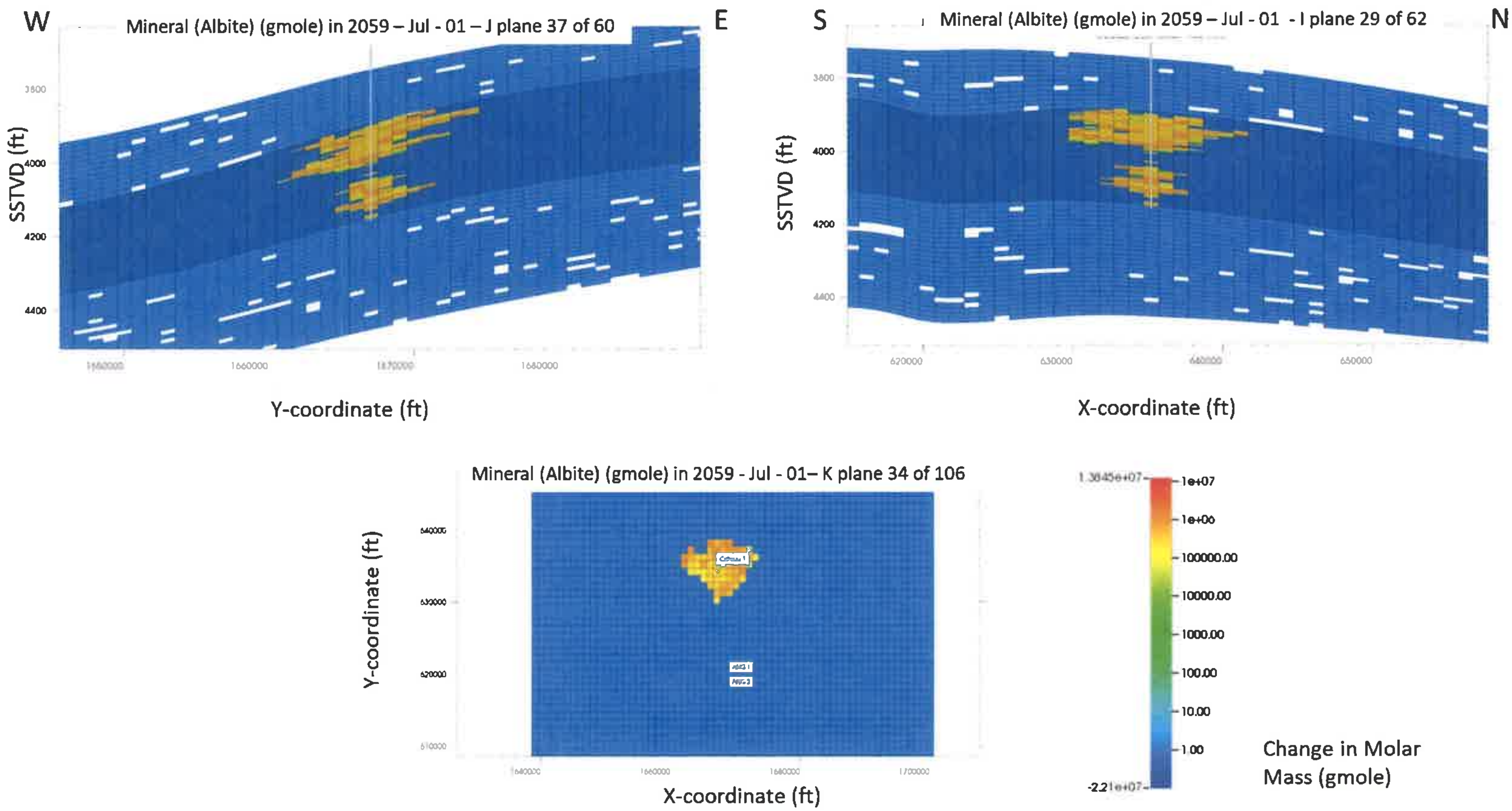

Figure 2-27. Change in molar distribution of albite, a precipitated mineral at the end of the 12-year injection + 25 years postinjection period in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

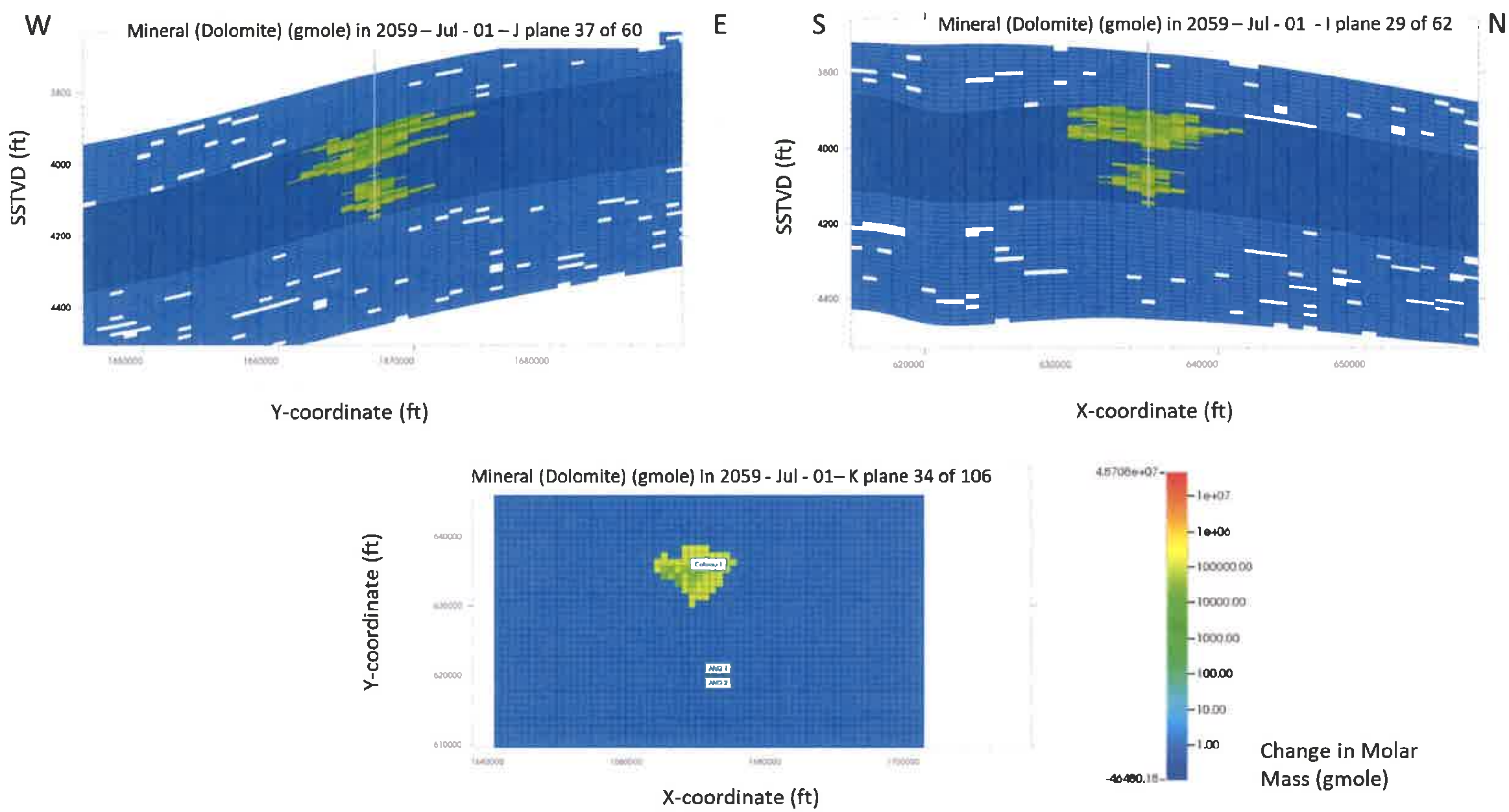

Figure 2-28. Change in molar distribution of dolomite, a precipitated mineral at the end of the 12-year injection + 25 years postinjection period in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

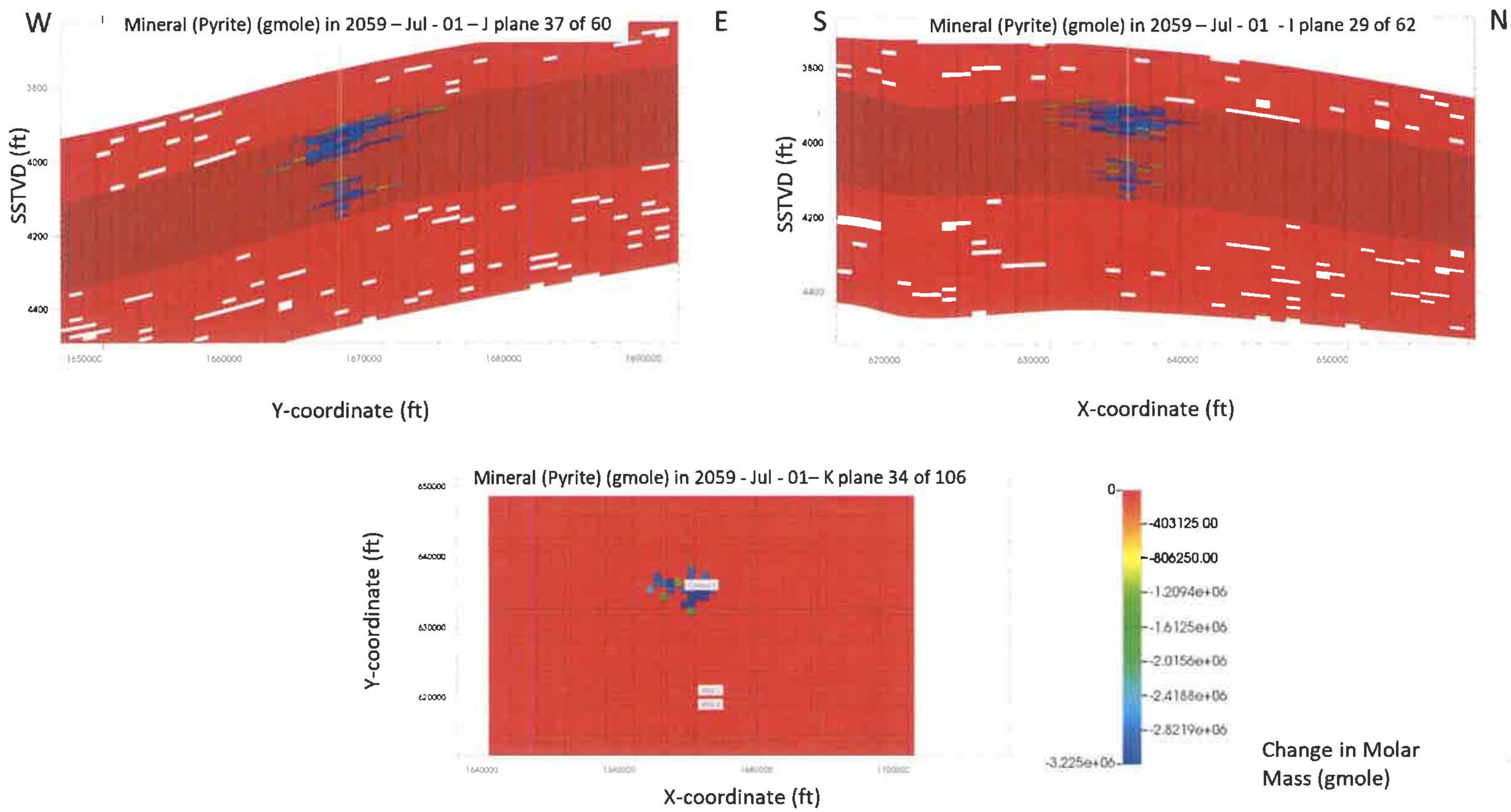

Figure 2-30. Change in molar distribution of pyrite, the most prominent precipitated mineral at the end of the 12-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

2.4 Confining Zones

The confining zones for the Broom Creek Formation are the Opeche interval and underlying Amsden Formation (Figure 2-3, Table 2-12). Both the Amsden and Opeche intervals consist of impermeable rock layers.

Table 2-12. Properties of Upper and Lower Confining Zones in Simulation Area (data based on the Coteau 1 well)

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	Opeche	Amsden
Primary Lithology	Silty mudstone	Dolostone
Formation Top Depth, ft	5,763	6,164
Thickness, ft	143	300
Porosity, % (core data) *	6.93	2.40
Permeability, mD (core data) **	0.002878	0.00116
Capillary Entry Pressure (CO_2/brine), psi	138.68	251.27
Depth below Lowest Identified USDW, ft	4,658	5,059

* Porosity values are reported as the arithmetic mean.
** Permeability values are reported as the geometric mean.

2.4.1 Upper Confining Zone

In the Great Plains CO_2 Sequestration Project area, the Opeche Formation consists of silty mudstone and anhydrite. The upper confining zone (Opeche) is laterally extensive across the Great Plains CO_2 Sequestration Project area (Figure 2-31). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche interval is 5,763 ft below the land surface and 143 ft thick at the Coteau 1 wellsite (Table 2-12, Figures 2-32 and 2-33). The contact between the upper confining zone and underlying Broom Creek sandstone is an unconformity that can be correlated across the formation's extent where the resistivity and GR logs show a significant change across the contact (Figure 2-34).

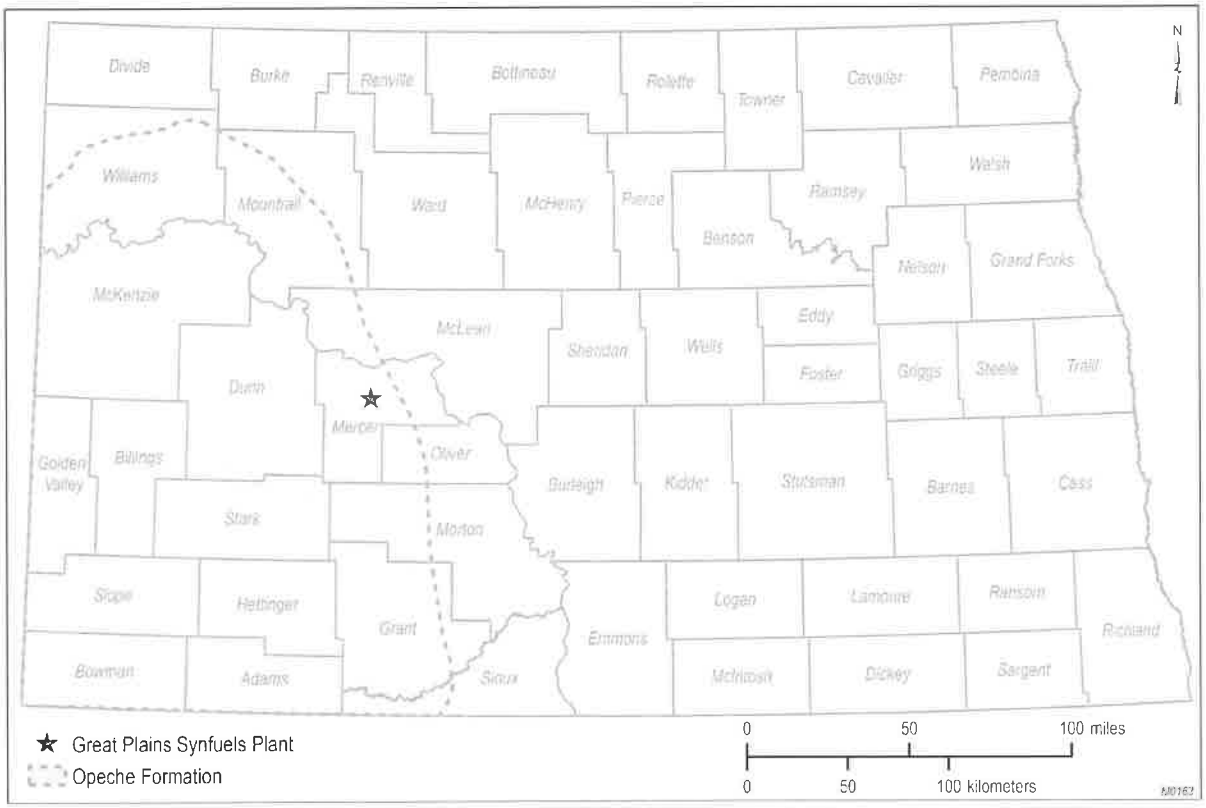

Figure 2-31. Areal extent of the Opeche Formation in North Dakota.

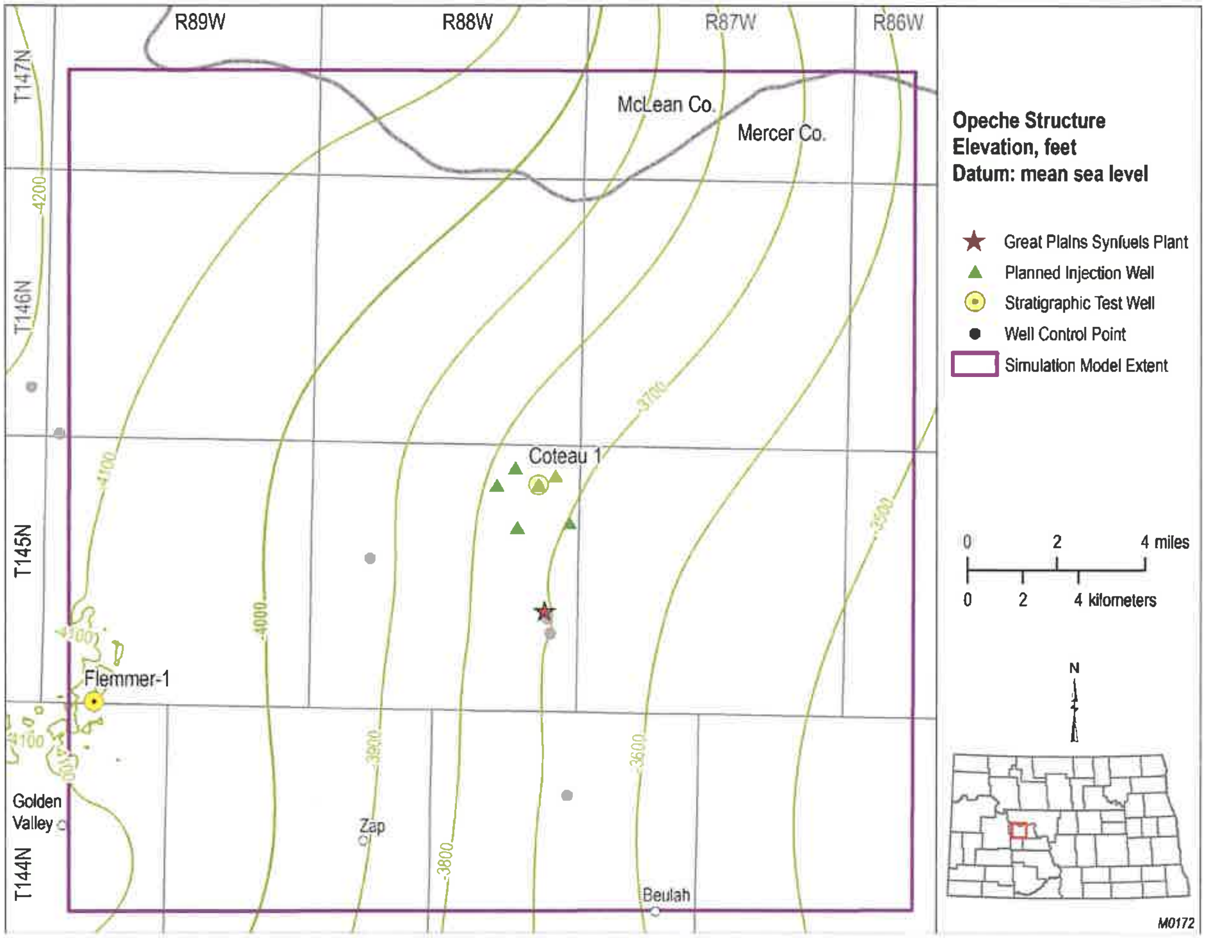

Figure 2-32. Structure map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops).

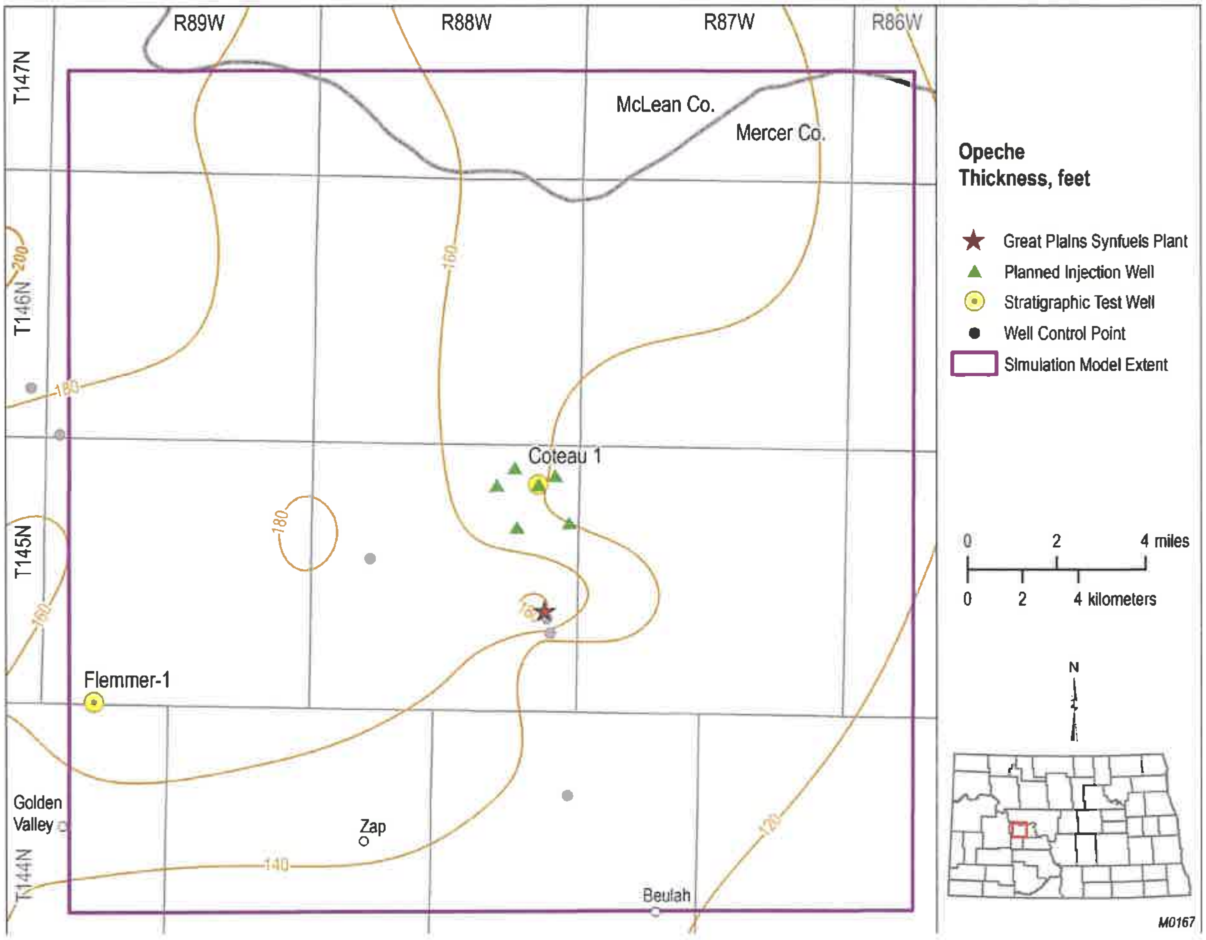

Figure 2-33. Isopach map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area.

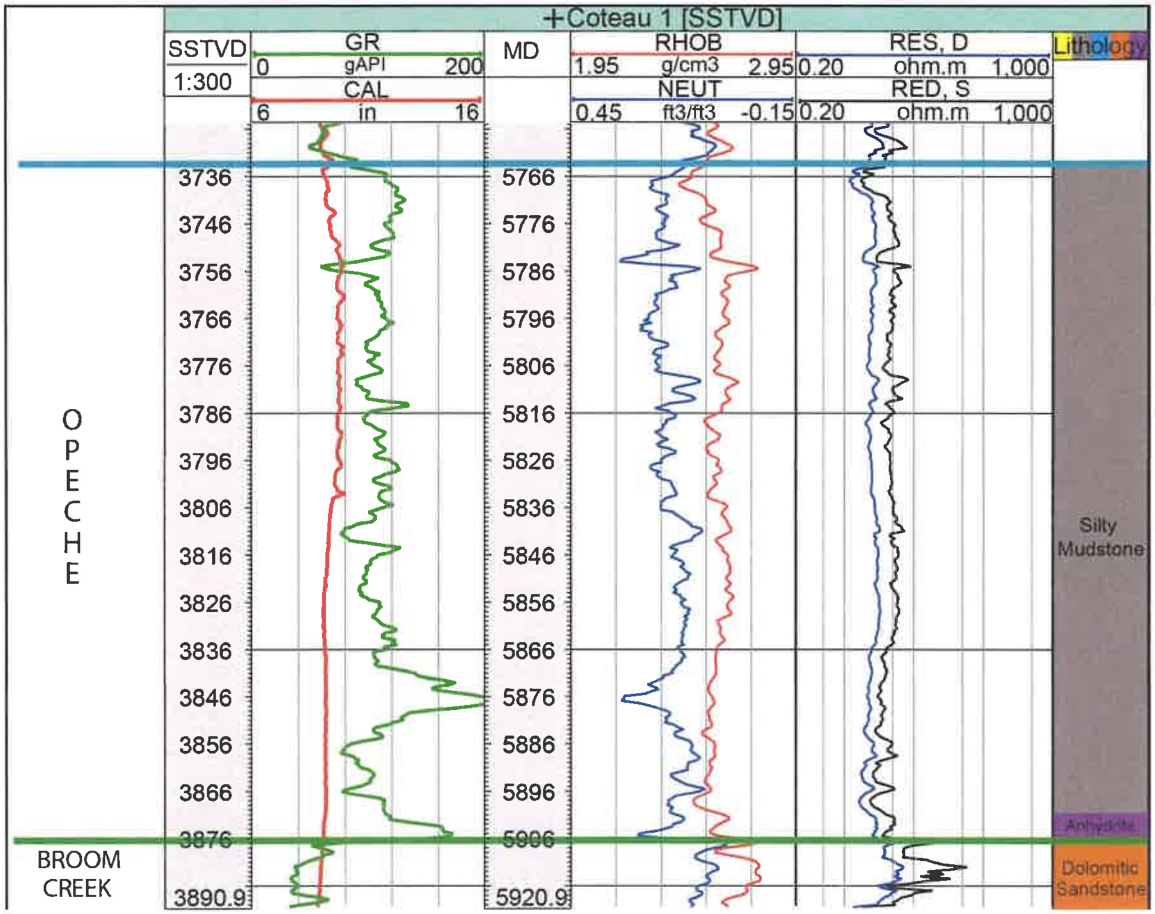

Figure 2-34. Well log display of the upper confining zone at the Coteau 1 well.

Microfracture in situ stress tests were not performed within the Opeche Formation in the Coteau 1 well. Microfracture in situ tests were performed using the MDT tool in the Flemmer 1 well, in the Opeche Formation, at a depth of 6,262 ft, which yielded results within good confidence. The MDT tool was able to cause breakdown in the formation at 8,157 psi. Propagation pressure for two cycles in close agreement were 4,879 and 5,085 psi, resulting in an average propagation pressure gradient of 0.80 psi/ft (Figure 2-35).

In situ fluid pressure testing was not performed in the Opeche Formation with the MDT tool. The CMR log shown in Figure 2-36 suggests that because of the low to almost zero permeability the fluid within the Opeche is pore- and capillary-bound fluid and not mobile. This is confirmed by unsuccessful attempts by others to extract fluid samples from the Opeche. The Tundra SGS (secure geologic storage) and Red Trail Energy storage facility permit applications describe unsuccessful attempts to draw down reservoir fluid in order to determine the reservoir pressure or to collect an in situ fluid sample; the formation was unable to rebound (build pressure) because of low to almost zero permeability (NDIC, 2021a, b). These unsuccessful attempts provide further evidence of the confining properties of the Opeche Formation, ensuring sufficient geologic integrity to contain the injected carbon dioxide stream.

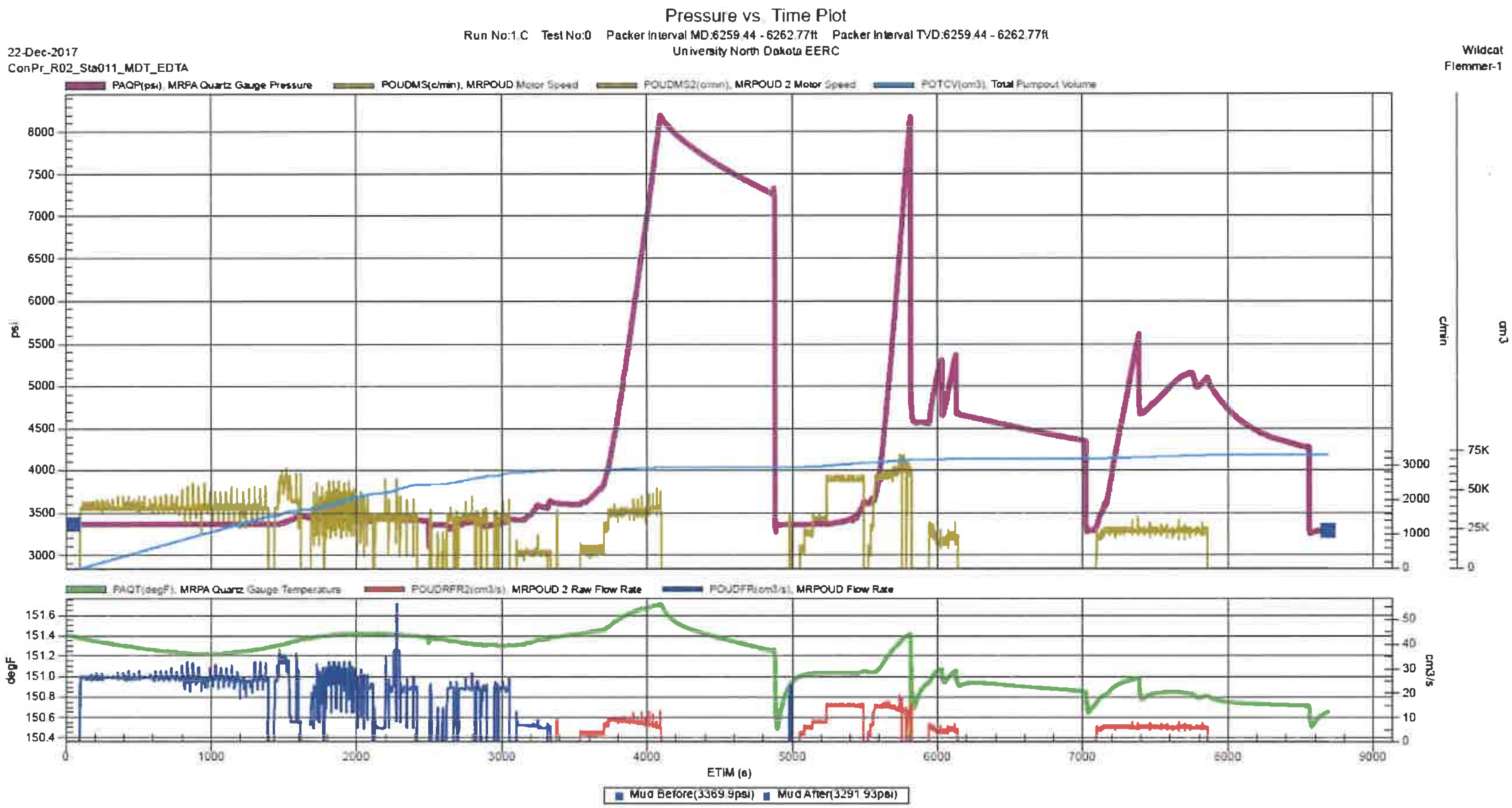

Figure 2-35. Flemmer 1 Opeche Formation MDT microfracture in situ stress pump cycle graph at 6,262 ft.

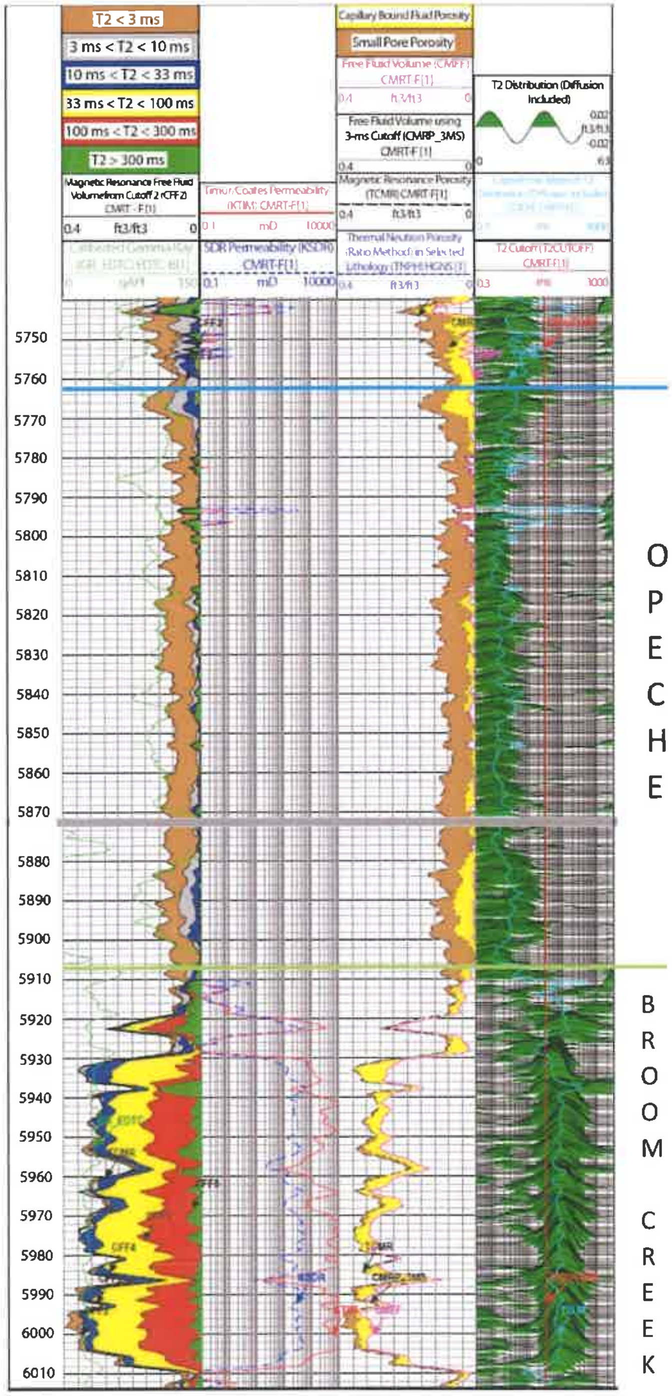

Figure 2-36. Well log display of the combinable magnetic resonance (CMR) log from the Coteau 1 well. Note: Small pore and capillary-bound fluid properties represent porosity containing immobile formation fluid. Fluid within the small pores cannot escape because of pore size, while capillary bound fluids cannot escape pores because of pressure constraints. T2 values smaller than the T2 cutoff, as seen in the fourth track, indicate smaller pore space and low permeabilities.

Laboratory measurements from the Opeche Formation core samples taken from the Coteau 1 well indicate a porosity value of 6.93% at 800 psi and 6.62% at 2,400 psi and geometric average permeability values of 0.002878 mD at 800 psi and 0.002083 mD at 2,400 psi. The lithology of the cored sections of the Opeche is primarily silty mudstone.

2.4.1.1 Mineralogy

Thin-section investigation shows that the Opeche Formation comprises alternating intervals of very fine silty mudstone and mudstone. In all, five thin sections were created over the 73 ft of core collected from the Opeche Formation. The mineral components present are clay, quartz, anhydrite, feldspar, dolomite, and iron oxides. The coarser grains are almost always surrounded by anhydrite or clay as cement or matrix. The observable porosity is very low and is due to the dissolution of quartz and feldspar. The porosity ranges between 5% and 9%. Permeability is very poor and ranges between 0.00026 to 0.0227 mD. Figure 2-37 shows examples of the texture, fabric, and nature of observable porosity for the intervals where thin sections were created. As shown, observable porosity (shown in blue) is generally isolated and not well connected throughout. Additionally, thin-section analysis shows the fine-grained, well-compacted nature of the intervals evaluated.

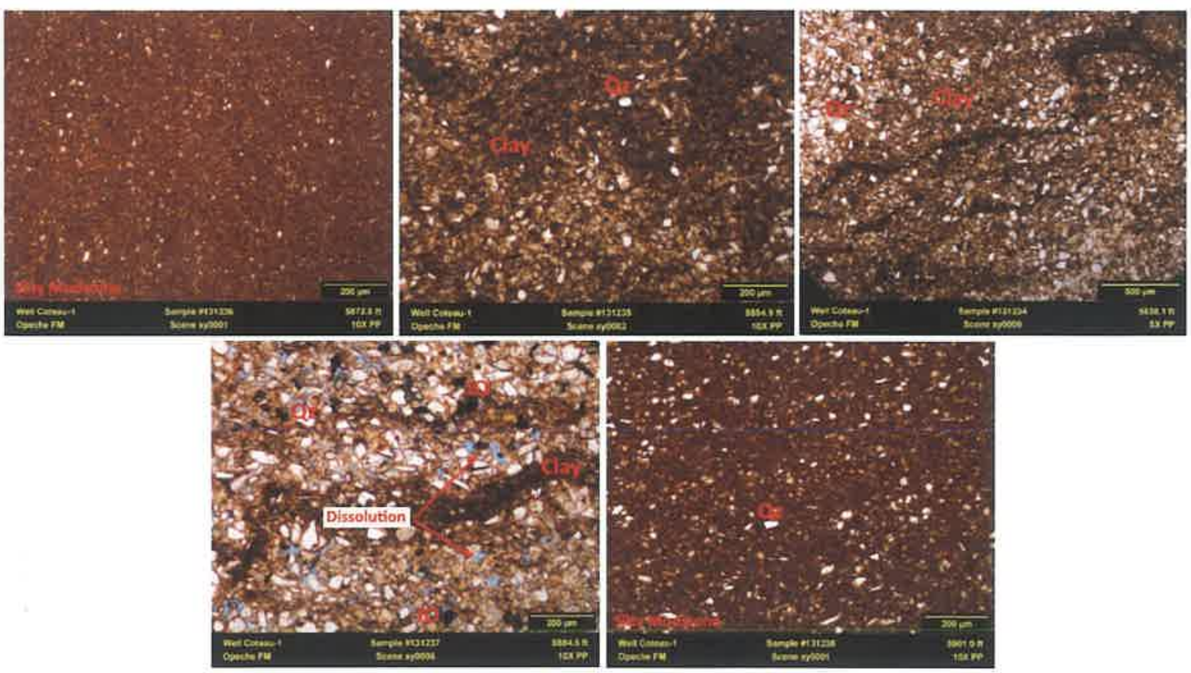

Figure 2-37. Thin sections from the five depth intervals of the Opeche Formation. As shown, the Opeche is composed of very fine silty mudstone and mudstone. Where porosity is shown (blue), it is generally isolated and disconnected.

XRD data from the five Opeche samples of the Coteau 1 core supported facies interpretations from core descriptions and thin-section analysis. The Opeche Formation mainly comprises clay, quartz, feldspar, dolomite, and anhydrite. Figure 2-38 shows the mineralogy determined from XRD data for the five samples tested through the cored interval of the Opeche Formation.

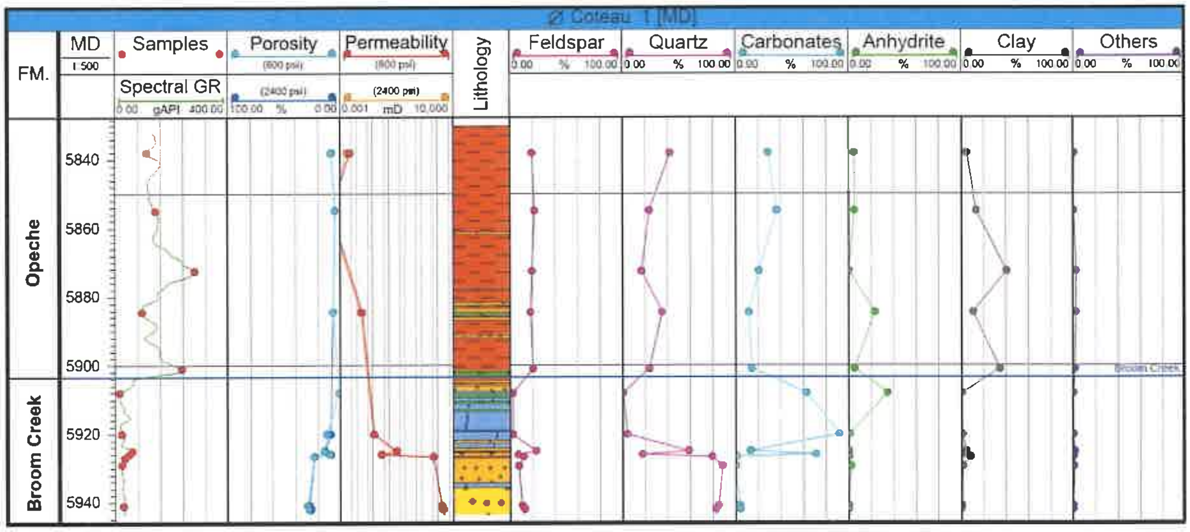

Figure 2-38. XRD data for the Opeche Formation from the Coteau 1.

XRF analysis of the Opeche Formation shown in Figure 2-39 identifies SiO_2 (44%–57%), Al_2O_3 (6%–18%), CaO (5%–15%), and MgO (3%–9%) as the major chemical constituents, correlating well with the silicate, carbonate, and aluminum-rich mineralogy determined by XRD. This is in good agreement with XRD, core description, and thin-section analysis.

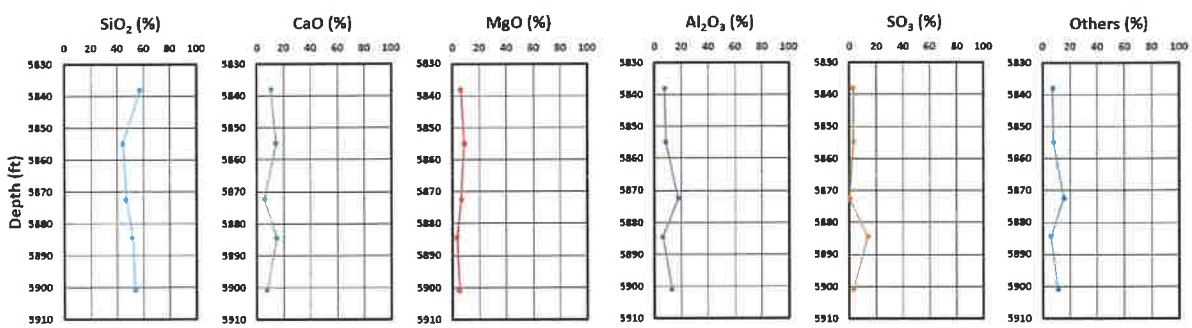

Figure 2-39. XRF data for the Opeche Formation from the Coteau 1.

2.4.1.2 Geochemical Interaction

Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected CO_2 stream on the Opeche Formation, the primary confining zone. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to CO_2 and minor amounts of H_2S at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Opeche by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the Opeche Formation. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock –CO_2/H_2S exposure boundary. The mineralogical composition of the Opeche Formation was honored (Table 2-13). The XRD data used to define mineral composition in the model correspond to a mudstone sample from the Opeche Formation. Formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone below (Table 2-14). The CO_2 stream composition was as described in Table 2-15. 96.45 mol% of the stream is CO_2, and the rest represents other components, including H_2S, the second major component of the stream. 96 mol% of CO_2 was used in the simulation instead of 96.45 mol% to keep the model input simple (Table 2.15). The 4 mol% H_2S used for this simulation represents the sum of all other components (CH_4, C_2H_6, C_3H_8, N_2) and thus overstates the actual H_2S fraction of 1.23 mol% (Table 2-15). The exposure level, expressed in moles per year, of the CO_2 stream to the cap rock used was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/year (Espinoza and Santamarina, 2017). This overestimate was done to ensure that the degree and pace of geochemical change would not be underestimated. This geochemical simulation was run for 37 years to match the reservoir injection zone geochemical model and represent 12 years of injection plus 25 years of postinjection. The simulation was performed at reservoir pressure and temperature conditions.

Table 2-13. Mineral Composition of the Opeche Derived from XRD Analysis of Coteau 1 Core Samples

Minerals, wt%	
Illite	32.3
K-Feldspar	12.7
Albite	7.6
Quartz	24.0
Dolomite	13.1
Anhydrite	5.1

Table 2-14. Formation Water Chemistry from Broom Creek Fluid Samples from Coteau 1

pH	6.7	TDS	42,800 mg/L
Total Alkalinity	853 mg/L $CaCO_3$	Calcium	1,860 mg/L
Bicarbonate	853 mg/L $CaCO_3$	Magnesium	212 mg/L
Carbonate	<20 mg/L $CaCO_3$	Sodium	12,800 mg/L
Hydroxide	<20 mg/L $CaCO_3$	Potassium	516 mg/L
Sulfate	469 mg/L	Strontium	70.8 mg/L
Chloride	24,900 mg/L	Iron	392 mg/L

Table 2-15. Composition of the Injection Stream with Constituents Normalized to 100% Mole Fraction

Component Flows	mol%	mol% Used in Simulation
CO_2	0.9645	0.960
H_2S	0.0123	0.04
CH_4	0.0054	
C_2H_6	0.0096	
C_3H_8	0.0028	
N_2	0.0054	

Results showed geochemical processes at work. Figures 2-40 through 2-43 show results from geochemical modeling. Figure 2-40 shows change in fluid pH over time as CO_2/H_2S enters the system. For the cell at the CO_2 interface, C1, the pH starts declining from an initial pH of 7.04 and stabilizes at a level of 5.34 after 12 years of simulation time. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH only begins to change after Year 27. Lastly, the pH is unaffected in Cell C3, indicating CO_2/H_2S does not penetrate this cell within the first 37 years.

Figure 2-41 shows the change in mineral dissolution and precipitation in grams per cubic meter of rock. The dashed lines are for Cell C1; solid lines that are only faintly seen in the figure are for Cell C2, 1.0 to 2.0 meters into the cap rock. The net change due to precipitation or dissolution in Cell C2 is less than 10 kg per cubic meter per year with little to no precipitation or dissolution taking place after injection ceases in Year 2034. Albite, K-feldspar, and anhydrite start to dissolve from the beginning of the simulation period while illite, quartz, and calcite start to precipitate for Cell C1. The presence of dissolved H_2S and aqueous iron in the Opeche Formation water (Table 2-14) favors minor amounts (less than 10 g) of pyrite precipitation. Any effects in Cell C3 are too small to represent at this scale.

Figure 2-42 represents the initial fractions of potentially reactive minerals in the Opeche Formation based on XRD data shown in Table 2-13. The overall Opeche lithology is characterized by a higher percentage of clay minerals. The expected dissolution of these minerals in weight percentage is also shown for Cells 1 and Cell 2 of the model. In Cell 1, albite, K-feldspar, and anhydrite are the primary minerals that go into dissolution. Dissolution (wt%) in Cell 2 is minimal (<0.5 wt%).

Figure 2-43 shows the change in porosity of the cap rock. Cell 1 experiences an initial increase in porosity as it is first exposed to CO_2/H_2S because of dissolution. The porosity decreases to nearly its initial condition after Year 13 because of precipitation. As dissolution occurs in Cell 1, reaction products move into Cell 2, where they precipitate, causing the porosity to slightly decrease. No significant change in porosity is seen in Cell 3 during the 37-year duration of the simulation. The net porosity changes from dissolution and precipitation are miniscule and unchanging in later years of the simulation. These results suggest that geochemical change from exposure to CO_2 and H_2S is minor and will not cause substantive deterioration of the Opeche cap rock.

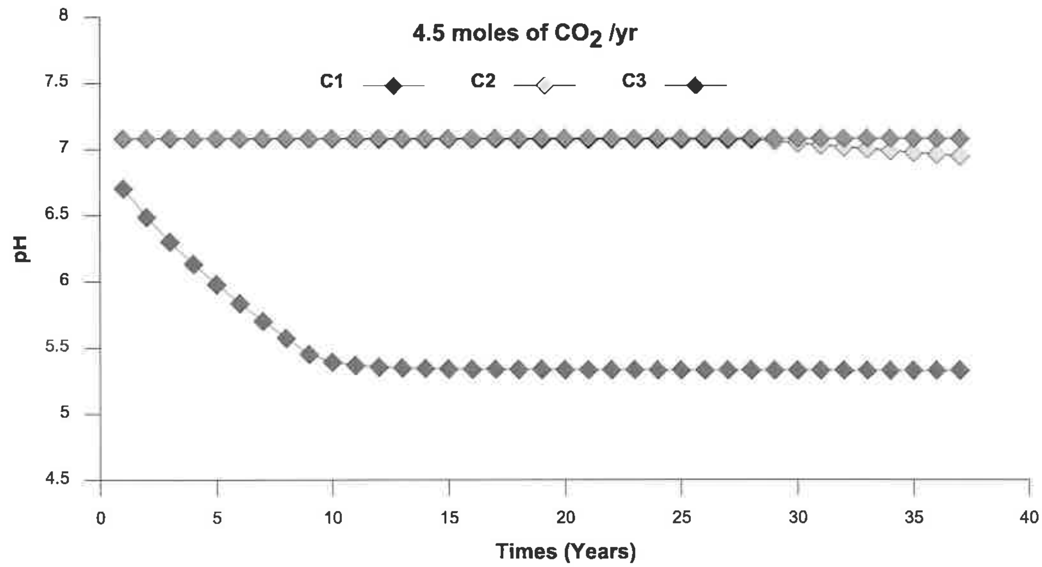

Figure 2-40. Change in fluid pH vs. time. The red line shows pH for the center of Cell C1, 0.5 meters above the Opeche cap rock base. The yellow line shows Cell C2, 1.5 meters above the cap rock base. The green line shows Cell C3, 2.5 meters above the cap rock base. pH for Cell C2 does not begin to change until after Year 27.

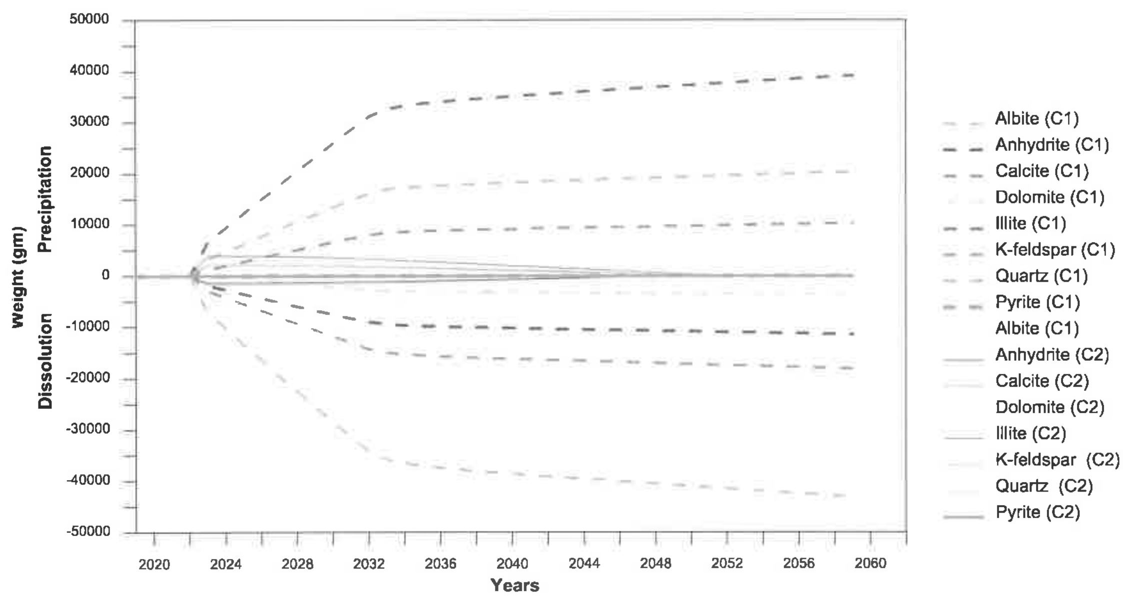

Figure 2-41. Dissolution and precipitation of minerals in the Opeche cap rock. Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. Solid lines show results for Cell C2, 1.5 meters above the cap rock base; these changes are barely visible. Results from Cell C3, 2.5 meters above the cap rock base, are not shown as they are too small to be seen at this scale.

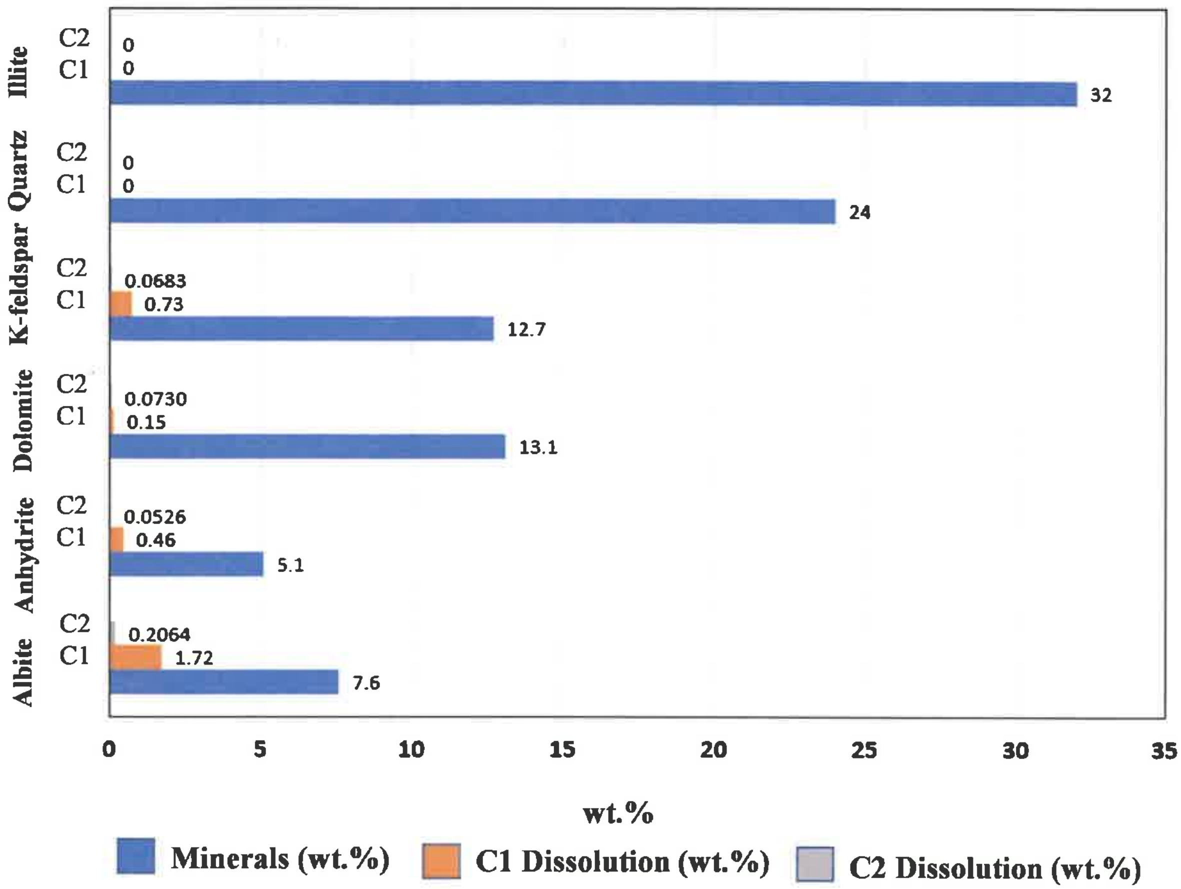

Figure 2-42. Weight percentage (wt.%) of potentially reactive minerals present in the Opeche Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray) after 12 years of injection plus 25 years of postinjection.

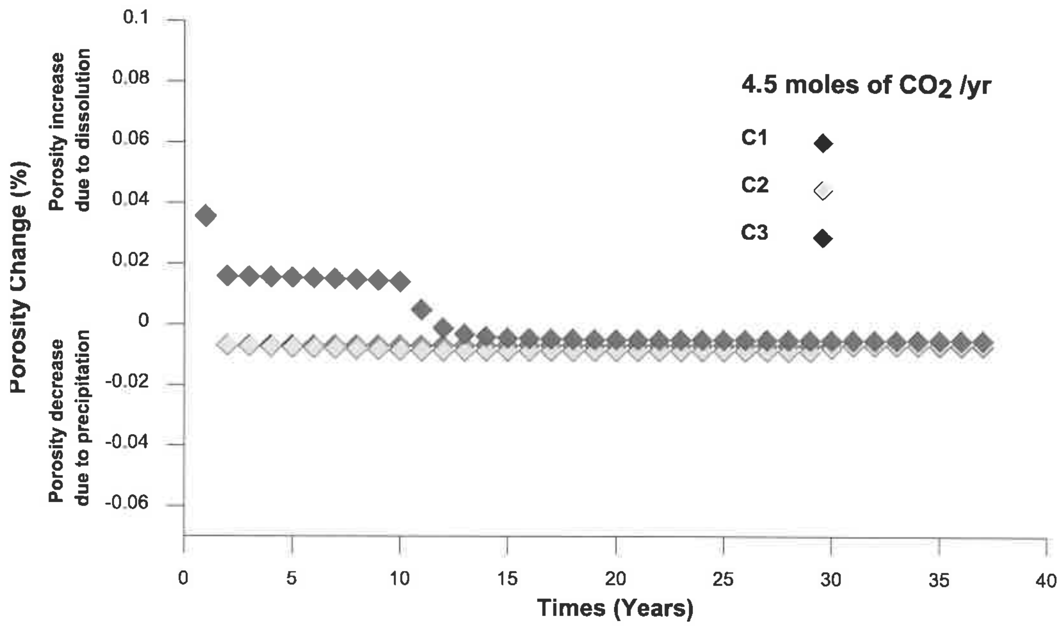

Figure 2-43. Change in percent porosity of the Opeche cap rock. Red line shows porosity change calculated for Cell C1 at 0.5 meters above the cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals, and negative change is due to mineral precipitation.

2.4.2 Additional Overlying Confining Zones

Several other formations provide additional confinement above the Opeche interval. Impermeable rocks above the primary seal include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-16). Together with the Opeche interval, these formations are 1,106 ft thick and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-44). Above the Inyan Kara Formation, 2,657 ft of impermeable rocks act as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (Figure 2-45). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-16).

Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (Opeche) (data based on the Coteau 1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,753	1,931	0
Greenhorn	Shale	3,685	376	1,931
Mowry	Shale	4,061	94	2,307
Skull Creek	Shale	4,156	254	2,402
Swift	Shale	4,800	411	3,046
Rierdon	Shale	5,212	205	3,458
Piper (Kline Member)	Limestone	5,417	112	3,663
Piper (Picard Member)	Shale	5,529	233	3,775

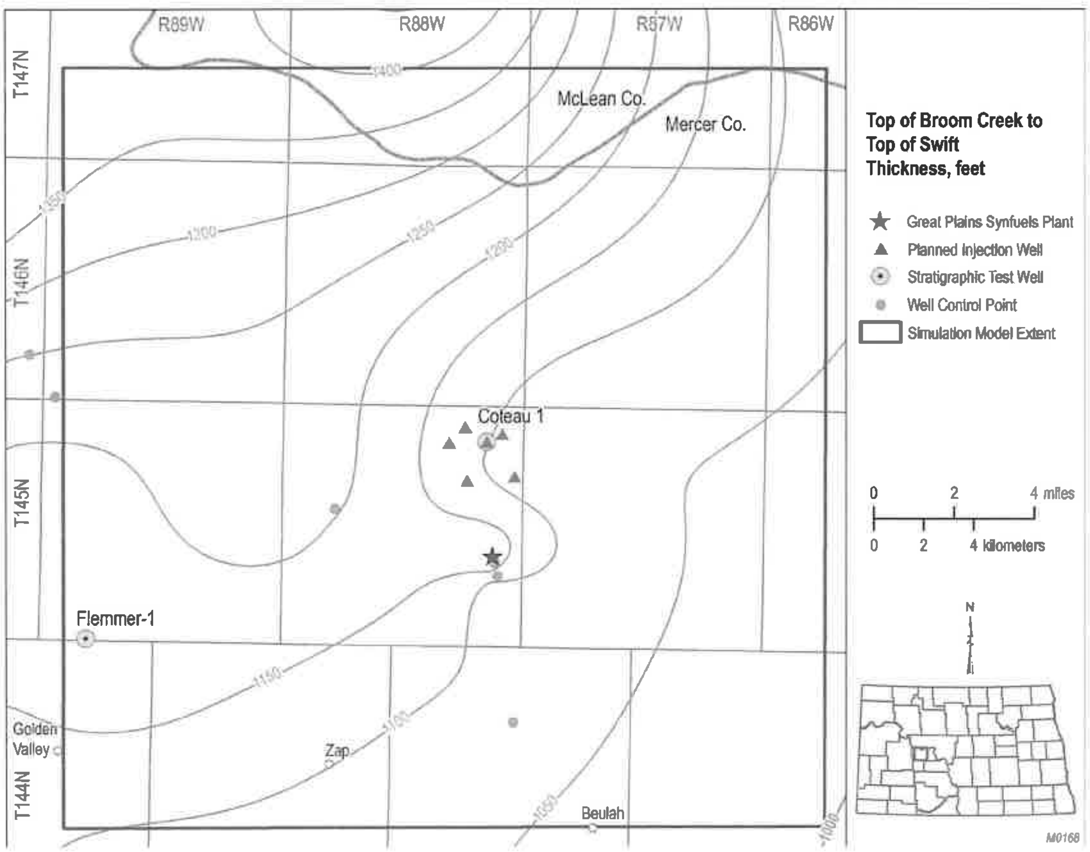

Figure 2-44. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones.

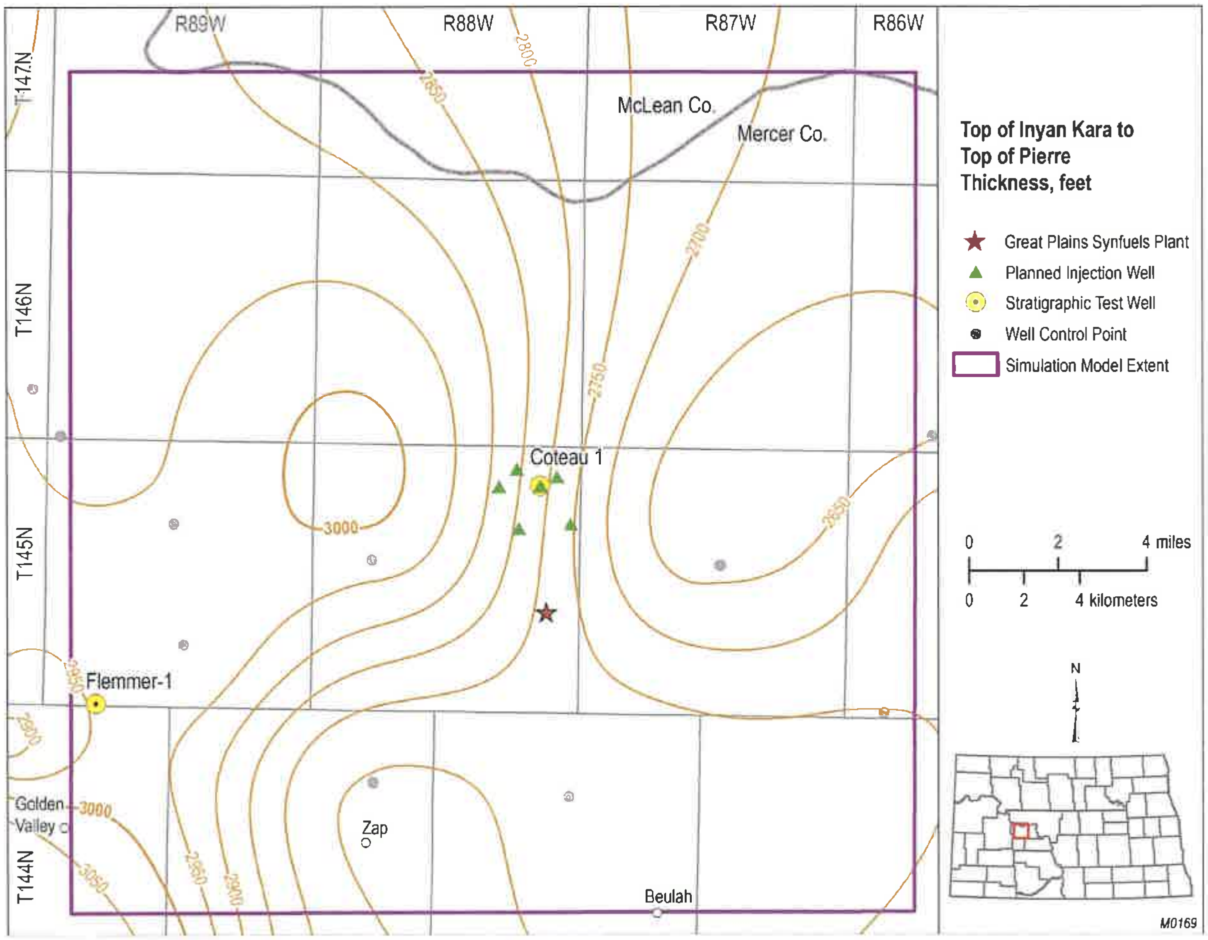

Figure 2-45. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone.

These formations between the Broom Creek and Inyan Kara and between the Inyan Kara and the lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin (Downey, 1986; Downey and Dinwiddie, 1988).

Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Inyan Kara Formation represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring using annual temperature and pulse neutron logging of the Inyan Kara Formation provides an additional opportunity for mitigation and remediation (Section 5). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at the Coteau 1 well is 4,512 ft, and the formation itself is 378 ft thick.

2.4.3 Lower Confining Zone

The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, mudstone, and anhydrite. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, with relatively high GR character that can be correlated across the Great Plains CO_2 Sequestration Project area (Figure 2-6). The Amsden Formation is 6,164 ft below land surface and approximately 300 ft thick at the Coteau 1 well (Figures 2-46 and 2-47, Table 2-12).

The contact between the overlying Broom Creek and Amsden Formations is evident on wireline logs as there is a lithological change from the porous sandstones of the Broom Creek Formation to the dolostone and anhydrite beds of the Amsden Formation. This lithologic change is recognized in the core from the Coteau 1 well. The lithology of the cored section of the Amsden Formation from the Coteau 1 well is dolostone, anhydrite, and mudstone with laminated, fine-grained sandstone and siltstone. Data acquired from the six core plug samples taken from the

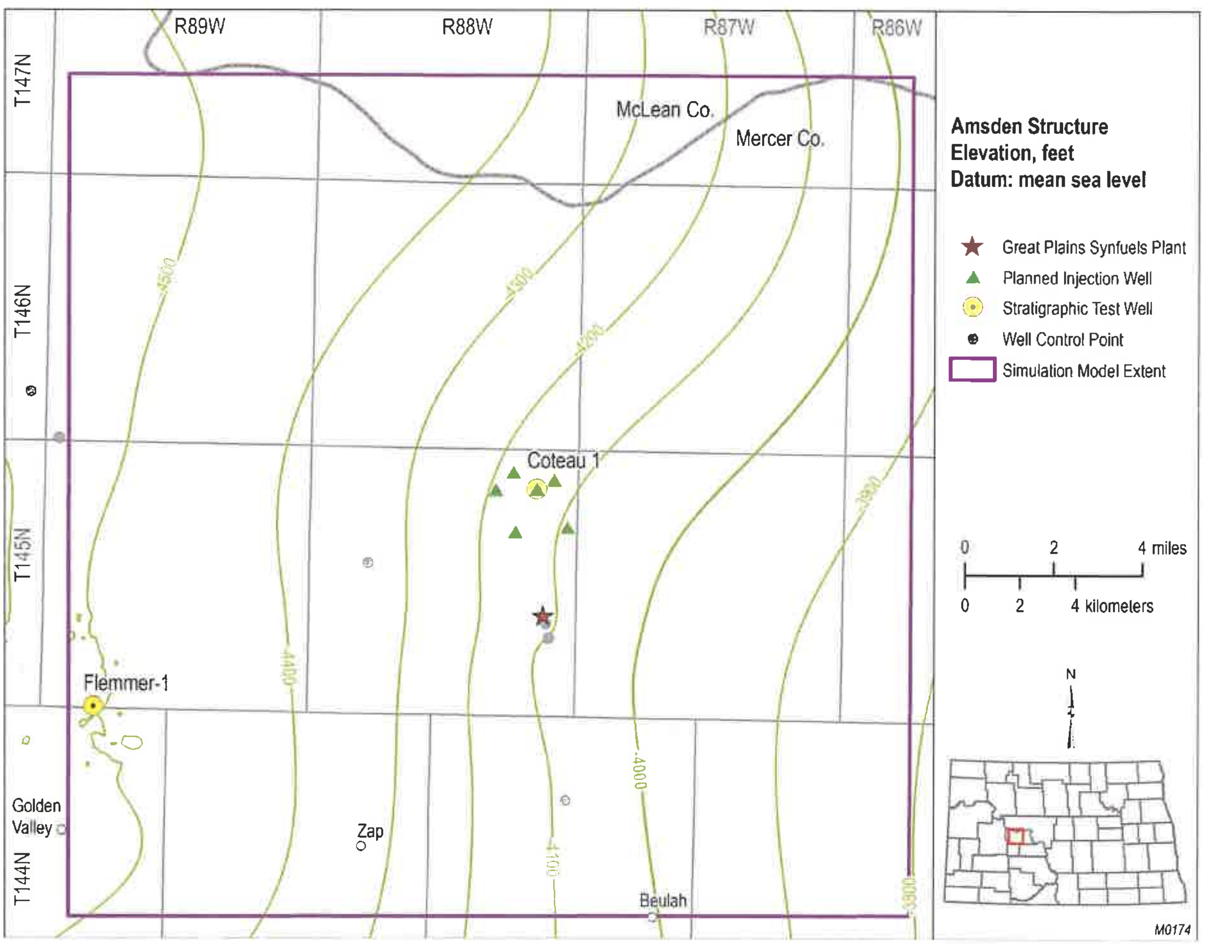

Figure 2-46. Structure map of the Amsden Formation across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops).

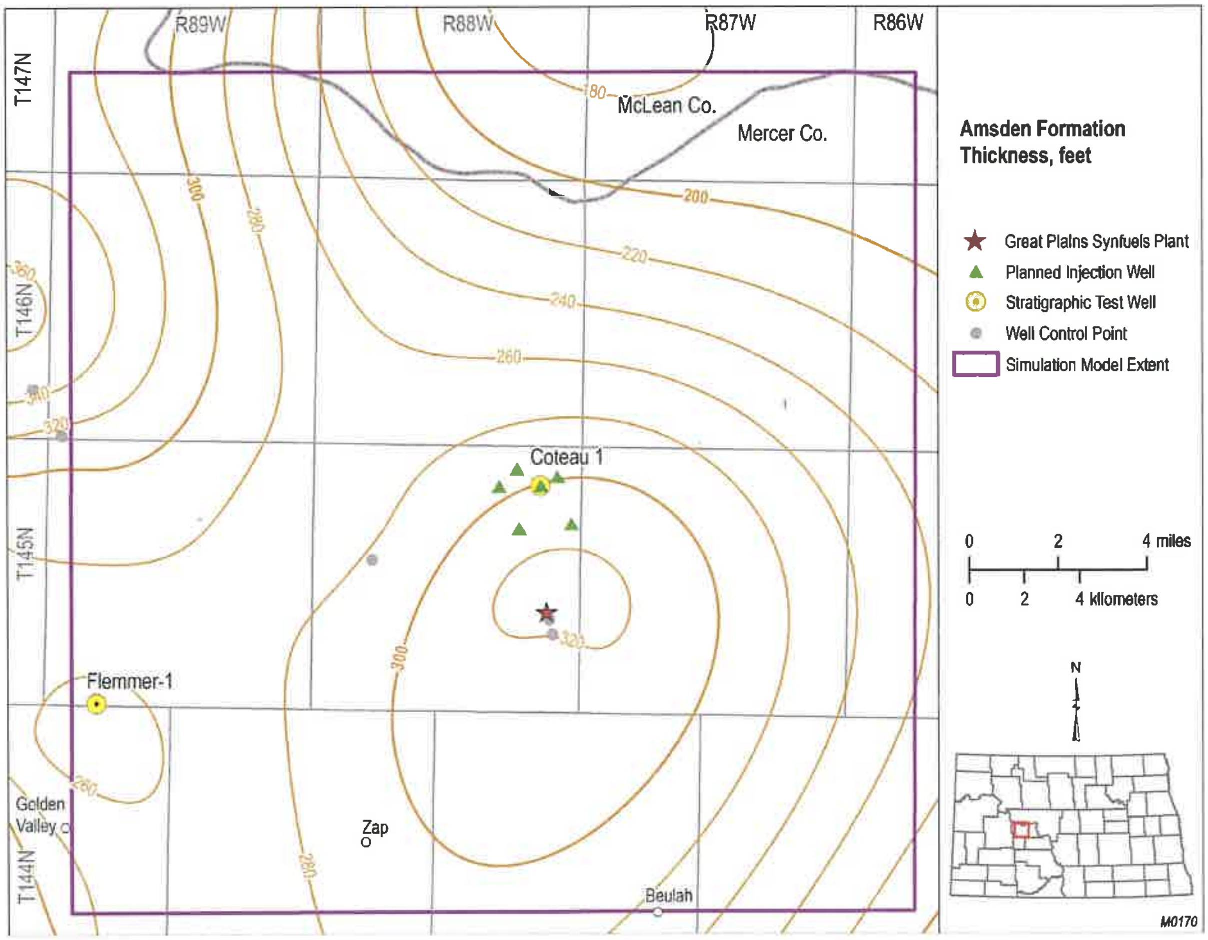

Figure 2-47. Isopach map of the Amsden Formation across the greater Great Plains CO_2 Sequestration Project area.

Amsden Formation show porosity values ranging from 1.00% to 5.27% at 800 psi and 0.91% to 4.54% at 2,400 psi. Permeability values range from 0.0000557 to 1.2 mD at 800 psi and 0.0000642 to 0.215 mD at 2,400 psi (Table 2-17).

Table 2-17. Amsden Core Sample Porosity and Permeability from Coteau 1

Sample Depth, ft	Porosity % (800 psi)	Permeability, mD (800 psi)
6,169	2.89	0.000198
6,183	1.04	0.0000557
6,190	2.96	0.00294
6,206	1.00	0.0000865
6,239	1.23	0.000709
6,242	5.27	1.2

2.4.3.1 Mineralogy

Thin-section analysis shows that the Amsden Formation comprises dolomite, anhydrite, sandy dolomite, and shaly sand. Six thin sections were created and described for the 83-ft cored Amsden section. The dolomite is expressed by very fine to fine-sized dolomite crystals with the presence of quartz of variable size and shape, feldspar, clay, anhydrite, and iron oxides. The porosity is very low and is mainly intragranular because of dissolution with an average of 2%.

Anhydrite is present as beds, nodules, and laminations in association with the dolomite intervals. Minor iron oxides inclusions are present. The porosity is almost nonexistent.

The dolomite is mainly composed of dolomite crystals and grains of quartz. Minor iron oxides and feldspar are present, with rare occurrence of anhydrite observed. The grains of quartz are almost always separated by dolomite matrix. The porosity is mainly due to the dissolution of feldspar and averages 1%.

Finally, the anhydritic sandstone interval is composed of quartz, clay, carbonates, and anhydrite. Iron oxides are present in some parts of the rock matrix as rims around some quartz grains and mostly fill the stylolite surfaces and some rare fractures. The grains of quartz are almost always separated by carbonate cement, clay minerals and, specifically, anhydrite cement. In this lithofacies, anhydrite acts as cement in most parts of the interval by connecting sand grains together and decreasing the overall porosity of the lithofacies. The porosity averages 3% and is mainly due to the dissolution of feldspar and quartz (Figure 2-48).

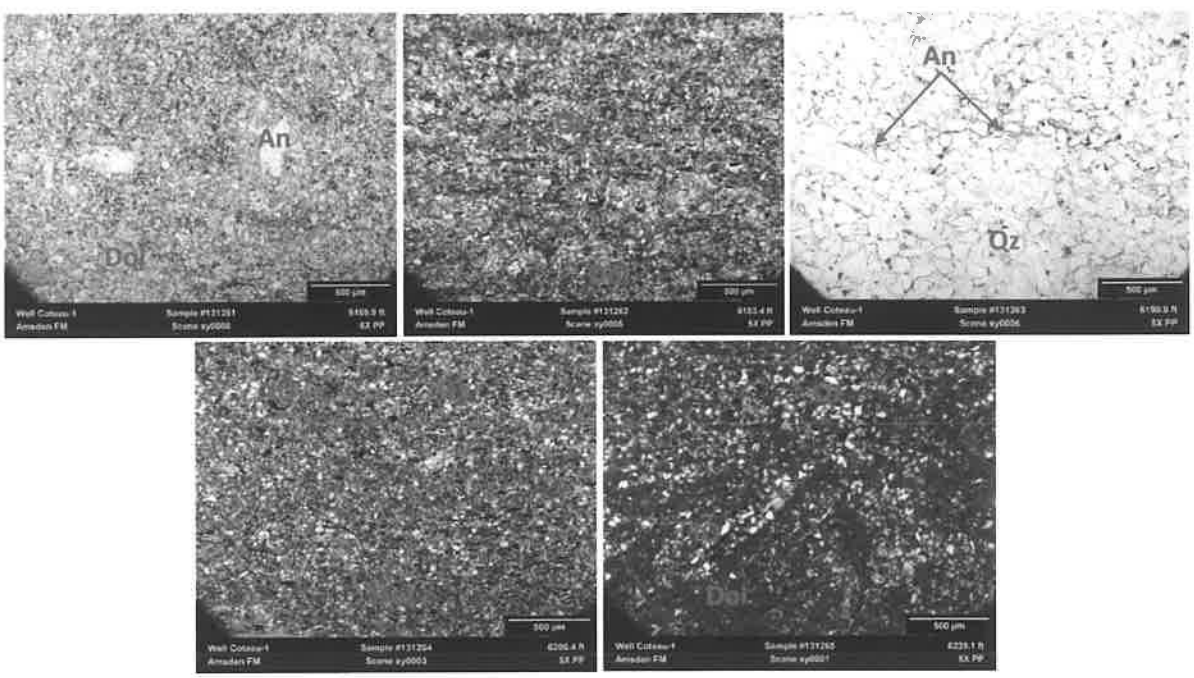

Figure 2-48. Thin sections from the five depth intervals of the Amsden Formation.

XRD was performed (Figure 2-49), and the results confirm the observations made during core analyses and thin-section description.

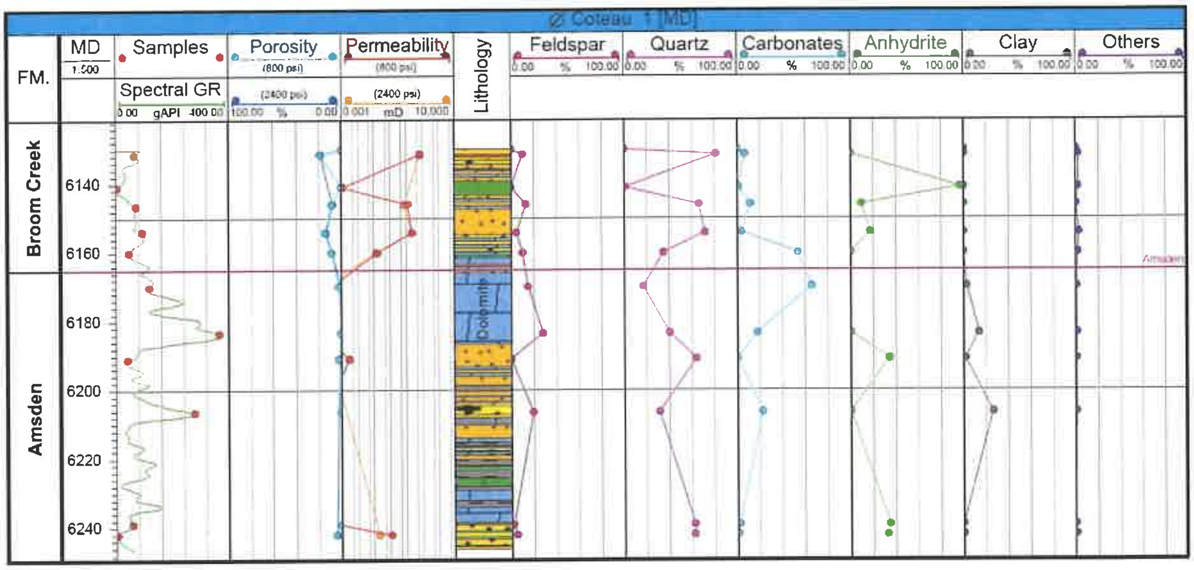

Figure 2-49. XRD data for the Amsden Formation from the Coteau 1.

XRF data shows that the Amsden Formation at the contact with the Broom Creek is dominated by CaO and MgO (major chemical components of dolomite). Deeper samples are more anhydrite-rich, fine- to medium-grained sandstones, as shown by the high percentage of SiO_2, CaO, and SO_3 (Figure 2-50).

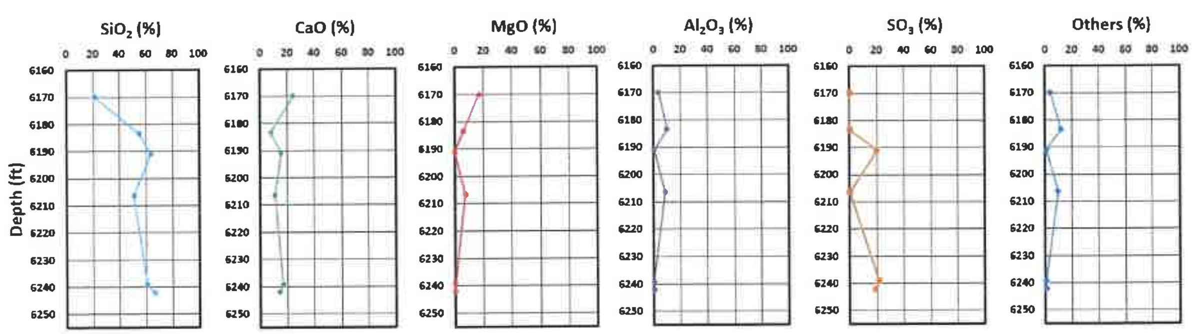

Figure 2-50. XRF data for the Amsden Formation from the Coteau 1.

2.4.3.2 Geochemical Interaction

The Broom Creek's underlying confining layer, the Amsden Formation, was investigated using PHREEQC geochemical software. A vertically oriented 1D simulation was created using a stack of six cells, each cell 1 meter in thickness. The formation was exposed to CO_2 and a minor amount of H_2S at the top boundary of the simulation which were allowed to enter the system by advection and dispersion processes. Direct contact between the Amsden and free-phase saturation from the injection stream is not expected to occur. Results were calculated at the center of each cell below the confining layer–CO_2/H_2S exposure boundary. The mineralogical composition of the Amsden was honored (Table 2-18). The Amsden formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone above. The CO_2 stream composition used is described in Section 2.4.1.2. The Amsden Formation temperature and pressure were collected from the 1D MEM. Two different pressure levels, 2,755 and 3,447 psi, were applied to the CO_2/H_2S saturated brine at the base of the Broom Creek Formation. These values represent the initial and potential maximum pore pressure levels. The higher-pressure results are shown here to represent a potentially more rapid pace of geochemical change.

Table 2-18. Mineral Composition of the Amsden Derived from XRD Analysis of Coteau 1 Core Samples at a Depth of 6,183 ft MD

	Sample Depth
	6,183 ft
Mineral	**wt%**
Illite/Muscovite	13.8
Fe Minerals	3.5
K-Feldspar	18.3
Albite	9.3
Quartz	40.1
Dolomite	14.3

Results show geochemical processes at work. Figures 2-51 through 2-56 show results from the geochemical modeling.

Figure 2-51 shows change in fluid pH over 37 years of simulation time as CO_2/H_2S enters the system. Initial change in pH in all of the cells from 7.04 to 7 is related to initial equilibration of the model. For the cell at the CO_2/H_2S interface, C1, the pH begins to decline after Year 7, declines to a level of 6.3 after 12 years of injection, and slowly declines further to 5.5 after an additional 25 years of post-injection. Progressively less or slower pH change occurs for each cell that is more distant from the CO_2/H_2S interface. The pH for Cells 5–6 did not decline over the 37 years of simulation time.

Figure 2-52 shows that CO_2 does not penetrate more than 4 meters (represented by Cells C5–C6) within the 37 years simulated.

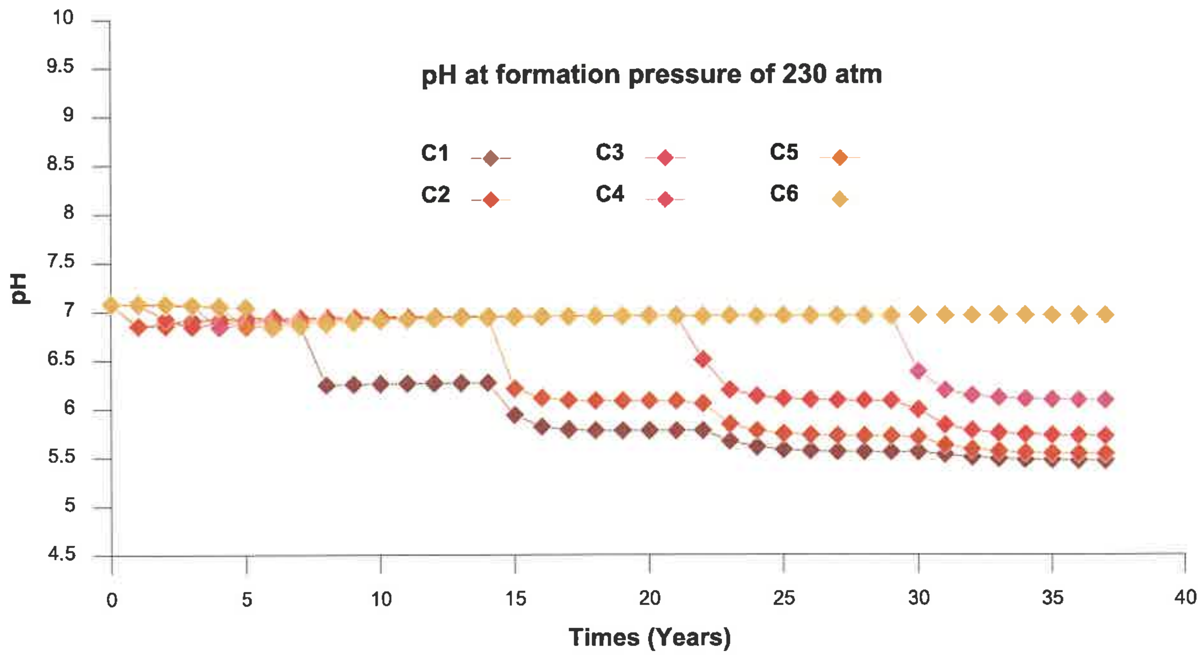

Figure 2-51. Change in fluid pH in the Amsden underlying confining layer for Cells C1-C6.

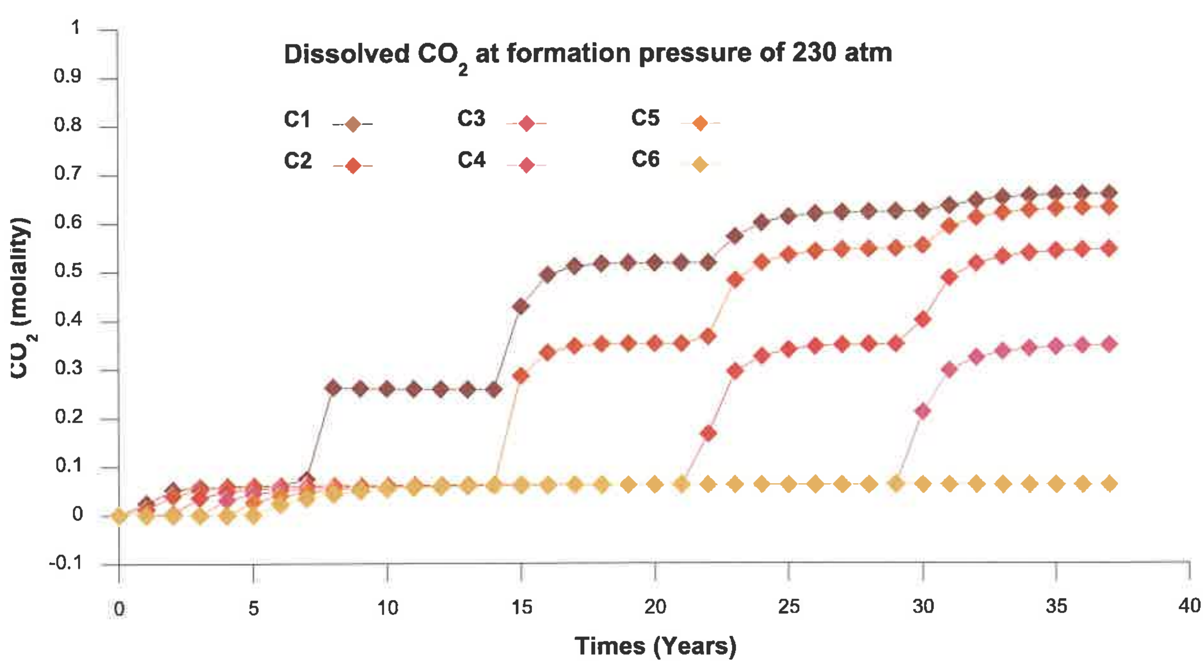

Figure 2-52. CO_2 concentration (molality) in the Amsden Formation underlying confining layer for Cells C1-C6.

Figure 2-53 shows the changes in mineral dissolution and precipitation in grams per cubic meter. For Cells C1 and C2, albite and K-feldspar start to dissolve from the beginning of the simulation period while quartz and illite clays start to precipitate and are largely a reflection of the paths of dissolution of albite and K-feldspar during the time of the simulation. Pyrite (FeS_2) precipitation is favored by the presence of dissolved H_2S and aqueous iron in the formation water.

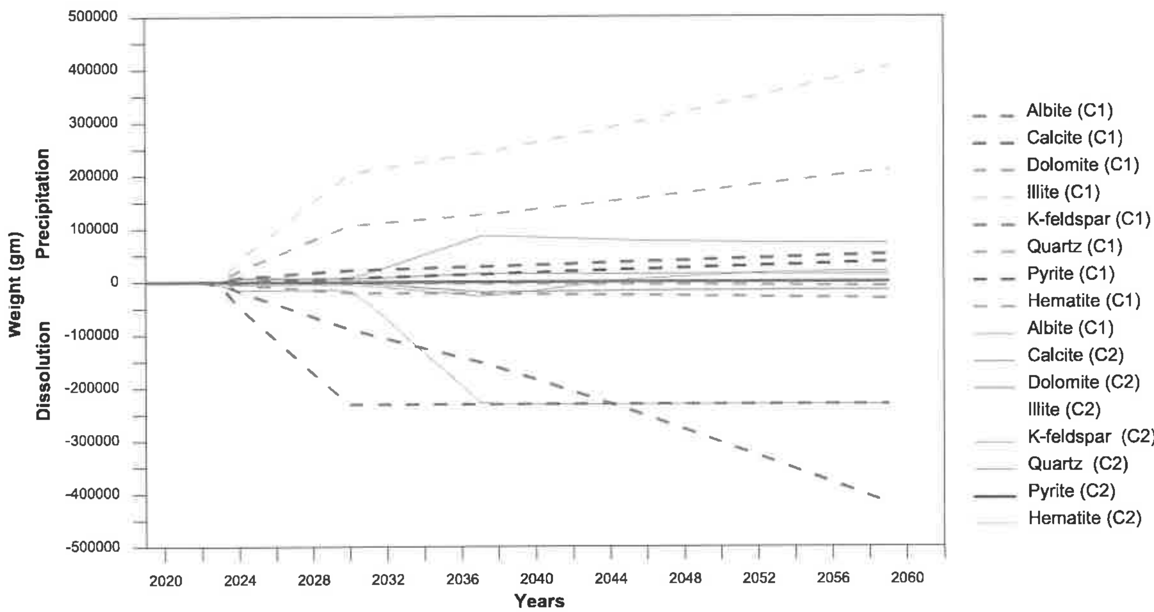

Figure 2-53. Dissolution and precipitation of minerals in the Amsden underlying confining layer. Dashed lines show results for Cell C1, 0 to 1 meter below the Amsden top. Solid lines show results for Cell C2, 1 to 2 meters below the Amsden top.

Figure 2-54 represents the initial fractions of potentially reactive minerals in the Amsden Formation based on the XRD data shown in Table 2-18. The expected dissolution of these minerals in weight percentage is also shown for Cells C1 and C2 of the model. In Cell 1, albite and K-feldspar are the primary minerals that go into dissolution. In Cell 2, albite and dolomite are the primary minerals that go into dissolution. No dissolution is observed for illite and quartz. These dissolved minerals are almost completely replaced by the precipitation of other minerals, as shown in Figure 2-55.

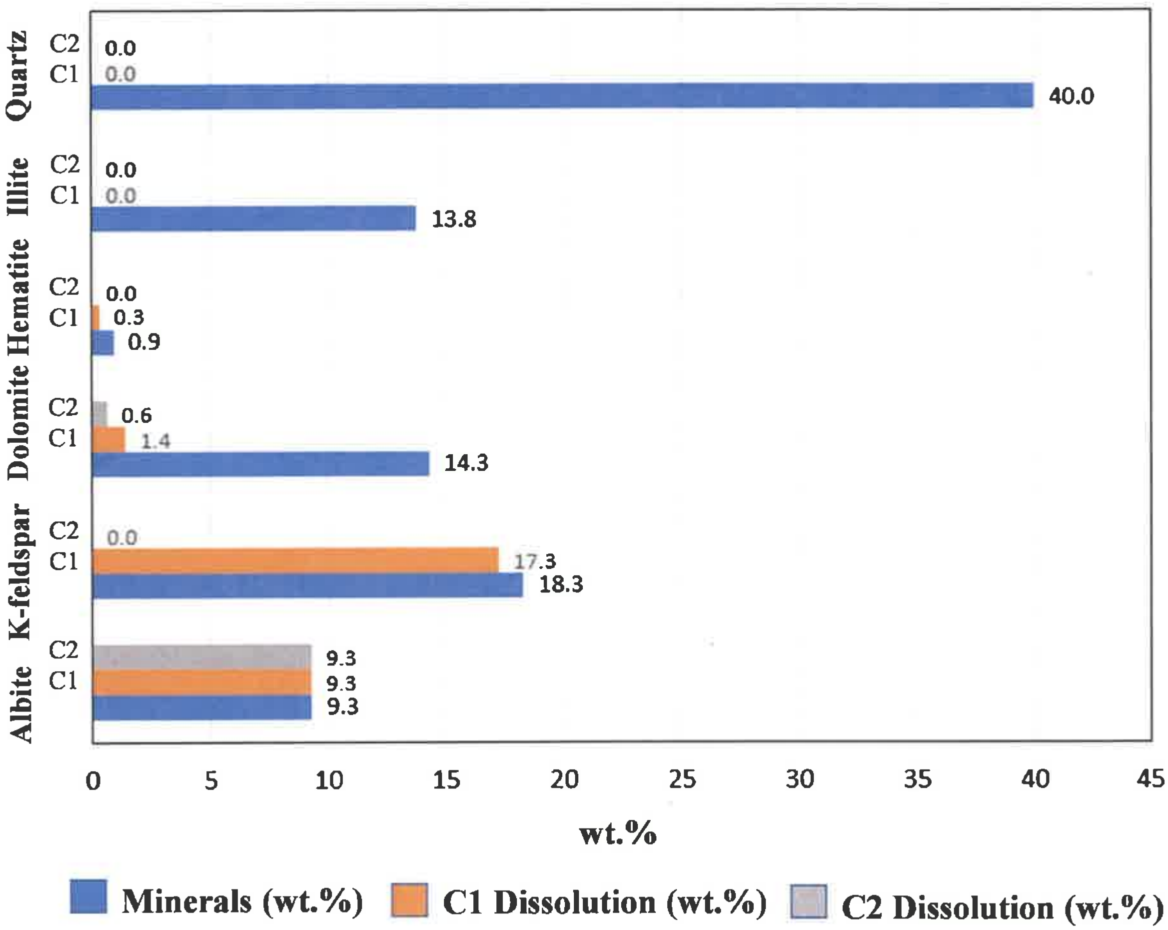

Figure 2-54. Weight percentage (wt.%) of potentially reactive minerals present in the Amsden Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 37 years of simulation time.

Figure 2-55 represents expected minerals to be precipitated in weight (%) shown for Cells C1 and C2 of the model. In Cell 1, illite, quartz, calcite, and pyrite are the minerals to be precipitated. In Cell 2, illite, quartz, calcite, and K-feldspar are the minerals to be precipitated. Pyrite precipitation is a result of the formation fluids reacting with the H_2S present in the CO_2 stream. While pyrite precipitation is also expected to occur if CO_2 encounters the overlying confining zone, the resulting weight (%) is negligible compared to the other minerals formed.

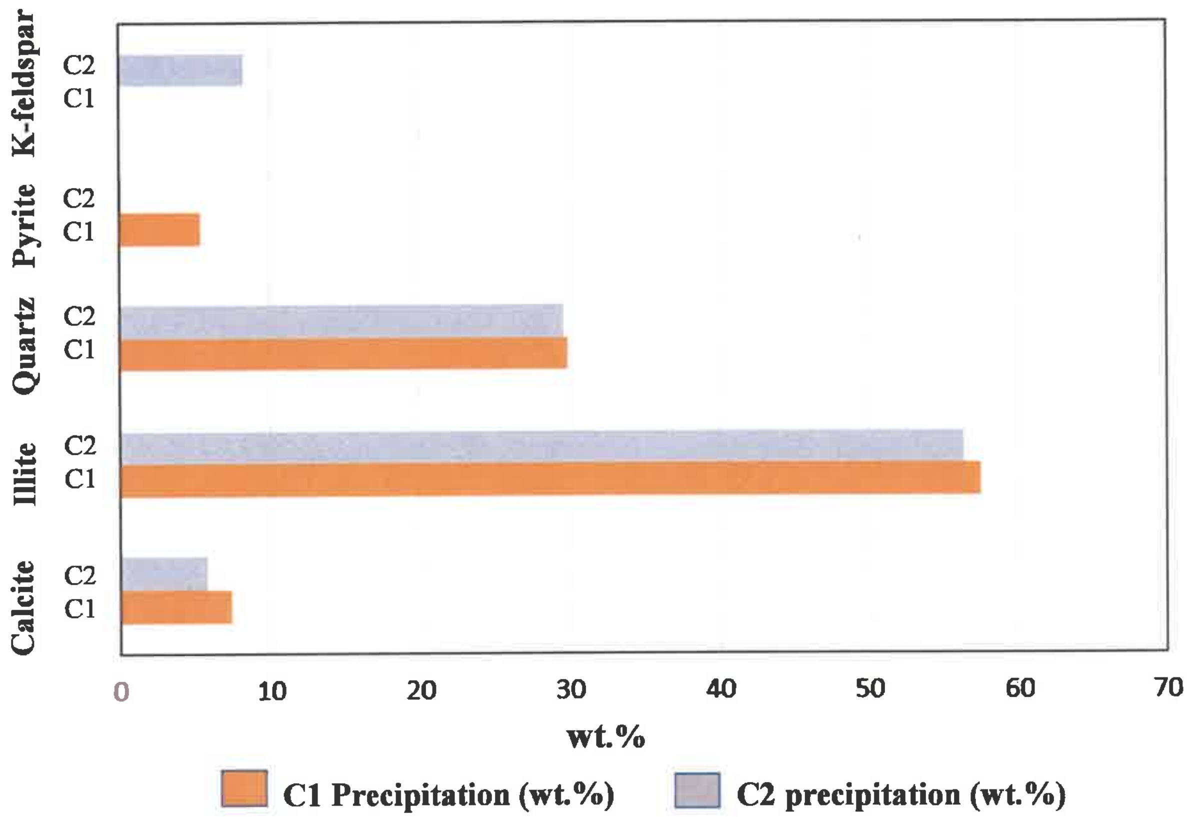

Figure 2-55. Weight percentage (wt.%) of precipitated minerals in the Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 37 years of simulation time.

Change in porosity (% units) of the Amsden underlying confining layer is displayed in Figure 2-56 for Cells C1–C3. The overall net porosity changes from dissolution and precipitation are minimal, less than 0.2% change during the life of the simulation. Cell C1 shows an initial porosity increase of 0.12%, but this change is temporary, and the cell quickly returns to its near initial porosity value of 2.0%. At later times, no significant porosity changes were observed. Cells C4–C6 showed similar results, with net porosity change being less than 0.03%.

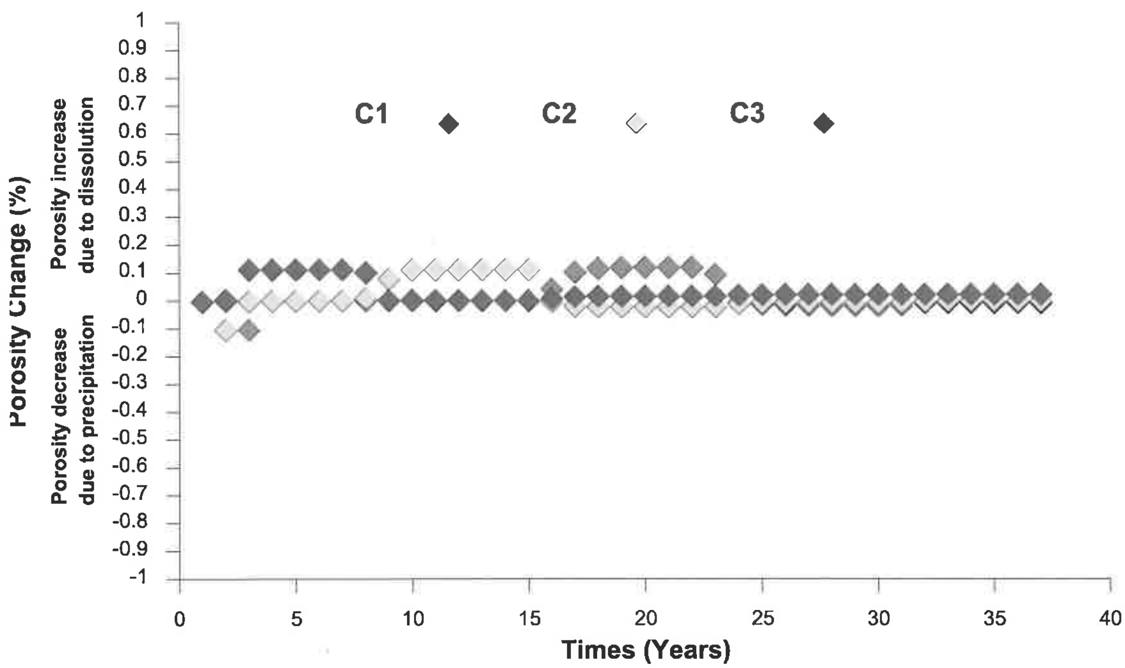

Figure 2-56. Change in percent porosity in the Amsden underlying confining layer red line shows porosity change for Cell C1, 0 to 1 meter below the Amsden Formation top. Yellow line shows Cell C2, 1 to 2 meters below the Amsden top. Green line shows Cell C3, 2 to 3 meters below the Amsden top. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals, and negative change is due to mineral precipitation.

2.4.4 Geomechanical Information of Confining Zones

2.4.4.1 Fracture Analysis

Fractures within the Opeche Formation, the overlying confining zone, and the Amsden Formation, the underlying confining zone, have been assessed during the description of the Coteau 1 well core. Observable fractures were categorized by attributes including morphology, orientation, aperture, and origin. Secondly, natural fractures and in situ stresses were assessed by Schlumberger through the interpretation of the fullbore formation microimager (FMI), bulk density (RHOB), dipole shear sonic (DTS), and dipole compressional sonic (DTC) logs acquired during the drilling of the Coteau 1 well.

2.4.4.2 Fracture Analysis Core Description

Fractures within the Opeche Formation are primarily litho-bound resistive fractures. They are commonly filled with anhydrite. However, some litho-bound conductive fractures are highlighted. The presence of microfaults is underlined mainly in the lower part of the Opeche Formation. The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. The aperture varies from closed to, in rare cases, centimeter-scale.

The Amsden Formation could be considered as a nonfractured interval. However, few litho-bound conductive fractures are commonly coincident with the horizontal compaction features (stylolite) observed.

2.4.4.3 Borehole Image Fracture Analysis (FMI)

Schlumberger's FMI log was chosen to evaluate the geomechanical condition of the formation in the subsurface. This log provides a 360-degree image of the formation of interest and can be oriented to provide an understanding of the general direction of features observed. Figure 2-57 shows examples of the interpreted FMI log for the Coteau 1 well. The examples show the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche FMI borehole image analysis. The far-right track on Figure 2-57 provides information on surface boundaries, slump deformed, and notes the presence of electrically conductive and resistive features. The latter are interpreted as minor anhydrite-filled fractures. Figure 2-58 shows two sections of the interpreted borehole imagery and primary features observed. Figure 2-58 demonstrates that the tool provides information on slump deformation, conductive fractures, and microfaults. These microfaults are identified in Figure 2-58 and are likely clay-filled because of their electrically conductive signal. Figure 2-59 and Figure 2-60 show two thin-section images and give an indication of different minerals within the reservoir with observed changes in the electrical response shown on the FMI log. Also, some drilled-induced fractures are highlighted in the upper part of the Opeche Formation.

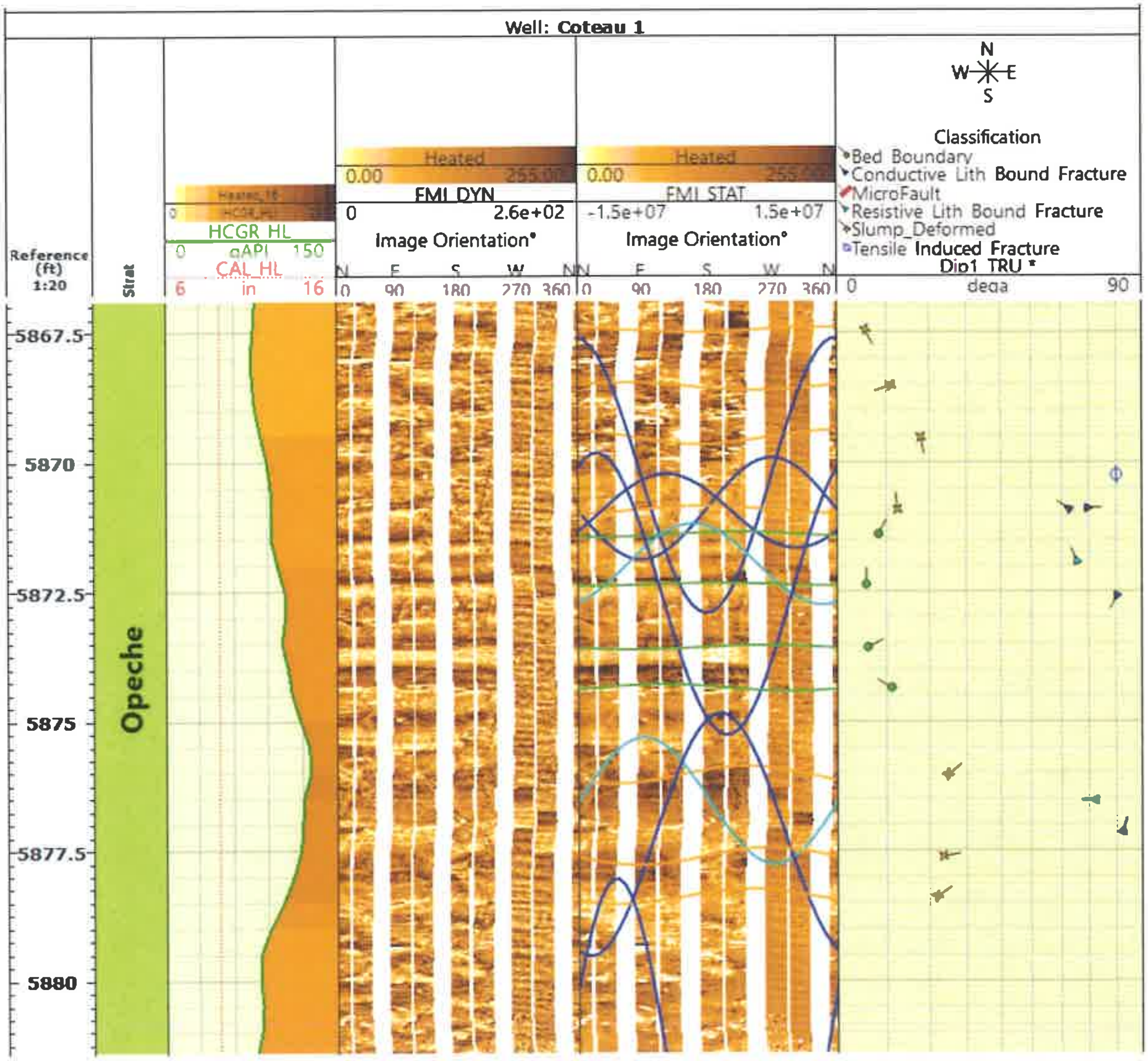

Figure 2-57. Examples of the interpreted FMI log for the Coteau 1 well. The examples show the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche FMI borehole image analysis.

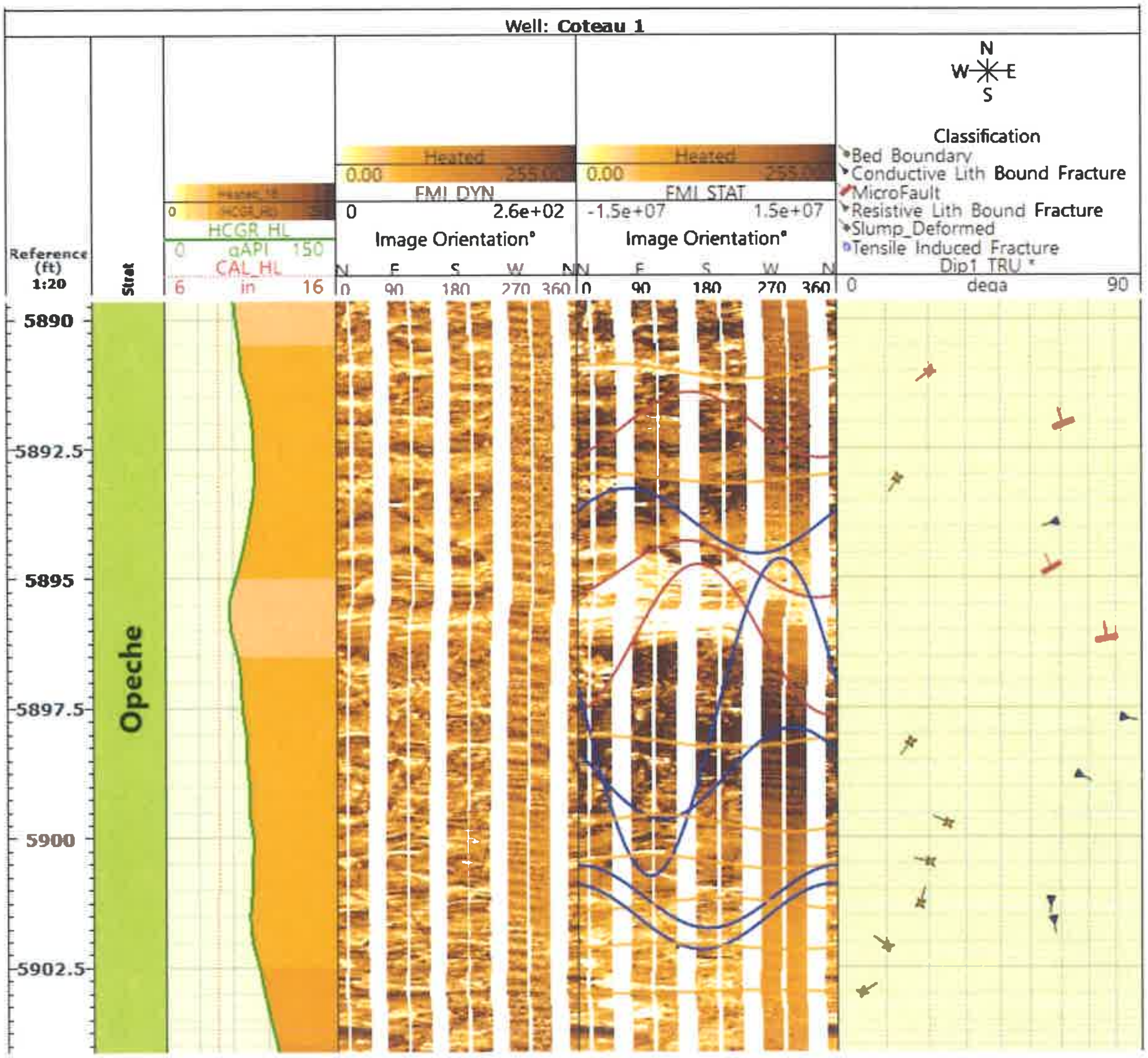

Figure 2-58. Examples of the interpreted FMI log for the Coteau 1 well. The examples show the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche FMI borehole image analysis.

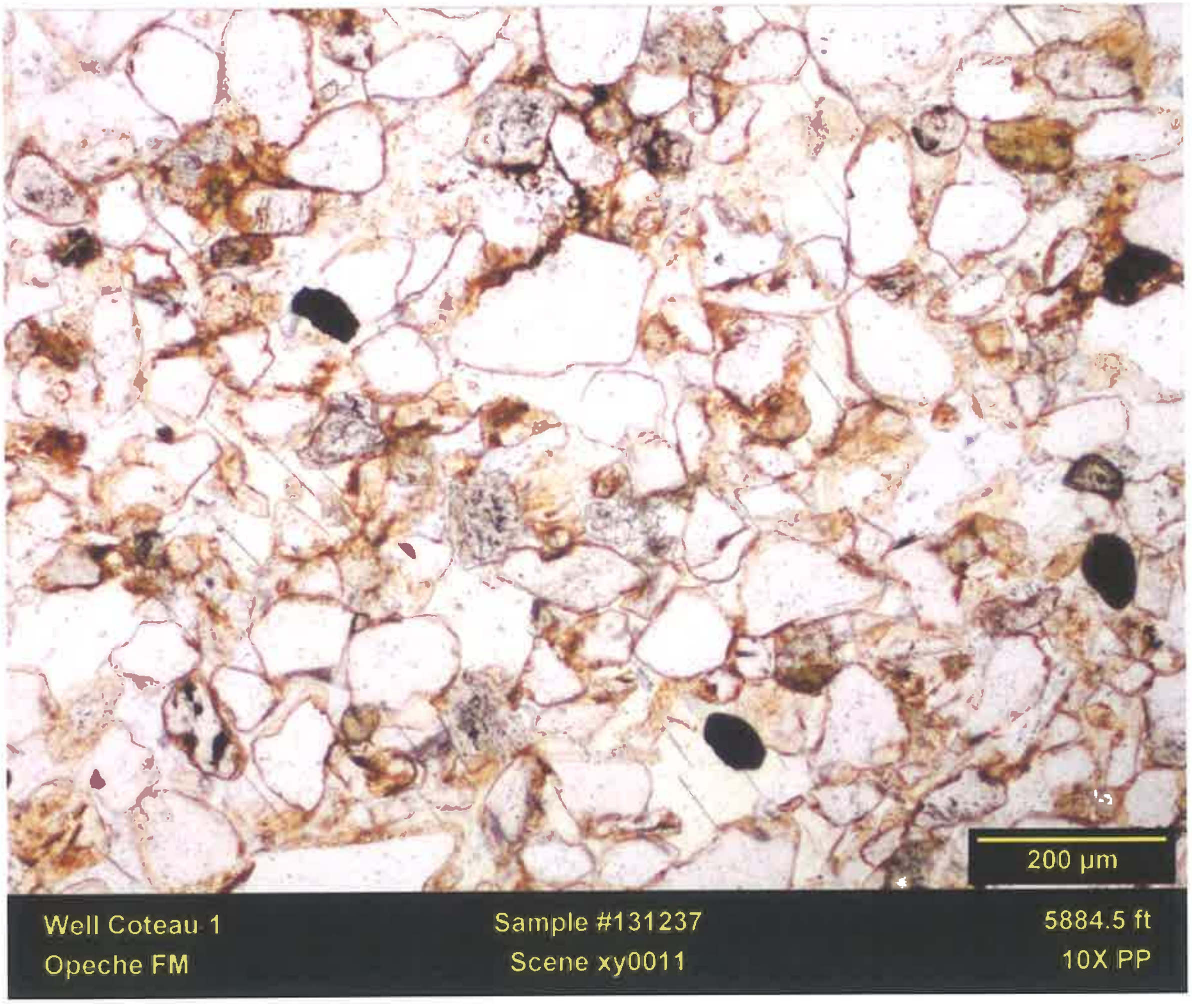

Figure 2-59. Plane-polarized light thin-section images from the Coteau 1 well Opeche Formation. This image shows the silt-rich nature of this interval of the Opeche Formation. On the example shown, the quartz grains (white) and iron oxides are rimmed by anhydrite.

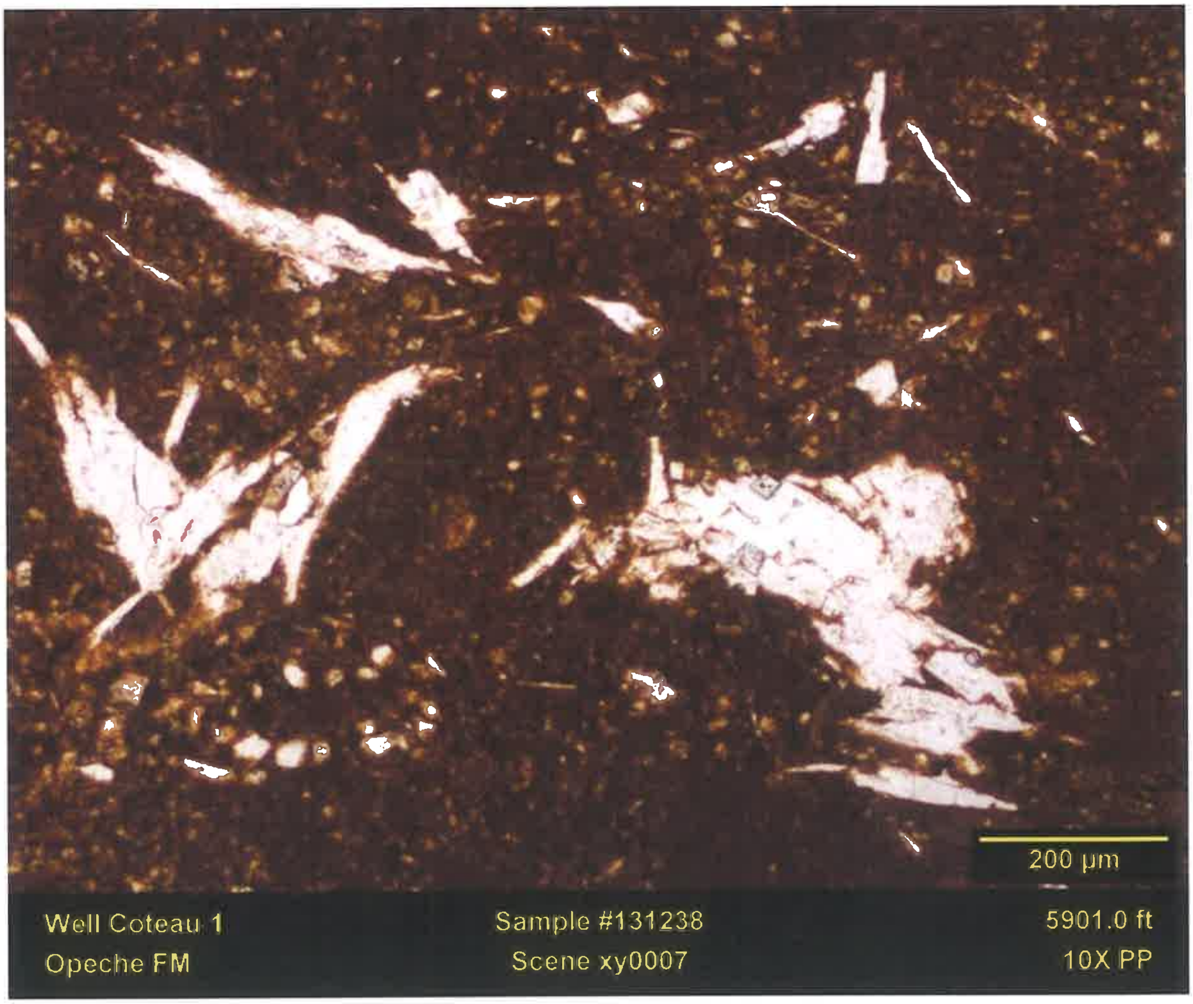

Figure 2-60. Plane-polarized light thin-section images from Coteau 1 well Opeche Formation. This image shows the heterogeneity of this interval. The dark material shown (between the white anhydrite and quartz grains) is clay and is likely responsible for the electrical conductivity identified on the FMI log.

Figure 2-61 shows the logged interval for the lower Opeche Formation at Coteau 1 well. As shown, the section closest to the Broom Creek Formation is dominated by litho-bound fractures and microfaults which are electrically conductive features likely due to the presence of clay. The rose diagrams shown in Figures 2-62 through 2-65 provide the orientation of the conductive, resistive, microfault, and drilling-induced features in the Opeche Formation. The drilling-induced fractures are oriented NE-SW and N-S which give an orientation of N060 and N000 to the maximum horizontal stress (Shmax), respectively.

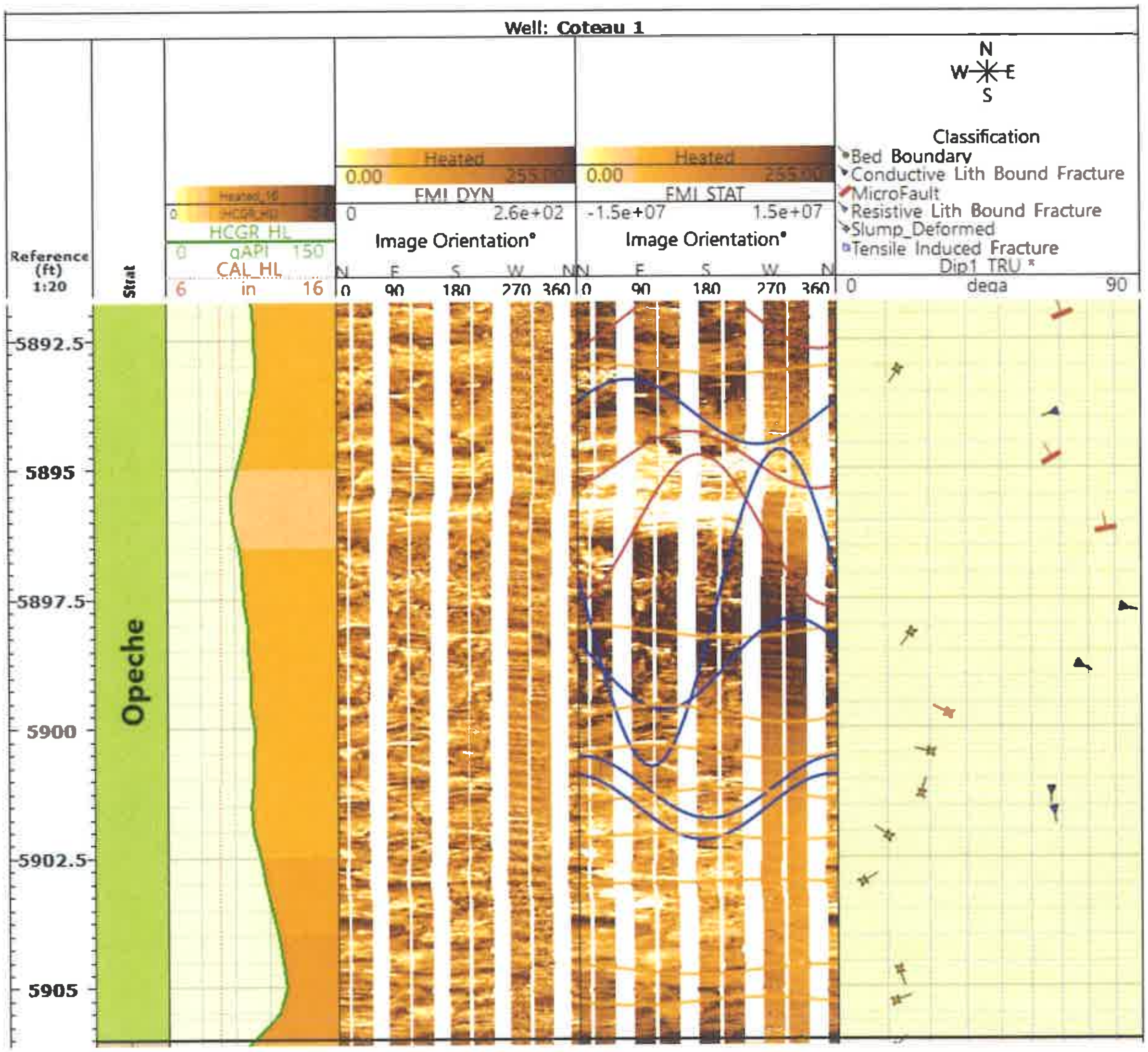

Figure 2-61. Interpreted FMI log through the lower Opeche Formation.

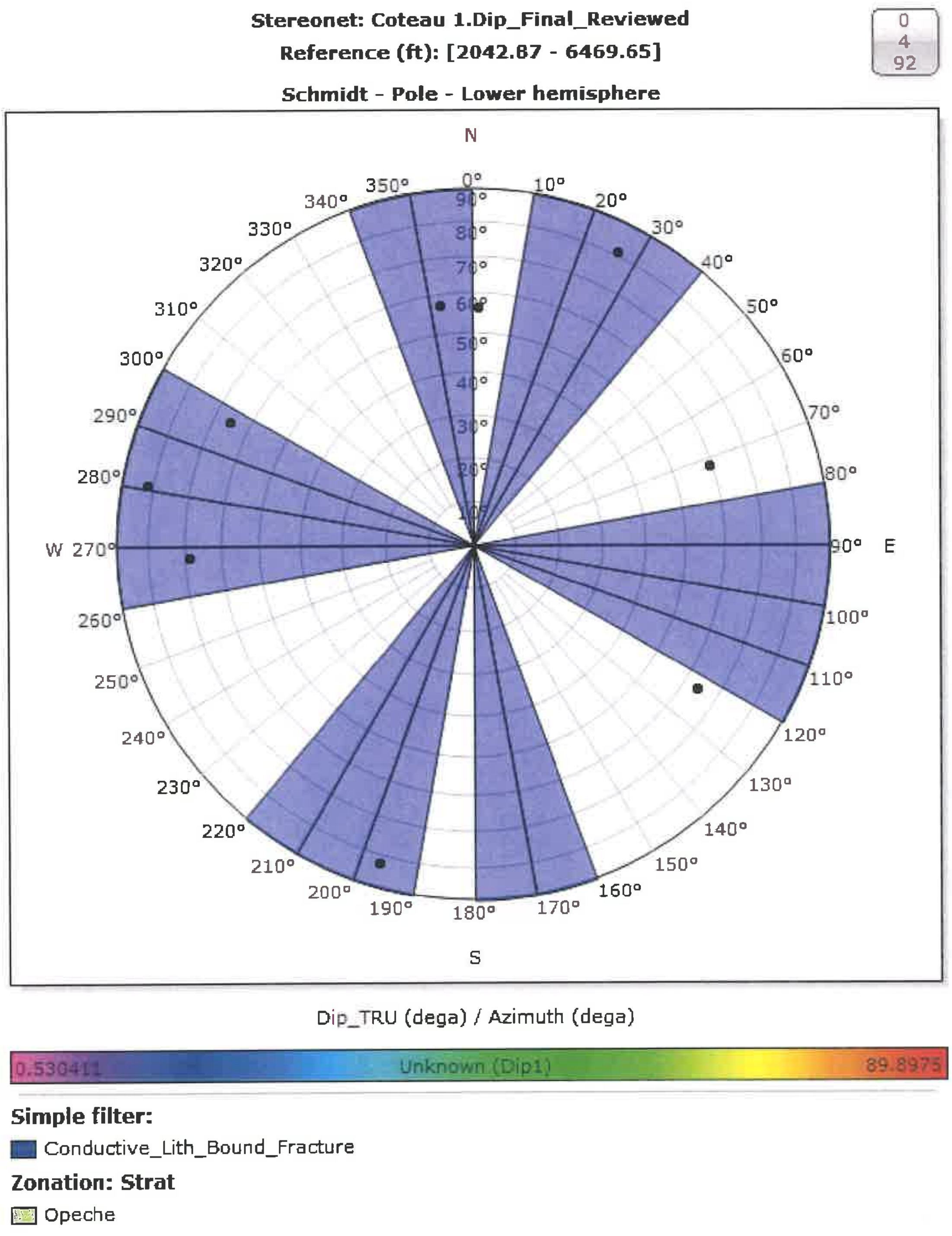

Figure 2-62. Conductive fracture orientation in the Opeche Formation.

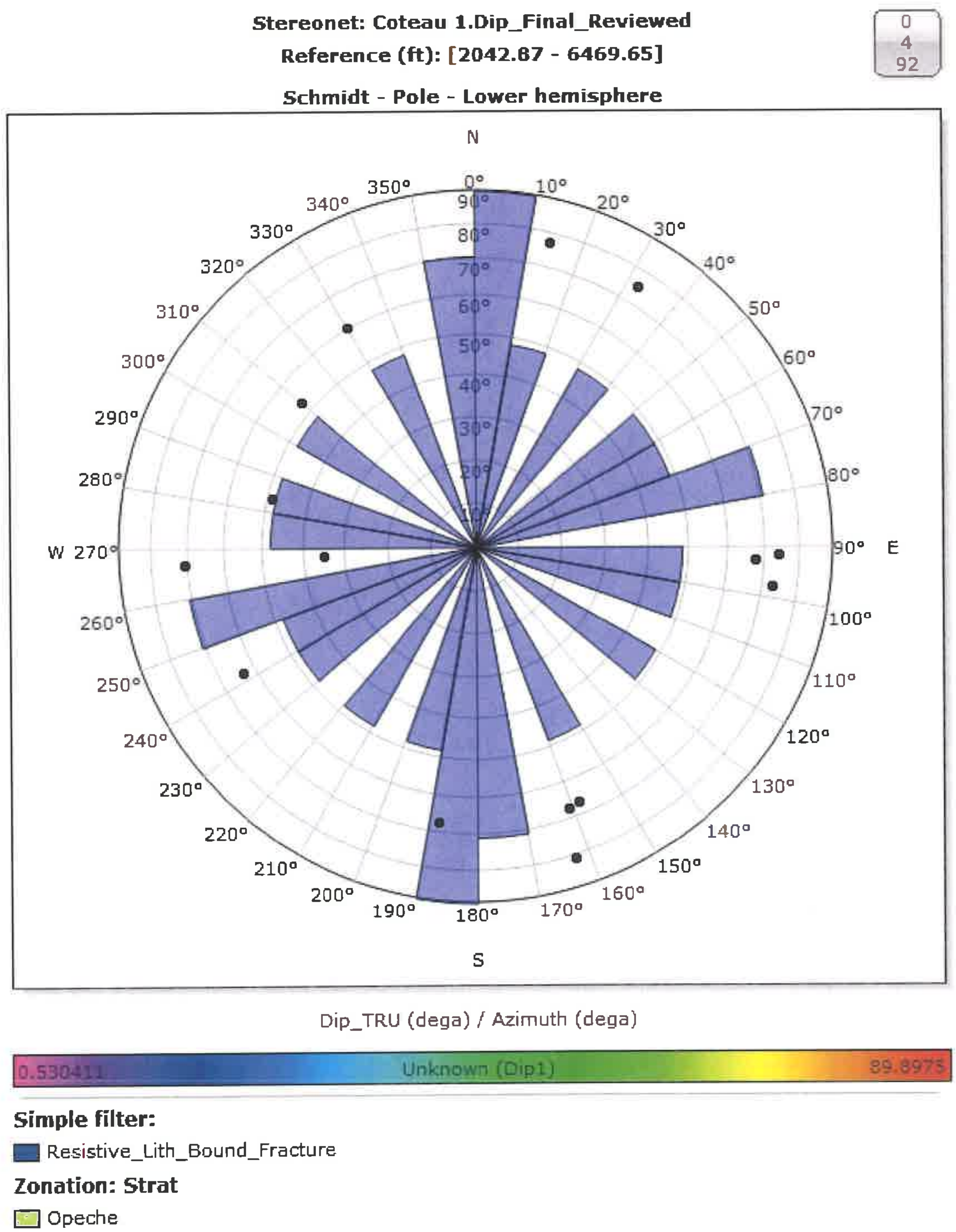

Figure 2-63. Resistive fracture orientation in the Opeche Formation.

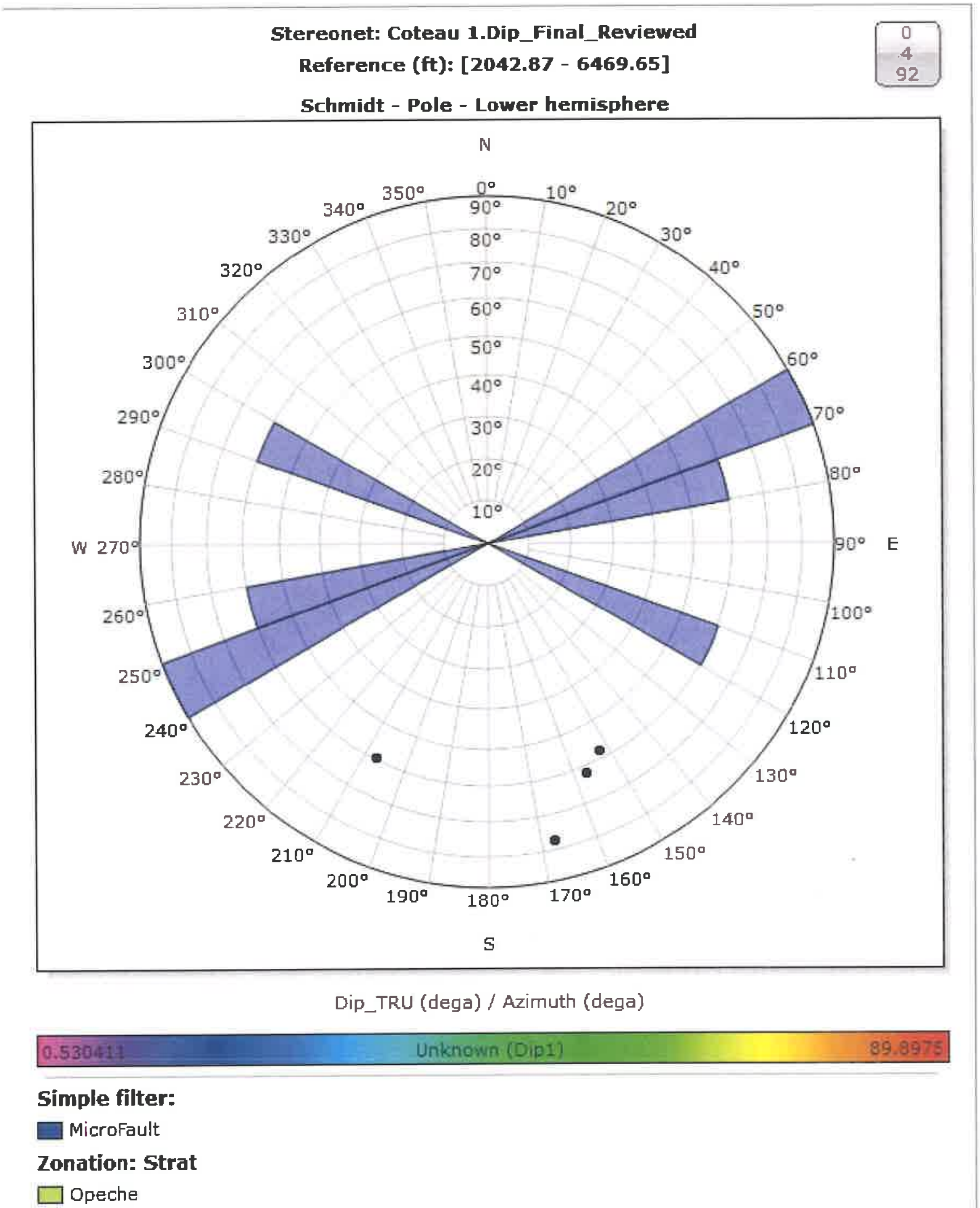

Figure 2-64. Microfault orientation in the Opeche Formation.

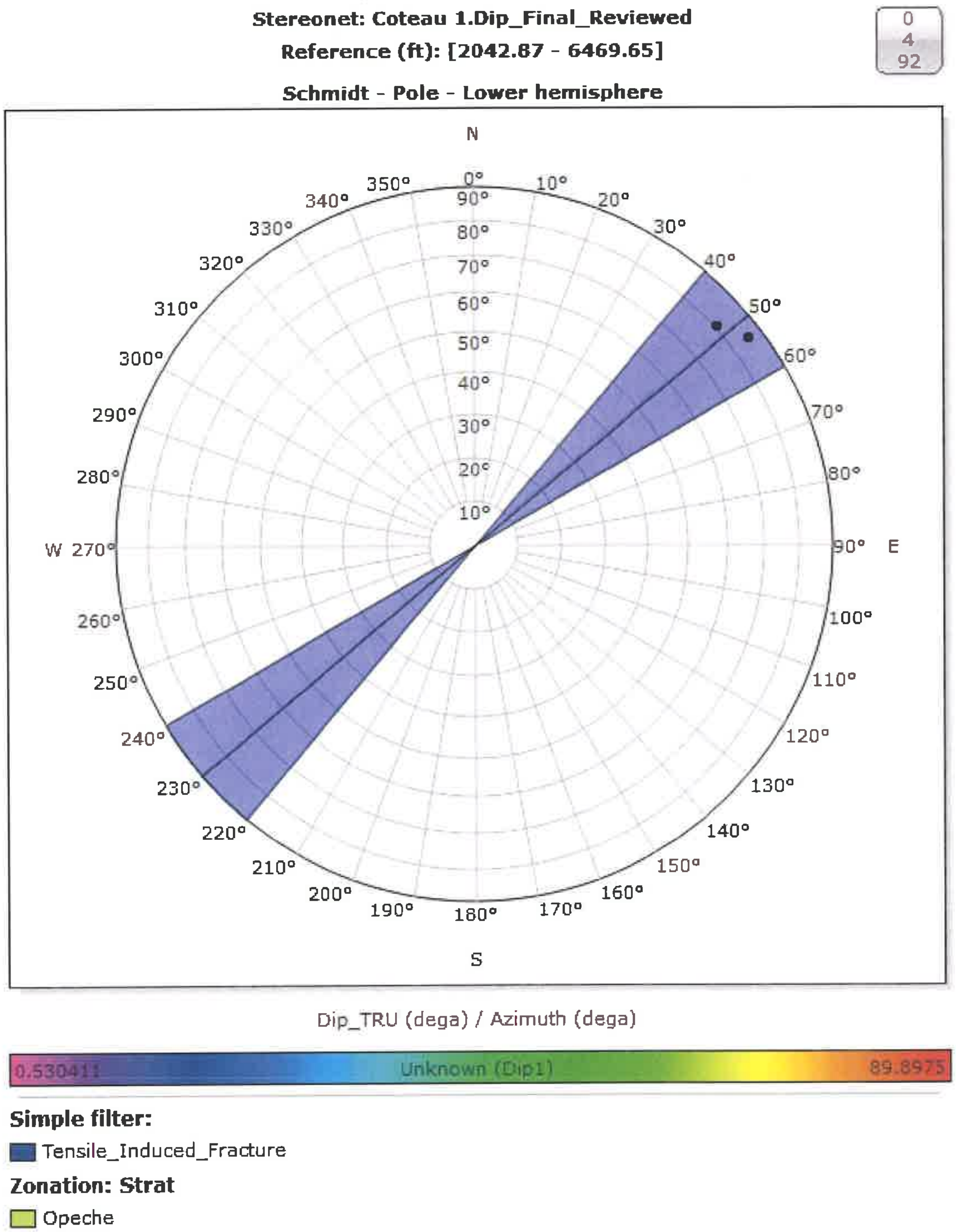

Figure 2-65. Drilling-induced fracture orientation in the Opeche Formation.

The logged interval of the Amsden Formation shows that the main features present are bed boundaries and slump deformation features (Figure 2-66). The depths 6,201.6 and 6,213.7 ft show some evidence of conductive fracture and drilling-induced fractures, respectively (Figure 2-67). The rose diagrams shown in Figures 2-67 and 2-68 provide the orientation of the conductive and drilling-induced fractures in the Amsden Formation. The drilling-induced fractures are oriented NE-SW which gives an orientation of N060 to the maximum horizontal stress (Shmax).

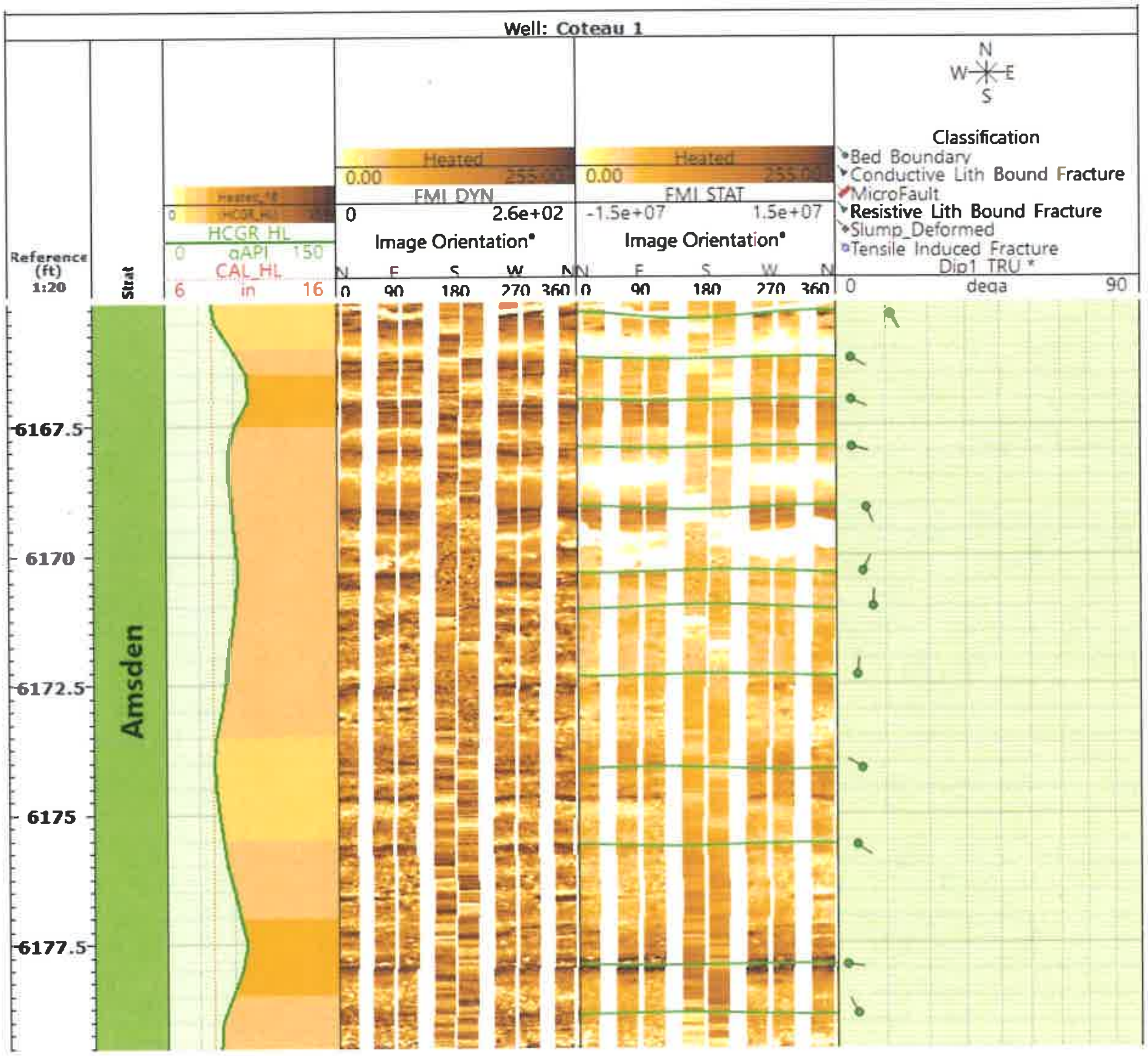

Figure 2-66. Interpreted FMI log through the upper Amsden Formation.

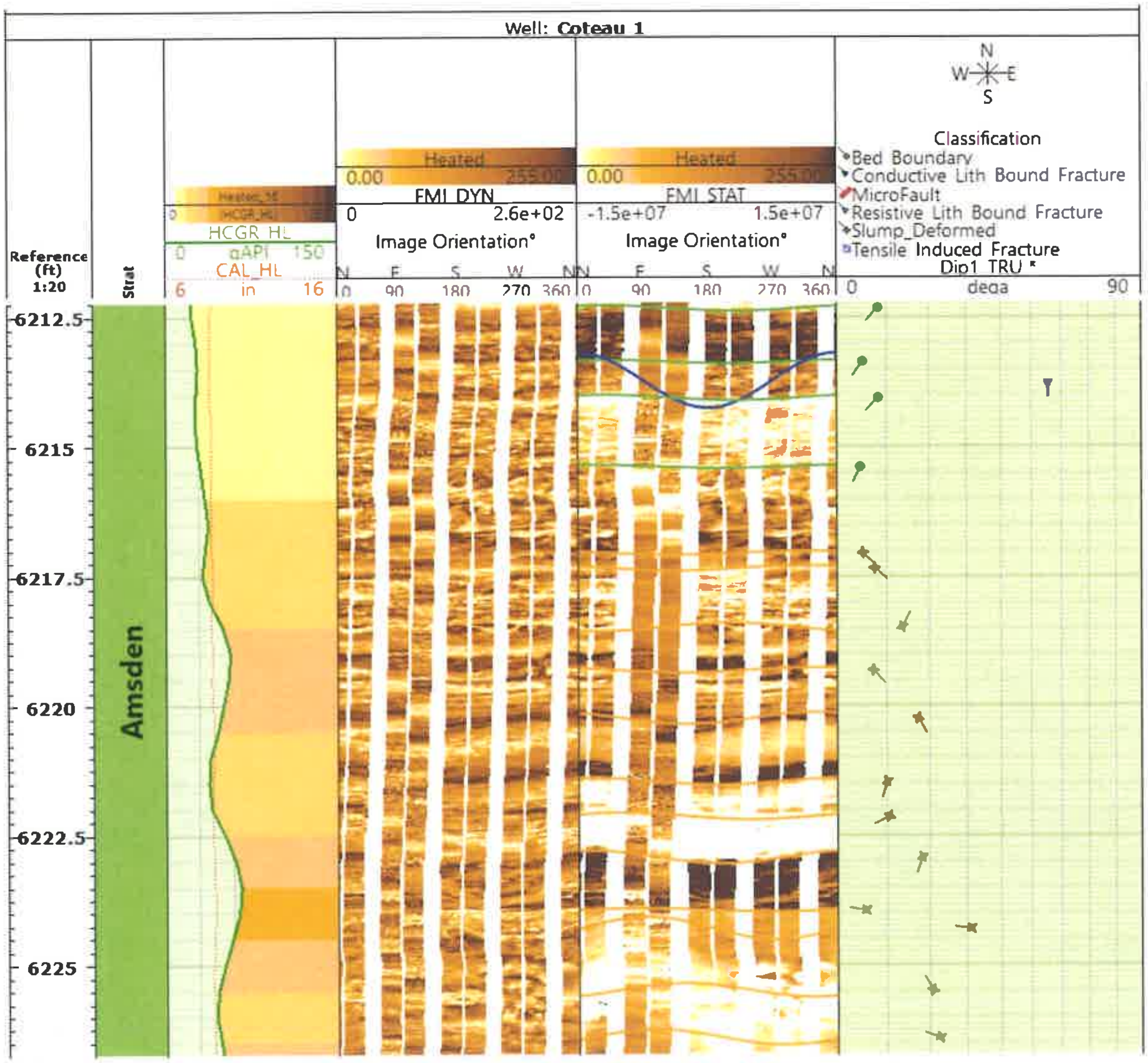

Figure 2-67. Interpreted FMI log through the lower Amsden Formation.

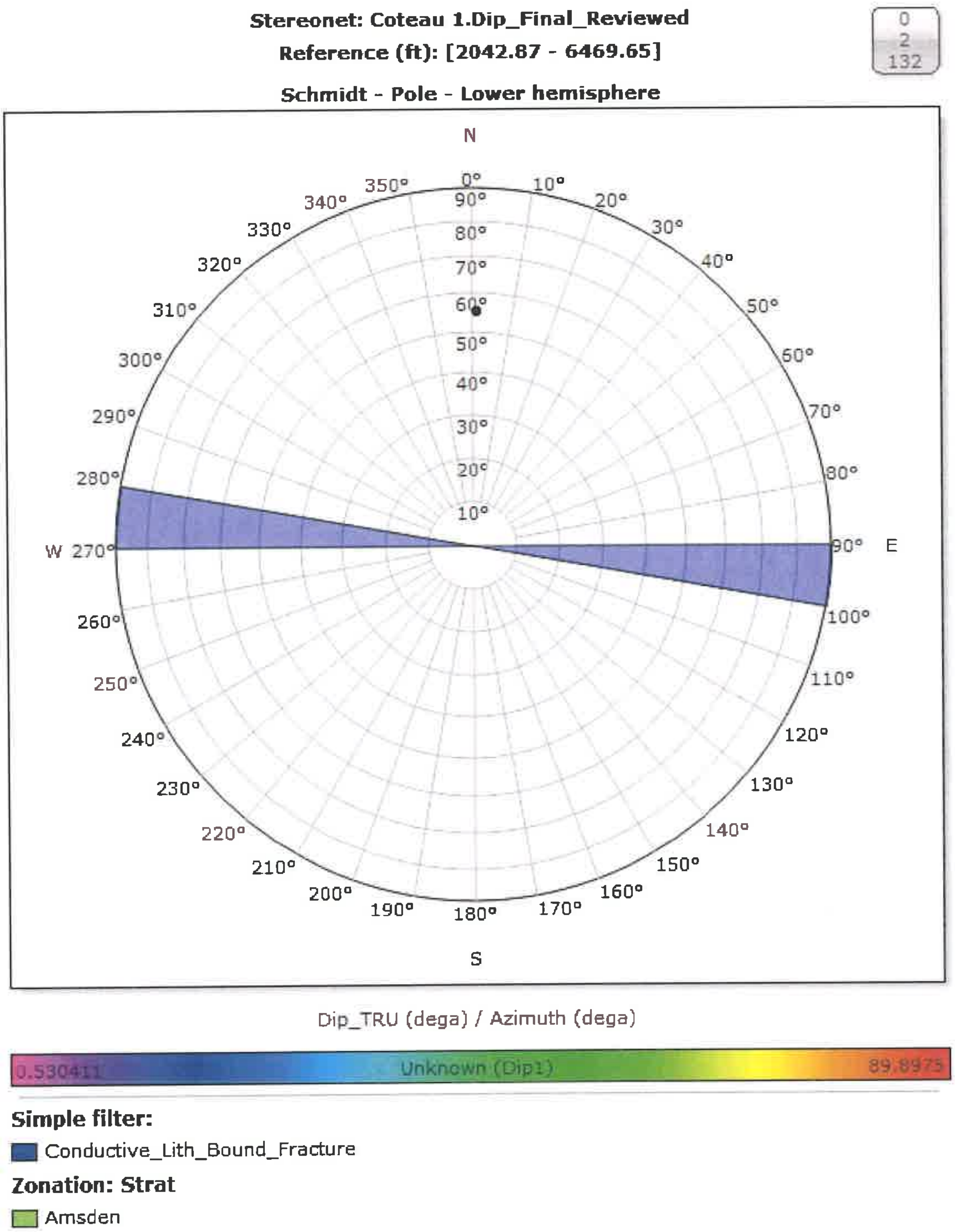

Figure 2-68. Conductive fracture orientation in the Amsden Formation.

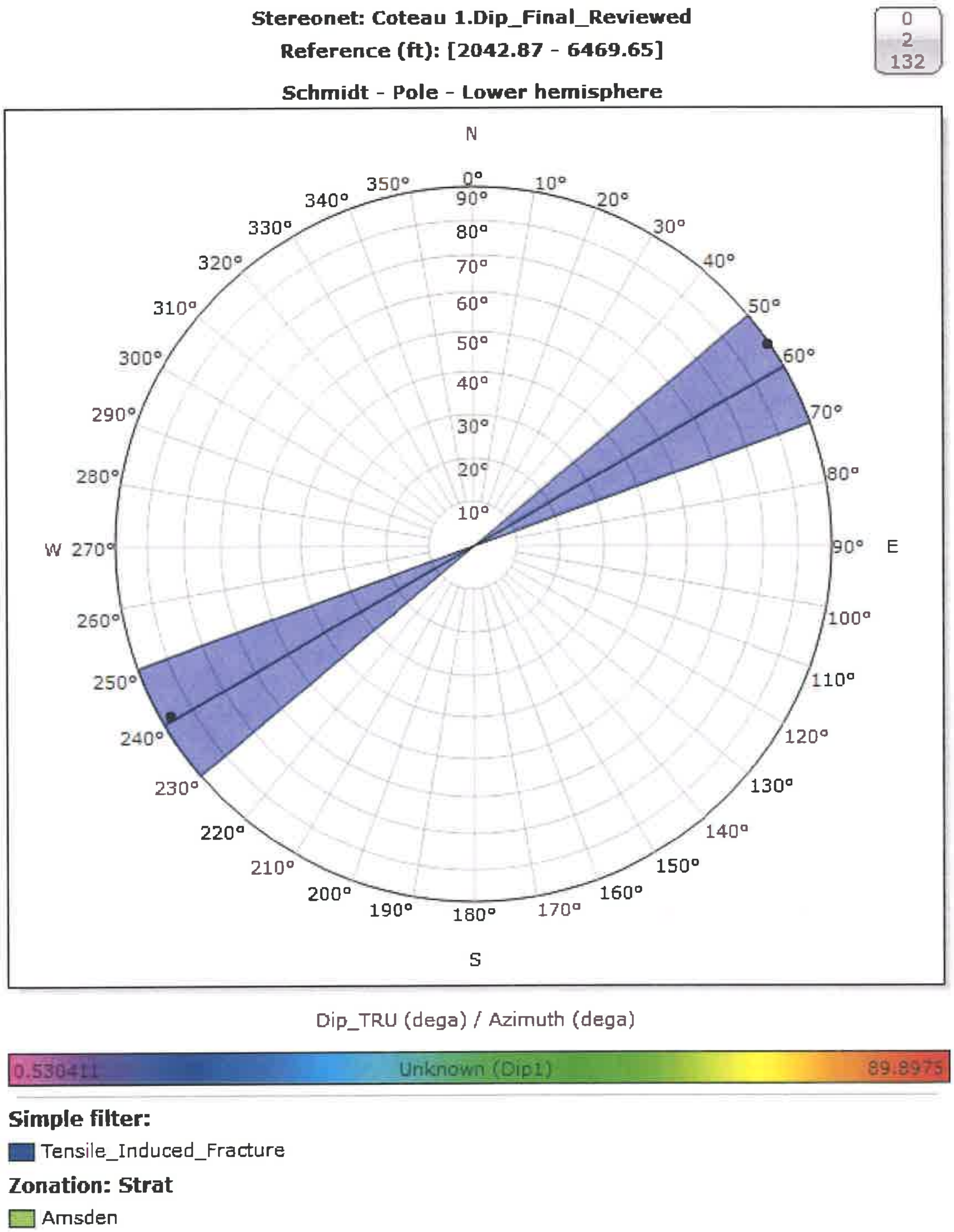

Figure 2-69. Drilling-induced fracture orientation in the Amsden Formation.

2.4.4.4 Stress

The 1D Mechanical Earth Model (MEM) for Opeche, Broom Creek, and Amsden Formations in Coteau 1 well was generated by Core Laboratories (Figures 2-70, 2-71, and 2-72). During construction of the 1D MEM, the effect of pore pressure on sonic transit time, accurate calculation of stress, and rock properties required corrections based on this effect. Dipole sonic logs (DTC, DTS) were corrected for formation pressure impedance and tool radius of investigation. The log corrections allow for a better match to core measurements and more robust geomechanical models.

The output data for the 1D MEM are vertical stress (Sv), pore pressure, pore pressure gradient, dynamic Poisson's ratio, dynamic Young's modulus, Biot factor, fracture closure pressure, fracture closure pressure gradient, fracture propagation pressure, fracture propagation pressure gradient, fracture breakdown pressure, and fracture breakdown pressure gradient. Laboratory-derived core measurements were used from the Coteau 1 well. The static and dynamic parameters from core including DTS, DTC, compressional wave velocity (Vp), shear wave velocity (Vs), dynamic Young's modulus, and dynamic Poisson's ratio were estimated for the Opeche, Broom Creek, and Amsden Formations and used to calibrate the geomechanical rock properties model.

The isotropic (dynamic) properties from well logs (Young's modulus and dynamic Poisson's ratio) were calculated based on the corrected DTC and DTS well logs and calibrated with core measurements. Pore pressure, pore pressure gradient, fracture closure pressure, fracture closure pressure gradient, fracture propagation pressure, fracture propagation fracture gradient, fracture breakdown pressure, and fracture breakdown pressure gradient were also estimated. Pore pressure was calibrated using the pressure and temperature data from the Coteau 1 well.

Triaxial tests were performed on 15 vertical samples: three in Opeche, nine in Broom Creek, and three in Amsden (Table 2-19 and 2-20). Static Young's modulus, Poisson's ratio, and compressive strength were measured at the confining pressure of 1,180 psi. Also, acoustic velocities (Vp, Vs) and dynamic moduli (Bulk modulus, Young's modulus, shear modulus, Poisson's ratio) were estimated under a confining pressure of 1,180 psi The triaxial outputs were calibrated with the estimated parameters using well logs. Figures 2-70–2-72 show the outputs of the 1D MEM for the Opeche, Broom Creek, and Amsden Formations.

In situ stresses such as vertical stress (Sv), maximum horizontal stress (Shmax), and minimum horizontal stress (Shmin) were calculated. The vertical stress is calculated using the density log (RHOB) and assumes 1 psi/ft above 1,500 ft where the RHOB data were not available. The minimum horizontal stress is estimated from a modified Eaton calculation method (Section 2.3). Shmax is estimated from Shmin and process zone stress as a function of porosity. Based on the calculated stresses, the stress regime of the Opeche, Broom Creek, and Amsden Formations is considered a normal stress regime where Sv > Shmax > Shmin.

Table 2-19. Triaxial Testing Results Showing the Calculated Static Young's Modulus, Poisson's Ratio, and Compressive Strength. The confining zone pressure was set at 1,180 psi for testing. The pore pressure used for calculations was assumed to be 0 psi.

Formation	Lithology	Depth (ft)	Sample Length (in.)	Sample Diameter (in.)	Length to Depth Ratio	Bulk Density (g/cm^3)	Compressive Strength (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio
Opeche	Silty-shale	5,872.80	2.0955	0.9725	2.15	2.47	15,954	1.67	0.17
	Silty-shale with anhydrite	5,884.75	2.0626	0.9870	2.09	2.57	20,329	3.25	0.18
	Shale with anhydrite	5,901.60	2.0358	0.9954	2.05	2.46	13,214	1.60	0.13
Broom Creek	Anhydrite	5,908.30	2.0566	0.9849	2.09	2.81	30,484	6.46	0.24
	Anhydritic-dolostone	5,920.40	2.1121	0.9898	2.13	2.47	19,474	4.52	0.31
	Sandy-dolostone	5,924.80	2.0576	0.9888	2.08	2.42	22,191	3.32	0.30
	Dolo-sandstone	5,928.70	2.0793	0.9875	2.11	2.51	25,379	3.91	0.34
	Sandstone	5,941.10	1.5251	0.9815	1.55	1.82	6,592	0.56	0.17
	Sandstone	5,989.60	1.7216	0.9953	1.73	1.76	7,678	0.76	0.23
	Anhydritic-sandstone	6,146.30	1.8015	0.9908	1.82	2.58	18,510	3.39	0.36
	Sandy-dolomite	6,160.10	2.1366	0.9881	2.16	2.49	24,511	3.75	0.33
Amsden	Dolostone	6,169.60	2.1593	0.9908	2.18	2.66	26,307	3.55	0.22
	Dolostone	6,183.20	2.1751	0.9903	2.20	2.55	17,558	2.49	0.17
	Anhydritic-sandstone	6,190.00	1.8448	0.9880	1.87	2.64	23,906	3.03	0.53

Table 2-20. Triaxial Testing Results Showing the Measured Acoustic Velocities and Calculated Dynamic Bulk Modulus, Young's Modulus, Poisson's Ratio, and Compressive Strength. The confining zone pressure was set at 1,180 psi for testing.

Formation	Lithology	Depth (ft)	Axial Stress (psi)	Bulk Density (g/cm³)	Acoustic Velocity: Compressional ft/sec	Acoustic Velocity: Compressional µs/ft	Acoustic Velocity: Shear ft/sec	Acoustic Velocity: Shear µs/ft	Dynamic Elastic Parameters: Bulk Modulus (×10⁶ psi)	Dynamic Elastic Parameters: Young's Modulus (×10⁶ psi)	Dynamic Elastic Parameters: Shear Modulus (×10⁶ psi)	Dynamic Elastic Parameters: Poisson's Ratio
Opeche	Shale silty-shale	5,872.80	3,000	2.47	15,413	64.9	7,450	134.2	5.45	4.99	1.85	0.35
	Silty-shale with anhydrite	5,884.75	100	2.57	14,170	70.6	8,897	112.4	3.30	6.44	2.74	0.17
	Shale with anhydrite	5,901.60	6,000	2.46	14,688	68.1	7,861	127.2	4.42	5.32	2.05	0.30
Broom Creek	Anhydrite	5,908.30	3,000	2.81	23,737	42.1	10,909	91.7	15.32	12.31	4.50	0.37
	Anhydritic-dolostone	5,920.40	3,000	2.47	19,888	50.3	10,366	96.5	8.39	9.39	3.57	0.31
	Sandy-dolostone	5,924.80	100	2.42	16,315	61.3	9,537	104.9	4.73	7.37	2.97	0.24
	Dolo-sandstone	5,928.70	2,000	2.51	17,993	55.6	9,896	101.1	6.54	8.50	3.31	0.28
	Sandstone	5,941.10	2,000	1.82	12,174	82.1	5,324	187.8	2.71	1.92	0.70	0.38
	Sandstone	5,951.75	2,000	1.86	13,339	75.0	6,413	155.9	3.09	2.79	1.03	0.35
	Sandstone	5,989.60	2,000	1.76	11,808	84.7	5,921	168.9	2.20	2.22	0.83	0.33
	Anhydritic-sandstone	6,146.30	3,000	2.57	19,027	52.56	9,623	103.91	8.28	8.54	3.21	0.33
	Sandy-dolomite	6,160.10	6,000	2.49	19,652	50.88	10,745	93.06	7.79	9.97	3.87	0.29
Amsden	Dolostone	6,169.60	3,000	2.66	18,842	53.07	10,622	94.14	7.34	10.26	4.05	0.27
	Dolostone	6,183.20	3,000	2.55	15,400	64.93	9,036	110.67	4.41	6.95	2.81	0.24
	Anhydritic-sandstone	6,190.00	8,000	2.64	20,663	48.40	10,942	91.39	9.52	11.12	4.26	0.31

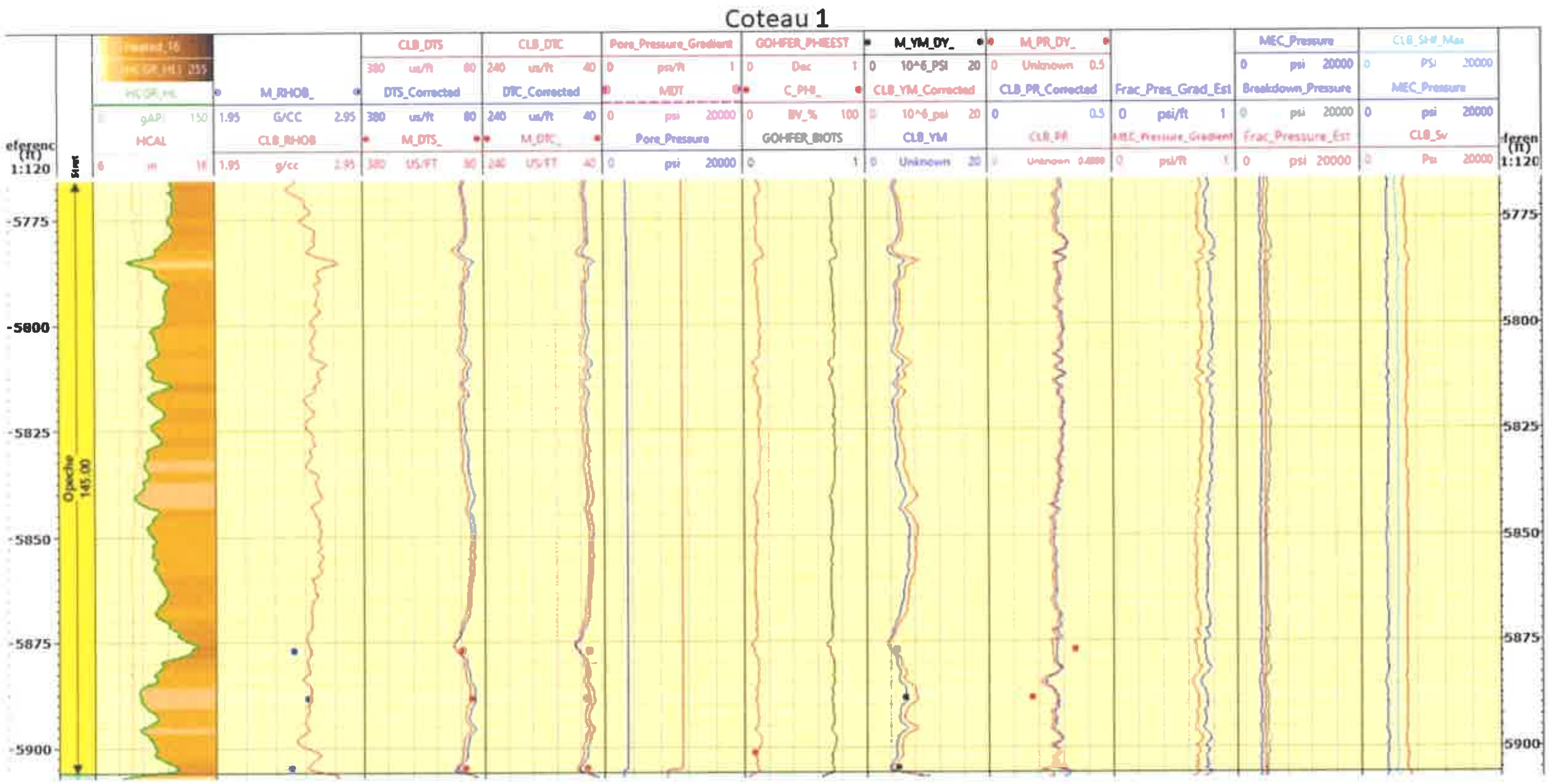

Figure 2-70. Calibrated geomechanical rock properties model in Opeche Formation.

Coteau 1

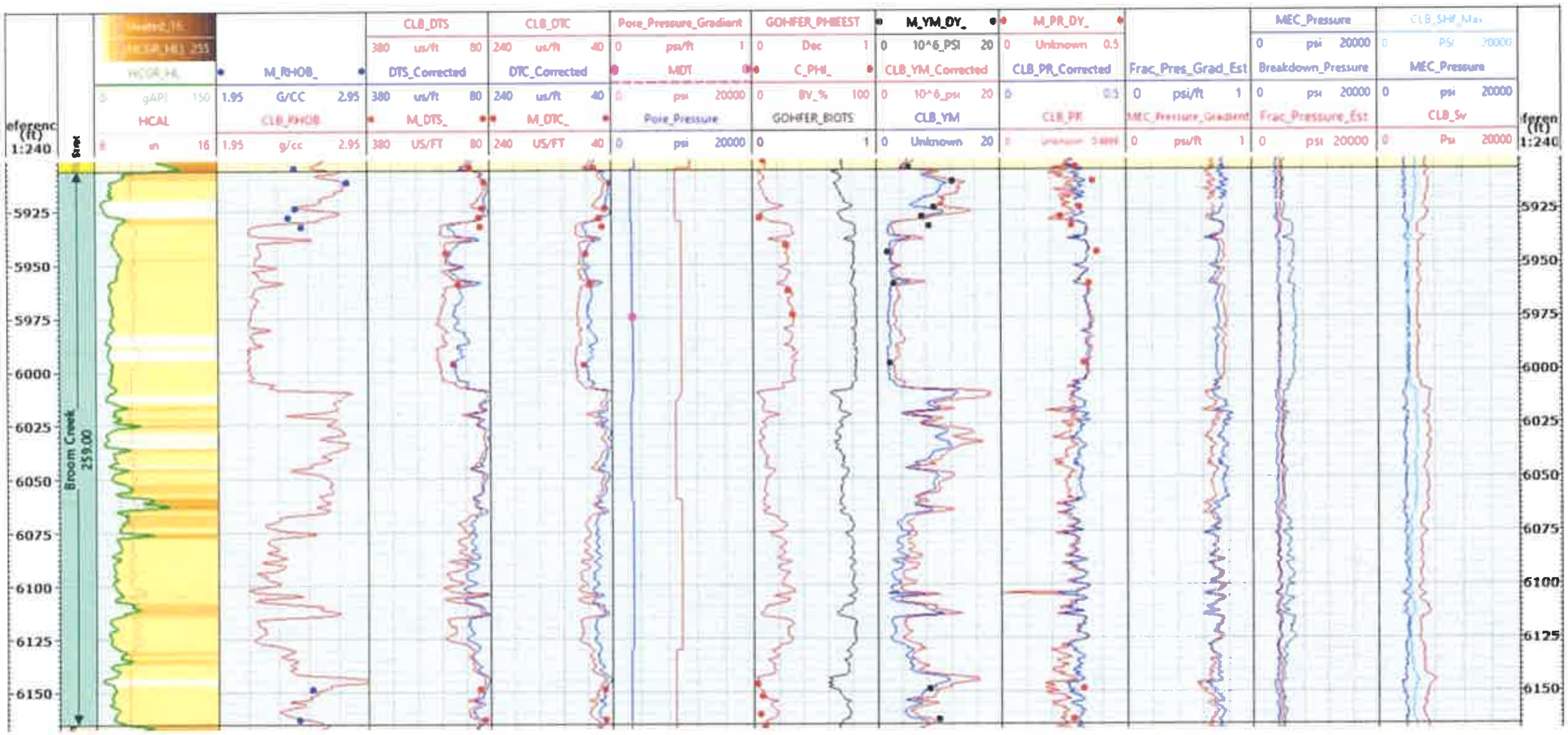

Figure 2-71. Calibrated geomechanical rock properties model in Broom Creek Formation.

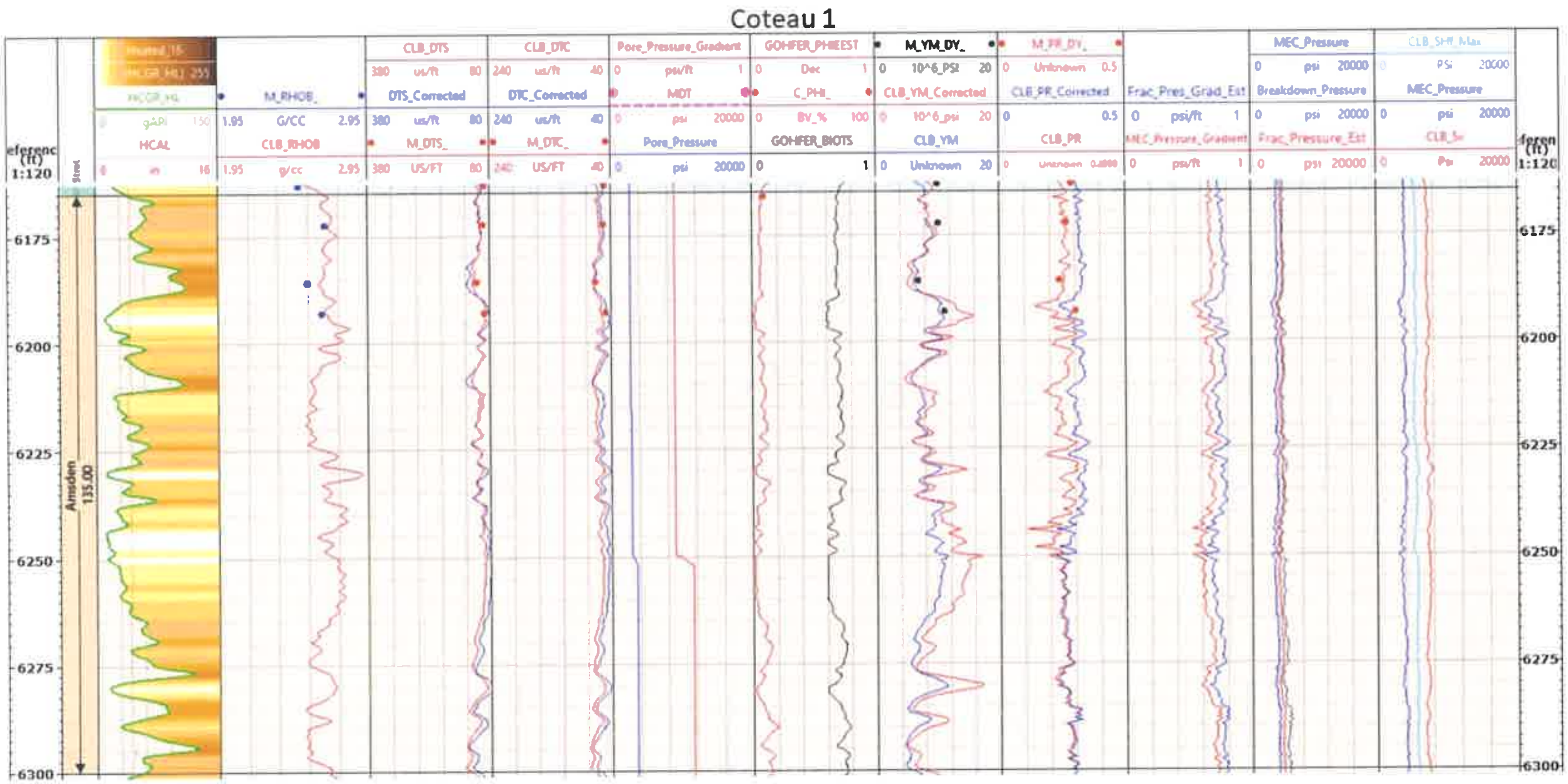

Figure 2-72. Calibrated geomechanical rock properties model in Amsden Formation.

2.5 Faults, Fractures, and Seismic Activity

In the Great Plains CO_2 Sequestration Project area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. The absence of transmissive faults is supported by fluid sample analysis results from Coteau 1 that suggest the injection interval, Broom Creek Formation (42,800 mg/L) is isolated from the next permeable interval, the Inyan Kara Formation (22,800 mg/L).

The Williston Basin is a tectonically stable region of the North American Craton. Zhou and others (2008) summarize that "the Williston Basin as a whole is in an overburden compressive stress regime," which could be attributed to the general stability of the North American Craton. Interpreted structural features associated with tectonic activity in the Williston Basin in North Dakota include anticlinal and synclinal structures in the western half of the state, lineaments associated with Precambrian basement block boundaries, and faults (North Dakota Industrial Commission, 2019).

Between 1870 and 2015, 13 earthquakes were detected within the North Dakota portion of the Williston Basin (Table 2-21) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-73). The seismic event recorded closest to the Great Plains CO_2 Sequestration Project storage facility area occurred 29.6 mi from the Coteau 1 well near Fort Berthold in southwestern North Dakota (Table 2-21). The magnitude of this seismic event is estimated to have been 1.9.

Table 2-21. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, miles	Longitude	Latitude	City or Vicinity of Earthquake	Map Label	Distance to the Coteau 1 Well, miles
Sept. 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	A	86.7
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	138.2
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	107.5
Aug. 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	29.6
Jan. 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	117.8
Nov. 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	85
Nov. 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	128.6
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	127.3
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	76.6
May 13, 1947	3.7**	U	−100.90	46.00	Selfridge	J	106.8
Oct. 26, 1946	3.7**	U	−103.70	48.20	Williston	K	102.6
April 29, 1927	3.2**	U	−102.10	46.90	Hebron	L	36.8
Aug. 8, 1915	3.7**	U	−103.60	48.20	Williston	M	98.5

* Estimated depth.

** Magnitude estimated from reported modified Mercalli intensity (MMI) value.

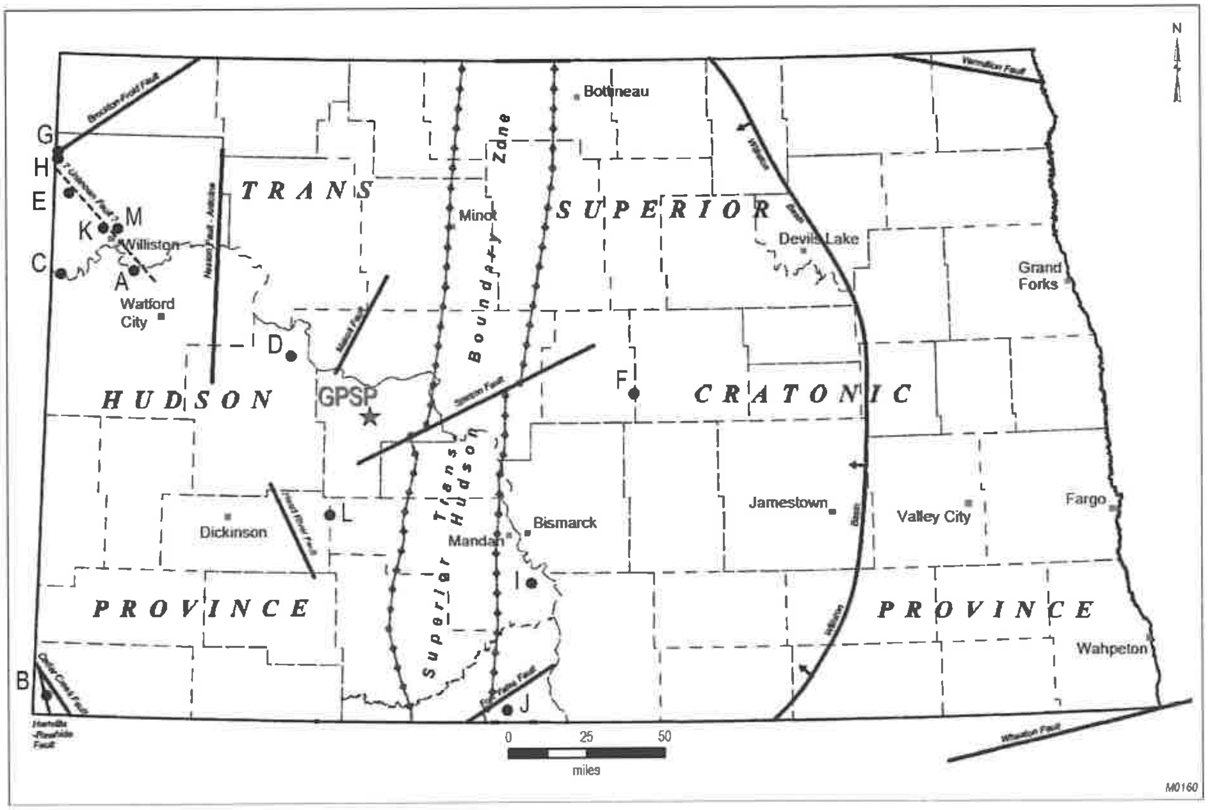

Figure 2-73. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-21.

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging earthquake events occurring in North Dakota, with less than two damaging earthquake events predicted to occur over a 10,000-year time period (Figure 2-74) (U.S. Geological Survey, 2019). A 1-year seismic forecast (including both induced and natural seismic events) released by 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 that could be associated with nearby 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 containment is low.

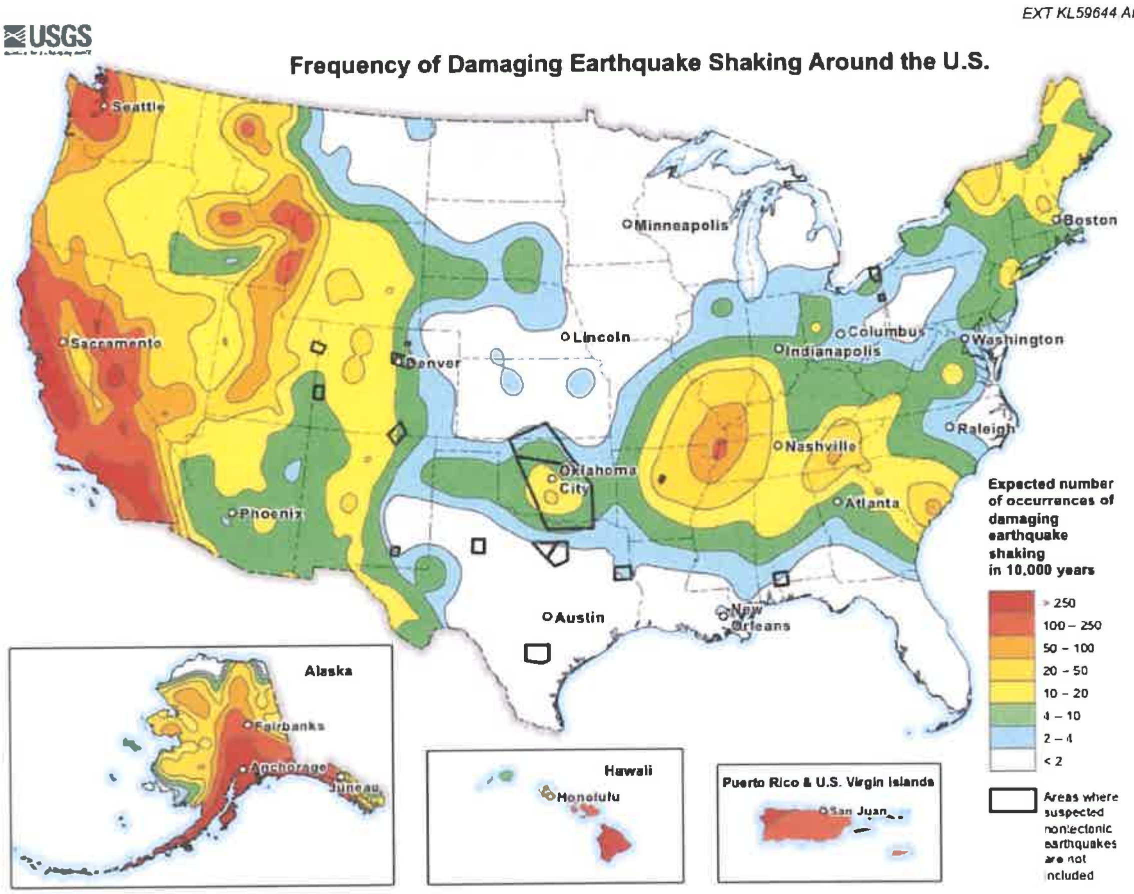

Figure 2-74. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

2.6 Potential Mineral Zones

There are no known producible accumulations of hydrocarbons in the storage facility area. The North Dakota Geological Survey recognizes the Spearfish Formation as the only potential oil-bearing formation above the Broom Creek Formation. However, production from the Spearfish Formation is limited to the northern tier of counties in western North Dakota (Figure 2-75). There has been no exploration for, nor development of, a hydrocarbon resource from the Spearfish Formation in the Great Plains CO_2 Sequestration Project area.

There has been no historic hydrocarbon exploration in, or production from, formations below the Broom Creek Formation in the storage facility area. The Herrmann 1 well (NDIC File No. 4177), the closest hydrocarbon exploration well to the storage facility area, located 4.1 miles from the Coteau 1 well, was drilled in 1966 to explore potential hydrocarbons in the Madison Group. The well was dry and did not suggest the presence of hydrocarbons. The closest

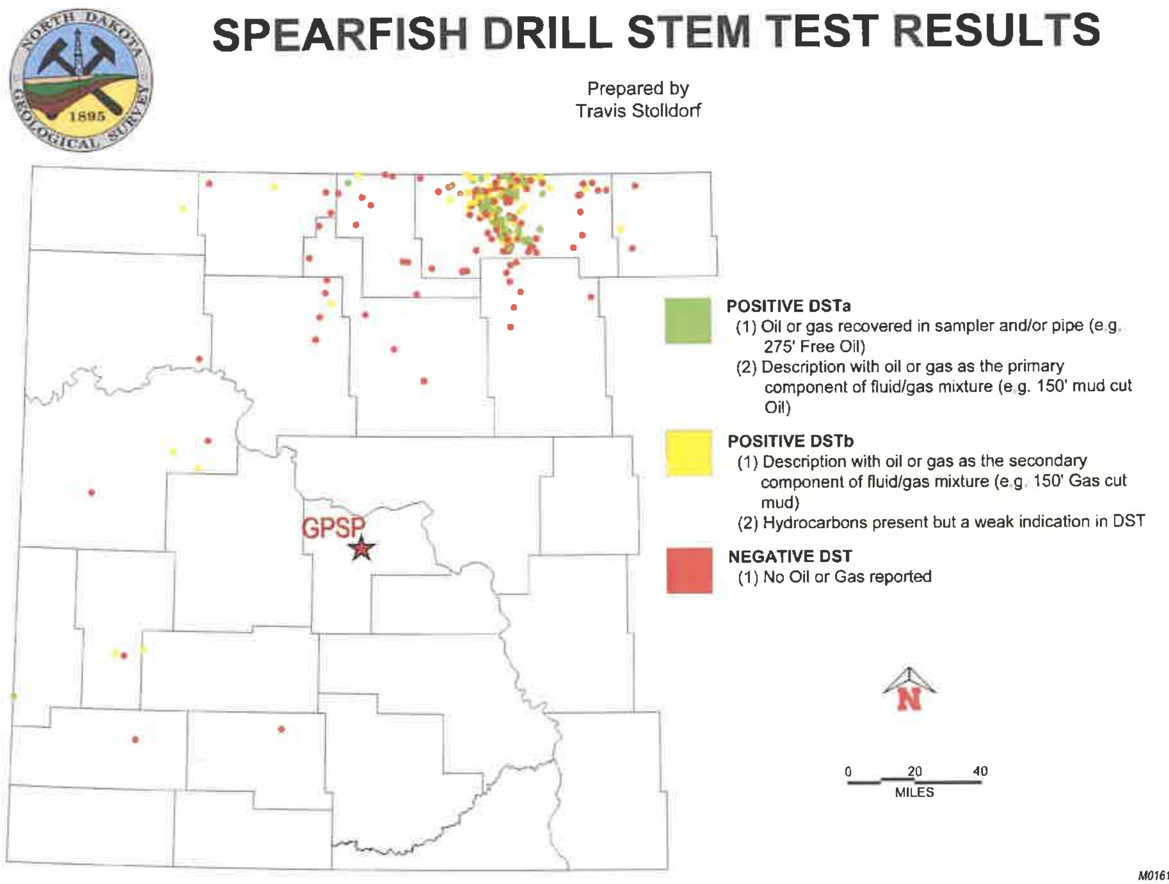

Figure 2-75. Drillstem test results indicating the presence of oil in the Spearfish Formation (modified from Stolldorf, 2020).

hydrocarbon producing well is Traxel 1-31H (NDIC File No. 17877), located 10.8 miles west from the Coteau 1 well (NDIC 38379). The Traxel 1-31H well was drilled in August 2009, producing a cumulative total of 12,021 bbl until December 2013. The well's current status is producer now abandoned (PNA) as of November 2014. Published studies suggest there are no economic deposits of hydrocarbons in the Bakken Formation in the storage facility area (Bergin, 2012; Theloy, 2016).

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a 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 (Figure 3-20). Pressure increases will relax postinjection as the area returns to its preinjection 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 placed across the storage reservoir, with CO_2-resistant cement used to anchor the casing in place.

Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations (NDCC 57-51-01) define shallow gas resources as "gas produced from a zone that consists of strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1,524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation (Jurassic), from which gas may be produced."

Lignite reserves in the Sentinel Butte Formation of the Fort Union Group (the Beulah of the Beulah-Zap interval and Twin Butte coal beds) are mined to be used as feedstock for the GPSP coal gasification process and power generation feedstock at Basin Electric Power Cooperative's Antelope Valley Station, located about 0.5 miles north of DGC's GPSP. The lignite is obtained from the Freedom Mine, which is operated by Coteau Properties Company, a wholly owned subsidiary of North American Coal Corporation.

The thickness of the Beulah–Zap averages between 18 to 22 feet in thickness (Figure 2-76). Above the Beulah horizon are several thin beds of lignite. In ascending order, these are the Schoolhouse and Twin Butte beds. Overburden on top of the Beulah ranges from 95 to 145 feet (Figure 2-77). The Twin Butte has an average thickness of about 6 feet under 25–30 feet of overburden where it is actively mined (Zygarlicke and others, 2019). The Beulah, Twin Butte, and other coal seams thicken and deepen to the west. The Beulah–Zap and Twin Butte seams pinch out to the east. The underlying Hagel coal seam is mined farther to the east at the BNI Coal Mine near Center, North Dakota, and the Falkirk Mine near Falkirk, North Dakota.

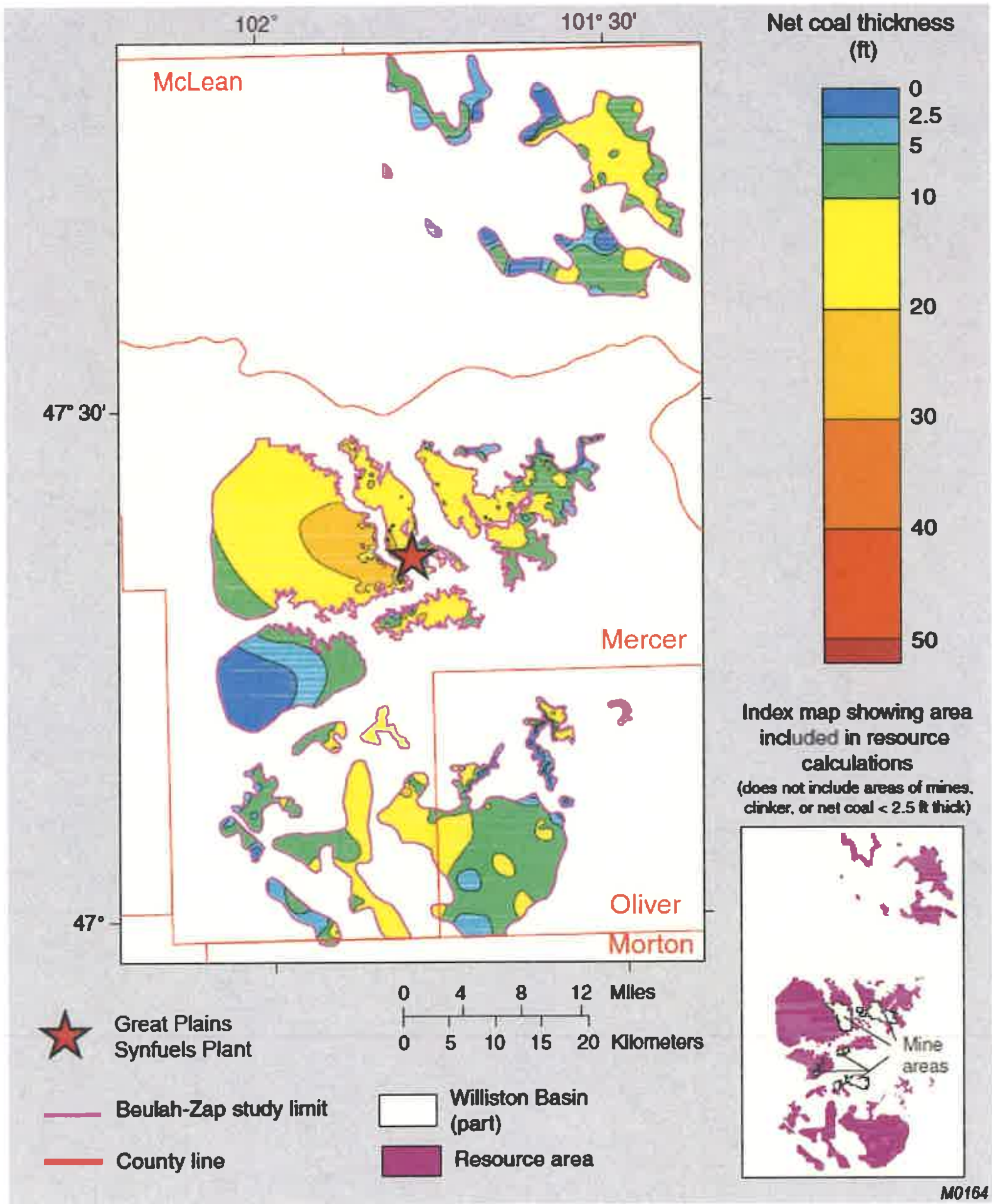

Figure 2-76. Beulah net coal isopach map (modified from Ellis and others, 1999).

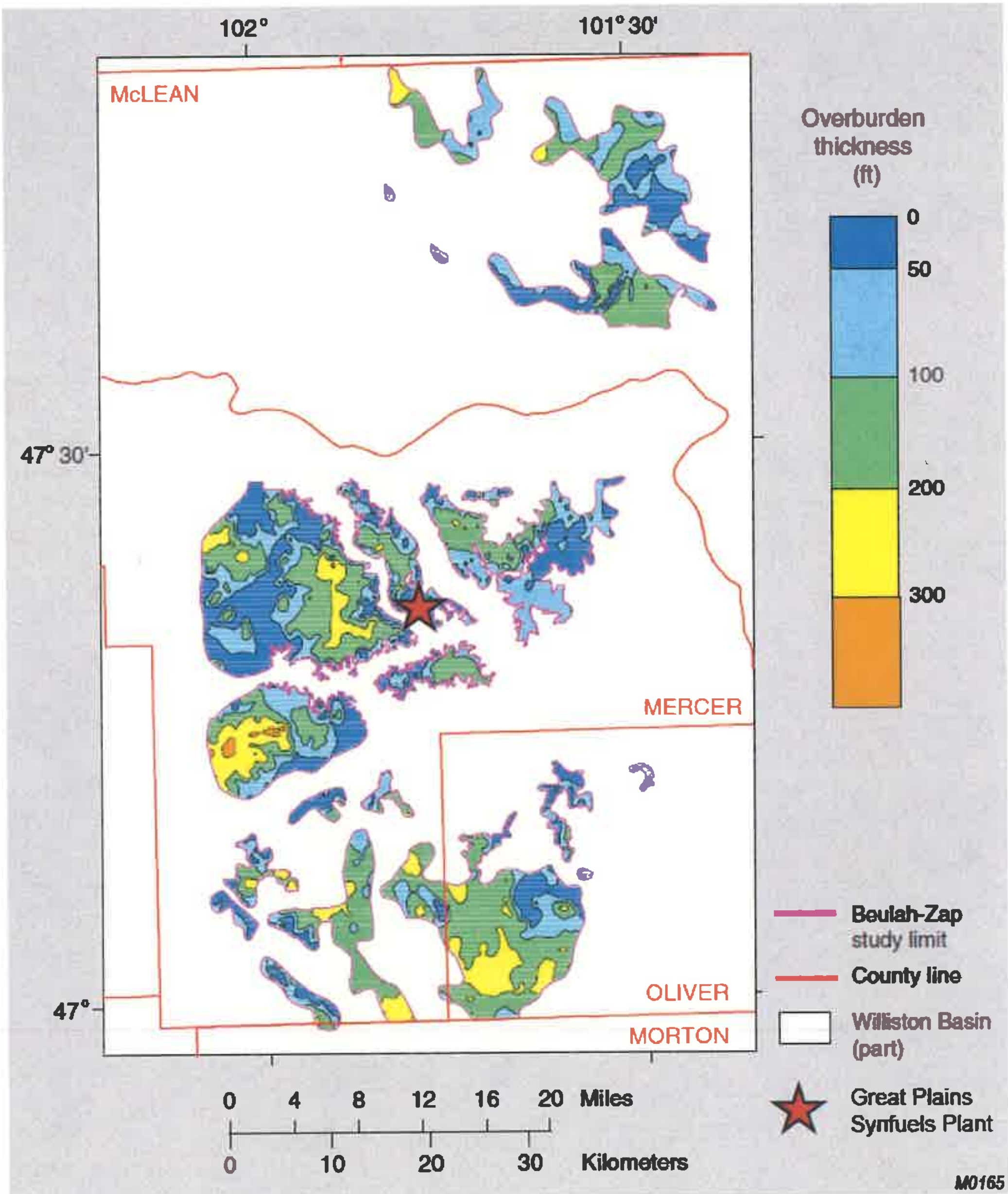

Figure 2-77. Beulah overburden isopach map (modified from Ellis and others, 1999).

The planned infrastructure for the Great Plains CO_2 Sequestration Project, the transmission line and injection well sites, will not impact mining of the lignite coal in the storage facility permit area. Injection well locations and the transmission line will be located in areas that have already been mined and since reclaimed or areas where no future mining is planned because of existing infrastructure such as powerlines, roadways, and other buried utilities (Figure 2-78).

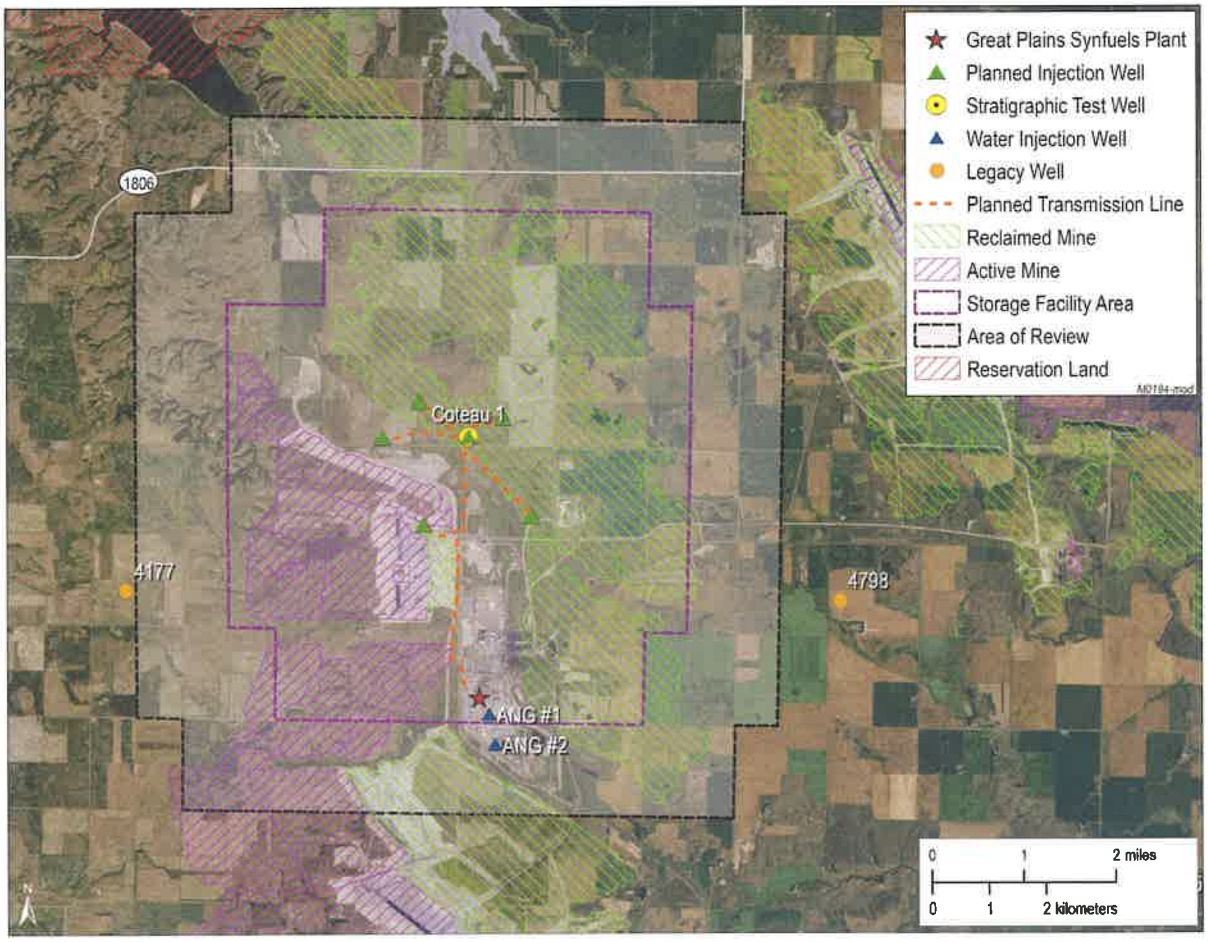

Figure 2-78. Map of the active and reclaimed mine land in the storage facility permit showing planned locations of project infrastructure (transmission line and injection wells).

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3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO_2 INJECTION

3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO_2 INJECTION

3.1 Introduction

Multiple sets of publicly available and newly acquired site-specific subsurface data were analyzed and interpreted (Section 2.2). The data and interpretations were used as inputs to Schlumberger's Petrel software (Schlumberger, 2020) to construct a geologic model of the injection zone: the Broom Creek Formation, the upper confining zone: the Opeche Formation, and the lower confining zone: the Amsden Formation. The geologic model encompasses a 76-mile × 72-mile area around the proposed storage site to characterize the geologic extent, depth, and thickness of the subsurface geologic strata (Figure 3-1). Geologic properties were distributed within the 3D model, including lithofacies, porosity, and permeability.

The geologic model and properties served as inputs for numerical simulations of CO_2 injection using Computer Modelling Group's (CMG's) GEM software (Computer Modelling

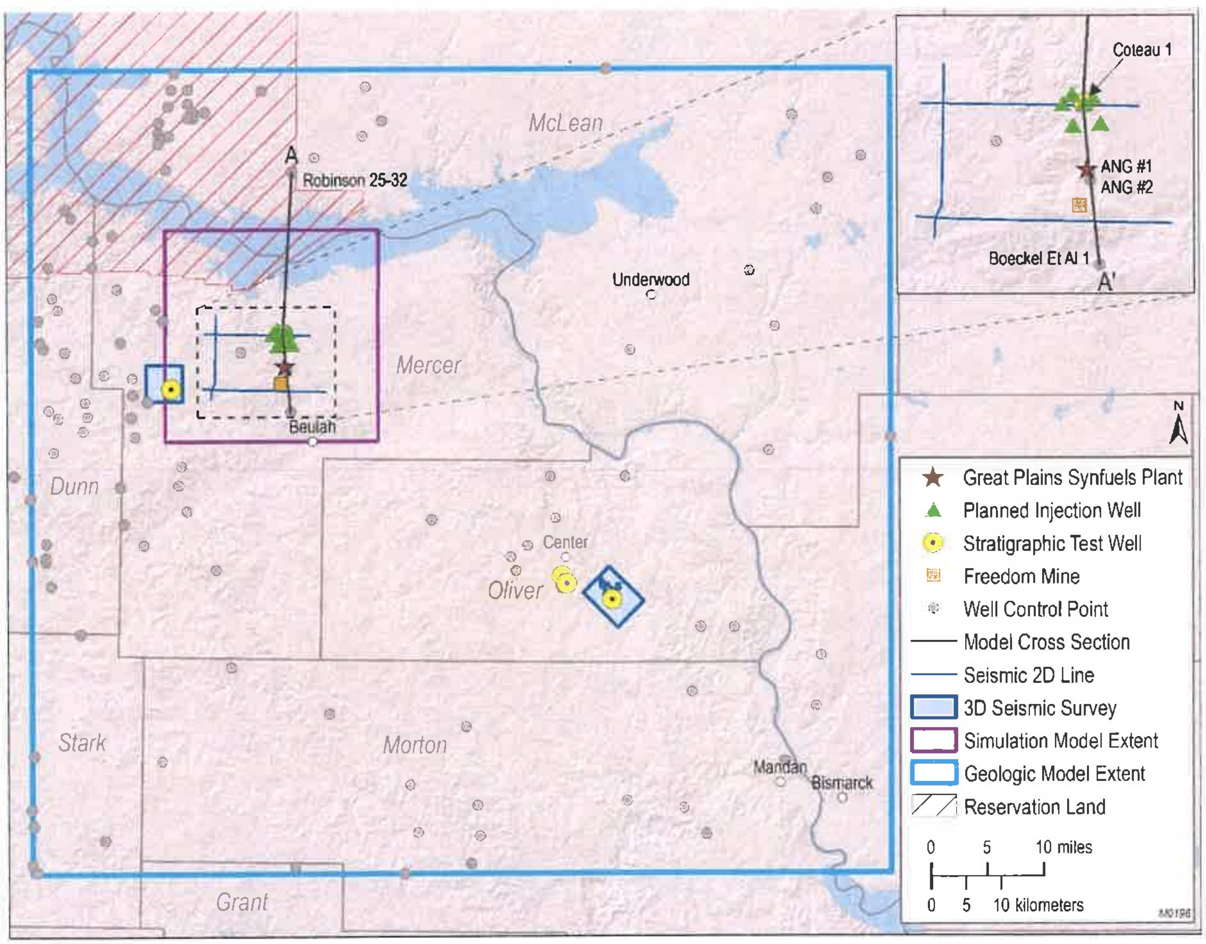


Figure 3-1. Map of the geologic model boundary (blue polygon), simulation model boundary (purple polygon), 3D seismic surveys, model cross section, and nearby Broom Creek wells.

Group, 2019). Numerical simulations of CO_2 injection were conducted to assess potential CO_2 injection rate, disposition of injected CO_2, wellhead pressure (WHP), bottomhole pressure (BHP), and pressure changes in the storage reservoir throughout the expected injection time frame and postinjection period. Results of the numerical simulations were then used to determine the project's area of review (AOR) pursuant to North Dakota's geologic CO_2 storage regulations.

3.2 Geologic Model Development

A geologic model was constructed to characterize the injection zone and upper and lower confining zones. Activities included data aggregation, structural framework creation, data analysis, and property distribution. Major inputs for the geologic model, which acted as control points during the distribution of the geologic properties throughout the modeled area, included seismic survey data, geophysical logs from nearby wells and core sample measurements.

Because of low well control and lack of site-specific 3D seismic data within the storage facility area, publicly available variograms were used to inform the distribution of the lithofacies and petrophysical properties in the geologic model. The variograms reported in the Tundra SGS (secure geologic storage) facility permit were selected as they provide a generalized representation of the property distributions expected within the Broom Creek Formation (North Dakota Industrial Commission, 2021).

3.2.1 Structural Framework Construction

Schlumberger's Petrel software was used to interpolate structural surfaces for the Opeche, Broom Creek, and Amsden Formations. Input data included formation top depths from the online NDIC database; data collected from the Coteau 1, Flemmer 1, ANG #1, J-LOC 1, J-ROC 1, and BNI-1 wells (Figure 2-5); and two 3D seismic surveys (Figure 3-1) conducted at Flemmer 1 and J-ROC 1 wellsites. The interpolated data were used to constrain the model extent in 3D space.

3.2.2 Data Analysis and Property Distribution

3.2.2.1 Confining Zones (Opeche and Amsden Formations)

The Opeche Formation was assigned a silty mudstone lithofacies designation, and the Amsden Formation was assigned a dolostone designation; both classifications were determined as primary lithologic constituents through core and well log analysis. Porosity logs, after comparison with core data sets, served as control points for property distribution. Available permeability measurements also served as control points. The control points were used in combination with variograms and a Gaussian random function simulation algorithm to distribute the properties. 4,000-ft major and minor axis length variogram structures in the lateral direction and a 6-ft vertical variogram length were used for the Opeche Formation. A major axis of 6,000-ft and a minor axis length of 3,000-ft were used for the Amsden Formation along an azimuth of 155° with a vertical variogram of 5 ft.

3.2.2.2 Injection Zone (Broom Creek Formation)

Prior variogram assessments completed for use in a similar storage facility permit application, the Tundra SGS CO_2 storage project, were used to assign variogram ranges within the injection zone. Variogram mapping investigations, as noted in the Tundra SGS application, investigated the size and shape of variograms in several different azimuthal directions, which indicated that geobody structures with the following dimensions were present in the Broom Creek Formation: major axis range of 5,000 ft, minor axis range of 4,500 ft, and an azimuth of 155° (NDIC, 2021). The Tundra SGS application used well logs recorded from the J-LOC 1, BNI-1, and J-ROC 1 wellbores to serve as the basis for deriving a vertical variogram length of 7 ft. The variogram ranges were used to distribute lithofacies and petrophysical properties.

Lithofacies classifications were determined from well log data and correlated with descriptions of core taken from the Coteau 1, Flemmer 1, ANG #1, J-LOC 1, J-ROC 1, and BNI-1 wells. Four predominant lithofacies were identified within the Broom Creek Formation: 1) sandstone, 2) dolomitic sandstone, 3) dolostone, and 4) anhydrite. Lithofacies were manually interpreted from these observations and upscaled to serve as control points for geostatistical distribution using a sequential indicator simulation (Figure 3-2).

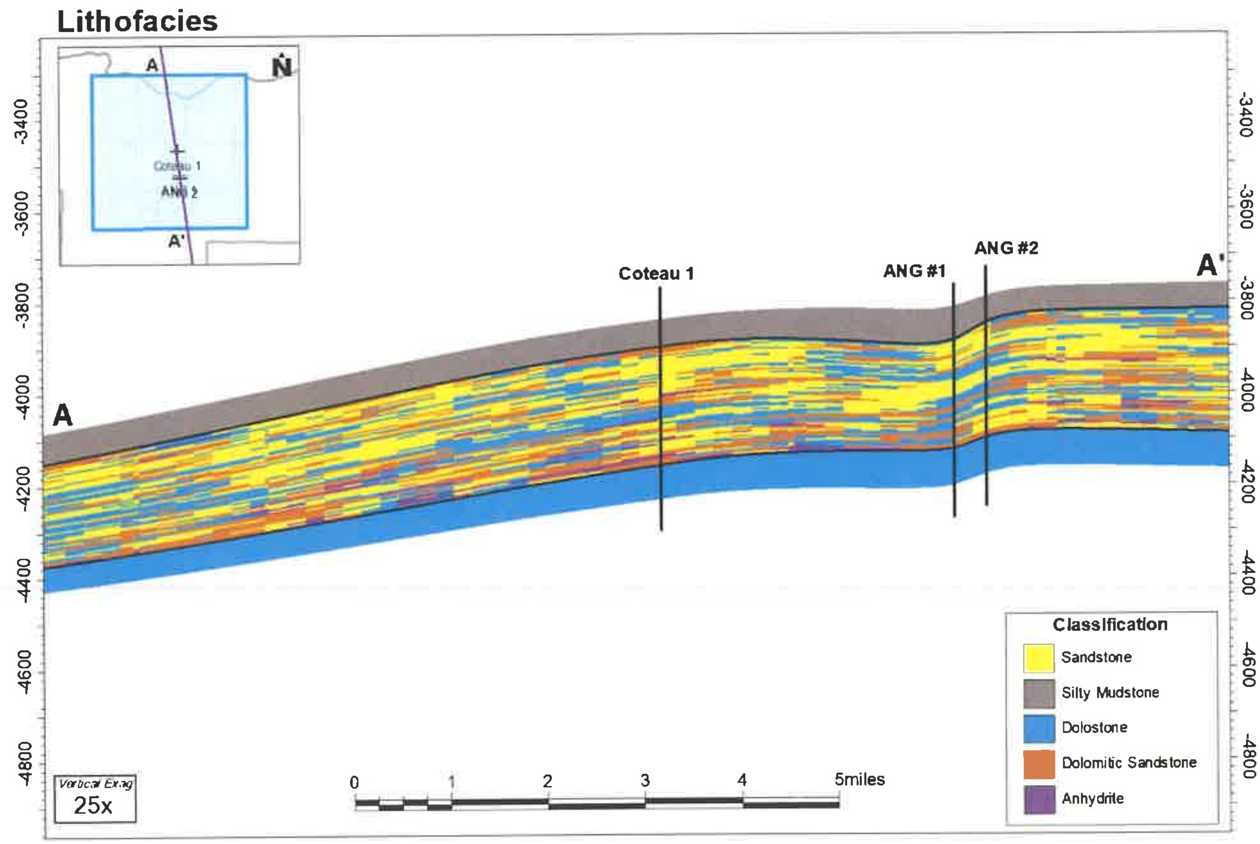


Figure 3-2. Cross-sectional view of lithofacies property. Vertical units on the y-axis are displayed as feet below sea level (25× vertical exaggeration shown).

Prior to distributing the porosity and permeability properties, core porosity and permeability measurements from Coteau 1, Flemmer 1, ANG #1, BNI-1, J-LOC 1, and J-ROC 1 wells were compared with effective porosity well logs and permeabilities estimated from the Wyllie-Rosa model (Wyllie and Rose, 1950) to ensure good agreement between the six data sets (Figure 3-3).

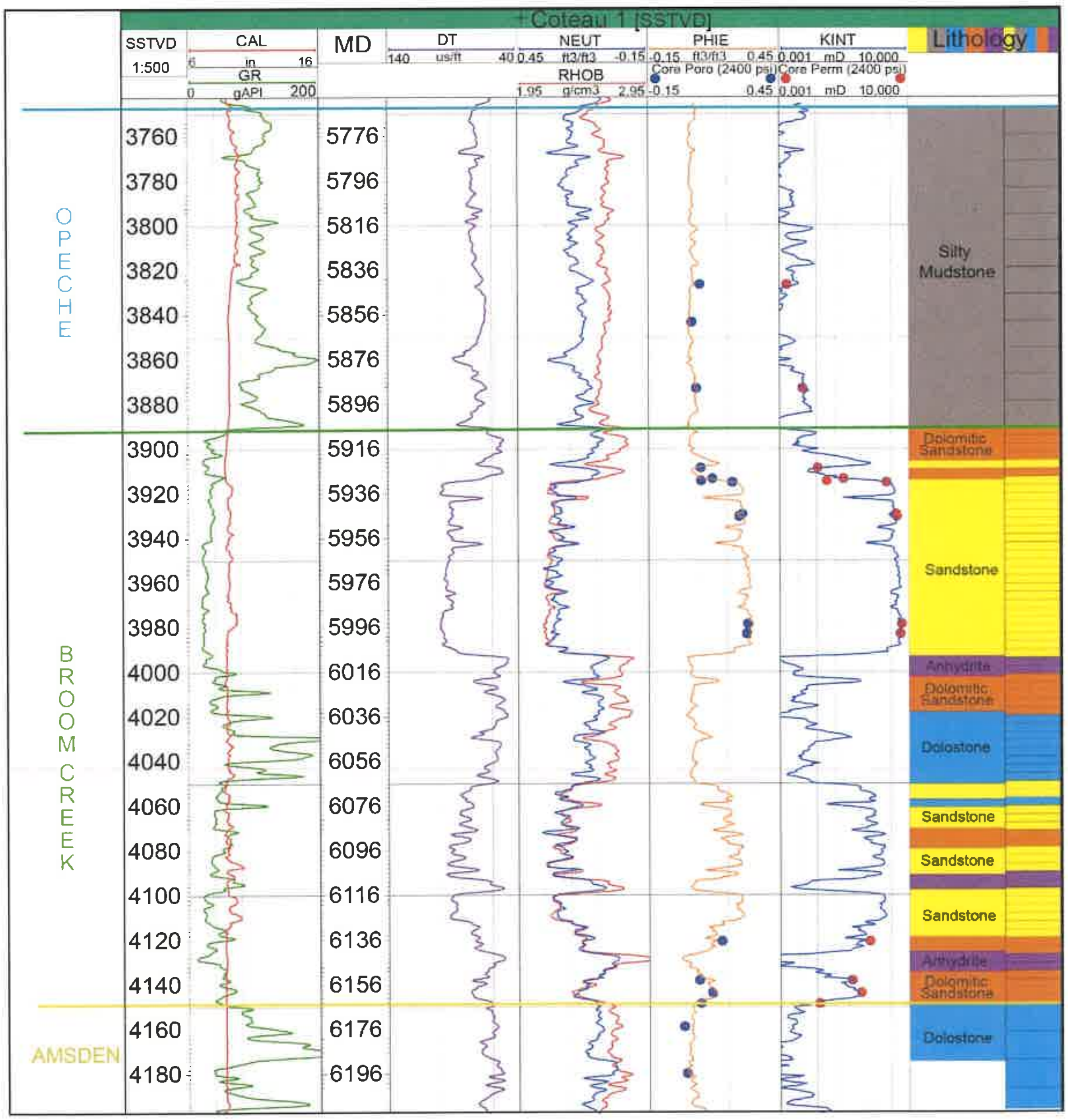


Figure 3-3. Lithofacies classification in Coteau 1 well. Well logs displayed in tracks from left to right are 1) gamma ray (green) and caliper (red), 2) delta time (purple), 3) neutron porosity (blue) and density (red), 4) effective porosity (orange) and core sample porosity (blue dots), 4) predicted intrinsic permeability (blue) and core sample permeability (red dots), 6) interpreted lithology, and 7) upscaled lithology.

A PHIE property (effective porosity; total porosity less occupied or isolated pore space) was distributed using calculated PHIE well logs, upscaled to the resolution of the 3D model as control points and variogram structures described previously with Gaussian random function simulation and conditioning to the distributed lithofacies. A permeability property was distributed using the same variables and algorithm, but cokriged to the PHIE volume (Figures 3-4 and 3-5).

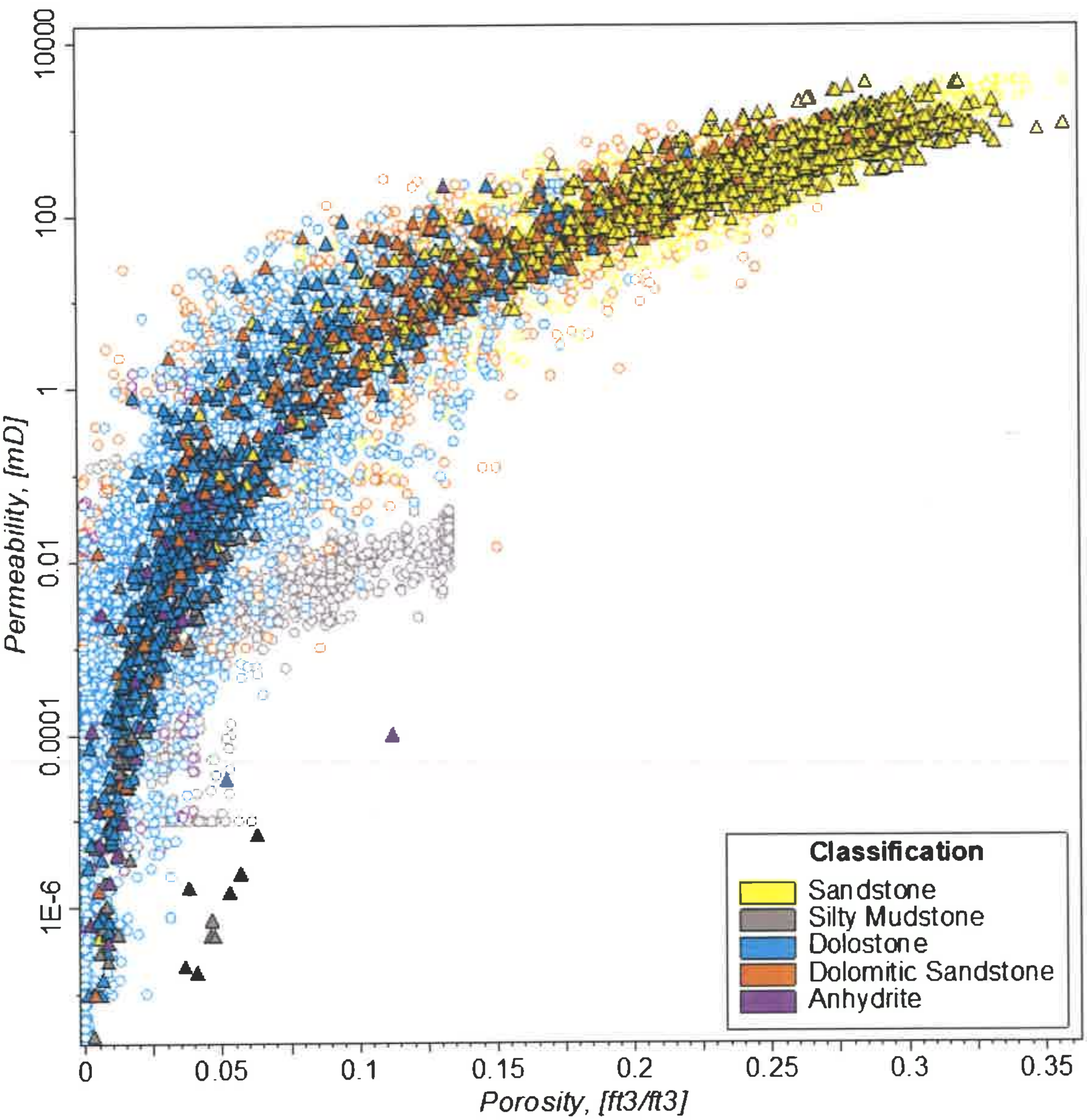


Figure 3-4. Illustration of the relationship between the modeled porosity and permeability. Upscaled well log values are represented by triangles, while circles represent distributed values. Values are colored according to lithofacies classification, as seen in Figure 3-3.

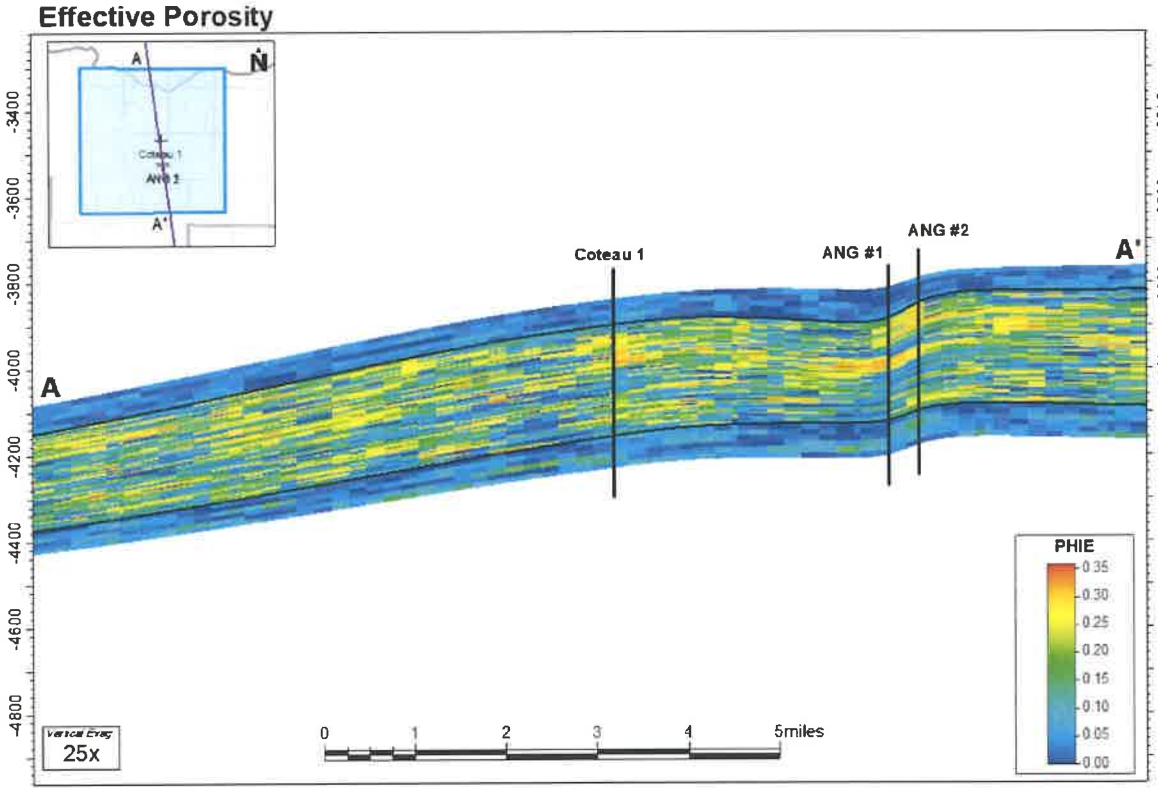


Figure 3-5. Distributed PHIE property along a NW-SE cross section. The distributed PHIE property was used to distribute permeability throughout the model. Units on the y-axis represent feet below mean sea level (25× vertical exaggeration shown).

3.3 Numerical Simulation of CO_2 Injection

Numerical simulations of CO_2 injection into the Broom Creek Formation were conducted using the geologic model described above in Section 3.2. Figure 3-6 displays the 3D view of the simulation model with the permeability property and Coteau 1 injection well. Simulations were carried out using CMG's GEM, a compositional reservoir simulation module. Both calculated temperature and pressure, along with the reference datum depth, were used to initialize the reservoir at equilibrium conditions for performing numerical simulation.

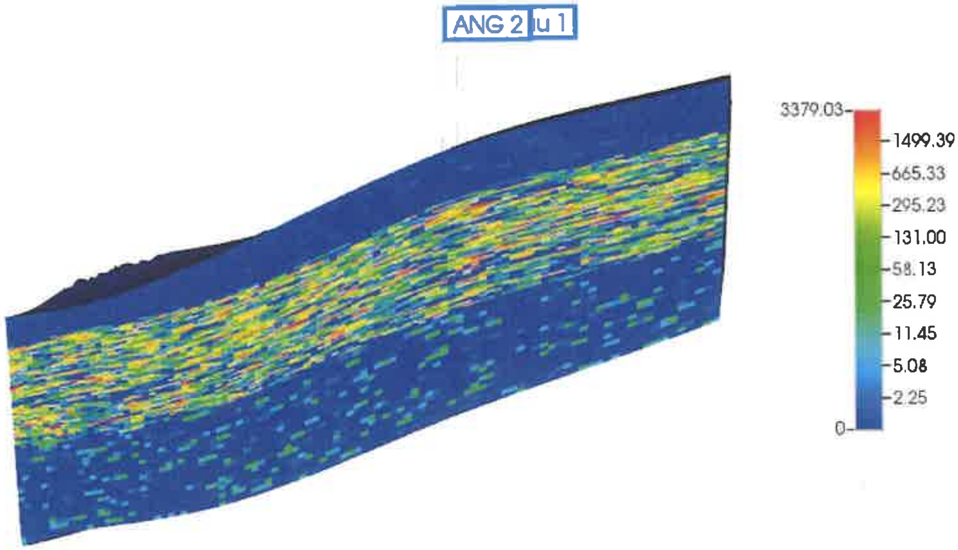


Figure 3-6. 3D view of the simulation model with the permeability property and injection wells displayed. Note the low-permeability layers (dark blue) at the top and bottom of the figure. These layers represent the Opeche Formation (upper) and the Amsden Formation (lower). The varied permeability of the Broom Creek is observed in between these layers.

The simulation model boundaries were assigned partially closed conditions as the Broom Creek Formation pinches out in the northern and eastern parts of the modeled area. From geologic interpretation for this model, distances to the formation pinch-out are assumed to be 170,016 feet (~32.2 miles) to the northeast and 158,400 feet (~30 miles) to the east from the edge of the simulation domain based on well log interpretation. The reservoir was assumed to be 100% brine-saturated with an initial formation salinity of 42,800-ppm total dissolved solids (TDS) based on the fluid sample analysis from the Coteau 1 well (Table 2-6).

CO_2 injection simulations performed allowed CO_2 to dissolve into the native formation brine. Both the relative permeability and the capillary pressure data for the Broom Creek Formation were analyzed and generated for four representative rock types in the simulation to describe the Broom Creek Formation: sandstone, dolostone, dolomitic sandstone, and anhydrite through Core Laboratory's MICP (mercury injection capillary pressure) evaluation and EERC laboratory analysis. Capillary pressure curves calculated from the MICP data were adapted to the permeability and porosity values from the numerical model.

Injection simulation scenarios were run using relative permeability and capillary pressure curves derived from the site-specific core samples from Coteau 1 well and compared to simulation scenarios that used publicly available values reported in the Project Tundra SGS facility permit (North Dakota Industrial Commission, 2021). In these scenarios, all other inputs and constraints besides relative permeability and capillary pressure curves were kept constant. Scenarios run with site-specific relative permeability and capillary pressure curves from Coteau 1 resulted in smaller plume sizes compared to the scenarios run with publicly available data (Figure 3-7 and 3-8). Based on these results, the decision was made to permit the scenario that uses the publicly available data to have a more conservative estimate for plume size.

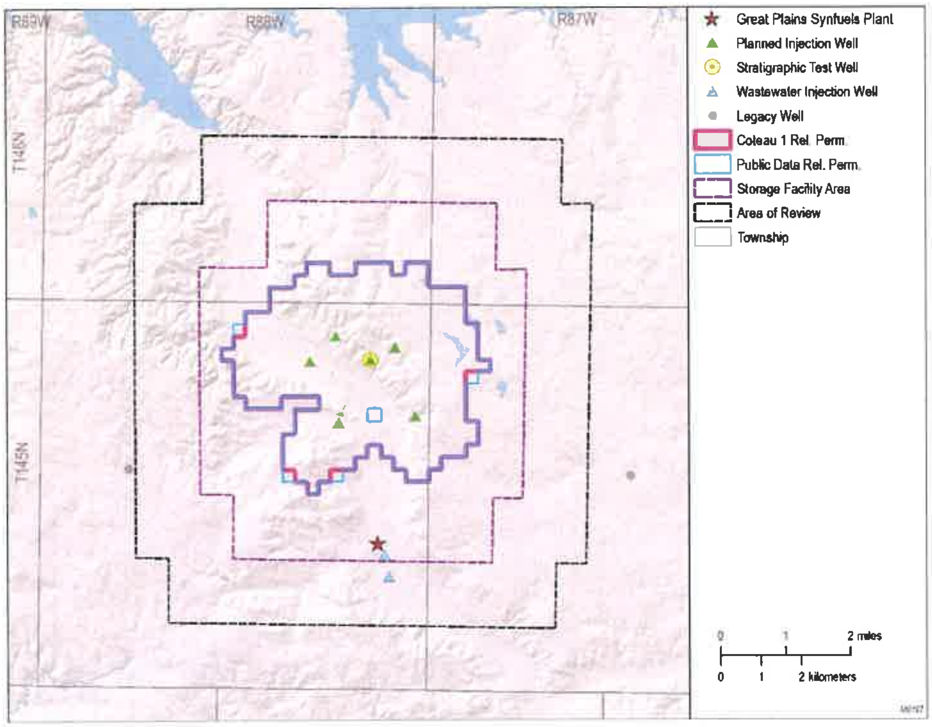


Figure 3-7. Simulated CO_2 plume extents at the end of 12 years of CO_2 injection for the scenario run using site-specific relative permeability data (pink) and the scenario run with publicly available relative permeability data (blue). The plume extent for the scenario using site-specific data is approximately 0.11 sq. mi. smaller.

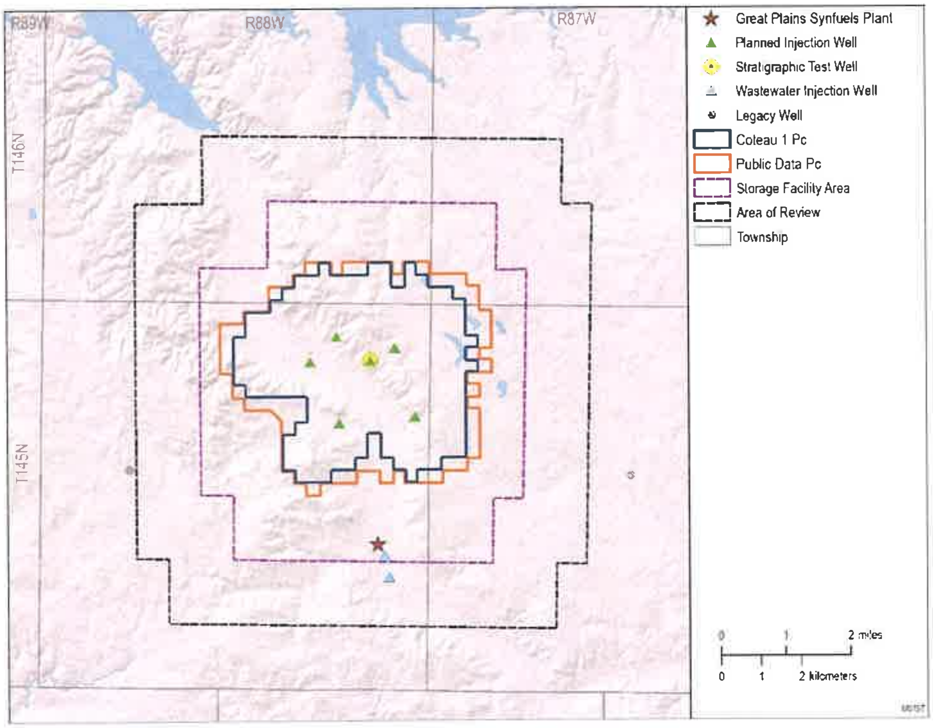


Figure 3-8. Simulated CO_2 plume extents at the end of 12 years of CO_2 injection for the scenario using site-specific relative permeability and capillary pressure (Pc) data (dark blue) and the scenario run with publicly available relative permeability and capillary data (orange). The plume extent for the scenario using site-specific data is approximately 2.2 sq. mi. smaller.

The publicly available capillary pressure curves used for the injection scenario presented in this permit are shown in Figures 3-9 through 3-12. Capillary entry pressures were determined from Broom Creek Formation core sample analysis and were assigned based on lithofacies. The assigned capillary entry pressures are 1) sandstone: 0.20 psi, 2) dolostone: 18.08 psi, and 3) mudstone and anhydrite: 168.10 psi. The dolostone pressure value, derived from a core sample within the Broom Creek Formation, was assigned to all dolostone lithofacies throughout the simulation model. Similarly, the mudstone and anhydrite pressure value, derived from a Broom Creek anhydrite core sample, was assigned to all mudstone and anhydrite lithofacies within the simulation model. The Opeche was assigned as silty mudstone, and the Amsden was assigned as dolostone.

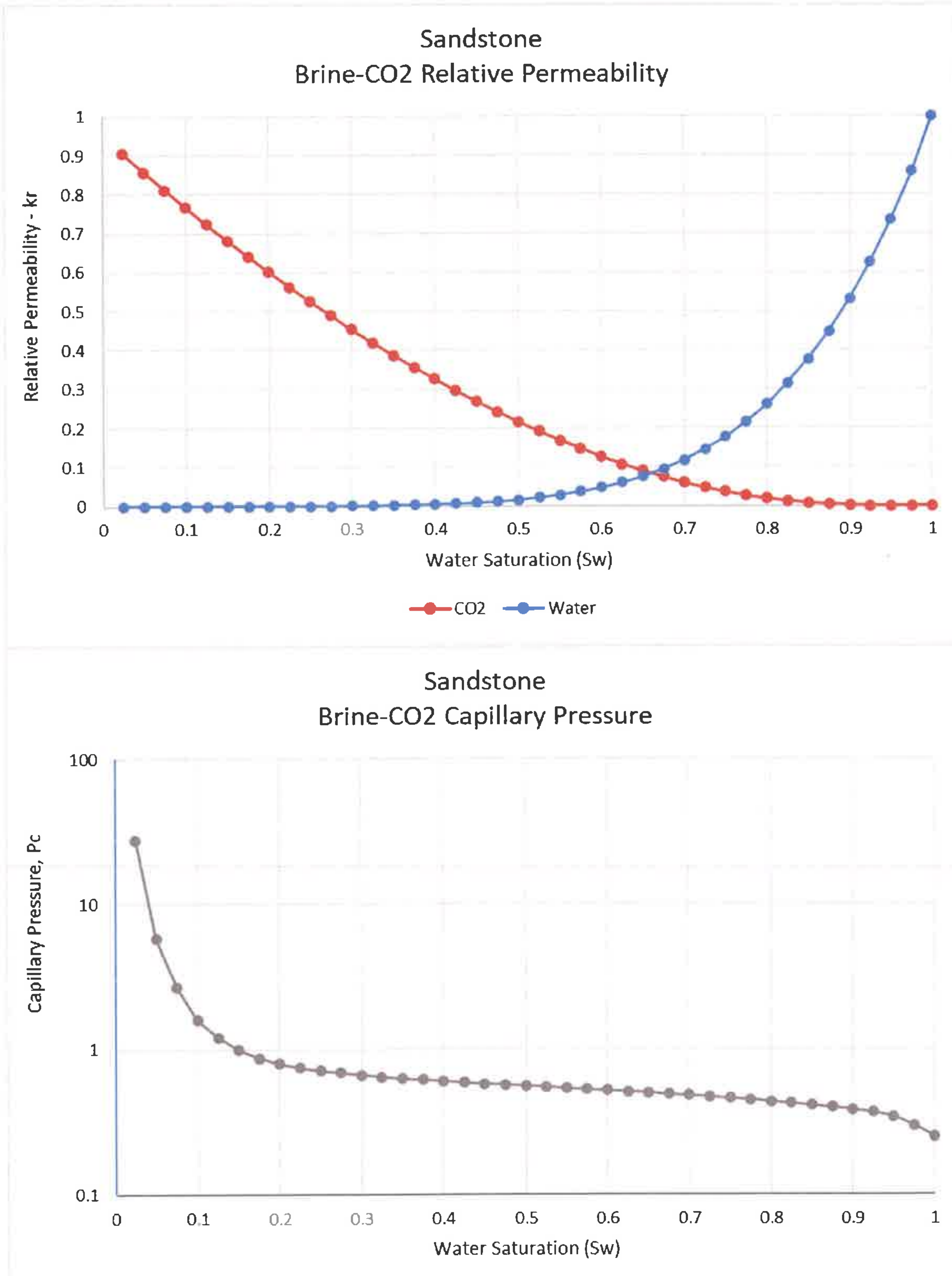
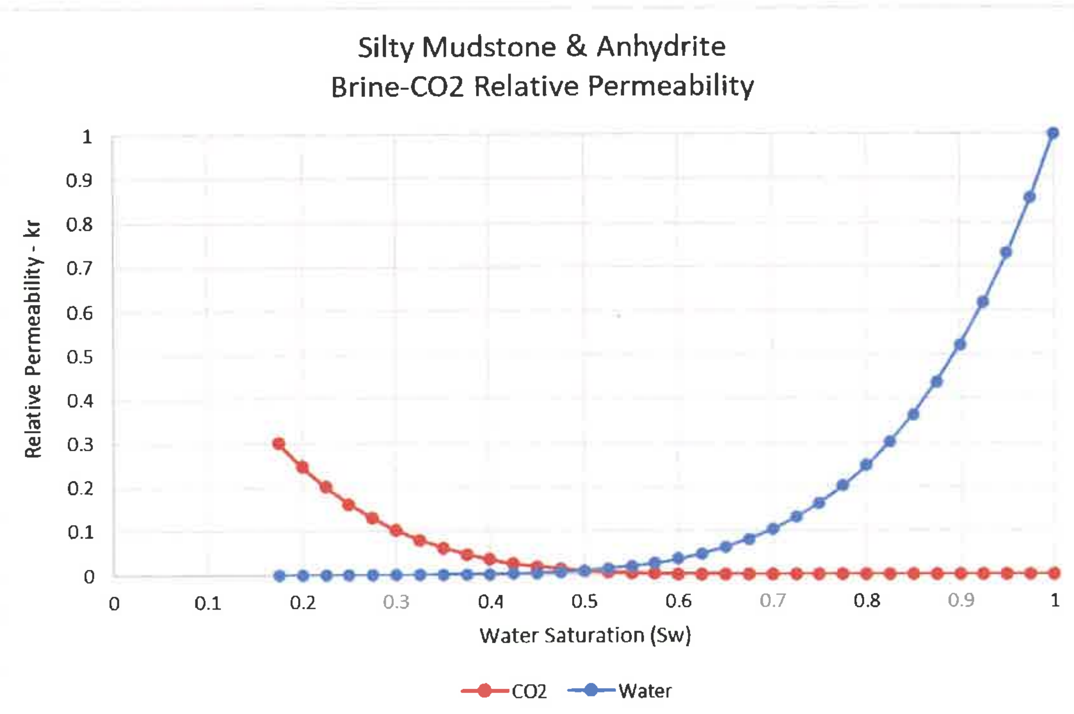


Figure 3-9. Relative permeability (top) and capillary pressure curves (bottom) for the sandstone rock type in the Broom Creek Formation.



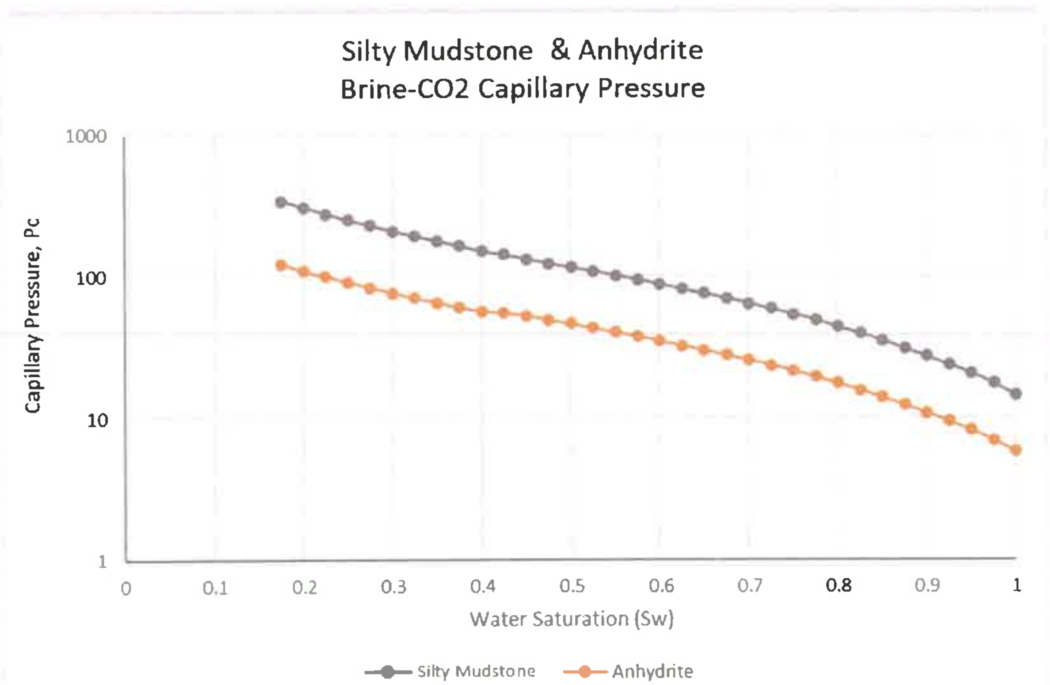


Figure 3-10. Relative permeability (top) and capillary pressure curves (bottom) for the silty mudstone rock type in the Opeche Formation and anhydrite rock type within in the Broom Creek Formation.

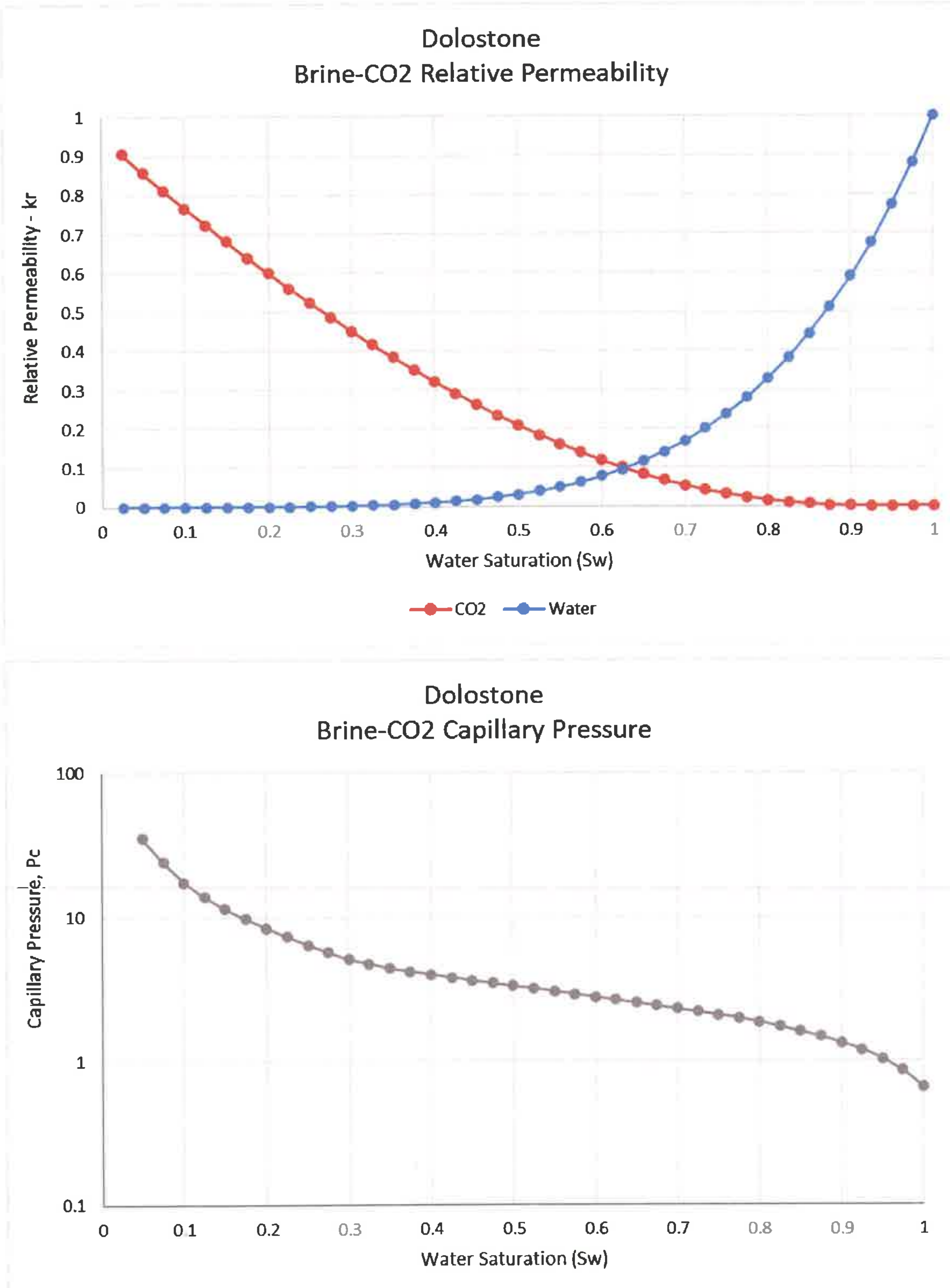
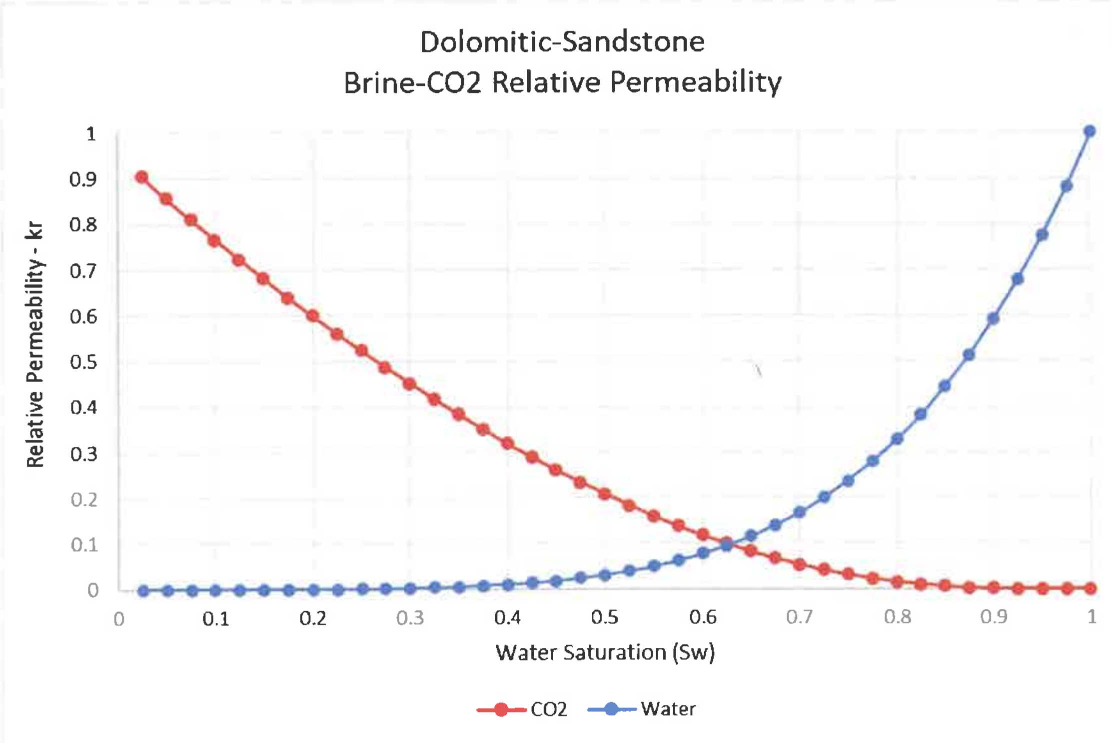


Figure 3-11. Relative permeability (top) and capillary pressure curves (bottom) for the dolostone rock types in the Broom Creek and Amsden Formations.



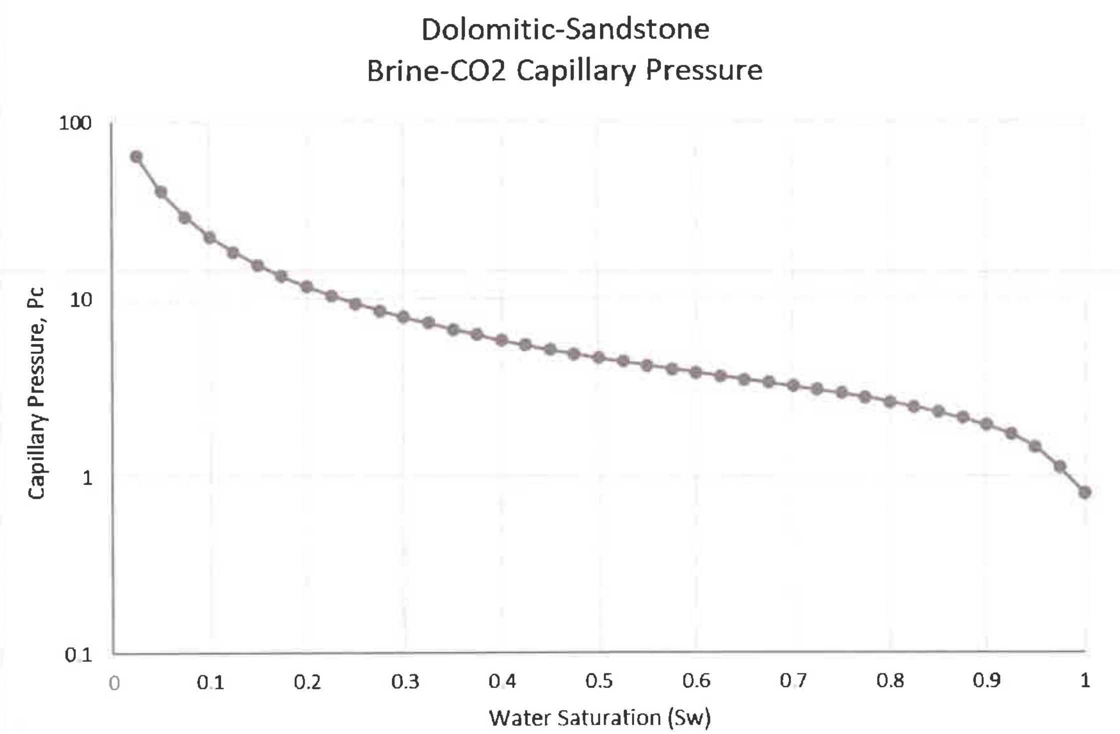


Figure 3-12. Relative permeability (top) and capillary pressure curves (bottom) for the dolomitic sandstone rock type in the Broom Creek Formation.

Temperature and pressure data recorded from a pressure test in the Coteau 1 were used to derive a temperature and pressure gradient to initialize the numerical simulation model for the proposed injection site. In combination with depth, this temperature gradient of 0.02°F/ft was used to calculate subsurface temperatures throughout the study area. A pressure reading recorded from the Broom Creek Formation was used to derive a pore pressure gradient of 0.49 psi/ft (Table 3-1). Table 3-2 shows the general properties used for numerical simulation analysis in this study.

Table 3-1. Pressure Measurement Recorded from the Coteau 1 Well and Derived Pressure Gradient

Test Depth, ft MD*	Formation Pressure, psi	Pressure Gradient, psi/ft
5,975.00	2,937.09	0.49

* Measured depth.

Table 3-2. Summary of Reservoir Properties in the Simulation Model

Formation	Average Permeability, mD	Average Porosity, %	Initial Pressure, P_i, psi	Salinity, ppm	Boundary Condition
Opeche	0.034	25.7	~2,937.1 (at 3,960.6 ft)	42,800	Partially closed
Broom Creek	241.2	14.5			
Amsden	2.55	4.4			

The CMG fluid property characterization tool, WinProp, was used to generate the fluid property input data for the simulation model. Only the major constituents in the gas stream were included for computational efficiency. After all the constituents were normalized to sum 100% mole fraction, the CO_2 composition in the gas stream was 96.45% CO_2. Other constituents represent 3.55% of the stream, including 1.23% hydrogen sulfide (H_2S) and 2.32% for methane, ethane, propane, and nitrogen.

The numerical simulation model was history-matched using the field injection data from the Class I injector wells located in the area of study, ANG #1 and ANG #2. The field injection data consisted of daily field data from Dakota Gasification Company (DGC) water injection into the ANG wells throughout July 1998 to August 2021. The field data provided were averaged per month and included in the numerical model for the history matching. The well skin factor was the parameter used to history-match the model based on data from a monitoring study conducted in the ANG wells in 2016. Figures 3-13 and 3-14 show a comparison between the WHP and water injection rate from the field data set and the predicted values from the history-matched model.

Six CO_2 injection wells, Coteau 1, Coteau 2, Coteau 3, Coteau 4, Coteau 5, and Coteau 6, were simulated as perforated across the entire Broom Creek Formation interval (Figure 2-2). The CO_2 injection well constraints and wellbore model inputs for the simulation model are shown in

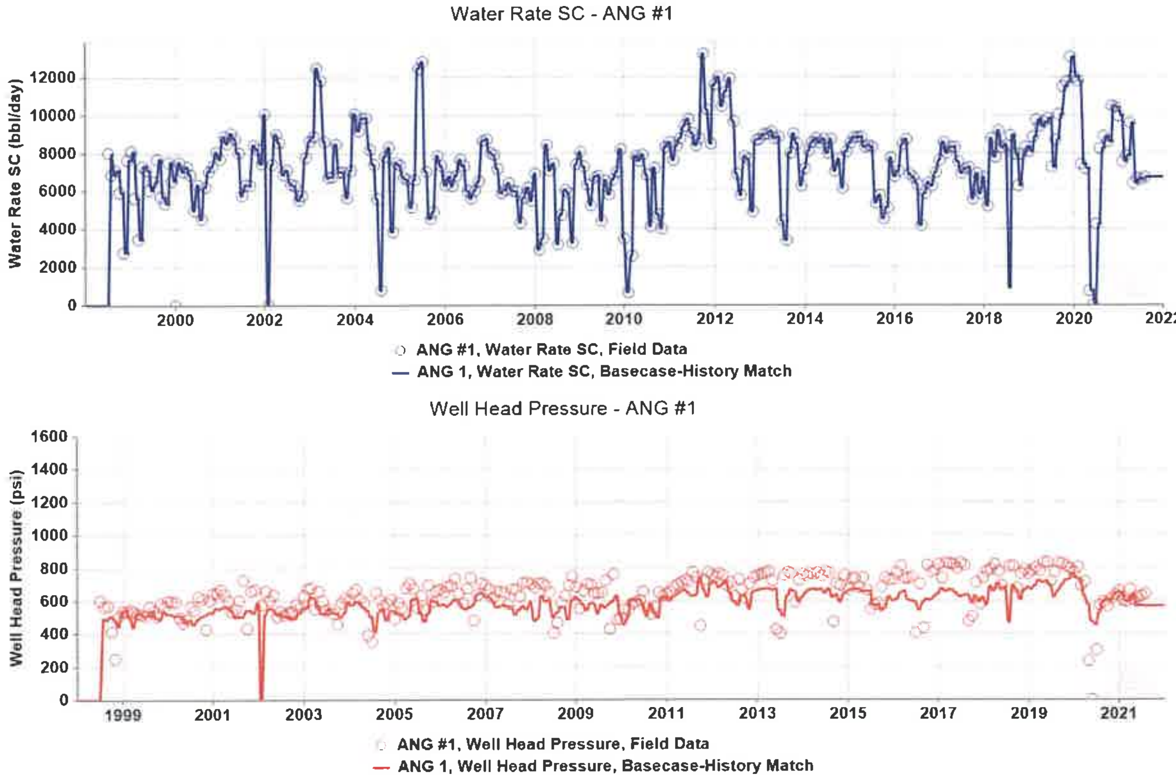


Figure 3-13. Water injection rate (top) and WHP curves (bottom) for the ANG #1 Class I disposal well. The circles represent the field data, and the lines represent the predicted values from the history-matched model.

Table 3-3. The CO_2 injection rate in the simulation model is based on initial CO_2 volumes expected to average 55 MMcfd (1.0 million metric tonnes per year [MMt/yr]), determined from existing compressor capacity and historical excess CO_2 availability after satisfying existing contractual arrangements. As additional volumes become available in the future, the daily rate is expected to increase to 70 MMcfd (1.3 MMt/yr) in January 2025, then to 140 MMcfd (2.7 MMt/yr) in May 2026 until the end of the 12-year CO_2 injection period.

The BHP constraint was calculated using the well depth at the top of the Broom Creek Formation (MD) and 90% of the formation fracture gradient. The fracture gradient was obtained from geomechanical modeling and core analysis, resulting in an average of 0.71 psi/ft fracture propagation pressure in the Coteau 1 well.

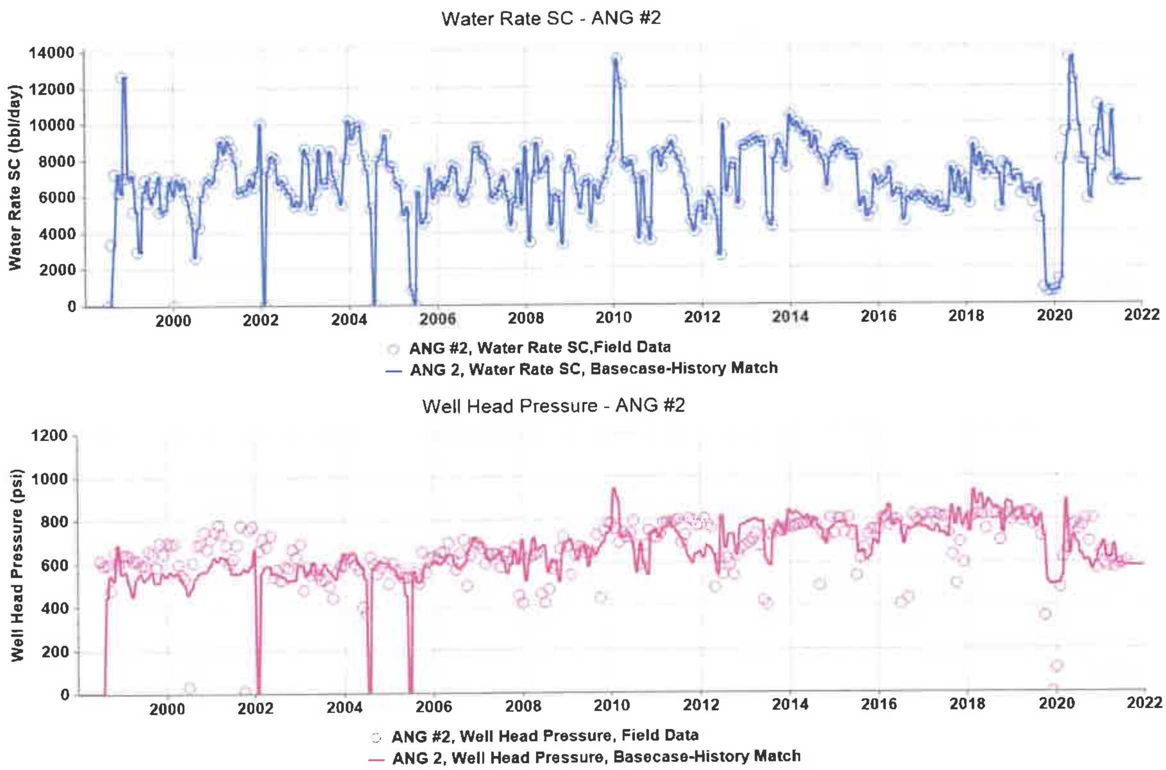


Figure 3-14. Water injection rate (top) and WHP curves (bottom) for the ANG #2 Class I disposal well. The circles represent the field data, and the lines represent the predicted values from the history-matched model.

Table 3-3. Well Constraints and Wellbore Model in the Simulation Model

Well Name	Start Date of Injection	Primary Well Constraint, maximum BHP	Secondary Well Constraint, maximum injection rate/well	Tubing Size	Wellhead Temperature	Downhole Temperature
Coteau 1*	July/2022	3,754 psi	25 MMcfd	4½ in.	90°F	151°F
Coteau 2*	July/2022	3,802 psi	17.5 MMcfd			
Coteau 3*	July/2022	3,772 psi	25 MMcfd			
Coteau 4*	July/2022	3,787 psi	25 MMcfd			
Coteau 5*	May/2026	3,776 psi	25 MMcfd			
Coteau 6*	May/2026	3,786 psi	25 MMcfd			

* Primary group constraint, injection rate: 55 MMcfd from July/2022 to Dec./2024, 70 MMcfd from Jan./2025 to April/2026, 140 MMcfd from May/2026 to July/2034.

Water injection conditions used for numerical simulation of the Class I disposal wells, ANG #1 and ANG #2, are shown in Table 3-4. The water injection rate constraint used for the ANG wells during the CO_2 injection period was determined from historical injection rates over the past 2 years. Water injection into ANG #1 and ANG #2 was held constant during the 12 years of the CO_2 injection period. For simulation evaluation purposes, it is assumed that water injection ceases at the end of CO_2 injection as the operations producing the water are likely to cease at the end of CO_2 injection.

Table 3-4. ANG #1 and ANG #2 Well Constraints in the Simulation Model

Primary Well Constraint, maximum water injection rate	Secondary Well Constraint, maximum permitted WHP
6,722.9 bpd for ANG #1	1,350 psi for ANG #1
6,722.4 bpd for ANG #2	1,100 psi for ANG #2

3.3.1 Sensitivity Analysis

Because the availability of data for this study included well logs, core sample data, and rock-fluid properties, the need for typical sensitivity studies of influential reservoir parameters has been reduced. A preliminary sensitivity analysis made to the wellbore model parameters suggested, at the given injection volume rates and BHP conditions, the wellhead temperature played a prominent role in determining WHP response. Thus a wellhead temperature value of 90°F was chosen that most closely represents the expected operational temperature.

3.4 Simulation Results

Simulations of CO_2 injection with the given well and group constraints, listed in Table 3-3, predicted the WHP of all six injector wells would not exceed 1,730 psi during injection (Figure 3-15). The predicted BHP for each of the CO_2 injection wells did not reach the maximum BHP constraint defined using 90% of the fracture pressure gradient (Table 3-5). The target

Table 3-5. BHP Constraint and Predicted from Simulations BHP and Associated Fracture Pressure Gradient

	Well Name					
	Coteau 1	Coteau 2	Coteau 3	Coteau 4	Coteau 5	Coteau 6
Max BHP Constraint,* psi	3,754	3,802	3,772	3,787	3,776	3,786
Max. BHP Predicted, psi	3,430	3,445	3,462	3,414	3,424	3,426
Fracture Pressure Gradient Associated with Predicted Max. BHP, ** psi/ft	0.585	0.580	0.587	0.577	0.580	0.580

* Calculated using 0.64 psi/ft (90% of the fracture pressure gradient) and the depth for the top of the Broom Creek Formation.

** Calculated using the depth for the top of the Broom Creek Formation.

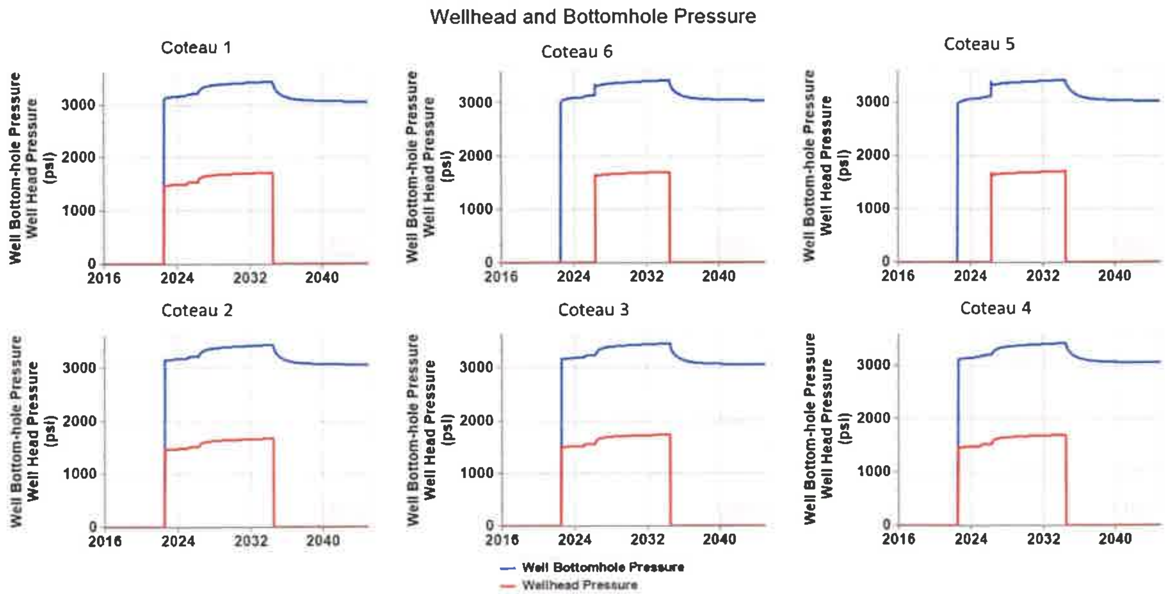


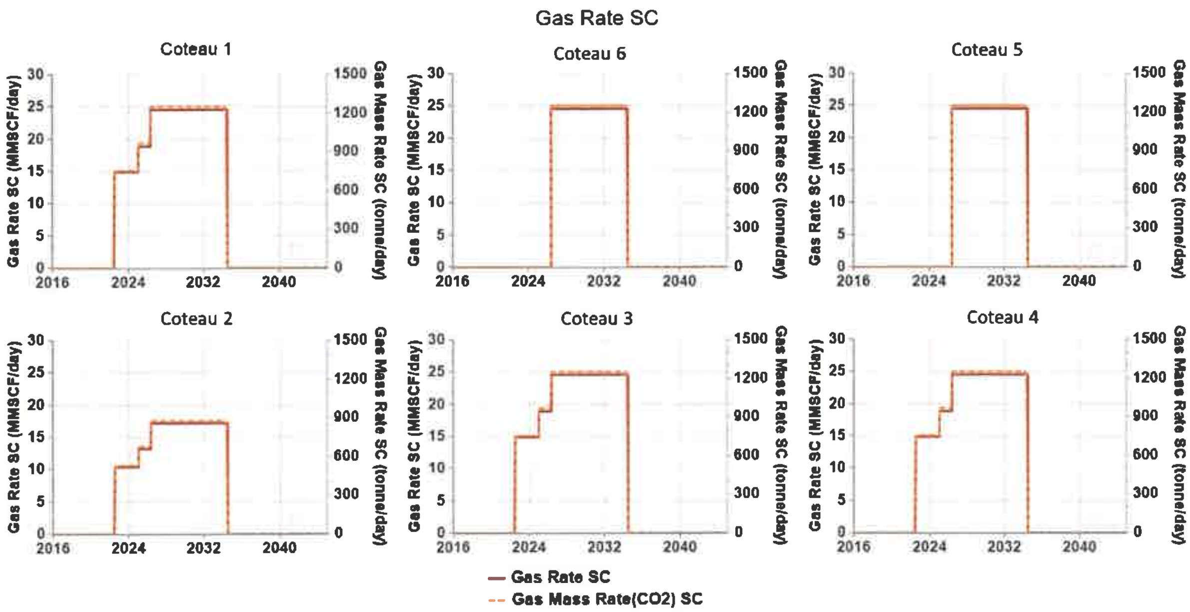
Figure 3-15. WHP and BHP response with the expected injection rate.

injection rates of 55 MMcfd from July 2022 to December 2024, 70 MMcfd from January 2025 to April 2026, and 140 MMcfd from May 2025 to July 2034 were achieved over the 12 years of injection (Figure 3-16).

A total of 25.61 MMt (501,755 MMscf) of CO_2 was injected into the Broom Creek Formation with six wells at the end of 12 years of simulated injection (Figure 3-17). The injected volume for each of the wells is shown in Table 3-6.

Simulation results showed that the maximum permitted WHP constraint for the ANG wells, Table 3-4, was not reached, and the WHP values for ANG #1 and ANG #2 did not exceed 833 and 829 psi, respectively, during the CO_2 injection period (Figure 3-18). Also, the water injection rate was not affected during the CO_2 injection period.

The simulation results did not show any interaction between the low salinity plume from the Class I disposal wells, ANG #1 and ANG #2, and the CO_2 plume at the end of the injection period. Any possible interaction during the CO_2 injection period is not affecting CO_2 injectivity. A limited interaction may occur between the low salinity plume and the CO_2 stabilized plume at 10 years postinjection. These simulation results can be seen in Section 2, Figure 2-22. However, no evidence from the simulation results indicates that this possible interaction will affect the CO_2 chemical behavior or storage performance.



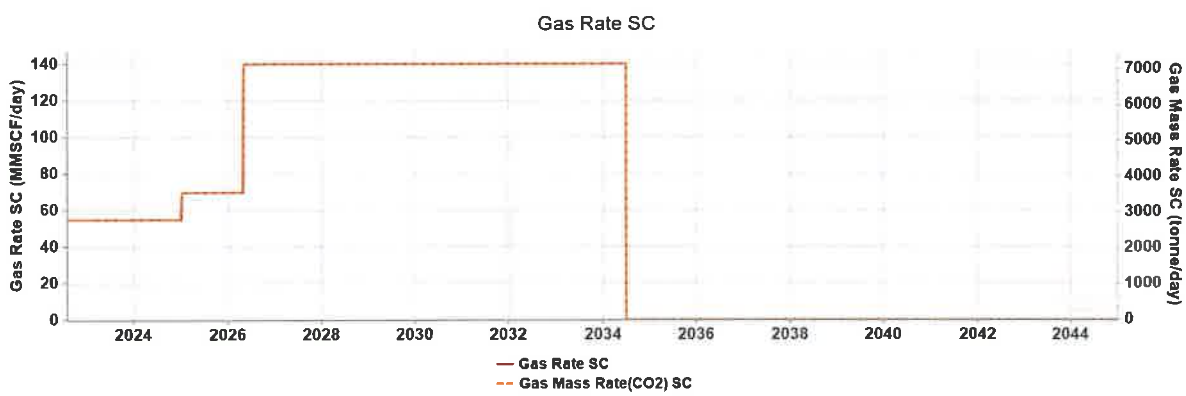


Figure 3-16. CO_2 injection rate (MMscf/day) response with the expected maximum injected rate per well (top) and group injection rate (bottom).

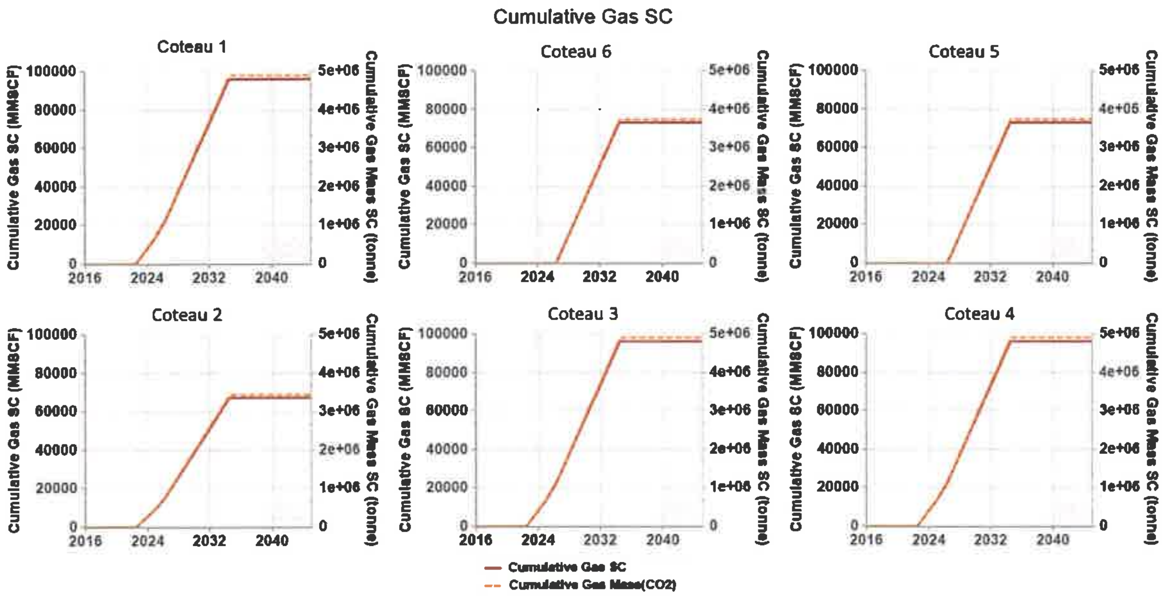


Figure 3-17. Cumulative injected CO_2 (MMscf) and CO_2 mass (metric tonnes) over 12 years of injection.

Table 3-6. CO_2 Volume Injected per Well

Well	CO_2 Volume Injected (MMscf)
Coteau 1	96,019
Coteau 2	67,213
Coteau 3	96,219
Coteau 4	96,219
Coteau 5	73,242
Coteau 6	73,242

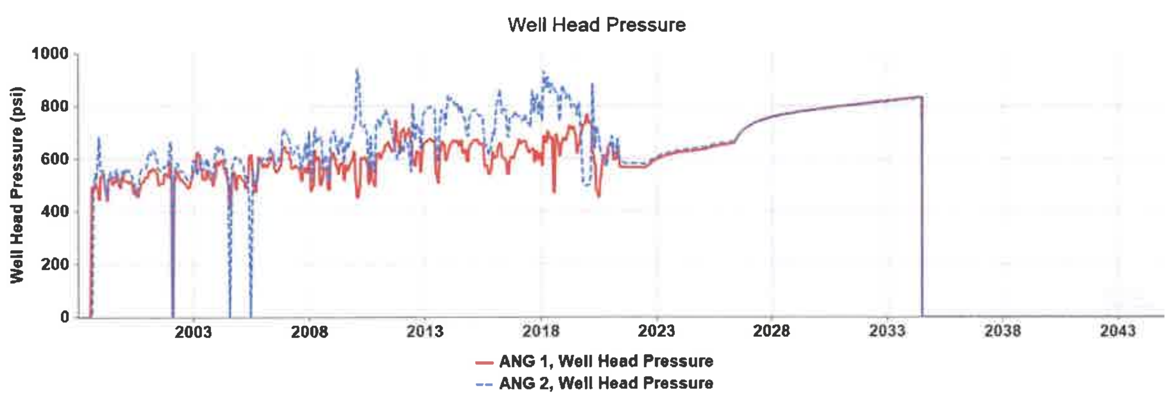


Figure 3-18. WHP response for the Class I disposal wells: ANG #1 and ANG #2.

During and after injection, supercritical CO_2 (free-phase CO_2) accounts for the majority of CO_2 observed in the modeled pore space. Throughout the injection operation, a portion of the free-phase CO_2 is trapped in the pore space through a process known as residual trapping. Residual trapping can occur as a function of low CO_2 saturation and inability to flow under the effects of relative permeability. CO_2 also dissolves into the formation brine throughout injection operations (and continues afterward), although the rate of dissolution slows over time. The free-phase CO_2 transitions to either residually trapped or dissolved CO_2 during the postinjection period, resulting in a decline in the mass of free-phase CO_2. The relative portions of supercritical, trapped, and dissolved CO_2 can be tracked throughout the duration of the simulation (Figure 3-19).

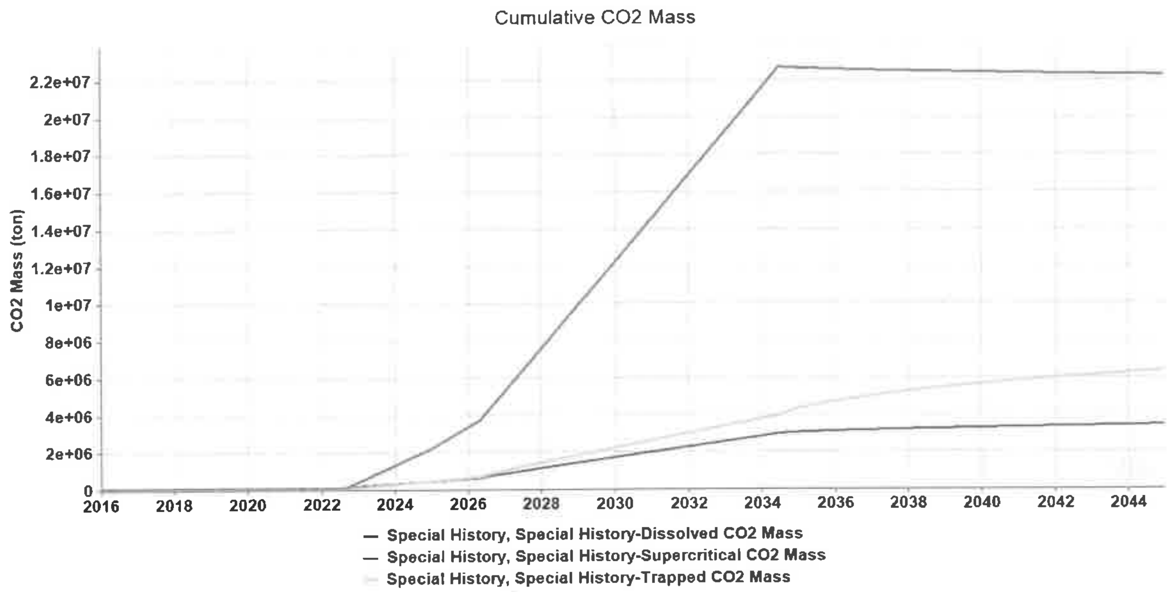


Figure 3-19. Simulated total supercritical free-phase CO_2, trapped CO_2, and dissolved CO_2 in brine.

The pressure front (Figure 3-20) shows the distribution of pressure increase throughout the Broom Creek Formation after 1, 5, and 12 years of injection as well as 8 years postinjection. A maximum increase of 436.53 psi is estimated in the near wellbore area at the end of the 12-year injection period.

Long-term CO_2 migration potential was also investigated through the numerical simulation efforts. The slow lateral migration of the plume is caused by the effects of buoyancy where the free-phase CO_2 injected into the formation rises to the bottom of the upper confining zone or lower-permeability layers present in the Broom Creek Formation and then outward. This process results in a higher concentration of CO_2 at the center which gradually spreads out toward the model edges where the CO_2 saturation is lower. Trapped CO_2 saturations, employed in the model to represent fractions of CO_2 trapped in small pores as immobile, tiny bubbles, ultimately immobilize the CO_2 plume and limit the plume's lateral migration and spreading. Figures 3-21 through 3-26 show the CO_2 saturation at the injection wells at the end of injection in north-to-south and east-to-west cross-sectional views.

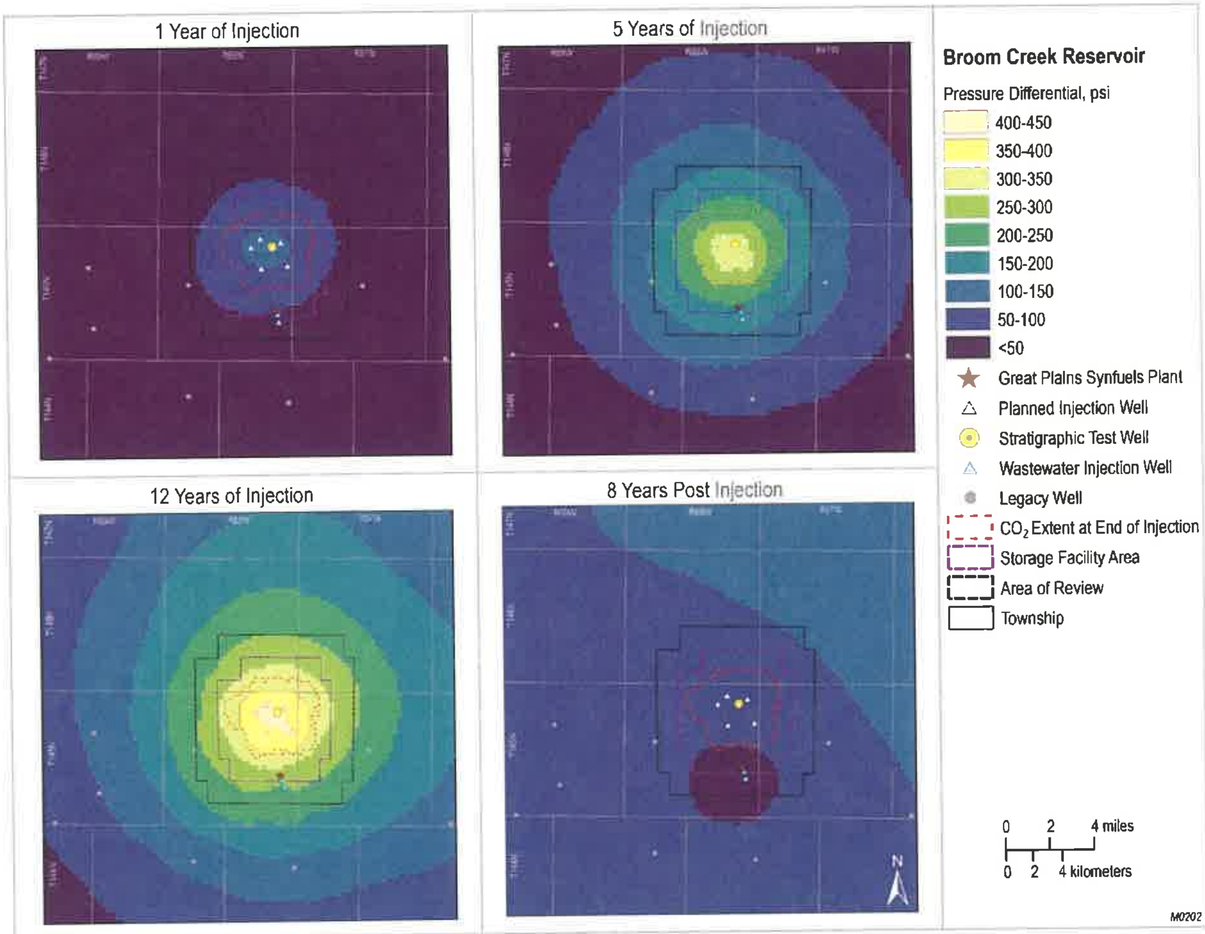


Figure 3-20. Average pressure increases within the Broom Creek Formation after 1, 5, and 12 years of simulated CO_2 injection operation as well as 8 years postinjection.

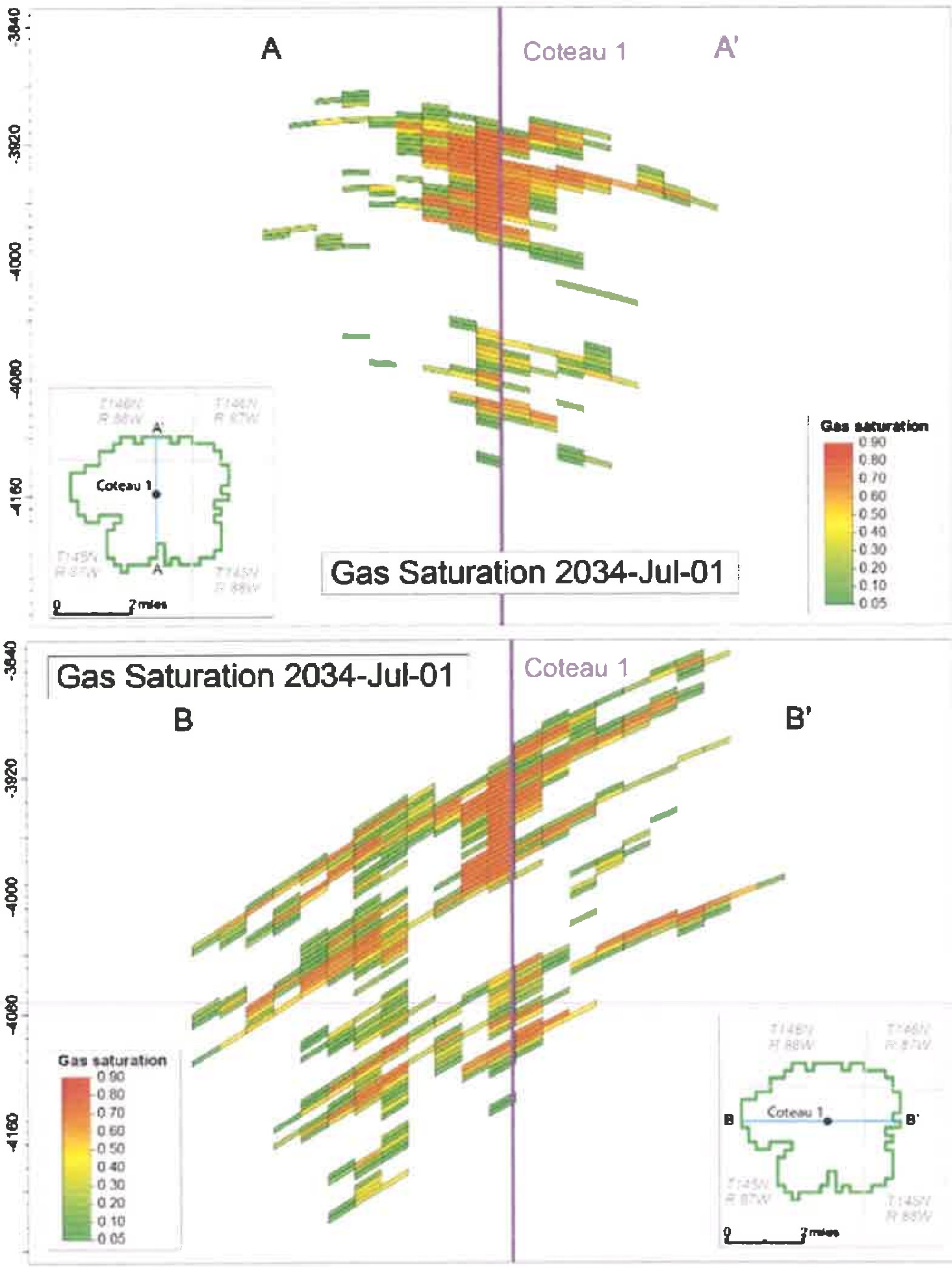


Figure 3-21. CO_2 plume cross section of Coteau 1 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

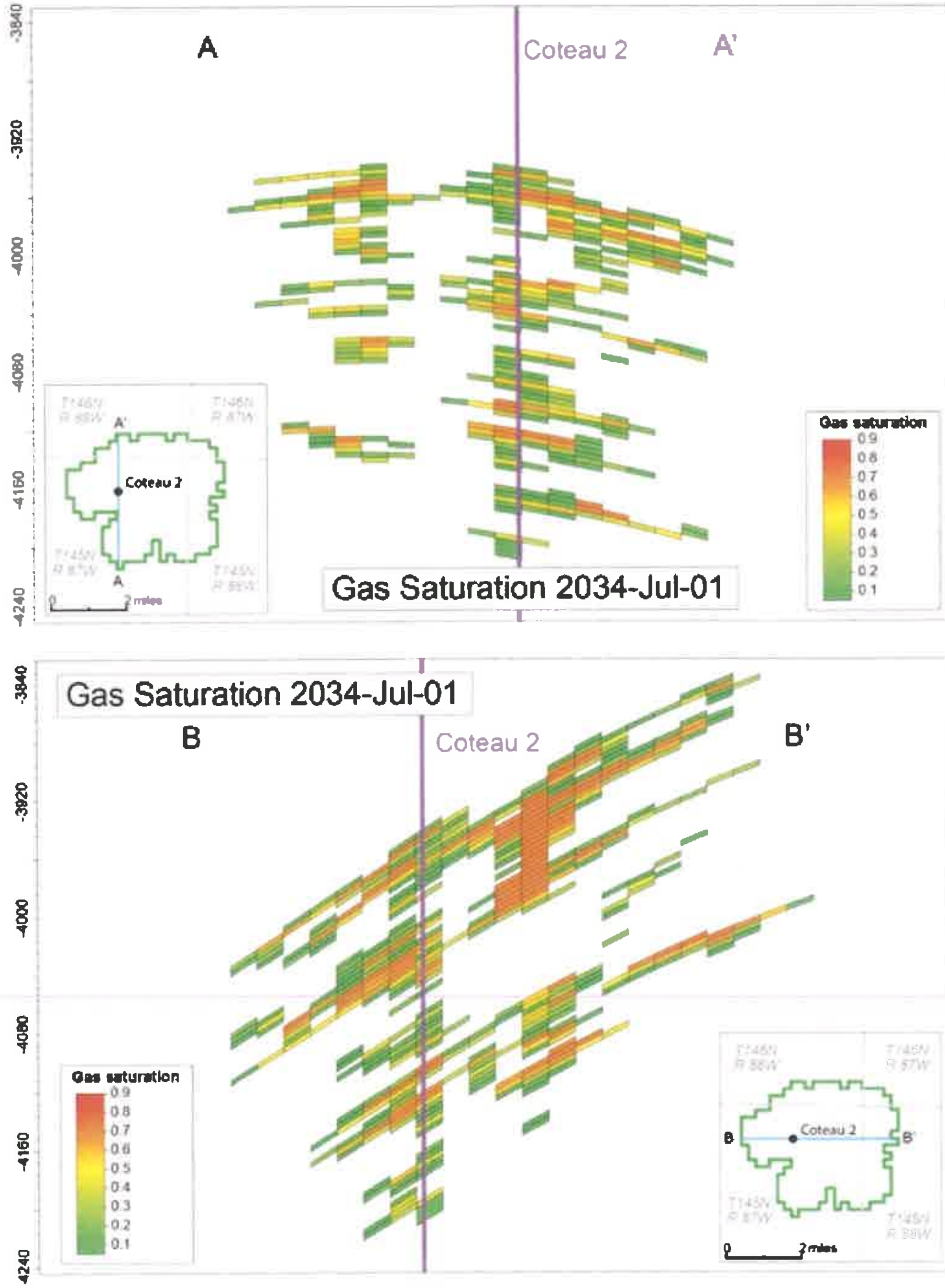


Figure 3-22. CO_2 plume cross section of Coteau 2 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

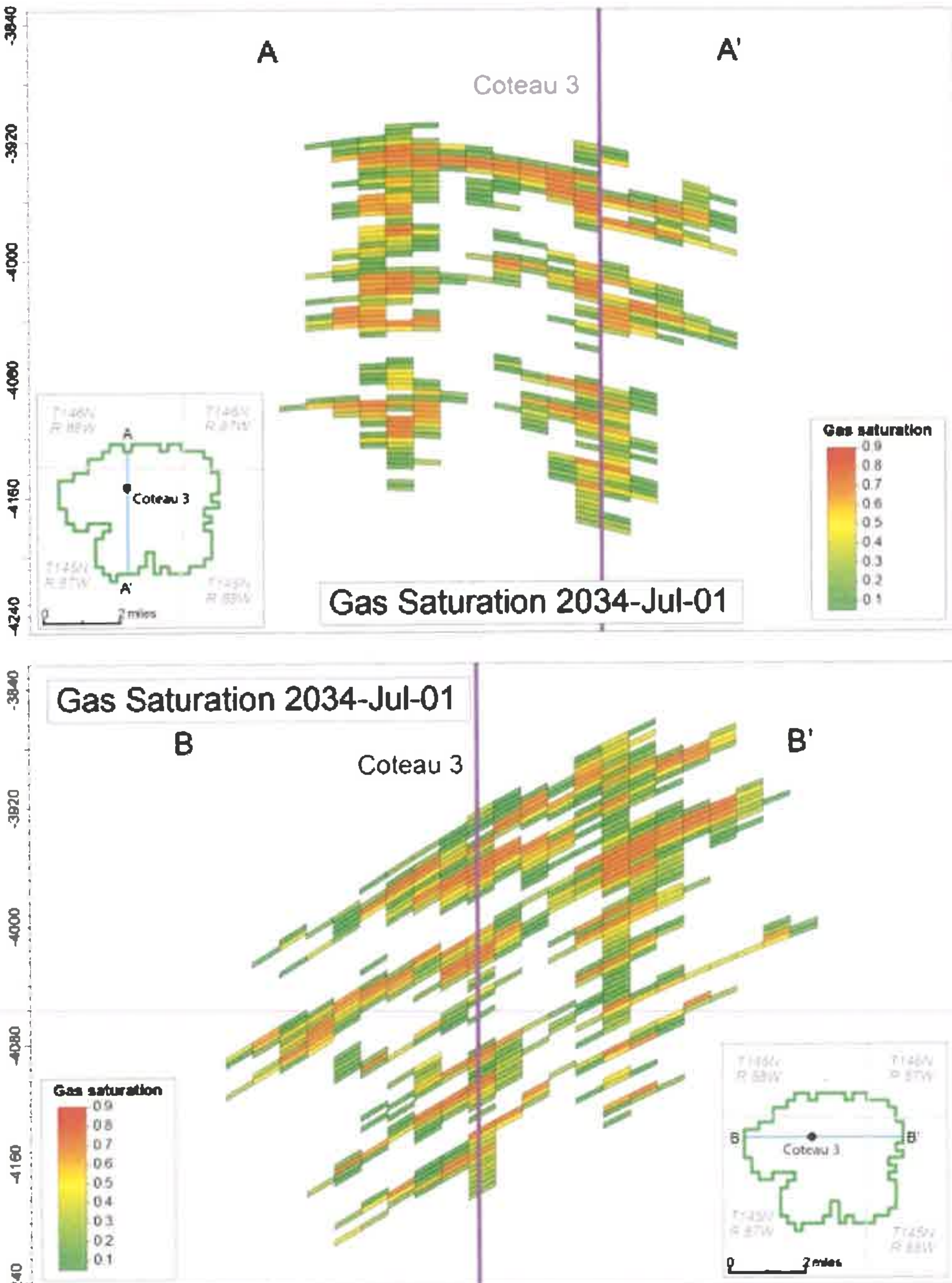


Figure 3-23. CO_2 plume cross section of Coteau 3 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

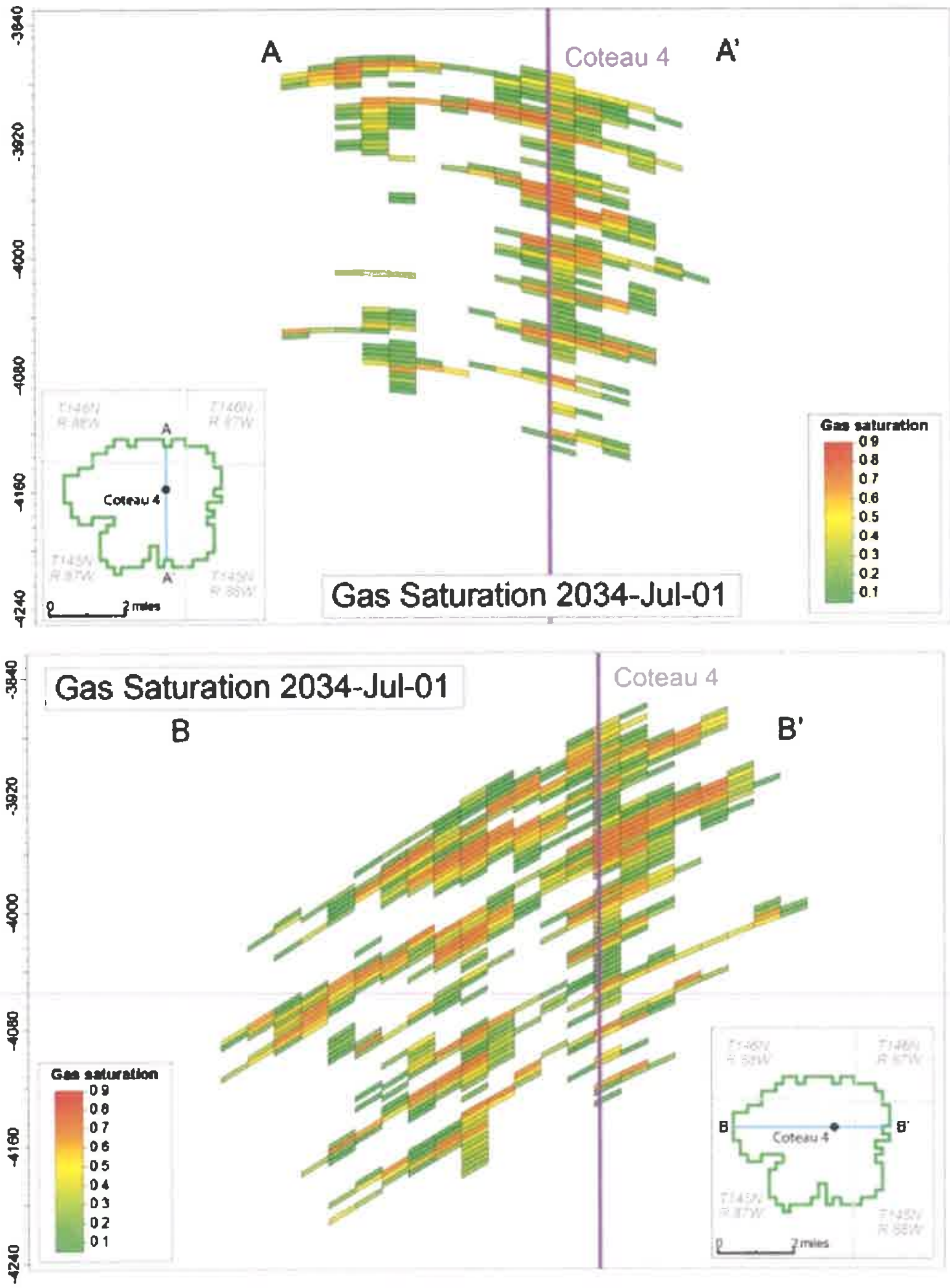


Figure 3-24. CO_2 plume cross section of Coteau 4 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

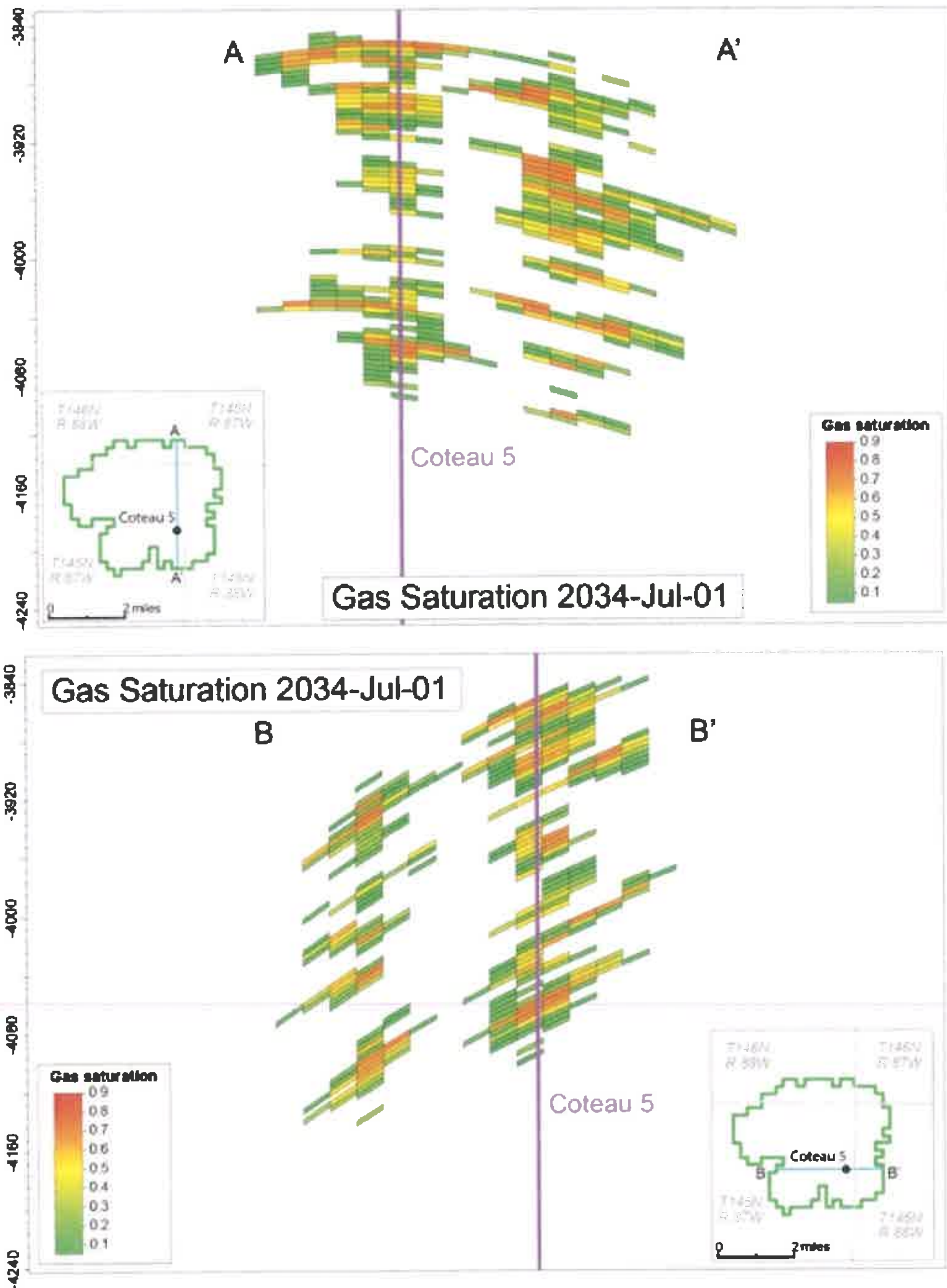


Figure 3-25. CO_2 plume cross section of Coteau 5 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

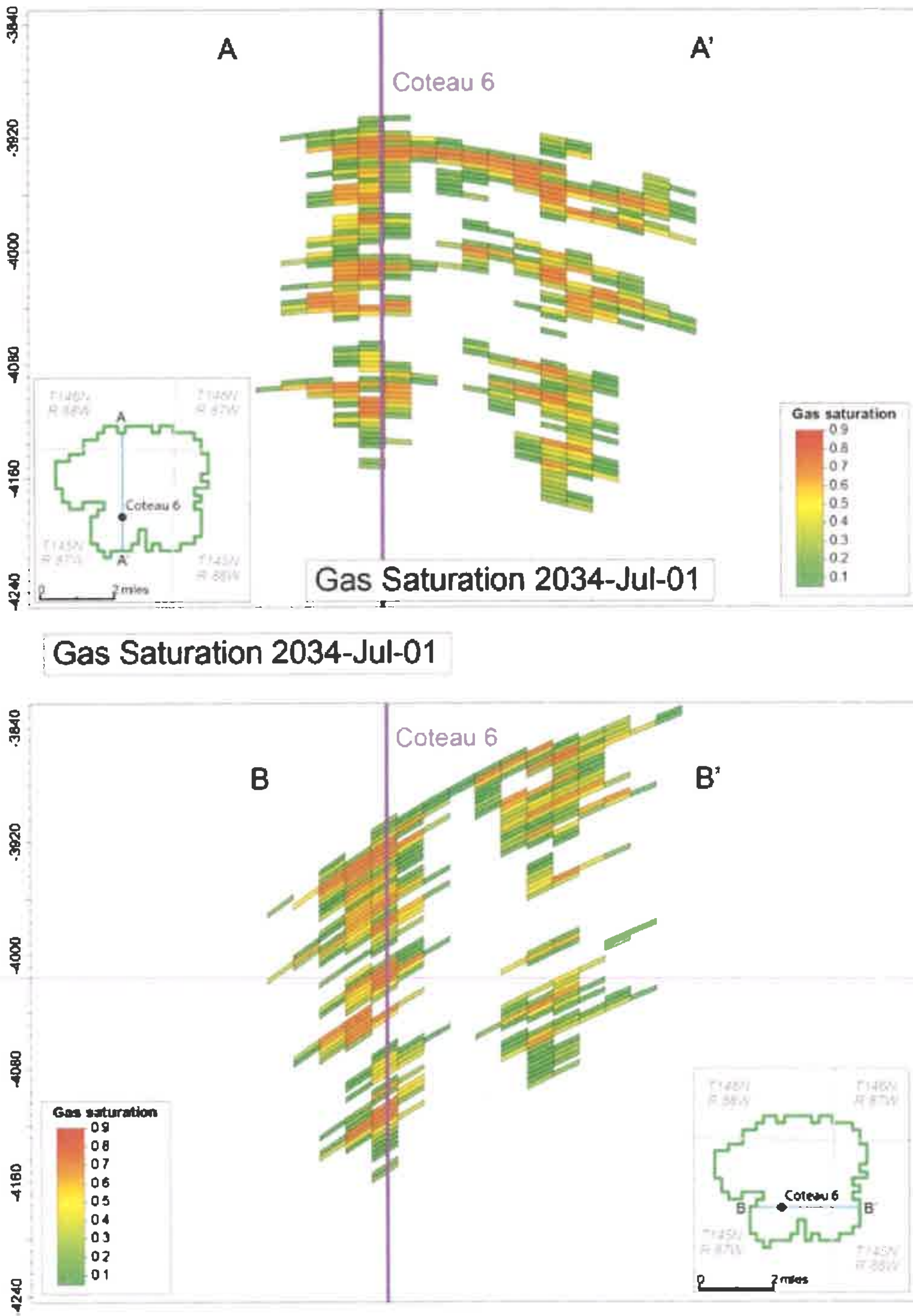


Figure 3-26. CO_2 plume cross section of Coteau 6 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

3.4.1 Maximum Surface Injection Pressure

An additional case was run to determine if the wells would ultimately be limited by maximum calculated downhole pressures of 3,754 psi for Coteau 1, 3,802 psi for Coteau 2, 3,772 psi for Coteau 3, 3,787 psi for Coteau 4, 3,776 psi for Coteau 5, and 3,786 psi for Coteau 6, Table 3-3.

The fracture propagation pressure gradient was used to calculate the maximum BHP constraints, based upon 90% of the fracture propagation pressure multiplied by the well depth at the top of the Broom Creek Formation. In this scenario, the group injection limit of 55 MMcfd from July 2022 to December 2024, 70 MMcfd from January 2025 to April 2026, and 140 MMcfd from May 2026 to July 2034, with the maximum injection rate constraint per well, was removed. Other parameters were kept the same as previously described for the additional tests.

The maximum BHPs were reached in the simulation. At the maximum BHP values, the corresponding predicted maximum wellhead injection pressure responses are shown in Figure 3-27.

In this scenario, the CO_2 injection wells were able to inject an average of 52.96 MMcfd of CO_2 per well (or 2685 tonnes/day of CO_2), with the planned 4½-in.-diameter tubing, thereby achieving a total injection volume of 64.18 MMt (1.257 Bcf) of CO_2.

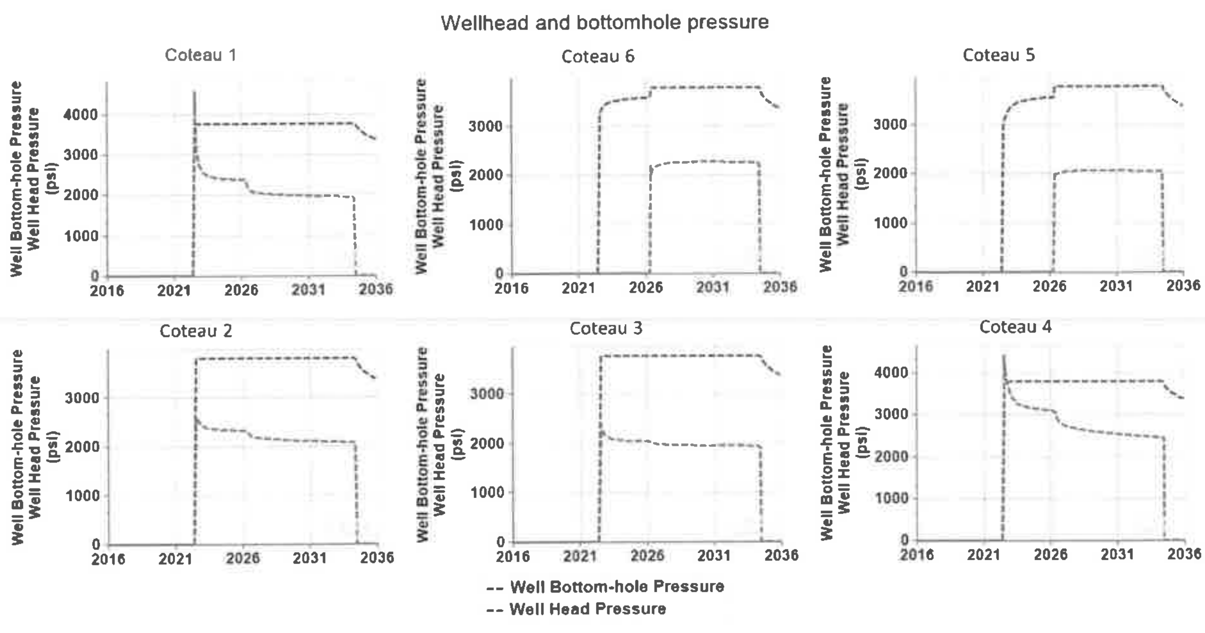


Figure 3-27. Maximum pressure responses (wellhead and bottomhole) when the wells were operated without any injection rate limits.

3.4.2 Stabilized Plume

Movement of the injected CO_2 plume is driven by the potential energy found in the buoyant force of the injected CO_2. As the plume spreads out within the reservoir and CO_2 is trapped residually through the effects of relative permeability and dissolution, the potential energy of the buoyant CO_2 is gradually lost. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized. The extent of the stabilized plume is important for determining the project's AOR and the corresponding scale and scope of the project's monitoring plans.

Plume stabilization can be visualized at the microscale as CO_2 being unable to exit its current pore space and enter the neighboring pore space, but at the macroscale, these interactions cannot be measured. Instead, plume stabilization may be estimated using the tools available to predict the CO_2 plume's extent. For the Great Plains CO_2 Project, stabilization was defined as the time when CO_2 no longer migrates to adjacent cells within the simulation model. CO_2 may still experience gradual redistribution within the plume, but the geographic extents of the plume remain unchanged.

The CO_2 plume was simulated in 5-year time steps until the rate of total areal extent change slowed to less than 0.25 square miles per 5-year time step to define the stabilized plume extent boundary and the associated buffers and boundaries (Figure 3-20). This estimate is anticipated to be regularly updated during the CO_2 storage operation as data collected from the site are used to update predictions made about the behavior of the injected CO_2.

3.5 Delineation of the Area of Review

The North Dakota Administrative Code (NDAC) defines the AOR as the region surrounding the geologic storage project where USDWs may be endangered by CO_2 injection activity (NDAC § 43-05-01-05). The primary endangerment risk is the potential for vertical migration of CO_2 and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the CO_2 plume within the storage reservoir.

However, the CO_2 plume has an associated pressure front where CO_2 injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the CO_2 plume. Therefore, the AOR encompasses both the areal extent of the CO_2 plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the CO_2 plume, AOR delineation focuses on the pressure front.

The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. U.S. Environmental Protection Agency (EPA) guidance for AOR delineation under the Underground Injection Control (UIC) Program for Class VI wells provides several methods for estimating the critical threshold pressure increase and resulting critical threshold pressure.

In this document, "storage reservoir" refers to the Broom Creek Formation (the injection zone), and the "lowest USDW" refers to the Fox Hills Formation.

3.5.1 EPA Methods 1 and 2: AOR Delineation for Class VI Wells

EPA (2013) guidance for AOR evaluation includes several computational methods for estimating the pressure buildup in the storage reservoir in response to CO_2 injection and the resultant areal extent of pressure buildup above a "critical threshold pressure" that could potentially drive higher salinity formation fluids from the storage reservoir up an open conduit to the lowest USDW. The following equations and analytical approach define the EPA methods used to delineate AOR. Each method can be applied both at a single location (e.g., the Coteau 1 stratigraphic well) using site-specific data or for each vertical stack of grid cells in a geocellular model, considering the varying stratigraphic thickness between storage reservoir and lowest USDW.

EPA (2013) Method 1 (*pressure front based on bringing the injection zone and USDW to equivalent hydraulic heads*) is presented as a method for determining whether a storage reservoir is in hydrostatic equilibrium with the lowest USDW. Under Method 1, the maximum pressure increase that may be sustained in the injection zone (critical threshold pressure increase) is given by:

$$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_i \qquad \text{[Eq. 1]}$$

Where:

P_u is the initial fluid pressure in the USDW (Pa).
ρ_i is the storage reservoir fluid density (mg/m^3).
g is the acceleration due to gravity (m/s^2).
z_u is the representative elevation of the USDW (m amsl).
z_i is the representative elevation of the injection zone (m amsl).
P_i is the initial pressure in the injection zone (Pa).
$\Delta P_{i,f}$ is the critical threshold pressure increase (Pa).

Equation 1 assumes that the hypothetical open borehole is perforated exclusively within the injection zone and USDW. If $\Delta Pi,f = 0$, then the reservoir and USDW are in hydrostatic equilibrium; if $\Delta Pi,f > 0$, then the reservoir is underpressurized relative to the USDW; and if $\Delta Pi,f < 0$, then the reservoir is overpressurized relative to the USDW.

In scenarios where the storage reservoir and USDW are in hydrostatic equilibrium ($\Delta P_{i,f} = 0$), EPA Method 2 (*pressure front based on displacing fluid initially present in the borehole*) can be used to calculate the critical pressure threshold. Method 2 was originally presented by Nicot and others (2008) and Bandilla and others (2012). Method 2 calculates the critical threshold pressure increase (ΔP_c), which is the fluid pressure increase sufficient to drive formation fluids into the lowermost USDW. This ΔP_c is determined using Equations 2 and 3, assuming 1) hydrostatic conditions, 2) initially linearly densities in the borehole, and 3) constant density once the injection zone fluid is lifted to the top of the borehole (i.e., uniform density approach):

$$\Delta P_C = \frac{1}{2}\, g\, \xi\, (Z_u - Z_i)^2 \qquad \text{[Eq. 2]}$$

Where ξ is a linear coefficient determined by:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i} \quad \text{[Eq. 3]}$$

Where:

ΔP_c is the critical threshold pressure increase (Pa).
g is the acceleration of gravity (m/s^2).
z_u is the elevation of the base of the lowermost USDW (m amsl).
z_i is the elevation of the top of the injections zone (m amsl).
ρ_i is the fluid density in the injection zone (kg/m^3).
ρ_u is the fluid density in the USDW (kg/m^3).

3.5.2 Risk-Based AOR Delineation

The methods described by EPA (2013) for estimating the AOR under the Class VI Rule were developed assuming that the storage reservoirs would be in hydrostatic equilibrium with overlying aquifers. However, in the state of North Dakota, and potentially elsewhere around the United States, candidate storage reservoirs are already overpressurized relative to overlying aquifers and thus subject to potential vertical formation fluid migration from the storage reservoir to the lowermost USDW even prior to the planned storage project. Consequently, applying EPA (2013) methods to these geologic situations essentially results in an infinite AOR, which makes regulatory compliance infeasible.

Several researchers have recognized the need for alternative methods for estimating the AOR for locations that are already overpressurized relative to overlying aquifers. For example, Birkholzer and others (2014) described the unnecessary conservatism in EPA's definition of critical pressure, which could lead to a heavy burden on storage facility permit applicants. As an alternative, Burton-Kelly and others (2021) proposed a risk-based reinterpretation of this framework that would allow for a reduction in the AOR while ensuring protection of drinking water resources.

A computational framework for estimating a risk-based AOR was proposed by Oldenburg and others (2014, 2016), who compared formation fluid leakage through a hypothetical open flow path in the baseline scenario (no CO_2 injection) to the incrementally larger leakage that would occur in the CO_2 injection case. The modeling for the risk-based AOR used semianalytical solutions to single-phase flow equations to model reservoir pressurization and vertical migration through leaky wells. These semianalytical solutions were extensions of earlier work for formation fluid leakage through abandoned wellbores by Raven and others (1990) and Avci (1994), which were creatively solved, coded, and compiled in FORTRAN under the name, ASLMA (Analytical Solution for Leakage in Multilayered Aquifers) and extensively described by Cihan and others (2011, 2012) (hereafter "ASLMA Model").

Recently, White and others (2020) outlined a similar risk-based approach for evaluating the AOR using the National Risk Assessment Partnership (NRAP) Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS). However, the NRAP-IAM-CS and subsequent open-sourced version (NRAP-Open-IAM) are constrained to the assumption that the storage reservoir is in hydrostatic equilibrium with overlying aquifers and, therefore, may not accurately estimate the AOR for storage projects located in regions where the storage reservoir is overpressurized relative to overlying aquifers.

Building a geologic model in a commercial-grade software platform (like Schlumberger Petrel) and running fluid flow simulations using numerical reservoir simulation in a commercial-grade software platform (like CMG's compositional simulator, GEM) provide the "gold standard" for estimating pressure buildup in response to CO_2 injection (e.g., Bosshart and others, 2018). However, these numerical reservoir simulations are typically limited to the storage reservoir and primary seal formation (cap rock) and do not include the geologic units overlying the cap rock because of the computational burden of conducting such a complex simulation. In addition, geologic modeling of the overlying units may add a substantial amount of time and effort during prefeasibility-phase projects that is unwarranted given the amount of uncertainty that may be present if only few nearby wells can be used for characterization activities. Earlier studies (e.g., Nicot and others, 2008; Birkholzer and others, 2009; Bandilla and others, 2012; Cihan and others, 2011, 2012) have shown that far-field fluid pressure changes outside of the CO_2 plume domain can be reasonably well described by a single-phase flow calculation by representing CO_2 injection as an equivalent-volume injection of brine (Oldenburg and others, 2014).

The semianalytical solutions embedded within the ASLMA Model have been shown to compare with the numerical model, TOUGH2-ECO2-N, and provided accurate results for pressures beyond the CO_2 plume zone (Birkholzer and others, 2009; Cihan and others, 2011, 2012). Therefore, the proposed workflow for delineating a risk-based AOR uses the ASLMA Model to examine pressure buildup in the storage reservoir and resultant effects of this buildup on the vertical migration of formation fluid via (single) hypothetical leaky wellbores located at progressively greater distances from the injection well (Figure 3-28).

An important distinction between EPA Methods 1 and 2, which both calculate a critical pressure threshold (either $\Delta P_{i,f}$ for Method 1 or ΔP_c for Method 2) and the risk-based AOR approach is that the risk-based approach 1) calculates and maps the potential incremental flow of formation fluids from the storage reservoir to the USDW that could occur and then 2) delineates the areal extent beyond which no significant leakage would occur. Therefore, the region beyond which no significant leakage would occur does not present an endangerment to the USDW; hence, the region inside of this areal extent is the risk-based AOR.

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021). Inputs, assumptions, and results are discussed in the current document.

Establish the Site Stratigraphy and Properties

- Simplify the storage complex stratigraphy into hydrostratigraphic units.
- Use the best available site characterization data to estimate the average depth, thickness, pressure, temperature, porosity, permeability, and salinity for each unit.

Use the ASLMA Excel Workbook to Derive Additional Inputs Needed for the ASLMA Model

- Derive the hydraulic conductivity and specific storage for each unit.
- Compute the initial hydraulic heads for each unit.
- Place a CO_2 injection well at the center of the coordinate reference system (0, 0).
- Convert the CO_2 mass injection rate into an equivalent-volume injection of formation fluid.
- Establish the effective permeability of the hypothetical leaky wellbore and the distances from the injection well to quantify the formation fluid leakage up a leaky wellbore located at progressively greater distances from the injection well.
- Use the ASLMA User Guide for reference and to inform additional inputs.

Integrate ASLMA Model Outputs with Results from Numerical Reservoir Simulation

- Run the ASLMA Model using the included custom scripting and generate standardized outputs.
- Derive the incremental leakage to the lowermost underground source of drinking water (USDW) by taking the difference between the baseline (no CO_2 injection) and injection cases.
- If applicable, generate results for cases with and without the leaky wellbore open to a saline aquifer (thief zone) located between the primary seal (cap rock) and the USDW.
- Derive the storage reservoir pressure buildup-USDW incremental leakage relationship.
- Using the derived relationship in the preceding step, generate potential incremental leakage maps based on the pressure buildup in response to CO_2 injection as determined by a compositional simulator.

Delineate Risk-Based Area of Review (AoR)

- Apply threshold criteria to the incremental leakage maps to delineate a risk-based AoR.
- Assess the sensitivity of the risk-based AoR to different input assumptions or risk judgments.

Figure 3-28. Workflow for delineating a risk-based AOR for a storage facility permit (modified from Burton-Kelly and others, 2021).

3.5.3 Critical Threshold Pressure Increase Estimation

For the purposes of delineating AOR for the Great Plains CO_2 Project study area, constant fluid densities for the lowermost USDW (Fox Hills Formation) and injection zone (Broom Creek Formation) were used in the calculations. A density of 1001 kg/m^3 was used to represent the USDW fluids (ρ_u), and a density of 1017 kg/m^3 was used to represent the injection zone fluids (ρ_i), which is estimated based on the in situ brine salinity, temperature, and pressure as measured with an MDT tool from the Coteau 1 stratigraphic test well.

Application of EPA Method 1 (Equation 1) using site-specific data from the Coteau 1 well shows that the injection zone in the Great Plains CO_2 Project area is overpressurized with respect to the lowest USDW (i.e., Method 1 $\Delta P_{i,f} < 0$). An example of the EPA Method 1 application showing negative $\Delta P_{i,f}$ (relative overpressure) is given in Table 3-7, with similar results when applied to each column of the grid cells in the Broom Creek Formation simulation model.

Table 3-7. EPA Method 1 Critical Threshold Pressure Increase Calculated at the Coteau 1 Wellbore Location Using MDT Data

Depth*		P_i Injection Zone Pressure	P_u USDW Pressure	ρ_i Injection Zone Density	Z_u USDW Base Elevation	Z_i Reservoir Elevation	$\Delta P_{i,f}$ Threshold Pressure Increase	
ft	m	MPa	MPa	kg/m^3	m amsl	m amsl	MPa	psi
5,975	1,811	20.25	5.12	1,017	102	−1,207	−2.08	−302

* Ground surface elevation is 608 m above mean sea level.

In accordance with EPA (2013) guidance, the combination of a) a Method 1 negative $\Delta P_{i,f}$ value across the Great Plains CO_2 Project area and b) lack of evidence for hydrostatic equilibrium between the reservoir and the USDW (i.e., Method 2 does not apply) indicates that a risk-based approach to AOR delineation may be pursued.

3.5.4 Risk-Based AOR Calculations

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021). The inputs, assumptions, and results discussed here provide the necessary details for reproducing and verifying the results. A macro-enabled Microsoft Excel file was used to define the inputs and calculations that were employed used in the method (hereafter "ASLMA Workbook").

3.5.4.1 Initial Hydraulic Heads

The original ASLMA Model (Cihan and others, 2011) initially assumed hydrostatic pressure distributions in the entire system. The current work uses a modified version of the ASLMA Model to simulate pressure perturbations and leakage rates when there are initial head differences in the aquifers (Oldenburg and others, 2014). The initial hydraulic heads are calculated assuming an equivalent freshwater head based on the unit-specific elevations and pressures. The equivalent freshwater heads are entered into the ASLMA Model and establish the initial pressure conditions for the storage complex prior to CO_2 injection.

For example, the initial reference case equivalent freshwater heads for the storage reservoir (Aquifer 1), potential thief zone (Aquifer 2), and USDW (Aquifer 3) are 832, 613, and 623 m, respectively, which illustrate the state of overpressure in the storage complex, as Aquifer 1 has a greater initial hydraulic head than Aquifers 2 and 3. Therefore, the storage complex requires different treatment than the default AOR calculations described by EPA (2013). Details on the calculations of initial hydraulic head are provided in Burton-Kelly and others (2021).

3.5.4.2 CO_2 Injection Parameters

The ASLMA Model for the Great Plains CO_2 Project used a Broom Creek CO_2 injection rate that matched the simulation scenario. A single injector is placed at the center of the ASLMA model grid at an x,y-location of (0,0) in the coordinate reference system. The ASLMA Model requires the CO_2 injection rate to be converted into an equivalent-volume injection of formation fluid in units of cubic meters per day. Microsoft Excel VBA functions were used to estimate the CO_2 density from the storage reservoir pressure and temperature, which resulted in an estimated density of 672 kg/m^3. The CO_2 mass injection rate and CO_2 density are then used to derive the daily equivalent-volume injection rate of approximately 4,333 m^3 per day for 2.5 years followed by 5,515 m^3 per day for 1.3 years, followed by 11,030 m^3 per day for 8.2 years.

3.5.4.3 Hypothetical Leaky Wellbore

In the Great Plains CO_2 Project area, few wellbores are known to exist that penetrate the primary seal of the Broom Creek storage reservoir. However, for heuristic, "what-if" scenario modeling, which is needed to generate the data for delineating a risk-based AOR, a single hypothetical leaky wellbore is inserted into the ASLMA Model at 1, 2, …, 100 km from the CO_2 injection well. The pressure buildup in the storage reservoir at each distance, along with the recorded cumulative volume of formation fluid vertically migrating through the leaky wellbore from the storage reservoir to the USDW (i.e., from Aquifer 1 to Aquifer 3) throughout the 12-year injection period, provides the data set needed to derive the risk-based AOR.

Published ranges for the effective permeability of a leaky wellbore (Figure 3-27) have included an "open wellbore" with an effective permeability as high as 10^{-5} m^2 (10^{10} mD) to values more representative of leakage through a wellbore annulus of 10^{-12} to 10^{-10} m^2 (10^3 to 10^5 mD) (Watson and Bachu, 2008, 2009; Celia and others, 2011). Carey (2017) provides probability distributions for the effective permeability of potentially leaking wells at CO_2 storage sites and estimated a wide range from 10^{-20} to 10^{-10} m^2 (10^{-5} to 10^5 mD). For the Great Plains CO_2 Project Broom Creek ASLMA Model, the effective permeability of the leaky wellbore is set to 10^{-16} m^2 (0.1 mD), which is a relatively conservative (highly permeable) value near the top of the published range for the effective permeability of potentially leaking wells at CO_2 storage sites (Figure 3-29).

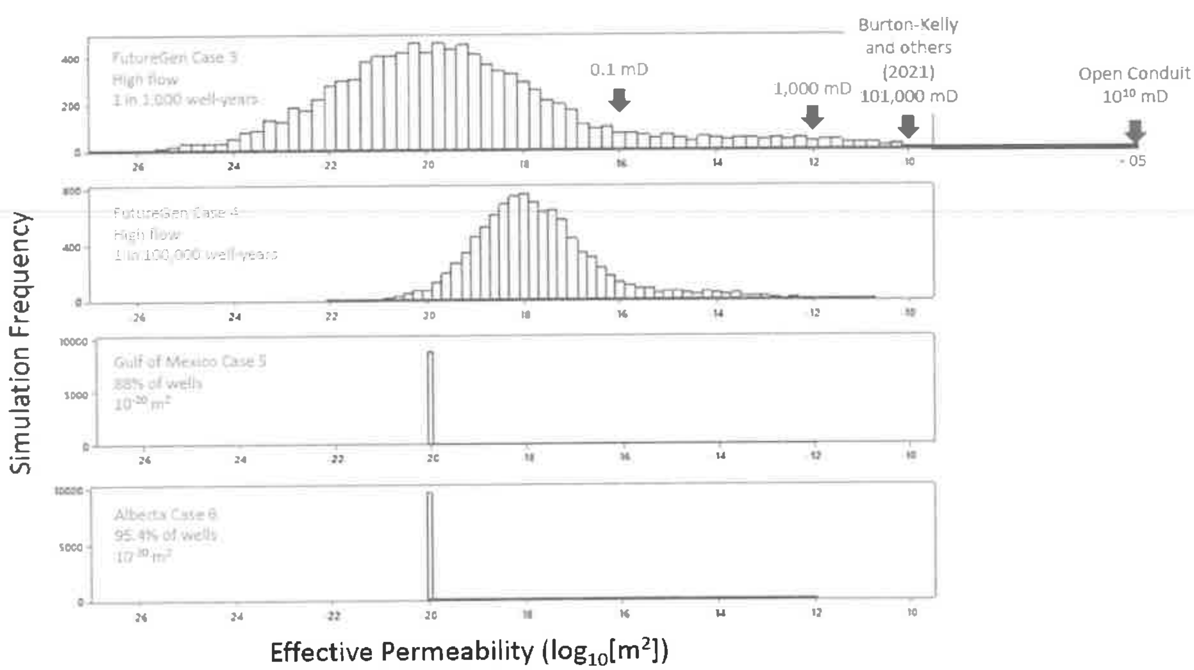


Figure 3-29. Histograms describing the expected frequency of leaky wellbore effective permeabilities under different scenarios. The ASLMA model used for AOR delineation used a value of approximately 0.1 mD. Constructed from data presented by Carey (2017).

The current work uses the ASLMA Model Type 1 feature (focused leakage only) for the nominal model response, which makes the conservative assumption that the aquitards are impermeable. This assumption prevents the pressure from diffusing into the overlying aquitards, resulting in a greater pressure buildup in the storage reservoir and a commensurately greater amount of formation fluid vertically migrating from the storage reservoir through the leaky wellbore. The conservative assumption of Model Type 1 rather than Model Type 3 (coupled focused and diffuse leakage) provides an added level of protection to the delineation of a risk-based AOR by projecting a larger pressure buildup in the storage reservoir than a scenario in which pressure is allowed to dissipate through the upper seal and, therefore, a greater leakage of formation fluid up the leaky wellbore.

3.5.4.4 Saline Aquifer Thief Zone

As shown in Table 3-7, a saline aquifer (Aquifer 2, Inyan Kara Formation) exists between the primary seal above the storage reservoir and USDW (Aquifer 3, Fox Hills Formation). Formation fluid migrating up a leaky wellbore that is open to Aquifer 2 will preferentially flow into Aquifer 2, and the continued flow up the wellbore and into the USDW will be reduced. Therefore, the presence of Aquifer 2 may act as a thief zone and reduces the potential for formation fluid impacts to the groundwater.

The thief zone phenomenon was described by Nordbotten and others (2004) as an "elevator model" by analogy with an elevator full of people on the main floor, who then get off at various floors as the elevator moves up, such that only very few people ride all the way to the top floor. The term "thief zone" is also used in the oil and gas industry to describe a formation encountered during drilling into which circulating fluids can be lost. Models with and without opening the leaky wellbore to Aquifer 2 (Inyan Kara Formation) were run and evaluated to quantify the effect of a thief zone on the risk-based AOR.

3.5.4.5 Aquifer- and Aquitard-Derived Properties

The ASLMA Model assumes homogeneous properties within each hydrostratigraphic unit (Table 3-7). For each unit shown in Table 3-7, pressure, temperature, porosity, permeability, and salinity are used to derive two key inputs for the ASLMA Model: hydraulic conductivity (HCON) and specific storage (SS). Average porosity and permeability values were derived as follows: Broom Creek, from distributed properties in the geologic model; Inyan Kara, from Coteau 1 well log data; and Fox Hills, from regional well log data. Porosity is represented as an arithmetic mean and permeability as a geometric mean values within each hydrostratigraphic unit (excluding non-sandstone rock types).

Visual Basic for Applications (VBA) functions included in the ASLMA Workbook are used to estimate the formation fluid density and viscosity from the aquifer or aquitard pressure, temperature, and salinity inputs, which are then used to estimate the HCON and SS. The estimated reference case HCON for the storage reservoir (Aquifer 1), thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table 3-8. Details about the HCON and SS derivations are provided in Supporting Information for Burton-Kelly and others (2021).

Table 3-8. Simplified Stratigraphy and Average Properties Used to Represent the Storage Complex

Hydrostratigraphic Unit	Depth to Top,* m	Thickness, m	Pressure, MPa	Temperature, °C	Salinity, ppm	Porosity, %	Permeability, mD	Permeability, m^2	HCON, m/d	Specific Storage, m^{-1}	Equivalent Freshwater Head, m
Overlying Units to Ground Surface (not directly modeled)	0	420									
Aquifer 3 (USDW–Fox Hills Fm)	420	89	4.7	19.6	1,800	34.4	280	2.76E-13	2.32E-01	7.82E-06	623
Aquitard 2 (Pierre Fm-Inyan Kara Fm)	509	849	9.3	33.3	22,800	10	0.1	9.87E-17	1.09E-04	1.25E-05	612
Aquifer 2 (Thief Zone–Inyan Kara Fm)	1,359	116	14.0	57.7	22,800	20.1	41.8	4.13E-14	6.92E-02	8.27E-06	634
Aquitard 1 (Swift—Broom Creek Fm) (primary upper seal)	1,474	355	16.4	54.3	42,800	10	0.1	9.87E-17	1.53E-04	1.28E-09	597
Aquifer 1 (Storage Reservoir – Broom Creek Fm)	1,829	77	20.8	70.8	42,800	14.5	246.7	2.44E-14	4.75E-01	8.46E-06	832

* Ground surface elevation 614 m amsl.

3.5.5 Risk-Based AOR Results

3.5.5.1 Relating Pressure Buildup to Incremental Leakage with ASLMA Model and Compositional Simulation

Figure 3-28 shows the relationship between the maximum pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 (USDW) for scenarios with and without the leaky wellbore open to Aquifer 2 (thief zone). In the case where the leaky wellbore is closed to Aquifer 2, there is no incremental leakage to Aquifer 2. The curvilinear relationship between pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 is used to predict the incremental leakage from the pressure buildup map produced by the compositional simulation of the geocellular model. The average simulated pressure buildup in the reservoir is represented by a raster (grid) map of pressure buildup values. For each raster value (grid cell map location), the relationship between pressure buildup and incremental leakage (Figure 3-30) is used to predict incremental leakage using a linear interpolation between the points making up the curve. The cumulative leakage potential from Aquifer 1 to Aquifer 3 along a hypothetical leaky wellbore without injection occurring (i.e., leakage due to natural overpressure) and no thief zone is estimated to be 0.01 m^3 over 20 years.

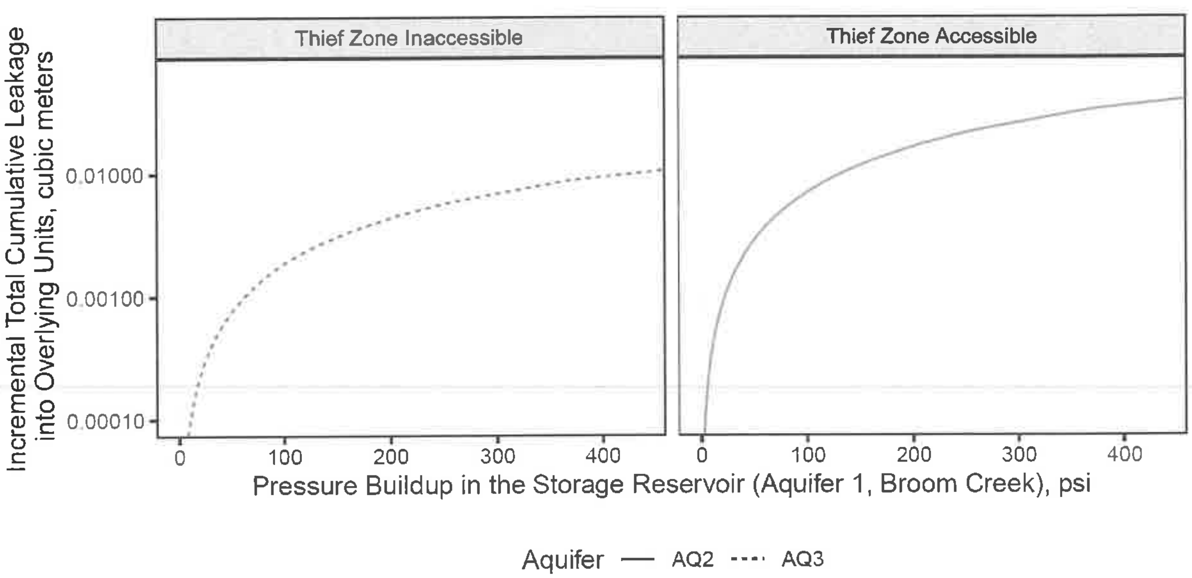


Figure 3-30. Relationship between pressure buildup (x-axis, psi) in the storage reservoir (Aquifer 1, Broom Creek) and incremental total cumulative leakage (y-axis, m^3) into Aquifer 2 (thief zone, Inyan Kara, red solid line) and Aquifer 3 (USDW, Fox Hills, dashed blue line). In the left-hand scenario, the leaky wellbore is closed to Aquifer 2 (Inyan Kara), so all flow is from the storage reservoir to the USDW. In the right-hand scenario, the leaky wellbore is open to Aquifer 2 (Inyan Kara), so the vast majority of flow is from the storage reservoir to the thief zone, and the curve showing flow into the USDW is not visible on this plot.

3.5.5.2 Incremental Leakage Maps and AOR Delineation

The pressure buildup-incremental leakage relationship, shown in Figure 3-28 results in the incremental leakage maps shown in Figure 3-31 which show the estimated total cumulative incremental leakage potential from a hypothetical leaky well into Aquifer 3 (USDW) over the entire 12-year period if the hypothetical leaky wellbore is not open to the thief zone.

The final step of the risk-based AOR workflow is to apply a threshold criterion to the incremental leakage maps to delineate a risk-based AOR. For the Broom Creek Formation injection at the Great Plains CO_2 Project site, a threshold of 1 m^3 of potential incremental flow into the Fox Hills Formation USDW along a hypothetical leaky wellbore over the 12-year injection period is established. A value of 1 m^3 is the lowest meaningful value that can be produced by the ASLMA Model; although the model can return smaller values, they likely represent statistical noise. This potential incremental flow threshold is greater than all calculated potential incremental flow values described by the curve in Figure 3-30. The maximum vertically averaged storage reservoir change in pressure at the end of the simulated injection period was 437 psi in a grid cell intersected by the injection well, which corresponds to less than 0.01 m^3 of flow over 12 years. This pressure is below the potential incremental flow threshold of 1 m^3. Therefore, the storage reservoir pressure buildup is not a deciding factor in determining the AOR extent.

The assumptions and calculations used to determine the risk-based AOR at the Great Plains CO_2 Project site incorporate at least four safety factors for the protection of groundwater resources. If the ASLMA model has resulted in an underestimation of the amount of potential leakage over the injection period, such underestimation is likely to be mitigated by:

- The statistical overestimation of hypothetical leaky wellbore permeability compared to known and estimated values in the literature—A more statistically likely hypothetical leaky wellbore permeability would be lower and allow less flow into the USDW.

- The lack of communication between the hypothetical leaky wellbore and Inyan Kara Formation, which would act as a thief zone—A real leaky wellbore would likely communicate with the Inyan Kara Formation, which would receive much, if not all, of the brine leaked from the storage reservoir.

- The low density of known legacy wellbores in the Great Plains CO_2 Project area—CO_2 injection is proposed to occur in an area with few available leakage pathways.

- The continued overpressurized nature of the Broom Creek Formation with respect to overlying saline aquifers—over relatively short (e.g., 50-year) timescales, overpressurized aquifers with leakage pathways would demonstrate a change in upward flow rate and corresponding pressure (Oldenburg and others, 2016).

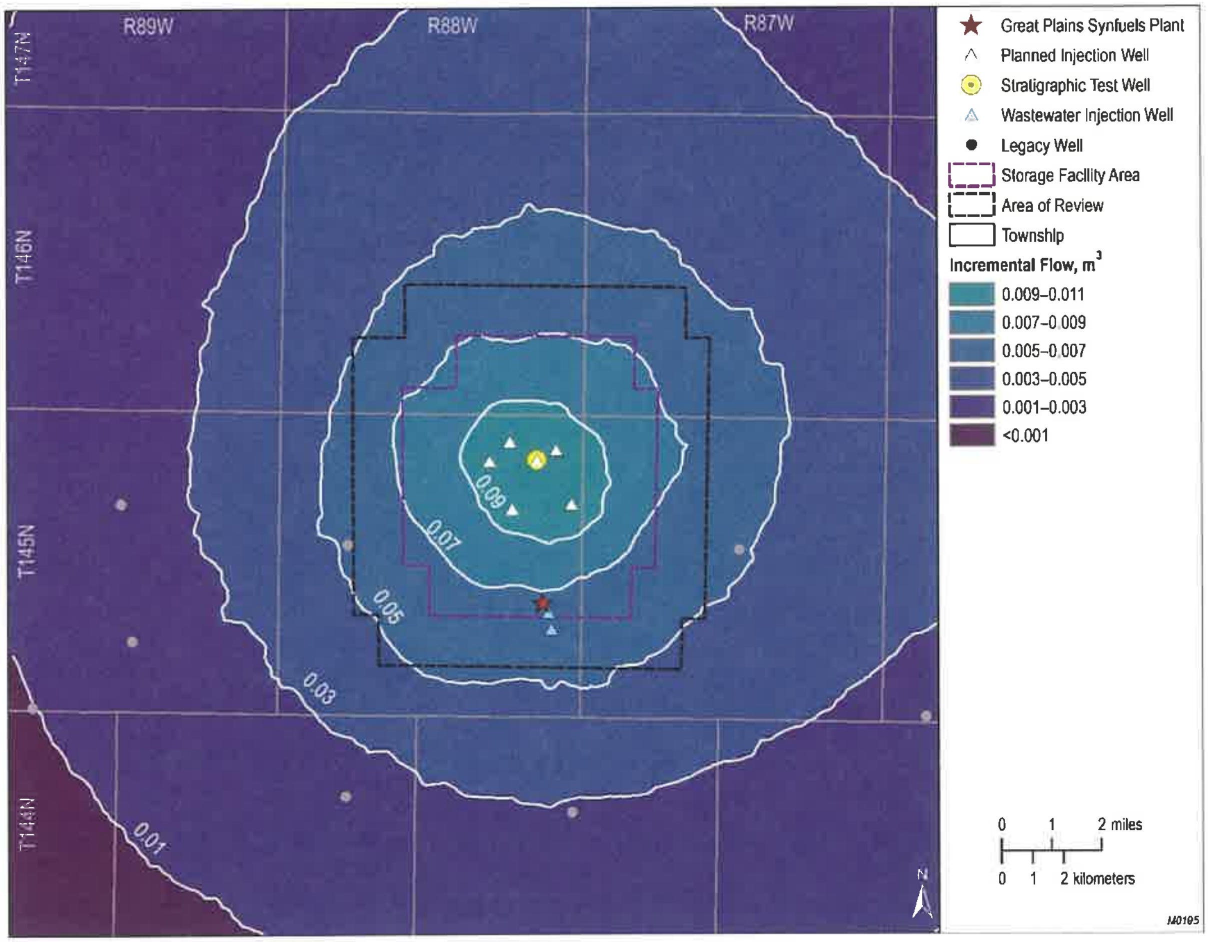


Figure 3-31. Incremental leakage maps at the end of 12 years of CO_2 injection for the scenario where the hypothetical leaky wellbore is closed to Aquifer 2 (thief zone).

Results of the risk-based method detailed above generate a minimum AOR extent which is equivalent to the storage facility area plus a 1-mile buffer. Within the AOR, the pressure increase is not expected to be large enough to cause incremental flow of more than 1 m^3 into the USDW over the injection period (Figure 3-32). As shown, the AOR is depicted by the gray shaded area, which includes the storage facility area. Figure 3-33 illustrates the land use within the AOR.

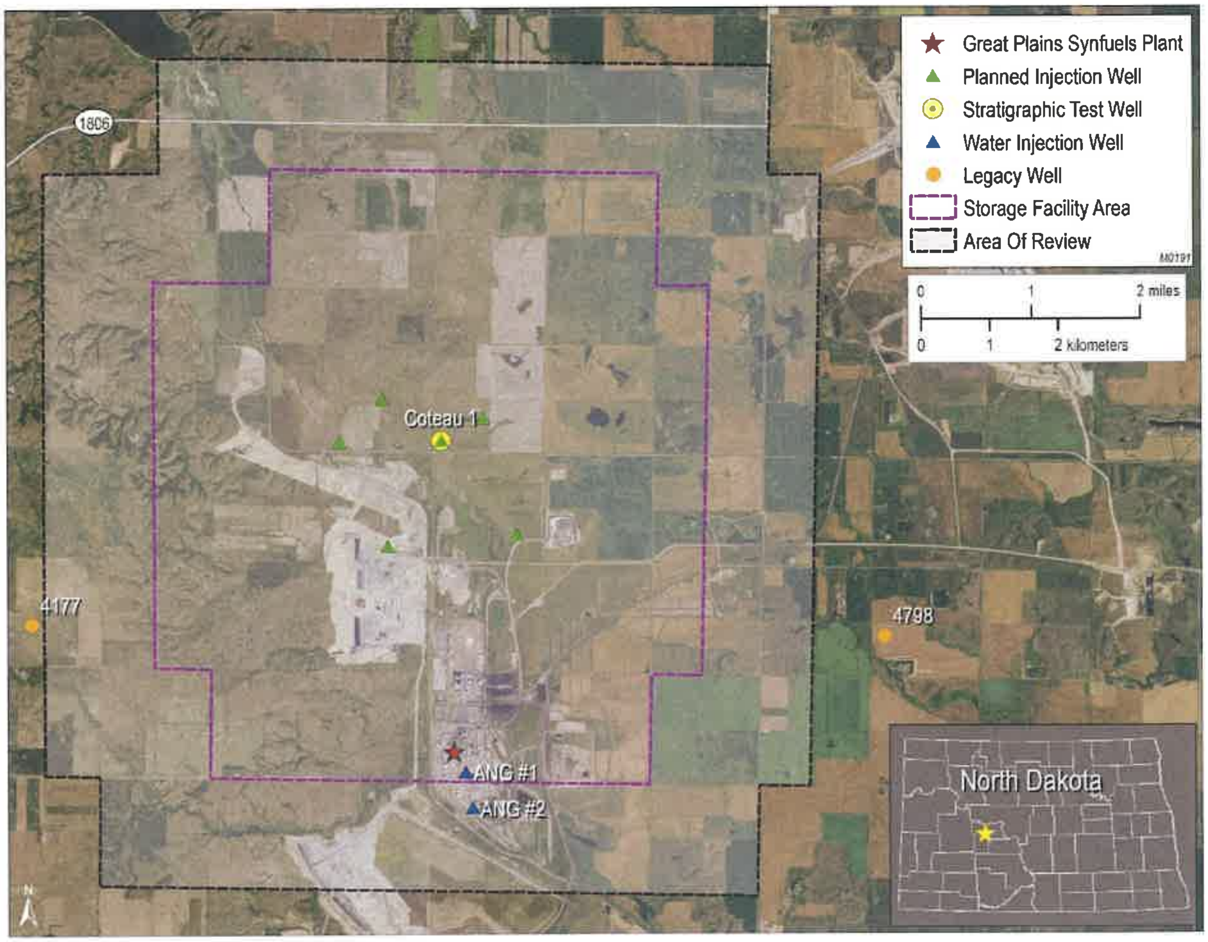


Figure 3-32. Final AOR estimations of the Great Plains CO_2 Project storage facility area in relation to nearby legacy wells. Shown is the storage facility area (purple boundary and shaded area) and area of review (black boundary and shaded area). Orange circles represent nearby legacy wells near the storage facility area.

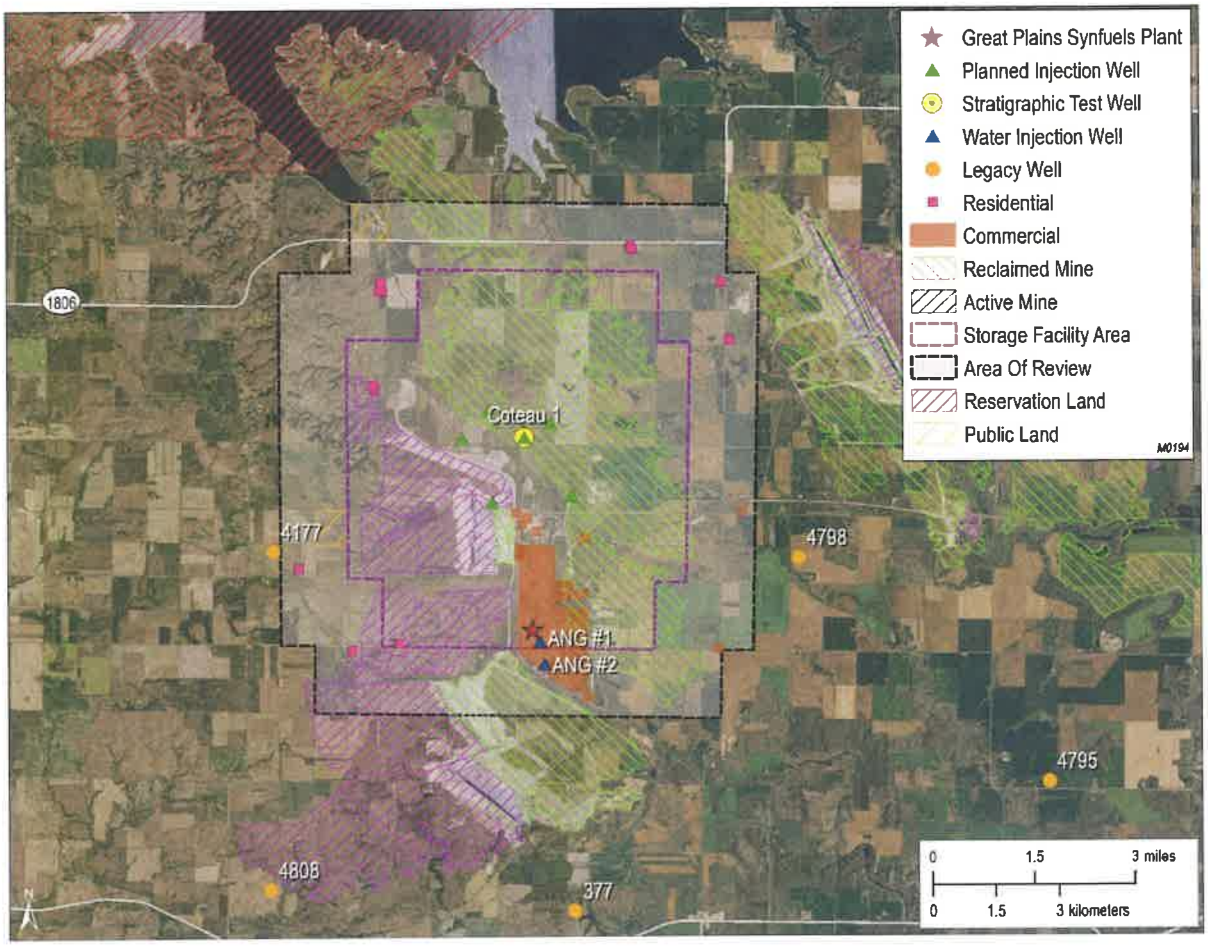


Figure 3-33. Land use in and around the AOR of the Great Plains CO_2 Project storage facility.

3.6 References

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4.0 AREA OF REVIEW

4.0 AREA OF REVIEW

4.1 Area of Review Delineation

4.1.1 Written Description

North Dakota geologic storage of CO_2 regulations require that each storage facility permit delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO_2 plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the Coteau 1 well (NDIC File No. 38379) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-7]).

Section 3 includes a detailed discussion on the computational modeling and simulations (e.g., storage facility area, pressure front, AOR boundary, etc.), assumptions, and justification used to delineate the AOR and method for delineation of the AOR.

NDAC § 43-05-01-05 subsection 1b(3) requires, "A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 4-1), the resulting AOR for the Great Plains CO_2 Sequestration Project is delineated as being 1 mile from the storage facility permit (SFP) boundary. This extent ensures compliance with existing state regulations.

All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 4-2 through 4-5) by a professional engineer pursuant to NDAC § 43-05-01-05 subsection 1b(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected CO_2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 through 4-6 and Figures 4-6 through 4-9).

An extensive geologic and hydrogeologic characterization performed by a team of geologists from the EERC resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.

This section of the SFP application is accompanied by maps and tables that include information required and in accordance with NDAC § 43-05-01-05 subsections 1(a) and 1(b) and 43-05-01-05.1 subsection 2, such as the storage facility area, location of any proposed injection wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05 subsections 1a and 1b(3) and 43-05-01-05.1 subsection 2. Surface features that were investigated but not found within the AOR boundary were identified in Table 4-1.

4.1.2 Supporting Maps

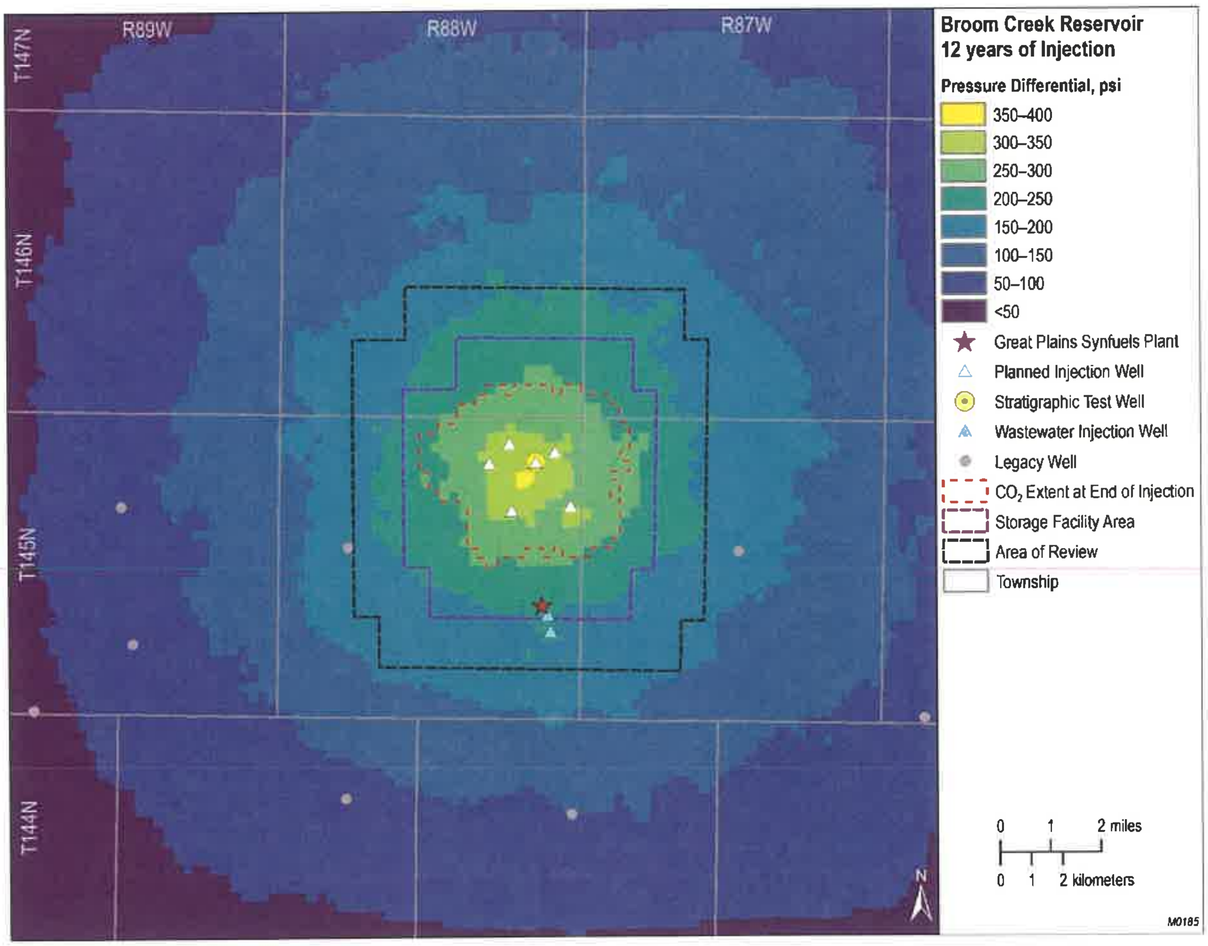


Figure 4-1. Pressure map showing the maximum subsurface pressure influence associated with CO_2 injection in the Broom Creek Formation. Shown is the CO_2 plume extent after end of injection, the storage facility area, and the 1-mile AOR boundary in relation to the maximum subsurface pressure influence.

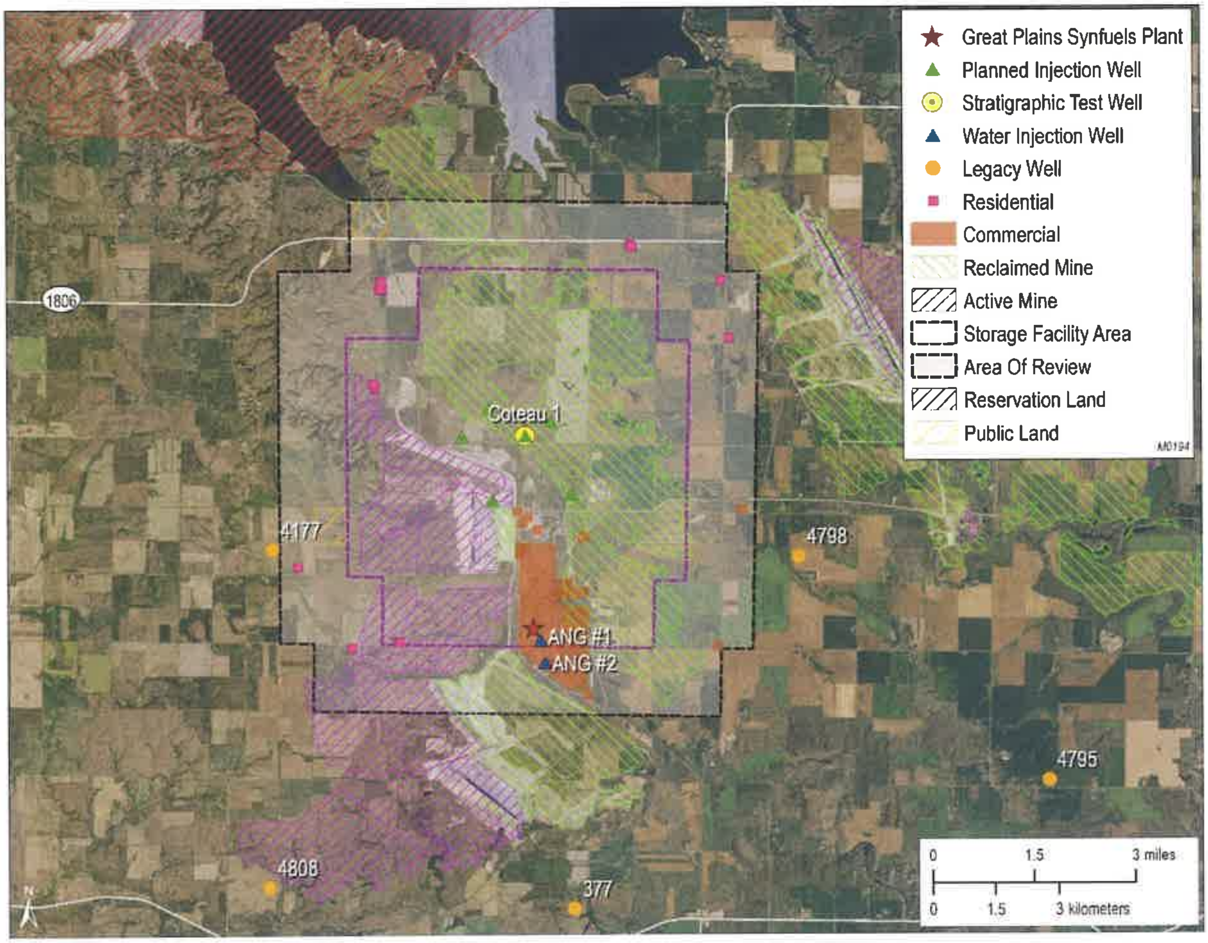


Figure 4-2. Final AOR map showing the Great Plains CO_2 Sequestration Project storage facility area, the storage facility area (dashed purple boundary), and the AOR (dashed black boundary). Pink squares represent occupied dwellings, teal squares represent vacant buildings, and blue squares represent commercial buildings.

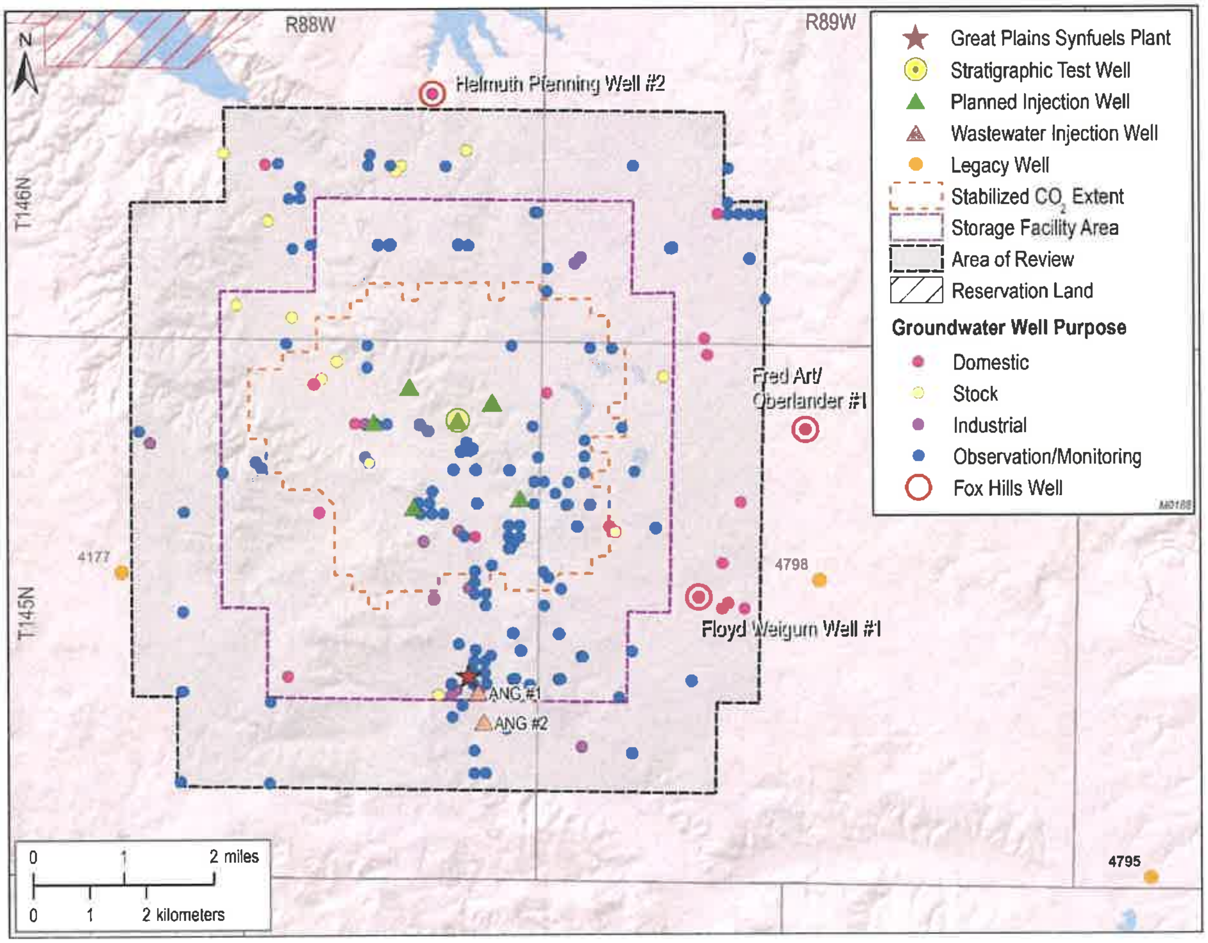


Figure 4-3. AOR map in relation to nearby legacy wells and groundwater wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR, and the light-orange triangles represent Class I ANG #1 and ANG #2 wells. All groundwater wells in the AOR are identified above. All observation/monitoring wells are shallow groundwater wells associated with the mine activities. No springs are present in the AOR.

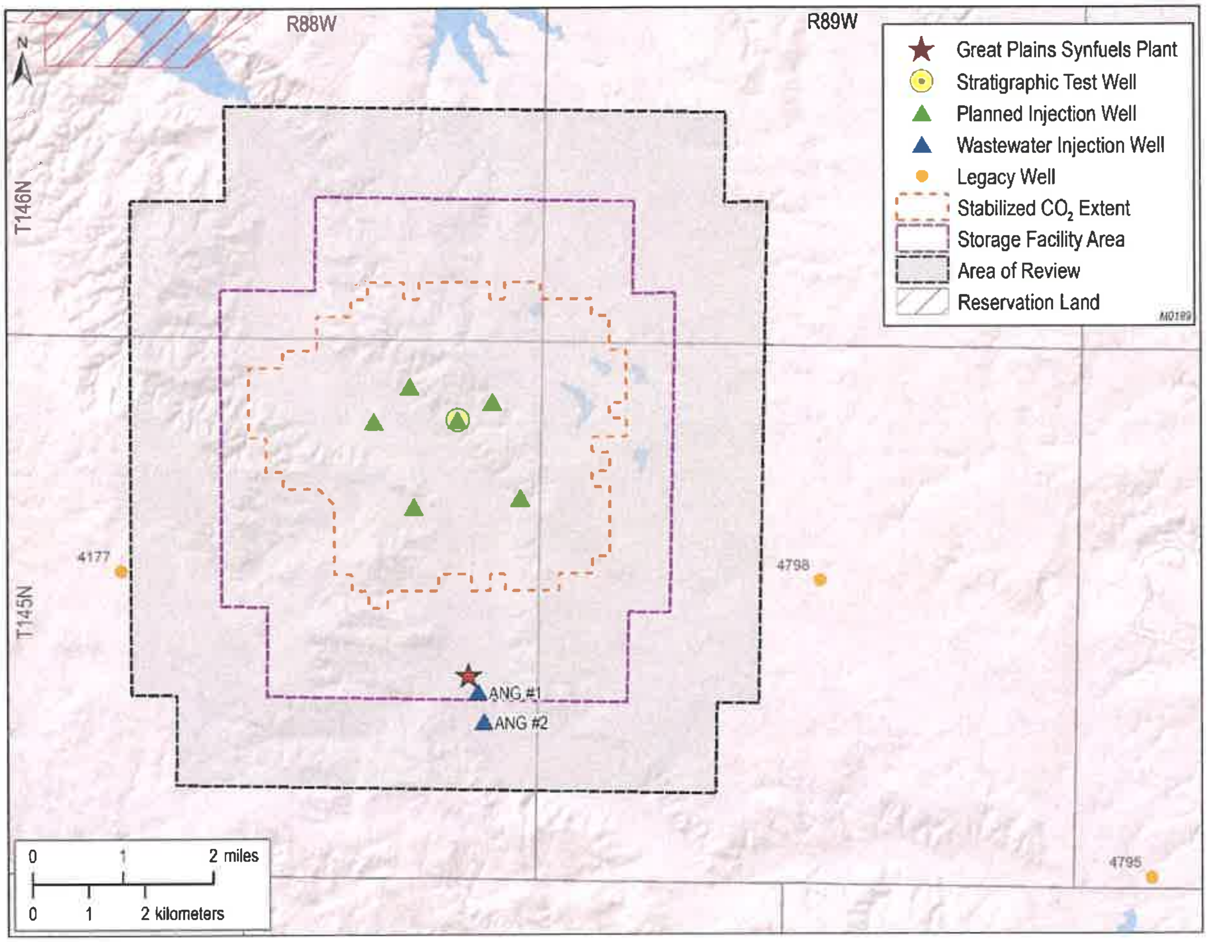
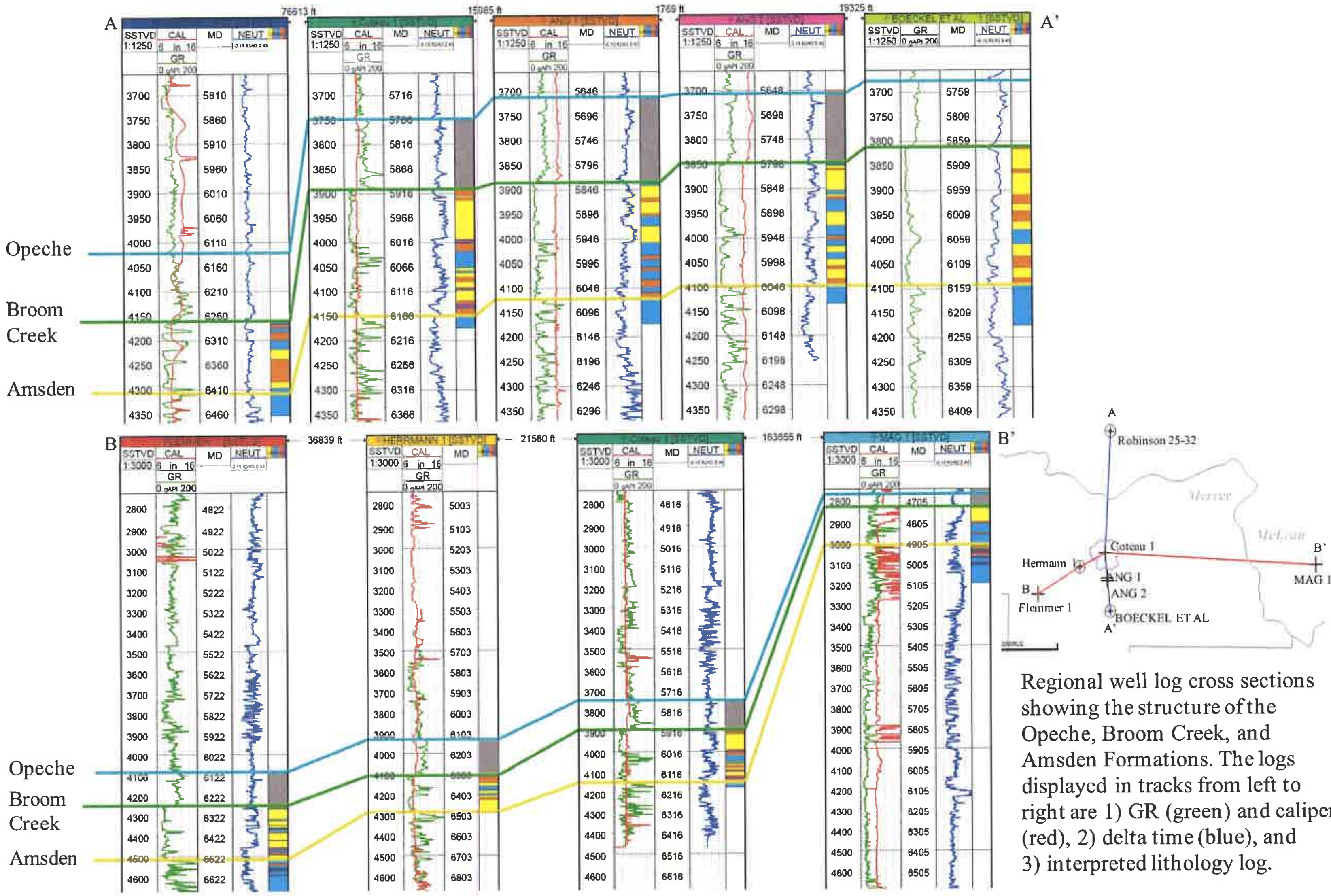


Figure 4-4. AOR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR and the Class I ANG #1 and ANG #2 wells are represented by blue triangles.



Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log.

Figure 4-5. Cross section of the AOR from the geologic model showing lithofacies distribution in the Broom Creek Formation, the proposed injection well (Coteau 1), and the ANG #1 and ANG #2 wells within the AOR. Depths are referenced to mean sea level.

Table 4-1. Investigated and Identified Surface and Subsurface Features (Figures 4-1 through 4-5)

Surface and Subsurface Features	Investigated and Identified (Figures 4-1–4-5)	Investigated But Not Found in AOR
Producing (active) Wells		X
Abandoned Wells	X	
Plugged Wells or Dry Holes	X	
Deep Stratigraphic Boreholes	X	
Subsurface Cleanup Sites		X
Surface Bodies of Water	X	
Springs		X
Water Wells	X	
Mines (surface and subsurface)	X	
Quarries		X
Subsurface Structures (e.g., coal mines)	X	
Location of Proposed Wells	X	
*Location of Proposed Cathodic Protection Boreholes		X
Any Existing Aboveground Facilities	X	
Roads	X	
State Boundary Lines		X
County Boundary Lines		X
Indian Country Boundary Lines	X	
Class I Injection Wells	X	

*There are no plans for cathodic protection for the Great Plains CO_2 Sequestration Project injection wells (Coteau 1–6 wells).

4.2 Corrective Action Evaluation

Table 4-2. Wells in AOR Evaluated for Corrective Action

NDIC Well File No.	Operator	Well Name	Spud Date	Surface Casing, o.d., inches	Surface Casing Seat, ft	Long-String Casing, o.d., Inches	Long-String Casing Seat, Inches	Hole Direction	TD, ft	TVD, ft	Status	Plug Date	TWN	RNG	Section	Qtr/Qtr	County	Corrective Action Needed
NDDEQ11308	Dakota Gasification Company	ANG #1	4/17/1982	16	2,017	9.625	6,784	Vertical	6,784	6,784	Active injector	N/A	145 N	88 W	24	SE/SW	Mercer	No
NDDEQ11309	Dakota Gasification Company	ANG #2	9/2/1984	13.375	2,118	9.625	6,910	Vertical	6,911	6,911	Active injector	N/A	145 N	88 W	25	CE2/NW	Mercer	No
38379	Rampart Energy Company	Coteau 1	6/27/2021	9.625	2,033	7	6,473	Vertical	6,484	6,484	DNC	N/A	145 N	88 W	1	SW/SW	Mercer	No
4177	Pel-Tex Petroleum Co. & Conoco	Herrmann 1 (Located outside of AOR)	11/8/1966	9.625	622	N/A	N/A	Vertical	8,057	8,057	Dry	12/2/1966	145 N	88 W	17	NE/SW	Mercer	No

Table 4-3. Herrmann 1 (NDIC File No. 4177) Well Evaluation

Well Name: Herrmann 1 (NDIC File No. 4177)

Cement Plugs				
Number	Interval, ft		Thickness, ft	Volume, sacks
1	7,980	7,910	70	20
2	7,800	7,730	70	20
3	4,720	4,650	70	20
4	640	570	70	20
5	20	Surface	20	5

*Data and information are provided from well-plugging report found in NDIC database.

Formation		Cement Plug Remarks
Name	Estimated Top, ft	
9⅝" Casing Shoe	622	Cement Plug 4 isolates the 9⅝" casing shoe.
Pierre	1,893	
Mowry	4,334	Cement Plug 3 isolates the uppermost Inyan Kara porosity.
Inyan Kara	4,660	
Swift	5,146	
Rierdon	5,562	
Broom Creek	6,310	
Big Snowy Group	6,918	
Madison	7,346	
Ratcliffe	7,597	
Frobisher	7,814	Cement Plugs 1 and 2 isolate deeper, unsuccessful wildcat horizons below the Frobisher.

Spud Date: 11/08/1966
Total Depth: 8,057 (Madison Formation)

Openhole plugging

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Herrmann 1 (NDIC File No. 4177) well will not be in contact with the CO_2 plume, and pressure increase in the Broom Creek Formation at this well location is predicted to be approximately 150–200 psi. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled and plugged.

Table 4-4. ANG #1 (NDEQ File No. NDOH11308) Well Evaluation

Well Name: ANG 1 (NDEQ File No. NDOH11308)

Casing Program				
Section	Casing Outside Diameter (o.d.), in.	Weight, lb/ft	Casing Seat, ft	Grade
Surface	16"	75	2,017	K-55
Production	9⅝"	40	6,784	K-55

Cement Program				
Casing, in.	Cement Type	TOC	Excess, %	Volume, sacks
16"	Class G	Surface	33%	1,600
9⅝"	Class G	1,700	NA	2,590

Formation		Remarks
Name	Estimated Top, ft	
16" Casing Shoe	2,017	Class G cement isolates the 16" casing shoe and all shallow water zones.
Mowry	3,950	
Inyan Kara	4,293	Production casing and Class G cement isolate all formations below the shoe of the surface casing.
Swift	4,664	
Rierdon	5,098	
Spearfish	5,510	
Opeche	5,654	
Broom Creek	5,821	
Amsden	6,070	

Corrective Action: No corrective action is necessary.

Table 4-5. ANG #2 (NDEQ File No. NDOH11309) Well Evaluation

Well Name: ANG 2 (NDEQ File No. NDOH11309)

Casing Program				
Section	Casing Outside Diameter (o.d.), in.	Weight, lb/ft	Casing Seat, ft	Grade
Surface	13⅜"	54.5	2,118	J-55
Production	9⅝"	47	6,910	N-80

Cement Program				
Casing, in.	Cement Type	TOC	Excess, %	Volume, sacks
13-⅜"	Class G & Halliburton Lightweight	Surface	38%	1,827
9⅝"	Class G & Halliburton Lightweight	2,220' (plus a top off cement job from surface to 670')	NA	2,301

Formation		
Name	Estimated Top, ft	Remarks
13-3/8" Casing Shoe	2,118	Class G cement isolates the 13-3/8" casing shoe and all shallow water zones.
Mowry	3,940	
Inyan Kara	4,263	Production casing and Class G cement isolate all formations below a depth of 2,220'. Therefore, there exists a 102' gap in the openhole cement coverage from 2,220' to 2,118' opposite the impermeable Pierre Shale.
Swift	4,692	
Rierdon	5,098	
Spearfish	5,499	
Opeche	5,644	
Broom Creek	5,795	
Amsden	6,042	

Corrective Action: No corrective action is necessary.

Table 4-6. Coteau 1 (NDIC File No. 38379) Well Evaluation

Well Name: Coteau 1 (NDIC File No. 38379)

Casing Program				
Section	Casing Outside Diameter (o.d.), in.	Weight, lb/ft	Casing Seat, ft	Grade
Surface	9⅝"	36	2,023	J-55
Production	7"	32	5,772	L-80
Production	7"	32	6,473	13CR L80

Cement Program				
Casing, in.	Cement Type	TOC	Excess, %	Volume, sacks
9⅝"	Varicem	Surface	100	750
7"	Varicem	Surface	100	285
7"	Corrosacem	3205'	100	645

Formation		
Name	Estimated Top, ft	Remarks
Pierre	1,750	Class G cement isolates the 9⅝" casing shoe.
9⅝" Casing Shoe	2,023	
Mowry	4,065	Stage collar with ECP at 3,205' Halliburton Corrosacem (CO_2-resistant cement) from TD to stage collar
Inyan Kara	4,395	
Swift	4,800	
Rierdon	5,212	
Spearfish	5,623	
Opeche	5,762	7" 13CR L80 production casing and Halliburton Corrosacem (CO_2-resistant cement) to isolate the Broom Creek Formation
Broom Creek	5,905	
Amsden	6,177	

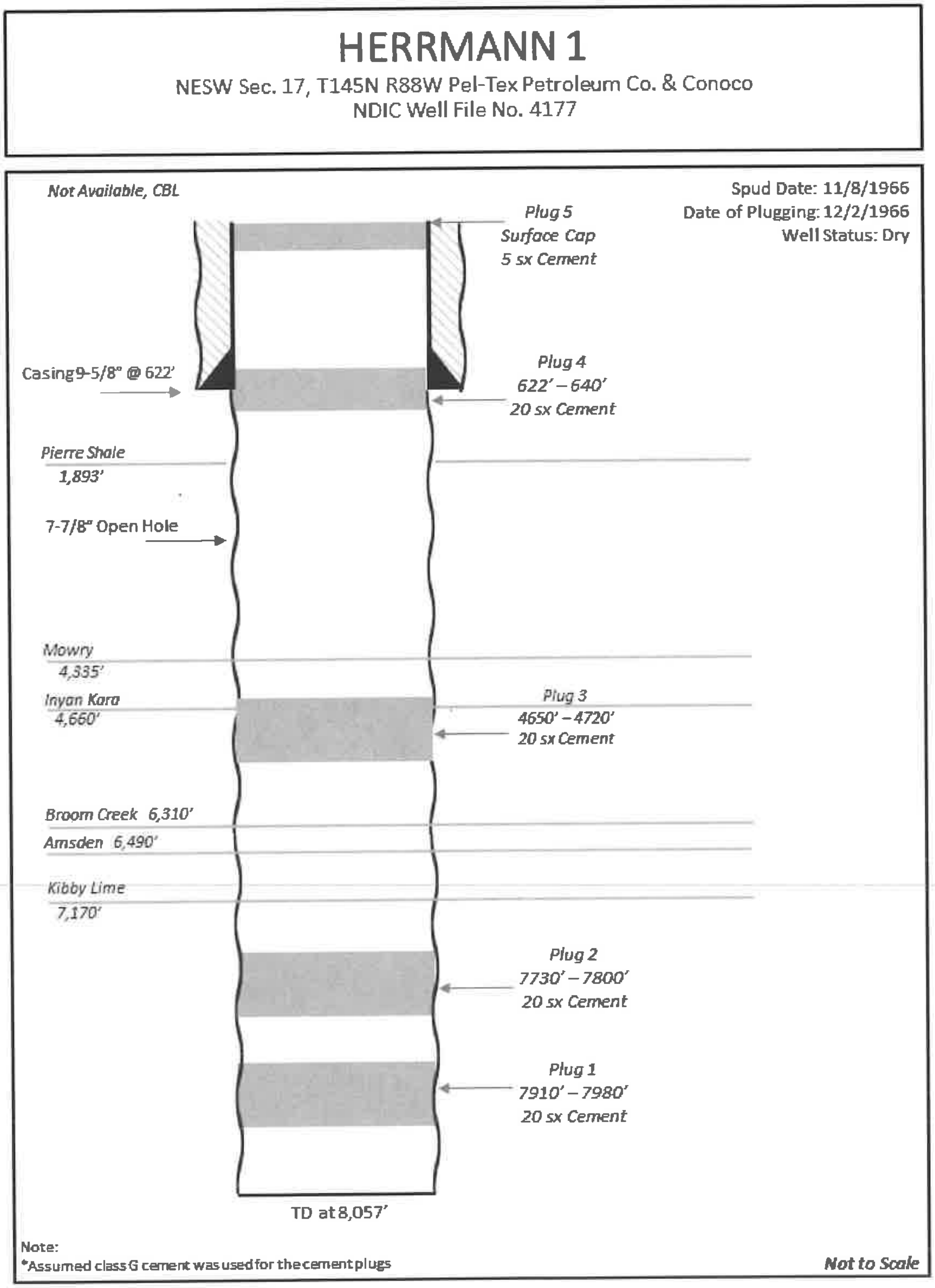
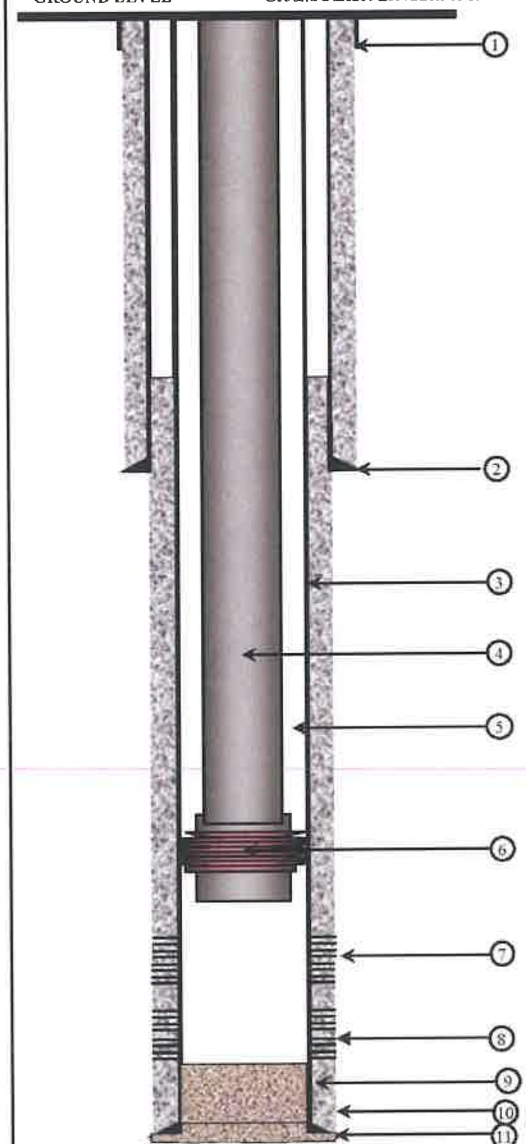


Figure 4-6. Herrmann 1 (NDIC File No. 4177) well schematic showing the location and thickness of cement plugs.

DAKOTA GASIFICATION COMPANY

DAKOTA GASIFICATION COMPANY
Mercer County, North Dakota
Injection Well No. 1 Schematic
Status: Active

GROUND LEVEL   Ground Surface Elevation of 1926' ASL



COMPLETION DETAIL

1. Conductor Pipe: 24"set in 40" hole from surface to 80'. Cemented to surface.
2. Surface Casing: 16", 75.0-ppf, K-55, ST&C. Set from surface to ±2,017.28' in a 20" drilled hole. Cemented to surface with 1,600 sacks 65/35 Pozolan and 300 sacks Class G cement.
3. Protection Casing: 9-5/8" casing set to 6,784'. 9-5/8", 40.0-ppf, K-55, LT&C from 3,967' to 6,784', 9-5/8", 36.0-ppf, K-55, LT&C from 15' to 3,967', and 9-5/8", 40.0-ppf, K-55, LT&C surface to 15' in a 13-1/2" drilled hole from 2,017' to 4,469', 12-1/2" drilled hole from 4,469' to 5,800' and a 12-1/4" drilled hole form 5,800' to 6,784'. Cemented with 990 sacks of Class G cement in the first stage and 1,600 sacks of Class G cement in the second stage. Cementing stage tool was set at 5,347'. Top of cement at 1,700'.

   Note: SLB USIT log (6/7/2020) identified reduced ID in jts 81 & 84, 3,641.7' & 3,760.0', probably 43.5 ppf. & reduced ID in jts 100 & 133, 4,422.5' & 5,731.4', probably 47.0 ppf.
4. Injection Tubing and Seal Assembly: 7", 26-ppf, J-55, LT&C from surface to ± 5740' with a 5-1/2" OD Baker Hughes GBH22 Locator Tubing Seal Assembly set to 5,751.5', minimum ID of 4.891". 5-1/2" OD Tail pipe extension to 5,762.2'.
5. Annulus filled with 10.4 lb/gal inhibited brine.
6. Injection Packer: Baker Model 194-60 "FB-1" Packer set at 5,740'.
7. Minnelusa Perforations:

5,835' to 5,836', 1'	5,836' to 5,867', 31'
5,867' to 5,870', 3'	5,870' to 5,880', 10'
5,880' to 5,884', 4'	5,884' to 5,894', 10'
5,894' to 5,900', 6'	5,920' to 5,952', 32'
5,952' to 5,954', 2'	

8. Kibbey Perforations:

6,621' to 6,631', 10'	6,637' to 6,657', 20'
6,659' to 6,669', 10'	

9. Fill Tagged at 6,721' on 6/25/2020 – Temperature Survey
10. Plugged back total depth of 6,728'
11. Drilled to a total depth of 6,784'.

Note: All depths referenced to original rotary kelly bushing of 20' above ground level unless otherwise noted.

GEOSTOCK SANDIA
ENTREPOSE

Drawn by: WHA	Date: 11/20/2002	*Drawing not to scale*
Revision 4 – 7/17/2020		

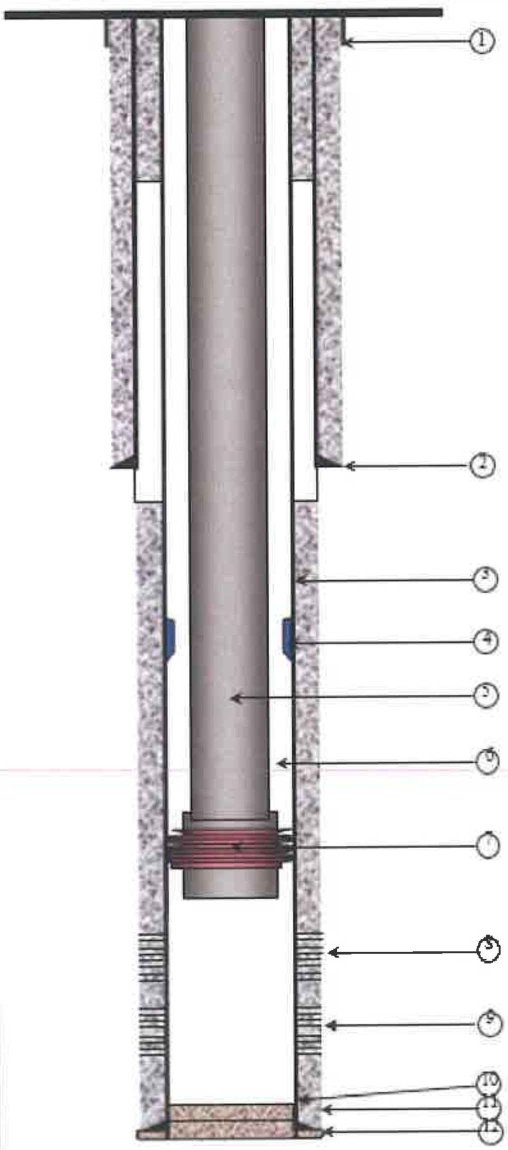
Figure 1: Injection Well No. 1 Schematic

Figure 4-7. ANG #1 (NDEQ File No. NDOH11308) well schematic.

DAKOTA GASIFICATION COMPANY

DAKOTA GASIFICATION COMPANY
Mercer County, North Dakota
Injection Well No. 2 Schematic
Status: Active

GROUND LEVEL — Ground Surface Elevation of 1918.6' ASL



COMPLETION DETAIL

1. Conductor Pipe: 20" with ¼" wall set in 26" hole from surface to 60' below grade. Cemented to surface.
2. Surface Casing: 13-3/8", 54.5-ppf, J-55, ST&C. Set from surface to ±2,118' in a 17-1/2" drilled hole. Cemented to surface with 1,515 sacks Halliburton Lightweight cement plus 2% CaCl and 312 sacks Class G cement 2% CaCl.
3. Protection Casing: 9-5/8", 47-ppf, N-80, LT&C. Set from surface to 6,910' in a 12-1/4" drilled hole. ID of 8.681". Cemented with 454 sacks of Class G cement, 15.8 lb/sk, lead and 857 sacks of Halliburton Lightweight, 13.1 lb/gal, tail in the first stage and 990 sacks of Class G cement in the second stage. Cementing stage tool was set at 3,697'. Top of cement at 2,220'. Annulus topped out with Class G cement, 15.8 lb/gal, from 670' to surface.
4. HOMCO 9-5/8", 47-ppf Internal Casing Patch set from 3,692' to 3,722'. ID through the patch is reduced to 8.381".
5. Injection Tubing and Seal Assembly: 7", 29-ppf, L-80, LT&C from surface to 5,772', locator seal assembly from 5,772' to 5,785', and a 5-1/2", 17-ppf, J-55, production tube with a ½ mule shoe bottom guide from 5,785' to 5,805', minimum ID of 4.875".
6. 7" x 9-5/8" Annulus filled w/ 10.5 lb/gal Brine containing 1.3% Nalco Champion CORR12264A Corrosion Inhibitor.
7. Injection Packer: Baker Model 194-60 "FB-1" Packer with 10' seal bore extension set from 5,772' to 5,784'. Seal bore ID of 6".
8. Minnelusa Perforations:

5,800' to 5,854' 54'	5,858' to 5,864' 6'
5,894' to 5,924' 30'	5,990' to 6,004' 14'
6,010' to 6,016' 6'	6,018' to 6,023' 5'
6,025' to 6,035' 10'	6,039' to 6,043' 4'

9. Kibbey Perforations:

6,587' to 6,603' 16'	6,608' to 6,628' 20'
6,632' to 6,642' 10'	6,727' to 6,737' 10'

10. Filled tagged at 6,784' on 11/29/19 – Temperature Survey
11. Plugged back total depth of 6,865'
12. Drilled to a total depth of 6,911'.

Note: All depths referenced to original rotary kelly bushing measurement of 19.44' above the tubing hanger flange unless stated otherwise.

GEOSTOCK SANDIA
ENTREPOSE

Drawn by: WHA	Date: 10/26/2012	*Drawing not to scale*
Revision 2: 1/15/2020		

Figure 1: Injection Well No. 2 Schematic

Figure 4-8. ANG #2 (NDEQ File No. NDOH11309) well schematic.

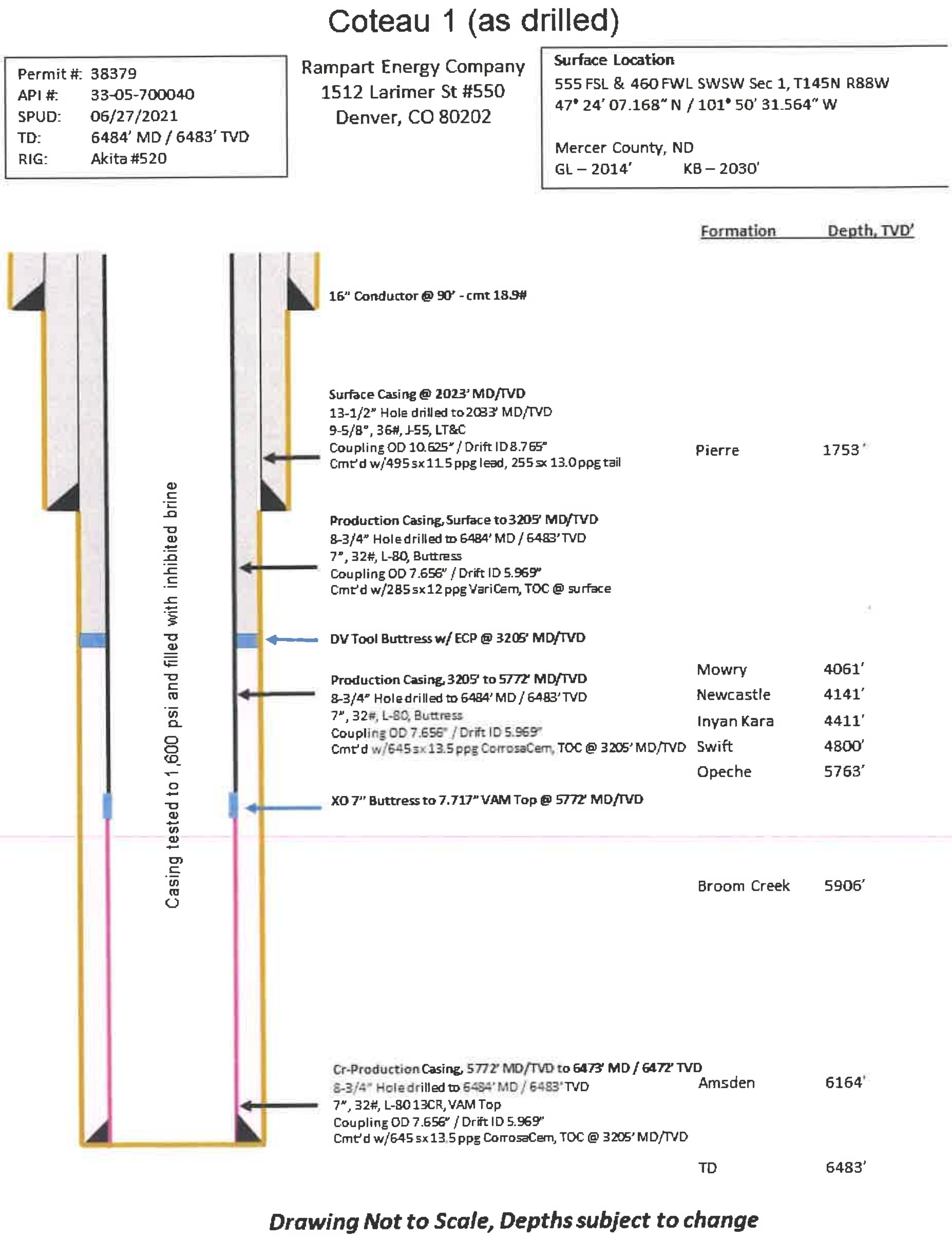


Figure 4-9. Coteau 1 (NDIC File No. 38379) well schematic.

4.3 Reevaluation of AOR and Corrective Action Plan

The Great Plains CO_2 Sequestration Project will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place not later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following:

- Any changes to the monitoring and operational data prior to the scheduled reevaluation date.
- Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and operational data to be utilized as the basis for that update will be identified.
- The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR.

4.4 Protection of USDWs

4.4.1 Introduction of USDW Protection

The primary confining zone and additional overlying confining zones geologically isolate the Fox Hills Formation, the lowest USDW in the area of investigation from the underlying injection zone. The Opeche Formation is the primary confining zone for the injection zone with additional confining layers above, geologically isolating all USDWs from the injection zone. The uppermost confining layer is the Pierre Formation, an impermeable shale in excess of 1,000 ft thick, providing an additional seal for all USDWs in the region.

4.4.2 Geology of USDW Formations

The hydrogeology of western North Dakota comprises several shallow freshwater-bearing formations of the Quaternary, Tertiary, and upper Cretaceous-aged sediments underlain by multiple saline aquifer systems of the Williston Basin (Figure 4-10). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1,000 and 1,500 ft thick (Thamke and others, 2014).

The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; the overlying Cannonball, Tongue River, and Sentinel Butte Formations of the Tertiary Fort Union Group; and the Tertiary Golden Valley Formation (Figure 4-11). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the area of investigation (Croft, 1973).

The lowest USDW in the area of investigation is the Fox Hills Formation, which, together with the overlying Hell Creek Formation, is a confined aquifer system. The Hell Creek Formation

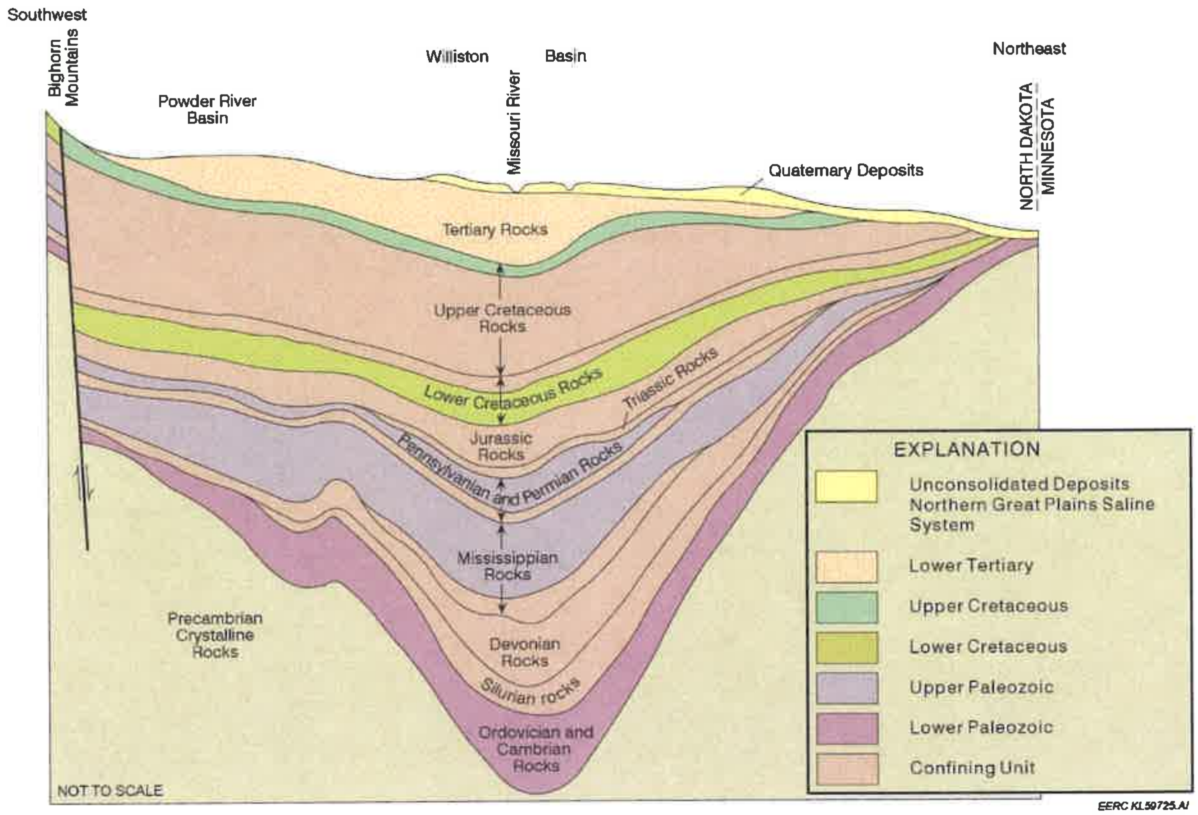


Figure 4-10. Major aquifer systems of the Williston Basin.

is a poorly consolidated unit composed of interbedded sandstone, siltstone, and claystones with occasional carbonaceous beds, all fluvial origin. The underlying Fox Hills Formation is interpreted as interbedded nearshore marine deposits of sand, silt, and shale deposited as part of the final Western Interior Seaway retreat (Fischer, 2013). The Fox Hills Formation in the area of investigation is approximately 1,100 to 1,400 ft deep and 200–340 ft thick (Croft, 1973). The structure of the Fox Hills and Hell Creek Formations follows that of the Williston Basin, dipping gently toward the center of the basin to the northwest of the area of investigation (Figure 4-12).

The Pierre Shale is a thick, regionally extensive shale unit which forms the lower boundary of the Fox Hills–Hell Creek system, also isolating all overlying freshwater aquifers from the deeper saline aquifer systems. The Pierre Shale is a dark gray to black marine shale and is typically over 1,000 ft thick in the area of investigation (Thamke and others, 2014).

ERATHEM	SYSTEM		SERIES	ROCK: GROUP	ROCK: FORMATION	FRESHWATER AQUIFER(S)	FRESHWATER AQUIFER(S) UNDER
CENOZOIC	Quaternary		Holocen		Oahe	No	
			Pleistocene	Coleharbor	"Glacial Drift"	Yes	
	Tertiary	Neoge	Pliocene		(Unnamed)	Yes	
			Miocene		Arikaree	No	
		Paleogene	Oligocene	White	Brule	No	
			Eocene		Chadron	No	
					Golden	No	
			Paleocene	Fort Union	Sentinel	Yes	
					Tongue River: Bullion	Yes	
					Tongue River: Slope	No	
					Cannonball	Yes	
					Ludlow	Yes	
MESOZOIC	Cretaceous		Upper	Montana	Hell Creek	Yes	
					Fox Hills	Yes	
					Pierre	No	

Modified from Murphy and others, 2009, NDGS MS 91

Figure 4-11. Upper stratigraphy of Mercer County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Murphy and others, 2009; NDGS MS 91).

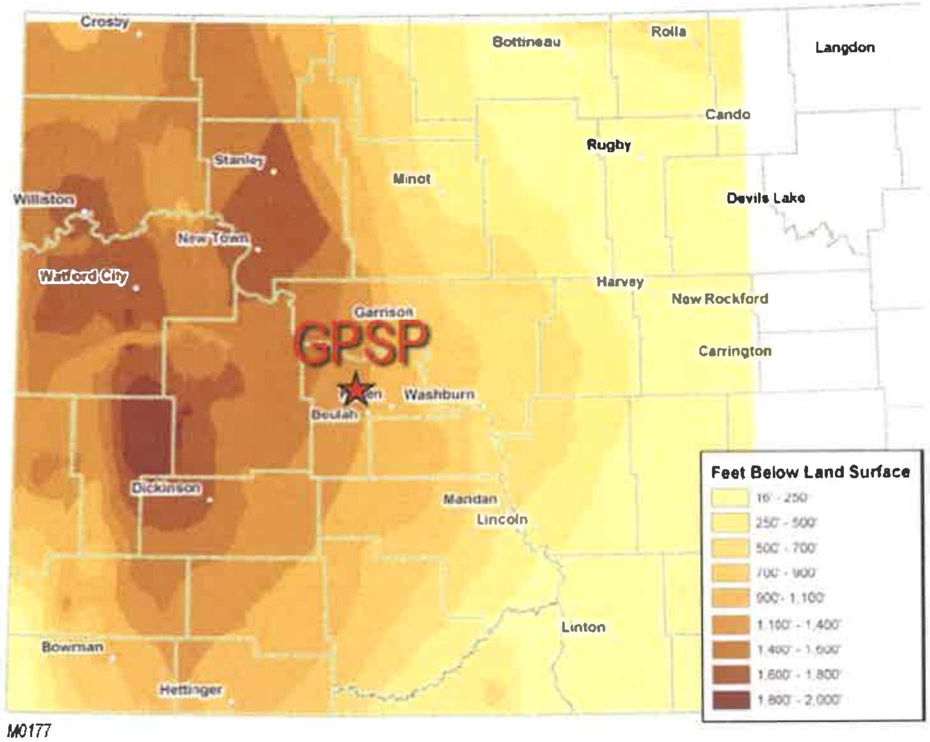


Figure 4-12. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

4.4.3 Hydrology of USDW Formations

Groundwater is obtained from both glacial drift and bedrock aquifers, with most of the water obtained from bedrock. Lignite beds and sands in the Sentinel Butte and Tongue River Formations provide shallow bedrock aquifers in most areas of Mercer County. Sandstones near the base of the Tongue River Formation and within the Hell Creek and Fox Hills Formations provide deeper artesian aquifers in many areas. Glacial drift is generally too thin or impermeable to provide good aquifers in the upland areas. However, in the valleys of the major streams and in the diversion channels, the glacial and alluvial fill provides adequate supplies of groundwater (Carlson, 1973).

The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the area of investigation is to the east (Figure 4-13). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,530 mg/L near the Great Plains CO_2 Sequestration Project area. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Trapp and Croft, 1975). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering.

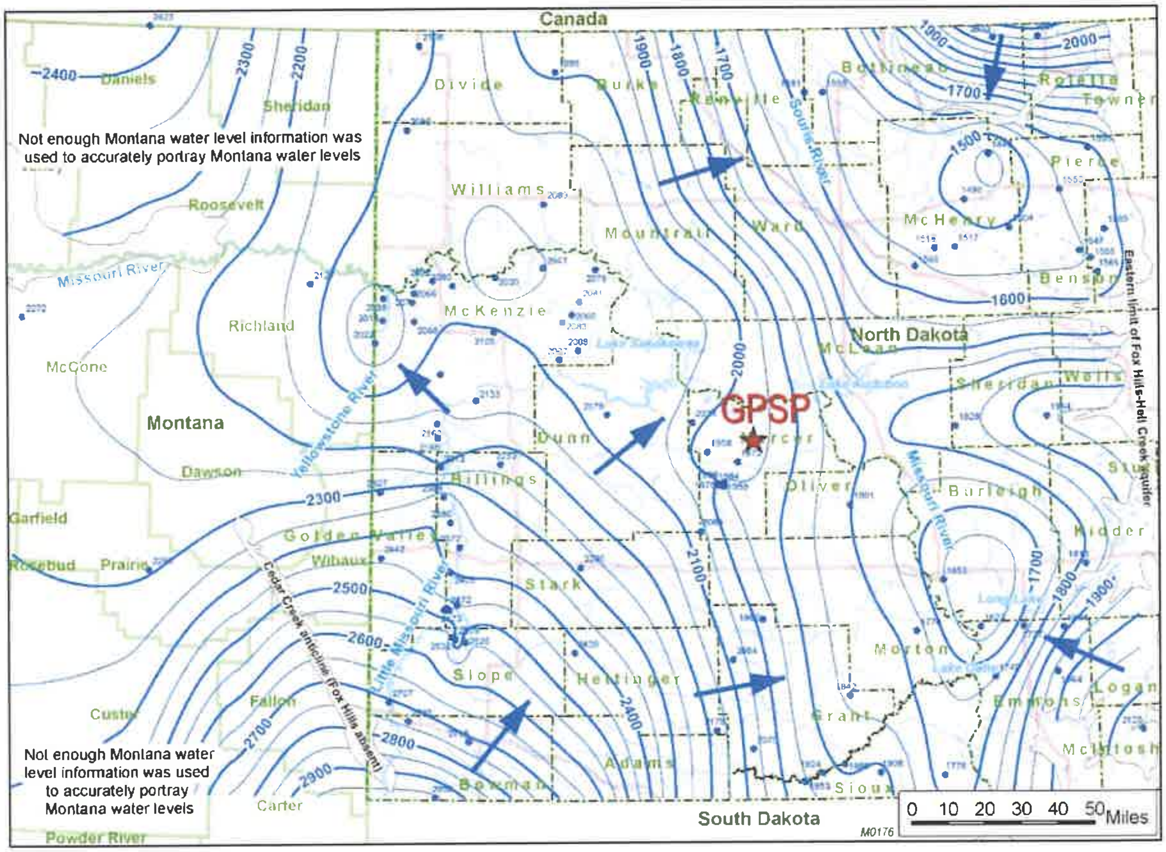


Figure 4-13. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in Mercer County (modified from Fischer, 2013).

There are several existing candidate groundwater wells to screen for sample collection in the area of investigation (Figure 4-14). Some of these wells are currently sampled as part of annual plant operational monitoring programs. Existing wells will be evaluated for inclusion into baseline, operational, and postinjection monitoring plans. Groundwater monitoring wells completed in the Fox Hills Formation will also be installed and sampled near injection well pads (one at each well for a total of six).

Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the area of investigation (Figure 4-15). These formations are often used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. Tongue River groundwaters are generally a sodium bicarbonate type with a TDS of approximately 1,000 ppm (Croft, 1973).

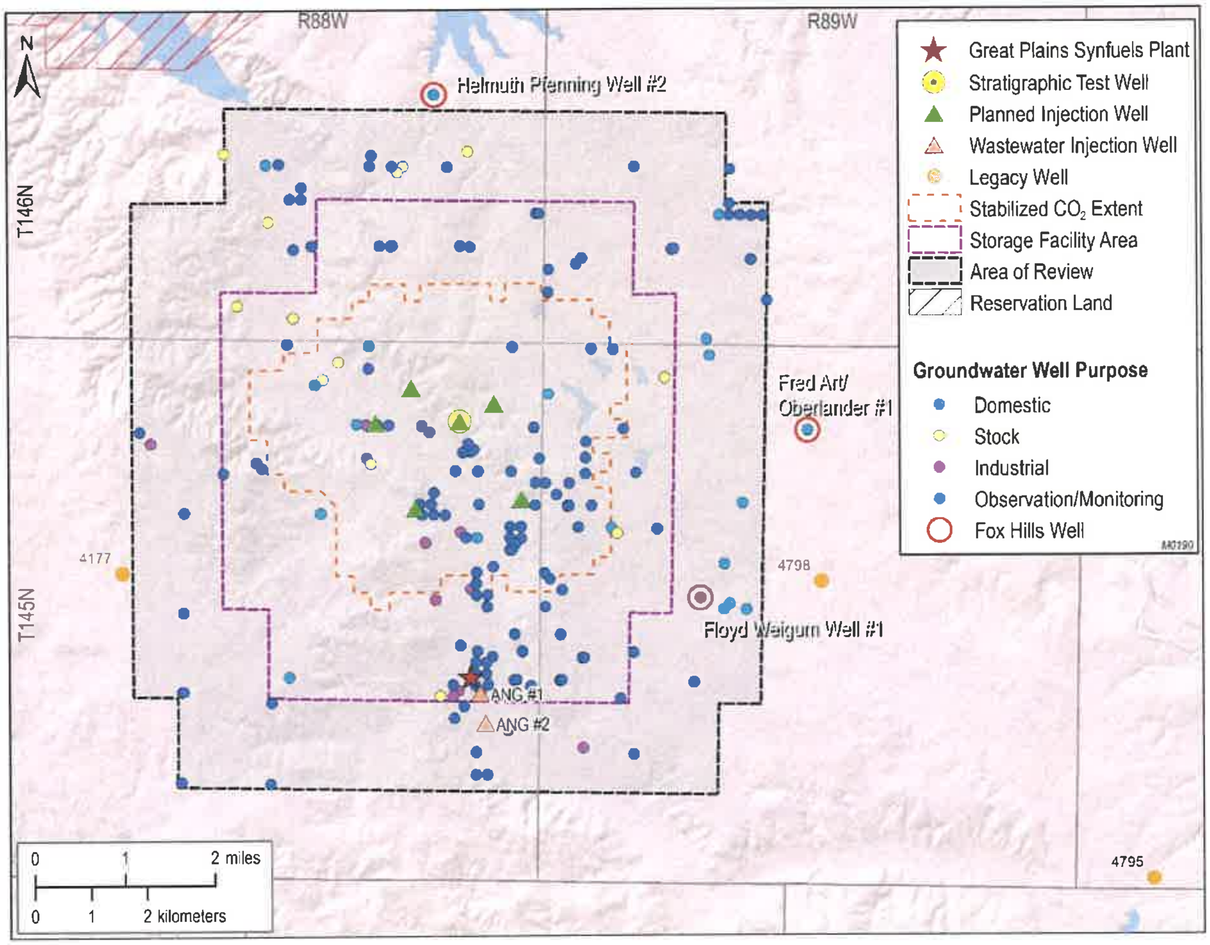


Figure 4-14. Map of water wells in the area of investigation in relation to the simulated plume.

The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The upper Sentinel Butte Formation is predominantly sandstone with lignite interbeds, forming another important source of groundwater in the region. Generally, the upper Sentinel Butte is up to 300 ft thick in the area of investigation. TDS in the Sentinel Butte Formation range from approximately 400–1,000 ppm (Croft, 1973).

In general, coal seams and glacial washouts contribute to shallow sources of groundwater in the area. Locally, the primary source of shallow groundwater is the Beulah Trench, a typical glacially carved valley that winds its way from Beaver Creek Bay (Lake Sakakawea), through the project site, to a point about 4 miles north of Beulah where it divides and continues eastward toward Hazen and westward toward Zap.

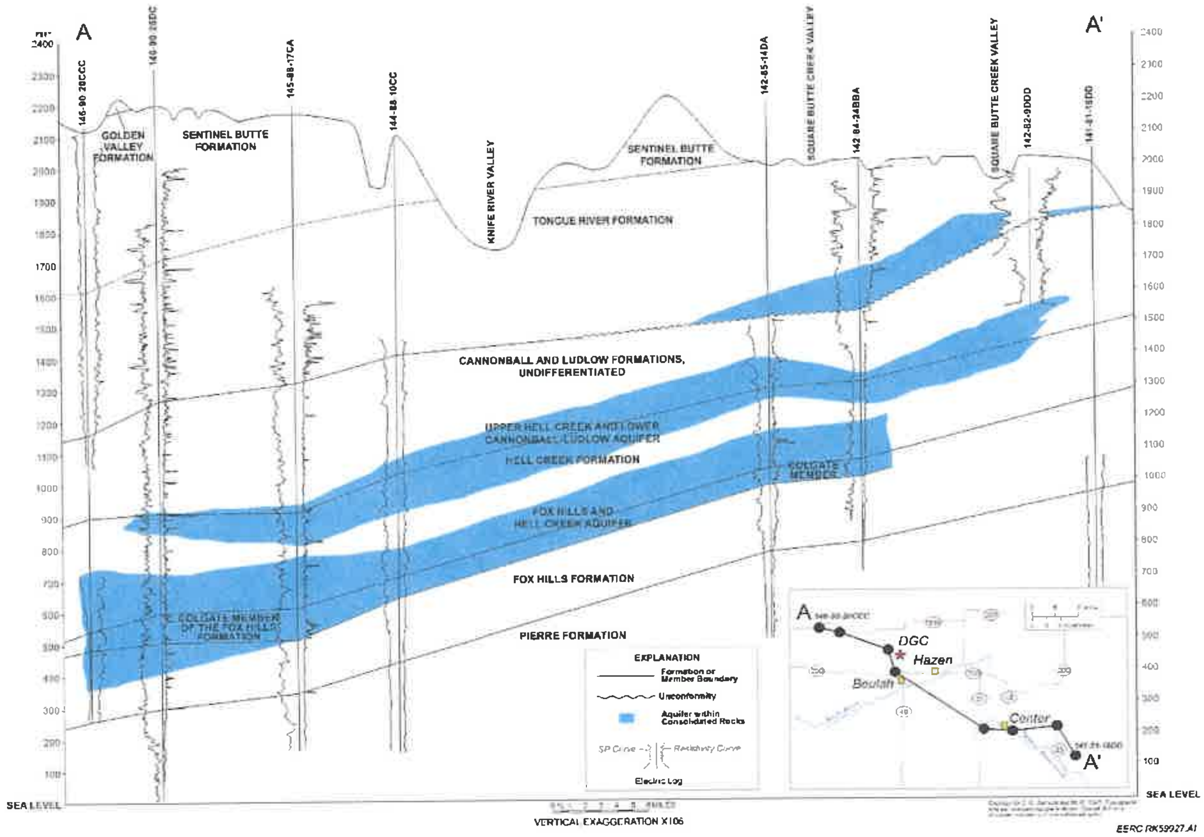


Figure 4-15. West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the locations of the water wells illustrated on the cross section.

4.4.4 Protection for USDWs

The Fox Hills–Hell Creek aquifer system is the lowest USDW in the AOR. The injection zone (Broom Creek Formation) and the lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and siltstone formations of Permian, Jurassic, and Cretaceous ages (Figure 4-10). The primary seal of the injection zone is the Permian-aged Opeche Formation with the shales of the Permian-aged Spearfish, the Jurassic-aged Piper (Picard), Rierdon, and Swift Formations, all of which overly the Opeche Formation. Above the Swift is the confined saltwater aquifer system of the Inyan Kara Formation, which extends across much of the Williston Basin. Above the Inyan Kara are the Cretaceous-aged shale formations Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre. The Pierre Formation is the thickest shale formation in the area of investigation and the tertiary geologic barrier between the USDWs and the injection zone (refer to Section 2.4.2 for additional overlying confining layers of the storage reservoir). The geologic strata overlying the injection zone consists of multiple impermeable rock layers that are free of transmissive faults or fractures and provide adequate isolation of the USDWs from CO_2 injection activities in the area of investigation.

4.5 References

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5.0 TESTING AND MONITORING PLAN

5.0 TESTING AND MONITORING PLAN

Pursuant to North Dakota Administrative Code (NDAC) § 43-05-01-11.4, this testing and monitoring plan includes an analysis of the injected CO_2 stream, periodic testing of the injection wells, a corrosion monitoring plan for the CO_2 injection well components and surface facilities, a leak detection and monitoring plan for surface components of the CO_2 injection system, and a leak detection plan to monitor any movement of the CO_2 outside of the storage reservoir. As such, this plan simultaneously meets the permit requirements for two other required plans: 1) a surface/subsurface leak detection and monitoring plan (NDAC § 43-05-01-14) and 2) a corrosion monitoring and prevention plan (NDAC § 43-05-01-15).

The combination of the above monitoring efforts is used to verify that the geologic storage project is operating as permitted and is protecting all USDWs. An overview of these individual monitoring efforts is provided in Table 5-1 along with the target area that will be monitored.

A regular review of the monitoring program (i.e., a minimum of every 5 years) will be conducted to ensure that it remains appropriate for the site and is adequately tracking the injected CO_2, thereby providing an accurate assessment of the performance of the surface/subsurface equipment and subsurface geologic structures in containing the stored CO_2.

If needed, amendments to the monitoring program (i.e., technologies applied, frequency of testing, etc.) will be submitted for approval by the North Dakota Industrial Commission (NDIC). Results of pertinent analyses and data evaluations conducted as part of the monitoring program will be compiled and reported as required. Another goal of this monitoring program is to establish preinjection baseline data for the storage complex, including baseline data for soil gas, nearby groundwater wells, and the Fox Hills Formation (lowest USDW).

Additional details of the individual efforts of the monitoring program are provided in the remainder of this section.

Table 5-1. Overview of DGC's Testing and Monitoring Plan

Monitoring Type	Equipment/Testing	Target Area
Analysis of CO_2 Stream	Compositional and isotopic analysis of the CO_2 stream	CO_2 compressors at the capture facility
Wellsite Flowline Leak Detection System	H_2S detection stations, pressure gauges, and SCADA[1] system	Wellsite flowline to wellhead
Surface Corrosion	Ultrasonic testing of tubing test sections installed at wellheads	Wellsite flowline to well infrastructure
Downhole Corrosion	PMIT[2] and/or surface tubing inspection and USIT[3] (material wall thickness)	Downhole tubing and casing strings
Continuous Recording of Injection Pressure, Rate, and Volume	Flowmeters	Transmission line to well infrastructure
Well Annulus Pressure Between Tubing and Casing	Digital annular pressure gauges for continuous monitoring	Surface-to-reservoir (injection wells)
Internal and External Mechanical Integrity Testing	Tubing-casing annulus pressure testing (internal), USIT (internal and external) and temperature logs	Well infrastructure
Atmospheric	H_2S detection stations	Outside of wellhead enclosures
Near-Surface	Compositional and isotopic analysis of soil gas profile stations and dedicated Fox Hills[1] monitoring wells	Vadose zone and lowest USDW
Direct Reservoir	Pulsed-neutron logs with temperature and pressure readings, pressure falloff testing, and surface pressure gauges	Storage reservoir and dissipation intervals
Indirect Reservoir	Time-lapse 2D seismic surveys and vertical seismic profiles (VSPs)	Entire storage complex

[1] Supervisory Control and Data Acquisition
[2] Platform multifinger imaging tool.
[3] Ultrasonic imaging tool.

[1] The Fox Hills aquifer underlying the Great Plains CO_2 Sequestration Project site and western North Dakota is a confined aquifer system which does not receive measurable flow from overlying aquifers or the underlying Pierre Shale. The overlying confining layer in the Hell Creek Formation comprises impermeable clays, and the underlying Pierre Shale serves as the lower confining layer (Trapp and Croft, 1975). Recharge occurs hundreds of miles to the southwest in the Black Hills of South Dakota, where the corresponding geologic layers are exposed at the surface. Flow within the aquifer is to the east with a rate on the order of single feet per year. Thus groundwater in the Fox Hills aquifer at the Great Plains CO_2 Sequestration Project site is geochemically stable, as it is isolated from its source of recharge and does not receive other sources of recharge (Fischer, 2013). The aquifer itself is a quartz-rich sand and is not known to contain reactive mineralogy. Minimal geochemical variation can be expected to occur across the site, attributable to minor variations in the geologic composition of the aquifer sediments.

5.1 CO_2 Stream Analysis and Injection Well Mechanical Integrity Testing

5.1.1 CO_2 Stream Analysis

The CO_2 stream is analyzed daily at the capture facility, using methods and standards generally accepted by industry. The chemical content of the captured gas is 95.9 by volume percent CO_2 and 4.1 by volume percent other chemical components, as summarized in Table 5-2. The physical characteristics of the CO_2 stream, including its corrosiveness, temperature, and density are also measured daily at the capture facility.

Table 5-2. Chemical Content of the CO_2 Stream

Chemical Content	Volume Percent
Carbon Dioxide	95.9
C_2^+ and Hydrocarbons	1.8
Hydrogen Sulfide	1.2
Methane	0.6
Nitrogen	0.5
Total	100.0

5.1.2 Injection Well Mechanical Integrity Testing

A USIT, in combination with variable density and cement bond logs, was used to establish the baseline external mechanical integrity in the Coteau 1 well. The same suite of logging tools will also establish baseline conditions in the other injection wells, and the USIT will be run during well workovers but not more frequently than once every 5 years. Baseline temperature data will also be collected prior to operations and will be regularly performed using a phased approach (described in the following paragraph) to verify external mechanical integrity in the injection wells.

DGC's phased approach: pulsed-neutron logs (PNLs), which include a temperature log and bottomhole pressure (BHP) readings, will be run in an individual injection well quarterly. Each injection well will be placed on a rotating schedule to gather these downhole data, starting with Coteau 1 in the first quarter, Coteau 2 in the second quarter, Coteau 3 in the third quarter, and Coteau 4 in the fourth quarter, at which point the rotation will be repeated. Once drilled, the Coteau 5 and Coteau 6 wells will be added to the rotating schedule and the frequency adjusted to a bimonthly basis.

A BHP survey will be acquired each month during the first quarter of operations to supplement the phased approach described above. These supplemental BHP readings will confirm that the wellhead pressure (WHP):BHP correlation (pressure gradient) is accurate and reliable. If the WHP:BHP correlation is reconciled with the BHP data in the first quarter, BHP surveys will continue to be acquired at the frequency and schedule described in the phased approach.

Internal mechanical integrity of the injection wells will be demonstrated via tubing-casing annulus pressure tests prior to injection and during well workovers but not more frequently than

once every 5 years. Pressure falloff tests will be performed in the injection wells prior to injection. During injection operations, pressure falloff testing will be carried out via surface pressure monitoring at least once every 5 years to demonstrate storage reservoir injectivity. In addition, the injection wells will be continuously monitored for surface and annular pressure anomalies by maintaining a consistent 200 pounds per square inch on the annulus with a nitrogen cushion that will be placed and maintained on top of the packer fluid. USITs may be run during workovers (including when tubing is pulled) but not more frequently than once every 5 years, to further assess the internal mechanical integrity of the injection wells.

5.2 Corrosion Monitoring and Prevention Plan

The purpose of the corrosion monitoring and prevention plan is to monitor the surface facilities and injection well components during the operational phase of the Great Plains CO_2 Sequestration Project to ensure that the materials meet the minimum standards for material strength and performance. Figure 5-1 illustrates the pad drawings for the Coteau 1 through Coteau 4 wells.

DGC permitted a new 6.8-mile-long transmission line through the North Dakota Public Service Commission (PSC) in July 2021 (PU-21-150). The transmission line implements a corrosion monitoring and prevention strategy that was approved by PSC and is not discussed in this storage facility permit application. At the transition from transmission line to flowline (Figure 5-2), DGC's efforts to monitor and prevent corrosion of the flowline and well materials at the injection wellsites are presented in Sections 5.2.1 and 5.2.2.

5.2.1 Corrosion Monitoring

DGC will install a 3-foot test section of 4½-inch L-80 tubing in the flowlines near each wellhead for regular testing and corrosion monitoring of the well material. The tubing joints will be inspected monthly via ultrasound equipment during the first quarter, then quarterly thereafter for the first 2 years. If the well materials (i.e., tubing) show no sign of corrosion within the first 2 years of the injection period, future internal monitoring of the tubing will be accomplished through a platform multifinger imaging tool (PMIT), or in the event a downhole tubing string is pulled for any reason, it will be inspected at the surface for corrosion and mechanical integrity. USITs may also be run during workovers (including when tubing is pulled), but not more frequently than once every 5 years, to further assess any corrosion of the injection string.

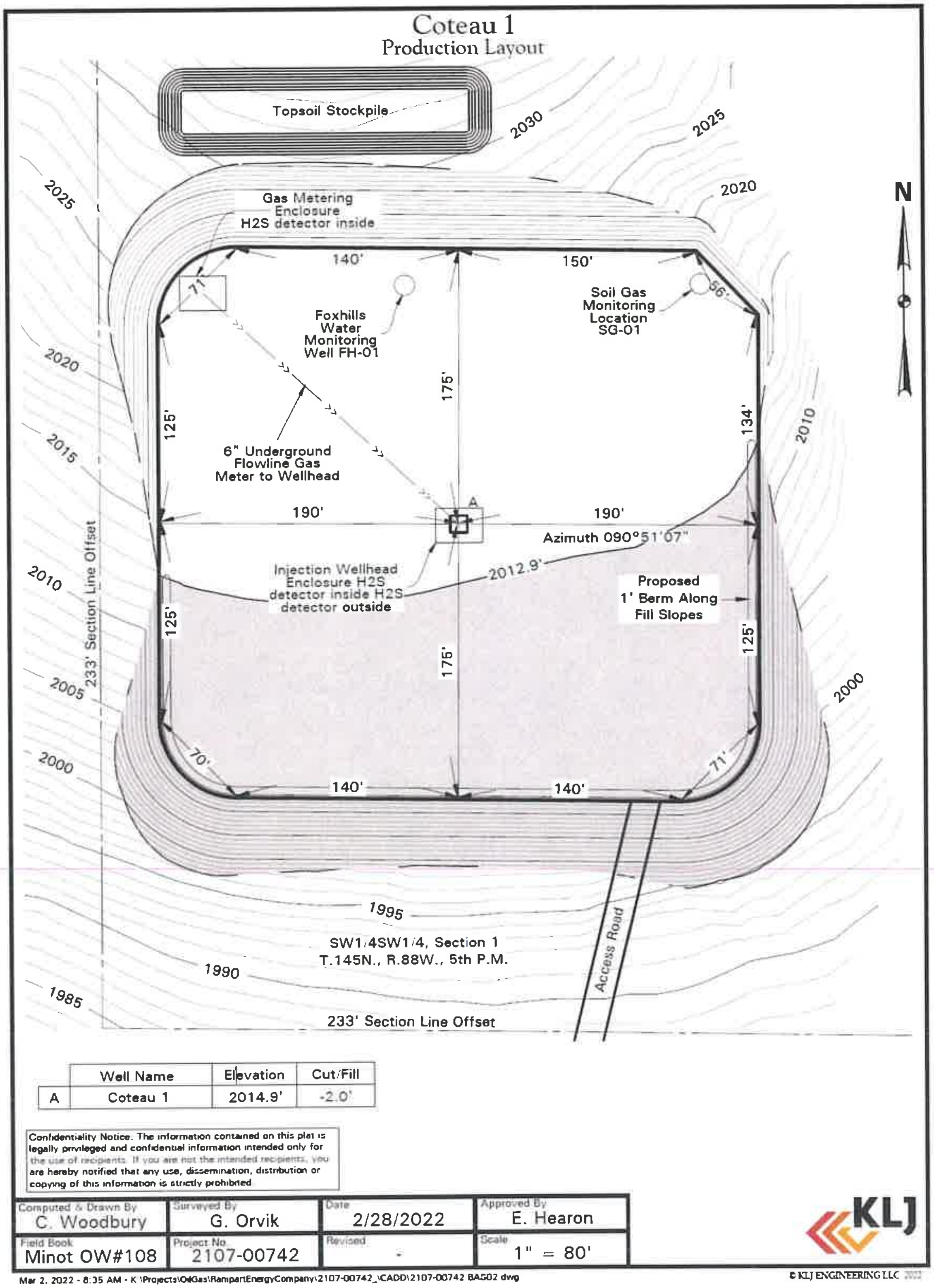
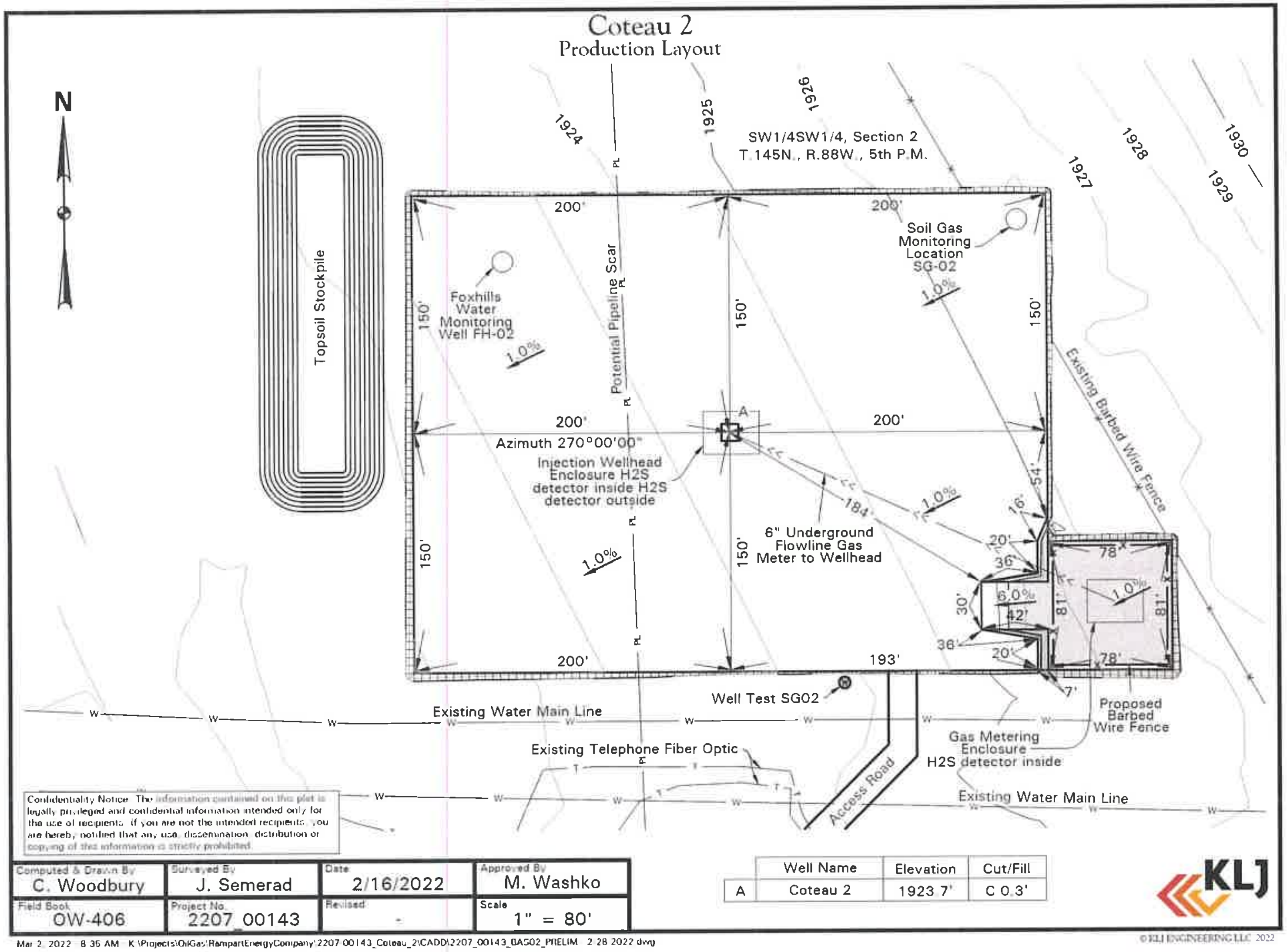


Figure 5-1A. Well pad drawing of the Coteau 1 well location.



	Well Name	Elevation	Cut/Fill
A	Coteau 2	1923.7'	C 0.3'

Figure 5-1B. Well pad drawing of the Coteau 2 well location.

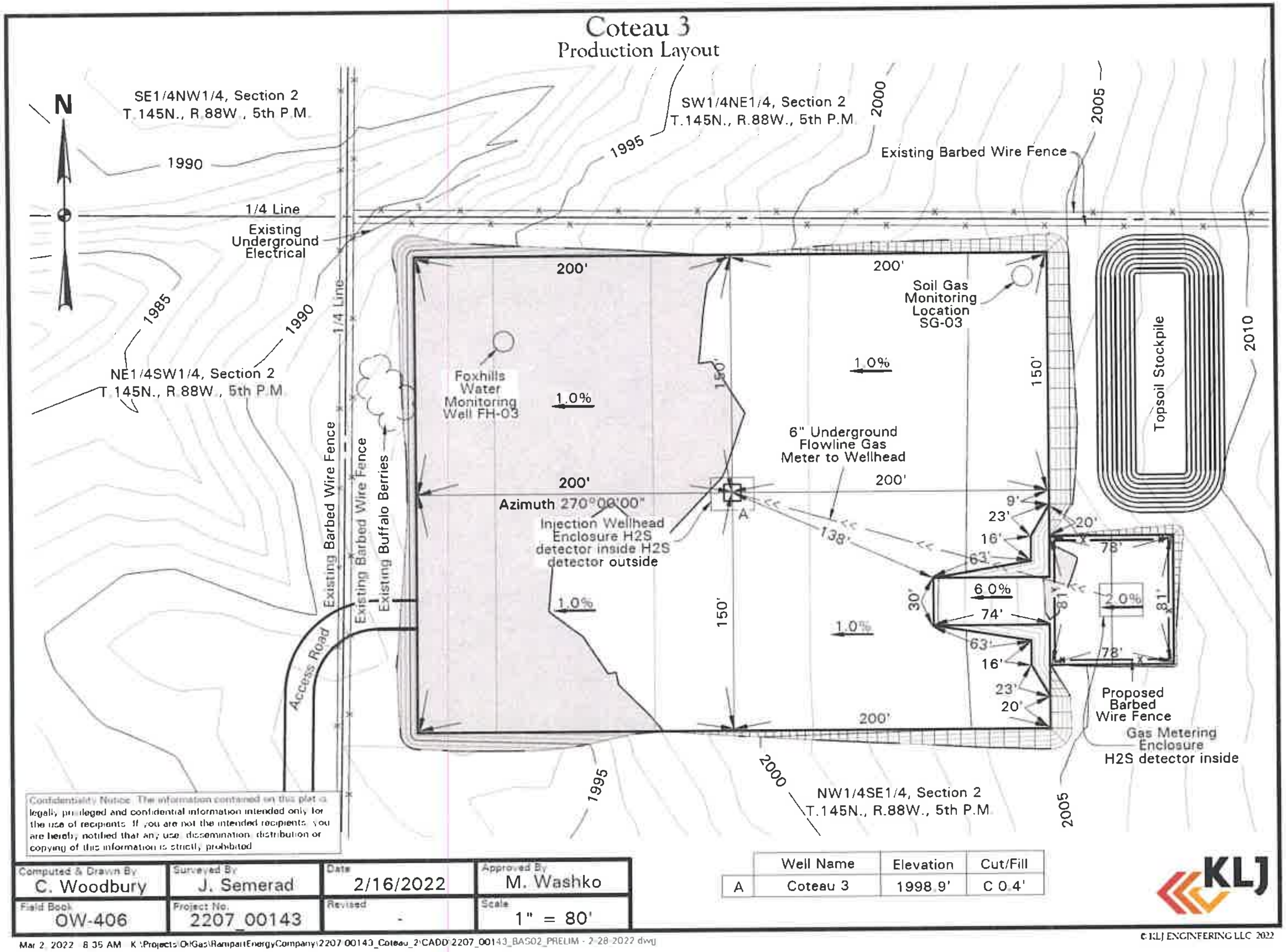


Figure 5-1C. Well pad drawing of the Coteau 3 well location.

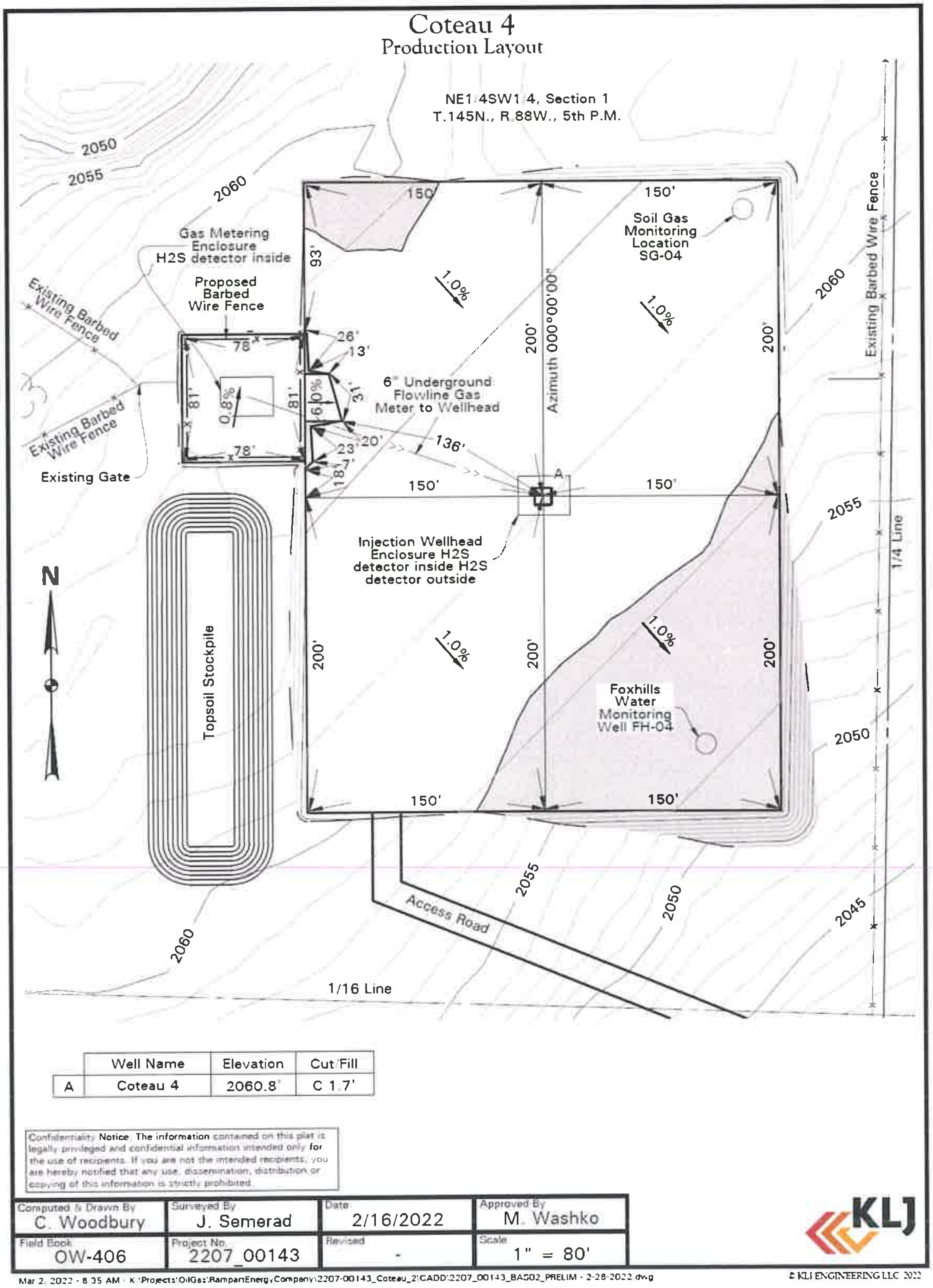
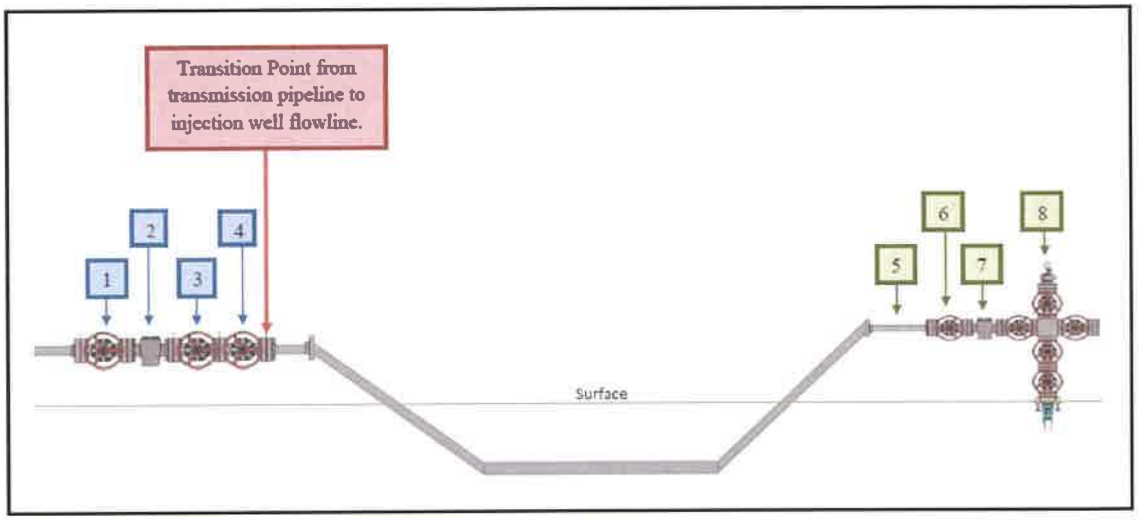


Figure 5-1D. Well pad drawing of the Coteau 4 well location.

Great Plains CO2 Sequestration Project
Coteau No. 1 Surface Connections



1. Block valve (capable of remote operation) - this valve will shut down CO_2 to the flowline in the event of a leak or other issue.
2. Flow Meter.
3. Pressure control valve.
4. Block valve (capable of remote operation) - this valve will shut off CO_2 to the well if for some reason the control valve outlet pressure approaches the maximum well head pressure.
5. 4 1/2" L-80 Tubing test section.
6. 4 1/16" 5M isolation wing valve.
7. One-way check valve to prevent backflow of CO2 from the reservoir in the event of an emergency shutdown.
8. 4 1/6" 5M Tree with 200 psi of static operating pressure held on the tubing-casing annulus. A deviation of 20% in either direction will trigger closure of the remote block valve, as will an alarm condition from the surface H2S monitors.

Figure 5-2. Diagram of surface connections at the Coteau 1 wellsite. The Coteau 2 through 5 wells will connect to a common gathering system at the Coteau 1 well pad. The Coteau 6 will be similarly equipped but will connect to a separate gathering system. The primary block valve (item 1 above) will be located at the Coteau 1 well while the rest of the equipment (Items 2 through 8 above) will be located on the well pads of each of the injection wells.

5.2.2 Corrosion Prevention

To prevent corrosion of the well materials, the following preemptive measures will be taken: 1) cement in the injection wells opposite the injection interval and extending more than 2,000 feet uphole will be CO_2-resistant, 2) the well casing (L-80 13Cr) will also be CO_2-resistant from the bottomhole to a depth just above the Opeche Formation in the injection wells, and 3) the packer fluid will be an industry standard corrosion inhibitor. In addition, the chemical composition of the CO_2 stream is highly pure (Table 5-2) and dry, with a moisture level for the CO_2 stream typically less than two parts per million by volume, both factors of which help to prevent corrosion of the surface and well materials.

5.3 Surface Leak Detection and Monitoring Plan

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. Performance targets designed for the Great Plains CO_2 Sequestration Project to detect potential leaks in the flowline are provided in Table 5-3. The performance targets are dependent upon the actual performance of instrumentation (e.g., pressure gauges) and the supervisory control and data acquisition (SCADA) system, which uses software to track the status of the pipeline system in real time by comparing live pressure and flow rate data to a comprehensive predictive model. The performance targets assume a flow rate of 200 million standard cubic feet per day (MMSCFD) of CO_2. An alarm will trigger on the SCADA system if a volume deviation of more than 2% is registered. H_2S detection stations will also be mounted on the inside and outside of wellhead enclosures to detect any potential indoor and atmospheric leaks at the well pad locations, respectively. The stations can detect H_2S concentrations as low as 1 part per million (ppm) and have an integrated alarm system if a 10 ppm threshold is crossed. The stations are further described in Appendix C (Attachment A-7). Field personnel will have multi gas detectors with them for wellsite visits or flowline inspections to detect potential leaks from the equipment. The multi gas detectors will primarily monitor for CH_4, CO, O_2, and H_2S up to 100 feet from a surface leakage source. The multi gas detector will measure H_2S as low as 0.1 ppm with an incremental resolution of 0.1 ppm and has built-in alarms. Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

Table 5-3. Performance Targets for Detecting Potential Leaks in Surface Equipment with SCADA

Leak Size (MMSCFD)	Detection Time (minutes)
200	<2
>10	<5
<10 and >4	<60

5.4 Subsurface Leak Detection and Monitoring Plan

The monitoring plan for detecting subsurface leaks comprises "surface/near-surface" and deep subsurface monitoring programs. "Surface/near-surface" refers to the region from ground surface down to, and including, the lowest USDW as well as surface waters, soil gas (vadose zone), and shallow groundwater (e.g., stock wells, residential drinking water wells, etc.). The deep subsurface zone extends from the base of the lowest USDW to the base of the injection zone of the storage reservoir.

Subsurface leak detection will include multiple approaches to ensure confidence that surface (i.e., ambient and workspace atmospheres and surface waters) and near-surface (i.e., vadose zone, groundwater wells, and the lowest USDW) environments are protected, and the CO_2 is safely and permanently stored in the storage reservoir. More specifically, for DGC's geologic storage project, near-surface monitoring will include 11 soil gas profile stations and seven dedicated Fox Hills Formation monitoring wells within the AOR to detect if the lowest USDW is being impacted by operations. These monitoring efforts will provide additional lines of evidence to assess whether the surface/near-surface environment is being protected and whether the CO_2 is being safely and permanently stored in the storage reservoir.

To complement surface/near-surface monitoring, additional monitoring of the subsurface will ensure CO_2 is staying in the targeted storage reservoir. Operational monitoring at the injection wells, including injection rates, pressures, and temperatures will provide data to inform the monitoring approaches. Internal and external mechanical integrity of the injection wells will also be demonstrated to ensure no leakage pathway exist that may allow vertical movement of the CO_2. Additionally, geophysical (seismic) surveys conducted over regular intervals will monitor subsurface CO_2 plume movement.

More details regarding the surface, near-surface, and deep subsurface monitoring efforts are provided in sections 5.5 through 5.7.

5.5 Near-Surface Soil Gas and Groundwater Sampling and Monitoring

Near-surface environments will be monitored to ensure that an out-of-zone migration has not occurred. This will be accomplished by monitoring the environment within the delineated AOR via vadose zone soil gas and Fox Hills (lowest USDW) sampling prior to CO_2 injection (preoperational baseline), during active CO_2 injection (operational), and during the postoperational monitoring time frame. Figure 5-3 illustrates the baseline sampling program for vadose zone and groundwater in the Fox Hills Formation. In addition, baselines for shallow groundwater aquifers within the AOR, which may be used in the future to monitor the geologic storage project area, are included in Appendix B.

DGC initiated a seasonal baseline sampling program for soil gas (Figure 5-3) and plans to complete this part of the baseline program by July 2022. Eleven soil gas profile stations have been installed: one station near each wellsite (Coteau 1 through 6 wells) and five more spaced apart and located around the edge of the predicted 12-year CO_2 plume extent. Sample analysis of each profile station will be provided to NDIC prior to CO_2 injection operations. This initial sampling program and the results are provided in detail in Section 5.5.1.

DGC initiated a baseline groundwater sampling program in the Fox Hills Formation in the Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells (Figure 5-3). Upon field investigation, it was found that the Floyd Weigum #1 was abandoned and could not be sampled; therefore, its historical data will be used as a baseline instead. Archived water quality analyses on all three wells are available in Appendix B.

Prior to injection, DGC will install six dedicated Fox Hills Formation monitoring wells at each injection wellsite (Coteau 1 through 6 wells). A seventh Fox Hills Formation monitoring well will be placed along the western edge of the AOR near the Herrmann 1 well (NDIC File No. 4177). A state-certified laboratory analysis will be provided to NDIC prior to injection for all additional groundwater sampling in the Fox Hills Formation. This initial sampling program and the results are provided in detail in Section 5.5.2.

The near-surface monitoring plan, including the additional baseline sampling of groundwater, the Fox Hills Formation, and the soil gas profile stations, is provided in Section 5.6.

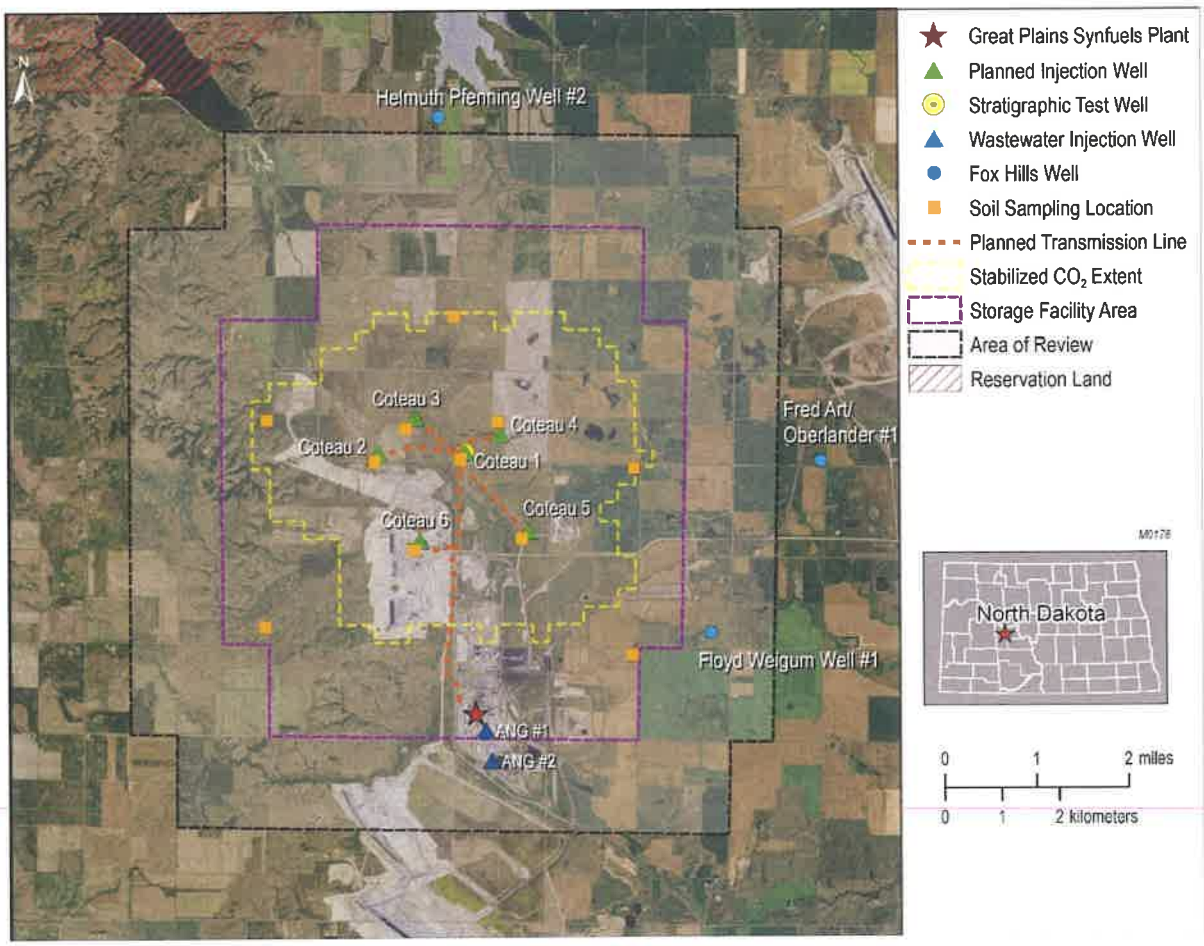


Figure 5-3. DGC's initiated baseline sampling program for vadose zone soil gas and groundwater in the Fox Hills Formation.

5.5.1 Soil Gas Baseline Sampling

Soil gas sampling and analyses have been initiated to establish seasonal baseline soil gas geochemical results, including concentrations of CO_2, O_2, and N_2 and isotopic ratios for $^{13}CO_2$, $^{13}C_1$, and δC_1. An initial set of samples and associated analyses were collected in October and November 2021, as shown in Table 5-4.

The sampling results from these efforts will provide a preoperational seasonal baseline of the soil gas geochemistry in the vadose zone in and around the CO_2 geologic storage project. DGC plans to sample and run analyses on the soil gas profile stations quarterly until July 2022. During operations, DGC will continue to collect soil gas concentrations quarterly from the 11 soil gas profile stations.

Table 5-4. DGC's Initial Soil Gas Geochemical Results – Fall 2021

Well No.	CO_2, ppm	O_2+Ar, ppm	N_2, ppm	$\delta^{13}CO_2$, ‰ VPDB[1]	$\delta^{13}C_1$, ‰ VPDB	δD_{C1}, ‰ VSMOW[2]
SG01[3]	305,420	16,923	685,166	−14.0	−13.1	−376
SG02[4,5]	2,402	194,468	796,541	−20.3		
SG03	193,032	27,421	786,850	−14.7		
SG04	209,353	11,773	784,351	−6.7		
SG05	202,316	51,148	760,674	−1.1		
SG06[4]	21,158	162,573	817,003	−20.5		
SG07[4,5]	2,582	215,422	781,419	−22.0		
SG08	213,591	13,855	781,768	−18.8		
SG09	135,306	13,292	863,995	−17.8		
SG10	158,590	89,475	767,489	−18.4		
SG11[4]	9,822	203,018	787,739	−17.1		

[1] Vienna Pee Dee Belemnite $\delta^{13}C$ Standard.
[2] Vienna Standard Mean Ocean Water.
[3] Single well in data set with sufficient volume of measured methane levels to run stable isotope analysis.
[4] Because of local variations in the water table, wells SG02, SG06, SG07, and SG11 were limited to sample depths from 4 to 9 feet below ground surface (bgs). All other locations obtained samples from 22 to 23 feet bgs.
[5] Low isotopic signal results.

5.5.2 *Groundwater Baseline Sampling*

Two Fox Hills Formation samples were obtained in November 2021 from the Fred Art/ Oberlander #1 and Helmuth Pfenning #2 wells. State-certified laboratory results for these two wells found in Appendix B show little variation among the reports.

The locations of the wells investigated for establishing baseline conditions are shown in Figure 5-3, and the results of the baseline measurements for pH, specific conductivity, and alkalinity are provided in Table 5-5, with state-certified laboratory results for each sampling event provided in Appendix B. In addition, DGC plans to obtain a baseline water sample from the Fox Hills monitoring well that will be drilled near the Herrmann 1 well (NDIC File No. 4177) prior to injection operations.

Table 5-5. DGC's Initial Baseline Groundwater Sampling Results – Fall 2021

Well Name	pH (pH unit)	Conductivity, µmhos/cm	Total Alkalinity, mg/L $CaCO_3$
Fred Art/Oberlander #1	8.5	2519	1020
Helmuth Pfenning #2	8.4	2347	1280
Floyd Weigum #1*	N/A	N/A	N/A

* Wellbore was confirmed in the field to be abandoned and determined inaccessible for sampling.

5.6 Near-Surface (groundwater and soil gas) Monitoring Plan

Prior to injection operations, DGC will drill and construct a total of five dedicated groundwater monitoring wells in the Fox Hills Formation (i.e., lowest USDW). One groundwater monitoring well will be placed at each of the injection well locations (Coteau 1 through 4 wells initially) and another will be placed near the Hermann 1 well (NDIC File No. 4177) (Figure 5-4). Baseline Fox Hills Formation water samples will be collected from all five monitoring wells prior to CO_2 injection. Dedicated Fox Hills Formation monitoring wells will also be drilled and constructed for the Coteau 5 and the Coteau 6 injection wells after they are drilled and constructed prior to 2026. DGC plans to monitor the vadose zone using the 11 soil gas profile stations already installed.

Over the life of CO_2 injection activities, the 11 soil gas profile stations will be sampled quarterly along with the Fox Hills groundwater monitoring wells located near each of the injection wells. State-certified laboratory results of the groundwater wells will be filed with NDIC. A detailed near-surface monitoring plan is presented in Table 5-6, including the duration and frequency of the sampling that will be made during each phase (i.e., preinjection, operational, and postoperational) of the geologic CO_2 storage project.

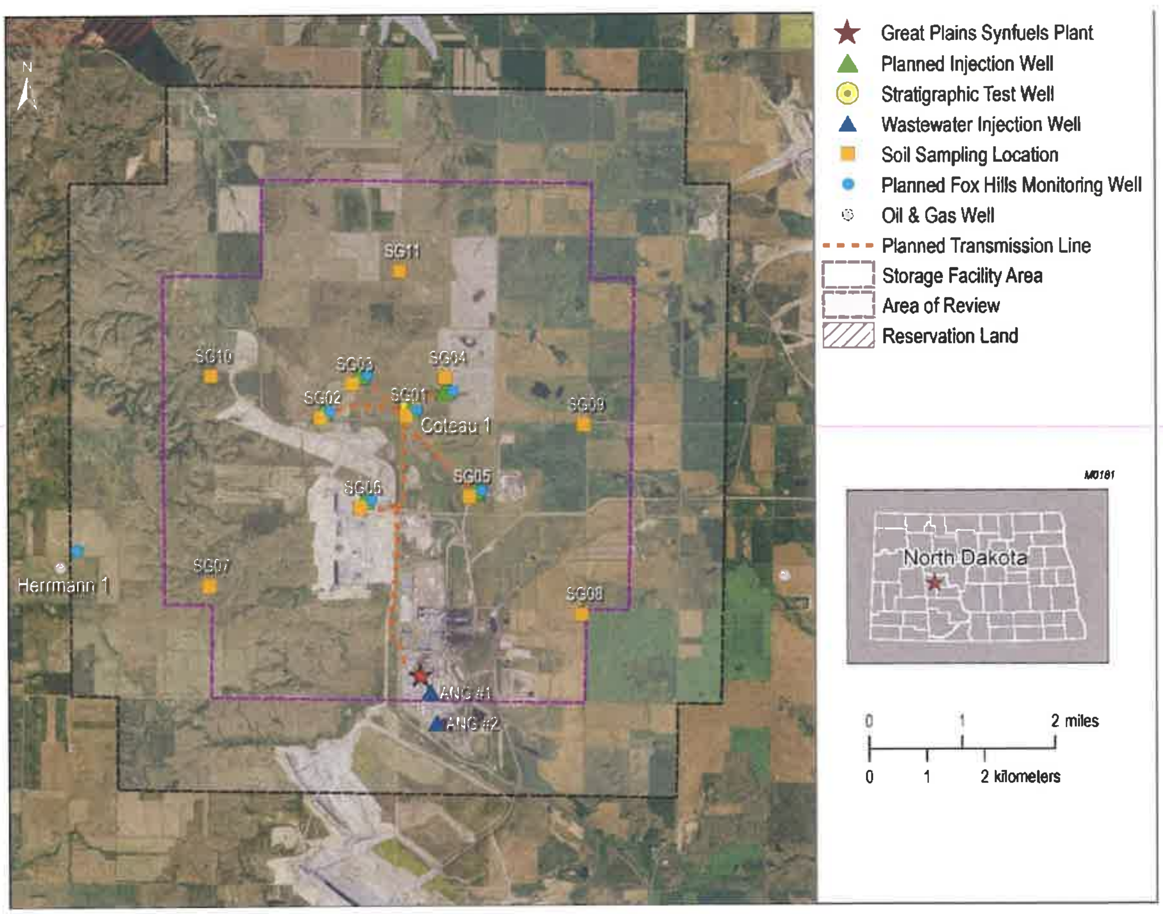


Figure 5-4. DGC's near-surface monitoring plan for seven Fox Hills Formation (lowest USDW) monitoring wells and the 11 soil gas profile stations around the storage facility area.

Table 5-6. Baseline (preinjection), Operational, and Postoperational Monitoring Duration and Frequency for Soil Gas and Groundwater

Monitoring Type	Baseline (preinjection)*	Operational	Postoperational
Soil Gas Monitoring			
Soil Gas Profile Stations (SG01 to SG11) (Figures 5-3 and 5-4)	Duration: Minimum one year Frequency: Sample 3–4 events per well to establish seasonal baseline Perform concentration and isotopic testing on all samples	Duration: 12 years Frequency: Sample 3–4 events per year to account for seasonal fluctuation Perform concentration testing on all samples	Duration: Minimum 10 years postinjection Frequency: Sample 3–4 events per year Perform concentration testing on all samples
Groundwater Monitoring			
Fred Art/Oberlander #1 and Helmuth Pfenning #2 (Figure 5-3) Fox Hills monitoring well by Herrmann 1 (Figure 5-4)	Duration: Prior to injection to establish baseline and verify historic geochemical data Frequency: Once to establish a baseline and verify consistency of historical well test data (Appendix B) Perform water quality and isotopic testing on all samples	None Shift sampling program to the dedicated Fox Hills monitoring wells	None
Six monitoring wells in the Fox Hills Formation (lowest USDW) at injection wellsites (Coteau 1 through 6 wells) (Figure 5-4)	Duration: Prior to injection Frequency: Sample 3–4 events per well annually Perform water quality testing on all samples	Duration: 12 years Frequency: Sample 3–4 events per well annually Perform water quality testing on all samples	Duration: Minimum 10 years postinjection Frequency: Sample 3–4 events per well annually Perform water quality testing on all samples

* The baseline (preinjection) monitoring effort has begun as of the writing of this permit application. As noted in the text, additional sampling will be performed between the submission date of this permit application and the start of CO_2 injection.

5.7 Deep Subsurface Monitoring of Free-Phase CO_2 Plume and Pressure Front

DGC will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume and associated pressure relative to the permitted storage reservoir. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and postoperational periods. The methods described in Table 5-7 will be used to characterize the plume and pressure within the AOR. DGC will employ an adaptive management approach to implementing the testing and monitoring plan by completing periodic reviews of the testing and monitoring plan (Ayash and others, 2017). During each review, monitoring and operational data will be analyzed, the AOR will be reevaluated, and if warranted, the testing and monitoring plan will be adjusted accordingly. The testing and monitoring plan will be reviewed in this manner at least once every 5 years. Based on this review, it will either be demonstrated that no amendment to the testing and monitoring program is needed or that modifications to the program are necessary to ensure proper monitoring of the storage performance is achieved and that the risk profile of the storage operations is addressed moving forward. This determination will be submitted to NDIC for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by NDIC. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.

Monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of the CO_2 plume and pressure distribution relative to the permitted geologic storage facility. If significant variance is observed, the monitoring and operational data will be used to calibrate the geologic model and associated simulations. The monitoring plan will be adapted to provide suitable characterization and calibration data as necessary to achieve such conformance. Subsequently, history-matched predictive simulation and model interpretations will, in turn, be used to inform adaptations to the monitoring program to demonstrate lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

Table 5-7. Description of DGC's Deep Subsurface Monitoring Program

Monitoring Type	Preoperational (baseline)	Operational	Postoperational
Mechanical Integrity Testing (MIT)			
USIT (external MIT)	Prior to injection	Duration: 12 years Frequency: Perform when tubing is pulled but not more frequently than once every 5 years.	None Injection wells will be plugged.
Temperature Logs Run with PNL (external MIT)	Prior to injection	Duration: 12 years Frequency: Quarterly using phased approach described in Section 5.1.2	None Injection wells will be plugged.
200 psi Kept on Annulus, Between Tubing and Long-String (multifinger imaging tool [internal MIT])	Prior to injection Initial volume of packer fluid (corrosion inhibitor) and nitrogen cushion to fill casing	Duration: 12 years Frequency: Continuous Nitrogen cushion will be used to maintain a consistent pressure.	None Injection wells will be plugged.
Tubing-Casing Annulus Pressure Testing (internal MIT)	Prior to injection	Duration: 12 years Frequency: Perform during well workovers but not more frequently than once every 5 years.	None Tubing will be pulled from the injection wells, and the injection wells will be plugged.
Pressure Falloff Test in the Injection Zone (internal MIT)	Prior to injection	Duration: 12 years Frequency: Once every 5 years	None Injection wells will be plugged.
Storage Reservoir (Direct) Monitoring			
Flow Rate and Volume, Surface Injection Pressure, and Surface Injectate Temperature	At start of injection operations	Duration: 12 years Frequency: Continuous monitoring	None Injection operations will have ceased.
PNLs with Temperature Logs and Pressure Recording Devices Attached	Prior to injection	Duration: 12 years Frequency: Quarterly, using phased approach described in Section 5.1.2	None Injection wells will be plugged.

Continued…

Table 5-7. Description of DGC's Deep Subsurface Monitoring Program (continued)

Monitoring Type	Baseline (preoperational)	Operational	Postoperational
Surface Pressure Gauges on the ANG #1 and ANG #2	None	Duration: 12 years Frequency: Continuous monitoring of surface pressures to history match predictions	Duration: Minimum 10 years postinjection Frequency: Continuous monitoring of surface pressures to history match predictions
Above-Zone Monitoring Interval (AZMI)			
PNLs with Temperature Logs Attached	Prior to injection	Duration: 12 years Frequency: Quarterly, using phased approach described in Section 5.1.2	None Injection wells will be plugged.
Geophysical (Indirect) Monitoring			
Time-Lapse Seismic (Figure 5-7)	Prior to injection Collect baseline 2D seismic survey	Repeat 2D seismic one year after injection begins, then in Years 3, 5, and 10.	Time-lapse seismic surveys will continue as part of minimum 10-year postinjection monitoring plan and until stability of plume is demonstrated. Frequency: Perform 2D radial seismic surveys at the cessation of CO_2 injection, 1 year after injection ends, then in Years 3, 5, and 10
VSPs	Prior to injection	Repeat VSP 1 year after injection begins, then (if deemed beneficial) in Years 3, 5, and 10.	None

Table 5-8 describes the testing and logging program developed for the Coteau 1 wellbore. Included in the table is a description of fluid sampling and pressure testing performed. The logging and testing program for the Coteau 2 through 6 wells will be the same as what is presented in Table 5-8 but without the combinable magnetic resonance and dipole sonic logs. Wellbore data collected from the Coteau 1 have been integrated with the geologic model and to inform the reservoir simulations that are used to characterize the initial state of the reservoir before injection operations. The simulated CO_2 plumes based on the current geologic model and simulations are shown in Figures 5-5 and 5-6. These simulated CO_2 plume extents inform the timing and frequency of the application of the direct and indirect monitoring methods of the testing and monitoring plan.

Table 5-8. Testing and Logging Program for the Coteau 1 Wellbore

Log/Test	Justification	NDAC Section
Ultrasonic, CCL (casing collar locator), VDL (variable-density log), GR (gamma ray)	Identified cement bond quality radially. Interpreted good azimuthal cement coverage. Evaluated the cement top and zonal isolation.	43-05-01-11.2(1c[2])
Triple Combo (resistivity, density, porosity, GR, caliper, and spontaneous potential)	Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. Provided input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve test design and interpretations.	43-05-01-11.2(1c[1])
Combinable Magnetic Resonance (CMR)	Aided in interpreting reservoir permeability, packer setting depths, and stress testing depths. CMR and MDT data combined provided enhanced permeability evaluation, temperature variation, fluid identification, and fluid contacts.	43-05-01-11.2(1c[1])
Spectral GR	Identified clays and lithology that could affect injectivity. Also used for core to log depth correlation.	43-05-01-11.2(2)
Dipole Sonic	Identified mechanical properties including stress anisotropy. Provided compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.	43-05-01-11.2(1c[1])
Fracture Finder Log	Quantified fractures in the Broom Creek Formations and confining layers to ensure safe, long-term storage of CO_2.	43-05-01-11.2(1c[1])
Perforation-Flowback	Collected fluid sample and pressure-tested the Broom Creek	43-05-01-11.2(2)

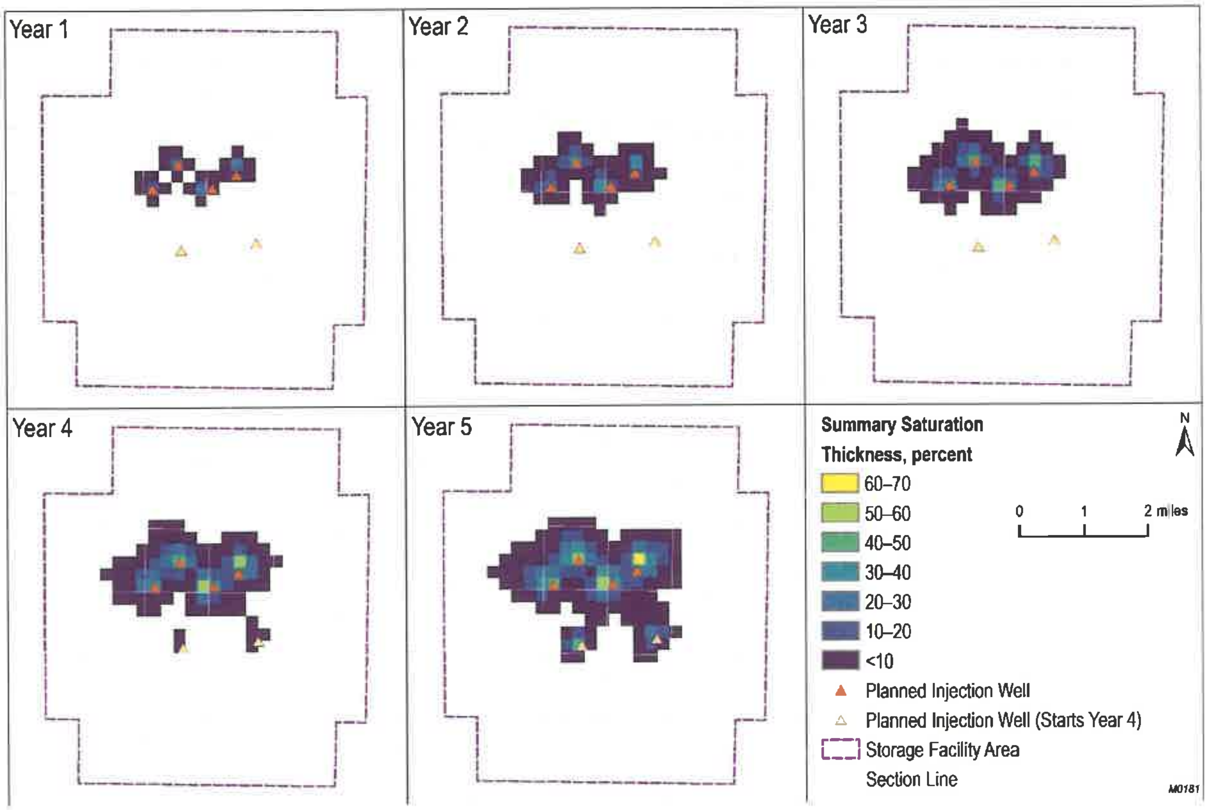


Figure 5-5. Simulated CO_2 plume saturation at the end of Years 1 through 5 after initial CO_2 injection. The simulated plume extent at 5 years (5.3 square miles) results in a CO_2 plume with an average radius of 6,442 feet.

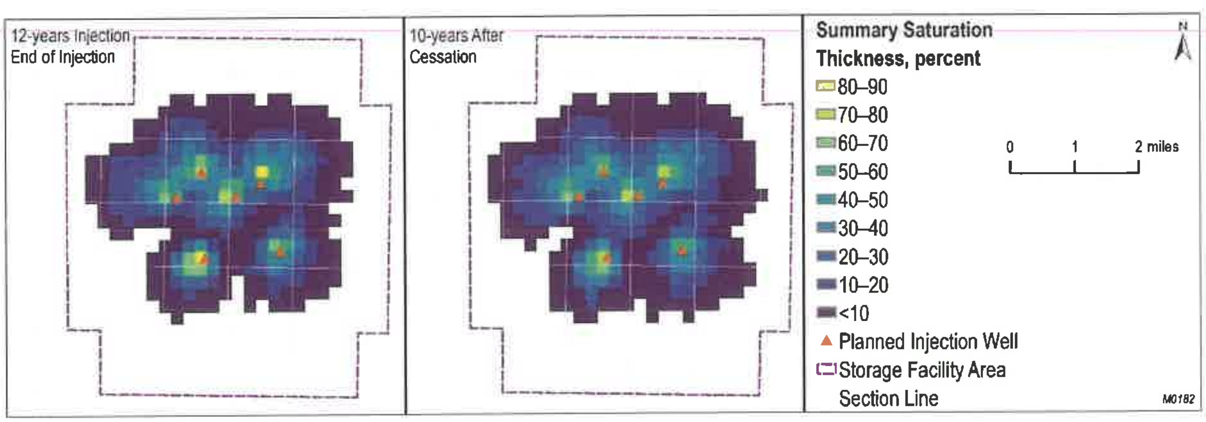


Figure 5-6. Simulated extent of the CO_2 plume at the cessation of injection and the postinjection stabilized plume.

5.7.1 Direct Monitoring Methods

To directly monitor and track the extent of the CO_2 plume within the storage reservoir, PNLs with temperature logs and pressure data will be performed quarterly in the injection wells using the phased approach described in Section 5.1.2 of this storage facility permit The temperature and saturation data collected in the overlying Inyan Kara Formation, the nearest overlying, highly permeable interval above the storage reservoir and main sealing formations, will provide confirmation of seal capacity for the upper confining zone (i.e., Opeche Formation) for monitoring the performance of the storage complex (see Figure 2-3 for stratigraphic reference). Monitoring of the overlying interval can provide an early warning of out-of-zone migration of fluids, providing sufficient time for the development and implementation of mitigation strategies to ensure these migrating fluids do not impact a USDW or reach the surface.

Preoperational baseline PNL data have been collected from the Coteau 1 well. These time-lapse saturation data will be used to monitor for CO_2 in the formation directly above the storage reservoir, otherwise known as the AZMI, as an assurance-monitoring technique.

5.7.2 Indirect Monitoring Methods

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 2D geophysical surveys and 2D VSPs (Figure 5-7). The 2D seismic acquisition lines indicated in Figure 5-7 will be extended over time to capture additional data as the CO_2 plume expands. Figure 5-8 illustrates the predicted extent of the injected free-phase CO_2 plume at the end of 12 years of injection relative to the baseline 2D seismic and storage facility area. To demonstrate conformance between the reservoir model simulation and site performance, a repeat 2D seismic survey and VSP will be collected to monitor the extent of the CO_2 plume after approximately 1 year of CO_2 injection. Additional 2D seismic data will be collected in Years 3, 5, and 10 to further delineate the CO_2 plume movement. Additional VSPs will be collected at the same frequency as the 2D seismic lines if the results of the first and second tests prove beneficial. These seismic monitoring data will provide confirmation of the simulation predictions and confirm the extents of the CO_2 plume within the AOR. Through the operational phase of the project, the time-lapse seismic monitoring plan will be adapted based on updated simulations of the predicted extents of the CO_2 plume. At the end of the operational phase, time-lapse seismic will be utilized during the postinjection period to confirm the stabilization of the CO_2 plume. These indirect monitoring methods for characterization of the deep subsurface CO_2 plume are commercially available and are proven time-lapse methods.

At the conclusion of the operating phase of the project, the planned monitoring program will continue to ensure the long-term containment and stability of the injected CO_2 in the storage complex (Table 6-1). Monitoring efforts in the postinjection phase will provide the data necessary for the required final assessment to prove long-term containment and stability of the injected CO_2 plume and secure a certificate of project completion from NDIC.

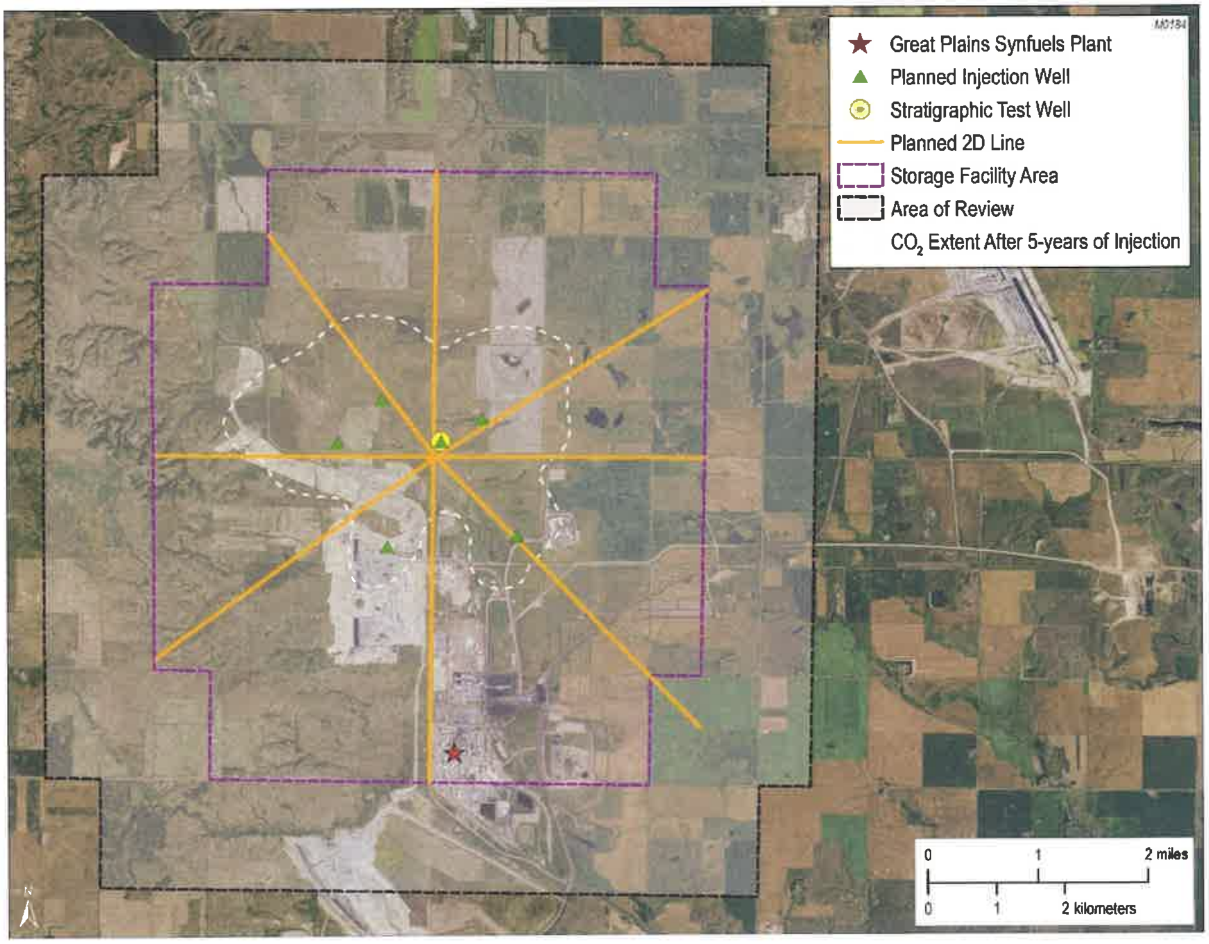


Figure 5-7. Locations of the planned 2D radial seismic lines near the Coteau 1 well to establish a baseline.

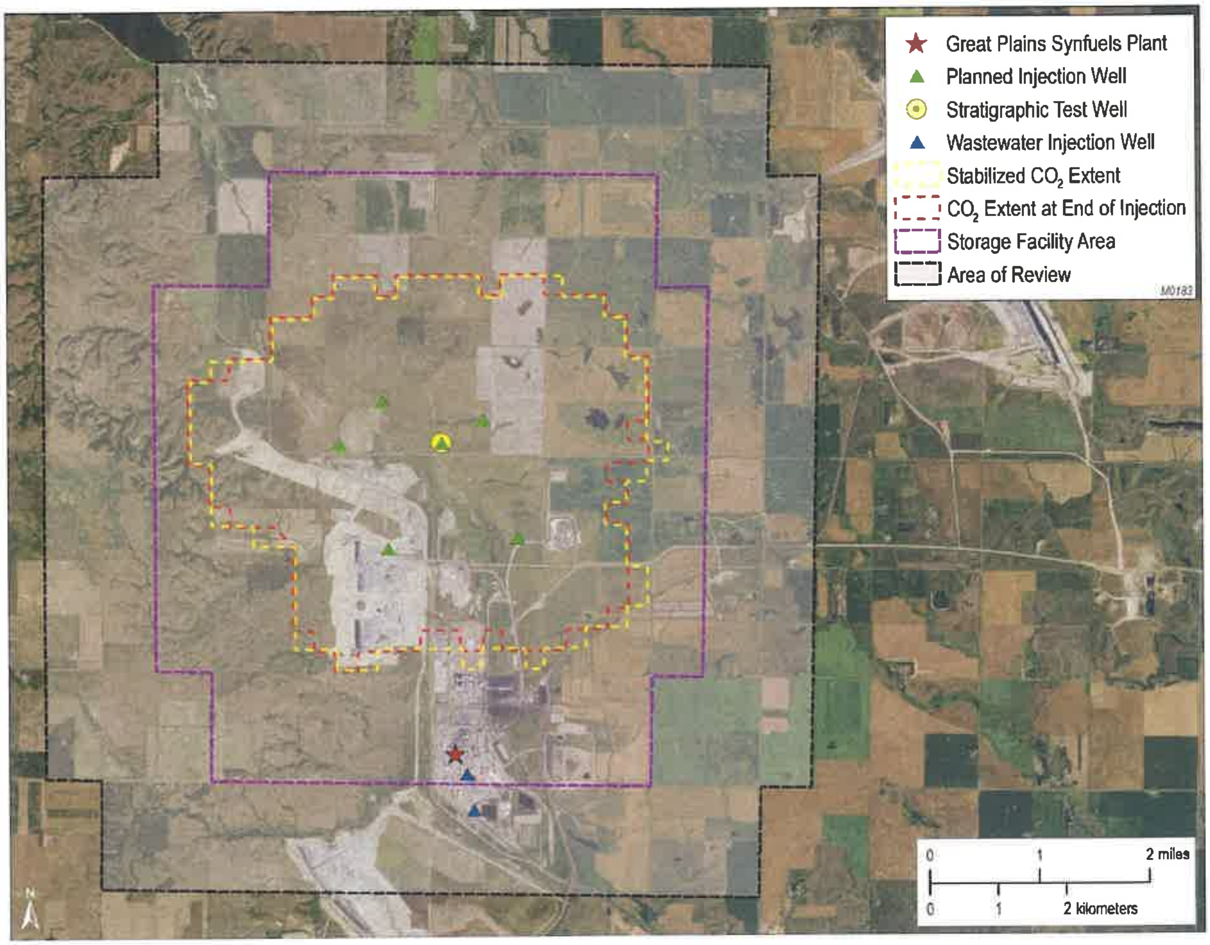


Figure 5-8. Simulated extent of the CO_2 plume at the end of injection operations in red and the stabilized CO_2 plume following the cessation of CO_2 injection in yellow.

5.8 References

Ayash, S.C., Nakles, D.V., Wildgust, N., Peck, W.D., Sorenson, J.A., Glazewski, K.A., Aulich, T.R., Klapperich, R.J., Azzolina, N.A., and Gorecki, C.D., 2017, Best practice for the commercial deployment of carbon dioxide geologic storage – the adaptive management approach: Plains CO_2 Reduction (PCOR) Partnership Phase III, Task 13 Deliverable D102/Milestone M59 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2017-EERC-05-01, Grand Forks, North Dakota, Energy and Environmental Research Center, August.

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6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

This postinjection site care (PISC) and facility closure plan describes the activities that DGC will perform following the cessation of CO_2 injection to achieve final closure of the site. A primary component of this plan is a postinjection monitoring program that will provide evidence that the injected CO_2 plume is stable (i.e., CO_2 migration will be unlikely to move beyond the boundary of the storage facility area). Based on simulations of the predicted CO_2 plume movement following the cessation of CO_2 injection, it is projected that the CO_2 plume will stabilize within the storage facility area boundary (Section 3). Based on these observations, a minimum postinjection monitoring period of 10 years is planned to confirm these current predictions of the CO_2 plume extent and postinjection stabilization. However, monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable CO_2 plume. The nature and duration of that extension will be determined based on an update of this plan and NDIC approval.

In addition to DGC executing the postinjection monitoring program, the Class VI injection wells will be plugged as described in the plugging plan of this permit application (Section 10), all surface equipment not associated with long-term monitoring will be removed, and the surface land of the site will be reclaimed to as close as is practical to its original condition. Following the plume stability demonstration, a final assessment will be prepared to document the status of the site and submitted as part of a site closure report.

6.1 Predicted Postinjection Subsurface Conditions

6.1.1 Pre- and Postinjection Pressure Differential

Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of CO_2 injection. The simulations were conducted for 12 years of CO_2 injection at rates between 1.0 and 2.7 million metric tons per year, followed by a postinjection period of 10 years. Figure 6-1 illustrates the predicted pressure differential at the conclusion of 12 years of CO_2 injection. At the time that CO_2 injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of 400 to 450 psi at the location of the injection wells, which is insufficient to move formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the area of review (AOR) delineation of this permit application (Section 3). An illustration of the predicted decrease in this pressure profile over the 10-year postinjection period is provided in Figure 6-2. The pressure in the reservoir gradually decreases over time following the cessation of CO_2 injection, with the pressure at the injection well after 10 years of postinjection predicted to decrease 300 to 350 psi as compared to the pressure at the time CO_2 injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions.

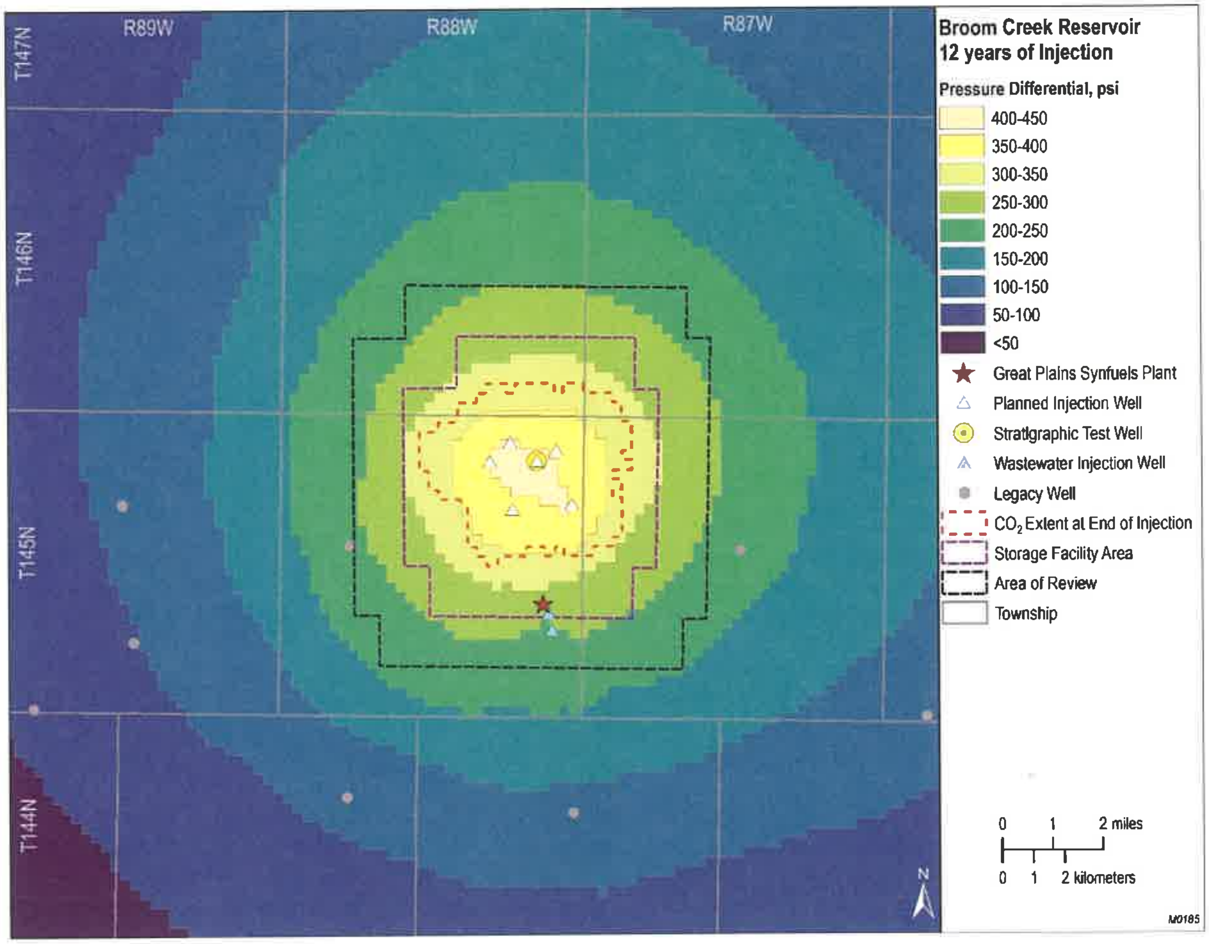


Figure 6-1. Predicted pressure differential in storage reservoir following 12 years of CO_2 injection at rates between 1.0 and 2.7 million metric tons per year.

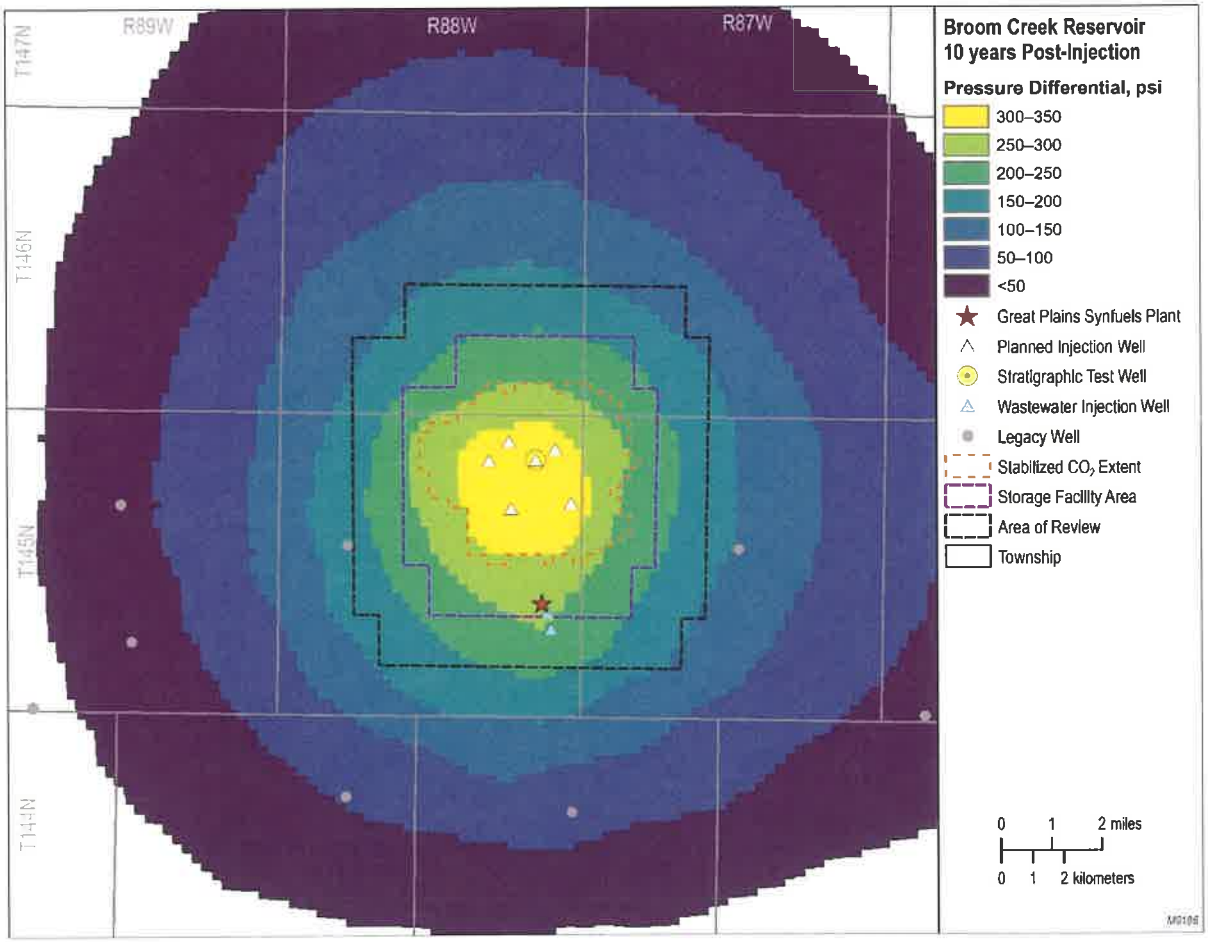


Figure 6-2. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection.

6.1.2 Predicted Extent of CO_2 Plume

Also shown in Figures 6-1 and 6-2 are numerical simulation predictions of the extent of the CO_2 plume at the time CO_2 injection was terminated (i.e., after 12 years of injection) and following the planned 10-year PISC period (also called the stabilized plume), respectively. The results of these simulations predict that 99% of the separate-phase CO_2 mass would be contained within an area of 11.28 mi^2 at the end of CO_2 injection (see Figure 6-1). As shown in Figure 6-2, the areal extent of the CO_2 plume is not predicted to change substantially over the planned 10-year PISC period.

Additional simulations beyond the 10-year PISC period were also performed and predict that at no time will the boundary of the stabilized plume at the site, which is shown in both Figures 6-1 and 6-2, extend beyond the boundary of the storage facility area. If such a determination can be made following the planned 10-year postinjection period, the CO_2 plume will meet the definition of stabilization as presented in NDCC § 38-22-17(5d) and qualify the geologic storage site for receipt of a certificate of project completion.

6.1.3 Postinjection Monitoring Plan

A summary of the postinjection monitoring plan that will be implemented during the 10-year postinjection period is provided in Table 6-1. The plan includes a combination of soil gas and groundwater/USDW monitoring as well as downhole and geophysical monitoring of the CO_2 plume in the storage reservoir.

Table 6-1. Summary of 10-year Postinjection Site Care Monitoring Plan

Type of Monitoring	Duration and Frequency	Justification
	Near-Surface Monitoring	
Soil Gas Profile Stations (SG01 to SG11) (Figure 6-3)	Duration: minimum 10 years Frequency: 3–4 seasonal sample events at soil gas stations SG01 to SG11	The sampling and analysis program will monitor the vadose zone for any signs of potential CO_2 leaks within the storage facility area.
Dedicated Fox Hills (lowest USDW) Monitoring Wells (Figure 6-3)	Duration: minimum 10 years Frequency: 3–4 seasonal sample events at each dedicated Fox Hills monitoring well	The sampling and analysis program will monitor the Fox Hills Formation at each injection well pad to ensure the USDW is not impacted by operations.
	Storage Reservoir Monitoring	
Surface Pressure Gauges on the ANG #1 and ANG #2 Wells (if WHP:BHP method is not satisfactory, DGC will perform a BHP survey in the first year of the PISC period)	Duration: minimum 10 years postinjection Frequency: continuous	Surface pressures will monitor the pressure decrease in the Broom Creek and history-match model predictions.
	Geophysical Monitoring	
Time-Lapse Seismic	Duration: minimum 10 years postinjection Frequency: perform 2D radial seismic surveys at the cessation of injection, 1 year after injection begins, then in Years 3, 5, and 10	Time-lapse seismic surveys will continue as part of the 10-year postinjection period to support a stabilization assessment of the CO_2 plume.

6.2 Groundwater and Soil Gas Monitoring

Eleven soil gas profile stations and six dedicated monitoring wells in the Fox Hills Formation (i.e., lowest USDW) will be sampled during the proposed 10-year PISC period. Figure 6-3 identifies the locations of the soil gas profile stations and dedicated Fox Hills Formation monitoring wells that will be included. It is proposed that these samples will be analyzed for the same list of parameters as described in the testing and monitoring plan (Section 5); however, it is anticipated

that the final target list of analytical parameters will likely be reduced for the PISC period based on an evaluation of the monitoring results that are generated during the 12-year injection period of the storage operations.

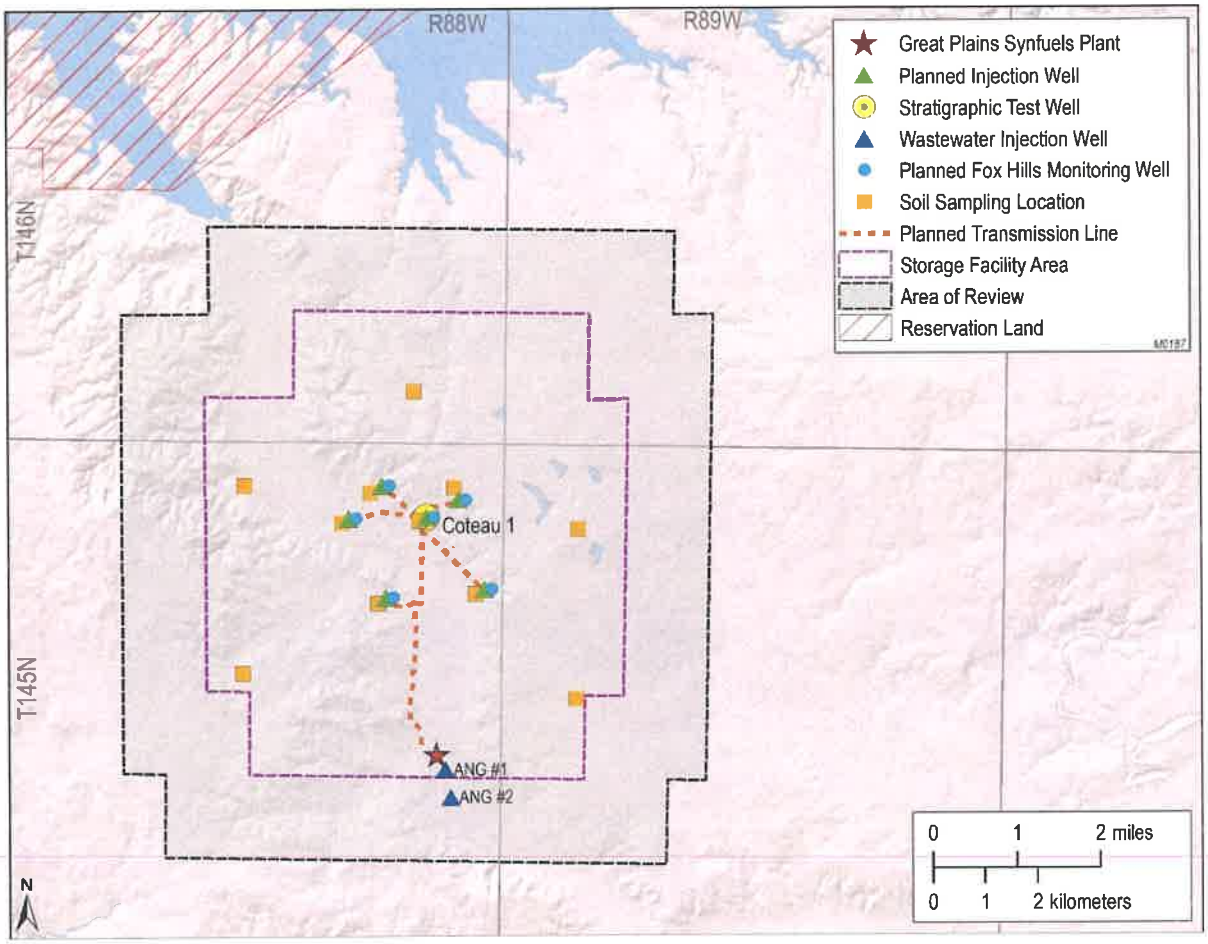


Figure 6-3. Soil gas and groundwater well sampling locations included in the PISC monitoring program.

6.3 CO_2 Plume Monitoring

Monitoring of the CO_2 plume migration in the subsurface will be conducted during the PISC period using the methods summarized in Table 6-1. Monitoring methods include a combination of near surface, deep subsurface, and geophysical techniques (i.e., surface seismic) that will monitor CO_2 saturation. Figure 6-4 illustrates the areal extents of the 2D seismic survey lines proposed during the PISC period in comparison to the areal extents of the stabilized CO_2 plume.

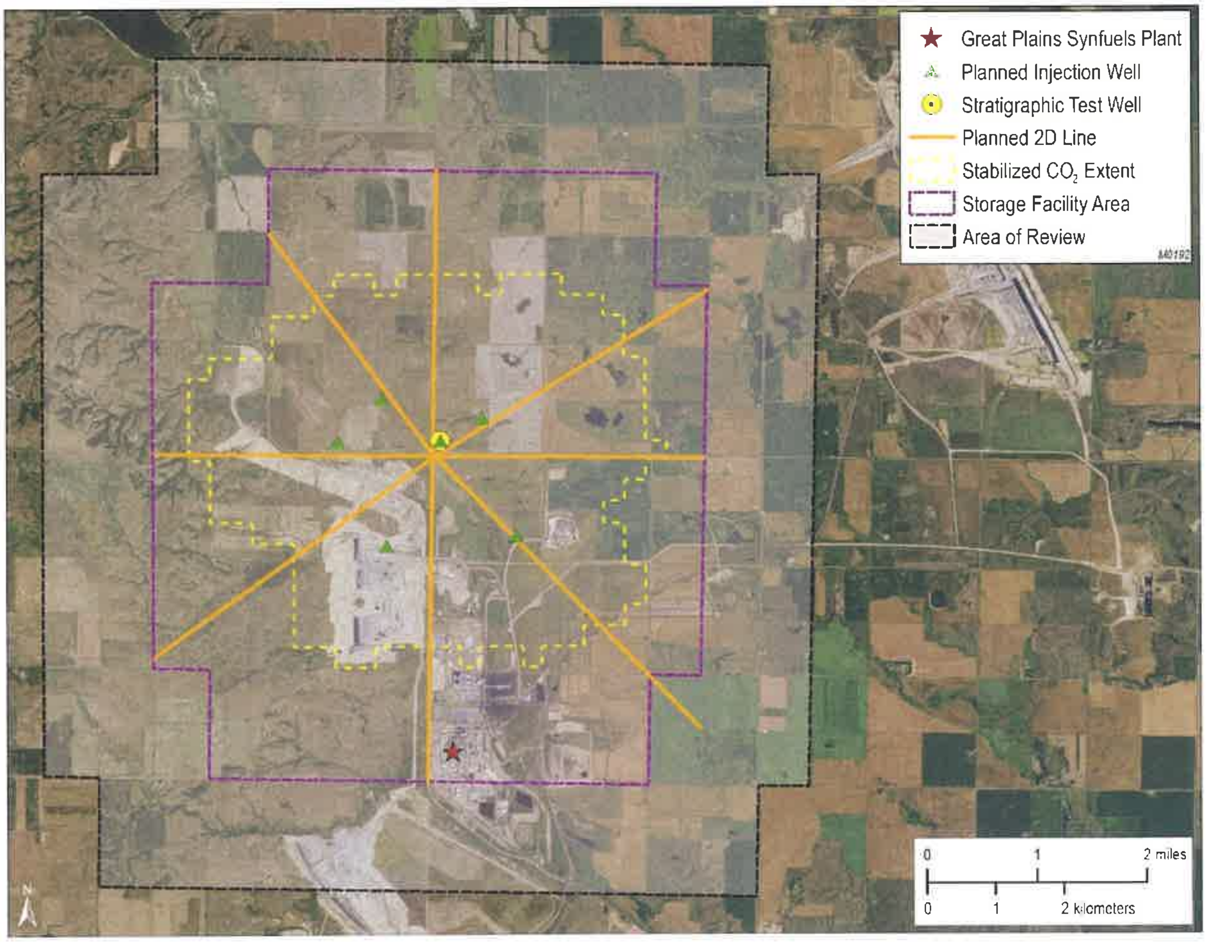


Figure 6-4. Areal extents of the 2D seismic survey lines proposed during the PISC period in comparison to the areal extents of the stabilized CO_2 plume.

6.3.1 Schedule for Submitting Postinjection Monitoring Results

All postinjection site care-monitoring data and monitoring results will be submitted to NDIC in annual reports. These reports will be submitted within 60 days of the anniversary date on which the CO_2 injection ceased.

The annual reports will contain information and data generated during the reporting period, including seismic data acquisition, formation-monitoring data, soil gas and groundwater sample analytical results, and simulation results from updated site models and numerical simulations.

6.3.2 Site Closure Plan

DGC will submit a final site closure plan and notify NDIC at least 90 days prior of its intent to close the site. The site closure plan will describe a set of closure activities that will be performed, following approval by NDIC, at the end of the postinjection site care period. Site closure activities will include the plugging of all wells that are not targeted for use as future subsurface observation wells; the decommissioning of storage facility equipment, appurtenances, and structures (e.g., buildings, gravel pads, access roads, etc.) not associated with monitoring; and the reclaiming of the surface land of the site to as close as is practical to its original condition.

6.3.3 Submission of Site Closure Report, Survey, and Deed

A site closure report will be prepared and submitted to NDIC within 90 days of the execution of the postinjection site care and facility closure plan. This report will provide NDIC with a final assessment that documents the location of the stored CO_2 in the reservoir, describes its characteristics, and demonstrates the stability of the CO_2 plume in the reservoir over time. The site closure report will also document the following:

- Plugging records of the injection wells.
- Location of sealed injection wells on a plat survey that has been submitted to the local zoning authority.
- Notifications to state and local authorities as required by NDAC § 43-05-01-19.
- Records regarding the nature, composition, and volume of the injected CO_2.
- Postinjection monitoring records.

At the same time, DGC will also provide NDIC with a copy of an accurate plat certified by a registered surveyor that has been submitted to the county recorder's office designated by NDIC. The plat will indicate the location of the injection wells relative to permanently surveyed benchmarks pursuant to NDAC § 43-05-01-19.

Lastly, DGC will record a notation on the deed (or any other title search document) to the property on which the injection wells were located pursuant to NDAC § 43-05-01-19.

7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

This emergency and remedial response plan (ERRP) 1) describes the local resources and infrastructure in proximity to the site; 2) identifies events that have the potential to endanger all underground sources of drinking water (USDWs) during the construction, operation, and postinjection site care periods of the geologic storage project; and 3) describes the response actions that are necessary to manage these risks to USDWs. In addition, the integration of the ERRP with the existing plant emergency plan and risk management plan of Dakota Gasification Company's (DGC's) Great Plains Synfuels Plant (GPSP) is described, emphasizing the command structure of DGC, the evacuation plan, hazmat (hazardous material) capabilities, and the emergency communication plan of the GPSP. Lastly, procedures are presented for regularly conducting and evaluating the adequacy of the ERRP and updating it, if warranted, over the lifetime of the Great Plains CO_2 Sequestration Project.

7.1 Background

CO_2 produced at GPSP (U.S. Environmental Protection Agency [EPA] Facility Identifier: NDD000690594) will be captured and geologically stored in close proximity to the plant location. The typical composition of the captured gas is 95.9% CO_2, 1.8% C^{2+} and hydrocarbons, 1.2% H_2S, 0.6% methane, and 0.5% nitrogen by volume. Figure 7-1 shows the location of the GPSP, which is in Mercer County, North Dakota, as well as the locations of CO_2 injection wells (Coteau 1 through Coteau 6 wells) and the planned CO_2 transmission lines from GPSP to the injection wells. The coordinates of the injection wells are provided in Table 7-1.

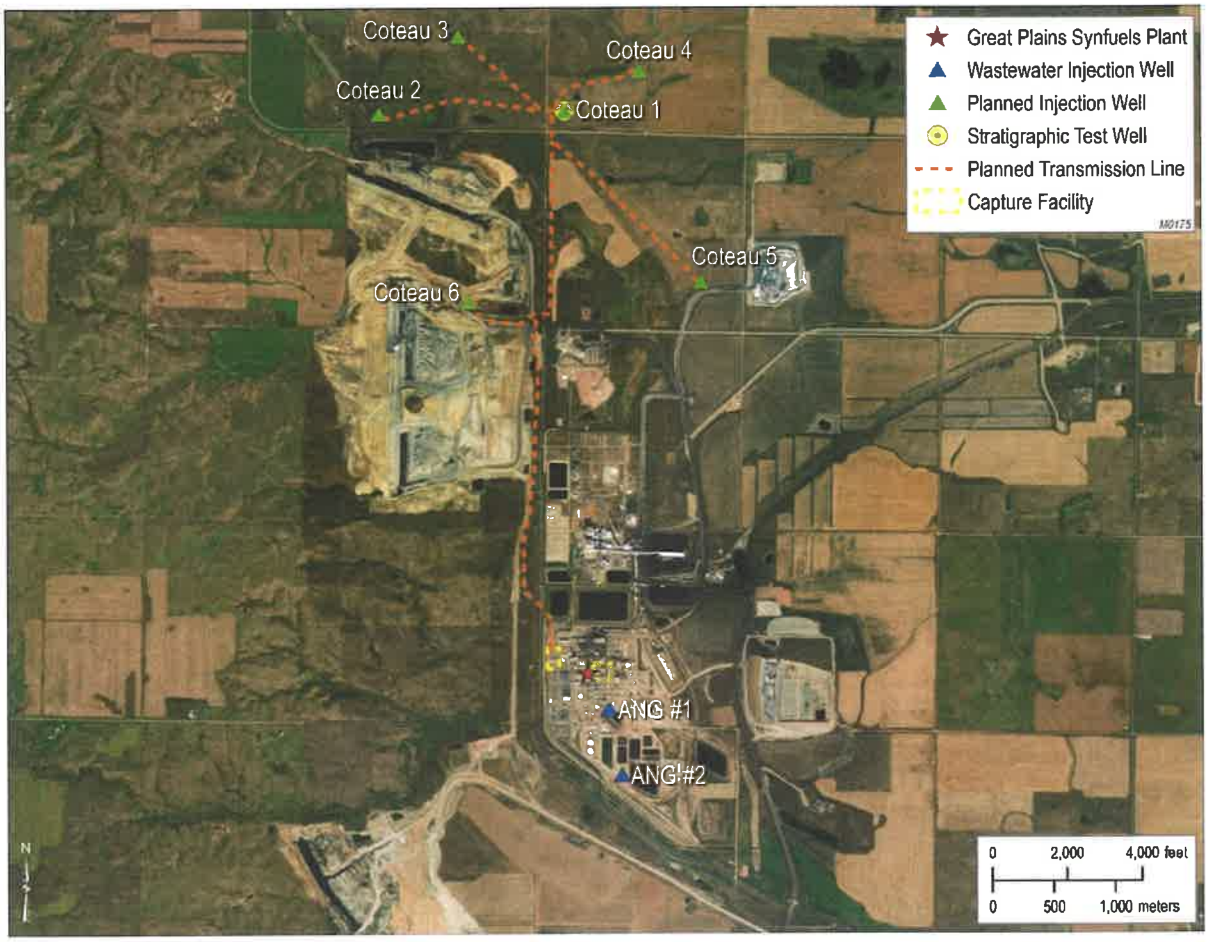


Figure 7-1. Locations of GPSP of DGC and the CO_2 injection wells (Coteau 1 through Coteau 6 wells). Also shown are the planned CO_2 transmission lines from GPSP to the injection wells.

Table 7-1. Well Names and Locations of the CO_2 Injection Wells of the DGC Geologic Storage Project

Well Name	Purpose	NDIC File No.	Quarter Call	Section	Township	Range	Latitude (NAD83*)	Longitude (NAD83*)
Coteau 1	CO_2 injection well	38379	SW/SW/SW	01	145N	88W	47.401991	−101.842101
Coteau 2	CO_2 injection well	TBD	SE/SW/SW	02	145N	88W	47.401572	−101.861988
Coteau 3	CO_2 injection well	TBD	NW/NW/SE	02	145N	88W	47.407308	−101.853618
Coteau 4	CO_2 injection well	TBD	NE/NE/SE	01	145N	88W	47.406940	−101.835330
Coteau 5	CO_2 injection well	TBD	SW/NE/SE	12	145N	88W	47.389640	−101.827219
Coteau 6	CO_2 injection well	TBD	NW/SW/SE	11	145N	88W	47.405000	−101.834090

* North American Datum of 1983.

The primary DGC contacts for the Great Plains CO_2 sequestration project and their contact information are as follows:

Primary DGC Project Contacts

Individual	Title	Contact Information Office Phone Number
Dale Johnson	VP & Plant Manager	701.873.6635
Trinity Turnbow	Operations & Assistant Plant Manager	701.873.6233
Daniel Whitley	Environmental Engineering Supervisor	701.873.6619

Primary Carbon Vault Project Contacts

Individual	Title	Contact Information Office Phone Number
Van Spence	President	303.588.5475
Rich McClure	Vice President – CO_2 Operations	720.635.1555
Gary Ramsdell	Operations Manager (Stanley, ND, Office)	701.629.1269

Contact names and information for other project personnel as well as key local emergency organizations/agencies are provided in a separate section of this ERRP (Section 7.6, Emergency Communications Plan).

7.2 Local Resources and Infrastructure

Local resources in the vicinity of the project that may be impacted as a result of an emergency event include 1) the holding ponds associated with GPSP and Antelope Valley Station; 2) Antelope Creek Aquifer; and 3) active and reclaimed mining land owned by Coteau Properties Company.

The infrastructure in the vicinity of the project that may be impacted as a result of an emergency event is shown in Figure 7-1 and includes 1) GPSP, 2) the CO_2 injection wellheads (Coteau 1 through Coteau 6), 3) the CO_2 transmission pipeline, 4) Antelope Valley Station, and 5) mining land owned by Coteau Properties Company. In addition, Figure 7-2 is provided to show residential, commercial, and public land use within 1 mile of the storage facility area boundary as required by North Dakota Administrative Code (NDAC) § 43-05-01-13.

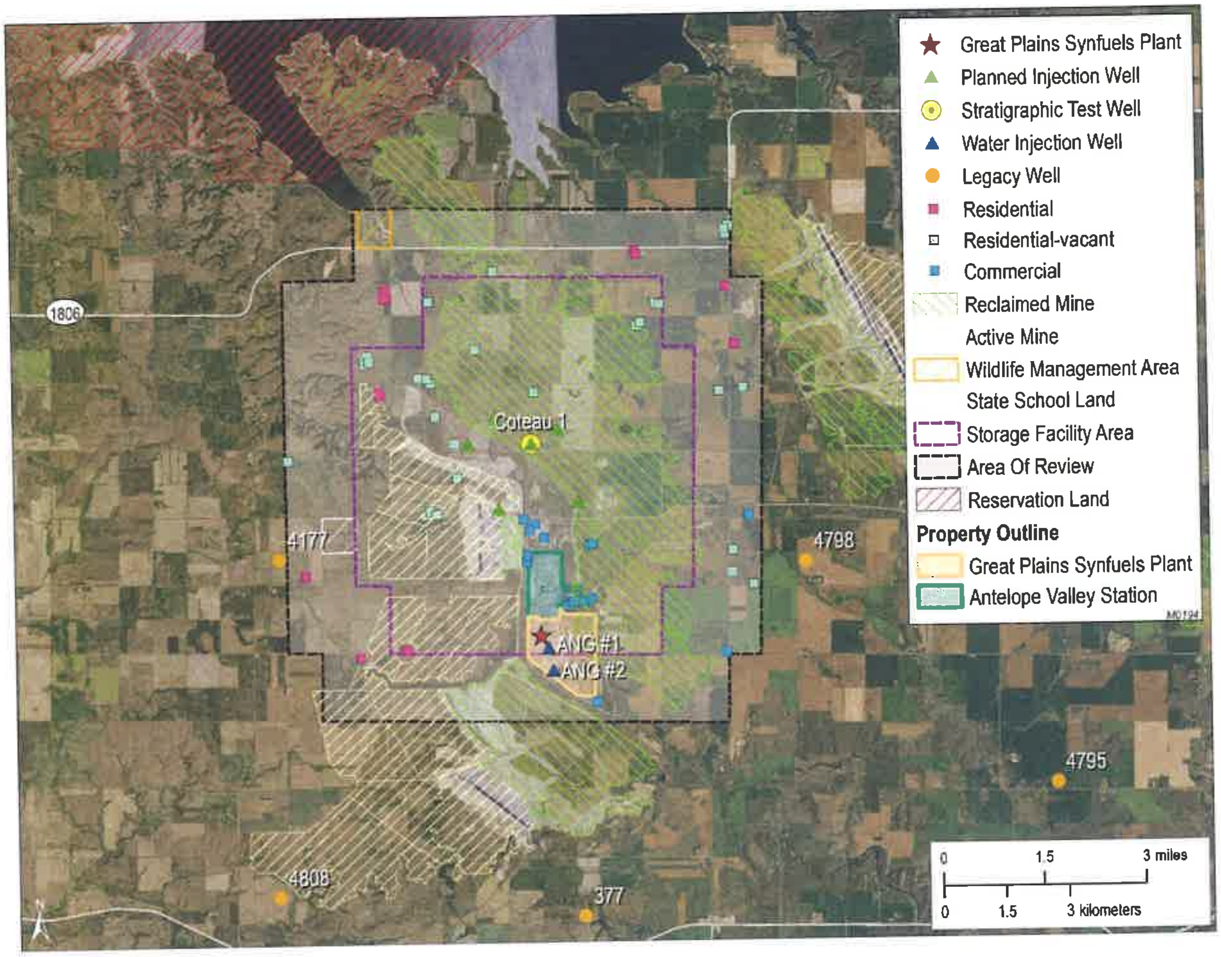


Figure 7-2. Residential, commercial, and public land use within 1 mile of the storage facility area.

7.3 Identification of Potential Emergency Events

7.3.1 Definition of an Emergency Event

An emergency event is an event that poses an immediate, or acute, risk to human health, resources, or infrastructure and requires a rapid, immediate response. This ERRP focuses on emergency events that have the potential to move the injected CO_2 stream or formation fluid in a manner that may endanger a USDW during operation or postinjection site care periods. Another emergency event of interest involves the accidental release of the CO_2 stream to the atmosphere.

7.3.2 Potential Project Emergency Events and Their Detection

Several potential technical project risks were considered and placed into the following five technical risk categories:

- Failure of surface equipment
- Integrity failure of an injection well

- Injection well monitoring equipment failure
- Inability of storage reservoir to contain the formation fluid or stored CO_2
- Natural disasters

Based on a review of these technical risk categories, a list of geologic storage project events that could potentially result in the movement of injection fluid or formation fluid in a manner that may endanger a USDW and require an emergency response was developed for inclusion in this ERRP. These events and means for their detection are provided in Table 7-2.

Table 7-2. Potential Project Emergency Events and Their Detection

Potential Emergency Events	Detection of Emergency Events
Failure of CO_2 Flowlines from CO_2 Capture System of DGC to CO_2 Injection Wellheads	Computational transmission pipeline and flowline continuous monitoring and leak detection system (LDS). Instrumentation at both ends of the transmission pipeline and the flowline for each injection well collects pressure, temperature, and flow data. The LDS software uses the pressure readings and flow rates in and out of the line to produce a real-time model and predictive model. By monitoring deviations between the real-time model and the predictive model, the software is able to detect pipeline leaks. Wellsite pressure and/or H_2S monitoring devices detect an anomaly.
Integrity Failure of Injection Wells	Pressure monitoring reveals wellhead pressure exceeds shutdown pressure specified in the permit. Annulus pressure indicates a loss of external or internal well containment. Mechanical integrity test results identify a loss of mechanical integrity.
Injection Well Monitoring Equipment Failure	Failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure is detected.
Storage Reservoir Unable to Contain the Formation Fluid or Stored CO_2	Elevated concentrations of indicator parameter(s) in soil gas, groundwater, and/or surface water sample(s) are detected.

In addition to these technical project risks, the occurrence of a natural disaster (e.g., naturally occurring earthquake, tornado, lightning strike, etc.) also represents an event for which an emergency response action may be warranted. For example, an earthquake or weather-related disaster (e.g., tornado or lightning strike) has the potential to result in injection well problems (integrity loss, leakage, or malfunction) and may also disrupt surface and subsurface storage operations. These events are addressed in the emergency plans of GPSP and will be extended to the geologic storage operations.

7.4 Emergency Response Actions

Discovery of an event triggers the corresponding response plan proposed herein. Specific response plan actions and activities will depend on the circumstances and severity of the event. The GPSP shift superintendent will address an event immediately and make all notifications as required by the emergency communications plan. The GPSP will be monitored in a manner consistent with the DGC's existing 205-mile CO_2 pipeline to Canada. Numerous automated safety features also exist along the CO_2 transmission line, the wellsite flowlines, and at the individual injection wellheads. Any alarm condition will be relayed to DGC's pipeline control room, which is manned continuously (7 days per week, 24 hours per day) by DGC personnel. An assessment of the alarm will be made by the control room operator, who will have the ability to remotely close any valve(s) necessary to isolate the problem and limit the duration and severity of the event.

The response actions that will be taken to address the events listed in Table 7-2, as well as the natural disasters, will follow the same protocol, which consists of the following actions:

- The GPSP shift superintendent (see Section 7.6, Emergency Communications Plan) will be notified and will immediately make an initial assessment of the automated response and the remote response and the severity of the event (i.e., does it represent an emergency event?).

- If designated as an emergency event, the DGC incident commander (IC) or designee shall notify the NDIC Department of Mineral Resources (DMR) Underground Injection Control (UIC) Program director pursuant to NDAC § 43-05-01-13 and implement the emergency communications plan. During this time, the GPSP shift superintendent will assume the role of incident commander.

- Following these actions, DGC will do the following:

    1. Ensure that the automated shutdown systems have isolated the event to the extent possible, and close additional isolation valves as required. If necessary, excess CO_2 volumes will be redirected back to the GPSP, where the CO_2 stream will be processed and safely released to the atmosphere.

    2. In the event of a leak to the surface, all H_2S precautions will be taken on-site, including, but not limited to, H_2S detectors and respirators, until natural dispersion returns the localized area to normal conditions. The nearest occupied dwellings are more than 1.5 miles from any wellsite, further under prevailing wind conditions, so evacuations should not be necessary. The IC should communicate with local authorities regarding the need for evacuations if deemed warranted.

    3. In the event of a mechanical integrity problem with one of the injection wellbores, the affected well will remain shut-in until an appropriate plan of action can be established by Carbon Vault personnel in coordination with NDIC DMR. The wellsite itself will remain secure as each location is to be fenced and locked at all times, with access only allowed by authorized personnel.

4. That portion of the CO_2 sequestration system that has been affected by the event will remain shut-in until DGC, the NDIC DMR, and other involved regulatory bodies are satisfied that a) the cause of the event has been identified and that b) it has been sufficiently addressed to resume operations. See Table 7-3 for details regarding the specific actions that will be taken to determine the cause and, if required, mitigate each of the events listed in Table 7-2.

The protocols described in this document are conceptual and may be adjusted based on actual circumstances and conditions of the event and any previous communication with governmental authorities having jurisdiction.

If an event triggers either a complete or partial cessation of injection and remedial actions, DGC shall demonstrate the efficacy of the response actions to the satisfaction of the UIC program director before resuming injection operations. Injection operations shall only resume upon receipt of written authorization from the UIC program director.

Table 7-3. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions

Failure of CO_2 Transmission Pipeline from CO_2 Capture System of DGC to Each Well Injection Wellsite Flowline and CO_2 Injection Wellhead	• The CO_2 stream release and its location will be detected by the LDS, which will trigger an alarm condition in the DGC control room where operators have the ability to remotely shut down the transmission line and wellsite flowline. • If warranted, initiate an evacuation plan. • The transmission line and/or flowline failure will be inspected to determine the root cause of the failure. • Repair/replace the damaged transmission line or flowline, and if warranted, put in place the measures necessary to eliminate such events in the future.
Integrity Failure of Injection Wells	• Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure. • Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the NDIC DMR UIC program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions to address impacts (in consultation with the NDIC DMR UIC program director).

Continued . . .

Table 7-3. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Injection Well-Monitoring Equipment Failure	• Monitor well pressure, temperature, and annulus pressure (manually if necessary) to determine the cause and extent of failure. • Identify and, if necessary, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).
Storage Reservoir Unable to Contain Formation Fluid or Stored CO_2	• Collect a confirmation sample(s) of groundwater from the Fox Hills monitoring wells and soil gas profile stations and analyze them for indicator parameters (see testing and monitoring plan in Section 5.0 of the SFP). • If the presence of indicator parameters is confirmed, develop (in consultation with the NDIC DMR UIC program director) a case-specific work plan to: 1. Install additional monitoring points near the impacted area to delineate the extent of impact: a. If a USDW is impacted above drinking water standards, arrange for an alternate potable water supply for all users of that USDW. b. If a surface release of CO_2 stream to the atmosphere is confirmed, initiate an evacuation plan, if warranted by workspace and/or ambient air-monitoring results. c. If surface release of CO_2 stream to surface waters is confirmed, implement appropriate surface water-monitoring program to determine if water quality standards are being exceeded. 2. Proceed with efforts, if necessary, to a) remediate the USDW to achieve compliance with drinking water standards (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" the impacted drinking water to mitigate CO_2/brine impacts) and/or b) manage surface waters using natural attenuation (i.e., natural processes, such as biological degradation, that are active in the environment and can reduce contaminant concentrations) or active treatment to achieve compliance with applicable water quality standards. • Continue all remediation and monitoring at an appropriate frequency (as determined by DGC and the NDIC DMR UIC program director) until unacceptable adverse impacts have been fully addressed.

Continued . . .

Table 7-3. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Natural Disasters	• Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure. • If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate extent of any impacts. • If impacts or endangerment are detected, identify and implement appropriate response actions in accordance with the GSPS emergency plan (in consultation with the NDIC DMR UIC program director).
Natural Disasters (seismicity)	• Identify when the event occurred and the epicenter and magnitude of the event. If magnitude is greater than 2.0 (Richter magnitude scale): 1. Demonstrate all project wells have maintained mechanical integrity. 2. If a loss of CO_2 containment is determined, proceed as described above to evaluate, and if warranted, mitigate the loss of containment. • If a loss of CO_2 containment is determined, proceed as described above to evaluate, and if warranted, mitigate the loss of containment.

7.5 Response Personnel/Equipment and Training

7.5.1 Response Personnel and Equipment

GPSP personnel will have operations and emergency response training. In addition, DGC will consult with the Mercer County Local Emergency Planning Committee (LEPC) for inclusion in the county's multihazard mitigation plan. The emergency "out call" system, which is also referred to as the R911 system, is designed to notify those residents living or working within the pipeline corridor that a pipeline emergency has occurred with the potential to affect them.

Equipment needed in the event of an emergency and remedial response will vary, depending on the emergency event. Response actions (e.g., cessation of injection, transmission line, flowline, and/or well shut-in, and possible evacuation) will generally not require specialized equipment to implement. However, when specialized equipment (such as a workover rig, logging equipment, potable water hauling, etc.) is required, DGC planning superintendent shall be responsible for its procurement. Because of its historical operations in the area, DGC is uniquely qualified to respond to emergencies. Its existing GPSP is home to a fire station in addition to emergency technician and medical professionals.

7.5.2 Staff Training and Exercise Procedures
DGC will train personnel involved in the CO_2 geologic storage project on the proper emergency responses, maintenance, and operating procedures. The training efforts will be documented. DGC will also work with Mercer County LEPC to perform coordinated training exercises associated with potential emergency events.

7.6 Emergency Communications Plan
Prior to the commencement of CO_2 injection operations, DGC will communicate in writing with landowners living in and adjacent to the permitted storage area to provide a summary of the information contained within this ERRP, including, but not limited to, information about the nature of the operations, operator contact list, potential risks, and possible response approaches.

In the event of an emergency, the GPSP shift superintendent and Protection Services Control Center (PSCC) supervisor will be notified immediately. The DGC shift superintendent will assume the role of IC. The IC's responsibilities may include, but are not limited to, developing an incident action plan, managing incident operations, notifying proper plant personnel (as shown below), and properly applying all resources.

DGC Personnel and Contact Information

Position	DGC Employee	Office Phone Number
Shift Superintendent		701.873.6777
Communications Manager	Joan Dietz	701.557.5070
PSCC (business)		701.873.6677
PSCC (24-hour emergency)		701.873.6600
DGC Medical		701.873.6789
Safety and Industrial Hygiene Superintendent	Jeff Graney	701.873.6605
Planning Superintendent	Dave Knudson	701.873.6219

In addition to DGC personnel, the IC is responsible for establishing and maintaining communications with appropriate off-site persons and/or agencies, including, but not limited to, the following:

Beulah Police Department	701.873.5252
Beulah Fire Department	701.873.2121
Mercer County Ambulance	701.747.5558
Mercer County Emergency Manager	701.745.3302
Mercer County Sheriff's Office	701.745.3333
Hazen Police Department	701.747.2414
North Dakota Highway Patrol	701.327.2447
North Dakota Highway Department	701.327.9921
North Dakota Poison Control	800.222.1222
Hazen Fire Department	701.747.5550
Sakakawea Medical Center	701.747.2225
NDIC DMR UIC Program Director	701.327.8020
North Dakota Department of Emergency Services	833.997.7455

Lastly, the DGC plant emergency plan contains addresses and contact information for approximately 58 neighboring facilities and residences located within 4.5 miles of the GPSP. This information is based on DGC's latest population density survey. DGC will update this information to document any changes that may occur by conducting semi-annual surveys. DGC will utilize an emergency out call system which is designed to notify residents in the area if an emergency occurs.

7.7 ERRP Review and Updates

This ERRP shall be reviewed:

- At least annually following its approval by NDIC DMR.
- Within 1 year of an area of review (AOR) reevaluation.
- Within a prescribed period (to be determined by NDIC DMR) following any significant changes to the project, e.g., injection process, injection rate, etc.
- As required by NDIC DMR.

Should the operational monitoring (see Section 5.0, Testing and Monitoring Plan) of the geologic storage operations identify trends that warrant a modification to the ERRP prior to the scheduled annual review, DGC will move forward with revising the plan and submitting a revised ERRP to NDIC DMR within 6 months of that determination.

If the annual review indicates that no amendments to the ERRP are necessary, DGC will provide NDIC DMR with the documentation supporting a no-amendment-necessary determination. If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to NDIC DMR within 6 months following their identification.

8.0 WORKER SAFETY PLAN

8.0 WORKER SAFETY PLAN

The worker safety plan (WSP) describes the minimum safety programs and training requirements for DGC employees and contract personnel during the construction, operation, and postinjection site periods. DGC will give NDIC personnel sufficient access to perform wellsite inspections.

This WSP incorporates the existing occupational, safety, and industrial hygiene (OSIH) program utilized by DGC for employees and contractors and their personnel (including subcontractors) working at the Great Plains Synfuels Plant and other DGC facilities. The OSIH program is designed to prevent accidents, injuries, property losses, illnesses, and violations of government and company standards.

8.1 DGC Employee Safety Requirements and Training

DGC has established a process for employees to acquire the knowledge, skills, and abilities to competently operate the facility in accordance with DGC safe work practices, procedures, and operating manuals. The safety requirements for DGC employees include, but are not limited to, the following:

1. An orientation for all newly hired employees to ensure they are aware of company safety policies and procedures, safety and health hazards, safe work practices, and government safety regulations.

2. Instruction and training for each employee regarding:

    a. Safety expectations while on DGC property.

    b. What to do in an emergency, including evacuation routes and assembly points.

    c. Safety and industrial hygiene information about hazardous materials/conditions and immediate actions to take following an accidental exposure.

    d. When and how to report safety incidents.

    e. How to report unsafe conditions and behaviors.

    f. Safe work practices as defined by government and company standards.

8.1.2 DGC Contractor Safety Requirements and Training

The DGC OSIH program also establishes requirements for contractors to interface with DGC to ensure compliance with DGC safety procedures and federal, state, and local safety standards. The scope of the requirements covers all contractors and their personnel (including subcontractors) working at DGC's facilities.

The safety requirements and training required for a contractor to access and perform work at DGC facilities include, but are not limited to, the following:

1. Full compliance with all Energy Coalition for Contractor Safety (ECCS) guidelines for a "Class A contractor." (The ECCS guidelines can be found at the North Dakota Safety Council [NDSC] website at www.ndsc.org.).

2. Attendance at an annual DGC contractor safety orientation.
3. Negative drug test results within the last 12 months.
4. Availability of a contractor employee training record (CETR) within the last 12 months:
    a. Documents that the contractor has trained its personnel on DGC procedures and process descriptions.
    b. Ensures contractor employees are instructed in the known potential fire, explosion, or toxic release hazards and applicable provisions of the emergency response plan.
5. Documentation of a contractor employee background check within the last 5 years.
6. Successful completion of an Occupational Safety and Health Administration (OSHA) 10-hour class within the last 36 months.
7. A contractor safety manual evaluation completed by a third party, i.e., the North Dakota Safety Council (NDSC), to demonstrate compliance with federal, state, and DGC safety standards.
8. Demonstration of acceptable safety performance by submitting the last year's safety statistics to NDSC at www.ndsc.org.
9. Demonstration of qualification requirements for pipeline (off-site) contractors, which includes the following:
    a. Submision of a drug/alcohol plan that meets 49 Code of Federal Regulations (CFR) Part 40 and Part 199.
    b. Submission of an operator qualification plan in accordance with 49 CFR Part 192 and Part 195.
    c. Submission of qualification data for personnel performing operation, maintenance, or emergency response task(s) on the carbon dioxide (CO_2) pipeline.
    d. Other qualification requirements include:
        i. DGC access to drug/alcohol and operator qualification information for random record audits.
        ii. Submission of Department of Transportation (DOT) annual drug testing satistical data to DGC for inclusion in an annual DGC submittal to DOT.

Only DGC employees and contractor personnel who have been properly trained will participate in the project activities of drilling, construction, operations, and equipment repair.

9.0 WELL CASING AND CEMENTING PROGRAM

9.0 WELL CASING AND CEMENTING PROGRAM

Rampart Energy Company has drilled one well, Coteau 1 (NDIC File No. 38379) thus far on behalf of DGC. The well was permitted and drilled in June 2021 as a stratigraphic test well in compliance with Class VI underground injection control (UIC) injection well construction requirements. Application to convert Coteau 1 to a CO_2 storage injection well is being filed upon approval of this storage facility permit (SFP). The following information includes the current, as-constructed wellbore schematic (illustrated in Figure 9-1 and detailed in Tables 9-1 through 9-4) and a radial cement evaluation log summary for Coteau 1 (Figure 9-2). After drilling, the Broom Creek Formation was perforated with four shots at 5975 ft and a reservoir pressure and fluid sample were obtained. The perforations were then squeezed with 100 sacks of Class G cement and the casing pressured tested to 1600 psi with an inhibited brine solution.

Five additional injection wells are planned. Three of these, the proposed Coteau 2, Coteau 3, and Coteau 4, are expected to be drilled in the second quarter of 2022, followed by the proposed Coteau 5 and Coteau 6 in late 2025, to accommodate additional CO_2 injection volumes in the spring of 2026.

9.1 Coteau 1: As-Constructed CO_2 Injection Well Casing and Cementing Program

The as-constructed wellbore schematic for the Coteau 1 well is provided in Figure 9-1.

Tables 9-1 through 9-4 provide the casing and cement programs for the Coteau 1 well and have been updated according to the drilling performed in June 2021. The tables demonstrate compliance with North Dakota Administrative Code (NDAC) § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for conversion to a CO_2 storage injection well.

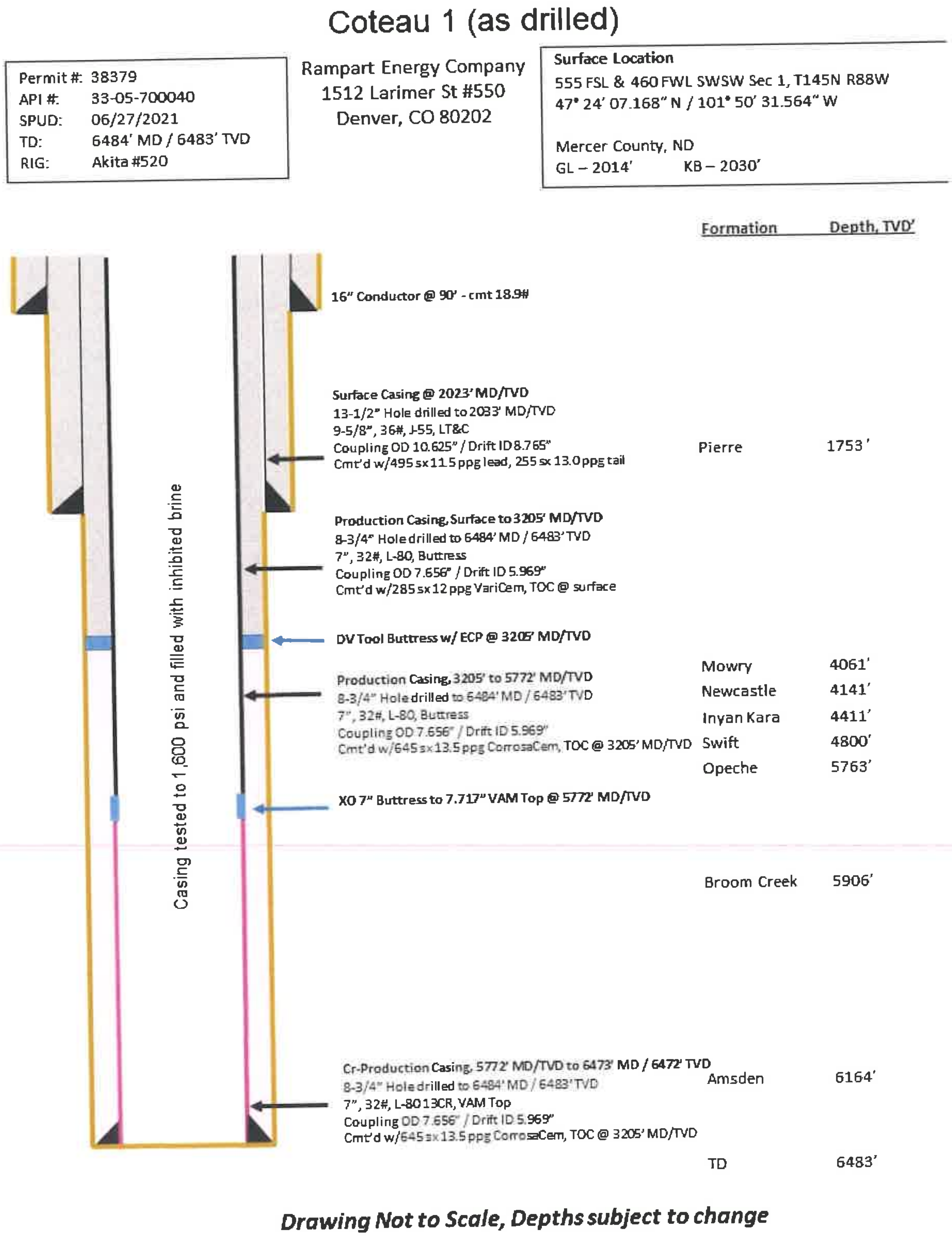


Figure 9-1. Coteau 1 as-constructed wellbore schematic.

Table 9-1. Coteau 1 As-Constructed Well Information

Well Name:	**Coteau 1**	**NDIC No.:**	**38379**	**API* No.:**	**33-057-00040**
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.1 T145N R88W	**Footages:**	555 FSL*, 60 FWL*	**Total Depth, ft:**	6484 MD

* API: American Petroleum Institute, FSL: from the south line, FWL: from the west line.

Table 9-2. Coteau 1 As-Constructed Casing Program

Section	Bit Size, in.	Casing OD*, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC*	Surface	2033	Cover freshwater aquifers
Production	8.75	7	32	L-80	Buttress	Surface	3205	Production casing
Production	8.75	DV* tool			Buttress	3205	3230	Stage collar with ECP*
Production	8.75	7	32	L-80	Buttress	3230	5772	Production casing
Production	8.75	7	32	13CR L80	VAM top*	5772	6474	CO_2-resistant production casing

* OD: outside diameter, LTC: long-thread and coupled, VAM top: premium thread and coupled, DV: differential valve: ECP: electrochemical pump.

Table 9-3. Coteau 1 As-Constructed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID*, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80	32	Buttress	6.094	5.969	9050	8610	745	791
7	13CR L80	32	VAM top	6.094	6.000	9060	8610	745	745

* ID: inside diameter.

Table 9-4. Coteau 1 As-Constructed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6474–3230	100	645
7	12.0 VariCem	3205–surface	OH 100	285

* The cement top was obtained from the radial cement evaluation. Figure 9.2 provides an evaluation of the isolation scanner performed on 9/17/2021. The top of cement is at the surface, while the top of CO_2-resistant cement is at 3205 ft.

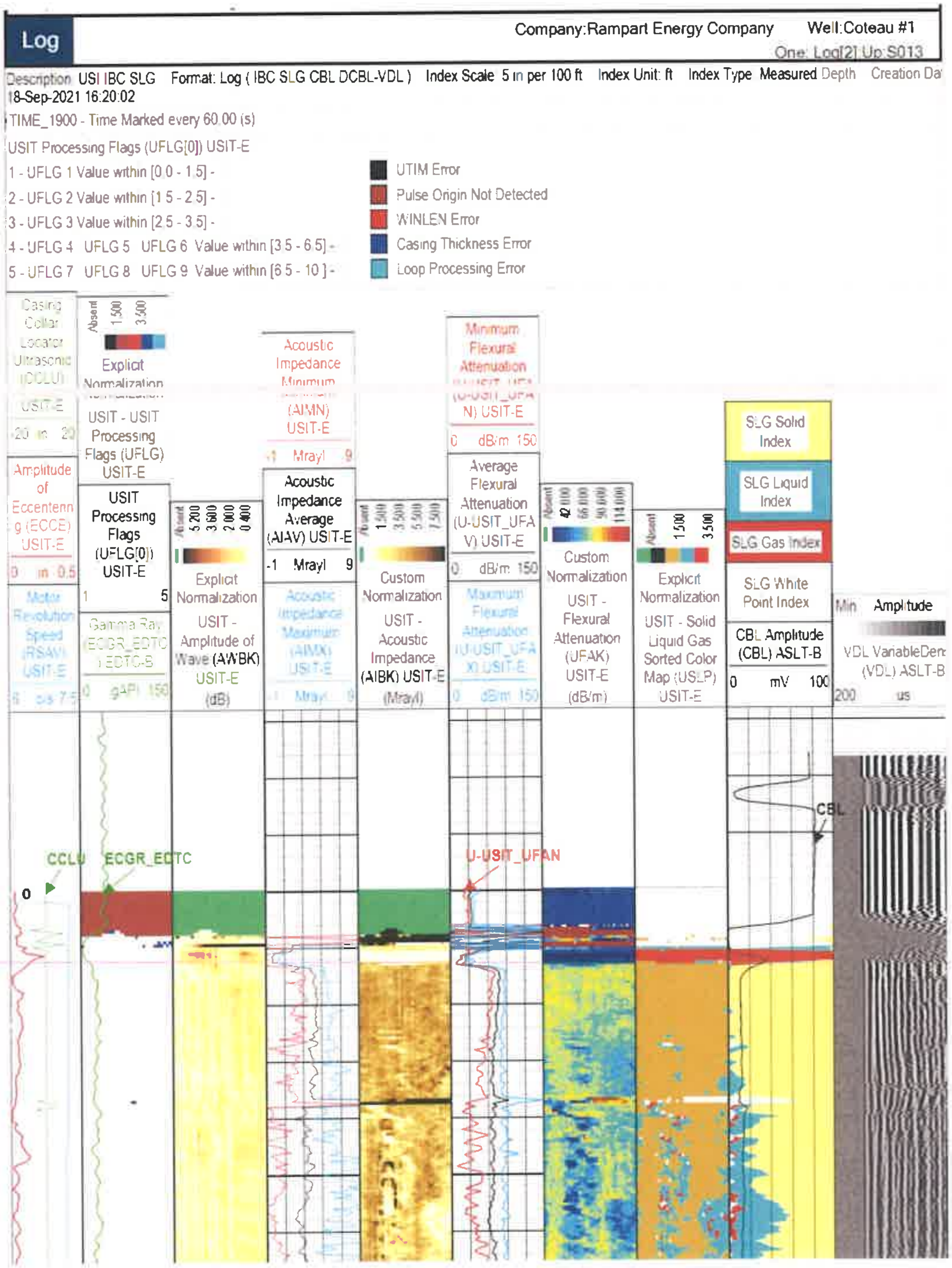


Figure 9-2. Coteau 1 isolation scanner results – radial cement evaluation log summary from Coteau 1 verifies the material behind the casing and the cement bond index. This enables the analyst to assess isolation in the CO_2 injection zone, confining zones, and underground sources of drinking water (USDWs) using a high-resolution image.

9.2 Coteau 2: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 2 well is expected to be drilled and completed in the second quarter of 2022. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-3.

Tables 9-5 through 9-8 include the proposed casing and cement programs for the Coteau 2 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

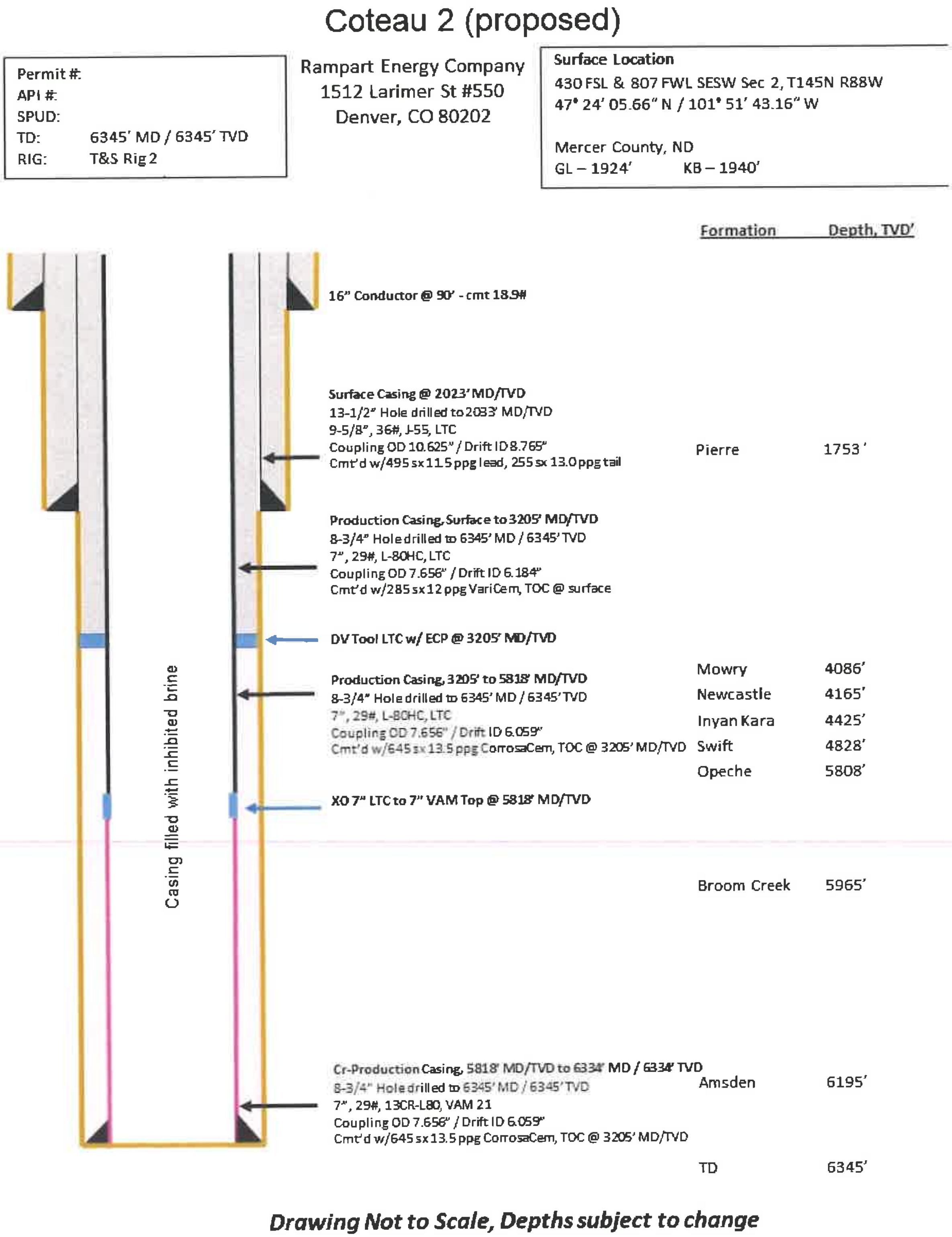


Figure 9-3. Coteau 2 proposed wellbore schematic.

Table 9-5. Coteau 2 Proposed Well Information

Well Name:	**Coteau 2**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.2 T145N R88W	**Footages:**	430 FSL, 807 FWL	**Total Depth, ft:**	6371 MD

Table 9-6. Coteau 2 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5829	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5829	6360	CO_2-resistant production casing

Table 9-7. Coteau 2 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7.717	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-8. Coteau 2 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6360–3205	100	625
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft.

9.3 Coteau 3: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 3 well is expected to be drilled and completed in the second quarter of 2022. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-4.

Tables 9-9 through 9-12 include the proposed casing and cement programs for the Coteau 3 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

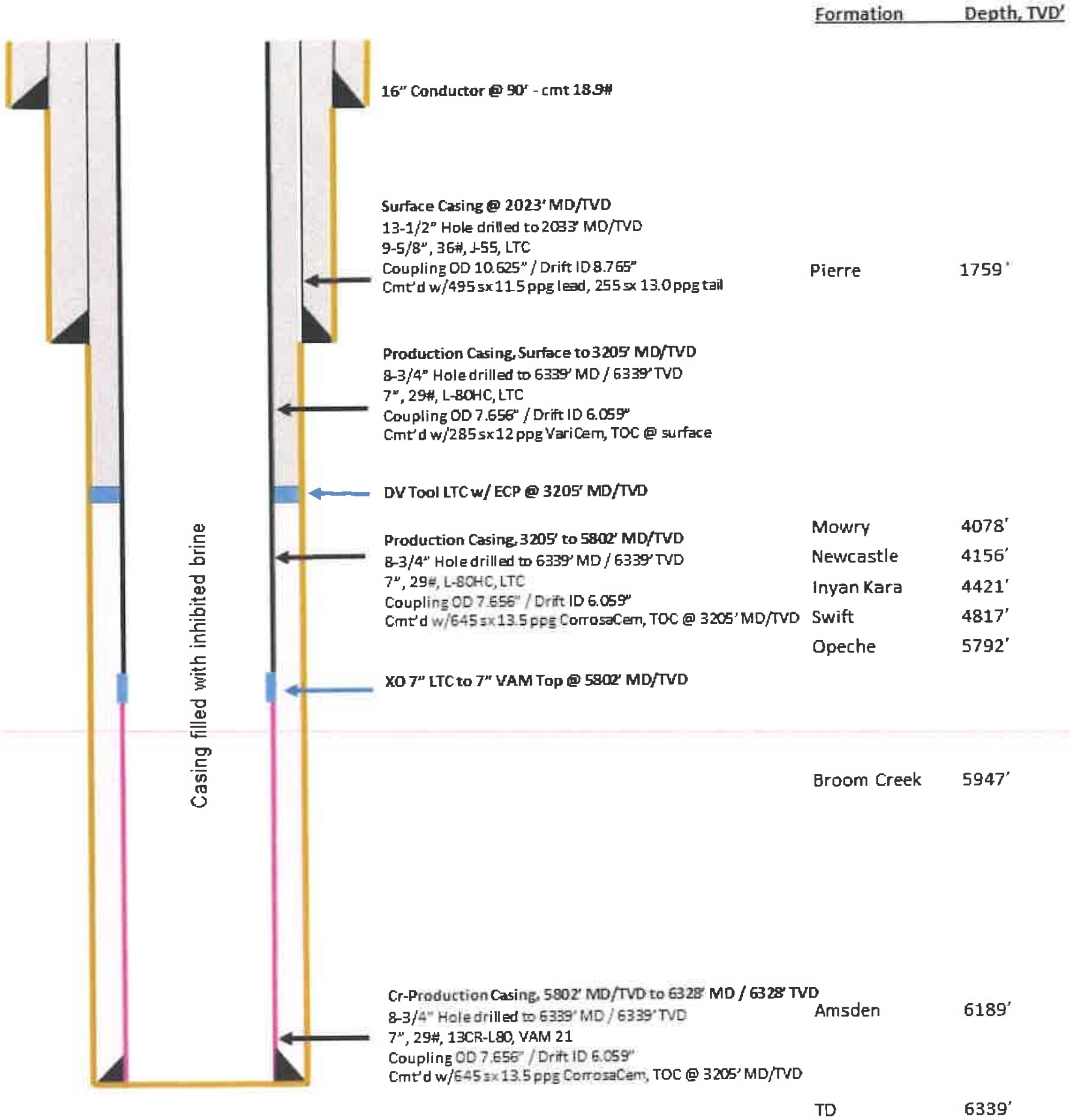
Coteau 3 (proposed)

Permit #:
API #:
SPUD:
TD: 6339' MD / 6339' TVD
RIG: T&S Rig 2

Rampart Energy Company
1512 Larimer St #550
Denver, CO 80202

Surface Location
2483 FSL & 2412 FEL SWNE Sec 2, T145N R88W
47° 24' 26.31" N / 101° 51' 13.02" W

Mercer County, ND
GL – 1988' KB – 2004'



Drawing Not to Scale, Depths subject to change

Figure 9-4. Coteau 3 proposed wellbore schematic.

Table 9-9. Coteau 3 Proposed Well Information

Well Name:	**Coteau 3**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.2 T145N R88W	**Footages:**	2483 FSL, 2412 FEL*	**Total Depth, ft:**	6361 MD

* FEL: from the east line.

Table 9-10. Coteau 3 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5815	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5815	6350	CO_2-resistant production casing

Table 9-11. Coteau 3 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7.717	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-12. Coteau 3 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6350–3205	100	620
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft.

9.4 Coteau 4: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 4 well is expected to be drilled and completed in the second quarter of 2022. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-5.

Tables 9-13 through 9-16 include the proposed casing and cement programs for the Coteau 4 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

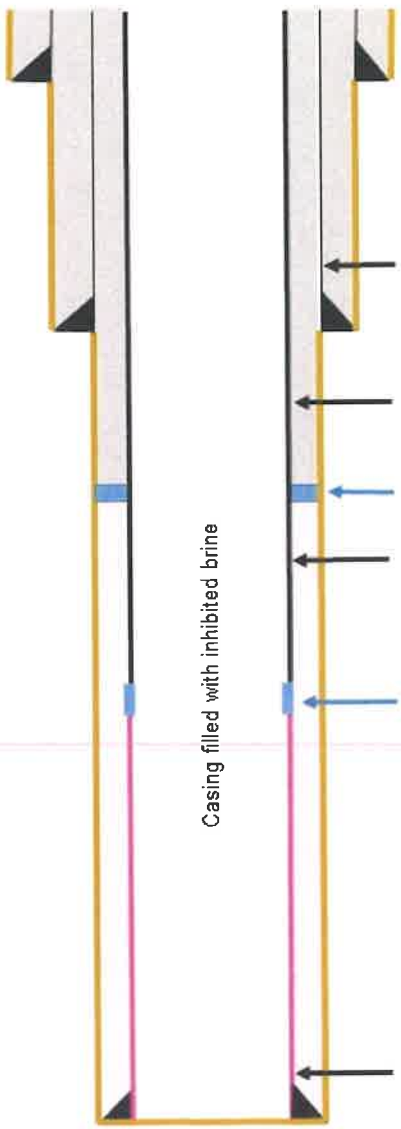
Coteau 4 (proposed)

Permit #:	
API #:	
SPUD:	
TD:	6301' MD / 6301' TVD
RIG:	T&S Rig 2

Rampart Energy Company
1512 Larimer St #550
Denver, CO 80202

Surface Location
1665 FSL & 2319 FWL NESW Sec 1, T145N R88W
47° 24' 18.00" N / 101° 50' 02.72" W

Mercer County, ND
GL – 2061' KB – 2077'



16" Conductor @ 90' - cmt 18.9#

Surface Casing @ 2023' MD/TVD
13-1/2" Hole drilled to 2033' MD/TVD
9-5/8", 36#, J-55, LTC
Coupling OD 10.625" / Drift ID 8.765"
Cmt'd w/495 sx 11.5 ppg lead, 255 sx 13.0 ppg tail

Production Casing, Surface to 3205' MD/TVD
8-3/4" Hole drilled to 6301' MD / 6301' TVD
7", 29#, L-80HC, LTC
Coupling OD 7.656" / Drift ID 6.059"
Cmt'd w/285 sx 12 ppg VariCem, TOC @ surface

DV Tool LTC w/ ECP @ 3205' MD/TVD

Production Casing, 3205' to 5757' MD/TVD
8-3/4" Hole drilled to 6301' MD / 6301' TVD
7", 29#, L-80HC, LTC
Coupling OD 7.656" / Drift ID 6.059"
Cmt'd w/645 sx 13.5 ppg CorrosaCem, TOC @ 3205' MD/TVD

XO 7" LTC to 7" VAM Top @ 5757' MD/TVD

Cr-Production Casing, 5757' MD/TVD to 6290' MD / 6290' TVD
8-3/4" Hole drilled to 6301' MD / 6301' TVD
7", 29#, 13CR-L80, VAM 21
Coupling OD 7.656" / Drift ID 6.059"
Cmt'd w/645 sx 13.5 ppg CorrosaCem, TOC @ 3205' MD/TVD

Formation	Depth, TVD'
Pierre	1754'
Mowry	4049'
Newcastle	4129'
Inyan Kara	4404'
Swift	4789'
Opeche	5747'
Broom Creek	5886'
Amsden	6151'
TD	6301'

Drawing Not to Scale, Depths subject to change

Figure 9-5. Coteau 4 proposed wellbore schematic.

Table 9-13. Coteau 4 Proposed Well Information

Well Name:	**Coteau 4**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.1 T145N R88W	**Footages:**	1665 FSL, 2319 FWL	**Total Depth, ft:**	6309 MD

Table 9-14. Coteau 4 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5769	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5769	6298	CO_2-resistant production casing

Table 9-15. Coteau 4 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-16. Coteau 4 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6298–3205	100	610
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft

9.5 Coteau 5: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 5 well is expected to be drilled and completed in late 2025. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-6.

Tables 9-17 through 9-20 include the proposed casing and cement programs for the Coteau 5 based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

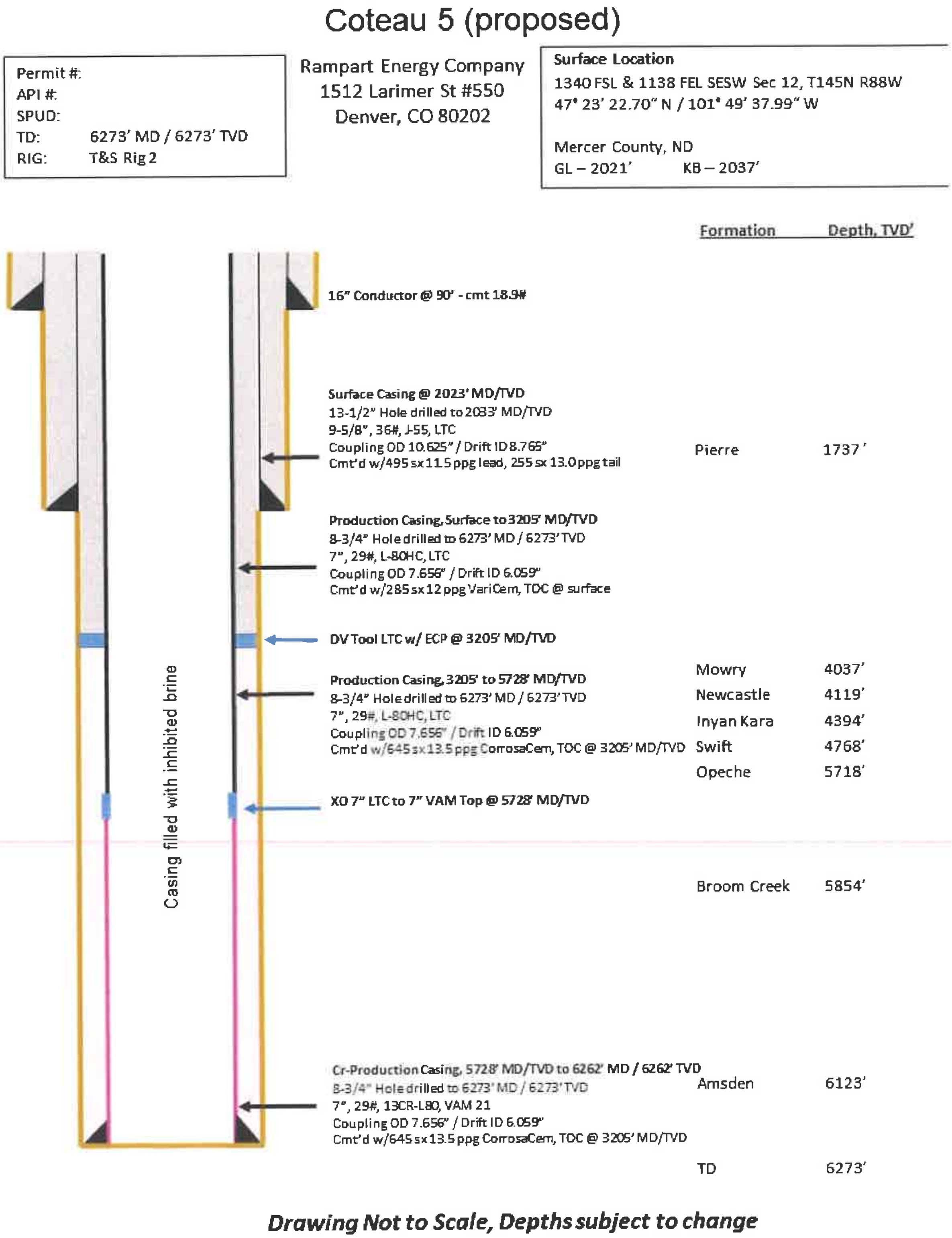


Figure 9-6. Coteau 5 proposed wellbore schematic.

Table 9-17. Coteau 5 Proposed Well Information

Well Name:	**Coteau 5**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.12 T145N R88W	**Footages:**	1340 FSL, 1138 FEL	**Total Depth, ft:**	6277 MD

Table 9-18. Coteau 5 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5741	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5741	6266	CO_2-resistant production casing

Table 9-19. Coteau 5 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-20. Coteau 5 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6266–3205	100	605
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft.

9.6 Coteau 6: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 6 well is expected to be drilled and completed in late 2025. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-7.

Tables 9-21 through 9-24 include the proposed casing and cement programs for the Coteau 6 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

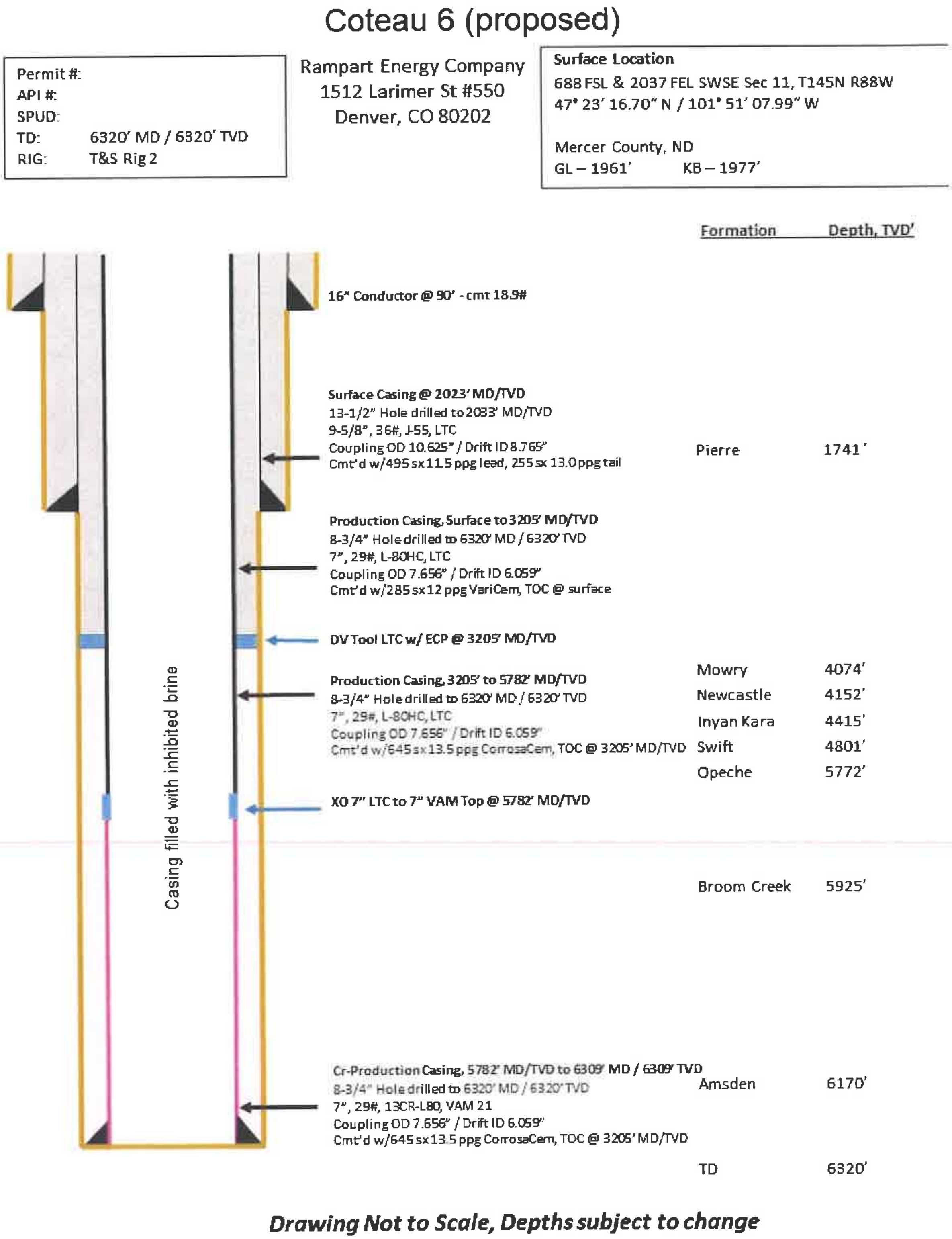


Figure 9-7. Coteau 6 proposed wellbore schematic.

Table 9-21. Coteau 6 Proposed Well Information

Well Name:	**Coteau 6**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.11 T145N R88W	**Footages:**	688 FSL, 2037 FEL	**Total Depth, ft:**	6335 MD

Table 9-22. Coteau 6 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2033	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5794	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5794	6324	CO_2-resistant production casing

Table 9-23. Coteau 6 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-24. Coteau 6 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6324–3230	100	615
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3,205 ft.

10.0 PLUGGING PLAN

10.0 PLUGGING PLAN FOR INJECTION WELLS

The plugging plans for all injection wells are intended to be interpreted as proposed conditions and do not reflect the current as-constructed state of a particular well. The schematics and procedure in this section illustrate what the estimated wellbore conditions will look like before and after the plugging and abandonment (P&A). The wells will be plugged and abandoned when CO_2 storage and injection operations cease.

The plugging plan will be provided to a representative from the NDIC, who will be present during the plugging operations. This will also be documented during workover reports. The plugging record will show that the material used will be compatible with CO_2 and isolate the injection zone.

10.1 Plugging & Abandonment (P&A) Program

A well schematic of the planned completion for the Coteau 1 well (NDIC File No. 38379) is provided in Figure 10-1 followed by a P&A procedure and a well-plugging schematic (Figure 10-2). The abandonment of subsequent injection wells, namely, the Coteau 2 through 6, will be performed in a manner consistent with that of the Coteau 1. The size and depths of the various plugs may vary as necessary to accomplish the zonal isolation, but in each instance, approval of specific P&A operations will be required from the NDIC prior to the initiation of fieldwork.

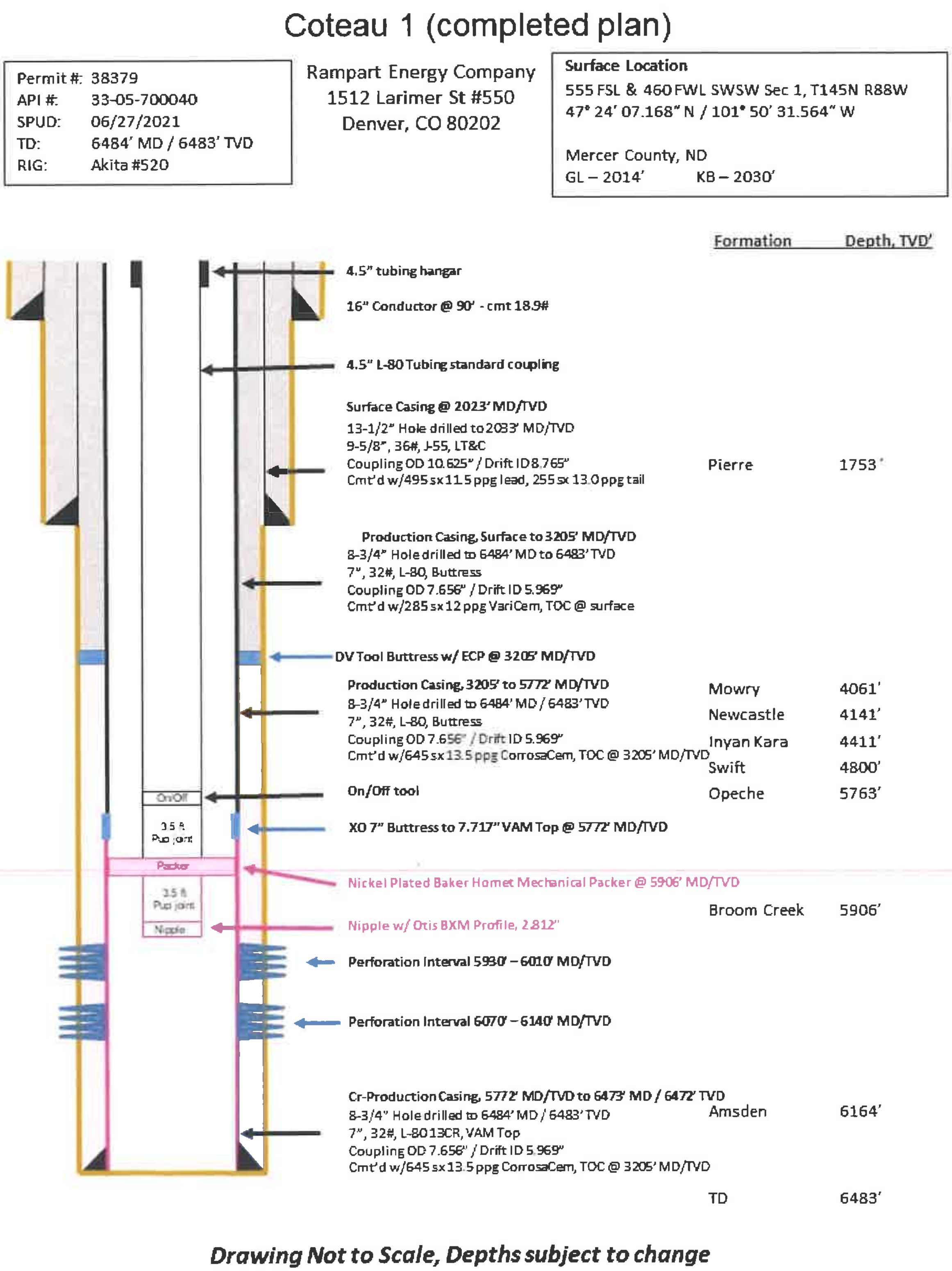


Figure 10-1. Coteau 1 CO_2 injection well schematic.

The NDIC will be contacted, and an intent to plug and abandon will be filed for approval. Final adjustments to the proposed P&A procedure will be made based on wellbore conditions at that time and NDIC field inspector recommendations. Currently, the proposed procedure for P&A of all wells is as follows.

The wellbore is to be plugged and abandoned at the end of the injection of CO_2. API standards, NDIC regulations, and best management practices will be employed to control the well at all times. Well work will be performed by experienced crews and contractors and supervised by Rampart Energy with other competent and experienced engineers and NDIC personnel on-site as necessary. Safety and environmental measures will be in place to ensure the well-being of all personnel and subsequent site reclamation. The protocol is as follows.

1. Capture and record bottomhole reservoir pressure for Broom Creek Formation using an electronic recording pressure gauge – NDAC § 43-05-01-11.5(2a).
   Note: calculate the required corrosion-inhibited kill fluid weight based on bottomhole reservoir pressure plus 100–300 psi for overbalanced pressure. Appropriate storage volume of weighted kill fluid will be stored in portable tanks on location.

2. Move in and rig up (MIRU) workover rig with 2⅞", work string.

3. Kill well by pumping calculated weight and volume of corrosion-inhibited kill fluid down 4.5" injection tubing. Ensure wellhead, tubing, and annular/casing pressures are showing 0 psi and stable.

4. Nipple down (ND) wellhead. Install blowout preventer (BOP), and test low/high 250 psi/ 4,000 psi.

5. While maintaining a hole full of kill fluid, trip out of hole (TOOH) with 4.5" injection tubing, seal assembly, and locator sub, and lay down 4.5" tubing with thread protectors. Also, remove injection packer at 5,906' ft.

6. MIRU wireline services to perform external mechanical integrity test, and set 7-in. cast iron cement retainer (CICR).

7. Install lubricator and pressure-test to 4,000 psi for 10 minutes.

8. Make up and run in hole (RIH) with ultrasonic log–variable-density log (VDL)–casing collar locator (CCL)–temperature–GR log from plug back total depth (PBTD) (anticipated at ~6,280 ft from GR–CCL log run September 17, 2021, to surface for external mechanical integrity test – NDAC § 43-05-01-11.5(2b).
   Note: The proposed logs satisfy requirements for determining external mechanical integrity – NDAC § 43-05-01-11.2(1d).

9. Make up and RIH with CICR. Set CICR at 5,906 ft or 25 ft above top perforation.

10. Rig down and move out (RDMO) wireline unit and crew.

Isolate Broom Creek Formation
Perforations will be isolated pursuant to NDAC § 43-05-01-11.5. They will be isolated with a CO_2-resistant cement.

11. RIH with 2⅞-in. L-80 work string and sting-in into the CICR.

12. Rig up (RU) cementing equipment. Mix and pump 75 sacks (sx) of CO_2-resistant cement to squeeze from 5,906 to 6,141 ft. Displace with corrosion-inhibited spacer fluid.
Note: Assumptions on the cement properties are 14.2 ppg, 100% excess, and a yield of 1.33 ft^3/sack.

13. Unsting 2⅞-in. work string from CICR.

14. TOOH and lay down with work string to ± 5,906 ft. Mix and pump a cement plug of 51 sx CO_2-resistant cement to plug interval of 206 ft. Displace with corrosion-inhibited spacer fluid.
Note: Assumptions on the cement properties are 14.2 ppg, 50% excess, and a yield of 1.33 ft^3/sack.

Isolate Dakota Group
The Inyan Kara Formation will be isolated pursuant to NDAC § 43-05-01-11.5. The method of isolation will be a CO_2-resistant cement plug placed inside of the casing.

15. TOOH and lay down with work string to ±4,841 ft. Mix and pump a balanced plug of 188 sx CO_2-resistant cement to plug interval of 820 ft. Displace with corrosion-inhibited spacer fluid.
Note: Assumptions on the cement properties are 14.2 ppg, 50% excess, and a yield of 1.33 ft^3/sack.

Isolate Surface Casing Shoe

16. TOOH and lay down with work string to ±2,100 ft. Mix and pump a balanced plug of 131 sx Class G cement to plug interval of 500 ft. Displace with corrosion-inhibited spacer fluid.
Note: Assumptions on the cement properties are 15.8 ppg, 50% excess, and a yield of 1.16 ft^3/sack.

Isolate Surface

17. TOOH and lay down with work string to ±120 ft. Mix and pump a balanced plug of 21 sx Class G cement to plug interval of 80 ft. Displace with corrosion-inhibited spacer fluid.
Note: Assumptions on the cement properties are 15.8 ppg, 50% excess, and a yield of 1.16 ft^3/sack.

18. TOOH and lay down remainder of work string.

19. RD cementing equipment.

20. ND BOP and RDMO workover rig.

21. Dig out wellhead and cut off casing 5 ft below ground level (GL). Weld ½-in. steel cap on casing with well name, date inscribed (confined space entry), and information that it was used for CO_2 injection. Dig out deadmen if applicable – NDAC § 43-05-01-19(6).

22. Within 60 days, submit Form 7 plugging report after plugging operations are complete – NDAC § 43-05-01-11.5(4).

23. Submit notice of intent to reclaim to NDIC 30 days in advance prior to reclamation – NDAC § 43-05-01-18(10d).

The proposed P&A plan for the Coteau 1 is summarized in Table 10-1 and provided in Figure 10-2.

Table 10-1. Summary of P&A Plan

Cement Plug No.	Interval Range, ft		Thickness ft	Volume sacks	Note
1 Squeeze	5,906	6,141	235	75	CO_2-resistant cement plug from CICR to bottom perf. Squeezed cement will isolate perforations in the Broom Creek.
2	5,700	5,906	206	51	CO_2-resistant cement plug isolates the Broom Creek Formation and 50' above the top of the Opeche Formation.
3	4,021	4,841	820	188	CO_2-resistant cement plug isolates from 50' above the top of the Inyan Kara Formation to 50' below the base of the Inyan Kara Formation
4	1,600	2,100	500	131	Class G balanced plug to isolate the 9 ⅝" casing shoe
5	40	120	80	21	Class G balanced surface cement plug

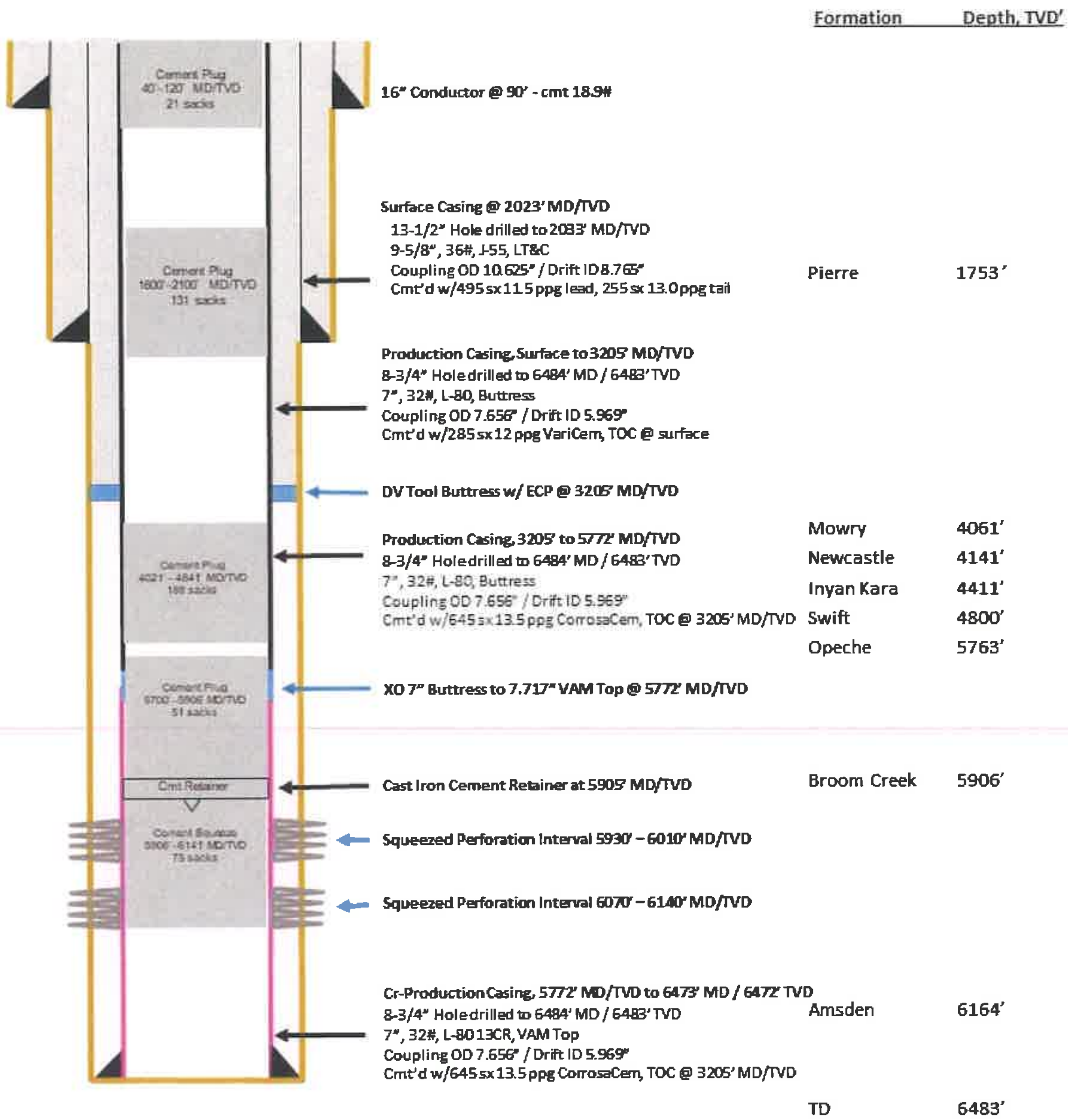
Coteau 1 (abandonment plan)

Permit #:	38379
API #:	33-05-700040
SPUD:	06/27/2021
TD:	6484' MD / 6483' TVD
RIG:	Akita #520

Rampart Energy Company
1512 Larimer St #550
Denver, CO 80202

Surface Location
555 FSL & 460 FWL SWSW Sec 1, T145N R88W
47° 24' 07.168" N / 101° 50' 31.564" W

Mercer County, ND
GL – 2014' KB – 2030'



Drawing Not to Scale, Depths subject to change

Figure 10-2. Schematic of proposed abandonment plan for each injection well.

11.0 INJECTION WELL AND STORAGE OPERATIONS

11.0 INJECTION WELL AND STORAGE OPERATIONS

This section of the storage facility permit (SFP) application presents the engineering criteria for completing and operating the injection wells in a manner that protects underground sources of drinking water (USDWs). The information that is presented meets the permit requirements for injection wells and storage operations as presented in North Dakota Administrative Code (NDAC) § 43-05-01-05 (SFP, Table 11-1) and NDAC § 43-05-01-11.3

Table 11-1. Proposed Injection Well Operating Parameters

Item	Coteau 1	Coteau 2	Coteau 3	Coteau 4	Coteau 5	Coteau 6	Total/Avg
Injected Volumes							
Total Injected Volume[1]	96.0 Bcf (4.9 MMt)	67.2 Bcf (3.4 MMt)	96.0 Bcf (4.9 MMt)	96.0 Bcf (4.9 MMt)	73.2 Bcf (3.7 MMt)	73.2 Bcf (3.7 MMt)	501.6 Bcf (25.6 MMt)
Injection Rates							
Predicted Average Injection Rate[2]	21.9 MMcfd (1,119 t/d)	15.3 MMcfd (783 t/d)	21.9 MMcfd (1,119 t/d)	21.9 MMcfd (1,119 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	114.5 MMcfd (5,845 t/d)
Predicted Maximum Injection Rate[2]	24.6 MMcfd (1,254 t/d)	17.2 mmcfd (878 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	140.0 MMcfd (7,146 t/d)
Injection Pressures							
Estimated Depth of Top Perforation (feet)[3]	5,930	5,998	5,981	5,928	5,901	5,961	5,950
Formation Fracture Pressure at Top Perforation (psi)[4]	4,210	4,259	4,247	4,209	4,190	4,232	4,224
Projected Avg Surface Injection Pressure (psi)[2]	1,628	1,597	1,644	1,604	1,682	1,677	1,639
Max Allowable Surface Injection Pressure (psi)[5]	1,976	1,998	1,993	1,975	1,966	1,986	1,982
Projected Avg Bottomhole Injection Pressure (psi)[2]	3,315	3,335	3,349	3,297	3,284	3,295	3,313
Projected Max. Bottomhole Injection Pressure (psi)[2]	3,430	3,445	3,462	3,414	3,424	3,426	3,434
Max. Bottomhole Pressure at Top Perforation (psi)[6]	3,801	3,845	3,834	3,800	3,782	3,821	3,814

[1] Assumes 55 MMcfd distributed between four wells (Coteau 1–4) from July/22 thru Dec/24, 70 MMcfd distributed between these same wells Jan/25 thru Apr/26, and 140 MMcfd distributed between six wells (Coteau 1–6) from May/26 through Jun/34.
[2] Per simulation modeling.
[3] Top perf. assumed to be 23 ft below the top of the Broom Creek Formation in all instances based on log results from Couteau 1.
[4] Based on a fracture pressure gradient of 0.71 psi/ft as calculated via CoreLabs D-Code algorithm.
[5] Based on a maximum allowable BHP equal to 90% of frac pressure and a CO_2 density of 0.306 psi/ft.
[6] Based on a maximum allowable BHP equalt to 90% of fracture pressure gradient at estimated depth of top perforation.

11.1 Coteau 1 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of the Dakota Gasification Company [DGC]) drilled and cased the Coteau 1 (Figure 9-1 and Tables 9-1 through 9-4) with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. The following proposed completion procedure outlines the steps necessary to complete the Coteau 1 well for injection purposes.

<u>Site and Well Work Preparation</u>

- Contact the NDIC and provide schedule to perform well work.
- Work road and location as needed for safe operations.
- Conduct safety meetings prior to shifts and treatments.
- Two 500-bbl tanks of 2% KCl water will be required for the step rate test.
- Well was left with no equipment in the hole, no open perforations, and filled with 2% KCl water (to a depth of 20' to avoid winter freezing).

<u>Clean Wellbore and Test Production Casing</u>

1. Move in and rig up (MIRU) workover rig.

2. Confirm zero pressure on wellhead gauges prior to removing night cap.

3. Nipple down 4-1/16" top valve and night cap.

4. Nipple up (NU) blowout preventer (BOP). Record BOP test with a low/high pressure of 250 psi/4,000 psi.

5. Pick up 2⅞" work string.

6. Trip in hole (TIH) open ended, confirm plug back total depth (PBTD). Trip out of hole (TOH).

7. Pressure-test production casing to 1,500 psi.
   a. Top off production casing with 2% KCl water.
   b. Pressure-test casing to 1,500 psi, record pressure for a minimum of 30 minutes.
   c. If casing pressure drops more than 10% variance (NDAC § 43-02-03-21), contact field engineer and DGC representative for further instructions.

<u>Run Cased-Hole Logs</u>

8. MIRU wireline service company.

9. RU wireline lubricator and pressure-test to 1,000 psi.

10. Run in hole (RIH) with temperature/gamma ray log and survey from PBTD to surface.

Perforate Broom Creek Formation

11. RIH with perforating guns and perforate the Broom Creek Formation from 5,930'–6,010' and 6,070'–6,140' (4 shots per foot, 90-degree phasing) utilizing the triple combo openhole log dated July 12, 2021, for correlation, Figure 11-1.

12. Rig down wireline service company.

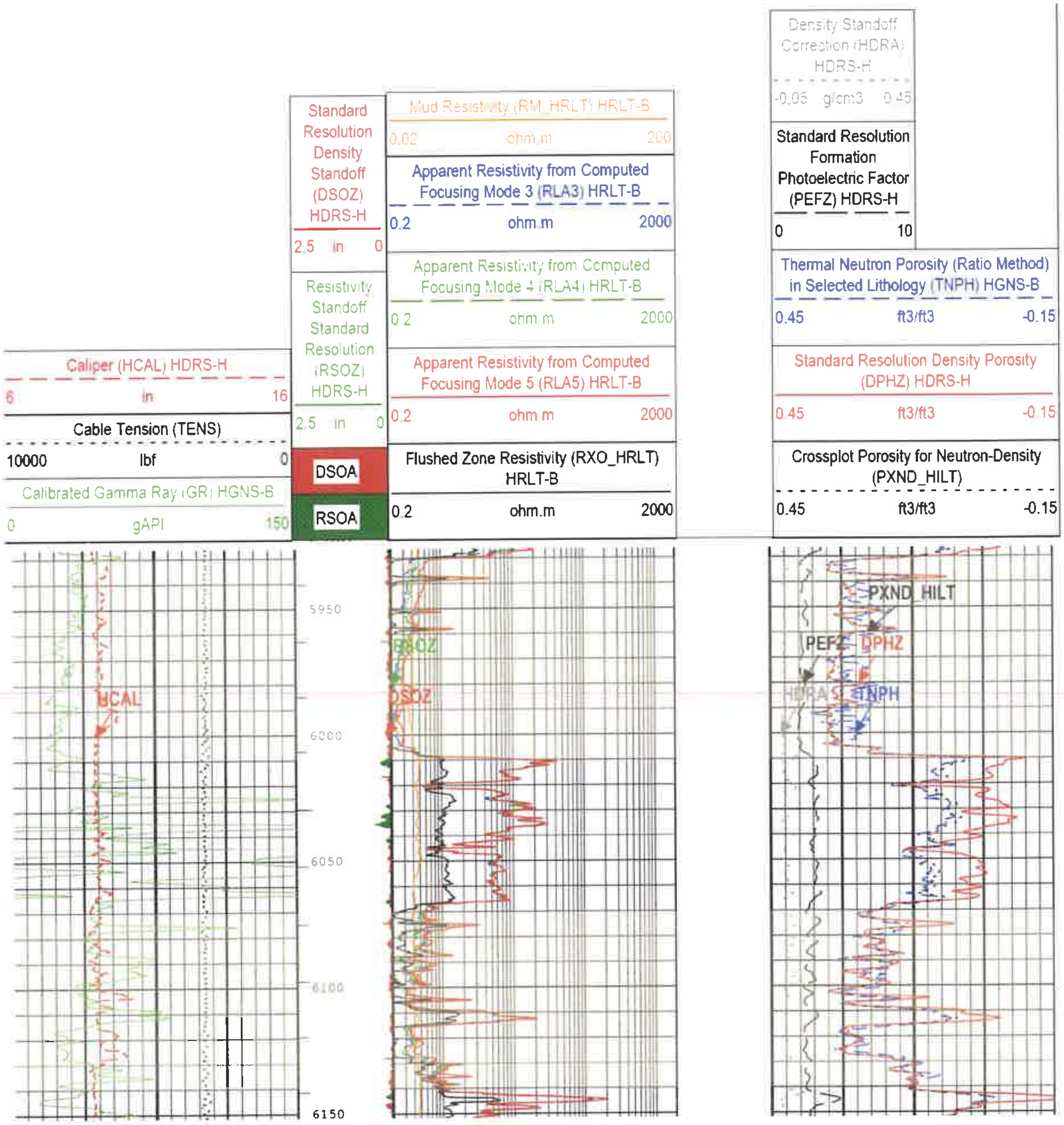


Figure 11-1. Coteau 1 proposed perforation intervals of the Broom Creek Formation (green-shaded sections based on the Coteau 1 triple combo openhole log July 2021).

Perform Step Test

13. PU 7" test packer on 2 7/8" work string, TIH, and set at ±5,900'.

14. Pressure-test packer via annulus to 2,000 psi for 30 minutes. If greater than 10% variance, contact field engineer and DGC representative for further instructions.

15. RU pump service company
    a. Pressure-test surface lines to 2,000 psi.
    b. Set pressure relief valve (PRV) at 2,000 psi or the maximum surface treating pressure.
    c. Monitor annulus with annular pressure gauge for communication.
    d. Perform proposed step rate injection test as follows:
        i. Inject at step rates of 1 barrel per minute.
        ii. Inject at constant rate for 15-min increments.
    e. After indication of formation breakdown (change in pressure slope):
        i. Continue to inject at breakdown rate for an additional 15 min.
        ii. Increase rate by 0.5 bpm for an additional 15 min.
    f. Continuously record rate vs. pressure data throughout the entire test.
    g. Shut down and record instant shut-in pressure (ISIP), 5-, 10-, and 15-min pressure readings.
    h. Shut-in well via master valve, and bleed pressure off surface lines back to pump truck.
    i. Monitor and record all pressures for initial reservoir radial flow, and continue to monitor for stable radial flow as required (NDAC § 43-05-01-11.2) and for pressure fall-off testing.
    j. RD pump service company.

16. TOH and lay down test packer and work string.

Run CO_2 Injection String

17. Change out the pipe rams from 2⅞" to 4½" and pressure-test (test low/high 250 psi/4,000 psi).

18. RU wireline service company.

19. Set 7" nickel-plated injection packer at ±5,905'.

20. Pressure-test packer to 1,500 psi.

21. RD wireline service company.

22. Make up seal assembly, locator subs, and necessary connections. RIH with 4½" L-80 tubing.

23. Pump 100 bbl corrosion-inhibited packer fluid down 4½" tubing and displace with 89 bbl 2% KCl water to displace packer fluid into the annulus.

24. Gently tag on/off tool, latch onto the on/off tool as directed by the tool hand. Verify the connection is made by slight overpull and by pumping into the tubing string. Space out and stack ±15,000-lb compression on packer, lock down, and secure. Pre-pressure-test annulus, packer, and seal bore to 1,000 psi for 30 min with rig pump. Record pressure readings every 5 min.

25. Contact NDIC to witness mechanical integrity test (MIT) 24 hr prior to official testing.
    a. Pressure well to 1,000 psi for 30 min, or as directed by NDIC while charting entire pressure test.
    b. NDIC must witness MIT in accordance with state regulations.

26. ND BOP and NU wellhead.

27. Pressure up tubing to ±2,250 psi to pump out the plug using the rig pump.

28. RDMO workover rig, continuing to be careful of wellhead equipment. Load out surplus equipment. Clear and clean location.

29. Well is to begin injection operations after NDIC approval, including approved MIT.

30. Well is completed as illustrated in Figure 11-2 and is ready for installation of surface equipment for injection operations.

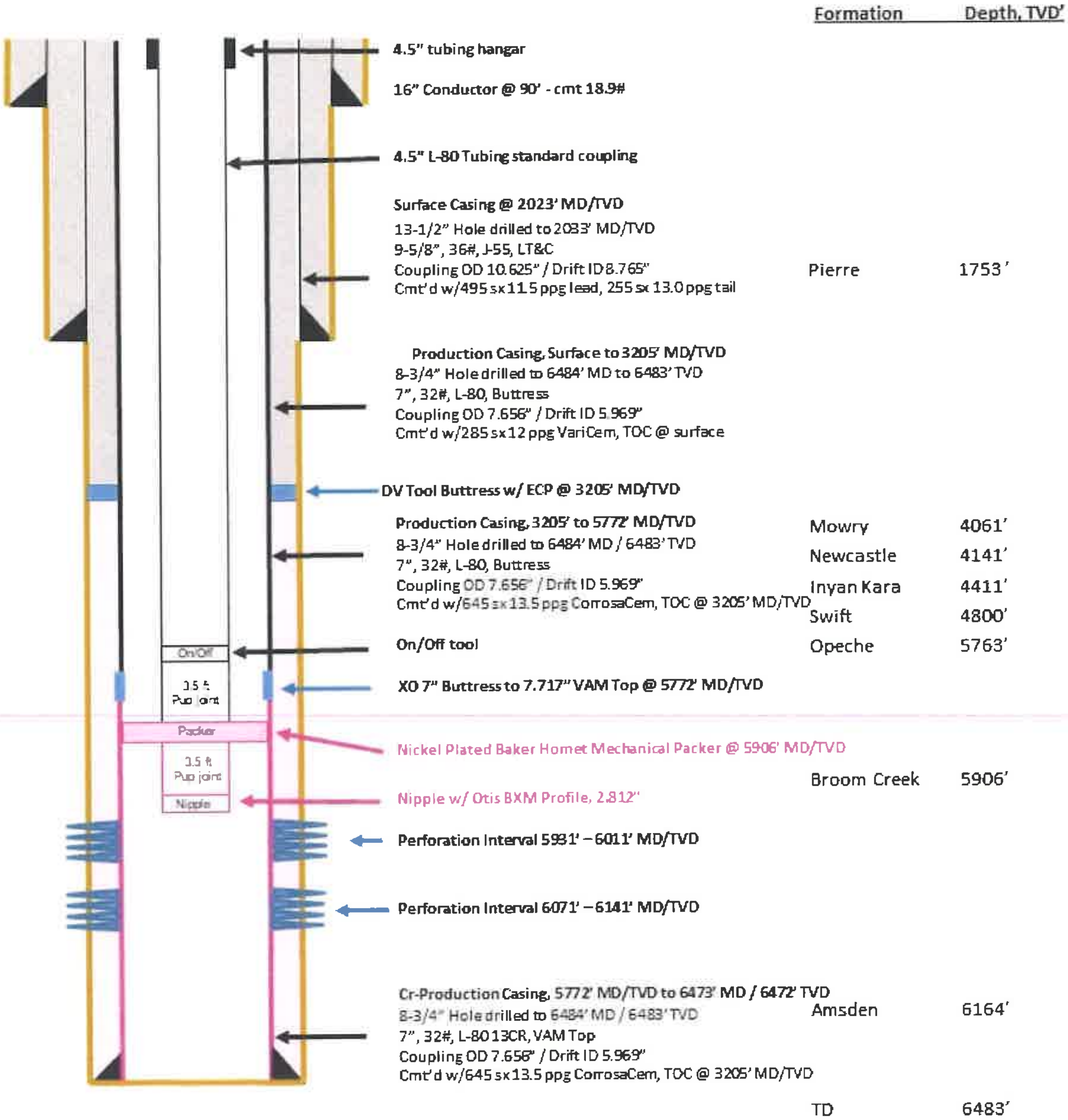
Coteau 1 (completed plan)

Permit #: 38379
API #: 33-05-700040
SPUD: 06/27/2021
TD: 6484' MD / 6483' TVD
RIG: Akita #520

Rampart Energy Company
1512 Larimer St #550
Denver, CO 80202

Surface Location
555 FSL & 460 FWL SWSW Sec 1, T145N R88W
47° 24' 07.168" N / 101° 50' 31.564" W

Mercer County, ND
GL – 2014' KB – 2030'

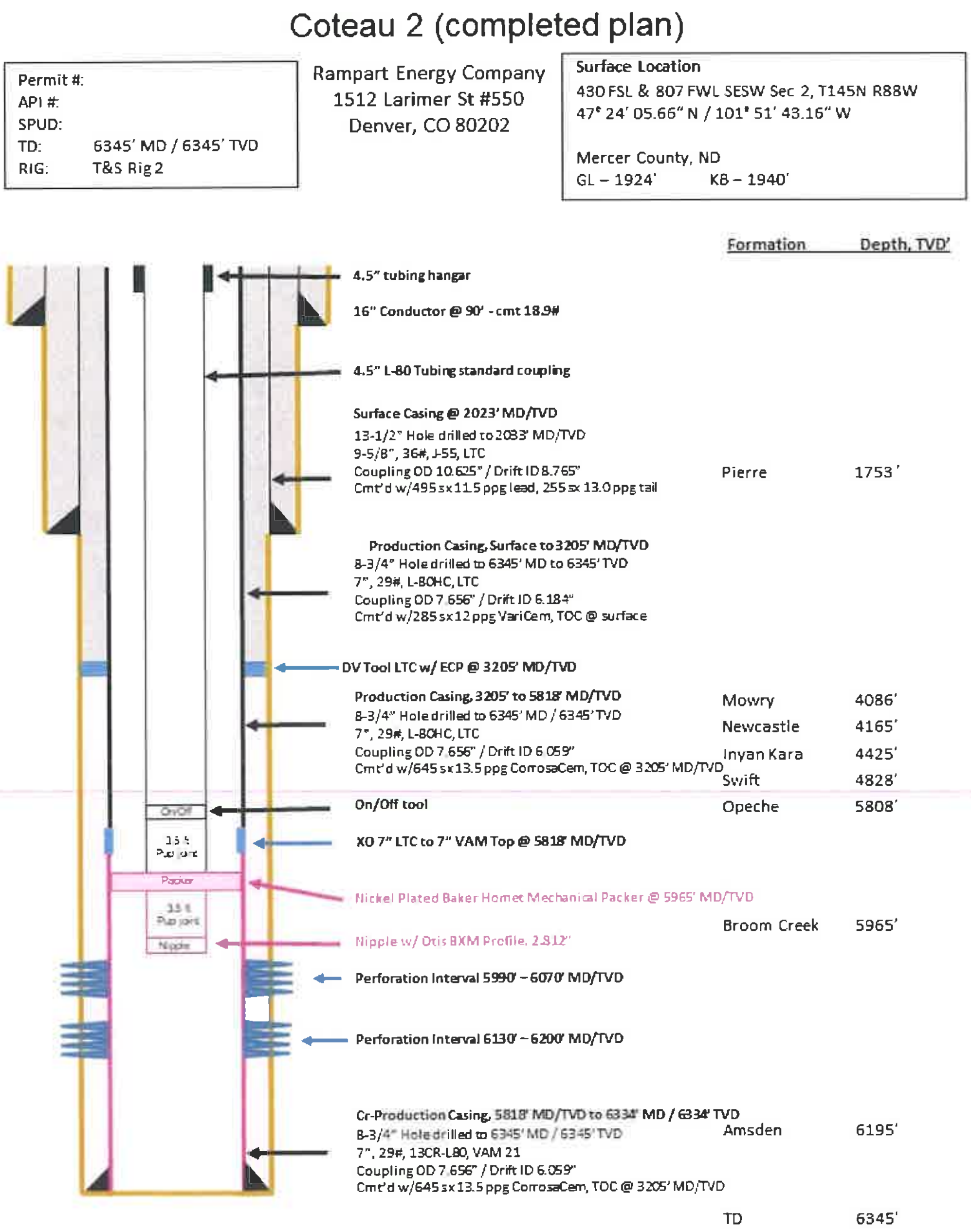


Drawing Not to Scale, Depths subject to change

Figure 11-2. Coteau 1 proposed completed wellbore schematic.

11.2 Coteau 2 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 2 (Figure 9-3 and Tables 9-5 through 9-8) prior to project start-up in 2022, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 2 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 2 completed wellbore is shown in Figure 11-3.



Drawing Not to Scale, Depths subject to change

Figure 11-3. Coteau 2 proposed completed wellbore schematic.

11.3 Coteau 3 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 3 (Figure 9-4 and Tables 9-9 through 9-12) prior to project start-up in 2022, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 3 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 3 completed wellbore is shown in Figure 11-4.

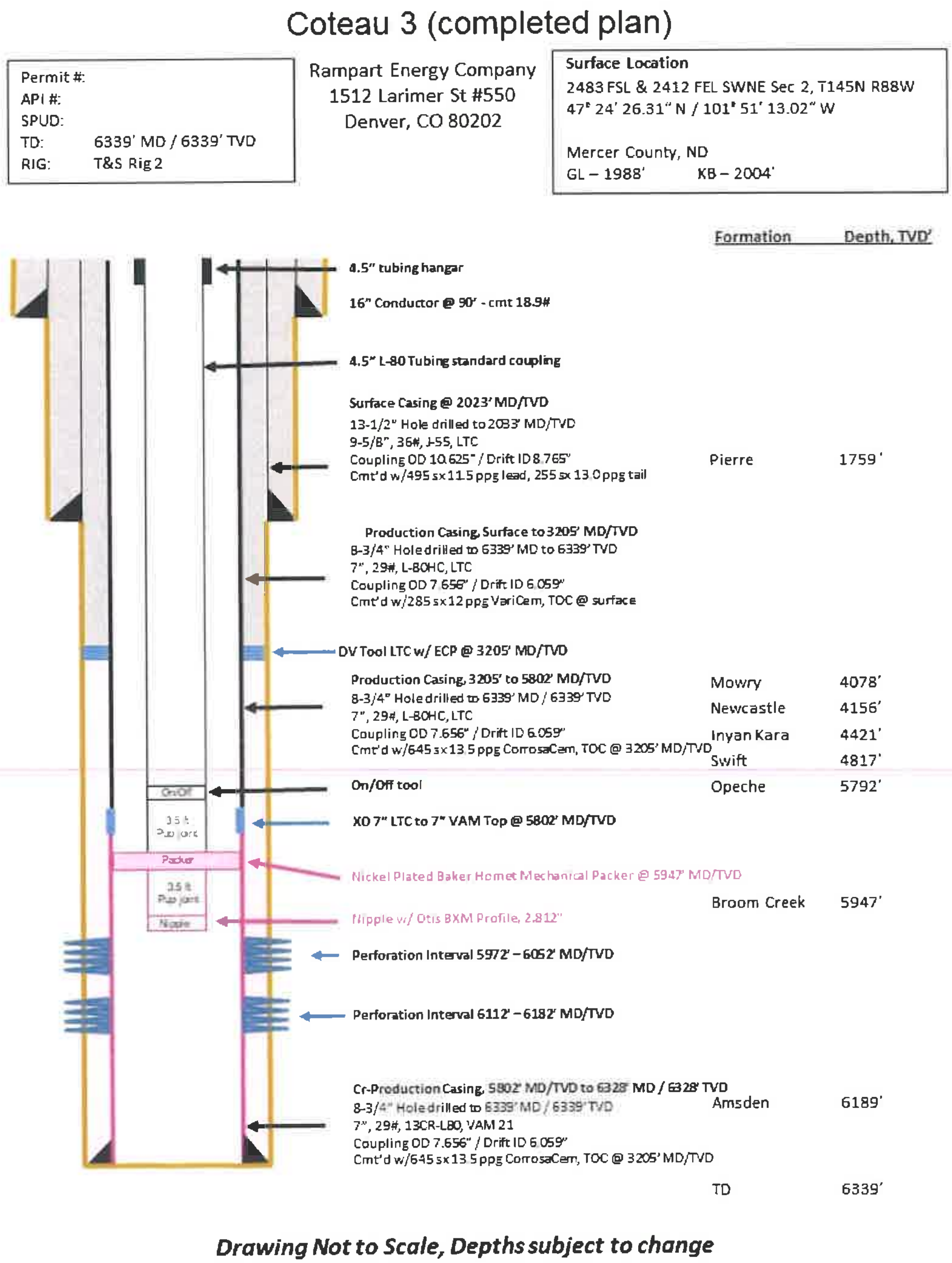


Figure 11-4. Coteau 3 proposed completed wellbore schematic.

11.4 Coteau 4 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 4 (Figure 9-5 and Tables 9-13 through 9-16) prior to project start-up in 2022, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 4 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 4 completed wellbore is shown in Figure 11-5.

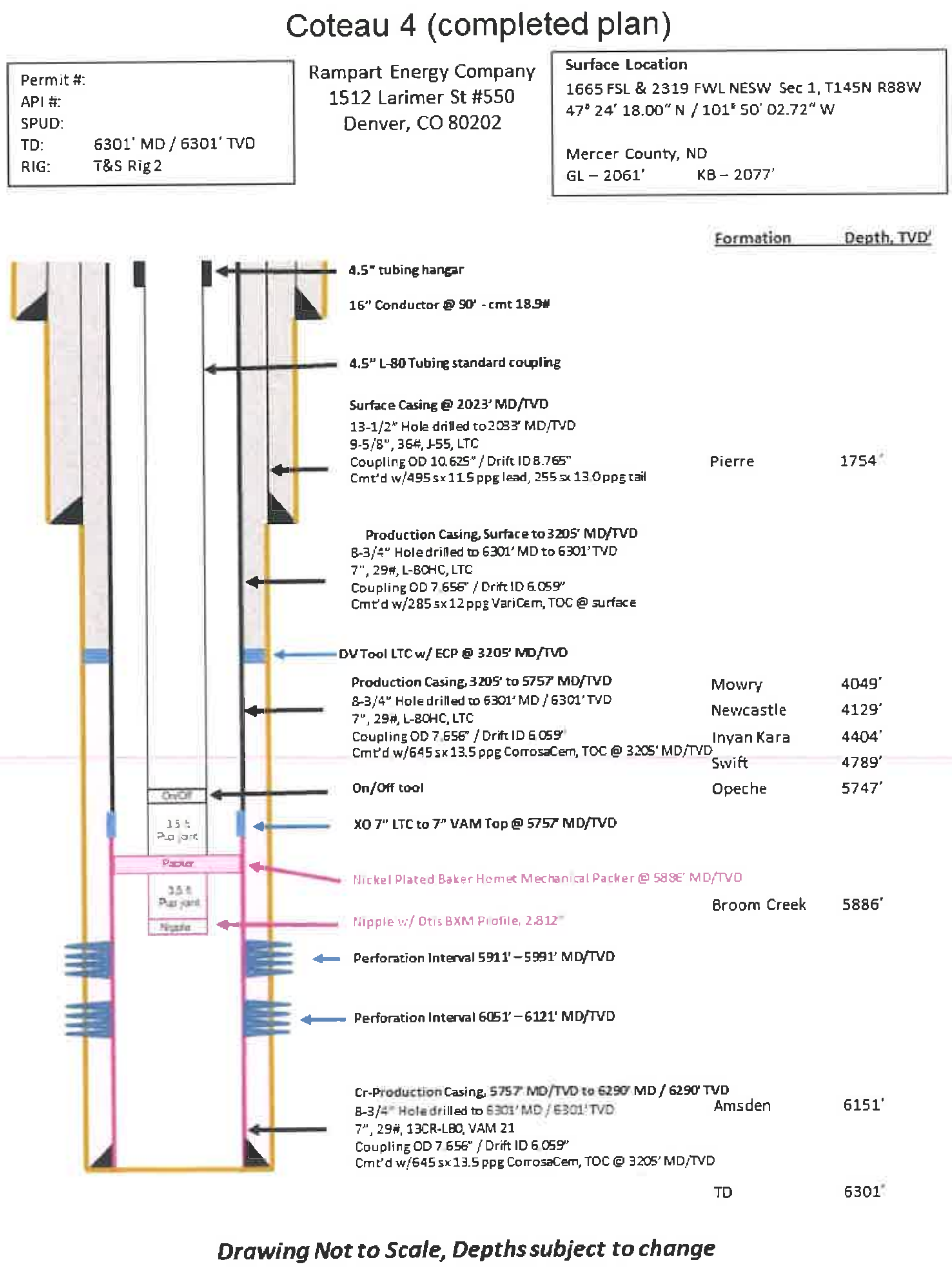


Figure 11-5. Coteau 4 proposed completed wellbore schematic.

11.5 Coteau 5 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 5 (Figure 9-6 and Tables 9-17 through 9-20) prior to an anticipated ramp-up in injection rates in 2026, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 5 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 5 completed wellbore is shown in Figure 11-6.

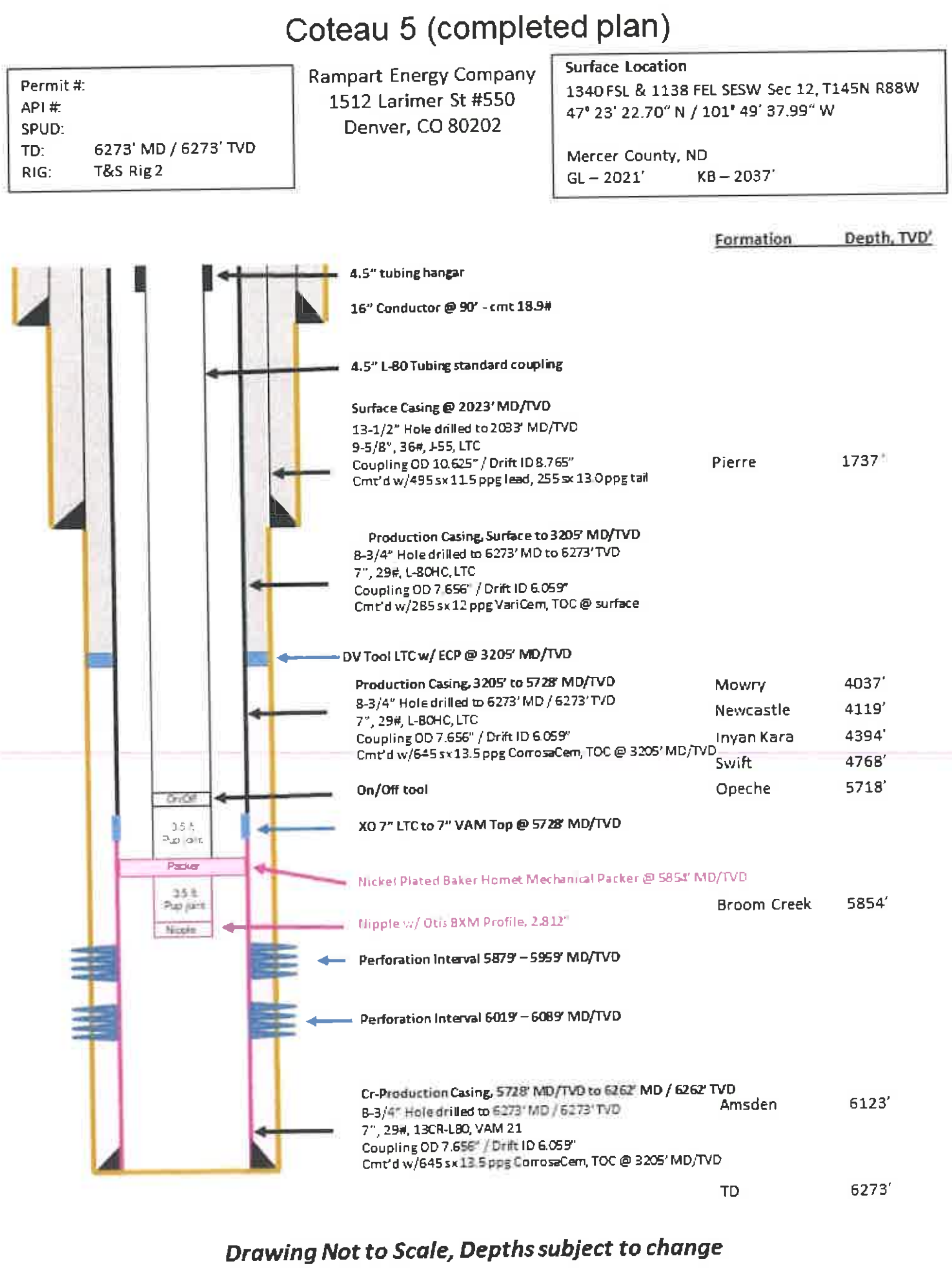


Figure 11-6. Coteau 5 proposed completed wellbore schematic.

11.6 Coteau 6 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 6 (Figure 9-7 and Tables 9-21 through 9-24) prior to an anticipated ramp-up in injection rates in 2026, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 6 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 6 completed wellbore is shown in Figure 11-7.

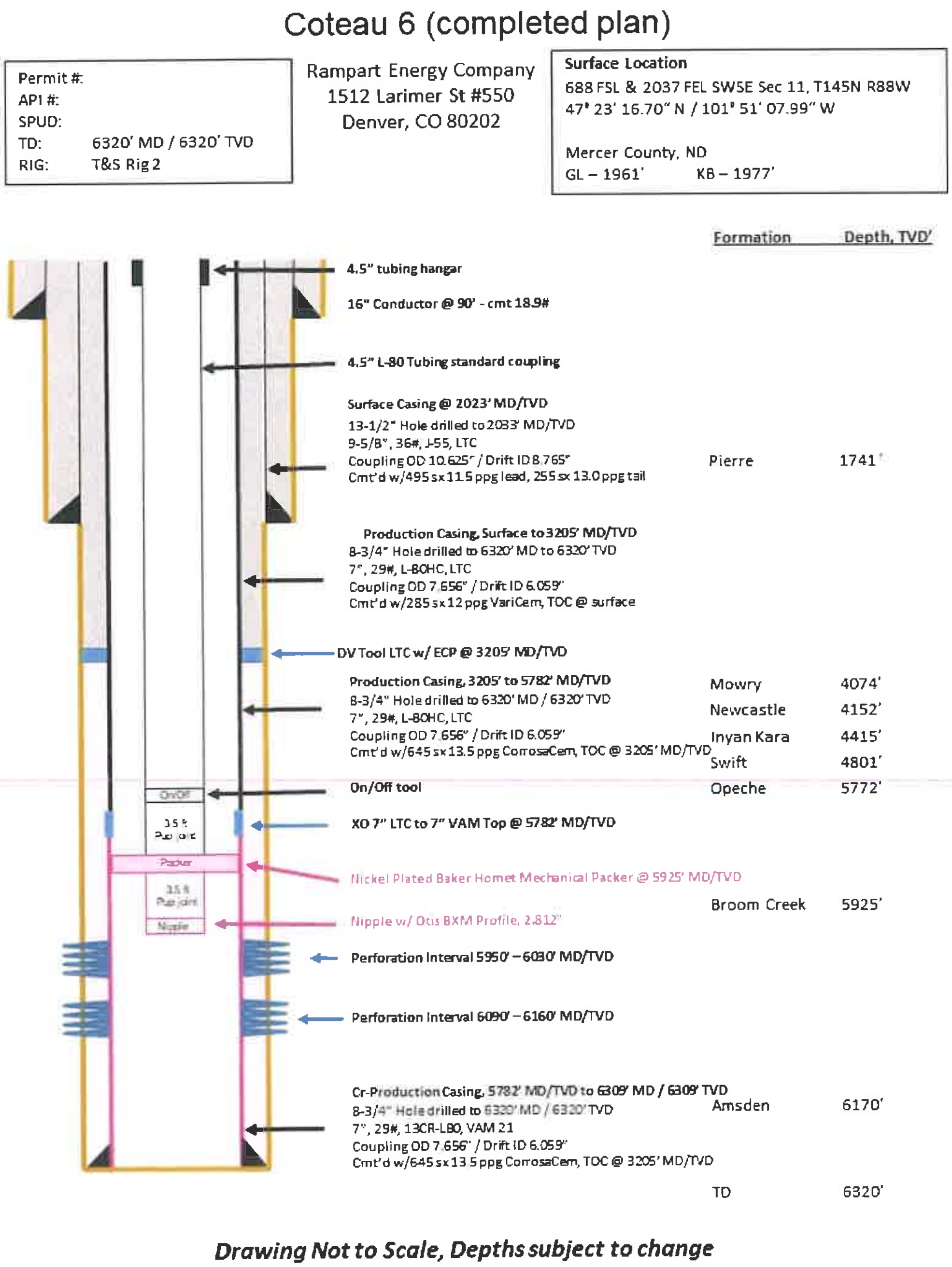


Figure 11-7. Coteau 6 proposed completed wellbore schematic.

11.7 Surface and Downhole Equipment Detail

Common packer and wellhead configurations are planned for each of the six injectors in the Great Plains CO_2 Sequestration Project (Figures 11-8 and 11-9).

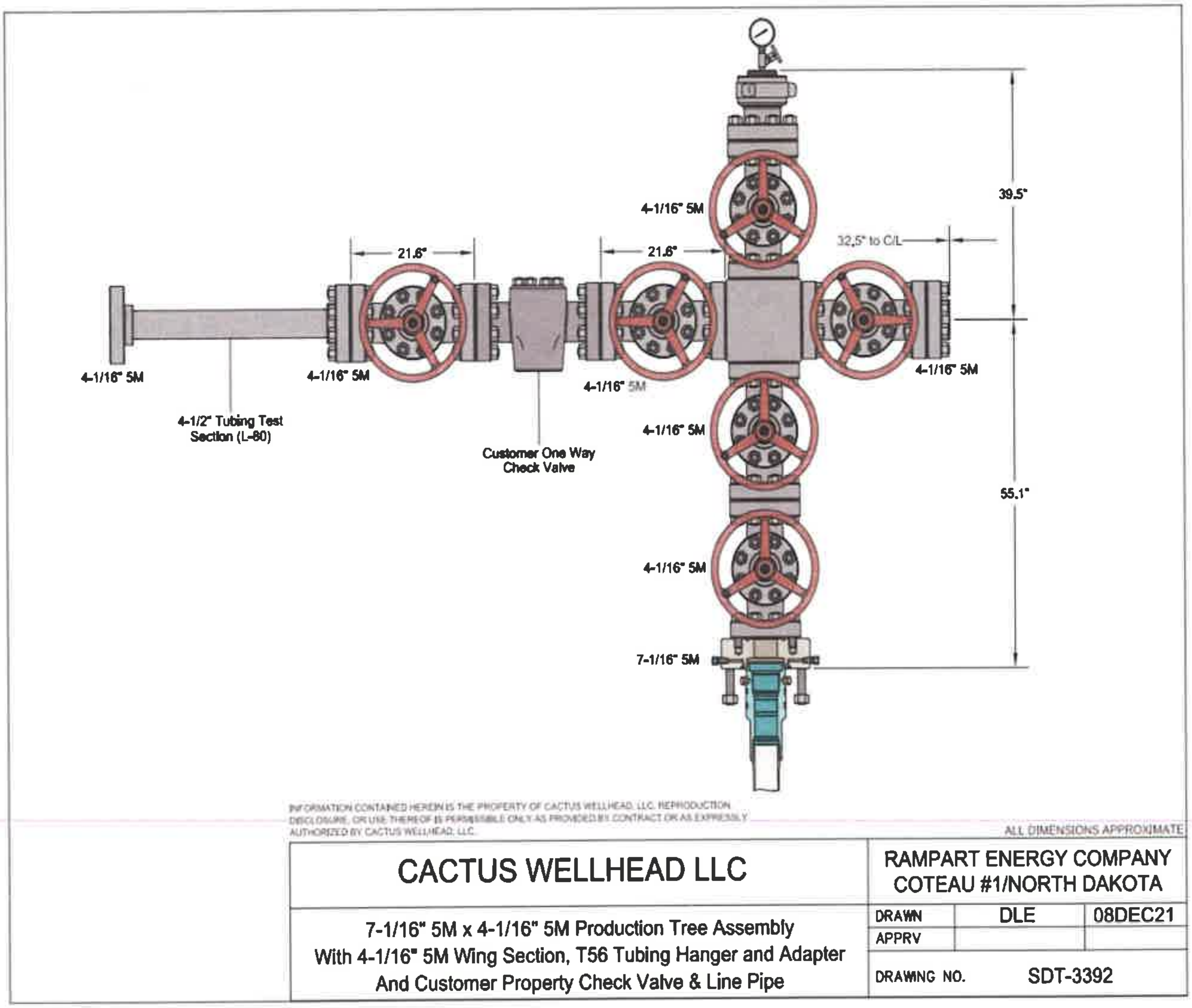


Figure 11-8. Proposed wellhead configuration for Coteau 1 through 6.

Baker Hughes

Proposed Completion Schematic

District: Minot- Bakken

District Ph:

Date Prepared: 19-Nov-2021

Prepared By: Kevin Harding

Proposal

Revision

Rev Date 11/19/2021

Nickel Coated Hornet Packer					
Bill Mernez					

Tubulars	OD (in)	Weight (lbm/ft)	ID (in)	Drift (in)	Grade	Thread	Top Depth	Bottom Depth	Comments
Casing 1	7	32.00	6.094	5.909	13Cr-30	Vam Top			
Tubing 1	4 1/2				L-30				

Open Hole ID: Hole Length: Casing Shoe Depth:

No	Description	OD (in)	ID (in)	Length (ft)	Depth (ft)
1	3-1/2 EUE Pin X TBD Thread Box Nickel Plated	TBD	TBD	TBD	
2	ON/OFF TL, L-10 3.500 2.813 X Profile Nickel Plated	5.500	2.810	2.48	
3	HORNET Wireline PACKER 600-292 07.000 IN 23.0-29.0 Nickel Plated	6.000	2.920	9.71	
4	COUPLING 3.5 Nickel Plated	4.479	N/A	0.48	
5	6' PUP JOINT 3.5 IN EU 8RD Nickel Plated	3.507	2.956	5.54	
6	SEATING NIPPLE W/OTIS PROFILE 2.812 BXN PROFILE 3.5 EUE BXP 9 CHROME	4.911	3.725	1.50	
7	WLEG W/ POP Pinned 2000 PSI , 3.5" 9.2# EU B Nickel Plated	4.511	3.025	0.50	

Figure 11-9. Proposed packer assembly for Coteau 1 through 6.

12.0 FINANCIAL ASSURANCE AND DEMONSTRATION PLAN

12.0 FINANCIAL ASSURANCE AND DEMONSTRATION PLAN

This financial assurance demonstration plan (FADP) is provided to meet the regulatory requirements for the geologic storage of carbon dioxide (CO_2) as prescribed by the state of North Dakota in North Dakota Administrative Code (NDAC) § 43-05-01-09.1. The storage facility permit application must demonstrate that a financial instrument is in place that is sufficient to cover the costs associated with the following actions:

- Pursuant to NDAC § 43-05-01-05.1, corrective action on all active and abandoned wells, which are within the area of review (AOR) and penetrate the confining zone, that have the potential to endanger underground sources of drinking water (USDWs) through the subsurface movement of the injected CO_2 or other fluids.

- Pursuant to NDAC § 43-05-01-11.5, plugging of injection wells.

- Pursuant to NDAC § 43-05-01-19, implementation of postinjection site care (PISC) and facility closure activities, which includes the 10-year PISC monitoring program.

- Pursuant to NDAC § 43-05-01-13, implementation of emergency and remedial response plan (ERRP) actions.

This FADP identifies the financial instruments that will be established (Section 12.2) and provides cost estimates for each of the above actions (Section 12.3) based on the information that is provided in the storage facility permit application.

12.1 Facility Information

The facility name, facility contact, and injection well locations are provided below:

Facility Name:	Dakota Gasification Company (DGC) Great Plains Synfuels Plant
Facility Contact:	Dale Johnson, Vice President and Plant Manager
Injection Well Locations:	Coteau 1 (North Dakota Industrial Commission [NDIC] File No. 38379) SW/SW of Section 01 T145N, R88W (47.401991, -101.842101) Coteau 2 (NDIC File No. TBD) SW/SW of Section 02 T145N, R88W (47.401572, -101.861988) Coteau 3 (NDIC File No. TBD) NW/SE of Section 02 T145, R88W (47.407308, -101.853618) Coteau 4 (NDIC File No. TBD) NE/SE of Section 01 T145N, R88W (47.406940, -101.835330) Coteau 5 (NDIC File No. TBD) NE/SE of Section 12 T145N, R88W (47.389640, -101.827219) Coteau 6 (NDIC File No. TBD) SW/SE of Section 11 T145N, R88W (47.405000, -101.834090)

12.2 Financial Instruments

DGC is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments:

- DGC will establish an escrow account to cover the costs of corrective action in accordance with NDAC § 43-05-01-05.1, plug injection wells in accordance with NDAC § 43-05-01-11.5, and implement PISC and facility closure activities in accordance with NDAC § 43-05-01-19. DGC will make four annual payments of $1 million to the escrow account. The first payment will occur on or before the first day of operations, and the final payment will occur in 2025, bringing the account balance to $4 million.

- A third-party pollution liability insurance policy with an aggregate limit of $16 million will be secured to cover the costs of implementing emergency and remedial response actions, if warranted, in accordance with NDAC § 43-05-01-13.

The estimated total costs of these activities are presented in Table 12-1. Section 12.3 of this FADP provides additional details of the financial responsibility cost estimates for each activity.

Table 12-1. Cost Estimates for Activities to Be Covered

Activity	Estimated Total Cost
Corrective Action on Wells in the AOR	$0
Plugging of Injection Wells	$1,000,000
PISC and Facility Closure	$3,000,000
Emergency and Remedial Response (including endangerment to USDWs)	$16,000,000
Total	$20,000,000

The third-party insurance, which will identify DGC as the principal, will be provided by one or a combination of companies shown below. The companies meet all of the following criteria:

1. The company is authorized to transact business in North Dakota.

2. The company has either passed the specified financial strength requirements based on credit ratings or has met a minimum rating, minimum capitalization, and ability to pass the rating, when applicable.

3. The third-party insurance can be maintained until such time that NDIC determines that the storage operator has fulfilled its financial obligations.

The third-party insurance, which identifies DGC as the covered party, will be provided by one or a combination of the companies shown below. The coverage limits of the policy are summarized below:

DGC has procured indicated terms for commercial environmental impairment liability (EIL) insurance coverage to fund covered emergency and remedial response actions to protect USDWs arising out of sequestration operations. Coverage terms are of an estimated nature only at this time, as firm and bindable terms are not possible this far in advance of commencement of sequestration operations. At this time, a coverage limit of $25 million per occurrence/aggregate is contemplated and expected to be provided by one or a combination of the following insurers:

- Ascot Insurance Group – AM Best-Rated A (excellent)
- Aspen Insurance Group – AM Best-Rated A (excellent)
- W.R. Berkley Insurance Group – AM Best-Rated A+ (superior)

Final coverage terms and costs will be determined upon full underwriting and firm/bindable quotations to be issued by insurers 30 to 60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations.

The third-party insurance companies listed above meet both of the following criteria, as specified in NDAC §43-05-01-09.1(1)(g):

1. The companies satisfy financial strength requirements based on credit ratings in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa).

2. The companies meet a minimum rating (minimum rating based on an issuer, credit, securities, or financial strength rating as a demonstration of financial stability) and minimum capitalization (i.e., demonstration that minimum thresholds are met for the following financial ratios: debt–equity, assets–liabilities, cash return on liabilities, liquidity, and net profit) and are able to pass bond rating in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa), when applicable.

12.3 Financial Responsibility Cost Estimates

12.3.1 Corrective Action

DGC implemented the following workflow to estimate costs associated with corrective action activities: 1) delineate the AOR and 2) identify and evaluate active and abandoned legacy wells within the AOR (i.e., ANG#1 and ANG#2) to ensure they meet the minimum completion standards for geologic storage of CO_2 and need no corrective action. Based on the results of the well evaluations, no correction action was needed.

12.3.2 Plugging of Injection Wells

DGC implemented the following approach to estimate costs associated with the plugging of injection wells: assume plugging of six Class VI injection wells at a total cost of $1 million, or $167,000 per well.

12.3.3 *Implementation of PISC and Facility Closure Activities*

The breakdown of estimated costs totaling $3 million for implementing the PISC as described in the PISC and facility closure plan is provided in Table 12-2, which includes the following: a) near-surface monitoring (i.e., soil gas and Fox Hills Formation testing), b) formation monitoring (i.e., downhole pressure and temperature surveys, pulsed-neutron logs) and mechanical integrity well tests (i.e., injection well annulus pressure, ultrasonic logs), c) coordinated repeat 2D seismic, and d) estimated cost of site closure activities, which has been estimated at $100K based on the integrated environmental control.

Table 12-2. Cost Estimates for 10-year PISC Monitoring Efforts

Monitoring Type	Comments	Total Estimated Cost
Near-Surface Monitoring		
Soil Gas Sampling and Analysis	10 years at $25,000 per year	$250,000
Fox Hills Sampling and Analysis	10 years at $25,000 per year plus $300,000 for site closure activities	$550,000
Geophysical Monitoring		
2D Seismic Data Acquisition	Perform four 2D seismic surveys (PISC years 1, 3, 5, and 10) at $550,000 per survey	$2,200,000
	Total	**$3,000,000**

12.3.4 *Implementation of Emergency and Remedial Response Actions*

12.3.4.1 Emergency Response Actions

A review of the technical risk categories for DGC's Great Plains CO_2 Sequestration Project identified a list of events that could potentially result in the movement of injected CO_2 or formation fluids in a manner that may endanger a USDW and require an emergency response. These events are as follows:

- Failure of the surface equipment
- Integrity failure of injection well
- Injection well-monitoring equipment failure
- Storage reservoir is unable to contain the formation fluid or stored CO_2
- Natural disasters

If it is determined that one or more of these events have occurred, the emergency response actions that will be implemented are described in the ERRP (Section 7). These response actions are summarized in Table 12-3.

Table 12-3. Response Actions for Potential Emergency Events

Emergency Event	Response Action
Failure of CO_2 Transmission Line or Flow Lines from DGC CO_2 Capture System to CO_2 Injection Wellheads	• The CO_2 stream release and its location will be detected by the leak detection system, which will trigger an alarm and result in the automated shutdown of the transmission line and wellsite flow line. • If warranted, initiate an evacuation plan. • The transmission line and/or flow line failure will be inspected to determine the root cause of the failure. • Repair/replace the damaged transmission line or flow line, and if warranted, put in place the measures necessary to eliminate such events in the future.
Integrity Failure of Injection Well	• Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure. • Stop CO_2 injection, and purge CO_2 from surface facilities. • Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the NDIC Department of Mineral Resources (DMR) underground injection control (UIC) program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).
Injection Well-Monitoring Equipment Failure	• Monitor well pressure, temperature, and annulus pressure (manually if necessary) to determine the cause and extent of failure. • Stop CO_2 injection, and purge CO_2 from surface facilities. • Identify and, if necessary, implement appropriate remedial actions to repair/replace well-monitoring equipment (in consultation with the NDIC DMR UIC program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).

Continued . . .

Table 12-3. Response Actions for Potential Emergency Events (continued)

Emergency Event	Response Action
Storage Reservoir Unable to Contain Formation Fluid or Stored CO_2	• Collect confirmation sample(s) of groundwater, soil gas, ambient air, and/or surface water, and analyze them for indicator parameters (see testing and monitoring plan of the supporting plans of the storage facility permit application). • If the presence of indicator parameters is confirmed, develop (in consultation with the NDIC DMR UIC program director) a case-specific work plan to: 1. Install additional monitoring points near the impacted area to delineate the extent of impact. a. If a USDW is impacted above drinking water standards, arrange for an alternative potable water supply for all users of that USDW. b. If a surface release of CO_2 to the atmosphere is confirmed, initiate an evacuation plan, if warranted, in tandem with an appropriate workspace and/or ambient air-monitoring program at the plant boundary to monitor the presence of CO_2 and its natural dispersion following the termination of CO_2 injection, following practices similar to those described in the DGC risk management plan for analyzing the potential impacts of other chemical releases from the DGC plant. c. If surface release of CO_2 to surface waters is confirmed, implement appropriate surface water-monitoring program to determine if water quality standards are being exceeded. 2. Proceed with efforts, if necessary, to 1) remediate the USDW to achieve compliance with drinking water standards (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to air-strip CO_2 from the impacted water or implement other active remediation processes) and reinject treated water into the subsurface, 2) monitor CO_2 concentrations in the workspace and ambient air to

Continued . . .

Table 12-3. Response Actions for Potential Emergency Events (continued)

Emergency Event	Response Action
Storage Reservoir Unable to Contain Formation Fluid or Stored CO_2 (continued)	document reduction of CO_2 concentrations to background levels over time, and 3) monitor the reduction of impacts to surface waters to background levels as a result of natural attenuation processes or implement active/passive remediation of surface waters to achieve acceptable background levels of impacts. • Continue all remediation and monitoring at an appropriate frequency (as determined by DGC and the NDIC DMR UIC program director) until the unacceptable, adverse impacts have been fully addressed.
Natural Disasters (seismic event)	• Identify where (i.e., the epicenter) and when the event occurred. • Determine whether there is a connection with injection activities. • Determine mechanical integrity of all project wells and formation seals. • If warranted, stop CO_2 injection, purge CO_2 from surface facilities, and implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).
Natural Disasters (other)	• Monitor well pressure, temperature, and annulus pressure to verify status of wells and determine the cause and extent of any failure. • If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate extent of any impacts. • If impacts or endangerment of USDWs are detected, identify and implement appropriate response actions in accordance with the DGC emergency action plan (in consultation with the NDIC DMR UIC program director).

12.3.4.2 Estimation of Costs of Emergency Response Actions

Estimating the costs of implementing the emergency response actions in Table 12-3 is challenging since remediation measures specifically dedicated to CO_2 storage impacts are poorly documented, with one of the more important data gaps being the lack of precise knowledge of the leakage mechanisms and associated impacts (Manceau and others, 2014). Without this knowledge, it is not possible to design appropriate remedial measures. Furthermore, to date, no remediation action following CO_2 leakage after geologic storage has ever been implemented mainly because of the absence of established impacts (Manceau and others, 2014). Consequently, the degree of maturity of remediation measures in the carbon capture and storage (CCS) field is low, making it necessary to rely on literature that is primarily based on modeling or analogies with other pollutants, e.g., the analogy between CO_2 and volatile organic compounds, the latter having been addressed extensively in the literature. Additionally, for the remedial measures, costs and time for adequate removal are generally site-dependent, and no information is specifically available in this area in the CCS field.

Based on this current situation, two key technical manuscripts were relied upon to identify and estimate the costs of mitigation/remediation technologies to address undesired migration of CO_2 from a geological storage unit (Manceau and others, 2014, and Bielicki and others, 2014).

12.3.4.2.1 Identification of Remediation Technologies

Manceau and others (2014) identified several remediation technologies/strategies that are available to address the potential impacted media that may result from an emergency event. These impacted media and remediation measures are listed in Table 12-4. The impacted media in Table 12-4 include surface and groundwater/USDWs, vadose zone, indoor settings, and atmosphere; the remedial measures include a combination of active (e.g., air sparging) and passive (e.g., dispersion, natural attenuation) systems. However, it is important to note that, at this time, there is no widely accepted methodology for designing intervention and remediation plans for CO_2 geologic storage projects. Consequently, there remains a need for establishing the best field-applied and test practices for mitigating an undesired CO_2 migration. This effort will be based on a combination of available literature and experience that is gained over time in existing CO_2 storage projects.

Table 12-4. Proposed Technologies/Strategies for Remediation of Potential Impacted Media

Impacted Media	Potential Remedial Measures
Groundwater/USDW	Monitored natural attenuation
	Pump-and-treat
	Air sparging
	Permeable reactive barrier
	Extraction/injection
	Biological remediation
Vadose Zone	Monitored natural attenuation
	Soil vapor extraction
	pH adjustment (via spreading of alkaline supplements, irrigation, and drainage)
Surface Water	Passive systems, e.g., natural attenuation
	Active treatment systems
Atmosphere	Passive systems, e.g., natural mixing, dispersion
Indoor/Workplace Settings	Sealing of leak points
	Depressurization
	Ventilation

12.3.4.2.2 Estimation of Costs for Implementing Emergency Event Responses

Given the lack of a site-specific estimate of implementing the emergency event responses at the CO_2 geologic storage site of DGC, cost estimates developed by Bielicki and others (2014) were used to derive a cost range for the project related to the undesired migration of CO_2 from a geologic storage unit. Extrapolating these literature costs, which were based on a case study site in the Michigan Sedimentary Basin, to DGC's Great Plains CO_2 Sequestration Project only provides an order-of-magnitude estimate of the potential costs due to the significant site-specific differences in the storage projects; however, the range of costs estimated in this manner are believed to be conservatively high in nature, making them more than sufficient for informing the value of the financial instrument that must be secured for the project, as described in the financial responsibility demonstration plan.

Case Study Description

Bielicki and others (2014) examined the costs associated with remediating undesired migration of CO_2 from a geologic storage unit as part of a case study of an extreme leakage situation. The case study involved the continuous annual injection of 9.5 Mt (9,500,000 metric tons) of CO_2 into the Mt. Simon sandstone of the Michigan Sedimentary Basin over a period of 30 years. It assumed every well in the basin was a potential leakage pathway and that no action was taken to mitigate any of these leakage pathways. In addition, eight UIC Class I injection wells, which were located within approximately 1 mile of the CO_2 injection well, were also identified as leakage pathways. Four hundred probabilistic simulations of the CO_2 injection were performed and produced estimates of the area of the CO_2 plume as well as leakage rates of CO_2 from the storage reservoir to four aquifers as well as to the surface.

Cost Estimates

Story lines were developed for the site based on 1) risk assessments for the geologic storage of CO_2; 2) consequences of leakage; 3) lay and expert opinion of leakage risk; 4) modeling of CO_2 injection and leakage for the case study; and 5) input from local experts, oil and gas engineers, academics, attorneys, and other environmental professionals familiar with the Michigan Sedimentary Basin. Cost estimates for managing leakage events were then generated for first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) projects based on a low-cost and high-cost story line. These cost estimates provided a breakdown of the costs into the following categories:

- Find and fix a leak
- Environmental remediation
- Injection interruption
- Technical remedies for damages
- Legal costs
- Business disruption to others, e.g., natural gas storage
- Labor burden to others

Of interest for the financial responsibility demonstration plan is the environmental remediation cost estimate, which was provided for a leak scenario where there was interference with groundwater as well as a scenario where there was groundwater interference combined with CO_2 migration to the surface.

Environmental Remediation – Low-Cost and High-Cost Story Line

The low-cost and high-cost story lines for the two components of environmental remediation, groundwater interference and migration to the surface, are summarized in Table 12-5. As shown in Table 12-5, the low-cost story lines are characterized by independent leak scenarios that either result in interference with groundwater or CO_2 migration to the surface. On the other hand, the high-cost story lines are interrelated, where it is assumed that the high-cost story line for CO_2 migration to the surface is conditional upon the existence of the high-cost story line for groundwater interference.

Estimated Environmental Remediation Costs – FOAK and NOAK Projects

Based on the above story lines, the estimated environmental remediation costs for the high-cost story lines are basically the same for both FOAK and NOAK projects:

- High-cost story line – Groundwater interference alone: ~ \$13MM
- High-cost story line – Groundwater interference with CO_2 migration to the surface: \$15MM to \$16MM

12.3.4.2.3 Input for the Financial Responsibility Demonstration Plan

The estimated costs for the environmental remediation of the high-cost story line for the case study, \$15MM to \$16MM, likely represents a conservatively high estimate of similar costs for DGC's Great Plains CO_2 Sequestration Project. This statement is based primarily on the fact that the quantity of CO_2 injection of the case study (9,500,000 metric tons of CO_2 per year) is significantly larger than the planned injection quantity of DGC's Great Plains CO_2 Sequestration Project (from 1.1 to 2.7 million metric tons of CO_2 per year). Furthermore, the case study site had 450,000 active and abandoned wells, 400,000 of which penetrate the shallow subsurface to provide for drinking water, irrigation, and industrial uses. In contrast, there are six proposed CO_2 injection wells and two wastewater disposal wells (ANG#1 and ANG#2) located in the area of DGC's Great Plains CO_2 Sequestration Project. As such, the extreme leakage scenario of the case study represents a more extensive leakage scenario that could exist at the DGC site. Accordingly, even though the same remedial technologies and strategies may be used at both sites to address CO_2 migration, it is assumed that the cost estimates provided for the case study represent a conservatively high maximum cost for DGC's Great Plains CO_2 Sequestration Project. It is on this basis that the value of $16MM has been used as one of the cost inputs into the determination of the financial instrument that will be put in place for DGC's Great Plains CO_2 Sequestration Project.

Table 12-5. Low-Cost and High-Cost Story Line for Environmental Remediation

	Low-Cost Story Line
Groundwater Interference	• A small amount of CO_2 migrates into a deep formation that has a total dissolved solids concentration of ~9000 ppm. By definition, this unit is a USDW, but the state has abundant water resources, and there are no foreseeable uses for water from this unit. • Regulators require that two monitoring wells be drilled into the affected USDW and three monitoring wells be drilled into the lowermost potable aquifer (total dissolved solids concentration of <1000 ppm) to verify the extent of the impacts of the leak. No legal action is taken. • Injection is halted from the time that the leak is discovered until monitoring confirms that containment is effective (9 months). • The UIC regulator determines that no additional remedial actions are necessary.
CO_2 Migration to the Surface	• A leaking well provides a pathway whereby CO_2 discharges directly to the atmosphere. • Neither CO_2 nor brine leaks into the subsurface formation outside the injection formation in significant quantities. • The CO_2 injection is halted for 5 days, and the leaking well is promptly plugged.
	High-Cost Story Line
Groundwater Interference	• A community water system reports elevated arsenic. Monitoring suggests that the native arsenic in the formation may have been mobilized by pH changes in the aquifer caused by CO_2 impacts to the aquifer. • A new water supply well is installed to serve the community, and the former water supply wells are plugged and capped. • Potable water is provided to the affected households during the 6 months required to drill the new water supply wells. • Groundwater regulators take legal action on the geologic storage operator to force remediation of the affected USDW using pump-and-treat technology. • UIC regulators require remedial action to remove, through a CO_2 extraction well, an accumulation of CO_2 that has the potential to affect the drinking water. • CO_2 injection is halted for 1 year during these remediation activities.
CO_2 Migration to the Surface	• The high-cost story line for groundwater is required. • A hyperspectral survey completed during the diagnostic monitoring program identifies surface leakage in a sparsely populated area. • Elevated CO_2 concentrations are detected by a soil gas survey and by indoor air quality sampling in the basements of several residences. • Affected residents are housed in a local hotel for several nights while venting systems are installed in their basements. • A soil-venting system is installed at the site. • CO_2 injection is halted for a year during these remediation activities.

To provide additional perspective for this \$16MM cost estimate for environmental remediation, two other cost estimates for the remediation of potential environmental impacts associated with the geologic storage of CO_2 were found in the literature. These costs ranged from \$9MM to \$34MM. The source of the lower limit (\$9MM) was a 2012 study (Trabucchi and others, 2012) which estimated the damages, i.e., dollars necessary to remediate or compensate for harm should a release occur at a commercial storage site (i.e., FutureGen 1.0 located in Jewett, Texas) that planned to inject 1,000,000 metric tons of CO_2 per year. This study estimated the "most likely (50th percentile)" total damages to be approximately \$8.7MM and the "upper end (95th and 99th percentiles)" of the total damages to be approximately \$20.1MM and \$26.2MM, respectively (all estimates in 2020 dollars).

The upper limit of the range (\$34MM) came from a Class VI UIC permit, which was issued to Archer Daniels Midland (ADM) by the U.S. Environmental Protection Agency (Underground Injection Control Permit – Class VI, Permit No. IL-115-6A-0001). As part of the financial responsibility demonstration plan of the ADM permit, a cost estimate of \$33.8MM was provided for the cost element, emergency and remedial response, which is slightly higher than the 99th percentile cost estimate of \$26.2MM for the FutureGen 1.0 site. The planned injection rate for the ADM geologic storage project was ~1,200,000 metric tons per year.[1]

12.4 References

Bielicki, J.M., Pollak, M.F., Fitts, J.P., Peters, C.A., and Wilson, E.J., 2013, Causes and financial consequences of geologic CO_2 storage reservoir leakage and interference with other subsurface resources: International Journal of Greenhouse Gas Control, v. 20, p. 272–284.

Manceau, J.C., Hatzignatiou, D.G., Latour, L.L, Jensen, N.B., and Réveillére, A., 2014, Mitigation and remediation technologies and practices in case of undesired migration of CO_2 from a geological storage unit—current status: International Journal of Greenhouse Gas Control, v. 22, p. 272–290.

Trabucchi, C., Donlan, M., Huguenin, M, Konopka, M., and Bolthrunis, S., 2012, Valuation of potential risks arising from a model, commercial-scale CCS project site: Prepared for CCS Valuation Sponsor Group, June 1, 2012.

[1] It should be noted that both of these examples are injecting CO_2 at a rate that is approximately the same planned injection at the DGC Great Plains Synfuels Plant CO_2 facility, which suggests that these cost estimates are likely similar to the costs that will be required for DGC's Great Plains CO_2 Sequestration Project.

APPENDIX A

COTEAU 1 FORMATION FLUID SAMPLING

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 14 Oct 21
Lab Number: 21-W3667
Work Order #:82-2651
Account #: 72540
Date Sampled: 28 Sep 21 19:35

Date Received: 29 Sep 21 7:44
Sampled By: MVTL Field Service

Bill Minnett
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Broom Creek

Temp at Receipt: 4.1C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	29 Sep 21	AC
pH	* 6.7	units	N/A	SM4500-H+-B-11	29 Sep 21 17:00	EMS
Conductivity (EC)	62019	umhos/cm	N/A	SM2510B-11	29 Sep 21 17:00	EMS
pH - Field	7.04	units	NA	SM 4500 H+ B	28 Sep 21 19:35	JSM
Temperature - Field	20.2	Degrees C	NA	SM 2550B	28 Sep 21 19:35	JSM
Total Alkalinity	853	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Bicarbonate	853	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Conductivity - Field	48194	umhos/cm	1	EPA 120.1	28 Sep 21 19:35	JSM
Cation Summation	701	meq/L	NA	SM1030-F	5 Oct 21 13:41	Calculated
Anion Summation	729	meq/L	NA	SM1030-F	1 Oct 21 14:38	Calculated
Percent Error	-2.00	%	NA	SM1030-F	5 Oct 21 13:41	Calculated
Total Organic Carbon	98.0	mg/l	0.5	SM5310C-11	1 Oct 21 16:29	NAS
Sulfate	469	mg/l	5.00	ASTM D516-11	1 Oct 21 14:38	SD
Chloride	24900	mg/l	2.0	SM4500-Cl-E-11	29 Sep 21 15:49	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	30 Sep 21 12:06	SD
Ammonia-Nitrogen as N	111	mg/l	0.20	EPA 350.1	5 Oct 21 13:41	SD
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	6 Oct 21 14:13	MDE
Total Dissolved Solids	42800	mg/l	10	USGS I1750-85	1 Oct 21 14:57	AC
Calcium - Total	1860	mg/l	1.0	6010D	4 Oct 21 11:34	SZ
Magnesium - Total	212	mg/l	1.0	6010D	4 Oct 21 11:34	SZ
Sodium - Total	12800	mg/l	1.0	6010D	4 Oct 21 11:34	SZ
Potassium - Total	516	mg/l	1.0	6010D	4 Oct 21 11:34	SZ
Iron - Total	392	mg/l	0.10	6010D	1 Oct 21 11:03	SZ
Manganese - Total	3.94	mg/l	0.05	6010D	1 Oct 21 11:03	SZ
Barium - Dissolved	4.58	mg/l	0.10	6010D	14 Oct 21 8:48	SZ
Strontium - Dissolved	70.8	mg/l	0.10	6010D	14 Oct 21 8:48	SZ
Arsenic - Dissolved	< 0.008 @	mg/l	0.0020	6020B	13 Oct 21 11:45	MDE
Cadmium - Dissolved	< 0.002 @	mg/l	0.0005	6020B	13 Oct 21 11:45	MDE
Chromium - Dissolved	0.0117	mg/l	0.0020	6020B	13 Oct 21 11:45	MDE
Copper - Dissolved	< 0.02 @	mg/l	0.0020	6020B	13 Oct 21 11:45	MDE
Lead - Dissolved	0.0042	mg/l	0.0005	6020B	13 Oct 21 11:45	MDE
Molybdenum - Dissolved	0.7754	mg/l	0.0020	6020B	13 Oct 21 11:45	MDE
Selenium - Dissolved	0.0277	mg/l	0.0050	6020B	13 Oct 21 11:45	MDE
Silver - Dissolved	< 0.002 @	mg/l	0.0005	6020B	13 Oct 21 11:45	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL guarantees the accuracy of the analysis done on the sample submitted for testing. It is not possible for MVTL to guarantee that a test result obtained on a particular sample will be the same on any other sample unless all conditions affecting the sample are the same, including sampling by MVTL. As a mutual protection to clients, the public and ourselves, all reports are submitted as the confidential property of clients, and authorization for publication of statements, conclusions or extracts from or regarding our reports is reserved pending our written approval.

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Bill Minnett
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Report Date: 14 Oct 21
Lab Number: 21-W3667
Work Order #:82-2651
Account #: 72540
Date Sampled: 28 Sep 21 19:35

Date Received: 29 Sep 21 7:44
Sampled By: MVTL Field Service

Project Name: Coteau #1
Sample Description: Broom Creek

Temp at Receipt: 4.1C ROI

	As Received Result	Method RL	Method Reference	Date Analyzed	Analyst

* Holding time exceeded

Approved by: Claudette K Carroll 14 OCT 21 CC

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MVTL
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Chain of Custody Record

Project Name: Coteau #1	Event:	Work Order Number: 82-2651
Report To: Rampart Energy Company Attn: Bill Minnett Address: 1512 Larimer St, Suite 550 Denver, CO 80202 Phone: 303-618-2696 Email: bminnett@earthlink.net	CC:	Collected By: [signature]

Lab Number	Sample ID	Date	Time	Sample Type	1 Liter Raw	500 mL Nitric	500 mL Nitric (filtered)	250 mL Sulfuric	3 VOC	4 TOC	1 Liter Amber	1 Liter Amber HCL	Temp (°C)	Spec. Cond.	pH	Analysis Required
W34007	**Broom Creek**	28Sept21	1935	GW	2	X	X	X		X			20.18	48194	7.04	See Attachment

Comments:

	Time	Temp (°C)	Cond.	pH
Field Readings	1903	24.03	57300	6.84
	1929	21.31	53589	6.93
	1935	20.18	48194	7.04

Sample Appearance
Turbid Brown

Relinquished By		Sample Condition		Received By	
Name	Date/Time	Location	Temp (°C)	Name	Date/Time
1 [signature]	29Sept21 0744	~~Log In~~ Walk In #2	4.1 Ros TM562 / ~~TM805~~	[signature]	29Sept21 0744
2					

A-3

APPENDIX B

FRESHWATER WELL FLUID SAMPLING

MINNESOTA VALLEY TESTING LABORATORIES, INC.
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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4509
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 12:00

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Oberlander

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	17 Nov 21	RAA
pH	* 8.5	units	N/A	SM4500-H+-B-11	17 Nov 21 18:00	AC
Conductivity (EC)	2519	umhos/cm	N/A	SM2510B-11	17 Nov 21 18:00	AC
pH - Field	8.37	units	NA	SM 4500 H+ B	17 Nov 21 12:00	JSM
Temperature - Field	6.69	Degrees C	NA	SM 2550B	17 Nov 21 12:00	JSM
Total Alkalinity	1020	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Bicarbonate	987	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Carbonate	33	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Conductivity - Field	2574	umhos/cm	1	EPA 120.1	17 Nov 21 12:00	JSM
Tot Dis Solids(Summation)	1470	mg/l	12.5	SM1030-F	22 Nov 21 14:48	Calculated
Percent Sodium of Cations	101	%	NA	N/A	22 Nov 21 13:09	Calculated
Total Hardness as CaCO3	9.49	mg/l	NA	SM2340B-11	22 Nov 21 13:09	Calculated
Hardness in grains/gallon	0.55	gr/gal	NA	SM2340-B	22 Nov 21 13:09	Calculated
Cation Summation	25.7	meq/L	NA	SM1030-F	22 Nov 21 13:09	Calculated
Anion Summation	27.4	meq/L	NA	SM1030-F	22 Nov 21 14:48	Calculated
Percent Error	-3.15	%	NA	SM1030-F	22 Nov 21 14:48	Calculated
Sodium Adsorption Ratio	70.7		NA	USDA 20b	22 Nov 21 13:09	Calculated
Bromide	1.86	mg/l	0.100	EPA 300.0	24 Nov 21 17:55	RMV
Total Organic Carbon	2.1	mg/l	0.5	SM5310C-11	19 Nov 21 16:46	NAS
Dissolved Organic Carbon	2.1	mg/l	0.5	SM5310C-96	19 Nov 21 16:46	NAS
Fluoride	1.81	mg/l	0.10	SM4500-F-C	19 Nov 21 17:00	RAA
Sulfate	< 5	mg/l	5.00	ASTM D516-11	19 Nov 21 16:05	SD
Chloride	248	mg/l	2.0	SM4500-Cl-E-11	22 Nov 21 14:48	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 16:44	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 11:26	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 9:35	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 14:00	MDE
Total Dissolved Solids	1560	mg/l	10	USGS I1750-85	19 Nov 21 12:14	RAA
Calcium - Total	3.8	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Magnesium - Total	< 1	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Sodium - Total	599	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Potassium - Total	3.0	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Lithium - Total	0.076	mg/l	0.020	6010D	18 Nov 21 11:06	SZ

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix # = Due to concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4509
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 12:00

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Temp at Receipt: 3.4C ROI

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Oberlander

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Aluminum - Total	< 0.1	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Iron - Total	0.29	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Silicon - Total	4.17	mg/l	0.10	6010D	29 Nov 21 14:40	MDE
Strontium - Total	0.14	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Zinc - Total	0.41	mg/l	0.05	6010D	19 Nov 21 11:52	SZ
Boron - Total	1.97	mg/l	0.10	6010D	24 Nov 21 11:57	SZ
Calcium - Dissolved	3.8	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Sodium - Dissolved	585	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Potassium - Dissolved	3.2	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Lithium - Dissolved	0.077	mg/l	0.020	6010D	18 Nov 21 11:06	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Iron - Dissolved	0.19	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Silicon - Dissolved	4.12	mg/l	0.10	6010D	29 Nov 21 14:40	MDE
Strontium - Dissolved	0.14	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Zinc - Dissolved	0.33	mg/l	0.05	6010D	19 Nov 21 13:52	SZ
Boron - Dissolved	1.95	mg/l	0.10	6010D	24 Nov 21 15:57	SZ
Antimony - Total	< 0.006 @	mg/l	0.0010	6020B	24 Nov 21 12:32	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Barium - Total	0.1168	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Lead - Total	0.0011	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Manganese - Total	0.0033	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	24 Nov 21 12:32	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Antimony - Dissolved	< 0.006 @	mg/l	0.0010	6020B	29 Nov 21 11:36	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Barium - Dissolved	0.1064	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	3 Dec 21 13:23	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
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= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4509
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 12:00

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Project Name: Coteau #1
Sample Description: Oberlander

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Lead - Dissolved	0.0007	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Manganese - Dissolved	0.0028	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 Nov 21 11:36	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE

* Holding time exceeded

cc
7 Dec 21

Approved by: Claudette K Carroll

Claudelle K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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! = Due to sample quantity
= Due to concentration of other analytes
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MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4510
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 14:08

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Helmuth

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	17 Nov 21	RAA
Preservation Flag					17 Nov 21	RAA
pH	* 8.4	units	N/A	SM4500-H+-B-11	17 Nov 21 18:00	AC
Conductivity (EC)	2347	umhos/cm	N/A	SM2510B-11	17 Nov 21 18:00	AC
pH - Field	8.51	units	NA	SM 4500 H+ B	17 Nov 21 14:08	JSM
Temperature - Field	5.16	Degrees C	NA	SM 2550B	17 Nov 21 14:08	JSM
Total Alkalinity	1280	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Bicarbonate	1272	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Conductivity - Field	2353	umhos/cm	1	EPA 120.1	17 Nov 21 14:08	JSM
Tot Dis Solids(Summation)	1500	mg/l	12.5	SM1030-F	22 Nov 21 14:48	Calculated
Percent Sodium of Cations	102	%	NA	N/A	22 Nov 21 13:09	Calculated
Total Hardness as CaCO3	10.4	mg/l	NA	SM2340B-11	22 Nov 21 13:09	Calculated
Hardness in grains/gallon	0.61	gr/gal	NA	SM2340-B	22 Nov 21 13:09	Calculated
Cation Summation	28.1	meq/L	NA	SM1030-F	22 Nov 21 13:09	Calculated
Anion Summation	27.6	meq/L	NA	SM1030-F	22 Nov 21 14:48	Calculated
Percent Error	0.88	%	NA	SM1030-F	22 Nov 21 14:48	Calculated
Sodium Adsorption Ratio	89.2		NA	USDA 20b	22 Nov 21 13:09	Calculated
Bromide	0.580	mg/l	0.100	EPA 300.0	24 Nov 21 18:16	RMV
Total Organic Carbon	4.8	mg/l	0.5	SM5310C-11	19 Nov 21 16:46	NAS
Dissolved Organic Carbon	4.8	mg/l	0.5	SM5310C-96	19 Nov 21 16:46	NAS
Fluoride	1.99	mg/l	0.10	SM4500-F-C	19 Nov 21 17:00	RAA
Sulfate	< 5	mg/l	5.00	ASTM D516-11	19 Nov 21 16:27	SD
Chloride	70.1	mg/l	2.0	SM4500-Cl-E-11	22 Nov 21 14:48	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 16:44	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 11:26	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 9:35	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 14:00	MDE
Total Dissolved Solids	1530	mg/l	10	USGS I1750-85	19 Nov 21 12:14	RAA
Calcium - Total	2.5	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Magnesium - Total	1.0	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Sodium - Total	660	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Potassium - Total	3.0	mg/l	1.0	6010D	22 Nov 21 10:09	SZ

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4510
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 14:08

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Helmuth

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lithium - Total	0.082	mg/l	0.020	6010D	18 Nov 21 11:06	SZ
Aluminum - Total	0.13	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Iron - Total	0.92	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Silicon - Total	5.01	mg/l	0.10	6010D	29 Nov 21 14:40	MDE
Strontium - Total	0.15	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Zinc - Total	0.43	mg/l	0.05	6010D	19 Nov 21 11:52	SZ
Boron - Total	1.76	mg/l	0.10	6010D	24 Nov 21 11:57	SZ
Calcium - Dissolved	2.4	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Sodium - Dissolved	640	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Potassium - Dissolved	3.2	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Lithium - Dissolved	0.077	mg/l	0.020	6010D	18 Nov 21 11:06	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Iron - Dissolved	0.54	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Silicon - Dissolved	4.34	mg/l	0.10	6010D	29 Nov 21 14:40	MDE
Strontium - Dissolved	0.14	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Zinc - Dissolved	0.06	mg/l	0.05	6010D	19 Nov 21 13:52	SZ
Boron - Dissolved	1.70	mg/l	0.10	6010D	24 Nov 21 15:57	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	24 Nov 21 12:32	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Barium - Total	0.1308	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Copper - Total	0.0036	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Lead - Total	0.0221	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Manganese - Total	0.0134	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Molybdenum - Total	0.0164	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	24 Nov 21 12:32	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	29 Nov 21 11:36	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Barium - Dissolved	0.1186	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4510
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 14:08

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Helmuth

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	3 Dec 21 13:23	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Lead - Dissolved	0.0019	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Manganese - Dissolved	0.0064	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Molybdenum - Dissolved	0.0153	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 Nov 21 11:36	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE

This sample was either unpreserved or needed additional preservation upon receipt at the laboratory. The following preservation was added by MVTL: sulfuric acid.

* Holding time exceeded

Approved by: Claudette K Carroll CC 7 Dec 21

Claudelle K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
● = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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B-7

MVTL
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Chain of Custody Record

Project Name:	Event:	Work Order Number:
Coteau #1		82-3203

Report To:	Rampart Energy	CC:	Rampart Energy	Collected By:
Attn:	Rich McClure		Shawna Harrison	Jeremy [signature]
Address:			1512 Larimer St. Suite 550	
			Denver, CO 80202	
Phone:	720-635-1555			
Email:	rfm@carbon-vault.com			

Lab Number	Sample ID	Date	Time	Sample Type	1 Liter Raw	1 Liter Raw (filtered)	500 mL Nitric	500 mL Nitric (filtered)	250 mL Sulfuric	250 mL Sulfuric (filtered)	3 TOC	3 TOC (filtered)	125 mL Raw	Temp (°C)	Spec. Cond.	pH	Analysis Required
W4509	Oberlander	17 Nov 21	1200	GW	3	X	X	X	X	X	X	X	2	6.69	2574	8.37	see attachment
W4310	Helmuth	17Nov21	1408	GW	3	X	X	X	X	X	X	X	2	5.16	2353	8.57	

Comments:

	Relinquished By		Sample Condition		Received By	
	Name	Date/Time	Location	Temp (°C)	Name	Date/Time
1	[signature]	17Nov21 1543	~~Log In~~ Walk In #2	Rol 3.4 ~~TM562~~/ TM805	[signature]	17Nov21 1543
2						

MVTL LABORATORIES, Inc.
PO BOX 1673
BISMARCK ND 58504-1673
PHONE (701) 258-9720 FAX (701) 258-9724

28 SEP 1990

FINAL ANALYSIS REPORT

Sample Number: 90-W1115
Client: Water Supply Inc.
P.O. Box 1191
Bismarck ND 58502

Report Date: 9/27/90
Work Order #: 82-980
PO #:
Payment Type::

Attn: Roger Schmid
(DAS 3/6/97)
FRED/ART OBERLANDER #1
~~Fred Oberlander #1~~

#1

Collection Date: 8/30/90
Collection Time: 16:12
Date Received: 8/31/90

Analyte	Result	Units	Comments
pH	8.5	units	
Specific Conductance	2585.	umhos/cm	
Total Alkalinity	980.	mg/l CaCO3	
Phenolphthalein Alk	14.0	mg/l CaCO3	
Bicarbonate	952.	mg/l CaCO3	
Carbonate	28.0	mg/l CaCO3	
Total Dissolved Solids	1520	mg/l	
Sulfate	9.00	mg/l	
Chloride	272.	mg/l	
Nitrate-Nitrite	< 1	mg/l	
Fluoride	4.70	mg/l	
Calcium - Total	5.2	mg/l	
Magnesium-Total	1.8	mg/l	
Sodium - Total	640.	mg/l	
Potassium - Total	3.8	mg/l	
Total Hardness as CaCO3	20.4	mg/l	
Hardness in grains/gallon	1.19	gr/gal	
Cation Summation	28.4		
Anion Summation	27.5		
Percent Error	1.61	%	
Sodium Adsorption Ratio	61.7		
Iron - Total	0.30	mg/l	
Manganese - Total	< 0.05	mg/l	

Approved by:
C. Leach

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ENERGY LABORATORIES

ENERGY LABORATORIES, INC.

P.O. BOX 30916 • 1107 SOUTH BROADWAY • BILLINGS, MT 59107-0916 • PHONE (406) 252-6325

LABORATORY REPORT

Lab. No. 82-6424

To Coteau Properties Date 11-9-82 CB

Address Kirkwood Office Tower Bismarck, North Dakota 58501

WATER ANALYSIS (DAS 3/6/97)

~~A. Oberlander #1~~ FRED/ART OBERLANDER #1

Sampled 10-14-82 @ 12:00

Sample Submitted 10-22-82

P.O. #12531

CONSTITUENT	MILLIGRAMS PER LITER	
Potassium	1	
Sodium	657	
Calcium	4	
Magnesium	1	
Sulfate	13	
Chloride	265	
Carbonate	0	
Bicarbonate	1,240	
Total Dissolved Solids @ 180°C	1,520	
Total Hardness as $CaCO_3$	13	
Total Alkalinity as $CaCO_3$	1,020	
Sum of Anions	28.1	meq/l
Sum of Cations	28.9	meq/l
Cation-Anion Balance, % difference	1.40	
Specific Conductance @ 25°C	2,480	micromhos/cm
pH 8.2		
Phenolphthalein Alkalinity as $CaCO_3$	0	
Nitrate as N	0.05	
Total Iron	0.50	
Manganese	<0.02	

Certified by:

[signature]

Chief Chemist

MVTL LABORATORIES, Inc.
P.O. BOX 1873, 1411 S. 12th STREET
BISMARCK, ND 58502
PHONE (701) 258-9720 WATS (800) 279-6885 FAX (701) 258-9724

WE ARE AN EQUAL OPPORTUNITY EMPLOYER

FINAL ANALYSIS REPORT

Sample Number: 94-W4482

Report Date: 11/10/94

Les Morgenstern
Braun Intertec Corporation
PO Box 2379
Bismarck ND 58502

Work Order #: 82-1398
PO #: CFEX-91-0014

Date Received 10/28/94

Sample Description: Standard Water Sample
Sample Site: H Pfenning #2
Sample Location: Rural Beulah, ND

Collection Date 10/27/94
Collection Time 18:34

Analyte	Results	Units
pH	8.4	units
Specific Conductance	2360	umhos/cm
Total Alkalinity	1267	mg/l CaCO3
Phenolphthalein Alk	32	mg/l CaCO3
Bicarbonate	1203	mg/l CaCO3
Bicarb as HCO3	1470	mg/l HCO3
Carbonate	64	mg/l CaCO3
Hydroxide	0.0	mg/l CaCO3
Total Dissolved Solids	1460	mg/l
Sulfate	10.0	mg/l
Chloride	59.1	mg/l
Nitrate-Nitrite as N	< 1	mg/l
Calcium - Total	3.5	mg/l
Magnesium - Total	0.8	mg/l
Sodium - Total	620	mg/l
Potassium - Total	2.3	mg/l
Total Hardness as CaCO3	12.0	mg/l
Cation Summation	27.3	
Anion Summation	27.2	
Percent Error	0.11	%
Sodium Adsorption Ratio	77.8	
Iron - Dissolved	0.16	mg/l
Manganese - Dissolved	< 0.05	mg/l

Approved By:
AKoel

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LABORATORY REPORT

Lab. No. 82-6176

To Coteau Properties Company Date 10-21-82 pb

Address Kirkwood Office Tower Bismarck, North Dakota 58501

WATER ANALYSIS
P.O. No. 12531
F. Welgum #1
Sampled 10-11-82 @ 10:00 a.m.
Sample received 10-12-82

CONSTITUENT	MILLIGRAMS PER LITER	
Potassium	5	
Sodium	617	
Calcium	3	
Magnesium	-1	
Sulfate	22	
Chloride	184	
Carbonate	15	
Bicarbonate	1,320	
Total Dissolved Solids @ 180°C	1,410	
Total Solids, calculated	1,500	
Total Hardness as $CaCO_3$	9	
Total Alkalinity as $CaCO_3$	1,100	
Sum of Anions	27.7	meq/l
Sum of Cations	27.1	meq/l
Cation-Anion Balance, % difference	1.09	
Specific Conductance @ 25°C	2,330	micromhos/cm
pH 8.4		
Phenolphthalein Alkalinity as $CaCO_3$	0	
Nitrate as N	-0.05	
Total Iron	0.84	
Manganese	-0.02	

Certified by:

Chief Chemist

a minus sign (-) indicates less than

ANALYTICAL SERVICES — WATER, SOIL, PETROLEUM, COAL

The Coteau Properties Company (CPC), a wholly owned subsidiary of North American Coal Corporation, has implemented a shallow groundwater monitoring program since 1979 as part of its operations at the Freedom Mine, thereby establishing a baseline water quality database for select shallow freshwater aquifers within the area of review (AOR).

More than 500 monitoring site locations have been drilled by CPC over an area of about 84 square miles around the Freedom Mine. A total of 460 of the monitoring sites have at least one water quality test date in the database, and approximately 100 of the sites are currently active. The monitoring sites sample from either surficial glacial aquifers of the Coleharbor Group (Pleistocene) or water-bearing coalbed (lignite) horizons of the Sentinel Butte Formation of the Fort Union Group (Paleocene). Figure B-1 summarizes the stratigraphy and freshwater aquifers present within the AOR. Lignite beds of the Sentinel Butte Formation are among the most tapped water resources (Croft, 1973), as they are the primary supply of domestic and stock water resources to the local area (U.S. Department of the Interior, 2016).

A description of the locations, sampling horizon, screen depth, and well status of 19 wells from the CPC shallow groundwater database is provided in Table B-1. Figure B-2 provides a map of the 19 selected monitoring sites. The 19 monitoring sites were selected based on the following criteria and considerations:

The Beulah, Spaer, and Stanton coalbed sampling horizons were selected because they are the primary sources of groundwater within the AOR and also have the greatest areal extent over the CO_2 plume area (U.S. Department of the Interior, 2016).

The monitoring site locations fall within the predicted 12-yr CO_2 plume extent. This was done to identify the most relevant sampling location to this geologic storage project.

Monitoring sites within a quarter mile of one another were eliminated to limit redundancy of individual data points.

The bed screen depth was required to be greater than 100 feet. This was done to help ensure consistent geochemical results and avoid surficial effects from previous mining operations or farming activities.

If two or more locations had water quality test data in the same location, the monitoring site with the deeper screen depth was selected and included in the final data set. This was done to limit the redundancy of individual data points.

Summaries of the geochemical analyses from the 19 monitoring sites, including pH, alkalinity, and total dissolved solids, is provided in Table B-2. Just two of the 19 sites had trace metal analyses conducted on them, provided in Table B-3.

ERATHEM	SYSTEM		SERIES	ROCK UNIT: GROUP	ROCK UNIT: FORMATION	FRESHWATER AQUIFER(S)	FRESHWATER AQUIFER(S) UNDER SURVEILLANCE
CENOZOIC	Quaternary		Holocene		Oahe	No	
			Pleistocene	Coleharbor	"Glacial Drift"	Yes	Antelope Creek
	Tertiary	Neogene	Pliocene		(Unnamed)	Yes	
			Miocene		Arikaree	No	
		Paleogene	Oligocene	White River	Brule	No	
			Eocene		Chadron	No	
					Golden Valley	No	
			Paleocene	Fort Union	Sentinel Butte	Yes	Beulah, Spaer, and Stanton coalbed horizons
					Tongue River: Bullion Creek	Yes	
					Tongue River: Slope	No	
					Cannonball	Yes	
					Ludlow	Yes	
MESOZOIC	Cretaceous		Upper	Montana	Hell Creek	Yes	
					Fox Hills	Yes	Lowest USDW
					Pierre	No	

Modified from Murphy et al., 2009, NDGS MS 91

Figure B-1. Stratigraphic column of the major freshwater aquifer systems of North Dakota, with the aquifer systems under surveillance within the geologic storage project indicated.

Table B-1. Names, Locations, Sampling Horizons, Screen Depths, and Well Status of Selected Monitoring Sites

Monitoring Site Location	Quarter Call	S-T-R	Latitude NAD 83	Longitude NAD 83	Sampling Horizon	Screen Depth (ft)	Well Status
MP81-P21	BBB	14-145N-88W	47.3853676	−101.86519	Beulah	123–137	Active
MP81-P32*	CBC	15-145N-88W	47.3748245	−101.88645	Beulah	170–180	Active
MP93-P07A	BAA	31-146N-87W	47.4291821	−101.81276	Spaer	160–165	Inactive
MP03-RP01A	ABB	06-145N-87W	47.4146862	−101.81177	Spaer	184–189	Inactive
MP81-P01	DDA	01-145N-88W	47.4028258	−101.82273	Spaer	235–242	Inactive
MP81-P07	BBB	02-145N-88W	47.4145552	−101.86515	Spaer	181–188	Inactive
MP81-P22	DAA	14-145N-88W	47.3781632	−101.84589	Spaer	115–119	Inactive
MP81-P24*	AAD	23-145N-88W	47.3681521	−101.84585	Spaer	111–115	Active
MP93-RP01A	ACD	12-145N-88W	47.3925468	−101.8291	Spaer	187–192	Inactive
MP16-P01A	CAD	11-145N-88W	47.3911977	−101.85454	Spaer	179–181	Active
MP16-P02A	BCB	11-145N-88W	47.3947722	−101.86503	Spaer	196–197	Active
MP95-RP03A	DDD	06-145N-87W	47.4005739	−101.80184	Spaer	241–246	Active
MP95-RP04A	BCC	08-145N-87W	47.39329	−101.8013	Spaer	184–189	Inactive
M77-P01	DDD	18-145N-87W	47.3715152	−101.80157	Stanton	131–141	Inactive
M77-P18	DCD	07-145N-87W	47.3860116	−101.80748	Stanton	233–238	Inactive
M77-P22	CCC	07-145N-87W	47.3860271	−101.82205	Stanton	213–218	Inactive
MP81-P12	DAA	02-145N-88W	47.4023753	−101.84407	Stanton	246–251	Inactive
MP83-P01	BAA	22-145N-88W	47.3713922	−101.87622	Stanton	278–283	Active
MP03-RP03A*	BCC	31-146N-87W	47.422307	−101.82244	Stanton	191–196	Active

* Monitoring site locations with recent laboratory reports provided in Appendix B.

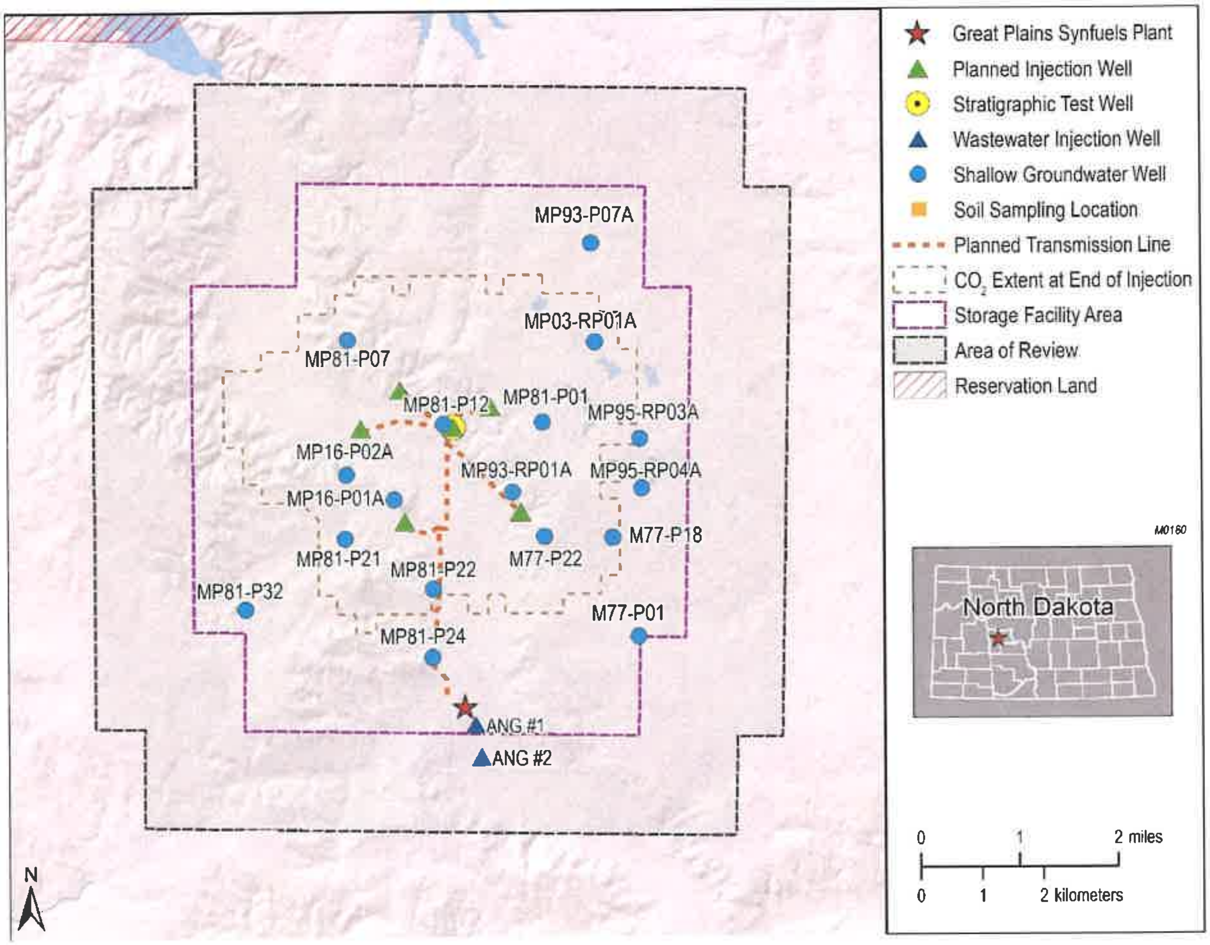

Figure B-2. Locations of the 19 monitoring sites operated by CPC.

Table B-2. Summarized Water Quality Test Results for 19 Monitoring Sites

Monitoring Site Location	Sampling Horizon	Mean* pH	pH Range	Mean* Alkalinity (mg/L $CaCO_3$)	Alkalinity Range (mg/L $CaCO_3$)	Mean* TDS (mg/L)	Range TDS (mg/L)
MP81-P21	Beulah	6.9	6.6–7.2	443	406–488	1,029	551–1,540
MP81-P32	Beulah	7.7	7.2–8.2	720	565–815	992	826–1,140
MP93-P07A	Spaer	7.8	6.7–8.2	1,593	950–1,770	3,160	2,910–5,070
MP03-RP01A	Spaer	8.2	8.1–8.3	1,755	1,740–1,770	3,278	3,180–3,380
MP81-P01	Spaer	8.1	7.8–8.5	1,670	1,488–1,750	1,917	1,680–2,270
MP81-P07	Spaer	7.4	7.2–7.9	577	543–648	1,402	1,291–1,480
MP81-P22	Spaer	7.5	7.1–8.8	476	252–574	929	603–1,170
MP81-P24	Spaer	8.2	7.7–8.9	637	333–810	1,250	620–1,708
MP93-RP01A	Spaer	8.2	7.9–8.7	882	817–992	1,507	1,350–1,670
MP16-P01A	Spaer	8.3	8.1–8.4	1,068	1,030–1,110	1,351	1,280–1,420
MP16-P02A	Spaer	8.4	8.2–8.6	880	843–928	1,243	1,190–1,300
MP95-RP03A	Spaer	8.0	7.6–8.3	1,537	512–1,820	2,070	894–2,460
MP95-RP04A	Spaer	8.2	7.8–8.4	1,574	1,420–1,680	1,819	1,600–2,160
M77-P01	Stanton	8.2	7.4–8.6	1,072	218–1,550	1,286	309–1,880
M77-P18	Stanton	8.0	7.6–8.3	1,129	256–1,492	1,373	372–1,720
M77-P22	Stanton	7.8	6.8–8.4	646	232–872	877	296–1,270
MP81-P12	Stanton	8.1	7.8–8.5	1,700	1,380–1,862	1,917	1,660–2,090
MP83-P01	Stanton	8.2	7.9–8.5	1,234	991–1,400	1,447	1,160–1,610
MP03-RP03A	Stanton	8.3	8.0–8.5	1,511	1,360–1,610	1,777	1,690–1,860

* Geometric mean.

Table B-3. Results of Trace Metal Analyses* (in mg/L) for Monitoring Sites in Table B-2

Monitoring Site Location	Sampling Horizon	Arsenic	Barium	Boron	Iron	Lead	Silver	Strontium
MP81-P01	Spaer	0.01	0.12	0.10	0.45	0.02	0.00	0.24
M77-P22	Stanton	0.00	0.21	0.53	0.80	0.25	0.01	0.25

* All water samples came back negative for Cd, Cr, Hg, Mo, and Se.

REFERENCES

Croft, M.G., 1973, Ground-water resources, Mercer and Oliver Counties, North Dakota: North Dakota Geological Survey Bulletin 56(III).

U.S. Department of the Interior, 2016, Environmental assessment for the Freedom Mine, West Mine Area, February 2016: U.S. Department of the Interior Office of Surface Mining Reclamation and Enforcement Report.

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MEMBER ACIL

Report Date: 30 Jun 21
Lab Number: 21-W1761
Work Order #: 82-1480
Account #: 002212
Date Sampled: 17 Jun 21 11:20
Date Received: 18 Jun 21 8:00
Sampled By: MVTL Field Services

Coteau Properties Company
204 County Road 15
Beulah ND 58523

PO #: 570610 OP

Project Name: 2021 Coteau Groundwater

Temp at Receipt: 0.2C ROI

Sample Description: GS21CW-52
Sample Site: MP81-P24
Event and Year: 2021

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	18 Jun 21	CC
pH	* 8.5	units	N/A	SM4500-H+-B-11	18 Jun 21 17:00	RAA
Conductivity (EC)	2172	umhos/cm	N/A	SM2510B-11	18 Jun 21 17:00	RAA
pH - Field	8.5	units	NA	4500 H+ B	17 Jun 21 11:20	DJN
Temperature - Field	11.2	Degrees C	NA	SM 2550B	17 Jun 21 11:20	DJN
Total Alkalinity	512	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Bicarbonate	487	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Carbonate	25	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Conductivity - Field	2123	umhos/cm	1	EPA 120.1	17 Jun 21 11:20	DJN
Tot Dis Solids(Summation)	1320	mg/l	12.5	SM1030-F	23 Jun 21 14:09	Calculat
Total Hardness as CaCO3	18.4	mg/l	NA	SM2340B-11	23 Jun 21 11:37	Calculat
Cation Summation	23.0	meq/L	NA	SM1030-F	24 Jun 21 13:24	Calculat
Anion Summation	20.5	meq/L	NA	SM1030-F	23 Jun 21 14:09	Calculat
Percent Error	5.57	%	NA	SM1030-F	24 Jun 21 13:24	Calculat
Sodium Adsorption Ratio	52.5		NA	USDA 20b	23 Jun 21 11:37	Calculat
Sulfate	480	mg/l	5.00	ASTM D516-11	21 Jun 21 14:46	SD
Chloride	10.8	mg/l	2.0	SM4500-Cl-E-11	18 Jun 21 15:38	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	23 Jun 21 14:09	SD
Calcium - Total	3.4	mg/l	1.0	6010D	23 Jun 21 11:37	MDE
Magnesium - Total	2.4	mg/l	1.0	6010D	23 Jun 21 11:37	MDE
Sodium - Total	517	mg/l	1.0	6010D	23 Jun 21 11:37	MDE
Potassium - Total	4.1	mg/l	1.0	6010D	23 Jun 21 11:37	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	24 Jun 21 13:24	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	24 Jun 21 13:24	MDE

* Holding time exceeded

Approved by: Claudette K Carroll CC 1 JUL 21

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
\# = Due to concentration of other analytes
! = Due to sample quantity
\+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 15 Jun 21
Lab Number: 21-W1599
Work Order #: 82-1362
Account #: 002212
Date Sampled: 8 Jun 21 11:01
Date Received: 9 Jun 21 8:00
Sampled By: MVTL Field Service

Coteau Properties Company
204 County Road 15
Beulah ND 58523

Project Name: 2021 Coteau Groundwater

PO #: 570610 OP

Sample Description: GS20CW-11
Sample Site: MP81-P32
Event and Year: 2021

Temp at Receipt: 3.4C

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	9 Jun 21	RAA
pH	* 7.8	units	N/A	SM4500-H+-B-11	9 Jun 21 18:00	RAA
Conductivity (EC)	1836	umhos/cm	N/A	SM2510B-11	9 Jun 21 18:00	RAA
pH - Field	7.2	units	NA	4500 H+ B	8 Jun 21 11:01	DJN
Temperature - Field	12.3	Degrees C	NA	SM 2550B	8 Jun 21 11:01	DJN
Total Alkalinity	676	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Bicarbonate	676	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Conductivity - Field	1811	umhos/cm	1	EPA 120.1	8 Jun 21 11:01	DJN
Tot Dis Solids(Summation)	1170	mg/l	12.5	SM1030-F	14 Jun 21 12:14	Calcula
Total Hardness as CaCO3	35.3	mg/l	NA	SM2340B-11	14 Jun 21 12:14	Calcula
Cation Summation	20.6	meq/L	NA	SM1030-F	14 Jun 21 12:14	Calcula
Anion Summation	19.7	meq/L	NA	SM1030-F	11 Jun 21 11:32	Calcula
Percent Error	2.37	%	NA	SM1030-F	14 Jun 21 12:14	Calcula
Sodium Adsorption Ratio	33.3		NA	USDA 20b	14 Jun 21 12:14	Calcula
Sulfate	285	mg/l	5.00	ASTM D516-11	11 Jun 21 11:32	SD
Chloride	7.8	mg/l	2.0	SM4500-Cl-E-11	10 Jun 21 11:22	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	10 Jun 21 15:04	SD
Calcium - Total	6.4	mg/l	1.0	6010D	14 Jun 21 12:14	SZ
Magnesium - Total	4.7	mg/l	1.0	6010D	14 Jun 21 12:14	SZ
Sodium - Total	455	mg/l	1.0	6010D	14 Jun 21 12:14	SZ
Potassium - Total	5.1	mg/l	1.0	6010D	14 Jun 21 12:14	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	11 Jun 21 12:06	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	11 Jun 21 12:06	SZ

* Holding time exceeded

Approved by: Claudette K. Carroll CC 16 Jun 21

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 29 Jun 20
Lab Number: 20-W1914
Work Order #: 82-1555
Account #: 002212
Date Sampled: 17 Jun 20 16:38
Date Received: 19 Jun 20 8:00
Sampled By: MVTL Field Services

Coteau Properties Company
204 County Road 15
Beulah ND 58523

Project Name: 2020 Coteau Groundwater

PO #: 556847

Sample Description: GS20CW-36
Sample Site: MP03-RP03A
Event and Year: 2020

Temp at Receipt: 3.0C

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	19 Jun 20	JD
pH	* 8.4	units	N/A	SM4500 H+ B	19 Jun 20 18:00	HT
Conductivity (EC)	2780	umhos/cm	N/A	SM2510-B	19 Jun 20 18:00	HT
pH - Field	8.0	units	NA	4500 H+ B	17 Jun 20 16:38	DJN
Temperature - Field	10.4	Degrees C	NA	SM 2550B	17 Jun 20 16:38	DJN
Total Alkalinity	1590	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Bicarbonate	1566	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Carbonate	24	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Conductivity - Field	2817	umhos/cm	1	EPA 120.1	17 Jun 20 16:38	DJN
Tot Dis Solids(Summation)	1850	mg/l	12.5	SM1030-F	25 Jun 20 14:04	Calculated
Total Hardness as CaCO3	26.4	mg/l	NA	SM2340-B	23 Jun 20 15:29	Calculated
Cation Summation	35.7	meq/L	NA	SM1030-F	25 Jun 20 12:24	Calculated
Anion Summation	33.6	meq/L	NA	SM1030-F	25 Jun 20 14:04	Calculated
Percent Error	2.93	%	NA	SM1030-F	25 Jun 20 14:04	Calculated
Sodium Adsorption Ratio	68.2		NA	USDA 20b	23 Jun 20 15:29	Calculated
Sulfate	38.5	mg/l	5.00	ASTM D516-11	25 Jun 20 9:08	EV
Chloride	37.1	mg/l	1.0	SM4500-Cl-E	22 Jun 20 9:48	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	25 Jun 20 14:04	EV
Calcium - Total	4.8	mg/l	1.0	6010D	23 Jun 20 15:29	MDE
Magnesium - Total	3.5	mg/l	1.0	6010D	23 Jun 20 15:29	MDE
Sodium - Total	805	mg/l	1.0	6010D	23 Jun 20 15:29	MDE
Potassium - Total	5.0	mg/l	1.0	6010D	23 Jun 20 15:29	MDE
Iron - Dissolved	0.30	mg/l	0.10	6010D	25 Jun 20 12:24	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	25 Jun 20 12:24	MDE

* Holding time exceeded

CC

Approved by: Claudette K Carroll 9 JUL 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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APPENDIX C

QUALITY ASSURANCE SURVEILLANCE PLAN

1.0 QUALITY ASSURANCE AND SURVEILLANCE PLAN

The primary goal of the testing and monitoring plan of this storage facility permit application is to ensure that the geologic sequestration project is operating as permitted and is not endangering USDWs. In compliance with North Dakota Administrative Code (NDAC) § 43-05-01-11.4 (Testing and Monitoring Requirements), this Quality Assurance and Surveillance Plan (QASP) was developed and is being provided as part of the testing and monitoring program.

The testing and monitoring program for the project includes the analysis of the injected CO_2 stream, periodic testing of the injection wells, a corrosion monitoring plan for the CO_2 injection well components and surface facilities, a leak detection and monitoring plan for surface components of the CO_2 injection system, and a leak detection plan to monitor any movement of the CO_2 outside of the storage reservoir (see Table 5-1). The latter consists of a combination of soil gas and groundwater monitoring, storage reservoir monitoring, downhole monitoring, and geophysical monitoring. The quality assurance and surveillance procedures for this testing and monitoring plan are provided in the remainder of this QASP.

1.1 CO_2 Stream Analysis and Injection Well Mechanical Integrity Testing

1.1.1 CO_2 Stream Analysis

NDAC § 43-05-01-11.4(1a) requires analysis of the CO_2 stream in compliance with applicable analytical methods and standards generally accepted by industry and with sufficient frequency to yield data representative of its chemical and physical characteristics. DGC will collect samples of the injected CO_2 stream daily at the capture facility and analyze them to determine the concentrations of CO_2, nitrogen, oxygen, hydrogen, water, hydrogen sulfide, carbon monoxide, and a suite of hydrocarbons (e.g., ethane, propane, n-butane, and methane). This is consistent with the daily analysis DGC has performed on volumes delivered to Canadian oil fields since 1998. DGC uses an Agilent gas chromatograph with flame ionization and thermal conductivity detectors and complies with American Society for Testing and Materials Standards D7833, D1946, D2163, and UOP 539. Selected stable and radiogenic isotopes (i.e., isotopes of carbon dioxide [^{13}C and ^{14}C], methane [^{13}C and ^{14}C], and deuterium [^{2}H]) will also be sampled three to four times in the first year to establish a baseline. The isotopic analyses will be outsourced to commercial laboratories that will employ standard analytical quality assurance/quality control (QA/QC) protocols used in the industry.

1.1.2 Injection Well Mechanical Integrity Testing

The external mechanical integrity of the injection wells will be established prior to injection with a USIT (ultrasonic imager tool) in combination with variable density (VDL) and cement bond logs (CBL). The USIT (includes the VDL and CBL) will be performed during well workovers not more frequently than once every 5 years. It will also be useful for assessing the internal mechanical integrity of the injection wells. In addition, the injection wells will be monitored with a pulsed neutron log tool (PNX), to include temperature and pressure readings, using the phased approach described in Section 5.1.2 of this storage facility permit. The tool specifications of the USIT and the PNX are provided in Attachments A-1 and A-2, respectively.

Internal mechanical integrity of the injection wells will be demonstrated via tubing-casing annulus pressure tests prior to injection and during well workovers but not more frequently than

once every 5 years. A detailed description of this test is provided in Attachment A-3. Pressure falloff tests will be performed in the injection wells prior to injection. During injection operations, pressure falloff testing will be carried out via surface pressure monitoring at least once every 5 years to demonstrate storage reservoir injectivity. In addition, the injection wells will be continuously monitored for surface and annular pressure anomalies by maintaining a consistent 200 pounds per square inch (psi) on the annulus with a nitrogen cushion that will be added on top of the packer fluid.

1.2 Corrosion Monitoring and Prevention Plan

1.2.1 Corrosion Monitoring

DGC will install a 3-foot test section of 4½-inch L-80 tubing in the flowlines near each wellhead for regular testing and corrosion monitoring of the well material (Figure 5-1 or the storage facility permit). The tubing joints will be inspected monthly via ultrasound equipment during the first quarter, then quarterly thereafter for the first 2 years. If the well materials (i.e., tubing) show no sign of corrosion within the first 2 years of the injection period, future internal monitoring of the tubing will be accomplished through a platform multifinger imaging tool (PMIT), or in the event a downhole tubing string is pulled for any reason, it will be inspected at the surface for corrosion and mechanical integrity. Wireline monitoring using the USIT, which will be run during workovers (including when tubing is pulled) but not more frequently than once every 5 years, will also be considered for assessing the corrosion of the casing in the injection wells. Details related to the PMIT and Tuboscope wellsite injection services are provided as Attachments A-4 and A-5, respectively.

1.2.2 Corrosion Prevention

To prevent corrosion of the well materials, the following preemptive measures will be taken: 1) cement in the injection wells opposite the injection interval and extending more than 2,000 feet uphole, will be CO_2-resistant, 2) the well casing (L-80 13Cr) will also be CO_2-resistant from the bottomhole to a depth just above the Opeche Formation, and 3) the packer fluid will be an industry standard corrosion inhibitor. In addition, the chemical composition of the CO_2 stream is highly pure (Table 5-2) and dry, with a moisture level for the CO_2 stream typically less than 2.00 parts per million by volume, both of which help prevent corrosion of the surface and well materials.

1.3 Surface Leak Detection and Monitoring Plan

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 (Attachment A-6) located inside each gas meter and wellhead enclosure. Another H_2S detection station will be installed on the exterior of each wellhead enclosure to monitor atmospheric conditions on the pad. This leak detection equipment will be integrated with automated warning systems capable of immediately notifying personnel in DGC's pipeline control center in the event of an anomalous reading. As an added measure for safety, field personnel will have multi gas detectors with them to monitor for H_2S (Attachment A-7). Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

1.4 Subsurface Leak Detection and Monitoring Plan

The monitoring plan for detecting subsurface leaks comprises "surface/near-surface" and deep subsurface monitoring programs. In this document, QA/QC information regarding the near-surface monitoring program is presented in Section 1.5, and QA/QC information regarding the deep subsurface monitoring programs is broken into Sections 1.6 and 1.7.

1.5 Near-Surface Soil Gas and Groundwater Monitoring

Near-surface sampling discussed herein comprises 1) sampling of soil gas in the shallow vadose zone and 2) sampling groundwater aquifers (lowest USDW). Sampling and chemical analysis of these zones provide concentrations of chemical constituents, including stable carbon isotopes [^{13}C and ^{12}C] of CO_2, which are focused on detecting movement of the CO_2 out of the reservoir. These monitoring efforts will provide data to confirm that near-surface environments are not adversely impacted by CO_2 injection and storage operations.

1.5.1 Soil Gas

Vadose zone soil gas monitoring directly measures the characteristics of the air space between soil components and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. A total of 11 soil gas sampling sites were drilled and installed in the storage facility area (SG01 through SG11 as shown in Figures 5-1, 5-2, and 5-3). All eleven locations (SG01 through SG11) are located on Coteau property.

1.5.1.1 Soil Gas Sampling and Analysis Protocol

Soil Gas Locations: SG01 to SG11

Fixed soil gas profile stations were installed for the sampling of soil gas at locations SG01 through SG11 prior to the initiation of CO_2 injection. Schematics of these soil gas profile stations are shown below in Figures C-1 and C-2. As shown, soil profile stations contain up to two isolated gas sampling intervals from which individual soil gas samples will be obtained.

Prior to the collection of each sample, a minimum of three casing volumes were removed, and the representativeness of the gas flow was determined by analyzing the soil gas for CO_2, hydrogen sulfide (H_2S), methane (CH_4), and O_2 using a Landtec GEM 5000 gas meter handheld multigas meter, which was calibrated daily based on manufacturer instructions. After these measurements of the soil gas composition stabilized, two soil gas samples were collected for characterization at each location using a Tedlar® bag, which was labeled with the appropriate sample number and site information and transported to the Dolan Integration Group (DIG) (Westminster, Colorado) for compositional and isotopic analysis. The target analytes for these analyses are shown below in Table C-1 and Table C-2, respectively.

Vista GeoScience

NESTED VAPOR WELL CONSTRUCTION DETAILS

Project Name: CCS Soil Gas Monitoring Well Installation
Vista GeoScience Project #: 21215.01
Address: NA
City: Beulah
State: North Dakota

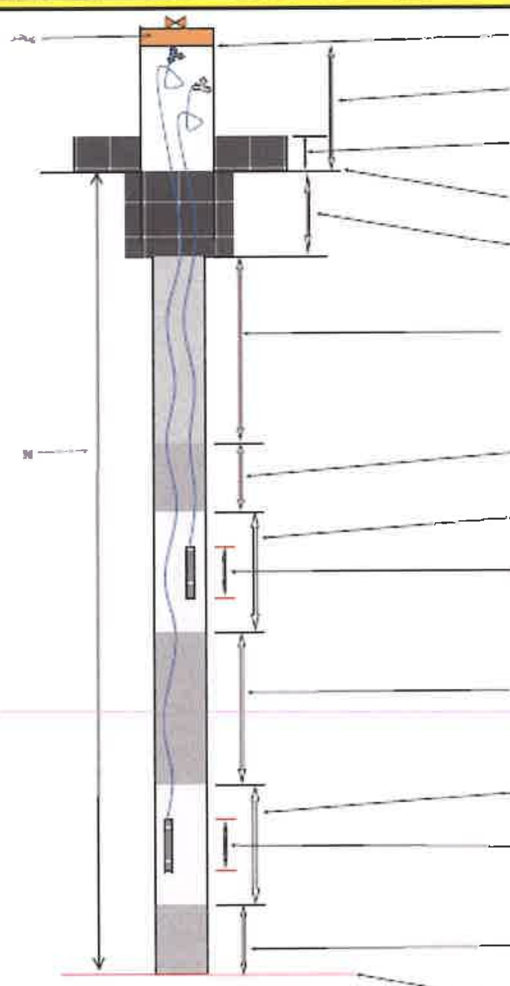
Permit No.:

Type of Well: Nested Vapor Well
Type of Screen: 21" Stainless Steel Implant
Tubing Type: NYLAFLOW Nylon Tubing ID Tubing 0.19 inches
Boring Diameter: 2.5 inches OD Tubing 0.25 inches

Location ID: SG-01
Shallow Vapor Well ID: SG-01S
Deep Vapor Well ID: SG-01D

D Ground Surface Elevation: feet MSL
A Top of Stick Up Elevation: feet MSL
Northing 47.40171198 Easting -101.841981

Driller #1 Name: Dave Heinecke
Driller #2 Name: David Fontana
Date Drilled: 10/04/2021 Date Installed: 10/04/2021



A Top of Well Vault

B Stick Up: Bot. 0 ags Top 2 ags Interval 2 ft
Material: 4" diameter PVC

C Well Pad: Bot. 0 ags Top 0.25 ags Interval 0.25 ft
Well Pad Material Description: 2' x 2' concrete pad with wood 2x4 frame

D Ground Surface

E Surface Seal: Bot. 3 bgs Top 0 bgs Interval 3 ft
Material Type: Concrete

F Bentonite Seal: Bot. 8 bgs Top 3 bgs Interval 5 ft
Material Type: Hydrated Bentonite Crumbles

G Bentonite Seal: Bot. 11 bgs Top 8 bgs Interval 3 ft
Material Type: Hydrated Bentonite Crumbles

H Filter Pack: Bot. 16 bgs Top 11 bgs Interval 5 ft
Material Type: 10-20 mesh sand

I Shallow Screen Interval: Bot. 14.3 bgs Top 12.55 bgs Interval 1.75 ft
Type: 21" Stainless Steel Implant Slot Size: n/a

J Bentonite Seal: Bot. 19.5 bgs Top 16 bgs Interval 3.5 ft
Material Type: Hydrated Bentonite Crumbles

K Filter Pack: Bot. 25 bgs Top 19.5 bgs Interval 5.5 ft
Material Type: 10-20 mesh sand

L Deep Screen Interval: Bot. 23.3 bgs Top 21.55 bgs Interval 1.75 ft
Type: 21" Stainless Steel Implant Slot Size: n/a

M Backfill Material: Bot. n/a bgs Top n/a bgs Interval n/a ft
Material Type: none

N Total Boring Depth: 25 ft bgs

Drilled By: Dave Heinecke
Logged By: David Fontana

Drilling Method: H.S.A. ☐ S.S.A. ☐ D.P.T. ☒

Drilling Tooling Max. Diameter: 2.5 inches

General Notes:

I hereby certify that the information on this form is true and correct to the best of my knowledge

Signature:

Printed Name: David Fontana

Figure C-1. Schematic of Soil Gas Profile Station SG01. Well design is the same for all stations except SG02 and SG11 (shown in Figure C-2).

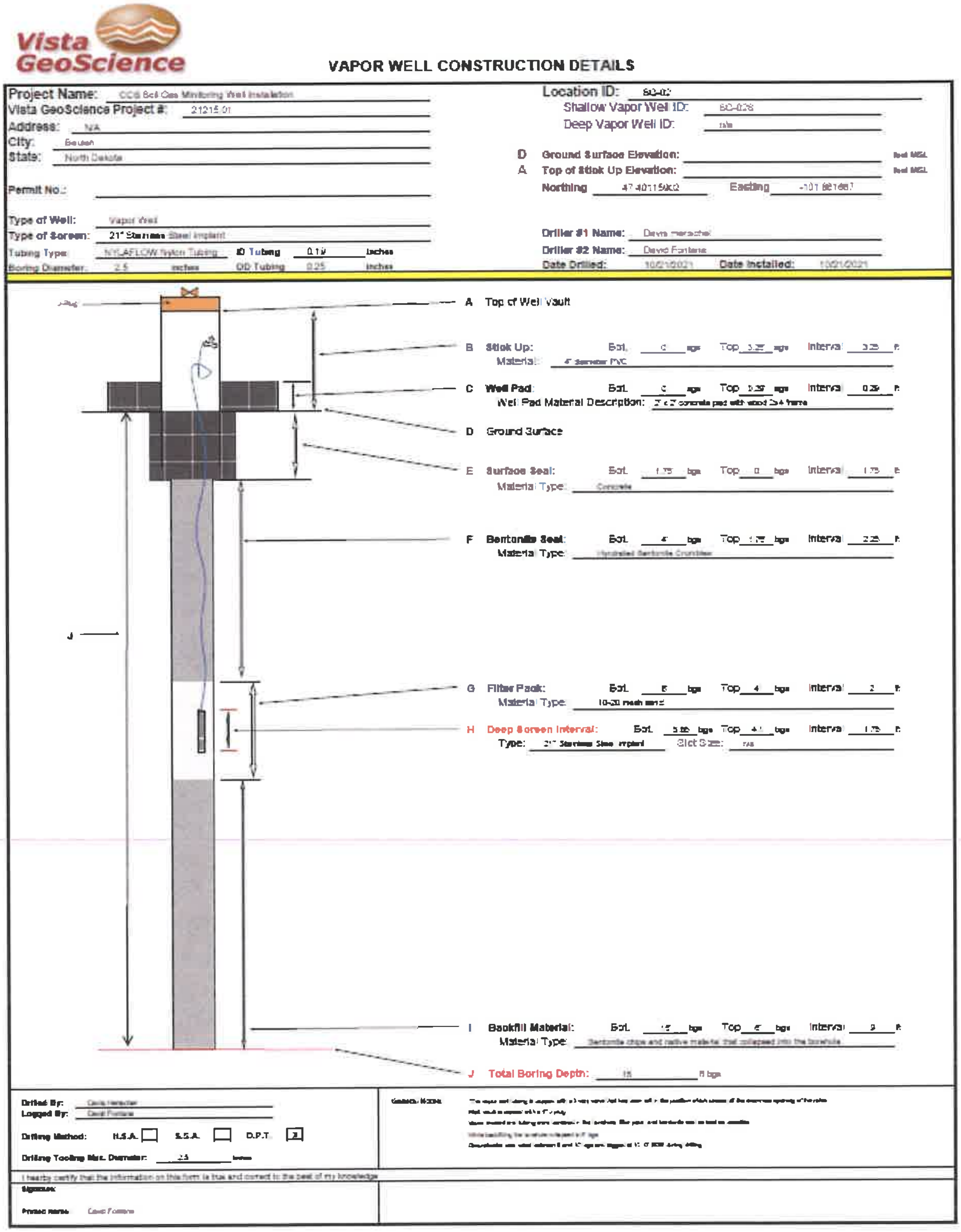


Figure C-2. Schematic of Soil Gas Profile Station SG02. Well design is the same for SG11.

Table C-1. Soil Gas Analytes Identified with Field and Laboratory Instruments

Landtec GEM 5000	*U.S. EPA Method TO-17*
Analyte	**Analyte**
CO_2	1,1,1,2-Tetrachloroethane
O_2	1,1,1-Trichloroethane
H_2S	1,1,2,2-Tetrachloroethane
CH_4	1,1,2-Trichloroethane
	1,1,2-Trichlorotrifluoroethane (Fr_113)
	1,1-Dichloroethane
	1,1-Dichloroethene
	1,2,3-Trichlorobenzene
	1,2,3-Trichloropropane
	1,2,4-Trichlorobenzene
	1,2,4-Trimethylbenzene
	1,2-Dibromoethane (EDB)
	1,2-Dichlorobenzene
	1,2-Dichloroethane
	1,3,5-Trimethylbenzene
	1,3-Dichlorobenzene
	1,4-Dichlorobenzene
	1,4-Dioxane
	2-Methylnaphthalene
	Benzene
	Carbon tetrachloride
	Chlorobenzene
	Chloroform
	cis-1,2-Dichloroethene
	Ethylbenzene
	Isopropylbenzene
	Methyl-t-butyl ether
	Naphthalene
	o-Xylene
	p and m-Xylene
	Tetrachloroethene
	Toluene
	trans-1,2-Dichloroethene
	Trichloroethene
	Vinyl chloride

Table C-2. Isotope Measurements of Soil Gas Samples

Isotope	Units
$\delta^{13}C$ of CO_2*	‰ (per mil)
$\delta^{13}C$ of CH_4*	‰ (per mil)
δD of CH_4*	‰ (per mil)

* Only measured if high enough concentration detected.

1.5.1.2 Quality Assurance/Quality Control Procedures

Soil Gas Locations: SG01 to SG11

The standard sampling and analytical QA/QC protocols that will be applied by DIG at sample locations SG01 through SG11 were provided earlier in Section C.6.1.1 of this QASP (see also https://digforenergy.com/geochemical-laboratory/).

1.5.2 Groundwater/USDW

Groundwater/USDW monitoring measures the water's chemical components and characteristics of soil components and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. A total of six Fox Hills groundwater sampling sites were drilled and installed in the storage facility area (Figure 5-4). All six locations are located on Coteau property. In addition, DGC will add one Fox Hills groundwater monitoring well near the Herrmann 1 (NDIC File No. 4177) and obtain a baseline sample prior to the start of injection operations (Figure 5-14).

1.5.2.1 Groundwater Sampling and Analysis Protocol

Baseline Groundwater Wells (Fred Art/Oberlander 1 and Helmuth Pfenning 2)

Groundwater samples were collected by Minnesota Valley Testing Laboratories (MVTL) (Bismarck, North Dakota) from these wells using the wells' submersible pumps. MVTL applied the following standard procedure for sampling the wells:

1. Determine use of well prior to sample collection, (e.g., domestic, livestock, irrigation, municipal)

2. Purge the well, using a measured bucket to determine the pumping rate when the valve is fully open.

   a. The longer that the well has not been in use, the longer the well will need to be purged before sample collection. Purge time will also depend on the total depth of the well.
   b. For wells used daily, purge the well for 1–2 minutes. For wells used on a seasonal basis, such as livestock or irrigation, purge the well for 15 minutes, or longer if the well is over 100 feet deep. If the well has not been in use in the past year, three well volumes may need to be removed to ensure a freshwater sample can be collected.

3. Collect the sample.
   a. Once the well has been sufficiently purged, sample collection can proceed.

b. Record location of sample point.
c. Record pumping rate and volume purged.
d. Collect field readings: temperature, conductivity, and pH.
e. Fill appropriate sample containers for analysis.

Two laboratories were used to analyze the water samples: 1) MVTL analyzed samples for general parameters, anions, cations, metals (dissolved and total), and nonmetals (Tables C-3 and C-4) and 2) the Dolan Integration Group (DIG) laboratory analyzed samples for dissolved gas composition (Table C-5) and the stable isotopes (Table C-6).

The standard sampling and analytical QA/QC protocols that will be applied by MVTL and DIG as part of the monitoring efforts at these sample locations were provided earlier in this QASP (www.mvtl.com/QualityAssurance and https://digforenergy.com/geochemical-laboratory/).

Table C-3. Measurements of General Parameters for Groundwater Samples

Parameter	Method
pH	SM4500-H+-B-11
Conductivity	SM2510B-11
Alkalinity	SM[1] 2320B
Temperature	SM2550B
Total Dissolved Solids	SM 2540C
Total Inorganic Carbon	EPA[2] 9060
Dissolved Inorganic Carbon (DIC)	EPA 9060
Total Organic Carbon	SM 5310B
Dissolved Organic Carbon	SM 5310B
Total Mercury	EPA 7470A
Dissolved Mercury	EPA 245.2
Total Metals[3] (26 metals)	EPA 6010B/6020
Dissolved Metals[3] (26 metals)	EPA 200.7/200.8
Bromide	EPA 300.0
Chloride	EPA 300.0
Fluoride	EPA 300.0
Sulfate	EPA 300.0
Nitrite	EPA 353.2

[1] Standard method; American Public Health Association (2017).
[2] U.S. Environmental Protection Agency.
[3] See Table B-2 for entire sampling list of total and dissolved metals.

Table C-4. Total and Dissolved Metals and Cation Measurements for Groundwater Samples

Metals	Major Cations	Trace Metals
Antimony	Barium	Aluminum
Arsenic	Boron	Cobalt
Beryllium	Calcium	Lithium
Cadmium	Iron	Molybdenum
Chromium	Magnesium	Vanadium
Copper	Manganese	
Lead	Potassium	
Mercury	Silicon	
Nickel	Sodium	
Selenium	Strontium	
Silver	Phosphorus	
Thallium		
Zinc		

Table C-5. Gas Compositional Analysis – Dissolved Gas in Water

Dissolved Gases*
N_2
O_2 + Ar
CO_2
C_1 Methane
Ethane
Propane
iso-Butane
nor-Butane
iso-Pentane
nor-Pentane
Helium
H_2

* EPA RSK-175 – Sample Preparation and Calculations for Dissolved Gas Analysis in Water Samples Using a GC Headspace Equilibration Technique.

Table C-6. Stable Isotope Measurements and Dissolved Gases in Groundwater

Isotope	Units
δD H_2O	‰ (per mil)
$\delta^{18}O$ H_2O	‰ (per mil)
$\delta^{13}C$ DIC	‰ (per mil)
$\delta^{13}C$ Methane (if present)	‰ (per mil)
$\delta^{13}C$ Ethane (if present)	‰ (per mil)
$\delta^{13}C$ Propane (if present)	‰ (per mil)
δD Methane (if present)	‰ (per mil)
$\delta^{13}C$ CO_2 (if present)	‰ (per mil)

Operational and PISC Groundwater Wells

The operational and PISC groundwater wells that will be monitored include sampling of the six dedicated groundwater Fox Hills Formation monitoring wells installed at each of the injection wells. DIG will assist with the sampling of the wells to provide two samples for analysis from each well. One sample will be analyzed by a state-certified laboratory for the general parameters, anions, cations, metals (dissolved and total), and nonmetals listed in Tables C-3 and C-4; the other sample will be sent to DIG for the determination of the dissolved gases and isotopic signatures (see Table C-6).

1.5.2.2 *Quality Assurance/Quality Control*

Baseline Groundwater Wells (Fred Art/Oberlander 1 and Helmuth Pfenning 2)

The laboratory analyses conducted by MVTL and DIG were performed in accordance with their internal QA/QC procedures (Table C-3 and www.mvtl.com/QualityAssurance). In addition, duplicate samples were taken to assess the combined accuracy of the field sampling and laboratory analysis methods. These duplicate samples were collected at the same time and location for each of the groundwater wells.

Operational and PISC Groundwater Wells

The standard sampling and analytical QA/QC protocols that will be applied by MVTL and DIG as part of the monitoring efforts at these sample locations were provided earlier in this QASP.

1.6 Storage Reservoir Monitoring

Monitoring of the storage reservoir during the injection operation includes monitoring of the injection flow rates and volumes, wellhead injection temperatures and pressures, bottomhole injection pressures, temperature, and saturation profiles from the storage reservoir to the AZMI (above-zone monitoring interval), and the tubing-casing annulus pressure or casing pressure.

The storage monitoring will be accomplished using flowmeters and surface digital pressure and temperature gauges. Surface measurements will be taken at the flowmeter and the wellhead (tubing and casing). These readings will be recorded in real-time. These pressure/temperature data will be continuously recorded as part of the supervisory control and data acquisition (SCADA) (see Attachment A-8) system that is employed on-site. All data collected by the SCADA system is routed to DGC's pipeline control center.

1.7 Wireline Logging and Retrievable Monitoring

The wireline logging and retrievable monitoring that will be performed comprise pulsed-neutron logs (PNLs), which include temperature and pressure data, ultrasonic logs, injection zone pressure falloff tests, and corrosion monitoring. The information provided by these monitoring efforts is as follows:

- PNL: provides information regarding gas saturation in the formations, which can be used to determine if the injected CO_2 is contained within the storage formation as well as ground-truth information provided by the seismic surveys. The PNL is also capable of gathering downhole pressure and temperature data.

- USIT (ultrasonic imaging tool): provides an assessment of the external and internal mechanical integrity and assessment of corrosion of the wellbore.

- PMIT: provides a measure of change in thickness of the wellbore materials over time due to interaction of the wellbore with the injected CO_2 and formation fluids.

- Pressure falloff test: provides an assessment of the storage reservoir injectivity.

All wireline logging events will follow API (American Petroleum Institute) guidelines along with the standard operating procedures of a third-party wireline operator. More details regarding each of these monitoring techniques is provided below.

1.7.1 Pulsed-Neutron Logs

PNLs provide formation evaluation and reservoir monitoring in cased holes. PNL is deployed as a wireline logging tool with an electronic pulsed neutron source and one or more detectors that typically measure neutrons or gamma rays (Rose and others, 2015). High-speed digital signal electronics process the gamma ray response and its time of arrival relative to the start of the neutron pulse. Spectral analysis algorithms translate the gamma ray energy and time relationship into concentrations of elements (Schlumberger, 2017).

Schlumberger's Pulsar Multifunction Spectroscopy Service (PNX) tool is a slim tool with an outer diameter (o.d.) of 1.72 in. for through-tubing access in cased hole environments. The housing is corrosion-resistant, allowing deployment in wellbore environments such as CO_2. The PNX tool can provide a direct volumetric measurement of gas-filled porosity and differentiate between gas-filled porosity, liquid-filled, and tight zones (Schlum20berger, 2017). Detection limits for CO_2 saturation for the PNX tool vary with the logging speed as well as the formation porosity as shown in Table C-7 below. Detailed measurement and mechanical specifications for the PNX tool are provided in Attachment A-2. The wireline operator will provide QA/QC procedures and tool calibration for their equipment.

Table C-7. Gas Saturation Detection Limits for PNL – PNX Tool

	Gas Saturation Detection Limit (%)	
Porosity Value (%)	**Minimum at Logging Speed of 1000 feet/hour**	**Minimum at Logging Speed of 200 feet/hour**
10	~39	~18
15	~22	~10
20	~18	~8

1.7.1.1 Description of Regular PNL Protocol

After the drilling and before CO_2 injection, a PNL will be run in each injector to confirm cement integrity and provide a baseline to which future PNL logging runs will be compared. Since the PNL tool also includes temperature and pressure measurements, profiles of both temperature and pressure will be constructed. The injection wells will be logged following the phased approach defined in Section 5.1.2 of this storage facility permit.

The following procedure will be followed when running a PNL in an injection well:

1. Hold a safety meeting and ensure that all personnel are wearing breathing equipment as the injection fluid contains H_2S:
   a. Rig up H_2S monitoring equipment
   b. Ensure that all safety precautions are taken

2. Shut well in by closing the outside wing valve and upper master valve.

3. Rig up lubricator, and pressure-test connections and seals to 2,000 pounds per square inch.

4. Open crown valve.

5. Open top master valve and proceed downhole to the injection packer with the PNL logging tool.

6. Make a 30-minute stop at the bottom of the hole, and record a static bottomhole pressure.

7. Proceed with running the PNL log making stops every 500' (approximately 12 stops) for 5 minutes each to record a static fluid pressure.

8. Once the logging tool is at the surface and in the lubricator, make a 5-minute stop to record the surface pressure in the tubing.

9. Close the crown valve and top master valve. Bleed pressure from the tree and lubricator.

10. Remove lubricator and replace the top cap and pressure gauge.

11. Open the top master valve, and again record the tubing and annular pressures.

12. Rig down the wireline company and clean the location.

13. Return the well to injection service by opening the outside wing valve.

1.7.2 Ultrasonic Imaging Tool

The USIT indicates the quality of the cement bond at the cement–casing interface and provides casing inspection (corrosion detection, monitoring, and casing thickness analysis). The tool is deployed on wireline with a transmitter emitting ultrasonic pulses and measuring the reflected ultrasonic waveforms received from the internal and external casing interfaces. The entire circumference of the casing is scanned, enabling the evaluation of the radial cement bond and the detection of internal and external casing damage or deformation. The high angular and vertical tool resolutions can detect cement channels as narrow as 1.2 inches (Attachment A-1). Detailed measurement and mechanical specifications for the USIT tool are provided in Attachment A-1. The wireline operator will provide QA/QC procedures and tool calibration for this equipment.

1.7.3 Platform Multifinger Tool

In instances where an individual tubing string has not been pulled for workover purposes, and thus made available for inspection at the surface, it may be useful to instead run a PMIT. The PMIT is a multifingered caliper tool that makes highly accurate radial measurements of the internal diameter of tubing and casing strings. In so doing it can quantify surface pitting and/or internal wall loss. Detailed measurements and mechanical specifications for the PMIT tool are provided in Attachment A-4.

1.7.4 Injection Zone Pressure Falloff Test

The injection zone pressure falloff test will be performed in the injection well prior to initiation of CO_2 injection activities and at least once every 5 years thereafter to demonstrate storage reservoir injectivity. Pressure data will be recorded during the pressure falloff test at the bottomhole.

1.8 Geophysical Monitoring Methods

The geophysical monitoring that is planned for the project includes time-lapse seismic surveys. This indirect monitoring method will characterize attributes associated with the injected CO_2, including the plume extents, mass changes, pressure changes, and potential seismicity. Details regarding the application and quality of this method are provided in the remainder of this section:

- Time-lapse seismic surveys: provide a measurement of the change in acoustic properties of the storage formation as injected CO_2 saturates the storage interval.

1.8.1 Time Lapse Seismic Surveys

Application of time-lapse seismic surveys for monitoring changes in acoustic properties requires a quality preoperational seismic survey for baseline conditions. The monitor survey should be repeated as closely to the baseline conditions and parameters as possible. The seismic monitor data should be reprocessed simultaneously with the original baseline data or processed with the same steps and workflow to ensure repeatability. Repeatability is a measure of 4D seismic quality (Lumley and others, 1997, 2000) that can be quantified once the processed data are analyzed by an experienced 4D seismic interpreter.

1.9 Completed Well Logging

Several continuous measurements of the storage formation properties were made in the Coteau 1 wellbore using wireline logging techniques. These logs, which are identified along with the justification for their use in Table 5-7, are listed below:

- Ultrasonic log
- Casing collar locator (CCL) log
- VDL
- CBL
- Gamma ray log
- Triple combo logs (i.e., resistivity, density, porosity, caliper, and spontaneous potential)
- Combinable magnetic resonance (CMR) log
- Spectral gamma ray log
- Dipole sonic log
- Fracture finder log

1.10 Perforation/Flowback Test (formation fluid and reservoir pressure)

Upon completion of initial drilling, casing, and cementing operations at the Coteau 1, the well was allowed to stand idle for a period of 3 months. Subsequently, the well was reentered, and a USIT was run to evaluate the cement bond to surface. A single foot of perforations was shot at 5,975 feet in the well in order to obtain a Broom Creek fluid sample and current reservoir pressure (Attachment A-9). The well was swabbed briefly and then began flowing back on its own. After the recovery of 50 barrels of formation fluid, multiple surface readings were taken to confirm consistent total dissolved solids readings. A fluid sample was then obtained for evaluation. After recording the bottomhole pressure, the perforations were squeeze-cemented. This cement was later drilled out, and the casing was tested to 1600 psi.

For future wells, namely, the Coteau 2 through 6, the flowback and pressure recording will be performed as part of their completion as CO_2 injection wells.

1.11 References

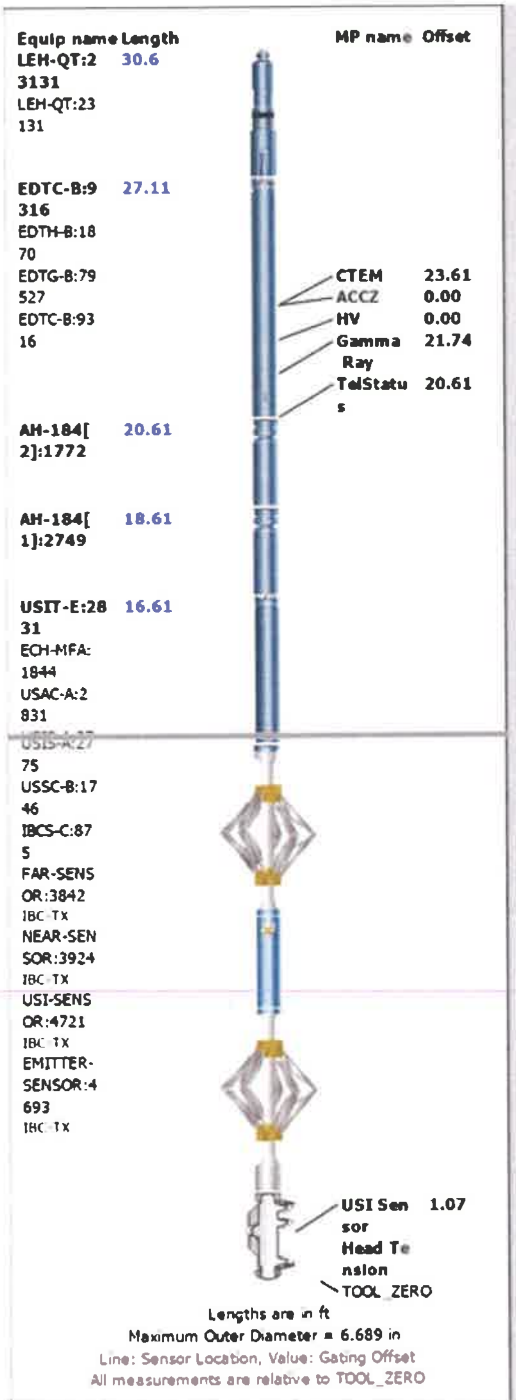
Lumley, D.E., Behrens, R.A., and Wang, Z., 1997, Assessing the technical risk of a 4-D seismic project: The Leading Edge, v. 16, p. 1287–1292, doi: 10.1190/1.1437784.

Lumley, D.E., Cole, S., Meadows, M.A., Tura, A., Hottman, B., Cornish, B., Curtis, M., and Maerefat, N., 2000, A risk analysis spreadsheet for both time-lapse VSP and 4D seismic reservoir monitoring: 70th Annual International Meeting, SEG, Expanded Abstracts, p. 1647–1650.

Rose D., Zhou, T., Beekman, S., Quinlan T., Delgadillo, M., Gonzalez, G., Fricke, S., Thornton, J., Clinton, D., Gicquel, F., Shestakova, I., Stephenson, K., Stoller, C., Philip, O., Miguel La Rotta Marin, J., Mainier, S., Perchonok, B., and Bailly, J.P., 2015, An innovative slim pulsed neutron logging tool: Society of Petrophysicists and Well Log Analysts 56th Annual Logging Symposium, Long Beach, California, July 2015.

Schlumberger, 2017, Pulsar multifunction spectroscopy tool: Society of Petrophysicists and Well Log Analysts 58th Annual Logging Symposium, Oklahoma City, Oklahoma, June 2017.

Attachment A-1 - Ultrasonic Imaging Tool



Measurement Specifications

	Isolation Scanner Tool
Output[1]	Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image
Max. logging speed	Standard resolution (6 in, 10° sampling): 823 m/h [2,700 ft/h] High resolution (0.6 in, 5° sampling): 172 m/h [563 ft/h]
Range of measurement	Min. casing thickness: 0.38 cm [0.15 in] Max. casing thickness: 2.01 cm [0.79 in]
Vertical resolution	High resolution: 1.52 cm [0.6 in] High speed: 15.24 cm [6 in]
Acoustic impedance[2]	Range: 0 to 10 Mrayl Resolution: 0.2 Mrayl Accuracy: 0 to 3.3 Mrayl = ±0.5 Mrayl, >3.3 Mrayl = ±15%
Flexural attenuation	Range: 0 to 2 dB/cm[3] Resolution: 0.05 dB/cm[3] Accuracy: 0.01 dB/cm[3]
Min. quantifiable channel width	30 mm [1.2 in]
Depth of investigation[1]	Casing and annulus up to 7.62 cm [3 in]
Mud type or weight limitation[††]	Conditions simulated before logging
Combinability	Bottom only, combinable with most wireline tools Telemetry: fast transfer bus (FTB) or enhanced FTB (EFTB)
Special applications	H_2S service

[1] Investigation of annulus width depends on the presence of third-interface echoes. Analysis and processing beyond cement evaluation can yield additional answers through additional outputs, including the Variable Density log (VDL) of the annulus waveform and polar movies in AVI format.

[2] Differentiation of materials by acoustic impedance alone requires a minimum gap of 0.5 MRayl between the fluid behind the casing and a solid.

[3] For 8-mm [0.3-in] casing thickness.

[††] Max. mud weight depends on the mud formulation, sub used, and casing size and weight, which are simulated before logging.

Mechanical Specifications

	Isolation Scanner Tool
Max. temperature	177 degC [350 degF]
Pressure range	1 to 138 MPa [145 to 20,000 psi]
Casing size—min.[†]	4½ in (min. pass-through restriction: 4 in)
Casing size—max.[†]	9⅝ in
Outside diameter	IBCS-A: 8.57 cm [3.375 in] IBCS-B: 11.36 cm [4.472 in] IBCS-C: 16.91 cm [6.657 in]
Length without sub	6.01 m [19.73 ft]
Weight without sub	151 kg [333 lbm]
Sub length, weight	IBCS-A: 61.22 cm [24.10 in], 7.59 kg [16.75 lbm] IBCS-B: 60.32 cm [23.75 in], 9.36 kg [20.64 lbm] IBCS-C: 60.32 cm [23.75 in], 10.73 kg [23.66 lbm]
Sub max. tension	10,000 N [2,250 lbf]
Sub max. compression	50,000 N [12,250 lbf]

[†] Limits for casing size depend on the sub used. Data can be acquired in casing larger than 9⅝ in with low-attenuation mud (e.g., water, brine).

Attachment A-1. Schlumberger's isolation scanner USIT used to provide evidence of external mechanical integrity in injection wells Coteau 1 through Coteau 6.

Attachment A-2 – Through-Tubing Pulsed Neutron Tool

Pulsar

Multifunction spectroscopy service

Measurement Specifications	
Acquisition	Real time with surface readout
Output	
Time domain	Sigma (SIGM), porosity (TPHI), fast-neutron cross section (FNXS)
Energy domain	Inelastic and capture yields of various elements, carbon/oxygen ratio, total organic carbon
Logging speed*	
Inelastic capture mode	200 ft/h [61 m/h]
Inelastic gas, sigma, and hydrogen index (GSH) mode	3,600 ft/h [1,097 m/h]
Sigma lithology mode	1,000 ft/h [305 m/h]
Range of measurement	Porosity: 0 to 60 pu
Mud type or weight limitations	None
Combinability	Combinable with tools that use the PS Platform production services platform's telemetry system and ThruBit through-the-bit logging services
Special application	Qualified per the requirements of NACE MR0175 H_2S and CO_2 resistance

* Logging speed determined using the tool planner

Mechanical Specifications	
Temperature rating	350 degF [175 degC]
Pressure rating	15,000 psi [103.4 MPa]
Casing size – min.	2⅜ in [6.03 cm]
Casing size – max.	9⅝ in [24.45 cm]
Outside diameter	1.72 in [4.37 cm]
Length	18.3 ft [5.58 m]
Weight	88 lbm [40 kg]
Tension	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N]

Attachment A-2. Measurement and mechanical specifications for Schlumberger's PNX (through-tubing pulsed neutron) tool.

Attachment A-3 – Standard Annulus Pressure Test Procedure

The tubing/casing annular pressure test provides an assessment of the internal mechanical integrity of the wellbore between the tubing-casing annulus. The pressure test procedure will be generated following the North Dakota Industrial Commission (NDIC) Injection Well Construction and Completion Standards (NDAC § 43-05-01-11), which state the pressure must be applied for a period of 30 minutes and must have no decrease in pressure greater than 10% of the required minimum test pressure.

Pursuant to Section 43-05-01-11.1

1. Contact NDIC to witness mechanical integrity test (MIT) procedure a minimum of 24 hours prior to test.

2. Completely fill the tubing/casing annulus with corrosion-inhibited packer fluid. Temperature stabilization of the well and annulus fluid is necessary; therefore, injection shall either be ceased, or a stabilized injection rate and temperature will be maintained.

3. After stabilization, the annulus will be pressurized to the maximum allowable injection pressure or an alternate pressure approved by NDIC. A positive pressure differential between the annulus and the injection string shall be maintained throughout the entire annulus.

4. Following pressurization, the annulus will be isolated from the source of pressure by a closed valve.

5. The annulus will remain isolated for a period no less than 30 minutes or as otherwise approved by NDIC. Pressure measurements will be recorded every 5 minutes, as well as continuously charted.

6. If the pressure deviates more than 10% of the required minimum test pressure, check for seal leaks, otherwise repeat steps. If failure occurs, well will be shut in, report of the failure will be sent to NDIC, and isolation and repair of the leak will commence within 90 days, unless otherwise approved by NDIC.

Attachment A-4 - Platform Multifinger Imaging Tool

Schlumberger

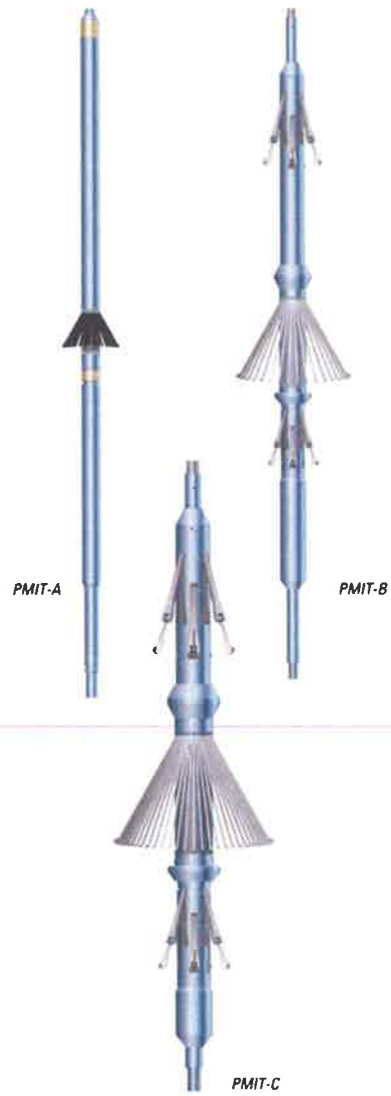
PS Platform Multifinger Imaging Tool

APPLICATIONS

- Identification and quantification of corrosion damage
- Identification of scale, wax, and solids accumulation
- Monitoring of anticorrosion systems
- Location of mechanical damage
- Evaluation of corrosion increase through periodic logs
- Determination of absolute inside diameter (ID)

The PS Platform* Multifinger Imaging Tool (PMIT) is a multifinger caliper tool that makes highly accurate radial measurements of the internal diameter of tubing and casing strings. The tool is available in three sizes to address a wide range of through-tubing and casing size applications.

The tool deploys an array of hard-surfaced fingers, which accurately monitor the inner pipe wall. Eccentricity effects are minimized by equal azimuthal spacing of the fingers and a special processing algorithm. The PMIT-B and PMIT-C tools incorporate powerful motorized centralizers to ensure effective centering force even in highly deviated intervals. The centralizers are equipped with rollers to prevent casing and tubing damage. The inclinometer in the tool provides information on well deviation and tool rotation. The PMIT-C tool can be fitted with special extended fingers for logging large-diameter casings. The PMIT-A is similarly fitted with special extended fingers for logging casing through tubing. All versions of the PMIT can be run in either real-time or memory mode.



The PMIT is available in three sizes for radially measuring the internal diameter of tubing and casing strings

Attachment A-4. Schlumberger's PMIT used as a possible alternative to surface tubing inspection in the Coteau 1 through Coteau 6 (continued).

PS Platform Multifinger Imaging Tool

Measurement Specifications

	PMIT-A	PMIT-B	PMIT-C
Output	Internal casing image from multiple internal radius measurements	Internal casing image from multiple internal radius measurements	Internal casing image from multiple internal radius measurements
Logging speed, m/h [ft/h]	Standard: 549 [1,800] Max.: 1,829 [6,000]	Standard: 549 [1,800] Max.: 1,829 [6,000]	Standard: 549 [1,800] Max.: 1,829 [6,000]
Minimum measurable casing ID, cm [in]	Standard or extended fingers: 5.08 [2]	7.62 [3]	Standard fingers: 12.7 [5] Extended fingers: 20.32 [8]
Maximum measurable casing ID, cm [in]	Standard fingers: 11.43 [4.5] Extended fingers: 17.78 [7]	17.78 [7]	Standard fingers: 25.4 [10] Extended fingers: 33.02 [13]
Vertical resolution at 529 m/h [1,800 ft/h], mm [in]	2.1 [0.082]	2.8 [0.11]	4.24 [0.167]
Radial resolution, mm [in]	Standard fingers: 0.10 [0.004] Extended fingers: 0.18 [0.007]	0.13 [0.005]	Standard fingers: 0.18 [0.007] Extended fingers: 0.23 [0.009]
Accuracy, mm [in]	Standard fingers: ±0.76 [±0.030] Extended fingers: ±1.07 [±0.042]	±0.76 [±0.030]	Standard fingers: ±0.76 [±0.030] Extended fingers: ±1.3 [±0.050]
Relative bearing accuracy, °	±5	±5	±5
Deviation accuracy at up to 70° deviation, °	±5	±5	±5
Depth of investigation	Casing inside surface	Casing inside surface	Casing inside surface
Borehole fluid limitations	None	None	None
Combinability	Real time: combinable with all PS Platform tools Memory mode: stand alone	Real time: combinable with all PS Platform tools Memory mode: stand alone	Real time: combinable with all PS Platform tools Memory mode: stand alone Bottom-only tool Extra centralizers required for casing larger than 9⅝ in
Special applications	H_2S service	H_2S service	H_2S service

Mechanical Specifications

	PMIT-A	PMIT-B	PMIT-C
Temperature rating, degF [degC]	302 [150]	302 [150]	PMIT-CA: 302 [150] PMIT-CB: 350 [177]
Pressure rating, MPa [psi]	103 [15,000]	103 [15,000]	PMIT-CA: 103 [15,000] PMIT-CB: 138 [20,000]
Outside diameter, cm [in]	Standard or extended fingers: 4.29 [1.6875]	6.99 [2.75]	Standard fingers: 10.16 [4] Extended fingers: 13.97 [5.5]
Fingers	24	40	60
Fingertip radius, mm [in]	1.5 [0.06]	1.27 [0.05]	1.52 [0.06]
Finger width, mm [in]	1.6 [0.063]	1.6 [0.063]	1.6 [0.063]
Length, m [ft]	3.62 [11.88] (with centralizers)	2.70 [8.86]	3.15 [10.34]
Weight, kg [lbm]	26 [56.5] (with centralizers)	40 [87.4]	54 [120]
Max. tensile strength, N [lbf]	44,480 [10,000]	44,480 [10,000]	44,480 [10,000]
Max. compressive strength, N [lbf]	8,230 [1,850]	11,120 [2,500]	11,120 [2,500]

www.slb.com/oilfield

Schlumberger

*Mark of Schlumberger
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Attachment A-4 (continued). Schlumberger's PMIT used as a possible alternative to surface tubing inspection in the Coteau 1 through Coteau 6.

Attachment A-5 – Tuboscope Wellsite Tubing Inspection System

TuboChek™ C101 – Non Gamma Wellsite Tubing Inspection System

Tuboscope is pleased to announce the introduction of the TuboChek C101 inspection system. This unit is certified and meets Class-1 Div-1 safety standards with intrinsically safe electronics and includes an encapsulated coil housing.

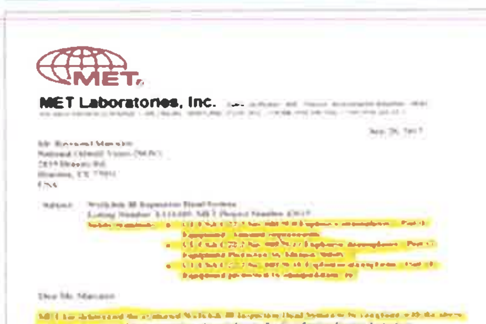
Similar to our WellChek system, TuboChek C101 utilizes the same reporting and database soft-ware, providing you real-time tubing inspection, data management and evaluation of your used tubing.

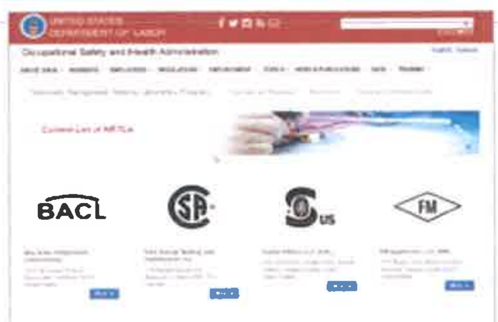
This new system delivers an accurate evaluation of each tube using the same proven eddy current based split detection and Sonoscope EMI inspection for pitting and corrosion detection. Unique to this system, a flux integration method is used for cross-sectional area, calculated rod-wear and a flux leakage technique for magnetic field discrimination to determine rod strokes.

TuboChek C101 increases the size range capabilities of inspected tubing to include: 2 ⅜", 2 ⅞", 3 ½", 4" and 4 ½"

Benefits
- Professionally trained crew for efficient and safe operations
- Records exact defect and joint location in the well
- Real time usable information
- On-site inspection eliminates need for trucking to inspection facilities
- Immediate re-use of good tubing

Defect Detection
- Corrosion pitting
- Rod wear
- Wall loss
- Cracks
- Erosion
- Splits
- Cuts
- Holes
- 3-Dimensional Transverse Defects





Tuboscope | NOV Wellbore Technologies
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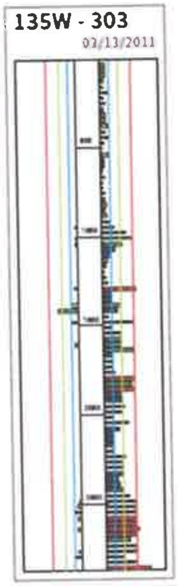
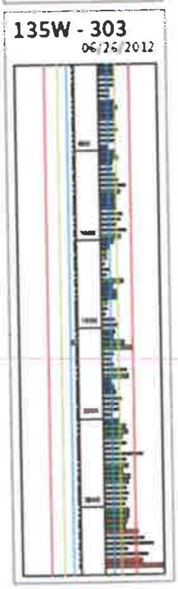
Attachment A-5. Tuboscope's wellsite tubing inspection service. This (or its equivalent) can be utilized for surface inspection of the Coteau 1 thru 6 tubing strings in the event they need to be pulled for any reason (continued).

TuboChek™$_{C1D1}$ — Non Gamma Wellsite Tubing Inspection System



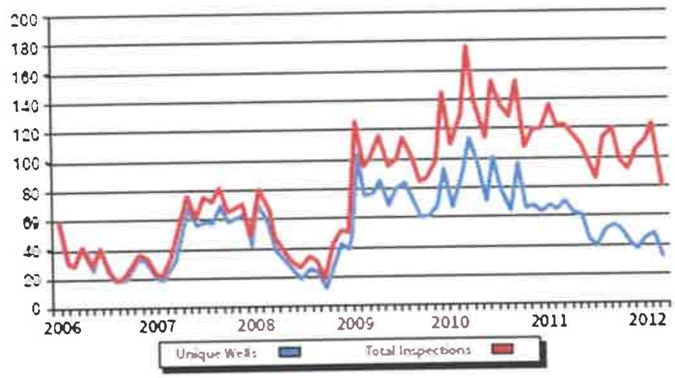


Sample Well

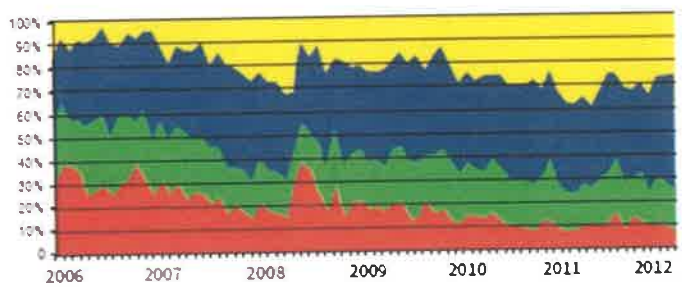
Wall profiles show the rate of corrosion (left bars) and wall loss (right bars) by joint at precise depths.

WellTrak Tubing Data Management and Evaluation System provides production engineers, well managers, rig supervisors and others in tubing management programs access to TuboChek™ inspection reports. The reports provide critical data at precise depths where string wear, corrosion, or failures have occurred.

Tubing Management decisions based on WellTrak's online historical database of well/field conditions can greatly assist in string design, treatments or mitigation techniques before the well is put back on production. This valuable information helps extend the run life of wells, measure the effectivenes of changes, and reduce overall tubing failures.



Inspections per month



Reject Rates per month

Continued application of on-site inspection at this field resulted in reduced reject rates and reduced tubing failures.

Benefits

- Individual full inspection history
- Online access to well records
- Identify patterns or correlations among historical inspections
- Quick rod guide assessment can be established in conjunction with rod design programs
- Generalized statistics for inspections performed

The exclusive Tuboscope TuboChek™ inspection coupled with WellTrak's data management system maximizes the potential of your tubing string, preventing future problems while reducing operating costs.

Tuboscope | NOV Wellbore Technologies
2835 Holmes Road
Houston, Texas 77051, USA
Phone 346 223 6100
tuboscopesales@nov.com nov.com/tuboscope

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Attachment A-5 (continued). Tuboscope's wellsite tubing inspection service. This (or its equivalent) can be utilized for surface inspection of the Coteau 1 through 6 tubing strings in the event they need to be pulled for any reason.

Attachment A-6 – H_2S Detection Station Overview

Honeywell

Sensepoint XCD SPECIFICATIONS

Flammable, toxic and oxygen gas detector for industrial applications

Use	3 wire, 4-20mA and RS485 MODBUS output fixed point detector with in-built alarm and fault relays for the protection of personnel and plant from flammable, toxic and Oxygen hazards. Incorporates a transmitter with local display and fully configurable via non-intrusive magnetic switch interface.
Electrical	
Input Voltage Range	12 to 32VDC (24VDC nominal)
Max Power Consumption	Maximum power consumption is dependent on the type of gas sensor being used. Electrochemical cells = 3.7W, IR = 3.7W and catalytic = 4.9W. Maximum inrush current = 800mA at 24VDC
Current Output	Sink or source
Relays	3 x 5A@250VAC Selectable normally open or normally closed (switch) and energized/de-energised (programmable) Alarm relays default normally open/de-energized. Fault relay default normally open/energized
Communication	RS485, MODBUS RTU
Construction	
Material	Housing: Epoxy painted aluminium alloy ADC12 or 316 stainless steel Sensor: 316 stainless steel
Weight (approx)	Aluminium Alloy LM25: 4.4lbs 316 Stainless Steel: 11lbs
Mounting	Integral mounting plate with 4 x mounting holes suitable for M8 bolts Optional pipe mounting kit for horizontal or vertical pipe Ø1.5 to 3" (2" nominal)
Cable Entries	UL\cUL versions: 2 x ¾"NPT conduit entries. Suitable blanking plug supplied for use if only 1 entry used. Seal to maintain IP rating; ATEX/IECEx versions: 2 x M20 cable entries
Environmental	
IP Rating	IP66 in accordance with EN60529:1992
Certified Temperature Range	-40°F to +149°F (-40°C to +65°C)

Detectable Gases and XCD Sensor Performance

Gas	User Selectable Full Scale Range	Default Range	Steps	User Selectable Cal Gas Range	Default Cal Point	Response Time (T90) Secs	Accuracy	Operating Temperature Min	Operating Temperature Max	Default Alarm Points A1	Default Alarm Points A2
Electrochemical Sensors											
Oxygen	25.0%Vol. only	25.0%Vol.	n/a	20.9%Vol. (Fixed)	20.9%Vol	<30	<±0.5%Vol.	-20°C / -4°F	55°C / 131°F	19.5%Vol. ▼	23.5%Vol. ▲
Hydrogen Sulfide*	10.0 to 100.0ppm	50.0ppm	0.1ppm	30 to 70% of selected full scale range	25ppm	<50	<±1ppm	-20°C / -4°F	55°C / 131°F	10ppm ▲	20ppm ▲
Carbon Monoxide**	100 to 1,000ppm	300ppm	100ppm		100ppm	<30	<±6ppm	-20°C / -4°F	55°C / 131°F	30ppm ▲	100ppm ▲
Hydrogen	1,000ppm only	1,000ppm	n/a		500ppm	<65	<±25ppm	-20°C / -4°F	55°C / 131°F	200ppm ▲	400ppm ▲
Nitrogen Dioxide***	10.0 to 50.0ppm	10.0ppm	5.0ppm		5.0ppm	<40	<±3ppm	-20°C / -4°F	55°C / 131°F	5.0ppm ▲	10.0ppm ▲
Catalytic Bead Sensors											
Flammable 1 to 8	20.0 to 100.0%LEL	100%LEL	10%LEL		50%LEL	<25	<±1.5%LEL	-20°C / -4°F	55°C / 131°F	20%LEL ▲	40%LEL ▲
Infrared Sensors											
Methane	20.0 to 100.0%LEL	100%LEL	10%LEL		50%LEL	<30	<±1.5%LEL	-20°C / -4°F	50°C / 122°F	20%LEL ▲	40%LEL ▲
Propane	20 to 100%LEL	100%LEL	10%LEL		50%LEL	<30	<±1%LEL	-20°C / -4°F	50°C / 122°F	20%LEL ▲	40%LEL ▲
Carbon Dioxide	2%Vol. only	2%Vol.	n/a		1%Vol	<30	<±0.04%Vol.	-20°C / -4°F	50°C / 122°F	0.5%Vol. ▲	0.8%Vol. ▲

* Lowest Alarm Limit = 5ppm; Lowest Detection Limit = 3ppm
** Lowest Alarm Limit = 15 ppm; Lowest Detection Limit = 10ppm
*** Lowest Alarm Limit = 0.6 ppm; Lowest Detection Limit = 0.3ppm

NOTE: For Cat Bead and Infrared sensors, Lowest Detectable Limit is 5% LEL and Lowest Alarm Level is 10% LEL.

▲ - Rising Alarm ▼ - Falling Alarm

Certification	
US, Latin America, Canada	UL/c-UL - Class I, Division 1, Groups B, C and D, Class I, Division 2, Groups B, C & D, Class II, Division 1, Groups E, F & G, Class II, Division 2, Groups F & G. -40°C to +65°C
European	ATEX Ex II 2 GD Ex d IIC Gb T6 (Ta -40°C to +65°C) Ex tb IIIC T85°C Db IP66
International	IEC Ex d IIC Gb T6 (Ta -40°C to +65°C) Ex tb IIIC T85°C Db IP66
EMC	CE: EN50270:2006 EN6100-6-4:2007
Performance	UL508; CSA 22.2 No. 152 (flammable gases, excludes infrared sensors); ATEX, IEC/EN60079-29-1:2007, EN45544, EN50104, EN50271; China: PA Pattern Measurement (for transmitter and toxic gas sensors) "CCCF" Shenyang for Flammable (fire dept approval)

Find out more
www.honeywellanalytics.com
Toll-free: 800.538.0363

Please Note:
While every effort has been made to ensure accuracy in this publication, no responsibility can be accepted for errors or omissions. Data may change, as well as legislation, and you are strongly advised to obtain copies of the most recently issued regulations, standards and guidelines. This publication is not intended to form the basis of a contract.

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Attachment A-7A – H_2S Detection Personnel Equipment

iBRID® MX6

Get ready to see hazardous levels of oxygen, toxic and combustible gas, and volatile organic compounds (VOCs) like never before.

The MX6 iBrid® is more than an intelligent hybrid of Industrial Scientific's best monitoring technologies—it's the most adaptable six-gas monitor on the market. With hundreds of possible sensor combinations, and a robust list of available configuration settings, the MX6 iBrid is ready to monitor oxygen, toxic and combustible gas, and volatile organic compounds (VOCs).

As your work changes, so can your MX6 iBrid. It uses five sensor slots to detect up to six gases. Each of those sensor slots accepts a variety of sensors, which means you can use the instrument with a PID sensor one day and an infrared sensor the next. What's more, settings allow you to adapt the instrument's behavior for your application. If you need to use a benzene PID response factor for one application, and butadiene for others, the familiar menu structure will allow you to quickly change settings.

The rugged MX6 iBrid carries our Guaranteed for Life™ warranty and is compatible with DSX™ Docking Stations. With a DSX Docking Station, maintenance is simplified and data becomes more than a spreadsheet filled with logged readings. Proactively manage your gas detection fleet—track trends, know when instrument maintenance will be required, and understand how your MX6 iBrid instruments are being used.

INDUSTRIAL SCIENTIFIC

- 24 "Plug-and-Play" field-replaceable sensors including PID and Infrared options
- Up to 6 gases monitored simultaneously
- Simple, user-friendly, customizable, menu-driven navigation
- Five-way navigation button
- Durable, concussion-proof overmold
- Optional integral sampling pump with strong 30.5 meter (100 feet) sample draw
- Full-color graphic LCD is highly visible in a variety of lighting conditions
- Powerful, 95 dB audible alarm

Continued...

Attachment A-7A – H_2S Detection Personnel Equipment (continued)

SPECIFICATIONS*

INSTRUMENT WARRANTY
Warranted for as long as the instrument is supported by Industrial Scientific

CASE MATERIAL
Lexan/ABS/Stainless Steel with protective rubber overmold

DIMENSIONS
135 x 77 x 48 mm (5.3 x 3.05 x 1.9 in) without Pump
193 x 77 x 56 mm (7.6 x 3.1 x 2.2 in) with Pump

WEIGHT
409 g (14.4 oz) typical, without Pump
511 g (18.0 oz) typical, with Pump

DISPLAY/READOUT
Color Graphic Liquid Crystal Display

POWER SOURCE/RUN TIMES
Rechargeable, Extended-Range Lithium-ion Battery Pack (36 hours) without Pump
Rechargeable, Extended-Range Lithium-ion Battery Pack (20 hours) with Pump
Replaceable AA Alkaline Battery Pack (10.5 hours) without Pump

OPERATING TEMPERATURE RANGE
-20 °C to 55 °C (-4 °F to 131 °F)

OPERATING HUMIDITY RANGE
15% to 95% non-condensing (continuous)

CERTIFICATIONS
INGRESS PROTECTION IP64

ANZEx	Ex ia s Zone 0 I, Ex ia s Zone 0 IIC T4
ATEX	Ex ia IIC T4 Ga, II 1G (or Ex d ia IIC T4 Gb IR sensor)
	Ex ia I, Equipment Group and Category I M1/II 1G
China CPC	Metrology Approval
China Ex	Ex ia d I/IIC T4
CMA:	Approval for Mining Products: CH_4, O_2, CO, CO_2
CSA	Cl I, Gr A-D T4; Ex d ia IIC T4
EAC	PBExiadI X, 1ExadIICT4 X
IECEx	Ex ia I (Ex ia d I IR sensor), Ex ia IIC T4 Ga, Ex d ia IIC T4 Gb
INMETRO	Ex ia IIC T4 Ga
KC	Ex d ia IIC T4
KIMM	Ex d ia IIC T4
MDR	Registration of Plant Design, CH_4, O_2, CO, H_2S, NO_2
MSHA	30 CFR, Part 22, Intrinsically safe for methane/air mixtures
PA-DEP	BFE 114-08 Permissible for PA Bituminous Underground Mines
UL	Cl I, Div 1, Gr A-D, T4; Cl II, Groups F G,
	Cl I, Zone 1, El 0, AEx ia d IIC T4 (or AEx ia d IIC T4 IR sensor)

MEASURING RANGES

SENSOR	RANGE	RESOLUTION
CATALYTIC BEAD		
Combustible Gas	0-100% LEL	1%
Methane	0-5% vol	0.01%
ELECTROCHEMICAL		
Ammonia	0-500 ppm	1
Carbon Monoxide	0-1,500 ppm	1
Carbon Monoxide (High Range)	0-9,999 ppm	1
Carbon Monoxide/Hydrogen low	0-1,000 ppm	1
Chlorine	0-50 ppm	0.1
Chlorine Dioxide	0-1 ppm	0.01
Carbon Monoxide/ Hydrogen Sulfide (COSH)	CO: 0-1,500 ppm H_2S: 0-500 ppm	1 0.1
Hydrogen	0-2,000 ppm	1
Hydrogen Chloride	0-30 ppm	0.1
Hydrogen Cyanide	0-30 ppm	0.1
Hydrogen Sulfide	0-500 ppm	0.1
Nitric Oxide	0-1,000 ppm	1
Nitrogen Dioxide	0-150 ppm	0.1
Oxygen	0-30% vol	0.1%
Phosphine	0-5 ppm	0.01
Phosphine (High Range)	0-1,000 ppm	1
Sulfur Dioxide	0-150 ppm	0.1
INFRARED		
Hydrocarbons	0-100% LEL	1%
Methane (% vol)	0-100% vol	1%
Methane (% LEL)	0-100% LEL	1%
Carbon Dioxide	0-5% vol	0.01%
PHOTOIONIZATION		
VOC	0-2,000 ppm	0.1

* These specifications are based on performance averages and may vary by instrument.

AVAILABLE FOR RENT

For a list of classes, videos, or to download the GDME App, visit www.indsci.com/training

Which Accessories Will You Need?

CHECKLIST

- ☐ Docking Stations
- ☐ Calibration Stations
- ☐ Compliance Tracking Software (iNet Control)
- ☐ Probes
- ☐ Sample Tubing
- ☐ Confined Space Kits
- ☐ Spare Batteries
- ☐ Replacement Sensors
- ☐ Desktop Chargers
- ☐ Vehicle Chargers
- ☐ Multi-Unit Chargers
- ☐ Carrying Cases
- ☐ Filters

For a list of all accessories, visit: www.indsci.com/mx6

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Attachment A-7B – H_2S Detection Personnel Equipment

VENTIS MX4

The Ventis® MX4 is a four-gas monitor with the portability and size of a single-gas monitor. Eliminate the need for extra monitors and transition seamlessly from personal monitoring to confined space entry with the Ventis® Slide-on Pump—ideal for operators who wear their gas monitors primarily for personal protection but occasionally require a pump for confined space entries.

- Detect up to four gases with a wide range of sensor options
- Select alarm set points, set latch alarms, disable instrument shutdown while in alarm, and more
- Save time and reduce human error with maintenance and usage data available from iNet Control software
- Available with or without an integral pump, or with the Ventis Slide-on Pump for ultimate flexibility
- Non-pumped instruments compatible with 12-hour, 18-hour, or 20-hour batteries

The Ventis® Slide-on Pump

The Ventis® Slide-on Pump is ideally suited for operators who wear their gas monitors primarily for personal protection but occasionally require a pump for confined space entries. Available in black or safety orange and powered by its own battery, the slide-on pump is compatible with the Ventis MX4 and Ventis® Pro5 Multi-Gas Monitor.

- **Convenient Sampling** – Sample draw distance of up to 50 feet provides convenient sampling in a wide range of applications
- **Easy to Attach** – No tools are required to attach or remove the Ventis Slide-on Pump to or from the monitor
- **Uses Same Batterys and Chargers as Ventis** – Monitor and pump each use the same batterys, and can easily be exchanged between instruments
- **Flexible Battery Options** – Three available battery options make this pump extremely flexible in the field

Build and price your Ventis MX4 online with the instrument builder
https://www.indsci.com/ventis-mx4-builder

Continued…

Attachment A-7B – H_2S Detection Personnel Equipment (continued)

SPECIFICATIONS*

WARRANTY
The following components are warranted for four (4) years from the device's date of manufacture: monitor, pump, and CO/H_2S/O_2/LEL sensors. All other components are warranted for two (2) years from the device's date of manufacture.**

CASE MATERIAL
Polycarbonate with protective rubber overmold

DIMENSIONS
103 x 58 x 30 mm (4.1 x 2.3 x 1.2 in) without pump, lithium-ion battery version
172 x 67 x 66 mm (6.8 x 2.6 x 2.6 in) with pump, lithium-ion battery version

WEIGHT
182 g (6.4 oz) without Pump, lithium-ion battery version
380 g (13.4 oz) with Pump, lithium-ion battery version

POWER SOURCE/RUN TIME
Rechargeable slim extended lithium-ion battery
(18 hours typical @ 20 °C) without Pump
Rechargeable lithium-ion battery
(12 hours typical @ 20 °C) without Pump
Rechargeable extended-range lithium-ion battery
(20 hours typical @ 20 °C) without Pump
(12 hours typical @ 20 °C) with Pump
Replaceable AAA alkaline battery
(8 hours typical @ 20 °C) without Pump
(4 hours typical @ 20 °C) with Pump

ALARMS
Ultra-bright LEDs, loud audible alarm (95 dB at 30 cm) and vibrating alarm

DISPLAY/READOUT
Backlit liquid crystal display (LCD)

TEMPERATURE RANGE
-20 °C to 50 °C (-4 °F to 122 °F) ***

HUMIDITY RANGE
15% to 95% Non-condensing (continuous)

SENSORS
Combustible gases/methane – Catalytic Bead
O_2, CO, CO/H_2 low, H_2S, NO_2, SO_2 – Electrochemical

MEASURING RANGES

Combustible Gases	0-100% LEL in 1% increments
Methane (CH_4):	0-5% of vol in 0.01% increments
Oxygen (O_2):	0-30% of vol in 0.1% increments
Carbon Monoxide (CO/H_2 low)	0-1,000 ppm in 1 ppm increments
Carbon Monoxide (CO)	0-1,000 ppm in 1 ppm increments
Hydrogen Sulfide (H_2S)	0-500 ppm in 0.1 ppm increments
Nitrogen Dioxide (NO_2)	0-150 ppm in 0.1 ppm increments
Sulfur Dioxide (SO_2):	0-150 ppm in 0.1 ppm increments

CERTIFICATIONS
INGRESS PROTECTION IP66/67

ANZEx:	Ex ia s Zone 0 I/IIC T4
ATEX:	Ex ia IIC T4 Ga and Ex ia I Ma; Equipment Group and Category II 1G/I M1
China CMC:	Metrology approval
China CPC:	CPA 2017-C103
China Ex:	Ex ia IIC T4 Ga; Ex ia d I Mb
China KA:	Approved for Underground Mines with CO, H_2S, O_2 and CH_4
China MA:	Approved for Underground Mines with CO, H_2S, O_2 and CH_4 (Note: Diffusion 17144453 pack only)
CSA:	Cl I, Div 1, G A-D, T4; Ex d ia IIC T4
EAC:	PB Ex d ia I X/1Ex d ia IIC T4 X
IECEx:	Ex ia IIC T4 Ga
INMETRO:	Ex ia IIC T4 Ga
KC:	Ex d ia IIC T4
KMM:	Ex d ia IIC T4
MSHA:	30 CFR Part 22; Permissible for underground mines; Li-ion
PA-DEP:	BFE 46-12 Permissible for PA Bituminous Underground Mines; Charger/docking station accessories; Category 1
SANS:	SANS 1515-1; Type A; Ex ia I/IIC T4; Li-ion
TIIS:	Ex ia IIC T4 X
UL:	Cl I, Div 1, Groups A-D, T4; Zone 0, AEx ia IIC T4; Cl II, Gr F-G (Carbonaceous and Grain dust)

SUPPLIED WITH MONITOR
Calibration Cup (without pump), Sample Tubing (with pump), Reference Guide

LANGUAGE
English (1), French (2), Spanish (3), German (4), Italian (5), Dutch (6), Portuguese (7), Russian (9), Polish (A), Czech (B), Chinese (C), Danish (D), Norwegian (E), Finnish (F), Swedish (G), Japanese (J)

* These specifications are based on performance averages and may vary by instrument.

** The 4-year warranty is strictly limited to the enumerated components in devices manufactured after December 31, 2019. Warranted components in devices manufactured before January 1st, 2020 are warranted for two (2) years from the device's date of manufacture.

*** Operating temperatures above 50 °C (122 °F) may cause reduced instrument accuracy. Operating temperatures below -20 °C (-4 °F) may cause reduced instrument accuracy and affect display and alarm performance. See Product Manual for details.

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Attachment A-8 – Supervisory Control and Data Acquisition (SCADA) System

The SCADA system is a computer-based system or systems used by personnel in a control room that aims to collect and display information about the Dakota Gasification Company (DGC) CO_2 storage injection operations in real time. This supervisory system collects data at an assigned time interval and stores the data in the historian server. Using DGC operator process control selections, the SCADA will have the ability to send commands and control the storage injection network (i.e., start or stop pumps, open or close valves, control process equipment remotely, etc.).

In addition to monitoring and control ability, the SCADA system will include warnings, both audible and visual, to alert the DGC control room, which is staffed 24/7, of near or excessive violations of set parameters within the system.

Attachment A-9 – Bottomhole Pressure Survey

Pressure Survey Report

EVOLUTION COMPLETIONS INC.

Williston, ND
(701) 572-2069
info@evolutioncompletions.com
www.evolutioncompletions.com

RAMPART ENERGY

COTEAU 1
COTEAU 1

SEP 27 - 28, 2021

Bottom Hole - Build-Up

Report Prepared by

E.S. KYLE INSTRUMENT LTD.

Red Deer, AB
PH 403.309.0980
Scott Brilz
Ref #: RD21-0365

EVOLUTION COMPLETIONS

Well Information

RAMPART ENERGY
COTEAU 1
COTEAU 1

SEP 27 - 28, 2021

Bottom Hole - Build-Up

AER Well License Number			
Test Purpose			
Field	WILDCAT		
Formation Name			
Well Fluid Status	(01) Oil	H2S	N
Well Type	Vertical		
KB Elevation	17.00	Open Hole	N
CF Elevation	0.00		
Production Interval			
Mid Point Perfs	ft KB-TVD		
Producing Through	Casing		
in Tbg	ft KB		
7.00 in Csg	ft KB		
PBTD	ft KB		

Test Summary

Start of Test	2021 09 27 1557		
Well Shut-In		Hrs	
Final Test Time	2021 09 28 2338		

Initial Tubing Pressure		Final Tubing Pressure		PSIA
Initial Casing Pressure	300.0	Final Casing Pressure	300.0	

	Run Depth	5975.00	ft KB-TVD
Primary Gauge (1):	Final Pressure	2937.09	PSIA
	Final Temperature	151.85	Deg F
	Gradient at Run Depth		PSIA/ft
	Calculated Pressure at MPP		PSIA
	Gauge Program	5 SEC	

Report Prepared by

E.S. KYLE INSTRUMENT LTD. Ref #: RD21-0365

EVOLUTION COMPLETIONS INC.

Extended Test Data

RAMPART ENERGY
COTEAU 1
COTEAU 1

SEP 27 - 28, 2021

Formation:

Test Type: **Bottom Hole - Build-Up**

Initial Tubing Pressure		PSIA	Final Tubing Pressure		PSIA
Initial Casing Pressure	300.0		Final Casing Pressure	300.0	

Top Gauge						Bottom Gauge			
			253	Gauge Serial #	254				
% Acc	0.024	KPAA	41369	Range	41369	KPAA		0.024	% Acc
% Res	0.0003		09/15/2021	Calibration Date	09/15/2021			0.0003	% Res
			Cal-Scan Recorder - Strain	Gauge Type	Cal-Scan Recorder - Strain				
			09/27/21 15:57:00	Gauge Start Time	09/27/21 15:57:00				
		ft KB-TVD	5974.70	Run Depth	5975.00	ft KB-TVD			
		PSIA	2936.41	Pressure	2937.09	PSIA			
		Deg F	151.79	Temperature	151.85	Deg F			
		PSIA/ft		Gradient		PSIA/ft			

Gauge Event	Temp Deg F	Pressure PSIA	Real Time (mm/dd/yy hh:mm:ss)	Temp Deg F	Pressure PSIA	Duration of Event Hours
On Bottom	152.20	2932.03	09/27/21 16:55:50	152.15	2932.70	
Open to Flow						
Shut-In						
Off Bottom	151.79	2936.41	09/28/21 18:53:25	151.85	2937.09	26.0

Pressure Corrected to Run Depth

PSIA	2936.41	5975.00	2937.09	PSIA

Calculated Pressure at MPP

PSIA				PSIA

Remarks

		Top Gauge			Bottom Gauge		
##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
912	2021 09 27 15:59:00	0.0333	13.46	95.18	0.0333	13.25	95.77
960	2021 09 27 16:03:00	0.1000	305.92	58.07	0.1000	309.82	58.60
					0.00 ft KB-TVD- Initial Surface		
1008	2021 09 27 16:07:00	0.1667	525.62	59.15	0.1667	526.31	59.02
1056	2021 09 27 16:11:00	0.2333	749.94	65.65	0.2333	750.88	65.53
1104	2021 09 27 16:15:00	0.3000	976.96	73.27	0.3000	977.55	73.00
1152	2021 09 27 16:19:00	0.3667	1201.53	82.84	0.3667	1202.26	82.63
1200	2021 09 27 16:23:00	0.4333	1426.41	91.98	0.4333	1427.25	91.92
1248	2021 09 27 16:27:00	0.5000	1655.05	103.44	0.5000	1655.59	101.99
1296	2021 09 27 16:31:00	0.5667	1852.01	114.18	0.5667	1852.03	113.02
1344	2021 09 27 16:35:00	0.6333	2074.32	127.18	0.6333	2075.26	125.48
1392	2021 09 27 16:39:00	0.7000	2286.38	135.12	0.7000	2287.18	134.43
1440	2021 09 27 16:43:00	0.7667	2538.85	140.96	0.7667	2539.50	140.06
1488	2021 09 27 16:47:00	0.8333	2736.96	147.66	0.8333	2738.49	146.99
1536	2021 09 27 16:51:00	0.9000	2889.52	151.95	0.9000	2889.52	151.81
1584	2021 09 27 16:55:00	0.9667	2932.92	152.17	0.9667	2933.57	152.13
1594	2021 09 27 16:55:50	0.9806	2932.03	152.20	0.9806	2932.70	152.15
					5975.00 ft KB-TVD- On Bottom		
1632	2021 09 27 16:59:00	1.0333	2931.99	152.23	1.0333	2932.58	152.21
1680	2021 09 27 17:03:00	1.1000	2932.26	152.23	1.1000	2932.89	152.25
1728	2021 09 27 17:07:00	1.1667	2932.53	152.23	1.1667	2933.16	152.26
1776	2021 09 27 17:11:00	1.2333	2932.80	152.23	1.2333	2933.38	152.26
1824	2021 09 27 17:15:00	1.3000	2933.03	152.22	1.3000	2933.60	152.27
1872	2021 09 27 17:19:00	1.3667	2933.25	152.23	1.3667	2933.87	152.27
1920	2021 09 27 17:23:00	1.4333	2933.49	152.23	1.4333	2934.10	152.27
1968	2021 09 27 17:27:00	1.5000	2933.70	152.23	1.5000	2934.35	152.27
2016	2021 09 27 17:31:00	1.5667	2933.94	152.23	1.5667	2934.54	152.27
2064	2021 09 27 17:35:00	1.6333	2934.13	152.23	1.6333	2934.76	152.27
2112	2021 09 27 17:39:00	1.7000	2934.33	152.23	1.7000	2934.94	152.27
2160	2021 09 27 17:43:00	1.7667	2934.50	152.22	1.7667	2935.14	152.27
2208	2021 09 27 17:47:00	1.8333	2934.71	152.22	1.8333	2935.30	152.26
2256	2021 09 27 17:51:00	1.9000	2934.84	152.22	1.9000	2935.53	152.26
2304	2021 09 27 17:55:00	1.9667	2935.04	152.22	1.9667	2935.68	152.26
2352	2021 09 27 17:59:00	2.0333	2935.17	152.22	2.0333	2935.89	152.26
2400	2021 09 27 18:03:00	2.1000	2935.33	152.21	2.1000	2936.01	152.25
2448	2021 09 27 18:07:00	2.1667	2935.51	152.21	2.1667	2936.09	152.25
2496	2021 09 27 18:11:00	2.2333	2935.62	152.21	2.2333	2936.24	152.24
2544	2021 09 27 18:15:00	2.3000	2935.74	152.20	2.3000	2936.32	152.24
2592	2021 09 27 18:19:00	2.3667	2935.79	152.20	2.3667	2936.45	152.23
2640	2021 09 27 18:23:00	2.4333	2935.84	152.20	2.4333	2936.48	152.23

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
2688	2021 09 27 18:27:00	2.5000	2935.87	152.19	2.5000	2936.49	152.23
2736	2021 09 27 18:31:00	2.5667	2935.88	152.19	2.5667	2936.52	152.22
2784	2021 09 27 18:35:00	2.6333	2935.92	152.18	2.6333	2936.52	152.22
2832	2021 09 27 18:39:00	2.7000	2935.92	152.17	2.7000	2936.56	152.21
2880	2021 09 27 18:43:00	2.7667	2935.93	152.16	2.7667	2936.53	152.21
2928	2021 09 27 18:47:00	2.8333	2935.94	152.14	2.8333	2936.61	152.20
2976	2021 09 27 18:51:00	2.9000	2935.95	152.11	2.9000	2936.58	152.20
3024	2021 09 27 18:55:00	2.9667	2935.94	152.08	2.9667	2936.58	152.19
3072	2021 09 27 18:59:00	3.0333	2935.97	152.06	3.0333	2936.61	152.19
3120	2021 09 27 19:03:00	3.1000	2935.97	152.03	3.1000	2936.65	152.18
3168	2021 09 27 19:07:00	3.1667	2936.00	152.01	3.1667	2936.62	152.17
3216	2021 09 27 19:11:00	3.2333	2935.95	152.00	3.2333	2936.60	152.17
3264	2021 09 27 19:15:00	3.3000	2936.00	151.98	3.3000	2936.59	152.16
3312	2021 09 27 19:19:00	3.3667	2936.01	151.97	3.3667	2936.63	152.16
3360	2021 09 27 19:23:00	3.4333	2936.05	151.96	3.4333	2936.69	152.15
3408	2021 09 27 19:27:00	3.5000	2935.99	151.95	3.5000	2936.65	152.14
3456	2021 09 27 19:31:00	3.5667	2936.01	151.94	3.5667	2936.66	152.11
3504	2021 09 27 19:35:00	3.6333	2936.04	151.94	3.6333	2936.66	152.08
3552	2021 09 27 19:39:00	3.7000	2936.08	151.94	3.7000	2936.65	152.05
3600	2021 09 27 19:43:00	3.7667	2936.04	151.93	3.7667	2936.68	152.03
3648	2021 09 27 19:47:00	3.8333	2936.05	151.93	3.8333	2936.71	152.01
3696	2021 09 27 19:51:00	3.9000	2936.06	151.93	3.9000	2936.70	152.00
3744	2021 09 27 19:55:00	3.9667	2936.08	151.92	3.9667	2936.66	151.99
3792	2021 09 27 19:59:00	4.0333	2936.08	151.92	4.0333	2936.66	151.99
3840	2021 09 27 20:03:00	4.1000	2936.04	151.92	4.1000	2936.71	151.98
3888	2021 09 27 20:07:00	4.1667	2936.07	151.91	4.1667	2936.70	151.98
3936	2021 09 27 20:11:00	4.2333	2936.05	151.91	4.2333	2936.70	151.98
3984	2021 09 27 20:15:00	4.3000	2936.07	151.91	4.3000	2936.68	151.97
4032	2021 09 27 20:19:00	4.3667	2936.11	151.91	4.3667	2936.70	151.97
4080	2021 09 27 20:23:00	4.4333	2936.11	151.91	4.4333	2936.72	151.97
4128	2021 09 27 20:27:00	4.5000	2936.08	151.91	4.5000	2936.72	151.96
4176	2021 09 27 20:31:00	4.5667	2936.09	151.91	4.5667	2936.72	151.96
4224	2021 09 27 20:35:00	4.6333	2936.09	151.90	4.6333	2936.72	151.96
4272	2021 09 27 20:39:00	4.7000	2936.09	151.90	4.7000	2936.76	151.96
4320	2021 09 27 20:43:00	4.7667	2936.08	151.90	4.7667	2936.70	151.96
4368	2021 09 27 20:47:00	4.8333	2936.13	151.90	4.8333	2936.74	151.95
4416	2021 09 27 20:51:00	4.9000	2936.09	151.89	4.9000	2936.76	151.95
4464	2021 09 27 20:55:00	4.9667	2936.14	151.89	4.9667	2936.76	151.95
4512	2021 09 27 20:59:00	5.0333	2936.10	151.89	5.0333	2936.75	151.95
4560	2021 09 27 21:03:00	5.1000	2936.14	151.89	5.1000	2936.75	151.95
4608	2021 09 27 21:07:00	5.1667	2936.14	151.89	5.1667	2936.77	151.95
4656	2021 09 27 21:11:00	5.2333	2936.14	151.89	5.2333	2936.76	151.94

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg F	Time (Hrs)	Pressure PSIA	Temp Deg F
4704	2021 09 27 21:15:00	5.3000	2936.15	151.88	5.3000	2936.73	151.94
4752	2021 09 27 21:19:00	5.3667	2936.08	151.88	5.3667	2936.78	151.94
4800	2021 09 27 21:23:00	5.4333	2936.14	151.88	5.4333	2936.82	151.94
4848	2021 09 27 21:27:00	5.5000	2936.11	151.88	5.5000	2936.75	151.93
4896	2021 09 27 21:31:00	5.5667	2936.12	151.88	5.5667	2936.75	151.93
4944	2021 09 27 21:35:00	5.6333	2936.08	151.87	5.6333	2936.77	151.93
4992	2021 09 27 21:39:00	5.7000	2936.11	151.87	5.7000	2936.75	151.93
5040	2021 09 27 21:43:00	5.7667	2936.13	151.87	5.7667	2936.77	151.93
5088	2021 09 27 21:47:00	5.8333	2936.12	151.87	5.8333	2936.79	151.93
5136	2021 09 27 21:51:00	5.9000	2936.12	151.87	5.9000	2936.78	151.93
5184	2021 09 27 21:55:00	5.9667	2936.16	151.87	5.9667	2936.79	151.93
5232	2021 09 27 21:59:00	6.0333	2936.09	151.87	6.0333	2936.77	151.92
5280	2021 09 27 22:03:00	6.1000	2936.11	151.87	6.1000	2936.75	151.92
5328	2021 09 27 22:07:00	6.1667	2936.10	151.86	6.1667	2936.76	151.92
5376	2021 09 27 22:11:00	6.2333	2936.17	151.86	6.2333	2936.80	151.92
5424	2021 09 27 22:15:00	6.3000	2936.10	151.86	6.3000	2936.79	151.92
5472	2021 09 27 22:19:00	6.3667	2936.16	151.86	6.3667	2936.76	151.92
5520	2021 09 27 22:23:00	6.4333	2936.15	151.86	6.4333	2936.75	151.92
5568	2021 09 27 22:27:00	6.5000	2936.13	151.86	6.5000	2936.81	151.92
5616	2021 09 27 22:31:00	6.5667	2936.18	151.86	6.5667	2936.77	151.92
5664	2021 09 27 22:35:00	6.6333	2936.14	151.86	6.6333	2936.79	151.91
5712	2021 09 27 22:39:00	6.7000	2936.15	151.86	6.7000	2936.80	151.91
5760	2021 09 27 22:43:00	6.7667	2936.15	151.86	6.7667	2936.77	151.91
5808	2021 09 27 22:47:00	6.8333	2936.15	151.85	6.8333	2936.81	151.91
5856	2021 09 27 22:51:00	6.9000	2936.18	151.85	6.9000	2936.85	151.91
5904	2021 09 27 22:55:00	6.9667	2936.17	151.85	6.9667	2936.81	151.91
5952	2021 09 27 22:59:00	7.0333	2936.15	151.85	7.0333	2936.83	151.91
6000	2021 09 27 23:03:00	7.1000	2936.18	151.85	7.1000	2936.80	151.91
6048	2021 09 27 23:07:00	7.1667	2936.13	151.85	7.1667	2936.81	151.90
6096	2021 09 27 23:11:00	7.2333	2936.18	151.85	7.2333	2936.79	151.90
6144	2021 09 27 23:15:00	7.3000	2936.16	151.85	7.3000	2936.79	151.90
6192	2021 09 27 23:19:00	7.3667	2936.15	151.84	7.3667	2936.82	151.90
6240	2021 09 27 23:23:00	7.4333	2936.19	151.85	7.4333	2936.85	151.90
6288	2021 09 27 23:27:00	7.5000	2936.18	151.84	7.5000	2936.82	151.90
6336	2021 09 27 23:31:00	7.5667	2936.19	151.85	7.5667	2936.82	151.90
6384	2021 09 27 23:35:00	7.6333	2936.19	151.84	7.6333	2936.84	151.90
6432	2021 09 27 23:39:00	7.7000	2936.20	151.84	7.7000	2936.80	151.90
6480	2021 09 27 23:43:00	7.7667	2936.18	151.84	7.7667	2936.82	151.90
6528	2021 09 27 23:47:00	7.8333	2936.17	151.84	7.8333	2936.84	151.90
6576	2021 09 27 23:51:00	7.9000	2936.18	151.84	7.9000	2936.80	151.90
6624	2021 09 27 23:55:00	7.9667	2936.18	151.84	7.9667	2936.84	151.90
6672	2021 09 27 23:59:00	8.0333	2936.19	151.84	8.0333	2936.80	151.89

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg F	Time (Hrs)	Pressure PSIA	Temp Deg F
6720	2021 09 28 00:03:00	8.1000	2936.20	151.84	8.1000	2936.87	151.89
6768	2021 09 28 00:07:00	8.1667	2936.19	151.84	8.1667	2936.85	151.89
6816	2021 09 28 00:11:00	8.2333	2936.20	151.84	8.2333	2936.83	151.89
6864	2021 09 28 00:15:00	8.3000	2936.18	151.83	8.3000	2936.87	151.89
6912	2021 09 28 00:19:00	8.3667	2936.19	151.83	8.3667	2936.86	151.89
6960	2021 09 28 00:23:00	8.4333	2936.20	151.84	8.4333	2936.82	151.89
7008	2021 09 28 00:27:00	8.5000	2936.19	151.83	8.5000	2936.82	151.89
7056	2021 09 28 00:31:00	8.5667	2936.22	151.83	8.5667	2936.84	151.89
7104	2021 09 28 00:35:00	8.6333	2936.20	151.83	8.6333	2936.86	151.89
7152	2021 09 28 00:39:00	8.7000	2936.19	151.83	8.7000	2936.85	151.89
7200	2021 09 28 00:43:00	8.7667	2936.20	151.83	8.7667	2936.81	151.89
7248	2021 09 28 00:47:00	8.8333	2936.21	151.83	8.8333	2936.86	151.89
7296	2021 09 28 00:51:00	8.9000	2936.21	151.83	8.9000	2936.85	151.89
7344	2021 09 28 00:55:00	8.9667	2936.20	151.83	8.9667	2936.87	151.89
7392	2021 09 28 00:59:00	9.0333	2936.19	151.83	9.0333	2936.84	151.88
7440	2021 09 28 01:03:00	9.1000	2936.19	151.83	9.1000	2936.85	151.89
7488	2021 09 28 01:07:00	9.1667	2936.20	151.83	9.1667	2936.88	151.88
7536	2021 09 28 01:11:00	9.2333	2936.21	151.83	9.2333	2936.87	151.88
7584	2021 09 28 01:15:00	9.3000	2936.16	151.83	9.3000	2936.84	151.88
7632	2021 09 28 01:19:00	9.3667	2936.22	151.83	9.3667	2936.82	151.88
7680	2021 09 28 01:23:00	9.4333	2936.17	151.83	9.4333	2936.86	151.88
7728	2021 09 28 01:27:00	9.5000	2936.23	151.82	9.5000	2936.85	151.88
7776	2021 09 28 01:31:00	9.5667	2936.18	151.82	9.5667	2936.85	151.88
7824	2021 09 28 01:35:00	9.6333	2936.22	151.83	9.6333	2936.85	151.88
7872	2021 09 28 01:39:00	9.7000	2936.20	151.82	9.7000	2936.85	151.88
7920	2021 09 28 01:43:00	9.7667	2936.19	151.82	9.7667	2936.87	151.88
7968	2021 09 28 01:47:00	9.8333	2936.20	151.82	9.8333	2936.90	151.88
8016	2021 09 28 01:51:00	9.9000	2936.22	151.82	9.9000	2936.88	151.88
8064	2021 09 28 01:55:00	9.9667	2936.22	151.82	9.9667	2936.86	151.88
8112	2021 09 28 01:59:00	10.0333	2936.24	151.82	10.0333	2936.86	151.88
8160	2021 09 28 02:03:00	10.1000	2936.21	151.82	10.1000	2936.89	151.88
8208	2021 09 28 02:07:00	10.1667	2936.22	151.82	10.1667	2936.88	151.88
8256	2021 09 28 02:11:00	10.2333	2936.22	151.82	10.2333	2936.83	151.88
8304	2021 09 28 02:15:00	10.3000	2936.27	151.82	10.3000	2936.87	151.88
8352	2021 09 28 02:19:00	10.3667	2936.22	151.82	10.3667	2936.90	151.88
8400	2021 09 28 02:23:00	10.4333	2936.20	151.82	10.4333	2936.92	151.88
8448	2021 09 28 02:27:00	10.5000	2936.22	151.82	10.5000	2936.88	151.88
8496	2021 09 28 02:31:00	10.5667	2936.24	151.82	10.5667	2936.89	151.87
8544	2021 09 28 02:35:00	10.6333	2936.24	151.82	10.6333	2936.90	151.87
8592	2021 09 28 02:39:00	10.7000	2936.22	151.82	10.7000	2936.91	151.87
8640	2021 09 28 02:43:00	10.7667	2936.26	151.82	10.7667	2936.87	151.87
8688	2021 09 28 02:47:00	10.8333	2936.22	151.82	10.8333	2936.91	151.87

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg F	Time (Hrs)	Pressure PSIA	Temp Deg F
8736	2021 09 28 02:51:00	10.9000	2936.19	151.82	10.9000	2936.86	151.87
8784	2021 09 28 02:55:00	10.9667	2936.20	151.82	10.9667	2936.90	151.87
8832	2021 09 28 02:59:00	11.0333	2936.25	151.82	11.0333	2936.87	151.87
8880	2021 09 28 03:03:00	11.1000	2936.23	151.82	11.1000	2936.91	151.87
8928	2021 09 28 03:07:00	11.1667	2936.25	151.82	11.1667	2936.88	151.87
8976	2021 09 28 03:11:00	11.2333	2936.23	151.81	11.2333	2936.90	151.87
9024	2021 09 28 03:15:00	11.3000	2936.23	151.81	11.3000	2936.89	151.87
9072	2021 09 28 03:19:00	11.3667	2936.25	151.82	11.3667	2936.91	151.87
9120	2021 09 28 03:23:00	11.4333	2936.25	151.81	11.4333	2936.88	151.87
9168	2021 09 28 03:27:00	11.5000	2936.23	151.81	11.5000	2936.88	151.87
9216	2021 09 28 03:31:00	11.5667	2936.29	151.82	11.5667	2936.90	151.87
9264	2021 09 28 03:35:00	11.6333	2936.25	151.81	11.6333	2936.91	151.87
9312	2021 09 28 03:39:00	11.7000	2936.24	151.81	11.7000	2936.93	151.87
9360	2021 09 28 03:43:00	11.7667	2936.23	151.81	11.7667	2936.88	151.87
9408	2021 09 28 03:47:00	11.8333	2936.21	151.81	11.8333	2936.90	151.87
9456	2021 09 28 03:51:00	11.9000	2936.23	151.81	11.9000	2936.91	151.87
9504	2021 09 28 03:55:00	11.9667	2936.25	151.81	11.9667	2936.88	151.87
9552	2021 09 28 03:59:00	12.0333	2936.27	151.81	12.0333	2936.90	151.87
9600	2021 09 28 04:03:00	12.1000	2936.25	151.81	12.1000	2936.90	151.87
9648	2021 09 28 04:07:00	12.1667	2936.28	151.81	12.1667	2936.91	151.87
9696	2021 09 28 04:11:00	12.2333	2936.23	151.81	12.2333	2936.91	151.87
9744	2021 09 28 04:15:00	12.3000	2936.24	151.81	12.3000	2936.93	151.87
9792	2021 09 28 04:19:00	12.3667	2936.23	151.81	12.3667	2936.89	151.87
9840	2021 09 28 04:23:00	12.4333	2936.25	151.81	12.4333	2936.91	151.87
9888	2021 09 28 04:27:00	12.5000	2936.24	151.81	12.5000	2936.89	151.87
9936	2021 09 28 04:31:00	12.5667	2936.25	151.81	12.5667	2936.88	151.87
9984	2021 09 28 04:35:00	12.6333	2936.27	151.81	12.6333	2936.93	151.86
10032	2021 09 28 04:39:00	12.7000	2936.24	151.81	12.7000	2936.93	151.87
10080	2021 09 28 04:43:00	12.7667	2936.24	151.81	12.7667	2936.95	151.86
10128	2021 09 28 04:47:00	12.8333	2936.27	151.81	12.8333	2936.96	151.87
10176	2021 09 28 04:51:00	12.9000	2936.26	151.81	12.9000	2936.92	151.87
10224	2021 09 28 04:55:00	12.9667	2936.27	151.81	12.9667	2936.94	151.86
10272	2021 09 28 04:59:00	13.0333	2936.25	151.81	13.0333	2936.97	151.87
10320	2021 09 28 05:03:00	13.1000	2936.26	151.81	13.1000	2936.96	151.87
10368	2021 09 28 05:07:00	13.1667	2936.27	151.81	13.1667	2936.96	151.86
10416	2021 09 28 05:11:00	13.2333	2936.28	151.81	13.2333	2936.93	151.87
10464	2021 09 28 05:15:00	13.3000	2936.24	151.81	13.3000	2936.94	151.87
10512	2021 09 28 05:19:00	13.3667	2936.25	151.81	13.3667	2936.94	151.86
10560	2021 09 28 05:23:00	13.4333	2936.26	151.81	13.4333	2936.94	151.86
10608	2021 09 28 05:27:00	13.5000	2936.24	151.81	13.5000	2936.97	151.86
10656	2021 09 28 05:31:00	13.5667	2936.28	151.81	13.5667	2936.98	151.86
10704	2021 09 28 05:35:00	13.6333	2936.24	151.81	13.6333	2936.96	151.86

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
10752	2021 09 28 05:39:00	13.7000	2936.26	151.81	13.7000	2936.97	151.86
10800	2021 09 28 05:43:00	13.7667	2936.26	151.81	13.7667	2936.95	151.86
10848	2021 09 28 05:47:00	13.8333	2936.29	151.81	13.8333	2936.98	151.86
10896	2021 09 28 05:51:00	13.9000	2936.30	151.81	13.9000	2936.94	151.86
10944	2021 09 28 05:55:00	13.9667	2936.27	151.81	13.9667	2936.95	151.86
10992	2021 09 28 05:59:00	14.0333	2936.31	151.81	14.0333	2936.94	151.86
11040	2021 09 28 06:03:00	14.1000	2936.32	151.81	14.1000	2936.99	151.86
11088	2021 09 28 06:07:00	14.1667	2936.30	151.81	14.1667	2936.95	151.86
11136	2021 09 28 06:11:00	14.2333	2936.29	151.81	14.2333	2936.96	151.86
11184	2021 09 28 06:15:00	14.3000	2936.28	151.80	14.3000	2936.95	151.86
11232	2021 09 28 06:19:00	14.3667	2936.30	151.80	14.3667	2936.99	151.86
11280	2021 09 28 06:23:00	14.4333	2936.28	151.80	14.4333	2936.97	151.86
11328	2021 09 28 06:27:00	14.5000	2936.33	151.80	14.5000	2936.94	151.86
11376	2021 09 28 06:31:00	14.5667	2936.30	151.80	14.5667	2936.98	151.86
11424	2021 09 28 06:35:00	14.6333	2936.27	151.80	14.6333	2936.97	151.86
11472	2021 09 28 06:39:00	14.7000	2936.32	151.80	14.7000	2936.96	151.86
11520	2021 09 28 06:43:00	14.7667	2936.27	151.80	14.7667	2936.98	151.86
11568	2021 09 28 06:47:00	14.8333	2936.29	151.80	14.8333	2936.98	151.86
11616	2021 09 28 06:51:00	14.9000	2936.31	151.80	14.9000	2936.98	151.86
11664	2021 09 28 06:55:00	14.9667	2936.29	151.80	14.9667	2936.95	151.86
11712	2021 09 28 06:59:00	15.0333	2936.32	151.80	15.0333	2936.97	151.86
11760	2021 09 28 07:03:00	15.1000	2936.29	151.80	15.1000	2936.98	151.86
11808	2021 09 28 07:07:00	15.1667	2936.29	151.80	15.1667	2936.99	151.86
11856	2021 09 28 07:11:00	15.2333	2936.29	151.80	15.2333	2936.98	151.86
11904	2021 09 28 07:15:00	15.3000	2936.33	151.80	15.3000	2936.97	151.86
11952	2021 09 28 07:19:00	15.3667	2936.32	151.80	15.3667	2936.97	151.86
12000	2021 09 28 07:23:00	15.4333	2936.30	151.80	15.4333	2936.98	151.86
12048	2021 09 28 07:27:00	15.5000	2936.32	151.80	15.5000	2936.98	151.86
12096	2021 09 28 07:31:00	15.5667	2936.31	151.80	15.5667	2937.00	151.86
12144	2021 09 28 07:35:00	15.6333	2936.31	151.80	15.6333	2936.99	151.86
12192	2021 09 28 07:39:00	15.7000	2936.33	151.80	15.7000	2936.99	151.86
12240	2021 09 28 07:43:00	15.7667	2936.30	151.80	15.7667	2936.98	151.86
12288	2021 09 28 07:47:00	15.8333	2936.30	151.80	15.8333	2937.00	151.86
12336	2021 09 28 07:51:00	15.9000	2936.35	151.80	15.9000	2937.00	151.86
12384	2021 09 28 07:55:00	15.9667	2936.33	151.80	15.9667	2936.99	151.85
12432	2021 09 28 07:59:00	16.0333	2936.32	151.80	16.0333	2936.99	151.86
12480	2021 09 28 08:03:00	16.1000	2936.32	151.80	16.1000	2936.98	151.85
12528	2021 09 28 08:07:00	16.1667	2936.33	151.80	16.1667	2937.00	151.86
12576	2021 09 28 08:11:00	16.2333	2936.34	151.80	16.2333	2937.00	151.86
12624	2021 09 28 08:15:00	16.3000	2936.31	151.80	16.3000	2936.98	151.86
12672	2021 09 28 08:19:00	16.3667	2936.33	151.80	16.3667	2936.99	151.86
12720	2021 09 28 08:23:00	16.4333	2936.34	151.80	16.4333	2936.99	151.86

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg F	Time (Hrs)	Pressure PSIA	Temp Deg F
12768	2021 09 28 08:27:00	16.5000	2936.35	151.79	16.5000	2936.96	151.86
12816	2021 09 28 08:31:00	16.5667	2936.35	151.80	16.5667	2937.00	151.86
12864	2021 09 28 08:35:00	16.6333	2936.33	151.80	16.6333	2937.02	151.86
12912	2021 09 28 08:39:00	16.7000	2936.36	151.80	16.7000	2936.99	151.86
12960	2021 09 28 08:43:00	16.7667	2936.33	151.80	16.7667	2936.98	151.85
13008	2021 09 28 08:47:00	16.8333	2936.34	151.80	16.8333	2936.98	151.86
13056	2021 09 28 08:51:00	16.9000	2936.32	151.80	16.9000	2937.01	151.85
13104	2021 09 28 08:55:00	16.9667	2936.32	151.80	16.9667	2936.99	151.86
13152	2021 09 28 08:59:00	17.0333	2936.34	151.80	17.0333	2937.01	151.86
13200	2021 09 28 09:03:00	17.1000	2936.30	151.80	17.1000	2936.99	151.85
13248	2021 09 28 09:07:00	17.1667	2936.34	151.80	17.1667	2937.00	151.86
13296	2021 09 28 09:11:00	17.2333	2936.34	151.80	17.2333	2936.97	151.85
13344	2021 09 28 09:15:00	17.3000	2936.31	151.79	17.3000	2937.02	151.85
13392	2021 09 28 09:19:00	17.3667	2936.32	151.80	17.3667	2937.00	151.85
13440	2021 09 28 09:23:00	17.4333	2936.34	151.80	17.4333	2937.02	151.85
13488	2021 09 28 09:27:00	17.5000	2936.34	151.79	17.5000	2936.99	151.85
13536	2021 09 28 09:31:00	17.5667	2936.37	151.79	17.5667	2937.04	151.85
13584	2021 09 28 09:35:00	17.6333	2936.35	151.80	17.6333	2936.99	151.85
13632	2021 09 28 09:39:00	17.7000	2936.32	151.79	17.7000	2937.02	151.85
13680	2021 09 28 09:43:00	17.7667	2936.33	151.79	17.7667	2936.99	151.85
13728	2021 09 28 09:47:00	17.8333	2936.34	151.79	17.8333	2937.00	151.85
13776	2021 09 28 09:51:00	17.9000	2936.34	151.79	17.9000	2937.01	151.85
13824	2021 09 28 09:55:00	17.9667	2936.31	151.80	17.9667	2936.99	151.85
13872	2021 09 28 09:59:00	18.0333	2936.35	151.79	18.0333	2937.02	151.85
13920	2021 09 28 10:03:00	18.1000	2936.34	151.79	18.1000	2937.02	151.85
13968	2021 09 28 10:07:00	18.1667	2936.33	151.79	18.1667	2937.03	151.86
14016	2021 09 28 10:11:00	18.2333	2936.32	151.79	18.2333	2937.03	151.86
14064	2021 09 28 10:15:00	18.3000	2936.31	151.79	18.3000	2937.03	151.86
14112	2021 09 28 10:19:00	18.3667	2936.36	151.80	18.3667	2937.00	151.85
14160	2021 09 28 10:23:00	18.4333	2936.34	151.79	18.4333	2937.05	151.85
14208	2021 09 28 10:27:00	18.5000	2936.36	151.80	18.5000	2937.01	151.85
14256	2021 09 28 10:31:00	18.5667	2936.33	151.79	18.5667	2937.02	151.85
14304	2021 09 28 10:35:00	18.6333	2936.34	151.79	18.6333	2936.99	151.85
14352	2021 09 28 10:39:00	18.7000	2936.34	151.79	18.7000	2937.00	151.85
14400	2021 09 28 10:43:00	18.7667	2936.33	151.79	18.7667	2937.04	151.85
14448	2021 09 28 10:47:00	18.8333	2936.35	151.79	18.8333	2937.04	151.85
14496	2021 09 28 10:51:00	18.9000	2936.33	151.79	18.9000	2936.99	151.85
14544	2021 09 28 10:55:00	18.9667	2936.35	151.79	18.9667	2937.01	151.85
14592	2021 09 28 10:59:00	19.0333	2936.36	151.79	19.0333	2937.01	151.85
14640	2021 09 28 11:03:00	19.1000	2936.39	151.80	19.1000	2937.03	151.85
14688	2021 09 28 11:07:00	19.1667	2936.36	151.79	19.1667	2937.01	151.85
14736	2021 09 28 11:11:00	19.2333	2936.33	151.79	19.2333	2937.04	151.85

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg F	Time (Hrs)	Pressure PSIA	Temp Deg F
14784	2021 09 28 11:15:00	19.3000	2936.39	151.79	19.3000	2937.00	151.85
14832	2021 09 28 11:19:00	19.3667	2936.34	151.79	19.3667	2937.01	151.85
14880	2021 09 28 11:23:00	19.4333	2936.35	151.79	19.4333	2937.04	151.85
14928	2021 09 28 11:27:00	19.5000	2936.35	151.79	19.5000	2937.06	151.85
14976	2021 09 28 11:31:00	19.5667	2936.33	151.79	19.5667	2937.02	151.85
15024	2021 09 28 11:35:00	19.6333	2936.33	151.79	19.6333	2937.03	151.85
15072	2021 09 28 11:39:00	19.7000	2936.38	151.79	19.7000	2937.05	151.85
15120	2021 09 28 11:43:00	19.7667	2936.34	151.79	19.7667	2937.00	151.85
15168	2021 09 28 11:47:00	19.8333	2936.37	151.79	19.8333	2937.03	151.85
15216	2021 09 28 11:51:00	19.9000	2936.36	151.79	19.9000	2937.02	151.85
15264	2021 09 28 11:55:00	19.9667	2936.37	151.79	19.9667	2937.05	151.85
15312	2021 09 28 11:59:00	20.0333	2936.32	151.79	20.0333	2937.03	151.85
15360	2021 09 28 12:03:00	20.1000	2936.35	151.79	20.1000	2937.04	151.85
15408	2021 09 28 12:07:00	20.1667	2936.36	151.79	20.1667	2937.04	151.85
15456	2021 09 28 12:11:00	20.2333	2936.34	151.79	20.2333	2937.03	151.85
15504	2021 09 28 12:15:00	20.3000	2936.35	151.79	20.3000	2937.03	151.85
15552	2021 09 28 12:19:00	20.3667	2936.34	151.79	20.3667	2937.03	151.85
15600	2021 09 28 12:23:00	20.4333	2936.35	151.79	20.4333	2937.01	151.86
15648	2021 09 28 12:27:00	20.5000	2936.36	151.79	20.5000	2937.00	151.85
15696	2021 09 28 12:31:00	20.5667	2936.37	151.79	20.5667	2937.00	151.85
15744	2021 09 28 12:35:00	20.6333	2936.38	151.80	20.6333	2937.04	151.85
15792	2021 09 28 12:39:00	20.7000	2936.38	151.79	20.7000	2937.06	151.85
15840	2021 09 28 12:43:00	20.7667	2936.31	151.79	20.7667	2937.02	151.85
15888	2021 09 28 12:47:00	20.8333	2936.33	151.79	20.8333	2937.02	151.85
15936	2021 09 28 12:51:00	20.9000	2936.36	151.79	20.9000	2937.05	151.85
15984	2021 09 28 12:55:00	20.9667	2936.35	151.79	20.9667	2937.03	151.85
16032	2021 09 28 12:59:00	21.0333	2936.36	151.79	21.0333	2937.03	151.85
16080	2021 09 28 13:03:00	21.1000	2936.36	151.79	21.1000	2937.04	151.85
16128	2021 09 28 13:07:00	21.1667	2936.33	151.79	21.1667	2937.00	151.85
16176	2021 09 28 13:11:00	21.2333	2936.36	151.79	21.2333	2937.01	151.85
16224	2021 09 28 13:15:00	21.3000	2936.38	151.79	21.3000	2937.04	151.85
16272	2021 09 28 13:19:00	21.3667	2936.34	151.79	21.3667	2937.03	151.85
16320	2021 09 28 13:23:00	21.4333	2936.37	151.79	21.4333	2937.03	151.85
16368	2021 09 28 13:27:00	21.5000	2936.36	151.79	21.5000	2937.03	151.85
16416	2021 09 28 13:31:00	21.5667	2936.35	151.79	21.5667	2937.03	151.85
16464	2021 09 28 13:35:00	21.6333	2936.36	151.79	21.6333	2937.03	151.85
16512	2021 09 28 13:39:00	21.7000	2936.38	151.79	21.7000	2937.01	151.85
16560	2021 09 28 13:43:00	21.7667	2936.37	151.79	21.7667	2937.05	151.85
16608	2021 09 28 13:47:00	21.8333	2936.37	151.79	21.8333	2937.03	151.85
16656	2021 09 28 13:51:00	21.9000	2936.37	151.79	21.9000	2937.06	151.85
16704	2021 09 28 13:55:00	21.9667	2936.39	151.79	21.9667	2937.05	151.85
16752	2021 09 28 13:59:00	22.0333	2936.35	151.79	22.0333	2937.02	151.85

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg F	Time (Hrs)	Pressure PSIA	Temp Deg F
16800	2021 09 28 14:03:00	22.1000	2936.36	151.79	22.1000	2937.02	151.85
16848	2021 09 28 14:07:00	22.1667	2936.40	151.79	22.1667	2937.02	151.85
16896	2021 09 28 14:11:00	22.2333	2936.39	151.79	22.2333	2937.07	151.85
16944	2021 09 28 14:15:00	22.3000	2936.37	151.79	22.3000	2937.04	151.85
16992	2021 09 28 14:19:00	22.3667	2936.36	151.79	22.3667	2937.03	151.85
17040	2021 09 28 14:23:00	22.4333	2936.38	151.79	22.4333	2937.04	151.85
17088	2021 09 28 14:27:00	22.5000	2936.38	151.79	22.5000	2937.05	151.85
17136	2021 09 28 14:31:00	22.5667	2936.37	151.79	22.5667	2937.04	151.85
17184	2021 09 28 14:35:00	22.6333	2936.40	151.79	22.6333	2937.03	151.85
17232	2021 09 28 14:39:00	22.7000	2936.35	151.79	22.7000	2937.05	151.85
17280	2021 09 28 14:43:00	22.7667	2936.37	151.79	22.7667	2937.04	151.85
17328	2021 09 28 14:47:00	22.8333	2936.36	151.79	22.8333	2937.03	151.85
17376	2021 09 28 14:51:00	22.9000	2936.39	151.79	22.9000	2937.07	151.85
17424	2021 09 28 14:55:00	22.9667	2936.37	151.79	22.9667	2937.03	151.85
17472	2021 09 28 14:59:00	23.0333	2936.37	151.79	23.0333	2937.02	151.85
17520	2021 09 28 15:03:00	23.1000	2936.37	151.79	23.1000	2937.05	151.85
17568	2021 09 28 15:07:00	23.1667	2936.33	151.79	23.1667	2937.04	151.85
17616	2021 09 28 15:11:00	23.2333	2936.33	151.79	23.2333	2937.02	151.85
17664	2021 09 28 15:15:00	23.3000	2936.38	151.79	23.3000	2937.02	151.85
17712	2021 09 28 15:19:00	23.3667	2936.37	151.79	23.3667	2937.02	151.85
17760	2021 09 28 15:23:00	23.4333	2936.35	151.79	23.4333	2937.04	151.85
17808	2021 09 28 15:27:00	23.5000	2936.35	151.79	23.5000	2937.03	151.85
17856	2021 09 28 15:31:00	23.5667	2936.37	151.79	23.5667	2937.05	151.85
17904	2021 09 28 15:35:00	23.6333	2936.38	151.80	23.6333	2937.01	151.85
17952	2021 09 28 15:39:00	23.7000	2936.35	151.80	23.7000	2937.08	151.86
18000	2021 09 28 15:43:00	23.7667	2936.37	151.79	23.7667	2937.06	151.85
18048	2021 09 28 15:47:00	23.8333	2936.36	151.79	23.8333	2937.03	151.86
18096	2021 09 28 15:51:00	23.9000	2936.37	151.79	23.9000	2937.02	151.86
18144	2021 09 28 15:55:00	23.9667	2936.35	151.79	23.9667	2937.01	151.85
18192	2021 09 28 15:59:00	24.0333	2936.36	151.79	24.0333	2937.07	151.86
18240	2021 09 28 16:03:00	24.1000	2936.38	151.80	24.1000	2937.00	151.85
18288	2021 09 28 16:07:00	24.1667	2936.36	151.79	24.1667	2937.03	151.85
18336	2021 09 28 16:11:00	24.2333	2936.37	151.79	24.2333	2937.02	151.85
18384	2021 09 28 16:15:00	24.3000	2936.39	151.79	24.3000	2936.99	151.85
18432	2021 09 28 16:19:00	24.3667	2936.39	151.79	24.3667	2937.02	151.85
18480	2021 09 28 16:23:00	24.4333	2936.38	151.79	24.4333	2937.05	151.85
18528	2021 09 28 16:27:00	24.5000	2936.35	151.79	24.5000	2937.02	151.85
18576	2021 09 28 16:31:00	24.5667	2936.37	151.79	24.5667	2937.04	151.85
18624	2021 09 28 16:35:00	24.6333	2936.37	151.79	24.6333	2937.04	151.85
18672	2021 09 28 16:39:00	24.7000	2936.36	151.79	24.7000	2937.07	151.85
18720	2021 09 28 16:43:00	24.7667	2936.36	151.79	24.7667	2937.03	151.85
18768	2021 09 28 16:47:00	24.8333	2936.34	151.79	24.8333	2937.02	151.85

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg F	Time (Hrs)	Pressure PSIA	Temp Deg F
18816	2021 09 28 16:51:00	24.9000	2936.37	151.79	24.9000	2937.02	151.85
18864	2021 09 28 16:55:00	24.9667	2936.36	151.79	24.9667	2937.01	151.85
18912	2021 09 28 16:59:00	25.0333	2936.35	151.79	25.0333	2937.06	151.85
18960	2021 09 28 17:03:00	25.1000	2936.37	151.79	25.1000	2937.01	151.85
19008	2021 09 28 17:07:00	25.1667	2936.39	151.79	25.1667	2937.04	151.85
19056	2021 09 28 17:11:00	25.2333	2936.36	151.79	25.2333	2937.04	151.85
19104	2021 09 28 17:15:00	25.3000	2936.38	151.79	25.3000	2937.01	151.85
19152	2021 09 28 17:19:00	25.3667	2936.39	151.79	25.3667	2937.02	151.85
19200	2021 09 28 17:23:00	25.4333	2936.36	151.79	25.4333	2937.07	151.85
19248	2021 09 28 17:27:00	25.5000	2936.37	151.79	25.5000	2937.04	151.85
19296	2021 09 28 17:31:00	25.5667	2936.38	151.79	25.5667	2937.02	151.85
19344	2021 09 28 17:35:00	25.6333	2936.39	151.79	25.6333	2937.04	151.85
19392	2021 09 28 17:39:00	25.7000	2936.31	151.79	25.7000	2937.03	151.85
19440	2021 09 28 17:43:00	25.7667	2936.35	151.80	25.7667	2937.05	151.85
19488	2021 09 28 17:47:00	25.8333	2936.39	151.79	25.8333	2937.04	151.85
19536	2021 09 28 17:51:00	25.9000	2936.36	151.79	25.9000	2937.03	151.85
19584	2021 09 28 17:55:00	25.9667	2936.34	151.79	25.9667	2937.06	151.86
19632	2021 09 28 17:59:00	26.0333	2936.38	151.79	26.0333	2937.06	151.86
19680	2021 09 28 18:03:00	26.1000	2936.38	151.79	26.1000	2937.02	151.85
19728	2021 09 28 18:07:00	26.1667	2936.35	151.79	26.1667	2937.02	151.85
19776	2021 09 28 18:11:00	26.2333	2936.37	151.80	26.2333	2937.05	151.85
19824	2021 09 28 18:15:00	26.3000	2936.36	151.79	26.3000	2937.02	151.85
19872	2021 09 28 18:19:00	26.3667	2936.42	151.79	26.3667	2937.07	151.85
19920	2021 09 28 18:23:00	26.4333	2936.37	151.79	26.4333	2937.05	151.85
19968	2021 09 28 18:27:00	26.5000	2936.37	151.79	26.5000	2937.00	151.85
20016	2021 09 28 18:31:00	26.5667	2936.33	151.79	26.5667	2937.04	151.85
20064	2021 09 28 18:35:00	26.6333	2936.35	151.79	26.6333	2937.03	151.85
20112	2021 09 28 18:39:00	26.7000	2936.39	151.79	26.7000	2937.03	151.85
20160	2021 09 28 18:43:00	26.7667	2936.36	151.79	26.7667	2937.04	151.85
20208	2021 09 28 18:47:00	26.8333	2936.38	151.79	26.8333	2937.03	151.85
20256	2021 09 28 18:51:00	26.9000	2936.34	151.79	26.9000	2936.99	151.85
20285	2021 09 28 18:53:25	26.9403	2936.41	151.79	26.9403	2937.09	151.85
					5975.00 ft KB-TVD- Off Bottom		
20304	2021 09 28 18:55:00	26.9667	2747.35	151.77	26.9667	2744.93	151.83
20352	2021 09 28 18:59:00	27.0333	2749.31	151.41	27.0333	2750.07	151.75
20400	2021 09 28 19:03:00	27.1000	2756.42	151.66	27.1000	2757.00	151.68
20448	2021 09 28 19:07:00	27.1667	2760.81	151.85	27.1667	2761.73	151.84
20496	2021 09 28 19:11:00	27.2333	2765.82	152.20	27.2333	2766.91	152.12
20544	2021 09 28 19:15:00	27.3000	2771.30	152.32	27.3000	2772.51	152.30
20592	2021 09 28 19:19:00	27.3667	2776.23	152.38	27.3667	2777.10	152.39
20640	2021 09 28 19:23:00	27.4333	2787.46	152.41	27.4333	2787.91	152.44
20688	2021 09 28 19:27:00	27.5000	2788.15	152.41	27.5000	2788.71	152.46

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg F	Time (Hrs)	Pressure PSIA	Temp Deg F
20736	2021 09 28 19:31:00	27.5667	2774.81	152.40	27.5667	2776.09	152.46
20784	2021 09 28 19:35:00	27.6333	2758.56	152.41	27.6333	2759.35	152.46
20832	2021 09 28 19:39:00	27.7000	2932.95	152.50	27.7000	2933.61	152.52
20880	2021 09 28 19:43:00	27.7667	2963.61	150.81	27.7667	2968.84	151.69
20928	2021 09 28 19:47:00	27.8333	2997.88	145.44	27.8333	3005.66	146.70
20976	2021 09 28 19:51:00	27.9000	3040.78	141.64	27.9000	3049.71	142.64
21024	2021 09 28 19:55:00	27.9667	2949.47	139.42	27.9667	2949.36	139.99
21072	2021 09 28 19:59:00	28.0333	2936.38	140.69	28.0333	2936.53	140.56
21120	2021 09 28 20:03:00	28.1000	2935.76	141.33	28.1000	2935.94	141.14
21168	2021 09 28 20:07:00	28.1667	2935.53	141.77	28.1667	2935.78	141.60
21216	2021 09 28 20:11:00	28.2333	2935.64	142.28	28.2333	2935.89	142.07
21264	2021 09 28 20:15:00	28.3000	2935.37	142.69	28.3000	2935.60	142.50
21312	2021 09 28 20:19:00	28.3667	2935.30	143.09	28.3667	2935.51	142.89
21360	2021 09 28 20:23:00	28.4333	2935.22	143.38	28.4333	2935.47	143.22
21408	2021 09 28 20:27:00	28.5000	2935.18	143.63	28.5000	2935.40	143.49
21438	2021 09 28 20:29:30	28.5417	2935.17	143.79	28.5417	2935.19	143.65
						Pulled Off Bottom	
21456	2021 09 28 20:31:00	28.5667	2908.06	144.95	28.5667	2908.44	144.46
21504	2021 09 28 20:35:00	28.6333	2907.48	145.88	28.6333	2908.00	145.73
21552	2021 09 28 20:39:00	28.7000	2878.16	146.01	28.7000	2875.12	145.99
21600	2021 09 28 20:43:00	28.7667	2798.66	144.65	28.7667	2799.14	144.84
21648	2021 09 28 20:47:00	28.8333	2719.79	142.78	28.8333	2714.63	143.16
21696	2021 09 28 20:51:00	28.9000	2629.59	140.11	28.9000	2630.01	140.93
21744	2021 09 28 20:55:00	28.9667	2515.15	137.19	28.9667	2509.25	138.01
21792	2021 09 28 20:59:00	29.0333	2432.27	134.64	29.0333	2432.47	135.49
21840	2021 09 28 21:03:00	29.1000	2315.63	131.83	29.1000	2320.02	132.32
21888	2021 09 28 21:07:00	29.1667	1946.30	130.35	29.1667	1939.87	130.18
21936	2021 09 28 21:11:00	29.2333	2116.73	128.61	29.2333	2117.35	128.81
21984	2021 09 28 21:15:00	29.3000	1863.48	131.17	29.3000	1864.03	130.87
22032	2021 09 28 21:19:00	29.3667	1715.35	131.94	29.3667	1709.50	131.28
22080	2021 09 28 21:23:00	29.4333	1674.00	131.87	29.4333	1674.16	130.67
22128	2021 09 28 21:27:00	29.5000	1314.92	130.24	29.5000	1241.41	130.20
22176	2021 09 28 21:31:00	29.5667	1161.92	124.85	29.5667	1215.69	124.95
22224	2021 09 28 21:35:00	29.6333	1334.67	119.26	29.6333	1335.20	119.56
22272	2021 09 28 21:39:00	29.7000	1231.57	119.61	29.7000	1224.47	119.71
22320	2021 09 28 21:43:00	29.7667	1194.94	112.92	29.7667	1195.07	113.29
22368	2021 09 28 21:47:00	29.8333	1080.17	109.49	29.8333	1080.05	109.77
22416	2021 09 28 21:51:00	29.9000	1069.25	106.48	29.9000	1069.57	106.57
22464	2021 09 28 21:55:00	29.9667	1036.89	106.12	29.9667	1037.06	105.87
22512	2021 09 28 21:59:00	30.0333	1005.20	104.25	30.0333	1005.45	104.17
22560	2021 09 28 22:03:00	30.1000	1005.50	103.01	30.1000	1005.68	103.10
22608	2021 09 28 22:07:00	30.1667	1005.54	101.93	30.1667	1005.69	102.12

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg F	Time (Hrs)	Pressure PSIA	Temp Deg F
22656	2021 09 28 22:11:00	30.2333	940.81	101.03	30.2333	941.01	100.93
22704	2021 09 28 22:15:00	30.3000	941.00	99.90	30.3000	941.18	99.88
22752	2021 09 28 22:19:00	30.3667	909.14	96.90	30.3667	909.28	97.07
22800	2021 09 28 22:23:00	30.4333	875.94	94.53	30.4333	876.07	94.78
22848	2021 09 28 22:27:00	30.5000	848.54	94.37	30.5000	848.04	94.48
22896	2021 09 28 22:31:00	30.5667	752.92	93.91	30.5667	764.76	93.49
22944	2021 09 28 22:35:00	30.6333	333.72	89.26	30.6333	564.03	89.12
22992	2021 09 28 22:39:00	30.7000	549.23	84.36	30.7000	539.07	84.07
23040	2021 09 28 22:43:00	30.7667	491.26	79.56	30.7667	490.68	79.56
23088	2021 09 28 22:47:00	30.8333	523.88	78.96	30.8333	516.81	79.11
23136	2021 09 28 22:51:00	30.9000	594.72	73.26	30.9000	595.80	72.92
23184	2021 09 28 22:55:00	30.9667	1716.90	70.66	30.9667	1709.33	71.12
23232	2021 09 28 22:59:00	31.0333	457.19	70.66	31.0333	456.41	71.04
23280	2021 09 28 23:03:00	31.1000	466.16	71.17	31.1000	467.09	71.29
23328	2021 09 28 23:07:00	31.1667	461.42	72.58	31.1667	461.52	72.51
23376	2021 09 28 23:11:00	31.2333	464.67	73.80	31.2333	465.66	73.58
23424	2021 09 28 23:15:00	31.3000	305.66	75.13	31.3000	294.68	75.07
23472	2021 09 28 23:19:00	31.3667	251.09	73.74	31.3667	251.38	74.05
23520	2021 09 28 23:23:00	31.4333	158.63	74.22	31.4333	158.81	73.96
23568	2021 09 28 23:27:00	31.5000	44.59	76.96	31.5000	43.58	76.84
23616	2021 09 28 23:31:00	31.5667	43.04	74.38	31.5667	43.78	74.16
23664	2021 09 28 23:35:00	31.6333	13.55	74.74	31.6333	13.42	74.72

APPENDIX D

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

Permit Item	NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
Pore Space Amalgamation	NDCC 38-22-06 §3 & 4 NDAC 43-05-01-08 §1 & 2	**NDCC 38-22-06** 3. Notice of the hearing must be given to each mineral lessee, mineral owner, and pore space owner within the storage reservoir and within one-half mile of the storage reservoir's boundaries. 4. Notice of the hearing must be given to each surface owner of land overlying the storage reservoir and within one-half mile of the reservoir's boundaries. **NDAC 43-05-01-08** 1. The commission shall hold a public hearing before issuing a storage facility permit. At least forty-five days prior to the hearing, the applicant shall give notice of the hearing to the following: a. Each operator of mineral extraction activities within the facility area and within one-half mile [.80 kilometer] of its outside boundary; b. Each mineral lessee of record within the facility area and within one-half mile [.80 kilometer] of its outside boundary; c. Each owner of record of the surface within the facility area and one-half mile [.80 kilometer] of its outside boundary; d. Each owner of record of minerals within the facility area and within one-half mile [.80 kilometer] of its outside boundary; e. Each owner and each lessee of record of the	a. An affidavit of mailing certifying that all pore space owners and lessees within the storage reservoir boundary and within one-half mile outside of its boundary have been notified of the proposed carbon dioxide storage project;	**1.0 PORE SPACE ACCESS (2nd paragraph, p. 1-1)** Dakota Gasification Company (DGC) has identified the owners (surface and mineral). In addition, with the exception of coal extraction, there are no mineral lessees or operators of mineral extraction activities within the facility area or within 0.5 miles of its outside boundary. DGC will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made.	N/A
			b. A map showing the extent of the pore space that will be occupied by carbon dioxide over the life of the project;	**1.0 PORE SPACE ACCESS (p. 1-1)** North Dakota law explicitly grants title of the pore space in all strata underlying the surface of lands and waters to the overlying surface estate, i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] Chapter 47-31 – Subsurface Pore Space Policy). Prior to issuance of the storage facility permit (SFP), the storage operator is mandated by the North Dakota statute governing geologic storage of carbon dioxide (CO_2) to obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir. The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are or will be equitably compensated. North Dakota law grants the North Dakota Industrial Commission (NDIC) the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation. Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application (NDCC §§ 38-22-06[3] and 38-22-06[4] and North Dakota Administrative Code [NDAC] §§ 43-05-01-08[1] and 43-05-01-08[2]). Dakota Gasification Company (DGC) has identified the owners (surface and mineral). In addition, with the exception of coal extraction, there are no mineral lessees or operators of mineral extraction activities within the facility area or within 0.5 miles of its outside boundary. DGC will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made. All owners, lessees, and operators that require notification have been identified in accordance with North Dakota law, which vests the title to the pore space in all strata underlying the surface of lands and water to the owner of the overlying surface estate (NDCC Chapter 47-31). The identification of pore space owners indicates that there was no severance of pore space or leasing of pore space to a third-party from the surface estate prior to 2009. Maps showing the extent of the pore space that will be occupied by CO_2 over the life of the project, including the storage reservoir boundary and 0.5 miles (0.8 kilometers) outside of the storage reservoir boundary with a description of pore space ownership, surface owner, and pore space lessees of record are illustrated in Figures 1-1 and 1-2.	Figure 1-1. Storage facility area map showing pore space ownership and Figure 1-2 (p. 1-2) Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area. (p. 1-3)
			c. A map showing the storage reservoir boundary and one-half mile outside of the storage reservoir boundary with a description of pore space ownership;		Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area. (p. 1-3).
			d. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each operator of mineral extraction activities;		Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area. (p. 1-3).
			e. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each mineral lessee of record;		
			f. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each surface owner of record;		Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area (p 1-3).
			g. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each owner of record of minerals.		Figure 1-2. Hearing notification area for landowners within ½ mile of

		pore space within the storage reservoir and within one-half mile [.80 kilometer] of the reservoir's boundary; and f. Any other persons as required by the commission. 2. The notice given by the applicant must contain: a. A legal description of the land within the facility area. b. The date, time, and place that the commission will hold a hearing on the permit application. c. A statement that a copy of the permit application and draft permit may be obtained from the commission.			the storage facility area. (p. 1-3).
Geologic Exhibits	NDAC 43-05-01-05 §1b(1)	NDAC 43-05-01-05 §1b(1) (1) The name, description, and average depth of the storage reservoirs;	a. Geologic description of the storage reservoir: Name Lithology Average depth Average thickness	**2.1 Overview of Project Area Geology (p. 2-1)** The proposed DGC Great Plains CO_2 Sequestration Project will be situated near Beulah, North Dakota (Figure 2-1). This project site is on the central portion of the Williston Basin. The Williston Basin is an intracratonic sedimentary basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted via the PCOR Partnership, the Williston Basin has been identified as an excellent candidate for long-term CO_2 storage because of, in part, the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structure character and tectonic stability (Peck and others, 2014; Glazewski and others, 2015). The target CO_2 storage reservoir for the Great Plains CO_2 Sequestration Project is the Broom Creek Formation, a predominantly sandstone horizon lying about 5,900 ft below DGC's Great Plains Synfuels Plant (Figure 2-2). Mudstones, siltstones, and interbedded evaporites of the Opeche Formation unconformably overly the Broom Creek and serve as the primary confining zone (Figure 2-3). The Amsden Formation (dolostone, limestone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-3). Together, the Opeche, Broom Creek, and Amsden comprise the CO_2 storage complex for the Great Plains CO_2 Sequestration Project (Table 2-1). Including the Opeche Formation, there is ~1,100 ft of impermeable formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation. An additional ~2,700 ft of impermeable intervals separates the Inyan Kara and the lowest USDW, the Fox Hills Formation (Figure 2-3).	Figure 2-1. Topographic map of the Great Plains CO_2 Sequestration Project area showing well locations and the Great Plains Synfuels Plant (p. 2-2) Figure 2-2. Map of the proposed CO_2 injection wells (p. 2-3) Figure 2-3. Stratigraphic column identifying the storage reservoir, confining zones, and lowest USDW addressed in this permit application for the Great Plains CO_2 Sequestration Project (p. 2-4) Table 2-1. Formations Comprising the Great Plains CO2 Sequestration Project Storage Complex (p. 2-5)

Table 2-1. Formations Comprising the Great Plains CO_2 Sequestration Project Storage Complex (average values calculated from the simulation model and well log data)

	Formation	Purpose	Average Thickness, ft	Average Measured Depth (MD), ft	Lithology
	Opeche	Upper confining zone	150	4,887	Mudstone, siltstone, evaporites
Storage Complex	Broom Creek	Storage reservoir (i.e., injection zone)	248	5,348	Sandstone, dolostone, dolomitic sandstone, anhydrite
	Amsden	Lower confining zone	268	5,558	Dolostone, limestone, anhydrite

NDAC 43-05-01-05 §1b(2)(k)

NDAC 43-05-01-05 §1b(2)(k)
(k) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;

b. Data on the injection zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:
- Depth
- Areal extent
- Thickness
- Mineralogy
- Porosity
- Permeability
- Capillary pressure
- Facies changes

SOURCE OF THE DATA:
2.2.1 Existing Data **(p. 2-3)**
The existing data used to characterize the geology beneath the Great Plains CO_2 Sequestration Project site included publicly available well logs and formation top depths acquired from the North Dakota Industrial Commission's (NDIC's) online database. Well log data and interpreted formation top depths were acquired for 120 wellbores within a 5472-mi² (72 × 76-mi) area centered on the proposed storage site (Figure 2-4). Well data were used to characterize the depth, thickness, and extent of the subsurface geologic formations.

Existing laboratory measurements from Broom Creek Formation core samples were available from five wells shown in Figure 2-5: Coteau 1 (NDIC File No. 38379), Flemmer 1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), J-LOC1 (NDIC File No. 37380), J-ROC1 (NDIC File No. 37672), and ANG #1 (North Dakota Department of Environmental Quality [NDEQ] No. 11308). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and integrated with newly acquired site-specific data.

Ten square miles of legacy 3D seismic data from Mercer County, encompassing the Flemmer 1 wellsite, and twenty-eight miles of legacy 2D seismic data were licensed and examined to understand the heterogeneity and geologic structure of the Broom Creek Formation interval. Additionally, publicly available seismic interpretation products for the Broom Creek from a 3D seismic survey in Oliver County were used to inform structure and variogram distributions (Section 3.2). The structural configurations of the formations of interest generated from the interpretation of the two 3D seismic data sets along with formation tops interpreted from well log data were used to construct the geologic model. Variogram distributions derived from inversion volumes generated using the 3D seismic data were used to inform property distribution in the geologic model which was, in turn, used to simulate migration of the CO_2 plume. These simulated CO_2 plumes were used to inform the testing and monitoring plan (Section 5).

DATA ON THE INJECTION ZONE:
2.3 Storage Reservoir (injection zone) (p. 2-12)
Locally, the Broom Creek Formation is laterally extensive (Figure 2-7) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers).

2.3 Storage Reservoir (injection zone) (p. 2-12)
Locally, the Broom Creek Formation is laterally extensive (Figure 2-7) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone, siltstones, and evaporites of the Opeche Formation (Figure 2-3).

Figure 2-4. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones (p. 2-5)

Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (modified from Rygh and others [1990]). Based on new well control shown outside of the green dashed line. (p. 2-13)

At Coteau 1, the Broom Creek Formation is 258 ft thick; is made up of 134 ft of sandstone, 35 ft of dolostone, 24 ft of anhydrite, and 65 ft of dolomitic sandstone; and is located at a depth of 5,906 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 163 to 322 ft (Figure 2-8), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 24 to 205 ft, with an average of 99 ft.

The top of the Broom Creek Formation was picked across the model area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-9). The top of the Amsden Formation was placed at the bottom of a relatively high GR signature representing an argillaceous dolostone that can be correlated across the entirety of the Great Plains CO2 Sequestration Project Area. 2D seismic data collected as part of site characterization efforts were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and analyses indicate that there should be few-to-no major reservoir stratigraphic discontinuities near the Coteau 1 well (Figures 2-10 and 2-11). The Broom Creek Formation is estimated to pinch out ~34 miles to the east of the Coteau 1 wellsite. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Great Plains CO2 Sequestration Project Area (Figure 2-12 and Figure 2-13). (p. 2-14)

Twenty-two 1-inch-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the Coteau 1 well. From the twenty-two samples, three samples at 5,941.95', 5,969.9', and 5,994.4' were duplicated and oriented 90 degrees compared to the original core plug to investigate the possibility of any orientation-dependent permeability existing in the reservoir. The remaining nineteen core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the Coteau 1 Broom Creek Formation core samples have porosity values ranging from 1.41% to 34.39% at 800 psi and 7.88% to 30.34% at 2400 psi. Permeabilities range from 0.13 to 12,300 mD at 800 psi and 0.118 to 3,990 mD at 2400 psi (Table 2-7). The wide range in porosity and permeability reflects the differences between the sandstone and dolostone lithofacies in the Broom Creek Formation. Portions of the Broom Creek Formation core revealed unconsolidated or poorly consolidated sandstone.

2.3.1 Mineralogy **(p. 2-23)**
XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek Formation core primarily comprises quartz, feldspar, carbonates, anhydrite, clay, and other minor minerals (Figure 2-19).

XRF data are shown in Figure 2-20 for the Broom Creek Formation. Sandstone and dolomite intervals are confirmed through the high percentages of SiO_2 (71%–98%), CaO (19%–36%), and MgO (13%–21%). The high percentage of CaO and SO_3 at 5,908.1, 6,141, and 6,154.2 ft indicate a presence of anhydrite beds. The formation shows little volumes of clay, with a range of 0.04% to 10.54% for all samples.

Table 2-9. XRD Results for Coteau 1 Broom Creek Core Sample

Mineral Data	%
Albite	2.25
Anhydrite	15.17
Anorthite	1.96
Dolomite	23.91
Illite	2.85
Pyrite	0.13
Quartz	54.15

Figure 2-3. Stratigraphic column identifying the storage reservoir, confining zones, and lowest USDW addressed in this permit application for the Great Plains CO_2 Sequestration Project (p. 2-4)

Figure 2-8. Isopach map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project Area (p. 2-14)

Figure 2-9. Well log display of the interpreted lithologies of the Opeche, Broom Creek, and upper Amsden Formations in the Coteau 1 well (p. 2-15)

Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-16)

Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-17)

Figure 2-12. Structure map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops). (p. 2-18)

Figure 2-13. Cross section of the Great Plains CO_2 Sequestration Project storage complex from the geologic

Table 2-7. Description of CO_2 Storage Reservoir (injection zone) at the Coteau 1 Well Injection Zone Properties

Property	Description
Formation Name	Broom Creek
Lithology	Sandstone, dolostone, dolomitic sandstone, anhydrite
Formation Top Depth, ft	**5,906**
Thickness, ft	Sandstone 134 Dolostone 35 Dolomitic sandstone 65 Anhydrite 24
Capillary Entry Pressure (CO_2/brine), psi	0.72

Geologic Properties

Formation	Property	Laboratory Analysis	Simulation Model Property Distribution
Broom Creek (sandstone)	Porosity, %*	21.28 **(7.88–30.34)**	**23.64 (3.65–35.77)**
	Permeability, mD**	221.84 (2.92–3,990)	246.74 (0.001–3,379)
Broom Creek (dolostone)	**Porosity, %**	**8.79 (8.66–8.94)**	**5.68 (0.1–25.99)**
	Permeability, mD	0.180 (0.118–0.361)	0.02 (0–220)

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses.
** Permeability values are reported as the geometric mean followed by the range of values in parentheses.

2.3.3 *Geochemical Information of Injection Zone*

Geochemical simulation has been performed to calculate the effects of introducing the CO_2 stream to the injection zone.

The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in the Computer Modelling Group Ltd. (CMG) compositional simulation software package GEM. GEM is also the primary simulation software used for evaluation of the reservoir's dynamic behavior resulting from the expected CO_2 injection. For this geochemical modeling study, the injection scenario consisted of a single injection well injecting for a 12-year period with maximum BHP and maximum gas injection rate (STG) constraints of 3,833 psi and 25 MMcfd (468,000 tonnes/year), respectively. A postinjection period of 25 years was run in the model to evaluate any dynamic behavior and/or geochemical reaction after the CO_2 injection is stopped. This geochemical scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared (Figure 2-21).

model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level. (p. 2-20)

Table 2-7. Description of CO_2 Storage Reservoir (injection zone) at the Coteau 1 Well Injection Zone Properties (p. 2-19)

Figure 2-19. Described core and laboratory-derived mineralogic characteristics of the Opeche, Broom Creek, and Amsden Formations (p. 2-26)

Figure 2-20. XRF data from the Broom Creek Formation from the Coteau 1 (p. 2-27)

Table 2-9. XRD Results for Coteau 1 Broom Creek Core Sample (p. 2-31)

Figure 2-21. Upper graph shows cumulative injection vs. time; the bottom figure shows the gas injection rate vs. time. There is no observable difference in injection due to geochemical reactions (p. 2-29)

Figure 2-22. 2D map showing the water salinity plume from the disposal wells, ANG #1 and ANG #2, and the gas mole fraction (CO_2) for the expected injection scenario for this project described in Section 3 consisting of six CO_2 injection wells. The lower map shows the stabilized CO_2 plume vs. the salinity plume extent after 10 years postinjection, in July 2044. (p. 2-30)

Table 2-9. XRD Results for Coteau 1 Broom Creek Core Sample (p. 2-31)

Table 2-10. Broom Creek Water Ionic Composition, expressed in molality (p. 2-31)

				Simulation results indicate that the low-salinity plume (TDS 8,050 ppm) associated with the ANG #1 and AN water and the injected CO_2 plume for the six-well injection scenario discussed in Section 3 may have little interaction after 10 years of postinjection (Figure 2-22). Based on this limited interaction of the injected CO_2 and the injected disposal water and the chemical composition of the disposal water, the ANG disposal well injection was not included as part of the geochemical modeling for computational efficiency. The historical ANG well injection up to August 2021 was included during the modeling. Geochemical alteration effects were seen in the geochemistry case, as described below. However, these effects were not significant enough to cause meaningful changes to the storage reservoir performance of the storage formation. For more details regarding the geochemical information of injection zone, see Section 2.3.3 on page 2-27.	Table 2-11. ANG #1 Water Ionic Composition, expressed in molality (p. 2-31) Figure 2-23. BHP and WHP vs. time. There is no observable difference in injection pressure due to geochemical reactions as compared to the results without the geochemical model. (p. 2-32) Figure 2-24a. CO_2 molality for the geochemistry case simulation results after 12 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east and right upper are north-south cross sections. Lower image is a planar view of simulation in layer k = 11. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-33) Figure 2-24b. CO2 molality for the non-geochemistry model (bottom) results after 12 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east and right upper are north-south cross sections. Lower image is a planar view of simulation in layer k = 11. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-34) Figure 2-25. Geochemistry case simulation results after 12 years of injection + 25 years postinjection showing the pH of formation brine in log scale. White grid cells correspond to cells omitted from calculations because of having porosity

					and/or permeability values that round to zero. (p. 2-35) Figure 2-26. Dissolution and precipitation quantities of reservoir minerals because of CO_2 injection. Dissolution of anorthite with precipitation of pyrite, albite, and dolomite was observed. Upper figure shows all the minerals; the lower figure is rescaled for better view of the minerals mass change except pyrite. (p. 2-36) Figure 2-27. Change in molar distribution of anorthite, the most prominent dissolved mineral at the end of the 12-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-37) Figure 2-28. Change in molar distribution of albite, a precipitated mineral at the end of the 12-year injection + 25 years postinjection period in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-38) Figure 2-29. Change in molar distribution of dolomite, a precipitated mineral at the end of the 12-year injection + 25 years postinjection period in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-39) Figure 2-30. Change in molar distribution of pyrite, the most prominent precipitated mineral at the end of the 12-year injection + 25 years

postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-40)

c. Data on the confining zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:
   - Depth
   - Areal extent
   - Thickness
   - Mineralogy
   - Porosity
   - Permeability
   - Capillary pressure
   - Facies changes

SOURCE OF THE DATA:
See discussion above under 2.2.1 Existing Data (p. 2-3 and 2-6)

DATA ON THE CONFINING ZONE:
See Figures 2-10 through 2-12 and Figure 2-19

AND

2.4 Confining Zones (p. 2-41)
The confining zones for the Broom Creek Formation are the Opeche interval and underlying Amsden Formation (Figure 2-3, Table 2-12). Both the Amsden and Opeche intervals consist of impermeable rock layers.

Table 2-12. Properties of Upper and Lower Confining Zones in Simulation Area (data based on the Coteau 1 well)

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	**Opeche**	**Amsden**
Primary Lithology	Silty mudstone	Dolostone
Formation Top Depth, ft	**5,763**	**6,164**
Thickness, ft	143	300
Porosity, % (core data) *	**6.93**	**2.40**
Permeability, mD (core data) **	0.002878	0.00116
Capillary Entry Pressure (CO_2/brine), psi	**138.68**	**251.27**
Depth below Lowest Identified USDW, ft	4,658	5,059

* Porosity values are reported as the arithmetic mean.
** Permeability values are reported as the geometric mean.

***2.4.1 Upper Confining Zone* (p. 2-41)**
In the Great Plains CO_2 Sequestration Project area, the Opeche Formation consists of silty mudstone and anhydrite. The upper confining zone (Opeche) is laterally extensive across the Great Plains CO_2 Sequestration Project area (Figure 2-31). The upper

Table 2-12. Properties of Upper and Lower Confining Zones in Simulation Area (p. 2-41)

Figure 2-31. Areal extent of the Opeche Formation in North Dakota (p. 2-42)

Figure 2-32. Structure map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (p. 2-43)

Figure 2-33. Isopach map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (p. 2-44)

Figure 2-34. Well log display of the upper confining zone at the Coteau 1 well (p. 2-45)

Figure 2-38. XRD data for the Opeche Formation from the Coteau 1 (p. 2-49)

				confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche interval is 5,763 ft below the land surface and 143 ft thick at the Coteau 1 wellsite (Table 2-12, Figures 2-32 and 2-33). The contact between the upper confining zone and underlying Broom Creek sandstone is an unconformity that can be correlated across the formation's extent where the resistivity and GR logs show a significant change across the contact (Figure 2-34). Microfracture in situ stress tests were not performed within the Opeche Formation in the Coteau 1 well. Microfracture in situ tests were performed using the MDT tool in the Flemmer 1 well, in the Opeche Formation, at a depth of 6,262 ft, which yielded results within good confidence. The MDT tool was able to cause breakdown in the formation at 8,157 psi. Propagation pressure for two cycles in close agreement were 4,879 and 5,085 psi, resulting in an average propagation pressure gradient of 0.80 psi/ft (Figure 2-35). In situ fluid pressure testing was not performed in the Opeche Formation with the MDT tool. The CMR log shown in Figure 2-36 suggests that because of the low to almost zero permeability the fluid within the Opeche is pore- and capillary-bound fluid and not mobile. This is confirmed by unsuccessful attempts by others to extract fluid samples from the Opeche. The Tundra SGS (secure geologic storage) and Red Trail Energy storage facility permit applications describe unsuccessful attempts to draw down reservoir fluid in order to determine the reservoir pressure or to collect an in situ fluid sample; the formation was unable to rebound (build pressure) because of low to almost zero permeability (NDIC, 2021a, b). These unsuccessful attempts provide further evidence of the confining properties of the Opeche Formation, ensuring sufficient geologic integrity to contain the injected carbon dioxide stream. Laboratory measurements from the Opeche Formation core samples taken from the Coteau 1 well indicate a porosity value of 6.93% at 800 psi and 6.62% at 2,400 psi and geometric average permeability values of 0.002878 mD at 800 psi and 0.002083 mD at 2,400 psi. The lithology of the cored sections of the Opeche is primarily silty mudstone. *2.4.1.1 Mineralogy* (p. 2-48) Thin-section investigation shows that the Opeche Formation comprises alternating intervals of very fine silty mudstone and mudstone. In all, five thin sections were created over the 73 ft of core collected from the Opeche Formation. The mineral components present are clay, quartz, anhydrite, feldspar, dolomite, and iron oxides. The coarser grains are almost always surrounded by anhydrite or clay as cement or matrix. The observable porosity is very low and is due to the dissolution of quartz and feldspar. The porosity ranges between 5% and 9%. Permeability is very poor and ranges between 0.00026 to 0.0227 mD. Figure 2-37 shows examples of the texture, fabric, and nature of observable porosity for the intervals where thin sections were created. As shown, observable porosity (shown in blue) is generally isolated and not well connected throughout. Additionally, thin-section analysis shows the fine-grained, well-compacted nature of the intervals evaluated. XRD data from the five Opeche samples of the Coteau 1 core supported facies interpretations from core descriptions and thin-section analysis. The Opeche Formation mainly comprises clay, quartz, feldspar, dolomite, and anhydrite. Figure 2-38 shows the mineralogy determined from XRD data for the five samples tested through the cored interval of the Opeche Formation. XRF analysis of the Opeche Formation shown in Figure 2-39 identifies SiO_2 (44%–57%), Al_2O_3 (6%–18%), CaO (5%–15%), and MgO (3%–9%) as the major chemical constituents, correlating well with the silicate, carbonate, and aluminum-rich mineralogy determined by XRD. This is in good agreement with XRD, core description, and thin-section analysis. *2.4.1.2 Geochemical Interaction (p. 2-50)* Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected CO2 stream on the Opeche Formation, the primary confining zone. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to CO_2 and minor amounts of H2S at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Opeche by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the Opeche Formation. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock –CO_2/H_2S exposure boundary. The mineralogical composition of the Opeche Formation was honored (Table 2-13). The XRD data used to define mineral composition in the model correspond to a mudstone sample from the Opeche Formation. Formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone below (Table 2-14). The CO_2 stream composition was as described in Table 2-15. 96.45 mol% of the stream is CO_2, and the rest represents other components, including H_2S, the second major component of the stream. 96 mol% of CO_2 was used in the simulation instead of 96.45 mol% to keep the model input simple (Table 2.15). The 4 mol% H2S used for this simulation represents the sum of all other components (CH_4, C_2H_6, C_3H_8, N_2) and thus overstates the actual H2S fraction of 1.23 mol% (Table 2-15). The exposure level, expressed in moles per year, of the CO_2 stream to the cap rock used was 4.5 moles/yr.	Figure 2-39. XRF data for the Opeche Formation from the Coteau 1 (p. 2-49) Table 2-13. Mineral Composition of the Opeche Derived from XRD Analysis of Coteau 1 Core Samples (p. 2-50) Table 2-14. Formation Water Chemistry from Broom Creek Fluid Samples from Coteau 1 (p. 2-50) Table 2-15. Composition of the Injection Stream (p. 2-51) Table 2-16. Description of Zones of Confinements above the Immediate Upper Confining Zone (Opeche) (p. 2-50) Figure 2-46. Structure map of the Amsden Formation across the greater Great Plains CO_2 Sequestration Project area (p. 2-57) Figure 2-47. Isopach of the Amsden Formation across the greater Great Plains CO_2 Sequestration Project area (p. 2-58) Figure 2-48. XRD data for the Amsden Formation from the Coteau 1 (p. 2-60) Figure 2-49. XRF data for the Amsden Formation from the Coteau 1 (p. 2-60)

This value is considerably higher than the expected actual exposure level of 2.3 moles/year (Espinoza and Santamarina, 2017). This overestimate was done to ensure that the degree and pace of geochemical change would not be underestimated. This geochemical simulation was run for 37 years to match the reservoir injection zone geochemical model and represent 12 years of injection plus 25 years of postinjection. The simulation was performed at reservoir pressure and temperature conditions.

For more details on Geochemical interaction of the confining zone, refer to section 2.4.1.2 on page 2-51.

2.4.2 Additional Overlying Confining Zones **(p. 2-54)**
Several other formations provide additional confinement above the Opeche interval. Impermeable rocks above the primary seal include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-16). Together with the Opeche interval, these formations are 1,106 ft thick and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-44). Above the Inyan Kara Formation, 2,657 ft of impermeable rocks act as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (Figure 2-44). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-16).

Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (Opeche) (data based on the Coteau 1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,753	1,931	0
Greenhorn	Shale	3,685	376	1,931
Mowry	Shale	4,061	94	2,307
Skull Creek	Shale	4,156	254	2,402
Swift	Shale	4,800	411	3,046
Rierdon	Shale	5,212	205	3,458
Piper (Kline Member)	Limestone	5,417	112	3,663
Piper (Picard Member)	Shale	5,529	233	3,775

2.4.3 Lower Confining Zones **(p. 2-57)**
The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, mudstone, and anhydrite. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, with relatively high GR character that can be correlated across the Great Plains CO_2 Sequestration Project area (Figure 2-6). The Amsden Formation is 6,164 ft below land surface and approximately 300 ft thick at the Coteau 1 well (Figures 2-46 and 2-47, Table 2-12).

The contact between the overlying Broom Creek and Amsden Formations is evident on wireline logs as there is a lithological change from the porous sandstones of the Broom Creek Formation to the dolostone and anhydrite beds of the Amsden Formation. This lithologic change is recognized in the core from the Coteau 1 well. The lithology of the cored section of the Amsden Formation from the Coteau 1 well is dolostone, anhydrite, and mudstone with laminated, fine-grained sandstone and siltstone. Data acquired from the six core plug samples taken from the Amsden Formation show porosity values ranging from 1.00% to 5.27% at 800 psi and 0.91% to 4.54% at 2,400 psi. Permeability values range from 0.0000557 to 1.2 mD at 800 psi and 0.0000642 to 0.215 mD at 2,400 psi (Table 2-17).

2.4.3.1 Mineralogy (p. 2-59)
Thin-section analysis shows that the Amsden Formation comprises dolomite, anhydrite, sandy dolomite, and shaly sand. Six thin sections were created and described for the 83-ft cored Amsden section. The dolomite is expressed by very fine to fine-sized

				dolomite crystals with the presence of quartz of variable size and shape, feldspar, clay, anhydrite, and iron oxides. The porosity is very low and is mainly intragranular because of dissolution with an average of 2%. Anhydrite is present as beds, nodules, and laminations in association with the dolomite intervals. Minor iron oxides inclusions are present. The porosity is almost nonexistent. The dolomite is mainly composed of dolomite crystals and grains of quartz. Minor iron oxides and feldspar are present, with rare occurrence of anhydrite observed. The grains of quartz are almost always separated by dolomite matrix. The porosity is mainly due to the dissolution of feldspar and averages 1%. Finally, the anhydritic sandstone interval is composed of quartz, clay, carbonates, and anhydrite. Iron oxides are present in some parts of the rock matrix as rims around some quartz grains and mostly fill the stylolite surfaces and some rare fractures. The grains of quartz are almost always separated by carbonate cement, clay minerals and, specifically, anhydrite cement. In this lithofacies, anhydrite acts as cement in most parts of the interval by connecting sand grains together and decreasing the overall porosity of the lithofacies. The porosity averages 3% and is mainly due to the dissolution of feldspar and quartz (Figure 2-48). XRD was performed (Figure 2-49), and the results confirm the observations made during core analyses and thin-section description. XRF data shows that the Amsden Formation at the contact with the Broom Creek is dominated by CaO and MgO (major chemical components of dolomite). Deeper samples are more anhydrite-rich, fine- to medium-grained sandstones, as shown by the high percentage of SiO_2, CaO, and SO_3 (Figure 2-50).	
	NDAC 43-05-01-05 §1b(2) ¶	**NDAC 43-05-01-05 §1b(2)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or	d. A description of the storage reservoir's mechanisms of geologic confinement characteristics with regard to preventing migration of carbon dioxide beyond the proposed storage reservoir, including: Rock properties Regional pressure gradients Adsorption processes	*2.2.2.3 Formation Temperature and Pressure* (2nd paragraph, p. 2-9) Temperature data recorded from logging the Coteau 1 and Flemmer 1 wellbores were used to derive a temperature gradient for the proposed injection site (Tables 2-2 and 2-3). In combination with depth, the temperature gradient was used to distribute a temperature property throughout the geologic model of the Great Plains CO2 Sequestration Project area. The temperature property was used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for the geochemical modeling. The formation pressure and temperature at Coteau 1 were collected with a bottomhole pressure (BHP) gauge. In the Coteau 1 well, the Broom Creek was perforated at 5975 ft (1 foot, 4 shots per foot). After perforating, the BHP gauge was run to the perforation depth where temperature and pressure measurements were collected (Appendix C, "Pressure Survey Report"). The pressure data recorded in the Coteau 1 well are shown in Table 2-4. (p. 2-9) ***2.3.2 Mechanism of Geologic Confinement*** 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. 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). After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period of time (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation and, therefore, is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.	Table 2-4. Description of Coteau 1 Formation Pressure Measurements and Calculated Pressure Gradients (p. 2-11) Table 2-5. Description of Flemmer 1 Formation Pressure Measurements and Calculated Pressure Gradients (p. 2-11)

	potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:			
NDAC 43-05-01-05 §1b(2)(g)	NDAC 43-05-01-05 §1b(2)(g) (g) Identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir;	e. Identification of all characteristics controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir, including: Structural spill points Stratigraphic discontinuities	*2.2.2.6 Seismic Survey* (p. 2-12) The proximity of the site to an active coal mine and industrial facilities makes acquisition of 3D seismic data problematic. Placement of seismic source and receiver locations required for a 3D seismic survey would be restricted because of these surface uses potentially resulting in insufficient data quality to image the subsurface for characterization and monitoring purposes. Interpretation of 2D seismic data provides a practical alternative to acquiring and interpreting 3D seismic data. 2D seismic surveys can be used to evaluate the subsurface across large tracts of land, can be oriented to avoid surface obstacles such as those found at this site, can be acquired more frequently for future site monitoring, and eliminates the need to overshoot areas that have already been swept with CO_2. Twenty-eight miles of 2D seismic lines that traverse the storage facility area and intersect the Coteau 1 well were licensed and interpreted (Figure 2-4). The 2D seismic lines were tied to the Coteau 1 well and used to evaluate the thickness and structure of the Broom Creek and upper and lower confining zones within the storage facility area. The interpreted surfaces for the formations of interest derived from the 2D seismic lines were used to confirm that the geologic model is representative of the reservoir thickness and structure within the storage facility area. The 2D seismic data suggest there are no major stratigraphic pinch-outs or structural features with associated spill points in the Great Plains CO_2 Sequestration Project area. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the lowest USDW, the Fox Hills Formation, were observed in the seismic data. Twenty-eight miles of new 2D seismic data centered around the Coteau 1 well was acquired in January 2022 and will be used to confirm these interpretations. **2.3 Storage Reservoir (injection zone) (last sentence in paragraph, p. 2-14)** The top of the Broom Creek Formation was picked across the model area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-9). The top of the Amsden Formation was placed at the bottom of a relatively high GR signature representing an argillaceous dolostone that can be correlated across the entirety of the Great Plains CO_2 Sequestration Project Area. 2D seismic data collected as part of site characterization efforts were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and analyses indicate that there should be few-to-no major reservoir stratigraphic discontinuities near the Coteau 1 well (Figures 2-10 and 2-11). The Broom Creek Formation is estimated to pinch out ~34 miles to the east of the Coteau 1 wellsite. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Great Plains CO_2 Sequestration Project Area (Figure 2-12 and Figure 2-13). ***2.3.2 Mechanism of Geologic Confinement*** 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. 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). After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period of time (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation and, therefore, is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.	Figure 2-9. Well log display of the interpreted lithologies of the Opeche, Broom Creek, and upper Amsden Formations in the Coteau 1 well (p. 2-15) Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-16) Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-17) Figure 2-12. Structure map of the Broom Creek Formation across the greater Great Plains CO2 Sequestration Project area (generated using 3D seismic horizons and well log tops). (p. 2-18) Figure 2-13. Cross section of the Great Plains CO2 Sequestration Project storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations

					are referenced to mean sea level. (p. 2-20)
	NDAC 43-05-01-05 §1b(2)c	NDAC 43-05-01-05 §1b(2)c (c) Any regional or local faulting;	f. Any regional or local faulting;	**2.5 Faults, Fractures, and Seismic Activity (First two paragraphs on p. 2-87)** In the Great Plains CO_2 Sequestration Project area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. The absence of transmissive faults is supported by fluid sample analysis results from Coteau 1 that suggest the injection interval, Broom Creek Formation (42,800 mg/L) is isolated from the next permeable interval, the Inyan Kara Formation (22,800 mg/L). The Williston Basin is a tectonically stable region of the North American Craton. Zhou and others (2008) summarize that "the Williston Basin as a whole is in an overburden compressive stress regime," which could be attributed to the general stability of the North American Craton. Interpreted structural features associated with tectonic activity in the Williston Basin in North Dakota include anticlinal and synclinal structures in the western half of the state, lineaments associated with Precambrian basement block boundaries, and faults (North Dakota Industrial Commission, 2019).	Figure 2-73. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (p. 2-89)
	NDAC 43-05-01-05 §1b(2)(j)	NDAC 43-05-01-05 §1b(2)(j) (j) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone in the area of review, and a determination that they would not interfere with containment;	g. Properties of known or suspected faults and fractures that may transect the confining zone in the area of review: Location Orientation Determination of the probability that they would interfere with containment	**2.5 Faults, Fractures, and Seismic Activity (1st paragraph, p. 2-87)** In the Great Plains CO2 Sequestration Project area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. The absence of transmissive faults is supported by fluid sample analysis results from Coteau 1 that suggest the injection interval, Broom Creek Formation (42,800 mg/L) is isolated from the next permeable interval, the Inyan Kara Formation (22,800 mg/L).	N/A
	NDAC 43-05-01-05 §1b(2) ¶ & §1b(2)(m)	NDAC 43-05-01-05 §1b(2) (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any	h. Information on any regional tectonic activity, and the seismic history, including: The presence and depth of seismic sources; Determination of the probability that seismicity would interfere with containment;	**2.5 Faults, Fractures, and Seismic Activity (3rd paragraph, p. 2-87 and p. 2-89)** Between 1870 and 2015, 13 earthquakes were detected within the North Dakota portion of the Williston Basin (Table 2-21) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-73). The seismic event recorded closest to the Great Plains CO_2 Sequestration Project storage facility area occurred 29.6 mi from the Coteau 1 well near Fort Berthold in southwestern North Dakota (Table 2-21). The magnitude of this seismic event is estimated to have been 1.9. Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging earthquake events occurring in North Dakota, with less than two damaging earthquake events predicted to occur over a 10,000-year time period (Figure 2-74) (U.S. Geological Survey, 2019). A 1-year seismic forecast (including both induced and natural seismic events) released by 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 that could be associated with nearby 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 containment is low.	Table 2-21. Summary of Earthquakes Reported to Have Occurred in North Dakota Figure 2-74. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (p. 2-90)

		productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following: NDAC 43-05-01-05 §1b(2)(m) (m) Information on the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment;			
	NDAC 43-05-01-05 §1b(2) ¶ NDAC 43-05-01-05 §1b(2)(n)	NDAC 43-05-01-05 §1b(2) (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include	i. Illustration of the regional geology, hydrogeology, and the geologic structure of the storage reservoir area: Geologic maps Topographic maps Cross sections	**2.1 Overview of Project Area Geology (1st paragraph, p. 2-1)** The proposed Dakota Gasification Company (DGC) Great Plains CO_2 Sequestration Project will be situated near Beulah, North Dakota (Figure 2-1). This project site is on the central portion of the Williston Basin. The Williston Basin is an intracratonic sedimentary basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. See also Figure 2-7 on p. 2-13, Figure 2-10 on p. 2-16, Figure 2-11 on p. 2-17, Figure 2-13 on p. 2-20, Figure 2-31 on p. 2-43, and Figure 2-72 on p. 2-88. ***4.4.3 Hydrology of USDW Formations*** **(p. 4-21)** Groundwater is obtained from both glacial drift and bedrock aquifers, with most of the water obtained from bedrock. Lignite beds and sands in the Sentinel Butte and Tongue River Formations provide shallow bedrock aquifers in most areas of Mercer County. Sandstones near the base of the Tongue River Formation and within the Hell Creek and Fox Hills Formations provide deeper artesian aquifers in many areas. Glacial drift is generally too thin or impermeable to provide good aquifers in the upland areas. However, in the valleys of the major streams and in the diversion channels, the glacial and alluvial fill provides adequate supplies of groundwater (Carlson, 1973). The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the area of investigation is to the east (Figure 4-13). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,530 mg/L near the Great Plains CO2 Sequestration Project area. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Trapp and Croft, 1975). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering. See also Figure 4-15 on p. 4-24.	Figure 2-1. Topographic map of the Great Plains CO_2 Sequestration Project area showing well locations and the Great Plains Synfuels Plant Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (modified from Rygh and others [1990]). Based on new well control shown outside of the green dashed line. (p. 2-13) Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-16) Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-17)

		exhibits and plan view maps showing the following: NDAC 43-05-01-05 §1b(2)(n) (n) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the facility area; and			Figure 2-13. Cross section of the Great Plains CO_2 Sequestration Project storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level. (p. 2-20) Figure 2-32. Structure map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (p. 2-43) Figure 2-73. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (p. 2-89) Figure 4-13. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in Mercer County (modified from Fischer, 2013). (p. 4-22) Figure 4-15. West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the locations of the water wells illustrated on the cross section. (p. 4-24)
	NDAC 43-05-01-05 §1b(2)(d)	NDAC 43-05-01-05 §1b(2)(d) (d) An isopach map of the storage reservoirs;	j. An isopach map of the storage reservoir(s);	See Figure 2-8 on p. 2-14	Figure 2-8. Isopach map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project Area (p. 2-14)
	NDAC 43-05-01-05 §1b(2)(e)	NDAC 43-05-01-05 §1b(2)(e) (e) An isopach map of the primary and any secondary containment barrier for the storage reservoir;	k. An isopach map of the primary containment barrier for the storage reservoir;	See Figure 2-33 on p. 2-44	Figure 2-33. Isopach map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area. (p. 2-44)

			l. An isopach map of the secondary containment barrier for the storage reservoir;	See Figure 2-44 on p. 2-55 and Figure 2-45 on p. 2-56	Figure 2-44. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. (p. 2-55) Figure 2-45. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone. (p. 2-56)
	NDAC 43-05-01-05 §1b(2)(f)	NDAC 43-05-01-05 §1b(2)(f) (f) A structure map of the top and base of the storage reservoirs;	m. A structure map of the top of the storage formation;	See Figure 2-12 on p. 2-18	Figure 2-12. Structure map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops). (p. 2-18)
			n. A structure map of the base of the storage formation;	See Figure 2-32 on p. 2-43	Figure 2-32. Structure map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops). (p. 2-43)
	NDAC 43-05-01-05 §1b(2)(i)	NDAC 43-05-01-05 §1b(2)(i) (i) Structural and stratigraphic cross sections that describe the geologic conditions at the storage reservoir;	o. Structural cross sections that describe the geologic conditions at the storage reservoir;	See Figure 2-11 on p. 2-17 and Figure 2-13 on p. 2-20	Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-17) Figure 2-13. Cross section of the Great Plains CO_2 Sequestration Project storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level. (p. 2-20)
			p. Stratigraphic cross sections that describe the geologic conditions at the storage reservoir;	See Figure 2-10 on p. 2-16	Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top

					of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-16)
	NDAC 43-05-01-05 §1b(2)(h)	**NDAC 43-05-01-05 §1b(2)(h)** (h) Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any;	q. Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any;	**3.4 Simulation Results (p. 3-22)** The pressure front (Figure 3-20) shows the distribution of pressure increase throughout the Broom Creek Formation at the end of the 12-year injection period. A maximum increase of 436.53 psi is estimated in the near wellbore area. ***6.1.1 Pre- and Postinjection Pressure Differential* (p. 6-1)** Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of CO_2 injection. The simulations were conducted for 12 years of CO_2 injection at rates between 1.1 and 2.7 million metric tons per year, followed by a postinjection period of 10 years. Figure 6-1 illustrates the predicted pressure differential at the conclusion of 12 years of CO_2 injection. At the time that CO_2 injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of 350 to 400 psi at the location of the injection wells, which is insufficient to move formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the AOR delineation of this permit application (Section 3). An illustration of the predicted decrease in this pressure profile over the 10-year postinjection period is provided in Figure 6-2. The pressure in the reservoir gradually decreases over time following the cessation of CO_2 injection, with the pressure at the injection well after 10 years of postinjection predicted to decrease 300 to 350 psi as compared to the pressure at the time CO_2 injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions.	Figure 3-20. Average pressure increases within the Broom Creek Formation at the end of a simulated 12-year CO_2 injection operation (p. 3-22) Figure 6-1. Predicted pressure differential in storage reservoir following 12 years of CO_2 injection at rates between 1.1 and 2.7 million metric tons per year (p. 6-2) Figure 6-2. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection (p. 6-3)
	NDAC 43-05-01-05 §1b(2)(l)	**NDAC 43-05-01-05 §1b(2)(l)** (l) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream;	r. Geomechanical information on the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide: Fractures Stress Ductility Rock strength In situ fluid pressure	*2.4.4.1 Fracture Analysis (p. 2-66)* Fractures within the Opeche Formation, the overlying confining zone, and the Amsden Formation, the underlying confining zone, have been assessed during the description of the Coteau 1 well core. Observable fractures were categorized by attributes including morphology, orientation, aperture, and origin. Secondly, natural fractures and in situ stresses were assessed by Schlumberger through the interpretation of the fullbore formation microimager (FMI), bulk density (RHOB), dipole shear sonic (DTS), and dipole compressional sonic (DTC) logs acquired during the drilling of the Coteau 1 well. *2.4.4.2 Fracture Analysis Core Description* (p. 2-66) Fractures within the Opeche Formation are primarily litho-bound resistive fractures. They are commonly filled with anhydrite. However, some litho-bound conductive fractures are highlighted. The presence of microfaults is underlined mainly in the lower part of the Opeche Formation. The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. The aperture varies from closed to, in rare cases, centimeter-scale. The Amsden Formation could be considered as a nonfractured interval. However, few litho-bound conductive fractures are commonly coincident with the horizontal compaction features (stylolite) observed. *2.4.4.3 Borehole Image Fracture Analysis (FMI)* Schlumberger's FMI log was chosen to evaluate the geomechanical condition of the formation in the subsurface. This log provides a 360-degree image of the formation of interest and can be oriented to provide an understanding of the general direction of features observed. Figure 2-57 showsFigure 2-57 The far-right track on Figure 2-57 provides information on surface boundaries, slump deformed, and notes the presence of electrically conductive and resistive features. The latter are interpreted as minor anhydrite-filled fractures. Figure 2-58 shows two sections of the interpreted borehole imagery and primary features observed. Figure 2-58 demonstrates that the tool provides information on slump deformation, conductive fractures, and microfaults. These microfaults are identified in Figure 2-58 and are likely clay-filled because of their electrically conductive signal. Figure 2-59 and Figure 2-60 show two thin-section images and give an indication of different minerals within the reservoir with observed changes in the electrical response shown on the FMI log. Also, some drilled-induced fractures are highlighted in the upper part of the Opeche Formation.	Table 2-19 Triaxial Testing Results Showing the Calculated Static Young's Modulus, Poisson's Ratio, and Compressive Strength. The confining zone pressure was set at 1,180 psi for testing. The pore pressure used for calculations was assumed to be 0 psi. (p. 2-82) Table 2-20 Triaxial Testing Results Showing the Measured Acoustic Velocities and Calculated Dynamic Bulk Modulus, Young's Modulus, Poisson's Ratio, and Compressive Strength. The confining zone pressure was set at 1,180 psi for testing. (p. 2-83) Figure 2-70. Calibrated geomechanical rock properties model in Opeche Formation (p. 2-84)

				Figure 2-61 shows the logged interval for the lower Opeche Formation at Coteau 1 well. As shown, the section closest to the Broom Creek Formation is dominated by litho-bound fractures and microfaults which are electrically conductive features likely due to the presence of clay. The rose diagrams shown in Figures 2-62 through 2-65 provide the orientation of the conductive, resistive, microfault, and drilling-induced features in the Opeche Formation. The drilling-induced fractures are oriented NE-SW and N-S which give an orientation of N060 and N000 to the maximum horizontal stress (Shmax), respectively. The logged interval of the Amsden Formation shows that the main features present are bed boundaries and slump deformation features (Figure 2-66). The depths 6,201.6 and 6,213.7 ft show some evidence of conductive fracture and drilling-induced fractures, respectively (Figure 2-67). The rose diagrams shown in Figures 2-67 and 2-68 provide the orientation of the conductive and drilling-induced fractures in the Amsden Formation. The drilling-induced fractures are oriented NE-SW which gives an orientation of N060 to the maximum horizontal stress (Shmax). *2.4.4.4 Stress* (p. 2-81) The 1D Mechanical Earth Model (MEM) for Opeche, Broom Creek, and Amsden Formations in Coteau 1 well was generated by Core Laboratories (Figures 2-70, 2-71, and 2-72). During construction of the 1D MEM, the effect of pore pressure on sonic transit time, accurate calculation of stress, and rock properties required corrections based on this effect. Dipole sonic logs (DTC, DTS) were corrected for formation pressure impedance and tool radius of investigation. The log corrections allow for a better match to core measurements and more robust geomechanical models. The output data for the 1D MEM are vertical stress (Sv), pore pressure, pore pressure gradient, dynamic Poisson's ratio, dynamic Young's modulus, Biot factor, fracture closure pressure, fracture closure pressure gradient, fracture propagation pressure, fracture propagation pressure gradient, fracture breakdown pressure, and fracture breakdown pressure gradient. Laboratory-derived core measurements were used from the Coteau 1 well. The static and dynamic parameters from core including DTS, DTC, compressional wave velocity (Vp), shear wave velocity (Vs), dynamic Young's modulus, and dynamic Poisson's ratio were estimated for the Opeche, Broom Creek, and Amsden Formations and used to calibrate the geomechanical rock properties model. The isotropic (dynamic) properties from well logs (Young's modulus and dynamic Poisson's ratio) were calculated based on the corrected DTC and DTS well logs and calibrated with core measurements. Pore pressure, pore pressure gradient, fracture closure pressure, fracture closure pressure gradient, fracture propagation pressure, fracture propagation fracture gradient, fracture breakdown pressure, and fracture breakdown pressure gradient were also estimated. Pore pressure was calibrated using the pressure and temperature data from the Coteau 1 well. Triaxial tests were performed on 15 vertical samples: three in Opeche, nine in Broom Creek, and three in Amsden (Table 2-19 and 2-20). Static Young's modulus, Poisson's ratio, and compressive strength were measured at the confining pressure of 1180 psi. Also, acoustic velocities (Vp, Vs) and dynamic moduli (Bulk modulus, Young's modulus, shear modulus, Poisson's ratio) were estimated under a confining pressure of 1,180 psi The triaxial outputs were calibrated with the estimated parameters using well logs. Figures 2-70–2-72 show the outputs of the 1D MEM for the Opeche, Broom Creek, and Amsden Formations. In situ stresses such as vertical stress (Sv), maximum horizontal stress (Shmax), and minimum horizontal stress (Shmin) were calculated. The vertical stress is calculated using the density log (RHOB) and assumes 1 psi/ft above 1,500 ft where the RHOB data were not available. The minimum horizontal stress is estimated from a modified Eaton calculation method. Shmax is estimated from Shmin and process zone stress as a function of porosity. Based on the calculated stresses, the stress regime of the Opeche, Broom Creek, and Amsden Formations is considered a normal stress regime where Sv > Shmax > Shmin. ***4.1.1 Written Description*** **(p. 4-1 and p. 4-2)** An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.	Figure 2-71. Calibrated geomechanical rock properties model in Broom Creek Formation (p. 2-85) Figure 2-72. Calibrated geomechanical rock properties model in the Amsden Formation (p. 2-86)

	NDAC 43-05-01-05 §1b(2)(o)	NDAC 43-05-01-05 §1b(2)(o) (o) Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement, are free of transmissive faults or fractures, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	s. Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement: Free of transmissive faults Free of transmissive fractures Effect on pressure dissipation Utility for monitoring, mitigation, and remediation.	***2.4.2 Additional Overlying Confining Zones* (p. 2-54 and p. 2-57)** Several other formations provide additional confinement above the Opeche interval. Impermeable rocks above the primary seal include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-16). Together with the Opeche interval, these formations are 1,106 ft thick and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-44). Above the Inyan Kara Formation, 2,657 ft of impermeable rocks act as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (Figure 2-44). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-16). These formations between the Broom Creek and Inyan Kara and between the Inyan Kara and the lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin (Downey, 1986; Downey and Dinwiddie, 1988). Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Inyan Kara Formation represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring using annual temperature and pulse neutron logging of the Inyan Kara Formation provides an additional opportunity for mitigation and remediation (Section 4). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at the Coteau 1 well is 4,512 ft, and the formation itself is 378 ft thick.	Table 2-16 (p. 2-55) Figure 2-44. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation (p. 2-55) Figure 2-45. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation (p. 2-56)
Area of Review Delineation	NDAC 43-05-01-05 §1j & §1b(3)	NDAC 43-05-01-05 §1j j. An area of review and corrective action plan that meets the requirements pursuant to section 43-05-01-05.1; NDAC 43-05-01-05 §1b(3) (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following:	The carbon dioxide storage reservoir area of review includes the areal extent of the storage reservoir and one mile outside of the storage reservoir boundary, plus the maximum extent of the pressure front caused by injection activities. The area of review delineation must include the following:	***4.1.1 Written Description*** North Dakota geologic storage of CO_2 regulations require that each storage facility permit delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO_2 plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the Coteau 1 well (NDIC File No. 38379) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-7]). Section 3 includes a detailed discussion on the computational modeling and simulations (e.g., storage facility area, pressure front, AOR boundary, etc.), assumptions, and justification used to delineate the AOR and method for delineation of the AOR. NDAC § 43-05-01-05 subsection 1b(3) requires, "A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 4-1), the resulting AOR for the Great Plains CO_2 Sequestration Project is delineated as being 1 mile from the storage facility permit (SFP) boundary. This extent ensures compliance with existing state regulations. All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 4-2 through 4-5) by a professional engineer pursuant to NDAC § 43- 05-01-05 subsection 1b(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected CO2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 through 4-6 and Figures 4-6 through 4-9). An extensive geologic and hydrogeologic characterization performed by a team of geologists from the EERC resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.	Figure 4-2. Final AOR map showing the Great Plains CO_2 Sequestration Project storage facility area, the storage facility area (dashed purple boundary), and the AOR (dashed black boundary). Pink squares represent occupied dwellings, teal squares represent vacant buildings, and blue squares represent commercial buildings. (p. 4-3) Figure 4-3. AOR map in relation to nearby legacy wells and groundwater wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR, and the light-orange triangles represent Class I ANG #1 and ANG #2 wells. All groundwater wells in the AOR are identified above. All observation/monitoring wells are shallow groundwater wells associated with the mine activities. No springs are present in the AOR. (p. 4-4)

				This section of the SFP application is accompanied by maps and tables that include information required and in accordance with NDAC § 43-05-01-05 subsections 1(a) and 1(b) and 43-05-01-05.1 subsection 2, such as the storage facility area, location of any proposed injection wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05 subsections 1a and 1b(3) and 43-05-01-05.1 subsection 2. Surface features that were investigated but not found within the AOR boundary were identified in Table 4-1. See Figure 4-2 on p. 4-3, Figure 4-3 on p. 4-4, and Figure 4-4 on p. 4-5.	Figure 4-4. AOR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR and the Class I ANG #1 and ANG #2 wells are represented by blue triangles. (p. 4-5)
	NDAC 43-05-01-05 §1b(3) & §1a	**NDAC 43-05-01-05 §1b(3)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: **NDAC 43-05-01-05 §1a** a. A site map showing the boundaries of the storage reservoir and the location of all proposed wells, proposed cathodic protection boreholes, and surface facilities within the carbon dioxide storage facility area;	a. A map showing the following within the carbon dioxide reservoir area: i. Boundaries of the storage reservoir ii. Location of all proposed wells iii. Location of proposed cathodic protection boreholes iv. Any existing or proposed above ground facilities;	**4.1.2 Supporting Maps (p. 4-2)** See Figure 4-2 on p. 4-3	Figure 4-2 Final AOR map showing the Great Plains CO_2 Sequestration Project storage facility area, the storage facility area (dashed purple boundary), and the AOR (dashed black boundary). Pink squares represent occupied dwellings, teal squares represent vacant buildings, and blue squares represent commercial buildings. (p. 4-3)
	NDAC 43-05-01-05 §1b(2)(a)	**NDAC 43-05-01-05 §1b(2)(a)** (a) All wells, including water, oil, and natural gas exploration and development wells, and other manmade subsurface structures and activities, including coal mines, within the facility area and within one mile [1.61 kilometers] of its outside boundary;	b. A map showing the following within the storage reservoir area and within one mile outside of its boundary: i. All wells, including water, oil, and natural gas exploration and development wells ii. All other manmade subsurface structures and activities, including coal mines;	**4.1.2 Supporting Maps (p. 4-2)** See Figure 4-3 on p. 4-4 and Figure 4-4 on p. 4-5	Figure 4-3 AOR map in relation to nearby legacy wells and groundwater wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR, and the light-orange triangles represent Class I ANG #1 and ANG #2 wells. All groundwater wells in the AOR are identified above.

					All observation/monitoring wells are shallow groundwater wells associated with the mine activities. No springs are present in the AOR. (p. 4-4) Figure 4-4 AOR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR and the Class I ANG #1 and ANG #2 wells are represented by blue triangles. (p. 4-5)
	NDAC 43-05-01-05 §1c NDAC 43-05-01-05.1 §1a	**NDAC 43-05-01-05 §1c** c. The extent of the pore space that will be occupied by carbon dioxide as determined by utilizing all appropriate geologic and reservoir engineering information and reservoir analysis, which must include various computational **NDAC 43-05-01-05.1 §1a** a. The method for delineating the area of review, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	c. A description of the method used for delineating the area of review, including: i. The computational model to be used ii. The assumptions that will be made iii. The site characterization data on which the model will be based;	**3.5 Delineation of the Area of Review (p. 3-25)** The North Dakota Administrative Code (NDAC) defines the AOR as the region surrounding the geologic storage project where USDWs may be endangered by CO_2 injection activity (NDAC § 43-05-01-05). The primary endangerment risk is the potential for vertical migration of CO_2 and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the CO_2 plume within the storage reservoir. However, the CO_2 plume has an associated pressure front where CO_2 injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the CO_2 plume. Therefore, the AOR encompasses both the areal extent of the CO_2 plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the CO_2 plume, AOR delineation focuses on the pressure front. The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. U.S. Environmental Protection Agency (EPA) guidance for AOR delineation under the Underground Injection Control (UIC) Program for Class VI wells provides several methods for estimating the critical threshold pressure increase and resulting critical threshold pressure. In this document, "storage reservoir" refers to the Broom Creek Formation (the injection zone), and the "lowest USDW" refers to the Fox Hills Formation.	
	NDAC 43-05-01-05.1 §1b(1-4)	**NDAC 43-05-01-05.1 §1b(1-4)** b. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review; (2) The monitoring and operational conditions	d. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review; (2) Any monitoring and operational conditions that would warrant a reevaluation of the area of	**4.3 Reevaluation of AOR and Corrective Action Plan (p. 4-17)** DGC will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place not later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following: • Any changes to the monitoring and operational data prior to the scheduled reevaluation date. • Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and operational data to be utilized as the basis for that update will be identified.	N/A

		that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date; (3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and (4) How corrective action will be conducted to meet the requirements of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	review prior to the next scheduled reevaluation date; (3)How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; (4)How corrective action will be conducted if necessary, including: a. What corrective action will be performed prior to injection b. How corrective action will be adjusted if there are changes in the area of review;	• The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR.	
	NDAC 43-05-01-05 §1b(2)(b)	NDAC 43-05-01-05 §1b(2)(b) (b) All manmade surface structures that are intended for temporary or permanent human occupancy within the facility area and within one mile [1.61 kilometers] of its outside boundary;	e. A map showing the areal extent of all manmade surface structures that are intended for temporary or permanent human occupancy within the storage reservoir area, and within one mile outside of its boundary;	**4.1.2 Supporting Maps (p. 4-2)** See Figure 4-2 on p. 4-3	Figure 4-2 Final AOR map showing the Great Plains CO_2 Sequestration Project storage facility area, the storage facility area (dashed purple boundary), and the AOR (dashed black boundary). Pink squares represent occupied dwellings, teal squares represent vacant buildings, and blue squares represent commercial buildings. (p. 4-3)
	NDAC 43-05-01-05 §1b(2) ¶	NDAC 43-05-01-05 §1b(2) (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any	f. A map and cross section identifying any productive existing or potential mineral zones occurring within the storage reservoir area and within one mile outside of its boundary;	**2.6 Potential Mineral Zones (p. 2-89 through 2-91)** There are no known producible accumulations of hydrocarbons in the storage facility area. The North Dakota Geological Survey recognizes the Spearfish Formation as the only potential oil-bearing formation above the Broom Creek Formation. However, production from the Spearfish Formation is limited to the northern tier of counties in western North Dakota (Figure 2-75). There has been no exploration for, nor development of, a hydrocarbon resource from the Spearfish Formation in the Great Plains CO_2 Sequestration Project area. There has been no historic hydrocarbon exploration in, or production from, formations below the Broom Creek Formation in the storage facility area. The Herrmann 1 well (NDIC File No. 4177), the closest hydrocarbon exploration well to the storage facility area, located 4.1 miles from the Coteau 1 well, was drilled in 1966 to explore potential hydrocarbons in the Madison Group. The well was dry and did not suggest the presence of hydrocarbons. The closest hydrocarbon producing well is Traxel 1-31H (NDIC File No. 17877), located 10.8 miles east from the Coteau 1 well (NDIC 38379). The Traxel 1-31H well was drilled in August 2009,	Figure 2-75. Drillstem test results indicating the presence of oil in the Spearfish Formation (modified from Stolldorf, 2020). (p. 2-91)

		regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:		producing a cumulative total of 12,021 bbl until December 2013. The well's current status is producer now abandoned (PNA) as of November 2014. Published studies suggest there are no economic deposits of hydrocarbons in the Bakken Formation in the storage facility area (Bergin, 2012; Theloy, 2016). In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a 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 (Figure 3-20). Pressure increases will relax postinjection as the area returns to its preinjection 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 placed across the storage reservoir, with CO_2-resistant cement used to anchor the casing in place. Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations (NDCC 57-51-01) define shallow gas resources as "gas produced from a zone that consists of strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1,524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation (Jurassic), from which gas may be produced." Lignite reserves in the Sentinel Butte Formation of the Fort Union Group (the Beulah of the Beulah-Zap interval and Twin Butte coal beds) are mined to be used as feedstock for the GPSP coal gasification process and power generation feedstock at Basin Electric Power Cooperative's Antelope Valley Station, located about 0.5 miles north of DGC's GPSP. The lignite is obtained from the Freedom Mine, which is operated by Coteau Properties Company, a wholly owned subsidiary of North American Coal Corporation. The thickness of the Beulah–Zap averages between 18 to 22 feet in thickness (Figure 2-76). Above the Beulah horizon are several thin beds of lignite. In ascending order, these are the Schoolhouse and Twin Butte beds. Overburden on top of the Beulah ranges from 95 to 145 feet (Figure 2-77). The Twin Butte has an average thickness of about 6 feet under 25–30 feet of overburden where it is actively mined (Zygarlicke and others, 2019). The Beulah, Twin Butte, and other coal seams thicken and deepen to the west. The Beulah–Zap and Twin Butte seams pinch out to the east. The underlying Hagel coal seam is mined farther to the east at the BNI Coal Mine near Center, North Dakota, and the Falkirk Mine near Falkirk, North Dakota.	Figure 2-76. Beulah net coal isopach map (modified from Ellis and others, 1999). (p. 2-93) Figure 2-77. Beulah overburden isopach map (modified from Ellis and others, 1999). (p. 2-94)
	NDAC 43-05-01-05 §1b(3) NDAC 43-05-01-05.1 §2b	**NDAC 43-05-01-05 §1b(3)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following:	g. A map identifying all wells within the area of review, which penetrate the storage formation or primary or secondary seals overlying the storage formation.	See Figure 4-4 on p. 4-5	Figure 4-4 AOR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR and the Class I ANG #1 and ANG #2 wells are represented by blue triangles. (p. 4-5)

		NDAC 43-05-01-05.1 §2b b. Using methods approved by the commission, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone. Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the commission may require;			
NDAC 43-05-01-05 §1b(3)(a) NDAC 43-05-01-05 §1b(3)(b) NDAC 43-05-01-05 §1b(3)(c)		**NDAC 43-05-01-05 §1b(3)(a)** (a) A determination that all abandoned wells have been plugged and all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping from the storage reservoir; **NDAC 43-05-01-05 §1b(3)(b)** (b) A description of each well's type, construction, date drilled, location, depth, record of plugging, and completion; **NDAC 43-05-01-05 §1b(3)(c)** (c) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all underground sources of drinking water, water wells, and springs within	h. A review of these wells must include the following: (1) A determination that all abandoned wells have been plugged in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation; (2) A determination that all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation; (3) A description of each well: a. Type b. Construction c. Date drilled d. Location e. Depth f. Record of plugging g. Record of completion (4) Maps and stratigraphic cross sections of all underground sources of drinking water within the area of review indicating the following: a. Their positions relative to the injection zone	**4.1.1 Written Description (4th paragraph, p. 4-1)** All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated by a professional engineer pursuant to NDAC § 43-05-01-05 subsection 1b(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected CO_2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 through 4-6 and Figures 4-6 through 4-9). 4.1.2 Supporting Maps See Figure 4-3 on p. 4-4. **4.2 Corrective Action Evaluation (p. 4-8)** See Table 4-2 on p. 4-8, Table 4-3 on p. 4-9, Table 4-4 on p. 4-10, Table 4-5 on p. 4-11, and Table 4-6 on p. 4-12. See Figure 4-6 on p. 4-13, Figure 4-7 on p. 4-14, Figure 4-8 on p. 4-15, and Figure 4-9 on p. 4-16.	Table 4-2. Wells in AOR Evaluated for Corrective Action (p. 4-8) Table 4-3. Hermann 1 (NDIC File No. 4177) Well Evaluation (p. 4-9) Table 4-4. ANG 1 (NDEQ File No. NDOH11308) Well Evaluation (p. 4-10) Table 4-5. ANG 2 (NDEQ File No. NDOH11309) Well Evaluation (p. 4-11) Table 4-6. Coteau 1 (NDIC File No. 38379) Well Evaluation (p. 4-12) Figure 4-3 (p. 4-4) Figure 4-6 Hermann 1 (NDIC File No. 4177) well schematic showing the location and thickness of cement plugs (p. 4-13) Figure 4-7. ANG 1 (NDEQ File No. NDOH11308) well schematic showing the location

	NDAC 43-05-01-05 §1b(3)(d) NDAC 43-05-01-05 §1b(3)(e) NDAC 43-05-01-05 §1b(3)(b)(f)	the area of review; their positions relative to the injection zone; and the direction of water movement, where known; NDAC 43-05-01-05 §1b(3)(d) (d)Maps and cross sections of the area of review; NDAC 43-05-01-05 §1b(3)(e) (e) A map of the area of review showing the number or name and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, state-approved or United States environmental protection agency-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features, including structures intended for human occupancy, state, county, or Indian country boundary lines, and roads;	b. The direction of water movement, where known c. General vertical and lateral limits d. Water wells e. Springs (5) Map and cross sections of the area of review; (6) A map of the area of review showing the following: a. Number or name and location of all injection wells b. Number or name and location of all producing wells c. Number or name and location of all abandoned wells d. Number of name and location of all plugged wells or dry holes e. Number or name and location of all deep stratigraphic boreholes f. Number or name and location of all state-approved or United States Environmental Protection Agency-approved subsurface cleanup sites g. Name and location of all surface bodies of water h. Name and location of all springs i. Name and location of all mines (surface and subsurface) j. Name and location of all quarries k. Name and location of all water wells l. Name and location of all other pertinent surface features m. Name and location of all structures intended for human occupancy n. Name and location of all state, county, or Indian country boundary lines o. Name and location of all roads		and thickness of cement plugs (p. 4-14) Figure 4-8. ANG 2 (NDEQ File No. NDOH11309) well schematic showing the location and thickness of cement plugs (p. 4-15) Figure 4-9. Coteau 1 (NDIC File No. 38379) well schematic showing the location and thickness of cement plugs (p. 4-16)

		NDAC-43-05-01-05 §1b(3)(b)(f) **(f) A list of contacts, submitted to the commission, when the area of review extends across state jurisdiction boundary lines;**	(7)A list of contacts, submitted to the Commission, when the area of review extends across state **jurisdiction boundary lines.**		
	NDAC 43-05-01-05 §1b(3)(g)	NDAC 43-05-01-05 **§1b(3)(g)** **(g) Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review; and**	i. Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review.	***5.5.2 Groundwater Baseline Sampling* (p. 5-13)** Two Fox Hills Formation samples were obtained in November 2021 from the Fred Art/Oberlander #1 and Helmuth Pfenning **#2** wells. State-certified laboratory results for these two wells found in Appendix B show little variation among the reports. The locations of the wells investigated for establishing baseline conditions are shown in Figure 5-3, and the results of the baseline measurements for pH, specific conductivity, and alkalinity are provided in Table 5-5, with state-certified laboratory **results** for each sampling event provided in Appendix B. In addition, DGC plans to obtain a baseline water sample from the Fox Hills monitoring well that will be drilled near the Herrmann 1 well (NDIC File No. 4177) prior to injection operations. **Appendix B - FRESHWATER WELL FLUID-SAMPLING LABORATORY ANALYSIS** **See Appendix B for detailed laboratory reports of geochemical data collected during the initial baseline sampling program**	**Figure 5-3. DGC's initiated baseline sampling program for vadose zone soil gas and groundwater in the Fox Hills Formation (p. 5-12)** **Table 5-4. DGC's Initial Baseline Groundwater Sampling Results – November 2021 (p. 5-13)**
Required Plans	NDAC 43-05-01-05 §1k	NDAC 43-05-01-05 §1k k. The storage operator shall comply with the financial responsibility requirements pursuant to section 43-05-01-9.1;	a. Financial Assurance Demonstration	**12.2 Financial Instruments (p. 12-1 and p. 12-2)** DGC is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments: • DGC will establish an escrow account to cover the costs of corrective action in accordance with NDAC § 43-05-01-05.1, plugging of injection wells in accordance with NDAC § 43-05-01-11.5, and implementing postinjection site care and facility closure activities in accordance with NDAC § 43-05-01-19. DGC will make four annual payments of $1 million to the escrow account. The first payment will occur on or before the first day of operations, and the final payment will occur in 2025, bringing the account balance to $4 million. • A third-party pollution liability insurance policy with an aggregate limit of $16 million will be secured to cover the costs of implementing emergency and remedial response actions, if warranted, in accordance with NDAC § 43-05-01-13. The estimated total costs of these activities are presented in Table 12-1. Section 12.3 of this FADP provides additional details of the financial responsibility cost estimates for each activity.	Table 12-1. Cost estimates for Activities to Be Covered (p. 12-2)
	NDAC 43-05-01-05 §1d	NDAC 43-05-01-05 §1d d. An emergency and remedial response plan pursuant to section 43-05-01-13;	b. An emergency and remedial response plan;	**7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN (p. 7-1)** This emergency and remedial response plan (ERRP) 1) describes the local resources and infrastructure in proximity to the site; 2) identifies events that have the potential to endanger all underground sources of drinking water (USDWs) during the construction, operation, and postinjection site care periods of the geologic storage project; and 3) describes the response actions that are necessary to manage these risks to USDWs. In addition, the integration of the ERRP with the existing plant emergency plan and risk management plan of Dakota Gasification Company's (DGC's) Great Plains Synfuels Plant (GPSP) is described, emphasizing the command structure of DGC, the evacuation plan, hazmat (hazardous material) capabilities, and the emergency communication plan of the GPSP. Lastly, procedures are presented for regularly conducting and evaluating the adequacy of the ERRP and updating it, if warranted, over the lifetime of the Great Plains CO2 Sequestration Project. Note: Refer to the following key tables instead: Table 7-2 on p. 7-6 and Table 7-3 on p. 7-8 through 7-10.	Table 7-2. Potential Project Emergency Events and Their Detection (p. 7-6) Table 7-3 Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (p. 7-8 through 7-10)
	NDAC 43-05-01-05 §1e	NDAC 43-05-01-05 §1e e. A detailed worker safety plan that addresses carbon	c. A detailed worker safety plan that addresses the following:	**8.1 DGC Employee Safety Requirements and Training (p. 8-1)**	N/A

		dioxide safety training and safe working procedures at the storage facility pursuant to section 43-05-01-13;	i. Carbon dioxide safety training ii. Safe working procedures at the storage facility;	DGC has established a process for employees to acquire the knowledge, skills, and abilities to competently operate the facility in accordance with DGC safe work practices, procedures, and operating manuals. The safety requirements for DGC employees include, but are not limited to, the following: 1. An orientation for all newly hired employees to ensure they are aware of company safety policies and procedures, safety and health hazards, safe work practices, and government safety regulations. 2. Instruction and training for each employee regarding: a. Safety expectations while on DGC property. b. What to do in an emergency, including evacuation routes and assembly points. c. Safety and industrial hygiene information about hazardous materials/conditions and immediate actions to take following an accidental exposure. d. When and how to report safety incidents. e. How to report unsafe conditions and behaviors. f. Safe work practices as defined by government and company standards. ***8.1.2 DGC Contractor Safety Requirements and Training* (p. 8-1 and p. 8-2)** The DGC OSIH program also establishes requirements for contractors to interface with DGC to ensure compliance with DGC safety procedures and federal, state, and local safety standards. The scope of the requirements covers all contractors and their personnel (including subcontractors) working at DGC's facilities. The safety requirements and training required for a contractor to access and perform work at DGC facilities include, but are not limited to, the following: 1. Full compliance with all Energy Coalition for Contractor Safety (ECCS) guidelines for a "Class A contractor." (The guidelines can be found at the North Dakota Safety Council [NDSC] website at www.ndsc.org.) 2. Attendance at an annual DGC contractor safety orientation. 3. Negative drug test results within the last 12 months. 4. Availability of a contractor employee training record (CETR) within the last 12 months: a. Documents that the contractor has trained its personnel on DGC procedures and process descriptions. b. Ensures contractor employees are instructed in the known potential fire, explosion, or toxic release hazards and applicable provisions of the emergency response plan. 5. Documentation of a contractor employee background check within the last 5 years. 6. Successful completion of an Occupational Safety and Health Administration (OSHA) 10-hour class within the last 36 months. 7. A contractor safety manual evaluation completed by a third party, i.e., the North Dakota Safety Council (NDSC), to demonstrate compliance with federal, state, and DGC safety standards. 8. Demonstration of acceptable safety performance by submitting the last year's safety statistics to NDSC at www.ndsc.org. 9. Demonstration of qualification requirements for pipeline (off-site) contractors, which includes the following: a. Submission of a drug/alcohol plan that meets 49 Code of Federal Regulations (CFR) Part 40 and Part 199. b. Submission of an operator qualification plan in accordance with 49 CFR Part 192 and Part 195. c. Submission of qualification data for personnel performing operation, maintenance, or emergency response task(s) on the carbon dioxide (CO_2) pipeline. d. Other qualification requirements include: i. DGC access to drug/alcohol and operator qualification information for random record audits. ii. Submission of Department of Transportation (DOT) annual drug testing statistical data to DGC for inclusion in an annual DGC submittal to DOT. Only DGC employees and contractor personnel who have been properly trained will participate in the project activities of drilling, construction, operations, and equipment repair.	
	NDAC 43-05-01-05 §1f	**NDAC 43-05-01-05 §1f** f. A corrosion monitoring and prevention plan for all wells and surface facilities pursuant to section 43-05-01-15;	d. A corrosion monitoring and prevention plan for all wells and surface facilities;	**5.2 Corrosion Monitoring and Prevention Plan (p. 5-4)** The purpose of the corrosion monitoring and prevention plan is to monitor the surface facilities and injection well components during the operational phase of the Great Plains CO_2 Sequestration Project to ensure that the materials meet the minimum standards for material strength and performance. Figure 5-1 illustrates the pad drawings for the Coteau 1 through Coteau 4 wells. DGC permitted a new 6.8-mile-long transmission line through the North Dakota Public Service Commission (PSC) in July 2021 (PU-21-150). The transmission line implements a corrosion monitoring and prevention strategy that was approved by PSC and is not discussed in this storage facility permit application. At the transition from transmission line to flowline (Figure 5-2), DGC's efforts	Figure 5-1A. Well pad drawing of the Coteau 1 well location (p. 5-5) Figure 5-1B. Well pad drawing of the Coteau 2 well location (p. 5-6)

				to monitor and prevent corrosion of the flowline and well materials at the injection wellsites are presented in Sections 5.2.1 and 5.2.2. ***5.2.1 Corrosion Monitoring* (p. 5-4)** DGC will install a 3-foot test section of 4½-inch L-80 tubing in the flowlines near each wellhead for regular testing and corrosion monitoring of the well material. The tubing joints will be inspected monthly via ultrasound equipment during the first quarter, then quarterly thereafter for the first 2 years. If the well materials (i.e., tubing) show no sign of corrosion within the first 2 years of the injection period, future internal monitoring of the tubing will be accomplished through a PMIT, or in the event a downhole tubing string is pulled for any reason, it will be inspected at the surface for corrosion and mechanical integrity. USITs may also be run during workovers (including when tubing is pulled), but not more frequently than once every 5 years, to further assess any corrosion of the injection string. ***5.2.2 Corrosion Prevention* (p. 5-9)** To prevent corrosion of the well materials, the following preemptive measures will be taken: 1) cement in the injection wells opposite the injection interval and extending more than 2,000 feet uphole will be CO_2-resistant, 2) the well casing (L-80 13Cr) will also be CO_2-resistant from the bottomhole to a depth just above the Opeche Formation in the injection wells, and 3) the packer fluid will be an industry standard corrosion inhibitor. In addition, the chemical composition of the CO_2 stream is highly pure (Table 5-2) and dry, with a moisture level for the CO_2 stream typically less than two parts per million by volume, both factors of which help to prevent corrosion of the surface and well materials.	Figure 5-1C. Well pad drawing of the Coteau 3 well location (p. 5-7) Figure 5-1D. Well pad drawing of the Coteau 4 well location Figure 5-2. Diagram of surface connections at the Coteau 1 wellsite (p. 5-9) Table 5-2. Chemical Content of the CO_2 Stream (p. 5-3)
	NDAC 43-05-01-05 §1g	NDAC 43-05-01-05 §1g g. A leak detection and monitoring plan for all wells and surface facilities pursuant to section 43-05-01-14. The plan must: (1) Identify the potential for release to the atmosphere; (2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area	c. A surface leak detection and monitoring plan for all wells and surface facilities pursuant to North Dakota Administrative Code (NDAC) Section 43-05-01-14;	**5.3 Surface Leak Detection and Monitoring Plan (p. 5-10)** 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. Performance targets designed for the Great Plains CO_2 Sequestration Project to detect potential leaks in the flowline are provided in Table 5-3. The performance targets are dependent upon the actual performance of instrumentation (e.g., pressure gauges) and the supervisory control and data acquisition (SCADA) system, which uses software to track the status of the pipeline system in real time by comparing live pressure and flow rate data to a comprehensive predictive model. The performance targets assume a flow rate of 200 million standard cubic feet per day (MMSCFD) of CO_2. An alarm will trigger on the SCADA system if a volume deviation of more than 2% is registered. H2S detection stations will also be mounted on the inside and outside of wellhead enclosures to detect any potential indoor and atmospheric leaks at the well pad locations, respectively. The stations can detect H2S concentrations as low as 1 part per million (ppm) and have an integrated alarm system if a 10 ppm threshold is crossed. The stations are further described in Appendix C (Attachment A-7). Field personnel will have multi gas detectors with them for wellsite visits or flowline inspections to detect potential leaks from the equipment. The multi gas detectors will primarily monitor for CH_4, CO, O_2, and H_2S up to 100 feet from a surface leakage source. The multi gas detector will measure H2S as low as 0.1 ppm with an incremental resolution of 0.1 ppm and has built-in alarms. Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.	N/A
	NDAC 43-05-01-05 §1h	NDAC 43-05-01-05 §1h h. A leak detection and monitoring plan to monitor any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile [1.61 kilometers] of the facility area's outside	f. A subsurface leak detection and monitoring plan to monitor for any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile of the facility area's outside boundary;	**5.4 Subsurface Leak Detection and Monitoring Plan (p. 5-10)** The monitoring plan for detecting subsurface leaks comprises "surface/near-surface" and deep subsurface monitoring programs. "Surface/near-surface" refers to the region from ground surface down to, and including, the lowest USDW as well as surface waters, soil gas (vadose zone), and shallow groundwater (e.g., stock wells, residential drinking water wells, etc.). The deep subsurface zone extends from the base of the lowest USDW to the base of the injection zone of the storage reservoir. Subsurface leak detection will include multiple approaches to ensure confidence that surface (i.e., ambient and workspace atmospheres and surface waters) and near-surface (i.e., vadose zone, groundwater wells, and the lowest USDW) environments are protected, and the CO_2 is safely and permanently stored in the storage reservoir. More specifically, for DGC's geologic storage project, near-surface monitoring will include 11 soil gas profile stations and seven dedicated Fox Hills Formation monitoring wells within the AOR to detect if the lowest USDW is being impacted by operations. These monitoring efforts will provide additional	

	boundary. Provisions in the plan will be dictated by the site characteristics as documented by materials submitted in support of the permit application but must: (1) Identify the potential for release to the atmosphere; (2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area		lines of evidence to assess whether the surface/near-surface environment is being protected and whether the CO_2 is being safely and permanently stored in the storage reservoir. To complement surface/near-surface monitoring, additional monitoring of the subsurface will ensure CO_2 is staying in the targeted storage reservoir. Operational monitoring at the injection wells, including injection rates, pressures, and temperatures will provide data to inform the monitoring approaches. Internal and external mechanical integrity of the injection wells will also be demonstrated to ensure no leakage pathway exist that may allow vertical movement of the CO_2. Additionally, geophysical (seismic) surveys conducted over regular intervals will monitor subsurface CO_2 plume movement. More details regarding the surface, near-surface, and deep subsurface monitoring efforts are provided in sections 5.5 through 5.7.	
NDAC 43-05-01-05 §1l	NDAC 43-05-01-05 §1l l. A testing and monitoring plan pursuant to section 43-05-01-11.4;	g. A testing and monitoring plan pursuant to NDAC Section 43-05-01-11.4;	See Section 5.0 Testing and Monitoring Plan and Appendix C: Quality Assurance Surveillance Plan Note: See Table 5-1 on p. 5-2 Table 5-5 on p.5-11, Table 5-6 on p. 5-13 and 5-14, Table 5-7 on p. 5-15 for detailed summaries of the testing and monitoring plan.	Table 5-1. Overview of DGC's Testing and Monitoring Plan (p. 5-2) Table 5-5. Baseline, Operational, and Postoperational Monitoring Duration and Frequency for Soil Gas and Groundwater (p. 5-13) Table 5-6. Description of DGC's Deep Subsurface Monitoring Program (p. 5-16) Table 5-7. Testing and Logging Program for the Coteau 1 Wellbore (p. 5-18)
NDAC 43-05-01-05 §1i	NDAC 43-05-01-05 §1i i. The proposed well casing and cementing program detailing compliance with section 43-05-01-09;	h. The proposed well casing and cementing program;	**9.0 WELL CASING AND CEMENTING PROGRAM (p. 9-1)** Rampart Energy Company has drilled one well, Coteau 1 (NDIC File No. 38379) thus far on behalf of DGC. The well was permitted and drilled in June 2021 as a stratigraphic test well in compliance with Class VI underground injection control (UIC) injection well construction requirements. Application to convert Coteau 1 to a CO_2 storage injection well is being filed upon approval of this storage facility permit (SFP). The following information includes the current, as-constructed wellbore schematic (illustrated in Figure 9-1 and detailed in Tables 9-1 through 9-4) and a radial cement evaluation log summary for Coteau 1 (Figure 9-2). After drilling, the Broom Creek Formation was perforated with four shots at 5975 ft and a reservoir pressure and fluid sample were obtained. The perforations were then squeezed with 100 sacks of Class G cement and the casing pressured tested to 1600 psi with an inhibited brine solution.	Figure 9-1. Coteau 1 as-constructed wellbore schematic (p. 9-2) Table 9-1. Coteau 1 As-Constructed Well Information (p. 9-3) Table 9-2. Coteau 1 As-Constructed Casing Program (p. 9-3)

				Five additional injection wells are planned. Three of these, the proposed Coteau 2, Coteau 3, and Coteau 4, are expected to be drilled in the second quarter of 2022, followed by the proposed Coteau 5 and Coteau 6 in late 2025, to accommodate additional CO2 injection volumes in the spring of 2026. Note: See also the proposed casing and cementing program details for the Coteau 2 through 6 wells on p. 9-7 through 9-20.	Table 9-3. Coteau 1 As-Constructed Casing Properties (p. 9-4) Table 9-4. Coteau 1 As-Constructed Cement Program (p. 9-4) Figure 9-2. Coteau 1 isolation scanner results (p. 9-5)
	NDAC 43-05-01-05 §1m	**NDAC 43-05-01-05 §1m** m. A plugging plan that meets requirements pursuant to section 43-05-01-11.5;	i. A plugging plan;	**10.1 Plugging & Abandonment (P&A) Program (p. 10-1)** A well schematic of the planned completion for the Coteau 1 well (NDIC File No. 38379) is provided in Figure 10-1 followed by a P&A procedure and a well-plugging schematic (Figure 10-2). The abandonment of subsequent injection wells, namely, the Coteau 2 through 6, will be performed in a manner consistent with that of the Coteau 1. The size and depths of the various plugs may vary as necessary to accomplish the zonal isolation, but in each instance, approval of specific P&A operations will be required from the NDIC Department of Mineral Resources (DMR) prior to the initiation of fieldwork.	Figure 10-1. Coteau 1 CO_2 injection well schematic (p. 10-2) Figure 10-2. Schematic of proposed abandonment plan for each injection well (p. 10-6)
	NDAC 43-05-01-05 §1n	**NDAC 43-05-01-05 §1n** n. A postinjection site care and facility closure plan pursuant to section 43-05-01-19; and	j. A post-injection site care and facility closure plan.	**6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN (p. 6-1)** This postinjection site care (PISC) and facility closure plan describes the activities that DGC will perform following the cessation of CO_2 injection to achieve final closure of the site. A primary component of this plan is a postinjection monitoring program that will provide evidence that the injected CO_2 plume is stable (i.e., CO_2 migration will be unlikely to move beyond the boundary of the storage facility area). Based on simulations of the predicted CO_2 plume movement following the cessation of CO_2 injection, it is projected that the CO_2 plume will stabilize within the storage facility area boundary (Section 3). Based on these observations, a minimum postinjection monitoring period of 10 years is planned to confirm these current predictions of the CO_2 plume extent and postinjection stabilization. However, monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable CO_2 plume. The nature and duration of that extension will be determined based on an update of this plan and NDIC approval. In addition to DGC executing the postinjection monitoring program, the Class VI injection wells will be plugged as described in the plugging plan of this permit application (Section 10), all surface equipment not associated with long-term monitoring will be removed, and the surface land of the site will be reclaimed to as close as is practical to its original condition. Following the plume stability demonstration, a final assessment will be prepared to document the status of the site and submitted as part of a site closure report. Note: Refer to Table 6-1 on p. 6-4 for a summary of the postinjection site care monitoring plan.	Table 6-1. Summary of 10-year Postinjection Site Care Monitoring Plan (p. 6-4)
Storage Facility Operations	NDAC 43-05-01-05 §1b(4)	**NDAC 43-05-01-05 §1b(4)** (4) The proposed calculated average and maximum daily injection rates, daily volume, and the total anticipated volume of the carbon dioxide stream using a method acceptable to and filed with the commission;	The following items are required as part of the storage facility permit application: a. The proposed average and maximum daily injection rates; b. The proposed average and maximum daily injection volume; c. The proposed total anticipated volume of the carbon dioxide to be stored;	**11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)** This section of the storage facility permit (SFP) application presents the engineering criteria for completing and operating the injection wells in a manner that protects underground sources of drinking water (USDWs). The information that is presented meets the permit requirements for injection wells and storage operations as presented in North Dakota Administrative Code (NDAC) § 43-05-01-05 (SFP, Table 11-1) and NDAC § 43-05-01-11.3	Table 11.1. Proposed Injection Well Operating Parameters (p. 11-1)

NDAC 43-05-01-05 §1b(5)

NDAC 43-05-01-05 §1b(5)
(5) The proposed average and maximum bottom hole injection pressure to be utilized at the reservoir. The maximum allowed injection pressure, measured in pounds per square inch gauge, shall be approved by the commission and specified in the permit. In approving a maximum injection pressure limit, the commission shall consider the results of well tests and other studies that assess the risks of tensile failure and shear failure. The commission shall approve limits that, with a reasonable degree of certainty, will avoid initiating a new fracture or propagating an existing fracture in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water;

d. The proposed average and maximum bottom hole injection pressure to be utilized;

e. The proposed average and maximum surface injection pressures to be utilized;

Table 11-1. Proposed Injection Well Operating Parameters

Item	Coteau 1	Coteau 2	Coteau 3	Coteau 4	Coteau 5	Coteau 6	Total/Avg
Injected Volumes							
Total Injected Volume[1]	96.0 Bcf (4.9 MMt)	67.2 Bcf (3.4 MMt)	96.0 Bcf (4.9 MMt)	96.0 Bcf (4.9 MMt)	73.2 Bcf (3.7 MMt)	73.2 Bcf (3.7 MMt)	501.6 Bcf (25.6 MMt)
Injection Rates							
Predicted Average Injection Rate[2]	21.9 MMcfd (1,119 t/d)	15.3 MMcfd (783 t/d)	21.9 MMcfd (1,119 t/d)	21.9 MMcfd (1,119 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	114.5 MMcfd (5,845 t/d)
Predicted Maximum Injection Rate[2]	24.6 MMcfd (1,254 t/d)	17.2 mmcfd (878 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	140.0 MMcfd (7,146 t/d)
Injection Pressures							
Estimated Depth of Top Perforation (feet)[3]	5,930	5,998	5,981	5,928	5,901	5,961	5,950
Formation Fracture Pressure at Top Perforation (psi)[4]	4,210	4,259	4,247	4,209	4,190	4,232	4,224
Projected Avg Surface Injection Pressure (psi)[2]	1,628	1,597	1,644	1,604	1,682	1,677	1,639
Max Allowable Surface Injection Pressure (psi)[5]	1,976	1,998	1,993	1,975	1,966	1,986	1,982
Projected Avg Bottomhole Injection Pressure (psi)[2]	3,315	3,335	3,349	3,297	3,284	3,295	3,313
Projected Max. Bottomhole Injection Pressure (psi)[2]	3,430	3,445	3,462	3,414	3,424	3,426	3,434
Max. Bottomhole Pressure at Top Perforation (psi)[6]	3,801	3,845	3,834	3,800	3,782	3,821	3,814

[1] Assumes 55 MMcfd distributed between four wells (Coteau 1–4) from July/22 thru Dec/24, 70 MMcfd distributed between these same wells Jan/25 thru Apr/26, and 140 MMcfd distributed between six wells (Coteau 1–6) from May/26 through Jun/34.
[2] Per simulation modeling.
[3] Top perf. assumed to be 23 ft below the top of the Broom Creek Formation in all instances based on log results from Coteau 1.
[4] Based on a fracture pressure gradient of 0.71 psi/ft as calculated via CoreLabs D-Code algorithm.
[5] Based on a maximum allowable BHP equal to 90% of frac pressure and a CO_2 density of 0.306 psi/ft.
[6] Based on a maximum allowable BHP equalt to 90% of fracture pressure gradient at estimated depth of top perforation

	NDAC 43-05-01-05 §1b(6)	**NDAC 43-05-01-05 §1b(6)** (6) The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone and confining zone pursuant to section 43-05-01-11.2;	f. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone;	See Table 5-7 on p. 5-18 See Appendix A: WELL AND WELL FORMATION FLUID SAMPLING LABORATORY ANALYSIS	Table 5-7 (p. 5-18)
			g. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the confining zone;	See Table 5-7 on p. 5-18	
	NDAC 43-05-01-05 §1b(7)	**NDAC 43-05-01-05 §1b(7)** (7) The proposed stimulation program, a description of stimulation fluids to be used, and a determination that stimulation will not interfere with containment; and	h. The proposed stimulation program: 1. A description of the stimulation fluids to be used 2. A determination of the probability that stimulation will interfere with containment;	**11.1 Coteau 1 Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-2)** Rampart Energy (on behalf of the Dakota Gasification Company [DGC]) drilled and cased the Coteau 1 with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. The following proposed completion procedure outlines the steps necessary to complete the Coteau 1 well for injection purposes. Note: See a full procedure provided from p. 11-3.	N/A
	NDAC 43-05-01-05 §1b(8)	**NDAC 43-05-01-05 §1b(8)** (8) The proposed procedure to outline steps necessary to conduct injection operations.	i. Steps to begin injection operations	**11.1 Coteau 1 Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-2)** Rampart Energy (on behalf of the Dakota Gasification Company [DGC]) drilled and cased the Coteau 1 with intentions to conduct $CO2_2$ stream injection operations, as referenced in previous sections. The following proposed completion procedure outlines the steps necessary to complete the Coteau 1 well for injection purposes. Note: See a full procedure provided from p. 11-3.	

Dakota Gasification Company

Case No. 29450

Application of Dakota Gasification Company requesting consideration for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Dakota Gasification Company intends to capture carbon dioxide from the Great Plains Synfuels Plant and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT July 19, 2022. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Steve Fried, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Dakota Gasification Company, 1717 East Interstate Avenue, Bismarck, ND 58503.

Case No. 29451

Application of Dakota Gasification Company to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Dakota Gasification Company storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code Section 38-22-10.

Case No. 29452

Application of Dakota Gasification Company for an order of the Commission determining the amount of financial responsibility for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant in the storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.

July 20, 2022

EXHIBIT 2

EXHIBIT B

Tract Summary

Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation	Acreage Leased
1	Section 30 - T146N-R87W	The Coteau Properties Co.	237.57	74.81%	1.48674499%	74.81%
		John D. Renner	80.00	25.19%	0.50065075%	0.00%
		Tract Total	**317.57**	100.00%		**74.81%**
2	Section 25 - R146N-R88W	The Coteau Properties Co.	**320.00**	100.00%	2.00260301%	**100.00%**
3	Section 26 - R146N-R88W	The Coteau Properties Co.	200.00	62.50%	1.25162688%	62.50%
		Lucille Sailer	120.00	37.50%	0.75097613%	37.50%
		Tract Total	**320.00**	100.00%		**100.00%**
4	Section 27 - R146N-R88W	The Coteau Properties Co.	80.00	50.00%	0.50065075%	50.00%
		Lyle Eisenbeis and Kathy Eisenbeis	80.00	50.00%	0.50065075%	50.00%
		Tract Total	**160.00**	100.00%		**100.00%**
5	Section 33 - R146N-R88W	Karen A. Walz	**160.00**	100.00%	1.00130150%	**100.00%**
6	Section 34 - R146N-R88W	E. Wayne Eisenbeis and Margo L. Eisenbeis	320.00	66.67%	2.00260301%	66.67%
		The Coteau Properties Co.	160.00	33.33%	1.00130150%	33.33%
		Tract Total	**480.00**	100.00%		**100.00%**
7	Section 35 - R146N-R88W	The Coteau Properties Co.	560.00	87.50%	3.50455526%	87.50%
		Lucille Sailer	80.00	12.50%	0.50065075%	12.50%
		Tract Total	**640.00**	100.00%		**100.00%**
8	Section 36 - R146N-R88W	The Coteau Properties Co.	320.00	50.00%	2.00260301%	50.00%
		Wayne Renner and Prudence Renner	240.00	37.50%	1.50195226%	37.50%
		Prudence Renner	40.00	6.25%	0.25032538%	6.25%
		Wayne Renner	40.00	6.25%	0.25032538%	6.25%
		Tract Total	**640.00**	100.00%		**100.00%**

EXHIBIT B
Tract Summary
Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation	Acreage Leased
9	Section 31 - T146N-R87W	Wayne Renner and Prudence Renner	**637.68**	100.00%	3.99068715%	**100.00%**
10	Section 32 - T146N-R87W	Wayne Renner and Prudence Renner	**160.00**	100.00%	1.00130150%	**100.00%**
11	Section 5 - T145N-R87W	David Young Payn	159.94	49.99%	1.00092602%	0.00%
		The Coteau Properties Co.	160.00	50.01%	1.00130150%	50.01%
		Tract Total	**319.94**	100.00%		**50.01%**
12	Section 6 - T145N-R87W	The Coteau Properties Co.	**639.31**	100.00%	4.00088790%	**100.00%**
13	Section 1 - T145N-R88W	The Coteau Properties Co.	**636.40**	100.00%	3.98267673%	**100.00%**
14	Section 2 - T145N-R88W	The Coteau Properties Co.	**634.96**	100.00%	3.97366502%	**100.00%**
15	Section 3 - T145N-R88W	E. Wayne Eisenbeis and Margo L. Eisenbeis	235.47	36.93%	1.47362168%	36.93%
		Ronnie Lee Parks	4.21	0.66%	0.02634675%	0.66%
		The Coteau Properties Co.	317.90	49.86%	1.98946093%	49.86%
		North American Coal Royalty Co.	80.00	12.55%	0.50065075%	12.55%
		Tract Total	**637.58**	100.00%		**100.00%**
16	Section 4 - T145N-R88W	The Coteau Properties Co.	233.71	73.46%	1.46260737%	73.46%
		Darvin Schlender and Janet Schlender	4.43	1.39%	0.02770476%	1.39%
		North American Coal Royalty Co.	80.00	25.15%	0.50065075%	25.15%
		Tract Total	**318.14**	100.00%		**100.00%**
17	Section 9 - T145N-R88W	The Coteau Properties Co.	**320.00**	100.00%	2.00260301%	**100.00%**
18	Section 10 - T145N-R88W	The Coteau Properties Co.	**640.00**	100.00%	4.00520602%	**100.00%**

EXHIBIT B

Tract Summary

Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation	Acreage Leased
19	Section 11 - T145N-R88W	The Coteau Properties Co.	**640.00**	100.00%	4.00520602%	**100.00%**
20	Section 12 - T145N-R88W	The Coteau Properties Co.	636.71	99.49%	3.98461675%	99.49%
		Mercer County	2.52	0.39%	0.01577050%	0.39%
		Basin Electric Power Coop	0.77	0.12%	0.00481876%	0.12%
		Tract Total	640.00	100.00%		**100.00%**
21	Section 7 - T145N-R87W	Wayne Renner and Prudence Renner	240.00	37.54%	1.50195226%	37.54%
		Basin Electric Power Coop	319.30	49.95%	1.99822231%	49.95%
		The Coteau Properties Co.	80.00	12.51%	0.50065075%	12.51%
		Tract Total	639.30	100.00%		**100.00%**
22	Section 8 - T145N-R87W	The Coteau Properties Co.	293.43	91.70%	1.83632438%	91.70%
		Ridge Runner Motorcycle Club, Inc.	26.57	8.30%	0.16627863%	0.00%
		Tract Total	**320.00**	100.00%		**91.70%**
23	Section 17 - T145N-R87W	The Coteau Properties Co.	**320.00**	100.00%	2.00260301%	**100.00%**
24	Section 18 - T145N-R87W	The Coteau Properties Co.	625.29	97.81%	3.91316138%	97.81%
		Dakota Gasification Co.	13.45	2.10%	0.08415939%	2.10%
		Basin Electric Power Coop	0.58	0.09%	0.00362972%	0.09%
		Tract Total	639.32	100.00%		**100.00%**
25	Section 13 - T145N-R88W	Basin Electric Power Coop	233.09	36.42%	1.45867726%	36.42%
		The Coteau Properties Co.	372.46	58.20%	2.33089848%	58.20%
		Dakota Gasification Co.	34.46	5.38%	0.21563028%	5.38%
		Tract Total	640.00	100.00%		**100.00%**
26	Section 14 - T145N-R88W	The Coteau Properties Co.	558.75	87.30%	3.49673260%	87.30%
		Mercer County	1.25	0.20%	0.00782267%	0.20%

EXHIBIT B
Tract Summary
Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation	Acreage Leased
		Basin Electric Power Coop	80.00	12.50%	0.50065075%	12.50%
		Tract Total	**640.00**	100.00%		**100.00%**
27	Section 15 - T145N-R88W	The Coteau Properties Co.	**640.00**	100.00%	4.00520602%	**100.00%**
28	Section 16 - T145N-R88W	The Coteau Properties Co.	240.00	75.00%	1.50195226%	75.00%
		Betty Scott	40.00	12.50%	0.25032538%	12.50%
		Dallas Crabtree	20.00	6.25%	0.12516269%	6.25%
		Denzel Crabtree	20.00	6.25%	0.12516269%	0.00%
		Tract Total	**320.00**	100.00%		**93.75%**
29	Section 22 - T145N-R88W	The Coteau Properties Co.	446.70	69.80%	2.79550864%	69.80%
		Karen A. Walz	152.92	23.89%	0.95699391%	23.89%
		Kelly L. Wilhelm	40.38	6.31%	0.25270347%	6.31%
		Tract Total	**640.00**	100.00%		**100.00%**
30	Section 23 - T145N-R88W	Basin Electric Power Coop	360.00	56.25%	2.25292838%	56.25%
		The Coteau Properties Co.	40.00	6.25%	0.25032538%	6.25%
		Robert L. Bitner and Irma M Bitner for Life	240.00	37.50%	1.50195226%	0.00%
		Tract Total	**640.00**	100.00%		**62.50%**
31	Section 24 - T145N-R88W	Dakota Gasification Co.	478.40	74.75%	2.99389150%	74.75%
		Basin Electric Power Coop	147.58	23.06%	0.92356922%	23.06%
		The Coteau Properties Co.	14.02	2.19%	0.08774530%	2.19%
		Tract Total	**640.00**	100.00%		**100.00%**
32	Section 19 - T145N-R87W	The Coteau Properties Co.	320.00	50.08%	2.00260301%	50.08%
		North American Coal Royalty Co.	159.45	24.95%	0.99785953%	24.95%
		Dakota Gasification Co.	159.55	24.97%	0.99848534%	24.97%
		Tract Total	**639.00**	100.00%		**100.00%**

EXHIBIT B
Tract Summary
Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

Tract No.	Land Description	Owner Name		Tract Net Acres	Tract Participation	Storage Facility Participation	Acreage Leased
		76583468.1	**Total Acres**	**15,979.20**	**Total Participation**	**100.00000000%**	**96.71%**

GREAT PLAINS CO_2 SEQUESTRATION PROJECT MERCER COUNTY, NORTH DAKOTA

Supplemental Filing: Response to the North Dakota Department of Environmental Quality Comments

Prepared for:

Stephen Fried

North Dakota Industrial Commission
Oil & Gas Division
600 East Boulevard Avenue
Department 405
Bismarck, ND 58505-0840

Prepared by:

Dakota Gasification Company
1717 East Interstate Avenue
Bismarck, ND 58503-0564

Carbon Vault Great Plains LLC
1512 Larimer Street, Suite 550
Denver, CO 80202-1620

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

April 2022

6A

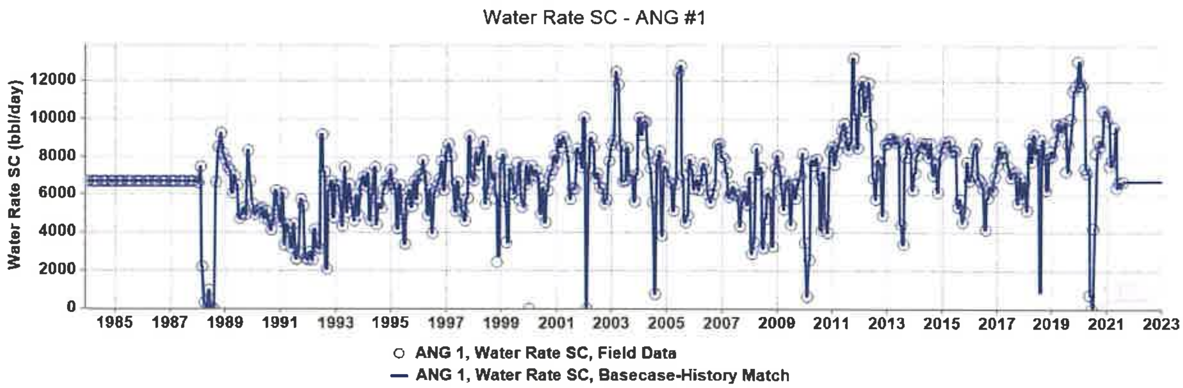
GREAT PLAINS CO_2 SEQUESTRATION PROJECT
MERCER COUNTY, NORTH DAKOTA

This supplemental report was generated in response to comments received from the North Dakota Department of Environmental Quality (DEQ) on April 7, 2022, regarding the historical data from the Class I injection wells, ANG #1 and ANG #2, that were used to history-match the numerical simulation model and evaluate the potential interaction between the low-salinity water injected in the ANG wells and the predicted CO_2 plume.

The numerical simulation model was history-matched using injection rate and wellhead pressure (WHP) data from the ANG wells from July 1998 to August 2021 (Section 3.3, Figure 3-13 and Figure 3-14). This 1998–2021 data set and a constant water injection rate (Section 3.3, Table 3-4), representing future injection in the ANG wells, were used to predict the extent of the low-salinity plume at the end of the CO_2 injection period. Simulation results indicate that the low-salinity plume (total dissolved solids [TDS] 8050 ppm) associated with the ANG #1 and ANG #2 disposal water and the injected CO_2 plume for the six-well injection scenario discussed in Section 3.0 may have negligible interaction after 10 years postinjection (Section 2.3.3, Figure 2-22). Based on the limited interaction of the injected CO_2 and the injected disposal water and the chemical composition of the disposal water, the ANG disposal well injection was not included as part of the geochemical modeling discussed in Section 2.3.3 for computational efficiency.

To address comments from the DEQ, additional historical data from the ANG wells were incorporated into the simulation model to account for all historical injection from the start of injection in December 1983 (ANG #1) and November 1984 (ANG #2). Injection rates and WHP data for the wells from 1988 to 1998 were digitized for input into the simulation model. Cumulative injection volume data were used to estimate monthly injection rates from 1983 to 1988 for the wells. The WHP values for 1983–1988 were estimated for each well based on the relationship between rate and WHP that was derived from the 1988–1998 data set.

The ANG injection rate and WHP data from 1983 to 2021 were used to history-match the simulation model. Results show a good match between the historical field data and the predicted injection rates and WHPs from the simulation model (Figures 1 and 2). No modifications to the model were required to obtain this match.



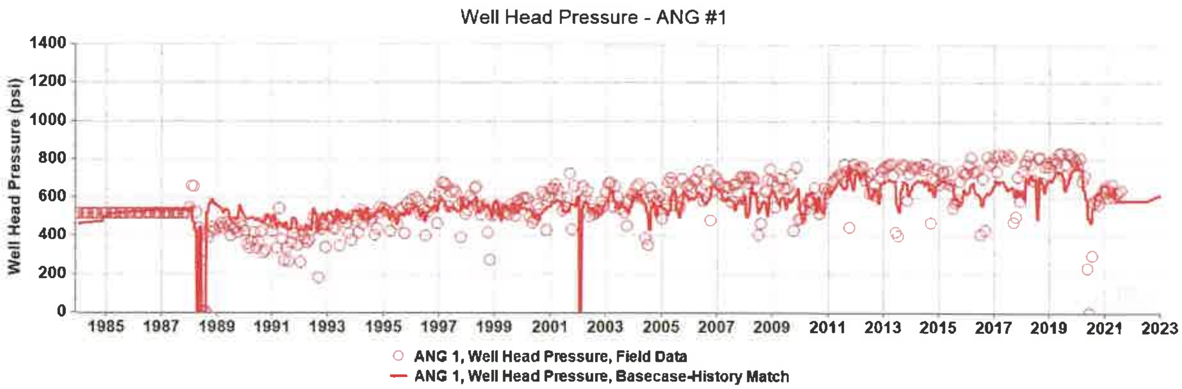


Figure 1. Water injection rate (top) and WHP curves (bottom) for the ANG #1 Class I disposal well. The circles represent the field data, and the lines represent the predicted values from the history-matched model.

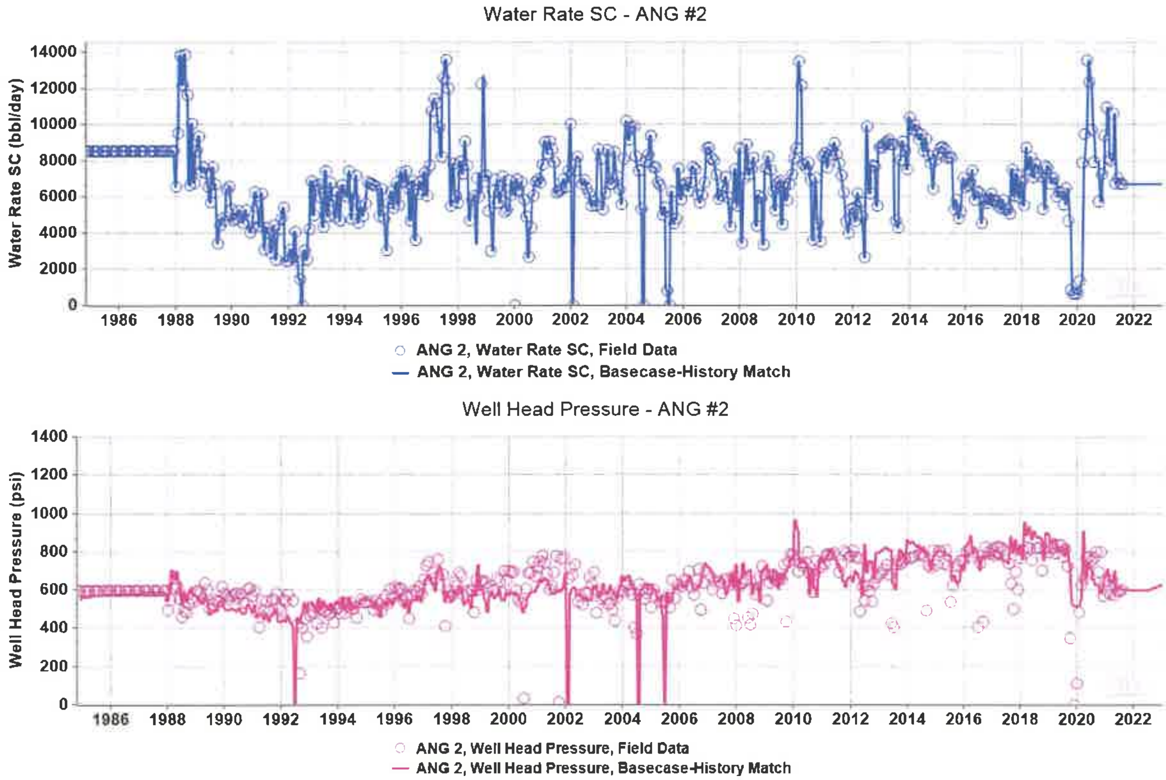


Figure 2. Water injection rate (top) and WHP curves (bottom) for the ANG #2 Class I disposal well. The circles represent the field data, and the lines represent the predicted values from the history-matched model.

The simulation model was rerun to account for the ANG injection volumes from start of injection in December 1983 (ANG #1) and November 1984 (ANG #2) to 2021. The simulation results show the low-salinity plume associated with water injection in the ANG wells slightly increases in size compared to the scenario discussed in Section 3.3 (Figure 3). This new simulation case shows that the low-salinity plume is still expected to have negligible interaction with the predicted CO_2 plume. The extent of the CO_2 plume at the end of injection is almost identical for both cases, with the extent of the CO_2 plume from the new case being one grid cell size smaller in two places along the northeast edge of the plume related to the predicted gas saturation in those cells falling below the 5% saturation cutoff in the new case (Figure 3). Similarly, the stabilized plume for the new case is slightly smaller than the simulation case described in Section 3.3 of the permit (Figure 3). The predicted bottomhole pressure and WHP for the ANG wells and the CO_2 injection wells are the same for both cases, and the predicted CO_2 injection rates and volumes are the same for both cases.

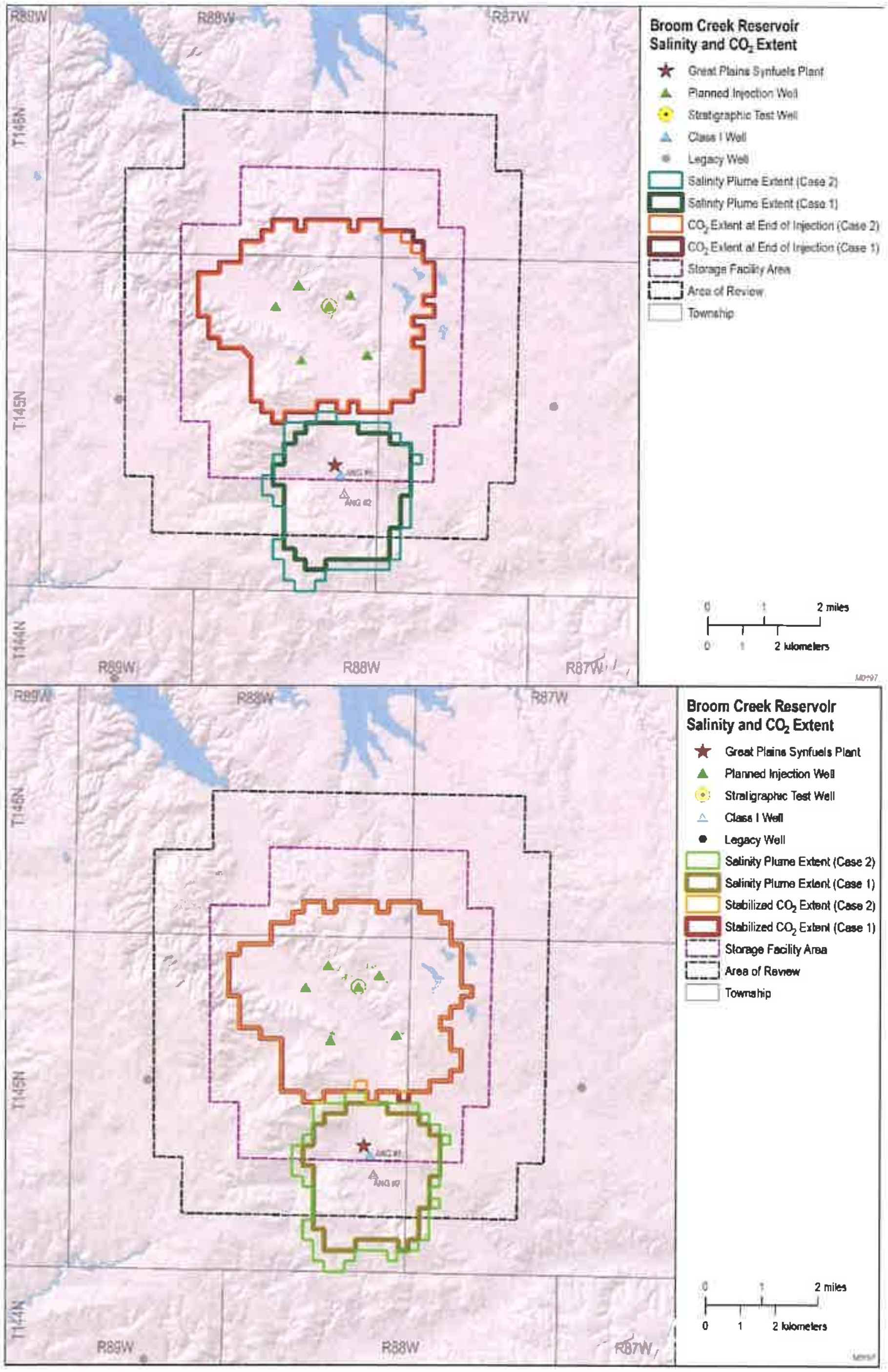


Figure 3. 2D map showing the water salinity plume from the Class 1 wells, ANG #1 and ANG #2, and the gas mole fraction (CO_2) for the expected injection scenario for this project, described in Section 3.3, consisting of six CO_2 injection wells. The lower map shows the stabilized CO_2 plume versus the salinity plume extent after 10 years postinjection in July 2044. Case 1 represents the scenario described in Section 3.3 that used field data for the ANG wells from 1998 to 2021. Case 2 represents the scenario run using ANG data from 1983 to 2021.

6E

Kadrmas, Bethany R.

From: Entzi-Odden, Lyn <lodden@fredlaw.com>
Sent: Monday, July 18, 2022 8:56 AM
To: Kadrmas, Bethany R.
Subject: Cases 29450, 29451 and 29452 - Dakota Gasification
Attachments: DGC filing.pdf; DGC additional affs.pdf

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Bethany,

Please see the attached for filing.

Thank you.

Fredrikson & BYRON, P.A.

Lyn Entzi-Odden
Executive Legal Assistant
1133 College Drive | Suite 1000 | Bismarck, ND 58501
Ph: 701.221.8700|lodden@fredlaw.com

****This is a transmission from the law firm of Fredrikson & Byron, P.A. and may contain information which is privileged, confidential, and protected by the attorney-client or attorney work product privileges. If you are not the addressee, note that any disclosure, copying, distribution, or use of the contents of this message is prohibited. If you have received this transmission in error, please destroy it and notify us immediately at our telephone number (701) 221-8700. The name and biographical data provided above are for informational purposes only and are not intended to be a signature or other indication of an intent by the sender to authenticate the contents of this electronic message.****

Fredrikson
& BYRON, P.A.

July 18, 2022

VIA EMAIL

Ms. Bethany Kadrmas
North Dakota Industrial Commission
Oil and Gas Division
600 East Boulevard
Bismarck, North Dakota 58505-0310

RE: CASE NOS. 29450, 29451 and 29452
Dakota Gasification Company

Dear Bethany:

Please find attached herewith the following for filing with regard to the captioned matter:

1. Memo from Dakota Gasification Company dated May 23, 2022;
2. Notice of Hearing;
3. Memo from Dakota Gasification Company dated June 16, 2022; and
4. Affidavits of Service by Mail indicating service on parties via certified mail, return receipt requested.

Should you have any questions, please advise.

Sincerely,

LAWRENCE BENDER

LB/leo
Enclosure
cc: Ms. Casey Jacobson – (w/enc.) *Via Email*

75954686 v1

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

May 23, 2022

ALL INTEREST OWNERS

RE: APPLICATION FOR GEOLOGIC STORAGE OF CARBON DIOXIDE, MERCER COUNTY, NORTH DAKOTA

Dear Sir/Madam:

Dakota Gasification Company ("DGC) has made application to the North Dakota Industrial Commission for a carbon dioxide storage facility permit. A hearing to consider the application of DGC has been scheduled as set forth in the attached Notice of Hearing.

If you have any questions regarding DGC's application, please do not hesitate to contact me at the following telephone number and address:

Mr. Dale Johnson
Vice President and Plant Manager
Dakota Gasification Company
1717 East Interstate Avenue
Bismarck ND 58503 USA
(701) 223-0441
dalej@bepc.com

Sincerely,

Dakota Gasification Company

/s/ Dale Johnson
Dale Johnson
Enc.

76151728 v1

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. _____

Application of Dakota Gasification Company for an order of the Commission to consider a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.

NOTICE OF HEARING

PLEASE TAKE NOTICE that Dakota Gasification Company, ("DGC") has made application to the North Dakota Industrial Commission ("Commission") requesting an order providing approval of a carbon dioxide storage facility permit as follows.

1. The carbon dioxide storage facility will be located near the city of Beulah, Mercer County, North Dakota, and comprised of the following described lands:

Township 146 North, Range 87 West
Section 30: S/2
Section 31: All
Section 32: SW/4

Township 146 North, Range 88 West
Section 25: S/2
Section 26: S/2
Section 27: SE/4
Section 33: SE/4
Section 34: SW/4, E/2
Section 35: All
Section 36: All

Township 145 North, Range 87 West
Section 5: W/2
Section 6: All
Section 7: All

Section 8: W/2
Section 17: W/2
Section 18: All
Section 19: All

<u>Township 145 North, Range 88 West</u>
Section 1: All
Section 2: All
Section 3: All
Section 4: E/2
Section 9: E/2
Section 10: All
Section 11: All
Section 12: All
Section 13: All
Section 14: All
Section 15: All
Section 16: E/2
Section 22: All
Section 23: All
Section 24: All

2. A hearing to consider the application of DGC will be held before the Commission at 9:00 a.m. on July 20, 2022, at the Department of Mineral Resources Conference Room, Oil and Gas Division, 1000 East Calgary Avenue, Bismarck, North Dakota.
3. A copy of the permit application and draft permit may be obtained from the Commission.
4. All comments regarding the application for the storage facility permit must be in writing and submitted to the Commission prior to hearing or presented at the hearing.
5. Amalgamation of the storage reservoirs pore space is required to operate the storage facility and the Commission may require that the pore space owned by nonconsenting owners be included in the storage facility and subject to geologic storage. The amalgamation of pore space will be considered at the hearing.

DATED this 23 day of May, 2022.

FREDRIKSON & BYRON, P.A.

By______________________________

LAWRENCE BENDER, ND Bar #03908
Attorneys for Applicant,
Dakota Gasification Company
1133 College Drive, Suite 1000
P. O. Box 1855
Bismarck, ND 58502-1000
(701) 221-8700

75954850 v1

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

June 16, 2022

MINERAL & SURFACE OWNERS

RE: Dakota Gasification Company's Carbon Dioxide Storage Permit Project

Dear Sir/Madam:

Several weeks ago, a Notice of Hearing was mailed to you regarding Dakota Gasification Company's ("DGC") application to the North Dakota Industrial Commission for a carbon dioxide storage facility permit in Mercer County, North Dakota. We have received a number of questions from mineral owners within the project area and thought providing additional information would be beneficial. I have included the most common questions/answers we have received to date.

Who is DGC?
DGC is a wholly owned subsidiary of Basin Electric Power Cooperative. Additional information can be obtained at the following link:

https://www.dakotagas.com/

What is DGC's proposed project?
The project consists of an already permitted carbon pipeline that will carry captured carbon dioxide (CO_2) from DGC's Great Plains Synfuels Plant to injection wells located approximately three-and-a-half miles north of the plant. The injection wells will be located on reclaimed land owned by The Coteau Properties Company, but will inject CO_2 more than a mile below the surface in the Broom Creek (sandstone) formation. This innovative project will benefit the environment by sequestering and permanently storing CO_2.

Why did I receive the notice of hearing?
North Dakota law provides that notice of the storage permit facility hearing must be given to each mineral lessee, mineral owner and pore space owner within one-half mile of the storage boundaries.

Where can I find additional information on this project?
The following web link from the North Dakota Department of Mineral Resources Geological of the North Dakota Industrial Commission provides the draft permit, fact sheet and DGC's storage facility permit application.

https://www.dmr.nd.gov/dmr/oilgas/ClassVI

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1717 East Interstate Avenue | Bismarck, ND 58503 | 701.223.0441 | Fax 701.557.4450 | dakotagas.com
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Do the mineral owners affected by this project receive compensation?
North Dakota law provides that title to pore space is vested in the owner of the overlying surface estate and that severing pore space is prohibited. Thus, compensation for the CO_2 lease is provided to the surface owners of real property.

If I am a mineral owner, do I need to provide written consent or written approval for the project?
No

What does amalgamation mean?
Amalgamation is a concept, provided for under North Dakota law whereby if a storage operator does not obtain the consent of all persons who own pore space in the storage reservoir, the North Dakota Industrial Commission may require that the pore space owned by nonconsenting owners be included in a storage facility and subject to geologic storage.

At this time, DGC has acquired 96.83% of the pore space needed for the project.

Where/how can I provide comments on the proposed project if I cannot attend the hearing on July 20th?
Submit written comments no later than 5:00 pm CDT July 19, 2022 to:
Oil and Gas Division
1016 East Calgary Avenue
Bismarck, North Dakota 58503-5512
or brkadrmas@nd.gov

Will the project impact the ability to recover oil or gas in the future?
No. The proposed injection zone for DGC's project is the Broom Creek Formation and has no known producible accumulations of hydrocarbons within the boundaries of storage facility area.

Should you have additional questions please reach out to me at 701-557-5454 or mmurray@bepc.com.

Sincerely,

Mike Murray

Mike Murray

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. _____

Application of Dakota Gasification Company for an order of the Commission to consider a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

Amber Nelson, being first duly sworn, deposes and says that on the 27th day of May, 2022, she served the attached:

Memo; and
Notice of Hearing

by placing a true and correct copy thereof in an envelope addressed as follows:

See attached Exhibit A

and depositing the same, with postage prepaid, certified mail, return receipt requested, in the United States mail at Bismarck, North Dakota.

Amber Nelson

Amber Nelson

Subscribed and sworn to before me this 27th day of May, 2022.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Lyn Odden

Notary Public
My Commission expires:

75954876 v1

A. Duane Rene
PO Box 47
Neche, ND 58265-0047

A. William Spiry
2101 8th Ave. N.
Fargo, ND 58102

A.E. Besch Legacy, LP
c/o Vera Bank, N.A., Agent
PO Box 820
Henderson, TX 75653

A.V.M., Inc
P.O. Box 411
Bismarck, ND 58502-0411

Aaron Roesler
923 Kohrs Street
Deer Lodge, MT 59722

Acoma Oil Corporation
408 St. Peter Street, #434
St. Paul, MN 55102

Adele Rene Westover
24030 SE 192nd Street
Maple Valley, WA 98038

Adeline A. Stevens
(Adeline A. Weiss)
31108 3rd Ave., Sp.322
Black Diamond, WA 98010

Adeline Oberembt
25622 409th Ave
Mitchell, SD 57301

Agnes S. Hipfner
320 Central Avenue North
Beulah, ND 58523

AgriBank FCB
375 Jackson Street, P.O. Box 64949
St. Paul, MN 55164-0949

Airy Klaudt
c/o Julie Klaudt Meyer
9326 Buena Vista Rd.
Lucerne Valley, CA 92356

Al E. Nick, as Trustee of the
Mondak Trust A
111 Church Street
Ferguson, MO 63135

Alan W. Zimmerman
3110 N. 19th St. #13
Bismarck, ND 58503

Albert Koerner
c/o Ellroy Koerner
27910 445th Avenue
Marion, SD 57043

Albert L. Boeckel
1710 Evergreen Drive NW
Jamestown, ND 58401-2218

Albert L. Boeckel and
Alice J. Boeckel
1710 Evergreen Drive NW
Jamestown, ND 58401-2218

Albert L. Boeckel and Alice J.
Boeckel Revocable Living Trust
1710 Evergreen Drive NW
Jamestown, ND 58401-22218

Albin E. Keller
220 Broadwater Ave.
Billings, MT 59100

Alden Renner
4711 Secret Valley Dr.
Billings, MT 59101-9382

Alerus Financial, Trustee of Jonette Rae
King Trust under the Last Will &
Testament of Margaret Blumhardt
3137 - 32nd Avenue South
Fargo, ND 58104

Alerus Financial, Trustee of the
Jonette Rae King Trust
3137 - 32nd Avenue South
Fargo, ND 58104

Alexander F. Rolle and
Andrew Rolle
2105 Adair
San Marino, CA 91108

Alf Richard Thompson
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College Station, TX 77840

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c/o Ferdinand Madche-POA
402 3rd Street NW
Hazen, ND 58545

Ellen Leonhard
Box 132
Lake Havasu City, AZ 86403

Ellie Dassinger
1720 W. Montebello, #217
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Elliott Family Trust
c/o Cathy Elliott Pate P.O.
Box 1356
Alpine, TX 79831

Ellis Oster & Gertrude Oster
Ellendale, ND 58432

Ellonore Nolz
Parkston, SD 57366

Ellroy Koerner
27910 - 445th Ave.
Marion, SD 57043

Elmer Klaudt
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Caldwell, ID 83605

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Elroy Eisenbeis
27910 445th Ave.
Marion, SD 57043

Elroy Koerner
27910 445th Ave
Marion, SD 57043-5800

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HC2 Box 105
Charlson, ND 58763

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Dodge, ND 58625

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Emogene Mefford and
Cheryl A. Mefford
RR #1
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EPEC OCS Company, Inc.
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Ermine Howerton
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Decatur, IL 62521

Erna C. Klaudt
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Vallejo, CA 94591

Ernest Hellickson and Jean
Hellickson
3910 116th R Avenue SW
Dickinson, ND 58601

Ernest L. Hull
1502 Tucker Rd
Perry, GA 31069

Ervin Eisenbeis
102 12th Avenue NW
Beulah, ND 58523

Ervin J. Hudson
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Great Falls, MT 59405-2425

Erwin Eisenbeis
102 12th Street N.W.
Beulah, ND 58523

Erwin Eisenbeis &
Evelyn Eisenbeis
102 12th Street N.W.
Beulah, ND 58523

Estate of Agnes Nelson
c/o Frances Leonhard Nelson
2113 NW Tarnesen Land
Paulsbo, WA 98370

Estate of Agnes Wiedrich
c/o Blair Wiedrich
405 2nd Ave. SW
Beulah, ND 58523

Estate of Alvin Gaines
c/o Anne Cerulli, for life
13641 Alderwood Lane, 35B
Seal Beach, CA 90740

Estate of Ann Barton
Address Unknown

Estate of Ann Golder Hull c/o
Ernest L. Hull
1502 Tucker Rd
Perry, GA 31069

Est of Annie Dwight Taylor , c/o Jean
Stromswold, as Trustee, Last Will & Test,
Rhoda F. Larson , dtd 8/24/1974, for life of
T.R.Larson, remainder to Jean Stromswold
Pendroy, MT 59467

Estate of Annie Dwight Taylor
c/o Estate of Niel E. Classon
19219-99th Place South
Renton, WA 98055

Estate of Annie Dwight Taylor
c/o Hugh Manessier
4330 Van Buren Blvd.
Riverside, CA 95203

Estate of Annie Dwight Taylor
c/o Estate of Esther Hankins
8606 Zerelda Street
Rosemead, CA 91770

Estate of Annie Dwight Taylor
c/o James J. Hankins, Jr., as Trustee,
Hankins Living Trust, dtd 12/13/2012
8606 Zerelda Street
Rosemead, CA 91770

Estate of Arnold Weiss
Attn: Armon A. Weiss
6550 66th Street NE
Bismarck, ND 58503

Estate of B.A Skipper, Sr.
Address Unknown

Estate of Belva L. Dalrymple
c/o Robert Lynn Dalrymple and
Elizabeth J. Feuerstein
5 West Faiview Street
Arlington Heights, IL 60005-2551

Estate of Bertha Boeckel
c/o Donna Soland
1107 Cherry Lane
Beulah, ND 58523

Estate of Bertha Boeckel
c/o Albert L. Boeckel
1710 Evergreen Drive NW
Jamestown, ND 59401-2218

Estate of Bertha Ost
c/o Milton Ost
1204 Kent Ave.
Albert Lea, MN 56007

Estate of C.E. Brehm
c/o Baumstark Braaten law Partners
109 North 4th Street, Suite 100
Bismarck, ND 58501

Estate of Charlene Salome Carlisle
c/o Clifford Clay Smith
2648 Mariposa Cir.
Plano, TX 75075

Estate of Charlene Salome Carlisle
c/o Tyler Marrie Webb
1504 Cherry Dr. #221
Arlingon, TX 76013

Estate of Charlene Salome Carlisle
c/o Carol Lee Webb, a/k/a Carol Wells
12200 IH 10 W #1402
San Antonio, TX 78230

Estate of Charlene Salome Carlisle
c/o Rachel Charleene Smith
2648 Mariposa Cir.
Plano, TX 75075

Estate of Charlene Salome Carlisle
c/o Ariel Diane Smith
2648 Mariposa Cir.
Plano, TX 75075

Estate of Charles Brandt
c/o Kim Sandau
3130 County Road 89
Hebron, ND 58638

Estate of Charles F. Smith and/or
Nancy M. Smith & Mary Sue Bruce
4167 North McArthur Road
Decatur, IL 62526

Estate of Charles L. McDaniels
c/o Marjorie McDaniels
Shelby, AL 35143

Estate of Clara Koerner
c/o Ellroy Koerner
27910 - 445th Ave.
Marion, SD 57043

Estate of Clara Koerner
c/o Albert and Ellroy Koerner
27910 - 445th Avenue
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Estate of Coleta Hoepfner, c/o
Gregory Hoepfner, PR
6860 S Pine Rock Dr
Salt Lake City, UT 84121-3427

Estate of Dale Ervin Boeckel
Beulah, ND 58523

Estate of David Boeckel
c/o Peggy Becker, Co-PR
P.O. Box 183
Bismarck, ND 58502

Estate of David Wolf
c/o Lynne Wolf
Box 986
Beulah, ND 58523

Estate of Dean Shew
c/o Helen Chaney
36 Cypress Point
Abilene, TX 79606

Estate of Delilah Hertha Herman
18 2nd Lane SW
Pick City, ND 58545

Estate of Delores R. Ost
c/o Sabrina Preston
2115 Vivian Lane NW
Rochester, MN 55901-8085

Estate of Delores R. Ost
c/o Catherine Ost
14909 91st Ave. N.
Maple Grove, MN 55369-8832

Estate of Delores R. Ost
c/o Deborah Durand
2436 Circle Drive
West Palm Beach, FL 33406-5889

Estate of Delores R. Ost
1204 Kent Avenue
Albert Lea, MN 56007

Estate of Donald Klaudt
c/o Dorothy D. Klaudt
5806 NE 76nd Ave.
Vancouver, WA 98661

Estate of Dorothy C. Kingsley
Address Unknown

Estate of Dosier Skipper
c/o Caroline Skipper Hollins
1605 Enterprise Boulevard
Lake Charles, LA 70601

Estate of Dosier Skipper
c/o LeGrande Kelly Skipper
6026 Spring Flower Trail
Dallas, TX 75248

Estate of E.A. Coyne
Address Unknown

Estate of Ella Madche
c/o Ferdinand Madche
402 3rd Street NW
Hazen, ND 58545

Estate of Elmer Weiss
304 Fair Street
Beulah, ND 58523

Estate of Emil Klaudt
c/o Virginia Campbell
307 Abbot St.
Richland, WA 99352

Estate of Emily G. Gudmundson
c/o Gene Gudmundson
Mountain, ND 58262-0177

Estate of Emma Keller
Beulah, ND 58523

Estate of Erwin Eisenbeis
c/o Evelyn Eisenbeis
100 - 12th Street NW
Beulah, ND 58523

Estate of Esther Benham
503 Mr. B's Estates, Rt. 3
Bismarck, ND 58501

Est of Esther Christensen Benham
503 Mr. B Estate, Route 3
Bismarck, ND 58501

Estate of Finley F. Hamilton
c/o Lawrence A. Hamilton
14702 Kellywood Ln.
Houston, TX 77079

Estate of Florence Cram, deceased
c/o Wilbert W. Cram
P.O. Box 593
Kittitas, WA 98934

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c/o Carol Ann Dilse
13307 77th St. SW
Scranton, ND 58563

Estate of G.F.M. Ward
c/o Chloe Ward Swoboda
14 Edgewood Lane
Centralia, IL 62801

Estate of G.F.M. Ward
c/o D'Ella Ward Jones
R. 8 Salem Road
Mt. Vernon, IL 62864

Estate of G.F.M. Ward
c/o George Michael Ward
5300 Valleyview Road
Blue Springs, MO 64015

Estate of G.F.M. Ward
c/o Mary Ward Eaton
114 Renfrew
Adrian, MI 49221

Estate of G.F.M. Ward
c/o Sarah Ward Henry
19 Oak Park West
Centralia, IL 62801

Estate of G.F.M. Ward
c/o Todd P. Ward
800 Fox Hill Drive
Edmond, OK 73034

Estate of Gaynelle May
a/k/a Johnnie Gaynelle May
c/o Emily Gaynelle Angel
39 Bpunty Road E
Ft. Worth, TX 76132-1001

Estate of Gaynelle May a/k/a Johnnie Gaynelle May
c/o Clifford Clay Smith
2648 Mariposa Cir.
Plano, TX 75075

Estate of Gaynelle May
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c/o Tyler Marrie Webb
1504 Cherry Dr. #221
Arlingon, TX 76013

Estate of Gaynelle May
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c/o Carol Lee Webb, a/k/a Carol Wells
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Estate of Gaynelle May
a/k/a Johnnie Gaynelle May
c/o Rachel Charleene Smith
2648 Mariposa Cir.
Plano, TX 75075

Estate of Gaynelle May
a/k/a Johnnie Gaynelle May
c/o Ariel Diane Smith
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Zap, ND 58580

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6550 66th Street NE
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Estate of Gladys Romona Jansonius
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Bismarck, ND 58501

Estate of Gladys Romona Jansonius
c/o Carol Jansonius Marino
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Ann Arbor, MI 48105

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c/o Loren Neubauer
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Estate of Helen Hurley
c/o Harold L. Hurley
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c/o Thomas F. Kelsch and
Karen L. Kelsch
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c/o Waldemar and Thorey Melsted
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c/o Carrie Klaudt
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Estate of John G. Weiss
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Estate of L.E. Kennedy
c/o Estelle B. Kennedy
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Newtown, IL 62448

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Longview, TX 75601

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802 8th Ave. SE
Sidney, MT 59270

Estate of Lester Renner
c/o Delores Renner
Address Unknown

Estate of Lester Renner
C/o Tallana Williams
8245 Substation Road
Davis, OK 73030

Estate of Lester Renner
c/o Bradley Lucas Renner
4456 Chalmers
Casper, WY 82609

Estate of Lester Renner
c/o Brandon Les Renner
306 Sisken
Casper, WY 82609

Estate of Lester Renner
C/o Tallana Williams
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Davis, OK 73030

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c/o Mark Eslinger
P.O. Box 873243
Wasilla, AK 99687

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c/o Mark Eslinger
P.O. Box 873243
Wasilla, AK 99687

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c/o Bank One, TX, Nat'l Ass'n, PR
1717 Main St
Dallas, TX 75201-4643

Estate of Margaret Blumhardt
c/o Jonette Rae King, PR
409 9th Ave S
Fargo, ND 58103

Estate of Margaret E. Krebs
Bay City, MI 48706

Estate of Margery Trenbeath
c/o Mary D. Einarson
311 Wall Street Ave N.
Moorehead, MN 56560

Estate of Marguerite D. Campbell
c/o J. W. King, Jr.
1258 Canterbury Dr
Abilene, TX 79602

Estate of Marjorie E. Rene
c/o Amanda Rene
508 - 17th St. NW
Mandan, ND 58554

Estate of Mary Hughes Davidson
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Austin, TX 78747

Estate of Mary M. Dhom
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2151 36th Ave. SW, Suite B
Minot, ND 58701

Estate of Mason W. Potter
c/o Jane Ogilvie
23 Geneva Dr.
Muscatine, IA 52761

Estate of May A. Coyne
Address Unknown

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3760 Learwood Dr.
Loxahatchee, FL 33470

Estate of Myrtle L. Griffith
c/o Emily Gaynelle Angel
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c/o Clifford Clay Smith
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Estate of Myrtle L. Griffith
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Plano, TX 75075

Estate of Reinhard Weiss
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Estate of Reinhard Weiss
Stillwater, MN 55082

Estate of Reinhold Klaudt
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Norcross, GA 30071

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c/o Mabel L. Eisenbeis
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Beulah, ND 58523

Estate of Reuben Scheid
c/o Bruce Winkler
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Hazen, ND 58545

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c/o Alice Halter
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Billings, MT 59102

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c/o Mary Fiess
7642 East Breeze Circle
Sacramento, CA 95828-5102

Estate of Sharon Drasnin
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Dallas, PA 18612

Estate of Sophie Boeckel
c/o Peggy Becker
3009 Northshore Loop SE
Mandan, ND 58554

Estate of Theophil Renk
c/o Ferdinand Madche
and Vernon Herman
402 3rd Street NW
Hazen, ND 58545

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Sacramento, CA 95828

Estate of Violet Neubauer
c/o Gothilf J. Neubauer PR
PO Box 253
Osburn, ID 83849

Estate of Violet Neubauer
c/o Gothilf J. Neubauer
PO Box 253
Osburn, ID 83849

Estate of Violet Neubauer
c/o Loren Neubauer
PO box 944
Osburn, ID 83849

Marc Newman Drasnin
5745 Tequesta Dr
West Bloomfield, MI 48323-2363

Estate of William C. Clementz, Amelia
R. Clementz, Edward L. Neubauer and
Velma R. Neubauer
1808 Lemon St Dr
Higland, IL 62249

Estate of Winne Gates Jenkins
c/o Sarah Lee Jenkins Knudson
3727 Bloxham Ct.
Chamblee, GA 30341

Estates of W.W. Potter and
R.W. Potter
Address Unknown

Esther Syrup
211 Park Ave. N.
Park River, ND 58270

Eugene E. Keller
1575 55th St.
Huff, ND 58554

Ev. Luther. St. Friedens
Gemeinde, Iowa Synod
(Peace Lutheran Church)
Kasmer, ND

Evangelical Lutheran Church in
America
87 West Higgins Road
Chicago, IL 60631

Evangeline Treiber
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Hebron, ND 58638

Evelyn Eisenbeis
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Beulah, ND 58523

Evelyn Hjalmarson
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Encinitas, CA 92024-2109

Evelyn Hoeven Arterburn
3109 Shore Road
Fort Collins, CO 80524

Evelyn Jane Duncan Florey
774 Sportsman Drive
Trinity, TX 75862

Farmers and Merchant Bank of
Vandalia and Robert Quandt, Trustees
for Helen E. Zeigler
P.O. Box 130
Vandalia, IL 62471

Ferdinand J. Madche
402 3rd Street NW
Hazen, ND 58545

Fern Jeppi
2217 "B" Street
Bakersfield, CA 93301

First Baptist Church of Hazelhurst,
Incorporated
151 Caldwell Drive
Hazelhurst, MN 39083

First Chicago Leasing Corporation
c/o The Corporation Trust Company
Corporation Trust Center
1209 Orange St
Wilmington, DE 19801

First Financial Bank, N.A.
f/k/a Crawford County State Bank
P.O. Box 531
Robinson, IL 62454

First National City Bank
c/o Citibank NA
5800 South Corporate Place
Sioux Falls, SD 57108

First Portfolio Ventures I LLC
c/o Robert Chalavoutis
3091 Governors Lake Dr, Ste 500
Norcross, GA 30071

Fisher Sand & Gravel Co.
PO Box 3024
Minot, ND 58702

Flossie Cramer
deceased

Floyd Mittelstedt
1449 East D Street
Ontario, CA 91764

Flying Wolf Enerprises, Inc.
21174 S. Sylvan Drive
Mundelein, IL 60060-9518

Gertrude E. Anderson
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Moorhead, MN 56560

Fortin Enterprises
201 Chilian Ave.
Palm Beach, FL 33480

Harry M McMillan
620 W 8th Ave
Bristow, OK 74010

Fortin Enterprises, Inc.
277 Pendleton Avenue
Palm Beach, FL 33480

Fortin Enterprises, Inc.
345 Australian Ave, Townhouse #6
Palm Beach, FL 33480

Foss Family Limited
Liability Company
22062 Lancrest Court
Farmington Hills, MI 48335

Frances Fell Malone, a/k/a Frances Fell
Kirkpatrick,
c/o Estate of Frances Fell Malone
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Enid, OK 73702-1466

Frances L. Huber
Route 2, Box 183
Austin, AR 72007

Frances Weber
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El Dorado, AR 71730

Francis P. Borden, III
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Francis X. Burns
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Frank Dilse
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Frank G. Mefford, Emogene
Mefford, and Cheryl A. Mefford
RR#1
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Frank L. Schmidt
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Gail Herman
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Gary L. Weigum
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Gary Miles Keith
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Gary Weiss
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Gary Weiss
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John K. Moss
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Gilbert C. Ost and Violet V. Ost
1001 Cherry Lane
Beulah, ND 58523

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P.O. Box 7500
Bartlesville, OK 74005-7500

Glacier Park Company
c/o ConocoPhillips
P.O. Box 7500
Bartlesville, OK 74005-7500

Glenda Carol O'Rourke
7212 Old Post Road
Boulder, CO 80301

Glenda O'Rourke
7212 Old Post Road
Boulder, CO 80301

Glengarry Oil Company
P.O. Box 267
Lima, OH 45802

Gordon C. Thompson
P.O. Box 1246
Williston, ND 58802-1246

Gordon Rene
2814 Ruger Ave
Janesville, WI 53545

Gothilf J. Neubauer
PO Box 253
Osburn, ID 83849

Gothilf J. Neubauer, PR of the Estate of
Violet Neubauer, deceased
PO Box 253
Osburn, ID 83849

Gramercy, LLC
7308 Arrowwood Rd.
Louisville, KY 40222

Gravel Products, Inc.
Route 1, Box 5
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Great Northern Properties
Limited Partnership
1101 N. 27th Street, Suite 201
Billings, MT 59101

Great Northern Properties
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1658 Cole Blvd. #6, Ste. 2
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Great Northern Properties
Limited Partnership
1035 3rd Avenue
Huntington, WV 25727-2827

Great Plains Gasification
1717 East Interstate Ave
Bismarck ND 58503

Greenstar Resources
Operating, L.L.C.
P.O. Box 721930
Norman, OK 73070

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PO Box 1200
Bristow, OK 74010

Harry M McMillan

Hancock Enterprises
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Billings, MT 59103

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Harold Flath
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Harold I. Stuart, Jr.
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Richard's Gebaur Air Force Base
Osage Beach, MO 65065

Hedwig K. Conrad
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Hemet, CA 92543

Helen E. Easley
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Bradenton, FL 33505

Helen E. Easley
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Apt 20101
Orlando, FL 32839

Helen E. Nelson
Christine, ND 58015

Helen Irene Klaudt
4261 Leavenworth Road
Kansas City, KS 66104

Hembdt Catawba, LLC
1 Great Elm Drive, P.O. Box 8
Sharon, CT 06069

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Cle Elum, WA 98922-9117

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Belva Huisinga
Box 92
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San Jose, CA 95125

Hilary Bostrom
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Sandra R. Mead
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Hilda Leraas and Sandra R. Mead
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Hilma R. Curtis
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Hilmer E. Hafner
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Beulah, ND 58523

Holly Gay Leer
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Portland, OR 97212

Ida Weiss
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Glendive, MT 59330

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Inez Bauer and Dale R. Bauer
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Ino M. Nichols
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Fort Worth, TX 76133-7516

Internal Revenue Service
P.O. Box 145595
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Irene A. Edmiston
6505 E. Whitier Street
Wake Forest, SC 27587

Irene A. Edmiston and
Tammie L. Merril
6505 E. Whitier Street
Wake Forest, NC 27587

Irene Fisher Bodine
2908-19th St.
Everett, WA 98201

Irene Fisher Bodine
1904 NW 4th Ave
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Irene L. Keller
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Irma Bitner
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Irma J. Goeckner
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Estate of Gerald Dean Weiss
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Estate of Laura Weiss Chapman
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Patrick T. Rooney Trust
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Oklahoma City, OK 73154

Timothy P. Rooney, Co-Trustee of
the Patrick T. Rooney Trust
9922 Rockbrook Dr
Dallas, TX 75220

James Harris Rooney, Co-Trustee of
the Patrick T. Rooney Trust
6121 Vernon Ter
Alexandria, VA 22307

Timothy P. Rooney, Co-Trustee of
the Timothy P. Tooney Trust
9922 Rockbrook Dr
Dallas, TX 75220

James Harris Rooney, Co-Trustee of
the Timothy P. Tooney Trust
6121 Vernon Ter
Alexandria, VA 22307

Patrick T. Rooney, Co-Trustee of the
Timothy P. Tooney
6604 N Hillcrest St Ave
Nichols Hills, OK 73116

Patrick T. Rooney, Co-Trustee of the
Timothy P. Tooney Trust
PO Box 54829
Oklahoma City, OK 73154

L.F. Rooney III, Co-Trustee of
The Timothy P. Tooney Trust
800 Admirality Parade
Naples, FL 24102

75558751.1

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. _____

Application of Dakota Gasification Company for an order of the Commission to consider a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

Amber Nelson, being first duly sworn, deposes and says that on the 16th day of June, 2022, she served the attached:

Memo; and
Notice of Hearing

by placing a true and correct copy thereof in an envelope addressed as follows:

Ardella Weidner
c/o Lori B. Weidner
1100 S Roosevelt St
Kennewick WA 99338

Betty L. Blahna
3074 Riviera Heights Dr.
Kelseyville, CA 95451

and depositing the same, with postage prepaid, certified mail, return receipt requested, in the United States mail at Bismarck, North Dakota.

Amber Nelson
Amber Nelson

Subscribed and sworn to before me this 16th day of June, 2022.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Lyn Odden
Notary Public
My Commission expires:

75954876 v1

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. _____

Application of Dakota Gasification Company for an order of the Commission to consider a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

Amber Nelson, being first duly sworn, deposes and says that on the 16th day of June, 2022, she served the attached:

Memo; and
Notice of Hearing

by placing a true and correct copy thereof in an envelope addressed as follows:

Burlington Resources Oil & Gas Co PK10-02-2007B, PO Box 2197 POB 8th Floor Houston, OK 77252-2197	MBI Oil & Gas 103 SE 5th Street Dickinson ND 58601	Bureau of Land Management 5001 Southgate Dr Billings, MT 59101
Cary Wolf 650 56th Ave SW Hazen, ND 58545	Nicholas E Wolf 973 Sandpoint Pond Ln Henderson, NV 89002	Elizabeth L Wolf PO Box 986 Beulah, ND 58523

and depositing the same, with postage prepaid, certified mail, return receipt requested, in the United States mail at Bismarck, North Dakota.

Amber Nelson
____
Amber Nelson

Subscribed and sworn to before me this 16th day of June, 2022.

Lyn Odden
____
Notary Public
My Commission expires:

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 29450

Application of Dakota Gasification Company for an order of the Commission to consider a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

Amber Nelson, being first duly sworn, deposes and says that on the 16th day of June, 2022, she served the attached:

Memo; and
Notice of Hearing

by placing a true and correct copy thereof in an envelope addressed as follows:

Michelle Wolf
501 Canterbury Lane
Bismarck, ND 58504

and depositing the same, with postage prepaid, certified mail, return receipt requested, in the United States mail at Bismarck, North Dakota.

Amber Nelson
Amber Nelson

Subscribed and sworn to before me this 16th day of June, 2022.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Lyn Odden
Notary Public
My Commission expires:

76353311 v1

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 29450

Application of Dakota Gasification Company for an order of the Commission to consider a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

Amber Nelson, being first duly sworn, deposes and says that on the 17th day of June, 2022, she served the attached:

Memo

by placing a true and correct copy thereof in an envelope addressed as follows:

see attached Exhibit A

and depositing the same, with postage prepaid in the United States mail at Bismarck, North Dakota.

Amber Nelson

Amber Nelson

Subscribed and sworn to before me this 17th day of June, 2022.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Lyn Odden

Notary Public
My Commission expires:

76356232 v1

A. Duane Rene
PO Box 47
Neche, ND 58265-0047

A. William Spiry
2101 8th Ave. N.
Fargo, ND 58102

A.E. Besch Legacy, LP
c/o Vera Bank, N.A., Agent
PO Box 820
Henderson, TX 75653

A.V.M., Inc
P.O. Box 411
Bismarck, ND 58502-0411

Aaron Roesler
923 Kohrs Street
Deer Lodge, MT 59722

Acoma Oil Corporation
408 St. Peter Street, #434
St. Paul, MN 55102

Adele Rene Westover
24030 SE 192nd Street
Maple Valley, WA 98038

Adeline A. Stevens
(Adeline A. Weiss)
31108 3rd Ave., Sp.322
Black Diamond, WA 98010

Adeline Oberembt
25622 409th Ave
Mitchell, SD 57301

Agnes S. Hipfner
320 Central Avenue North
Beulah, ND 58523

AgriBank FCB
375 Jackson Street, P.O. Box 64949
St. Paul, MN 55164-0949

Airy Klaudt
c/o Julie Klaudt Meyer
9326 Buena Vista Rd.
Lucerne Valley, CA 92356

Al E. Nick, as Trustee of the
Mondak Trust A
111 Church Street
Ferguson, MO 63135

Alan W. Zimmerman
3110 N. 19th St. #13
Bismarck, ND 58503

Albert Koerner
c/o Ellroy Koerner
27910 445th Avenue
Marion, SD 57043

Albert L. Boeckel
1710 Evergreen Drive NW
Jamestown, ND 58401-2218

Albert L. Boeckel and
Alice J. Boeckel
1710 Evergreen Drive NW
Jamestown, ND 58401-2218

Albert L. Boeckel and Alice J.
Boeckel Revocable Living Trust
1710 Evergreen Drive NW
Jamestown, ND 58401-22218

Albin E. Keller
220 Broadwater Ave.
Billings, MT 59100

Alden Renner
4711 Secret Valley Dr.
Billings, MT 59101-9382

Alerus Financial, Trustee of Jonette Rae
King Trust under the Last Will &
Testament of Margaret Blumhardt
3137 - 32nd Avenue South
Fargo, ND 58104

Alerus Financial, Trustee of the
Jonette Rae King Trust
3137 - 32nd Avenue South
Fargo, ND 58104

Alexander F. Rolle and
Andrew Rolle
2105 Adair
San Marino, CA 91108

Alf Richard Thompson
R.R. #2, Box 90H
Effingham, IL 62401

Alfred Kristjanson
2102 Carnelian Lane
Eagan, MN 55122-2833

Alice Arends
118 Oak St., Apt. 302
DeKalb, IL 60115

Alice Arends
Sigma Kappa Sorority
928 Hillcress Drive
Dekalb, IL 60115

EXHIBIT A

Alice Halter
3941 Teal
Billings, MT 59102

Alice Marlene Heaton
863 County Road 500 East
Toledo, IL 62468

Alistair K. Bostrom
HC 3, Box 13554
Keaau, HI 96749

Allen Dakota Corporation
Address Unknown
Bismarck, ND

Allen Eisenbeis
2979 Mesquite Drive
Idaho Falls, ID

Allen J. Eisenbeis
2979 Mesquite Drive
Idaho Falls, ID 83404

Alma Weiss
Hazen, ND 58545

Alma Weiss & Edmund Weiss
Hazen, ND 58545

Alma Weiss
(Alma Weiss Woodson)
6215 Whisper Lane S.W.
Tacoma, WA 98499

Aloysius Schmidt
Parkston, SD 57366

Alvin Keller
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Billings, MT 59101

Alyssa S. Connor
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Wasilla, AK 99623

Amanda L. Rene-Matthews
508 17th St. NW
Mandan, ND 58554

Andrew F. Rolle & Andrew Rolle,
Trustees, Andrew Rolle O&G Trust
2105 Adair
San Marino, CA 91108

ANG Coal Gasification Company,
Administrator of Great Plains Coal
Gasification Project for US Dept of Energy
400 East Broadway
P.O. Box 1977
Bismarck, ND 58502-1977

Anita Rambo Dunlap, as Trustee of
the M.W. Rambo Family Trust
122 West Lilac Ridge Place
The Woodlands, TX 77384

Anne Cerulli, for life
13641 Alderwood Lane, 35B
Seal Beach, CA 90740

Ann Dilse
13307 77th St SW
Scranton, ND 58653

Ann E. Ervin
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Anna Goldade
Box 197
Silverton, ID 83867

Anne Carlsen Center for Children
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Jamestown, ND 58401-2971

Anne Carlson School (formerly
Crippled Children's School)
301 7th Avenue NW
Jamestown, ND 58401-2971

Anthony James Cerulli
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Aqua Purple Reef, LLC
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Los Angeles, CA 90046

Arbella Leasing Corporation
111 S King St
Honolulu, HI 96813-3501

Ardell Long
26 Feldspar Way
Billings, MT 59106

Ardella Weidner
c/o Lori B. Weidner
1100 S Roosevelt St
Kennewick WA 99338

Arkoma Bakken, LLC
203 E. Interstate 30
Rockwall, TX 75087

Armon A. Weiss
6550 66th Street NE
Bismarck, ND 58503

Armstrong Minerals LLC
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Dickinson, ND 58602

Arnold L. Colpitts and
Esther M. Colpitts
701 Oak Avenue
Clearwater, FL 33516

Arthur and Charisse Zimmerman
15833 Hayes Trail Court
Apple Valley, MN 55124

Arthur L. Keller
3512-46th Ave. Dr. West
Bradenton, FL 33505

Audrey Knudson
Address Unknown

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3404 Calypso Drive
Bismarck, ND 58504

Austin Crews Group, L.P., Austin
Crews Resource Series
P.O. Box 128
Effingham, IL 62401

Authur Huber and June E. Huber
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Astoria, OR 97103

Avalon North LLC
P.O. Box 815
Bismarck, ND 58502-0815

B & J Resources LLC
410 17th Street, Ste. 1150
Denver, CO 80202

BM Marcus Royalty LLC
c/o Lawco of North Dakota, Inc
4911 Lake View Loop
Williston, ND 58801-9348

Barbara A. Schuler
7996 Buckthorn Dr.
Mentor, OH 44060-7445

Barbara Breen, Estate of William
Wallace Dalrymple
4 Stuart on Oxford
Rolling Meadows, IL 60008

Barbara Breen, as Personal Representative
of the Estate of William Wallace Calrymple
4 Stuart on Oxford
Rolling Meadows, IL 60008

Basin Electric Power Cooperative
1717 East Interstate Ave.
Bismarck, ND 58503-0564

Bavendick Minerals &
Royalties, LLC
P.O. Box 313
Bismarck, ND 58502-0313

Beatrice Financial Services, Inc.
c/o CT Corporation System
314 N Broadway
Saint Louis, MO 63102-2035

BM Marcus Royalty LLC
3948 Greencastle Ave. SW
Oxford, IA 52322-9344

Benjamin Ripley Forsyth, a/k/a Benjamin
R. Forsyth, and Mary Janette Forsyth
3301 Ninth Street NE
Great Falls, MT 59404

Bernard F. Desloge
14 Pine Valley Drive
St. Louis, MO 63124

Beatrice Financial Services, Inc.
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3011 American Way
Missoula, MT 59808-1921

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Beulah, ND 58523

Beth Tarduno
74 Oakdale Drive
Rochester, NY 14618

Bette J. Mathis
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Sioux Falls, SD 57108-8543

Betty A. Horning and
Harold R. Horning
Box 62
Osburn, ID 83849

Betty Eileen Ferrel
3740 Pinebrook Circle, #107
Bradenton, FL 34209

Betty Eileen Ferrel, a life estate
3470 Pinebrook Circle, #207
Bradenton, FL 34209

Betty L. Blahna
3074 Riviera Heights Dr.
Kelseyville, CA 95451

Betty Marie Klaudt & Keri Beth Pruett, Co-Trustees, Credit Shelter Trust under Item 5 of Last Will & Test, Vernon R. Klaudt
1165 River Laurel Drive
Suwanee, GA 30024

Betty Parnell
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Longview, TX 75606

Betty Scott
P.O. Box 297
Osburn, ID 83811

Betty Unruh
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Cheyenne, WY 82001

Beulah Community Nursing Home
509 Central Avenue North
Beulah, ND 58523

Beverly G. Gunlaugson
5000 65th Ave. North
Brooklyn Center, MN 55429

Beverly J. Johnson
P.O. Box 1158
Dickinson, NE 58602

Biglow Properties, a Partnership
c/o Tom Krupp
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Fostoria, OH 44830

Black Stone Minerals
Company, L.P.
1001 Fanin, Suite 2020
Houston, TX 77002-6709

Bobby Gene Story
8749 N. 600th Street
Newton, IL 62448

Bradley Gurley
11232 E. 2000th Ave.
Hutsonville, IL 62433

Bradley Gutknecht
11105 W Center Ave
Lakewood, CO 80226

Bradley Lucas Renner
4456 Chalmers
Casper, WY 82609

Bradley Scott
7905 Apache Canyon Drive
Las Cruces, NM 88007

Brandon Les Renner
306 Sisken
Casper, WY 82609

Breck Minerals, LP
a Texas limited partnership
P.O. Box 911
Breckenridge, TX 76424

Brehm Investment Group Inc.
P.O. Box 648
Mt. Vernon, IL 62864

Bremer Trust NA, Trustee, Borstad
Family Mineral Interest
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Minot, ND 58702-1548

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Highlands Ranch, CO 80129-5479

Brenda Kay Fake
5237 W. 145th Str.
Savage, MN 55378

Brenda Kay Fake
1599 Coastwalk, Ste. 100
San Diego, CA 92037

Brenda L. Sullivan
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Pasco, WA 99301

Bresco, Inc.
1215 Orchard Rd.
Essexville, MI 48732

Brian Fake
4148 County View Dr.
Eagan, MN 55123

Brian Francis Arman
81 Tribute Avenue
Hudson, WI 54016

Brian Henry Hess
115 Parkview Dr.
Swan River Manitoba, R0L 1Z0,
Canada

Brian Joseph Pierce
417 K Street NE
Washington, DC 20002

Bruce M. Bitterman & Gail J.
Bitterman, as Joint Tenants
100 7th Street NW #209
Beulah, ND 58523

Bruce Winkler
470 50th Ave. SW
Hazen, ND 58545

Bruce Winkler, PR of the Estate of
Berniece M. Winkler Scheid, deceased
470 50th Ave. SW
Hazen, ND 58545

Bryan A. Kostelecky
1150 11th Avenue W.
Dickinson, ND 58601

Burch Holdings Management Co., LLC
c/o Samuel A. Burch, President
12270 Sable Lane
Whitehouse, TX 75791

BURLINGTON RESOURCES
OIL & GAS CO
PK10-02-2007B, PO Box 2197
POB 8TH FLOOR
HOUSTON, OK 77252-2197

Busey Trust Company, Trustee of the Helen
Phipps Testamentary Trust
P.O. Box 260
Champaign, IL 61824-0260

C. D. Shallenberger, Jr.
1196 Lavendel Lane
Kirkwood, MO 63122

C. D. Shallenberger, Jr. as Trustee
of the C. D. Shallenberger, Jr. Trust
1196 Lavendel Ln
Kirkwood, MO 63122

C. C. Harmon and
Pearl M. Harmon
317 N Maple Street
Nowata, OK 74048

C. C. Harmon and
Pearl M. Harmon
114 West Deleware Ave.
Nowata, OK 74048

C.T.S. Properties, L.L.C.
Box 220
Flora, IL 62839

Candace Furlong
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Capital One Bank (USA), N.A.
c/o Corp. Serv. Co. Dba Csc - Lawyers
Inc. Serv. Co.
211 E 7th St, Ste 620
Austin, TX 78701-3218

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123 S. 10th St., Suite 506
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Carol Hafner Miller and
Myron D. Mill
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Greenwood, IN 46143

Carol Susan Nestleroad, Trustee of
C.S.N. Minerals Trust
110 N. Washington St.
P.O. Box 44
Martinsville, IL 62442

Caroline Skipper Hollins
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Lake Charles, LA 70601-6365

Carolyn Ann Ferguson
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Carolyn Dutzi
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Carrie R. Reber
7017 Bentley Avenue
Fort Worth, TX 76102

Carroll College
Norman D. Schneckloth & Howard
T. Schneckloth Endow Schol Fund
Helena, MT 59602

Carroll George Weiss
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Williston, ND 58801

Cary Lee Ost and Ava Ost
Star Route, Box 52
Beulah, ND 58523

Cary Wolf
650 56th Ave SW
Hazen, ND 58545

Caryn Y. Clements
121 East Fifth Street
Shelton, NE 68876

Casey Huber
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Kirkwood, MO 63122

Catherine (Kay) Ost
14909 91st Ave. N.
Maple Grove, MN 55369-8832

Cecil Hagen
Address Unknown

Celestine M. Weigum
(aka Celestine M. Hafner)
1185 76th Ave. NE
New Rockford, ND 58356

Chad A. Wiedenmeyer
8826 Sage Drive
Bismarck, ND 58503

Charles Howard Thornburg II
977 Highway 308 Shelby, AL
35143-5629

Mildred M. Hembdt & Ethel A. Hemdbt
Trustees under that certain Trust Indenture
2000 Maple HIll St, Ste 106
Yorktown Heights, NY 10598

Charles Stroup (Land Agent for
David Young Payn)
209 Central Avenue
Hazen, ND 58545

Cheryl A. Axtman
6416 Shoal Drive
Bismarck, ND 58503

Cheryl A. Mefford
16187 E. 1050th Ave.
Palestine, IL 62451

Cheryl D. Hogle
4829 West 60th
Minneapolis, MN 55424

Chester Alexander
1590 Martha Drive
Elgin, IL 60120

Chester C. Alexander
1590 Martha Drive
Elgin, IL 60120

Christian Klaudt
23659 300th Street
Neola, IA 51559-4055

Christie E. Herman
1125 North 15th Street
Moorhead, MN 56560

Christoph Leonhard
Bismarck, ND 58501

Christopher George Weiss
2003 East Wildwood Drive
Grand Island, NE 68801

Christopher Thorson
12542 Carow Circle
Frazee, MN 56544

Chrysler Financing Corporation
c/o The Corporation Trust Company
1209 N Orange St
Wilmington, DE 19801-1120

Citation 2002 Investment Ltd Part., f/k/a
Citation 1994 Investment Ltd Part.
c/o Citation Oil & Gas Corp., Managing
General Partner
14077 Cutten Road
Houston, TX 77069

Clayton Boeckel
1007 Central Ave. N.
Beulah, ND 58523

Clayton E. Schott
26230 North Tower Road
Detroit Lakes, MN 56501

Clayton J. Boeckel
1007 Central Ave. N.
Beulah, ND 58523

Clinton D. Chapman
12909 Green Avenue
Los Angeles, CA 90066

Clifford Morris
and Millie D. Morris
Wheatland, ND 58079

Clyde Eisenbeis
2819 Hogan Drive
Bismarck, ND 58501

Clyde Neubauer
PO Box 253
Osburn, ID 83849

Clyde T. Eisenbeis
2819 Hogan Drive
Bismarck, ND 58501

Cody Oil & Gas Corporation
P.O. Box 597
Bismarck, ND 58502-0597

Comerica Bank, as Trustee for Florence
Klein Irrevocable Trust, under the Klein
Family Trust, dated October 1, 1971
8850 Boedeker Street, 5th Floor
Dallas, TX 75225

Comerica Bank, as Trustee of the Deer
Siblings 2005 Mineral Trust,
dated 5/18/2005
8850 Boedeker Street, 5th Floor
Dallas, TX 75225

Concise Oil & Gas Partnership
c/o Hallwood G.P.Inc.
4582 S. Ulster Street, Parkway, Suite 1700
Denver, CO 80237

Connie Anderson
2008 - 8th Ave. SE
Mandan, ND 58554

Connie C. Hausauer
373 31st Street West
Billings, MT 59101

Connie Sailer
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Beulah, ND 58523

Connor Sullivan
941 Cottonwood Drive
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Consolidation Coal Company, a
Delaware corporation
1209 N Orange St
Wilmington, DE 19801-1120

Corey Thorson
105 Harbor Way
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Corlyss Bronston Delashaw
c/o Kenneth L. Delashaw Jr.,
Attorney at Law
P.O. Box 328
Marietta, OK 73448

Cory Herman
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Pick City, ND 58545

Craig Beck
1602 47th Street SW #307
Fargo, ND 58103

Craig O. Zeller
205 5th St. NW
Beulah, ND 58523

Craig Steven Beck
500 16th Ave. SW
Fargo, ND 58103

Crawford County State Bank
PO Box 531
Robinson, IL 62454

Crawford County State Bank, rustee
(aka Donald J. Weber and
Shari M. Weber Trust)
PO Box 531
Robinson, IL 62454

Crawford County State Bank, Trustee
Under Trust #328, dated April 3, 1980
PO Box 531
Robinson, IL 62454

Crawford County State Bank, trustee
under trust #328 (aka Donald J. Weber
and Shari M. Weber Trust)
PO Box 531
Robinson, IL 62454

Crawford County State Bank, Trustee
Donald J. Weber and
Shari M. Weber Trust
PO Box 531
Robinson, IL 62454

Crescent Energy, Inc.
P.O. Box 271229
Louisville, CO 80027

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Crystal D. Pickens
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Crystal Leer
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Scottsdale, AZ 85262

Curtis Bennett
P.O. Box 4381
Houston, TX 77210

Curtis Bennett
Expat-Jakarta
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Curtis Herman
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Edgemoor, SC 29712

Cynthia A. Colvin
2680 Co.Rd 116
Fort Payne, Alabama 35968

Cynthia C. Fowler, as Trustee of the
Cotton 4 Mineral Trust
1411 North Blvd.
Houston, TX 77006

Cynthia C. Fowler, as Trustee of the
Cotton 6 Mineral Trust
1411 North Blvd.
Houston, TX 77006

Cynthia Friedrich
709 11th Ave S., Apt. 6
Hopkins MN 55343

Cynthia Sailer Watts
12131 Unity St
Coon Rapids, MN 55448

D&K Financial Corporation
3 Capital Dr
Eden Prairie, MN 55344-3890

D.J. Erickson
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Beulah, ND 58523

Daisy George
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Olney, IL 62450

Dakota West Energy LLC
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Bismarck, ND 58502-0816

Dakota Gasification Company
1717 East Interstate Avenue
Bismarck, ND 58503-0564

Dakota West Energy LLC
P.O. Box 816
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Dale Isaak
1908 Beauford Street
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Dale Klaudt
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Kent, WA 98031

Dale L. Huisinga
c/o Omar T. Shawler
220 S. 6th St., PO Box 67
Marshall, IL 62441

Dale L. Huisinga, Est of Belva
Huisinga, c/o Omar T. Shawler
220 S. 6th St., P.O. Box 67
Marshall, IL 62441

Dale L. Huisinga, PR of Estate of Belva
Huisinga, c/o Omar T. Shawler
220 S. 6th St., PO Box 67
Marshall, IL 62441

Dale Rene
3325 Laurel Wood Circle NE
Tacoma, WA 98422

Dallas Crabtree
W. 809 Westmoreland Road
Deer Park, ID 99006

Dana Leners
3208 Harrison Rd.
Ames, IA 50010

Daniel W. Vanderhoof
1225 Tappadero Trail
Billings, MT 59101

Danny L. Keller
P.O. Box 268
Beulah, ND 58523

Danny L. Walker
1112 Sunflower Lane
Hazen, ND 58545

Darlene Harris
386 Turner Ford Rd.
Franklin, KY 42134

Darlene Isaak
130 Central Ave. N
Golden Valley, ND 58541

Darnell Boeckel
7558 101st Street
Lemmon, SD 57638

Dart and Kraft Financial
3 Capital Dr
Eden Prairie, MN 55344-3890

David D. Weidner
2281 - 120th Str.
Barnesville, MN 56541-9036

Singer Brothers, a partnership,
Alex Singer and Joe L. Singer
c/o Singer Bros. LLC
4124 S Rockford Ave
Tulsa, OK 74105

David Drasnin
22 Kingswood Drive
Dallas, PA 18612

David J. Weiss
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Stillwater, MN 55082

David L. Huber
821 Williamson Loop
Grant Pass, OR 97526

David L. Huber
144 NE 20th Drive
Hillsboro, OR 97124

David Lorenson
1708 Norris Rd.
Vancouver, WA 98661

David Ost
424 W. Washington
Union City, TX 38261

David Steffan and Dianne Steffan
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Deborah Durand
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Debra Morast and Dean K. Morast
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Delmar Kruckenberg and Yvonne
Kruckenberg, for life as JT
c/o Julie Ann Kittelson
455 Benton Street
Dickinson, ND 58601

Delmar Kruckenberg and Yvonne
Kruckenberg, for life as JT
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1315 Orange
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Donald Keller
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Emmett, ID 83617

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Doris R. Beckman
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Emmett, ID 83617

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Fargo, ND 58102

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Douglas Bostrom
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Douglas Kelly, Jr.
752 Eventide Drive
Memphis, TN 38138

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and Dr. Ernest R. Britton, Trustees, Holman
Educational Tr for McKendree College
c/o McKendree College
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Lebanon, IL 62254

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Yakima, WA 98902

Duane Moderow
Buffalo, ND 58011

Duel S. Pickens
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22062 Lancrest Court
Farmington Hills, MI 48335

E. H. Arbuthnot, deceased
Foss Family LLC
22062 Lancrest Court
Farmington Hills, MI 48335

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Commerce City CO 80640-7608

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Hazen, ND 58545

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Box 132
Lake Havasu City, AZ 86403

Ellie Dassinger
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c/o Cathy Elliott Pate P.O.
Box 1356
Alpine, TX 79831

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Ellendale, ND 58432

Ellonore Nolz
Parkston, SD 57366

Ellroy Koerner
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Marion, SD 57043

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Caldwell, ID 83605

Eloise McKig
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Marion, SD 57043

Elroy Koerner
27910 445th Ave
Marion, SD 57043-5800

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c/o Loretta Fleckenstein
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Dodge, ND 58625

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Cheryl A. Mefford
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Palestine, IL 62451

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Ermine Howerton
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Dickinson, ND 58601

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Ervin J. Hudson
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Great Falls, MT 59405-2425

Erwin Eisenbeis
102 12th Street N.W.
Beulah, ND 58523

Erwin Eisenbeis &
Evelyn Eisenbeis
102 12th Street N.W.
Beulah, ND 58523

Estate of Agnes Nelson
c/o Frances Leonhard Nelson
2113 NW Tarnesen Land
Paulsbo, WA 98370

Estate of Agnes Wiedrich
c/o Blair Wiedrich
405 2nd Ave. SW
Beulah, ND 58523

Estate of Alvin Gaines
c/o Anne Cerulli, for life
13641 Alderwood Lane, 35B
Seal Beach, CA 90740

Estate of Ann Barton
Address Unknown

Estate of Ann Golder Hull c/o
Ernest L. Hull
1502 Tucker Rd
Perry, GA 31069

Est of Annie Dwight Taylor , c/o Jean
Stromswold, as Trustee, Last Will & Test,
Rhoda F. Larson , dtd 8/24/1974, for life of
T.R.Larson, remainder to Jean Stromswold
Pendroy, MT 59467

Estate of Annie Dwight Taylor
c/o Estate of Niel E. Classon
19219-99th Place South
Renton, WA 98055

Estate of Annie Dwight Taylor
c/o Hugh Manessier
4330 Van Buren Blvd.
Riverside, CA 95203

Estate of Annie Dwight Taylor
c/o Estate of Esther Hankins
8606 Zerelda Street
Rosemead, CA 91770

Estate of Annie Dwight Taylor
c/o James J. Hankins, Jr., as Trustee,
Hankins Living Trust, dtd 12/13/2012
8606 Zerelda Street
Rosemead, CA 91770

Estate of Arnold Weiss
Attn: Armon A. Weiss
6550 66th Street NE
Bismarck, ND 58503

Estate of B.A Skipper, Sr.
Address Unknown

Estate of Belva L. Dalrymple
c/o Robert Lynn Dalrymple and
Elizabeth J. Feuerstein
5 West Faiview Street
Arlington Heights, IL 60005-2551

Estate of Bertha Boeckel
c/o Donna Soland
1107 Cherry Lane
Beulah, ND 58523

Estate of Bertha Boeckel
c/o Albert L. Boeckel
1710 Evergreen Drive NW
Jamestown, ND 59401-2218

Estate of Bertha Ost
c/o Milton Ost
1204 Kent Ave.
Albert Lea, MN 56007

Estate of C.E. Brehm
c/o Baumstark Braaten law Partners
109 North 4th Street, Suite 100
Bismarck, ND 58501

Estate of Charlene Salome Carlisle
c/o Clifford Clay Smith
2648 Mariposa Cir.
Plano, TX 75075

Estate of Charlene Salome Carlisle
c/o Tyler Marrie Webb
1504 Cherry Dr. #221
Arlingon, TX 76013

Estate of Charlene Salome Carlisle
c/o Carol Lee Webb, a/k/a Carol Wells
12200 IH 10 W #1402
San Antonio, TX 78230

Estate of Charlene Salome Carlisle
c/o Rachel Charleene Smith
2648 Mariposa Cir.
Plano, TX 75075

Estate of Charlene Salome Carlisle
c/o Ariel Diane Smith
2648 Mariposa Cir.
Plano, TX 75075

Estate of Charles Brandt
c/o Kim Sandau
3130 County Road 89
Hebron, ND 58638

Estate of Charles F. Smith and/or
Nancy M. Smith & Mary Sue Bruce
4167 North McArthur Road
Decatur, IL 62526

Estate of Charles L. McDaniels
c/o Marjorie McDaniels
Shelby, AL 35143

Estate of Clara Koerner
c/o Ellroy Koerner
27910 - 445th Ave.
Marion, SD 57043

Estate of Clara Koerner
c/o Albert and Ellroy Koerner
27910 - 445th Avenue
Marion, SD 57043

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Gregory Hoepfner, PR
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Estate of David Wolf
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Box 986
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c/o Helen Chaney
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18 2nd Lane SW
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Estate of Delores R. Ost
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Estate of Delores R. Ost
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Estate of Dorothy C. Kingsley
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c/o Caroline Skipper Hollins
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Estate of Dosier Skipper
c/o LeGrande Kelly Skipper
6026 Spring Flower Trail
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Estate of E.A. Coyne
Address Unknown

Estate of Ella Madche
c/o Ferdinand Madche
402 3rd Street NW
Hazen, ND 58545

Estate of Elmer Weiss
304 Fair Street
Beulah, ND 58523

Estate of Emil Klaudt
c/o Virginia Campbell
307 Abbot St.
Richland, WA 99352

Estate of Emily G. Gudmundson
c/o Gene Gudmundson
Mountain, ND 58262-0177

Estate of Emma Keller
Beulah, ND 58523

Estate of Erwin Eisenbeis
c/o Evelyn Eisenbeis
100 - 12th Street NW
Beulah, ND 58523

Estate of Esther Benham
503 Mr. B's Estates, Rt. 3
Bismarck, ND 58501

Est of Esther Christensen Benham
503 Mr. B Estate, Route 3
Bismarck, ND 58501

Estate of Finley F. Hamilton
c/o Lawrence A. Hamilton
14702 Kellywood Ln.
Houston, TX 77079

Estate of Florence Cram, deceased
c/o Wilbert W. Cram
P.O. Box 593
Kittitas, WA 98934

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c/o Carol Ann Dilse
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Estate of G.F.M. Ward
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14 Edgewood Lane
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Estate of G.F.M. Ward
c/o D'Ella Ward Jones
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Adrian, MI 49221

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c/o Sarah Ward Henry
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Centralia, IL 62801

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Estate of Gaynelle May
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c/o Emily Gaynelle Angel
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Estate of Gaynelle May a/k/a Johnnie Gaynelle May
c/o Clifford Clay Smith
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c/o Tyler Marrie Webb
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c/o Carol Lee Webb, a/k/a Carol Wells
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c/o Rachel Charleene Smith
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c/o Ariel Diane Smith
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c/o Delores Renner
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C/o Tallana Williams
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c/o Bradley Lucas Renner
4456 Chalmers
Casper, WY 82609

Estate of Lester Renner
c/o Brandon Les Renner
306 Sisken
Casper, WY 82609

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Dallas, TX 75201-4643

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c/o Jonette Rae King, PR
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Fargo, ND 58103

Estate of Margaret E. Krebs
Bay City, MI 48706

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c/o Mary D. Einarson
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c/o J. W. King, Jr.
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c/o Amanda Rene
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c/o Jane Ogilvie
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Estate of May A. Coyne
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a/k/a Carol Wells
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c/o Bruce Winkler
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c/o Alice Halter
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c/o Mary Fiess
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Dallas, PA 18612

Estate of Sophie Boeckel
c/o Peggy Becker
3009 Northshore Loop SE
Mandan, ND 58554

Estate of Theophil Renk
c/o Ferdinand Madche
and Vernon Herman
301 4TH Ave NE
Hazen, ND 58545

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Sacramento, CA 95828

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Osburn, ID 83849

Estate of Violet Neubauer
c/o Gothilf J. Neubauer
PO Box 253
Osburn, ID 83849

Estate of Violet Neubauer
c/o Loren Neubauer
PO box 944
Osburn, ID 83849

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5745 Tequesta Dr
West Bloomfield, MI 48323-2363

Estate of William C. Clementz, Amelia
R. Clementz, Edward L. Neubauer and
Velma R. Neubauer
1808 Lemon St Dr
Higland, IL 62249

Estate of Winne Gates Jenkins
c/o Sarah Lee Jenkins Knudson
3727 Bloxham Ct.
Chamblee, GA 30341

Estates of W.W. Potter and
R.W. Potter
Address Unknown

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211 Park Ave. N.
Park River, ND 58270

Eugene E. Keller
1575 55th St.
Huff, ND 58554

Ev. Luther. St. Friedens
Gemeinde, Iowa Synod
(Peace Lutheran Church)
Kasmer, ND

Evangelical Lutheran Church in
America
87 West Higgins Road
Chicago, IL 60631

Evangeline Treiber
Box 54
Hebron, ND 58638

Evelyn Eisenbeis
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Beulah, ND 58523

Evelyn Hjalmarson
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Encinitas, CA 92024-2109

Evelyn Hoeven Arterburn
3109 Shore Road
Fort Collins, CO 80524

Evelyn Jane Duncan Florey
774 Sportsman Drive
Trinity, TX 75862

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Vandalia and Robert Quandt, Trustees
for Helen E. Zeigler
P.O. Box 130
Vandalia, IL 62471

Ferdinand J. Madche
402 3rd Street NW
Hazen, ND 58545

Fern Jeppi
2217 "B" Street
Bakersfield, CA 93301

First Baptist Church of Hazelhurst,
Incorporated
151 Caldwell Drive
Hazelhurst, MN 39083

First Chicago Leasing Corporation
c/o The Corporation Trust Company
Corporation Trust Center
1209 Orange St
Wilmington, DE 19801

First Financial Bank, N.A.
f/k/a Crawford County State Bank
P.O. Box 531
Robinson, IL 62454

First National City Bank
c/o Citibank NA
5800 South Corporate Place
Sioux Falls, SD 57108

First Portfolio Ventures I LLC
c/o Robert Chalavoutis
3091 Governors Lake Dr, Ste 500
Norcross, GA 30071

Fisher Sand & Gravel Co.
PO Box 3024
Minot, ND 58702

Flossie Cramer
deceased

Floyd Mittelstedt
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Ontario, CA 91764

Flying Wolf Enerprises, Inc.
21174 S. Sylvan Drive
Mundelein, IL 60060-9518

Gertrude E. Anderson
1121 River Dr
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as Trustee of the Joyce E. Larson
Revocable Living Trust dtd 9/11/2013
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September 7, 2001
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Farmington, NM 57102

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David Wolf
c/o Elizabeth L Wolf
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BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 29450

Application of Dakota Gasification Company for an order of the Commission to consider a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

Kim Nagel, being first duly sworn, deposes and says that on the 21st day of June, 2022, she served the attached:

Memo dated May 23, 2022;
Notice of Hearing; and,
Memo dated June 16, 2022

by placing a true and correct copy thereof in an envelope addressed as follows:

Janis Ritter
2 Alcott Way
Marlton, NJ 08053

and depositing the same, with postage prepaid in the United States mail at Bismarck, North Dakota.

Kim Nagel

Kim Nagel

Subscribed and sworn to before me this 21st day of June, 2022.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Lyn Odden

Notary Public
My Commission expires:

76390789 v1

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 29450

Application of Dakota Gasification Company for an order of the Commission to consider a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

Amber Nelson, being first duly sworn, deposes and says that on ~~the~~ 29 day of June, 2022, she served the attached:

Memo dated May 23, 2022;
Notice of Hearing; and,
Memo dated June 16, 2022

by placing a true and correct copy thereof in an envelope addressed as follows:

see attached Exhibit A

and depositing the same, with postage prepaid in the United States mail at Bismarck, North Dakota.

Amber Nelson
Amber Nelson

Subscribed and sworn to before me this 29 day of June, 2022.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Lyn Odden
Notary Public
My Commission expires:

76463844 v1

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BEULAH, ND 58523-9402

Ludelle L. Enochson
7808 TIMBERLINE RD
BLACK HAWK, SD 57718-9689

76459447 v1

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 29450

Application of Dakota Gasification Company for an order of the Commission to consider a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

Amber Nelson, being first duly sworn, deposes and says that on the 30 day of June, 2022, she served the attached:

Memo dated May 23, 2022;
Notice of Hearing; and,
Memo dated June 16, 2022

by placing a true and correct copy thereof in an envelope addressed as follows:

see attached Exhibit A

and depositing the same, with postage prepaid in the United States mail at Bismarck, North Dakota.

Amber Nelson
Amber Nelson

Subscribed and sworn to before me this 30 day of June, 2022.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Lyn Odden
Notary Public
My Commission expires:

76490041 v1

Lisa Baker Wilson and Diane B. Rowland,
Co-Trustees of the Baker Mineral Trust c/o
Lisa Baker Wilson
828 End Haven Place
Cary, NC 27519

Elaine Walker
350 County Road 13
Zap, ND 58580

Veda Stellwagen
659 Minnesota Ave.
Oostburg, WI 53070

Estate of David Boeckel
c/o Peggy Becker, Co-PR
3009 Northshore Loop SE
Mandan, ND 58554

Delmar Kruckenberg
455 Benton Street
Dickinson, ND 58601

JC Penney
2401 S. Stemmons Fwy, Ste. 4000
Lewisville, KY 75067-8797

EXHIBIT A

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 29450

Application of Dakota Gasification Company for an order of the Commission to consider a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

Amber Nelson, being first duly sworn, deposes and says that on the 8th day of July, 2022, she served the attached:

Memo dated May 23, 2022;
Notice of Hearing; and,
Memo dated June 16, 2022

by placing a true and correct copy thereof in an envelope addressed as follows:

see attached Exhibit A

and depositing the same, with postage prepaid in the United States mail at Bismarck, North Dakota.

Amber Nelson
Amber Nelson

Subscribed and sworn to before me this 8th day of July, 2022.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Lyn Odden
Notary Public
My Commission expires:

76543832 v1

Bette A. Ljunggren
1915 19TH AVE NW
MINOT, ND 58703-1198

Estate of Lawrence N. Skipper
c/o Joan Skipper
29 PATTI LYNN LN
HOUSTON, TX 77024-7125

L. Lowery Mays, as successor trustee of
Ralph Maddox Family Trust
c/o Mays Family Foundation
250 W. Nottingham Dr. Ste #400
San Antonio, TX 78209

Estate of Charles F. Smith and/or Nancy M.
Smith & Mary Sue Bruce,
c/o Sue Mary Bruce
36 GREENRIDGE DR
DECATUR, IL 62526-1404

Estate of Myrtle L. Griffith
c/o Carol Lee Webb, a/k/a Carol Wells
10503 HUEBNER RD APT 521
SAN ANTONIO, TX 78240-1357

Estate of Charlene Salome Carlisle
c/o Carol Lee Webb a/k/a Carol Wells
10503 HUEBNER RD APT 521
SAN ANTONIO, TX 78240-1357

Estate of Gaynelle May a/k/a Johnnie
Gaynelle May
c/o Carol Lee Webb a/k/a Carol Wells
10503 HUEBNER RD APT 521
SAN ANTONIO, TX 78240-1357

Wilbur Elder
1125 TACOMA AVE APT 314
BISMARCK, ND 58504-7457

Judy Hamilton Casper
104 BERKELEY PL # 1
BROOKLYN, NY 11217-3604

Wildcat Investments Corp.
c/o James Leuty
125 North 11th St. #846
Mt Vernon, IL 62864

Lois Launt
415 FRAN LN
WICHITA FALLS, TX 76301-1818

Kimberly A. H. Mahon
a/k/a Kim Mahon-Rude
100 VICKIE DR
ELIZABETH CITY, NC 27909-2934

Joanna Dilger
100 SANTA FE AVE APT 5112
BISMARCK, ND 58504-7655

Estate of Belva L. Dalrymple
c/o Robert Lynn Dalrymple and
Elizabeth J. Feuerstein
65 S AGUA FRIA LN
CASA GRANDE, AZ 85194-3836

Milton Gutknecht
22761 MULE DEER TRL
BOX ELDER, SD 57719-9456

Peggy P. Gilson
101 PINTAIL ST
KYLE, TX 78640-8894

J.H. Steinmensch, deceased
c/o Janet S. Monetgomery
620 E Main Cross Street
Taylorsville, L 62568

Beatrice Financial Services, Inc.
c/o C T CORPORATION SYSTEM
120 S Central Ave
CLAYTON, MO 63105

Karen Sue Quinn
3414 Clinton Ave
Berwyn, IL 60402-3322

Evelyn Jane Duncan Florey,
2305 Wicklow Dr.
Pearland, TX 77581

Mark Herrmann & Carol Herrmann,
H/W, as Joint Tenants
1402 S. Meadow Brook Ct
Gillette, WY 82718

Linda Walke Argudin, Executor of Estate of
Frances Whiteside, c/o Linda Louise Walke
206 Potter LN
Georgetown,TX 78663

Mark Bitner
3198 Alden Pond LN
St. Paul, MN 55121

William John Cornog
5431 E. River Road
Kindred, ND 58051

Victoria E. Masad and Vivian G. Coury
2523 Sumac Rdg
St. Paul, MN 55110

Sharon Stamps
185 Frances Street
Ventura, CA 91763

Patricia Ann Cadwallader
c/o Patricia Ann Abraham
4908 N Penn Ave
Spokane WA 99206

Ramona Ann Leer
f/k/a Ramona Ann Dilse
9332 E Southwind LN # E
Scottsdale, AZ 85262-2303

Jacqueline Ferderer, Trustee of the
Zimmerman Charitable Trust, and
Jacqueline Ferderer, individually
3903 Downing ST
Bismarck, ND 58504-8857

James John Bauer
1515 CRESTVIEW LN
BISMARCK, ND 58501-3052

EXHIBIT A

Clarice Zander
1508 SHARLOH LOOP
BISMARCK, ND 58501-7773

Estate of Donald Klaudt
c/o Dorothy D. Klaudt
1105 NE 89TH AVE
Vancouver, WA 98664-2482

Estate of Gladys Romona Jansonius
c/o Carol Jansonius Marino
3180 Bolgos CIR # 205
Ann Arbor, MI 48105-1564

Stewart J. Schutte
11556 E Cripple Creek Ave
Robinson, IL 62454-5337

Southwest Guaranty Trust Co., Nat'l, Trustee
for Elizabeth Dunn, Charles Dunn and Oscar
Besch, Jr. Testamentary Trust
Cadance Bank
Nine Greenway Plaza, Suite 1000
Houston, Texas 77046

Southwest Guaranty Trust Company, Nat'l,
Trustee for John Obadal, Testamentary Trust,
Cadance Bank
Nine Greenway Plaza, Suite 1000
Houston, Texas 77046

Michael Wiedrich
971 13TH ST W
Dickinson, ND 58601-3538

C.T.S. Properties, L.L.C.
c/o Agent STEVE STEIN
200 W. MAIN ST.
SALEM , IL 62881

Estate of Reinhold Klaudt
c/o Raymond C. Klaudt
720 BANYAN CT
SAN MARCOS, CA 92069-1954

Raymond C. Klaudt and
Constance Joanne Klaudt
720 BANYAN CT
SAN MARCOS, CA 92069-1954

Marino S. Melsted
3701 S HARMONY DR
SIOUX FALLS, SD 57110-6036

Diane Baker Rowland
2520 WATERSIDE DR UNIT 107
FREDERICK, MD 21701-3023

LaDawn R. Eisenbeis
3110 N 19TH ST APT 7
BISMARCK, ND 58503-5341

Valerie D. Wiedrich
971 13TH ST W
DICKINSON, ND 58601-3538

Lori Voight
149 99TH AVE NW
DUNN CENTER, ND 58626-9667

Great Northern Properties,
Limited Partnership
601 Jefferson Street Suite 3600
Houston, TX 77002

Crystal D. Pickens
26720 HIAWATHA ST
ATLANTA, MO 63530-3605

Cory Herman
2502 River Road
Center, ND 58530

Beulah Community Nursing Home
Knife River Care Center
118 22nd Street NE
Beulah, ND 58523

Kayleen Davie
28227 CLEAR BREEZE CT
SPRING, TX 77386-4869

Al E. Nick, as Trustee
of the Mondak Trust A
10309 NIEMAN RD
OVERLAND PARK, KS 66214-3004

Karen L. Chapman & William O. Chapman,
co-trustees of Karen L. Chapman Revocable
Trust dtd 9/7/2001
PO Box 1253
Angel Fire, NM 87710-1253

Karen L. Chapman & William O. Chapman,
co-trustees of Karen L. Chapman Revocable
Trust dtd 9/7/2001
6220 Wildwood St
Farmington, NM 87402-0926

Bernard F. Desloge
3 Warson LN
Saint Louis, MO 63124-1251

Marie S. Desloge, Joseph Desloge, Jr.,
Bernard F. Desloge, Anne Desloge Werner,
& Zoe Desloge Lippman, Tr of Will of
Joseph Desloge, Sr., c/o Bernard F. Desloge
3 Warson LN
Saint Louis, MO 63124-1251

Jayne R. Posey
27169 Buckskin TRL
Harbeson, DE 19951-2721

Ramona A. Leer
9332 E Southwind LN # E
Scottsdale, AZ 85262-2303

Linda Petroleum Company
301 Natoma St Suite 202
Folsom, CA 95630

Samuel Mark Skipper
4403 Breakwood Dr.
Houston, TX 77096-3504

William Barney Gibbons
3940 Canal St
New Orleans, LA 70119-6003

Karen A. Walz
5103 Fountainblue Dr
Bismarck, ND 58503-8893

Delfine Wiedrich
985 Franklin ST
Dickinson, ND 58601-6203

Roger D. Schafer
PO Box 43
Stratford, WA 98853-0013

Lori J. Uhlig, PR,
Estate of Laura Weiss Chapman
1124 E Riggs ST
East Helena, MT 59635-3371

Janco, Inc.
c/o Robert D. Langford
6360 N CRAYCROFT RD
TUCSON, AZ 85750-1075

Teri Lynn Steckler
1334 46TH AVE W
DICKINSON, ND 58601-7014

Perry P. Walker
350 67TH AVE NW
ZAP, ND 58580-8017

Amanda L. Rene-Matthews
600 14TH ST SE
MANDAN, ND 58554-4512

Therese Borden Sloane
6362 W BLACKHAWK DR
GLENDALE, AZ 85308-6678

Thais Weisenburger
8540 E McDowell RD Unit 74
Mesa, AZ 85207-1432

Linda Gray
c/o Mary L. Ensor
840 Harris Drive
Schenectady, NY 12309

Jim Sailer
3064 Via Loma
Fallbrook, CA 92028-9334

Richard S. Dobson
2025 McNeil ST # 7A
Dupont, WA 98327-8786

Maria Keith
1901 John F Kennedy Blvd. apt 2014
Philadelphia, PA 19103-1517

E. H. Arbuthnot, Foss Family LLC
Agent: Jill A Rees
32923 Perth
Livonia, MI 48154

Estate of Winne Gates Jenkins
c/o Sarah Lee Jenkins Knudson
640 Henry Ross RD
Crandall, GA 30711-6244

Wilfred A. Hauck
2560 Horizon Hills Rd
Willmar, MN 56201

Kadrmas, Bethany R.

From: Eliot Huggins <eliot@drcinfo.com>
Sent: Tuesday, July 12, 2022 12:23 PM
To: Kadrmas, Bethany R.
Subject: Public Comment
Attachments: Public Comment (3).pdf

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Hi Bethany:
Attached you will find public comment regarding Case No. 29450: Application of Dakota Gasification Company requesting consideration for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant. Thank you!

--
Best,
Eliot Huggins
Field Organizer
Dakota Resource Council
eliot@drcinfo.com
Office:701-224-8587
Cell/Direct Line: 231-313-5161

Bethany Kadrmas
Case No: 29451
July 12, 20222
Oil and Gas Division
1016 East Calgary Avenue
Bismarck, North Dakota 58503-5512

Dear members of the North Dakota Industrial Commission:

After reviewing the draft permit: "Application of Dakota Gasification Company requesting consideration for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant" we have some concerns that we believe should be addressed before a permit is issued by the Industrial Commission.

Page 3-2 section 3.2 within the application states: " Because of low well control and lack of site-specific 3D seismic data within the storage facility area, publicly available variograms were used to inform the distribution of the lithofacies and petrophysical properties in the geologic model. The variograms reported in the Tundra SGS (secure geologic storage) facility permit were selected as they provide a generalized representation of the property distributions expected within the Broom Creek Formation (North Dakota Industrial Commission, 2021)." In our view, the applicant should be required to conduct modeling regarding lithofacies and petrophysical properties that are specific to the site. While the publicly available data supports that this location is safe— to ensure the success and longevity of this project we believe it would be prudent to require site specific data as geologic formations are not entirely uniform.

Additionally, page 7-11 section 7.5.2 states: "DGC will train personnel involved in the CO2 geologic storage project on the proper emergency responses, maintenance, and operating procedures. The training efforts will be documented. DGC will also work with Mercer County LEPC to perform coordinated training exercises associated with potential emergency events." It is encouraging that the applicant has outlined steps to ensure preparedness in the event of an emergency. When a C02 pipeline ruptured in Satartia, Mississippi a lack of emergency training was cited as greatly inhibiting the response effort in a report conducted by the PHSMA.[1] In our view, the applicant should explain in more specific detail their plans to work with Mercer County LEPC. A leak from a Class VI injection well would be a new event for local first responders. If local emergency crews are not equipped and educated on the uniqueness of this event— the consequences could be extremely severe for both environmental and human health.

In conclusion, before this permit is approved, we ask that to the extent in which it is possible, that site specific data is collected regarding lithofacies and petrophysical properties. Lastly, we ask that the applicant outline in specific detail their plans to engage with Mercer County LEPC to ensure preparedness in the event of a leak. Thank you for your time and attention to this matter.

Sincerely,

---

[1] "PHMSA Failure Investigation Report - Denbury Gulf Coast Pipelines, LLC," PHMSA Failure Investigation Report - Denbury Gulf Coast Pipelines, LLC, 26, 2022, https://www.phmsa.dot.gov/news/phmsa-failure-investigation-report-denbury-gulf-coast-pipelines-llc.

Scott Skokos: Dakota Resource Council: Executive Director

RECEIVED 7-5-2022

JUL 1 1 2022

N.D. INDUSTRIAL COMMISSION

SiR (S);

Comment on Carbon Storage Project:

Be advised that land owned by Bruce + Gail Bitterman in Mercer County is not in favor of the Carbon Storage Project!

Science does not agree that this storage is Permanent or Forever.

Bruce Bitterman
Gail Bitterman

Scenic Acres
Bruce & Gail Bitterman
6480 Hwy. 1806
Zap, ND 58580-9618

BISMARCK ND 585
6 JUL 2022 PM 1 L

USA FOREVER

Oil and Gas Division
1016 East Calgary Avenue
Bismarck, ND 58503-5512

58503-551216

RECEIVED
JUN 27 2022
N.D. INDUSTRIAL COMMISSION

June 21, 2022
Department of Mineral Resources
Oil & Gas Division
1000 East Calgary Avenue
Bismarck, North Dakota 58503

RE: Application for Geologic Storage of Carbon Dioxide
Hearing to consider application:
July 20, 2022, 9 am, Dept. of Mineral Resources Conference Room

I, along with two siblings, own farmland north of Beulah:
T146N R88W S34 N1/2 of NW1/4
T146N R88W S34 S1/2 of NW1/4

We also own the mineral rights north of Beulah for:
T145N R88W S3 Lot 1, Lot 2, and S1/2 of NE1/4
T145N R88W S3 SE1/4
T146N R88W S27 SE1/4
T146N R88W S27 SW1/4
T146N R88W S36 N1/2 of SE1/4
T145N R88W S10 S1/2 of N1/2
T145N R88W S11 NW1/4

In October 2021, Dakota Gasification Company sent me a letter offering \$500 to sign an agreement to allow them to store CO_2 on our property. I consider offering me the sum of \$500 as a ridiculous offer for the loss of the oil underground our property worth more than a thousand times that amount.

The land, from the center of the earth to the heavens, belongs to the property owners, not to the state of North Dakota nor to the Dakota Gasification Company. If Dakota Gasification Company wants to store CO_2 underground, then they need to do so on property that they own, not try to steal property that doesn't belong to them. Furthermore, pressurized CO_2 is a cryogenic. North Dakota is already the coldest state in the continental lower 48 states. Why would anyone want to make North Dakota even colder?

Has the United States of America now evolved into a communist country where the government and/or large corporations can come in and seize property that belongs to private citizens? The land and mineral rights have belonged to our family since it was homesteaded by our grandfather over a hundred years ago. How can someone else just come in and take it without paying us fair market value for our land and for our oil?

NOTARY: [signature]
DATE: 06/21/2022
COMMISSION EXP: 10/22/2025

BRIAN D SASSER
NOTARY PUBLIC
COMM NO. 20192248
STATE OF IDAHO

Sincerely,

Allen Eisenbeis

Allen Eisenbeis
2979 Mesquite Drive
Idaho Falls, Idaho 83404
Phone # 208 390-7810

Kadrmas, Bethany R.

From:	Perry Anderson <perryanderson_55@q.com>
Sent:	Sunday, June 26, 2022 10:13 PM
To:	Kadrmas, Bethany R.
Subject:	Fwd: BEPC Deal to purchase DGC assets Confidential info
Attachments:	News-CSEAawards.pdf

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

----- On Jun 26, 2022, at 9:59 PM, Perry Anderson <perryanderson_55@q.com> wrote:

BAKKEN ENERGY REACHES AGREEMENT TO PURCHASE DAKOTA GASIFICATION COMPANY ASSETS

Transformational plan to develop $2 billion North Dakota Hydrogen Hub and make Bakken Energy the largest and lowest-cost clean hydrogen producer in the USA.

ARE YOU THE SUBSIDARY MENTIONED IN THE DAKOTA GASIFICATION COMPANIES APPLICATION FOR A CO2 STORAGE FACILITY TO BE HEARD ON 7/20/2022 BEFORE THE NDIC??? YOUR APPLICATION FOR THE DAKOTA H2 HUB BEFORE THE CSEA (WHICH GRANTED YOU 10 MILLION DOLLARS AND A LOAN OF 80 MILLION) SEEKS APPROVAL FOR THE SAME SIX INJECTION WELLS??? BASIN ELECTRIC POWER COOPERATIVE MEMBERS VOTED AGAINST FUNDING THE H2 HUB!!! ARE YOU TO BECOME BAKKEN ENERGY LLC A SUBSIDARY OF BASIN ELECTRIC POWER COOPERATIVE??

A SIMPLE YES OR NO QUESTION!!!

Perry L Anderson
309 3rd Ave NW Apt 4
Mandan, ND
perryanderson_55@q.com

INDUSTRIAL COMMISSION OF NORTH DAKOTA

Doug Burgum Governor	Wayne Stenehjem Attorney General	Doug Goehring Agriculture Commissioner

NEWS December 20, 2021

INDUSTRIAL COMMISSION AWARDS FUNDING FOR CLEAN SUSTAINABLE ENERGY PROJECTS

BISMARCK, N.D. – The North Dakota Industrial Commission awarded funding today from the Clean Sustainable Energy Fund in the amount of $28 million in grants and $135 million in loans for six projects.

"We are excited about the quality and quantity of the projects that were presented today after going through an extensive review process. These projects have the potential of capturing over 30% of the annual carbon dioxide production in North Dakota, capturing natural gas that would otherwise be flared, and identifying opportunities that will diversify North Dakota's economy," the Industrial Commission said in a joint statement. "Each of these awards will be matched by other funds and result in over $4.5 billion in investment in North Dakota."

The six projects and their funding awards are as follows:

- Production of Blue Hydrogen – Dakota H2 Hub – BakkenEnergy LLC - $10 million grant; $80 million loan
- Converting Gas to Value-Added Projects – Cerilon GTL – Cerilon GTL ND Inc. - $7 million grant; $40 million loan
- Unlocking the Full Potential of Produced Water as a Key Component of Clean Sustainable Energy – Wellspring Hydro - $1 million grant
- Commercial Deployment of Carbon Dioxide Capture & Geological Sequestration in McLean County – Midwest AgEnergy Group - $3 million grant
- Front-End Engineering and Design for CO2 Capture at Coal Creek Station – Energy & Environmental Research Center - $7 million grant
- Solving North Dakota Flaring: Mobile Flare Gas Capture & Fueling Platform Expansion – Valence Natural Gas Solutions - $15 million loan

"The Legislature established and funded the Clean Sustainable Energy program during the recent legislative sessions and directed that the projects selected be transformational in developing energy projects for North Dakota's future," said Lt. Gov. Brent Sanford, chairman of the Clean Sustainable Energy Authority. "The Authority believes these projects have met the goals of the program to enhance the production of clean sustainable energy and to make North Dakota a world leader in the production of clean sustainable energy."

"The program received applications totaling over $49 million in grant requests and $165 million in loan requests during this first grant round," said Al Anderson, director of the Clean Sustainable Energy Authority. "The Authority is appreciative of the work completed by all the reviewers and advisors."

The Industrial Commission, which oversees the Clean Sustainable Energy Authority, consists of Gov. Doug Burgum as chairman, Attorney General Wayne Stenehjem and Agriculture Commissioner Doug Goehring.

Karlene K. Fine, Executive Director and Secretary
State Capitol, 14th Floor - 600 E Boulevard Ave Dept 405 - Bismarck, ND 58505-0840
E-Mail: kfine@nd.gov
Phone: (701) 328-3722 FAX: (701) 328-2820
"Your Gateway to North Dakota": www.nd.gov

The next submission deadline for funding requests is March 1, 2022. More information about the program, including the application process, can be found on the CSEA website at http://www.nd.gov/ndic/csea-infopage.htm.

For more information, contact Al Anderson at 701-595-9668.

Karlene K. Fine, Executive Director and Secretary
State Capitol, 14th Floor - 600 E Boulevard Ave Dept 405 - Bismarck, ND 58505-0840
E-Mail: kfine@nd.gov
Phone: (701) 328-3722 FAX: (701) 328-2820
"Your Gateway to North Dakota": www.nd.gov

RECEIVED
JUN - 9 2022
N.D. INDUSTRIAL COMMISSION

Clyde Eisenbeis
2819 Hogan Dr
Bismarck, ND 58503
641-691-0110
cte677@gmail.com

6-Jun-2022

Department of Mineral Resources
Oil & Gas Division
1000 East Calgary Avenue
Bismarck, North Dakota

RE: Application for Geologic Storage of Carbon Dioxide
Hearing to consider application
9am, 20 Jul 2022, Dept. of Mineral Resources Conference Room

My siblings and I own farmland and mineral rights north of Beulah.
T145N R88W S3 Lot 1, Lot 2, and S1/2 of NE1/4
T145N R88W S3 SE1/4
T146N R88W S27 SE1/4
T146N R88W S27 SW1/4
T146N R88W S34 N1/2 of NW1/4
T146N R88W S34 S1/2 of NW1/4
T146N R88W S36 N1/2 of SE1/4
T145N R88W S10 S1/2 of N1/2
T145N R88W S11 NW1/4

On 15 Oct 2021, Shauna Laber [Basin Electric] and Kevin Solie [Basin Electric] approached me to sign a seismic permit. I would not sign that permit until it was modified.

Shauna Laber invited me to meet again on 4 Nov 2021. Bruce Fulker [Cougar Land Services] was there too. They wanted me to sign the "unmodified" permit. I said that would not happen until it was modified.

I asked Bruce Fulker if Carbon Dioxide Injection would affect the Bakken Formation. Bruce Fulker said no. The Bakken Formation is 2 to 3 miles below the surface. I responded that I thought Bakken is 1 to 2 miles below the surface in Mercer County.

Bruce Fulker said that I was wrong. The Carbon Dioxide Injection would be between 1 and 2 miles below the surface. Bruce Fulker said that the Bakken Formation is 2 to 3 miles below the surface.

I received the Bakken Formation elevation map from Kevin Solie [Basin Electric]. I added more numbers to put it into perspective (see enclosed maps). If injected, the Carbon Dioxide Injection could displace oil and gas in the Bakken Formation. All farmers should be told this.

Bruce Fulker lied to me. I wonder to whom else did Bruce Fulker and his cohorts lie?

I asked Shauna Laber if Bruce Fulker's lie was reported to Todd Telesz, Basin Electric CEO? She did not respond.

I asked Shauna Laber if Todd Telesz knew that the Carbon Dioxide Injection could displace oil and gas in the Bakken Formation, which could eliminate future income for farmers? She did not respond.

I asked Shauna Laber if Basin Electric will reimburse land owners for the future loss of oil and gas income? She did not respond.

I called my cousins Wayne Eisenbeis and Lyle Eisenbeis. They signed the permit. Lyle said he knew they would do it anyway with eminent domain, so he signed it to get rid of them.

Recently Shauna Laber emailed that the Carbon Dioxide Injection would be into the Broom Creek Formation.

I requested a Broom Creek Formation elevation map similar to the Bakken Formation elevation map. There has been no response.

After my meeting with Bruce Fulker [Cougar Land Services], I don't trust what they say.

If oil and gas were displaced, by accident, there is no way to fix that. It would be too late. The CO_2 should be put in a location where there is no potential problem. Zero chance is the best.

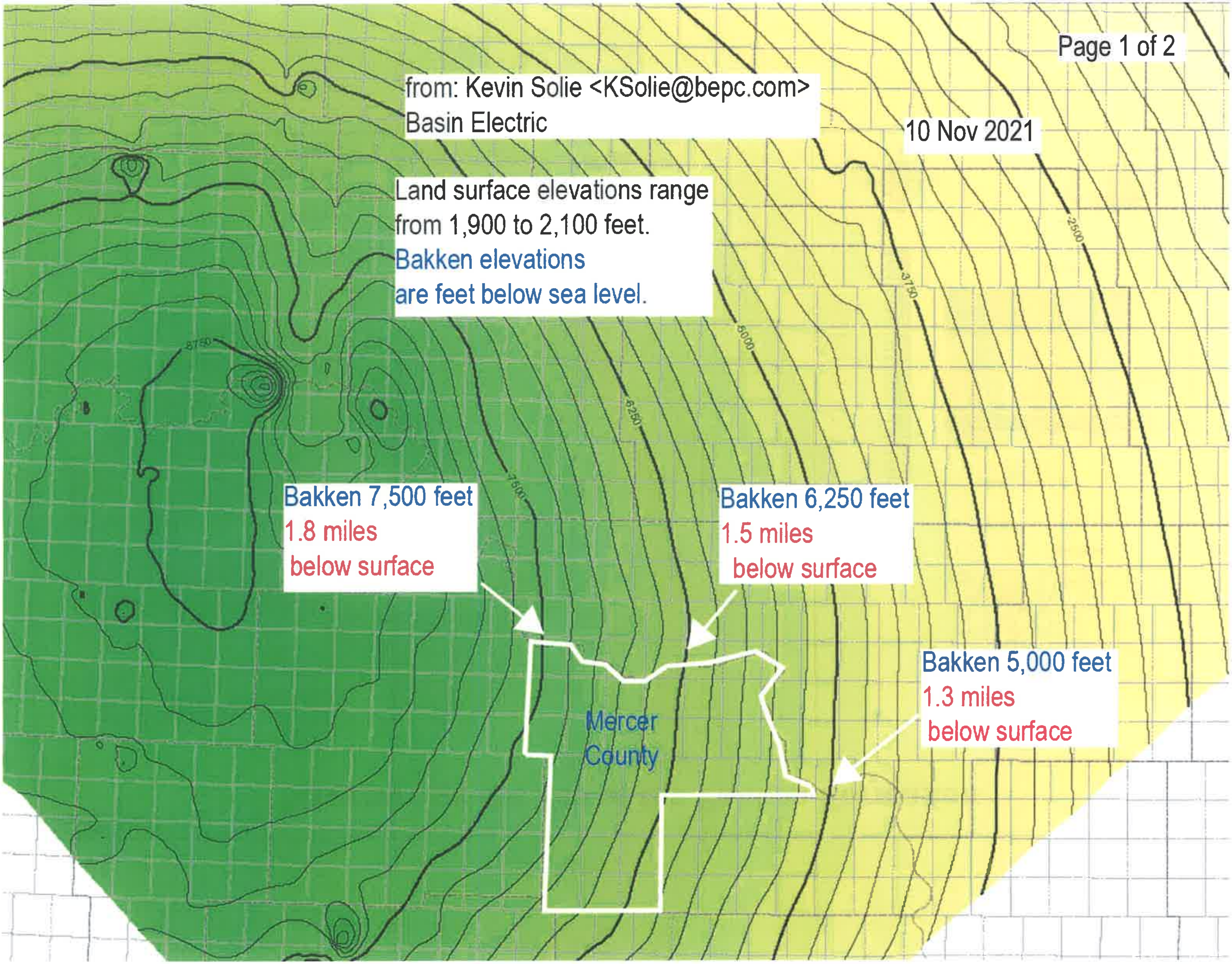
---

1) Are all farmland owners and mineral rights owners given the Bakken Formation elevation information, and the potential of oil and gas displacement by CO_2?

2) Will Basin Electric reimburse farmland owners and mineral rights owners for potential future loss of oil and gas income?

Best Regards,

BTW Enclosed are the Bakken Formation elevation maps.



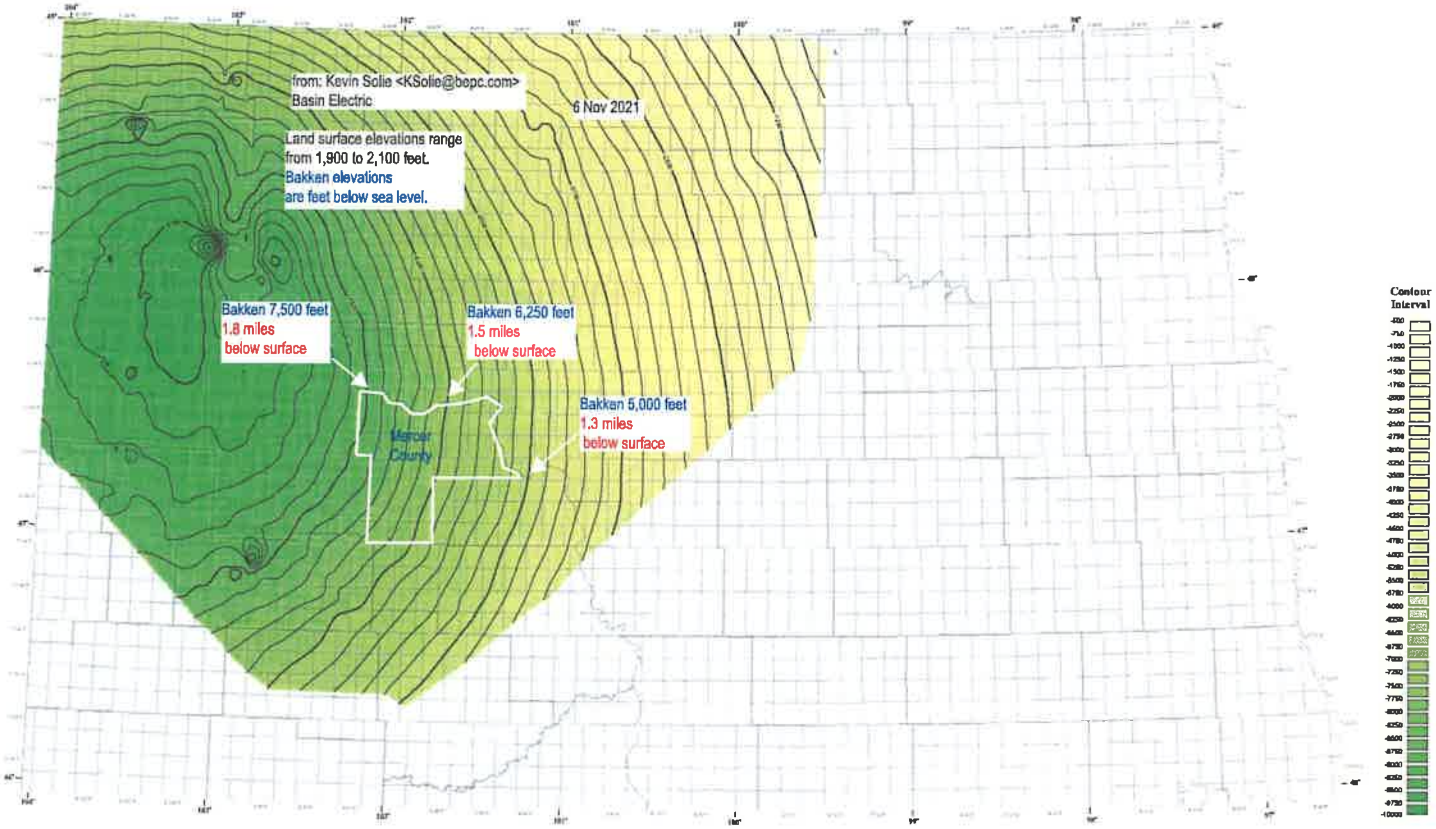
Page 1 of 2
from: Kevin Solie <KSolie@bepc.com>
Basin Electric
10 Nov 2021
Land surface elevations range
from 1,900 to 2,100 feet.
Bakken elevations
are feet below sea level.
8750
7500
6250
5000
3750
2500
Bakken 7,500 feet
1.8 miles
below surface
Bakken 6,250 feet
1.5 miles
below surface
Bakken 5,000 feet
1.3 miles
below surface
Mercer
County

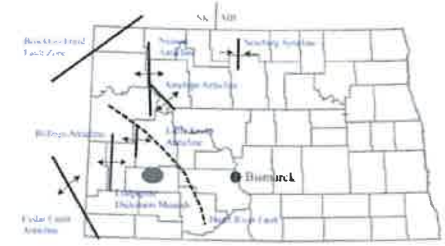
North Dakota Geological Survey
Geologic Investigations No. 59
Bakken Formation Map Series: Sheet 5
2008

Edward C. Murphy, State Geologist
Lynn D. Helms, Director Dept. of Mineral Resources

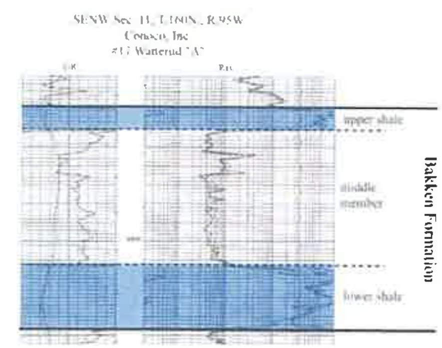
Structure on the Top of the Bakken Formation

Julie A. LeFever





Index Map



Typical Log

Explanation

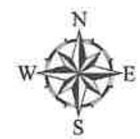
Top of Bakken Formation (in feet below sea level)
Township Boundaries
County Boundaries

Scale 1:1,000,000

0 20 40 60 80
Miles

0 20 40 60 80
Kilometers

North American Datum 1927 Lambert Conformal Conic



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June 6, 2022

NOTICE OF HEARING
N.D. INDUSTRIAL COMMISSION
OIL AND GAS DIVISION

You are hereby notified of a hearing pursuant to North Dakota Administrative Code § 43-05-01 requesting consideration for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota. **The hearing will be held July 20, 2022 at 9:00 a.m.**, 1000 East Calgary Avenue, Bismarck, North Dakota.

Case No. **29450**: Application of Dakota Gasification Company requesting consideration for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Dakota Gasification Company intends to capture carbon dioxide from the Great Plains Synfuels Plant and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT July 19, 2022. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Steve Fried, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Dakota Gasification Company, 1717 East Interstate Avenue, Bismarck, ND 58503.

Case No. **29451**: Application of Dakota Gasification Company to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Dakota Gasification Company storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code Section 38-22-10.

Bruce E. Hicks
ASSISTANT DIRECTOR
OIL AND GAS DIVISION

Lynn D. Helms
DIRECTOR
DEPT. OF MINERAL RESOURCES

Edward C. Murphy
STATE GEOLOGIST
GEOLOGICAL SURVEY

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NORTH DAKOTA D M R Department of Mineral Resources

Case No. **29452**: Application of Dakota Gasification Company for an order of the Commission determining the amount of financial responsibility for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant in the storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.Please contact our office if you have any questions.

Sincerely,

Lynn D Helms

Lynn D. Helms
Director

Bruce E. Hicks
ASSISTANT DIRECTOR
OIL AND GAS DIVISION

Lynn D. Helms
DIRECTOR
DEPT. OF MINERAL RESOURCES

Edward C. Murphy
STATE GEOLOGIST
GEOLOGICAL SURVEY

600 E Boulevard Ave – Dept 405 | Bismarck, ND 58505-0840 | PHONE: 701-328-8020 | FAX: 701-328-8022 | dmr.nd.gov

From:	Kadrmas, Bethany R.
Bcc:	jcather@summitag.com; jerickson@e-m-services.com; phoenixenergyadvisors@gmail.com; jessica.gregg@carbonamerica.com; cynthia.fischer7@gmail.com; JASON_MARTIN@TCENERGY.COM; mhj303@gmail.com; sarah.leung@hq.doe.gov; markfalck@hotmail.com; tjiang@undeerc.org; katie@mckennettlaw.com; kate@inlandoil.net; megan.lindquist@dvn.com; LEWIS18022@AOL.COM; bthoma@gmellc.com; levijohns@vitesseoil.com; eliot@drcinfo.com; carlaneal@eis-llc.com; nkoudouonambelesimplice@gmail.com; christopher.friez@nacco.com; jonwgt@viagellc.com; jay.g@badlandshydrovac.com; tip.meckel@beg.utexas.edu; jacob.cullip@outlook.com; keefekat@bresnan.net; Christian.Sizemore@ovintiv.com; jeb@evosquared.com; mark.rainey@radpros.com; snance@catahoularesources.com; quimber@yahoo.com; molly_block@cramer.senate.gov; daveb@redtrailenergy.com; pdjordan@lbl.gov; kdarnay@kxnet.com; gburshteyn@wellington.com; miles.demster@nexteraenergy.com; will.houser@clr.com; julia.johnson@agribank.com; rfvanvoorhees@bclplaw.com; getitdone@wrangousa.com; c-jwentz@gmellc.com; cfgress@yahoo.com; brad@fayglobal.com; kconnors@undeerc.org; kanagnost@undeerc.org; hvettleson@undeerc.org; jon@tradesmanadvisors.com; ejbrown@blm.gov; scook8@slb.com; charlesb@ajcm.com; hdemuth@petrotek.com; SHHS70@GMAIL.COM; orleysinkler@outlook.com; rab@inflowpetro.com; cebreckon@aol.com; DJSNOW@MARATHONPETROLEUM.COM; katrinachristiansen@gmail.com; dness777@gmail.com; hillsvalleyranch@gmail.com; colsen@undeerc.org; cjacobson@bepc.com; ktracy@elysian.cc; klesmann@fibt.com; darst@google.com; zeiken@crowleyfleck.com; melodyhacker@me.com; jeggleton@dorahg.com; kennethaschmidt@hotmail.com; mtwocrow@gmail.com; littlejudyd@gmail.com; ejedison@crowleyfleck.com; albert.x.reiss@gs.com; dthorson@inbox.lv; keith.hapipsr1@gmail.com; klurfeld@nyc.rr.com; kurt@mapmechanical.com; justin.b.sanders@exxonmobil.com; Sales@dacotahwest.com; cevans@energyintel.com; courtneyturich@echantillonadvising.com; Sisk, Amy (Bismarck Tribune); Nodaky12@gmail.com; smh@rampartenergy.com; dave_french@mckinsey.com; clweaver@eprod.com; laura.bird@whiting.com; josh.armstrong@ameritas.com; jwilcoxen@cliftygroup.com; matthew.elias@ashlercapital.com; cbellet55@gmail.com; brentbrannan@gmail.com; abargelski@gmail.com; sara.phiaxay@steelreef.ca; jennifer_lee@tcenergy.com; abdelmalek.bellal@und.edu; kaylae@jmacresources.com; Spangelo, Kayla M.; nnowiski@slb.com; chelsea.carpenter@ovintiv.com; JDeWitt@MarathonOil.com; darnell.bortz@kochind.com
Subject:	North Dakota Industrial Commission Notice of Hearing
Date:	Monday, June 6, 2022 1:47:00 PM
Attachments:	DGC_Notice of Hearing.pdf image001.png

The attached hearing notice is sent pursuant to North Dakota Administrative Code Section 43-05-01-08(5).

Please contact our office if you have any questions.

Bethany Kadrmas

Legal Assistant, Oil and Gas Division

701.328.8020 • brkadrmas@nd.gov • www.dmr.nd.gov

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600 E Boulevard Ave, Dept. 405 • Bismarck, ND 58505

From:	Kadrmas, Bethany R.
Bcc:	ksolie@bepc.com; LBender@fredlaw.com; Anderson, Carl J.; Murphy, Ed C.; Paczkowski, John A.; Best, Steve L.; boomgaard.craig@epa.gov; ndfieldoffice@fws.gov; achp@achp.gov; Williams, Jeb R.; Peterson, Bill; lwickstr@blm.gov; Kbear@mhanation.com; slhall@mhanation.com; texx@restel.com; klyson@mhanation.com; chairmanfox; Cynthia.monteau@Tax-MHANation.com; ceverett@mhanation.com; heidi@cityofbeulah.com; -Info-Public Service Commission; Zueger, Cyndi L.; Heringer, Joe A.; Schulz, Cody J.; Henke, Ron J.; Brost, Shana L.
Subject:	North Dakota Industrial Commission Notice of Hearing
Date:	Monday, June 6, 2022 1:39:00 PM
Attachments:	image001.png DGC_Notice of Hearing.pdf

The attached hearing notice is sent pursuant to North Dakota Administrative Code Section 43-05-01-08(5).

The fact sheet, storage facility permit application, and draft permit are available for download at: https://www.dmr.nd.gov/dmr/oilgas/ClassVI

Please contact our office if you have any questions.

Bethany Kadrmas

Legal Assistant, Oil and Gas Division

701.328.8020 • brkadrmas@nd.gov • www.dmr.nd.gov

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600 E Boulevard Ave, Dept. 405 • Bismarck, ND 58505

FedEx

June 14, 2022

Dear Customer,

The following is the proof-of-delivery for tracking number: 865583504844

Delivery Information:

Status:	Delivered	**Delivered To:**	
Signed for by:	Signature release on file	**Delivery Location:**	
Service type:	FedEx Express Saver		
Special Handling:	Deliver Weekday		DC,
		Delivery date:	Jun 9, 2022 10:15

Shipping Information:

Tracking number:	865583504844	**Ship Date:**	Jun 8, 2022
		Weight:	3.0 LB/1.36 KG

Recipient:

DC, US,

Shipper:

BISMARCK, ND, US,

Proof-of-delivery details appear below; however, no signature is available for this FedEx Express shipment because a signature was not required.

Thank you for choosing FedEx

MUR11

FedEx Express US Airbill

FedEx Tracking Number 8655 8350 4844

Form ID No. 0215

Sender's Copy

1 From *Please print and press hard.*

Date 6-8-22

Sender's FedEx Account Number 1145-9344-3

Sender's Name Reyne Kadrmas Phone (701) 328-8000

Company NORTH DAKOTA INDUSTRL COMMISSN

Address 1016 E CALGARY AVE

Dept/Floor/Suite/Room

City BISMARCK State ND ZIP 58503-5512

2 Your Internal Billing Reference
First 24 characters will appear on invoice.

OPTIONAL

3 To

Recipient's Name Phone (202) 208-5116

Company Bureau of Indian Affairs

Recipient's Address MS-4606

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Dept/Floor/Suite/Room

Address 1849 C Street N.W.

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4a Express Package Service *Packages up to 150 lbs.*

- [ ] FedEx Priority Overnight — Next business morning.* Friday shipments will be delivered on Monday unless SATURDAY Delivery is selected.
- [ ] FedEx Standard Overnight — Next business afternoon.* Saturday Delivery NOT available.
- [ ] FedEx First Overnight — Earliest next business morning delivery to select locations.* Saturday Delivery NOT available.
- [ ] FedEx 2Day — Second business day.* Thursday shipments will be delivered on Monday unless SATURDAY Delivery is selected.
- [x] FedEx Express Saver — Third business day.* Saturday Delivery NOT available.

FedEx Envelope rate not available. Minimum charge: One-pound rate.

* To most locations.

4b Express Freight Service *Packages over 150 lbs.*

- [ ] FedEx 1Day Freight* — Next business day.** Friday shipments will be delivered on Monday unless SATURDAY Delivery is selected.
- [ ] FedEx 2Day Freight — Second business day.** Thursday shipments will be delivered on Monday unless SATURDAY Delivery is selected.
- [ ] FedEx 3Day Freight — Third business day.** Saturday Delivery NOT available.

* Call for Confirmation:

** To most locations.

5 Packaging

- [ ] FedEx Envelope*
- [x] FedEx Pak* — Includes FedEx Small Pak, FedEx Large Pak, and FedEx Sturdy Pak.
- [ ] FedEx Box
- [ ] FedEx Tube
- [ ] Other

* Declared value limit $500.

6 Special Handling Include FedEx address in Section 3.

- [ ] SATURDAY Delivery — NOT Available for FedEx Standard Overnight, FedEx First Overnight, FedEx Express Saver, or FedEx 3Day Freight.
- [ ] HOLD Weekday at FedEx Location — NOT Available for FedEx First Overnight.
- [ ] HOLD Saturday at FedEx Location — Available ONLY for FedEx Priority Overnight and FedEx 2Day to select locations.

Does this shipment contain dangerous goods? One box must be checked.

- [ ] No
- [ ] Yes As per attached Shipper's Declaration.
- [ ] Yes Shipper's Declaration not required.
- [ ] Dry Ice — Dry Ice, 9, UN 1845 ____ x ____ kg

Dangerous goods (including dry ice) cannot be shipped in FedEx packaging.

- [ ] Cargo Aircraft Only

7 Payment *Bill to:* Enter FedEx Acct. No. or Credit Card No. below.

- [x] Sender — Acct. No. in Section 1 will be billed.
- [ ] Recipient
- [ ] Third Party
- [ ] Credit Card
- [ ] Cash/Check

FedEx Acct. No. Credit Card No. Exp. Date

Total Packages	Total Weight	Total Declared Value†
1	2.5 lb.	$ 0 .00

†Our liability is limited to $100 unless you declare a higher value. See back for details. By using this Airbill you agree to the service conditions on the back of this Airbill and in the current FedEx Service Guide, including terms that limit our liability.

8 Residential Delivery Signature Options If you require a signature, check Direct or Indirect.

- [ ] No Signature Required — Package may be left without obtaining a signature for delivery.
- [ ] Direct Signature — Someone at recipient's address may sign for delivery. Fee applies.
- [ ] Indirect Signature — If no one is available at recipient's address, someone at a neighboring address may sign for delivery. Fee applies.

519

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FedEx

June 14, 2022

Dear Customer,

The following is the proof-of-delivery for tracking number: 807317924697

Delivery Information:

Status:	Delivered	**Delivered To:**	Mailroom
Signed for by:	W.SIMMONS	**Delivery Location:**	
Service type:	FedEx Express Saver		
Special Handling:	Deliver Weekday		DC,
		Delivery date:	Jun 9, 2022 10:06

Shipping Information:

Tracking number:	807317924697	**Ship Date:**	Jun 8, 2022
		Weight:	3.0 LB/1.36 KG

Recipient:

DC, US,

Shipper:

BISMARCK, ND, US,

Signature image is available. In order to view image and detailed information, the shipper or payor account number of the shipment must be provided.

Thank you for choosing FedEx

MUR3

FedEx Express **Package US Airbill**

FedEx Tracking Number 8073 1792 4697

Form ID No. 0215

Sender's Copy

1 From *Please print and press hard.*

Date 6-8-22

Sender's FedEx Account Number 1145-9344-3

Sender's Name Reyne Kadrmas

Phone (701) 328-8000

Company NORTH DAKOTA INDUSTRL COMMISSN

Address 1016 E CALGARY AVE

Dept./Floor/Suite/Room

City BISMARCK State ND ZIP 58503-5512

2 Your Internal Billing Reference

First 24 characters will appear on invoice.

3 To

Recipient's Name

Phone (202) 208-3100

Company U.S Department of the Interior

Address 1849 C Street N W

We cannot deliver to P.O. boxes or P.O. ZIP codes.

Dept./Floor/Suite/Room

HOLD Weekday
FedEx location address REQUIRED. NOT available for FedEx First Overnight.

HOLD Saturday
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0117670299

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  Earliest next business morning delivery to select locations. Friday shipments will be delivered on Monday unless SATURDAY Delivery is selected.
- [ ] FedEx Priority Overnight
  Next business morning.* Friday shipments will be delivered on Monday unless SATURDAY Delivery is selected.
- [ ] FedEx Standard Overnight
  Next business afternoon.* Saturday Delivery NOT available.

2 or 3 Business Days

- [ ] FedEx 2Day A.M.
  Second business morning.* Saturday Delivery NOT available.
- [ ] FedEx 2Day
  Second business afternoon.* Thursday shipments will be delivered on Monday unless SATURDAY Delivery is selected.
- [x] FedEx Express Saver
  Third business day.* Saturday Delivery NOT available.

5 Packaging * Declared value limit $500.

- [ ] FedEx Envelope*
- [x] FedEx Pak*
- [ ] FedEx Box
- [ ] FedEx Tube
- [ ] Other

6 Special Handling and Delivery Signature Options

- [ ] SATURDAY Delivery
  NOT available for FedEx Standard Overnight, FedEx 2Day A.M., or FedEx Express Saver.
- [ ] No Signature Required
  Package may be left without obtaining a signature for delivery.
- [ ] Direct Signature
  Someone at recipient's address may sign for delivery. *Fee applies.*
- [ ] Indirect Signature
  If no one is available at recipient's address, someone at a neighboring address may sign for delivery. For residential deliveries only. *Fee applies.*

Does this shipment contain dangerous goods?

One box must be checked.

- [ ] No
- [ ] Yes As per attached Shipper's Declaration
- [ ] Yes Shipper's Declaration not required.
- [ ] Dry Ice Dry Ice, 9, UN 1845 ____ x ____ kg

Dangerous goods (including dry ice) cannot be shipped in FedEx packaging or placed in a FedEx Express Drop Box.

- [ ] Cargo Aircraft Only

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- [ ] Recipient
- [ ] Third Party
- [ ] Credit Card
- [ ] Cash/Check

FedEx Acct. No. Credit Card No. Exp. Date

Total Packages	Total Weight	Total Declared Value†
1	2.5 lbs.	$ .00

†Our liability is limited to US$100 unless you declare a higher value. See back for details. By using this Airbill you agree to the service conditions on the back of this Airbill and in the current FedEx Service Guide, including terms that limit our liability.

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Case No.: 29450
Date Established: June 6, 2022

DRAFT STORAGE FACILITY PERMIT

STORAGE FACILITY FOR CARBON SEQUESTRATION UNDER THE NORTH DAKOTA UNDERGROUND INJECTION CONTROL PROGRAM

In compliance with North Dakota Century Code Chapter (NDCC) 38-22 (Carbon Dioxide Underground Storage) and North Dakota Administrative Code (NDAC) Chapter 43-05-01 (Geologic Storage of Carbon Dioxide), Dakota Gasification Company has applied for a carbon dioxide storage facility permit. A draft permit does not grant the authorization to inject. This is a document prepared under NDAC 43-05-01-07.2 indicating the Commission's tentative decision to issue a storage facility permit. Before preparing the draft permit, the Commission has consulted with the Department of Environmental Quality and determined the storage facility permit application to be complete. The draft permit contains permit conditions required under NDAC 43-05-01-07.3 and 43-05-01-07.4. A fact sheet is included and contains the following information:

1. A brief description of the type of facility or activity which is the subject of the draft permit.
2. The quantity and quality of the carbon dioxide which is proposed to be injected and stored.
3. A brief summary of the basis for the draft permit conditions, including references to applicable statutory or regulatory provisions.
4. The reasons why any requested variances or alternatives to required standards do or do not appear justified.
5. A description of the procedures for reaching a final decision of the draft permit, including:
    a. The beginning and ending dates of the comment period.
    b. The address where comments will be received.
    c. The date, time, and location of the storage facility permit hearing.
    d. Any other procedures by which the public may participate in the final decision.
6. The name and telephone number of a person to contact for additional information.

This draft permit has been established on June 6, 2022 and shall remain in effect until a storage facility permit is granted under NDAC 43-05-01-05, unless amended or terminated by the Department of Mineral Resources (commission).

Stephen Fried, CCUS Supervisor
Department of Mineral Resources
Date: June 6, 2022

I. APPLICANT

Dakota Gasification Company
1717 East Interstate Avenue
Bismarck, ND 58503

II. PERMIT CONDITIONS (NDAC 43-05-01-07.3)

1. The storage operator shall comply with all conditions of the permit. Any noncompliance with the permit constitutes a violation and is grounds for enforcement action, including permit termination, revocation, or modification pursuant to NDAC 43-05-01-12.

2. In an administrative action, it shall not be a defense that it would have been necessary for the storage operator to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

3. The storage operator shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with the storage facility permit.

4. The storage operator shall develop and implement an emergency and remedial response plan pursuant to section 43-05-01-13.

5. The storage operator shall at all times properly operate and maintain all storage facilities which are installed or used by the storage operator to achieve compliance with the conditions of the storage facility permit. Proper operation and maintenance include effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the storage facility permit.

6. The permit may be modified, revoked and reissued, or terminated pursuant to section 43-05-01-12. The filing of a request by the storage operator for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. The injection well permit or the permit to operate an injection well does not convey any property rights of any sort or any exclusive privilege.

8. The storage operator shall furnish to the commission, within a time specified by the commission, any information which the commission may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. The storage operator shall also

furnish to the commission, upon request, copies of records required to be kept by the storage facility permit.

9. The storage operator shall allow the commission, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

    a. Enter upon the storage facility premises where records must be kept under the conditions of the permit;
    b. At reasonable times, have access to and copy any records that must be kept under the conditions of the permit;
    c. At reasonable times, inspect any facilities, equipment, including monitoring and control equipment, practices, or operations regulated or required under the permit; and
    d. At reasonable times, sample or monitor for the purposes of assuring permit compliance, any substances or parameters at any location.

10. The storage operator shall prepare, maintain, and comply with a testing and monitoring plan pursuant to section 43-05-01-11.4.

11. The storage operator shall comply with the reporting requirements provided in section 43-05-01-18.

12. The storage operator must obtain an injection well permit under section 43-05-01-10 and injection wells must meet the construction and completion requirements in section 43-05-01-11.

13. The storage operator shall prepare, maintain, and comply with a plugging plan pursuant to section 43-05-01-11.5.

14. The storage operator shall establish mechanical integrity prior to commencing injection and maintain mechanical integrity pursuant to section 43-05-01-11.1.

15. The storage operator shall implement the worker safety plan pursuant to section 43-05-01.13.

16. The storage operator shall comply with leak detection and reporting requirements pursuant to section 43-05-01-14.

17. The storage operator shall conduct a corrosion monitoring and prevention program pursuant to section 43-05-01-15.

18. The storage operator shall prepare, maintain, and comply with the area of review and corrective action plan pursuant to section 43-05-01-05.1.

19. The storage operator shall maintain financial responsibility pursuant to section 43-05-01-09.1

20. The storage operator shall maintain and comply with post-injection site care and facility closure plan pursuant to section 43-05-01-19.

III. CASE SPECIFIC PERMIT CONDITIONS

1. NDAC 43-05-01-11.4, subsection 1, subdivision b; The operator shall notify the commission within 24 hours of failure or malfunction of the surface gauges in the Coteau 1 (File No. 38379 – SWSW 1-145N-88W) injector, and the proposed Coteau 2, Coteau 3, Coteau 4, Coteau 5, and Coteau 6 injectors.

2. NDAC 43-05-01-11.4, subsection 1, subdivision c and NDAC 43-05-01-11, subsection 14; The operator shall run an ultrasonic or other log capable of evaluating internal and external pipe condition to establish a baseline for corrosion monitoring for the proposed Coteau 2, Coteau 3, Coteau 4, Coteau 5, and Coteau 6 wells. The operator shall run logs with the same capabilities for the Coteau 1, Coteau 2, Coteau 3, Coteau 4, Coteau 5, and Coteau 6 wells on a 5 year schedule, unless analysis of corrosion coupons or subsequent logging necessitates a more frequent schedule.

3. NDAC 43-05-01-11.4, subsection 1, subdivision d and NDAC 43-05-01-13, subsection 2, The operator shall cease injection immediately, take all steps reasonably necessary to identify and characterize any release, implement the emergency and remedial response plan approved by the commission, and notify the commission within 24 hours of carbon dioxide detected above the confining zone.

4. NDAC 43-05-01-11.4, subsection 1, subdivision h, paragraph 1, Surface air and soil gas monitoring is required to be implemented as planned by the operator in Section 5.3 (Surface Leak Detection and Monitoring Plan) and Section 5.5 (Near-Surface Soil Gas and Groundwater Sampling and Monitoring) of its permit.

5. NDAC 43-05-01-10, subsection 9, subdivision c, NDAC 43-05-01-11, subsection 15, and NDAC 43-05-01-11.1, subsection 2, The operator shall notify the commission at least 48 hours in advance to witness a mechanical integrity test of the tubing-casing annulus. The packer must be set within 100’ of the upper most perforation and in the 13CR-80 casing. Dependent on evaluation, the operator shall run the same test on a 5 year schedule for the Coteau 1, Coteau 2, Coteau 3, Coteau 4, Coteau 5, and Coteau 6 injection wells.

6. NDAC 43-05-01-11, subsections 3 and 5, The operator shall continuously monitor the surface casing-production casing annulus with a gauge not to exceed 300 psi. The commission must be notified in advance if there is pressure that needs to be bled off.

Fact Sheet

1. Description of Facility

The Dakota Gasification Company's (DGC) Great Plains Synfuels Plant is located 5 miles northwest of Beulah, North Dakota and has been in operation since 1984. The plant is capable of gasifying 6 million tons of lignite coal per year and generates approximately 150 million standard cubic feet of natural gas daily. Carbon dioxide is among the by-products of the gasification process.

2. Quantity and Quality of Carbon Dioxide Stream

DGC's plant will initially sequester 1 million metric tons of the captured carbon dioxide stream annually in the proposed storage facility. As additional compressed volumes become available over the next 4 years, annual sequestration is expected to be increased to 2.7 million metric tons. The carbon dioxide stream is analyzed daily at the capture facility and is 95.9% carbon dioxide, 1.8% C_2+ hydrocarbons, 1.2% hydrogen sulfide, 0.6% methane, and 0.5% nitrogen.

3. Summary of Basis of Draft Permit Conditions

The case specific permit conditions are unique to this storage facility, and not indicative of conditions for other storage facility permits. The conditions take into consideration the equipment proposed for this storage facility. Regulatory provisions for these conditions are all cited from NDAC Chapter 43-05-01 (Geologic Storage of Carbon Dioxide).

4. Reasons for Variances or Alternatives

No variances or alternatives.

5. Procedures Required for Final Decision

The beginning and ending dates of the comment period:
June 6, 2022 to 5:00 P.M. CDT July 19, 2022

The address where comments will be received:
Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512
or brkadrmas@nd.gov

Date, time, and location of the storage facility permit hearing:
July 20, 2022 9:00 A.M. CDT at 1000 East Calgary Avenue, Bismarck, North Dakota 58503

Any other procedures by which the public may participate in the final decision:
At the hearing, the Commission will receive testimony and exhibits of interested parties.
#

6. Contact for Additional Information

Draft Permit Information: Stephen Fried – sjfried@nd.gov – 701-328-8020
Hearing Information: Bethany Kadrmas – brkadrmas@nd.gov – 701-328-8020#

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

RECEIVED
MAR 14 2022
N.D. INDUSTRIAL COMMISSION

March 10, 2022

Mr. Lynn Helms
Director
North Dakota Industrial Commission (NDIC)
Department of Mineral Resources (DMR)
State Capitol, Department 405
600 East Boulevard Avenue
Bismarck, ND 58505-0840

Dear Mr. Helms:

Subject: Great Plains CO_2 Sequestration Project – Storage Facility Permit Application

Dakota Gasification Company, together with its partners and affiliates, respectfully submits a storage facility permit application for the dedicated geologic storage of carbon dioxide at Dakota Gasification Company's Great Plains Synfuels Plant in Mercer County, North Dakota.

Following is a link to the application: SFP Application - 3.8.22

Please find attached the permit application certification for filing.

If you have any questions, please contact me by phone at (701) 873-6635 or by e-mail at dalej@bepc.com.

Sincerely,

Dale A. Johnson
Vice President & Plant Manager
Dakota Gasification Company

Attachment
c/att: Stephen Fried, NDIC DMR

RESPONSIBLE CARE®
OUR COMMITMENT TO SUSTAINABILITY

RECEIVED
MAR 14 2022
N.D. INDUSTRIAL COMMISSION

STORAGE FACILITY PERMIT APPLICATION CERTIFICATION

BEFORE ME, the undersigned authority, personally appeared Dale Johnson of Dakota Gasification Company, who being duly sworn upon oath stated and certifies that:

1. I, Dale Johnson, am over 18 years of age. I have personal knowledge of the information and facts stated by me in this Certification, and they are true and correct. I have never been convicted of any felony or of any crime involving moral turpitude and am fully competent to make these representations.

2. I hold the position of Vice President and Plant Manager for Dakota Gasification Company. As required in accordance with North Dakota Administrative Code 43-05-01-07.1 and by virtue of my position with Dakota Gasification Company, I am authorized to make the representations on behalf of Dakota Gasification Company.

3. Attached is the storage facility permit application requesting a permit under Chapter 38-22 of the North Dakota Century Code and in accordance with Article 43-05 of the North Dakota Administrative Code for the establishment of a carbon dioxide storage facility located in Mercer County, North Dakota.

4. Based upon information and reports provided by individuals immediately responsible for compiling and preparing the enclosed permit applications and supporting information, I have personal knowledge and am familiar with the information being submitted in the attached documents to the permit application. Based upon information and belief, the information contained herein is true, accurate, and complete.

5. I affirm under penalty of perjury that the representations contained in this affidavit are true to the best of my knowledge, information, and belief. I understand that there are significant penalties for submitting false information, including the possibility of a fine and imprisonment.

6. By my signature below, I hereby submit the attached application and supporting documentation and information on behalf of Dakota Gasification Company.

Executed this 10th day of March 2022.

Dale A. Johnson

STATE OF NORTH DAKOTA)
)
COUNTY OF BURLEIGH)

Subscribed and sworn to before me this 10th day of March 2022.

SHEILA E. WALD
Notary Public
State of North Dakota
My Commission Expires May 2, 2022

Sheila E. Wald
Notary Public

GREAT PLAINS CO_2 SEQUESTRATION PROJECT MERCER COUNTY, NORTH DAKOTA

North Dakota CO_2 Storage Facility Permit Application

Prepared for:

Stephen Fried

North Dakota Industrial Commission
Oil & Gas Division
600 East Boulevard Avenue
Department 405
Bismarck, ND 58505-0840

Prepared by:

Dakota Gasification Company
1717 East Interstate Avenue
Bismarck, ND 58503-0564

CarbonVault Great Plains LLC
1512 Larimer Street, Suite 550
Denver, CO 80202-1620

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

March 2022

TABLE OF CONTENTS

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TABLE OF CONTENTS (continued)

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TABLE OF CONTENTS (continued)

GREAT PLAINS CO_2 SEQUESTRATION PROJECT
MERCER COUNTY, NORTH DAKOTA

PERMIT APPLICATION SUMMARY

The Dakota Gasification Company (DGC), together with its partners and affiliates, requests consideration of this application for the dedicated geologic storage of carbon dioxide (CO_2) at DGC's Great Plains Synfuels Plant, located 5 miles northwest of Beulah, North Dakota.

Built in the 1970s as a response to America's quest for energy independence, the Great Plains Synfuels Plant has been owned and operated by DGC since 1988. Capable of gasifying 6 million tons of lignite coal per year, the facility generates approximately 150 million standard cubic feet (MMscf) of natural gas daily and is the only such plant of its kind in the country. Among the by-products of the gasification process is a nearly pure stream of CO_2 (95+% by volume).

The plant has captured and transported more than 40 million metric tons of CO_2 for enhanced oil recovery purposes since 2000. This is accomplished by means of a 205-mile pipeline that has operated without incident for the past 22 years. The CO_2 is first compressed to a pressure of ±2,500 psi, then transported north as a supercritical fluid. There currently exists excess compressor capacity which makes the capture of an additional 1.0 MMt/year possible. As additional compressed volumes become available over the next 4 years, on-site sequestration of 2.7 MMt/year is expected. Over the anticipated 12-year life of this project, sequestered volumes of CO_2 are expected to total 26 MMt. Four injection wells are anticipated initially, with two additional wells planned as increased volumes in 2026 or beyond warrant. Extensive reservoir simulations have been conducted to predict the full extent of the injected CO_2 plume in the subsurface over the life of the project, the results of which are displayed in Figure PS-1.

DGC is a wholly owned subsidiary of Basin Electric Power Cooperative (Basin), a consumer owned utility that serves over 3 million customers across nine states and is one of North Dakota's largest employers. Basin employees have played an integral role in the preparation of this application, as have representatives from the University of North Dakota's Energy & Environmental Research Center (EERC) and Denver's Carbon Vault Great Plains LLC (CV). The EERC has a 19-year history studying the CO_2 sequestration potential of North Dakota's Williston Basin in general and the Broom Creek sandstone formation specifically. The EERC also leads the Plains CO_2 Reduction (PCOR) Partnership, whose mission is "making safe practical carbon capture, utilization, and storage (CCUS) projects a reality." CV is a subsidiary of Rampart Energy Company (fka Duncan Energy Company), which has been a long-time oil and gas operator in the state and is lending its drilling, reservoir, operations, and injection well expertise to this project.

The target storage interval for the project is the Broom Creek sandstone formation, which underlies the synfuels plant and surrounding region. The Broom Creek Formation, and more specifically its CO_2 storage potential, has been the subject of numerous studies conducted by the North Dakota Geological Survey, the U.S. Geological Survey, and the EERC. It has been deemed an ideal storage candidate because of its superior reservoir quality, depth, impermeable upper and lower confining zones, and expansive areal extent. Preliminary estimates suggest a maximum storage capacity exceeding 10 billion metric tons of CO_2. The Coteau 1 stratigraphic test well was drilled in June 2021 and confirmed all expectations for the Broom Creek interval as the preferred sequestration zone at this location.

The operational plan calls for a 6.8-mile transmission line consisting of a 12" mainline and adjoining 6" lateral lines to the individual injection sites (permitted through the North Dakota Public Service Commission) to deliver CO_2 from the synfuels plant to the nearby sequestration area. Sequestration closer to the synfuels plant was originally considered but was ultimately adjusted northward because of possible interference with existing Class I Broom Creek water disposal wells associated with DGC plant operations. This transmission line will be operated and monitored in a manner consistent with the existing 205-mile CO_2 transmission line to Canada.

As the transmission lines dead-end at the individual wellsites, a pressure drop commensurate with anticipated injection conditions will take place, thus transitioning to the individual well flowlines included in this permit application.

The effluent from the synfuels plant operation includes other constituents beyond CO_2. Among these are ethane (1% by volume) and hydrogen sulfide (H_2S), 1.2% by volume. Exposure to H_2S can be harmful at very low concentrations. For that reason, continuous H_2S monitoring is planned, with automated alarms and emergency shutdown valves included. In addition, soil gas and Fox Hills water samples will be analyzed on a quarterly basis to detect any changes. The Fox Hills Formation represents the deepest subsurface formation that contains an underground source of drinking water (USDW). At this location, the base of the Fox Hills Formation is more than 4,500 feet above the Broom Creek injection interval, with both the Opeche Shale and the thousands of feet thick Pierre Shale in between.

The condition of downhole equipment will be monitored with multiple degrees of redundancy. Surface pressures will be tracked continuously for signs of anomalies, tubulars will be evaluated via ultrasonic electrical logs and/or caliper diagnoses, and regular mechanical integrity tests will be performed. Periodic pulse neutron logging will be conducted to monitor the near wellbore environment and confirm CO_2 is confined to the injection zone. As for the expansion of the CO_2 plume itself, periodic seismic surveys will be conducted, and compared to a preinjection baseline, to determine the extent of the plume's progression. Given the four to six injection wells anticipated with this project, sufficient operational flexibility will exist to maintain control of the stabilized plume within the anticipated project area.

Details of this sequestration opportunity are included in the pages to follow.

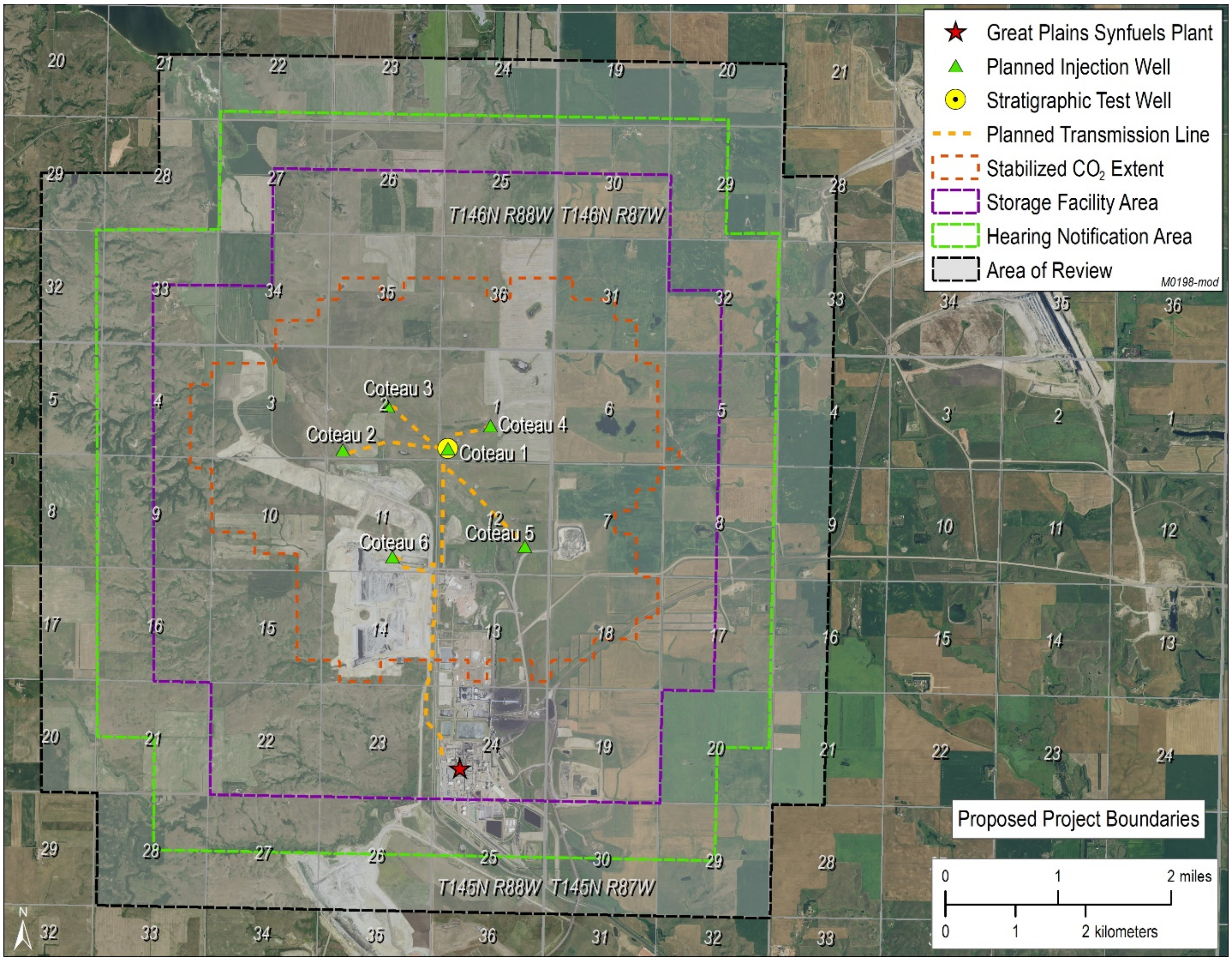


Figure PS-1. The projected stabilized CO_2 plume, storage facility area, notification area, and area of review.

1.0 PORE SPACE ACCESS

1.0 PORE SPACE ACCESS

North Dakota law explicitly grants title of the pore space in all strata underlying the surface of lands and waters to the overlying surface estate, i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] Chapter 47-31 – Subsurface Pore Space Policy). Prior to issuance of the storage facility permit (SFP), the storage operator is mandated by the North Dakota statute governing geologic storage of carbon dioxide (CO_2) to obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir. The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are or will be equitably compensated. North Dakota law grants the North Dakota Industrial Commission (NDIC) the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation. Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application (NDCC §§ 38-22-06[3] and 38-22-06[4] and North Dakota Administrative Code [NDAC] §§ 43-05-01-08[1] and 43-05-01-08[2]).

Dakota Gasification Company (DGC) has identified the owners (surface and mineral). In addition, with the exception of coal extraction, there are no mineral lessees or operators of mineral extraction activities within the facility area or within 0.5 miles of its outside boundary. DGC will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made.

All owners, lessees, and operators that require notification have been identified in accordance with North Dakota law, which vests the title to the pore space in all strata underlying the surface of lands and water to the owner of the overlying surface estate (NDCC Chapter 47-31). The identification of pore space owners indicates that there was no severance of pore space or leasing of pore space to a third-party from the surface estate prior to 2009.

Maps showing the extent of the pore space that will be occupied by CO_2 over the life of the project, including the storage reservoir boundary and 0.5 miles (0.8 kilometers) outside of the storage reservoir boundary with a description of pore space ownership, surface owner, and pore space lessees of record are illustrated in Figures 1-1 and 1-2.

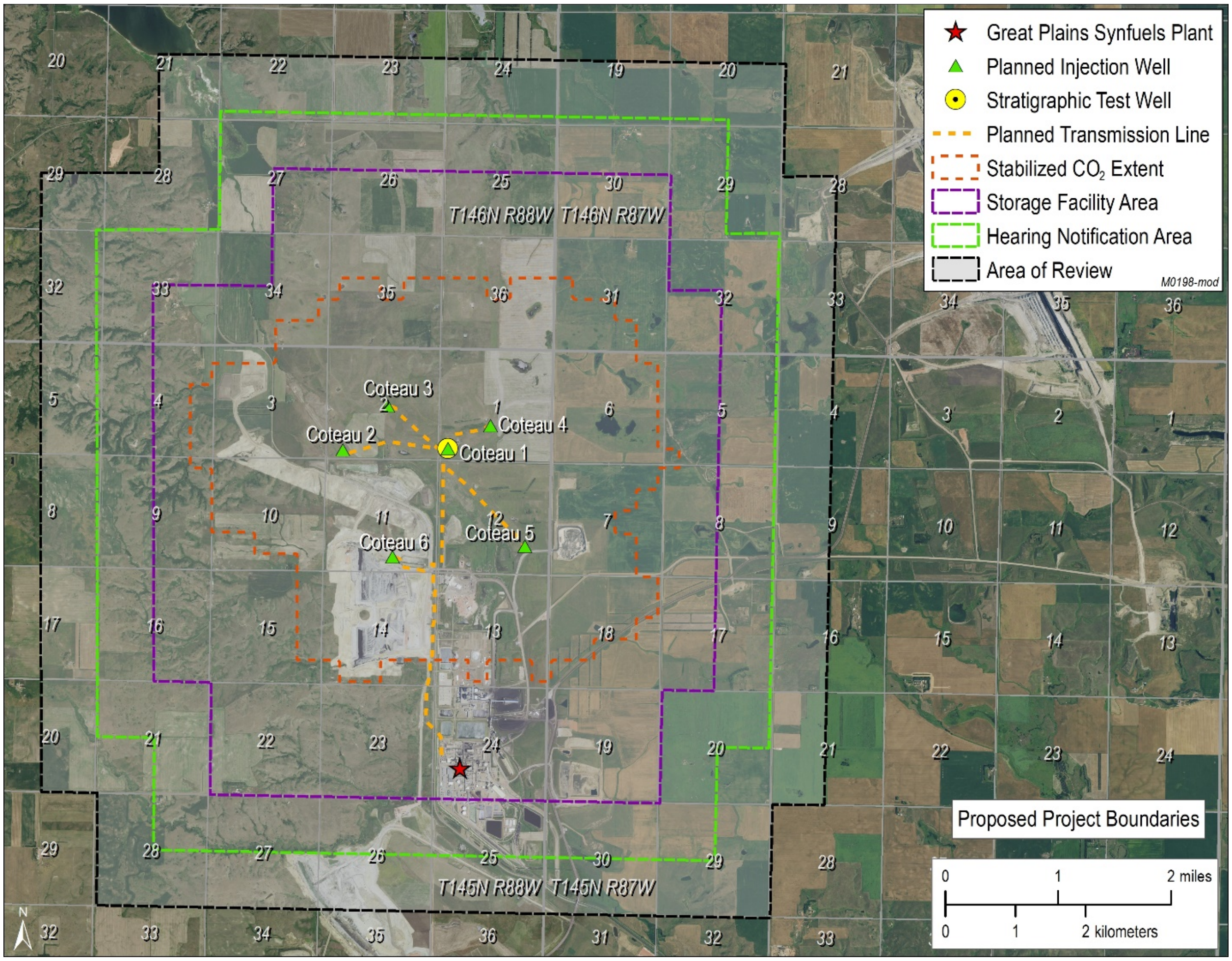


Figure 1-1. Storage facility area map.

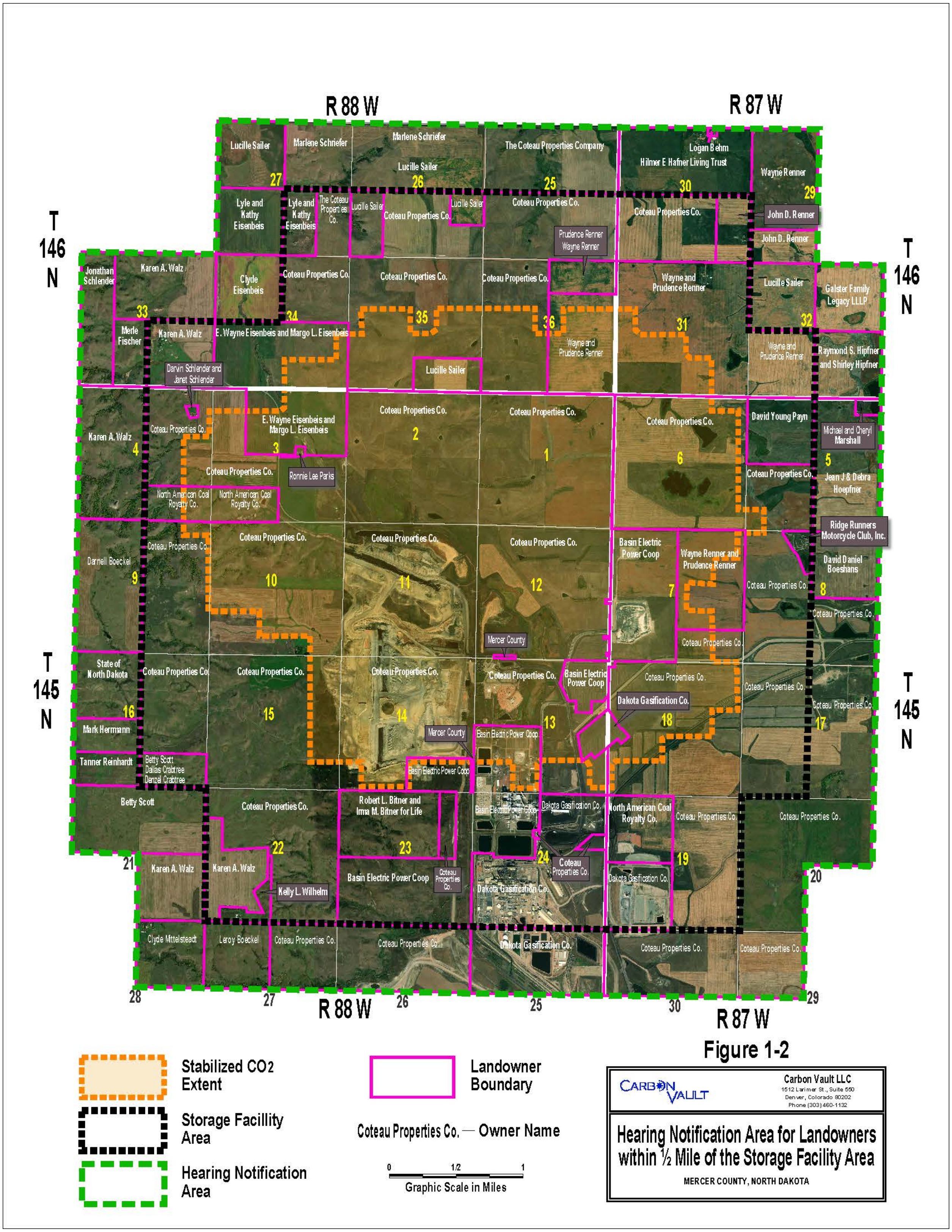


Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area.

RECEIVED
MAY - 3 2022
N.D. INDUSTRIAL COMMISSION

Fredrikson
& BYRON, P.A.

May 3, 2022

HAND DELIVERED

Mr. Bruce Hicks
Assistant Director
North Dakota Industrial Commission
Oil and Gas Division
600 East Boulevard
Bismarck, North Dakota 58505-0310

RE: Application of Dakota Gasification Company for an order of the Commission to consider a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.

Dear Mr. Hicks:

Please find enclosed herewith the following for filing:

1. STORAGE AGREEMENT, GREAT PLAINS CO2 SEQUESTRATION PROJECT, (BROOM CREEK FORMATION, MERCER COUNTY, NORTH DAKOTA)

Should you have any questions, please advise.

Sincerely,

LAWRENCE BENDER

LB/leo
Enclosure
cc: Ms. Casey Jacobson - (w/enc.) *Via Email*
75938438 v1

STORAGE AGREEMENT
GREAT PLAINS CO2 SEQUESTRATION PROJECT
(BROOM CREEK FORMATION,
MERCER COUNTY, NORTH DAKOTA)

STORAGE AGREEMENT
GREAT PLAINS CO2 SEQUESTRATION PROJECT
(BROOM CREEK FORMATION,
MERCER COUNTY, NORTH DAKOTA)

THIS AGREEMENT ("Agreement") is entered into as of the 1st day of June, 2022, by the parties who have signed the original of this instrument, a counterpart thereof, ratification and joinder or other instrument agreeing to become a Party hereto.

RECITALS:

A. It is in the public interest to promote the geologic storage of carbon dioxide in a manner which will benefit the state and the global environment by reducing greenhouse gas emissions and in a manner which will help ensure the viability of the state's coal and power industries, to the economic benefit of North Dakota and its citizens;

B. To further geologic storage of carbon dioxide, a potentially valuable commodity, may allow for its ready availability if needed for commercial, industrial, or other uses, including enhanced recovery of oil, gas, and other minerals; and

C. For geologic storage, however, to be practical and effective requires cooperative use of surface and subsurface property interests and the collaboration of property owners, which may require procedures that promote, in a manner fair to all interests, cooperative management, thereby ensuring the maximum use of natural resources.

AGREEMENT:

It is agreed as follows:

ARTICLE 1
DEFINITIONS

As used in this Agreement:

1.1 **Carbon Dioxide** means carbon dioxide in gaseous, liquid, or supercritical fluid state together with incidental associated substances derived from the source materials, capture process and any substances added or used to enable or improve the injection process.

1.2 **Commission** means the North Dakota Industrial Commission.

1.3 **Effective Date** is the time and date this Agreement becomes effective as provided in Article 14.

1.4 **Facility Area** is the land described by Tracts in Exhibit "B" and shown on Exhibit "A" containing 15,979.20 acres, more or less.

1.5 **Party** is any individual, corporation, limited liability company, partnership, association, receiver, trustee, curator, executor, administrator, guardian, tutor, fiduciary, or other representative of any kind, any department, agency, or instrumentality of the state, or any governmental subdivision thereof, or any other entity capable of holding an interest in the Storage Reservoir.

1.6 **Pore Space** means a cavity or void, whether natural or artificially created, in any subsurface stratum.

1.7 **Pore Space Interest** is a right to or interest in the Pore Space in any Tract within the boundaries of the Facility Area.

1.8 **Pore Space Owner** is a Party hereto who owns Pore Space Interest.

1.9 **Storage Equipment** is any personal property, lease and well equipment, plants and other facilities and equipment for use in Storage Operations.

1.10 **Storage Expense** is all costs, expense or indebtedness incurred by the Storage Operator pursuant to this Agreement for or on account of Storage Operations.

1.11 **Storage Facility** is the unitized or amalgamated Storage Reservoir created pursuant to an order of the Commission.

1.12 **Storage Facility Participation** is the percentage shown on Exhibit "C" for allocating payments for use of the Pore Space under each Tract identified in Exhibit "B".

1.13 **Storage Operations** are all operations conducted by the Storage Operator pursuant to this Agreement or otherwise authorized by any lease covering any Pore Space Interest.

1.14 **Storage Operator** is the person or entity named in Section 4.1 of this Agreement.

1.15 **Storage Reservoir** consists of the Pore Space and confining subsurface strata underlying the Facility Area described as the Broom Creek Formation and geologically confined by the Opeche Formation (upper confining zone) and the Amsden Formation (lower confining zone) identified by the laterolog gamma ray (LGR) log run in the Hermann #1 well (File No. 4177), located in the NE/4 SW/4 of Section 17, Township 145 North, Range 88 West, Mercer County, North Dakota, which encompasses the stratigraphic interval from a depth of 6132 feet to a depth of 6839 feet as measured from the Kelly Bushing elevation of 2203 feet, within the limits of the Facility Area.

1.16 **Storage Rights** are the rights to explore, develop, and operate lands within the Facility Area for the storage of Storage Substances.

1.17 **Storage Substances** are Carbon Dioxide and incidental associated substances, fluids, and minerals.

1.18 **Tract** is the land described as such and given a Tract number in Exhibit "B."

ARTICLE 2
EXHIBITS

2.1 **Exhibits.** The following exhibits, which are attached hereto, are incorporated herein by reference:

2.1.1 Exhibit "A" is a map that shows the boundary lines of the Great Plains Broom Creek Facility Area and the tracts therein;

2.1.2 Exhibit "B" is a schedule that describes the acres of each Tract in the Great Plains Broom Creek Facility Area;

2.1.3 Exhibit "C" is a schedule that shows the Storage Facility Participation of each Tract; and

2.1.4 Exhibit "D" is a form of Surface Use and Pore Space Lease.

2.2 **Reference to Exhibits.** When reference is made to an exhibit, it is to the exhibit as originally attached or, if revised, to the last revision.

2.3 **Exhibits Considered Correct.** Exhibits "A," "B," "C" and "D" shall be considered to be correct until revised as herein provided.

2.4 **Correcting Errors.** The shapes and descriptions of the respective Tracts have been established by using the best information available. If it subsequently appears that any Tract, mechanical miscalculation or clerical error has been made, Storage Operator, with the approval of Pore Space Owners whose interest is affected, shall correct the mistake by revising the exhibits to conform to the facts. The revision shall not include any re-evaluation of engineering or geological interpretations used in determining Storage Facility Participation. Each such revision of an exhibit made prior to thirty (30) days after the Effective Date shall be effective as of the Effective Date. Each such revision thereafter made shall be effective at 7:00 a.m. on the first day of the calendar month next following the filing for record of the revised exhibit or on such other date as may be determined by Storage Operator and set forth in the revised exhibit.

2.5 **Filing Revised Exhibits.** If an exhibit is revised, Storage Operator shall execute an appropriate instrument with the revised exhibit attached and file the same for record in the county or counties in which this Agreement or memorandum of the same is recorded and shall also file the amended changes with the Commission.

ARTICLE 3
CREATION AND EFFECT OF STORAGE FACILITY

3.1 **Unleased Pore Space Interests.** Any Pore Space Owner in the Storage Facility who owns a Pore Space Interest in the Storage Reservoir that is not leased for the purposes of this Agreement and during the term hereof, shall be treated as if it were subject to the Surface Use and Pore Space Lease attached hereto as Exhibit "D".

3.2 **Amalgamation of Pore Space.** All Pore Space Interests in and to the Tracts are hereby amalgamated and combined insofar as the respective Pore Space Interests pertain to the Storage Reservoir, so that Storage Operations may be conducted with respect to said Storage Reservoir as if all of the Pore Space Interests in the Facility Area had been included in a single lease executed by all Pore Space Owners, as lessors, in favor of Storage Operator, as lessee and as if the lease contained all of the provisions of this Agreement.

3.3 **Amendment of Leases and Other Agreements.** The provisions of the various leases, agreements, or other instruments pertaining to the respective Tracts or the storage of the Storage Substances therein, including the Surface Use and Pore Space Lease attached hereto as Exhibit "D", are amended to the extent necessary to make them conform to the provisions of this Agreement, but otherwise shall remain in effect.

3.4 **Continuation of Leases and Term Interests.** Injection in to any part of the Storage Reservoir, or other Storage Operations, shall be considered as injection in to or upon each Tract within said Storage Reservoir, and such injection or operations shall continue in effect as to each lease as to all lands and formations covered thereby just as if such operations were conducted on and as if a well were injecting in each Tract within said Storage Reservoir.

3.5 **Titles Unaffected by Storage.** Nothing herein shall be construed to result in the transfer of title of the Pore Space Interest of any Party hereto to any other Party or to Storage Operator.

3.6 **Injection Rights.** Storage Operator is hereby granted the right to inject into the Storage Reservoir any Storage Substances in whatever amounts Storage Operator may deem expedient for Storage Operations, together with the right to drill, use, and maintain injection wells in the Facility Area, and to use for injection purposes.

3.7 **Transfer of Storage Substances from Storage Facility.** Storage Operator may transfer from the Storage Facility any Storage Substances, in whatever amounts Storage Operator may deem expedient for Storage Operations, to any other reservoir, subsurface stratum or formation permitted by the Commission for the storage of carbon dioxide under Chapter 38-22 of the North Dakota Century Code. The transfer of such Storage Substances out of the Storage Facility shall be disregarded for the purposes of calculating the royalty under any lease covering a Pore Space Interest (including Exhibit "D") and shall not affect the allocation of Storage Substances injected into the Storage Facility through the surface of the Facility Area in accordance with Article 6 of this Agreement.

3.8 **Receipt of Storage Substances.** Storage Operator may accept and receive into the Storage Facility any Storage Substances, in whatever amounts Storage Operator may deem expedient for Storage Operations, being stored in any other reservoir, subsurface stratum or formation permitted by the Commission for the storage of carbon dioxide under Chapter 38-22 of the North

Dakota Century Code. The receipt of such Storage Substances into the Storage Facility shall be disregarded for the purposes of calculating the royalty under any lease covering a Pore Space Interest (including Exhibit "D") and shall not affect the allocation of Storage Substances injected into the Storage Facility through the surface of the Facility Area in accordance with Article 6 of this Agreement.

3.9 **Cooperative Agreements.** Storage Operator may enter into cooperative agreements with respect to lands adjacent to the Facility Area for the purpose of coordinating Storage Operations. Such cooperative agreements may include, but shall not be limited to, agreements regarding the transfer and receipt of Storage Substances pursuant to Sections 3.7 and 3.8 of this Agreement.

3.10 **Border Agreements.** Storage Operator may enter into an agreement or agreements with owners of adjacent lands with respect to operations which may enhance the injection of the Storage Substances in the Storage Reservoir in the Facility Area or which may otherwise be necessary for the conduct of Storage Operations.

ARTICLE 4
STORAGE OPERATIONS

4.1 **Storage Operator.** Dakota Gasification Company is hereby designated as the initial Storage Operator. Storage Operator shall have the exclusive right to conduct Storage Operations, which shall conform to the provisions of this Agreement and any lease covering a Pore Space Interest. If there is any conflict between such agreements, this Agreement shall govern.

4.2 **Successor Operators**. The initial Storage Operator and any subsequent operator may, at any time, transfer operatorship of the Storage Facility with and upon the approval of the Commission.

4.3 **Method of Operation.** Storage Operator shall engage in Storage Operations with diligence and in accordance with good engineering and injection practices.

4.4 **Change of Method of Operation.** As permitted by the Commission nothing herein shall prevent Storage Operator from discontinuing or changing in whole or in part any method of operation which, in its opinion, is no longer in accord with good engineering or injection practices. Other methods of operation may be conducted or changes may be made by Storage Operator from time to time if determined by it to be feasible, necessary or desirable to increase the injection or storage of Storage Substances.

ARTICLE 5
TRACT PARTICIPATIONS

5.1 **Tract Participations.** The Storage Facility Participation of each Tract is shown in Exhibit "C." The Storage Facility Participation of each Tract shall be based 100% upon the ratio of surface acres in each Tract to the total surface acres for all Tracts within the Facility Area.

5.2 **Relative Storage Facility Participations.** If the Facility Area is enlarged or reduced, the revised Storage Facility Participation of the Tracts remaining in the Facility Area and which were within the Facility Area prior to the enlargement or reduction shall remain in the same ratio to one another.

ARTICLE 6
ALLOCATION OF STORAGE SUBSTANCES

6.1 **Allocation of Tracts.** All Storage Substances injected shall be allocated to the several Tracts in accordance with the respective Storage Facility Participation effective during the period that the Storage Substances are injected. The amount of Storage Substances allocated to each tract, regardless of whether the amount is more or less than the actual injection of Storage Substances from the well or wells, if any, on such Tract, shall be deemed for all purposes to have been injected into such Tract. Storage Substances transferred or received pursuant to Sections 3.7 and 3.8 of this Agreement shall be disregarded for the purposes of this Section 6.1.

6.2 **Distribution within Tracts.** The Storage Substances injected and allocated to each Tract shall be distributed among, or accounted for to, the Pore Space Owners who own a Pore Space Interest in such Tract in accordance with each Pore Space Owner's Storage Facility Participation effective during the period that the Storage Substances were injected. If any Pore Space Interest in a Tract hereafter becomes divided and owned in severalty as to different parts of the Tract, the owners of the divided interests, in the absence of an agreement providing for a different division, shall be compensated for the storage of the Storage Substances in proportion to the surface acreage of their respective parts of the Tract. Storage Substances transferred or received pursuant to Sections 3.7 and 3.8 of this Agreement shall be disregarded for the purposes of this Section 6.2.

ARTICLE 7
TITLES

7.1 **Warranty and Indemnity.** Each Pore Space Owner who, by acceptance of revenue for the injection of Storage Substances into the Storage Reservoir, shall be deemed to have warranted title to its Pore Space Interest, and, upon receipt of the proceeds thereof to the credit of such interest, shall indemnify and hold harmless the Storage Operator and other Parties from any loss due to failure, in whole or in part, of its title to any such interest.

7.2 **Injection When Title Is in Dispute.** If the title or right of any Pore Space Owner claiming the right to receive all or any portion of the proceeds for the storage of any Storage Substances allocated to a Tract is in dispute, Storage Operator shall require that the Pore Space Owner to whom the proceeds thereof are paid furnish security for the proper accounting thereof to the rightful Pore Space Owner if the title or right of such Pore Space Owner fails in whole or in part.

7.3 **Payments of Taxes to Protect Title.** The owner of surface rights to lands within the Facility Area is responsible for the payment of any *ad valorem* taxes on all such rights, interests or property, unless such owner and the Storage Operator otherwise agree. If any *ad valorem* taxes are not paid by or for such owner when due, Storage Operator may at any time prior to tax sale or expiration of period of redemption after tax sale, pay the tax, redeem such rights, interests or property, and discharge the tax lien. Storage Operator shall, if possible, withhold from any proceeds derived from the storage of Storage Substances otherwise due any Pore Space Owner who is a delinquent taxpayer an amount sufficient to defray the costs of such payment or redemption, such withholding to be credited to the Storage Operator. Such withholding shall be without prejudice to any other remedy available to Storage Operator.

7.4 **Pore Space Interest Titles.** If title to a Pore Space Interest fails, but the tract to which it relates is not removed from the Facility Area, the Party whose title failed shall not be entitled to share under this Agreement with respect to that interest.

ARTICLE 8
EASEMENTS OR USE OF SURFACE

8.1 **Grant of Easement.** Storage Operator shall have the right to use as much of the surface of the land within the Facility Area as may be reasonably necessary for Storage Operations and the injection of Storage Substances.

8.2 **Use of Water.** Storage Operator shall have and is hereby granted free use of water from the Facility Area for Storage Operations, except water from any well, lake, pond or irrigation ditch of a Pore Space Owner; notwithstanding the foregoing, Storage Operator may access any well, lake, or pond as provided in Exhibit "D".

8.3 **Surface Damages.** Storage Operator shall pay surface owners for damage to growing crops, timber, fences, improvements and structures located on the Facility Area that result from Storage Operations.

8.4 **Surface and Sub-Surface Operating Rights.** Except to the extent modified in this Agreement, Storage Operator shall have the same rights to use the surface and sub-surface and use of water and any other rights granted to Storage Operator in any lease covering Pore Space Interests. Except to the extent expanded by this Agreement or the extent that such rights are common to the effected leases, the rights granted by a lease may be exercised only on the land covered by that lease. Storage Operator will to the extent possible minimize surface impacts.

ARTICLE 9
ENLARGEMENT OF STORAGE FACILITY

9.1 **Enlargement of Storage Facility.** The Storage Facility may be enlarged from time to time to include acreage and formations reasonably proven to be geologically capable of storing Storage Substances. Any expansion must be approved in accordance with the rules and regulations of the Commission.

9.2 **Determination of Tract Participation.** Storage Operator, subject to Section 5.2, shall determine the Storage Facility Participation of each Tract within the Storage Facility as enlarged, and shall revise Exhibits "A", "B" and "C" accordingly and in accordance with the rules, regulations and orders of the Commission.

9.3 **Effective Date.** The effective date of any enlargement of the Storage Facility shall be effective as determined by the Commission.

ARTICLE 10
TRANSFER OF TITLE PARTITION

10.1 **Transfer of Title.** Any conveyance of all or part of any interest owned by any Party hereto with respect to any Tract shall be made expressly subject to this Agreement. No change of title shall be binding upon Storage Operator, or any Party hereto other than the Party so transferring, until 7:00 a.m. on the first day of the calendar month following thirty (30) days from the date of receipt by Storage Operator of a photocopy, or a certified copy, of the recorded or filed instrument evidencing such a change in ownership.

10.2 **Waiver of Rights to Partition.** Each Party hereto agrees that, during the existence of this Agreement, it will not resort to any action to partition any Tract or parcel within the Facility Area or the facilities used in the development or operation thereof, and to that extent waives the benefits or laws authorizing such partition.

ARTICLE 11
RELATIONSHIP OF PARTIES

11.1 **No Partnership.** The duties, obligations and liabilities arising hereunder shall be several and not joint or collective. This Agreement is not intended to create, and shall not be construed to create, an association or trust, or to impose a partnership duty, obligation or liability with regard to any one or more of the Parties hereto. Each Party hereto shall be individually responsible for its own obligations as herein provided.

11.2 **No Joint Marketing.** This Agreement is not intended to provide, and shall not be construed to provide, directly or indirectly, for any joint marketing of Storage Substances.

11.3 **Pore Space Owners Free of Costs.** This Agreement is not intended to impose, and shall not be construed to impose, upon any Pore Space Owner any obligation to pay any Storage Expense unless such Pore Space Owner is otherwise so obligated.

11.4 **Information to Pore Space Owners.** Each Pore Space Owner shall be entitled to all information in possession of Storage Operator to which such Pore Space Owner is entitled by an existing lease or a lease imposed by this Agreement.

ARTICLE 12
LAWS AND REGULATIONS

12.1 **Laws and Regulations.** This Agreement shall be subject to all applicable federal, state and municipal laws, rules, regulations and orders.

ARTICLE 13
FORCE MAJEURE

13.1 **Force Majeure.** All obligations imposed by this Agreement on each Party, except for the payment of money, shall be suspended while compliance is prevented, in whole or in part, by a labor dispute, fire, war, civil disturbance, or act of God; by federal, state or municipal laws; by any rule, regulation or order of a governmental agency; by inability to secure materials; or by any other cause or causes, whether similar or dissimilar, beyond reasonable control of the Party. No Party shall be required against his will to adjust or settle any labor dispute. Neither this Agreement nor any lease or other instrument subject hereto shall be terminated by reason of suspension of Storage Operations due to any one or more of the causes set forth in this Article.

ARTICLE 14
EFFECTIVE DATE

14.1 **Effective Date.** This Agreement shall become effective as determined by the Commission.

14.2 **Ipso Facto Termination.** If the requirements of Section 14.1 are not accomplished on or before December 31, 2022 this Agreement shall *ipso facto* terminate on that date (hereinafter called "termination date") and thereafter be of no further effect, unless prior thereto Pore Space Owners owning a combined Storage Facility Participation of at least thirty percent (30%) of the Facility Area have become Parties to this Agreement and have decided to extend the termination date for a period not to exceed six (6) months. If the termination date is so extended and the requirements of Section 14.1 are not accomplished on or before the extended termination date this Agreement shall *ipso facto* terminate on the extended termination date and thereafter be of no further effect.

14.3 **Certificate of Effectiveness.** Storage Operator shall file for record in the county or counties in which the land affected is located a certificate stating the Effective Date of this Agreement.

ARTICLE 15
TERM

15.1 **Term.** Unless sooner terminated in the manner hereinafter provided or by order of the Commission, this Agreement shall remain in full force and effect until the Commission has issued a certificate of project completion with respect to the Storage Facility in accordance with § 38-22-17 of the North Dakota Century Code.

15.2 **Termination by Storage Operator.** This Agreement may be terminated at any time by the Storage Operator with the approval of the Commission.

15.3 **Effect of Termination.** Upon termination of this Agreement all Storage Operations shall cease. Each lease and other agreement covering Pore Space within the Facility Area shall remain in force for ninety (90) days after the date on which this Agreement terminates, and for such further period as is provided by Exhibit "C" or other agreement.

15.4 **Salvaging Equipment Upon Termination.** If not otherwise granted by Exhibit "C" or other instruments affecting each Tract, Pore Space Owners hereby grant Storage Operator a period of six (6) months after the date of termination of this Agreement within which to salvage and remove Storage Equipment.

15.5 **Certificate of Termination.** Upon termination of this Agreement, Storage Operator shall file for record in the county or counties in which the land affected is located a certificate that this Agreement has terminated, stating its termination date.

ARTICLE 16
APPROVAL

16.1 **Original, Counterpart or Other Instrument.** A Pore Space Owner may approve this Agreement by signing the original of this instrument, a counterpart thereof, ratification or joinder or other instrument approving this instrument hereto. The signing of any such instrument shall have the same effect as if all Parties had signed the same instrument.

16.2 **Joinder in Dual Capacity.** Execution as herein provided by any Party as either a Pore Space Owner or the Storage Operator shall commit all interests owned or controlled by such Party and any additional interest thereafter acquired in the Facility Area.

16.3 **Approval by the North Dakota Industrial Commission.** Notwithstanding anything in this Article to the contrary, all Tracts within the Facility Area shall be deemed to be qualified for participation if this Agreement is duly approved by order of the Commission.

ARTICLE 17
GENERAL

17.1 **Amendments Affecting Pore Space Owners.** Amendments hereto relating wholly to Pore Space Owners may be made with approval by the Commission.

17.4 **Construction.** This agreement shall be construed according to the laws of the State of North Dakota.

ARTICLE 18
SUCCESSORS AND ASSIGNS

18.1 **Successors and Assigns.** This Agreement shall extend to, be binding upon, and inure to the benefit of the Parties hereto and their respective heirs, devisees, legal representatives, successors and assigns and shall constitute a covenant running with the lands, leases and interests covered hereby.

[*Remainder of page intentionally left blank. Signature page follows.*]

Executed the date set opposite each name below but effective for all purposes as provided by Article 14.

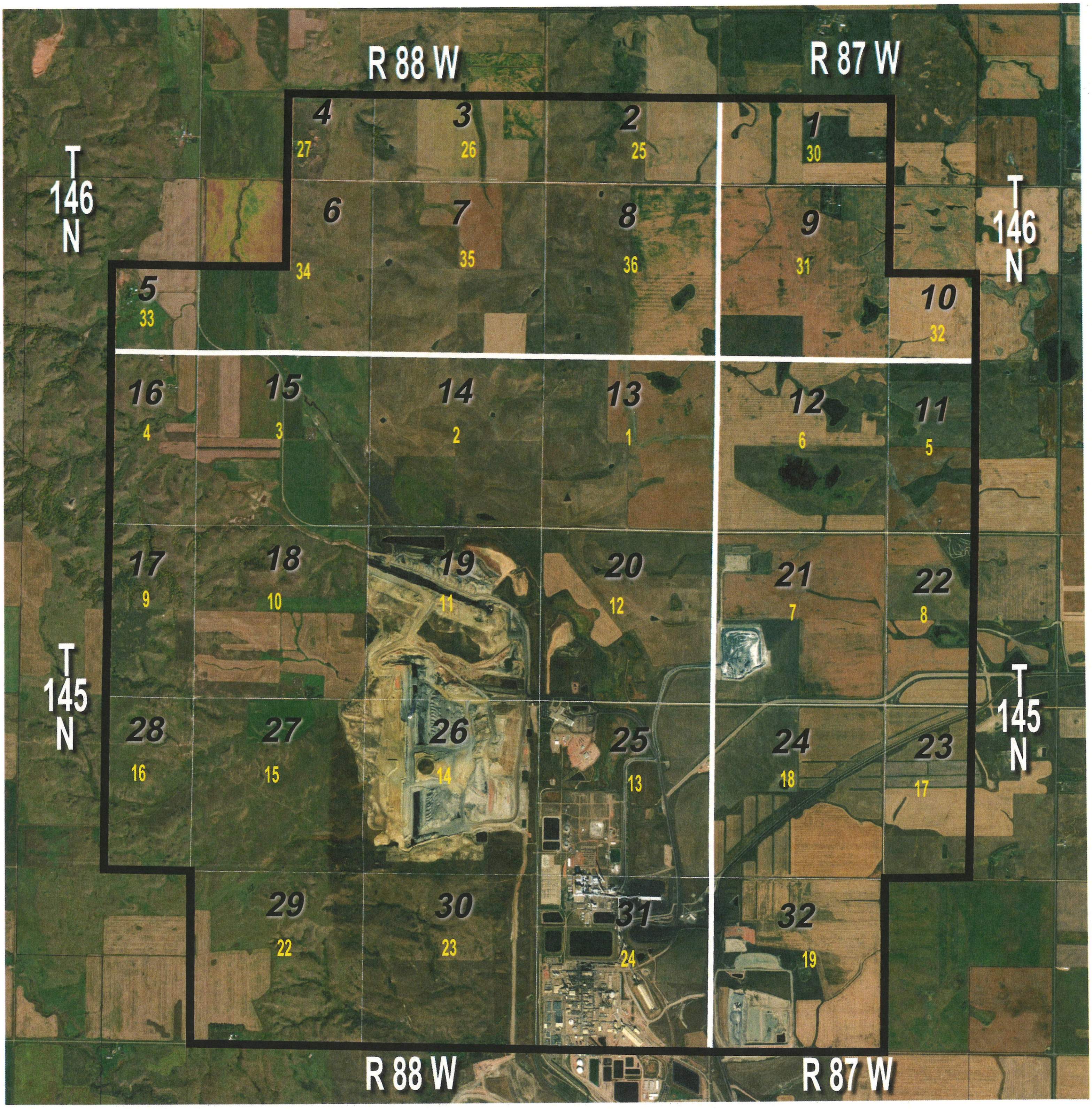
Dated: ____________, 2022/

STORAGE OPERATOR

DAKOTA GASIFICATION COMPANY

By:__________________________________
[Name]
Its: [Title]

75907136 v1



Permit Boundary

27 Tract Number

0 1/2 1

Graphic Scale in Miles

75931620.1

Great Plains
DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY
SYNFUELS

Exhibit A

Attached to and made part of the Storage Agreement

Great Plains CO2 Sequestration Project

(Broom Creek Formation, Mercer County, North Dakota)

EXHIBIT B
Tract Summary

Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation
1	Section 30 - T146N-R87W	The Coteau Properties Co.	237.57	74.81%	1.48674499%
		John D. Renner	80.00	25.19%	0.50065075%
		Tract Total	**317.57**	100.00%	
2	Section 25 - R146N-R88W	The Coteau Properties Co.	**320.00**	100.00%	2.00260301%
3	Section 26 - R146N-R88W	The Coteau Properties Co.	200.00	62.50%	1.25162688%
		Lucille Sailer	120.00	37.50%	0.75097613%
		Tract Total	**320.00**	100.00%	
4	Section 27 - R146N-R88W	The Coteau Properties Co.	80.00	50.00%	0.50065075%
		Lyle Eisenbeis and Kathy Eisenbeis	80.00	50.00%	0.50065075%
		Tract Total	**160.00**	100.00%	
5	Section 33 - R146N-R88W	Karen A. Walz	**160.00**	100.00%	1.00130150%
6	Section 34 - R146N-R88W	E. Wayne Eisenbeis and Margo L. Eisenbeis	320.00	66.67%	2.00260301%
		The Coteau Properties Co.	160.00	33.33%	1.00130150%
		Tract Total	**480.00**	100.00%	
7	Section 35 - R146N-R88W	The Coteau Properties Co.	560.00	87.50%	3.50455526%
		Lucille Sailer	80.00	12.50%	0.50065075%
		Tract Total	**640.00**	100.00%	
8	Section 36 - R146N-R88W	The Coteau Properties Co.	320.00	50.00%	2.00260301%
		Wayne Renner and Prudence Renner	240.00	37.50%	1.50195226%
		Prudence Renner	40.00	6.25%	0.25032538%
		Wayne Renner	40.00	6.25%	0.25032538%
		Tract Total	**640.00**	100.00%	
9	Section 31 - T146N-R87W	Wayne Renner and Prudence Renner	**637.68**	100.00%	3.99068715%
10	Section 32 - T146N-R87W	Wayne Renner and Prudence Renner	**160.00**	100.00%	1.00130150%
11	Section 5 - T145N-R87W	David Young Payn	159.94	49.99%	1.00092602%
		The Coteau Properties Co.	160.00	50.01%	1.00130150%
		Tract Total	**319.94**	100.00%	
12	Section 6 - T145N-R87W	The Coteau Properties Co.	**639.31**	100.00%	4.00088790%
13	Section 1 - T145N-R88W	The Coteau Properties Co.	**636.40**	100.00%	3.98267673%
14	Section 2 - T145N-R88W	The Coteau Properties Co.	**634.96**	100.00%	3.97366502%

EXHIBIT B
Tract Summary
Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation
15	Section 3 - T145N-R88W	E. Wayne Eisenbeis and Margo L. Eisenbeis	235.47	36.93%	1.47362168%
		Ronnie Lee Parks	4.21	0.66%	0.02634675%
		The Coteau Properties Co.	317.90	49.86%	1.98946093%
		North American Coal Royalty Co.	80.00	12.55%	0.50065075%
		Tract Total	**637.58**	100.00%	
16	Section 4 - T145N-R88W	The Coteau Properties Co.	233.71	73.46%	1.46260737%
		Darvin Schlender and Janet Schlender	4.43	1.39%	0.02770476%
		North American Coal Royalty Co.	80.00	25.15%	0.50065075%
		Tract Total	**318.14**	100.00%	
17	Section 9 - T145N-R88W	The Coteau Properties Co.	**320.00**	100.00%	2.00260301%
18	Section 10 - T145N-R88W	The Coteau Properties Co.	**640.00**	100.00%	4.00520602%
19	Section 11 - T145N-R88W	The Coteau Properties Co.	**640.00**	100.00%	4.00520602%
20	Section 12 - T145N-R88W	The Coteau Properties Co.	636.71	99.49%	3.98461675%
		Mercer County	2.52	0.39%	0.01577050%
		Basin Electric Power Coop	0.77	0.12%	0.00481876%
		Tract Total	**640.00**	100.00%	
21	Section 7 - T145N-R87W	Wayne Renner and Prudence Renner	240.00	37.54%	1.50195226%
		Basin Electric Power Coop	319.30	49.95%	1.99822231%
		The Coteau Properties Co.	80.00	12.51%	0.50065075%
		Tract Total	**639.30**	100.00%	
22	Section 8 - T145N-R87W	The Coteau Properties Co.	293.43	91.70%	1.83632438%
		Ridge Runner Motorcycle Club, Inc.	26.57	8.30%	0.16627863%
		Tract Total	**320.00**	100.00%	
23	Section 17 - T145N-R87W	The Coteau Properties Co.	**320.00**	100.00%	2.00260301%
24	Section 18 - T145N-R87W	The Coteau Properties Co.	625.29	97.81%	3.91316138%
		Dakota Gasification Co.	13.45	2.10%	0.08415939%
		Basin Electric Power Coop	0.58	0.09%	0.00362972%
		Tract Total	**639.32**	100.00%	
25	Section 13 - T145N-R88W	Basin Electric Power Coop	233.09	36.42%	1.45867726%
		The Coteau Properties Co.	372.46	58.20%	2.33089848%
		Dakota Gasification Co.	34.46	5.38%	0.21563028%
		Tract Total	**640.00**	100.00%	
26	Section 14 - T145N-R88W	The Coteau Properties Co.	558.75	87.30%	3.49673260%

EXHIBIT B

Tract Summary

Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation
		Mercer County	1.25	0.20%	0.00782267%
		Basin Electric Power Coop	80.00	12.50%	0.50065075%
		Tract Total	**640.00**	100.00%	
27	Section 15 - T145N-R88W	The Coteau Properties Co.	**640.00**	100.00%	4.00520602%
28	Section 16 - T145N-R88W	The Coteau Properties Co.	240.00	75.00%	1.50195226%
		Betty Scott	40.00	12.50%	0.25032538%
		Dallas Crabtree	20.00	6.25%	0.12516269%
		Denzel Crabtree	20.00	6.25%	0.12516269%
		Tract Total	**320.00**	100.00%	
29	Section 22 - T145N-R88W	The Coteau Properties Co.	446.70	69.80%	2.79550864%
		Karen A. Walz	152.92	23.89%	0.95699391%
		Kelly L. Wilhelm	40.38	6.31%	0.25270347%
		Tract Total	**640.00**	100.00%	
30	Section 23 - T145N-R88W	Basin Electric Power Coop	360.00	56.25%	2.25292838%
		The Coteau Properties Co.	40.00	6.25%	0.25032538%
		Robert L. Bitner and Irma M Bitner for Life	240.00	37.50%	1.50195226%
		Tract Total	**640.00**	100.00%	
31	Section 24 - T145N-R88W	Dakota Gasification Co.	478.40	74.75%	2.99389150%
		Basin Electric Power Coop	147.58	23.06%	0.92356922%
		The Coteau Properties Co.	14.02	2.19%	0.08774530%
		Tract Total	**640.00**	100.00%	
32	Section 19 - T145N-R87W	The Coteau Properties Co.	320.00	50.08%	2.00260301%
		North American Coal Royalty Co.	159.45	24.95%	0.99785953%
		Dakota Gasification Co.	159.55	24.97%	0.99848534%
		Tract Total	**639.00**	100.00%	
		Total Acres	**15,979.20**	**Total Participation**	**100.00000000%**

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EXHIBIT C

Tract Participation

Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

Tract No.	Tract Acres	Tract Participation
1	317.57	1.98739611%
2	320.00	2.00260338%
3	320.00	2.00260338%
4	160.00	1.00130169%
5	160.00	1.00130169%
6	480.00	3.00390508%
7	640.00	4.00520677%
8	640.00	4.00520677%
9	637.68	3.99068789%
10	160.00	1.00130169%
11	319.94	2.00222790%
12	639.31	4.00088866%
13	636.40	3.98267748%
14	634.96	3.97366577%
15	637.58	3.99006208%
16	318.14	1.99096325%
17	320.00	2.00260338%
18	640.00	4.00520677%
19	640.00	4.00520677%
20	640.00	4.00520677%
21	639.30	4.00082607%
22	320.00	2.00260338%
23	320.00	2.00260338%
24	639.32	4.00095124%
25	640.00	4.00520677%
26	640.00	4.00520677%
27	640.00	4.00520677%
28	320.00	2.00260338%
29	640.00	4.00520677%
30	640.00	4.00520677%
31	640.00	4.00520677%
32	639.00	3.99894863%
	15,979.20	**100.00000000%**

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EXHIBIT D
Pore Space Lease
Attached to and made part of the Storage Agreement
Great Plains CO2 Sequestration Project
(Broom Creek Formation, Mercer County, North Dakota)

THIS PORE SPACE LEASE (this "Lease") is made effective as of the Effective Date (as defined below), by and between «Surface_Owner», whose address is «Address», «City» «State» «Zip», (whether one or more, "Lessor"), and Dakota Gasification Company, a North Dakota corporation, whose address is 1717 East Interstate Avenue, Bismarck, North Dakota 58503 (whether one or more, "Lessee"). Lessor and Lessee may be individually referred to herein as a "Party" and collectively as the "Parties".

1. Leased Premises. Lessor, for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, does hereby grant, demise, lease and let unto Lessee for Lessee's geologic storage operations and other purposes set forth herein, the following-described lands situated in Mercer County, North Dakota:

Township [__] North, Range [___] West
Section [__]: [__]

containing «Acres» acres, more or less (the "Leased Premises"), subject to the terms and conditions set forth herein. The entire project area includes acres, more or less (the "Project Area").

2. Term.

(a) Primary Term. This Lease shall commence on the date Lessee executes this Lease ("Effective Date") and continue for an initial term of Fifteen (15) years ("Primary Term") unless sooner terminated in accordance with the terms of this Lease. On the Effective Date of this Lease and thereafter on or before each annual anniversary date of this Lease, Lessee shall pay to Lessor the sum of ($) per surface acre covered by this Lease. After the Primary Term, Lessee retains the right to extend this lease up to three (3) additional five (5) year terms by providing Lessor with at least a 60-day notice, as long as Lessee continues to pay to Lessor through any extension period, the annual lease rate provided for above and any royalty rates as set forth in Section 3 of this Lease.

(b) Operational Term. This Lease shall continue beyond the Initial Term for so long as any portion of the Leased Premises or Lessee's storage facilities located in, on or under the Leased Premises (including without limitation, any Reservoirs) are subject to a permit issued by the North Dakota Industrial Commission (the "Commission") (a "Permit") or under the ownership or control of the State of North Dakota; *provided*, *however*, that all of Lessee's obligations under this Lease shall terminate upon issuance of a certificate of project completion pursuant to Chapter 38-22 of the North Dakota Century Code (the "Operational Term"). If the Primary Term expires and no portion of the Leased Premises or Lessee's storage facilities located in, on or under the Leased Premises is subject to a Permit, this Lease shall terminate, and Lessee shall execute a document evidencing termination of this Lease in recordable form and shall record it in the official records of the county or counties in which any portion of the Leased Premises is located.

3. Royalty. Lessee shall pay to Lessor its proportionate share of ($) per metric ton of carbon dioxide (CO_2) injected into the reservoirs and subsurface pore spaces (as used herein, such terms shall have the meanings set forth in Chapter 38-22 and Chapter 47-31 of the North Dakota Century Code), stratum or strata underlying the Leased Premises (collectively, "Reservoirs"), or reservoirs and subsurface pore spaces, stratum or strata unitized or amalgamated therewith (the "Amalgamated Reservoirs"). Lessor's "proportionate share" shall be determined on a net acre basis and the Parties hereby stipulate that the acreage set forth in Section 1 shall be used to calculate Lessor's proportionate share of the Project Area. The quantity of carbon dioxide injected into the Reservoirs or any Amalgamated Reservoirs shall be determined through the use of metering equipment installed and operated by Lessee at the injection site. All royalties due hereunder for carbon dioxide injected into the Reservoirs or any Amalgamated Reservoirs during any calendar year shall be paid to Lessor within sixty (60) days of the end of said year. Lessor and Lessee agree that this Lease shall continue as specified herein even in the absence of injection operations and the payment of royalties.

4. Right to Pore Space/Storage of Carbon Dioxide. Lessor grants to Lessee the exclusive right to inject and store carbon dioxide and other incidental gaseous substances into and in the Reservoirs, together with the right of reasonable use of the surface of the Leased Premises as set forth in Section 5. Lessor shall not grant to any other person the right to inject or store carbon dioxide or any other gases, liquids, solids or semi-solids into the Reservoirs underlying the Leased Premises.

5. Surface Access. Lessor grants Lessee the right of reasonable use of the surface of the Leased Premises, including without limitation, the rights of ingress and egress over the Leased Premises, for purposes of any surveys and/or ongoing testing activities related to this Lease provided, however, that Lessee shall compensate Lessor, or its tenants, for any physical damages to growing crops, livestock and improvements located on the Leased Premises, if such damages are caused by Lessee's use of the Leased Premises.

6. Amalgamation. Lessee, in its sole discretion, shall have the right and power, at any time and from time to time during the term of this Lease to pool, unitize, or amalgamate any reservoirs or subsurface pore spaces, stratum or strata underlying the Leased Premises with any other lands or interests into which such reservoirs or subsurface pore spaces extend and document such unit in accordance with applicable law or agency order. Amalgamated units shall be of such shape and dimensions as Lessee may elect and as are approved by the Commission. Amalgamated areas may include, but are not required to include, land upon which injection or extraction wells have been completed or upon which the injection and/or withdrawal of carbon dioxide and/or related gaseous substances has commenced prior to the effective date of amalgamation. In exercising its amalgamation rights under this Lease and if required by law, Lessee shall record or cause to be recorded a copy of the Commission's amalgamation order or other notice thereof in the county or counties in which any portion of the amalgamated unit is located. Amalgamating in one or more instances shall, if approved by the Commission, not exhaust the rights of Lessee to amalgamate Reservoirs or portions of Reservoirs into other amalgamation areas, and Lessee shall have the recurring right to revise any amalgamated area formed under this Lease by expansion or contraction or both. Lessee may dissolve any amalgamated area at any time and document such dissolution by recording an instrument in accordance with applicable law or agency order. Lessee shall have the right to negotiate, on behalf of and as agent for Lessor, any unit, amalgamation, storage or operating agreements with respect to amalgamation of reservoir or pore space interests

underlying the Leased Premises or the operation of any amalgamated areas formed under such agreements and Lessor shall ratify any such agreements upon Lessee's request. To the extent any of the terms of such agreements conflict with the terms of this Lease, the terms of such agreements shall control and the provisions of this Lease shall be deemed modified to conform to the terms, conditions, and provisions of any such agreements which are approved by the Commission.

7. Lessee Obligations. Lessee shall have no obligation, express or implied, to begin, prosecute or continue storage operations in, upon or under the Leased Premises, or store and/or sell or use all or any portion of the gaseous substances stored thereon. The timing, nature, manner and extent of Lessee's operations, if any, under this Lease shall be at the sole discretion of Lessee. All obligations of Lessee are expressed herein, and there shall be no covenants implied under this Lease, it being agreed that all amounts paid hereunder constitute full and adequate consideration for this Lease.

8. Ownership. Lessee shall at all times be the owner of (i) the carbon dioxide and other gaseous substances stored in the Reservoirs or any Amalgamated Reservoirs, and (ii) all Facilities constructed or installed by Lessee on the Leased Premises. Lessee shall have the right, but not the obligation, at any time during this Lease to remove all or any portion of the property or fixtures placed by Lessee on the Lease Premises. Notwithstanding the foregoing, title to the storage facility and to the stored carbon dioxide or other gaseous substances shall be transferred to the State of North Dakota upon issuance of a certificate of project completion by the Commission in accordance with Chapter 38-22 of the North Dakota Century Code.

9. Minerals, Oil and Gas. This lease is not intended to grant or convey, nor does it grant or convey, any right to or obligation for lessee to explore for or produce minerals, including oil and gas, that may exist on or under the leased premises.

10. Surrender of Leased Premises. Lessee shall have the right, but not the obligation, at any time from time to time to execute and deliver to Lessor a surrender and/or release covering all or any part of the Leased Premises for which the Reservoirs are not being utilized for storage as set forth herein, and upon delivery of such surrender and/or release to Lessor this Lease shall terminate as to such lands, and Lessee shall be released from all further obligations and duties as to the lands so surrendered and/or released, including, without limitation, any obligation to make payments provided for herein, except obligations accrued as of the date of the surrender and/or release. Lessee shall be able to surrender any and or all of the Leased Premises if not utilizing the Reservoirs located thereunder.

11. Hold Harmless and Indemnification. The Lessee agrees to defend, indemnify, and hold harmless Lessor from any claims by any person that are a direct result of the Lessee's use of the Leased Premises or Reservoirs. Notwithstanding the foregoing, such indemnity/hold harmless obligation excludes (i) any claim or cause of action, or alleged or threatened claim or cause of action, damage, judgment, interest, penalty or other loss arising or resulting from the negligence or intentional acts of Lessor or Lessor's agents, invitees, or licensees; or third parties, and (ii) any claim for exemplary, punitive, special or consequential damages claimed by Lessor. Lessee further accepts liability and indemnifies Lessor for reasonable costs, expenses and attorneys' fees incurred in establishing and litigating the indemnification coverage provided above. The legal defense provided by Lessee to the Lessor under this paragraph must be free of any conflicts of interest even if this requires Lessee to retain separate legal counsel for Lessor.

12. Hazardous Substances. Lessee shall have no liability for any regulated hazardous substances located on the Leased Premises prior to the Effective Date or placed in, on or about the Leased Premises by Lessor or any third-party on or after the Effective Date, and nothing in this Lease shall be construed to impose upon Lessee any obligation for the removal of such regulated hazardous substances. As used herein, "hazardous substances" shall have the meaning set forth in the Comprehensive Environmental Response Compensation and Liability Act (CERCLA) and any amendments thereto, or any other local, state or federal statutes.

13. Termination. A material violation or default of any terms of this Lease by Lessee shall be grounds for termination of the Lease. Lessor shall provide Lessee written notice of violation or default and Lessee shall have sixty (60) days after receipt of said notice to substantially cure such violations or defaults. If Lessee fails to substantially cure such violations or defaults within the 60-day cure period, Lessor may terminate the Lease; *provided that*, if it is not reasonably possible to cure such violations or defaults within the 60-day cure period, Lessee shall have additional time as is reasonably necessary to cure such violations or defaults provided Lessee has commenced its efforts to cure within the initial sixty (60) day period and thereafter diligently pursues such cure. Lessee may terminate the lease with thirty (30) days written notice to Lessor. Upon termination of this Lease, Lessee shall have one hundred eighty (180) days to remove all facilities and property (except for carbon dioxide or other incidental gaseous substances which have been injected into the Reservoirs) of Lessee located on the Leased Premises.

14. Taxes. Lessee shall pay all taxes, if any, levied against its personal property or on its improvements to the Leased Premises. Lessor shall pay for all real estate taxes and other assessments levied upon the Leased Premises. Lessee shall have the right to pay all taxes, assessments and other fees on behalf of Lessor and to deduct the amount so paid from other payments due to Lessor hereunder.

15. Conduct of Operations. In conducting its operations hereunder, Lessee shall use its best efforts to comply with all applicable laws, rules and regulations and ordinances pertaining thereto. Lessee reserves and shall have the right to challenge and/or appeal any law, ruling, regulation, order or other determination and to carry on its operations in accordance with Lessee's interpretation of the same, pending final determination.

16. Force Majeure. Should Lessee be prevented from complying with any express covenant of this Lease, from utilizing the Lease Premises for underground storage purposes by reason of scarcity of or an inability to obtain or to use equipment or material or failure or breakdown of equipment, or by operation of force majeure, any federal or state law or any order, rule or regulation of governmental authority, then while so prevented, Lessee's obligation to comply with such covenant shall be suspended and this Lease shall be extended while and so long as Lessee is prevented by any such cause from utilizing the property for underground storage purposes and the time while Lessee is so prevented shall not be counted against Lessee, anything in this Lease to the contrary notwithstanding.

17. Warranty of Title. Lessor represents and warrants to Lessee that Lessor is the owner of the surface of the Leased Premises and the pore space located thereunder. Lessor hereby warrants and agrees to defend title to the Leased Premises and the pore space located thereunder and Lessor hereby agrees that Lessee, at its option, shall have the right to discharge any tax, mortgage, or other lien upon the Leased Premises, and in the event Lessee does so, Lessee shall be subrogated to such

lien with the right to enforce the same and apply royalty payments or any other payments due to Lessor toward satisfying the same.

18. Quiet Enjoyment. Lessor shall have the quiet use and enjoyment of the Leased Premises in accordance with the terms of this Lease. Lessor's activities and any grant of rights Lessor makes to any person or entity, whether located on the Leased Premises or elsewhere, shall not interfere with the rights granted to Lessee hereunder.

19. Environmental Incentives and Tax Credits. Lessee shall be the owner of (i) any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to Lessee's geologic storage operations, including any avoided emissions and the reporting rights related to these avoided emissions, such as 26 U.S.C. § 45Q Tax Credits, and any other attributes of Lessee's ownership of the Facilities and Lessee's geologic storage operations ("Environmental Attributes"), and (ii) any and all credits, rebates, subsidies, payments or other incentives that relate to the use of technology incorporated into Lessee's geologic storage operations, environmental benefits of such operations, or other similar programs available from any regulated entity or any governmental authority ("Environmental Incentives"). Lessee is further entitled to the benefit of any and all (a) investment tax credits, (b) production tax credits, (c) credits under 26 U.S.C. § 45Q credits, and (d) similar tax credits or grants under federal, state or local law relating to Lessee's geologic storage operations ("Tax Credits"). Lessor shall (i) cooperate with Lessee in obtaining, securing and transferring all Environmental Attributes and Environmental Incentives and the benefit of all Tax Credits, and (ii) shall allow Lessee to take any actions necessary to install additional equipment on the Facilities to comply with all monitoring and reporting obligations, and allow Lessee's personnel to enter the premises and collect any data Lessee requires to satisfy its obligations required in connection with obtaining Tax Credits and Environmental Attributes. Lessor shall not be obligated to incur any out-of-pocket costs or expenses in connection with such actions unless reimbursed by Lessee. If any Environmental Incentives are paid directly to Lessor, Lessor shall immediately pay such amounts over to Lessee.

20. Financing. Lessor acknowledges and agrees that Lessee may, at Lessee's own expense, seek equity or debt financing or refinancing in connection with Lessee's geologic storage operations, including any construction financing, whether on a project basis or a portfolio basis ("Financing"). In order to facilitate the Financing, Lessor agrees, at Lessee's expense, to cooperate and to execute all documents including, if applicable, any title policy affidavits reasonably necessary to obtain the Financing, provided that the foregoing shall not require Lessor to execute any documents that (a) result in Lessor incurring liabilities or obligations not contemplated in this Lease, or (b) encumber Lessor's fee interest in the Leased Premises, except to the extent any such interest is covered by this Lease. Lessor agrees that Lessor shall execute and deliver to Lessee any documents reasonably required by a financing party within five (5) business days after presentation of said documents by Lessee. Lessee shall have the absolute right in its sole and exclusive discretion, without obtaining the consent of Lessor, to mortgage, encumber, hypothecate, pledge, transfer, assign, or collateral assign, to one or more financing parties any or all of the rights granted to Lessee hereunder and/or any or all right or interest of Lessee in the Leased Premises or in any or all of the Facilities.

21. Assignment. The rights of either Party hereto may be assigned in whole or part. The assigning party shall provide written notice of any assignment within sixty (60) days after such assignment has become effective; *provided, however,* that an assigning party's failure to deliver written notice

of assignment within such 60-day period shall not be deemed a breach of this Lease unless such failure is willful and intentional. The Lessor's consent shall not be required for an assignment by the Lessee of this Lease, whether by way of a collateral assignment to its financiers or otherwise.

22. Change of Ownership. Lessee understands that this Lease runs with the land and transfers to any new owner of the surface acres. No change of ownership in the Leased Premises or assignment of Lessor's rights hereunder shall be binding on the Lessee for purpose of making payments to Lessor hereunder until the date Lessor, or Lessor's successors or assigns, furnishes Lessee the recorded original or a certified copy of the instrument evidencing the change in ownership or assignment.

23. Notices. All notices required to be given under this Lease shall be in writing and addressed to the respective Party at the addresses set forth at the beginning of this Lease unless otherwise directed by either Party.

24. No Waiver. The failure of either Party to insist in any one or more instances upon strict performance of any of the provisions of this Lease or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provision or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

25. Notice of Lease. This Lease shall not be recorded in the real property records. Lessee shall cause a memorandum of this Lease to be recorded in the real property records of the county or counties in which any portion of the Leased Premises are situated. A recorded copy of said memorandum shall be furnished to Lessor within thirty (30) days of recording.

26. Confidentiality. Lessor shall maintain in the strictest confidence, for the benefit of Lessee, all information pertaining to the compensation paid under this Lease, any information regarding Lessee and its business or operations on the Leased Premises or on any other lands, the capacity and suitability of any Reservoir or Amalgamated Reservoir, and any other information that is deemed proprietary or that Lessee requests or identifies to be held confidential, in each such case whether disclosed by Lessee or discovered by Lessor.

27. Counterparts. This Lease may be executed in any number of counterparts, each of which, when executed and delivered, shall be an original, but all of which shall collectively constitute one and the same instrument.

28. Severability. If any provision of this Lease is found to be invalid, illegal or unenforceable in any respect, such provision shall be deemed to be severed from this Agreement, and the validity, legality and enforceability of the remaining provisions contained herein shall not in any way be affected or impaired thereby.

29. Governing Law. This Lease shall be governed by, construed and enforced in accordance with the laws of the State of North Dakota and the Parties hereby submit to the jurisdiction of the state or federal courts located in the State of North Dakota.

30. Further Assurances. Each Party will execute and deliver all documents, provide all information, and take or forbear from all actions as may be necessary or appropriate to achieve the purposes of this Lease, including without limitation executing a memorandum of this Lease and all documents required to obtain any necessary government approvals.

31. Entire Agreement. This Lease constitutes the entire agreement between the Parties and supersedes all prior negotiations, undertakings, notices, memoranda and agreement between the Parties, whether oral or written, with respect to the subject matter hereof. This Lease may only be amended or modified by a written agreement duly executed by Lessor and Lessee.

32. Electronic Signatures. This Lease, and any amendments hereto, to the extent signed and delivered by means of electronic transmission in portable document format (pdf) or by DocuSign or similar electronic signature process, shall be treated in all manner and respects as an original contract and shall be considered to have the same binding legal effect as if it were the original signed version thereof delivered in person.

IN WITNESS WHEREOF, the Parties have executed this Lease effective for all purposes as of the Effective Date.

LESSOR:

By: ______________________________

Print: ______________________________

By: ______________________________

Print: ______________________________

Effective Date:__________________

LESSEE:

Dakota Gasification Company

By: ______________________________

Print: ______________________________

Its: ______________________________

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2.0 GEOLOGIC EXHIBITS

2.0 GEOLOGIC EXHIBITS

2.1 Overview of Project Area Geology

The proposed DGC Great Plains CO_2 Sequestration Project will be situated near Beulah, North Dakota (Figure 2-1). This project site is on the central portion of the Williston Basin. The Williston Basin is an intracratonic sedimentary basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota.

Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted via the PCOR Partnership, the Williston Basin has been identified as an excellent candidate for long-term CO_2 storage because of, in part, the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structure character and tectonic stability (Peck and others, 2014; Glazewski and others, 2015).

The target CO_2 storage reservoir for the Great Plains CO_2 Sequestration Project is the Broom Creek Formation, a predominantly sandstone horizon lying about 5,900 ft below DGC's Great Plains Synfuels Plant (Figure 2-2). Mudstones, siltstones, and interbedded evaporites of the Opeche Formation unconformably overly the Broom Creek and serve as the primary confining zone (Figure 2-3). The Amsden Formation (dolostone, limestone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-3). Together, the Opeche, Broom Creek, and Amsden comprise the CO_2 storage complex for the Great Plains CO_2 Sequestration Project (Table 2-1).

Including the Opeche Formation, there is ~1,100 ft of impermeable formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation. An additional ~2,700 ft of impermeable intervals separates the Inyan Kara and the lowest USDW, the Fox Hills Formation (Figure 2-3).

2.2 Data and Information Sources

Several sets of data were used to characterize the injection and confining zones to establish their suitability for the storage and containment of injected CO_2. Data sets used for characterization included both existing data (sources and uses are discussed within Section 2.2) and site-specific data acquired by the applicant specifically to characterize the storage complex.

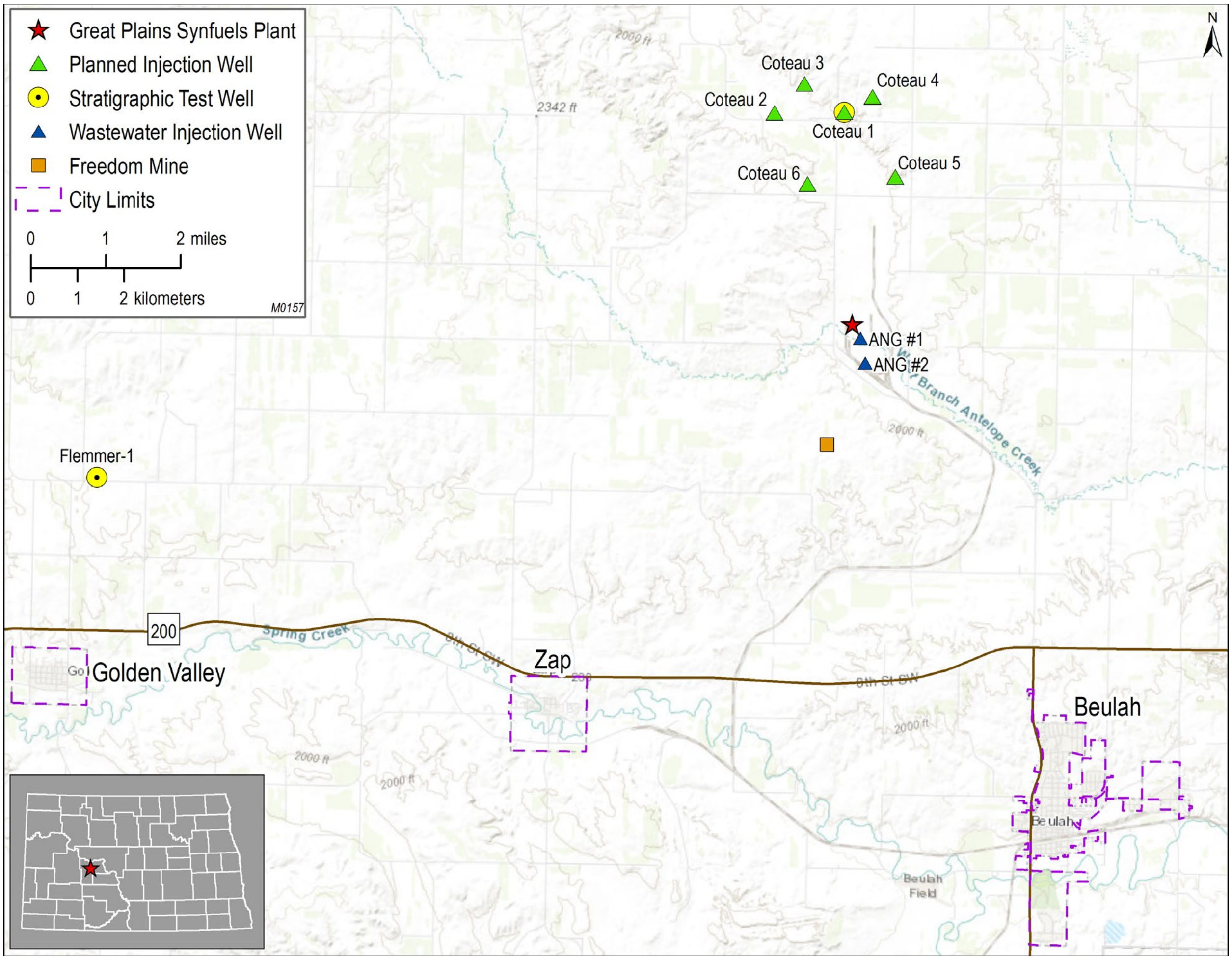


Figure 2-1. Topographic map of the Great Plains CO_2 Sequestration Project area showing well locations and the Great Plains Synfuels Plant.

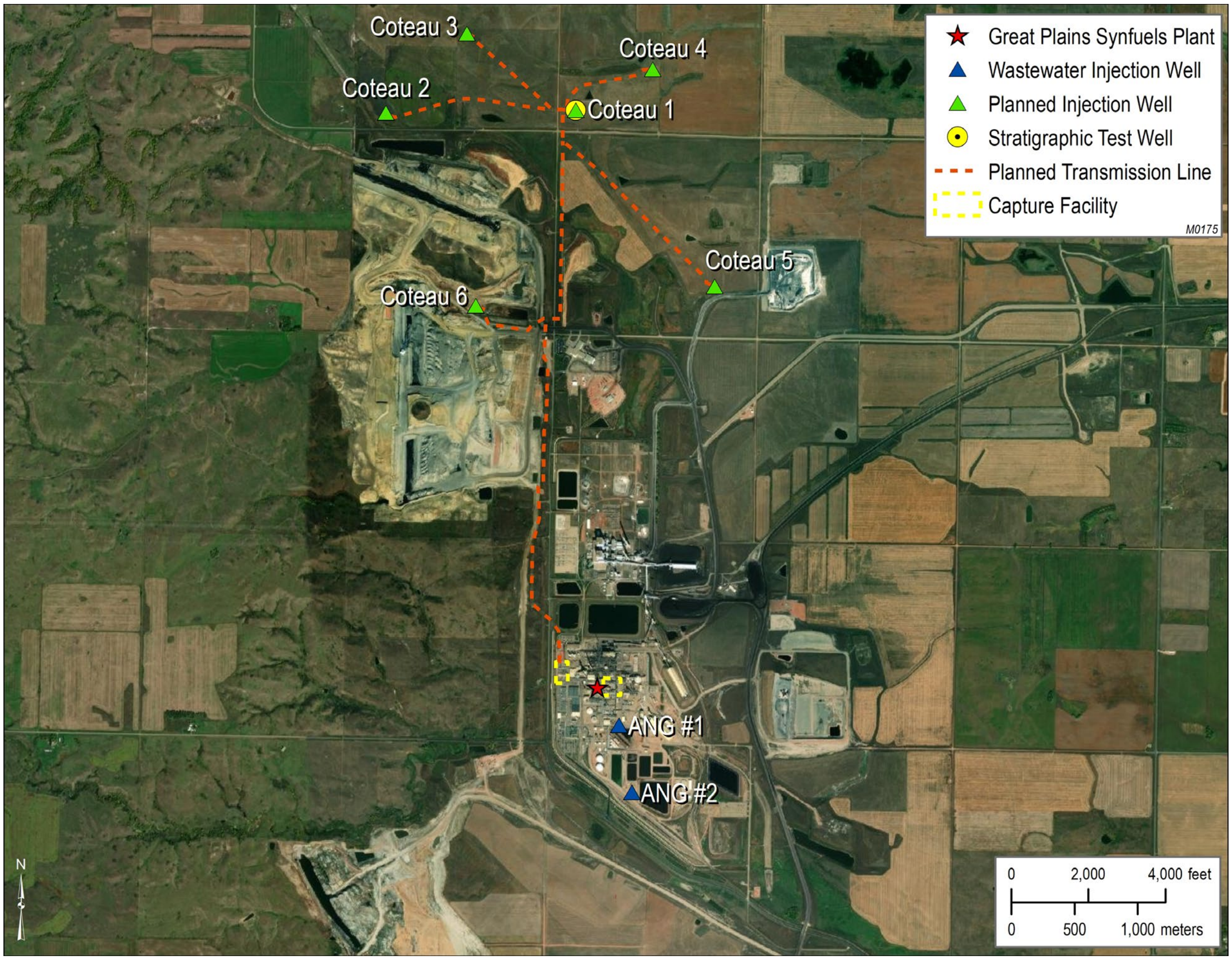


Figure 2-2. Map of the proposed CO_2 injection wells.

2.2.1 Existing Data

The existing data used to characterize the geology beneath the Great Plains CO_2 Sequestration Project site included publicly available well logs and formation top depths acquired from the NDIC online database. Well log data and interpreted formation top depths were acquired for 120 wellbores within a 5,472-mi^2 (72 × 76-mi) area centered on the proposed storage site (Figure 2-4). Well data were used to characterize the depth, thickness, and extent of the subsurface geologic formations.

Existing laboratory measurements from Broom Creek Formation core samples were available from five wells shown in Figure 2-5: Coteau 1 (NDIC File No. 38379), Flemmer 1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), J-LOC1 (NDIC File No. 37380), J-ROC1 (NDIC File No. 37672), and ANG #1 (North Dakota Department of Environmental Quality [NDEQ] No. 11308). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and integrated with newly acquired site-specific data.

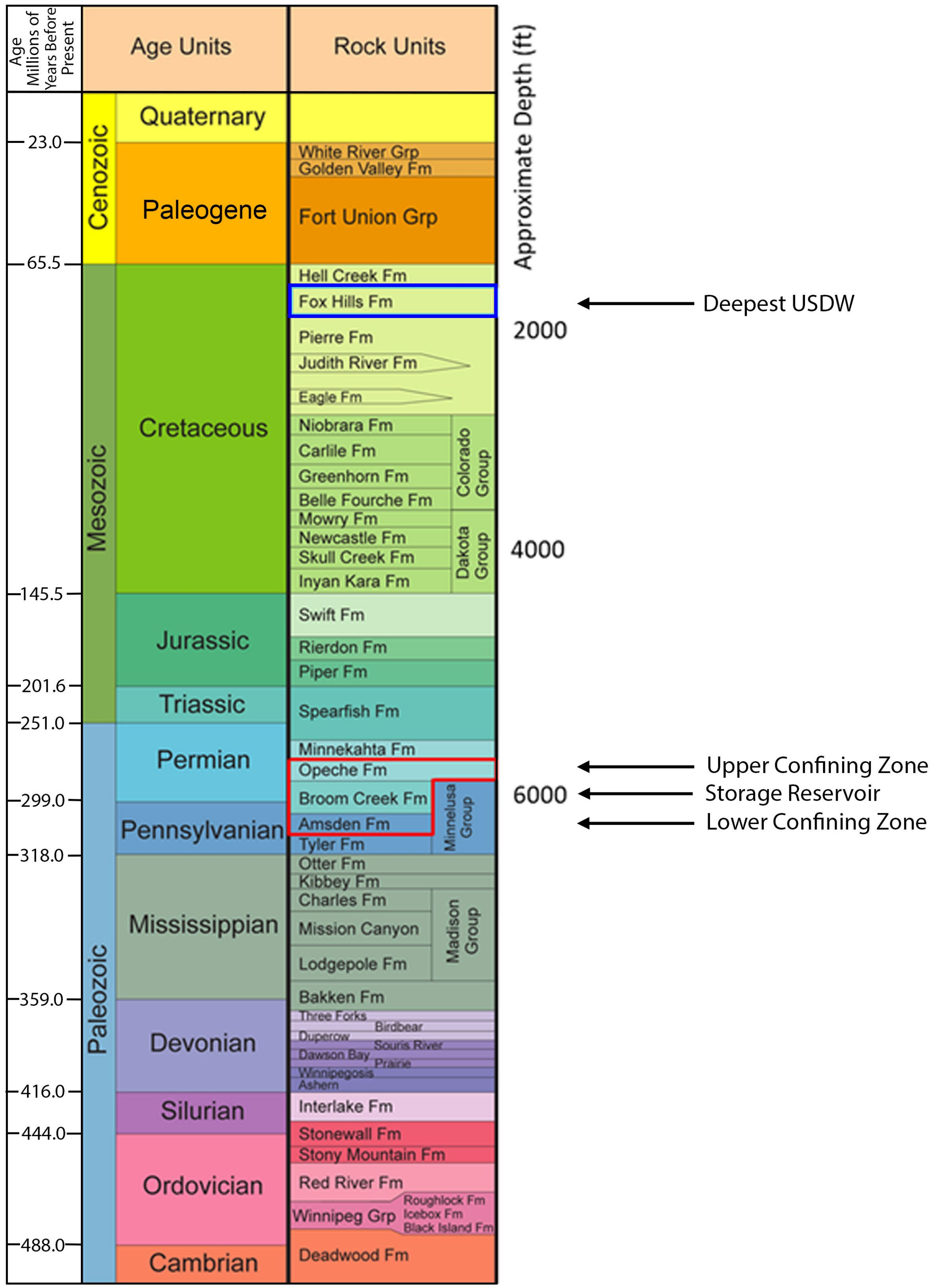


Figure 2-3. Stratigraphic column identifying the storage reservoir, confining zones, and lowest USDW addressed in this permit application for the Great Plains CO_2 Sequestration Project.

Table 2-1. Formations Comprising the Great Plains CO_2 Sequestration Project Storage Complex (average values calculated from the simulation model and well log data)

	Formation	Purpose	Average Thickness, ft	Average Measured Depth (MD), ft	Lithology
Storage Complex	Opeche	Upper confining zone	150	4,887	Mudstone, siltstone, evaporites
	Broom Creek	Storage reservoir (i.e., injection zone)	248	5,348	Sandstone, dolostone, dolomitic sandstone, anhydrite
	Amsden	Lower confining zone	268	5,558	Dolostone, limestone, anhydrite

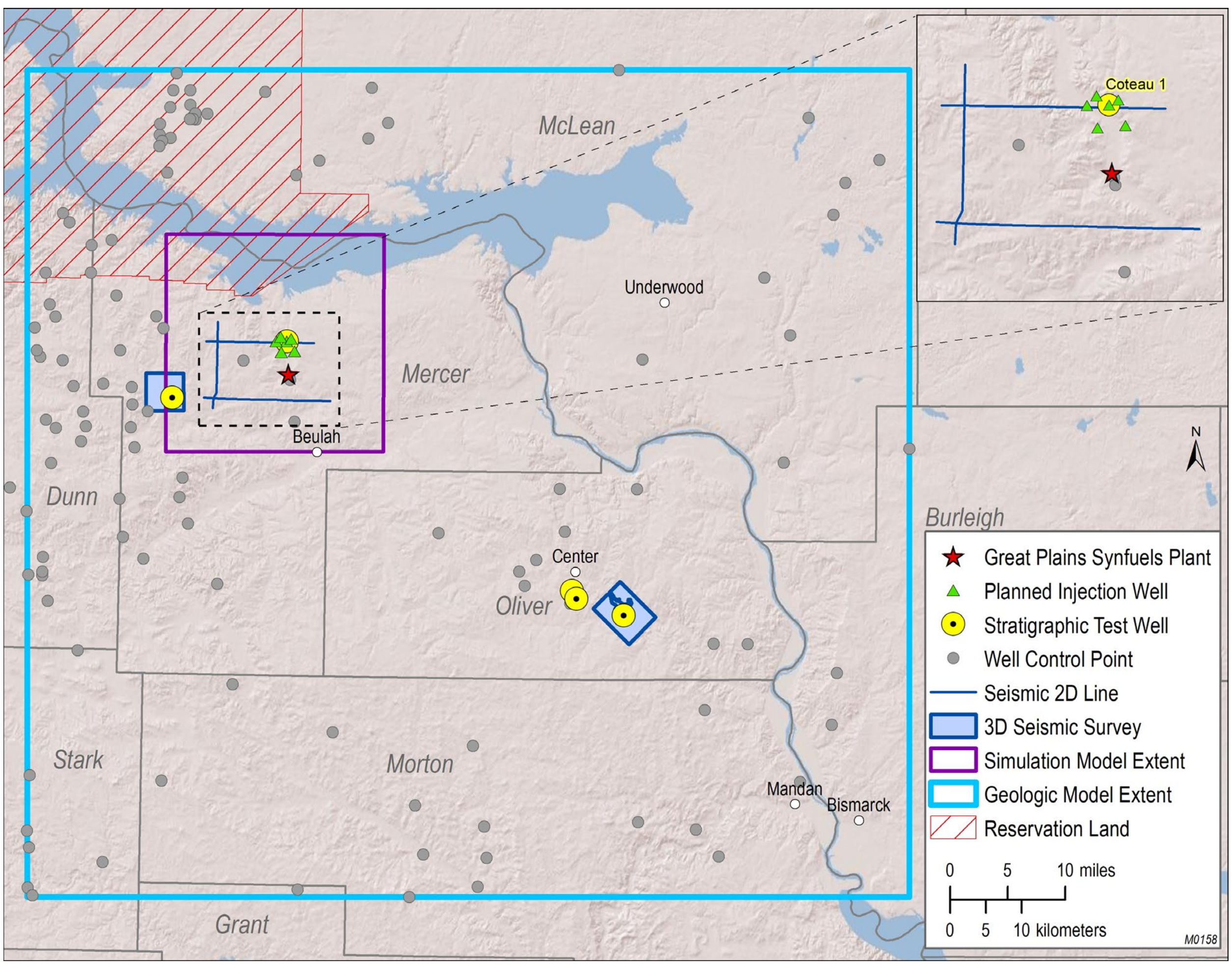


Figure 2-4. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones.

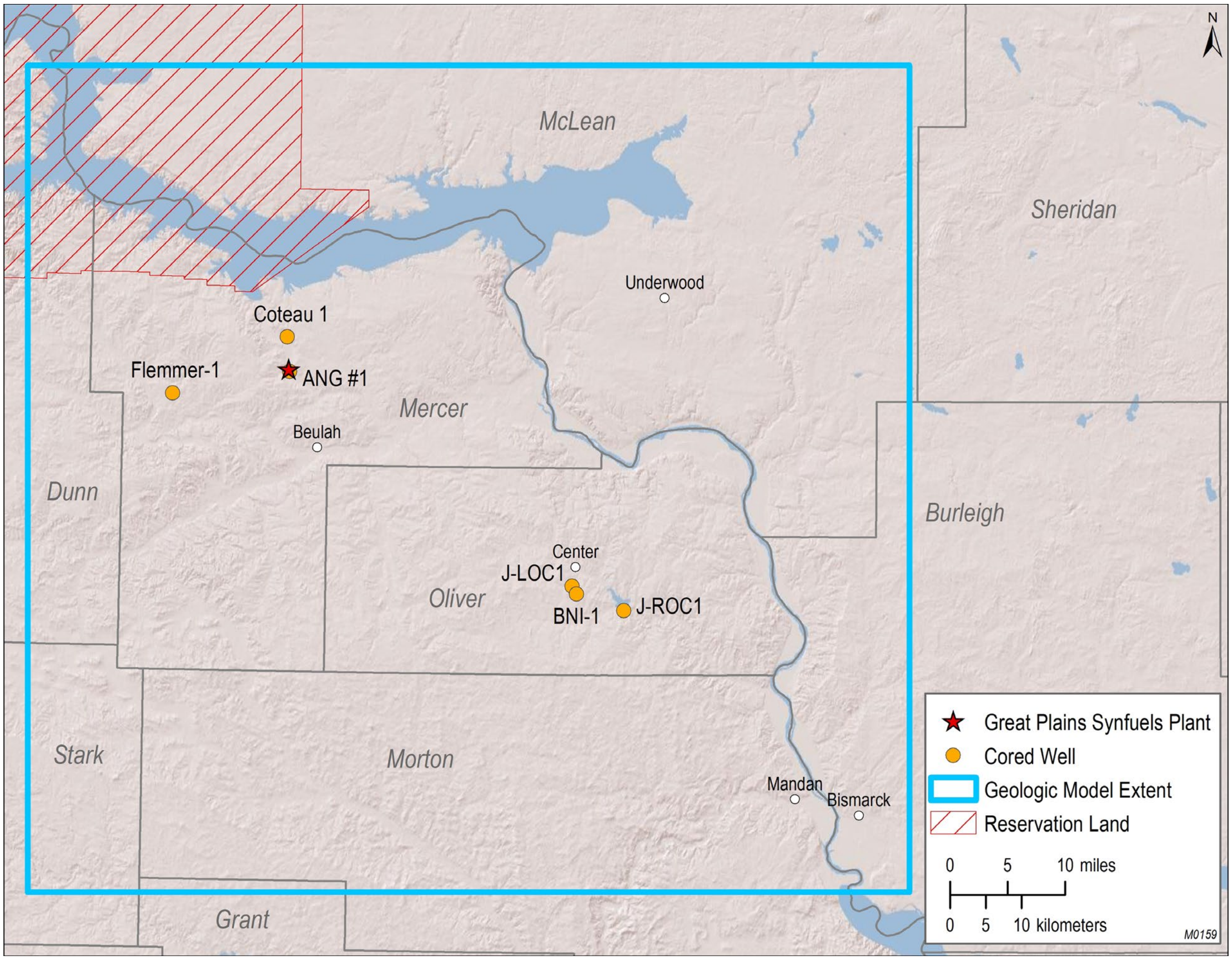


Figure 2-5. Map showing the spatial relationship between the Great Plains CO_2 Sequestration Project area and wells where the Broom Creek Formation core samples were collected. Wells with core data include the Coteau 1 (NDIC File No. 38379), Flemmer 1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), ANG #1 (NDEQ No. 11308), J-LOC1 (NDIC File No. 37380), and J-ROC1 (NDIC File No. 37672).

Ten square miles of legacy 3D seismic data from Mercer County, encompassing the Flemmer 1 wellsite, and twenty-eight miles of legacy 2D seismic data were licensed and examined to understand the heterogeneity and geologic structure of the Broom Creek Formation interval. Additionally, publicly available seismic interpretation products for the Broom Creek from a 3D seismic survey in Oliver County were used to inform structure and variogram distributions (Section 3.2). The structural configurations of the formations of interest generated from the interpretation of the two 3D seismic data sets along with formation tops interpreted from well log data were used to construct the geologic model. Variogram distributions derived from inversion volumes generated using the 3D seismic data were used to inform property distribution in the geologic model which was, in turn, used to simulate migration of the CO_2 plume (Section 3). These simulated CO_2 plumes were used to inform the testing and monitoring plan (Section 5).

2.2.2 *Site-Specific Data*

Site-specific efforts to characterize the proposed Broom Creek storage complex generated multiple data sets, including geophysical well logs, fluid analyses, and 2D seismic data. The Flemmer 1 well was drilled in 2017 to a depth of 6,790 ft in the Amsden Formation. The ANG #1 well was drilled in 1982 to a depth of 6,784 ft in the Amsden Formation. In 2021, the Coteau 1 well was drilled specifically to gather subsurface geologic data to support the development of a CO_2 storage facility permit. The Coteau 1 well was drilled to a depth of 6,484 ft. The downhole sampling and measurement program focused on the proposed storage complex (i.e., the Opeche, Broom Creek, and Amsden Formations) (Figure 2-6).

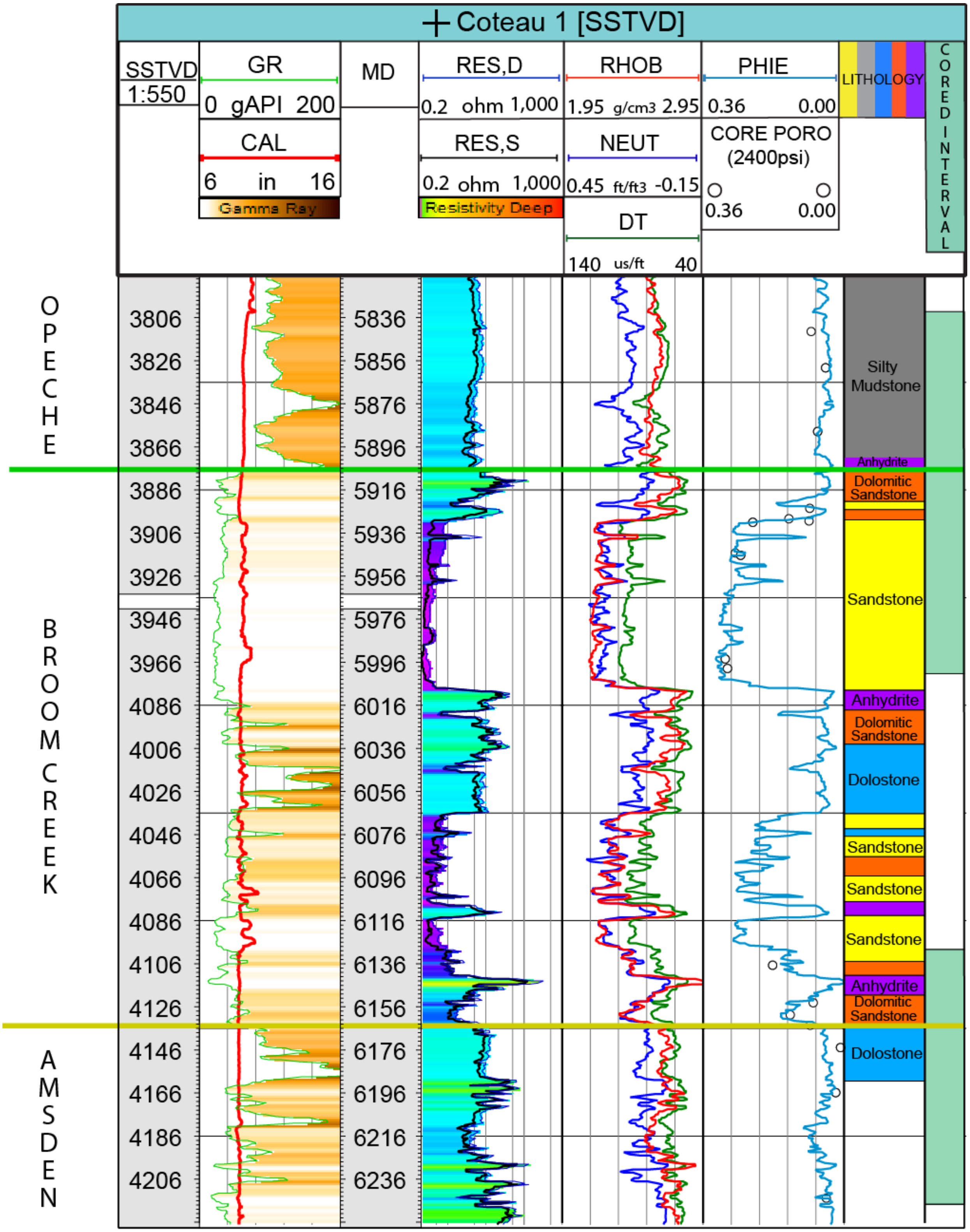


Figure 2-6. Schematic showing vertical relationship of coring (rightmost track) and core plug porosity (third track from right) intervals in the Opeche, Broom Creek, and Amsden Formations in the Coteau 1 well.

Site-specific data were used to assess the suitability of the storage complex for safe and permanent storage of CO_2. Site-specific data were also used as inputs for geologic model construction (Section 3.2), numerical simulations of CO_2 injection (Section 3.3.1), geochemical simulation (Sections 2.3.3, 2.4.1.2, and 2.4.3.2), and geomechanical analysis (Section 2.4.4). The site-specific data improved the understanding of the subsurface and directly informed the selection of monitoring technologies, development of the timing and frequency of collecting monitoring data, and interpretation of monitoring data with respect to potential subsurface risks. Furthermore, these data guided and influenced the design and operation of site equipment and infrastructure.

2.2.2.1 Geophysical Well Logs

Openhole wireline geophysical well logs were acquired in the Coteau 1 well along the entire open section of the wellbore. The logging suite included caliper, gamma ray (GR), density, porosity, dipole sonic, resistivity, combinable magnetic resonance (CMR) log, spectral GR, and fracture finder or image log. A similar logging suite was acquired from the Flemmer 1 well. The suite included caliper, GR, density, porosity, dipole sonic, spectroscopy, and spectral GR.

The acquired well logs were used to pick formation top depths, interpret lithology and petrophysical properties, and create synthetic seismic traces for tying depth to time. Formation top depths were picked from the top of the Pierre Formation to the top of the Amsden Formation. The site-specific formation top depths were added to the existing data of 120 wellbores within the 5472-mi^2 area covered by the model to understand the geologic extent, depth, and thickness of the subsurface geologic strata. The formation top depths were interpolated to create structural surfaces which served as inputs for geologic model construction.

2.2.2.2 Core Sample Analyses

Core (283 ft) was collected from the Broom Creek storage complex in the Coteau 1 well. This core was analyzed to characterize the lithologies of the Broom Creek, Opeche, and Amsden Formations and correlated to the well log data. Core analysis also included porosity and permeability measurements, x-ray diffraction (XRD), x-ray fluorescence (XRF), relative permeability testing, thin-section analysis, capillary entry pressure measurements, and triaxial geomechanics testing. The results were used to inform geologic modeling, predictive simulation inputs and assumptions, geochemical modeling, and geomechanical modeling.

2.2.2.3 Formation Temperature and Pressure

Temperature data recorded from logging the Coteau 1 and Flemmer 1 wellbores were used to derive a temperature gradient for the proposed injection site (Tables 2-2 and 2-3). In combination with depth, the temperature gradient was used to distribute a temperature property throughout the geologic model of the Great Plains CO_2 Sequestration Project area. The temperature property was used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for the geochemical modeling.

The formation pressure and temperature at Coteau 1 were collected with a bottomhole pressure (BHP) gauge. In the Coteau 1 well, the Broom Creek was perforated at 5975 ft (1 foot, 4 shots per foot). After perforating, the BHP gauge was run to the perforation depth where temperature and pressure measurements were collected (Appendix C, "Pressure Survey Report"). The pressure data recorded in the Coteau 1 well are shown in Table 2-4.

Table 2-2. Description of Coteau 1 Temperature Measurements and Calculated Temperature Gradients

Formation	Test Depth, ft	Temperature, °F
Broom Creek	5,975	151.85
Broom Creek Temperature Gradient, °F/ft	0.02*	

* The temperature gradient is the BHP measured temperature minus the average annual surface temperature of 40°F, divided by the associated test depth.

Table 2-3. Description of Flemmer 1 Temperature Measurements and Calculated Temperature Gradients

Formation	Test Depth, ft	Temperature, °F
Opeche/Spearfish	6,260	151.43
	6,261	151.83
Broom Creek	6,306	150.76
	6,308	149.46
	6,358	150.35
	6,367	149.31
	6,372	149.83
	6,402	149.87
	6,403	149.78
	6,426	149.24
	6,453	149.23
	6,454	149.36
	6,455	149.68
Mean Broom Creek Temp., °F	149.72	
Broom Creek Temperature Gradient, °F/ft	0.02*	

* The temperature gradient is an average of the MDT modular formation dynamics tester tool measured temperatures minus the average annual surface temperature of 40°F, divided by the associated test depth.

Flemmer 1 formation pressure and temperature measurements were performed with the Schlumberger MDT tool. The MDT tool is a wireline-conveyed tool assembly incorporated with a dual-packer module to isolate intervals, a large-diameter probe for formation pressure and temperature measurements, a pump-out module to pump unwanted mud filtrate, a flow control module, and sample chambers for formation fluid collection. The MDT tool formation pressure measurements from the Broom Creek Formation in the Flemmer 1 well are included in Table 2-5. The calculated pressure gradients from the Flemmer 1 and Coteau 1 wells were used to model formation pressure profiles for use in the numerical simulations of CO_2 injection.

Table 2-4. Description of Coteau 1 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Test Depth, ft	Formation Pressure, psi
Broom Creek	5,975	2,937.09
Broom Creek Pressure Gradient, psi/ft	0.49*	

* The pressure gradient is the BHP measured pressure minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.

Table 2-5. Description of Flemmer 1 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Test Depth, ft	Formation Pressure, psi
Broom Creek	6,306	3,093.67
Broom Creek	6,308	3,094.53
Broom Creek	6,367	3,125.21
Broom Creek	6,372	3,127.00
Broom Creek	6,454	3,168.26
Broom Creek	6,455	3,167.00
Mean Broom Creek Pressure, psi	3,129.28	
Broom Creek Pressure Gradient, psi/ft	0.49*	

* The pressure gradient is an average of the MDT tool measured pressures minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.

2.2.2.4 Microfracture In Situ Stress Tests

Microfracture in situ stress tests were not performed in the Coteau 1 well. The in situ stresses for Coteau 1 were estimated using a 1D Mechanical Earth Model (1D MEM) that was generated using laboratory-derived core data and well log data from the Coteau 1 well. Discussion of the 1D MEM can be found in Sections 2.3 and 2.4.4.4. The Flemmer 1 microfracture in situ stress test results can be found in Sections 2.3 and 2.4.

2.2.2.5 Fluid Samples

A fluid sample from the Broom Creek Formation was collected from the Coteau 1 wellbore by perforating 1 foot at 5,975 ft and then swabbing the well until formation fluid flowed back to surface for collection. Results were analyzed by Minnesota Valley Testing Laboratories (MVTL), a state-certified lab. The results from the Coteau 1 sample are shown in Table 2-6. Fluid sample analysis results were used as inputs for geochemical modeling and dynamic reservoir simulations. Fluid sample analysis reports can be found in Appendix A.

Table 2-6. Description of Fluid Sample Test and Corresponding Total Dissolved Solids (TDS) Value

Formation	Well	Test Depth, ft	MVTL TDS, mg/L	EERC Lab TDS, mg/L
Broom Creek	Coteau 1	5,976	42,800	NA

2.2.2.6 Seismic Survey

The proximity of the site to an active coal mine and industrial facilities makes acquisition of 3D seismic data problematic. Placement of seismic source and receiver locations required for a 3D seismic survey would be restricted because of these surface uses potentially resulting in insufficient data quality to image the subsurface for characterization and monitoring purposes. Interpretation of 2D seismic data provides a practical alternative to acquiring and interpreting 3D seismic data. 2D seismic surveys can be used to evaluate the subsurface across large tracts of land, can be oriented to avoid surface obstacles such as those found at this site, can be acquired more frequently for future site monitoring, and eliminates the need to overshoot areas that have already been swept with CO_2.

Twenty-eight miles of 2D seismic lines that traverse the storage facility area and intersect the Coteau 1 well were licensed and interpreted (Figure 2-4). The 2D seismic lines were tied to the Coteau 1 well and used to evaluate the thickness and structure of the Broom Creek and upper and lower confining zones within the storage facility area. The interpreted surfaces for the formations of interest derived from the 2D seismic lines were used to confirm that the geologic model is representative of the reservoir thickness and structure within the storage facility area.

The 2D seismic data suggest there are no major stratigraphic pinch-outs or structural features with associated spill points in the Great Plains CO_2 Sequestration Project area. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the lowest USDW, the Fox Hills Formation, were observed in the seismic data. Twenty-eight miles of new 2D seismic data centered around the Coteau 1 well was acquired in January 2022 and will be used to confirm these interpretations.

2.3 Storage Reservoir (Injection Zone)

Locally, the Broom Creek Formation is laterally extensive (Figure 2-7) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone, siltstones, and evaporites of the Opeche Formation (Figure 2-3).

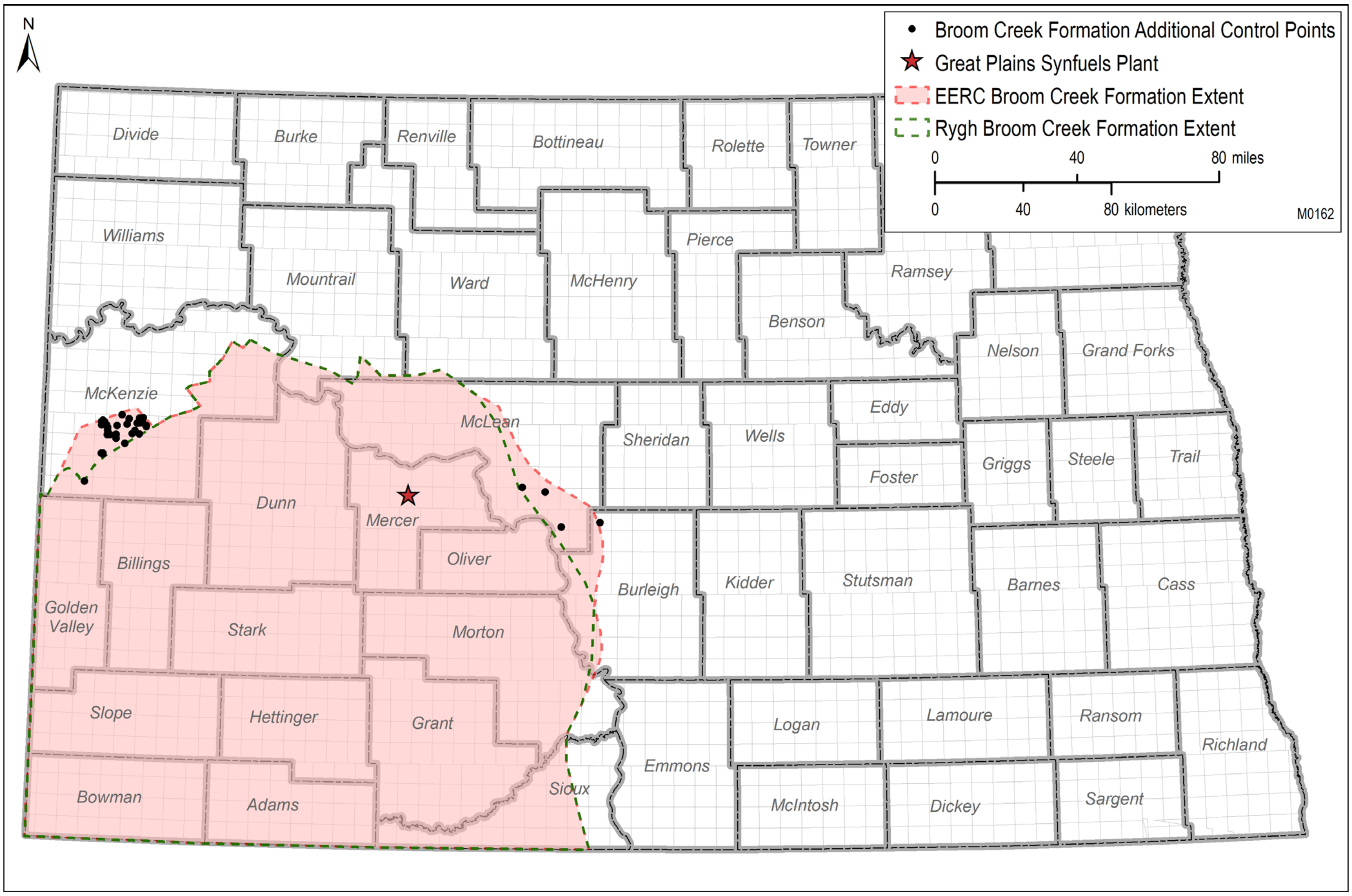


Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (modified from Rygh and others [1990]). Based on new well control shown outside of the green dashed line.

At Coteau 1, the Broom Creek Formation is 258 ft thick; is made up of 134 ft of sandstone, 35 ft of dolostone, 24 ft of anhydrite, and 65 ft of dolomitic sandstone; and is located at a depth of 5,906 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 163 to 322 ft (Figure 2-8), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 24 to 205 ft, with an average of 99 ft.

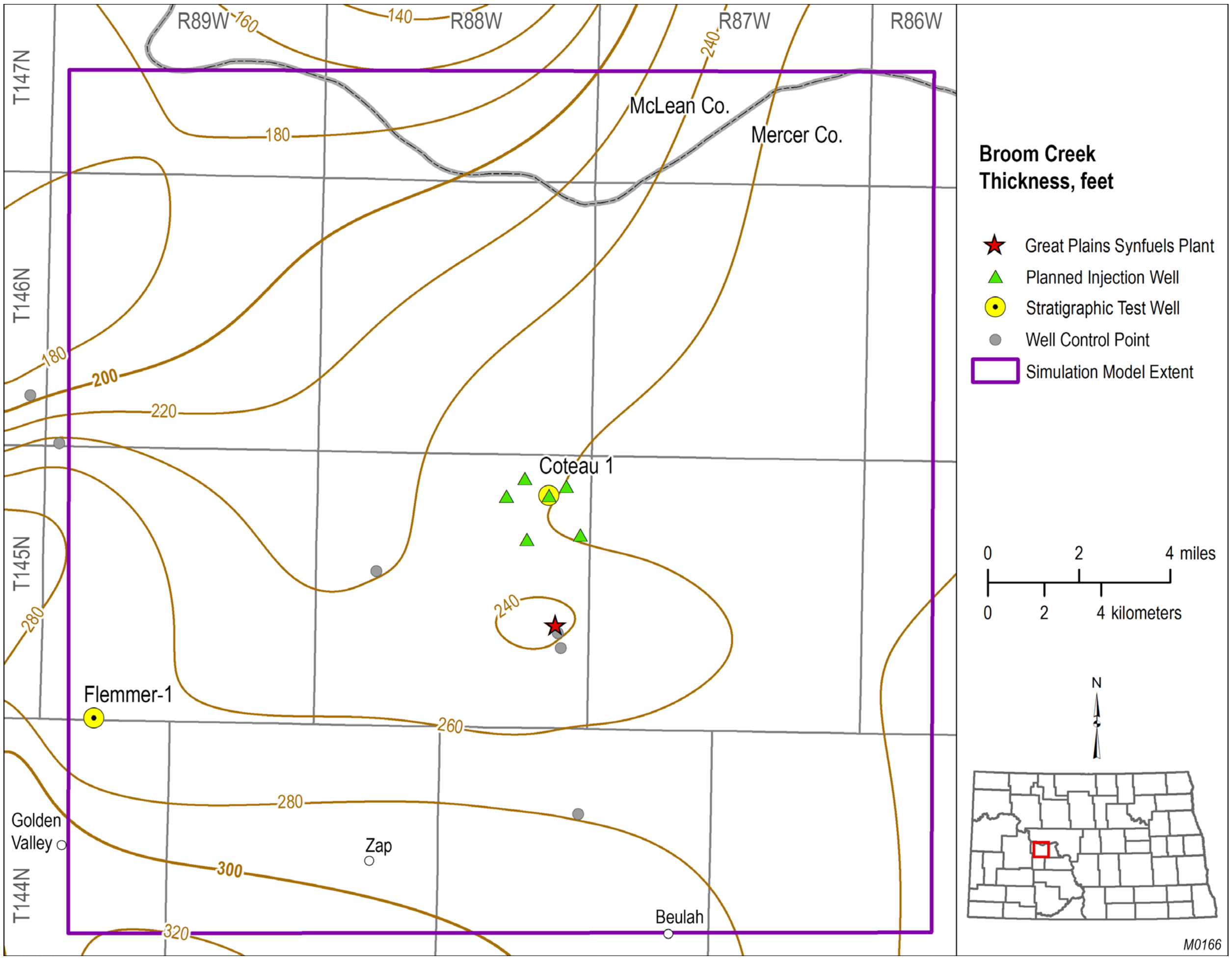


Figure 2-8. Isopach map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project area.

The top of the Broom Creek Formation was picked across the model area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-9). The top of the Amsden Formation was placed at the bottom of a relatively high GR signature representing an argillaceous dolostone that can be correlated across the entirety of the Great Plains CO_2 Sequestration Project area. 2D seismic data collected as part of site characterization efforts were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and analyses indicate that there should be few-to-no major reservoir stratigraphic discontinuities near the Coteau 1 well (Figures 2-10 and 2-11). The Broom Creek Formation is estimated to pinch out ~34 miles to the east of the Coteau 1 wellsite. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Great Plains CO_2 Sequestration Project area (Figure 2-12 and Figure 2-13).

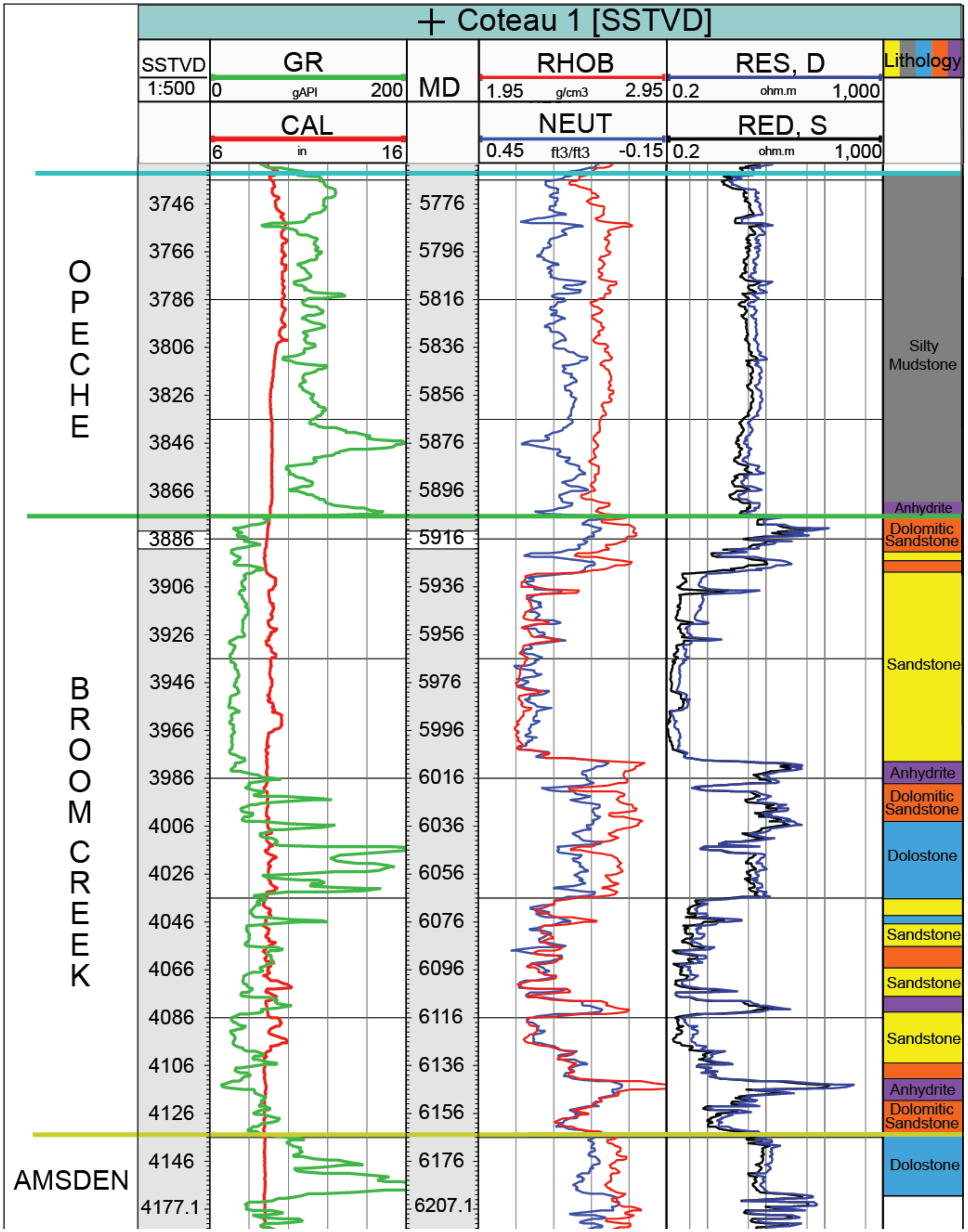


Figure 2-9. Well log display of the interpreted lithologies of the Opeche, Broom Creek, and upper Amsden Formations in the Coteau 1 well.

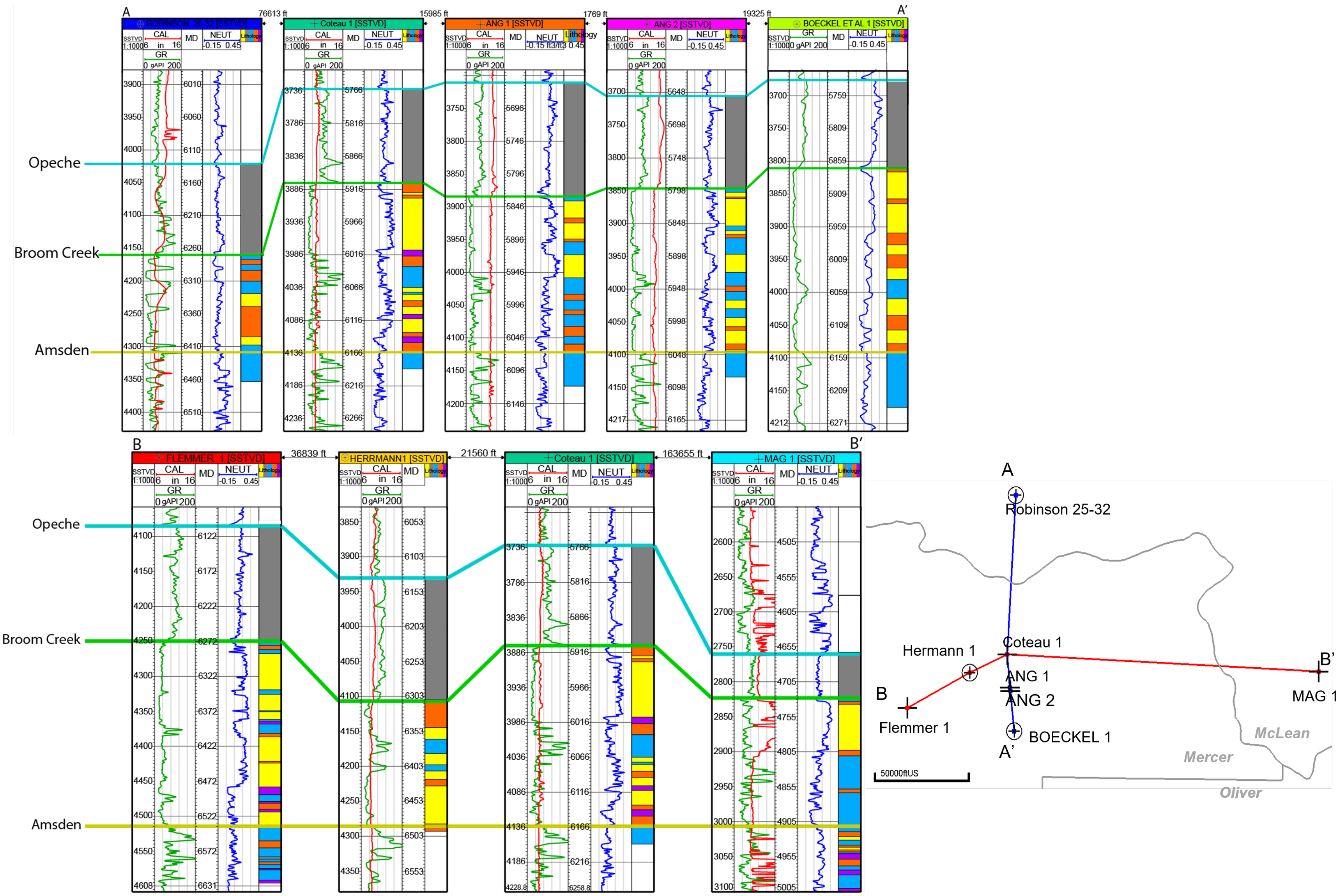


Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log.

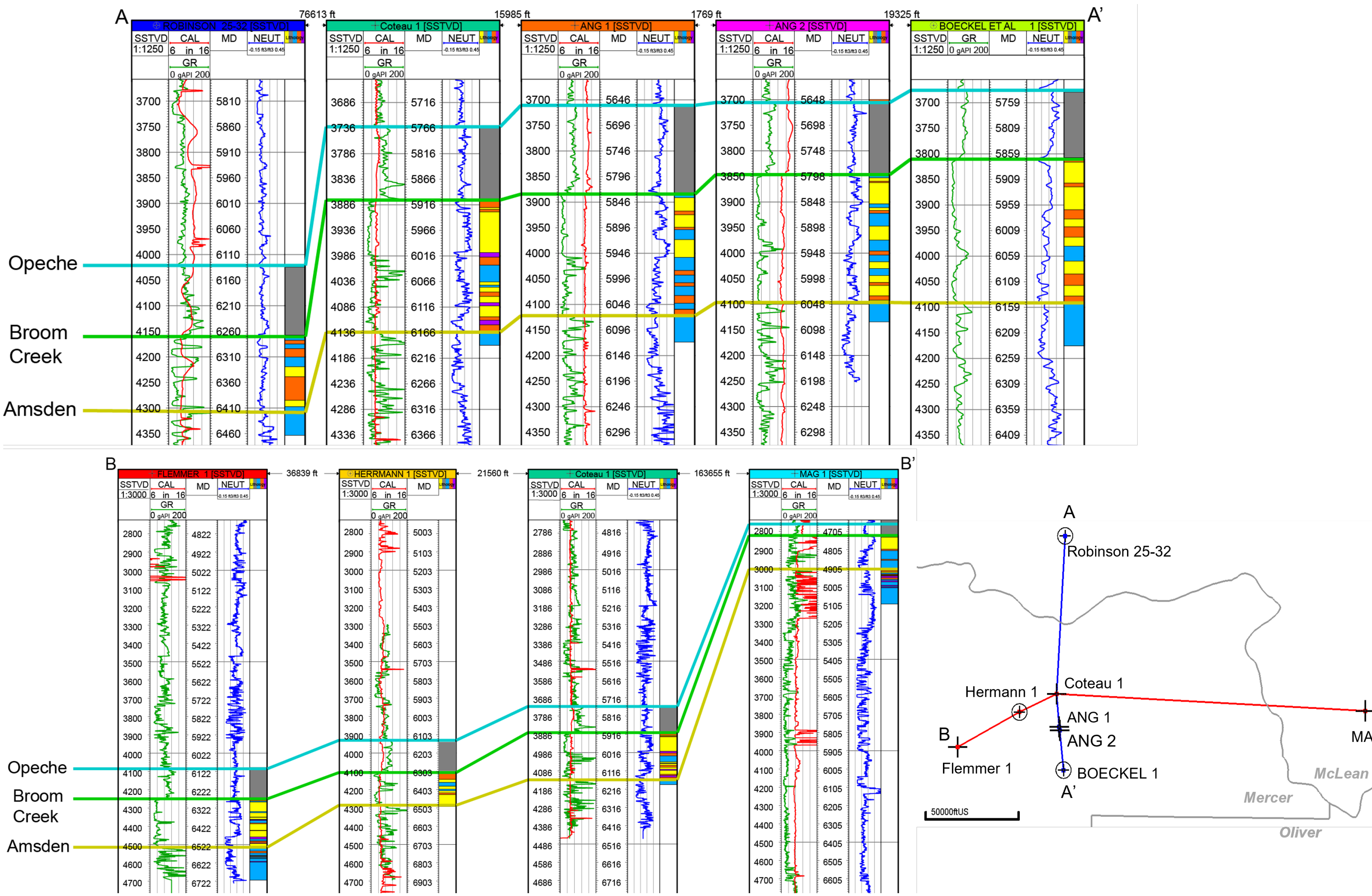


Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log.

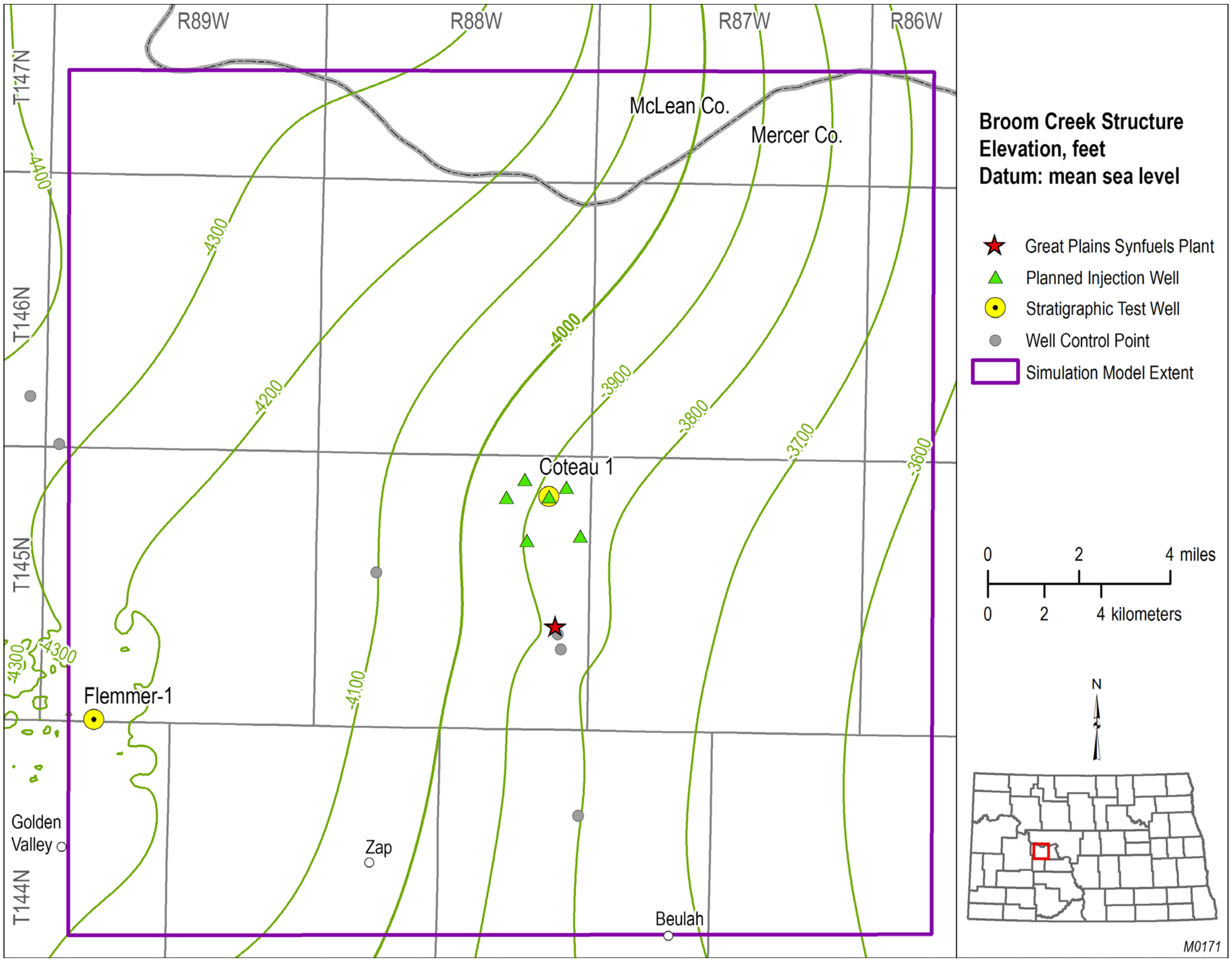


Figure 2-12. Structure map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops).

Twenty-two 1-inch-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the Coteau 1 well. From the twenty-two samples, three samples at 5,941.9', 5,969.9', and 5,994.4' were duplicated and oriented 90 degrees compared to the original core plug to investigate the possibility of any orientation-dependent permeability existing in the reservoir. The remaining nineteen core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the Coteau 1 Broom Creek Formation core samples have porosity values ranging from 1.41% to 34.39% at 800 psi and 7.88% to 30.34% at 2400 psi. Permeabilities range from 0.13 to 12,300 mD at 800 psi and 0.118 to 3,990 mD at 2,400 psi (Table 2-7). The wide range in porosity and permeability reflects the differences between the sandstone and dolostone lithofacies in the Broom Creek Formation. Portions of the Broom Creek Formation core revealed unconsolidated or poorly consolidated sandstone.

Table 2-7. Description of CO_2 Storage Reservoir (injection zone) at the Coteau 1 Well

Injection Zone Properties			
Property	**Description**		
Formation Name	Broom Creek		
Lithology	Sandstone, dolostone, dolomitic sandstone, anhydrite		
Formation Top Depth, ft	5,906		
Thickness, ft	Sandstone 134 Dolostone 35 Dolomitic sandstone 65 Anhydrite 24		
Capillary Entry Pressure (CO_2/brine), psi	0.72		
Geologic Properties			
Formation	**Property**	**Laboratory Analysis**	**Simulation Model Property Distribution**
Broom Creek (sandstone)	Porosity, %*	21.28 (7.88–30.34)	23.64 (3.65–35.77)
	Permeability, mD**	221.84 (2.92–3,990)	246.74 (0.001–3,379)
Broom Creek (dolostone)	Porosity, %	8.79 (8.66–8.94)	5.68 (0.1–25.99)
	Permeability, mD	0.180 (0.118–0.361)	0.02 (0–220)

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses.
** Permeability values are reported as the geometric mean followed by the range of values in parentheses.

Analysis of thirteen core samples from the sandstone portion of the Broom Creek Formation core from the Coteau 1 well showed porosity values ranging from 8.73% to 34.39% at 800 psi and 7.88% to 30.34% at 2,400 psi, with an average of 25.10% and 21.28% respectively. Permeability of the sandstone samples ranged from 3.22 to 9,660 mD at 800 psi and 2.92 to 3,990 mD at 2,400 psi, with a geometric average of 728.35 mD and 221.84 mD, respectively. Porosity values of dolostone samples from the Broom Creek Formation core ranged from 1.41% to 12.31% at 800 psi and 8.66% to 8.94% at 2400 psi, with an average of 6.64% and 8.79%, respectively. Dolostone permeability values ranged from 0.001 to 1.62 mD at 800 psi and 0.118 to 0.361 mD at 2,400 psi, with a geometric average of 0.109 mD and 0.180 mD, respectively (Table 2-7 and Figure 2-14).

Core-derived measurements were used as the foundation for the generation of porosity and permeability properties within the 3D geologic model. The core sample measurements showed good agreement with the wireline logs collected from the Coteau 1 well. This agreement allowed for confident extrapolation of porosity and permeability from offset well logs, thus creating a spatially and computationally larger data set to populate the geologic model. The model property distribution statistics shown in Table 2-7 are derived from a combination of the core analysis and larger data set derived from offset well logs.

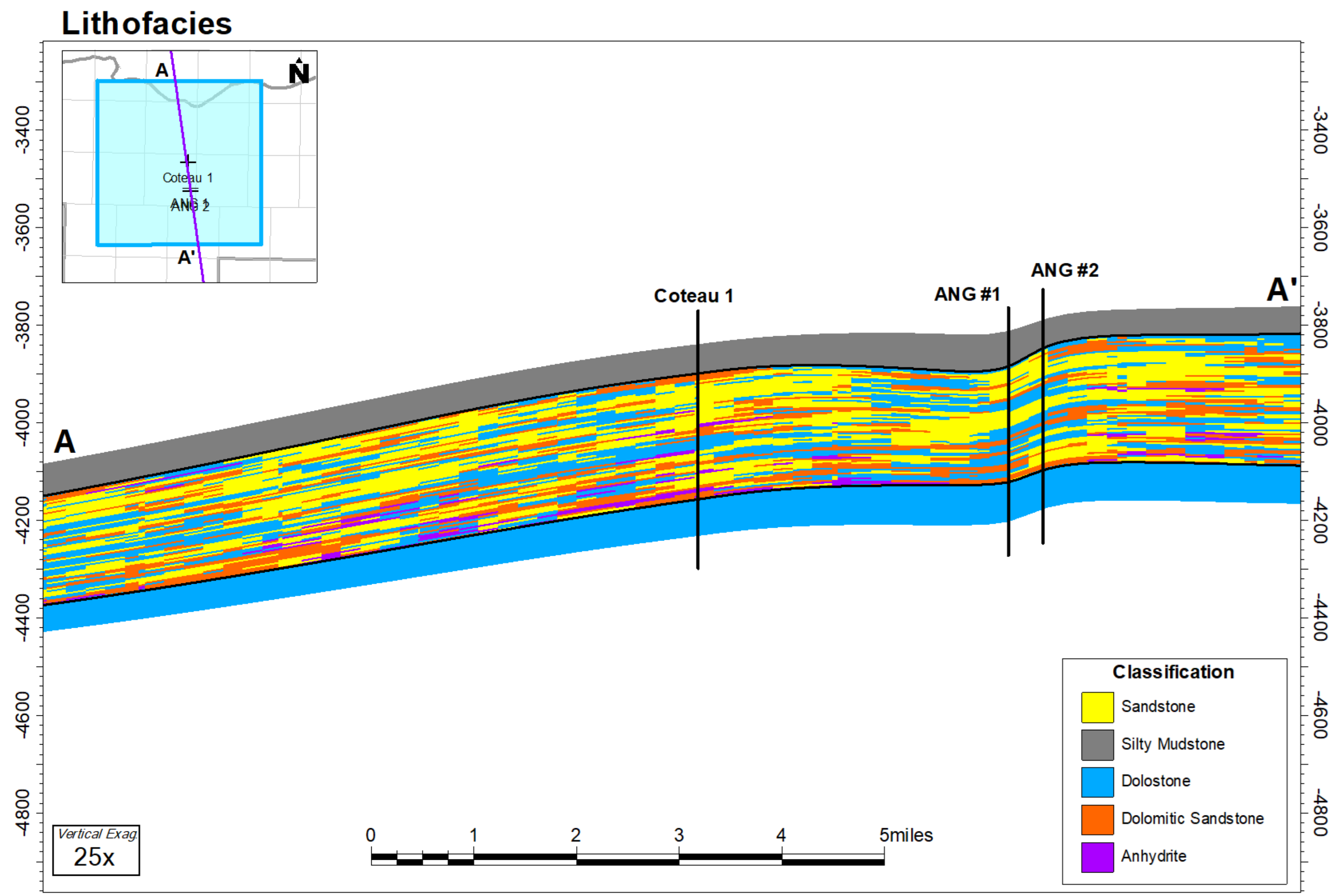


Figure 2-13. Cross section of the Great Plains CO_2 Sequestration Project storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level.

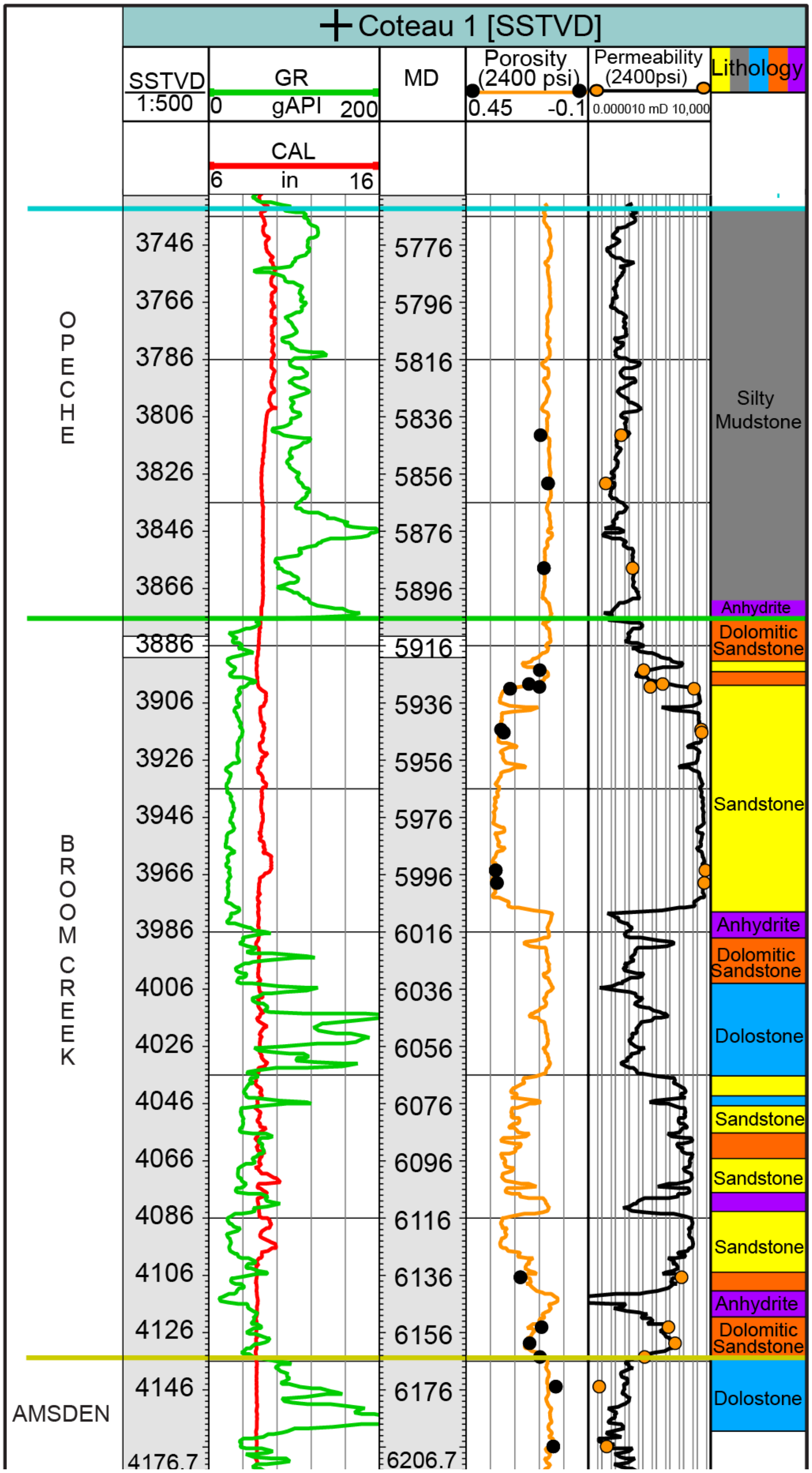


Figure 2-14. Vertical distribution of core-derived porosity and permeability values in the Great Plains CO_2 Sequestration Project storage complex.

Sandstone intervals in the Broom Creek Formation are associated with low GR, low density, high porosity (neutron, density, and sonic), low resistivity due to high porosity and brine salinity, and high sonic velocity measurements. The dolostone intervals in the formation are associated with an increase in GR measurements compared to the sandstone intervals, in addition to high density, low porosity (neutron, density, and sonic), high resistivity, and low sonic velocity measurements.

During drilling of the Coteau 1 well, the hole condition did not allow an openhole MDT microfracture in situ stress test to determine the formation breakdown pressure, fracture closure pressure, fracture propagation pressure, and minimum horizontal stress to be performed. To overcome this lack of data, a 1D MEM for Opeche, Broom Creek, and Amsden Formations was generated using laboratory-derived core data and well log data from the Coteau 1 well. A discussion of how the 1D MEM was generated can be found in Section 2.4.4.4.

The 1D MEM was used to determine the formation breakdown pressure, fracture closure pressure, and fracture propagation pressure for the Broom Creek Formation. The breakdown pressure was computed by setting the minimum tangential stress around the circumference of the well to zero and applying Kirsch (1898); Aadnoy (2008); and Grandi, Rao, and Toksoz (2002) equations. The fracture propagation pressure is assumed to be the same as the fracture pressure and allows the estimation of a maximum threshold whereby connected flow may be sustained. In this case, the estimated fracture pressure is considered to be the estimated fracture closure pressure. The fracture closure pressure was defined using the minimum horizontal stress (Shmin). Typically, Shmin, can be estimated from a modified Eaton calculation method and is viewed as a lower bound for the reservoir fracture closure pressure or the maximum stress prior to breakdown of the system competency. The modified Eaton formula used is shown in Equation 1. This equation has been widely used in the industry and has a good match with the field test data:

$$P = \frac{v}{1-v} * \left((S_v - \alpha_v) * P_p\right) + \alpha_H * P_p \quad \text{[Eq. 1]}$$

Where:

P is pressure.
v is Poisson's ration.
S_v is the vertical stress.
α_V is the vertical Biot's constant.
α_H is the horizonal Biot's constant.
P_p is pore pressure.

The estimated pressures were compared to MDT-deployed microfracture in situ stress test results from Flemmer 1. The Flemmer 1 microfracture in situ stress test in the Broom Creek Formation (6,358 ft depth) was conducted over 7 cycles of injection and falloff. The first two cycles reached approximately 7,250 psi and 8,000 psi, respectively, without breakdown. The breakdown occurred on the third cycle, with an initial breakdown pressure of 4,950 psi. Fracture reopening pressures increased to 5,214 psi, 6,255 psi, and, finally, 7,293 psi in Cycles 5, 6, and 7. Fracture reopening pressures are generally lower than initial breakdown pressure; however, Cycles 5 and 6 show a steady rise in measured closure pressure, indicating the possible formation of pore space plugging. Propagation pressure recorded in Cycle 4 was 4,384 psi. The average pressures of the stress test from prior tests on the Flemmer 1 and estimates for the Coteau 1 well results are shown in Table 2-8.

The average fracture propagation pressure gradient of 0.71 psi/ft for the Coteau 1 well agrees with the average fracture propagation values determined from microfracture in situ stress tests in other regional wells: the J-LOC 1 and BNI-1 (NDIC, 2021b). Because of the confidence in the calculated value for fracture propagation pressure gradient and the predicted maximum BHP (Table 3-5), there are no plans to run an MDT test in one of the other injection wells.

Table 2-8. Broom Creek Microfracture Results from Flemmer 1 and Interpreted Results from Coteau 1

	Coteau 1		Flemmer 1	
Depth, ft	NA		6358	
Pressure/Gradient	**psi**	**psi/ft**	**psi**	**psi/ft**
Breakdown	5,193	0.85	4,950	0.77
Avg. Fracture Propagation	4,263	0.71	4,384	0.69
Avg. Closure	4,014	0.71	4,195	0.66

Note: Flemmer 1 average fracture propagation and closure pressure are representative of Cycle 4 because of possible plugging in the later cycles.

2.3.1 Mineralogy

The combined interpretation of core, well logs, and thin sections shows that the Broom Creek Formation is dominated by fine- to medium-grained sandstone with lesser amounts of carbonates and anhydrites. Twenty-two depth intervals across 131.25 ft of the Broom Creek Formation were sampled for XRD mineralogical determination and XRF bulk chemical analysis. Out of 22 samples, 18 samples were selected to create thin sections. For the assessment below, thin sections and XRD provide independent confirmation of the mineralogical constituents of the Broom Creek Formation. No core was acquired for the interval of 6,001' to 6,130' (the middle dolomite-rich section of the Broom Creek Formation) because of the low rate of penetration.

Thin-section analysis of the upper Broom Creek interval shows that quartz (84%) is the dominant mineral. Throughout these intervals are minor occurrences of feldspar (6%), dolomite (5%), and anhydrite as cement (5%). Where present, anhydrite is crystallized between quartz grains and obstructs the intercrystalline porosity. The quartz minerals sometimes show overgrowth and, occasionally, dissolution. The contact between grains is long (straight) to tangential. In most cases, grains are surrounded/rimmed by a thin red brown to dark red iron oxides. The porosity ranges between 15% to 34%, except for a sample at the depth of 6,146 ft with a porosity of 9% that is extensively cemented by anhydrite. Figure 2-15 shows the primary features observed in thin sections within the upper sand of the Broom Creek Formation.

Within the intervals of core collected, occurrences of carbonates are notable in the 5,903'–6,001' interval. The first occurrence at 5,908'–5,924' (Figure 2-16) is a relatively thick carbonate that comprises a very fine- to fine-grained dolostone (75%), with quartz of variable size and shape (7%) and anhydrite (18%). The porosity averages 8% and is mainly intercrystalline and moldic in

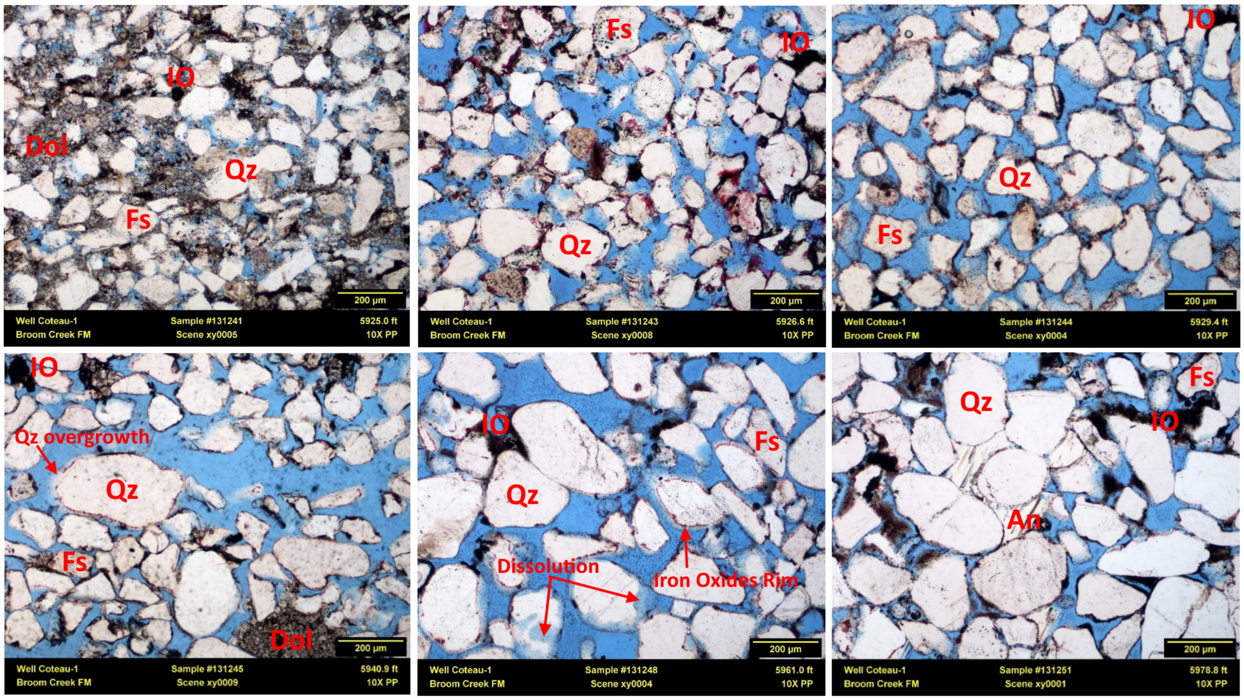


Figure 2-15. Thin sections from the upper sand interval of the Broom Creek Formation.

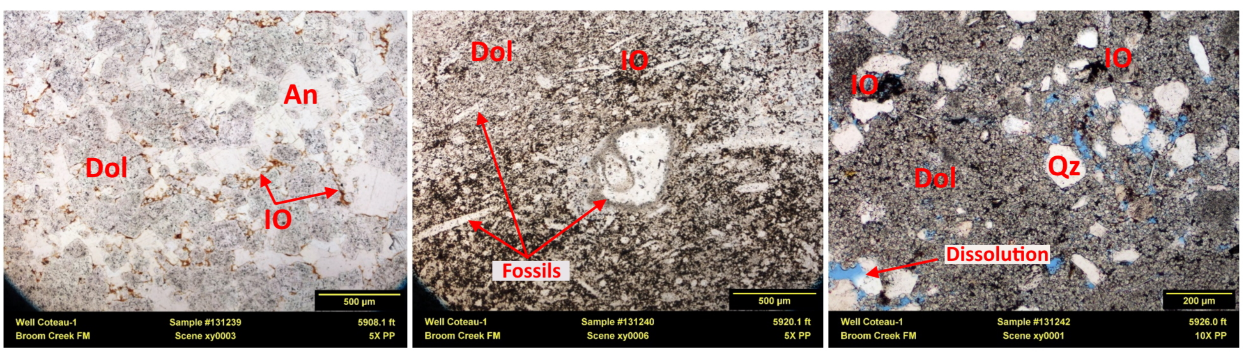


Figure 2-16. Thin sections from the three carbonate depth intervals of the upper Broom Creek Formation.

structure. Diagenesis is expressed by dolomitization of the original calcite grains. Fossils include some dolomitized bivalve shell fragments.

A small section of carbonate was penetrated at 5,999' to 6,001' prior to ceasing the first coring run. This bed is a pure dolomite (Figure 2-17) that comprises dolosparite/micro-dolosparite (78%). The presence of clay (11%) and iron oxides is noticeable in the rock matrix. Anhydrite as the clasts and veins is the other comprising mineral (7%). The quartz (very fine grains) presents in low content (4%). The observed thin-section porosity averages 7% and occurs as the dissolution of anhydrite and open fractures. It is noted that the scale of observed fractures in these carbonate intervals is on the micrometer scale and may be induced by the thin-section creation process.

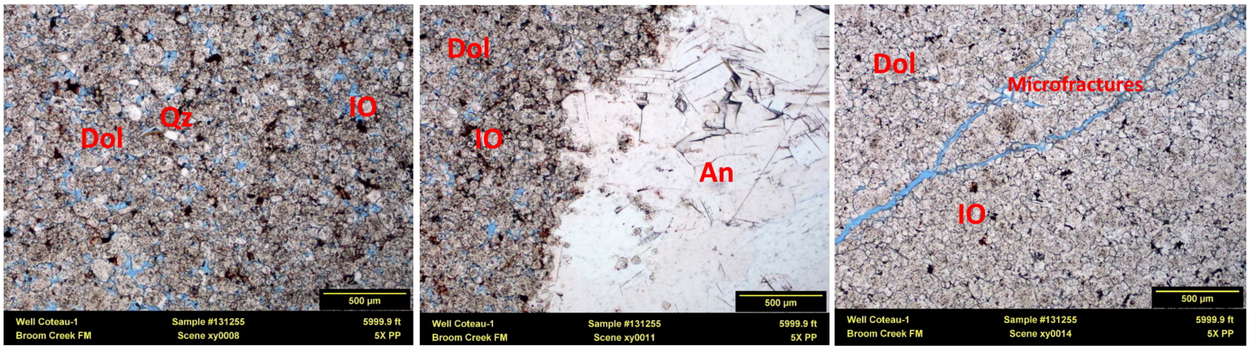


Figure 2-17. Thin section from the carbonate depth interval of the middle Broom Creek Formation.

The last occurrence of carbonates in the Broom Creek Formation is notable at the depth interval of 6,130'–6,163'. This occurrence of carbonate (6,160'–6,163.25') is much more quartz-rich dolomite (sandy dolomite) and comprises mainly micro-dolomite (54%), quartz (35%), feldspar (10%), and clay (1%). The presence of iron oxides is noticeable. The quartz minerals show some dissolution. The contact between grains is tangential and separated by a dolomitic matrix and locally by iron oxide cements. The observed porosity is due to the dissolution of feldspar and averages 9%. Figure 2-18 shows the characteristics observed within this carbonate.

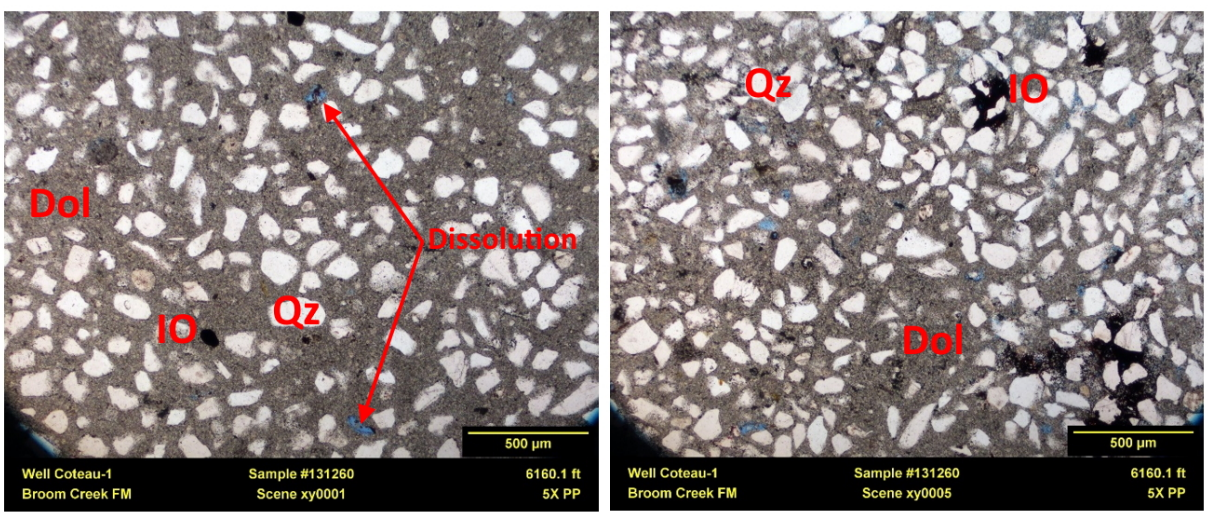


Figure 2-18. Thin section from a carbonate depth interval of the lower Broom Creek Formation.

XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek Formation core primarily comprises quartz, feldspar, carbonates, anhydrite, clay, and other minor minerals (Figure 2-19).

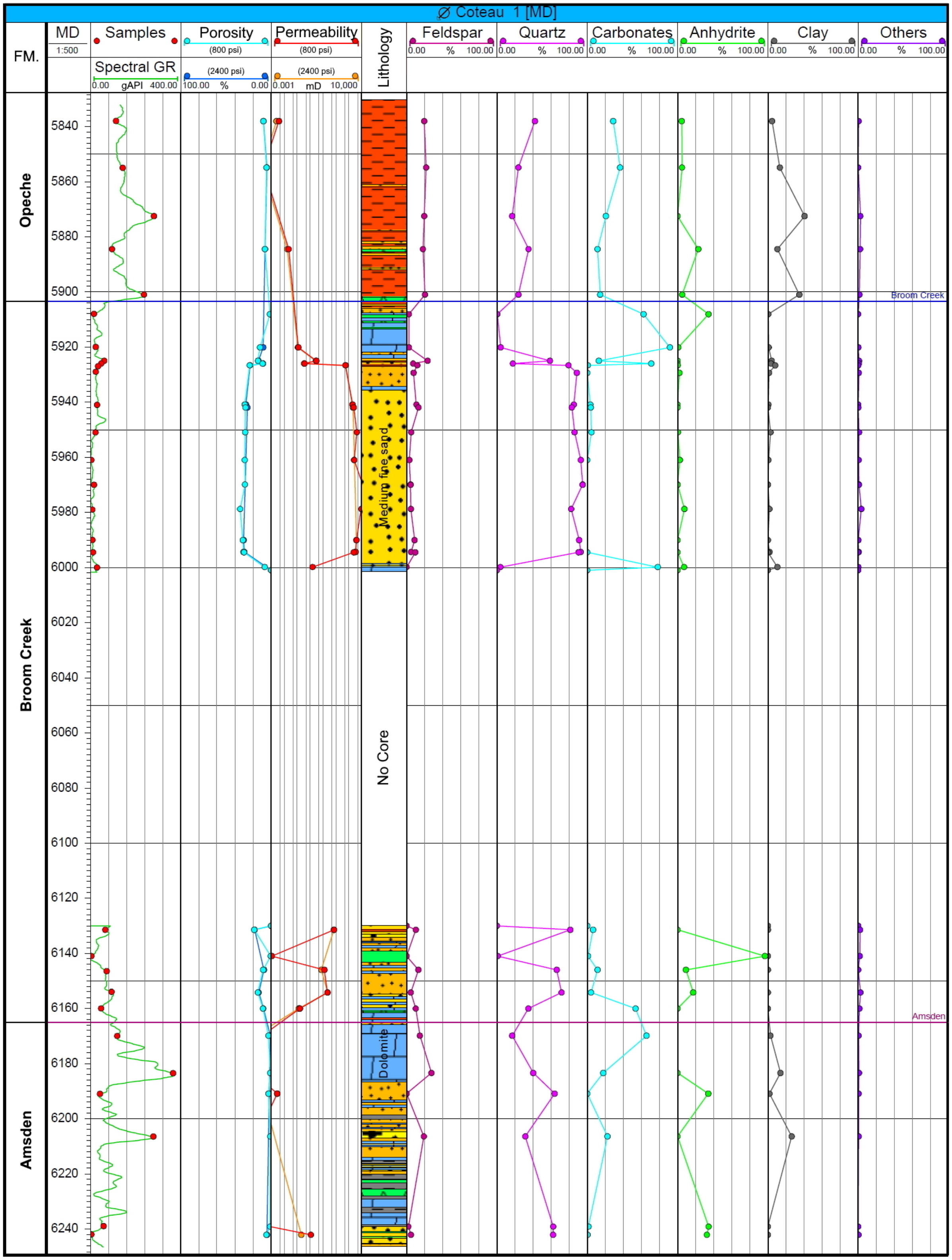


Figure 2-19. Described core and laboratory-derived mineralogic characteristics of the Opeche, Broom Creek, and Amsden Formations.

XRF data are shown in Figure 2-20 for the Broom Creek Formation. Sandstone and dolomite intervals are confirmed through the high percentages of SiO_2 (71%–98%), CaO (19%–36%), and MgO (13%–21%). The high percentage of CaO and SO_3 at 5,908, 6,141, and 6,154 ft indicate a presence of anhydrite beds. The formation shows little volumes of clay, with a range of 0.04% to 10.54% for all samples.

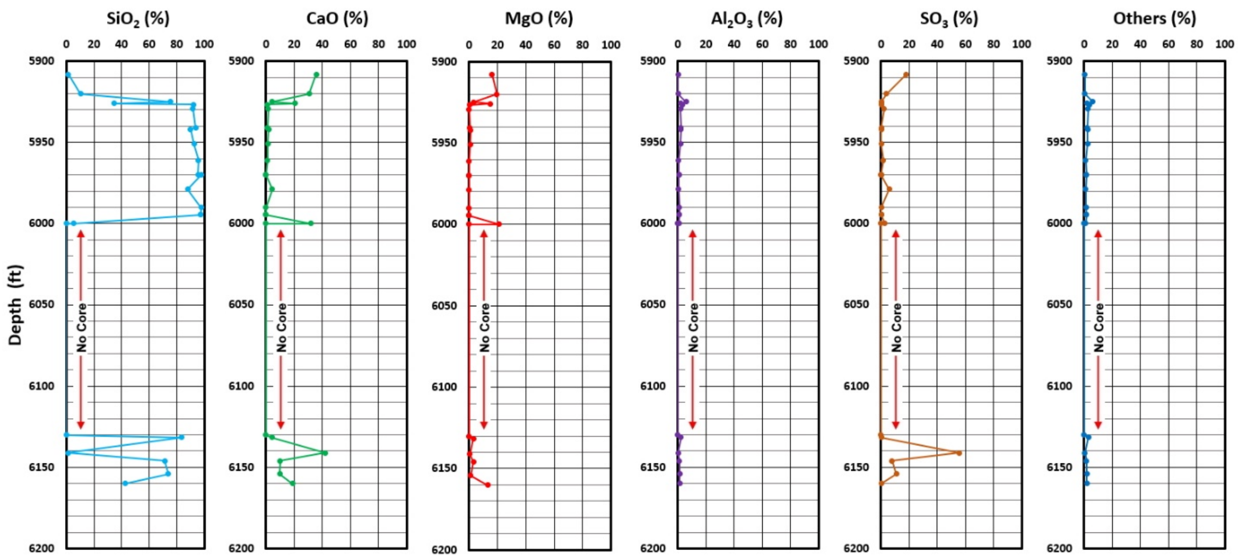


Figure 2-20. XRF data from the Broom Creek Formation from the Coteau 1.

2.3.2 Mechanism of Geologic Confinement

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. 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). After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period of time (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation and, therefore, is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.

2.3.3 Geochemical Information of Injection Zone

Geochemical simulation has been performed to calculate the effects of introducing the CO_2 stream to the injection zone.

The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in the Computer Modelling Group Ltd. (CMG) compositional simulation software package GEM. GEM is also the primary simulation software used for evaluation of the reservoir's dynamic behavior resulting from the expected CO_2 injection. For this geochemical modeling study, the injection scenario consisted of a single injection well injecting for a 12-year period with maximum BHP and maximum gas injection rate (STG) constraints of 3,833 psi and 25 MMcfd (468,000 tonnes/year), respectively. A postinjection period of 25 years was run in the model to evaluate any dynamic behavior and/or geochemical reaction after the CO_2 injection is stopped. This geochemical scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared (Figure 2-21).

Simulation results indicate that the low-salinity plume (TDS 8,050 ppm) associated with the ANG #1 and ANG #2 disposal water and the injected CO_2 plume for the six-well injection scenario discussed in Section 3 may have little interaction after 10 years of postinjection (Figure 2-22). Based on this limited interaction of the injected CO_2 and the injected disposal water and the chemical composition of the disposal water, the ANG disposal well injection was not included as part of the geochemical modeling for computational efficiency. The historical ANG well injection up to August 2021 was included during the modeling.

Geochemical alteration effects were seen in the geochemistry case, as described below. However, these effects were not significant enough to cause meaningful changes to the storage reservoir performance of the storage formation.

The scenario with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (86% of bulk reservoir volume) and average formation brine composition (14% of bulk reservoir volume). XRD data from the Coteau 1 well core samples were used to inform the mineralogical composition of the Broom Creek Formation (Table 2-9). Illite was chosen to represent clay for geochemical modeling as it was the most prominent type of clay identified in the XRD data. Kaolinite is the only other clay mineral that was identified in XRD data and was only identified in one of twenty-two samples analyzed. Ionic composition of the Broom Creek Formation water and the ANG disposal water chemistry are listed in Tables 2-10 and 2-11.

The injection stream is expected to be 95.9% CO_2. For input into CMG, this value was normalized along with the other constituents in the stream to sum to 100% mole fraction. The CO_2 composition in the gas stream used for the simulated injection stream was 96.45% CO_2. Other constituents represent 3.55% of the stream and are expected to include 1.23% hydrogen sulfide (H_2S) and 2.32% including methane, ethane, and propane. N_2, known to be an inert gas, was not included in the gas stream. Some of the other carbon constituents such as butane, ethylene, pentane, isobutane, isopentane, and n-pentane may also be present but in a negligible amount that would have no impact on geochemical reactions in the storage formation and were also not included. The simulated injection stream was 96.45% CO_2, 1.23 H_2S, and 2.32% CH_4. As in the model without geochemical reactions, the geochemistry case was run for the 12-year injection period followed by 25 years of postinjection monitoring.

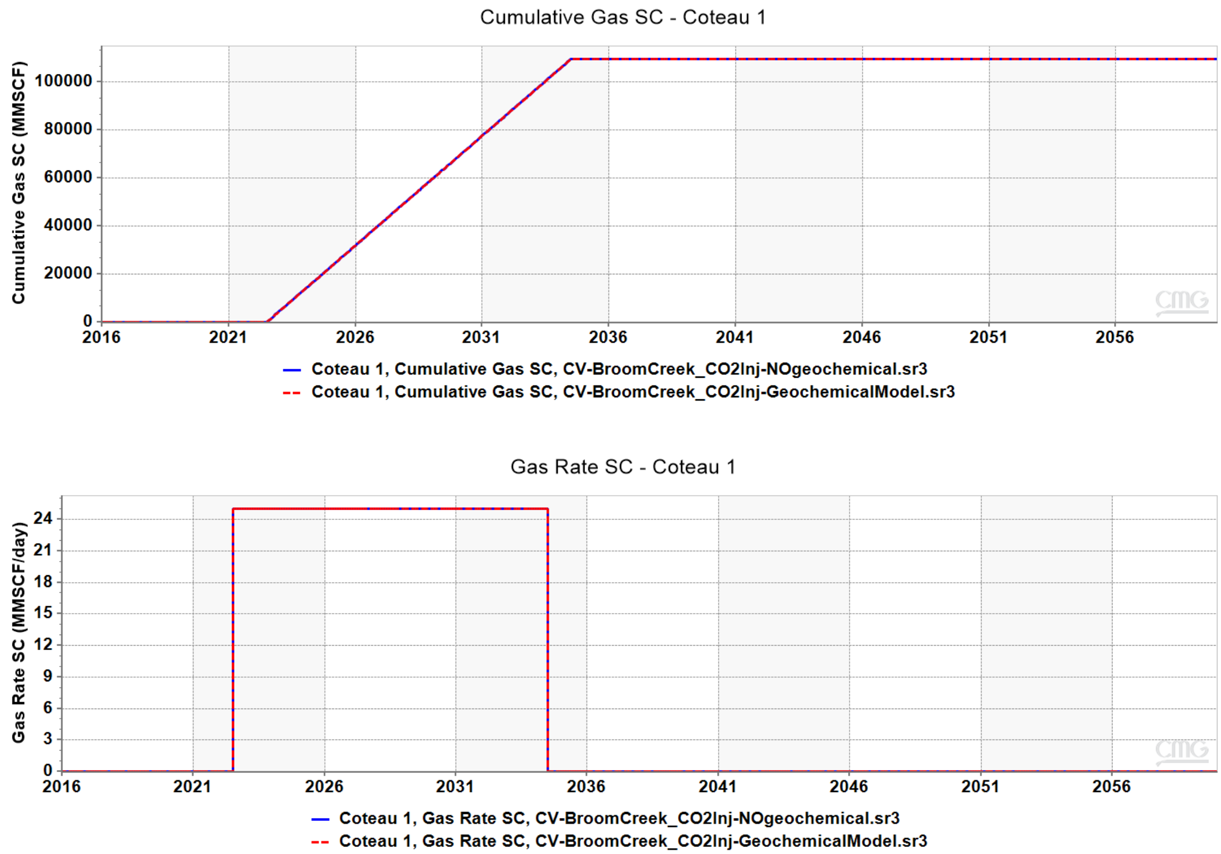


Figure 2-21. Upper graph shows cumulative injection vs. time; the bottom figure shows the gas injection rate vs. time. There is no observable difference in injection due to geochemical reactions.

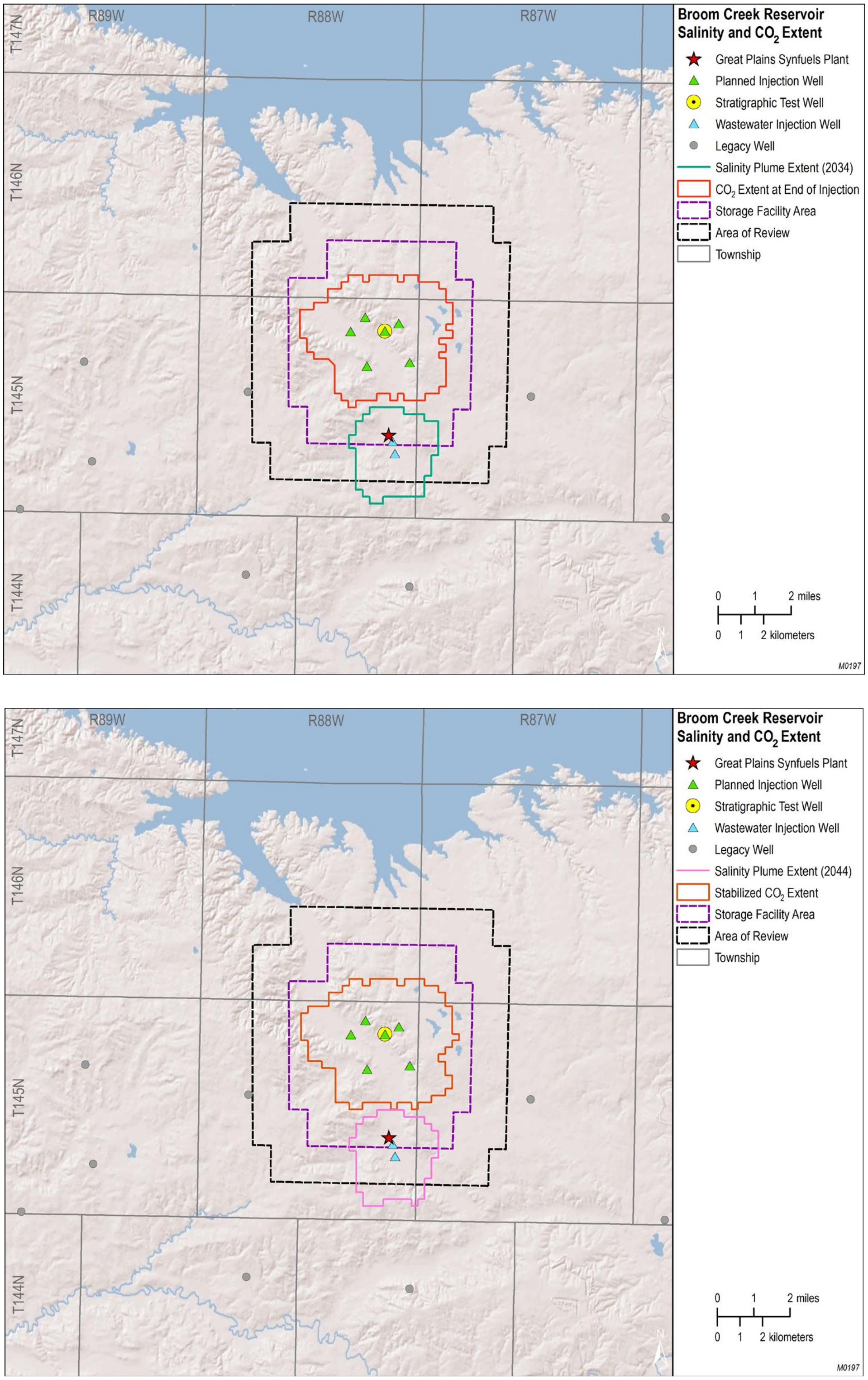


Figure 2-22. 2D map showing the water salinity plume from the disposal wells, ANG #1 and ANG #2, and the gas mole fraction (CO_2) for the expected injection scenario for this project described in Section 3 consisting of six CO_2 injection wells. The lower map shows the stabilized CO_2 plume vs. the salinity plume extent after 10 years postinjection, in July 2044.

Table 2-9. XRD Results for Coteau 1 Broom Creek Core Sample

Mineral Data	%
Albite	2.25
Anhydrite	15.17
Anorthite	1.96
Dolomite	23.91
Illite	2.85
Pyrite	0.13
Quartz	54.15

Table 2-10. Broom Creek Water Ionic Composition, expressed in molality

Component	mg/L, ppm	Molality
SO_4^{2-}	469	0.00474
K^+	516	0.01281
Na^+	12,800	0.54698
Ca^{2+}	1,860	0.04511
Mg^{2+}	212	0.00847
Fe^{3+}	392	0.00681
CO_3^{2-}	<20	0.00032
Cl^-	24,900	0.69829
HCO_3^-	853	0.01357
TDS, ppm	42,800	

Table 2-11. ANG #1 Water Ionic Composition, expressed in molality

Component	mg/L, ppm	Molality
SO_4^{2-}	2,280	0.02355
K^+	38.5	0.00098
Na^+	2,200	0.09495
Ca^{2+}	283	0.00699
Mg^{2+}	175	0.00713
Cl^-	2,880	0.08066
HCO_3^-	63	0.00102
TDS, ppm	8,050	

Figure 2-21 shows that reservoir performance results for the two cases are essentially identical. As a result of geochemical reactions in the reservoir, there is no observable difference in cumulative injection. The injection BHP and wellhead pressure (WHP) are shown in Figure 2-23. The two cases are also essentially the same, and no difference was appreciable between the case with and without geochemical modeling.

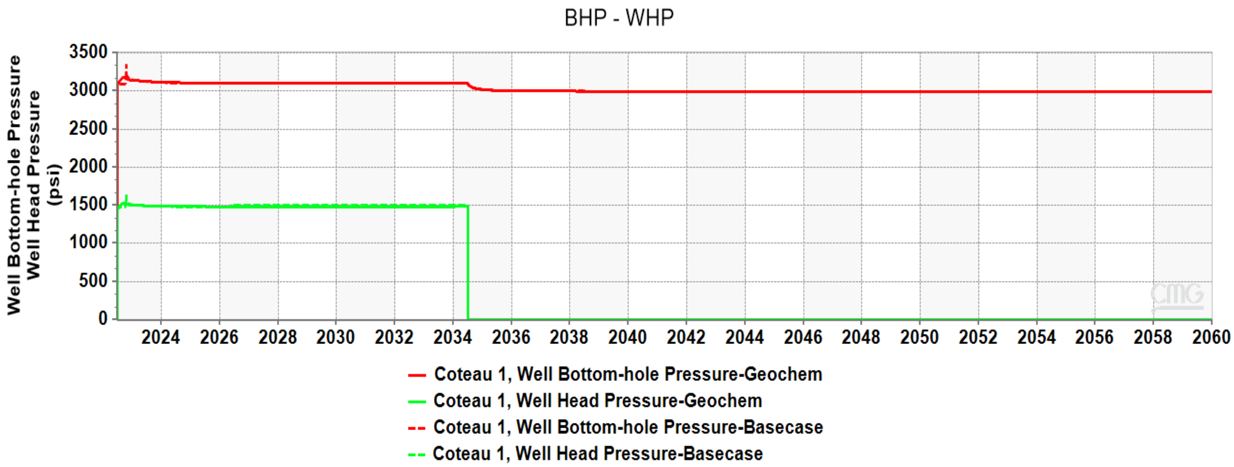


Figure 2-23. BHP and WHP vs. time. There is no observable difference in injection pressure due to geochemical reactions as compared to the results without the geochemical model.

Figures 2-24a and 2-24b show the concentration of CO_2, in molality, in the reservoir after 12 years of injection plus 25 years of postinjection for the geochemistry model case (upper figure) and for the non-geochemistry model (bottom figure) for comparisons. The results are not showing an evident difference in the CO_2 gas molality fraction between both cases as seen in the previous figures for volume injected and injection pressure simulation results.

The pH of the reservoir brine changes in the vicinity of the CO_2 accumulation, as shown in Figure 2-25. The pH of the Broom Creek native brine sample is 6.7 whereas the fluid pH declines to approximately 5.6 in the CO_2-flooded areas.

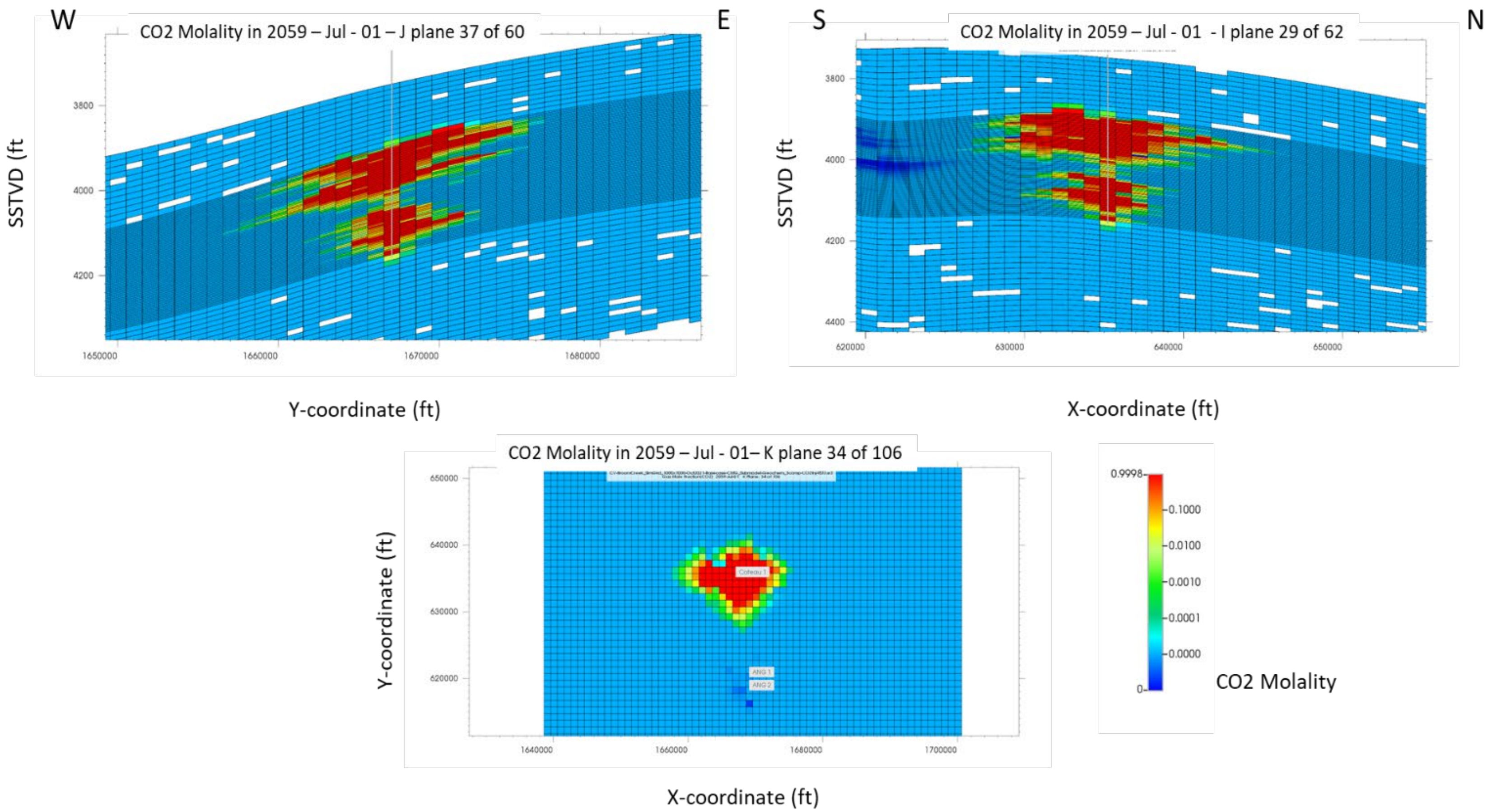


Figure 2-24a. CO_2 molality for the geochemistry case simulation results after 12 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east and right upper are north-south cross sections. Lower image is a planar view of simulation in layer k = 11. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

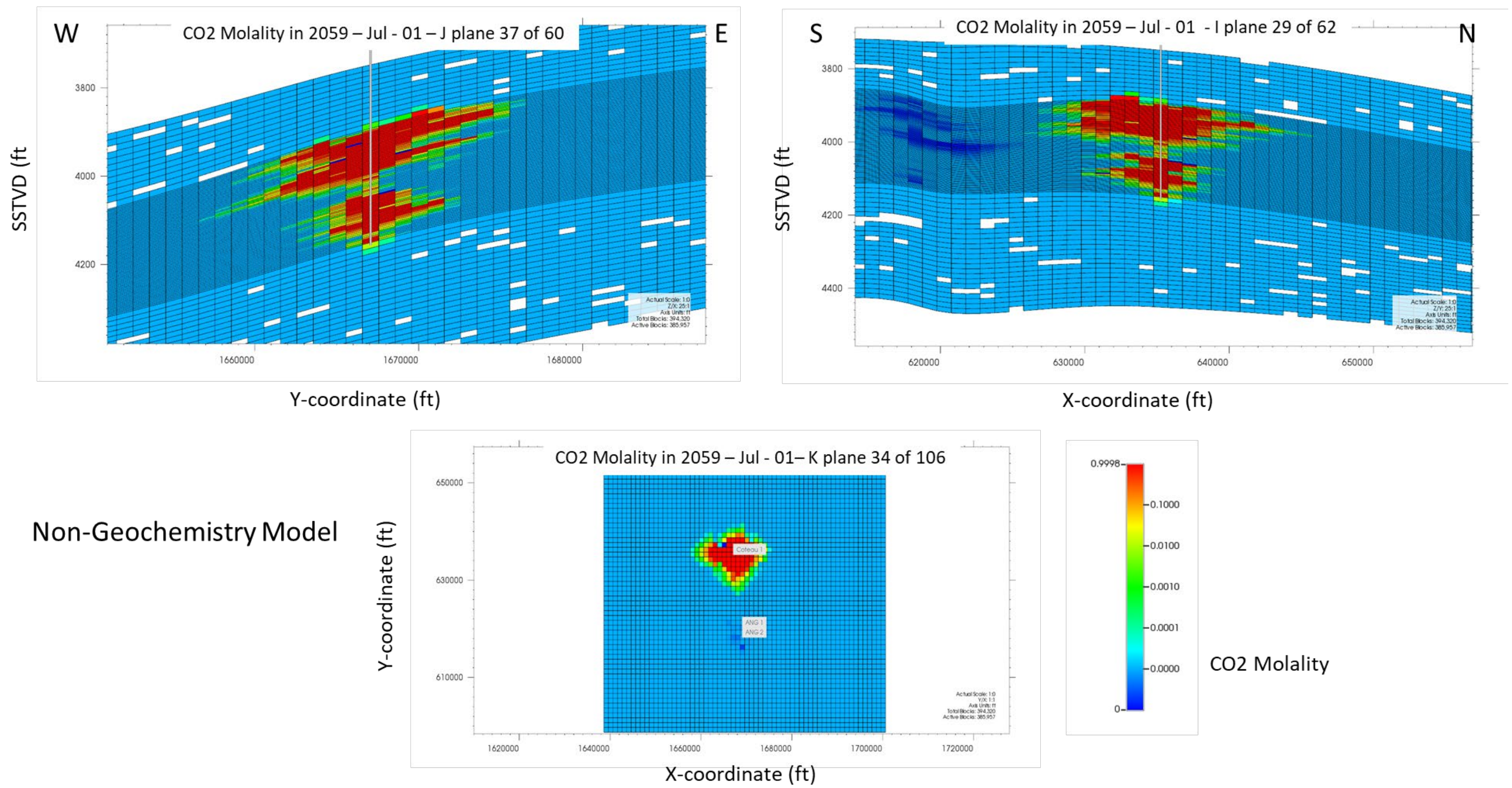


Figure 2-24b. CO_2 molality for the non-geochemistry model (bottom) results after 12 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east and right upper are north-south cross sections. Lower image is a planar view of simulation in layer k = 11. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

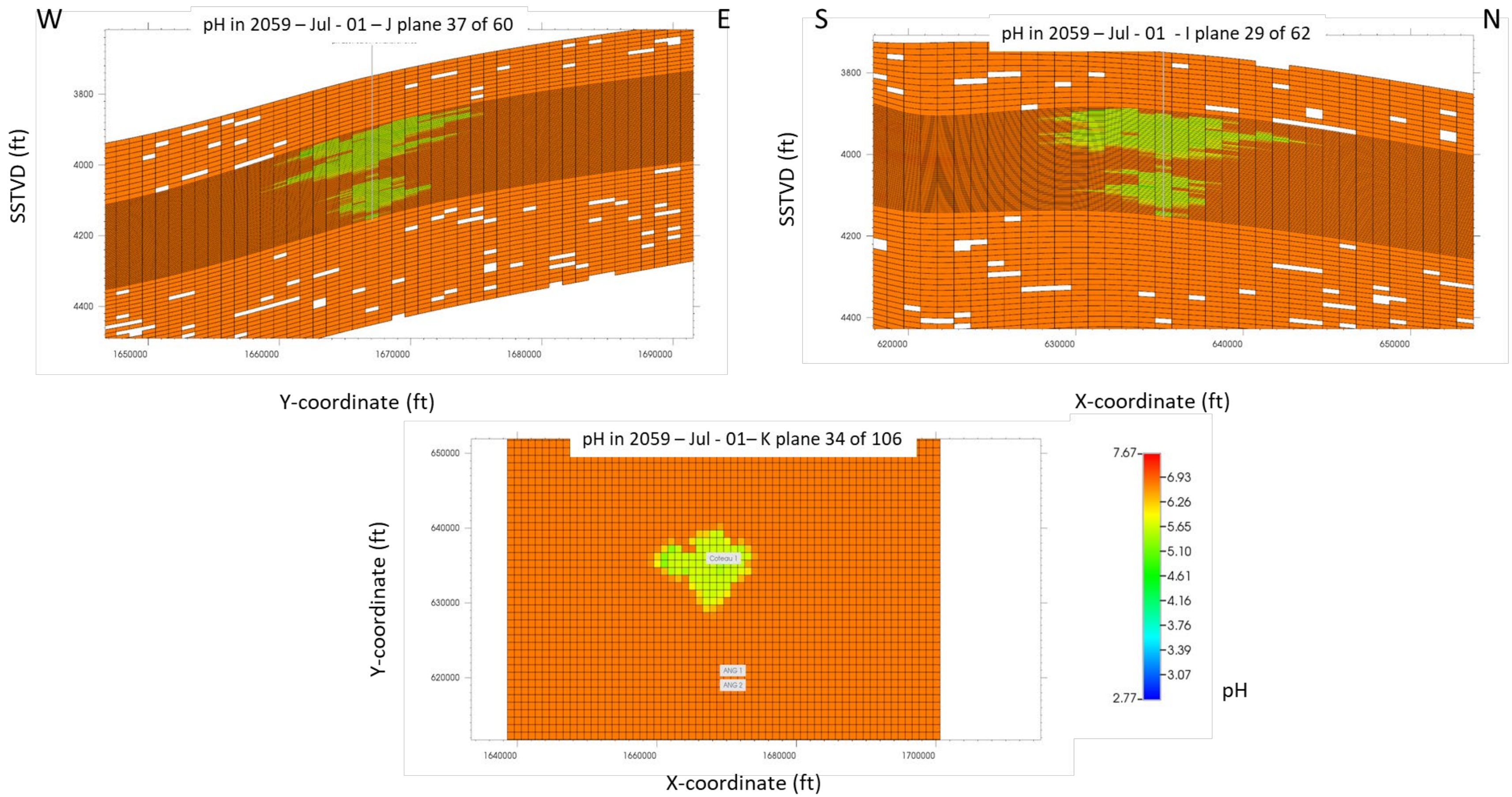
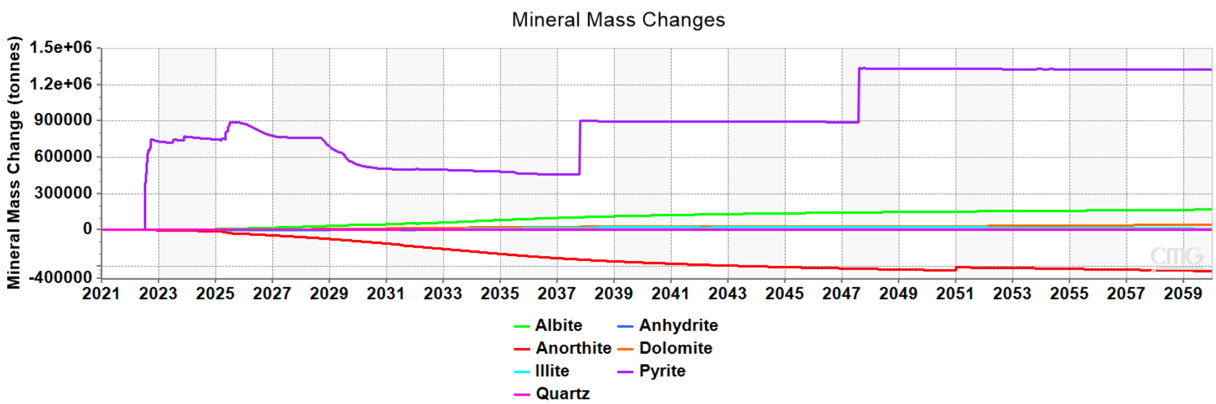


Figure 2-25. Geochemistry case simulation results after 12 years of injection + 25 years postinjection showing the pH of formation brine in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

Figure 2-26 shows the mass of mineral dissolution and precipitation due to geochemical reaction in the Broom Creek Formation. Anorthite is the most prominent dissolution mineral. Illite starts to dissolve and then precipitate after Year 2034, the year in which injection ends. Dolomite, albite, and pyrite are the primary precipitation minerals. Pyrite (FeS_2) precipitation is favored by the presence of dissolved H_2S in the gas stream injected and aqueous iron in the Broom Creek Formation water. There is a small amount of precipitation for quartz and anhydrite during the simulation period possibly due to the additional SiO_2 released by anorthite dissolution and the presence of Ca^{2+} and SO_4^{-2} ions in the water formation, respectively.

Figures 2-27 through 2-30 provide an indication of the change in distribution of the mineral that experienced the most dissolution, anorthite, and the minerals that have experienced significant precipitation: dolomite, albite, and pyrite.



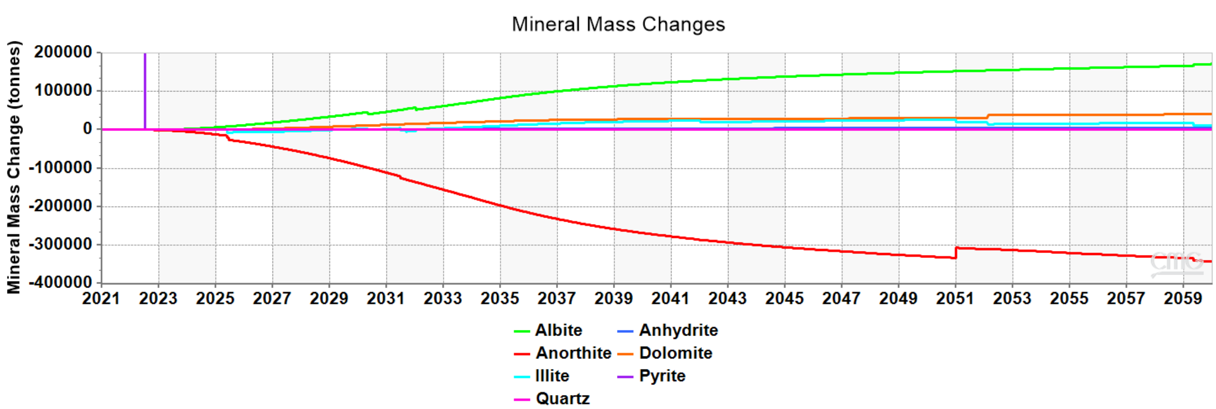


Figure 2-25. Dissolution and precipitation quantities of reservoir minerals because of CO_2 injection. Dissolution of anorthite with precipitation of pyrite, albite, and dolomite was observed. Upper figure shows all the minerals; the lower figure is rescaled for better view of the minerals mass change except pyrite.

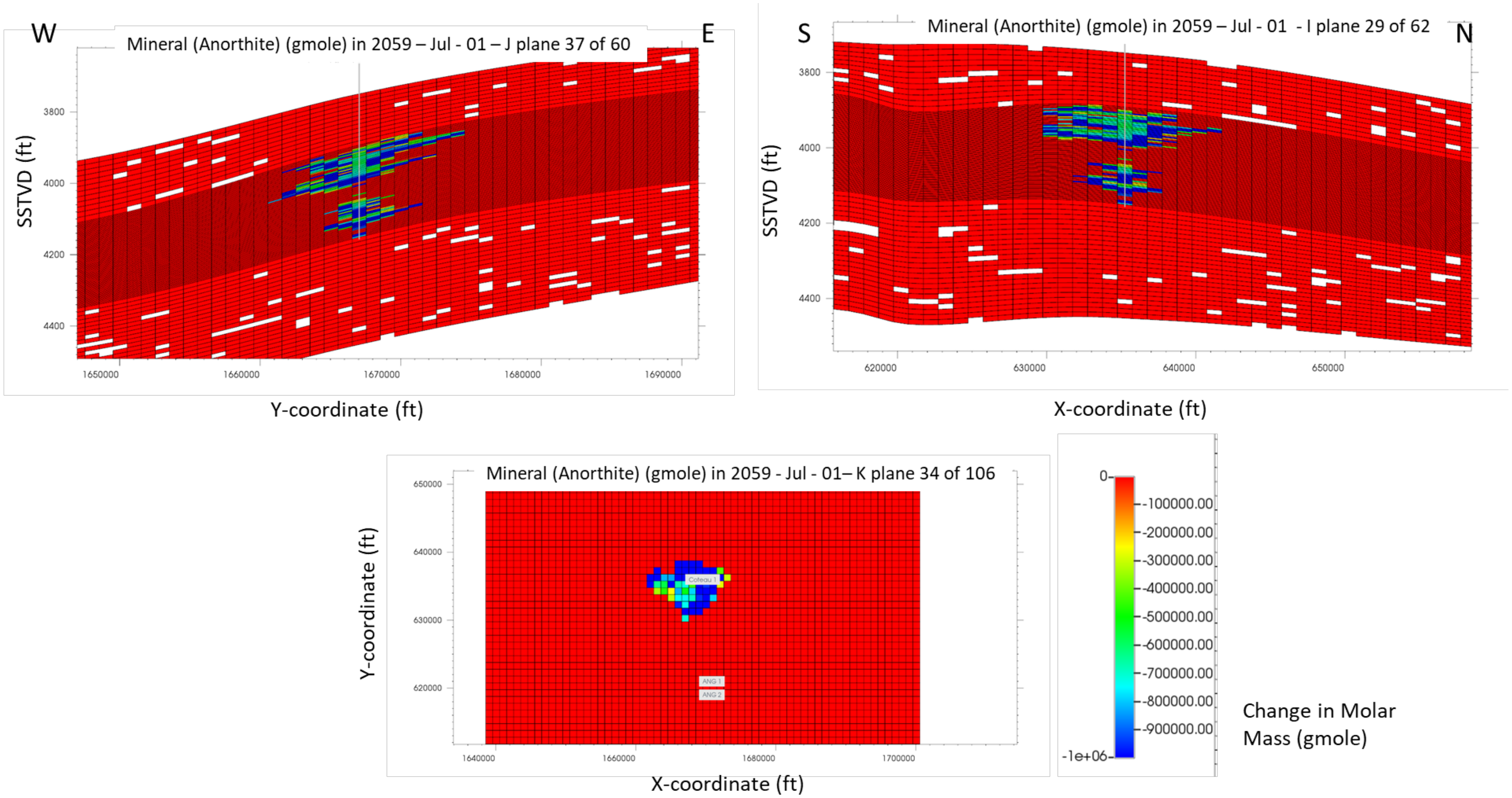


Figure 2-26. Change in molar distribution of anorthite, the most prominent dissolved mineral at the end of the 12-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

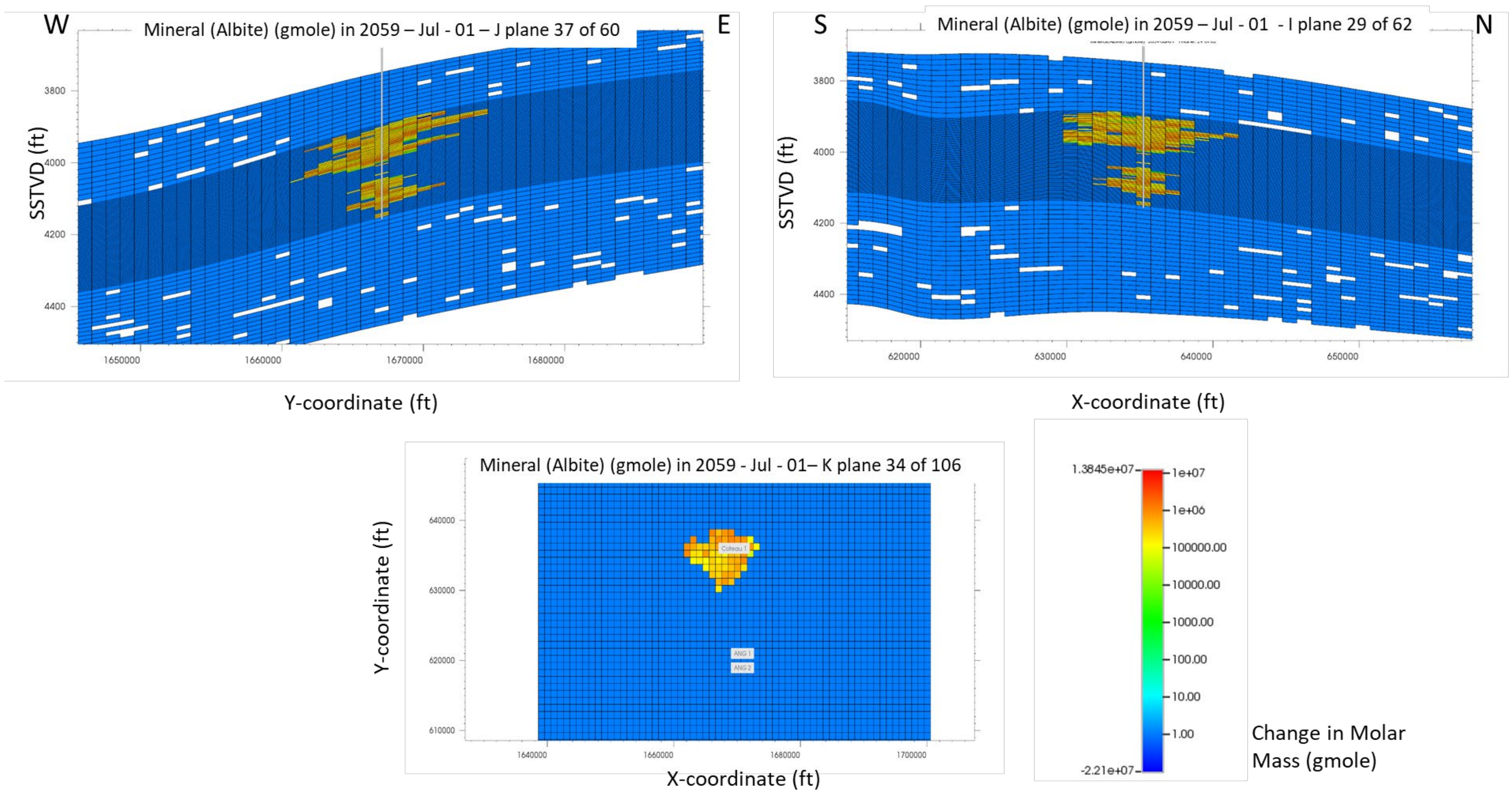


Figure 2-27. Change in molar distribution of albite, a precipitated mineral at the end of the 12-year injection + 25 years postinjection period in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

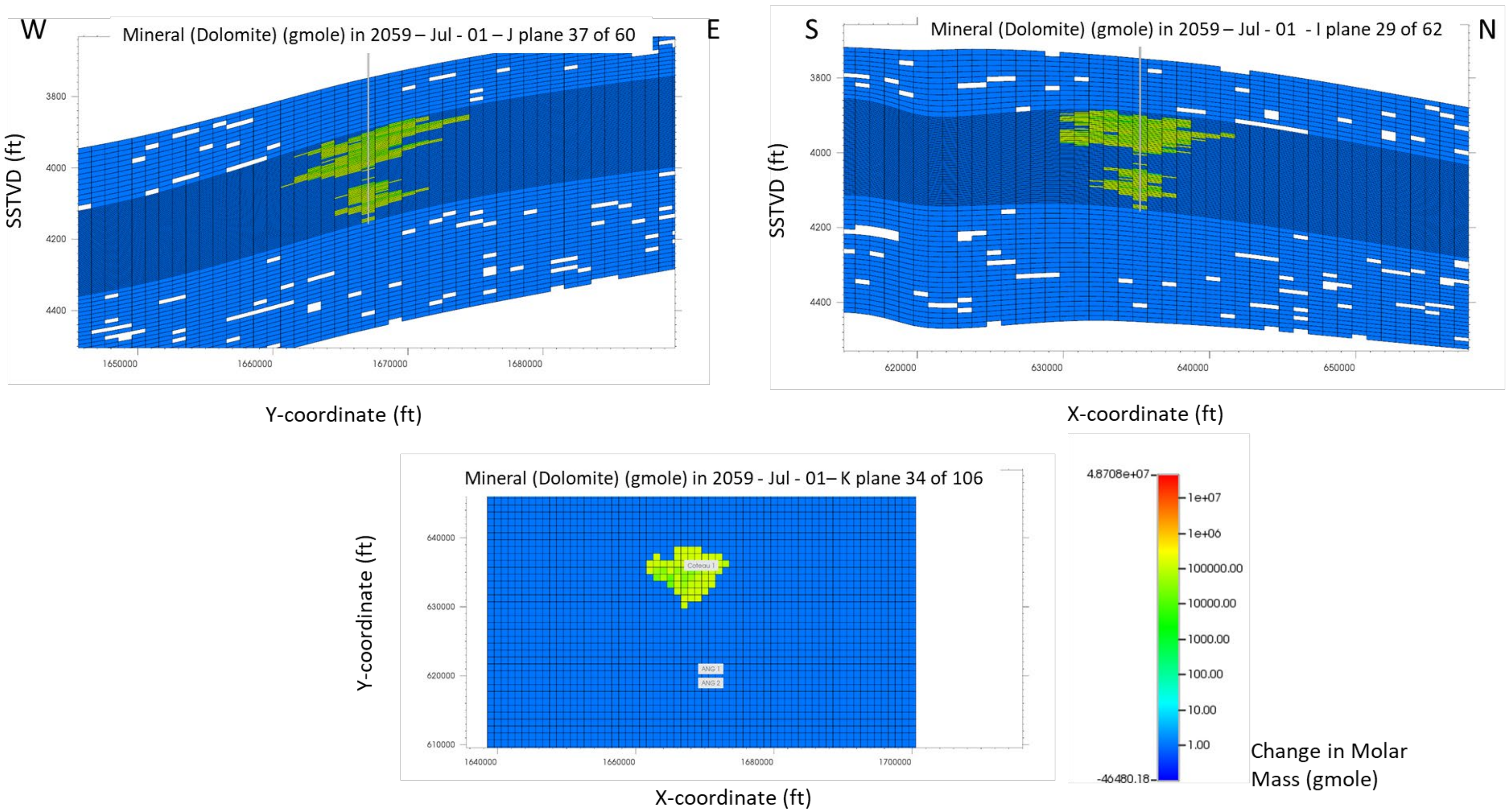


Figure 2-28. Change in molar distribution of dolomite, a precipitated mineral at the end of the 12-year injection + 25 years postinjection period in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

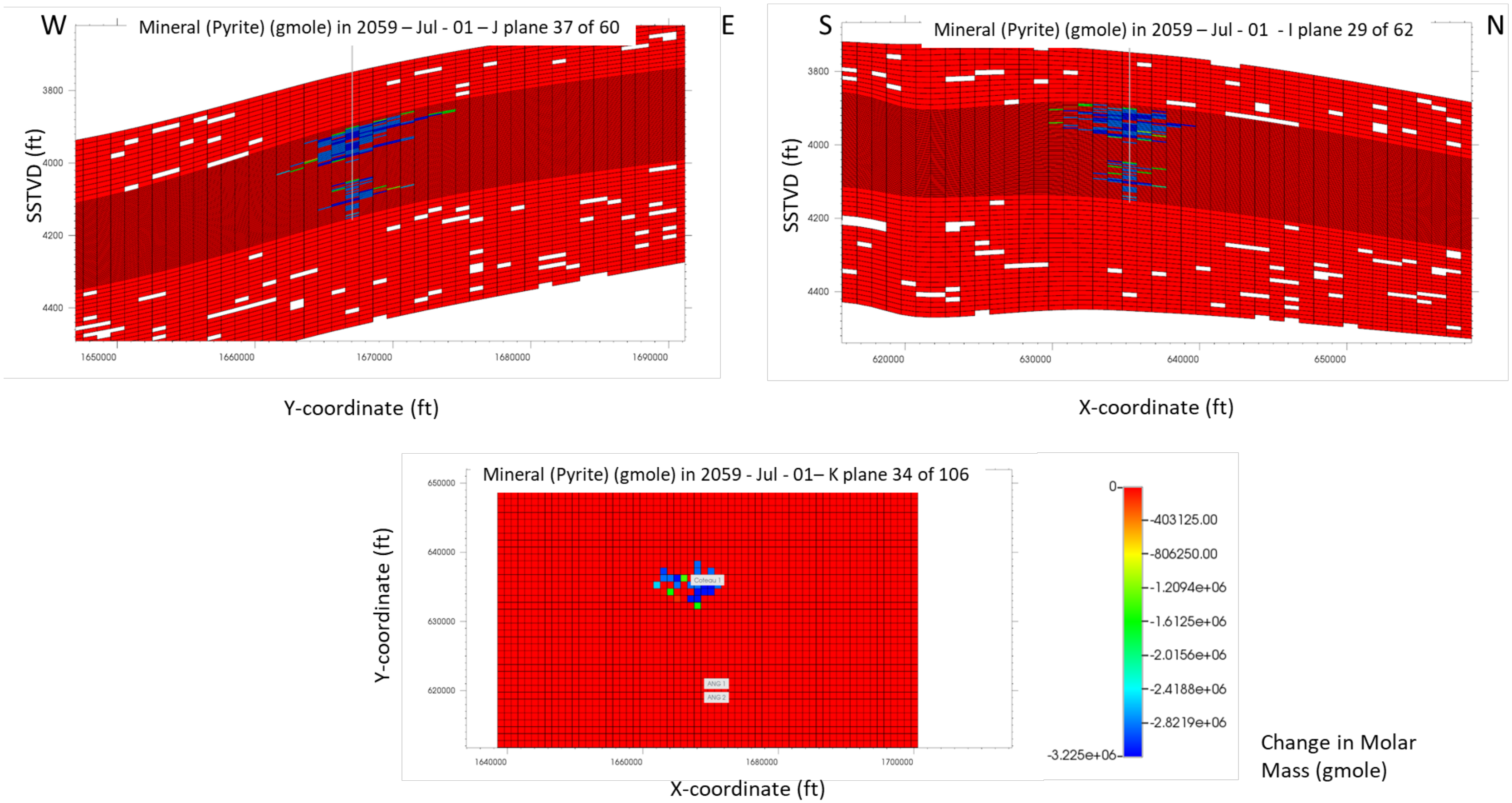


Figure 2-30. Change in molar distribution of pyrite, the most prominent precipitated mineral at the end of the 12-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

2.4 Confining Zones

The confining zones for the Broom Creek Formation are the Opeche interval and underlying Amsden Formation (Figure 2-3, Table 2-12). Both the Amsden and Opeche intervals consist of impermeable rock layers.

Table 2-12. Properties of Upper and Lower Confining Zones in Simulation Area (data based on the Coteau 1 well)

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	Opeche	Amsden
Primary Lithology	Silty mudstone	Dolostone
Formation Top Depth, ft	5,763	6,164
Thickness, ft	143	300
Porosity, % (core data) *	6.93	2.40
Permeability, mD (core data) **	0.002878	0.00116
Capillary Entry Pressure (CO_2/brine), psi	138.68	251.27
Depth below Lowest Identified USDW, ft	4,658	5,059

* Porosity values are reported as the arithmetic mean.
** Permeability values are reported as the geometric mean.

2.4.1 Upper Confining Zone

In the Great Plains CO_2 Sequestration Project area, the Opeche Formation consists of silty mudstone and anhydrite. The upper confining zone (Opeche) is laterally extensive across the Great Plains CO_2 Sequestration Project area (Figure 2-31). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche interval is 5,763 ft below the land surface and 143 ft thick at the Coteau 1 wellsite (Table 2-12, Figures 2-32 and 2-33). The contact between the upper confining zone and underlying Broom Creek sandstone is an unconformity that can be correlated across the formation's extent where the resistivity and GR logs show a significant change across the contact (Figure 2-34).

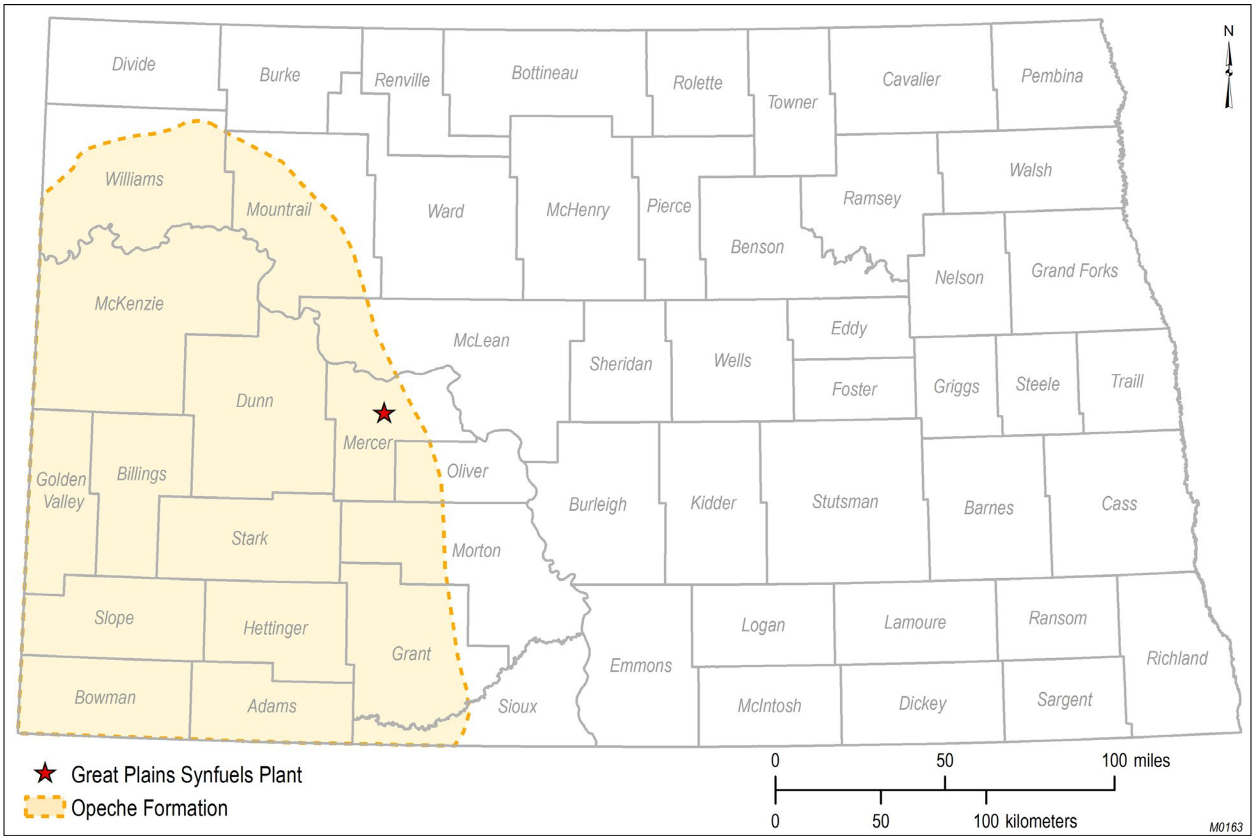


Figure 2-31. Areal extent of the Opeche Formation in North Dakota.

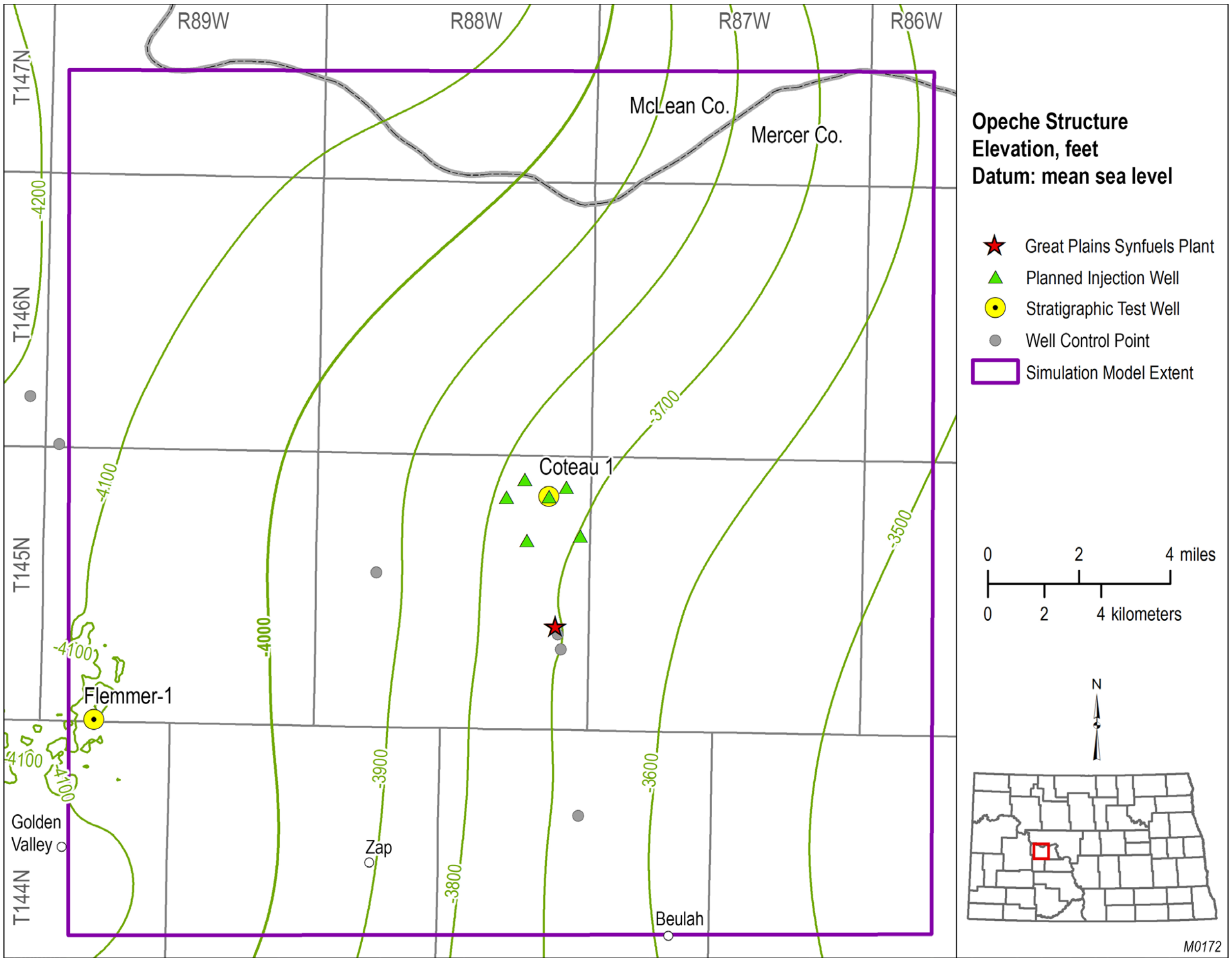


Figure 2-32. Structure map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops).

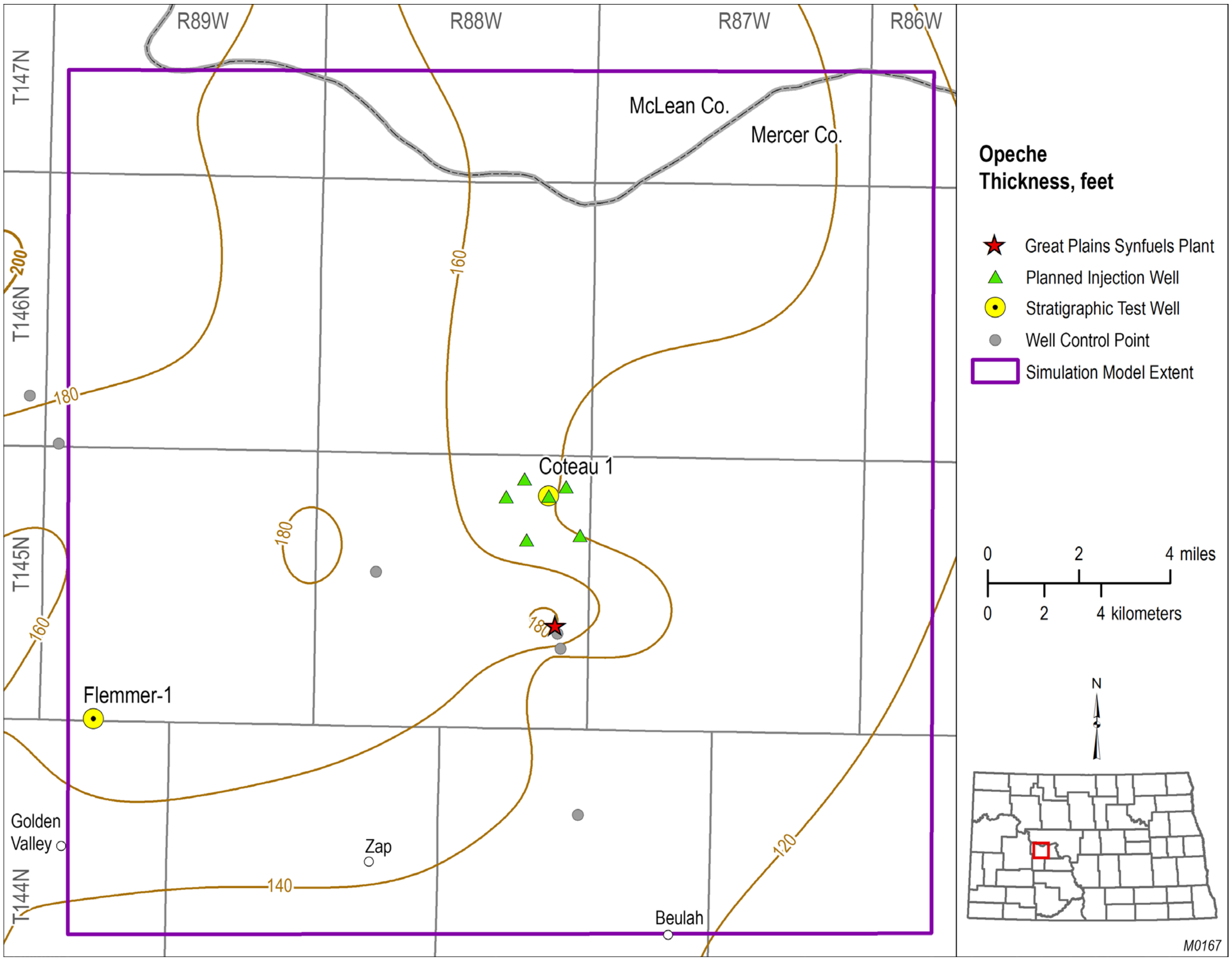


Figure 2-33. Isopach map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area.

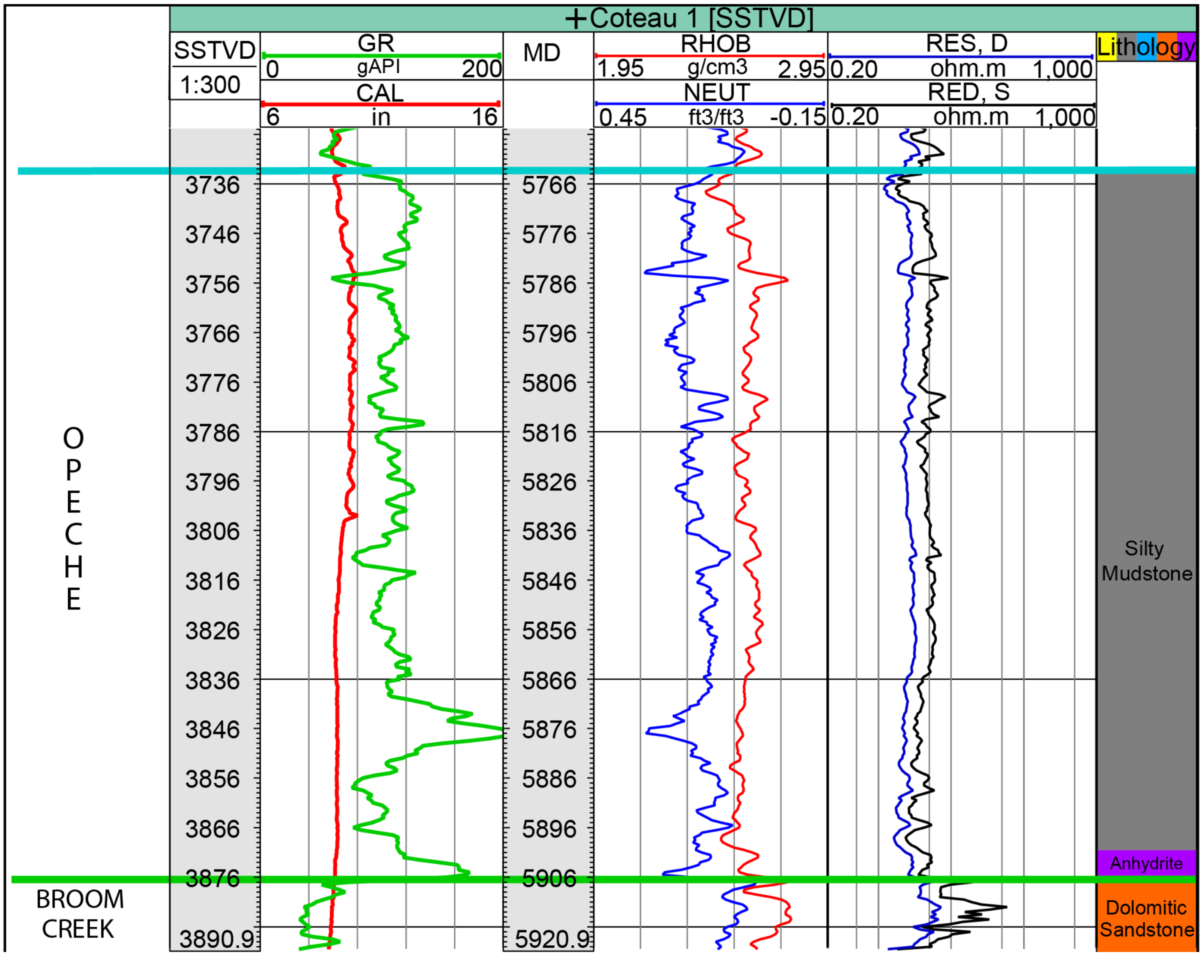


Figure 2-34. Well log display of the upper confining zone at the Coteau 1 well.

Microfracture in situ stress tests were not performed within the Opeche Formation in the Coteau 1 well. Microfracture in situ tests were performed using the MDT tool in the Flemmer 1 well, in the Opeche Formation, at a depth of 6,262 ft, which yielded results within good confidence. The MDT tool was able to cause breakdown in the formation at 8,157 psi. Propagation pressure for two cycles in close agreement were 4,879 and 5,085 psi, resulting in an average propagation pressure gradient of 0.80 psi/ft (Figure 2-35).

In situ fluid pressure testing was not performed in the Opeche Formation with the MDT tool. The CMR log shown in Figure 2-36 suggests that because of the low to almost zero permeability the fluid within the Opeche is pore- and capillary-bound fluid and not mobile. This is confirmed by unsuccessful attempts by others to extract fluid samples from the Opeche. The Tundra SGS (secure geologic storage) and Red Trail Energy storage facility permit applications describe unsuccessful attempts to draw down reservoir fluid in order to determine the reservoir pressure or to collect an in situ fluid sample; the formation was unable to rebound (build pressure) because of low to almost zero permeability (NDIC, 2021a, b). These unsuccessful attempts provide further evidence of the confining properties of the Opeche Formation, ensuring sufficient geologic integrity to contain the injected carbon dioxide stream.

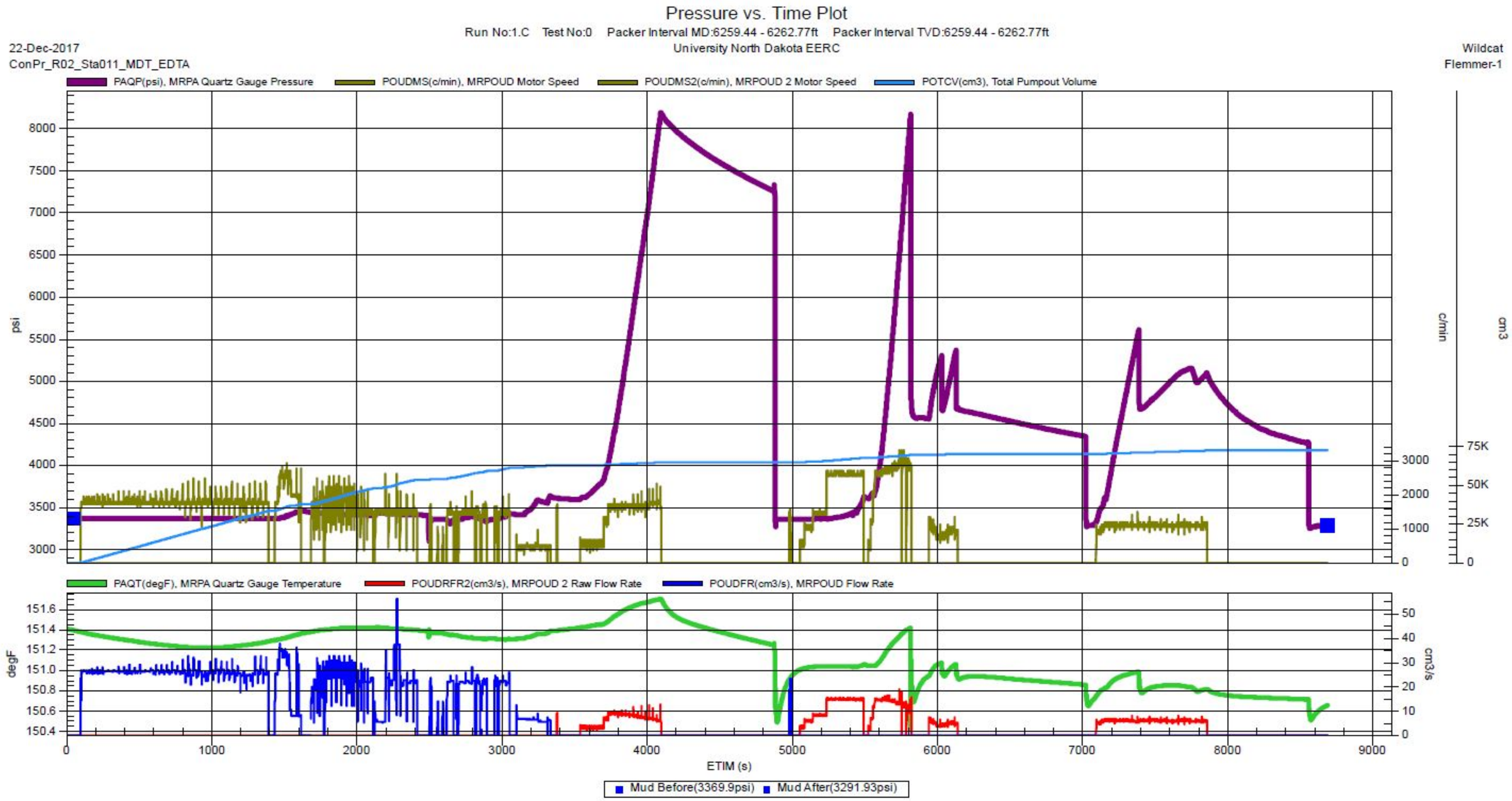


Figure 2-35. Flemmer 1 Opeche Formation MDT microfracture in situ stress pump cycle graph at 6,262 ft.

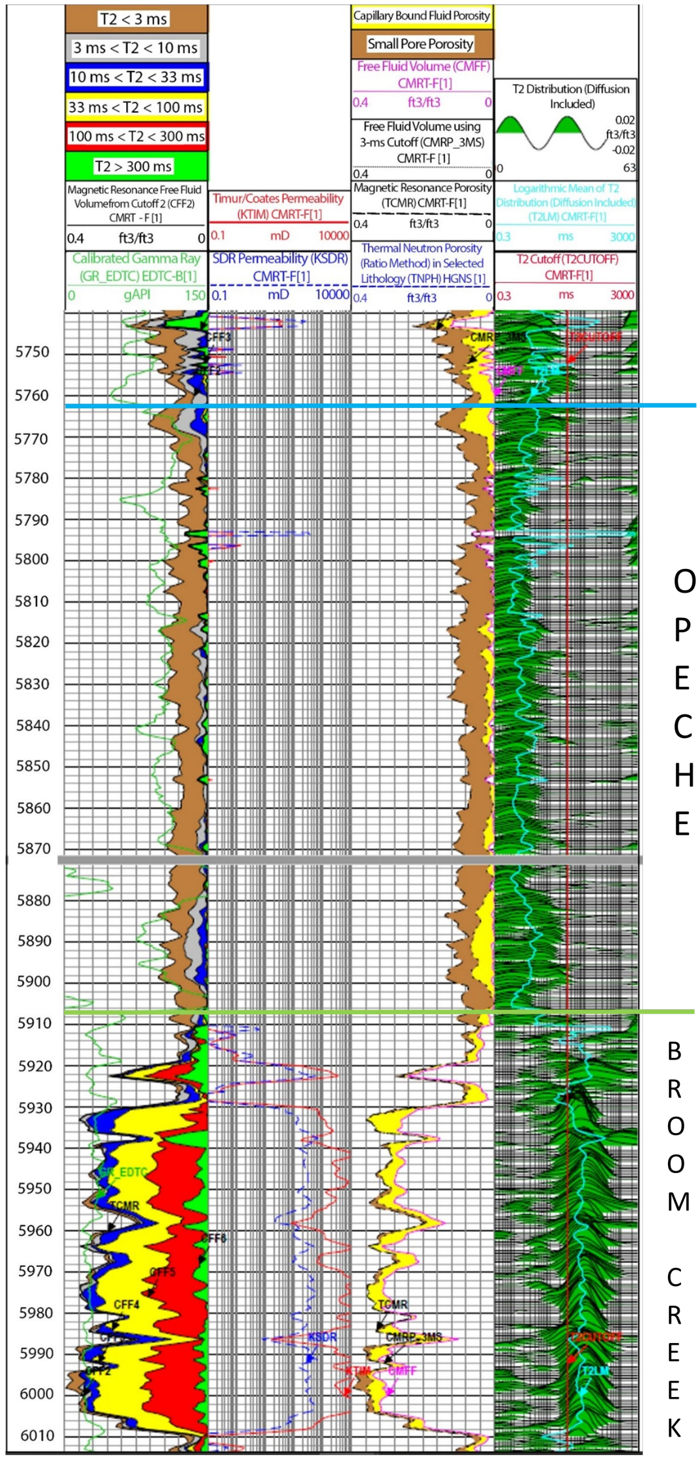


Figure 2-36. Well log display of the combinable magnetic resonance (CMR) log from the Coteau 1 well. Note: Small pore and capillary-bound fluid properties represent porosity containing immobile formation fluid. Fluid within the small pores cannot escape because of pore size, while capillary bound fluids cannot escape pores because of pressure constraints. T2 values smaller than the T2 cutoff, as seen in the fourth track, indicate smaller pore space and low permeabilities.

Laboratory measurements from the Opeche Formation core samples taken from the Coteau 1 well indicate a porosity value of 6.93% at 800 psi and 6.62% at 2,400 psi and geometric average permeability values of 0.002878 mD at 800 psi and 0.002083 mD at 2,400 psi. The lithology of the cored sections of the Opeche is primarily silty mudstone.

2.4.1.1 Mineralogy

Thin-section investigation shows that the Opeche Formation comprises alternating intervals of very fine silty mudstone and mudstone. In all, five thin sections were created over the 73 ft of core collected from the Opeche Formation. The mineral components present are clay, quartz, anhydrite, feldspar, dolomite, and iron oxides. The coarser grains are almost always surrounded by anhydrite or clay as cement or matrix. The observable porosity is very low and is due to the dissolution of quartz and feldspar. The porosity ranges between 5% and 9%. Permeability is very poor and ranges between 0.00026 to 0.0227 mD. Figure 2-37 shows examples of the texture, fabric, and nature of observable porosity for the intervals where thin sections were created. As shown, observable porosity (shown in blue) is generally isolated and not well connected throughout. Additionally, thin-section analysis shows the fine-grained, well-compacted nature of the intervals evaluated.

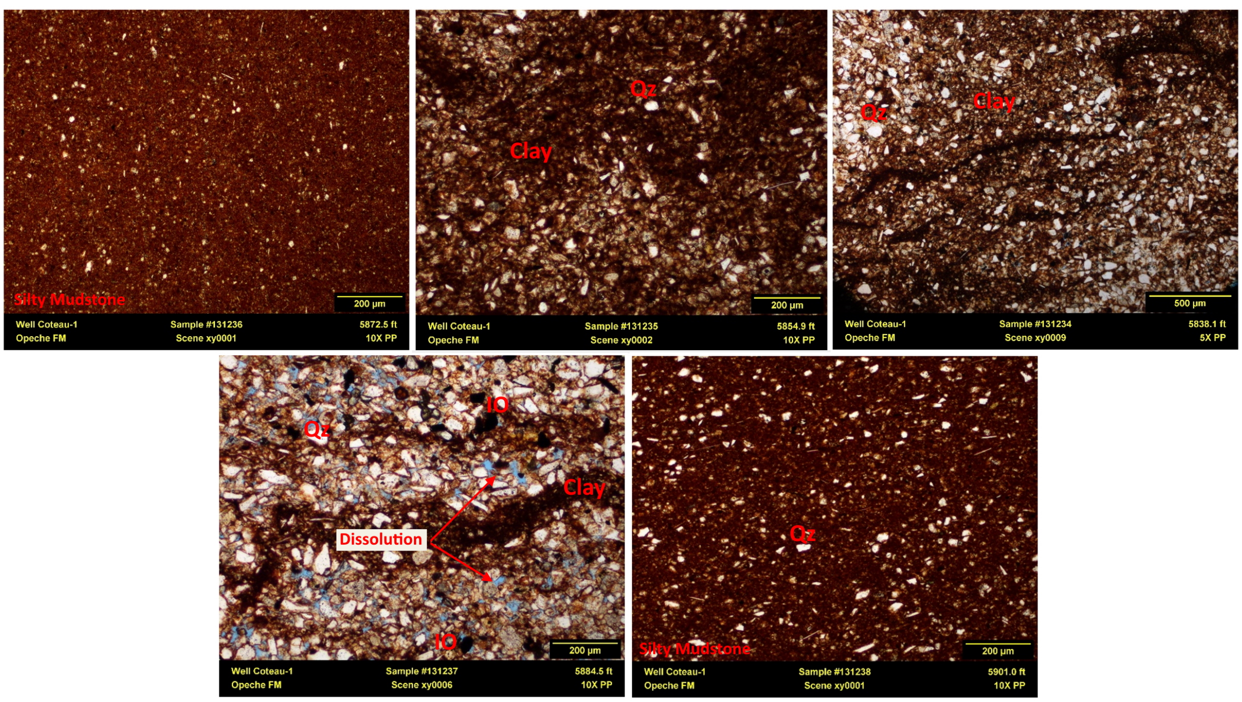


Figure 2-37. Thin sections from the five depth intervals of the Opeche Formation. As shown, the Opeche is composed of very fine silty mudstone and mudstone. Where porosity is shown (blue), it is generally isolated and disconnected.

XRD data from the five Opeche samples of the Coteau 1 core supported facies interpretations from core descriptions and thin-section analysis. The Opeche Formation mainly comprises clay, quartz, feldspar, dolomite, and anhydrite. Figure 2-38 shows the mineralogy determined from XRD data for the five samples tested through the cored interval of the Opeche Formation.

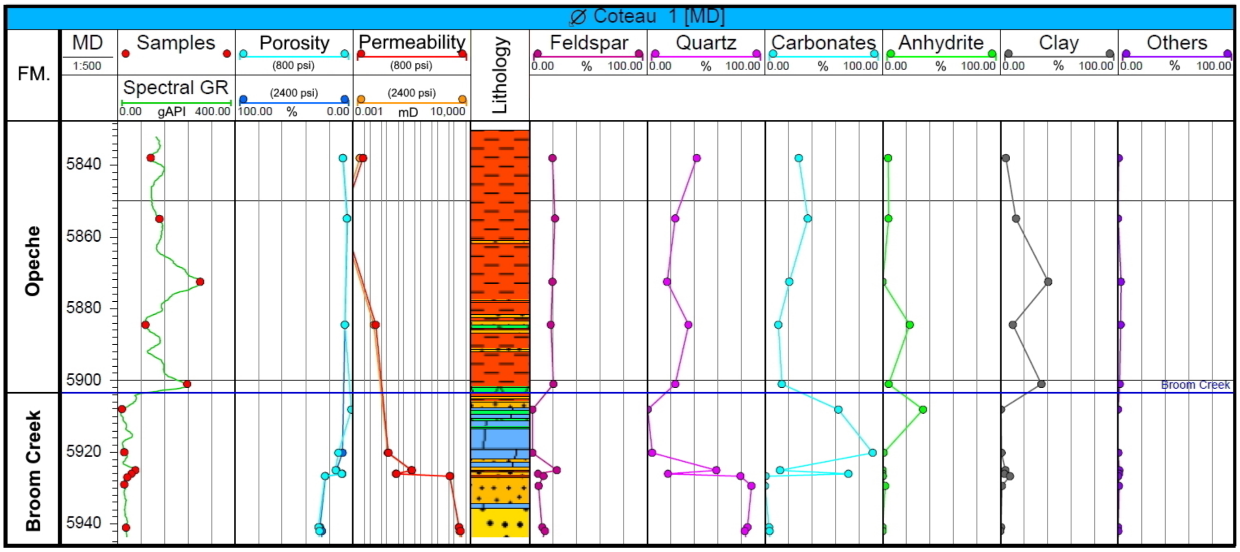


Figure 2-38. XRD data for the Opeche Formation from the Coteau 1.

XRF analysis of the Opeche Formation shown in Figure 2-39 identifies SiO_2 (44%–57%), Al_2O_3 (6%–18%), CaO (5%–15%), and MgO (3%–9%) as the major chemical constituents, correlating well with the silicate, carbonate, and aluminum-rich mineralogy determined by XRD. This is in good agreement with XRD, core description, and thin-section analysis.

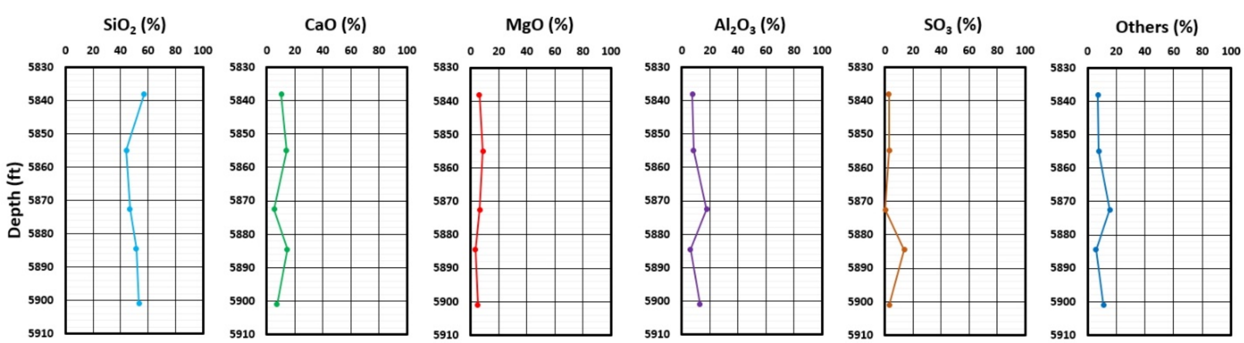


Figure 2-39. XRF data for the Opeche Formation from the Coteau 1.

2.4.1.2 Geochemical Interaction

Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected CO_2 stream on the Opeche Formation, the primary confining zone. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to CO_2 and minor amounts of H_2S at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Opeche by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the Opeche Formation. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock –CO_2/H_2S exposure boundary. The mineralogical composition of the Opeche Formation was honored (Table 2-13). The XRD data used to define mineral composition in the model correspond to a mudstone sample from the Opeche Formation. Formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone below (Table 2-14). The CO_2 stream composition was as described in Table 2-15. 96.45 mol% of the stream is CO_2, and the rest represents other components, including H_2S, the second major component of the stream. 96 mol% of CO_2 was used in the simulation instead of 96.45 mol% to keep the model input simple (Table 2.15). The 4 mol% H_2S used for this simulation represents the sum of all other components (CH_4, C_2H_6, C_3H_8, N_2) and thus overstates the actual H_2S fraction of 1.23 mol% (Table 2-15). The exposure level, expressed in moles per year, of the CO_2 stream to the cap rock used was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/year (Espinoza and Santamarina, 2017). This overestimate was done to ensure that the degree and pace of geochemical change would not be underestimated. This geochemical simulation was run for 37 years to match the reservoir injection zone geochemical model and represent 12 years of injection plus 25 years of postinjection. The simulation was performed at reservoir pressure and temperature conditions.

Table 2-13. Mineral Composition of the Opeche Derived from XRD Analysis of Coteau 1 Core Samples

Minerals, wt%	
Illite	32.3
K-Feldspar	12.7
Albite	7.6
Quartz	24.0
Dolomite	13.1
Anhydrite	5.1

Table 2-14. Formation Water Chemistry from Broom Creek Fluid Samples from Coteau 1

pH	6.7	TDS	42,800 mg/L
Total Alkalinity	853 mg/L $CaCO_3$	Calcium	1,860 mg/L
Bicarbonate	853 mg/L $CaCO_3$	Magnesium	212 mg/L
Carbonate	<20 mg/L $CaCO_3$	Sodium	12,800 mg/L
Hydroxide	<20 mg/L $CaCO_3$	Potassium	516 mg/L
Sulfate	469 mg/L	Strontium	70.8 mg/L
Chloride	24,900 mg/L	Iron	392 mg/L

Table 2-15. Composition of the Injection Stream with Constituents Normalized to 100% Mole Fraction

Component Flows	mol%	mol% Used in Simulation
CO_2	0.9645	0.960
H_2S	0.0123	0.04
CH_4	0.0054	
C_2H_6	0.0096	
C_3H_8	0.0028	
N_2	0.0054	

Results showed geochemical processes at work. Figures 2-40 through 2-43 show results from geochemical modeling. Figure 2-40 shows change in fluid pH over time as CO_2/H_2S enters the system. For the cell at the CO_2 interface, C1, the pH starts declining from an initial pH of 7.04 and stabilizes at a level of 5.34 after 12 years of simulation time. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH only begins to change after Year 27. Lastly, the pH is unaffected in Cell C3, indicating CO_2/H_2S does not penetrate this cell within the first 37 years.

Figure 2-41 shows the change in mineral dissolution and precipitation in grams per cubic meter of rock. The dashed lines are for Cell C1; solid lines that are only faintly seen in the figure are for Cell C2, 1.0 to 2.0 meters into the cap rock. The net change due to precipitation or dissolution in Cell C2 is less than 10 kg per cubic meter per year with little to no precipitation or dissolution taking place after injection ceases in Year 2034. Albite, K-feldspar, and anhydrite start to dissolve from the beginning of the simulation period while illite, quartz, and calcite start to precipitate for Cell C1. The presence of dissolved H_2S and aqueous iron in the Opeche Formation water (Table 2-14) favors minor amounts (less than 10 g) of pyrite precipitation. Any effects in Cell C3 are too small to represent at this scale.

Figure 2-42 represents the initial fractions of potentially reactive minerals in the Opeche Formation based on XRD data shown in Table 2-13. The overall Opeche lithology is characterized by a higher percentage of clay minerals. The expected dissolution of these minerals in weight percentage is also shown for Cells 1 and Cell 2 of the model. In Cell 1, albite, K-feldspar, and anhydrite are the primary minerals that go into dissolution. Dissolution (wt%) in Cell 2 is minimal (<0.5 wt%).

Figure 2-43 shows the change in porosity of the cap rock. Cell 1 experiences an initial increase in porosity as it is first exposed to CO_2/H_2S because of dissolution. The porosity decreases to nearly its initial condition after Year 13 because of precipitation. As dissolution occurs in Cell 1, reaction products move into Cell 2, where they precipitate, causing the porosity to slightly decrease. No significant change in porosity is seen in Cell 3 during the 37-year duration of the simulation. The net porosity changes from dissolution and precipitation are miniscule and unchanging in later years of the simulation. These results suggest that geochemical change from exposure to CO_2 and H_2S is minor and will not cause substantive deterioration of the Opeche cap rock.

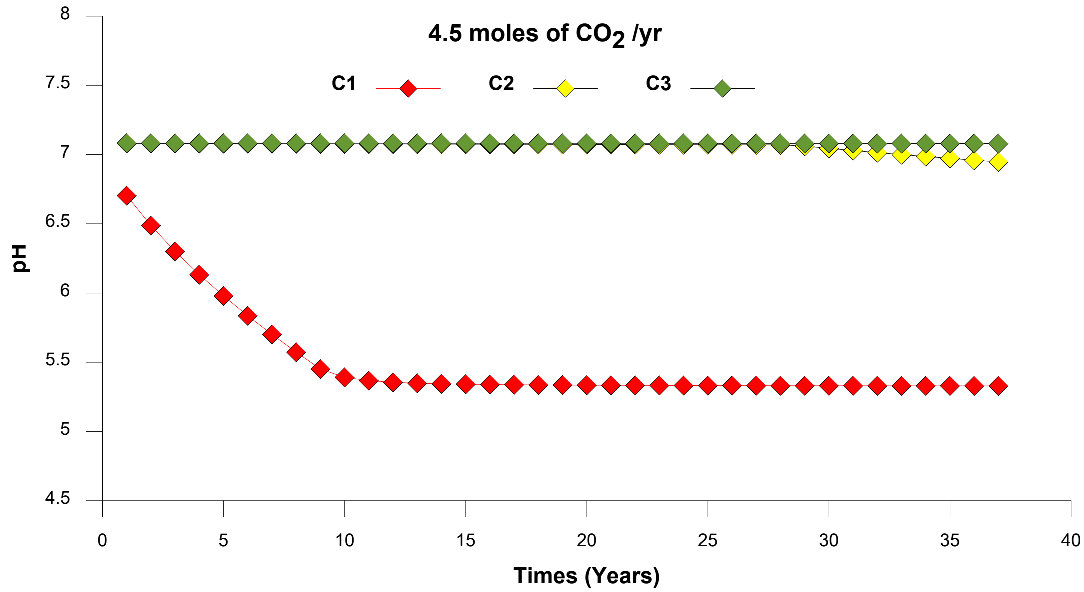


Figure 2-40. Change in fluid pH vs. time. The red line shows pH for the center of Cell C1, 0.5 meters above the Opeche cap rock base. The yellow line shows Cell C2, 1.5 meters above the cap rock base. The green line shows Cell C3, 2.5 meters above the cap rock base. pH for Cell C2 does not begin to change until after Year 27.

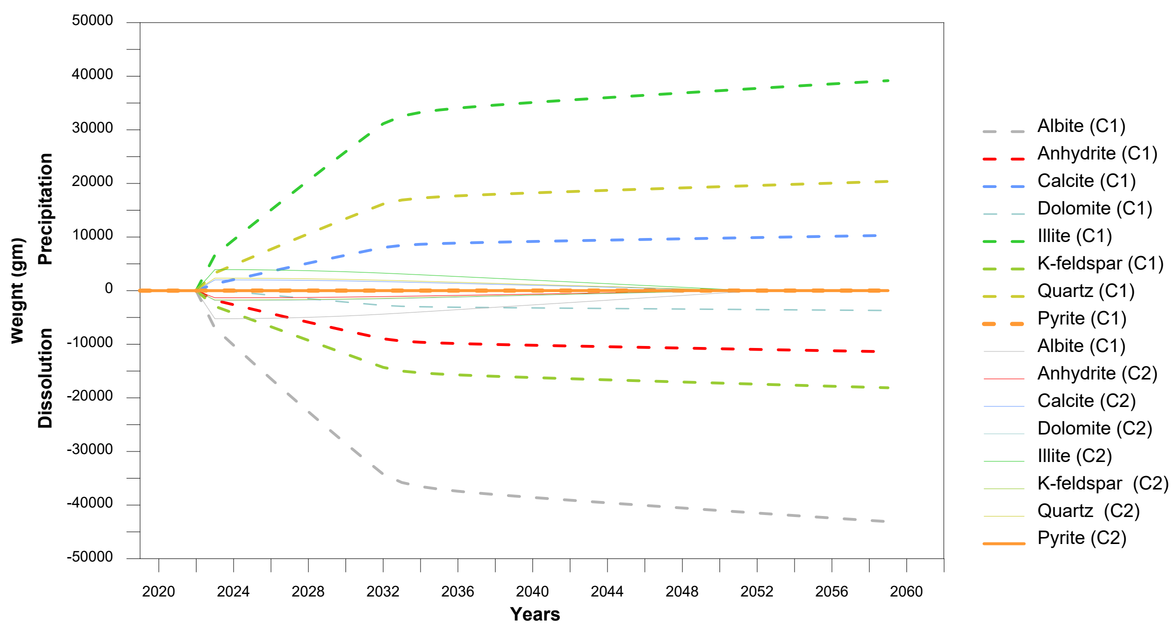


Figure 2-41. Dissolution and precipitation of minerals in the Opeche cap rock. Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. Solid lines show results for Cell C2, 1.5 meters above the cap rock base; these changes are barely visible. Results from Cell C3, 2.5 meters above the cap rock base, are not shown as they are too small to be seen at this scale.

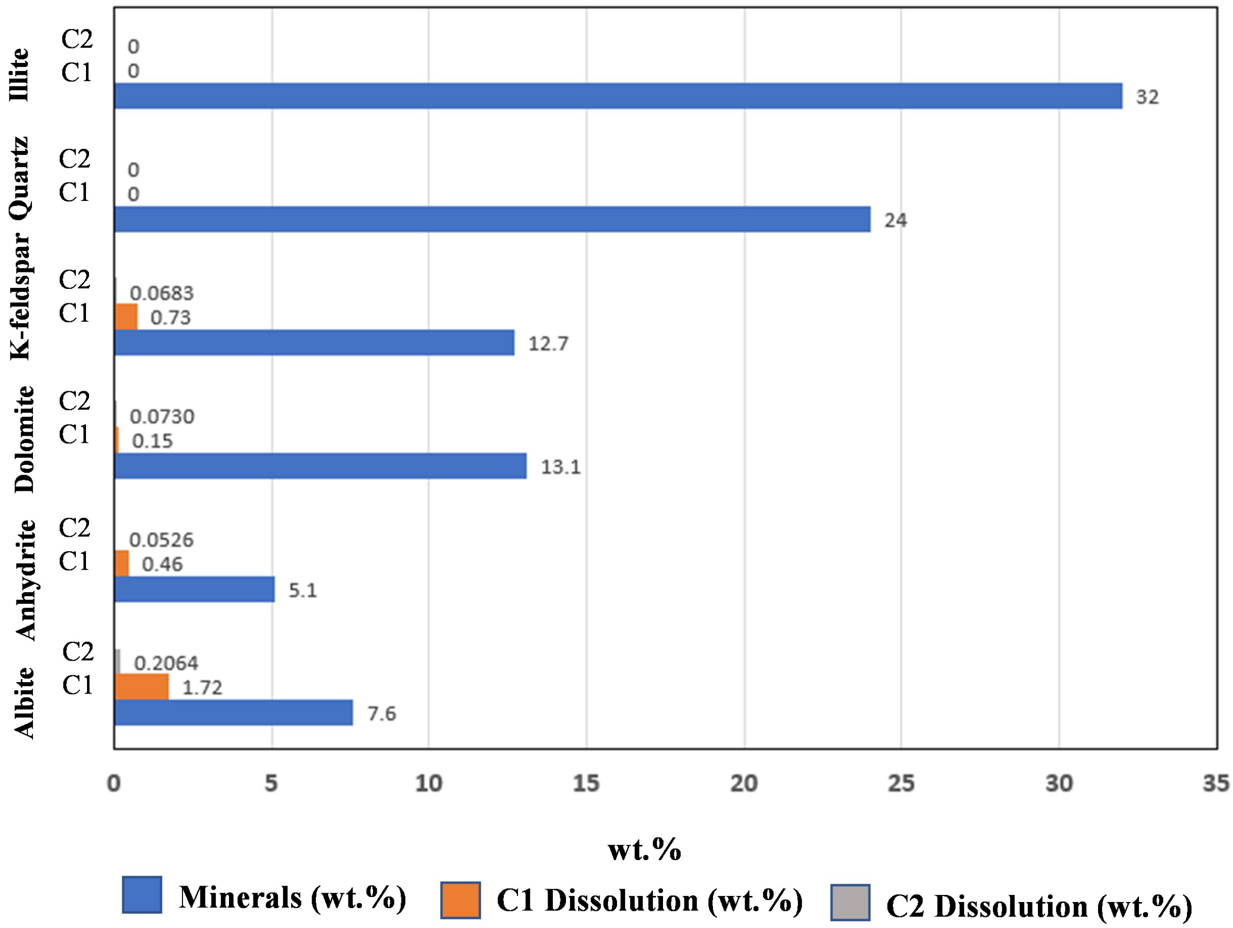


Figure 2-42. Weight percentage (wt.%) of potentially reactive minerals present in the Opeche Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray) after 12 years of injection plus 25 years of postinjection.

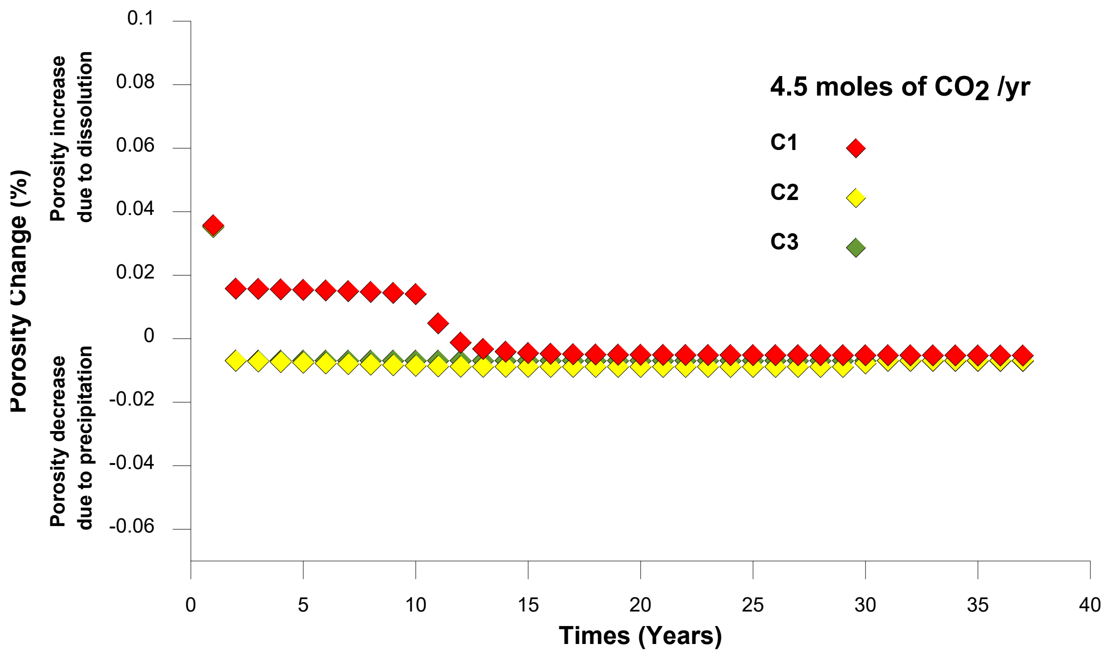


Figure 2-43. Change in percent porosity of the Opeche cap rock. Red line shows porosity change calculated for Cell C1 at 0.5 meters above the cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals, and negative change is due to mineral precipitation.

2.4.2 Additional Overlying Confining Zones

Several other formations provide additional confinement above the Opeche interval. Impermeable rocks above the primary seal include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-16). Together with the Opeche interval, these formations are 1,106 ft thick and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-44). Above the Inyan Kara Formation, 2,657 ft of impermeable rocks act as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (Figure 2-45). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-16).

Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (Opeche) (data based on the Coteau 1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,753	1,931	0
Greenhorn	Shale	3,685	376	1,931
Mowry	Shale	4,061	94	2,307
Skull Creek	Shale	4,156	254	2,402
Swift	Shale	4,800	411	3,046
Rierdon	Shale	5,212	205	3,458
Piper (Kline Member)	Limestone	5,417	112	3,663
Piper (Picard Member)	Shale	5,529	233	3,775

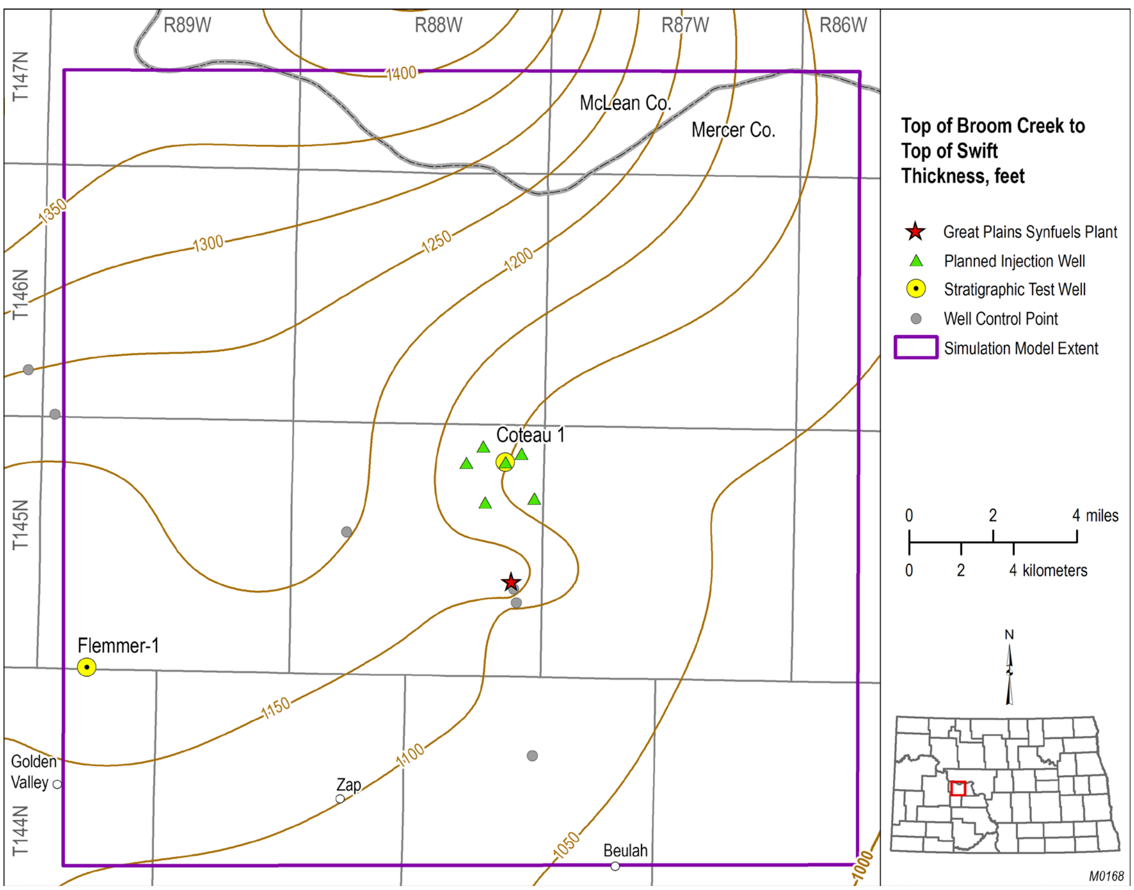


Figure 2-44. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones.

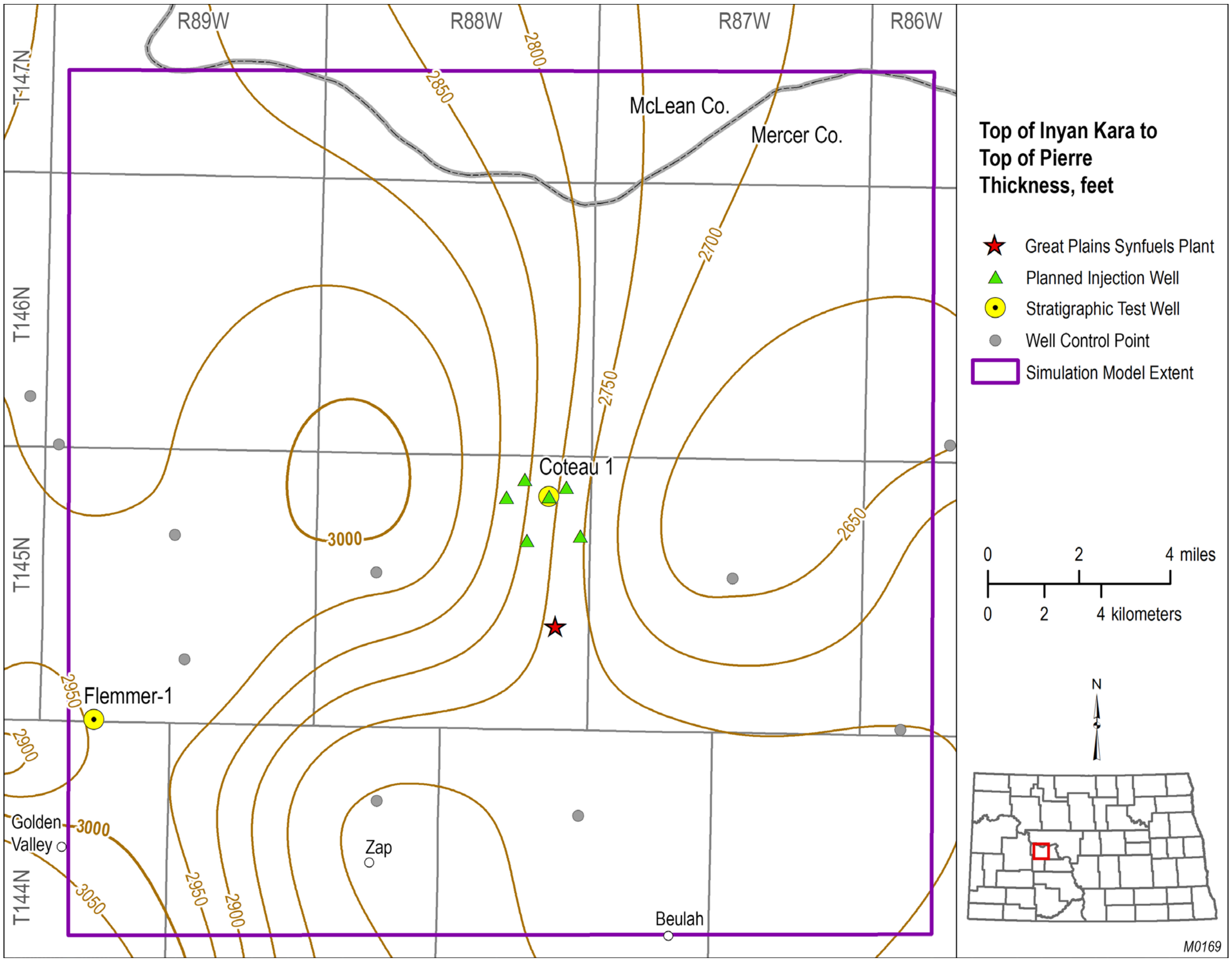


Figure 2-45. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone.

These formations between the Broom Creek and Inyan Kara and between the Inyan Kara and the lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin (Downey, 1986; Downey and Dinwiddie, 1988).

Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Inyan Kara Formation represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring using annual temperature and pulse neutron logging of the Inyan Kara Formation provides an additional opportunity for mitigation and remediation (Section 5). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at the Coteau 1 well is 4,512 ft, and the formation itself is 378 ft thick.

2.4.3 Lower Confining Zone

The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, mudstone, and anhydrite. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, with relatively high GR character that can be correlated across the Great Plains CO_2 Sequestration Project area (Figure 2-6). The Amsden Formation is 6,164 ft below land surface and approximately 300 ft thick at the Coteau 1 well (Figures 2-46 and 2-47, Table 2-12).

The contact between the overlying Broom Creek and Amsden Formations is evident on wireline logs as there is a lithological change from the porous sandstones of the Broom Creek Formation to the dolostone and anhydrite beds of the Amsden Formation. This lithologic change is recognized in the core from the Coteau 1 well. The lithology of the cored section of the Amsden Formation from the Coteau 1 well is dolostone, anhydrite, and mudstone with laminated, fine-grained sandstone and siltstone. Data acquired from the six core plug samples taken from the

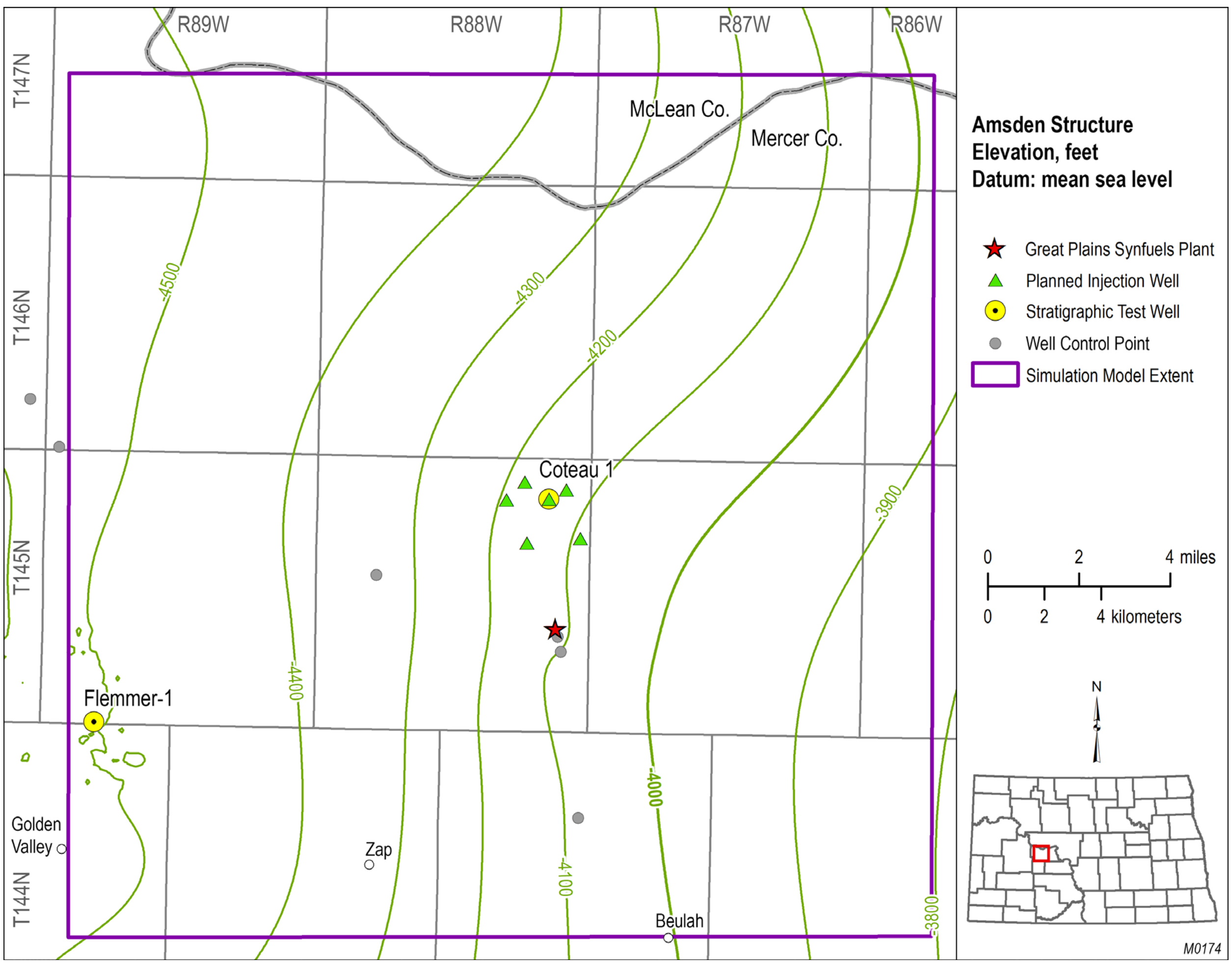


Figure 2-46. Structure map of the Amsden Formation across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops).

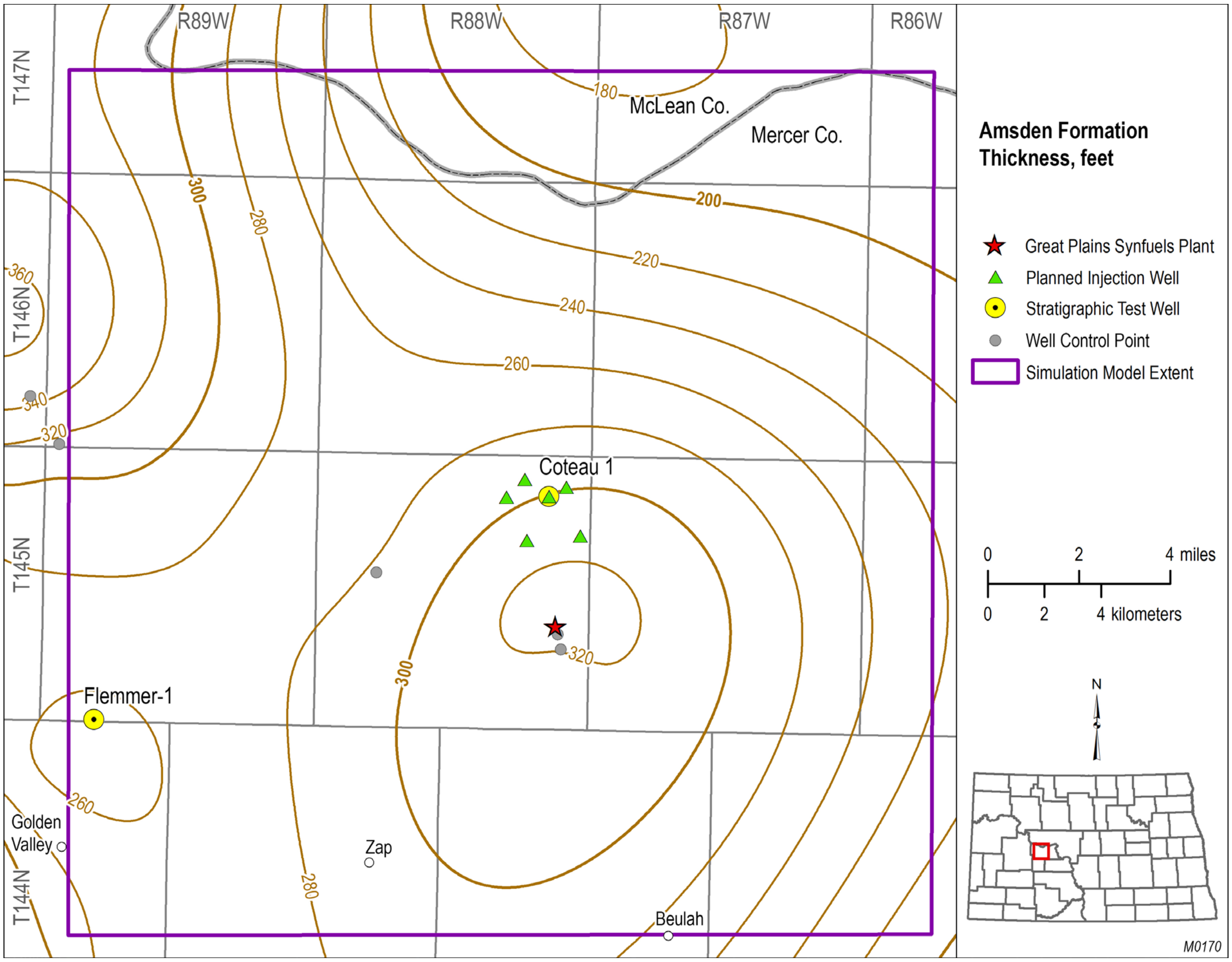


Figure 2-47. Isopach map of the Amsden Formation across the greater Great Plains CO_2 Sequestration Project area.

Amsden Formation show porosity values ranging from 1.00% to 5.27% at 800 psi and 0.91% to 4.54% at 2,400 psi. Permeability values range from 0.0000557 to 1.2 mD at 800 psi and 0.0000642 to 0.215 mD at 2,400 psi (Table 2-17).

Table 2-17. Amsden Core Sample Porosity and Permeability from Coteau 1

Sample Depth, ft	Porosity % (800 psi)	Permeability, mD (800 psi)
6,169	2.89	0.000198
6,183	1.04	0.0000557
6,190	2.96	0.00294
6,206	1.00	0.0000865
6,239	1.23	0.000709
6,242	5.27	1.2

2.4.3.1 Mineralogy

Thin-section analysis shows that the Amsden Formation comprises dolomite, anhydrite, sandy dolomite, and shaly sand. Six thin sections were created and described for the 83-ft cored Amsden section. The dolomite is expressed by very fine to fine-sized dolomite crystals with the presence of quartz of variable size and shape, feldspar, clay, anhydrite, and iron oxides. The porosity is very low and is mainly intragranular because of dissolution with an average of 2%.

Anhydrite is present as beds, nodules, and laminations in association with the dolomite intervals. Minor iron oxides inclusions are present. The porosity is almost nonexistent.

The dolomite is mainly composed of dolomite crystals and grains of quartz. Minor iron oxides and feldspar are present, with rare occurrence of anhydrite observed. The grains of quartz are almost always separated by dolomite matrix. The porosity is mainly due to the dissolution of feldspar and averages 1%.

Finally, the anhydritic sandstone interval is composed of quartz, clay, carbonates, and anhydrite. Iron oxides are present in some parts of the rock matrix as rims around some quartz grains and mostly fill the stylolite surfaces and some rare fractures. The grains of quartz are almost always separated by carbonate cement, clay minerals and, specifically, anhydrite cement. In this lithofacies, anhydrite acts as cement in most parts of the interval by connecting sand grains together and decreasing the overall porosity of the lithofacies. The porosity averages 3% and is mainly due to the dissolution of feldspar and quartz (Figure 2-48).

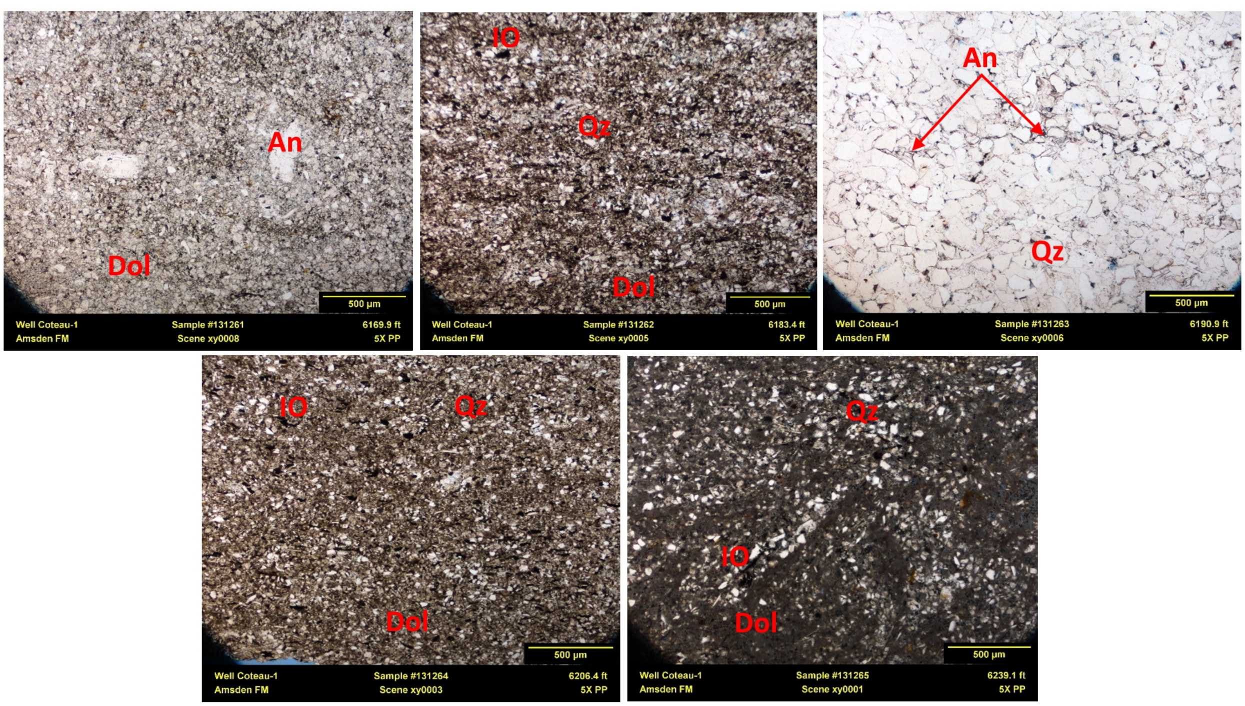


Figure 2-48. Thin sections from the five depth intervals of the Amsden Formation.

XRD was performed (Figure 2-49), and the results confirm the observations made during core analyses and thin-section description.

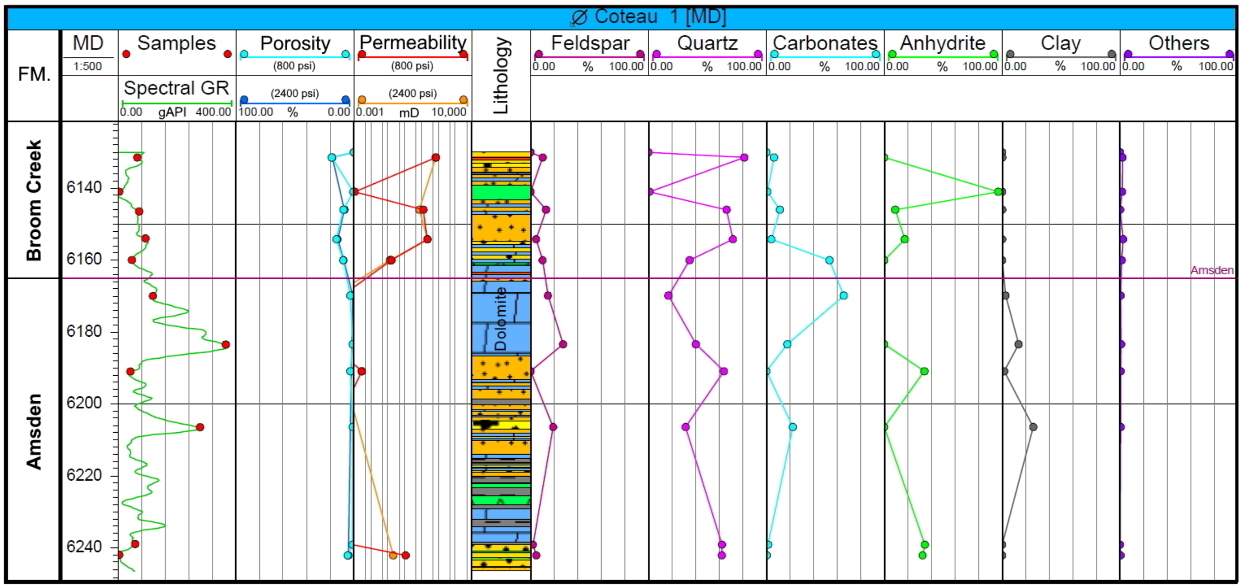


Figure 2-49. XRD data for the Amsden Formation from the Coteau 1.

XRF data shows that the Amsden Formation at the contact with the Broom Creek is dominated by CaO and MgO (major chemical components of dolomite). Deeper samples are more anhydrite-rich, fine- to medium-grained sandstones, as shown by the high percentage of SiO_2, CaO, and SO_3 (Figure 2-50).

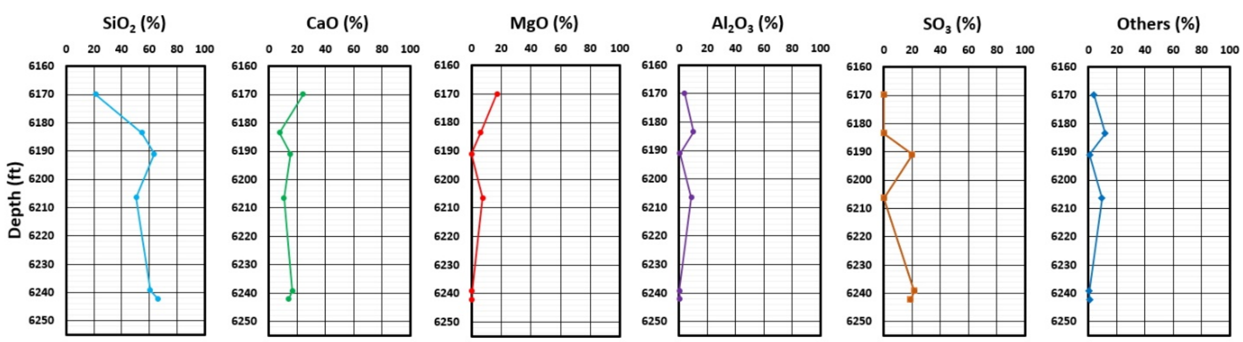


Figure 2-50. XRF data for the Amsden Formation from the Coteau 1.

2.4.3.2 Geochemical Interaction

The Broom Creek's underlying confining layer, the Amsden Formation, was investigated using PHREEQC geochemical software. A vertically oriented 1D simulation was created using a stack of six cells, each cell 1 meter in thickness. The formation was exposed to CO_2 and a minor amount of H_2S at the top boundary of the simulation which were allowed to enter the system by advection and dispersion processes. Direct contact between the Amsden and free-phase saturation from the injection stream is not expected to occur. Results were calculated at the center of each cell below the confining layer–CO_2/H_2S exposure boundary. The mineralogical composition of the Amsden was honored (Table 2-18). The Amsden formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone above. The CO_2 stream composition used is described in Section 2.4.1.2. The Amsden Formation temperature and pressure were collected from the 1D MEM. Two different pressure levels, 2,755 and 3,447 psi, were applied to the CO_2/H_2S saturated brine at the base of the Broom Creek Formation. These values represent the initial and potential maximum pore pressure levels. The higher-pressure results are shown here to represent a potentially more rapid pace of geochemical change.

Table 2-18. Mineral Composition of the Amsden Derived from XRD Analysis of Coteau 1 Core Samples at a Depth of 6,183 ft MD

	Sample Depth
	6,183 ft
Mineral	**wt%**
Illite/Muscovite	13.8
Fe Minerals	3.5
K-Feldspar	18.3
Albite	9.3
Quartz	40.1
Dolomite	14.3

Results show geochemical processes at work. Figures 2-51 through 2-56 show results from the geochemical modeling.

Figure 2-51 shows change in fluid pH over 37 years of simulation time as CO_2/H_2S enters the system. Initial change in pH in all of the cells from 7.04 to 7 is related to initial equilibration of the model. For the cell at the CO_2/H_2S interface, C1, the pH begins to decline after Year 7, declines to a level of 6.3 after 12 years of injection, and slowly declines further to 5.5 after an additional 25 years of post-injection. Progressively less or slower pH change occurs for each cell that is more distant from the CO_2/H_2S interface. The pH for Cells 5–6 did not decline over the 37 years of simulation time.

Figure 2-52 shows that CO_2 does not penetrate more than 4 meters (represented by Cells C5–C6) within the 37 years simulated.

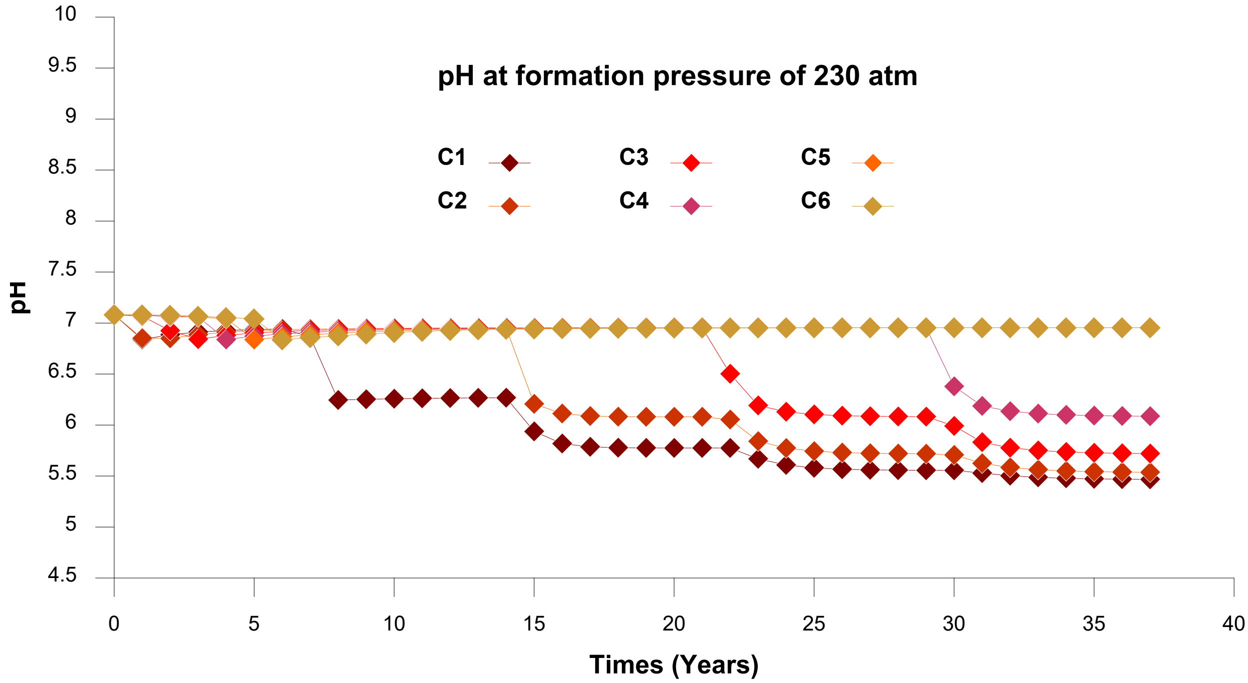


Figure 2-51. Change in fluid pH in the Amsden underlying confining layer for Cells C1‑C6.

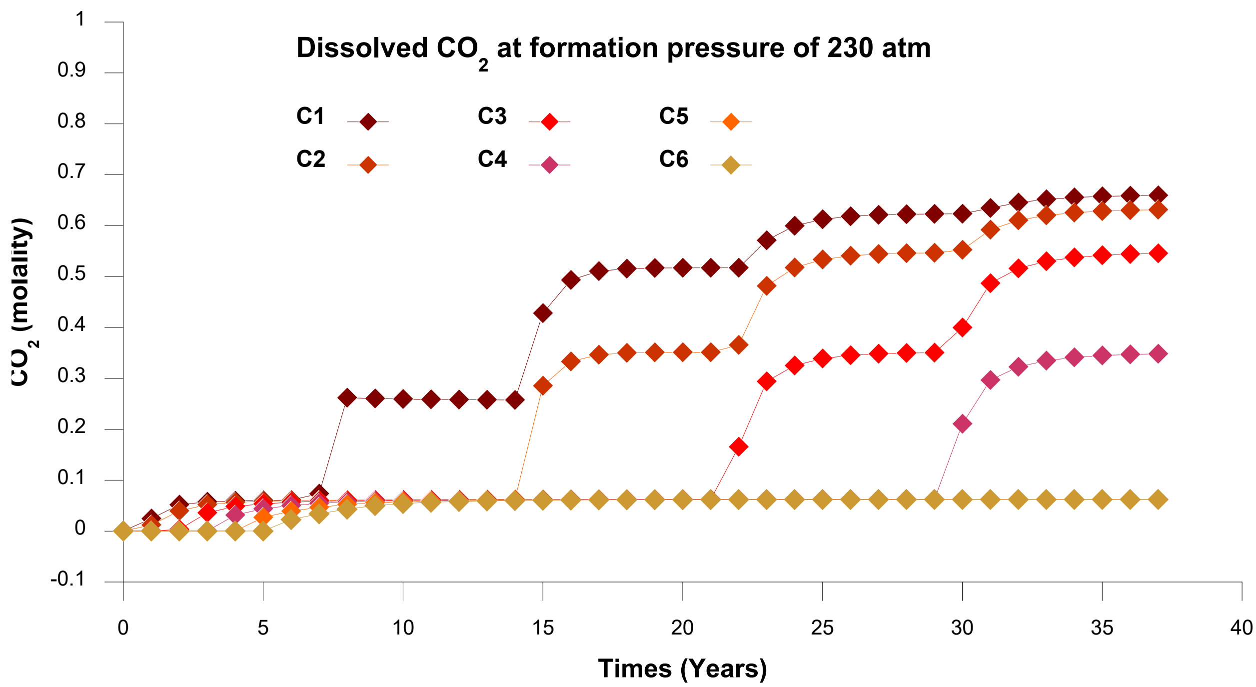


Figure 2-52. CO_2 concentration (molality) in the Amsden Formation underlying confining layer for Cells C1‑C6.

Figure 2-53 shows the changes in mineral dissolution and precipitation in grams per cubic meter. For Cells C1 and C2, albite and K-feldspar start to dissolve from the beginning of the simulation period while quartz and illite clays start to precipitate and are largely a reflection of the paths of dissolution of albite and K-feldspar during the time of the simulation. Pyrite (FeS_2) precipitation is favored by the presence of dissolved H_2S and aqueous iron in the formation water.

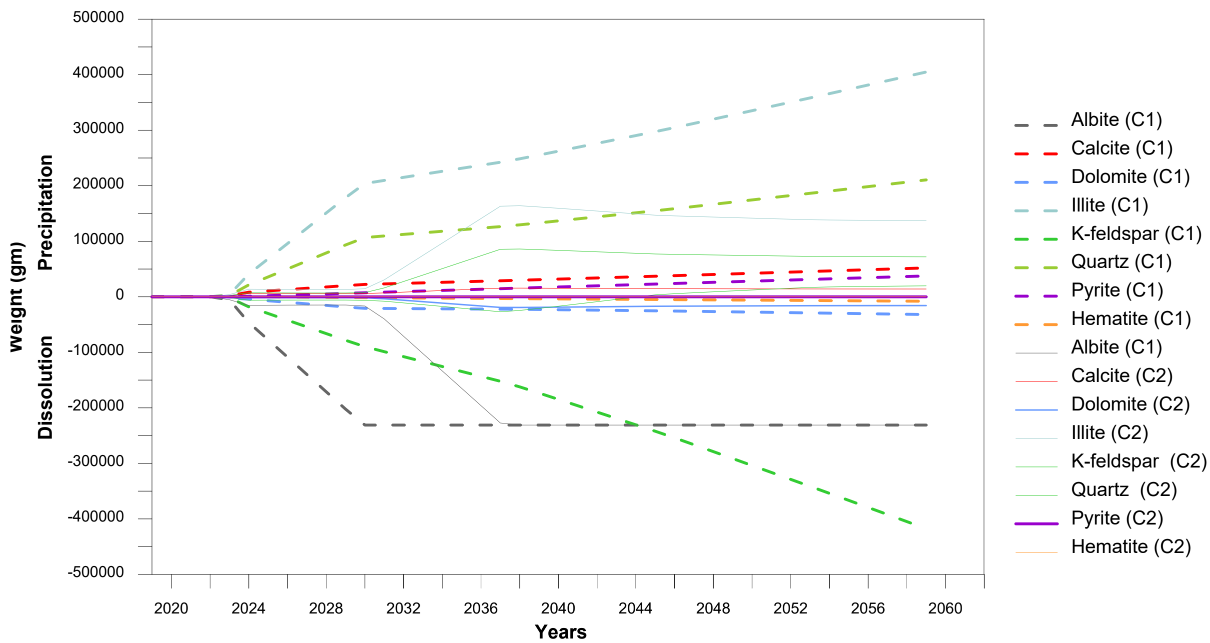


Figure 2-53. Dissolution and precipitation of minerals in the Amsden underlying confining layer. Dashed lines show results for Cell C1, 0 to 1 meter below the Amsden top. Solid lines show results for Cell C2, 1 to 2 meters below the Amsden top.

Figure 2-54 represents the initial fractions of potentially reactive minerals in the Amsden Formation based on the XRD data shown in Table 2-18. The expected dissolution of these minerals in weight percentage is also shown for Cells C1 and C2 of the model. In Cell 1, albite and K-feldspar are the primary minerals that go into dissolution. In Cell 2, albite and dolomite are the primary minerals that go into dissolution. No dissolution is observed for illite and quartz. These dissolved minerals are almost completely replaced by the precipitation of other minerals, as shown in Figure 2-55.

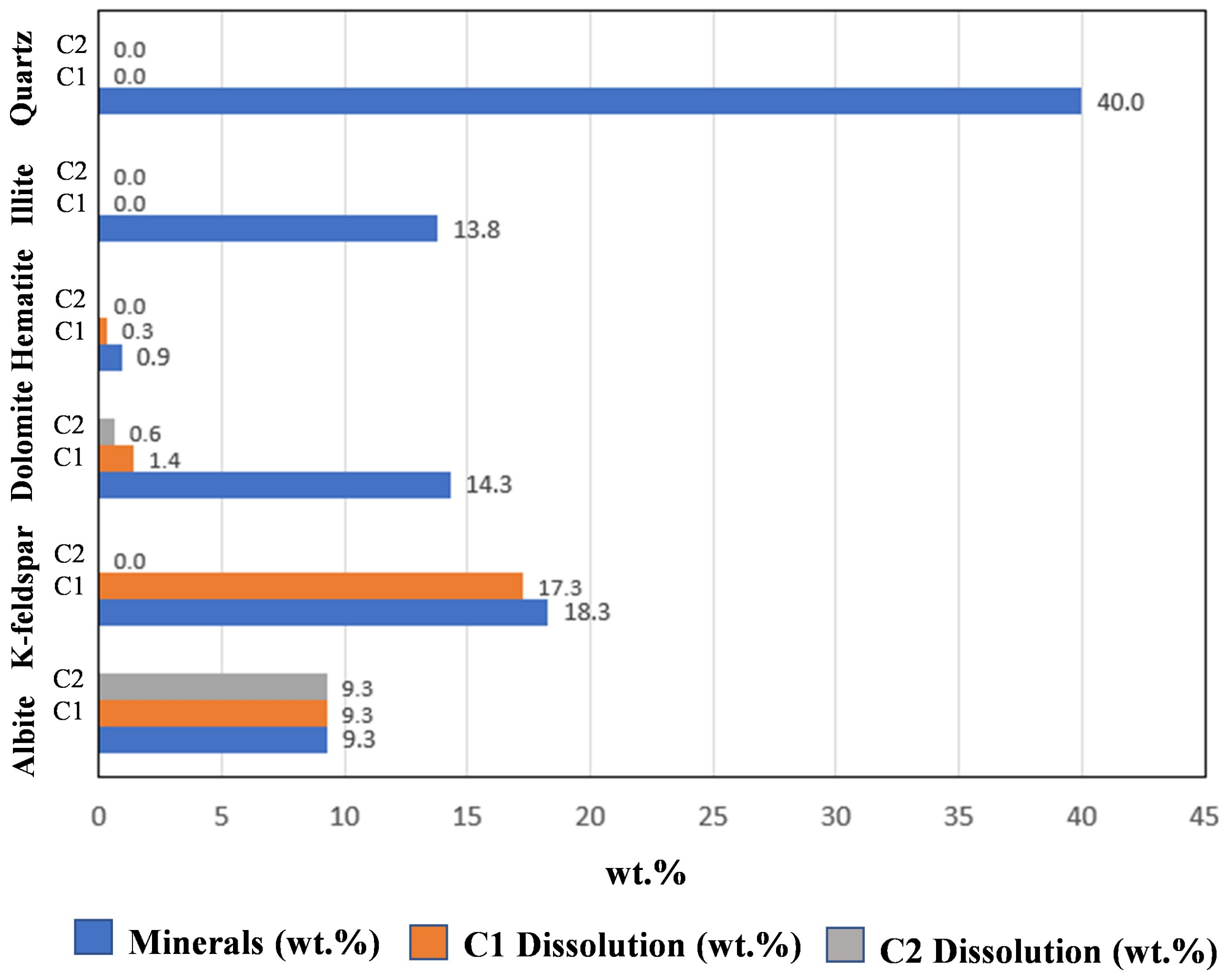


Figure 2-54. Weight percentage (wt.%) of potentially reactive minerals present in the Amsden Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 37 years of simulation time.

Figure 2-55 represents expected minerals to be precipitated in weight (%) shown for Cells C1 and C2 of the model. In Cell 1, illite, quartz, calcite, and pyrite are the minerals to be precipitated. In Cell 2, illite, quartz, calcite, and K-feldspar are the minerals to be precipitated. Pyrite precipitation is a result of the formation fluids reacting with the H_2S present in the CO_2 stream. While pyrite precipitation is also expected to occur if CO_2 encounters the overlying confining zone, the resulting weight (%) is negligible compared to the other minerals formed.

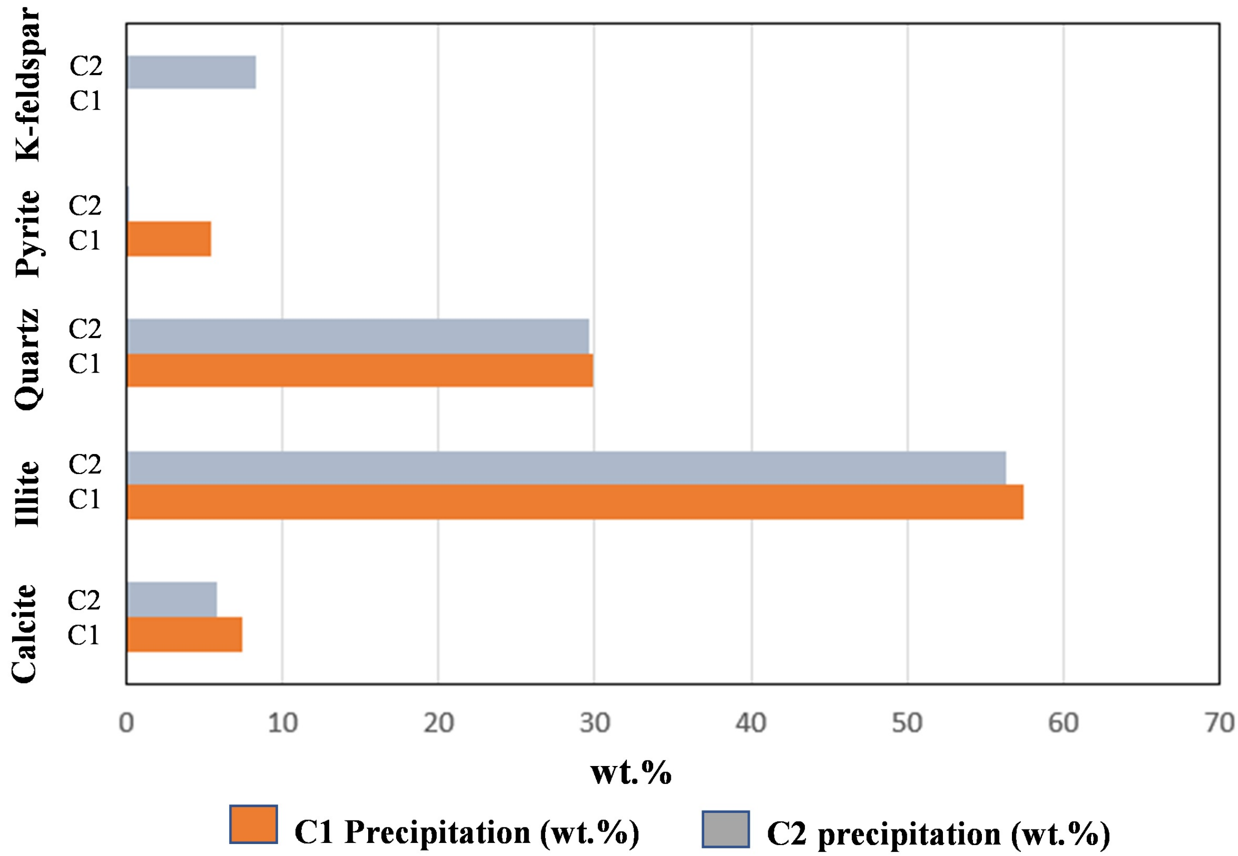


Figure 2-55. Weight percentage (wt.%) of precipitated minerals in the Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 37 years of simulation time.

Change in porosity (% units) of the Amsden underlying confining layer is displayed in Figure 2-56 for Cells C1–C3. The overall net porosity changes from dissolution and precipitation are minimal, less than 0.2% change during the life of the simulation. Cell C1 shows an initial porosity increase of 0.12%, but this change is temporary, and the cell quickly returns to its near initial porosity value of 2.0%. At later times, no significant porosity changes were observed. Cells C4–C6 showed similar results, with net porosity change being less than 0.03%.

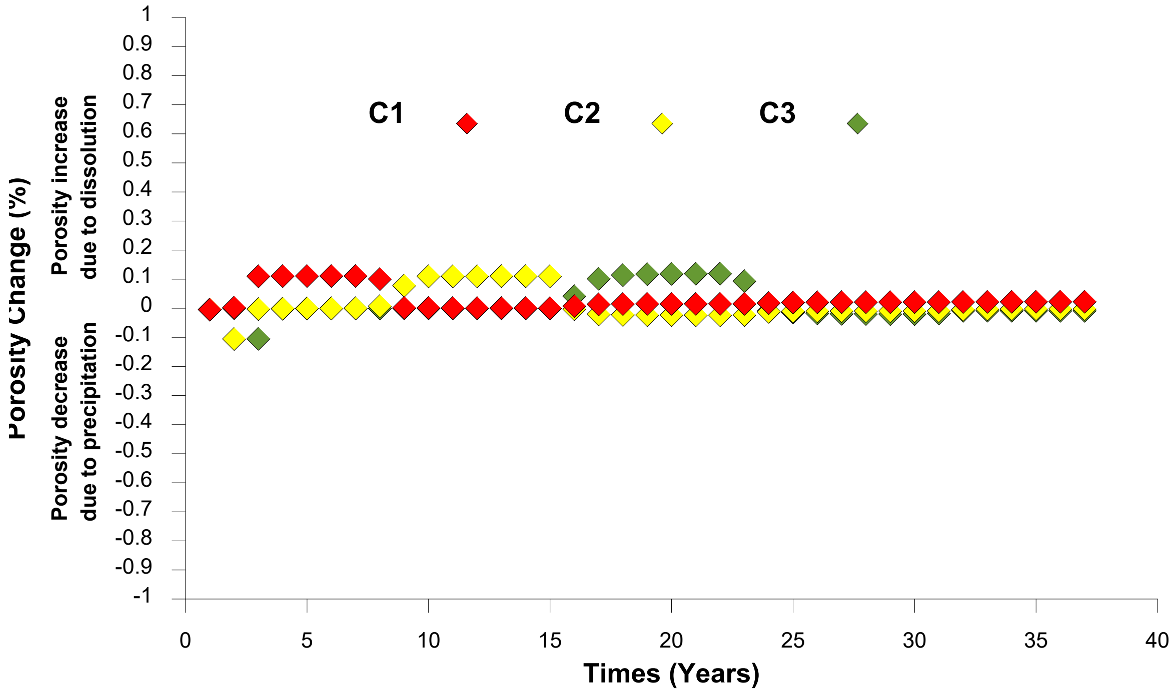


Figure 2-56. Change in percent porosity in the Amsden underlying confining layer red line shows porosity change for Cell C1, 0 to 1 meter below the Amsden Formation top. Yellow line shows Cell C2, 1 to 2 meters below the Amsden top. Green line shows Cell C3, 2 to 3 meters below the Amsden top. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals, and negative change is due to mineral precipitation.

2.4.4 Geomechanical Information of Confining Zones

2.4.4.1 Fracture Analysis

Fractures within the Opeche Formation, the overlying confining zone, and the Amsden Formation, the underlying confining zone, have been assessed during the description of the Coteau 1 well core. Observable fractures were categorized by attributes including morphology, orientation, aperture, and origin. Secondly, natural fractures and in situ stresses were assessed by Schlumberger through the interpretation of the fullbore formation microimager (FMI), bulk density (RHOB), dipole shear sonic (DTS), and dipole compressional sonic (DTC) logs acquired during the drilling of the Coteau 1 well.

2.4.4.2 Fracture Analysis Core Description

Fractures within the Opeche Formation are primarily litho-bound resistive fractures. They are commonly filled with anhydrite. However, some litho-bound conductive fractures are highlighted. The presence of microfaults is underlined mainly in the lower part of the Opeche Formation. The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. The aperture varies from closed to, in rare cases, centimeter-scale.

The Amsden Formation could be considered as a nonfractured interval. However, few litho-bound conductive fractures are commonly coincident with the horizontal compaction features (stylolite) observed.

2.4.4.3 Borehole Image Fracture Analysis (FMI)

Schlumberger's FMI log was chosen to evaluate the geomechanical condition of the formation in the subsurface. This log provides a 360-degree image of the formation of interest and can be oriented to provide an understanding of the general direction of features observed. Figure 2-57 shows examples of the interpreted FMI log for the Coteau 1 well. The examples show the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche FMI borehole image analysis. The far-right track on Figure 2-57 provides information on surface boundaries, slump deformed, and notes the presence of electrically conductive and resistive features. The latter are interpreted as minor anhydrite-filled fractures. Figure 2-58 shows two sections of the interpreted borehole imagery and primary features observed. Figure 2-58 demonstrates that the tool provides information on slump deformation, conductive fractures, and microfaults. These microfaults are identified in Figure 2-58 and are likely clay-filled because of their electrically conductive signal. Figure 2-59 and Figure 2-60 show two thin-section images and give an indication of different minerals within the reservoir with observed changes in the electrical response shown on the FMI log. Also, some drilled-induced fractures are highlighted in the upper part of the Opeche Formation.

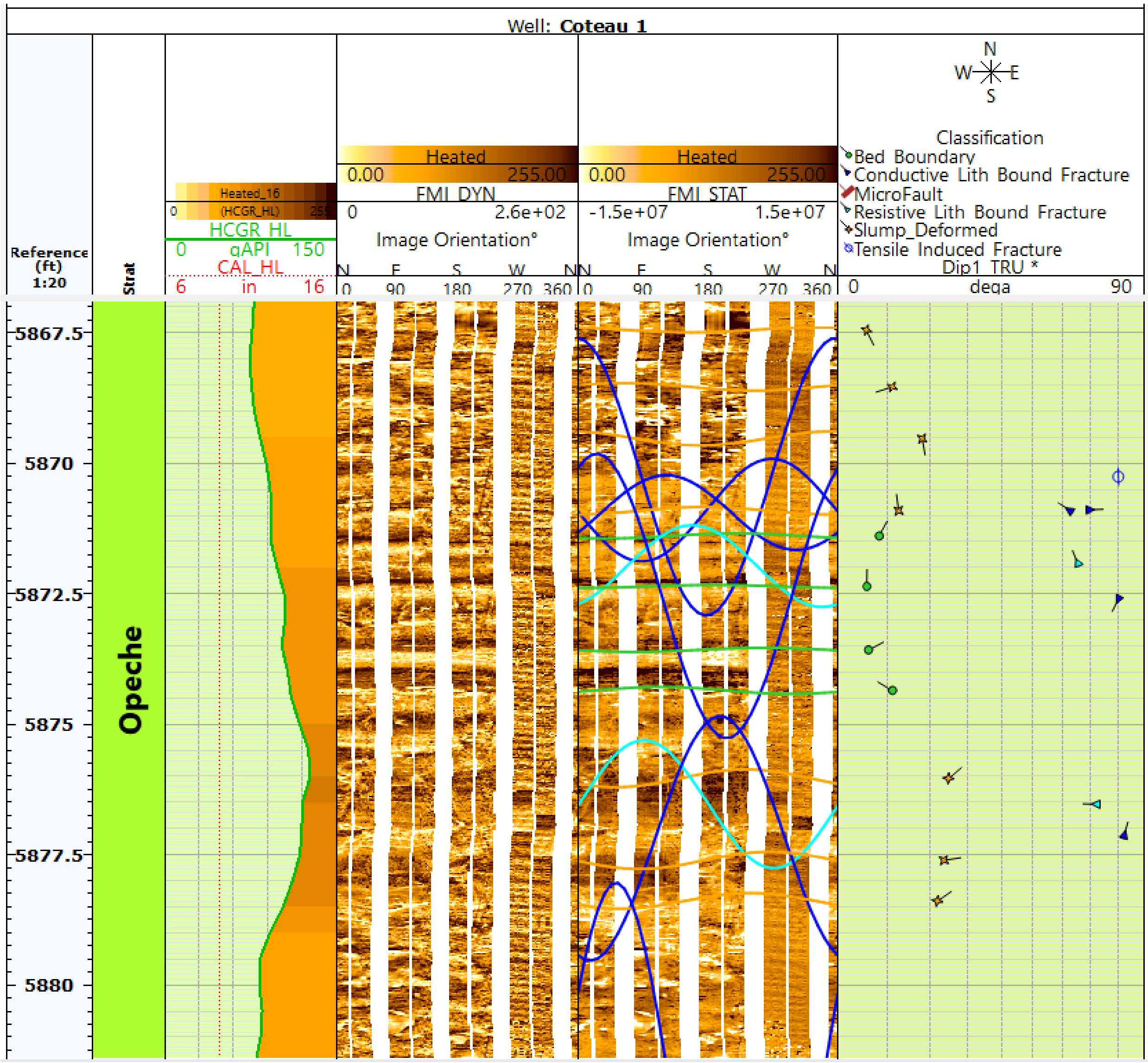


Figure 2-57. Examples of the interpreted FMI log for the Coteau 1 well. The examples show the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche FMI borehole image analysis.

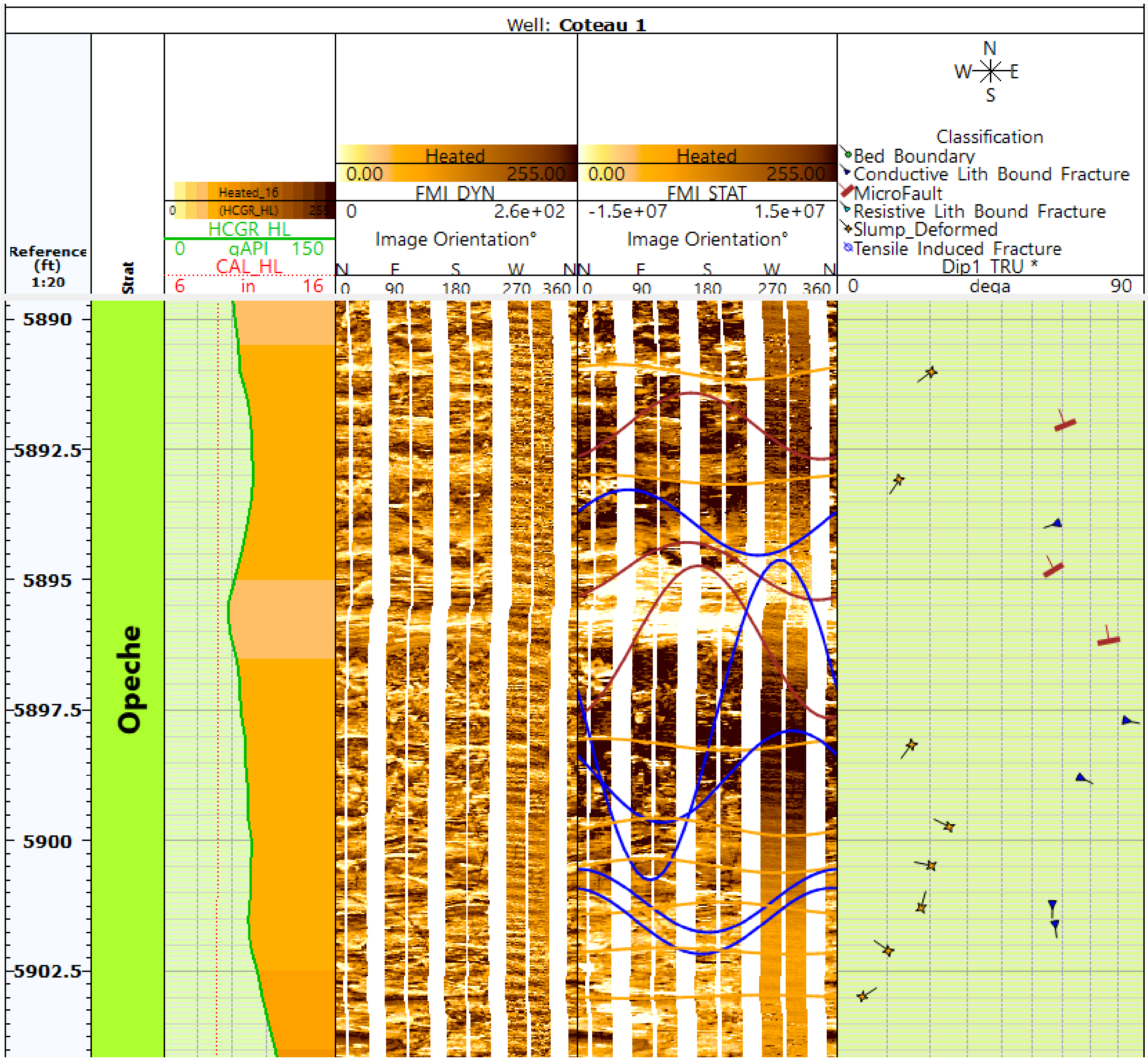


Figure 2-58. Examples of the interpreted FMI log for the Coteau 1 well. The examples show the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche FMI borehole image analysis.

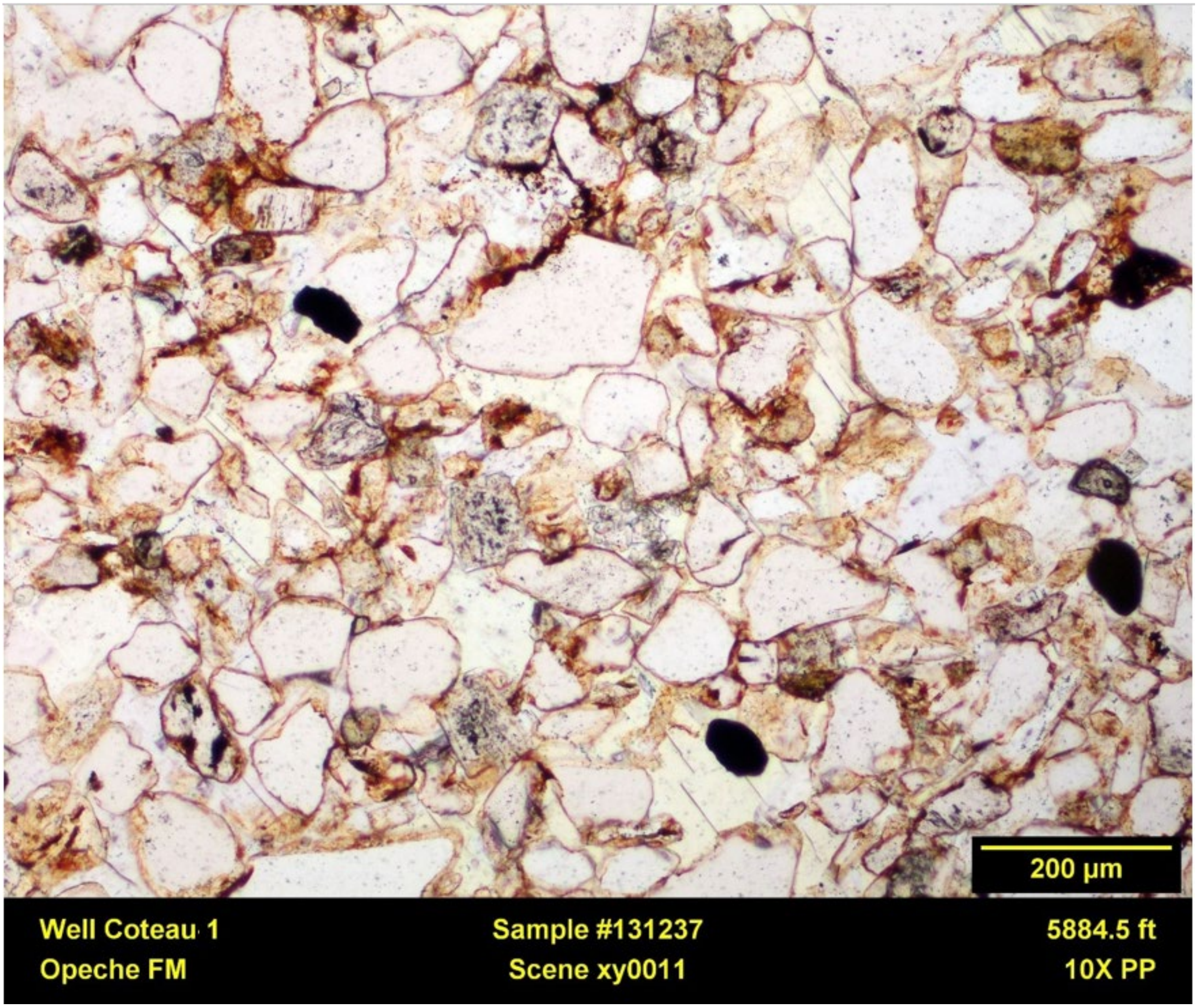


Figure 2-59. Plane-polarized light thin-section images from the Coteau 1 well Opeche Formation. This image shows the silt-rich nature of this interval of the Opeche Formation. On the example shown, the quartz grains (white) and iron oxides are rimmed by anhydrite.

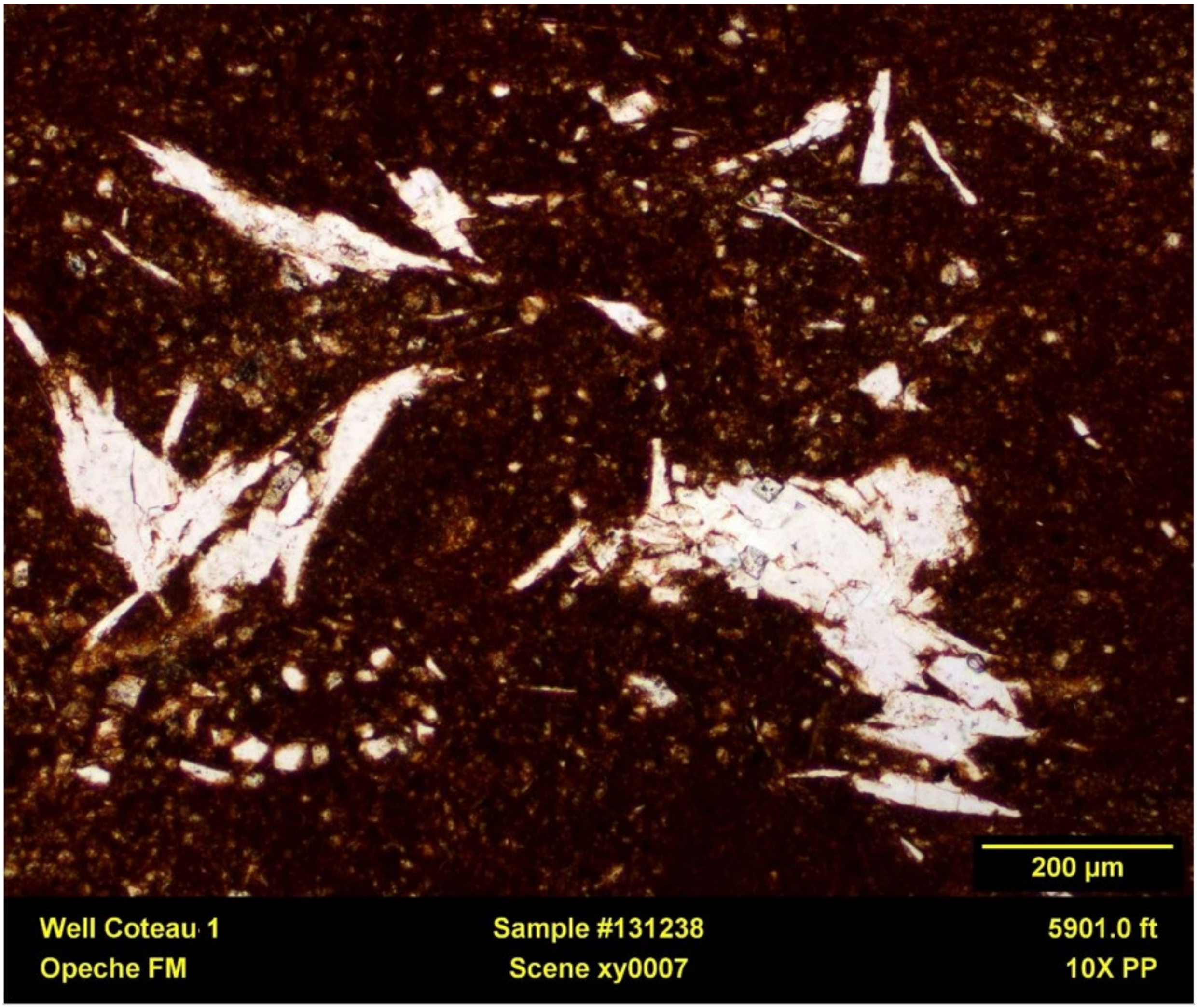


Figure 2-60. Plane-polarized light thin-section images from Coteau 1 well Opeche Formation. This image shows the heterogeneity of this interval. The dark material shown (between the white anhydrite and quartz grains) is clay and is likely responsible for the electrical conductivity identified on the FMI log.

Figure 2-61 shows the logged interval for the lower Opeche Formation at Coteau 1 well. As shown, the section closest to the Broom Creek Formation is dominated by litho-bound fractures and microfaults which are electrically conductive features likely due to the presence of clay. The rose diagrams shown in Figures 2-62 through 2-65 provide the orientation of the conductive, resistive, microfault, and drilling-induced features in the Opeche Formation. The drilling-induced fractures are oriented NE-SW and N-S which give an orientation of N060 and N000 to the maximum horizontal stress (Shmax), respectively.

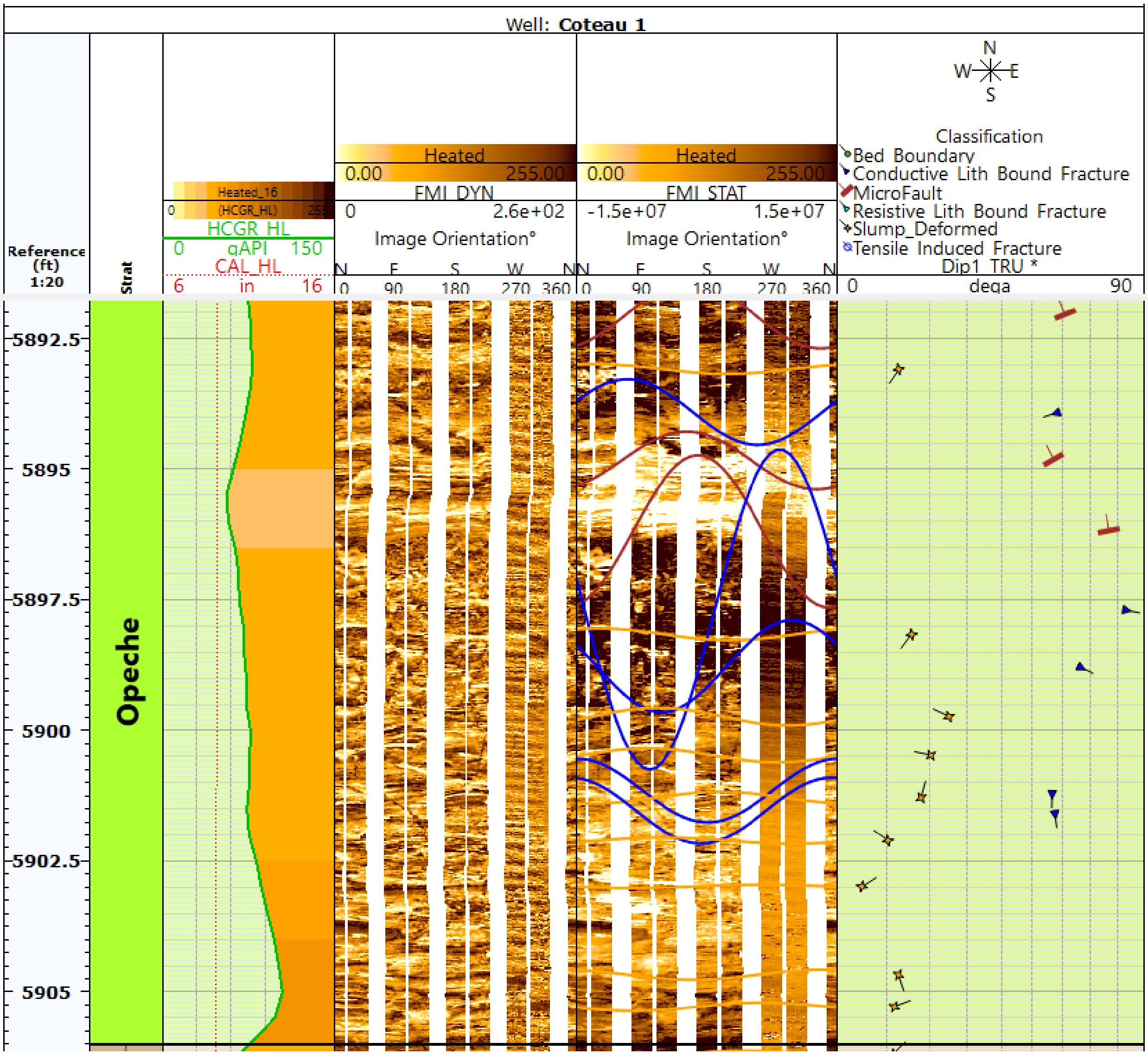


Figure 2-61. Interpreted FMI log through the lower Opeche Formation.

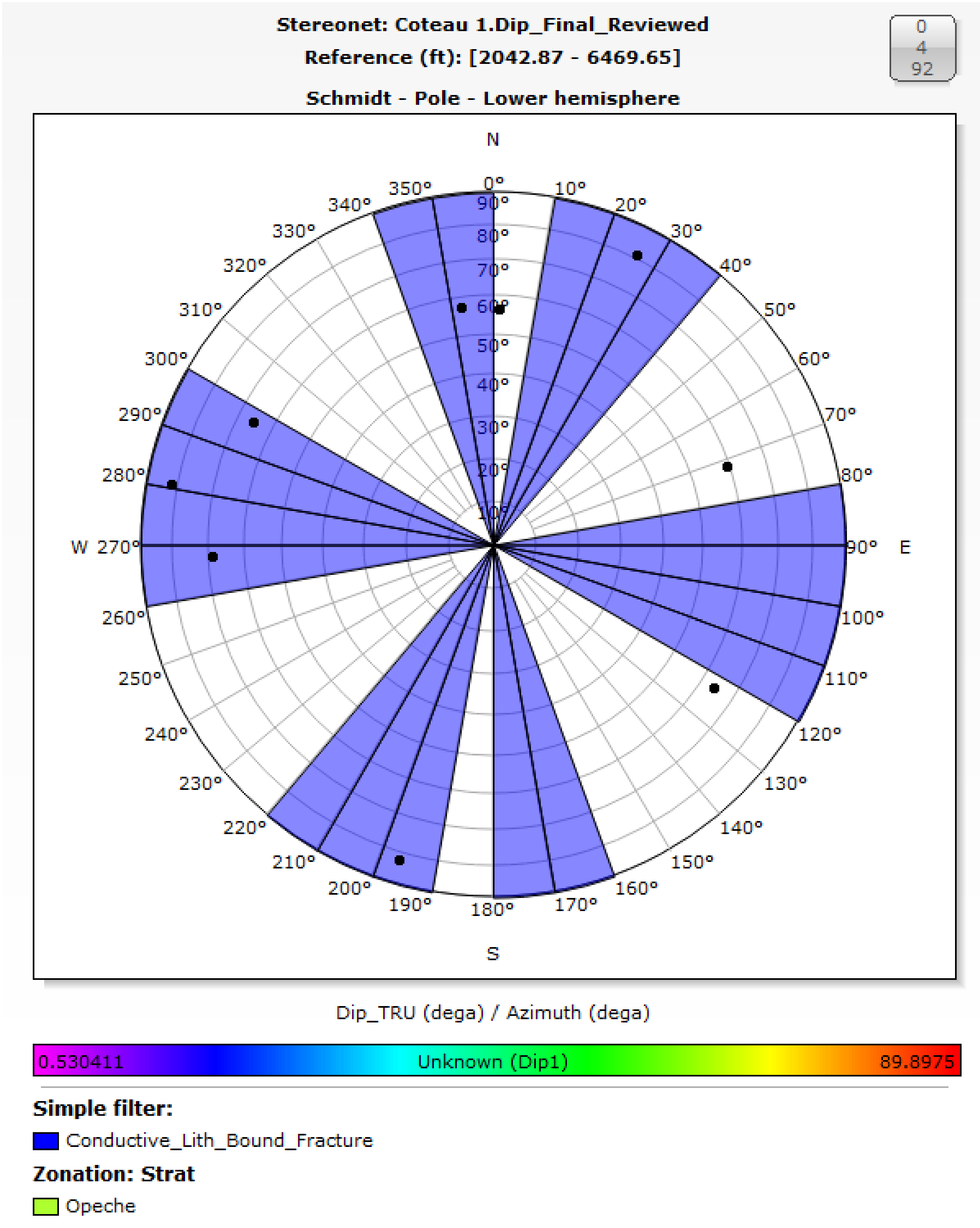


Figure 2-62. Conductive fracture orientation in the Opeche Formation.

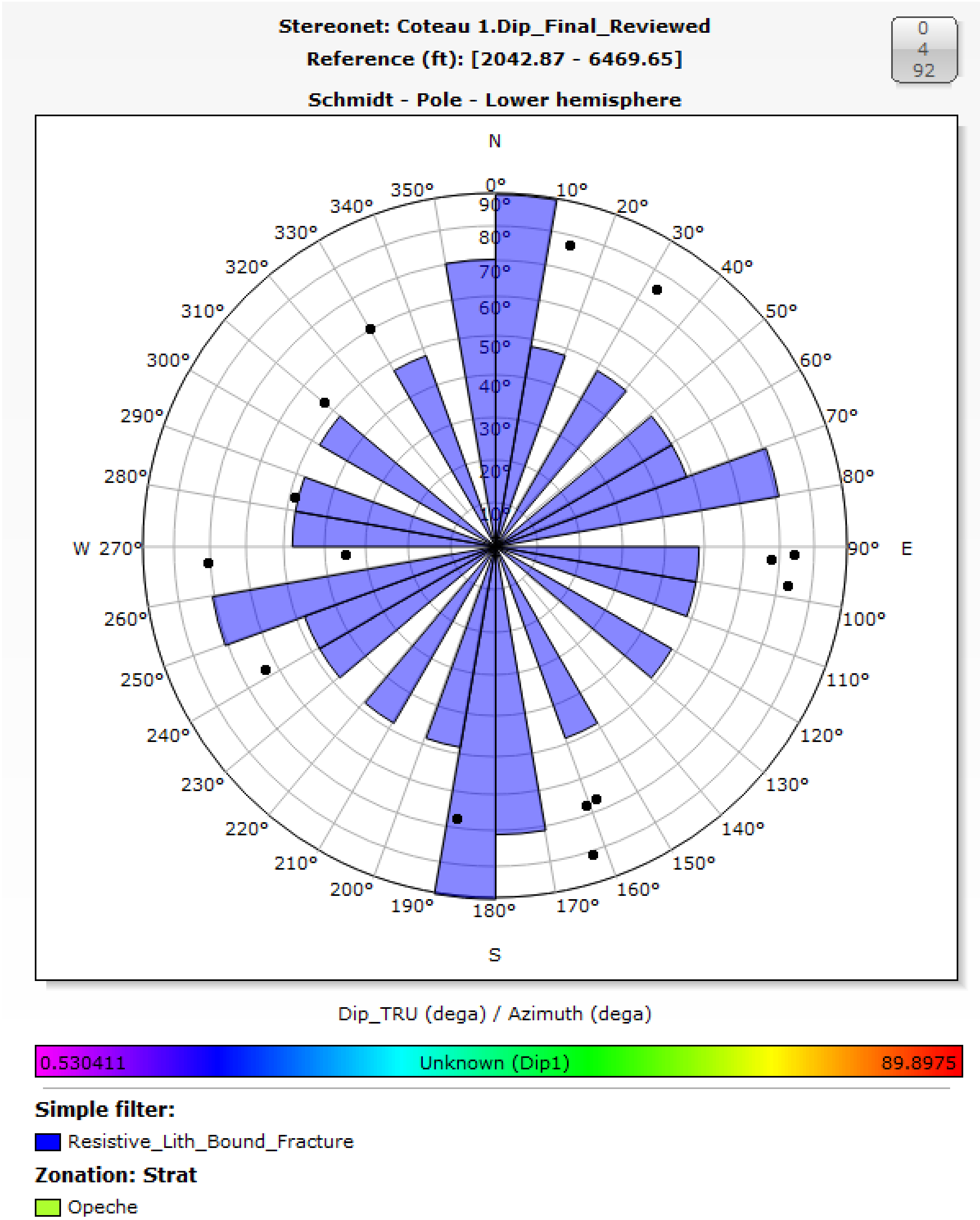


Figure 2-63. Resistive fracture orientation in the Opeche Formation.

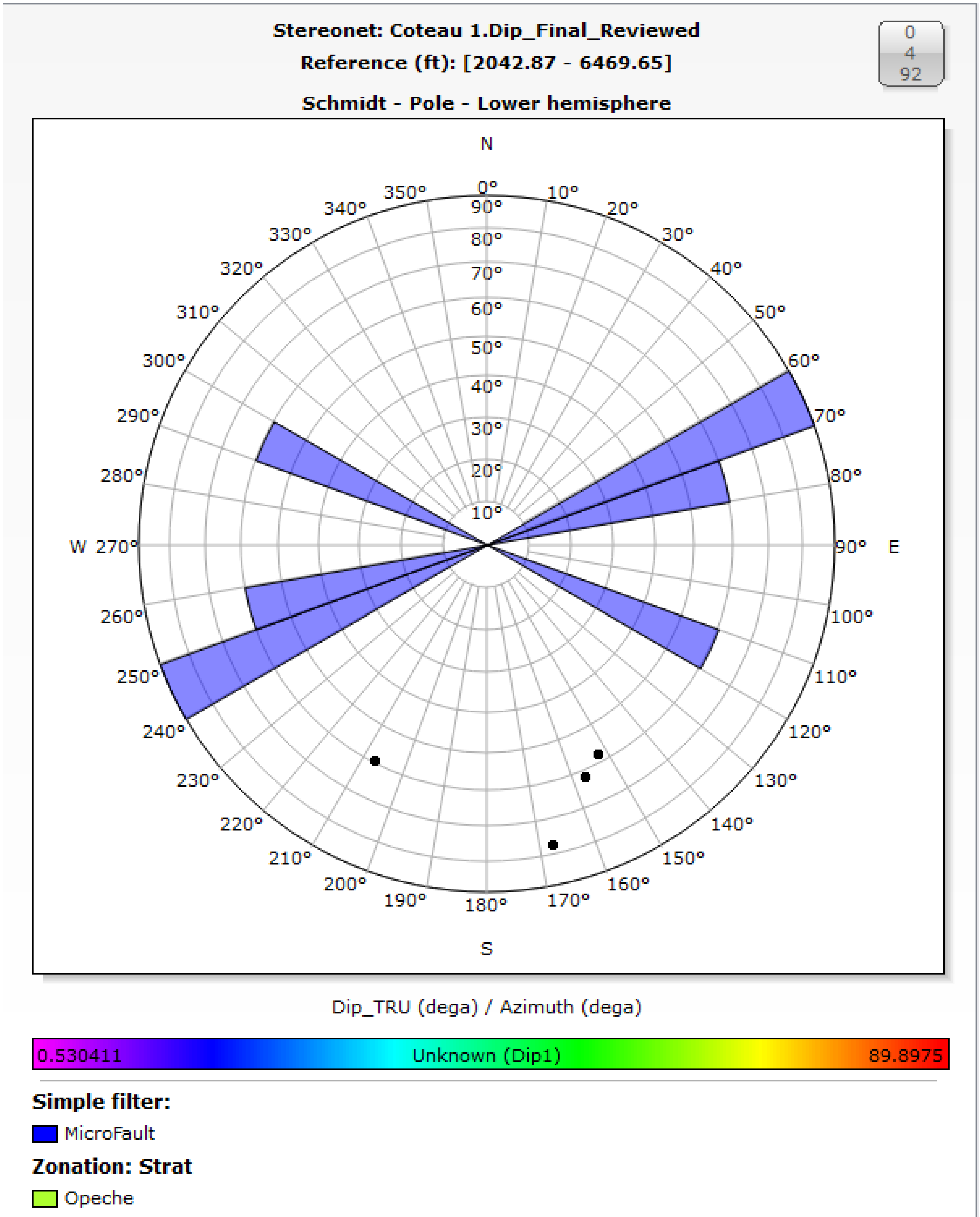


Figure 2-64. Microfault orientation in the Opeche Formation.

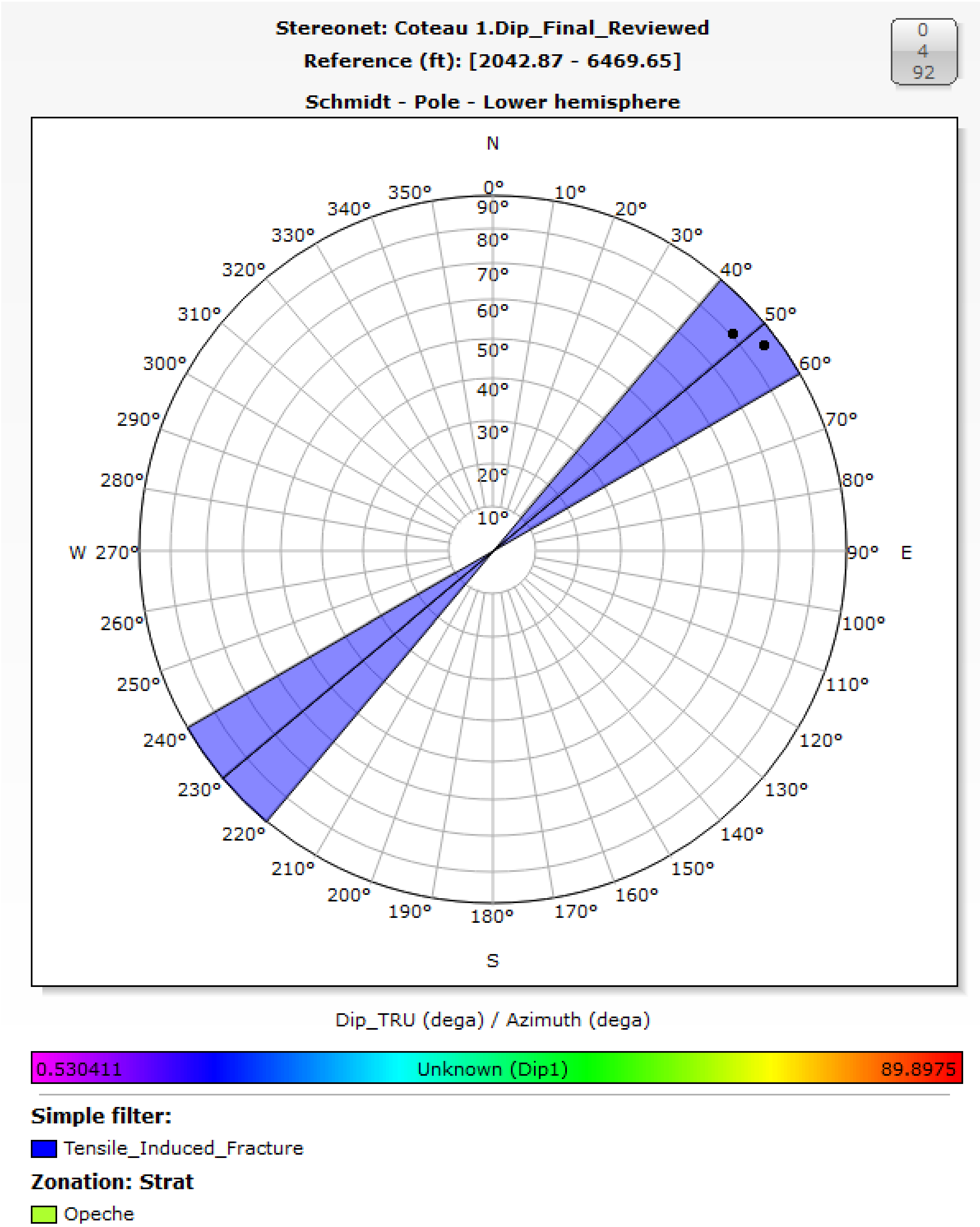


Figure 2-65. Drilling-induced fracture orientation in the Opeche Formation.

The logged interval of the Amsden Formation shows that the main features present are bed boundaries and slump deformation features (Figure 2-66). The depths 6,201.6 and 6,213.7 ft show some evidence of conductive fracture and drilling-induced fractures, respectively (Figure 2-67). The rose diagrams shown in Figures 2-67 and 2-68 provide the orientation of the conductive and drilling-induced fractures in the Amsden Formation. The drilling-induced fractures are oriented NE-SW which gives an orientation of N060 to the maximum horizontal stress (Shmax).

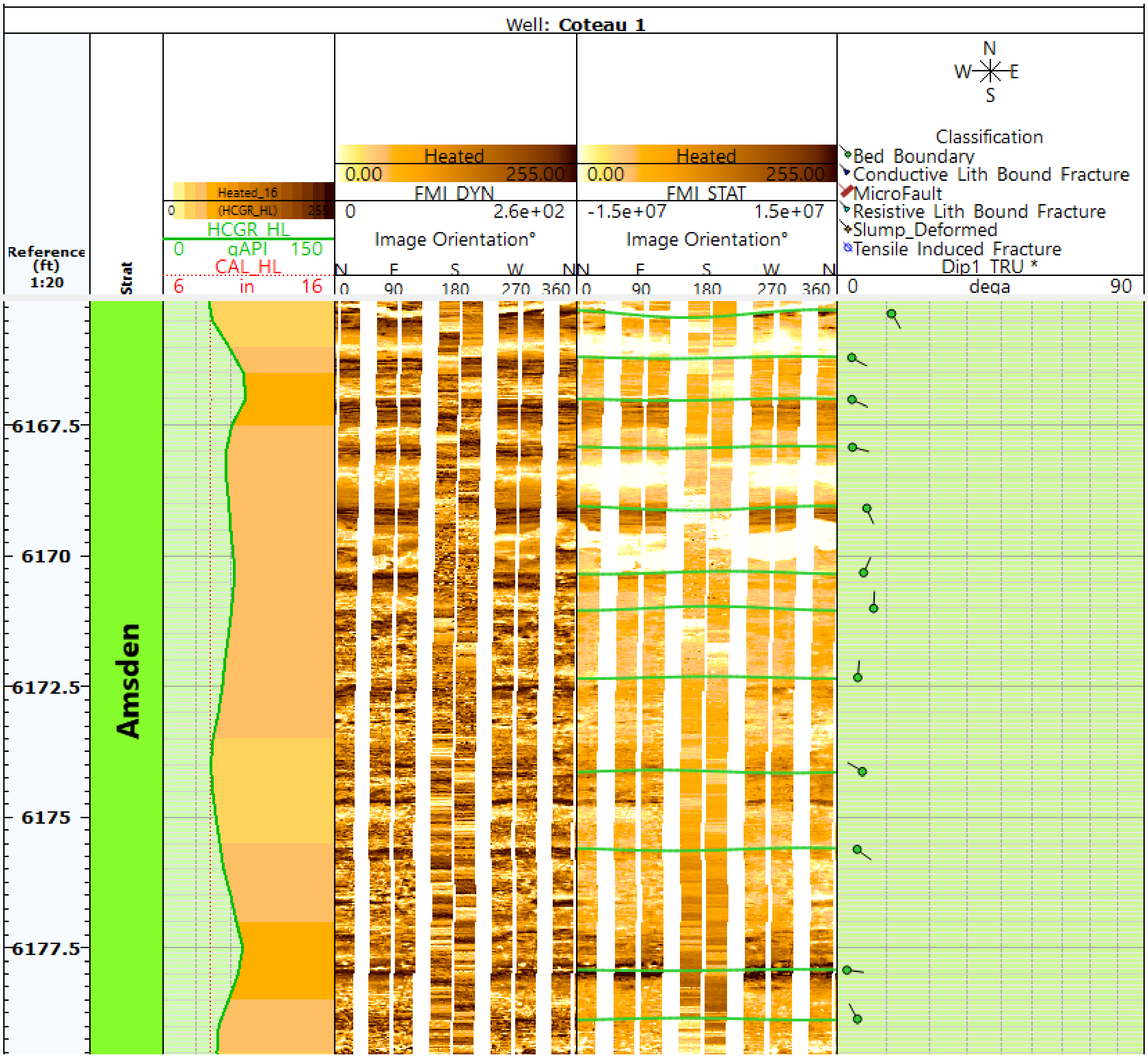


Figure 2-66. Interpreted FMI log through the upper Amsden Formation.

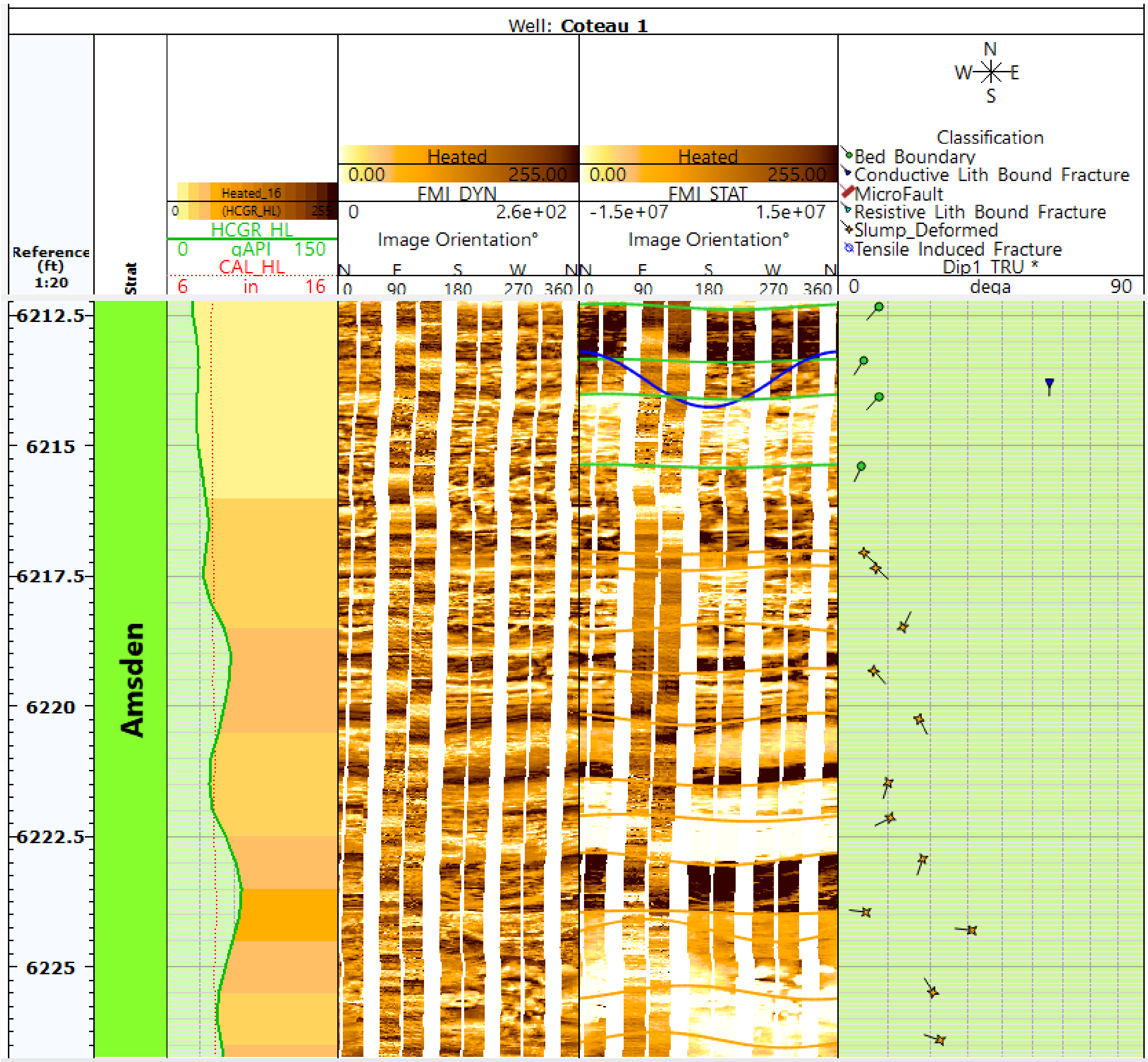


Figure 2-67. Interpreted FMI log through the lower Amsden Formation.

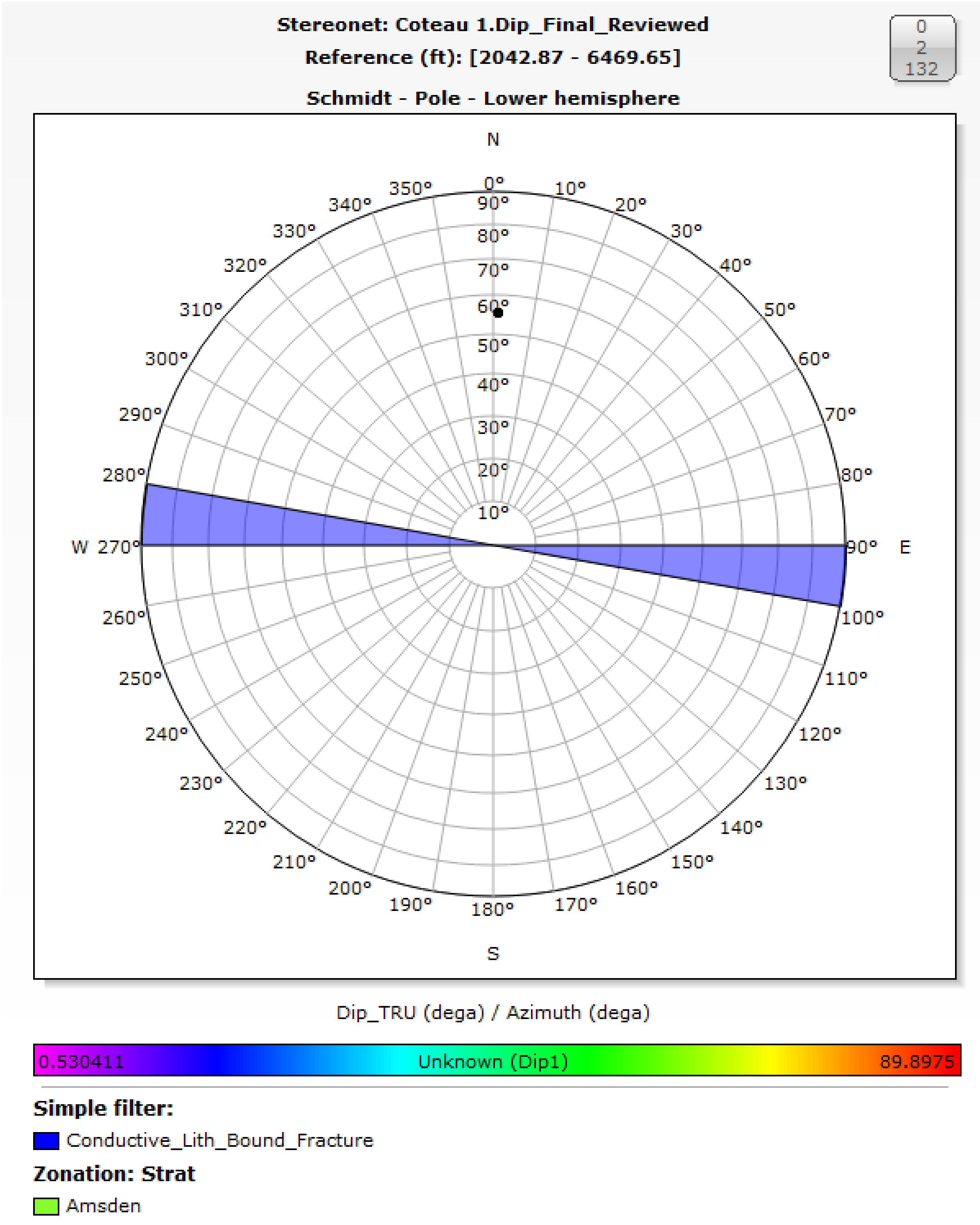


Figure 2-68. Conductive fracture orientation in the Amsden Formation.

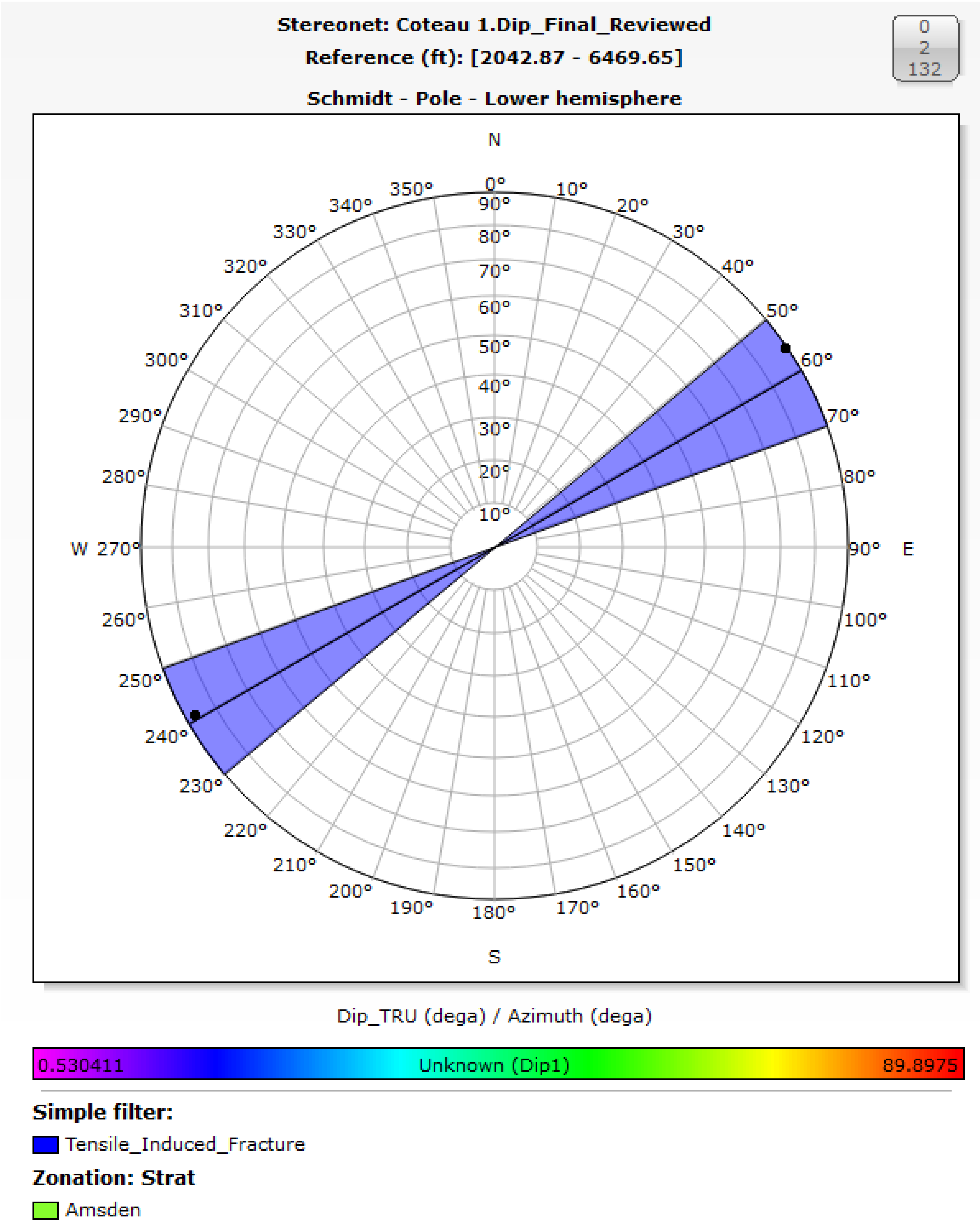


Figure 2-69. Drilling-induced fracture orientation in the Amsden Formation.

2.4.4.4 Stress

The 1D Mechanical Earth Model (MEM) for Opeche, Broom Creek, and Amsden Formations in Coteau 1 well was generated by Core Laboratories (Figures 2-70, 2-71, and 2-72). During construction of the 1D MEM, the effect of pore pressure on sonic transit time, accurate calculation of stress, and rock properties required corrections based on this effect. Dipole sonic logs (DTC, DTS) were corrected for formation pressure impedance and tool radius of investigation. The log corrections allow for a better match to core measurements and more robust geomechanical models.

The output data for the 1D MEM are vertical stress (Sv), pore pressure, pore pressure gradient, dynamic Poisson's ratio, dynamic Young's modulus, Biot factor, fracture closure pressure, fracture closure pressure gradient, fracture propagation pressure, fracture propagation pressure gradient, fracture breakdown pressure, and fracture breakdown pressure gradient. Laboratory-derived core measurements were used from the Coteau 1 well. The static and dynamic parameters from core including DTS, DTC, compressional wave velocity (Vp), shear wave velocity (Vs), dynamic Young's modulus, and dynamic Poisson's ratio were estimated for the Opeche, Broom Creek, and Amsden Formations and used to calibrate the geomechanical rock properties model.

The isotropic (dynamic) properties from well logs (Young's modulus and dynamic Poisson's ratio) were calculated based on the corrected DTC and DTS well logs and calibrated with core measurements. Pore pressure, pore pressure gradient, fracture closure pressure, fracture closure pressure gradient, fracture propagation pressure, fracture propagation fracture gradient, fracture breakdown pressure, and fracture breakdown pressure gradient were also estimated. Pore pressure was calibrated using the pressure and temperature data from the Coteau 1 well.

Triaxial tests were performed on 15 vertical samples: three in Opeche, nine in Broom Creek, and three in Amsden (Table 2-19 and 2-20). Static Young's modulus, Poisson's ratio, and compressive strength were measured at the confining pressure of 1,180 psi. Also, acoustic velocities (Vp, Vs) and dynamic moduli (Bulk modulus, Young's modulus, shear modulus, Poisson's ratio) were estimated under a confining pressure of 1,180 psi The triaxial outputs were calibrated with the estimated parameters using well logs. Figures 2-70–2-72 show the outputs of the 1D MEM for the Opeche, Broom Creek, and Amsden Formations.

In situ stresses such as vertical stress (Sv), maximum horizontal stress (Shmax), and minimum horizontal stress (Shmin) were calculated. The vertical stress is calculated using the density log (RHOB) and assumes 1 psi/ft above 1,500 ft where the RHOB data were not available. The minimum horizontal stress is estimated from a modified Eaton calculation method (Section 2.3). Shmax is estimated from Shmin and process zone stress as a function of porosity. Based on the calculated stresses, the stress regime of the Opeche, Broom Creek, and Amsden Formations is considered a normal stress regime where Sv > Shmax > Shmin.

Table 2-19. Triaxial Testing Results Showing the Calculated Static Young's Modulus, Poisson's Ratio, and Compressive Strength. The confining zone pressure was set at 1,180 psi for testing. The pore pressure used for calculations was assumed to be 0 psi.

Formation	Lithology	Depth (ft)	Sample Length (in.)	Sample Diameter (in.)	Length to Depth Ratio	Bulk Density (g/cm³)	Compressive Strength (psi)	Young's Modulus (10^6 psi)	Poisson's Ratio
Opeche	Silty-shale	5,872.80	2.0955	0.9725	2.15	2.47	15,954	1.67	0.17
	Silty-shale with anhydrite	5,884.75	2.0626	0.9870	2.09	2.57	20,329	3.25	0.18
	Shale with anhydrite	5,901.60	2.0358	0.9954	2.05	2.46	13,214	1.60	0.13
Broom Creek	Anhydrite	5,908.30	2.0566	0.9849	2.09	2.81	30,484	6.46	0.24
	Anhydritic-dolostone	5,920.40	2.1121	0.9898	2.13	2.47	19,474	4.52	0.31
	Sandy-dolostone	5,924.80	2.0576	0.9888	2.08	2.42	22,191	3.32	0.30
	Dolo-sandstone	5,928.70	2.0793	0.9875	2.11	2.51	25,379	3.91	0.34
	Sandstone	5,941.10	1.5251	0.9815	1.55	1.82	6,592	0.56	0.17
	Sandstone	5,989.60	1.7216	0.9953	1.73	1.76	7,678	0.76	0.23
	Anhydritic-sandstone	6,146.30	1.8015	0.9908	1.82	2.58	18,510	3.39	0.36
	Sandy-dolomite	6,160.10	2.1366	0.9881	2.16	2.49	24,511	3.75	0.33
Amsden	Dolostone	6,169.60	2.1593	0.9908	2.18	2.66	26,307	3.55	0.22
	Dolostone	6,183.20	2.1751	0.9903	2.20	2.55	17,558	2.49	0.17
	Anhydritic-sandstone	6,190.00	1.8448	0.9880	1.87	2.64	23,906	3.03	0.53

Table 2-20. Triaxial Testing Results Showing the Measured Acoustic Velocities and Calculated Dynamic Bulk Modulus, Young's Modulus, Poisson's Ratio, and Compressive Strength. The confining zone pressure was set at 1,180 psi for testing.

Formation	Lithology	Depth (ft)	Axial Stress (psi)	Bulk Density (g/cm³)	Acoustic Velocity – Compressional ft/sec	Acoustic Velocity – Compressional µs/ft	Acoustic Velocity – Shear ft/sec	Acoustic Velocity – Shear µs/ft	Dynamic Elastic Parameters – Bulk Modulus (×10⁶ psi)	Dynamic Elastic Parameters – Young's Modulus (×10⁶ psi)	Dynamic Elastic Parameters – Shear Modulus (×10⁶ psi)	Dynamic Elastic Parameters – Poisson's Ratio
Opeche	Shale silty-shale	5,872.80	3,000	2.47	15,413	64.9	7,450	134.2	5.45	4.99	1.85	0.35
	Silty-shale with anhydrite	5,884.75	100	2.57	14,170	70.6	8,897	112.4	3.30	6.44	2.74	0.17
	Shale with anhydrite	5,901.60	6,000	2.46	14,688	68.1	7,861	127.2	4.42	5.32	2.05	0.30
Broom Creek	Anhydrite	5,908.30	3,000	2.81	23,737	42.1	10,909	91.7	15.32	12.31	4.50	0.37
	Anhydritic-dolostone	5,920.40	3,000	2.47	19,888	50.3	10,366	96.5	8.39	9.39	3.57	0.31
	Sandy-dolostone	5,924.80	100	2.42	16,315	61.3	9,537	104.9	4.73	7.37	2.97	0.24
	Dolo-sandstone	5,928.70	2,000	2.51	17,993	55.6	9,896	101.1	6.54	8.50	3.31	0.28
	Sandstone	5,941.10	2,000	1.82	12,174	82.1	5,324	187.8	2.71	1.92	0.70	0.38
	Sandstone	5,951.75	2,000	1.86	13,339	75.0	6,413	155.9	3.09	2.79	1.03	0.35
	Sandstone	5,989.60	2,000	1.76	11,808	84.7	5,921	168.9	2.20	2.22	0.83	0.33
	Anhydritic-sandstone	6,146.30	3,000	2.57	19,027	52.56	9,623	103.91	8.28	8.54	3.21	0.33
	Sandy-dolomite	6,160.10	6,000	2.49	19,652	50.88	10,745	93.06	7.79	9.97	3.87	0.29
Amsden	Dolostone	6,169.60	3,000	2.66	18,842	53.07	10,622	94.14	7.34	10.26	4.05	0.27
	Dolostone	6,183.20	3,000	2.55	15,400	64.93	9,036	110.67	4.41	6.95	2.81	0.24
	Anhydritic-sandstone	6,190.00	8,000	2.64	20,663	48.40	10,942	91.39	9.52	11.12	4.26	0.31

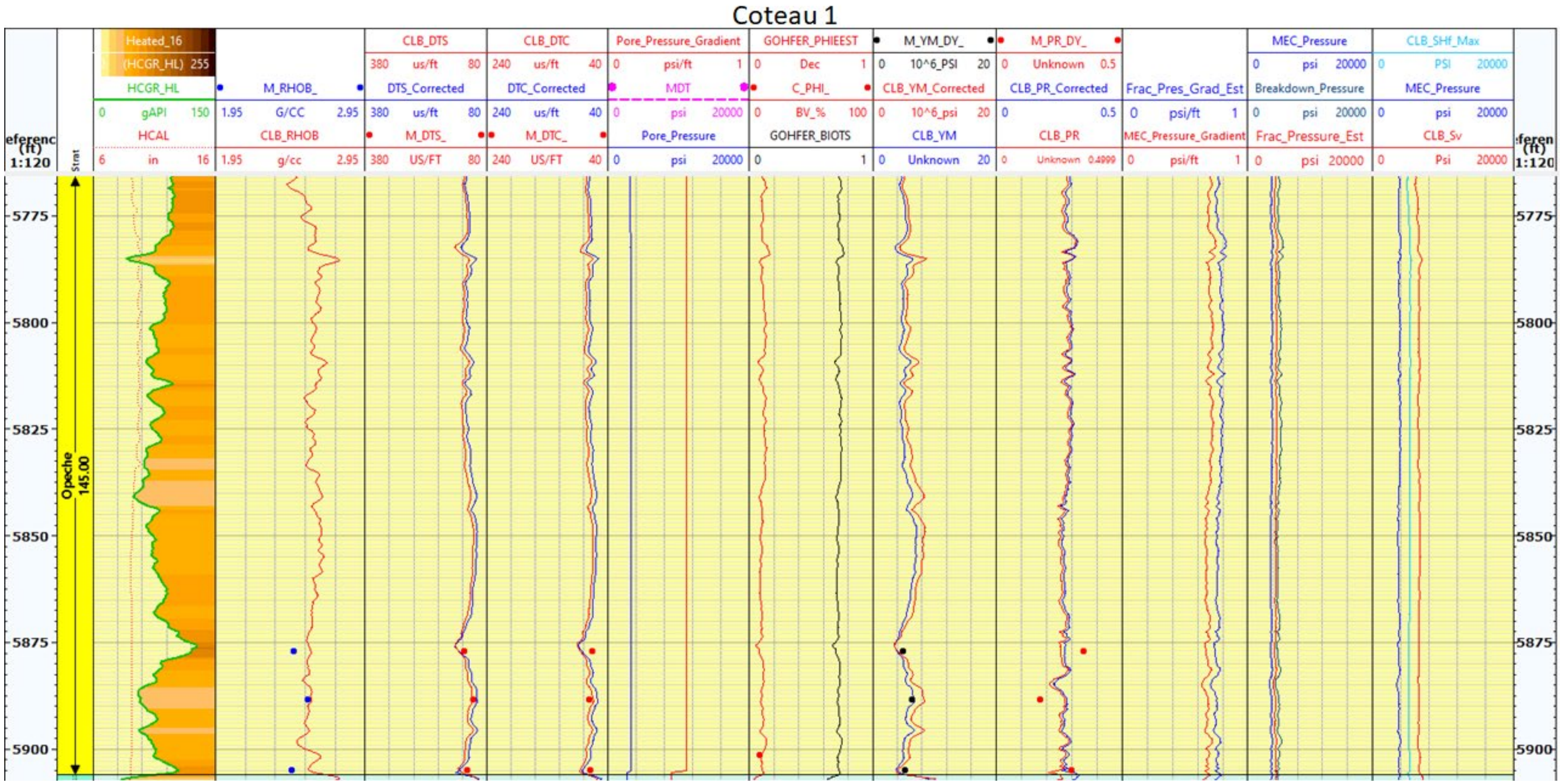


Figure 2-70. Calibrated geomechanical rock properties model in Opeche Formation.

Coteau 1

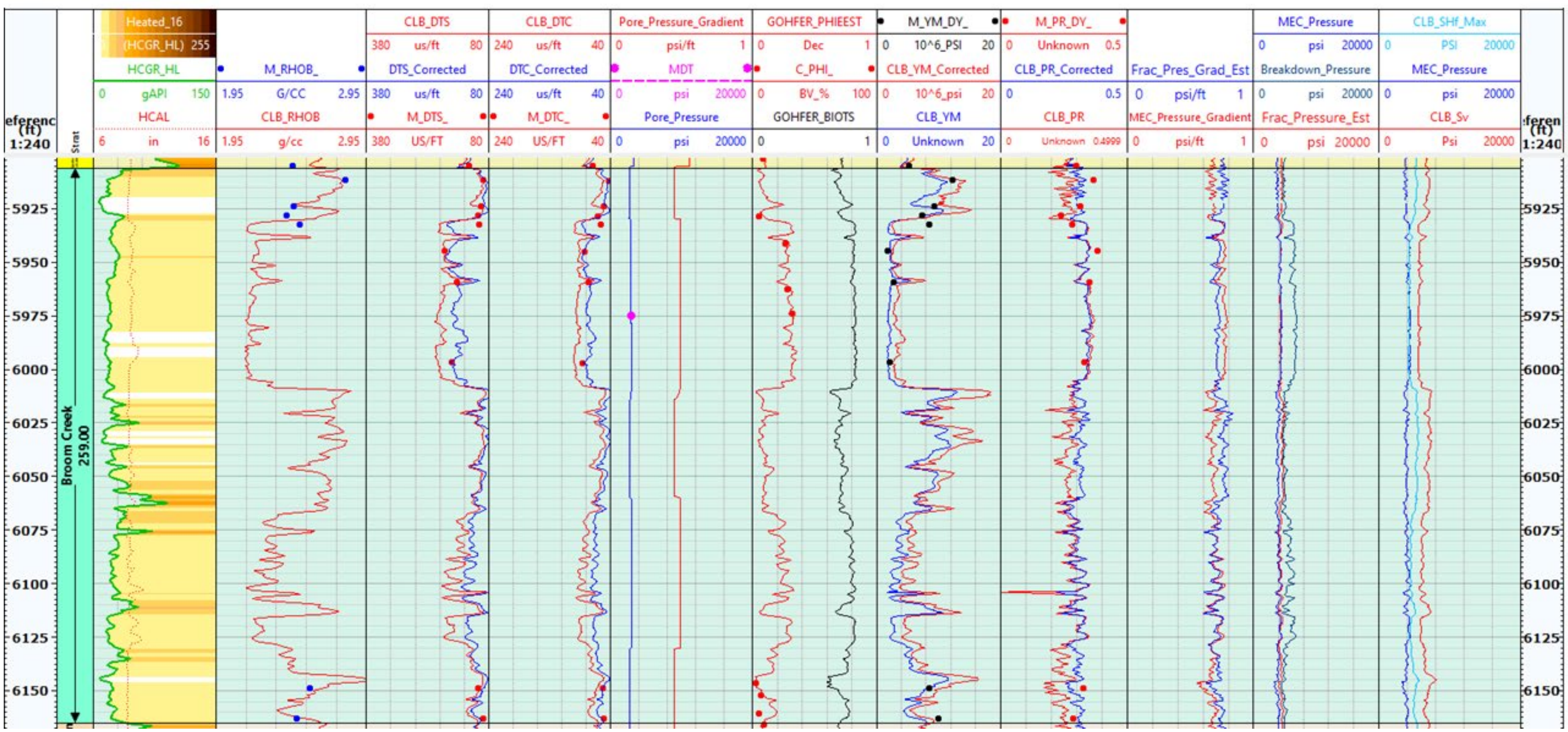


Figure 2-71. Calibrated geomechanical rock properties model in Broom Creek Formation.

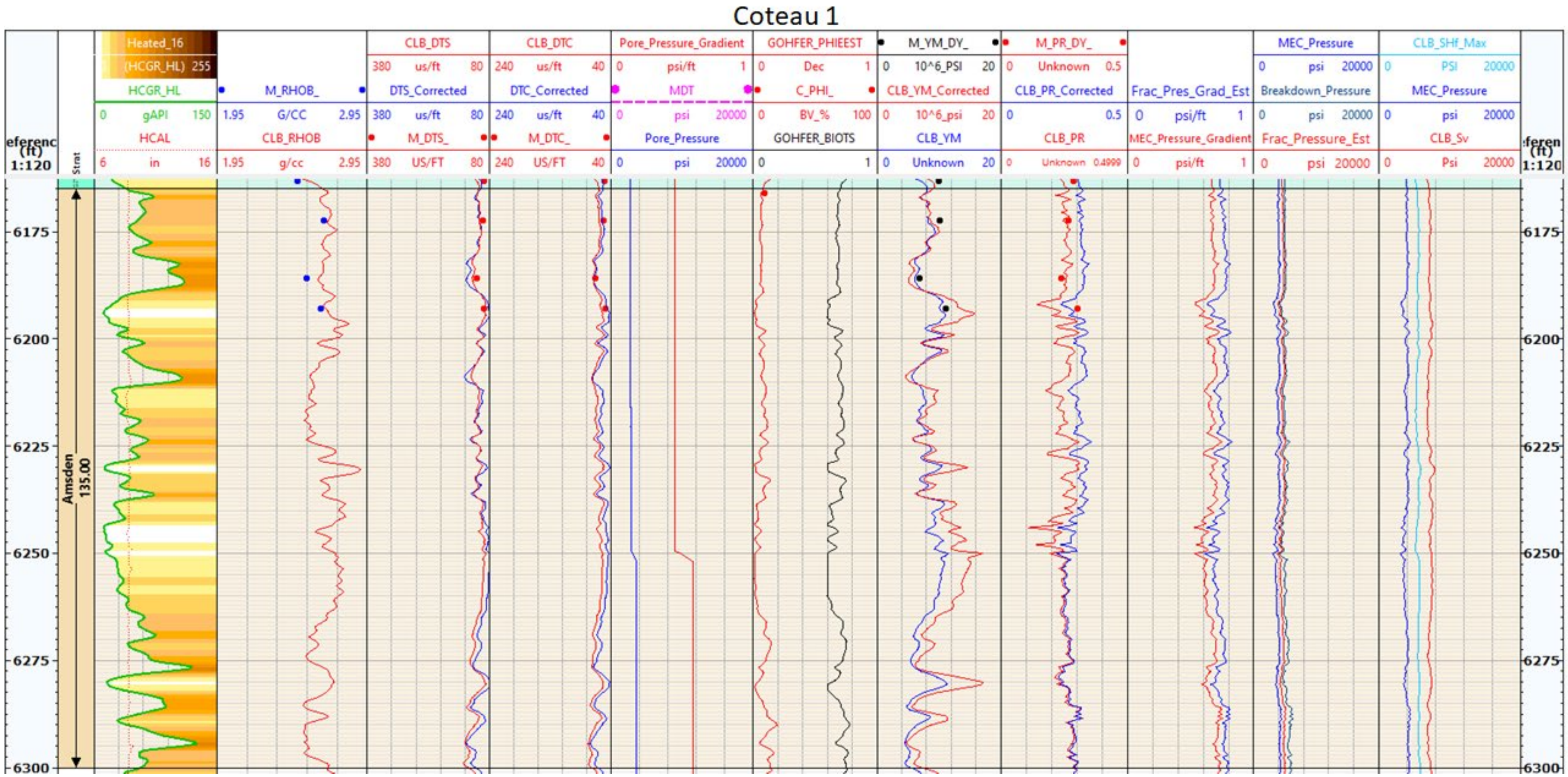


Figure 2-72. Calibrated geomechanical rock properties model in Amsden Formation.

2.5 Faults, Fractures, and Seismic Activity

In the Great Plains CO_2 Sequestration Project area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. The absence of transmissive faults is supported by fluid sample analysis results from Coteau 1 that suggest the injection interval, Broom Creek Formation (42,800 mg/L) is isolated from the next permeable interval, the Inyan Kara Formation (22,800 mg/L).

The Williston Basin is a tectonically stable region of the North American Craton. Zhou and others (2008) summarize that "the Williston Basin as a whole is in an overburden compressive stress regime," which could be attributed to the general stability of the North American Craton. Interpreted structural features associated with tectonic activity in the Williston Basin in North Dakota include anticlinal and synclinal structures in the western half of the state, lineaments associated with Precambrian basement block boundaries, and faults (North Dakota Industrial Commission, 2019).

Between 1870 and 2015, 13 earthquakes were detected within the North Dakota portion of the Williston Basin (Table 2-21) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-73). The seismic event recorded closest to the Great Plains CO_2 Sequestration Project storage facility area occurred 29.6 mi from the Coteau 1 well near Fort Berthold in southwestern North Dakota (Table 2-21). The magnitude of this seismic event is estimated to have been 1.9.

Table 2-21. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, miles	Longitude	Latitude	City or Vicinity of Earthquake	Map Label	Distance to the Coteau 1 Well, miles
Sept. 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	A	86.7
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	138.2
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	107.5
Aug. 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	29.6
Jan. 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	117.8
Nov. 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	85
Nov. 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	128.6
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	127.3
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	76.6
May 13, 1947	3.7**	U	−100.90	46.00	Selfridge	J	106.8
Oct. 26, 1946	3.7**	U	−103.70	48.20	Williston	K	102.6
April 29, 1927	3.2**	U	−102.10	46.90	Hebron	L	36.8
Aug. 8, 1915	3.7**	U	−103.60	48.20	Williston	M	98.5

* Estimated depth.

** Magnitude estimated from reported modified Mercalli intensity (MMI) value.

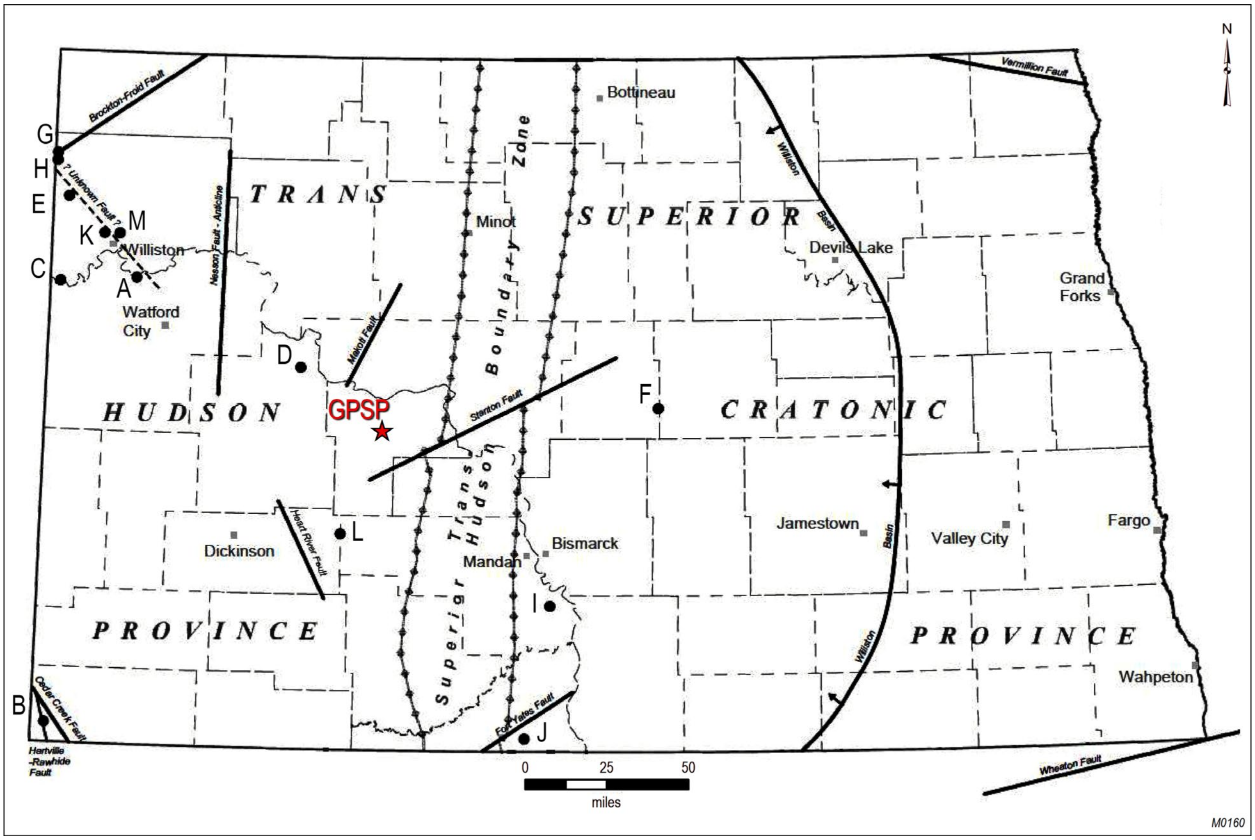


Figure 2-73. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-21.

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging earthquake events occurring in North Dakota, with less than two damaging earthquake events predicted to occur over a 10,000-year time period (Figure 2-74) (U.S. Geological Survey, 2019). A 1-year seismic forecast (including both induced and natural seismic events) released by 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 that could be associated with nearby 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 containment is low.

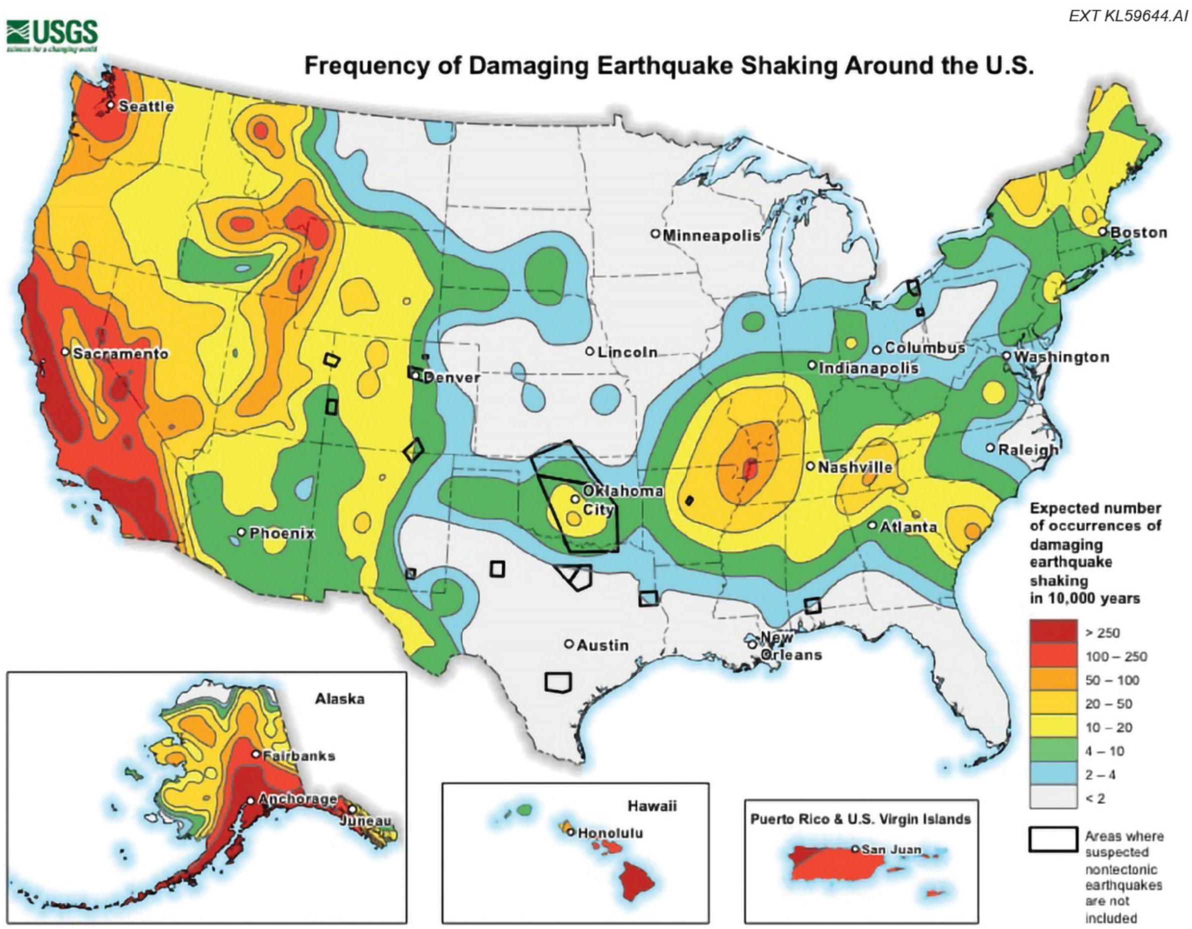


Figure 2-74. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

2.6 Potential Mineral Zones

There are no known producible accumulations of hydrocarbons in the storage facility area. The North Dakota Geological Survey recognizes the Spearfish Formation as the only potential oil-bearing formation above the Broom Creek Formation. However, production from the Spearfish Formation is limited to the northern tier of counties in western North Dakota (Figure 2-75). There has been no exploration for, nor development of, a hydrocarbon resource from the Spearfish Formation in the Great Plains CO_2 Sequestration Project area.

There has been no historic hydrocarbon exploration in, or production from, formations below the Broom Creek Formation in the storage facility area. The Herrmann 1 well (NDIC File No. 4177), the closest hydrocarbon exploration well to the storage facility area, located 4.1 miles from the Coteau 1 well, was drilled in 1966 to explore potential hydrocarbons in the Madison Group. The well was dry and did not suggest the presence of hydrocarbons. The closest

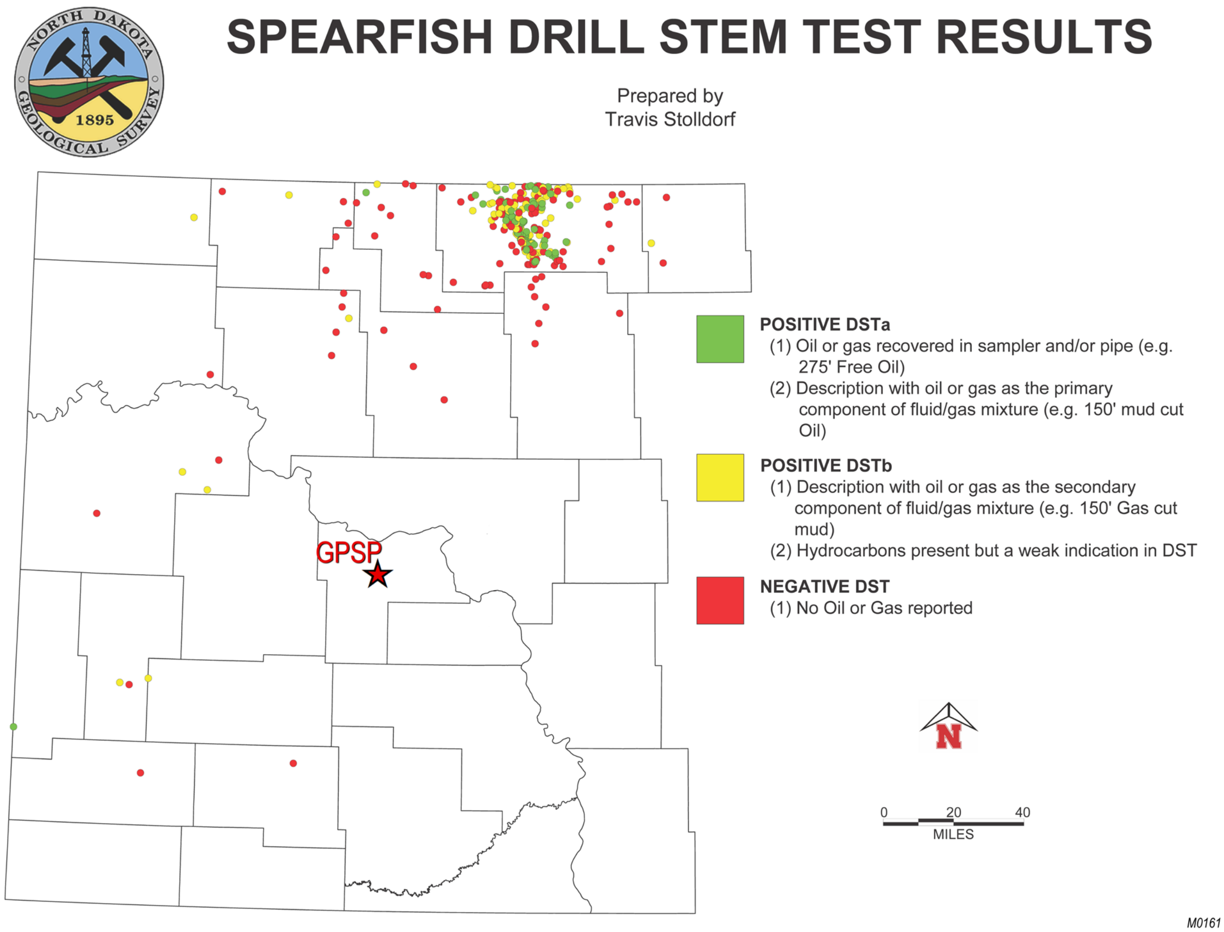


Figure 2-75. Drillstem test results indicating the presence of oil in the Spearfish Formation (modified from Stolldorf, 2020).

hydrocarbon producing well is Traxel 1-31H (NDIC File No. 17877), located 10.8 miles west from the Coteau 1 well (NDIC 38379). The Traxel 1-31H well was drilled in August 2009, producing a cumulative total of 12,021 bbl until December 2013. The well's current status is producer now abandoned (PNA) as of November 2014. Published studies suggest there are no economic deposits of hydrocarbons in the Bakken Formation in the storage facility area (Bergin, 2012; Theloy, 2016).

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a 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 (Figure 3-20). Pressure increases will relax postinjection as the area returns to its preinjection 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 placed across the storage reservoir, with CO_2-resistant cement used to anchor the casing in place.

Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations (NDCC 57-51-01) define shallow gas resources as "gas produced from a zone that consists of strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1,524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation (Jurassic), from which gas may be produced."

Lignite reserves in the Sentinel Butte Formation of the Fort Union Group (the Beulah of the Beulah-Zap interval and Twin Butte coal beds) are mined to be used as feedstock for the GPSP coal gasification process and power generation feedstock at Basin Electric Power Cooperative's Antelope Valley Station, located about 0.5 miles north of DGC's GPSP. The lignite is obtained from the Freedom Mine, which is operated by Coteau Properties Company, a wholly owned subsidiary of North American Coal Corporation.

The thickness of the Beulah–Zap averages between 18 to 22 feet in thickness (Figure 2-76). Above the Beulah horizon are several thin beds of lignite. In ascending order, these are the Schoolhouse and Twin Butte beds. Overburden on top of the Beulah ranges from 95 to 145 feet (Figure 2-77). The Twin Butte has an average thickness of about 6 feet under 25–30 feet of overburden where it is actively mined (Zygarlicke and others, 2019). The Beulah, Twin Butte, and other coal seams thicken and deepen to the west. The Beulah–Zap and Twin Butte seams pinch out to the east. The underlying Hagel coal seam is mined farther to the east at the BNI Coal Mine near Center, North Dakota, and the Falkirk Mine near Falkirk, North Dakota.

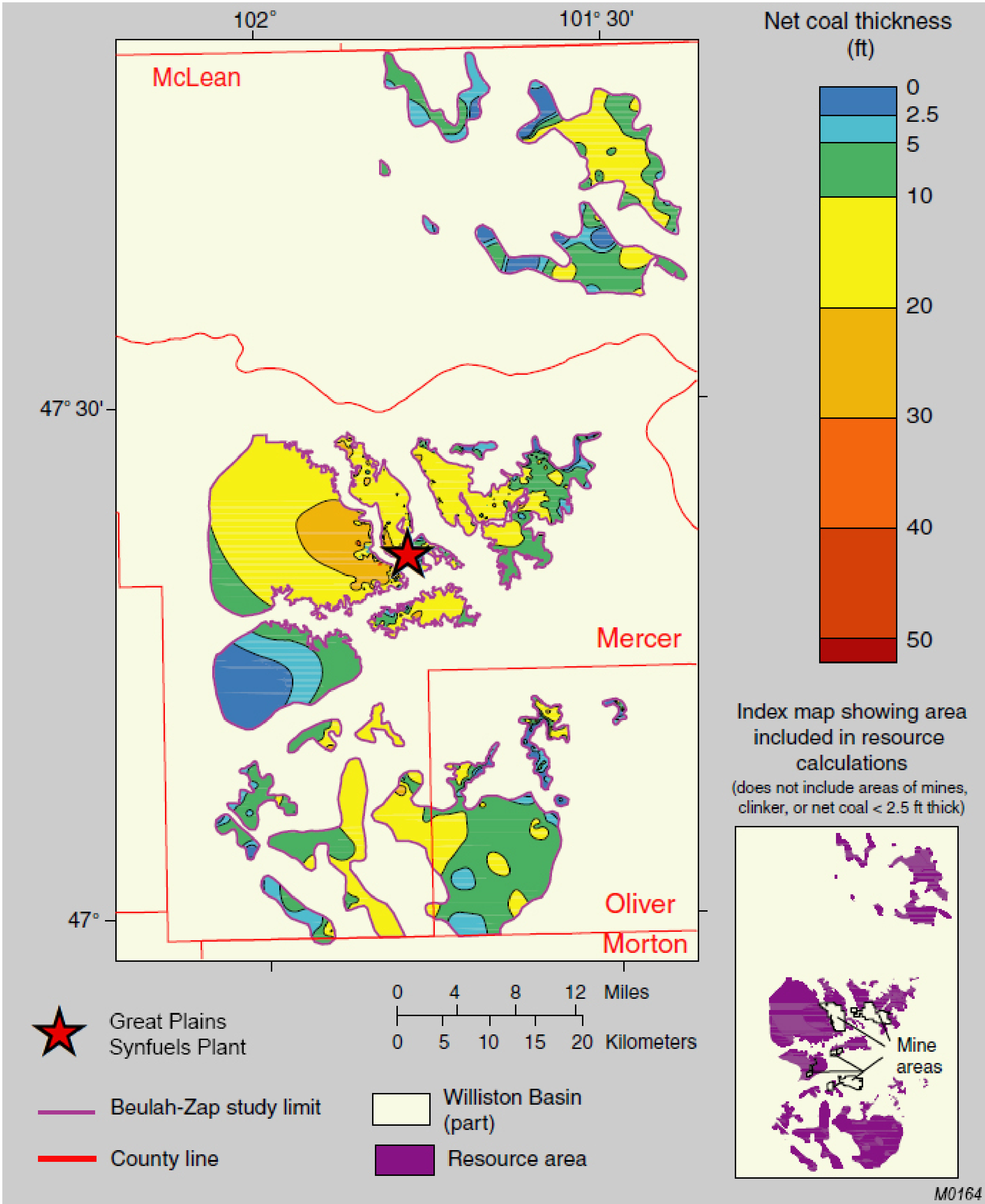


Figure 2-76. Beulah net coal isopach map (modified from Ellis and others, 1999).

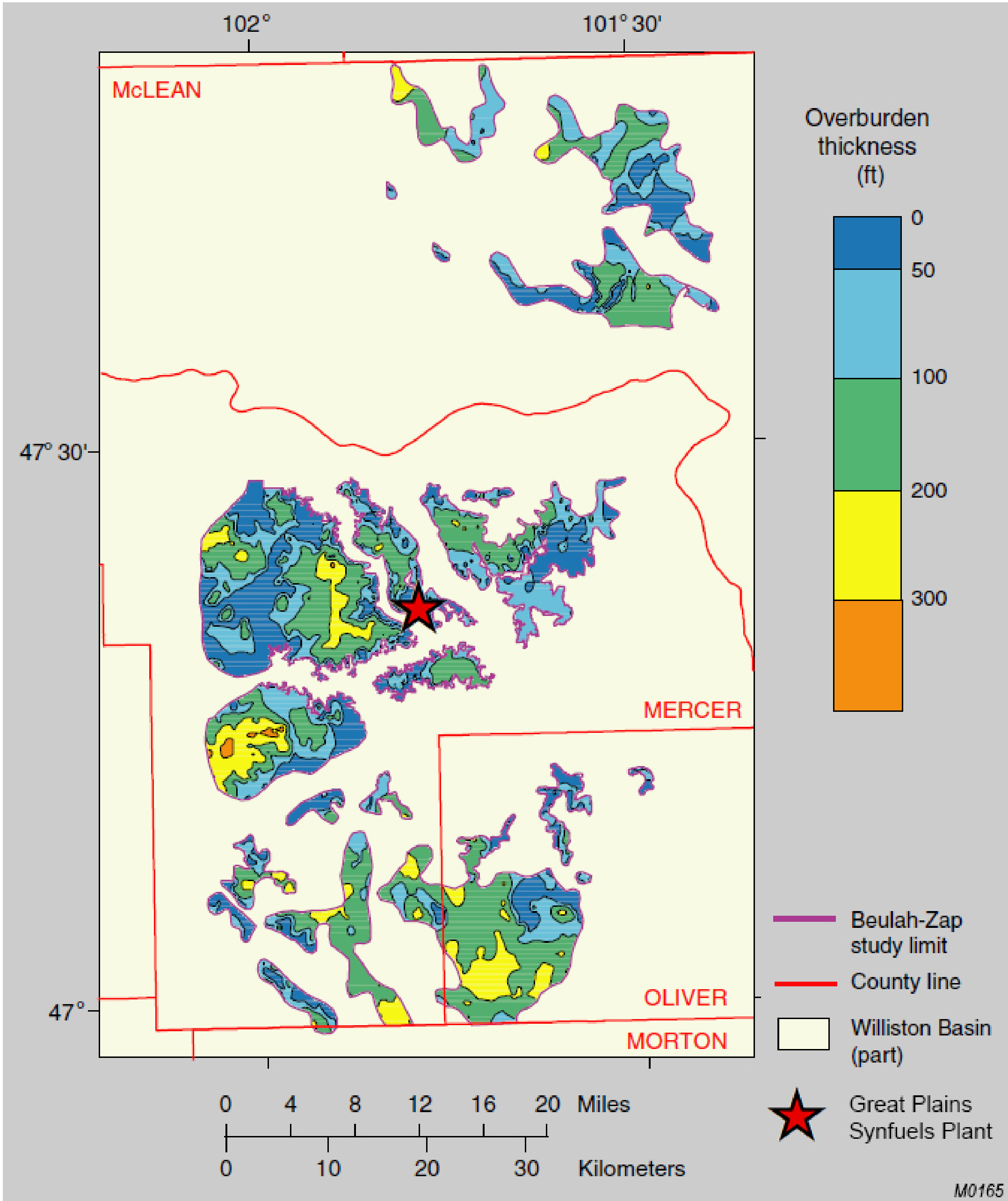


Figure 2-77. Beulah overburden isopach map (modified from Ellis and others, 1999).

The planned infrastructure for the Great Plains CO_2 Sequestration Project, the transmission line and injection well sites, will not impact mining of the lignite coal in the storage facility permit area. Injection well locations and the transmission line will be located in areas that have already been mined and since reclaimed or areas where no future mining is planned because of existing infrastructure such as powerlines, roadways, and other buried utilities (Figure 2-78).

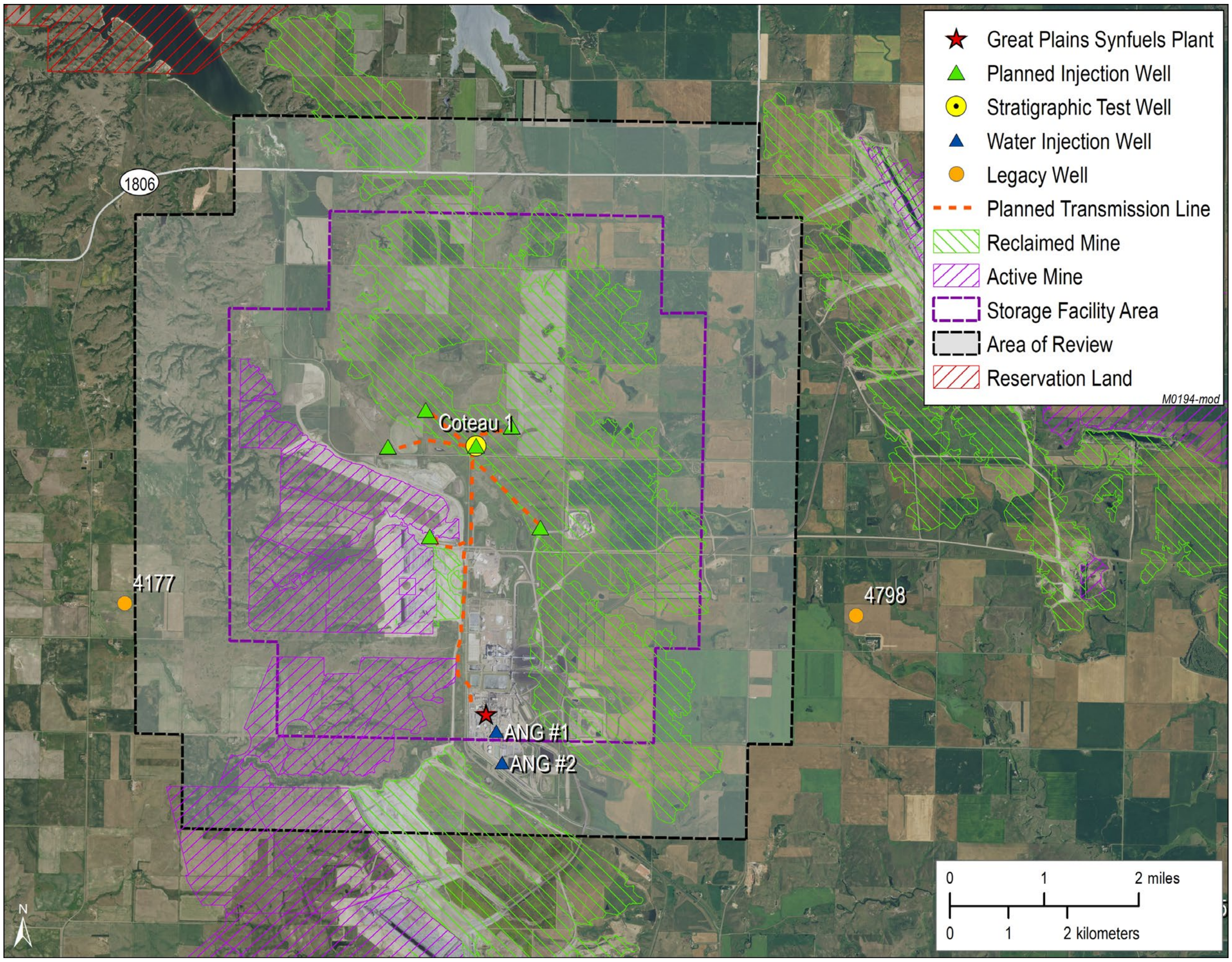


Figure 2-78. Map of the active and reclaimed mine land in the storage facility permit showing planned locations of project infrastructure (transmission line and injection wells).

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3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO_2 INJECTION

3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO_2 INJECTION

3.1 Introduction

Multiple sets of publicly available and newly acquired site-specific subsurface data were analyzed and interpreted (Section 2.2). The data and interpretations were used as inputs to Schlumberger's Petrel software (Schlumberger, 2020) to construct a geologic model of the injection zone: the Broom Creek Formation, the upper confining zone: the Opeche Formation, and the lower confining zone: the Amsden Formation. The geologic model encompasses a 76-mile × 72-mile area around the proposed storage site to characterize the geologic extent, depth, and thickness of the subsurface geologic strata (Figure 3-1). Geologic properties were distributed within the 3D model, including lithofacies, porosity, and permeability.

The geologic model and properties served as inputs for numerical simulations of CO_2 injection using Computer Modelling Group's (CMG's) GEM software (Computer Modelling

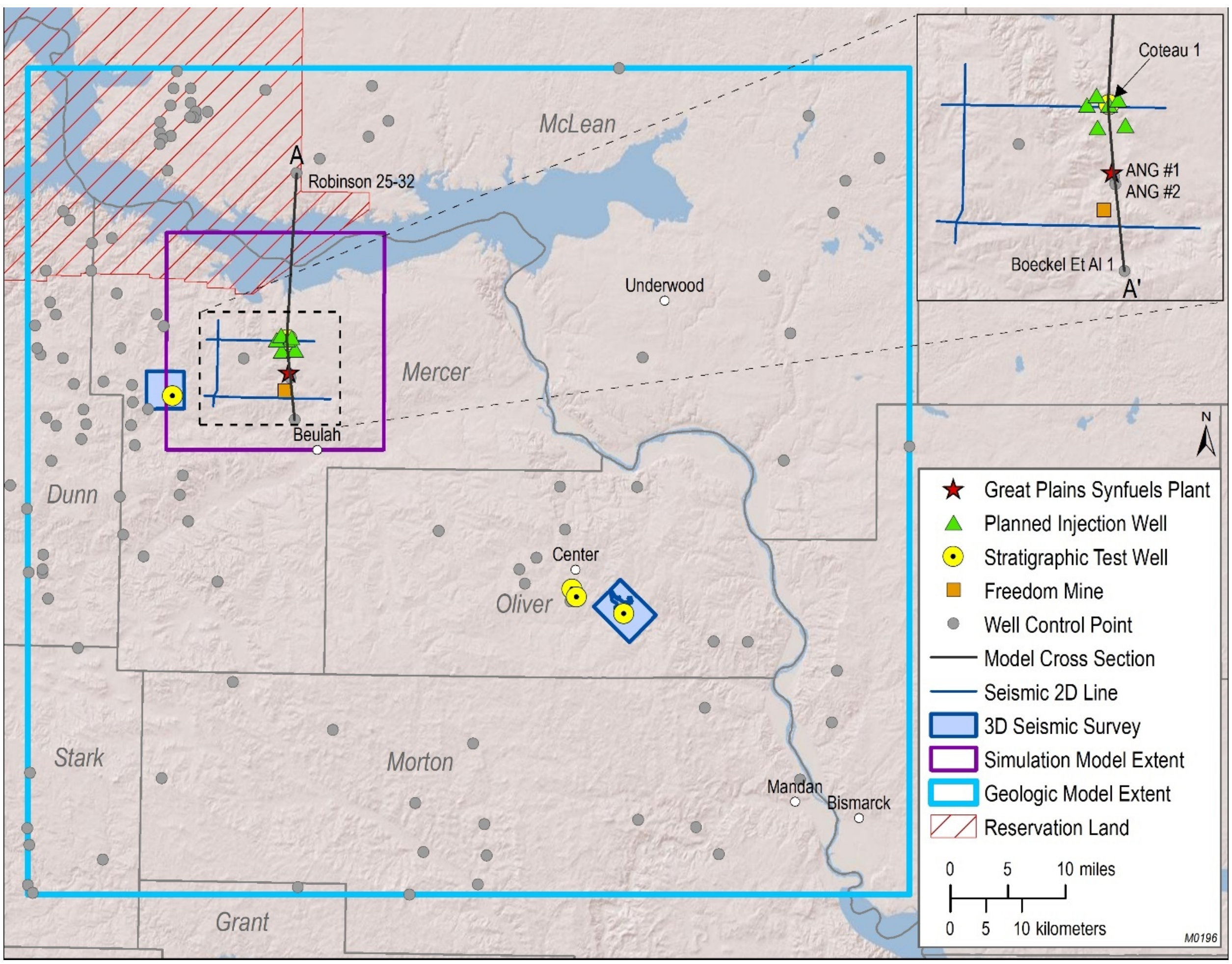


Figure 3-1. Map of the geologic model boundary (blue polygon), simulation model boundary (purple polygon), 3D seismic surveys, model cross section, and nearby Broom Creek wells.

Group, 2019). Numerical simulations of CO_2 injection were conducted to assess potential CO_2 injection rate, disposition of injected CO_2, wellhead pressure (WHP), bottomhole pressure (BHP), and pressure changes in the storage reservoir throughout the expected injection time frame and postinjection period. Results of the numerical simulations were then used to determine the project's area of review (AOR) pursuant to North Dakota's geologic CO_2 storage regulations.

3.2 Geologic Model Development

A geologic model was constructed to characterize the injection zone and upper and lower confining zones. Activities included data aggregation, structural framework creation, data analysis, and property distribution. Major inputs for the geologic model, which acted as control points during the distribution of the geologic properties throughout the modeled area, included seismic survey data, geophysical logs from nearby wells and core sample measurements.

Because of low well control and lack of site-specific 3D seismic data within the storage facility area, publicly available variograms were used to inform the distribution of the lithofacies and petrophysical properties in the geologic model. The variograms reported in the Tundra SGS (secure geologic storage) facility permit were selected as they provide a generalized representation of the property distributions expected within the Broom Creek Formation (North Dakota Industrial Commission, 2021).

3.2.1 Structural Framework Construction

Schlumberger's Petrel software was used to interpolate structural surfaces for the Opeche, Broom Creek, and Amsden Formations. Input data included formation top depths from the online NDIC database; data collected from the Coteau 1, Flemmer 1, ANG #1, J-LOC 1, J-ROC 1, and BNI-1 wells (Figure 2-5); and two 3D seismic surveys (Figure 3-1) conducted at Flemmer 1 and J-ROC 1 wellsites. The interpolated data were used to constrain the model extent in 3D space.

3.2.2 Data Analysis and Property Distribution

3.2.2.1 Confining Zones (Opeche and Amsden Formations)

The Opeche Formation was assigned a silty mudstone lithofacies designation, and the Amsden Formation was assigned a dolostone designation; both classifications were determined as primary lithologic constituents through core and well log analysis. Porosity logs, after comparison with core data sets, served as control points for property distribution. Available permeability measurements also served as control points. The control points were used in combination with variograms and a Gaussian random function simulation algorithm to distribute the properties. 4,000-ft major and minor axis length variogram structures in the lateral direction and a 6-ft vertical variogram length were used for the Opeche Formation. A major axis of 6,000-ft and a minor axis length of 3,000-ft were used for the Amsden Formation along an azimuth of 155° with a vertical variogram of 5 ft.

3.2.2.2 Injection Zone (Broom Creek Formation)

Prior variogram assessments completed for use in a similar storage facility permit application, the Tundra SGS CO_2 storage project, were used to assign variogram ranges within the injection zone. Variogram mapping investigations, as noted in the Tundra SGS application, investigated the size and shape of variograms in several different azimuthal directions, which indicated that geobody structures with the following dimensions were present in the Broom Creek Formation: major axis range of 5,000 ft, minor axis range of 4,500 ft, and an azimuth of 155° (NDIC, 2021). The Tundra SGS application used well logs recorded from the J-LOC 1, BNI-1, and J-ROC 1 wellbores to serve as the basis for deriving a vertical variogram length of 7 ft. The variogram ranges were used to distribute lithofacies and petrophysical properties.

Lithofacies classifications were determined from well log data and correlated with descriptions of core taken from the Coteau 1, Flemmer 1, ANG #1, J-LOC 1, J-ROC 1, and BNI-1 wells. Four predominant lithofacies were identified within the Broom Creek Formation: 1) sandstone, 2) dolomitic sandstone, 3) dolostone, and 4) anhydrite. Lithofacies were manually interpreted from these observations and upscaled to serve as control points for geostatistical distribution using a sequential indicator simulation (Figure 3-2).

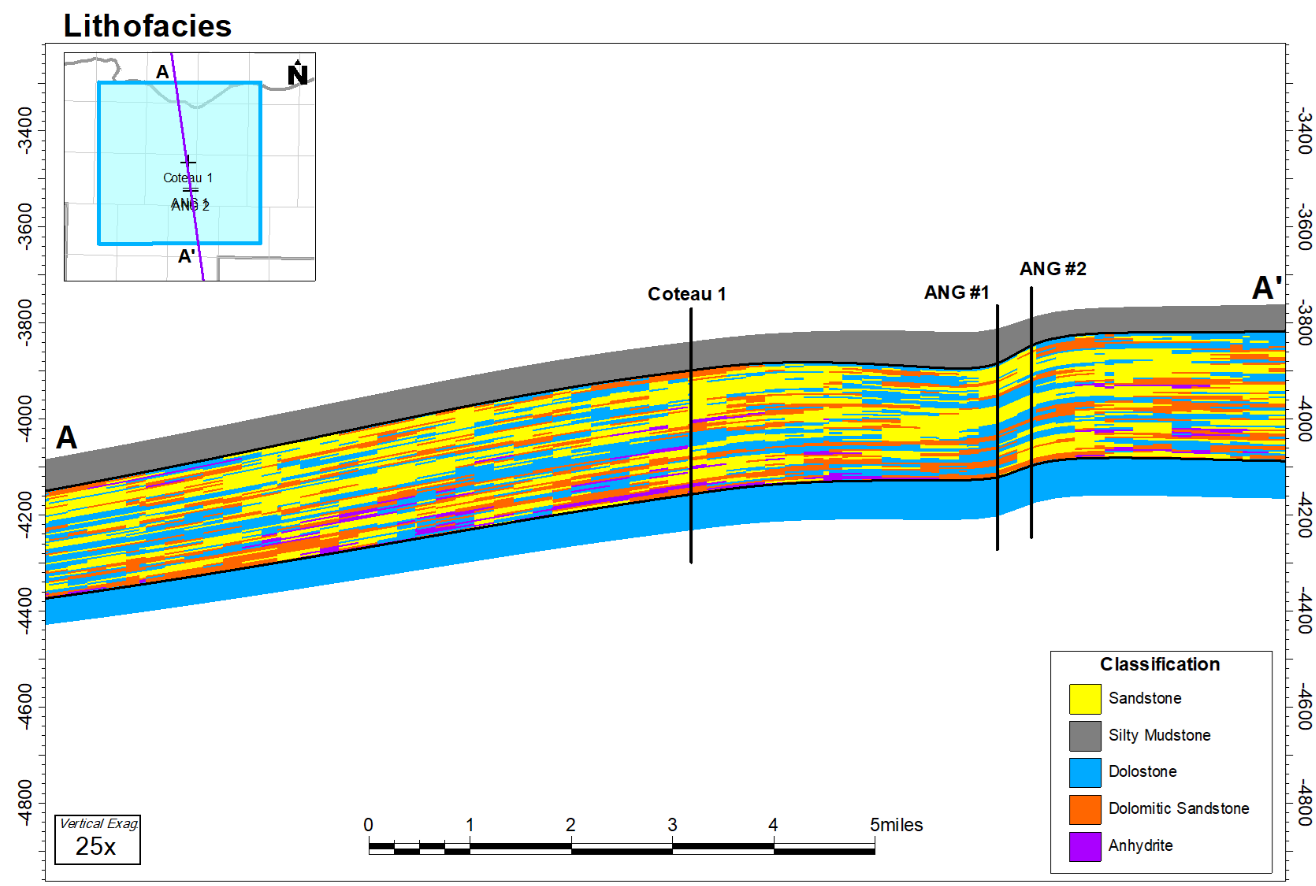


Figure 3-2. Cross-sectional view of lithofacies property. Vertical units on the y-axis are displayed as feet below sea level (25× vertical exaggeration shown).

Prior to distributing the porosity and permeability properties, core porosity and permeability measurements from Coteau 1, Flemmer 1, ANG #1, BNI-1, J-LOC 1, and J-ROC 1 wells were compared with effective porosity well logs and permeabilities estimated from the Wyllie-Rosa model (Wyllie and Rose, 1950) to ensure good agreement between the six data sets (Figure 3-3).

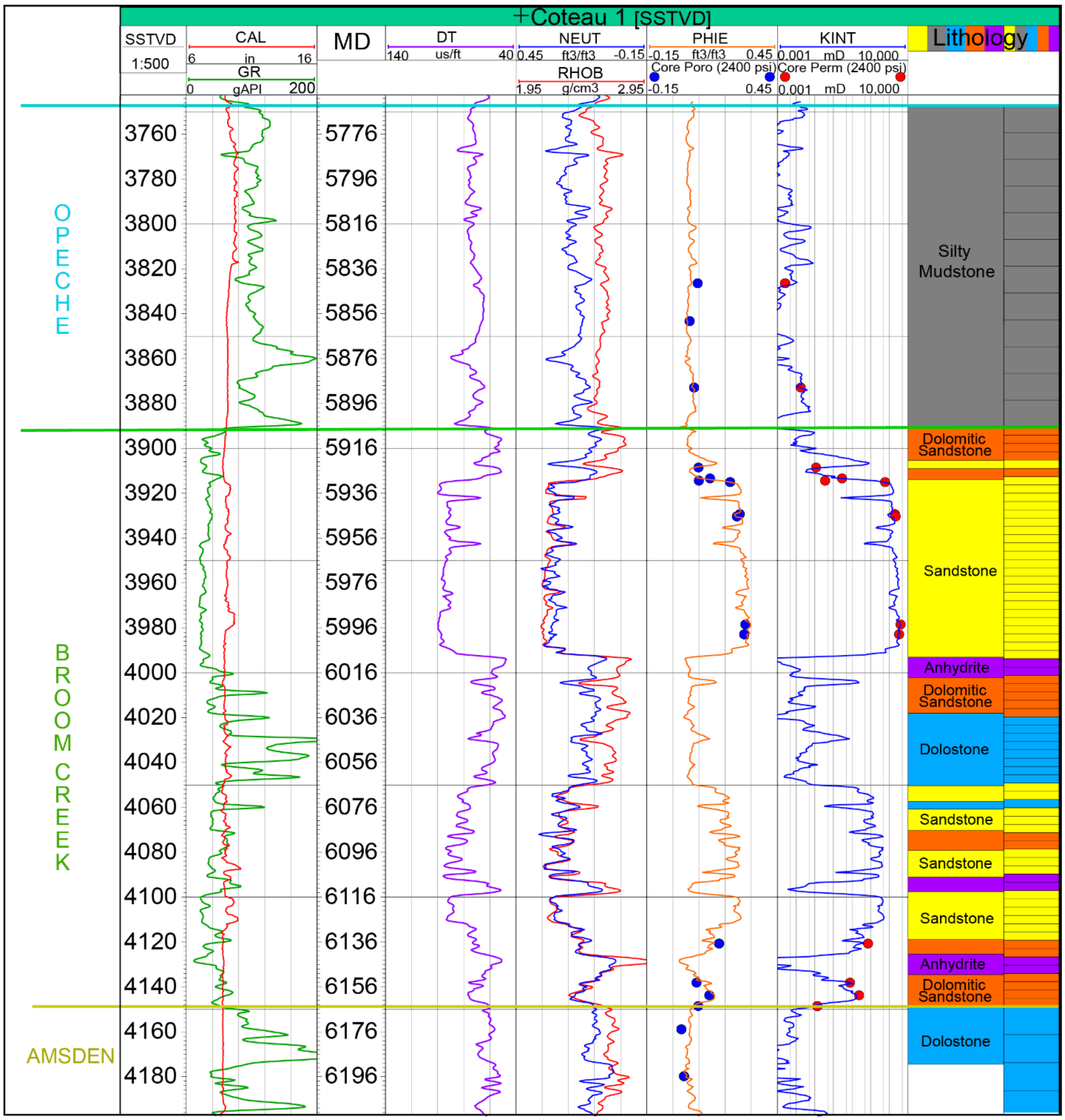


Figure 3-3. Lithofacies classification in Coteau 1 well. Well logs displayed in tracks from left to right are 1) gamma ray (green) and caliper (red), 2) delta time (purple), 3) neutron porosity (blue) and density (red), 4) effective porosity (orange) and core sample porosity (blue dots), 4) predicted intrinsic permeability (blue) and core sample permeability (red dots), 6) interpreted lithology, and 7) upscaled lithology.

A PHIE property (effective porosity; total porosity less occupied or isolated pore space) was distributed using calculated PHIE well logs, upscaled to the resolution of the 3D model as control points and variogram structures described previously with Gaussian random function simulation and conditioning to the distributed lithofacies. A permeability property was distributed using the same variables and algorithm, but cokriged to the PHIE volume (Figures 3-4 and 3-5).

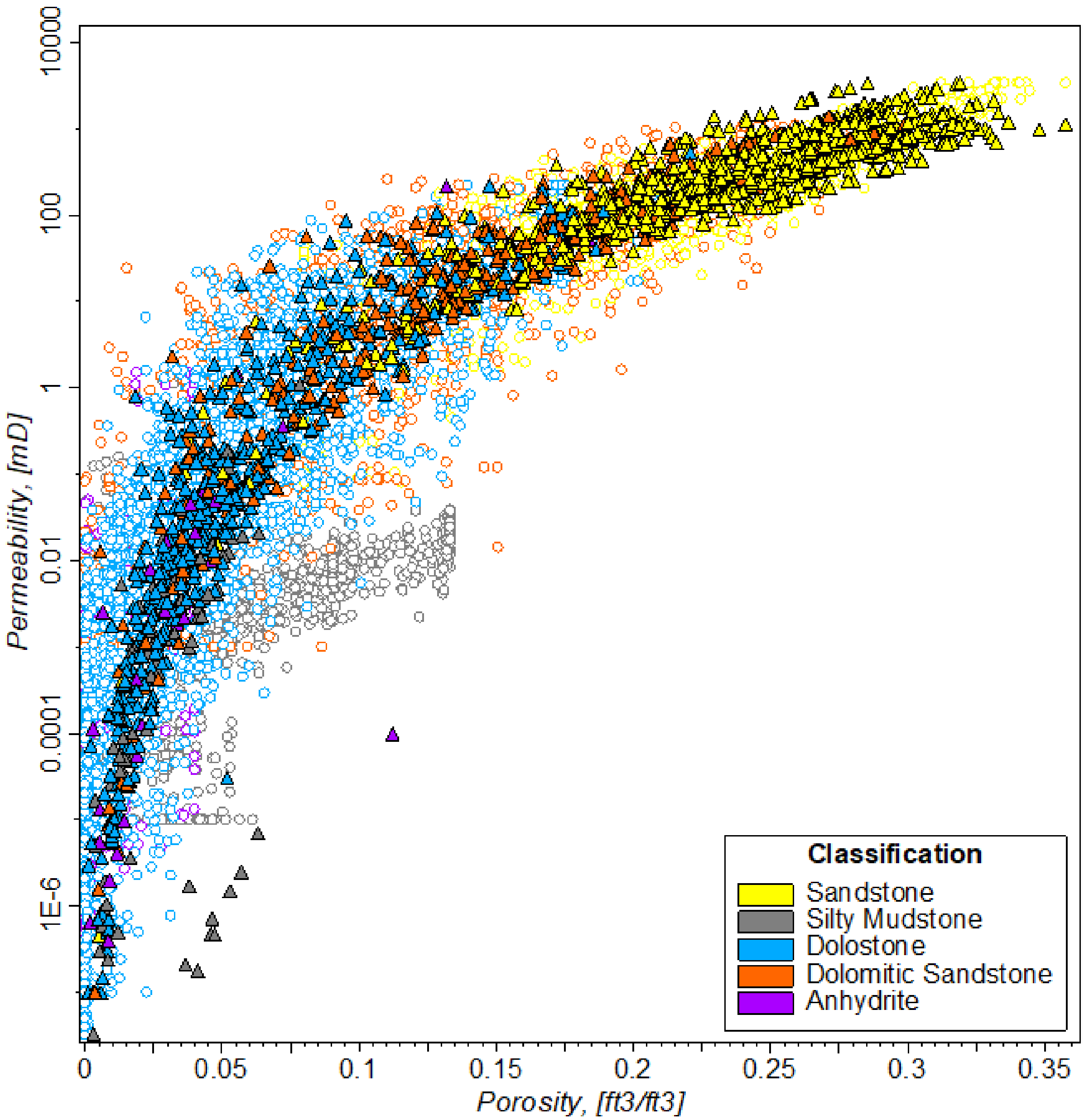


Figure 3-4. Illustration of the relationship between the modeled porosity and permeability. Upscaled well log values are represented by triangles, while circles represent distributed values. Values are colored according to lithofacies classification, as seen in Figure 3-3.

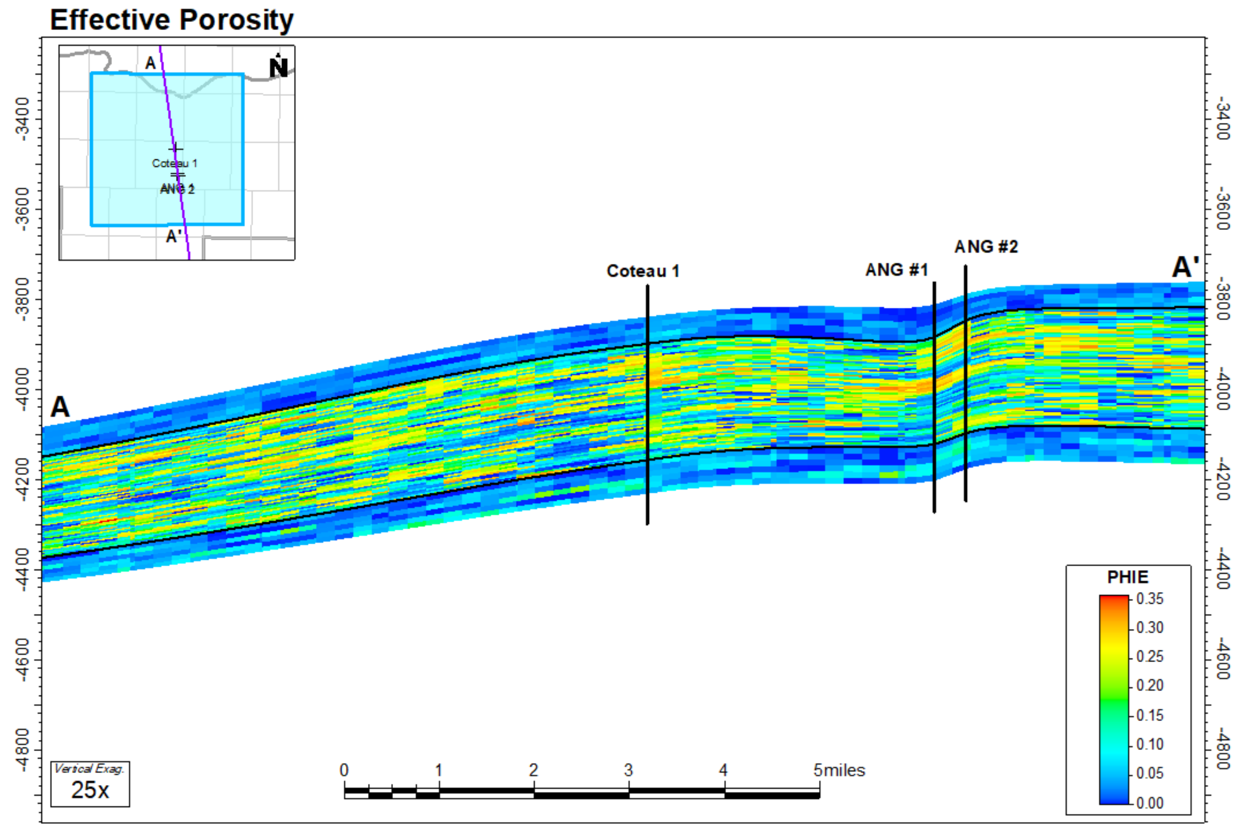


Figure 3-5. Distributed PHIE property along a NW-SE cross section. The distributed PHIE property was used to distribute permeability throughout the model. Units on the y-axis represent feet below mean sea level (25× vertical exaggeration shown).

3.3 Numerical Simulation of CO_2 Injection

Numerical simulations of CO_2 injection into the Broom Creek Formation were conducted using the geologic model described above in Section 3.2. Figure 3-6 displays the 3D view of the simulation model with the permeability property and Coteau 1 injection well. Simulations were carried out using CMG's GEM, a compositional reservoir simulation module. Both calculated temperature and pressure, along with the reference datum depth, were used to initialize the reservoir at equilibrium conditions for performing numerical simulation.

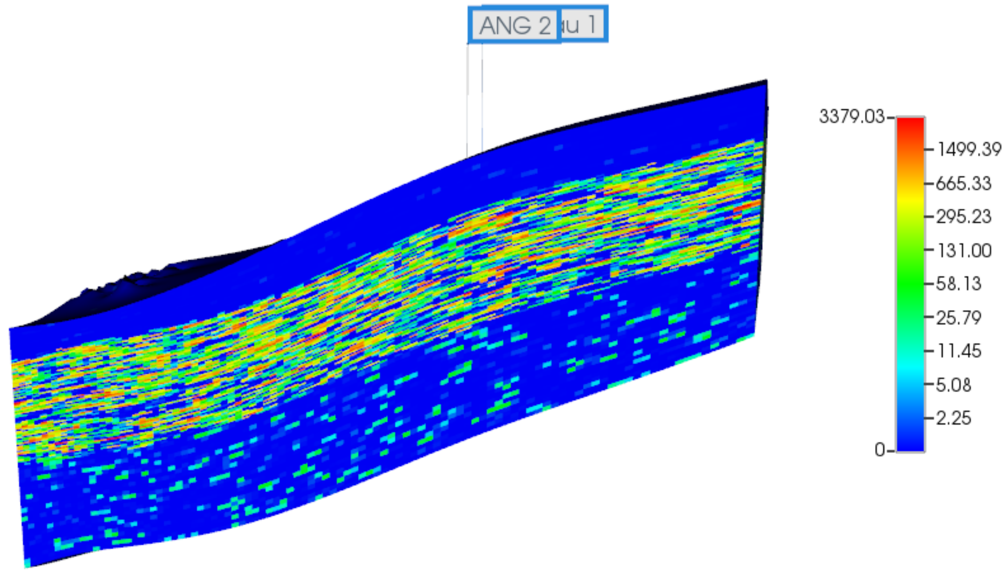


Figure 3-6. 3D view of the simulation model with the permeability property and injection wells displayed. Note the low-permeability layers (dark blue) at the top and bottom of the figure. These layers represent the Opeche Formation (upper) and the Amsden Formation (lower). The varied permeability of the Broom Creek is observed in between these layers.

The simulation model boundaries were assigned partially closed conditions as the Broom Creek Formation pinches out in the northern and eastern parts of the modeled area. From geologic interpretation for this model, distances to the formation pinch-out are assumed to be 170,016 feet (~32.2 miles) to the northeast and 158,400 feet (~30 miles) to the east from the edge of the simulation domain based on well log interpretation. The reservoir was assumed to be 100% brine-saturated with an initial formation salinity of 42,800-ppm total dissolved solids (TDS) based on the fluid sample analysis from the Coteau 1 well (Table 2-6).

CO_2 injection simulations performed allowed CO_2 to dissolve into the native formation brine. Both the relative permeability and the capillary pressure data for the Broom Creek Formation were analyzed and generated for four representative rock types in the simulation to describe the Broom Creek Formation: sandstone, dolostone, dolomitic sandstone, and anhydrite through Core Laboratory's MICP (mercury injection capillary pressure) evaluation and EERC laboratory analysis. Capillary pressure curves calculated from the MICP data were adapted to the permeability and porosity values from the numerical model.

Injection simulation scenarios were run using relative permeability and capillary pressure curves derived from the site-specific core samples from Coteau 1 well and compared to simulation scenarios that used publicly available values reported in the Project Tundra SGS facility permit (North Dakota Industrial Commission, 2021). In these scenarios, all other inputs and constraints besides relative permeability and capillary pressure curves were kept constant. Scenarios run with site-specific relative permeability and capillary pressure curves from Coteau 1 resulted in smaller plume sizes compared to the scenarios run with publicly available data (Figure 3-7 and 3-8). Based on these results, the decision was made to permit the scenario that uses the publicly available data to have a more conservative estimate for plume size.

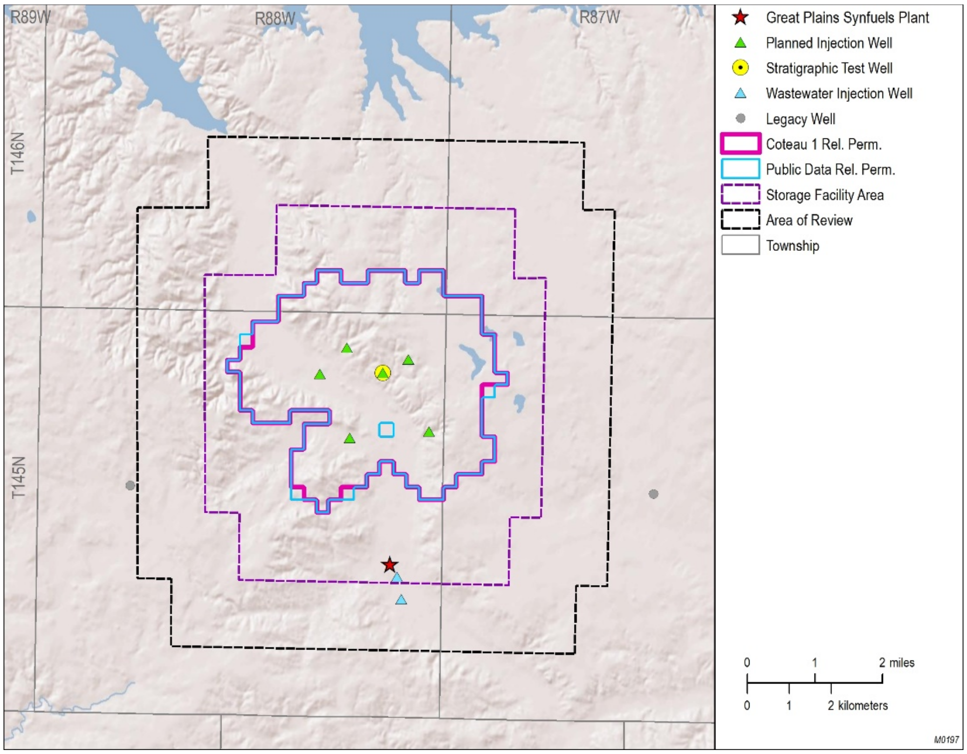


Figure 3-7. Simulated CO_2 plume extents at the end of 12 years of CO_2 injection for the scenario run using site-specific relative permeability data (pink) and the scenario run with publicly available relative permeability data (blue). The plume extent for the scenario using site-specific data is approximately 0.11 sq. mi. smaller.

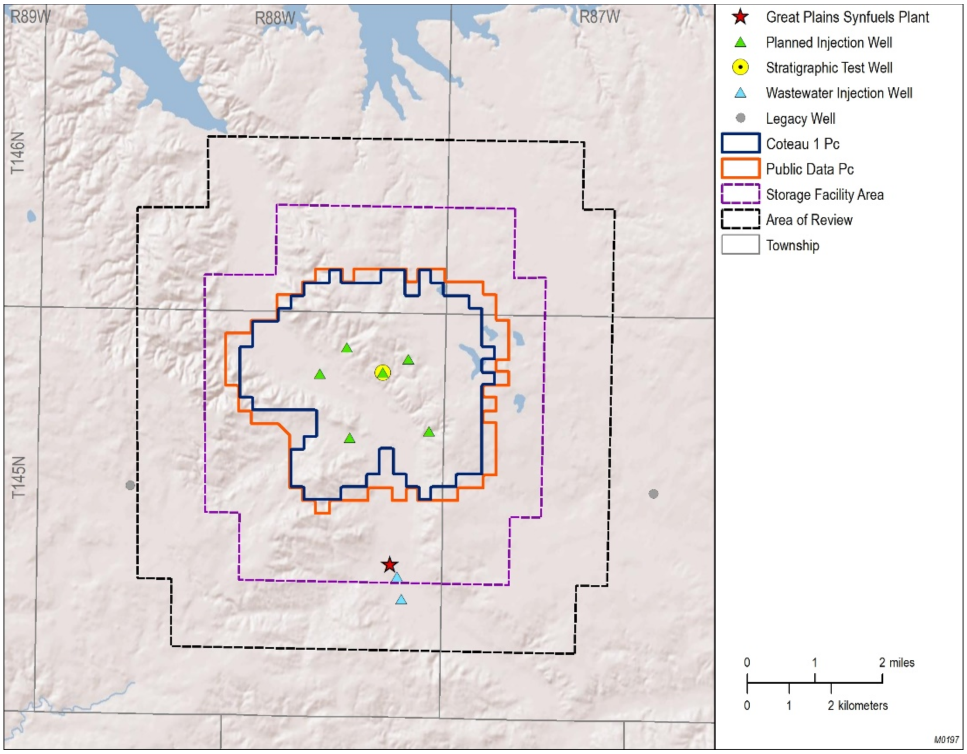
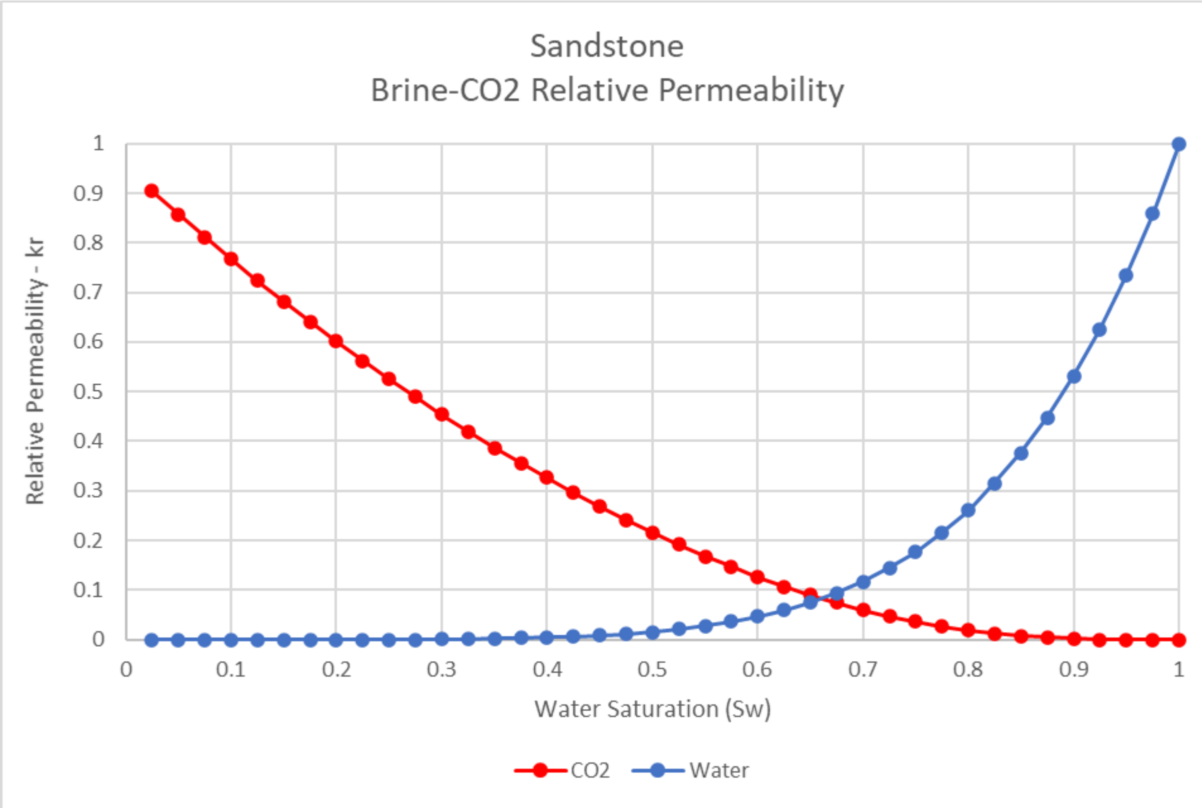


Figure 3-8. Simulated CO_2 plume extents at the end of 12 years of CO_2 injection for the scenario using site-specific relative permeability and capillary pressure (Pc) data (dark blue) and the scenario run with publicly available relative permeability and capillary data (orange). The plume extent for the scenario using site-specific data is approximately 2.2 sq. mi. smaller.

The publicly available capillary pressure curves used for the injection scenario presented in this permit are shown in Figures 3-9 through 3-12. Capillary entry pressures were determined from Broom Creek Formation core sample analysis and were assigned based on lithofacies. The assigned capillary entry pressures are 1) sandstone: 0.20 psi, 2) dolostone: 18.08 psi, and 3) mudstone and anhydrite: 168.10 psi. The dolostone pressure value, derived from a core sample within the Broom Creek Formation, was assigned to all dolostone lithofacies throughout the simulation model. Similarly, the mudstone and anhydrite pressure value, derived from a Broom Creek anhydrite core sample, was assigned to all mudstone and anhydrite lithofacies within the simulation model. The Opeche was assigned as silty mudstone, and the Amsden was assigned as dolostone.



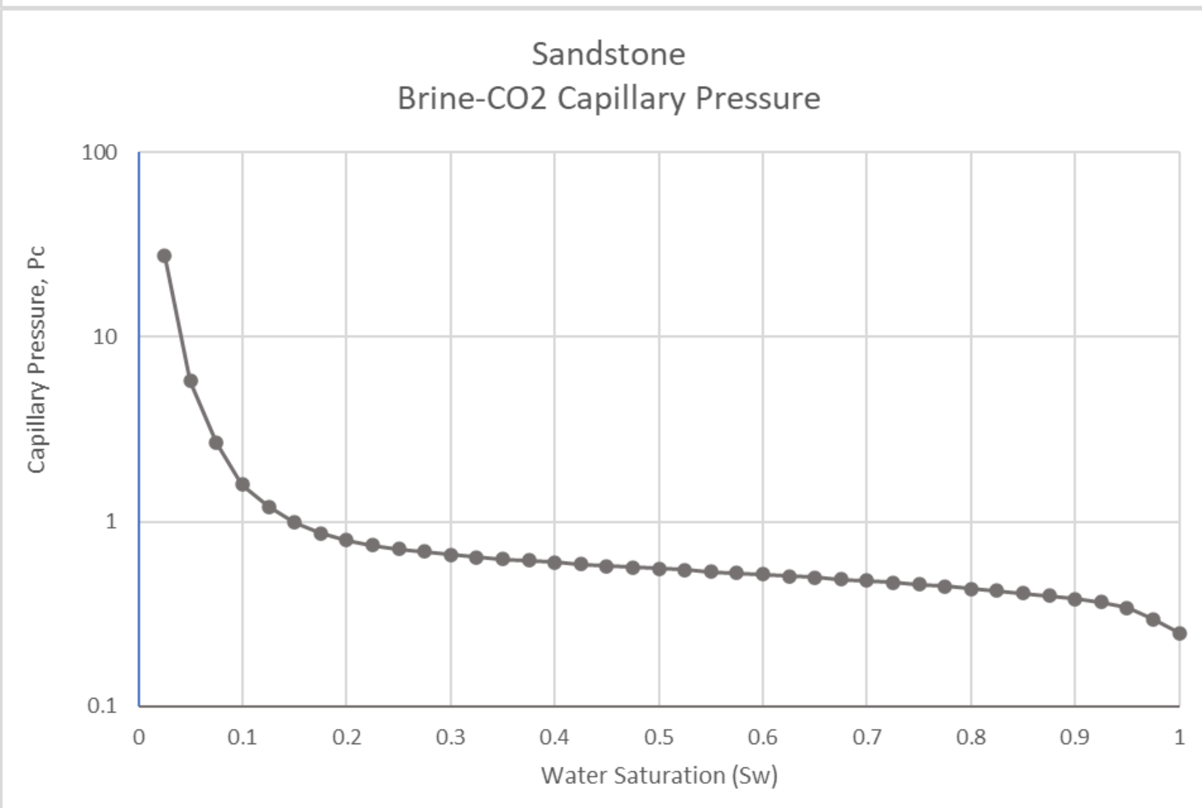
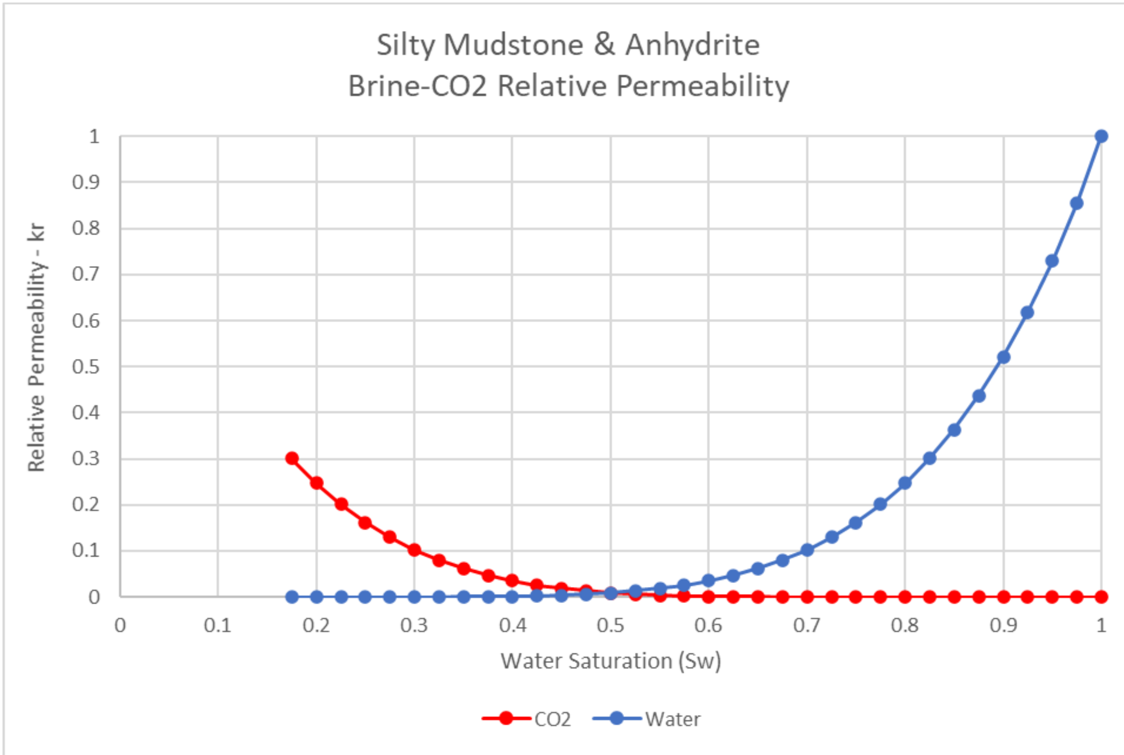


Figure 3-9. Relative permeability (top) and capillary pressure curves (bottom) for the sandstone rock type in the Broom Creek Formation.



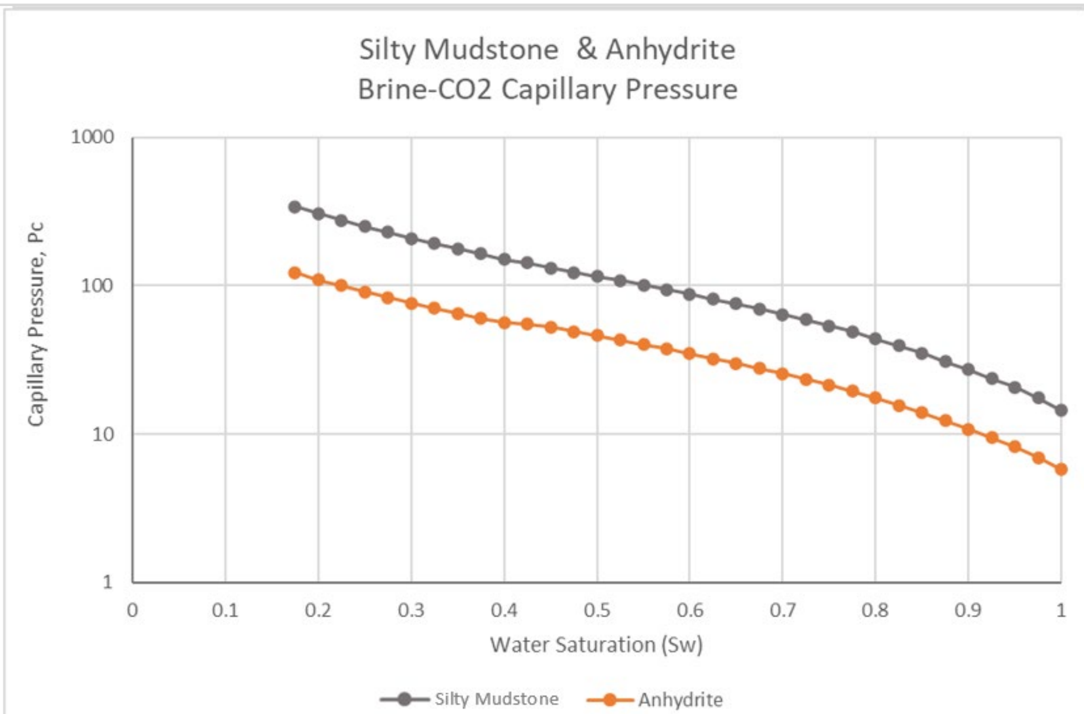
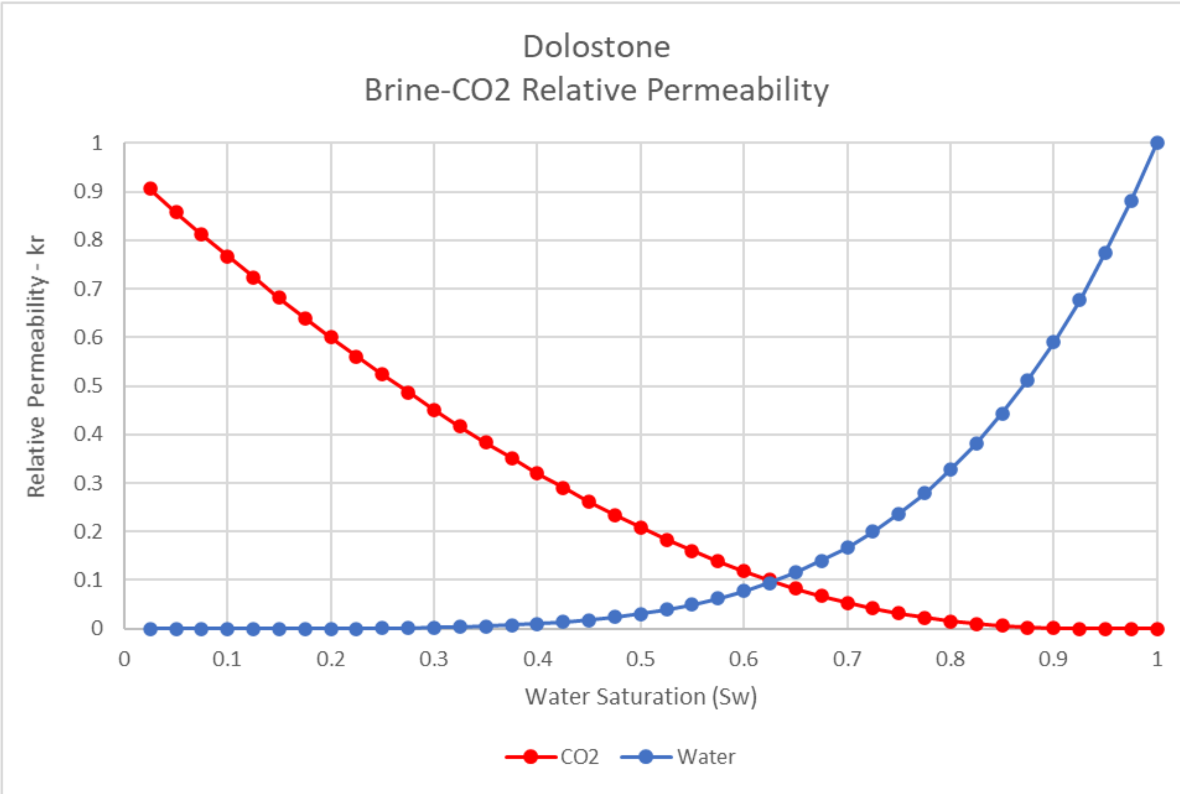


Figure 3-10. Relative permeability (top) and capillary pressure curves (bottom) for the silty mudstone rock type in the Opeche Formation and anhydrite rock type within in the Broom Creek Formation.



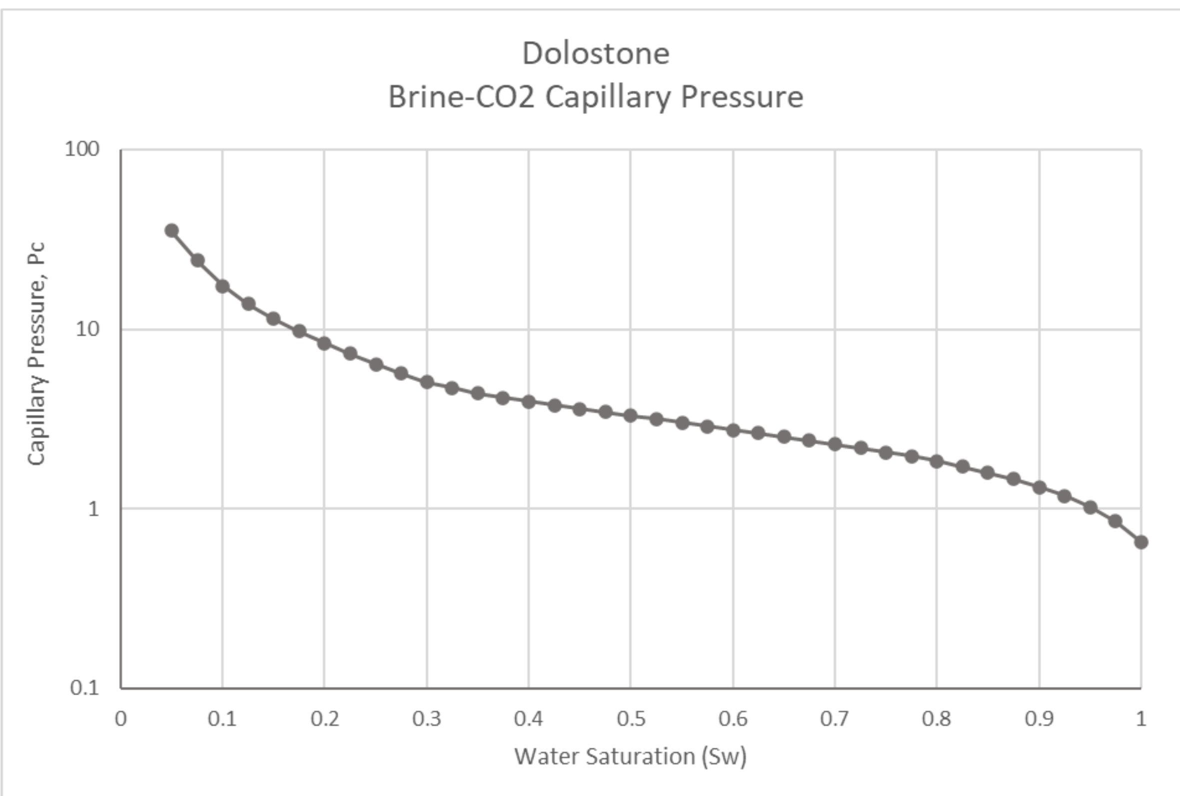
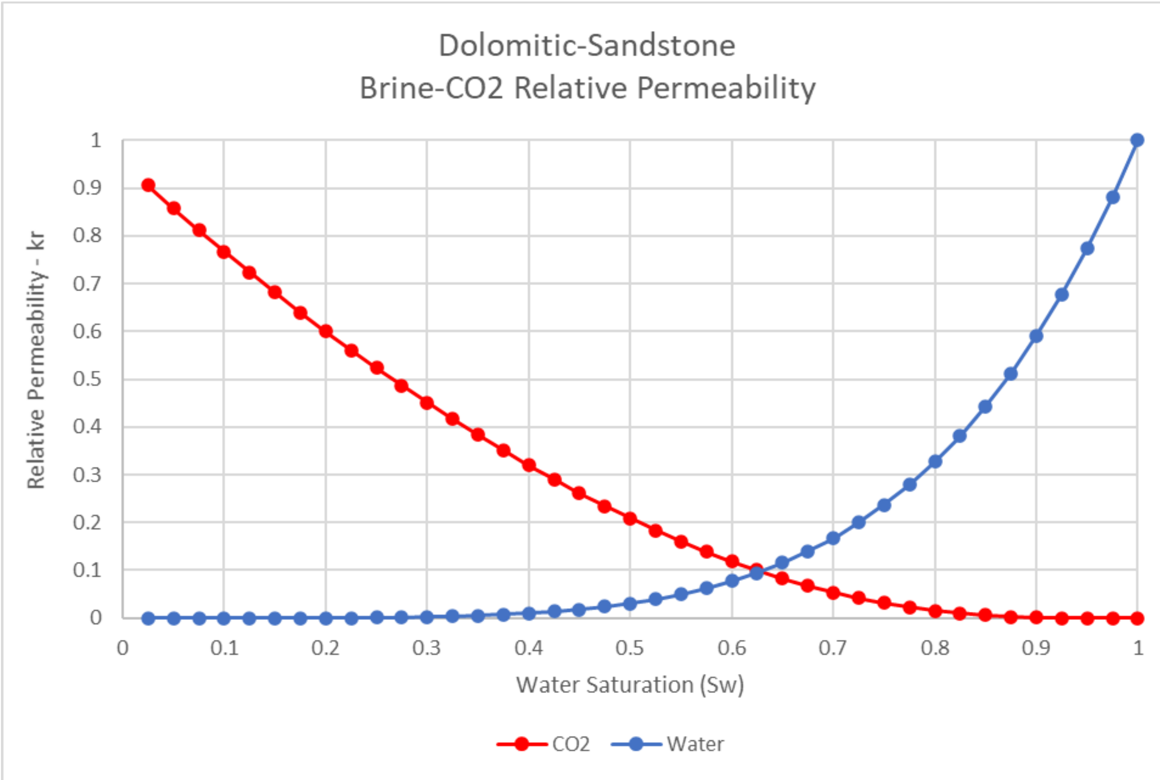


Figure 3-11. Relative permeability (top) and capillary pressure curves (bottom) for the dolostone rock types in the Broom Creek and Amsden Formations.



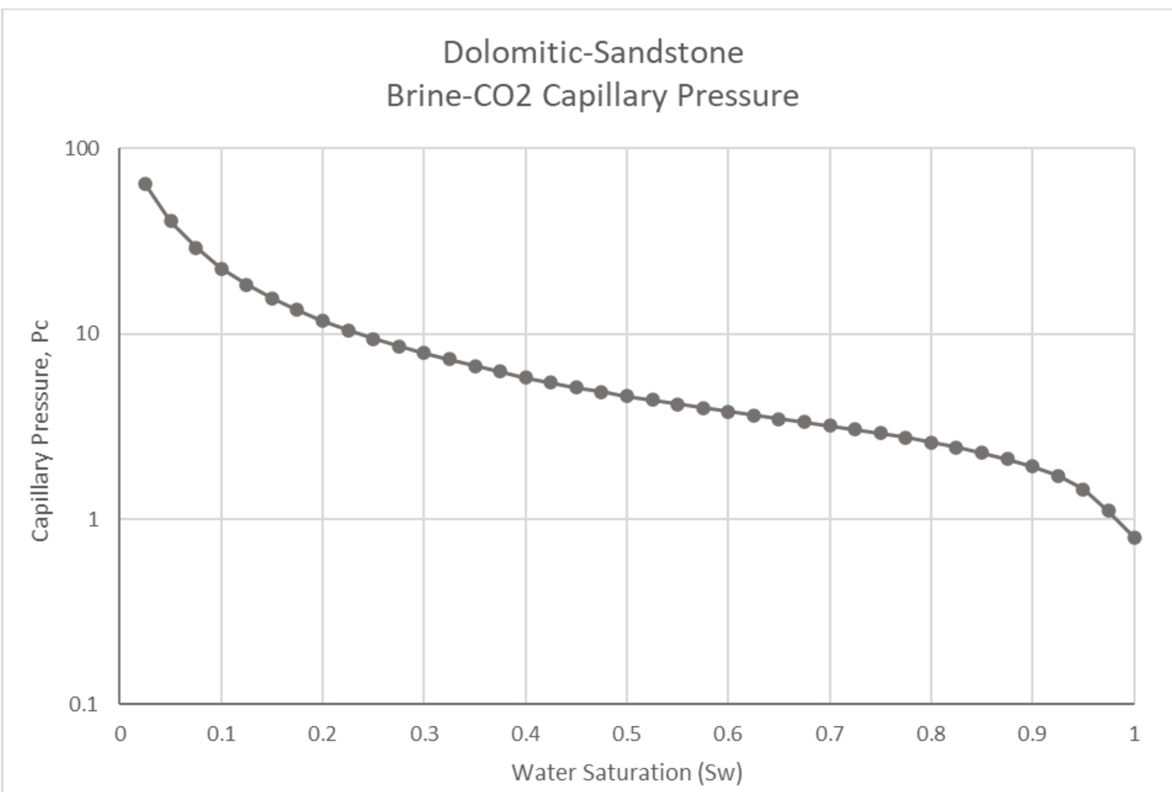


Figure 3-12. Relative permeability (top) and capillary pressure curves (bottom) for the dolomitic sandstone rock type in the Broom Creek Formation.

Temperature and pressure data recorded from a pressure test in the Coteau 1 were used to derive a temperature and pressure gradient to initialize the numerical simulation model for the proposed injection site. In combination with depth, this temperature gradient of 0.02°F/ft was used to calculate subsurface temperatures throughout the study area. A pressure reading recorded from the Broom Creek Formation was used to derive a pore pressure gradient of 0.49 psi/ft (Table 3-1). Table 3-2 shows the general properties used for numerical simulation analysis in this study.

Table 3-1. Pressure Measurement Recorded from the Coteau 1 Well and Derived Pressure Gradient

Test Depth, ft MD*	Formation Pressure, psi	Pressure Gradient, psi/ft
5,975.00	2,937.09	0.49

* Measured depth.

Table 3-2. Summary of Reservoir Properties in the Simulation Model

Formation	Average Permeability, mD	Average Porosity, %	Initial Pressure, P_i, psi	Salinity, ppm	Boundary Condition
Opeche	0.034	25.7	~2,937.1 (at 3,960.6 ft)	42,800	Partially closed
Broom Creek	241.2	14.5			
Amsden	2.55	4.4			

The CMG fluid property characterization tool, WinProp, was used to generate the fluid property input data for the simulation model. Only the major constituents in the gas stream were included for computational efficiency. After all the constituents were normalized to sum 100% mole fraction, the CO_2 composition in the gas stream was 96.45% CO_2. Other constituents represent 3.55% of the stream, including 1.23% hydrogen sulfide (H_2S) and 2.32% for methane, ethane, propane, and nitrogen.

The numerical simulation model was history-matched using the field injection data from the Class I injector wells located in the area of study, ANG #1 and ANG #2. The field injection data consisted of daily field data from Dakota Gasification Company (DGC) water injection into the ANG wells throughout July 1998 to August 2021. The field data provided were averaged per month and included in the numerical model for the history matching. The well skin factor was the parameter used to history-match the model based on data from a monitoring study conducted in the ANG wells in 2016. Figures 3-13 and 3-14 show a comparison between the WHP and water injection rate from the field data set and the predicted values from the history-matched model.

Six CO_2 injection wells, Coteau 1, Coteau 2, Coteau 3, Coteau 4, Coteau 5, and Coteau 6, were simulated as perforated across the entire Broom Creek Formation interval (Figure 2-2). The CO_2 injection well constraints and wellbore model inputs for the simulation model are shown in

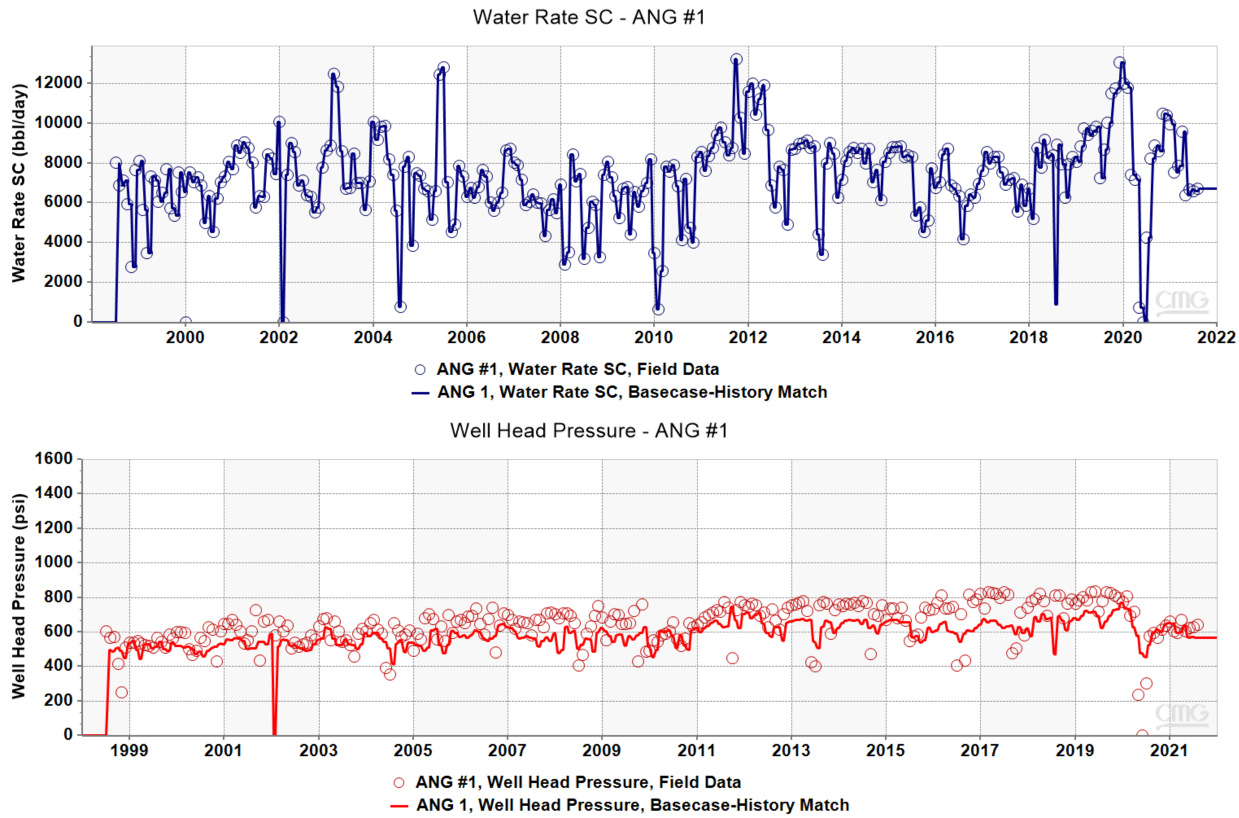


Figure 3-13. Water injection rate (top) and WHP curves (bottom) for the ANG #1 Class I disposal well. The circles represent the field data, and the lines represent the predicted values from the history-matched model.

Table 3-3. The CO_2 injection rate in the simulation model is based on initial CO_2 volumes expected to average 55 MMcfd (1.0 million metric tonnes per year [MMt/yr]), determined from existing compressor capacity and historical excess CO_2 availability after satisfying existing contractual arrangements. As additional volumes become available in the future, the daily rate is expected to increase to 70 MMcfd (1.3 MMt/yr) in January 2025, then to 140 MMcfd (2.7 MMt/yr) in May 2026 until the end of the 12-year CO_2 injection period.

The BHP constraint was calculated using the well depth at the top of the Broom Creek Formation (MD) and 90% of the formation fracture gradient. The fracture gradient was obtained from geomechanical modeling and core analysis, resulting in an average of 0.71 psi/ft fracture propagation pressure in the Coteau 1 well.

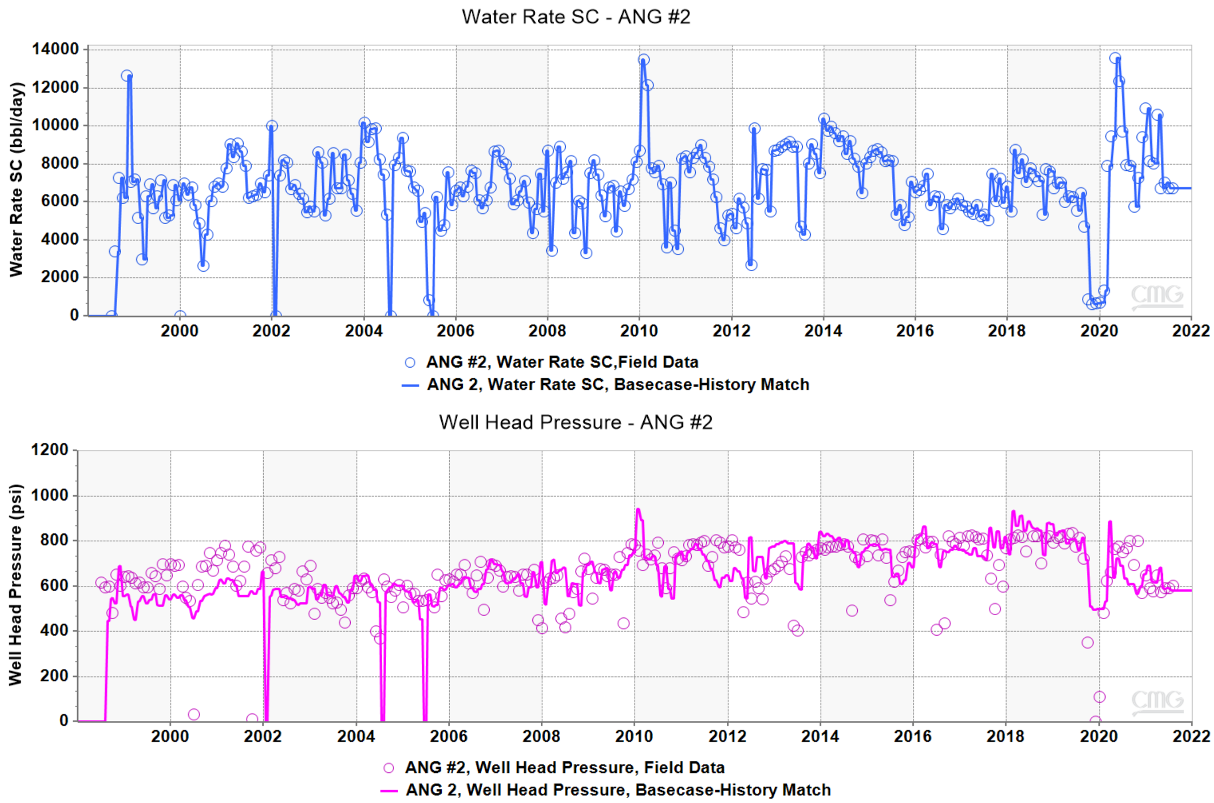


Figure 3-14. Water injection rate (top) and WHP curves (bottom) for the ANG #2 Class I disposal well. The circles represent the field data, and the lines represent the predicted values from the history-matched model.

Table 3-3. Well Constraints and Wellbore Model in the Simulation Model

<table>
<tr><th>Well Name</th><th>Start Date of Injection</th><th>Primary Well Constraint, maximum BHP</th><th>Secondary Well Constraint, maximum injection rate/well</th><th>Tubing Size</th><th>Wellhead Temperature</th><th>Downhole Temperature</th></tr>
<tr><td>Coteau 1*</td><td>July/2022</td><td>3,754 psi</td><td>25 MMcfd</td><td rowspan="6">4½ in.</td><td rowspan="6">90°F</td><td rowspan="6">151°F</td></tr>
<tr><td>Coteau 2*</td><td>July/2022</td><td>3,802 psi</td><td>17.5 MMcfd</td></tr>
<tr><td>Coteau 3*</td><td>July/2022</td><td>3,772 psi</td><td>25 MMcfd</td></tr>
<tr><td>Coteau 4*</td><td>July/2022</td><td>3,787 psi</td><td>25 MMcfd</td></tr>
<tr><td>Coteau 5*</td><td>May/2026</td><td>3,776 psi</td><td>25 MMcfd</td></tr>
<tr><td>Coteau 6*</td><td>May/2026</td><td>3,786 psi</td><td>25 MMcfd</td></tr>
</table>

* Primary group constraint, injection rate: 55 MMcfd from July/2022 to Dec./2024, 70 MMcfd from Jan./2025 to April/2026, 140 MMcfd from May/2026 to July/2034.

Water injection conditions used for numerical simulation of the Class I disposal wells, ANG #1 and ANG #2, are shown in Table 3-4. The water injection rate constraint used for the ANG wells during the CO_2 injection period was determined from historical injection rates over the past 2 years. Water injection into ANG #1 and ANG #2 was held constant during the 12 years of the CO_2 injection period. For simulation evaluation purposes, it is assumed that water injection ceases at the end of CO_2 injection as the operations producing the water are likely to cease at the end of CO_2 injection.

Table 3-4. ANG #1 and ANG #2 Well Constraints in the Simulation Model

Primary Well Constraint, maximum water injection rate	Secondary Well Constraint, maximum permitted WHP
6,722.9 bpd for ANG #1	1,350 psi for ANG #1
6,722.4 bpd for ANG #2	1,100 psi for ANG #2

3.3.1 Sensitivity Analysis

Because the availability of data for this study included well logs, core sample data, and rock-fluid properties, the need for typical sensitivity studies of influential reservoir parameters has been reduced. A preliminary sensitivity analysis made to the wellbore model parameters suggested, at the given injection volume rates and BHP conditions, the wellhead temperature played a prominent role in determining WHP response. Thus a wellhead temperature value of 90°F was chosen that most closely represents the expected operational temperature.

3.4 Simulation Results

Simulations of CO_2 injection with the given well and group constraints, listed in Table 3-3, predicted the WHP of all six injector wells would not exceed 1,730 psi during injection (Figure 3-15). The predicted BHP for each of the CO_2 injection wells did not reach the maximum BHP constraint defined using 90% of the fracture pressure gradient (Table 3-5). The target

Table 3-5. BHP Constraint and Predicted from Simulations BHP and Associated Fracture Pressure Gradient

	Well Name					
	Coteau 1	**Coteau 2**	**Coteau 3**	**Coteau 4**	**Coteau 5**	**Coteau 6**
Max BHP Constraint,* psi	3,754	3,802	3,772	3,787	3,776	3,786
Max. BHP Predicted, psi	3,430	3,445	3,462	3,414	3,424	3,426
Fracture Pressure Gradient Associated with Predicted Max. BHP, ** psi/ft	0.585	0.580	0.587	0.577	0.580	0.580

* Calculated using 0.64 psi/ft (90% of the fracture pressure gradient) and the depth for the top of the Broom Creek Formation.

** Calculated using the depth for the top of the Broom Creek Formation.

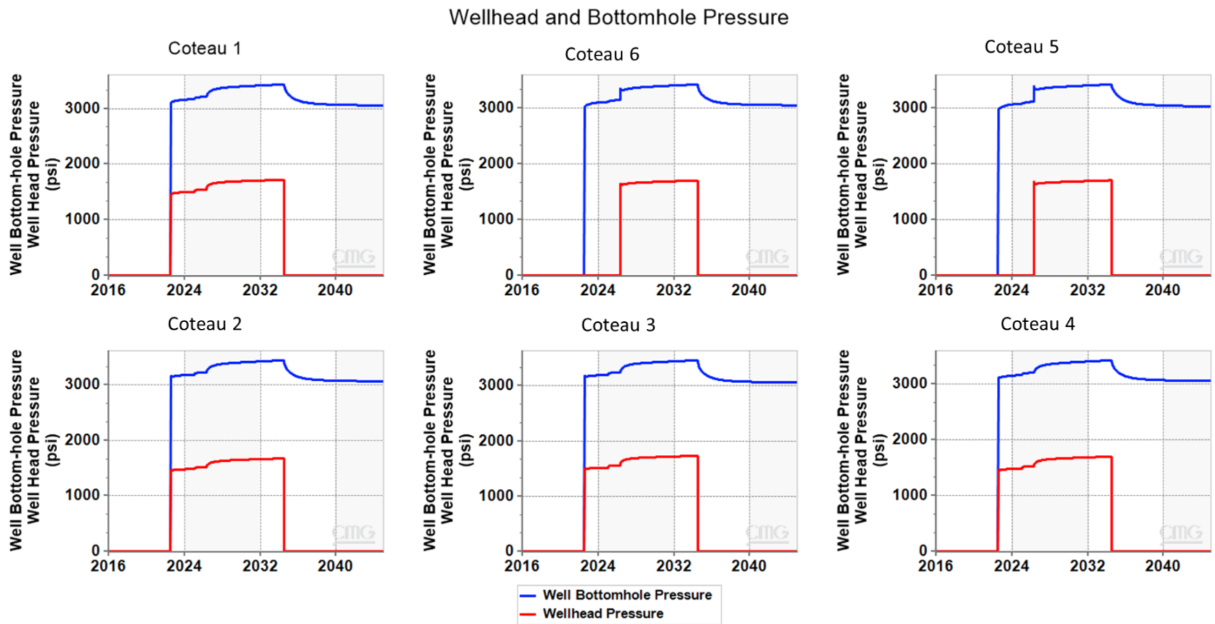


Figure 3-15.WHP and BHP response with the expected injection rate.

injection rates of 55 MMcfd from July 2022 to December 2024, 70 MMcfd from January 2025 to April 2026, and 140 MMcfd from May 2025 to July 2034 were achieved over the 12 years of injection (Figure 3-16).

A total of 25.61 MMt (501,755 MMscf) of CO_2 was injected into the Broom Creek Formation with six wells at the end of 12 years of simulated injection (Figure 3-17). The injected volume for each of the wells is shown in Table 3-6.

Simulation results showed that the maximum permitted WHP constraint for the ANG wells, Table 3-4, was not reached, and the WHP values for ANG #1 and ANG #2 did not exceed 833 and 829 psi, respectively, during the CO_2 injection period (Figure 3-18). Also, the water injection rate was not affected during the CO_2 injection period.

The simulation results did not show any interaction between the low salinity plume from the Class I disposal wells, ANG #1 and ANG #2, and the CO_2 plume at the end of the injection period. Any possible interaction during the CO_2 injection period is not affecting CO_2 injectivity. A limited interaction may occur between the low salinity plume and the CO_2 stabilized plume at 10 years postinjection. These simulation results can be seen in Section 2, Figure 2-22. However, no evidence from the simulation results indicates that this possible interaction will affect the CO_2 chemical behavior or storage performance.

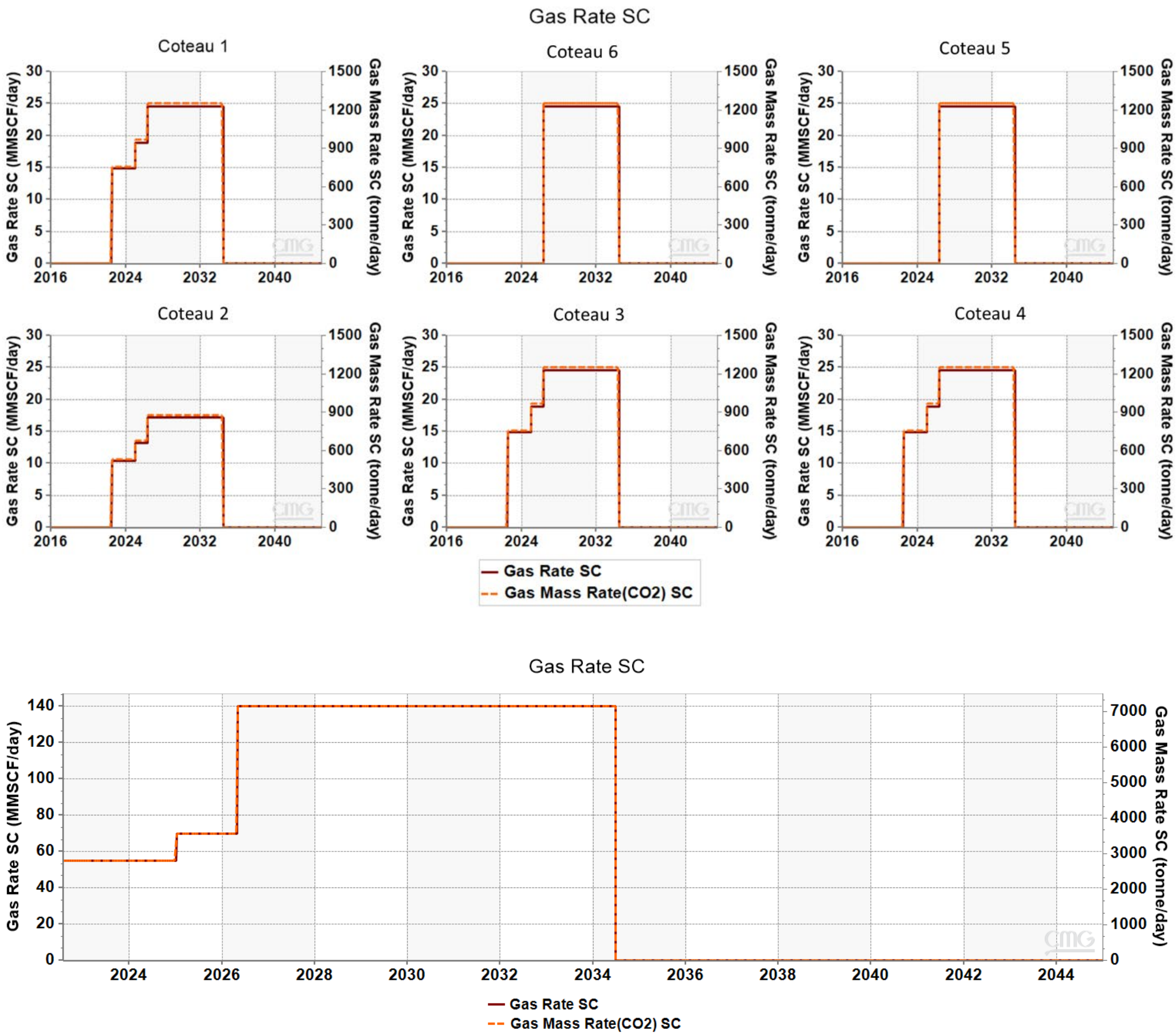


Figure 3-16. CO_2 injection rate (MMscf/day) response with the expected maximum injected rate per well (top) and group injection rate (bottom).

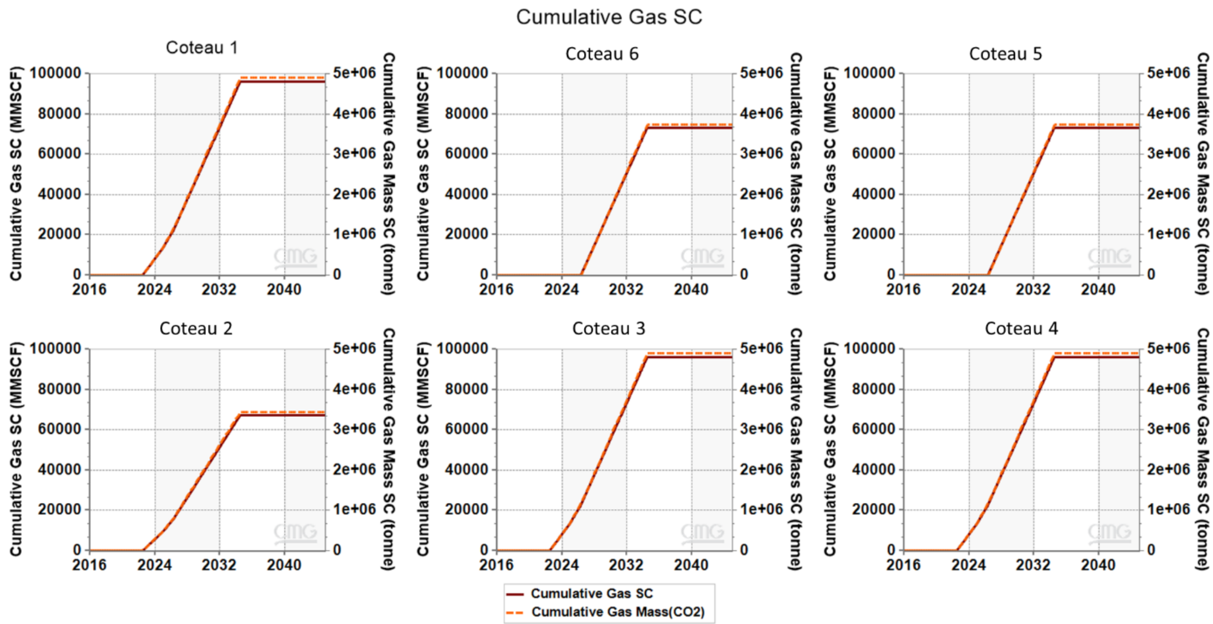


Figure 3-17. Cumulative injected CO_2 (MMscf) and CO_2 mass (metric tonnes) over 12 years of injection.

Table 3-6. CO_2 Volume Injected per Well

Well	CO_2 Volume Injected (MMscf)
Coteau 1	96,019
Coteau 2	67,213
Coteau 3	96,219
Coteau 4	96,219
Coteau 5	73,242
Coteau 6	73,242

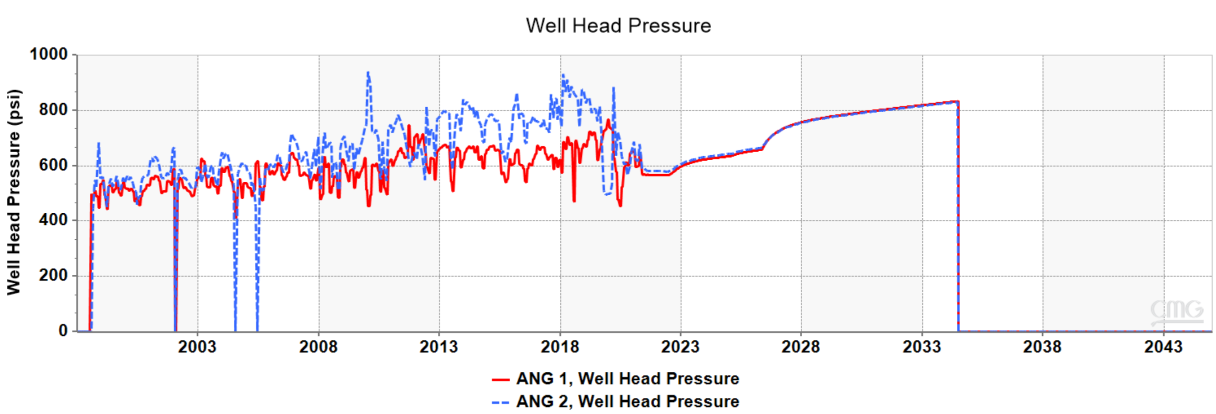


Figure 3-18. WHP response for the Class I disposal wells: ANG #1 and ANG #2.

During and after injection, supercritical CO_2 (free-phase CO_2) accounts for the majority of CO_2 observed in the modeled pore space. Throughout the injection operation, a portion of the free-phase CO_2 is trapped in the pore space through a process known as residual trapping. Residual trapping can occur as a function of low CO_2 saturation and inability to flow under the effects of relative permeability. CO_2 also dissolves into the formation brine throughout injection operations (and continues afterward), although the rate of dissolution slows over time. The free-phase CO_2 transitions to either residually trapped or dissolved CO_2 during the postinjection period, resulting in a decline in the mass of free-phase CO_2. The relative portions of supercritical, trapped, and dissolved CO_2 can be tracked throughout the duration of the simulation (Figure 3-19).

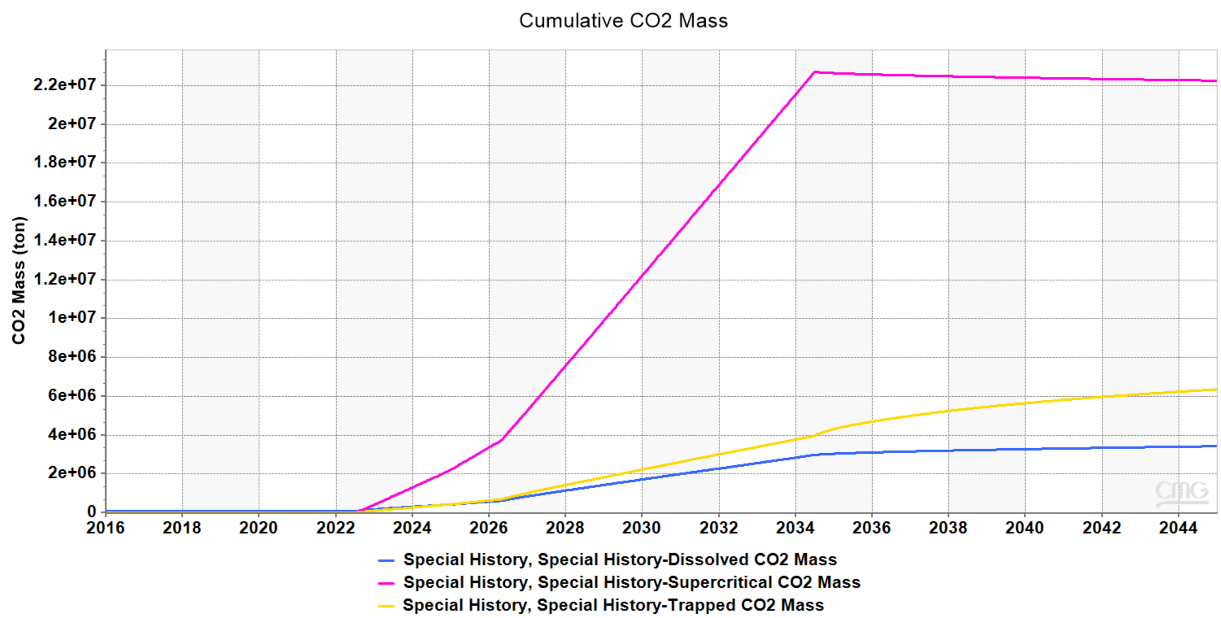


Figure 3-19. Simulated total supercritical free-phase CO_2, trapped CO_2, and dissolved CO_2 in brine.

The pressure front (Figure 3-20) shows the distribution of pressure increase throughout the Broom Creek Formation after 1, 5, and 12 years of injection as well as 8 years postinjection. A maximum increase of 436.53 psi is estimated in the near wellbore area at the end of the 12-year injection period.

Long-term CO_2 migration potential was also investigated through the numerical simulation efforts. The slow lateral migration of the plume is caused by the effects of buoyancy where the free-phase CO_2 injected into the formation rises to the bottom of the upper confining zone or lower-permeability layers present in the Broom Creek Formation and then outward. This process results in a higher concentration of CO_2 at the center which gradually spreads out toward the model edges where the CO_2 saturation is lower. Trapped CO_2 saturations, employed in the model to represent fractions of CO_2 trapped in small pores as immobile, tiny bubbles, ultimately immobilize the CO_2 plume and limit the plume's lateral migration and spreading. Figures 3-21 through 3-26 show the CO_2 saturation at the injection wells at the end of injection in north-to-south and east-to-west cross-sectional views.

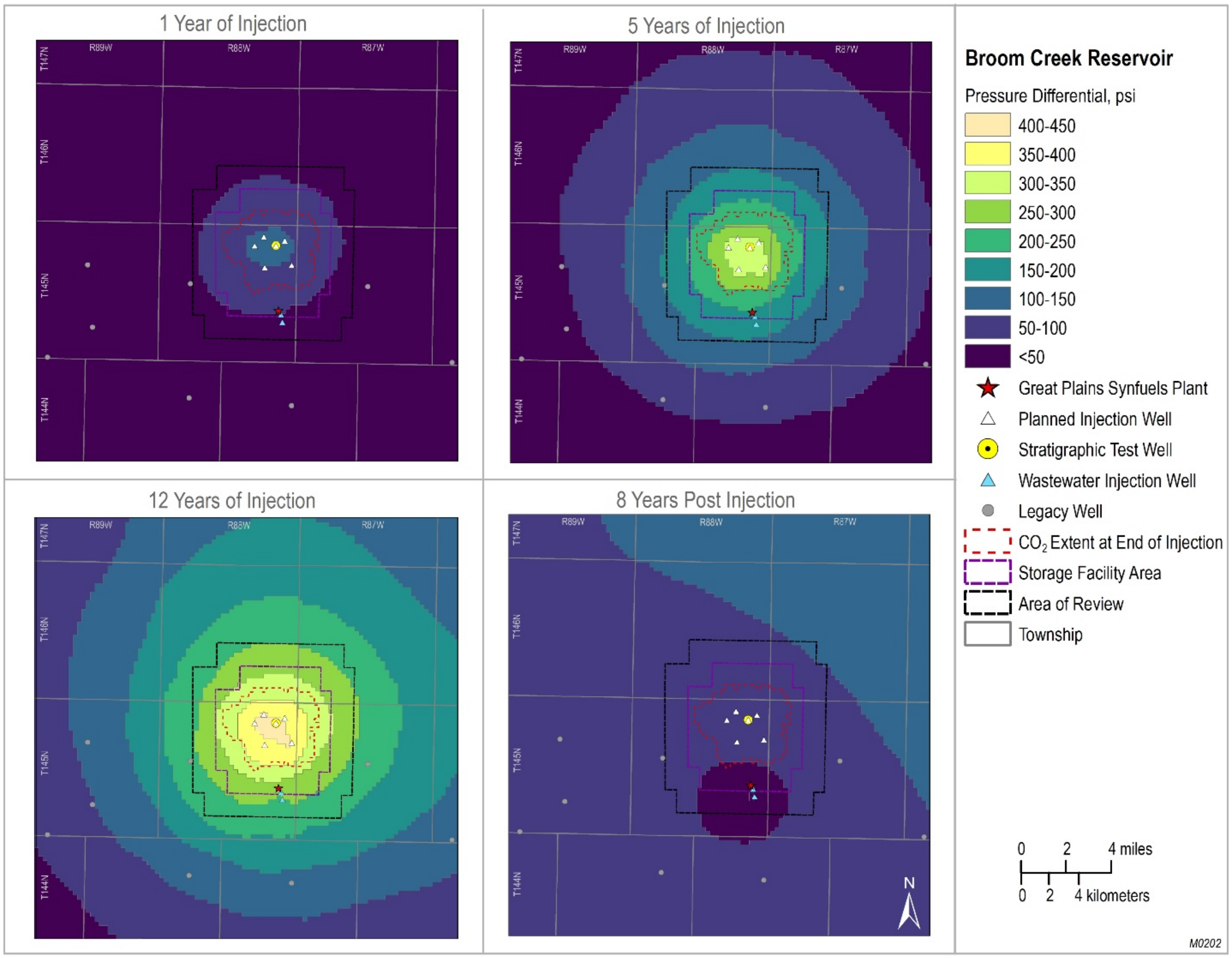


Figure 3-20. Average pressure increases within the Broom Creek Formation after 1, 5, and 12 years of simulated CO_2 injection operation as well as 8 years postinjection.

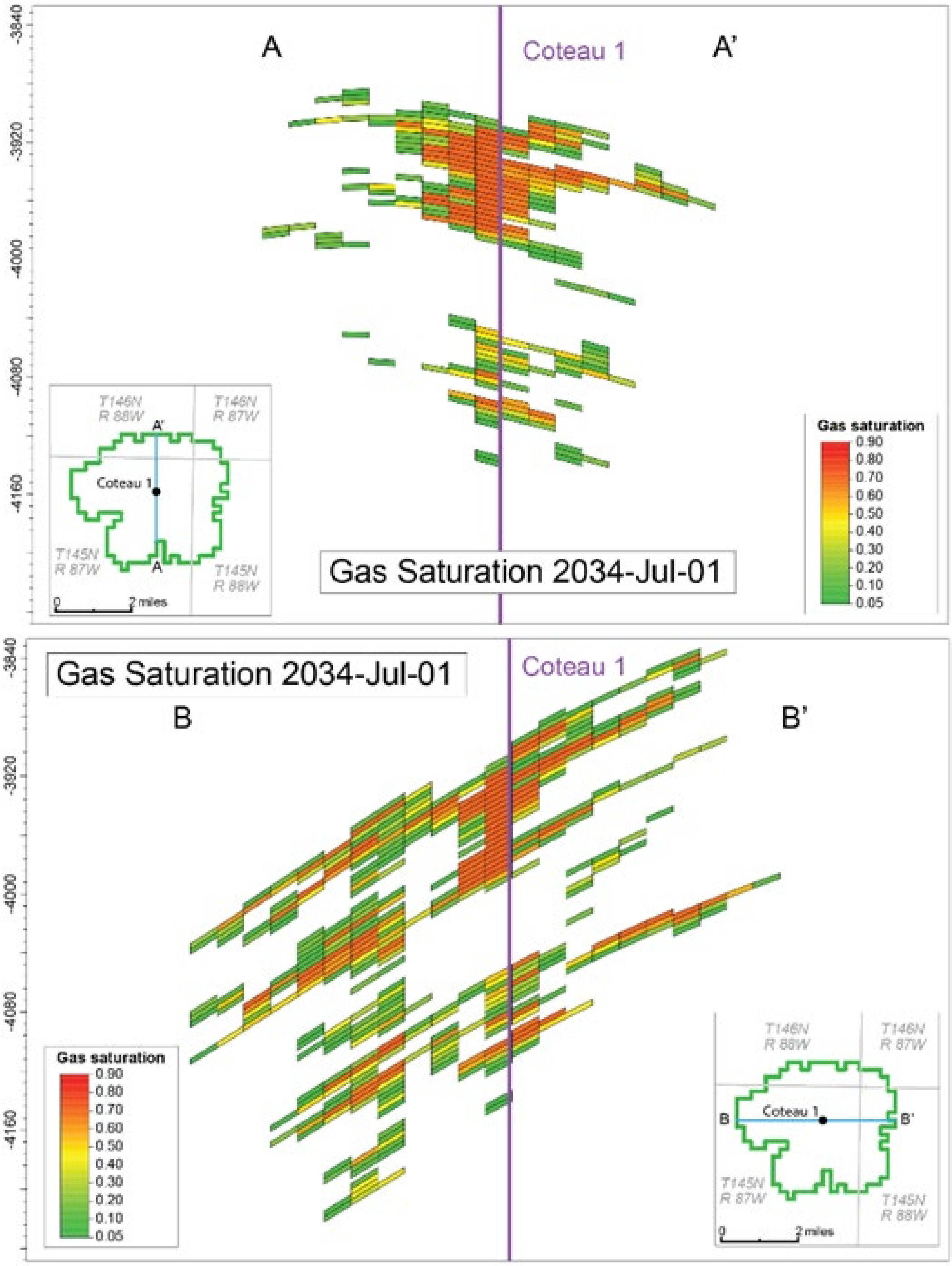


Figure 3-21. CO_2 plume cross section of Coteau 1 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

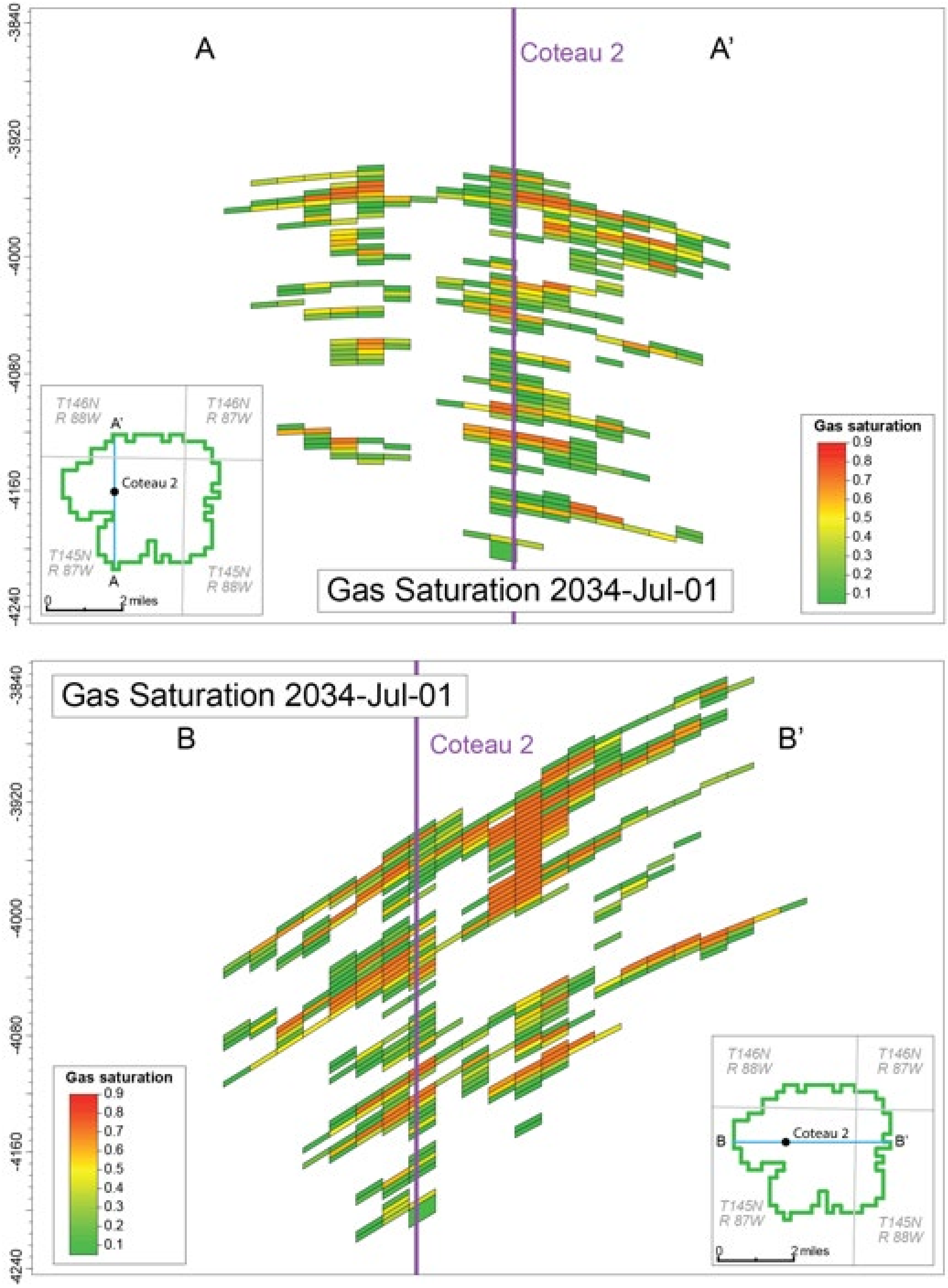


Figure 3-22. CO_2 plume cross section of Coteau 2 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

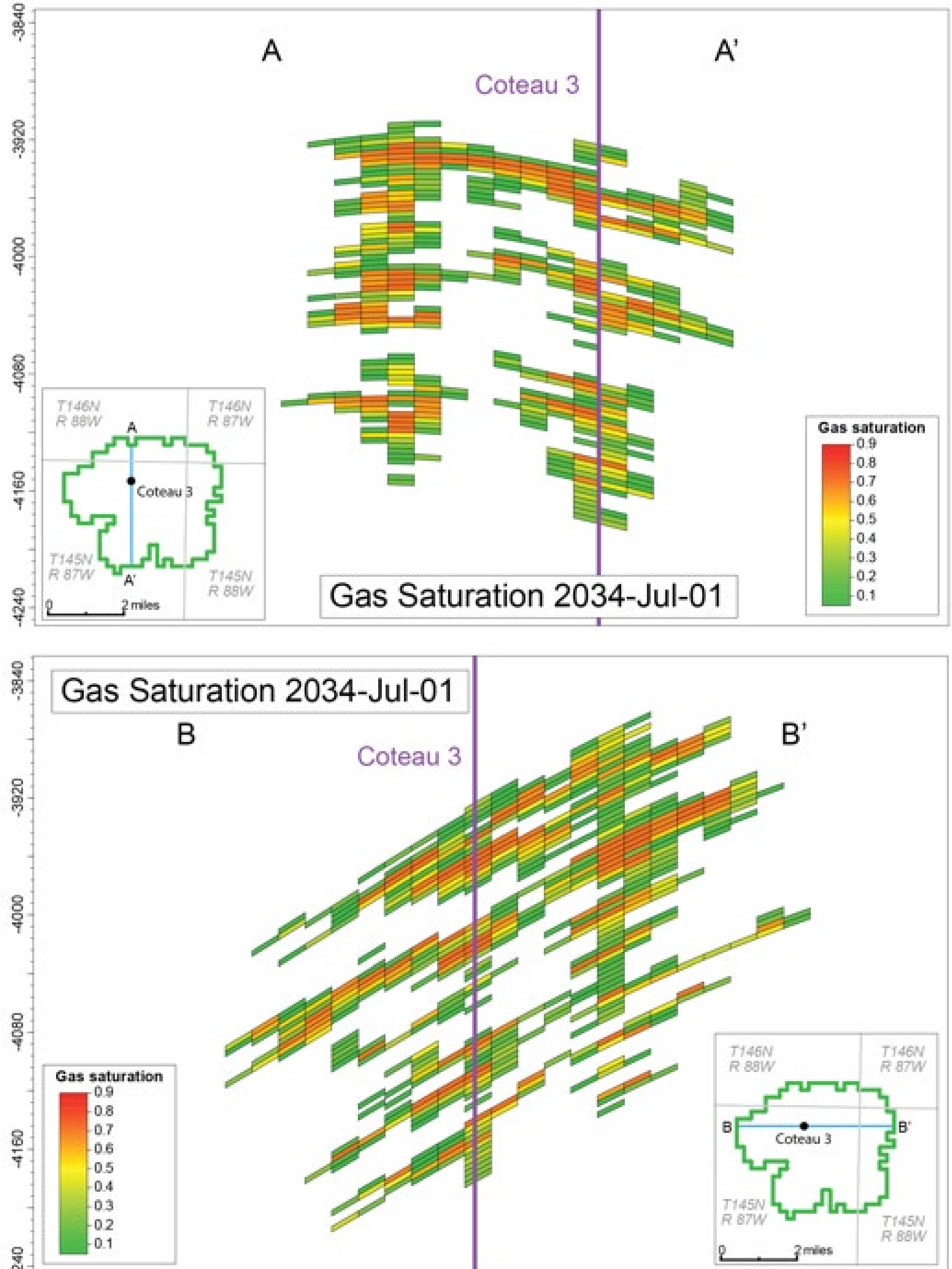


Figure 3-23. CO_2 plume cross section of Coteau 3 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

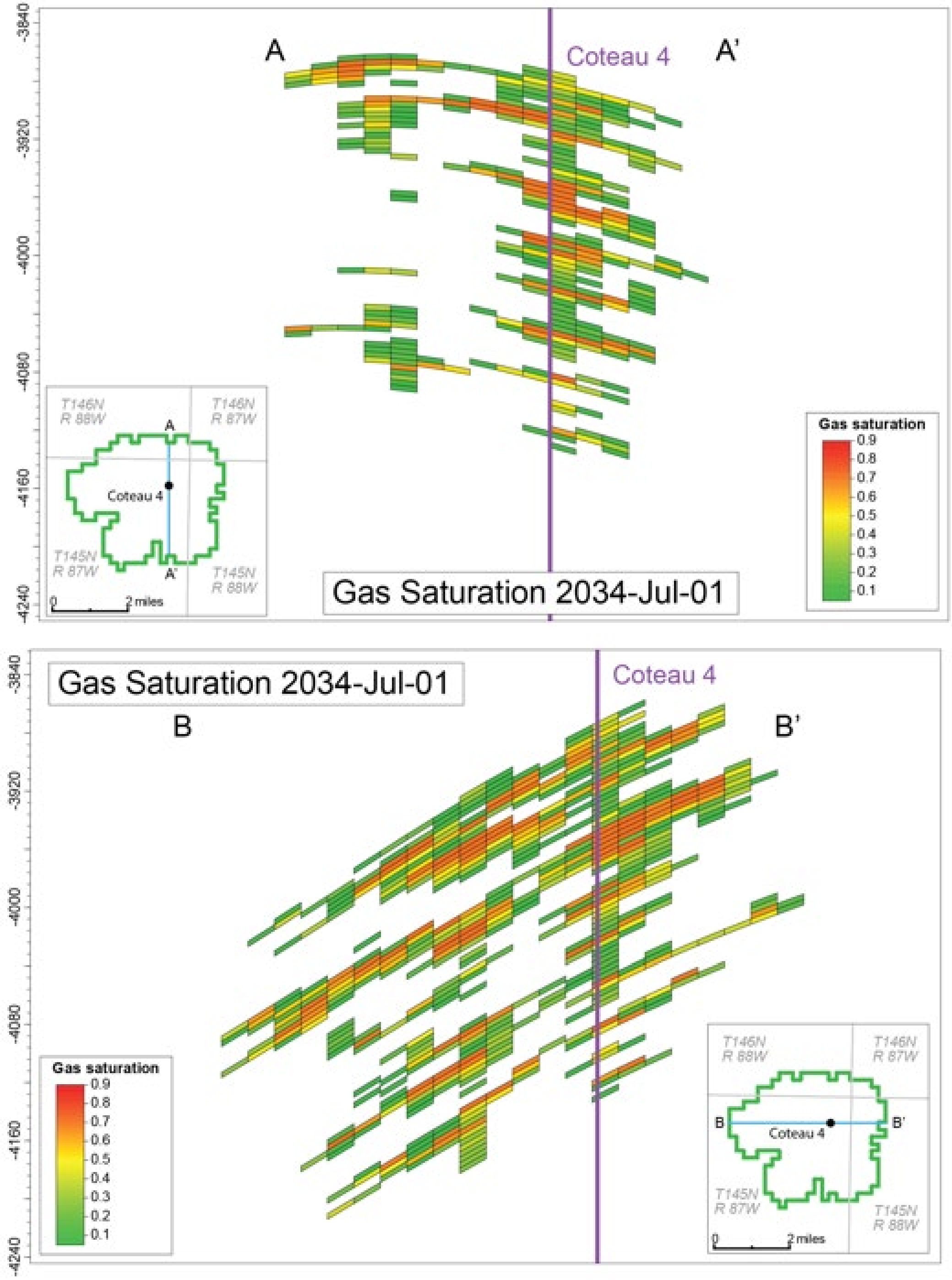


Figure 3-24. CO_2 plume cross section of Coteau 4 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

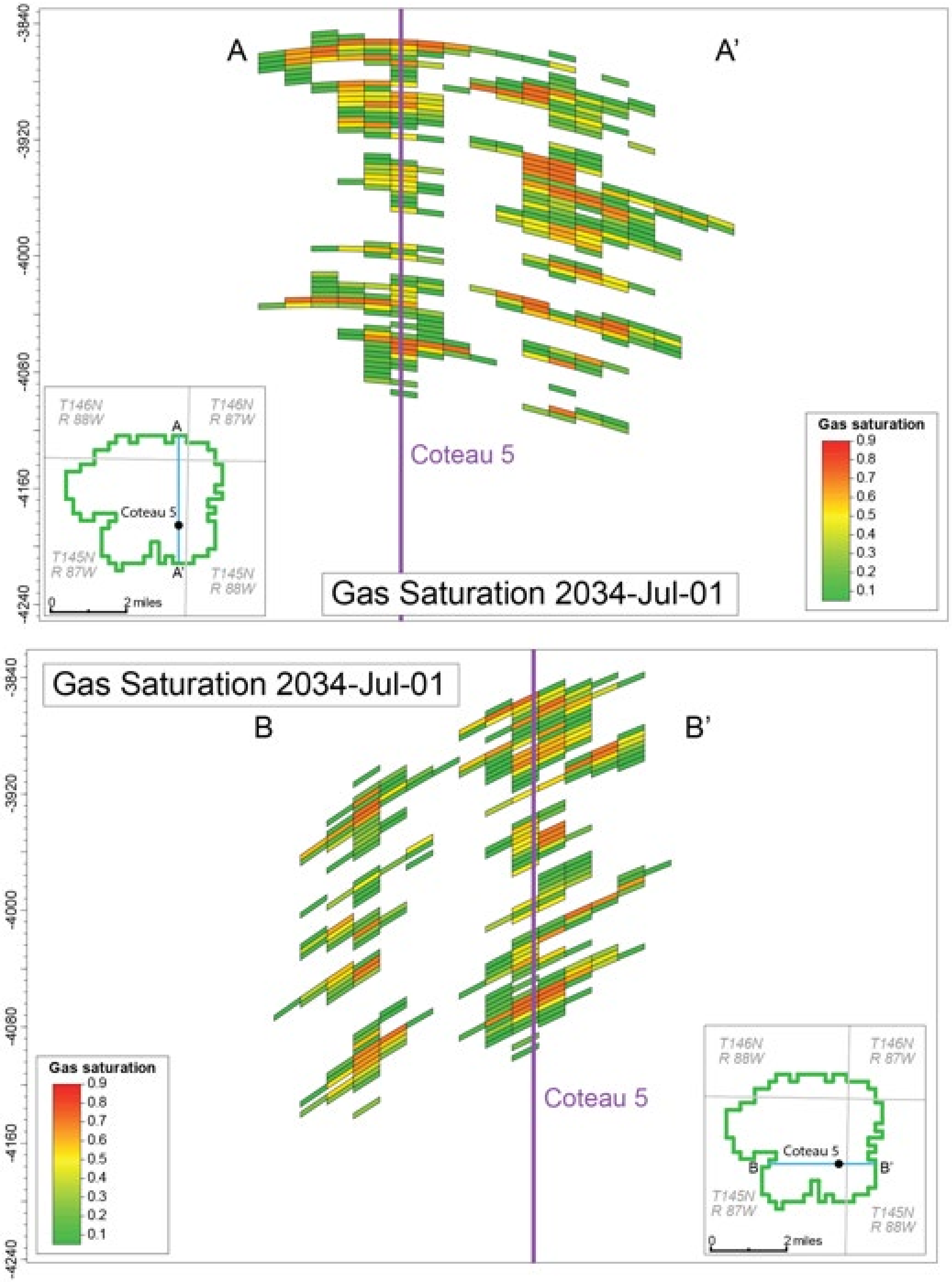


Figure 3-25. CO_2 plume cross section of Coteau 5 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

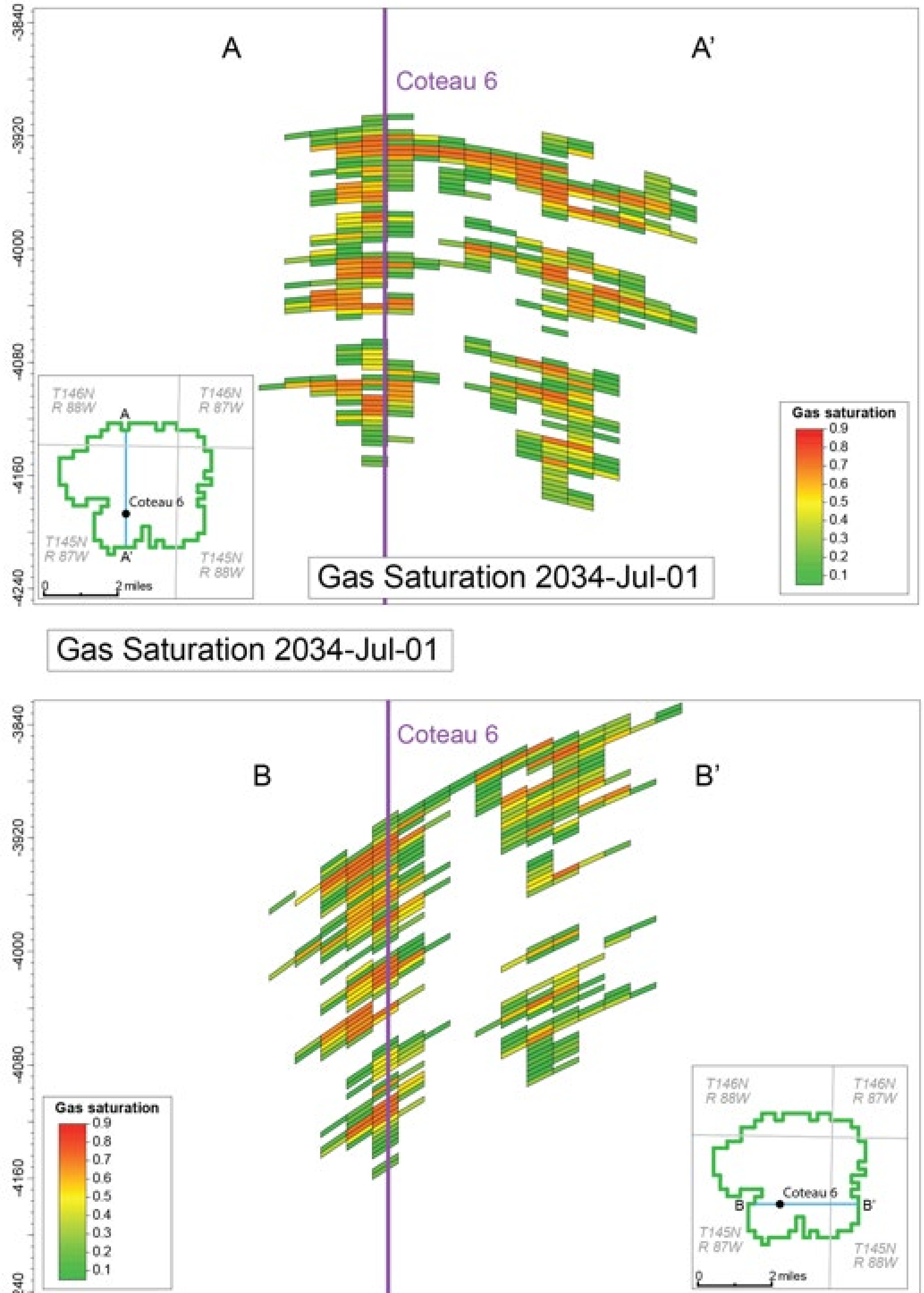


Figure 3-26. CO_2 plume cross section of Coteau 6 at the end of injection displayed by a) south to north and b) east to west (55× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

3.4.1 Maximum Surface Injection Pressure

An additional case was run to determine if the wells would ultimately be limited by maximum calculated downhole pressures of 3,754 psi for Coteau 1, 3,802 psi for Coteau 2, 3,772 psi for Coteau 3, 3,787 psi for Coteau 4, 3,776 psi for Coteau 5, and 3,786 psi for Coteau 6, Table 3-3.

The fracture propagation pressure gradient was used to calculate the maximum BHP constraints, based upon 90% of the fracture propagation pressure multiplied by the well depth at the top of the Broom Creek Formation. In this scenario, the group injection limit of 55 MMcfd from July 2022 to December 2024, 70 MMcfd from January 2025 to April 2026, and 140 MMcfd from May 2026 to July 2034, with the maximum injection rate constraint per well, was removed. Other parameters were kept the same as previously described for the additional tests.

The maximum BHPs were reached in the simulation. At the maximum BHP values, the corresponding predicted maximum wellhead injection pressure responses are shown in Figure 3-27.

In this scenario, the CO_2 injection wells were able to inject an average of 52.96 MMcfd of CO_2 per well (or 2685 tonnes/day of CO_2), with the planned 4½-in.-diameter tubing, thereby achieving a total injection volume of 64.18 MMt (1.257 Bcf) of CO_2.

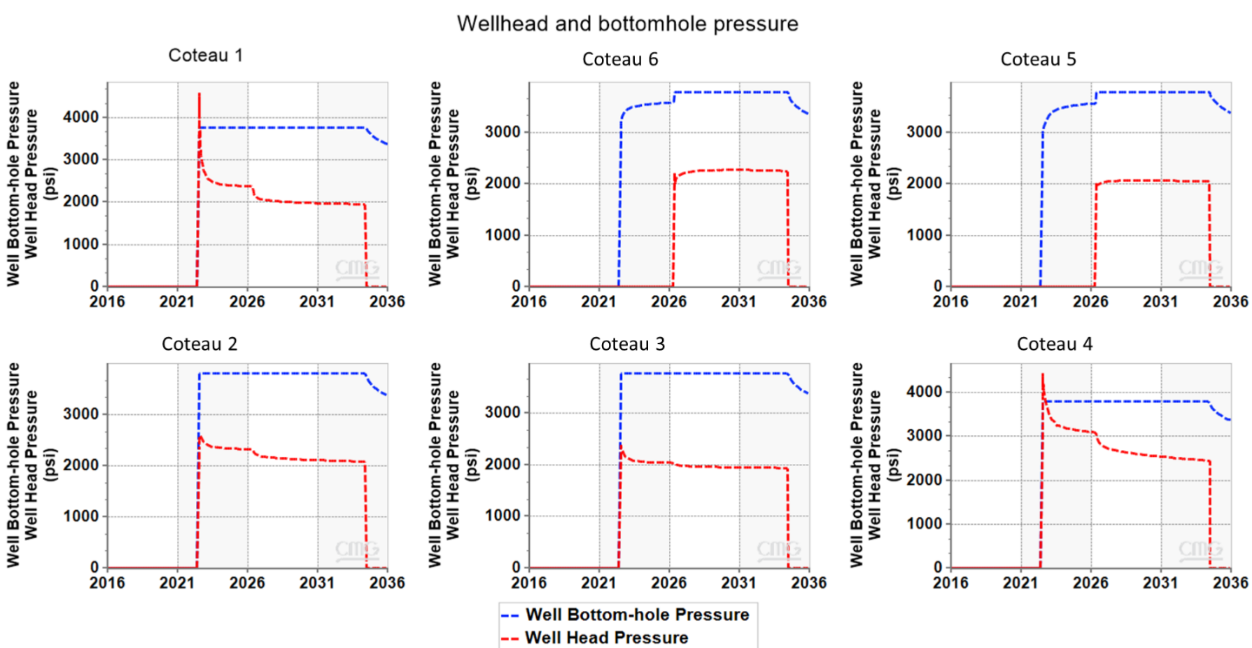


Figure 3-27. Maximum pressure responses (wellhead and bottomhole) when the wells were operated without any injection rate limits.

3.4.2 Stabilized Plume

Movement of the injected CO_2 plume is driven by the potential energy found in the buoyant force of the injected CO_2. As the plume spreads out within the reservoir and CO_2 is trapped residually through the effects of relative permeability and dissolution, the potential energy of the buoyant CO_2 is gradually lost. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized. The extent of the stabilized plume is important for determining the project's AOR and the corresponding scale and scope of the project's monitoring plans.

Plume stabilization can be visualized at the microscale as CO_2 being unable to exit its current pore space and enter the neighboring pore space, but at the macroscale, these interactions cannot be measured. Instead, plume stabilization may be estimated using the tools available to predict the CO_2 plume's extent. For the Great Plains CO_2 Project, stabilization was defined as the time when CO_2 no longer migrates to adjacent cells within the simulation model. CO_2 may still experience gradual redistribution within the plume, but the geographic extents of the plume remain unchanged.

The CO_2 plume was simulated in 5-year time steps until the rate of total areal extent change slowed to less than 0.25 square miles per 5-year time step to define the stabilized plume extent boundary and the associated buffers and boundaries (Figure 3-20). This estimate is anticipated to be regularly updated during the CO_2 storage operation as data collected from the site are used to update predictions made about the behavior of the injected CO_2.

3.5 Delineation of the Area of Review

The North Dakota Administrative Code (NDAC) defines the AOR as the region surrounding the geologic storage project where USDWs may be endangered by CO_2 injection activity (NDAC § 43-05-01-05). The primary endangerment risk is the potential for vertical migration of CO_2 and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the CO_2 plume within the storage reservoir.

However, the CO_2 plume has an associated pressure front where CO_2 injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the CO_2 plume. Therefore, the AOR encompasses both the areal extent of the CO_2 plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the CO_2 plume, AOR delineation focuses on the pressure front.

The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. U.S. Environmental Protection Agency (EPA) guidance for AOR delineation under the Underground Injection Control (UIC) Program for Class VI wells provides several methods for estimating the critical threshold pressure increase and resulting critical threshold pressure.

In this document, "storage reservoir" refers to the Broom Creek Formation (the injection zone), and the "lowest USDW" refers to the Fox Hills Formation.

3.5.1 EPA Methods 1 and 2: AOR Delineation for Class VI Wells

EPA (2013) guidance for AOR evaluation includes several computational methods for estimating the pressure buildup in the storage reservoir in response to CO_2 injection and the resultant areal extent of pressure buildup above a "critical threshold pressure" that could potentially drive higher salinity formation fluids from the storage reservoir up an open conduit to the lowest USDW. The following equations and analytical approach define the EPA methods used to delineate AOR. Each method can be applied both at a single location (e.g., the Coteau 1 stratigraphic well) using site-specific data or for each vertical stack of grid cells in a geocellular model, considering the varying stratigraphic thickness between storage reservoir and lowest USDW.

EPA (2013) Method 1 (*pressure front based on bringing the injection zone and USDW to equivalent hydraulic heads*) is presented as a method for determining whether a storage reservoir is in hydrostatic equilibrium with the lowest USDW. Under Method 1, the maximum pressure increase that may be sustained in the injection zone (critical threshold pressure increase) is given by:

$$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_i \qquad \text{[Eq. 1]}$$

Where:

P_u is the initial fluid pressure in the USDW (Pa).
ρ_i is the storage reservoir fluid density (mg/m^3).
g is the acceleration due to gravity (m/s^2).
z_u is the representative elevation of the USDW (m amsl).
z_i is the representative elevation of the injection zone (m amsl).
P_i is the initial pressure in the injection zone (Pa).
$\Delta P_{i,f}$ is the critical threshold pressure increase (Pa).

Equation 1 assumes that the hypothetical open borehole is perforated exclusively within the injection zone and USDW. If $\Delta P_{i,f}$ = 0, then the reservoir and USDW are in hydrostatic equilibrium; if $\Delta P_{i,f} > 0$, then the reservoir is underpressurized relative to the USDW; and if $\Delta P_{i,f} < 0$, then the reservoir is overpressurized relative to the USDW.

In scenarios where the storage reservoir and USDW are in hydrostatic equilibrium ($\Delta P_{i,f} = 0$), EPA Method 2 (*pressure front based on displacing fluid initially present in the borehole*) can be used to calculate the critical pressure threshold. Method 2 was originally presented by Nicot and others (2008) and Bandilla and others (2012). Method 2 calculates the critical threshold pressure increase (ΔP_c), which is the fluid pressure increase sufficient to drive formation fluids into the lowermost USDW. This ΔP_c is determined using Equations 2 and 3, assuming 1) hydrostatic conditions, 2) initially linearly densities in the borehole, and 3) constant density once the injection zone fluid is lifted to the top of the borehole (i.e., uniform density approach):

$$\Delta P_C = \frac{1}{2}\, g\, \xi\, (Z_u - Z_i)^2 \qquad \text{[Eq. 2]}$$

Where ξ is a linear coefficient determined by:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i} \quad \text{[Eq. 3]}$$

Where:

ΔP_c is the critical threshold pressure increase (Pa).
g is the acceleration of gravity (m/s^2).
z_u is the elevation of the base of the lowermost USDW (m amsl).
z_i is the elevation of the top of the injections zone (m amsl).
ρ_i is the fluid density in the injection zone (kg/m^3).
ρ_u is the fluid density in the USDW (kg/m^3).

3.5.2 Risk-Based AOR Delineation

The methods described by EPA (2013) for estimating the AOR under the Class VI Rule were developed assuming that the storage reservoirs would be in hydrostatic equilibrium with overlying aquifers. However, in the state of North Dakota, and potentially elsewhere around the United States, candidate storage reservoirs are already overpressurized relative to overlying aquifers and thus subject to potential vertical formation fluid migration from the storage reservoir to the lowermost USDW even prior to the planned storage project. Consequently, applying EPA (2013) methods to these geologic situations essentially results in an infinite AOR, which makes regulatory compliance infeasible.

Several researchers have recognized the need for alternative methods for estimating the AOR for locations that are already overpressurized relative to overlying aquifers. For example, Birkholzer and others (2014) described the unnecessary conservatism in EPA's definition of critical pressure, which could lead to a heavy burden on storage facility permit applicants. As an alternative, Burton-Kelly and others (2021) proposed a risk-based reinterpretation of this framework that would allow for a reduction in the AOR while ensuring protection of drinking water resources.

A computational framework for estimating a risk-based AOR was proposed by Oldenburg and others (2014, 2016), who compared formation fluid leakage through a hypothetical open flow path in the baseline scenario (no CO_2 injection) to the incrementally larger leakage that would occur in the CO_2 injection case. The modeling for the risk-based AOR used semianalytical solutions to single-phase flow equations to model reservoir pressurization and vertical migration through leaky wells. These semianalytical solutions were extensions of earlier work for formation fluid leakage through abandoned wellbores by Raven and others (1990) and Avci (1994), which were creatively solved, coded, and compiled in FORTRAN under the name, ASLMA (Analytical Solution for Leakage in Multilayered Aquifers) and extensively described by Cihan and others (2011, 2012) (hereafter "ASLMA Model").

Recently, White and others (2020) outlined a similar risk-based approach for evaluating the AOR using the National Risk Assessment Partnership (NRAP) Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS). However, the NRAP-IAM-CS and subsequent open-sourced version (NRAP-Open-IAM) are constrained to the assumption that the storage reservoir is in hydrostatic equilibrium with overlying aquifers and, therefore, may not accurately estimate the AOR for storage projects located in regions where the storage reservoir is overpressurized relative to overlying aquifers.

Building a geologic model in a commercial-grade software platform (like Schlumberger Petrel) and running fluid flow simulations using numerical reservoir simulation in a commercial-grade software platform (like CMG's compositional simulator, GEM) provide the "gold standard" for estimating pressure buildup in response to CO_2 injection (e.g., Bosshart and others, 2018). However, these numerical reservoir simulations are typically limited to the storage reservoir and primary seal formation (cap rock) and do not include the geologic units overlying the cap rock because of the computational burden of conducting such a complex simulation. In addition, geologic modeling of the overlying units may add a substantial amount of time and effort during prefeasibility-phase projects that is unwarranted given the amount of uncertainty that may be present if only few nearby wells can be used for characterization activities. Earlier studies (e.g., Nicot and others, 2008; Birkholzer and others, 2009; Bandilla and others, 2012; Cihan and others, 2011, 2012) have shown that far-field fluid pressure changes outside of the CO_2 plume domain can be reasonably well described by a single-phase flow calculation by representing CO_2 injection as an equivalent-volume injection of brine (Oldenburg and others, 2014).

The semianalytical solutions embedded within the ASLMA Model have been shown to compare with the numerical model, TOUGH2-ECO2-N, and provided accurate results for pressures beyond the CO_2 plume zone (Birkholzer and others, 2009; Cihan and others, 2011, 2012). Therefore, the proposed workflow for delineating a risk-based AOR uses the ASLMA Model to examine pressure buildup in the storage reservoir and resultant effects of this buildup on the vertical migration of formation fluid via (single) hypothetical leaky wellbores located at progressively greater distances from the injection well (Figure 3-28).

An important distinction between EPA Methods 1 and 2, which both calculate a critical pressure threshold (either $\Delta P_{i,f}$ for Method 1 or ΔP_c for Method 2) and the risk-based AOR approach is that the risk-based approach 1) calculates and maps the potential incremental flow of formation fluids from the storage reservoir to the USDW that could occur and then 2) delineates the areal extent beyond which no significant leakage would occur. Therefore, the region beyond which no significant leakage would occur does not present an endangerment to the USDW; hence, the region inside of this areal extent is the risk-based AOR.

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021). Inputs, assumptions, and results are discussed in the current document.

Establish the Site Stratigraphy and Properties

- Simplify the storage complex stratigraphy into hydrostratigraphic units.
- Use the best available site characterization data to estimate the average depth, thickness, pressure, temperature, porosity, permeability, and salinity for each unit.

↓

Use the ASLMA Excel Workbook to Derive Additional Inputs Needed for the ASLMA Model

- Derive the hydraulic conductivity and specific storage for each unit.
- Compute the initial hydraulic heads for each unit.
- Place a CO_2 injection well at the center of the coordinate reference system (0, 0).
- Convert the CO_2 mass injection rate into an equivalent-volume injection of formation fluid.
- Establish the effective permeability of the hypothetical leaky wellbore and the distances from the injection well to quantify the formation fluid leakage up a leaky wellbore located at progressively greater distances from the injection well.
- Use the ASLMA User Guide for reference and to inform additional inputs.

↓

Integrate ASLMA Model Outputs with Results from Numerical Reservoir Simulation

- Run the ASLMA Model using the included custom scripting and generate standardized outputs.
- Derive the incremental leakage to the lowermost underground source of drinking water (USDW) by taking the difference between the baseline (no CO_2 injection) and injection cases.
- If applicable, generate results for cases with and without the leaky wellbore open to a saline aquifer (thief zone) located between the primary seal (cap rock) and the USDW.
- Derive the storage reservoir pressure buildup-USDW incremental leakage relationship.
- Using the derived relationship in the preceding step, generate potential incremental leakage maps based on the pressure buildup in response to CO_2 injection as determined by a compositional simulator.

↓

Delineate Risk-Based Area of Review (AoR)

- Apply threshold criteria to the incremental leakage maps to delineate a risk-based AoR.
- Assess the sensitivity of the risk-based AoR to different input assumptions or risk judgments.

Figure 3-28. Workflow for delineating a risk-based AOR for a storage facility permit (modified from Burton-Kelly and others, 2021).

3.5.3 Critical Threshold Pressure Increase Estimation

For the purposes of delineating AOR for the Great Plains CO_2 Project study area, constant fluid densities for the lowermost USDW (Fox Hills Formation) and injection zone (Broom Creek Formation) were used in the calculations. A density of 1001 kg/m^3 was used to represent the USDW fluids (ρ_u), and a density of 1017 kg/m^3 was used to represent the injection zone fluids (ρ_i), which is estimated based on the in situ brine salinity, temperature, and pressure as measured with an MDT tool from the Coteau 1 stratigraphic test well.

Application of EPA Method 1 (Equation 1) using site-specific data from the Coteau 1 well shows that the injection zone in the Great Plains CO_2 Project area is overpressurized with respect to the lowest USDW (i.e., Method 1 $\Delta P_{i,f} < 0$). An example of the EPA Method 1 application showing negative $\Delta P_{i,f}$ (relative overpressure) is given in Table 3-7, with similar results when applied to each column of the grid cells in the Broom Creek Formation simulation model.

Table 3-7. EPA Method 1 Critical Threshold Pressure Increase Calculated at the Coteau 1 Wellbore Location Using MDT Data

Depth*		P_i Injection Zone Pressure	P_u USDW Pressure	ρ_i Injection Zone Density	Z_u USDW Base Elevation	Z_i Reservoir Elevation	$\Delta P_{i,f}$ Threshold Pressure Increase	
ft	m	MPa	MPa	kg/m^3	m amsl	m amsl	MPa	psi
5,975	1,811	20.25	5.12	1,017	102	−1,207	−2.08	−302

* Ground surface elevation is 608 m above mean sea level.

In accordance with EPA (2013) guidance, the combination of a) a Method 1 negative $\Delta P_{i,f}$ value across the Great Plains CO_2 Project area and b) lack of evidence for hydrostatic equilibrium between the reservoir and the USDW (i.e., Method 2 does not apply) indicates that a risk-based approach to AOR delineation may be pursued.

3.5.4 Risk-Based AOR Calculations

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021). The inputs, assumptions, and results discussed here provide the necessary details for reproducing and verifying the results. A macro-enabled Microsoft Excel file was used to define the inputs and calculations that were employed used in the method (hereafter "ASLMA Workbook").

3.5.4.1 Initial Hydraulic Heads

The original ASLMA Model (Cihan and others, 2011) initially assumed hydrostatic pressure distributions in the entire system. The current work uses a modified version of the ASLMA Model to simulate pressure perturbations and leakage rates when there are initial head differences in the aquifers (Oldenburg and others, 2014). The initial hydraulic heads are calculated assuming an equivalent freshwater head based on the unit-specific elevations and pressures. The equivalent freshwater heads are entered into the ASLMA Model and establish the initial pressure conditions for the storage complex prior to CO_2 injection.

For example, the initial reference case equivalent freshwater heads for the storage reservoir (Aquifer 1), potential thief zone (Aquifer 2), and USDW (Aquifer 3) are 832, 613, and 623 m, respectively, which illustrate the state of overpressure in the storage complex, as Aquifer 1 has a greater initial hydraulic head than Aquifers 2 and 3. Therefore, the storage complex requires different treatment than the default AOR calculations described by EPA (2013). Details on the calculations of initial hydraulic head are provided in Burton-Kelly and others (2021).

3.5.4.2 CO_2 Injection Parameters

The ASLMA Model for the Great Plains CO_2 Project used a Broom Creek CO_2 injection rate that matched the simulation scenario. A single injector is placed at the center of the ASLMA model grid at an x,y-location of (0,0) in the coordinate reference system. The ASLMA Model requires the CO_2 injection rate to be converted into an equivalent-volume injection of formation fluid in units of cubic meters per day. Microsoft Excel VBA functions were used to estimate the CO_2 density from the storage reservoir pressure and temperature, which resulted in an estimated density of 672 kg/m^3. The CO_2 mass injection rate and CO_2 density are then used to derive the daily equivalent-volume injection rate of approximately 4,333 m^3 per day for 2.5 years followed by 5,515 m^3 per day for 1.3 years, followed by 11,030 m^3 per day for 8.2 years.

3.5.4.3 Hypothetical Leaky Wellbore

In the Great Plains CO_2 Project area, few wellbores are known to exist that penetrate the primary seal of the Broom Creek storage reservoir. However, for heuristic, "what-if" scenario modeling, which is needed to generate the data for delineating a risk-based AOR, a single hypothetical leaky wellbore is inserted into the ASLMA Model at 1, 2, …, 100 km from the CO_2 injection well. The pressure buildup in the storage reservoir at each distance, along with the recorded cumulative volume of formation fluid vertically migrating through the leaky wellbore from the storage reservoir to the USDW (i.e., from Aquifer 1 to Aquifer 3) throughout the 12-year injection period, provides the data set needed to derive the risk-based AOR.

Published ranges for the effective permeability of a leaky wellbore (Figure 3-27) have included an "open wellbore" with an effective permeability as high as 10^{-5} m^2 (10^{10} mD) to values more representative of leakage through a wellbore annulus of 10^{-12} to 10^{-10} m^2 (10^3 to 10^5 mD) (Watson and Bachu, 2008, 2009; Celia and others, 2011). Carey (2017) provides probability distributions for the effective permeability of potentially leaking wells at CO_2 storage sites and estimated a wide range from 10^{-20} to 10^{-10} m^2 (10^{-5} to 10^5 mD). For the Great Plains CO_2 Project Broom Creek ASLMA Model, the effective permeability of the leaky wellbore is set to 10^{-16} m^2 (0.1 mD), which is a relatively conservative (highly permeable) value near the top of the published range for the effective permeability of potentially leaking wells at CO_2 storage sites (Figure 3-29).

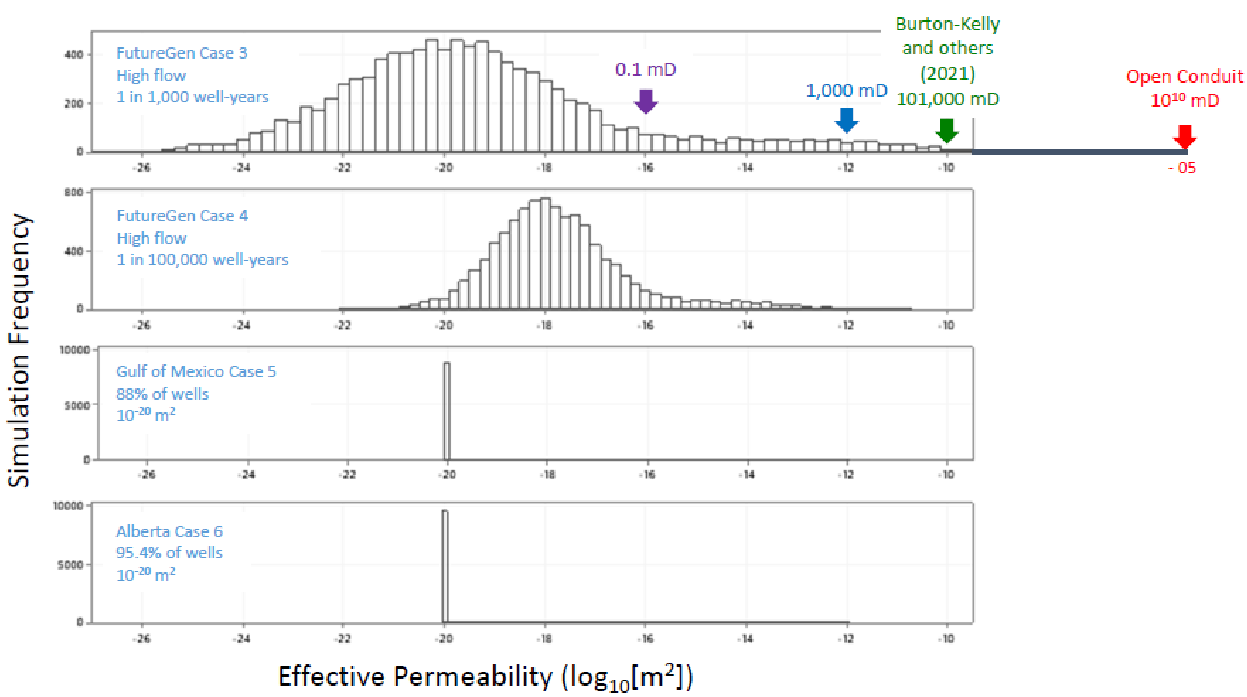


Figure 3-29. Histograms describing the expected frequency of leaky wellbore effective permeabilities under different scenarios. The ASLMA model used for AOR delineation used a value of approximately 0.1 mD. Constructed from data presented by Carey (2017).

The current work uses the ASLMA Model Type 1 feature (focused leakage only) for the nominal model response, which makes the conservative assumption that the aquitards are impermeable. This assumption prevents the pressure from diffusing into the overlying aquitards, resulting in a greater pressure buildup in the storage reservoir and a commensurately greater amount of formation fluid vertically migrating from the storage reservoir through the leaky wellbore. The conservative assumption of Model Type 1 rather than Model Type 3 (coupled focused and diffuse leakage) provides an added level of protection to the delineation of a risk-based AOR by projecting a larger pressure buildup in the storage reservoir than a scenario in which pressure is allowed to dissipate through the upper seal and, therefore, a greater leakage of formation fluid up the leaky wellbore.

3.5.4.4 Saline Aquifer Thief Zone

As shown in Table 3-7, a saline aquifer (Aquifer 2, Inyan Kara Formation) exists between the primary seal above the storage reservoir and USDW (Aquifer 3, Fox Hills Formation). Formation fluid migrating up a leaky wellbore that is open to Aquifer 2 will preferentially flow into Aquifer 2, and the continued flow up the wellbore and into the USDW will be reduced. Therefore, the presence of Aquifer 2 may act as a thief zone and reduces the potential for formation fluid impacts to the groundwater.

The thief zone phenomenon was described by Nordbotten and others (2004) as an "elevator model" by analogy with an elevator full of people on the main floor, who then get off at various floors as the elevator moves up, such that only very few people ride all the way to the top floor. The term "thief zone" is also used in the oil and gas industry to describe a formation encountered during drilling into which circulating fluids can be lost. Models with and without opening the leaky wellbore to Aquifer 2 (Inyan Kara Formation) were run and evaluated to quantify the effect of a thief zone on the risk-based AOR.

3.5.4.5 Aquifer- and Aquitard-Derived Properties

The ASLMA Model assumes homogeneous properties within each hydrostratigraphic unit (Table 3-7). For each unit shown in Table 3-7, pressure, temperature, porosity, permeability, and salinity are used to derive two key inputs for the ASLMA Model: hydraulic conductivity (HCON) and specific storage (SS). Average porosity and permeability values were derived as follows: Broom Creek, from distributed properties in the geologic model; Inyan Kara, from Coteau 1 well log data; and Fox Hills, from regional well log data. Porosity is represented as an arithmetic mean and permeability as a geometric mean values within each hydrostratigraphic unit (excluding non-sandstone rock types).

Visual Basic for Applications (VBA) functions included in the ASLMA Workbook are used to estimate the formation fluid density and viscosity from the aquifer or aquitard pressure, temperature, and salinity inputs, which are then used to estimate the HCON and SS. The estimated reference case HCON for the storage reservoir (Aquifer 1), thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table 3-8. Details about the HCON and SS derivations are provided in Supporting Information for Burton-Kelly and others (2021).

Table 3-8. Simplified Stratigraphy and Average Properties Used to Represent the Storage Complex

Hydrostratigraphic Unit	Depth to Top,* m	Thickness, m	Pressure, MPa	Temperature, °C	Salinity, ppm	Porosity, %	Permeability, mD	Permeability, m^2	HCON, m/d	Specific Storage, m^{-1}	Equivalent Freshwater Head, m
Overlying Units to Ground Surface (not directly modeled)	0	420									
Aquifer 3 (USDW–Fox Hills Fm)	420	89	4.7	19.6	1,800	34.4	280	2.76E-13	2.32E-01	7.82E-06	623
Aquitard 2 (Pierre Fm-Inyan Kara Fm)	509	849	9.3	33.3	22,800	10	0.1	9.87E-17	1.09E-04	1.25E-05	612
Aquifer 2 (Thief Zone–Inyan Kara Fm)	1,359	116	14.0	57.7	22,800	20.1	41.8	4.13E-14	6.92E-02	8.27E-06	634
Aquitard 1 (Swift—Broom Creek Fm) (primary upper seal)	1,474	355	16.4	54.3	42,800	10	0.1	9.87E-17	1.53E-04	1.28E-09	597
Aquifer 1 (Storage Reservoir – Broom Creek Fm)	1,829	77	20.8	70.8	42,800	14.5	246.7	2.44E-14	4.75E-01	8.46E-06	832

* Ground surface elevation 614 m amsl.

3.5.5 Risk-Based AOR Results

3.5.5.1 Relating Pressure Buildup to Incremental Leakage with ASLMA Model and Compositional Simulation

Figure 3-28 shows the relationship between the maximum pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 (USDW) for scenarios with and without the leaky wellbore open to Aquifer 2 (thief zone). In the case where the leaky wellbore is closed to Aquifer 2, there is no incremental leakage to Aquifer 2. The curvilinear relationship between pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 is used to predict the incremental leakage from the pressure buildup map produced by the compositional simulation of the geocellular model. The average simulated pressure buildup in the reservoir is represented by a raster (grid) map of pressure buildup values. For each raster value (grid cell map location), the relationship between pressure buildup and incremental leakage (Figure 3-30) is used to predict incremental leakage using a linear interpolation between the points making up the curve. The cumulative leakage potential from Aquifer 1 to Aquifer 3 along a hypothetical leaky wellbore without injection occurring (i.e., leakage due to natural overpressure) and no thief zone is estimated to be 0.01 m^3 over 20 years.

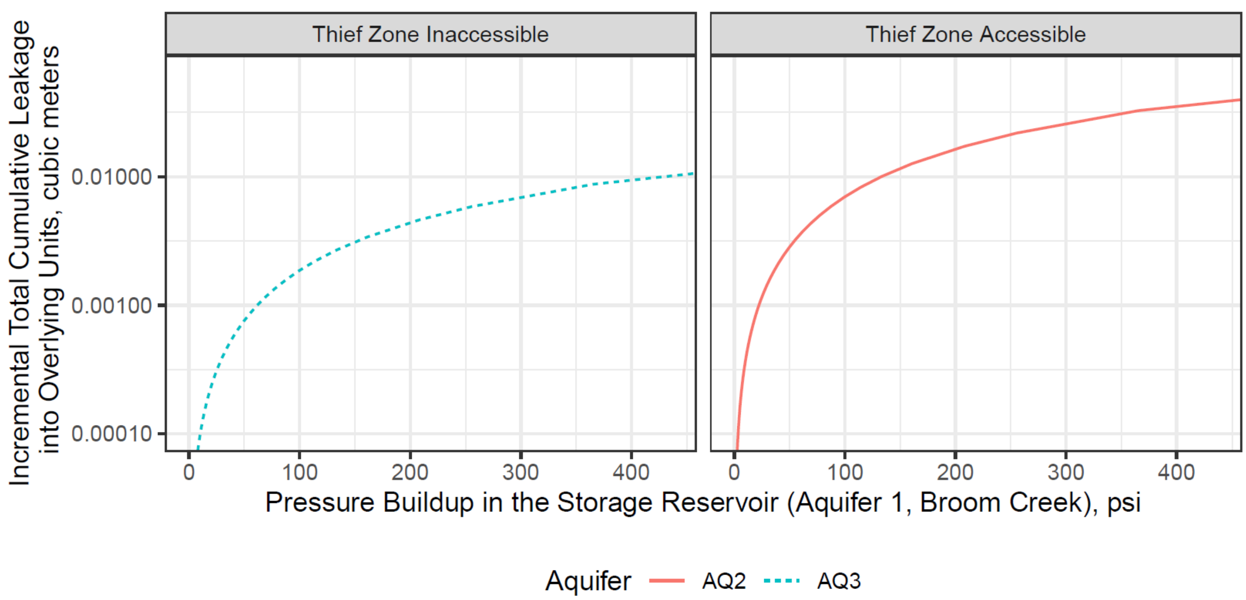


Figure 3-30. Relationship between pressure buildup (x-axis, psi) in the storage reservoir (Aquifer 1, Broom Creek) and incremental total cumulative leakage (y-axis, m^3) into Aquifer 2 (thief zone, Inyan Kara, red solid line) and Aquifer 3 (USDW, Fox Hills, dashed blue line). In the left-hand scenario, the leaky wellbore is closed to Aquifer 2 (Inyan Kara), so all flow is from the storage reservoir to the USDW. In the right-hand scenario, the leaky wellbore is open to Aquifer 2 (Inyan Kara), so the vast majority of flow is from the storage reservoir to the thief zone, and the curve showing flow into the USDW is not visible on this plot.

3.5.5.2 Incremental Leakage Maps and AOR Delineation

The pressure buildup-incremental leakage relationship, shown in Figure 3-28 results in the incremental leakage maps shown in Figure 3-31 which show the estimated total cumulative incremental leakage potential from a hypothetical leaky well into Aquifer 3 (USDW) over the entire 12-year period if the hypothetical leaky wellbore is not open to the thief zone.

The final step of the risk-based AOR workflow is to apply a threshold criterion to the incremental leakage maps to delineate a risk-based AOR. For the Broom Creek Formation injection at the Great Plains CO_2 Project site, a threshold of 1 m^3 of potential incremental flow into the Fox Hills Formation USDW along a hypothetical leaky wellbore over the 12-year injection period is established. A value of 1 m^3 is the lowest meaningful value that can be produced by the ASLMA Model; although the model can return smaller values, they likely represent statistical noise. This potential incremental flow threshold is greater than all calculated potential incremental flow values described by the curve in Figure 3-30. The maximum vertically averaged storage reservoir change in pressure at the end of the simulated injection period was 437 psi in a grid cell intersected by the injection well, which corresponds to less than 0.01 m^3 of flow over 12 years. This pressure is below the potential incremental flow threshold of 1 m^3. Therefore, the storage reservoir pressure buildup is not a deciding factor in determining the AOR extent.

The assumptions and calculations used to determine the risk-based AOR at the Great Plains CO_2 Project site incorporate at least four safety factors for the protection of groundwater resources. If the ASLMA model has resulted in an underestimation of the amount of potential leakage over the injection period, such underestimation is likely to be mitigated by:

- The statistical overestimation of hypothetical leaky wellbore permeability compared to known and estimated values in the literature—A more statistically likely hypothetical leaky wellbore permeability would be lower and allow less flow into the USDW.

- The lack of communication between the hypothetical leaky wellbore and Inyan Kara Formation, which would act as a thief zone—A real leaky wellbore would likely communicate with the Inyan Kara Formation, which would receive much, if not all, of the brine leaked from the storage reservoir.

- The low density of known legacy wellbores in the Great Plains CO_2 Project area—CO_2 injection is proposed to occur in an area with few available leakage pathways.

- The continued overpressurized nature of the Broom Creek Formation with respect to overlying saline aquifers—over relatively short (e.g., 50-year) timescales, overpressurized aquifers with leakage pathways would demonstrate a change in upward flow rate and corresponding pressure (Oldenburg and others, 2016).

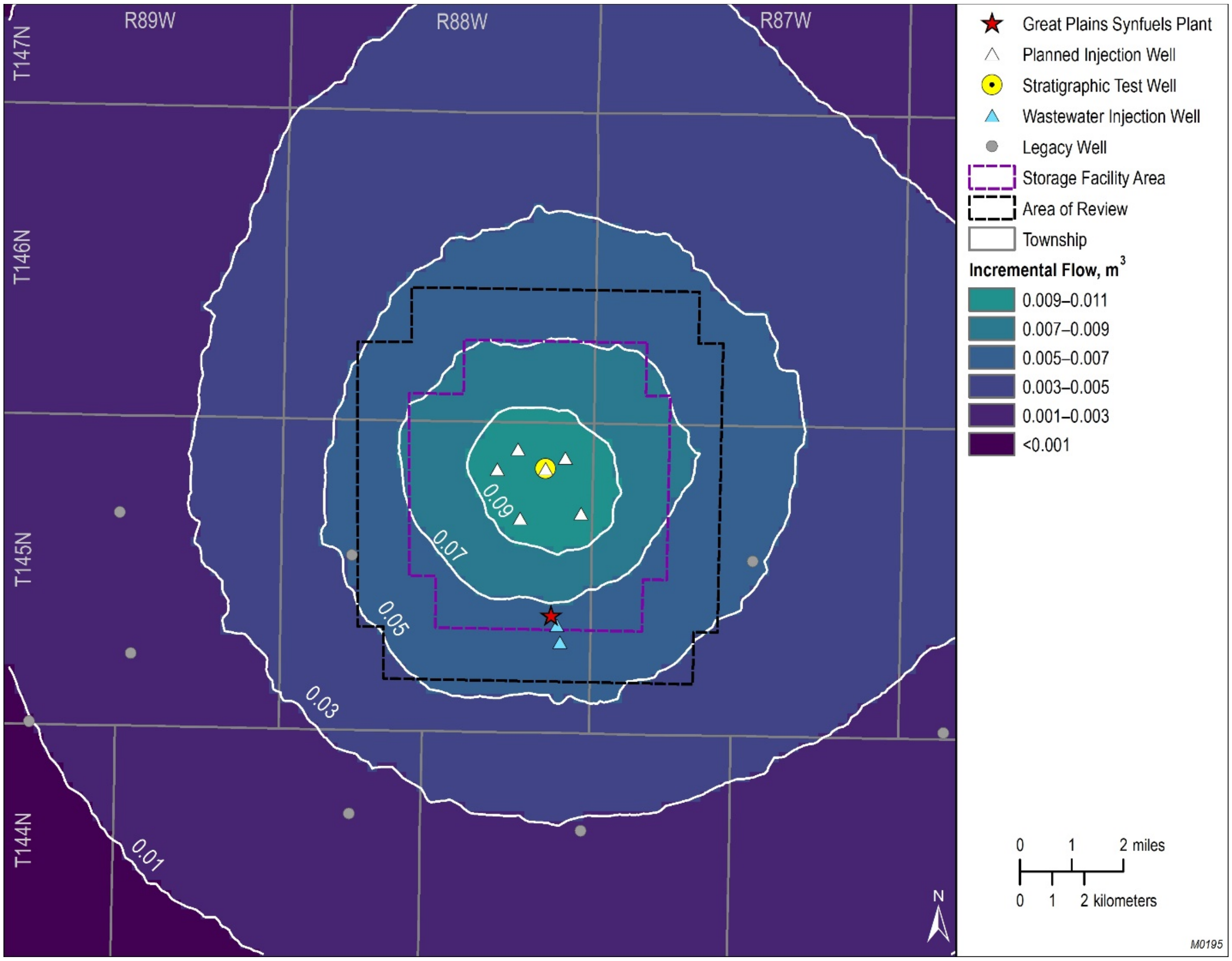


Figure 3-31. Incremental leakage maps at the end of 12 years of CO_2 injection for the scenario where the hypothetical leaky wellbore is closed to Aquifer 2 (thief zone).

Results of the risk-based method detailed above generate a minimum AOR extent which is equivalent to the storage facility area plus a 1-mile buffer. Within the AOR, the pressure increase is not expected to be large enough to cause incremental flow of more than 1 m^3 into the USDW over the injection period (Figure 3-32). As shown, the AOR is depicted by the gray shaded area, which includes the storage facility area. Figure 3-33 illustrates the land use within the AOR.

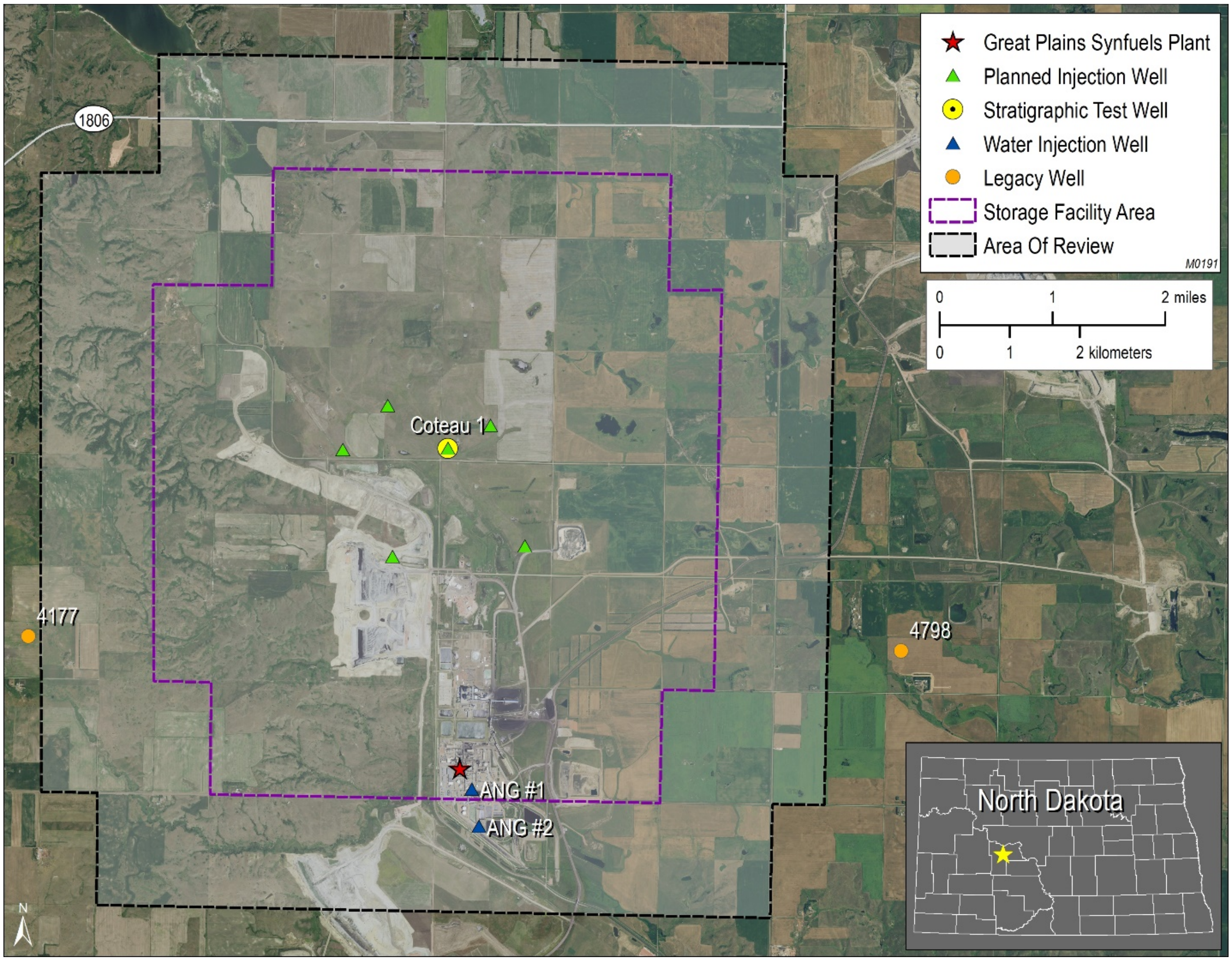


Figure 3-32. Final AOR estimations of the Great Plains CO_2 Project storage facility area in relation to nearby legacy wells. Shown is the storage facility area (purple boundary and shaded area) and area of review (black boundary and shaded area). Orange circles represent nearby legacy wells near the storage facility area.

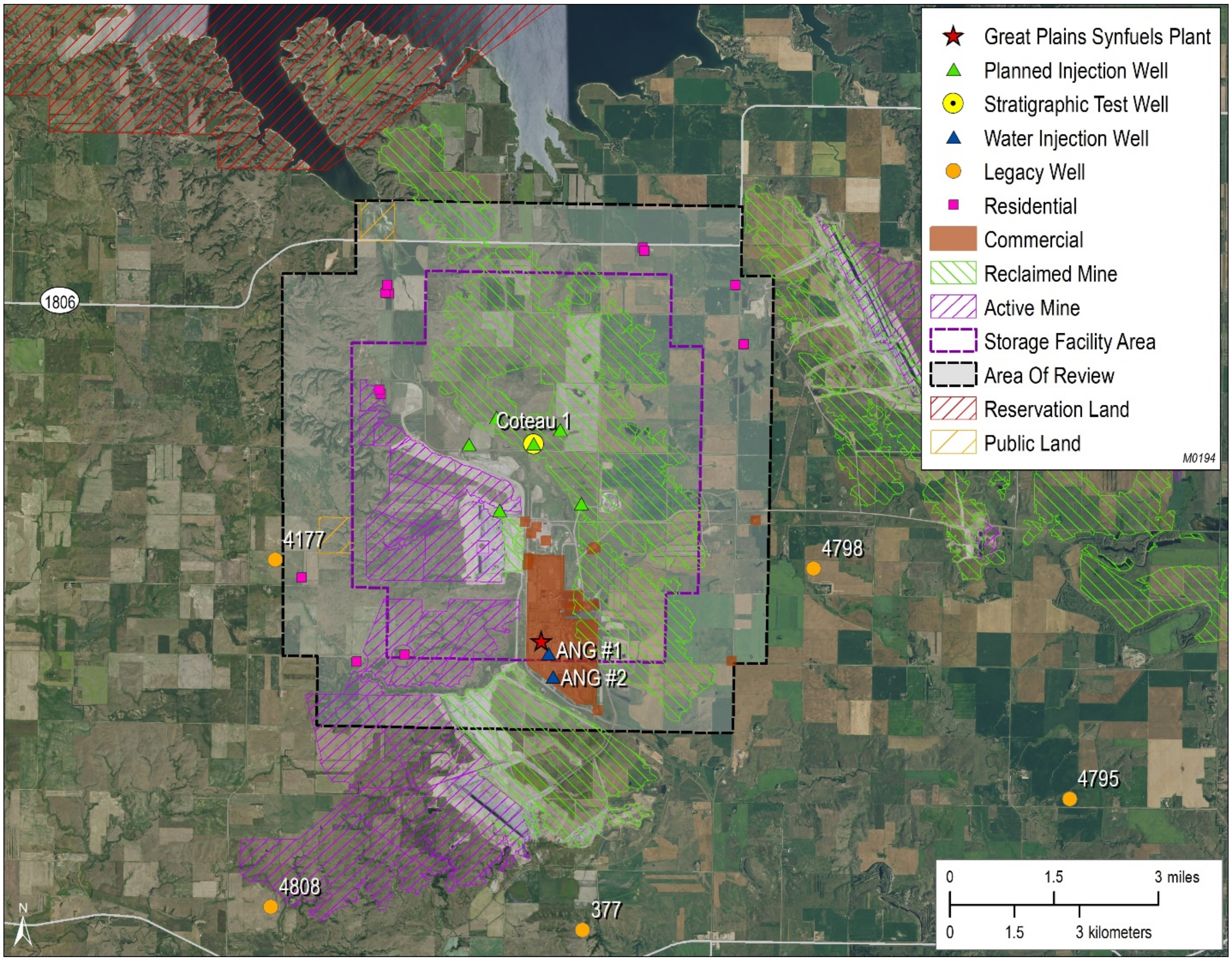


Figure 3-33. Land use in and around the AOR of the Great Plains CO_2 Project storage facility.

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4.0 AREA OF REVIEW

4.0 AREA OF REVIEW

4.1 Area of Review Delineation

4.1.1 Written Description

North Dakota geologic storage of CO_2 regulations require that each storage facility permit delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO_2 plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the Coteau 1 well (NDIC File No. 38379) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-7]).

Section 3 includes a detailed discussion on the computational modeling and simulations (e.g., storage facility area, pressure front, AOR boundary, etc.), assumptions, and justification used to delineate the AOR and method for delineation of the AOR.

NDAC § 43-05-01-05 subsection 1b(3) requires, "A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 4-1), the resulting AOR for the Great Plains CO_2 Sequestration Project is delineated as being 1 mile from the storage facility permit (SFP) boundary. This extent ensures compliance with existing state regulations.

All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 4-2 through 4-5) by a professional engineer pursuant to NDAC § 43-05-01-05 subsection 1b(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected CO_2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 through 4-6 and Figures 4-6 through 4-9).

An extensive geologic and hydrogeologic characterization performed by a team of geologists from the EERC resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.

This section of the SFP application is accompanied by maps and tables that include information required and in accordance with NDAC § 43-05-01-05 subsections 1(a) and 1(b) and 43-05-01-05.1 subsection 2, such as the storage facility area, location of any proposed injection wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05 subsections 1a and 1b(3) and 43-05-01-05.1 subsection 2. Surface features that were investigated but not found within the AOR boundary were identified in Table 4-1.

4.1.2 Supporting Maps

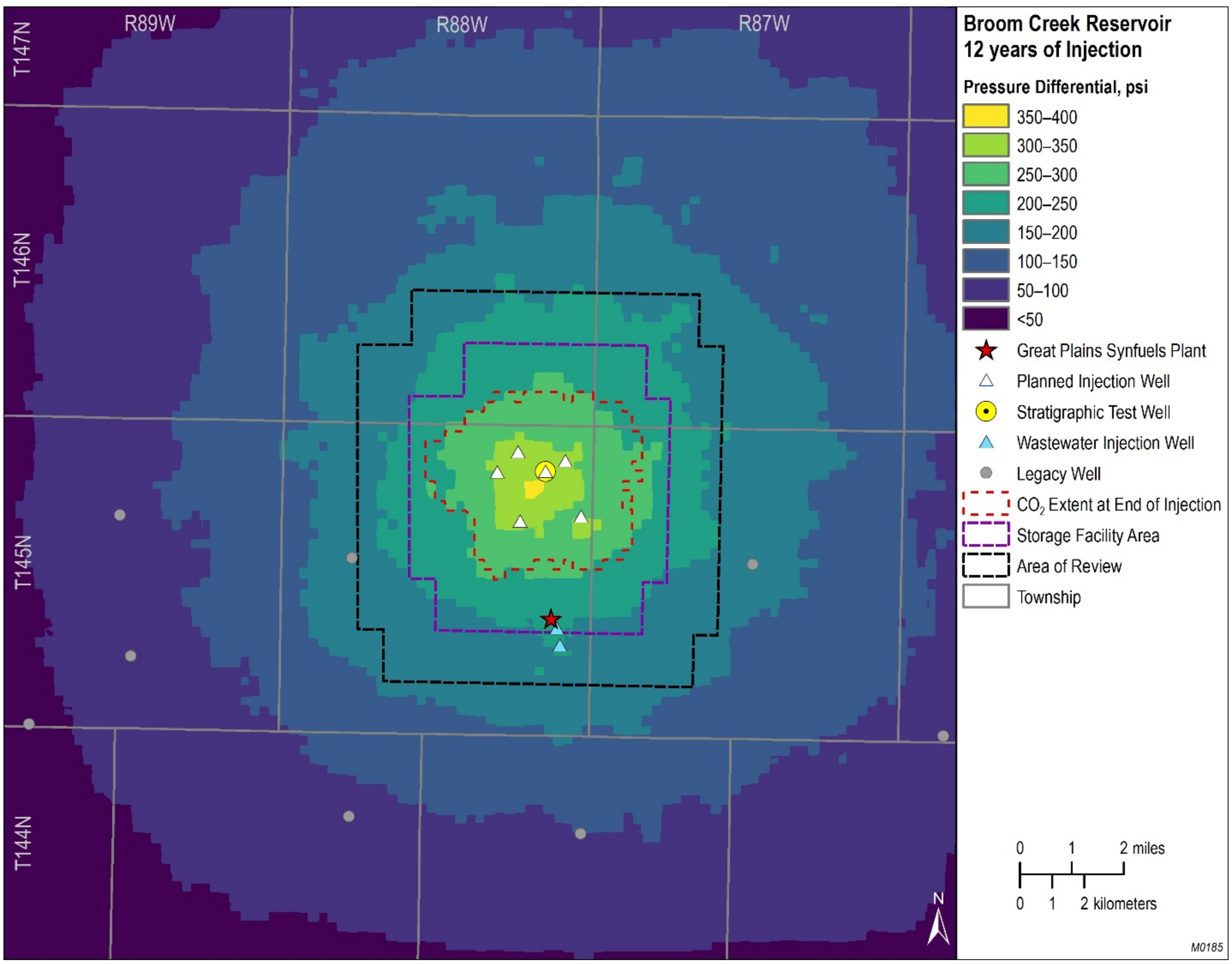


Figure 4-1. Pressure map showing the maximum subsurface pressure influence associated with CO_2 injection in the Broom Creek Formation. Shown is the CO_2 plume extent after end of injection, the storage facility area, and the 1-mile AOR boundary in relation to the maximum subsurface pressure influence.

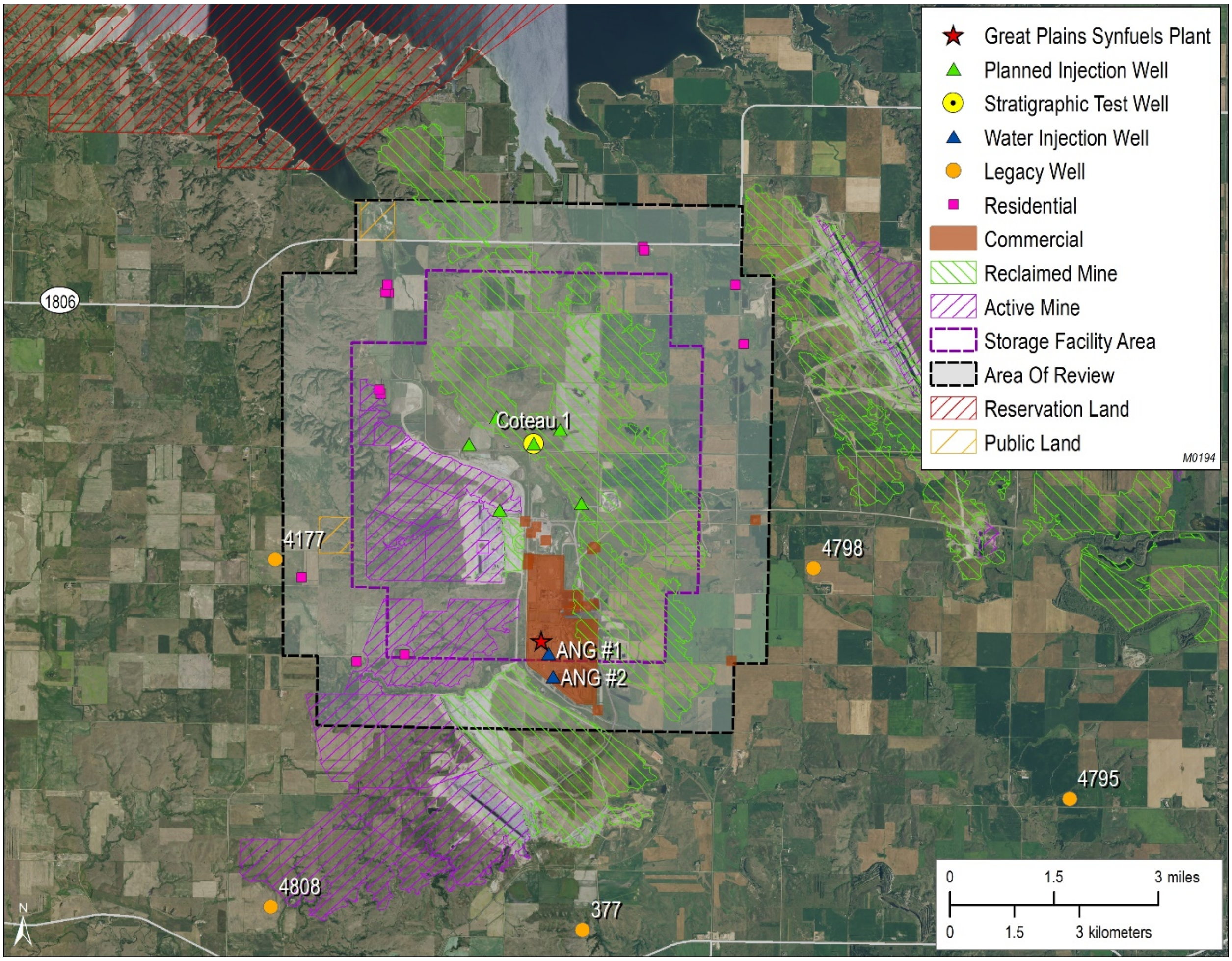


Figure 4-2. Final AOR map showing the Great Plains CO_2 Sequestration Project storage facility area, the storage facility area (dashed purple boundary), and the AOR (dashed black boundary). Pink squares represent occupied dwellings, teal squares represent vacant buildings, and blue squares represent commercial buildings.

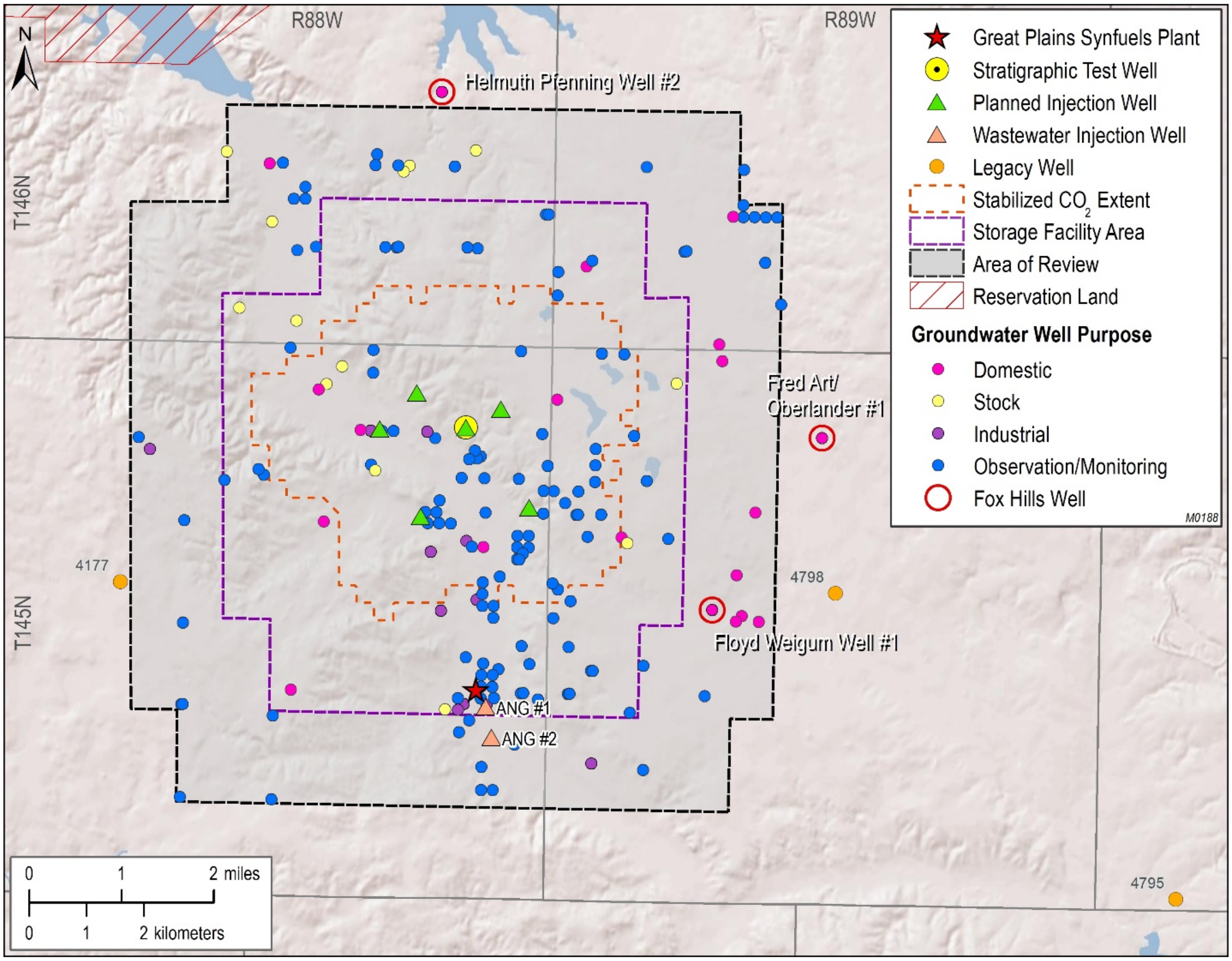


Figure 4-3. AOR map in relation to nearby legacy wells and groundwater wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR, and the light-orange triangles represent Class I ANG #1 and ANG #2 wells. All groundwater wells in the AOR are identified above. All observation/monitoring wells are shallow groundwater wells associated with the mine activities. No springs are present in the AOR.

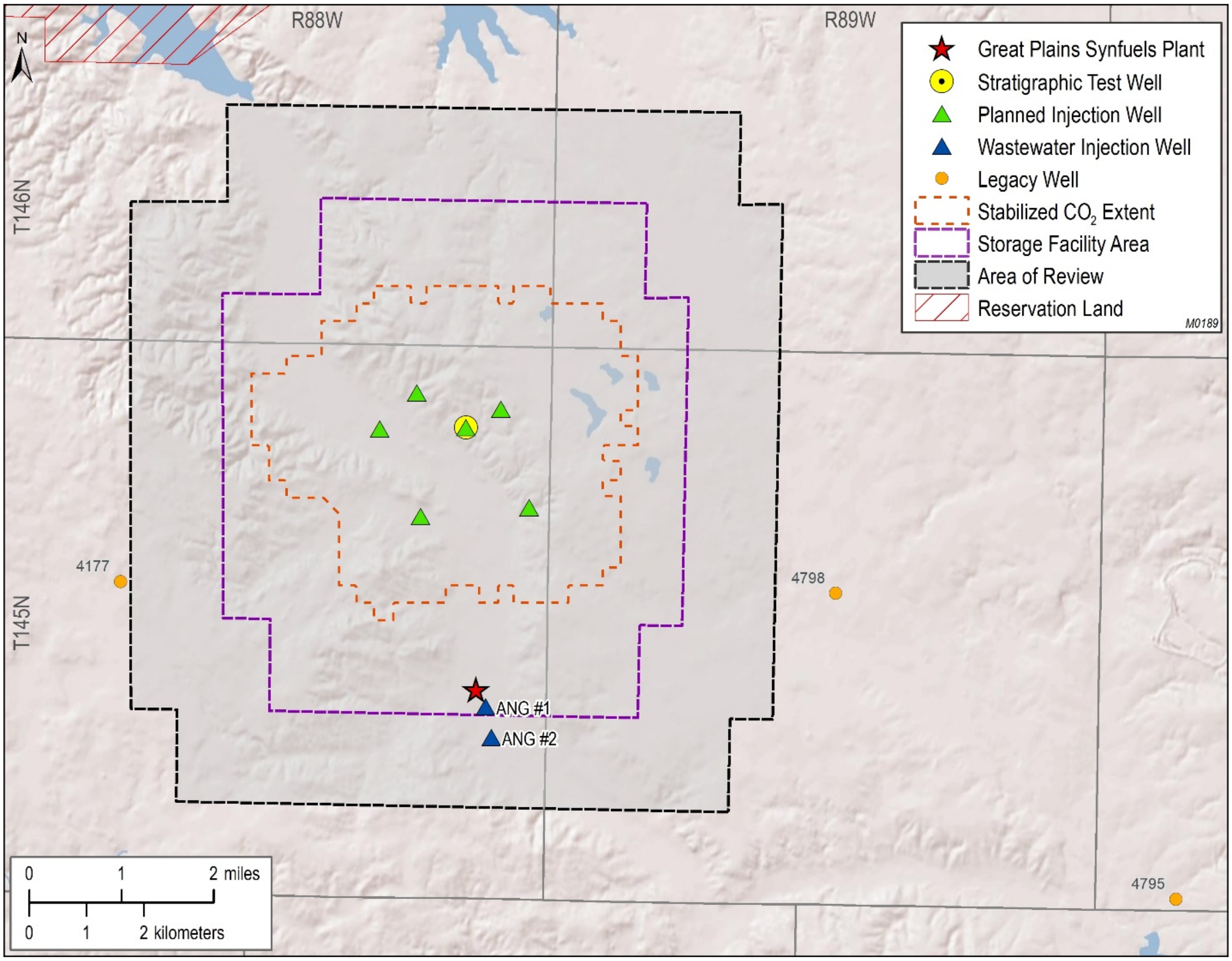
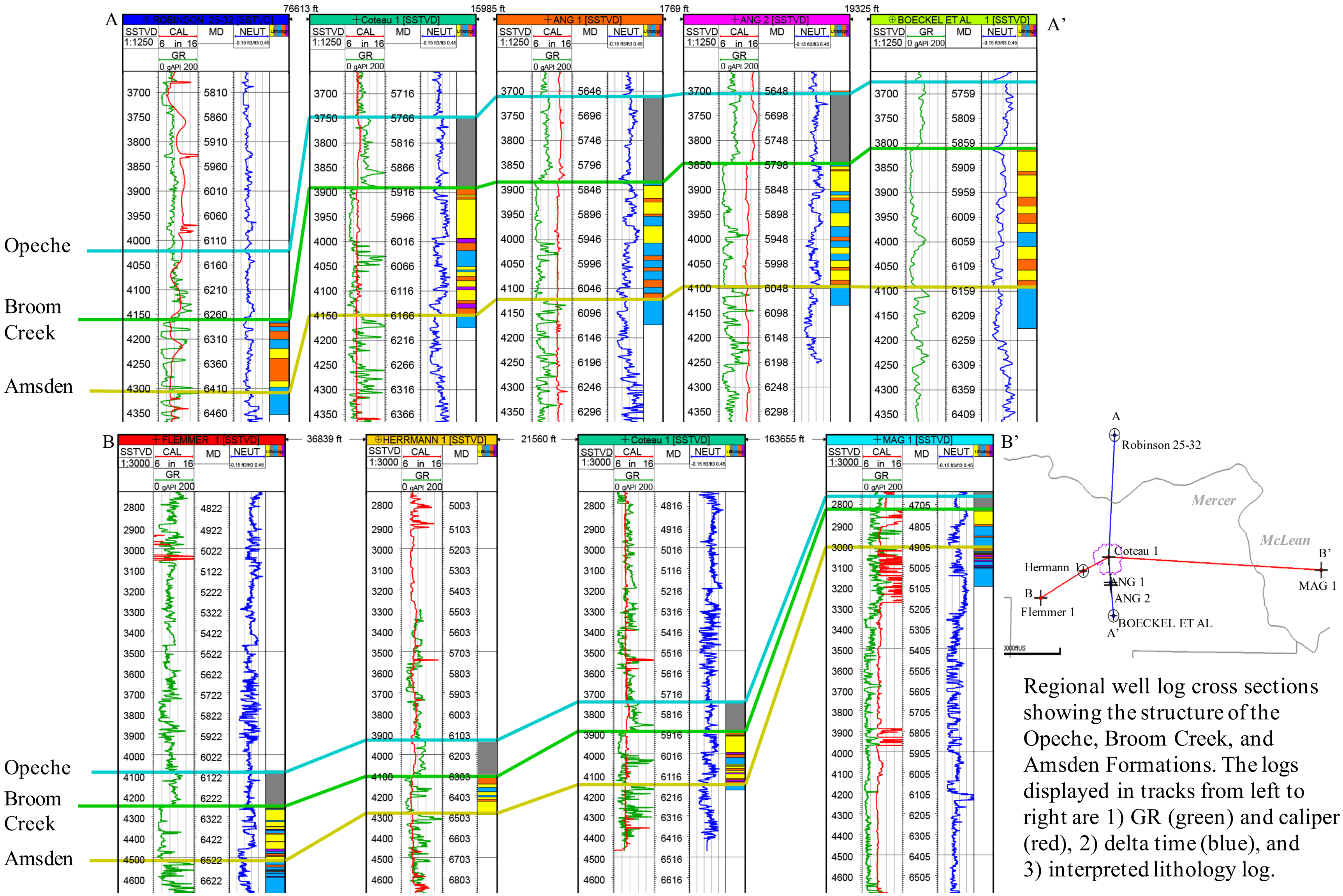


Figure 4-4. AOR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR and the Class I ANG #1 and ANG #2 wells are represented by blue triangles.



Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log.

Figure 4-5. Cross section of the AOR from the geologic model showing lithofacies distribution in the Broom Creek Formation, the proposed injection well (Coteau 1), and the ANG #1 and ANG #2 wells within the AOR. Depths are referenced to mean sea level.

Table 4-1. Investigated and Identified Surface and Subsurface Features (Figures 4-1 through 4-5)

Surface and Subsurface Features	Investigated and Identified (Figures 4-1–4-5)	Investigated But Not Found in AOR
Producing (active) Wells		X
Abandoned Wells	X	
Plugged Wells or Dry Holes	X	
Deep Stratigraphic Boreholes	X	
Subsurface Cleanup Sites		X
Surface Bodies of Water	X	
Springs		X
Water Wells	X	
Mines (surface and subsurface)	X	
Quarries		X
Subsurface Structures (e.g., coal mines)	X	
Location of Proposed Wells	X	
*Location of Proposed Cathodic Protection Boreholes		X
Any Existing Aboveground Facilities	X	
Roads	X	
State Boundary Lines		X
County Boundary Lines		X
Indian Country Boundary Lines	X	
Class I Injection Wells	X	

*There are no plans for cathodic protection for the Great Plains CO_2 Sequestration Project injection wells (Coteau 1–6 wells).

4.2 Corrective Action Evaluation

Table 4-2. Wells in AOR Evaluated for Corrective Action

NDIC Well File No.	Operator	Well Name	Spud Date	Surface Casing, o.d., inches	Surface Casing Seat, ft	Long-String Casing, o.d., inches	Long-String Casing Seat, inches	Hole Direction	TD, ft	TVD, ft	Status	Plug Date	TWN	RNG	Section	Qtr/Qtr	County	Corrective Action Needed
NDDEQ11308	Dakota Gasification Company	ANG #1	4/17/1982	16	2,017	9.625	6,784	Vertical	6,784	6,784	Active injector	N/A	145 N	88 W	24	SE/SW	Mercer	No
NDDEQ11309	Dakota Gasification Company	ANG #2	9/2/1984	13.375	2,118	9.625	6,910	Vertical	6,911	6,911	Active injector	N/A	145 N	88 W	25	CE2/NW	Mercer	No
38379	Rampart Energy Company	Coteau 1	6/27/2021	9.625	2,033	7	6,473	Vertical	6,484	6,484	DNC	N/A	145 N	88 W	1	SW/SW	Mercer	No
4177	Pel-Tex Petroleum Co. & Conoco	Herrmann 1 (Located outside of AOR)	11/8/1966	9.625	622	N/A	N/A	Vertical	8,057	8,057	Dry	12/2/1966	145 N	88 W	17	NE/SW	Mercer	No

Table 4-3. Herrmann 1 (NDIC File No. 4177) Well Evaluation

Well Name: Herrmann 1 (NDIC File No. 4177)

Cement Plugs				
Number	Interval, ft		Thickness, ft	Volume, sacks
1	7,980	7,910	70	20
2	7,800	7,730	70	20
3	4,720	4,650	70	20
4	640	570	70	20
5	20	Surface	20	5

*Data and information are provided from well-plugging report found in NDIC database.

Formation		Cement Plug Remarks
Name	Estimated Top, ft	
9⅝" Casing Shoe	622	Cement Plug 4 isolates the 9⅝" casing shoe.
Pierre	1,893	
Mowry	4,334	Cement Plug 3 isolates the uppermost Inyan Kara porosity.
Inyan Kara	4,660	
Swift	5,146	
Rierdon	5,562	
Broom Creek	6,310	
Big Snowy Group	6,918	
Madison	7,346	
Ratcliffe	7,597	
Frobisher	7,814	Cement Plugs 1 and 2 isolate deeper, unsuccessful wildcat horizons below the Frobisher.

Spud Date: 11/08/1966
Total Depth: 8,057 (Madison Formation)

Openhole plugging

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Herrmann 1 (NDIC File No. 4177) well will not be in contact with the CO_2 plume, and pressure increase in the Broom Creek Formation at this well location is predicted to be approximately 150–200 psi. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled and plugged.

Table 4-4. ANG #1 (NDEQ File No. NDOH11308) Well Evaluation

Well Name: ANG 1 (NDEQ File No. NDOH11308)

Casing Program				
Section	Casing Outside Diameter (o.d.), in.	Weight, lb/ft	Casing Seat, ft	Grade
Surface	16"	75	2,017	K-55
Production	9⅝"	40	6,784	K-55

Cement Program				
Casing, in.	Cement Type	TOC	Excess, %	Volume, sacks
16"	Class G	Surface	33%	1,600
9⅝"	Class G	1,700	NA	2,590

Formation		Remarks
Name	Estimated Top, ft	
16” Casing Shoe	2,017	Class G cement isolates the 16” casing shoe and all shallow water zones.
Mowry	3,950	
Inyan Kara	4,293	Production casing and Class G cement isolate all formations below the shoe of the surface casing.
Swift	4,664	
Rierdon	5,098	
Spearfish	5,510	
Opeche	5,654	
Broom Creek	5,821	
Amsden	6,070	

Corrective Action: No corrective action is necessary.

Table 4-5. ANG #2 (NDEQ File No. NDOH11309) Well Evaluation

Well Name: ANG 2 (NDEQ File No. NDOH11309)

Casing Program				
Section	Casing Outside Diameter (o.d.), in.	Weight, lb/ft	Casing Seat, ft	Grade
Surface	13⅜”	54.5	2,118	J-55
Production	9⅝”	47	6,910	N-80

Cement Program				
Casing, in.	Cement Type	TOC	Excess, %	Volume, sacks
13-⅜”	Class G & Halliburton Lightweight	Surface	38%	1,827
9⅝”	Class G & Halliburton Lightweight	2,220' (plus a top off cement job from surface to 670')	NA	2,301

Formation		
Name	Estimated Top, ft	Remarks
13-3/8" Casing Shoe	2,118	Class G cement isolates the 13-3/8" casing shoe and all shallow water zones.
Mowry	3,940	
Inyan Kara	4,263	Production casing and Class G cement isolate all formations below a depth of 2,220'. Therefore, there exists a 102' gap in the openhole cement coverage from 2,220' to 2,118' opposite the impermeable Pierre Shale.
Swift	4,692	
Rierdon	5,098	
Spearfish	5,499	
Opeche	5,644	
Broom Creek	5,795	
Amsden	6,042	

Corrective Action: No corrective action is necessary.

Table 4-6. Coteau 1 (NDIC File No. 38379) Well Evaluation

Well Name: Coteau 1 (NDIC File No. 38379)

Casing Program				
Section	Casing Outside Diameter (o.d.), in.	Weight, lb/ft	Casing Seat, ft	Grade
Surface	9⅝"	36	2,023	J-55
Production	7"	32	5,772	L-80
Production	7"	32	6,473	13CR L80

Cement Program				
Casing, in.	Cement Type	TOC	Excess, %	Volume, sacks
9⅝"	Varicem	Surface	100	750
7”	Varicem	Surface	100	285
7”	Corrosacem	3205'	100	645

Formation		
Name	Estimated Top, ft	Remarks
Pierre	1,750	Class G cement isolates the 9⅝" casing shoe.
9⅝" Casing Shoe	2,023	
Mowry	4,065	Stage collar with ECP at 3,205' Halliburton Corrosacem (CO_2-resistant cement) from TD to stage collar
Inyan Kara	4,395	
Swift	4,800	
Rierdon	5,212	
Spearfish	5,623	
Opeche	5,762	7" 13CR L80 production casing and Halliburton Corrosacem (CO_2-resistant cement) to isolate the Broom Creek Formation
Broom Creek	5,905	
Amsden	6,177	

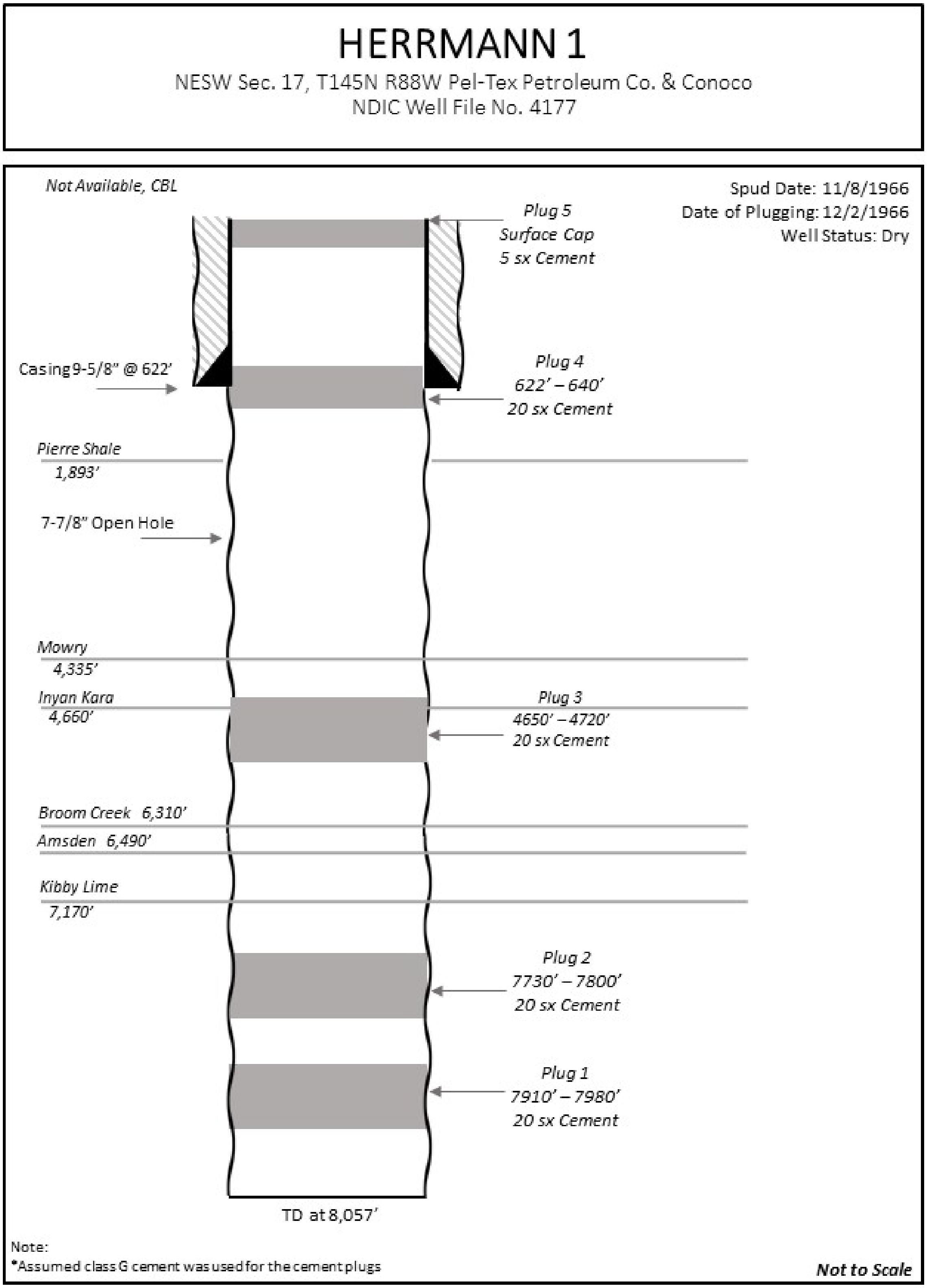
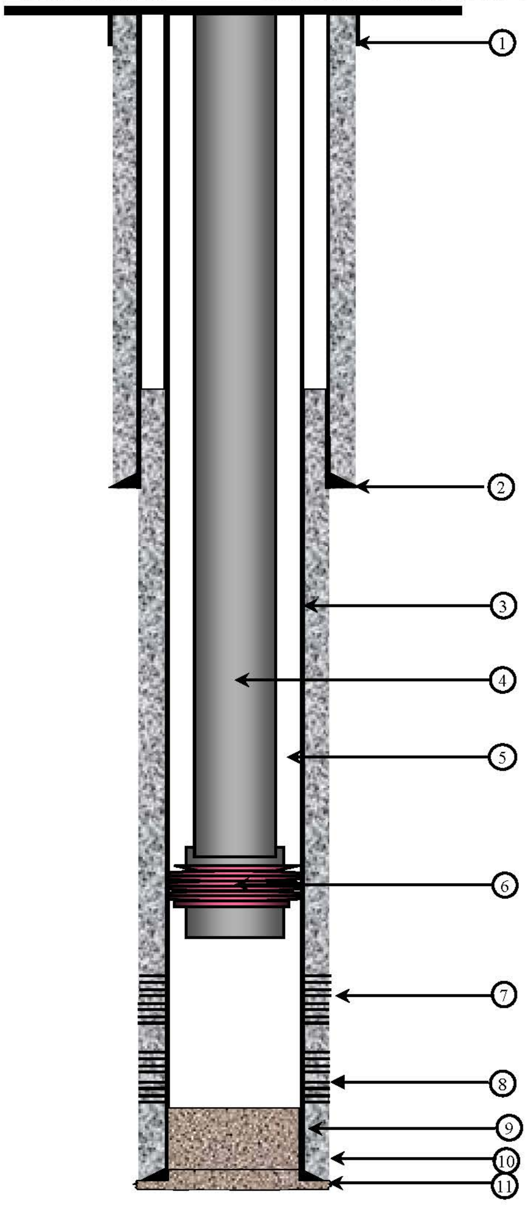


Figure 4-6. Herrmann 1 (NDIC File No. 4177) well schematic showing the location and thickness of cement plugs.

DAKOTA GASIFICATION COMPANY
Mercer County, North Dakota
Injection Well No. 1 Schematic
Status: Active

GROUND LEVEL   Ground Surface Elevation of 1926' ASL



COMPLETION DETAIL

1. Conductor Pipe: 24"set in 40" hole from surface to 80'. Cemented to surface.
2. Surface Casing: 16", 75.0-ppf, K-55, ST&C. Set from surface to ±2,017.28' in a 20" drilled hole. Cemented to surface with 1,600 sacks 65/35 Pozolan and 300 sacks Class G cement.
3. Protection Casing: 9-5/8" casing set to 6,784'. 9-5/8", 40.0-ppf, K-55, LT&C from 3,967' to 6,784', 9-5/8", 36.0-ppf, K-55, LT&C from 15' to 3,967', and 9-5/8", 40.0-ppf, K-55, LT&C surface to 15' in a 13-1/2" drilled hole from 2,017' to 4,469', 12-1/2" drilled hole from 4,469' to 5,800' and a 12-1/4" drilled hole form 5,800' to 6,784'. Cemented with 990 sacks of Class G cement in the first stage and 1,600 sacks of Class G cement in the second stage. Cementing stage tool was set at 5,347'. Top of cement at 1,700'.

   Note: SLB USIT log (6/7/2020) identified reduced ID in jts 81 & 84, 3,641.7' & 3,760.0', probably 43.5 ppf, & reduced ID in jts 100 & 133, 4,422.5'& 5,731.4', probably 47.0 ppf.
4. Injection Tubing and Seal Assembly: 7", 26-ppf, J-55, LT&C from surface to ± 5740' with a 5-1/2" OD Baker Hughes GBH22 Locator Tubing Seal Assembly set to 5,751.5', minimum ID of 4.891". 5-1/2" OD Tail pipe extension to 5,762.2'.
5. Annulus filled with 10.4 lb/gal inhibited brine.
6. Injection Packer: Baker Model 194-60 "FB-1" Packer set at 5,740'.
7. Minnelusa Perforations:

5,835' to 5,836', 1'	5,836' to 5,867', 31'
5,867' to 5,870', 3'	5,870' to 5,880', 10'
5,880' to 5,884', 4'	5,884' to 5,894', 10'
5,894' to 5,900', 6'	5,920' to 5,952', 32'
5,952' to 5,954', 2'	

8. Kibbey Perforations:

6,621' to 6,631', 10'	6,637' to 6,657', 20'
6,659' to 6,669', 10'	

9. Fill Tagged at 6,721' on 6/25/2020 – Temperature Survey
10. Plugged back total depth of 6,728'
11. Drilled to a total depth of 6,784'.

Note: All depths referenced to original rotary kelly bushing of 20' above ground level unless otherwise noted.

GEOSTOCK SANDIA ENTREPOSE
8860 Fallbrook Drive Houston, TX 77064 USA Tel: (346) 314-4347 Fax: (832) 478-5172
info@geostocksandia.com · www.geostocksandia.com

Drawn by: WHA	Date: 11/20/2002	*Drawing not to scale*
Revision 4 – 7/17/2020		

Figure 1: Injection Well No. 1 Schematic

Figure 4-7. ANG #1 (NDEQ File No. NDOH11308) well schematic.

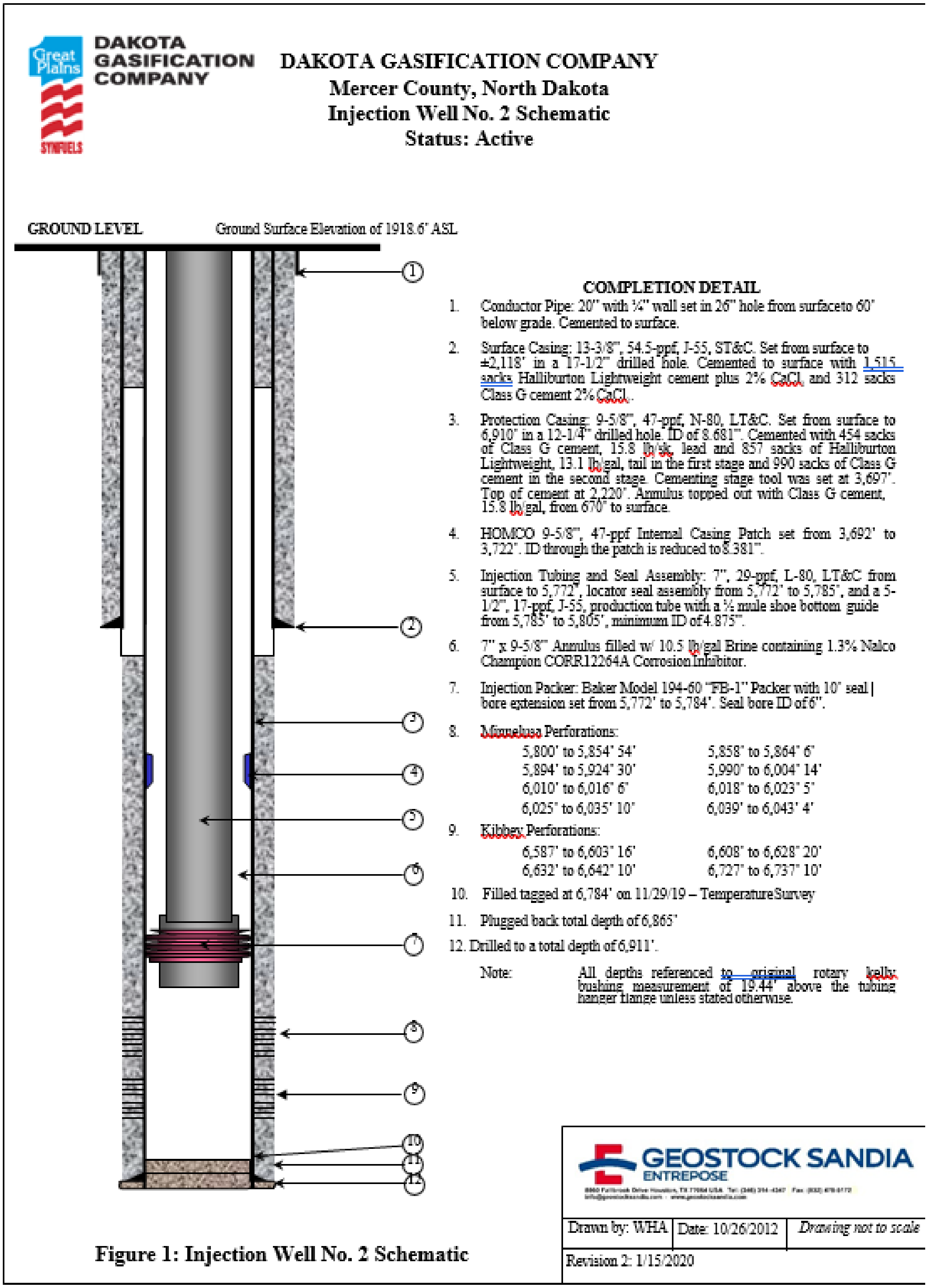


Figure 4-8. ANG #2 (NDEQ File No. NDOH11309) well schematic.

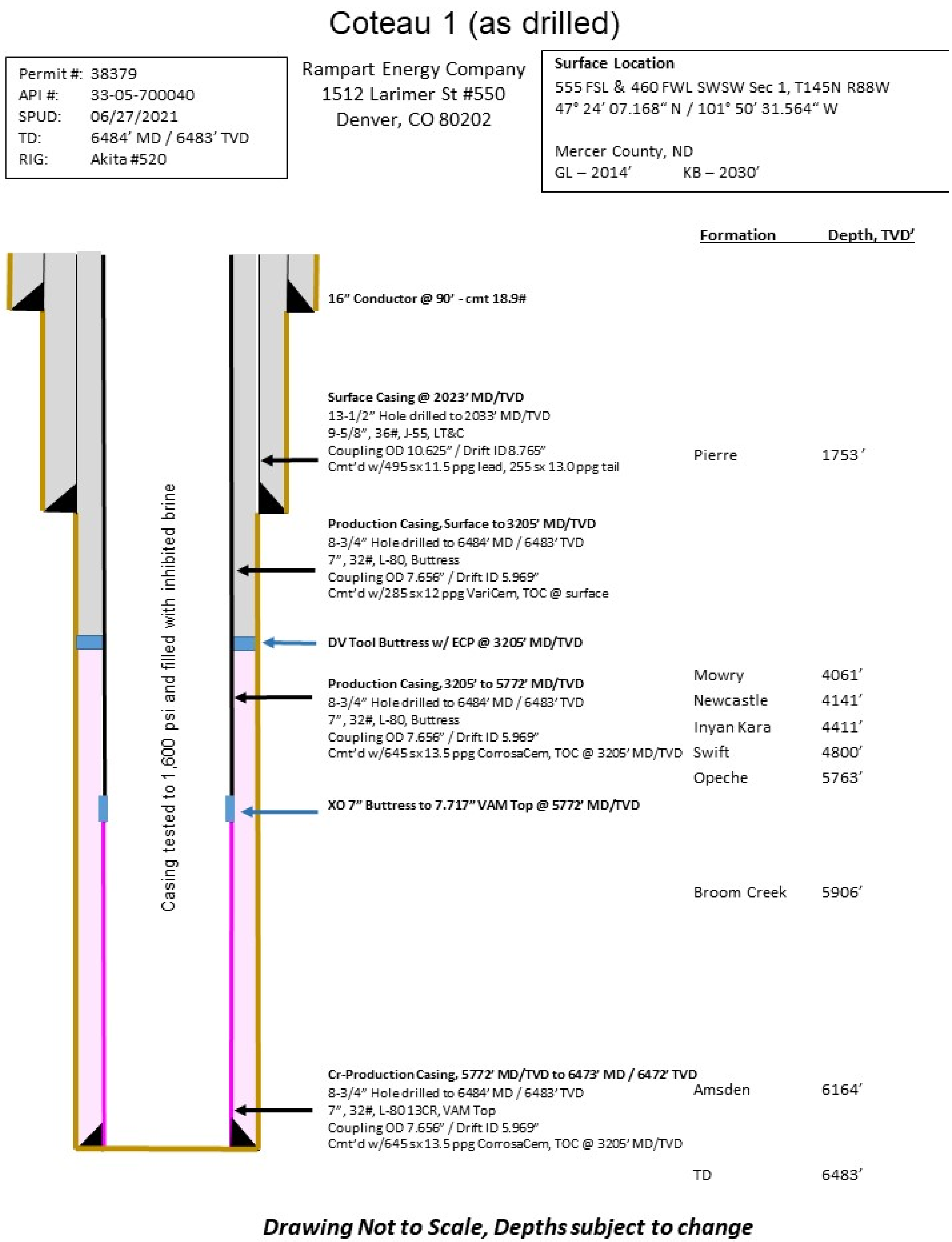


Figure 4-9. Coteau 1 (NDIC File No. 38379) well schematic.

4.3 Reevaluation of AOR and Corrective Action Plan

The Great Plains CO_2 Sequestration Project will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place not later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following:

- Any changes to the monitoring and operational data prior to the scheduled reevaluation date.

- Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and operational data to be utilized as the basis for that update will be identified.

- The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR.

4.4 Protection of USDWs

4.4.1 Introduction of USDW Protection

The primary confining zone and additional overlying confining zones geologically isolate the Fox Hills Formation, the lowest USDW in the area of investigation from the underlying injection zone. The Opeche Formation is the primary confining zone for the injection zone with additional confining layers above, geologically isolating all USDWs from the injection zone. The uppermost confining layer is the Pierre Formation, an impermeable shale in excess of 1,000 ft thick, providing an additional seal for all USDWs in the region.

4.4.2 Geology of USDW Formations

The hydrogeology of western North Dakota comprises several shallow freshwater-bearing formations of the Quaternary, Tertiary, and upper Cretaceous-aged sediments underlain by multiple saline aquifer systems of the Williston Basin (Figure 4-10). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1,000 and 1,500 ft thick (Thamke and others, 2014).

The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; the overlying Cannonball, Tongue River, and Sentinel Butte Formations of the Tertiary Fort Union Group; and the Tertiary Golden Valley Formation (Figure 4-11). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the area of investigation (Croft, 1973).

The lowest USDW in the area of investigation is the Fox Hills Formation, which, together with the overlying Hell Creek Formation, is a confined aquifer system. The Hell Creek Formation

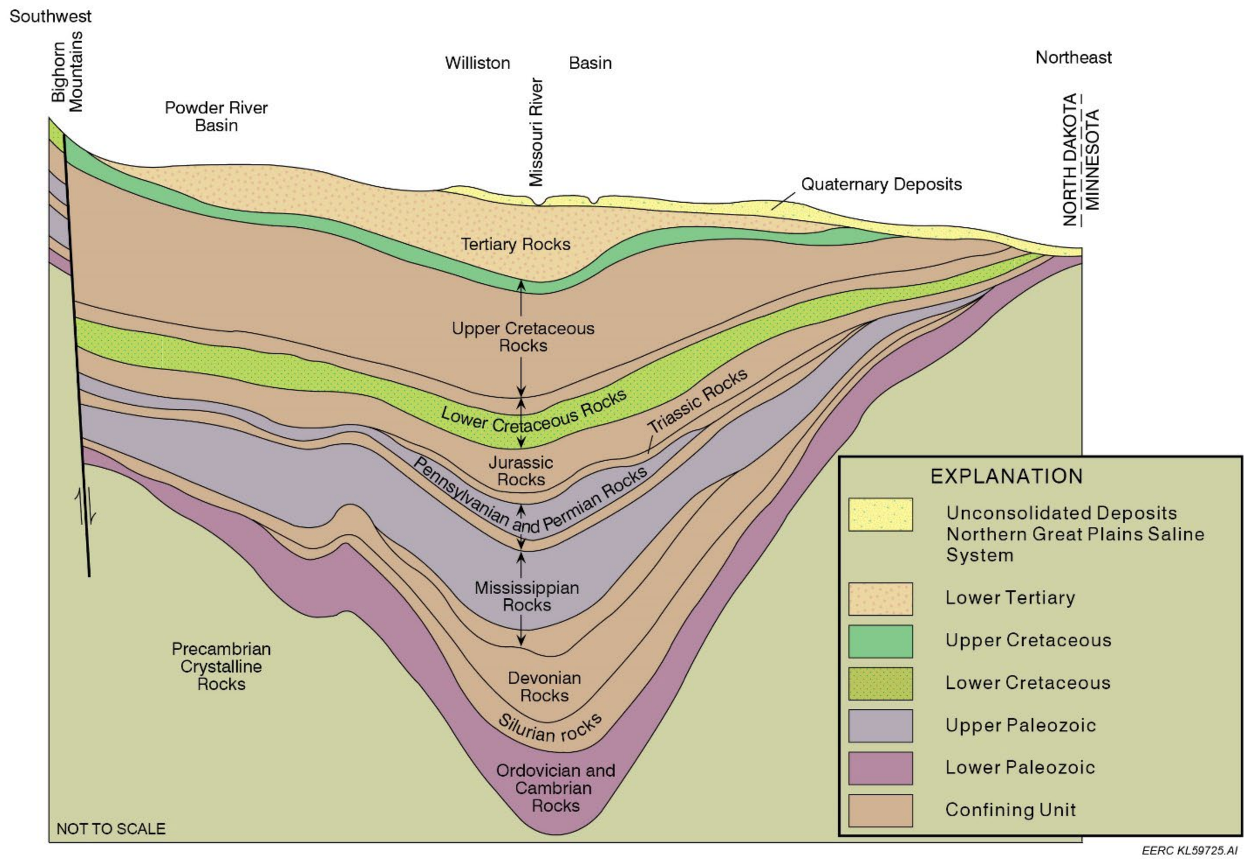


Figure 4-10. Major aquifer systems of the Williston Basin.

is a poorly consolidated unit composed of interbedded sandstone, siltstone, and claystones with occasional carbonaceous beds, all fluvial origin. The underlying Fox Hills Formation is interpreted as interbedded nearshore marine deposits of sand, silt, and shale deposited as part of the final Western Interior Seaway retreat (Fischer, 2013). The Fox Hills Formation in the area of investigation is approximately 1,100 to 1,400 ft deep and 200–340 ft thick (Croft, 1973). The structure of the Fox Hills and Hell Creek Formations follows that of the Williston Basin, dipping gently toward the center of the basin to the northwest of the area of investigation (Figure 4-12).

The Pierre Shale is a thick, regionally extensive shale unit which forms the lower boundary of the Fox Hills–Hell Creek system, also isolating all overlying freshwater aquifers from the deeper saline aquifer systems. The Pierre Shale is a dark gray to black marine shale and is typically over 1,000 ft thick in the area of investigation (Thamke and others, 2014).

ERATHEM	SYSTEM		SERIES	ROCK: GROUP	ROCK: FORMATION		FRESHWATER AQUIFER(S)	FRESHWATER AQUIFER(S) UNDER
CENOZOIC	Quaternary		Holocen		Oahe		No	
			Pleistocene	Coleharbor	“Glacial Drift”		Yes	
	Tertiary	Neoge	Pliocene		(Unnamed)		Yes	
			Miocene		Arikaree		No	
		Paleogene	Oligocene	White	Brule		No	
			Eocene		Chadron		No	
					Golden		No	
			Paleocene	Fort Union	Sentinel		Yes	
					Tongue River	Bullion	Yes	
						Slope	No	
					Cannonball		Yes	
					Ludlow		Yes	
MESOZOIC	Cretaceous		Upper	Montana	Hell Creek		Yes	
					Fox Hills		Yes	
					Pierre		No	

Modified from Murphy and others, 2009, NDGS MS 91

Figure 4-11. Upper stratigraphy of Mercer County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Murphy and others, 2009; NDGS MS 91).

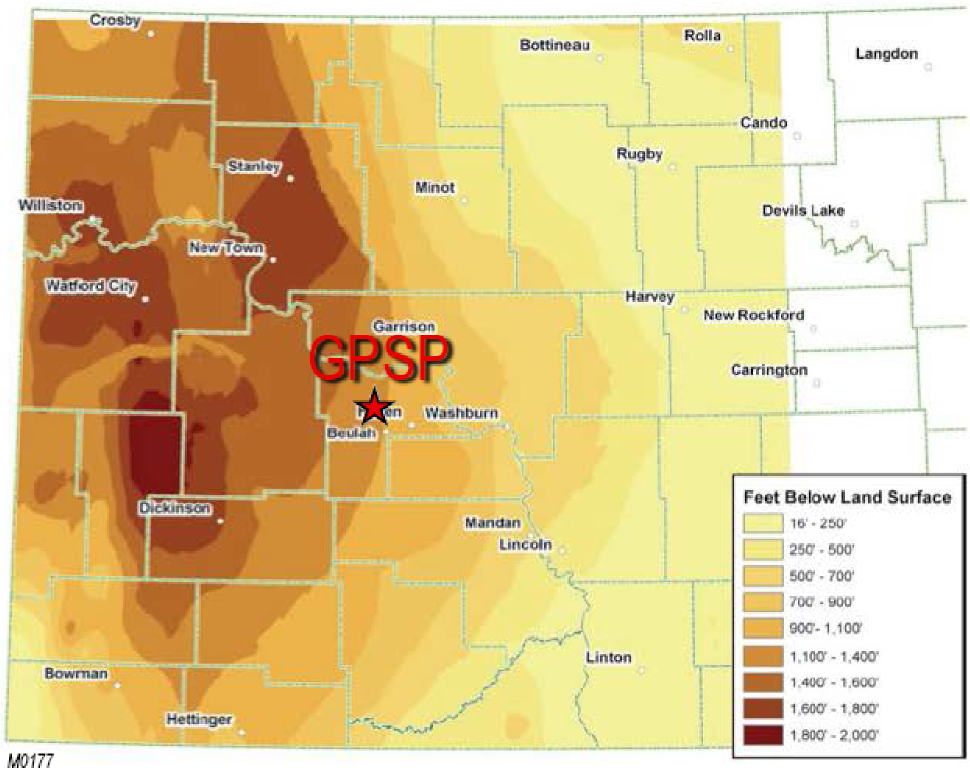


Figure 4-12. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

4.4.3 Hydrology of USDW Formations

Groundwater is obtained from both glacial drift and bedrock aquifers, with most of the water obtained from bedrock. Lignite beds and sands in the Sentinel Butte and Tongue River Formations provide shallow bedrock aquifers in most areas of Mercer County. Sandstones near the base of the Tongue River Formation and within the Hell Creek and Fox Hills Formations provide deeper artesian aquifers in many areas. Glacial drift is generally too thin or impermeable to provide good aquifers in the upland areas. However, in the valleys of the major streams and in the diversion channels, the glacial and alluvial fill provides adequate supplies of groundwater (Carlson, 1973).

The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the area of investigation is to the east (Figure 4-13). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,530 mg/L near the Great Plains CO_2 Sequestration Project area. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Trapp and Croft, 1975). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering.

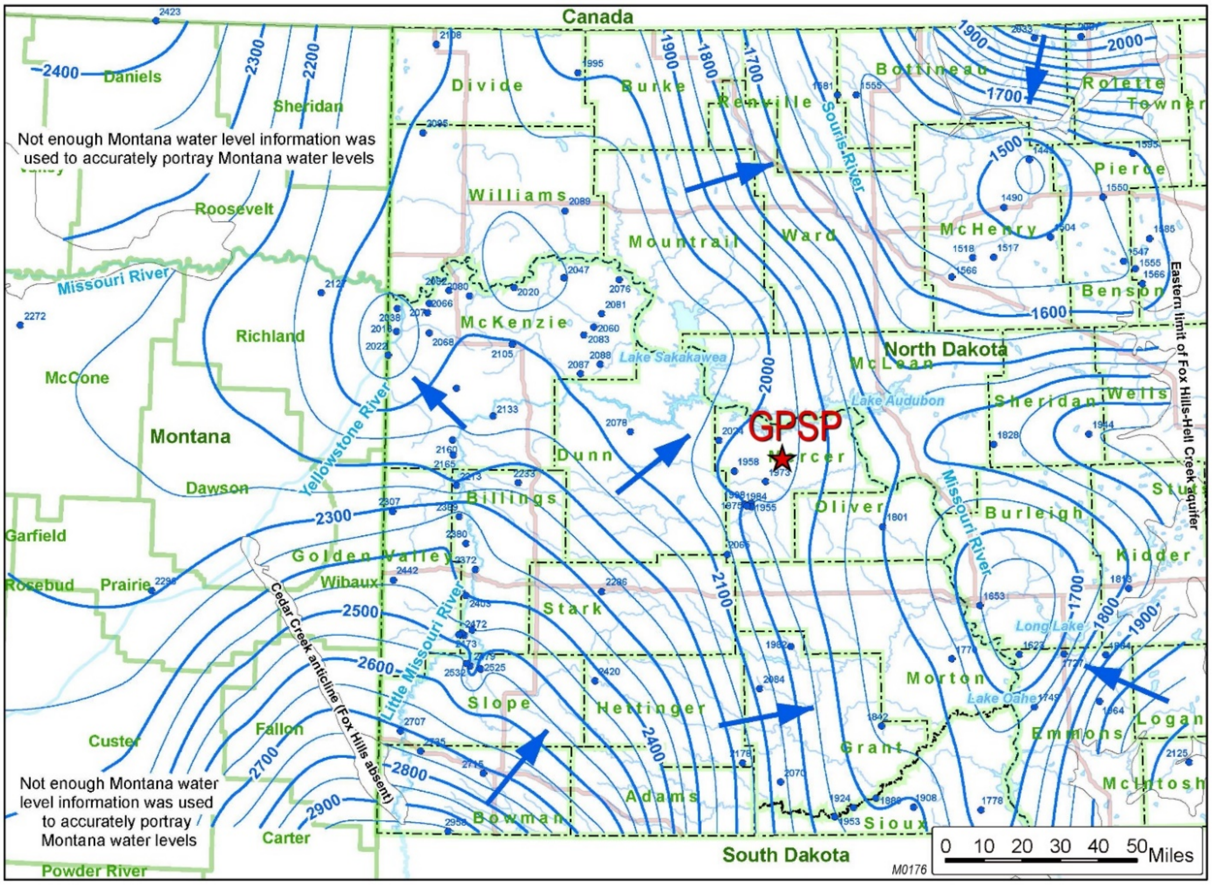


Figure 4-13. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in Mercer County (modified from Fischer, 2013).

There are several existing candidate groundwater wells to screen for sample collection in the area of investigation (Figure 4-14). Some of these wells are currently sampled as part of annual plant operational monitoring programs. Existing wells will be evaluated for inclusion into baseline, operational, and postinjection monitoring plans. Groundwater monitoring wells completed in the Fox Hills Formation will also be installed and sampled near injection well pads (one at each well for a total of six).

Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the area of investigation (Figure 4-15). These formations are often used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. Tongue River groundwaters are generally a sodium bicarbonate type with a TDS of approximately 1,000 ppm (Croft, 1973).

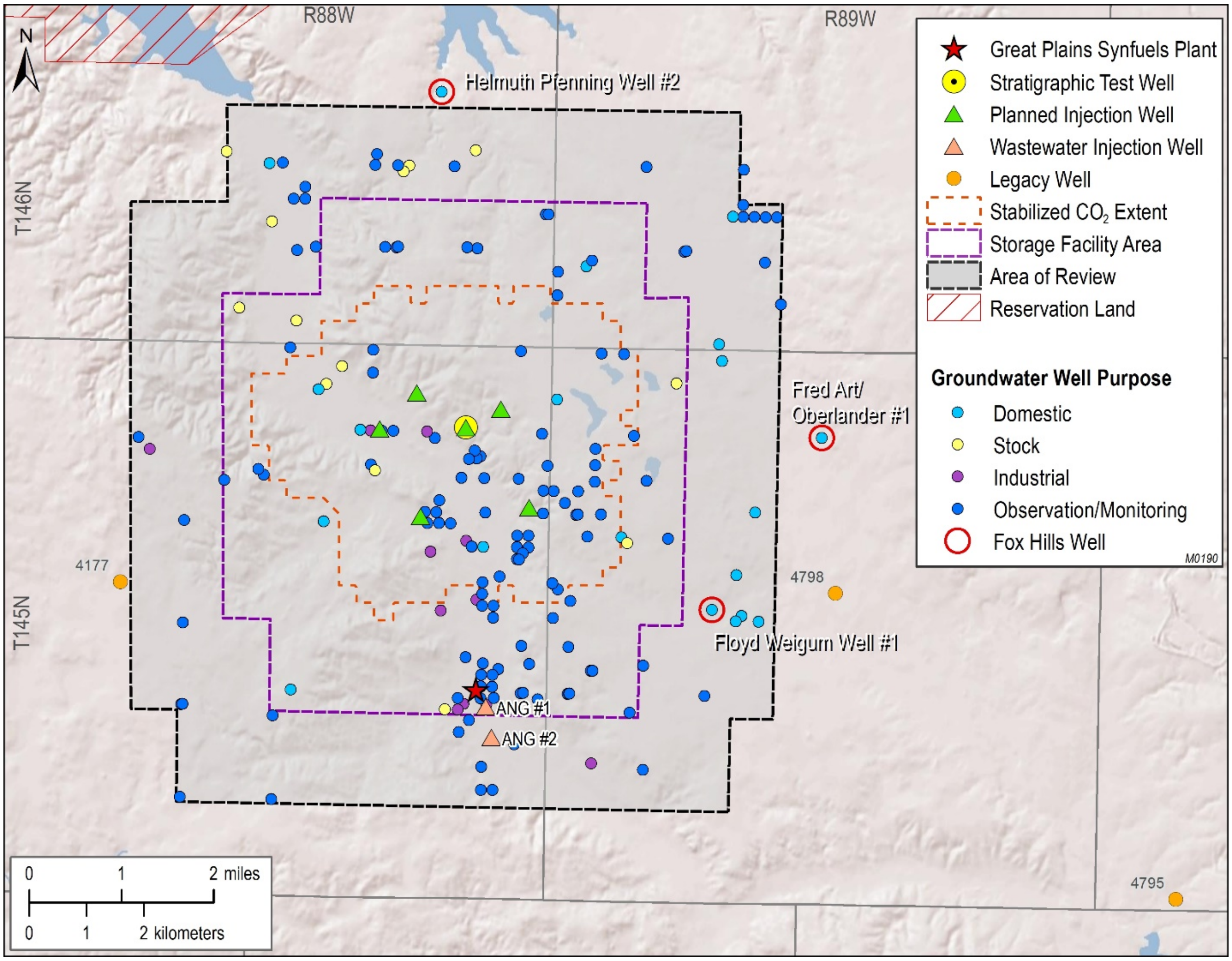


Figure 4-14. Map of water wells in the area of investigation in relation to the simulated plume.

The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The upper Sentinel Butte Formation is predominantly sandstone with lignite interbeds, forming another important source of groundwater in the region. Generally, the upper Sentinel Butte is up to 300 ft thick in the area of investigation. TDS in the Sentinel Butte Formation range from approximately 400–1,000 ppm (Croft, 1973).

In general, coal seams and glacial washouts contribute to shallow sources of groundwater in the area. Locally, the primary source of shallow groundwater is the Beulah Trench, a typical glacially carved valley that winds its way from Beaver Creek Bay (Lake Sakakawea), through the project site, to a point about 4 miles north of Beulah where it divides and continues eastward toward Hazen and westward toward Zap.

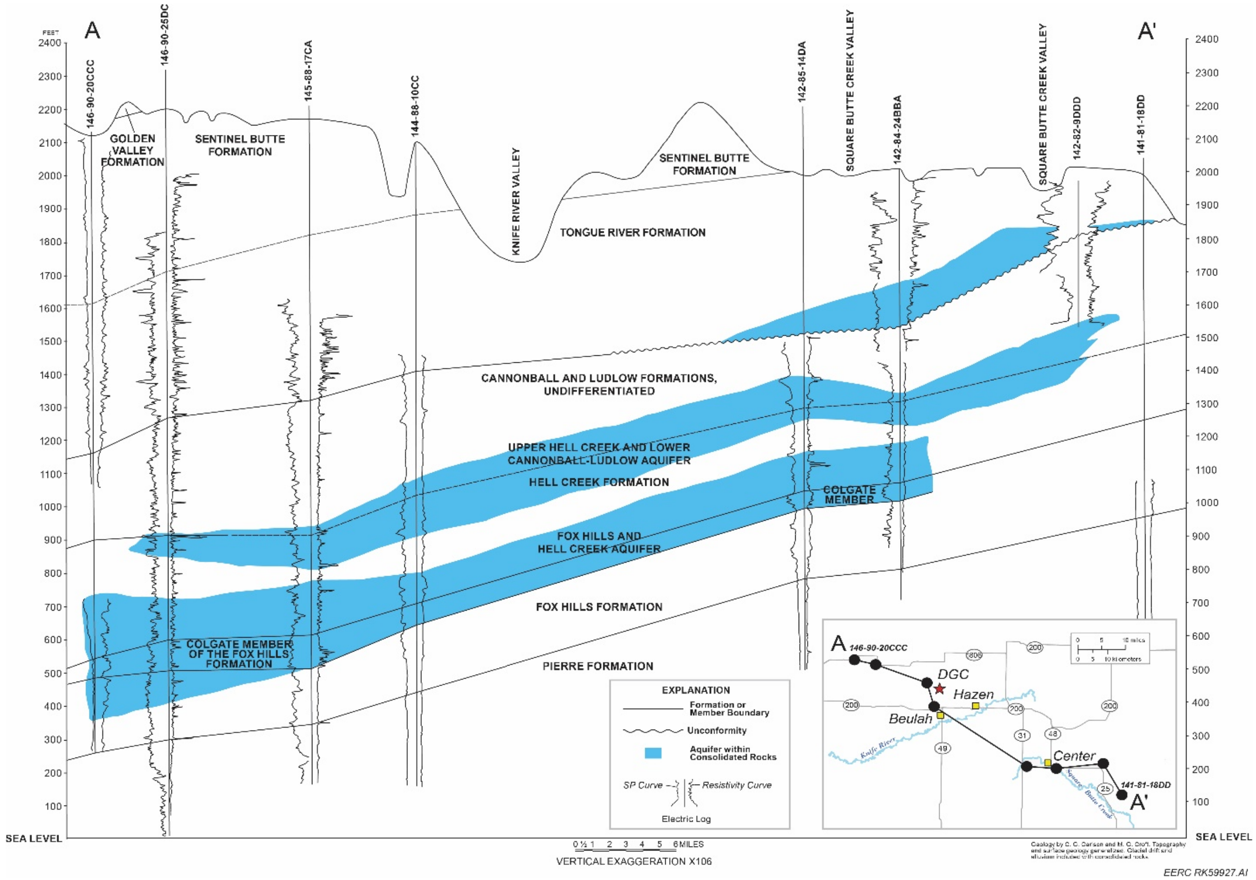


Figure 4-15. West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the locations of the water wells illustrated on the cross section.

4.4.4 Protection for USDWs

The Fox Hills–Hell Creek aquifer system is the lowest USDW in the AOR. The injection zone (Broom Creek Formation) and the lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and siltstone formations of Permian, Jurassic, and Cretaceous ages (Figure 4-10). The primary seal of the injection zone is the Permian-aged Opeche Formation with the shales of the Permian-aged Spearfish, the Jurassic-aged Piper (Picard), Rierdon, and Swift Formations, all of which overly the Opeche Formation. Above the Swift is the confined saltwater aquifer system of the Inyan Kara Formation, which extends across much of the Williston Basin. Above the Inyan Kara are the Cretaceous-aged shale formations Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre. The Pierre Formation is the thickest shale formation in the area of investigation and the tertiary geologic barrier between the USDWs and the injection zone (refer to Section 2.4.2 for additional overlying confining layers of the storage reservoir). The geologic strata overlying the injection zone consists of multiple impermeable rock layers that are free of transmissive faults or fractures and provide adequate isolation of the USDWs from CO_2 injection activities in the area of investigation.

4.5 References

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5.0 TESTING AND MONITORING PLAN

5.0 TESTING AND MONITORING PLAN

Pursuant to North Dakota Administrative Code (NDAC) § 43-05-01-11.4, this testing and monitoring plan includes an analysis of the injected CO_2 stream, periodic testing of the injection wells, a corrosion monitoring plan for the CO_2 injection well components and surface facilities, a leak detection and monitoring plan for surface components of the CO_2 injection system, and a leak detection plan to monitor any movement of the CO_2 outside of the storage reservoir. As such, this plan simultaneously meets the permit requirements for two other required plans: 1) a surface/subsurface leak detection and monitoring plan (NDAC § 43-05-01-14) and 2) a corrosion monitoring and prevention plan (NDAC § 43-05-01-15).

The combination of the above monitoring efforts is used to verify that the geologic storage project is operating as permitted and is protecting all USDWs. An overview of these individual monitoring efforts is provided in Table 5-1 along with the target area that will be monitored.

A regular review of the monitoring program (i.e., a minimum of every 5 years) will be conducted to ensure that it remains appropriate for the site and is adequately tracking the injected CO_2, thereby providing an accurate assessment of the performance of the surface/subsurface equipment and subsurface geologic structures in containing the stored CO_2.

If needed, amendments to the monitoring program (i.e., technologies applied, frequency of testing, etc.) will be submitted for approval by the North Dakota Industrial Commission (NDIC). Results of pertinent analyses and data evaluations conducted as part of the monitoring program will be compiled and reported as required. Another goal of this monitoring program is to establish preinjection baseline data for the storage complex, including baseline data for soil gas, nearby groundwater wells, and the Fox Hills Formation (lowest USDW).

Additional details of the individual efforts of the monitoring program are provided in the remainder of this section.

Table 5-1. Overview of DGC's Testing and Monitoring Plan

Monitoring Type	Equipment/Testing	Target Area
Analysis of CO_2 Stream	Compositional and isotopic analysis of the CO_2 stream	CO_2 compressors at the capture facility
Wellsite Flowline Leak Detection System	H_2S detection stations, pressure gauges, and SCADA[1] system	Wellsite flowline to wellhead
Surface Corrosion	Ultrasonic testing of tubing test sections installed at wellheads	Wellsite flowline to well infrastructure
Downhole Corrosion	PMIT[2] and/or surface tubing inspection and USIT[3] (material wall thickness)	Downhole tubing and casing strings
Continuous Recording of Injection Pressure, Rate, and Volume	Flowmeters	Transmission line to well infrastructure
Well Annulus Pressure Between Tubing and Casing	Digital annular pressure gauges for continuous monitoring	Surface-to-reservoir (injection wells)
Internal and External Mechanical Integrity Testing	Tubing-casing annulus pressure testing (internal), USIT (internal and external) and temperature logs	Well infrastructure
Atmospheric	H_2S detection stations	Outside of wellhead enclosures
Near-Surface	Compositional and isotopic analysis of soil gas profile stations and dedicated Fox Hills[1] monitoring wells	Vadose zone and lowest USDW
Direct Reservoir	Pulsed-neutron logs with temperature and pressure readings, pressure falloff testing, and surface pressure gauges	Storage reservoir and dissipation intervals
Indirect Reservoir	Time-lapse 2D seismic surveys and vertical seismic profiles (VSPs)	Entire storage complex

[1] Supervisory Control and Data Acquisition
[2] Platform multifinger imaging tool.
[3] Ultrasonic imaging tool.

[1] The Fox Hills aquifer underlying the Great Plains CO_2 Sequestration Project site and western North Dakota is a confined aquifer system which does not receive measurable flow from overlying aquifers or the underlying Pierre Shale. The overlying confining layer in the Hell Creek Formation comprises impermeable clays, and the underlying Pierre Shale serves as the lower confining layer (Trapp and Croft, 1975). Recharge occurs hundreds of miles to the southwest in the Black Hills of South Dakota, where the corresponding geologic layers are exposed at the surface. Flow within the aquifer is to the east with a rate on the order of single feet per year. Thus groundwater in the Fox Hills aquifer at the Great Plains CO_2 Sequestration Project site is geochemically stable, as it is isolated from its source of recharge and does not receive other sources of recharge (Fischer, 2013). The aquifer itself is a quartz-rich sand and is not known to contain reactive mineralogy. Minimal geochemical variation can be expected to occur across the site, attributable to minor variations in the geologic composition of the aquifer sediments.

5.1 CO_2 Stream Analysis and Injection Well Mechanical Integrity Testing

5.1.1 CO_2 Stream Analysis

The CO_2 stream is analyzed daily at the capture facility, using methods and standards generally accepted by industry. The chemical content of the captured gas is 95.9 by volume percent CO_2 and 4.1 by volume percent other chemical components, as summarized in Table 5-2. The physical characteristics of the CO_2 stream, including its corrosiveness, temperature, and density are also measured daily at the capture facility.

Table 5-2. Chemical Content of the CO_2 Stream

Chemical Content	Volume Percent
Carbon Dioxide	95.9
C_2^+ and Hydrocarbons	1.8
Hydrogen Sulfide	1.2
Methane	0.6
Nitrogen	0.5
Total	100.0

5.1.2 Injection Well Mechanical Integrity Testing

A USIT, in combination with variable density and cement bond logs, was used to establish the baseline external mechanical integrity in the Coteau 1 well. The same suite of logging tools will also establish baseline conditions in the other injection wells, and the USIT will be run during well workovers but not more frequently than once every 5 years. Baseline temperature data will also be collected prior to operations and will be regularly performed using a phased approach (described in the following paragraph) to verify external mechanical integrity in the injection wells.

DGC's phased approach: pulsed-neutron logs (PNLs), which include a temperature log and bottomhole pressure (BHP) readings, will be run in an individual injection well quarterly. Each injection well will be placed on a rotating schedule to gather these downhole data, starting with Coteau 1 in the first quarter, Coteau 2 in the second quarter, Coteau 3 in the third quarter, and Coteau 4 in the fourth quarter, at which point the rotation will be repeated. Once drilled, the Coteau 5 and Coteau 6 wells will be added to the rotating schedule and the frequency adjusted to a bimonthly basis.

A BHP survey will be acquired each month during the first quarter of operations to supplement the phased approach described above. These supplemental BHP readings will confirm that the wellhead pressure (WHP):BHP correlation (pressure gradient) is accurate and reliable. If the WHP:BHP correlation is reconciled with the BHP data in the first quarter, BHP surveys will continue to be acquired at the frequency and schedule described in the phased approach.

Internal mechanical integrity of the injection wells will be demonstrated via tubing-casing annulus pressure tests prior to injection and during well workovers but not more frequently than

once every 5 years. Pressure falloff tests will be performed in the injection wells prior to injection. During injection operations, pressure falloff testing will be carried out via surface pressure monitoring at least once every 5 years to demonstrate storage reservoir injectivity. In addition, the injection wells will be continuously monitored for surface and annular pressure anomalies by maintaining a consistent 200 pounds per square inch on the annulus with a nitrogen cushion that will be placed and maintained on top of the packer fluid. USITs may be run during workovers (including when tubing is pulled) but not more frequently than once every 5 years, to further assess the internal mechanical integrity of the injection wells.

5.2 Corrosion Monitoring and Prevention Plan

The purpose of the corrosion monitoring and prevention plan is to monitor the surface facilities and injection well components during the operational phase of the Great Plains CO_2 Sequestration Project to ensure that the materials meet the minimum standards for material strength and performance. Figure 5-1 illustrates the pad drawings for the Coteau 1 through Coteau 4 wells.

DGC permitted a new 6.8-mile-long transmission line through the North Dakota Public Service Commission (PSC) in July 2021 (PU-21-150). The transmission line implements a corrosion monitoring and prevention strategy that was approved by PSC and is not discussed in this storage facility permit application. At the transition from transmission line to flowline (Figure 5-2), DGC's efforts to monitor and prevent corrosion of the flowline and well materials at the injection wellsites are presented in Sections 5.2.1 and 5.2.2.

5.2.1 Corrosion Monitoring

DGC will install a 3-foot test section of 4½-inch L-80 tubing in the flowlines near each wellhead for regular testing and corrosion monitoring of the well material. The tubing joints will be inspected monthly via ultrasound equipment during the first quarter, then quarterly thereafter for the first 2 years. If the well materials (i.e., tubing) show no sign of corrosion within the first 2 years of the injection period, future internal monitoring of the tubing will be accomplished through a platform multifinger imaging tool (PMIT), or in the event a downhole tubing string is pulled for any reason, it will be inspected at the surface for corrosion and mechanical integrity. USITs may also be run during workovers (including when tubing is pulled), but not more frequently than once every 5 years, to further assess any corrosion of the injection string.

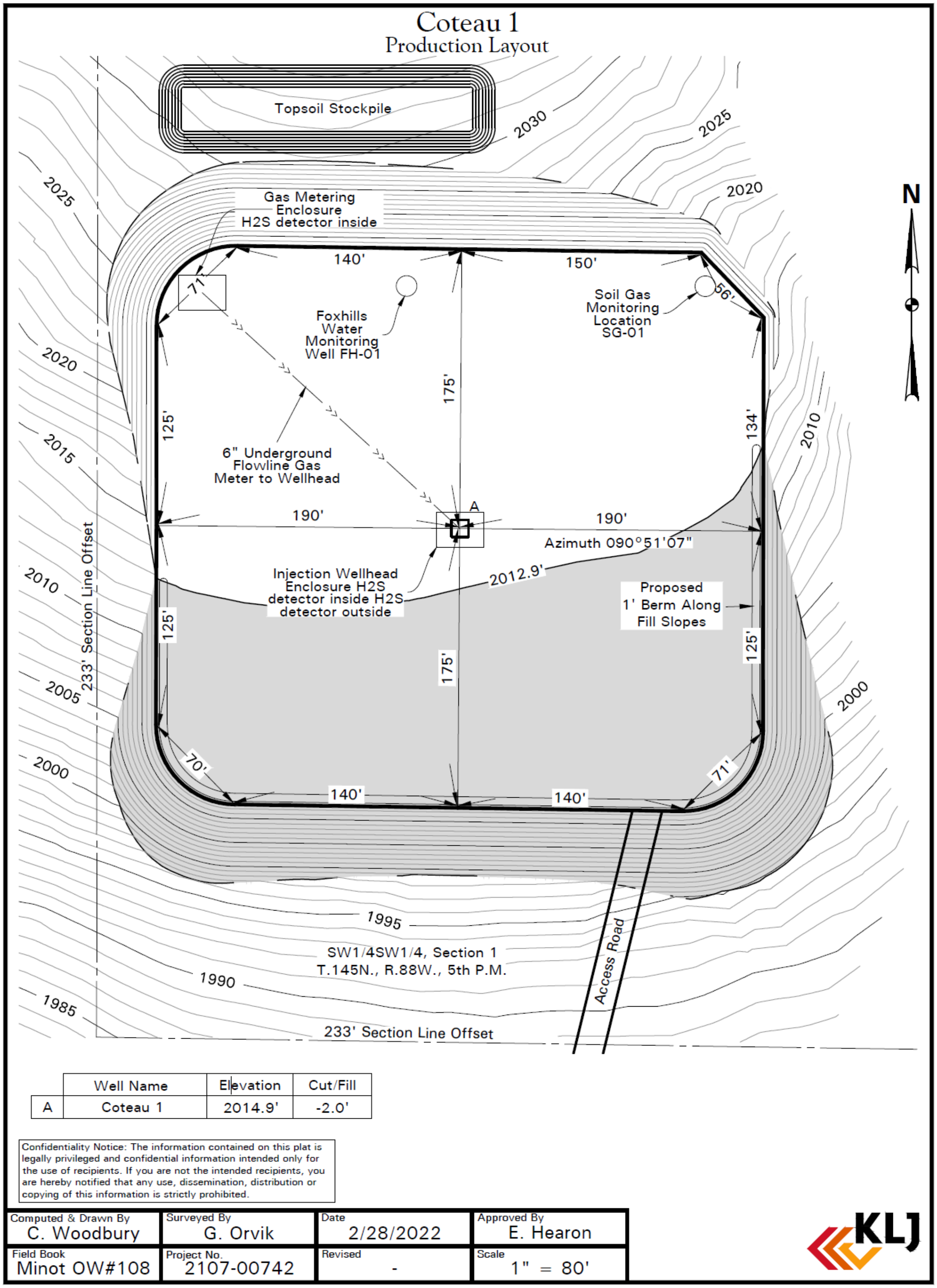

Figure 5-1A. Well pad drawing of the Coteau 1 well location.

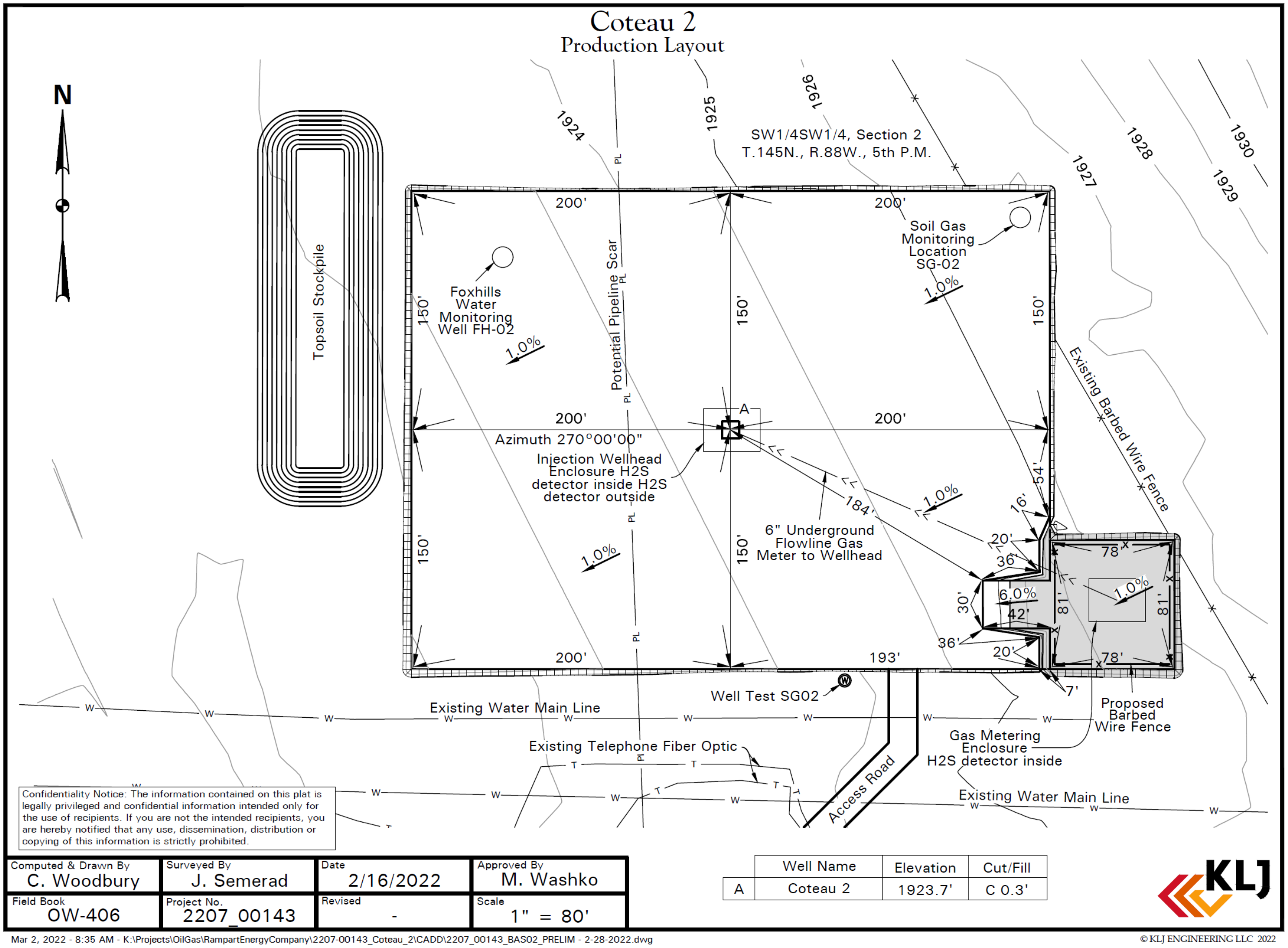

Figure 5-1B. Well pad drawing of the Coteau 2 well location.

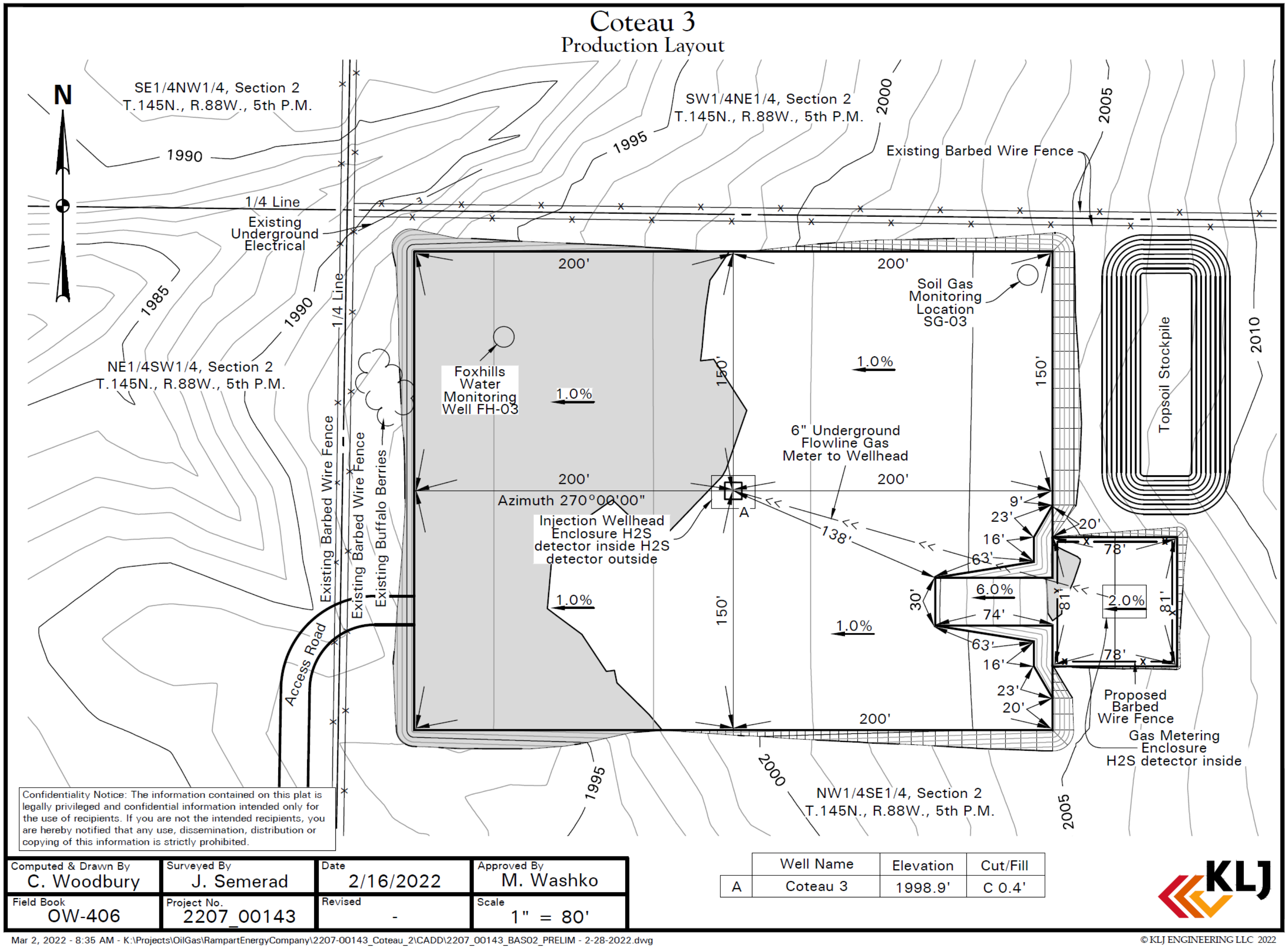

Figure 5-1C. Well pad drawing of the Coteau 3 well location.

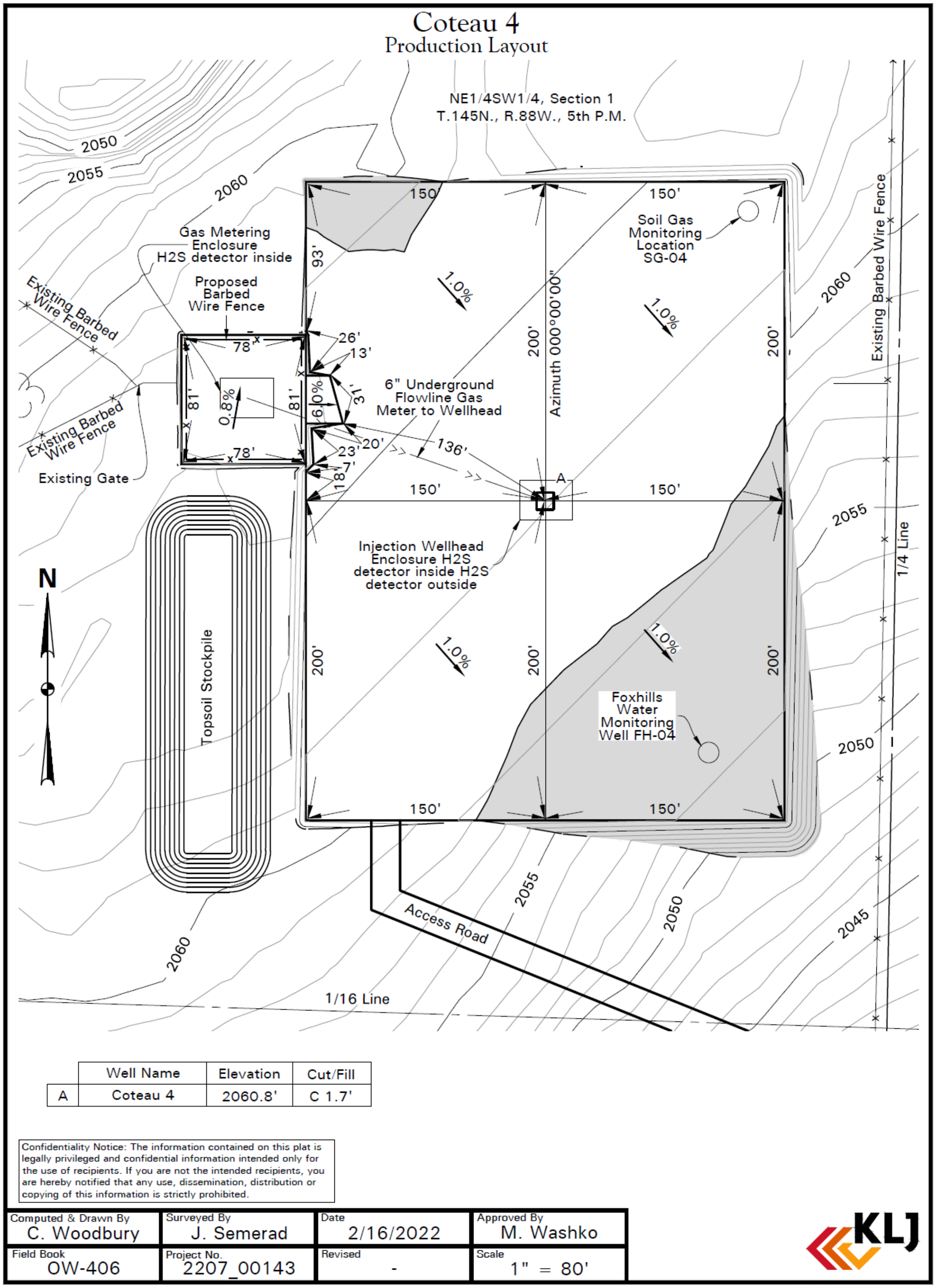

Figure 5-1D. Well pad drawing of the Coteau 4 well location.

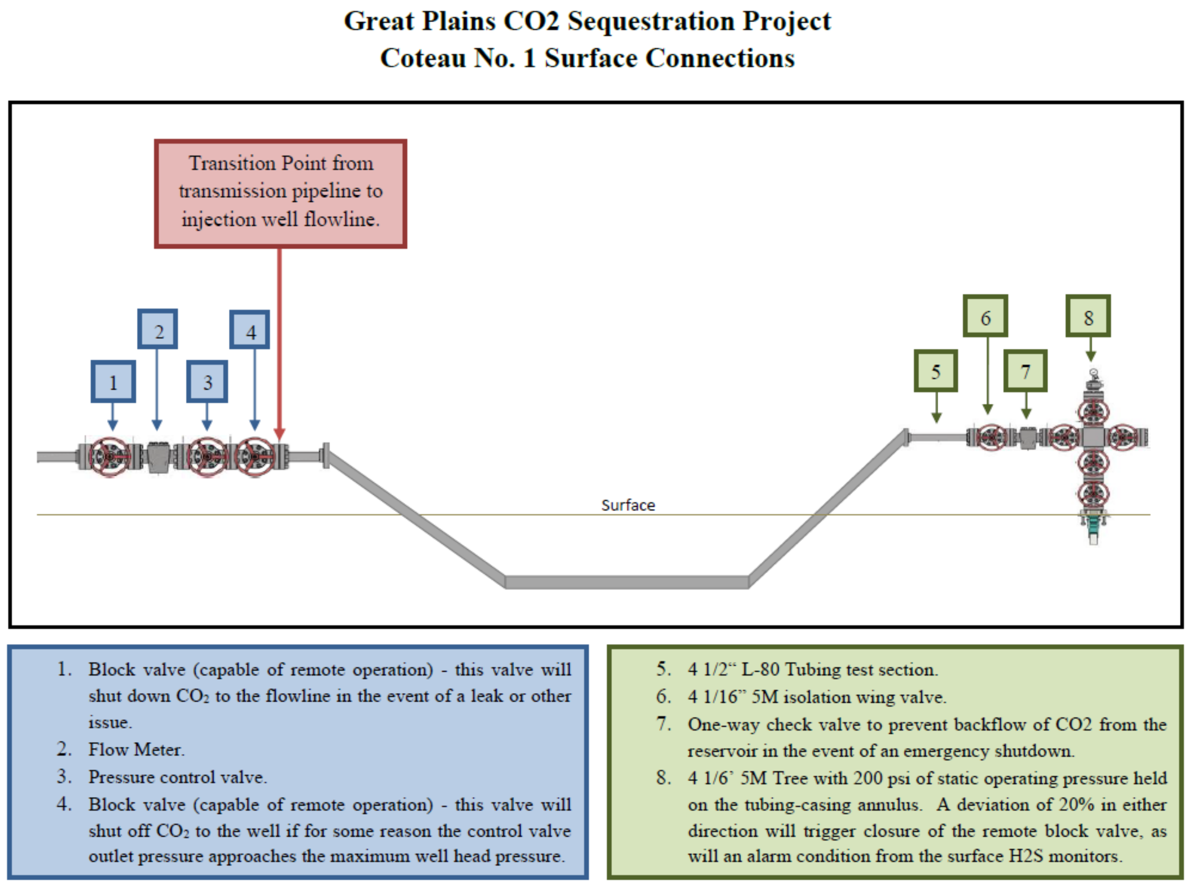

Figure 5-2. Diagram of surface connections at the Coteau 1 wellsite. The Coteau 2 through 5 wells will connect to a common gathering system at the Coteau 1 well pad. The Coteau 6 will be similarly equipped but will connect to a separate gathering system. The primary block valve (item 1 above) will be located at the Coteau 1 well while the rest of the equipment (Items 2 through 8 above) will be located on the well pads of each of the injection wells.

5.2.2 Corrosion Prevention

To prevent corrosion of the well materials, the following preemptive measures will be taken: 1) cement in the injection wells opposite the injection interval and extending more than 2,000 feet uphole will be CO_2-resistant, 2) the well casing (L-80 13Cr) will also be CO_2-resistant from the bottomhole to a depth just above the Opeche Formation in the injection wells, and 3) the packer fluid will be an industry standard corrosion inhibitor. In addition, the chemical composition of the CO_2 stream is highly pure (Table 5-2) and dry, with a moisture level for the CO_2 stream typically less than two parts per million by volume, both factors of which help to prevent corrosion of the surface and well materials.

5.3 Surface Leak Detection and Monitoring Plan

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. Performance targets designed for the Great Plains CO_2 Sequestration Project to detect potential leaks in the flowline are provided in Table 5-3. The performance targets are dependent upon the actual performance of instrumentation (e.g., pressure gauges) and the supervisory control and data acquisition (SCADA) system, which uses software to track the status of the pipeline system in real time by comparing live pressure and flow rate data to a comprehensive predictive model. The performance targets assume a flow rate of 200 million standard cubic feet per day (MMSCFD) of CO_2. An alarm will trigger on the SCADA system if a volume deviation of more than 2% is registered. H_2S detection stations will also be mounted on the inside and outside of wellhead enclosures to detect any potential indoor and atmospheric leaks at the well pad locations, respectively. The stations can detect H_2S concentrations as low as 1 part per million (ppm) and have an integrated alarm system if a 10 ppm threshold is crossed. The stations are further described in Appendix C (Attachment A-7). Field personnel will have multi gas detectors with them for wellsite visits or flowline inspections to detect potential leaks from the equipment. The multi gas detectors will primarily monitor for CH_4, CO, O_2, and H_2S up to 100 feet from a surface leakage source. The multi gas detector will measure H_2S as low as 0.1 ppm with an incremental resolution of 0.1 ppm and has built-in alarms. Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

Table 5-3. Performance Targets for Detecting Potential Leaks in Surface Equipment with SCADA

Leak Size (MMSCFD)	Detection Time (minutes)
200	<2
>10	<5
<10 and >4	<60

5.4 Subsurface Leak Detection and Monitoring Plan

The monitoring plan for detecting subsurface leaks comprises "surface/near-surface" and deep subsurface monitoring programs. "Surface/near-surface" refers to the region from ground surface down to, and including, the lowest USDW as well as surface waters, soil gas (vadose zone), and shallow groundwater (e.g., stock wells, residential drinking water wells, etc.). The deep subsurface zone extends from the base of the lowest USDW to the base of the injection zone of the storage reservoir.

Subsurface leak detection will include multiple approaches to ensure confidence that surface (i.e., ambient and workspace atmospheres and surface waters) and near-surface (i.e., vadose zone, groundwater wells, and the lowest USDW) environments are protected, and the CO_2 is safely and permanently stored in the storage reservoir. More specifically, for DGC's geologic storage project, near-surface monitoring will include 11 soil gas profile stations and seven dedicated Fox Hills Formation monitoring wells within the AOR to detect if the lowest USDW is being impacted by operations. These monitoring efforts will provide additional lines of evidence to assess whether the surface/near-surface environment is being protected and whether the CO_2 is being safely and permanently stored in the storage reservoir.

To complement surface/near-surface monitoring, additional monitoring of the subsurface will ensure CO_2 is staying in the targeted storage reservoir. Operational monitoring at the injection wells, including injection rates, pressures, and temperatures will provide data to inform the monitoring approaches. Internal and external mechanical integrity of the injection wells will also be demonstrated to ensure no leakage pathway exist that may allow vertical movement of the CO_2. Additionally, geophysical (seismic) surveys conducted over regular intervals will monitor subsurface CO_2 plume movement.

More details regarding the surface, near-surface, and deep subsurface monitoring efforts are provided in sections 5.5 through 5.7.

5.5 Near-Surface Soil Gas and Groundwater Sampling and Monitoring

Near-surface environments will be monitored to ensure that an out-of-zone migration has not occurred. This will be accomplished by monitoring the environment within the delineated AOR via vadose zone soil gas and Fox Hills (lowest USDW) sampling prior to CO_2 injection (preoperational baseline), during active CO_2 injection (operational), and during the postoperational monitoring time frame. Figure 5-3 illustrates the baseline sampling program for vadose zone and groundwater in the Fox Hills Formation. In addition, baselines for shallow groundwater aquifers within the AOR, which may be used in the future to monitor the geologic storage project area, are included in Appendix B.

DGC initiated a seasonal baseline sampling program for soil gas (Figure 5-3) and plans to complete this part of the baseline program by July 2022. Eleven soil gas profile stations have been installed: one station near each wellsite (Coteau 1 through 6 wells) and five more spaced apart and located around the edge of the predicted 12-year CO_2 plume extent. Sample analysis of each profile station will be provided to NDIC prior to CO_2 injection operations. This initial sampling program and the results are provided in detail in Section 5.5.1.

DGC initiated a baseline groundwater sampling program in the Fox Hills Formation in the Fred Art/Oberlander #1, Floyd Weigum #1, and Helmuth Pfenning #2 wells (Figure 5-3). Upon field investigation, it was found that the Floyd Weigum #1 was abandoned and could not be sampled; therefore, its historical data will be used as a baseline instead. Archived water quality analyses on all three wells are available in Appendix B.

Prior to injection, DGC will install six dedicated Fox Hills Formation monitoring wells at each injection wellsite (Coteau 1 through 6 wells). A seventh Fox Hills Formation monitoring well will be placed along the western edge of the AOR near the Herrmann 1 well (NDIC File No. 4177). A state-certified laboratory analysis will be provided to NDIC prior to injection for all additional groundwater sampling in the Fox Hills Formation. This initial sampling program and the results are provided in detail in Section 5.5.2.

The near-surface monitoring plan, including the additional baseline sampling of groundwater, the Fox Hills Formation, and the soil gas profile stations, is provided in Section 5.6.

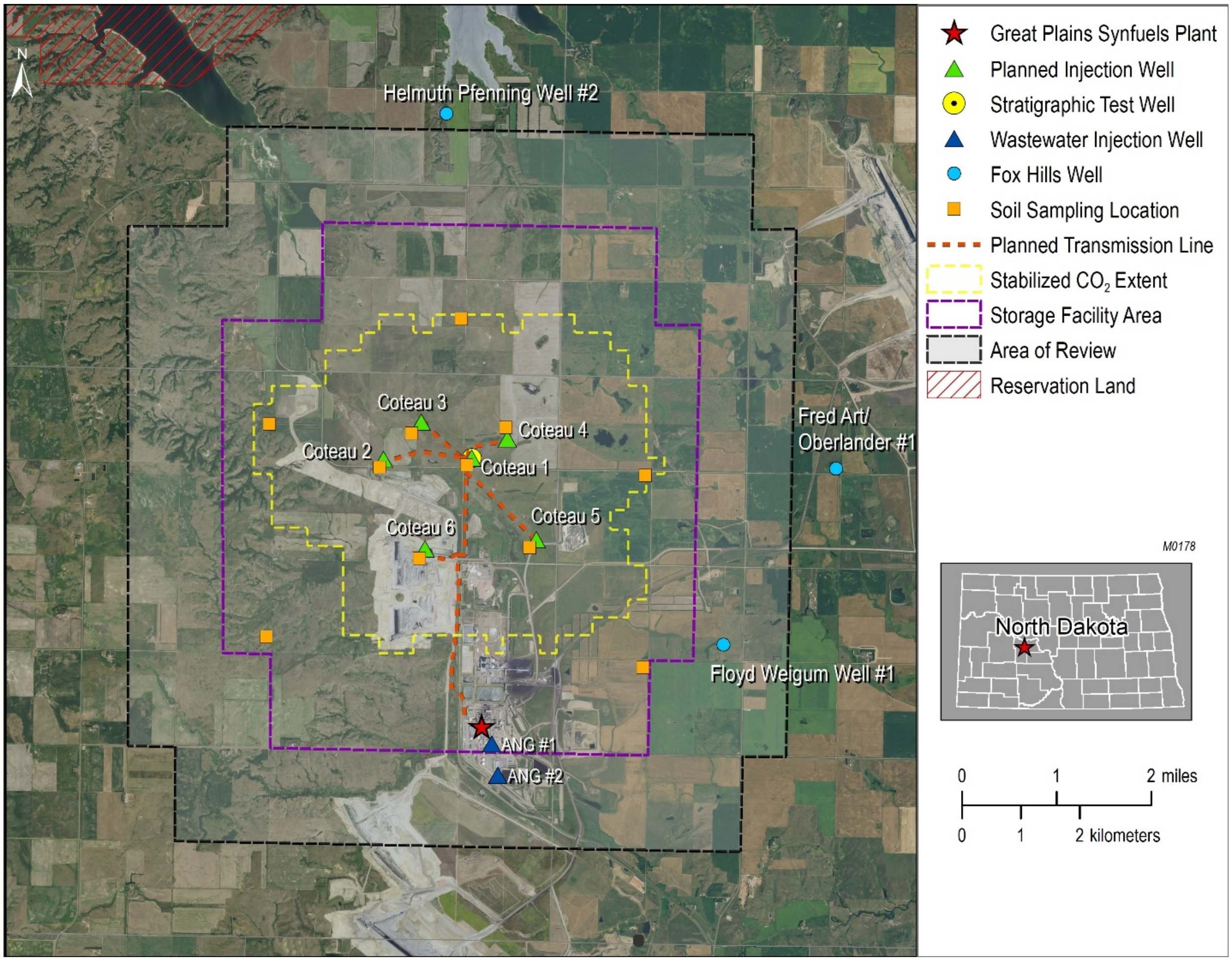

Figure 5-3. DGC's initiated baseline sampling program for vadose zone soil gas and groundwater in the Fox Hills Formation.

5.5.1 Soil Gas Baseline Sampling

Soil gas sampling and analyses have been initiated to establish seasonal baseline soil gas geochemical results, including concentrations of CO_2, O_2, and N_2 and isotopic ratios for $^{13}CO_2$, $^{13}C_1$, and δC_1. An initial set of samples and associated analyses were collected in October and November 2021, as shown in Table 5-4.

The sampling results from these efforts will provide a preoperational seasonal baseline of the soil gas geochemistry in the vadose zone in and around the CO_2 geologic storage project. DGC plans to sample and run analyses on the soil gas profile stations quarterly until July 2022. During operations, DGC will continue to collect soil gas concentrations quarterly from the 11 soil gas profile stations.

Table 5-4. DGC's Initial Soil Gas Geochemical Results – Fall 2021

Well No.	CO_2, ppm	O_2+Ar, ppm	N_2, ppm	$\delta^{13}CO_2$, ‰ VPDB[1]	$\delta^{13}C_1$, ‰ VPDB	δD_{C1}, ‰ VSMOW[2]
SG01[3]	305,420	16,923	685,166	−14.0	−13.1	−376
SG02[4,5]	2,402	194,468	796,541	−20.3		
SG03	193,032	27,421	786,850	−14.7		
SG04	209,353	11,773	784,351	−6.7		
SG05	202,316	51,148	760,674	−1.1		
SG06[4]	21,158	162,573	817,003	−20.5		
SG07[4,5]	2,582	215,422	781,419	−22.0		
SG08	213,591	13,855	781,768	−18.8		
SG09	135,306	13,292	863,995	−17.8		
SG10	158,590	89,475	767,489	−18.4		
SG11[4]	9,822	203,018	787,739	−17.1		

1 Vienna Pee Dee Belemnite $\delta^{13}C$ Standard.
2 Vienna Standard Mean Ocean Water.
3 Single well in data set with sufficient volume of measured methane levels to run stable isotope analysis.
4 Because of local variations in the water table, wells SG02, SG06, SG07, and SG11 were limited to sample depths from 4 to 9 feet below ground surface (bgs). All other locations obtained samples from 22 to 23 feet bgs.
5 Low isotopic signal results.

5.5.2 Groundwater Baseline Sampling

Two Fox Hills Formation samples were obtained in November 2021 from the Fred Art/ Oberlander #1 and Helmuth Pfenning #2 wells. State-certified laboratory results for these two wells found in Appendix B show little variation among the reports.

The locations of the wells investigated for establishing baseline conditions are shown in Figure 5-3, and the results of the baseline measurements for pH, specific conductivity, and alkalinity are provided in Table 5-5, with state-certified laboratory results for each sampling event provided in Appendix B. In addition, DGC plans to obtain a baseline water sample from the Fox Hills monitoring well that will be drilled near the Herrmann 1 well (NDIC File No. 4177) prior to injection operations.

Table 5-5. DGC's Initial Baseline Groundwater Sampling Results – Fall 2021

Well Name	pH (pH unit)	Conductivity, µmhos/cm	Total Alkalinity, mg/L $CaCO_3$
Fred Art/Oberlander #1	8.5	2519	1020
Helmuth Pfenning #2	8.4	2347	1280
Floyd Weigum #1*	N/A	N/A	N/A

* Wellbore was confirmed in the field to be abandoned and determined inaccessible for sampling.

5.6 Near-Surface (groundwater and soil gas) Monitoring Plan

Prior to injection operations, DGC will drill and construct a total of five dedicated groundwater monitoring wells in the Fox Hills Formation (i.e., lowest USDW). One groundwater monitoring well will be placed at each of the injection well locations (Coteau 1 through 4 wells initially) and another will be placed near the Hermann 1 well (NDIC File No. 4177) (Figure 5-4). Baseline Fox Hills Formation water samples will be collected from all five monitoring wells prior to CO_2 injection. Dedicated Fox Hills Formation monitoring wells will also be drilled and constructed for the Coteau 5 and the Coteau 6 injection wells after they are drilled and constructed prior to 2026. DGC plans to monitor the vadose zone using the 11 soil gas profile stations already installed.

Over the life of CO_2 injection activities, the 11 soil gas profile stations will be sampled quarterly along with the Fox Hills groundwater monitoring wells located near each of the injection wells. State-certified laboratory results of the groundwater wells will be filed with NDIC. A detailed near-surface monitoring plan is presented in Table 5-6, including the duration and frequency of the sampling that will be made during each phase (i.e., preinjection, operational, and postoperational) of the geologic CO_2 storage project.

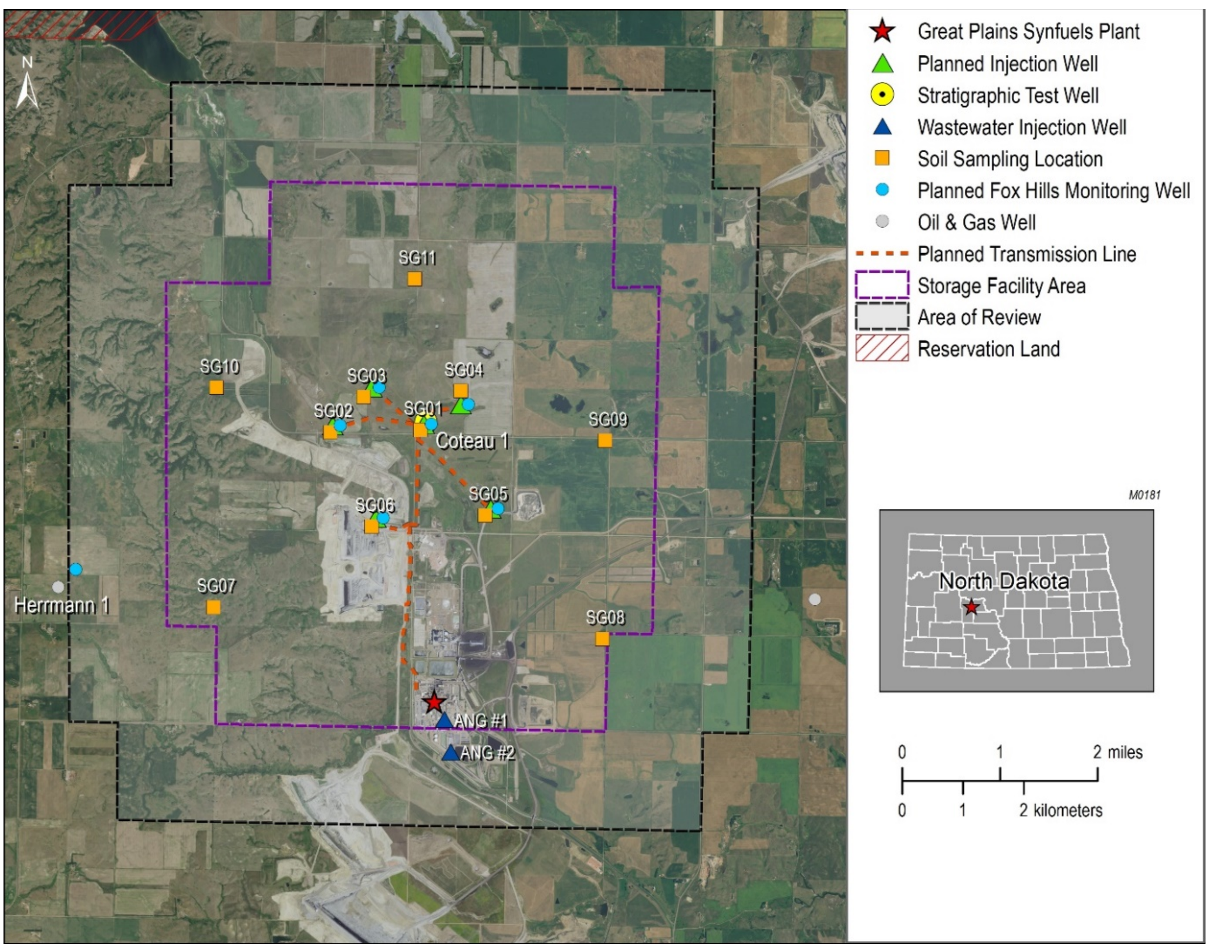

Figure 5-4. DGC's near-surface monitoring plan for seven Fox Hills Formation (lowest USDW) monitoring wells and the 11 soil gas profile stations around the storage facility area.

Table 5-6. Baseline (preinjection), Operational, and Postoperational Monitoring Duration and Frequency for Soil Gas and Groundwater

Monitoring Type	Baseline (preinjection)*	Operational	Postoperational
Soil Gas Monitoring			
Soil Gas Profile Stations (SG01 to SG11) (Figures 5-3 and 5-4)	Duration: Minimum one year Frequency: Sample 3–4 events per well to establish seasonal baseline Perform concentration and isotopic testing on all samples	Duration: 12 years Frequency: Sample 3–4 events per year to account for seasonal fluctuation Perform concentration testing on all samples	Duration: Minimum 10 years postinjection Frequency: Sample 3–4 events per year Perform concentration testing on all samples
Groundwater Monitoring			
Fred Art/Oberlander #1 and Helmuth Pfenning #2 (Figure 5-3) Fox Hills monitoring well by Herrmann 1 (Figure 5-4)	Duration: Prior to injection to establish baseline and verify historic geochemical data Frequency: Once to establish a baseline and verify consistency of historical well test data (Appendix B) Perform water quality and isotopic testing on all samples	None Shift sampling program to the dedicated Fox Hills monitoring wells	None
Six monitoring wells in the Fox Hills Formation (lowest USDW) at injection wellsites (Coteau 1 through 6 wells) (Figure 5-4)	Duration: Prior to injection Frequency: Sample 3–4 events per well annually Perform water quality testing on all samples	Duration: 12 years Frequency: Sample 3–4 events per well annually Perform water quality testing on all samples	Duration: Minimum 10 years postinjection Frequency: Sample 3–4 events per well annually Perform water quality testing on all samples

* The baseline (preinjection) monitoring effort has begun as of the writing of this permit application. As noted in the text, additional sampling will be performed between the submission date of this permit application and the start of CO_2 injection.

5.7 Deep Subsurface Monitoring of Free-Phase CO_2 Plume and Pressure Front

DGC will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume and associated pressure relative to the permitted storage reservoir. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and postoperational periods. The methods described in Table 5-7 will be used to characterize the plume and pressure within the AOR. DGC will employ an adaptive management approach to implementing the testing and monitoring plan by completing periodic reviews of the testing and monitoring plan (Ayash and others, 2017). During each review, monitoring and operational data will be analyzed, the AOR will be reevaluated, and if warranted, the testing and monitoring plan will be adjusted accordingly. The testing and monitoring plan will be reviewed in this manner at least once every 5 years. Based on this review, it will either be demonstrated that no amendment to the testing and monitoring program is needed or that modifications to the program are necessary to ensure proper monitoring of the storage performance is achieved and that the risk profile of the storage operations is addressed moving forward. This determination will be submitted to NDIC for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by NDIC. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.

Monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of the CO_2 plume and pressure distribution relative to the permitted geologic storage facility. If significant variance is observed, the monitoring and operational data will be used to calibrate the geologic model and associated simulations. The monitoring plan will be adapted to provide suitable characterization and calibration data as necessary to achieve such conformance. Subsequently, history-matched predictive simulation and model interpretations will, in turn, be used to inform adaptations to the monitoring program to demonstrate lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

Table 5-7. Description of DGC's Deep Subsurface Monitoring Program

Monitoring Type	Preoperational (baseline)	Operational	Postoperational
Mechanical Integrity Testing (MIT)			
USIT (external MIT)	Prior to injection	Duration: 12 years Frequency: Perform when tubing is pulled but not more frequently than once every 5 years.	None Injection wells will be plugged.
Temperature Logs Run with PNL (external MIT)	Prior to injection	Duration: 12 years Frequency: Quarterly using phased approach described in Section 5.1.2	None Injection wells will be plugged.
200 psi Kept on Annulus, Between Tubing and Long-String (multifinger imaging tool [internal MIT])	Prior to injection Initial volume of packer fluid (corrosion inhibitor) and nitrogen cushion to fill casing	Duration: 12 years Frequency: Continuous Nitrogen cushion will be used to maintain a consistent pressure.	None Injection wells will be plugged.
Tubing-Casing Annulus Pressure Testing (internal MIT)	Prior to injection	Duration: 12 years Frequency: Perform during well workovers but not more frequently than once every 5 years.	None Tubing will be pulled from the injection wells, and the injection wells will be plugged.
Pressure Falloff Test in the Injection Zone (internal MIT)	Prior to injection	Duration: 12 years Frequency: Once every 5 years	None Injection wells will be plugged.
Storage Reservoir (Direct) Monitoring			
Flow Rate and Volume, Surface Injection Pressure, and Surface Injectate Temperature	At start of injection operations	Duration: 12 years Frequency: Continuous monitoring	None Injection operations will have ceased.
PNLs with Temperature Logs and Pressure Recording Devices Attached	Prior to injection	Duration: 12 years Frequency: Quarterly, using phased approach described in Section 5.1.2	None Injection wells will be plugged.

Continued…

Table 5-7. Description of DGC's Deep Subsurface Monitoring Program (continued)

Monitoring Type	Baseline (preoperational)	Operational	Postoperational
Surface Pressure Gauges on the ANG #1 and ANG #2	None	Duration: 12 years Frequency: Continuous monitoring of surface pressures to history match predictions	Duration: Minimum 10 years postinjection Frequency: Continuous monitoring of surface pressures to history match predictions
Above-Zone Monitoring Interval (AZMI)			
PNLs with Temperature Logs Attached	Prior to injection	Duration: 12 years Frequency: Quarterly, using phased approach described in Section 5.1.2	None Injection wells will be plugged.
Geophysical (Indirect) Monitoring			
Time-Lapse Seismic (Figure 5-7)	Prior to injection Collect baseline 2D seismic survey	Repeat 2D seismic one year after injection begins, then in Years 3, 5, and 10.	Time-lapse seismic surveys will continue as part of minimum 10-year postinjection monitoring plan and until stability of plume is demonstrated. Frequency: Perform 2D radial seismic surveys at the cessation of CO_2 injection, 1 year after injection ends, then in Years 3, 5, and 10
VSPs	Prior to injection	Repeat VSP 1 year after injection begins, then (if deemed beneficial) in Years 3, 5, and 10.	None

Table 5-8 describes the testing and logging program developed for the Coteau 1 wellbore. Included in the table is a description of fluid sampling and pressure testing performed. The logging and testing program for the Coteau 2 through 6 wells will be the same as what is presented in Table 5-8 but without the combinable magnetic resonance and dipole sonic logs. Wellbore data collected from the Coteau 1 have been integrated with the geologic model and to inform the reservoir simulations that are used to characterize the initial state of the reservoir before injection operations. The simulated CO_2 plumes based on the current geologic model and simulations are shown in Figures 5-5 and 5-6. These simulated CO_2 plume extents inform the timing and frequency of the application of the direct and indirect monitoring methods of the testing and monitoring plan.

Table 5-8. Testing and Logging Program for the Coteau 1 Wellbore

Log/Test	Justification	NDAC Section
Ultrasonic, CCL (casing collar locator), VDL (variable-density log), GR (gamma ray)	Identified cement bond quality radially. Interpreted good azimuthal cement coverage. Evaluated the cement top and zonal isolation.	43-05-01-11.2(1c[2])
Triple Combo (resistivity, density, porosity, GR, caliper, and spontaneous potential)	Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. Provided input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve test design and interpretations.	43-05-01-11.2(1c[1])
Combinable Magnetic Resonance (CMR)	Aided in interpreting reservoir permeability, packer setting depths, and stress testing depths. CMR and MDT data combined provided enhanced permeability evaluation, temperature variation, fluid identification, and fluid contacts.	43-05-01-11.2(1c[1])
Spectral GR	Identified clays and lithology that could affect injectivity. Also used for core to log depth correlation.	43-05-01-11.2(2)
Dipole Sonic	Identified mechanical properties including stress anisotropy. Provided compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.	43-05-01-11.2(1c[1])
Fracture Finder Log	Quantified fractures in the Broom Creek Formations and confining layers to ensure safe, long-term storage of CO_2.	43-05-01-11.2(1c[1])
Perforation-Flowback	Collected fluid sample and pressure-tested the Broom Creek	43-05-01-11.2(2)

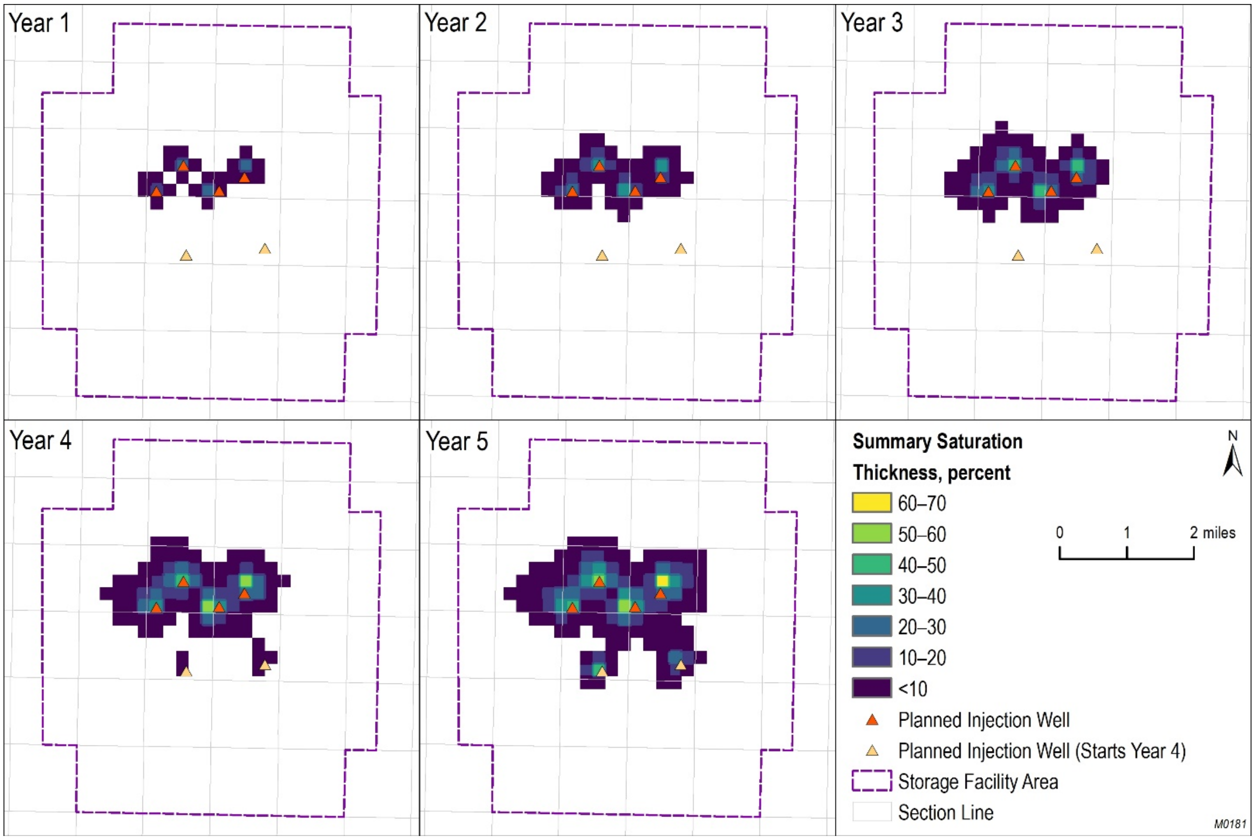

Figure 5-5. Simulated CO_2 plume saturation at the end of Years 1 through 5 after initial CO_2 injection. The simulated plume extent at 5 years (5.3 square miles) results in a CO_2 plume with an average radius of 6,442 feet.

Figure 5-6. Simulated extent of the CO_2 plume at the cessation of injection and the postinjection stabilized plume.

5.7.1 Direct Monitoring Methods

To directly monitor and track the extent of the CO_2 plume within the storage reservoir, PNLs with temperature logs and pressure data will be performed quarterly in the injection wells using the phased approach described in Section 5.1.2 of this storage facility permit The temperature and saturation data collected in the overlying Inyan Kara Formation, the nearest overlying, highly permeable interval above the storage reservoir and main sealing formations, will provide confirmation of seal capacity for the upper confining zone (i.e., Opeche Formation) for monitoring the performance of the storage complex (see Figure 2-3 for stratigraphic reference). Monitoring of the overlying interval can provide an early warning of out-of-zone migration of fluids, providing sufficient time for the development and implementation of mitigation strategies to ensure these migrating fluids do not impact a USDW or reach the surface.

Preoperational baseline PNL data have been collected from the Coteau 1 well. These time-lapse saturation data will be used to monitor for CO_2 in the formation directly above the storage reservoir, otherwise known as the AZMI, as an assurance-monitoring technique.

5.7.2 Indirect Monitoring Methods

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 2D geophysical surveys and 2D VSPs (Figure 5-7). The 2D seismic acquisition lines indicated in Figure 5-7 will be extended over time to capture additional data as the CO_2 plume expands. Figure 5-8 illustrates the predicted extent of the injected free-phase CO_2 plume at the end of 12 years of injection relative to the baseline 2D seismic and storage facility area. To demonstrate conformance between the reservoir model simulation and site performance, a repeat 2D seismic survey and VSP will be collected to monitor the extent of the CO_2 plume after approximately 1 year of CO_2 injection. Additional 2D seismic data will be collected in Years 3, 5, and 10 to further delineate the CO_2 plume movement. Additional VSPs will be collected at the same frequency as the 2D seismic lines if the results of the first and second tests prove beneficial. These seismic monitoring data will provide confirmation of the simulation predictions and confirm the extents of the CO_2 plume within the AOR. Through the operational phase of the project, the time-lapse seismic monitoring plan will be adapted based on updated simulations of the predicted extents of the CO_2 plume. At the end of the operational phase, time-lapse seismic will be utilized during the postinjection period to confirm the stabilization of the CO_2 plume. These indirect monitoring methods for characterization of the deep subsurface CO_2 plume are commercially available and are proven time-lapse methods.

At the conclusion of the operating phase of the project, the planned monitoring program will continue to ensure the long-term containment and stability of the injected CO_2 in the storage complex (Table 6-1). Monitoring efforts in the postinjection phase will provide the data necessary for the required final assessment to prove long-term containment and stability of the injected CO_2 plume and secure a certificate of project completion from NDIC.

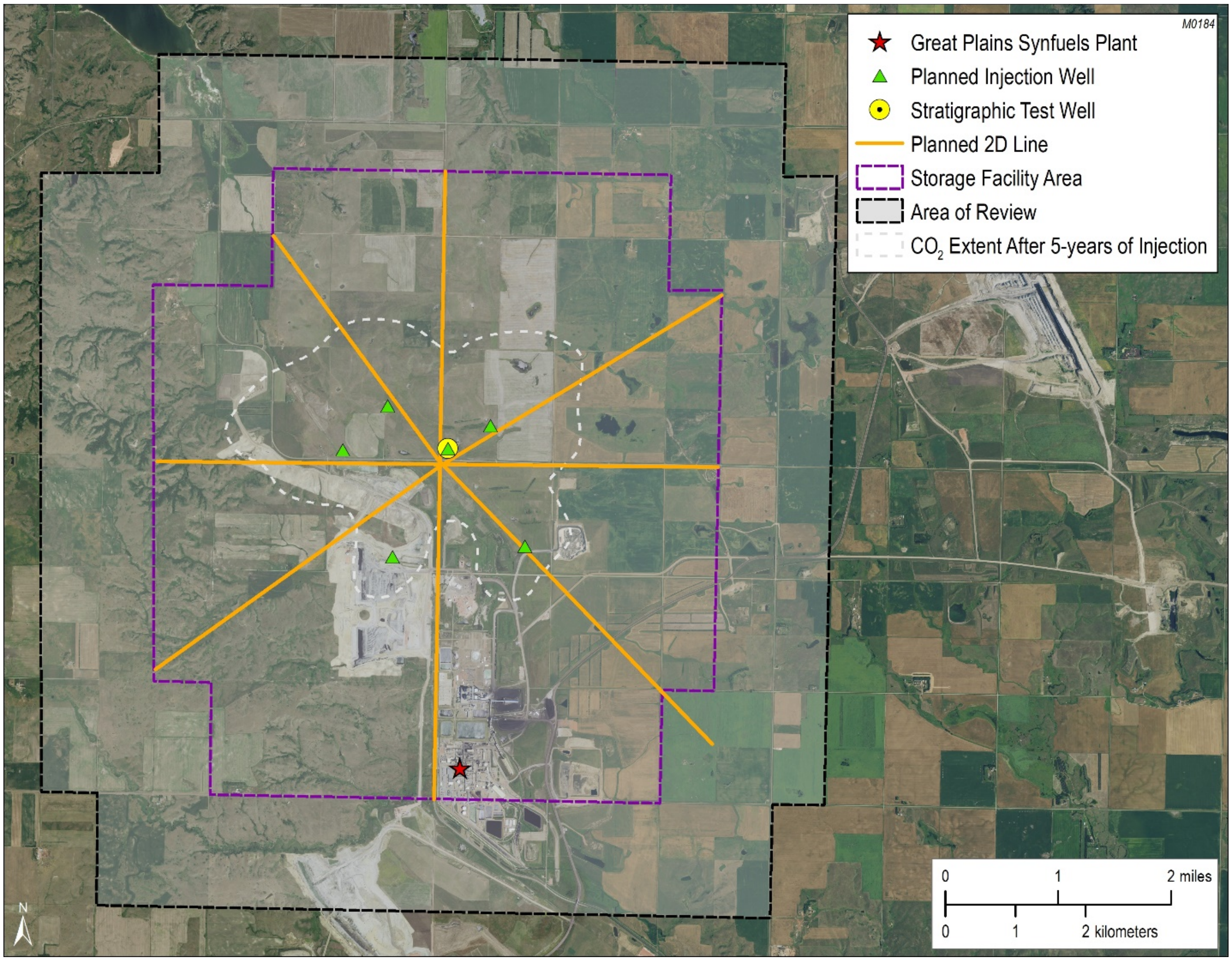

Figure 5-7. Locations of the planned 2D radial seismic lines near the Coteau 1 well to establish a baseline.

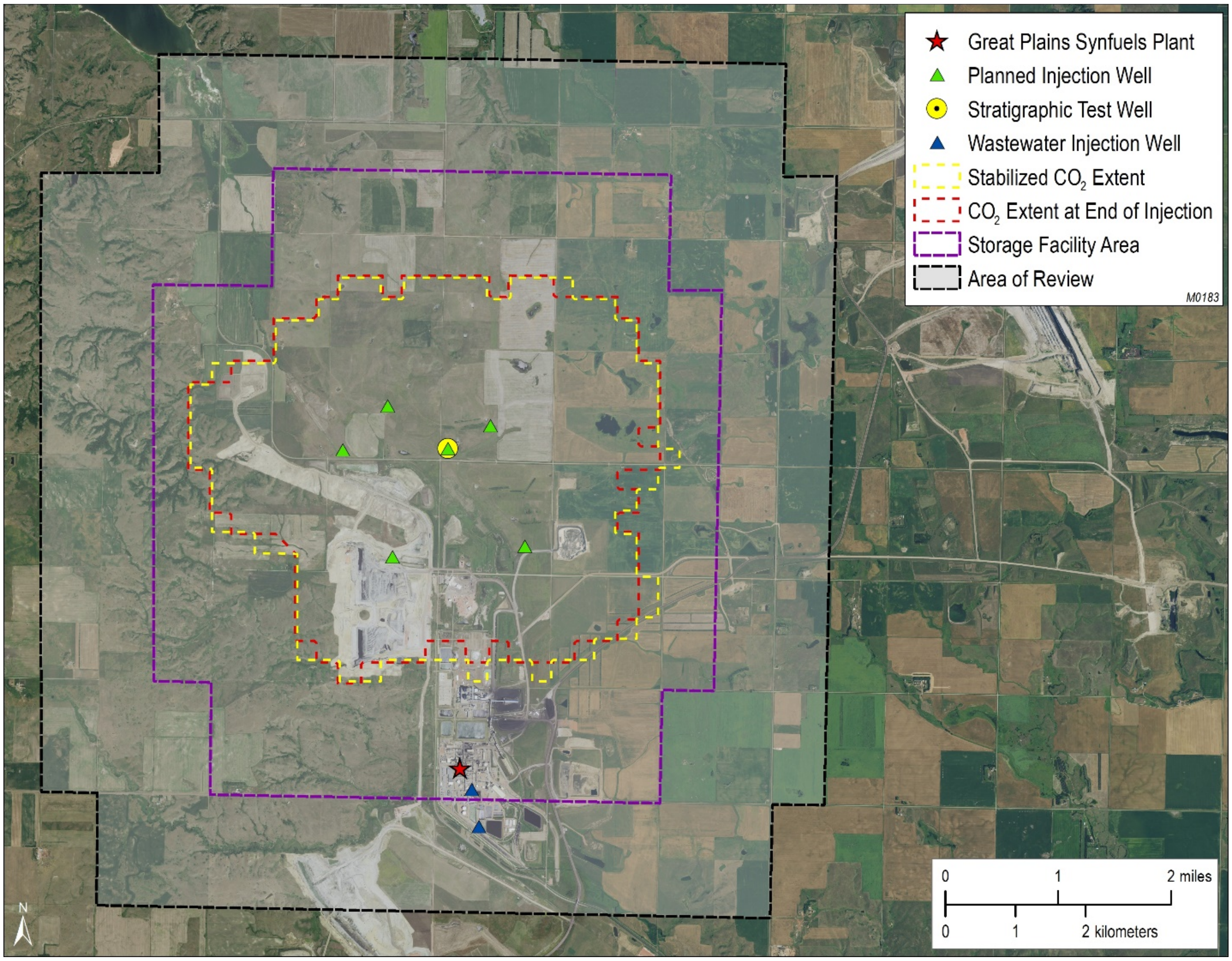

Figure 5-8. Simulated extent of the CO_2 plume at the end of injection operations in red and the stabilized CO_2 plume following the cessation of CO_2 injection in yellow.

5.8 References

Ayash, S.C., Nakles, D.V., Wildgust, N., Peck, W.D., Sorenson, J.A., Glazewski, K.A., Aulich, T.R., Klapperich, R.J., Azzolina, N.A., and Gorecki, C.D., 2017, Best practice for the commercial deployment of carbon dioxide geologic storage – the adaptive management approach: Plains CO_2 Reduction (PCOR) Partnership Phase III, Task 13 Deliverable D102/Milestone M59 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2017-EERC-05-01, Grand Forks, North Dakota, Energy and Environmental Research Center, August.

Fischer, K., 2013, Groundwater flow model inversion to assess water availability in the Fox Hills–Hell Creek Aquifer: North Dakota State Water Commission Water Resources Investigation 54.

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6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

This postinjection site care (PISC) and facility closure plan describes the activities that DGC will perform following the cessation of CO_2 injection to achieve final closure of the site. A primary component of this plan is a postinjection monitoring program that will provide evidence that the injected CO_2 plume is stable (i.e., CO_2 migration will be unlikely to move beyond the boundary of the storage facility area). Based on simulations of the predicted CO_2 plume movement following the cessation of CO_2 injection, it is projected that the CO_2 plume will stabilize within the storage facility area boundary (Section 3). Based on these observations, a minimum postinjection monitoring period of 10 years is planned to confirm these current predictions of the CO_2 plume extent and postinjection stabilization. However, monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable CO_2 plume. The nature and duration of that extension will be determined based on an update of this plan and NDIC approval.

In addition to DGC executing the postinjection monitoring program, the Class VI injection wells will be plugged as described in the plugging plan of this permit application (Section 10), all surface equipment not associated with long-term monitoring will be removed, and the surface land of the site will be reclaimed to as close as is practical to its original condition. Following the plume stability demonstration, a final assessment will be prepared to document the status of the site and submitted as part of a site closure report.

6.1 Predicted Postinjection Subsurface Conditions

6.1.1 Pre- and Postinjection Pressure Differential

Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of CO_2 injection. The simulations were conducted for 12 years of CO_2 injection at rates between 1.0 and 2.7 million metric tons per year, followed by a postinjection period of 10 years. Figure 6-1 illustrates the predicted pressure differential at the conclusion of 12 years of CO_2 injection. At the time that CO_2 injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of 400 to 450 psi at the location of the injection wells, which is insufficient to move formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the area of review (AOR) delineation of this permit application (Section 3). An illustration of the predicted decrease in this pressure profile over the 10-year postinjection period is provided in Figure 6-2. The pressure in the reservoir gradually decreases over time following the cessation of CO_2 injection, with the pressure at the injection well after 10 years of postinjection predicted to decrease 300 to 350 psi as compared to the pressure at the time CO_2 injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions.

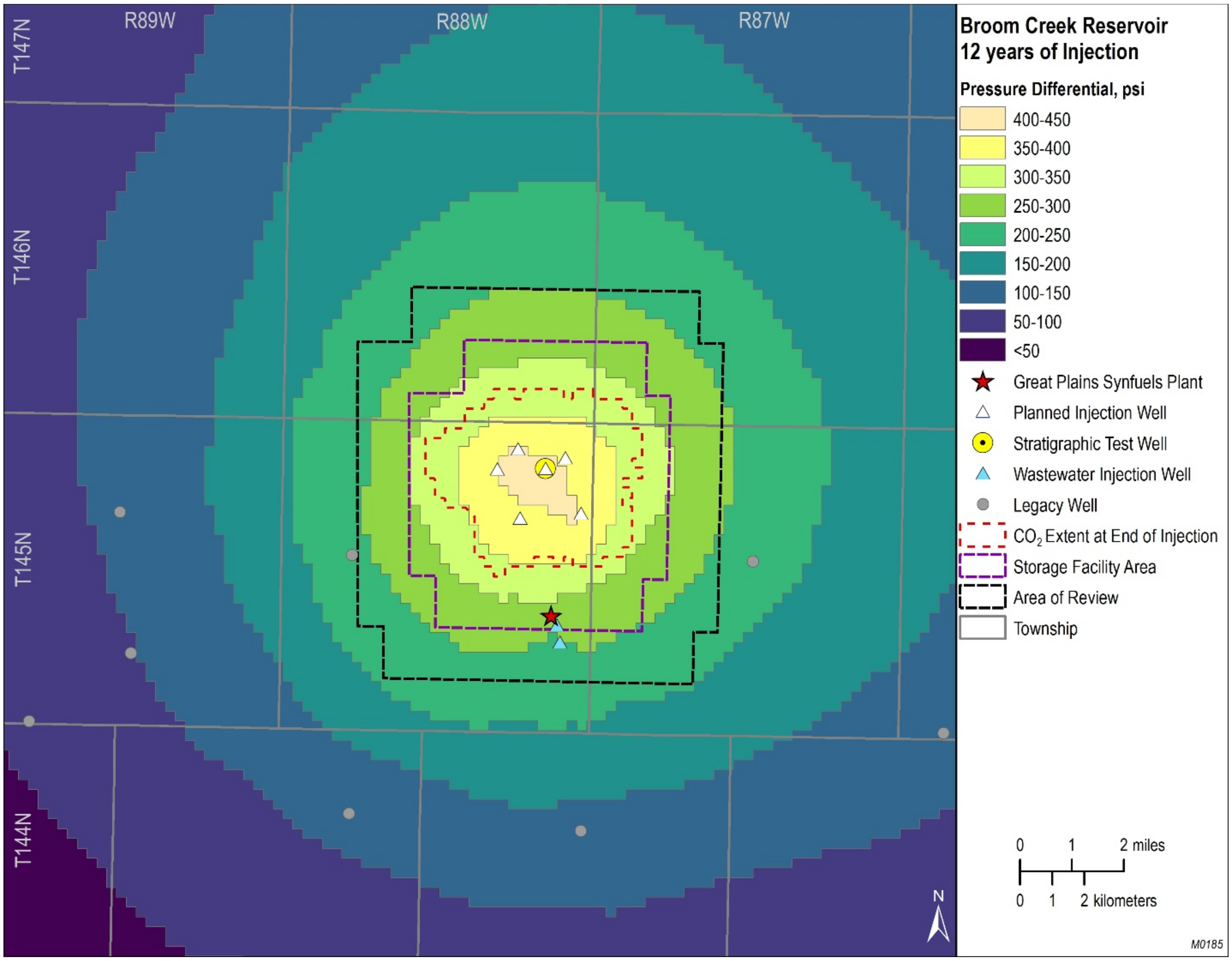


Figure 6-1. Predicted pressure differential in storage reservoir following 12 years of CO_2 injection at rates between 1.0 and 2.7 million metric tons per year.

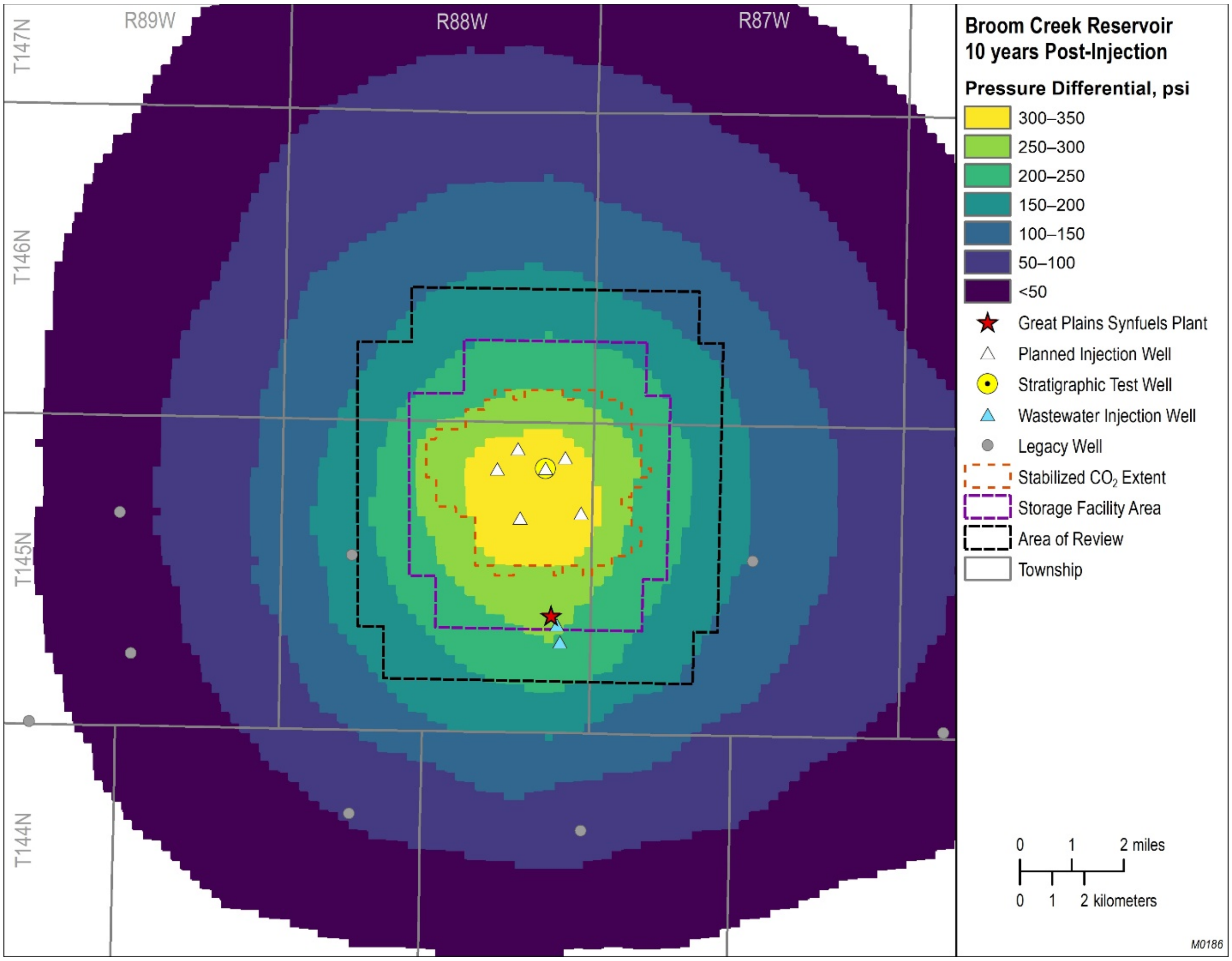


Figure 6-2. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection.

6.1.2 Predicted Extent of CO_2 Plume

Also shown in Figures 6-1 and 6-2 are numerical simulation predictions of the extent of the CO_2 plume at the time CO_2 injection was terminated (i.e., after 12 years of injection) and following the planned 10-year PISC period (also called the stabilized plume), respectively. The results of these simulations predict that 99% of the separate-phase CO_2 mass would be contained within an area of 11.28 mi^2 at the end of CO_2 injection (see Figure 6-1). As shown in Figure 6-2, the areal extent of the CO_2 plume is not predicted to change substantially over the planned 10-year PISC period.

Additional simulations beyond the 10-year PISC period were also performed and predict that at no time will the boundary of the stabilized plume at the site, which is shown in both Figures 6-1 and 6-2, extend beyond the boundary of the storage facility area. If such a determination can be made following the planned 10-year postinjection period, the CO_2 plume will meet the definition of stabilization as presented in NDCC § 38-22-17(5d) and qualify the geologic storage site for receipt of a certificate of project completion.

6.1.3 Postinjection Monitoring Plan

A summary of the postinjection monitoring plan that will be implemented during the 10-year postinjection period is provided in Table 6-1. The plan includes a combination of soil gas and groundwater/USDW monitoring as well as downhole and geophysical monitoring of the CO_2 plume in the storage reservoir.

Table 6-1. Summary of 10-year Postinjection Site Care Monitoring Plan

Type of Monitoring	Duration and Frequency	Justification
Near-Surface Monitoring		
Soil Gas Profile Stations (SG01 to SG11) (Figure 6-3)	Duration: minimum 10 years Frequency: 3–4 seasonal sample events at soil gas stations SG01 to SG11	The sampling and analysis program will monitor the vadose zone for any signs of potential CO_2 leaks within the storage facility area.
Dedicated Fox Hills (lowest USDW) Monitoring Wells (Figure 6-3)	Duration: minimum 10 years Frequency: 3–4 seasonal sample events at each dedicated Fox Hills monitoring well	The sampling and analysis program will monitor the Fox Hills Formation at each injection well pad to ensure the USDW is not impacted by operations.
Storage Reservoir Monitoring		
Surface Pressure Gauges on the ANG #1 and ANG #2 Wells (if WHP:BHP method is not satisfactory, DGC will perform a BHP survey in the first year of the PISC period)	Duration: minimum 10 years postinjection Frequency: continuous	Surface pressures will monitor the pressure decrease in the Broom Creek and history-match model predictions.
Geophysical Monitoring		
Time-Lapse Seismic	Duration: minimum 10 years postinjection Frequency: perform 2D radial seismic surveys at the cessation of injection, 1 year after injection begins, then in Years 3, 5, and 10	Time-lapse seismic surveys will continue as part of the 10-year postinjection period to support a stabilization assessment of the CO_2 plume.

6.2 Groundwater and Soil Gas Monitoring

Eleven soil gas profile stations and six dedicated monitoring wells in the Fox Hills Formation (i.e., lowest USDW) will be sampled during the proposed 10-year PISC period. Figure 6-3 identifies the locations of the soil gas profile stations and dedicated Fox Hills Formation monitoring wells that will be included. It is proposed that these samples will be analyzed for the same list of parameters as described in the testing and monitoring plan (Section 5); however, it is anticipated

that the final target list of analytical parameters will likely be reduced for the PISC period based on an evaluation of the monitoring results that are generated during the 12-year injection period of the storage operations.

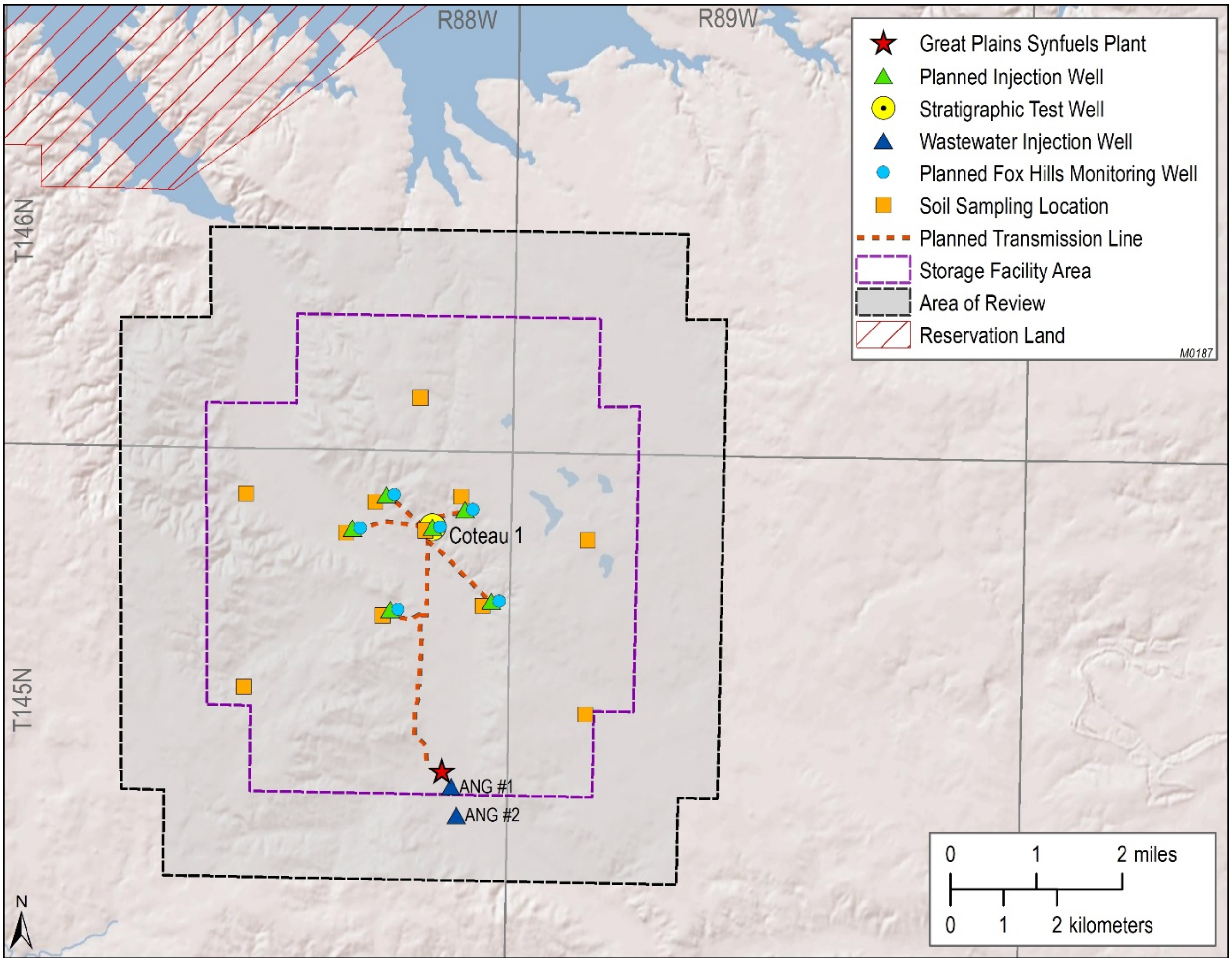


Figure 6-3. Soil gas and groundwater well sampling locations included in the PISC monitoring program.

6.3 CO_2 Plume Monitoring

Monitoring of the CO_2 plume migration in the subsurface will be conducted during the PISC period using the methods summarized in Table 6-1. Monitoring methods include a combination of near surface, deep subsurface, and geophysical techniques (i.e., surface seismic) that will monitor CO_2 saturation. Figure 6-4 illustrates the areal extents of the 2D seismic survey lines proposed during the PISC period in comparison to the areal extents of the stabilized CO_2 plume.

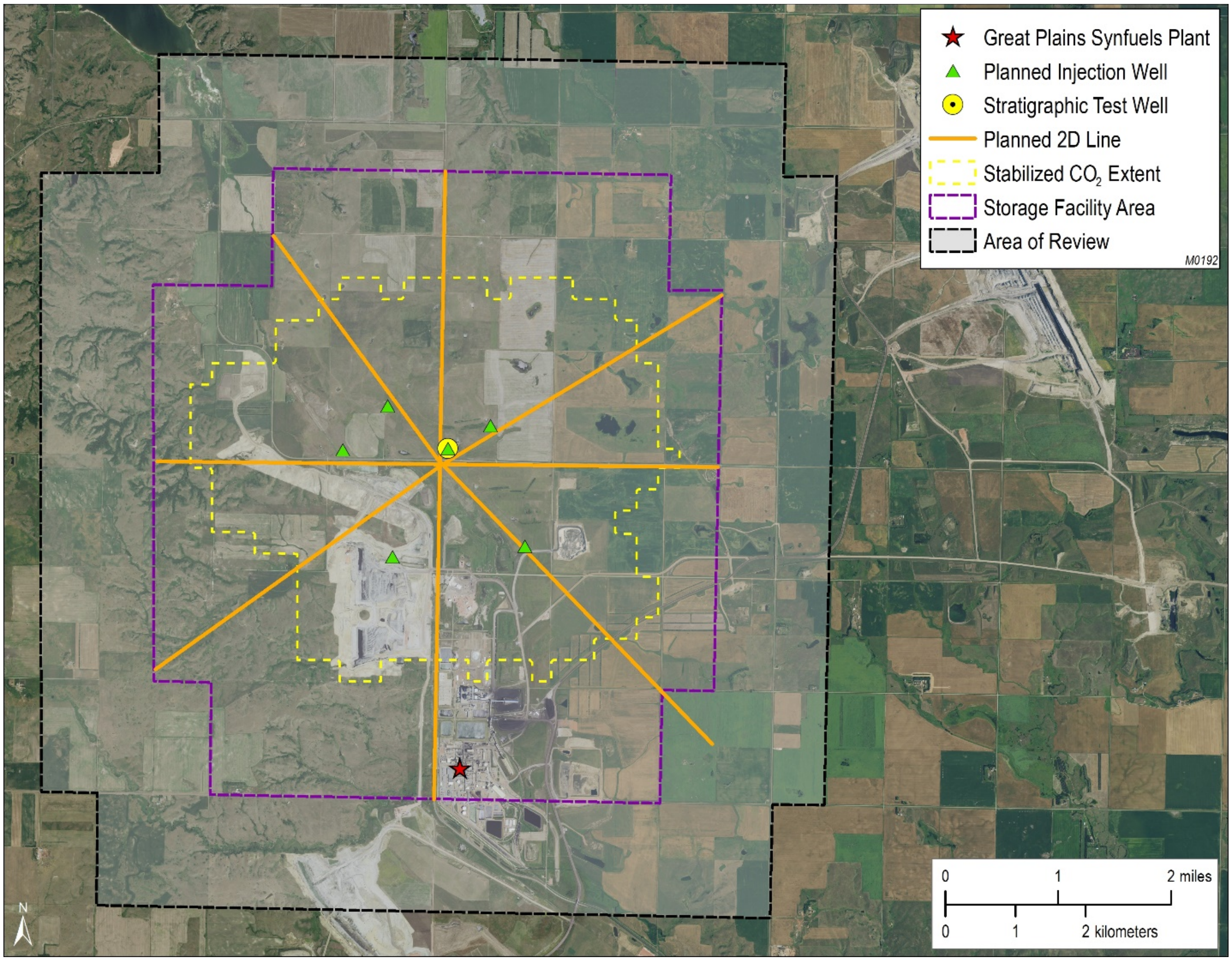


Figure 6-4. Areal extents of the 2D seismic survey lines proposed during the PISC period in comparison to the areal extents of the stabilized CO_2 plume.

6.3.1 Schedule for Submitting Postinjection Monitoring Results

All postinjection site care-monitoring data and monitoring results will be submitted to NDIC in annual reports. These reports will be submitted within 60 days of the anniversary date on which the CO_2 injection ceased.

The annual reports will contain information and data generated during the reporting period, including seismic data acquisition, formation-monitoring data, soil gas and groundwater sample analytical results, and simulation results from updated site models and numerical simulations.

6.3.2 Site Closure Plan

DGC will submit a final site closure plan and notify NDIC at least 90 days prior of its intent to close the site. The site closure plan will describe a set of closure activities that will be performed, following approval by NDIC, at the end of the postinjection site care period. Site closure activities will include the plugging of all wells that are not targeted for use as future subsurface observation wells; the decommissioning of storage facility equipment, appurtenances, and structures (e.g., buildings, gravel pads, access roads, etc.) not associated with monitoring; and the reclaiming of the surface land of the site to as close as is practical to its original condition.

6.3.3 Submission of Site Closure Report, Survey, and Deed

A site closure report will be prepared and submitted to NDIC within 90 days of the execution of the postinjection site care and facility closure plan. This report will provide NDIC with a final assessment that documents the location of the stored CO_2 in the reservoir, describes its characteristics, and demonstrates the stability of the CO_2 plume in the reservoir over time. The site closure report will also document the following:

- Plugging records of the injection wells.
- Location of sealed injection wells on a plat survey that has been submitted to the local zoning authority.
- Notifications to state and local authorities as required by NDAC § 43-05-01-19.
- Records regarding the nature, composition, and volume of the injected CO_2.
- Postinjection monitoring records.

At the same time, DGC will also provide NDIC with a copy of an accurate plat certified by a registered surveyor that has been submitted to the county recorder's office designated by NDIC. The plat will indicate the location of the injection wells relative to permanently surveyed benchmarks pursuant to NDAC § 43-05-01-19.

Lastly, DGC will record a notation on the deed (or any other title search document) to the property on which the injection wells were located pursuant to NDAC § 43-05-01-19.

7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

This emergency and remedial response plan (ERRP) 1) describes the local resources and infrastructure in proximity to the site; 2) identifies events that have the potential to endanger all underground sources of drinking water (USDWs) during the construction, operation, and postinjection site care periods of the geologic storage project; and 3) describes the response actions that are necessary to manage these risks to USDWs. In addition, the integration of the ERRP with the existing plant emergency plan and risk management plan of Dakota Gasification Company's (DGC's) Great Plains Synfuels Plant (GPSP) is described, emphasizing the command structure of DGC, the evacuation plan, hazmat (hazardous material) capabilities, and the emergency communication plan of the GPSP. Lastly, procedures are presented for regularly conducting and evaluating the adequacy of the ERRP and updating it, if warranted, over the lifetime of the Great Plains CO_2 Sequestration Project.

7.1 Background

CO_2 produced at GPSP (U.S. Environmental Protection Agency [EPA] Facility Identifier: NDD000690594) will be captured and geologically stored in close proximity to the plant location. The typical composition of the captured gas is 95.9% CO_2, 1.8% C^{2+} and hydrocarbons, 1.2% H_2S, 0.6% methane, and 0.5% nitrogen by volume. Figure 7-1 shows the location of the GPSP, which is in Mercer County, North Dakota, as well as the locations of CO_2 injection wells (Coteau 1 through Coteau 6 wells) and the planned CO_2 transmission lines from GPSP to the injection wells. The coordinates of the injection wells are provided in Table 7-1.

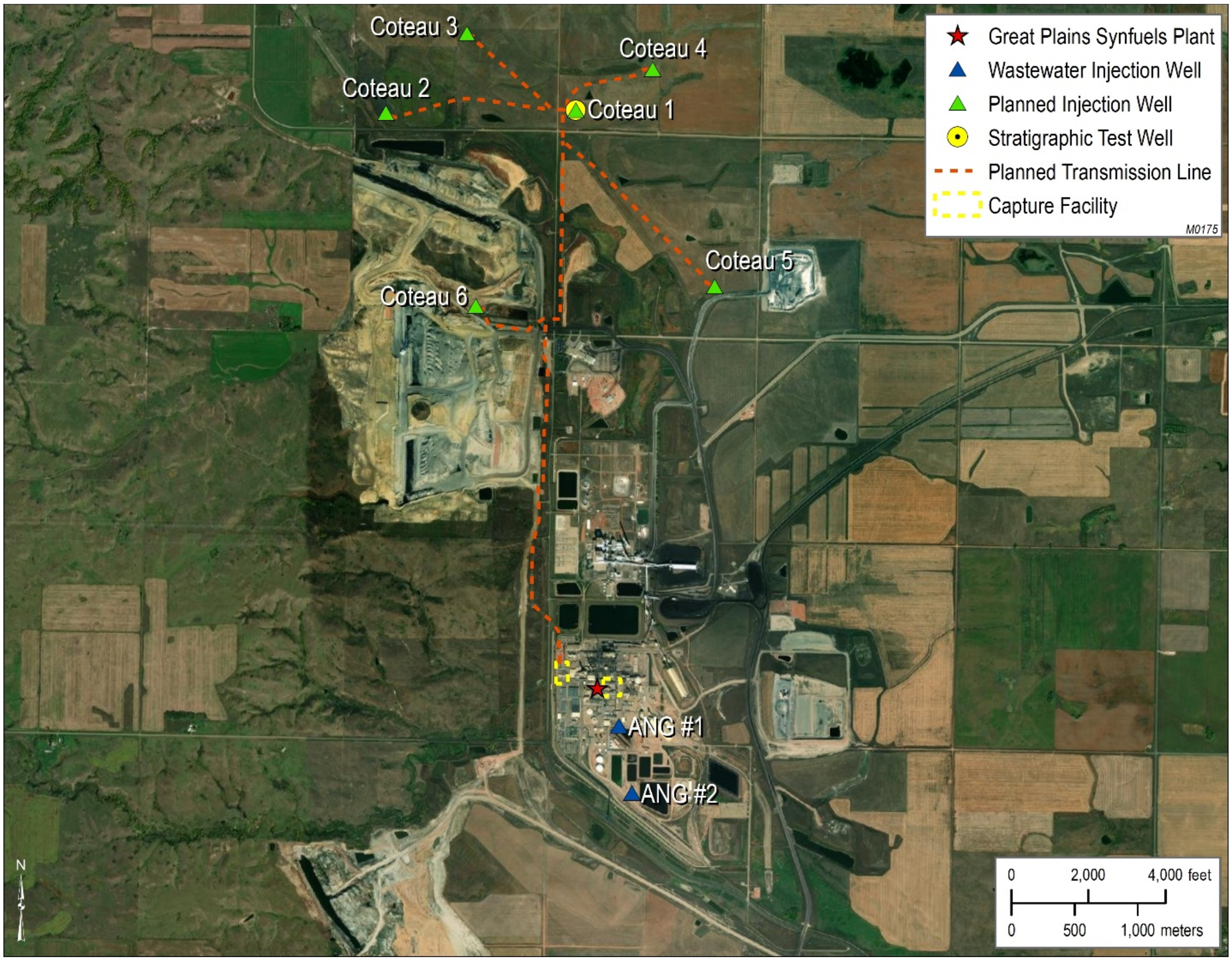


Figure 7-1. Locations of GPSP of DGC and the CO_2 injection wells (Coteau 1 through Coteau 6 wells). Also shown are the planned CO_2 transmission lines from GPSP to the injection wells.

Table 7-1. Well Names and Locations of the CO_2 Injection Wells of the DGC Geologic Storage Project

Well Name	Purpose	NDIC File No.	Quarter Call	Section	Township	Range	Latitude (NAD83*)	Longitude (NAD83*)
Coteau 1	CO_2 injection well	38379	SW/SW/SW	01	145N	88W	47.401991	−101.842101
Coteau 2	CO_2 injection well	TBD	SE/SW/SW	02	145N	88W	47.401572	−101.861988
Coteau 3	CO_2 injection well	TBD	NW/NW/SE	02	145N	88W	47.407308	−101.853618
Coteau 4	CO_2 injection well	TBD	NE/NE/SE	01	145N	88W	47.406940	−101.835330
Coteau 5	CO_2 injection well	TBD	SW/NE/SE	12	145N	88W	47.389640	−101.827219
Coteau 6	CO_2 injection well	TBD	NW/SW/SE	11	145N	88W	47.405000	−101.834090

* North American Datum of 1983.

The primary DGC contacts for the Great Plains CO_2 sequestration project and their contact information are as follows:

Primary DGC Project Contacts

Individual	Title	Contact Information
		Office Phone Number
Dale Johnson	VP & Plant Manager	701.873.6635
Trinity Turnbow	Operations & Assistant Plant Manager	701.873.6233
Daniel Whitley	Environmental Engineering Supervisor	701.873.6619

Primary Carbon Vault Project Contacts

Individual	Title	Contact Information
		Office Phone Number
Van Spence	President	303.588.5475
Rich McClure	Vice President – CO_2 Operations	720.635.1555
Gary Ramsdell	Operations Manager (Stanley, ND, Office)	701.629.1269

Contact names and information for other project personnel as well as key local emergency organizations/agencies are provided in a separate section of this ERRP (Section 7.6, Emergency Communications Plan).

7.2 Local Resources and Infrastructure

Local resources in the vicinity of the project that may be impacted as a result of an emergency event include 1) the holding ponds associated with GPSP and Antelope Valley Station; 2) Antelope Creek Aquifer; and 3) active and reclaimed mining land owned by Coteau Properties Company.

The infrastructure in the vicinity of the project that may be impacted as a result of an emergency event is shown in Figure 7-1 and includes 1) GPSP, 2) the CO_2 injection wellheads (Coteau 1 through Coteau 6), 3) the CO_2 transmission pipeline, 4) Antelope Valley Station, and 5) mining land owned by Coteau Properties Company. In addition, Figure 7-2 is provided to show residential, commercial, and public land use within 1 mile of the storage facility area boundary as required by North Dakota Administrative Code (NDAC) § 43-05-01-13.

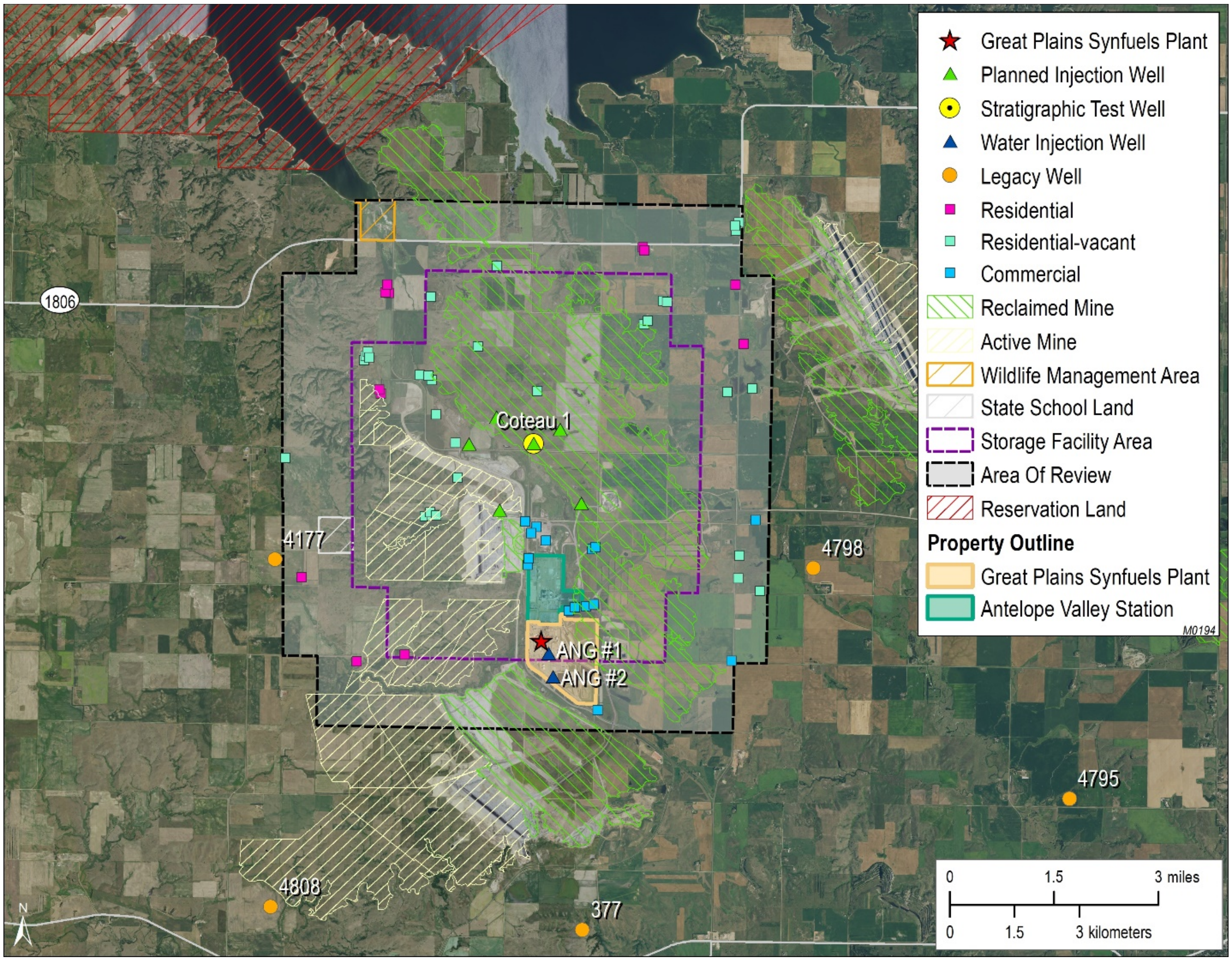


Figure 7-2. Residential, commercial, and public land use within 1 mile of the storage facility area.

7.3 Identification of Potential Emergency Events

7.3.1 Definition of an Emergency Event

An emergency event is an event that poses an immediate, or acute, risk to human health, resources, or infrastructure and requires a rapid, immediate response. This ERRP focuses on emergency events that have the potential to move the injected CO_2 stream or formation fluid in a manner that may endanger a USDW during operation or postinjection site care periods. Another emergency event of interest involves the accidental release of the CO_2 stream to the atmosphere.

7.3.2 Potential Project Emergency Events and Their Detection

Several potential technical project risks were considered and placed into the following five technical risk categories:

- Failure of surface equipment
- Integrity failure of an injection well

- Injection well monitoring equipment failure
- Inability of storage reservoir to contain the formation fluid or stored CO_2
- Natural disasters

Based on a review of these technical risk categories, a list of geologic storage project events that could potentially result in the movement of injection fluid or formation fluid in a manner that may endanger a USDW and require an emergency response was developed for inclusion in this ERRP. These events and means for their detection are provided in Table 7-2.

Table 7-2. Potential Project Emergency Events and Their Detection

Potential Emergency Events	Detection of Emergency Events
Failure of CO_2 Flowlines from CO_2 Capture System of DGC to CO_2 Injection Wellheads	Computational transmission pipeline and flowline continuous monitoring and leak detection system (LDS). Instrumentation at both ends of the transmission pipeline and the flowline for each injection well collects pressure, temperature, and flow data. The LDS software uses the pressure readings and flow rates in and out of the line to produce a real-time model and predictive model. By monitoring deviations between the real-time model and the predictive model, the software is able to detect pipeline leaks. Wellsite pressure and/or H_2S monitoring devices detect an anomaly.
Integrity Failure of Injection Wells	Pressure monitoring reveals wellhead pressure exceeds shutdown pressure specified in the permit. Annulus pressure indicates a loss of external or internal well containment. Mechanical integrity test results identify a loss of mechanical integrity.
Injection Well Monitoring Equipment Failure	Failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure is detected.
Storage Reservoir Unable to Contain the Formation Fluid or Stored CO_2	Elevated concentrations of indicator parameter(s) in soil gas, groundwater, and/or surface water sample(s) are detected.

In addition to these technical project risks, the occurrence of a natural disaster (e.g., naturally occurring earthquake, tornado, lightning strike, etc.) also represents an event for which an emergency response action may be warranted. For example, an earthquake or weather-related disaster (e.g., tornado or lightning strike) has the potential to result in injection well problems (integrity loss, leakage, or malfunction) and may also disrupt surface and subsurface storage operations. These events are addressed in the emergency plans of GPSP and will be extended to the geologic storage operations.

7.4 Emergency Response Actions

Discovery of an event triggers the corresponding response plan proposed herein. Specific response plan actions and activities will depend on the circumstances and severity of the event. The GPSP shift superintendent will address an event immediately and make all notifications as required by the emergency communications plan. The GPSP will be monitored in a manner consistent with the DGC's existing 205-mile CO_2 pipeline to Canada. Numerous automated safety features also exist along the CO_2 transmission line, the wellsite flowlines, and at the individual injection wellheads. Any alarm condition will be relayed to DGC's pipeline control room, which is manned continuously (7 days per week, 24 hours per day) by DGC personnel. An assessment of the alarm will be made by the control room operator, who will have the ability to remotely close any valve(s) necessary to isolate the problem and limit the duration and severity of the event.

The response actions that will be taken to address the events listed in Table 7-2, as well as the natural disasters, will follow the same protocol, which consists of the following actions:

- The GPSP shift superintendent (see Section 7.6, Emergency Communications Plan) will be notified and will immediately make an initial assessment of the automated response and the remote response and the severity of the event (i.e., does it represent an emergency event?).

- If designated as an emergency event, the DGC incident commander (IC) or designee shall notify the NDIC Department of Mineral Resources (DMR) Underground Injection Control (UIC) Program director pursuant to NDAC § 43-05-01-13 and implement the emergency communications plan. During this time, the GPSP shift superintendent will assume the role of incident commander.

- Following these actions, DGC will do the following:

    1. Ensure that the automated shutdown systems have isolated the event to the extent possible, and close additional isolation valves as required. If necessary, excess CO_2 volumes will be redirected back to the GPSP, where the CO_2 stream will be processed and safely released to the atmosphere.

    2. In the event of a leak to the surface, all H_2S precautions will be taken on-site, including, but not limited to, H_2S detectors and respirators, until natural dispersion returns the localized area to normal conditions. The nearest occupied dwellings are more than 1.5 miles from any wellsite, further under prevailing wind conditions, so evacuations should not be necessary. The IC should communicate with local authorities regarding the need for evacuations if deemed warranted.

    3. In the event of a mechanical integrity problem with one of the injection wellbores, the affected well will remain shut-in until an appropriate plan of action can be established by Carbon Vault personnel in coordination with NDIC DMR. The wellsite itself will remain secure as each location is to be fenced and locked at all times, with access only allowed by authorized personnel.

4. That portion of the CO_2 sequestration system that has been affected by the event will remain shut-in until DGC, the NDIC DMR, and other involved regulatory bodies are satisfied that a) the cause of the event has been identified and that b) it has been sufficiently addressed to resume operations. See Table 7-3 for details regarding the specific actions that will be taken to determine the cause and, if required, mitigate each of the events listed in Table 7-2.

The protocols described in this document are conceptual and may be adjusted based on actual circumstances and conditions of the event and any previous communication with governmental authorities having jurisdiction.

If an event triggers either a complete or partial cessation of injection and remedial actions, DGC shall demonstrate the efficacy of the response actions to the satisfaction of the UIC program director before resuming injection operations. Injection operations shall only resume upon receipt of written authorization from the UIC program director.

Table 7-3. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions

Failure of CO_2 Transmission Pipeline from CO_2 Capture System of DGC to Each Well Injection Wellsite Flowline and CO_2 Injection Wellhead	• The CO_2 stream release and its location will be detected by the LDS, which will trigger an alarm condition in the DGC control room where operators have the ability to remotely shut down the transmission line and wellsite flowline. • If warranted, initiate an evacuation plan. • The transmission line and/or flowline failure will be inspected to determine the root cause of the failure. • Repair/replace the damaged transmission line or flowline, and if warranted, put in place the measures necessary to eliminate such events in the future.
Integrity Failure of Injection Wells	• Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure. • Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the NDIC DMR UIC program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions to address impacts (in consultation with the NDIC DMR UIC program director).

Continued . . .

Table 7-3. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Injection Well-Monitoring Equipment Failure	• Monitor well pressure, temperature, and annulus pressure (manually if necessary) to determine the cause and extent of failure. • Identify and, if necessary, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).
Storage Reservoir Unable to Contain Formation Fluid or Stored CO_2	• Collect a confirmation sample(s) of groundwater from the Fox Hills monitoring wells and soil gas profile stations and analyze them for indicator parameters (see testing and monitoring plan in Section 5.0 of the SFP). • If the presence of indicator parameters is confirmed, develop (in consultation with the NDIC DMR UIC program director) a case-specific work plan to: 1. Install additional monitoring points near the impacted area to delineate the extent of impact: a. If a USDW is impacted above drinking water standards, arrange for an alternate potable water supply for all users of that USDW. b. If a surface release of CO_2 stream to the atmosphere is confirmed, initiate an evacuation plan, if warranted by workspace and/or ambient air-monitoring results. c. If surface release of CO_2 stream to surface waters is confirmed, implement appropriate surface water-monitoring program to determine if water quality standards are being exceeded. 2. Proceed with efforts, if necessary, to a) remediate the USDW to achieve compliance with drinking water standards (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" the impacted drinking water to mitigate CO_2/brine impacts) and/or b) manage surface waters using natural attenuation (i.e., natural processes, such as biological degradation, that are active in the environment and can reduce contaminant concentrations) or active treatment to achieve compliance with applicable water quality standards. • Continue all remediation and monitoring at an appropriate frequency (as determined by DGC and the NDIC DMR UIC program director) until unacceptable adverse impacts have been fully addressed.

Continued . . .

Table 7-3. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Natural Disasters	• Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure. • If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate extent of any impacts. • If impacts or endangerment are detected, identify and implement appropriate response actions in accordance with the GSPS emergency plan (in consultation with the NDIC DMR UIC program director).
Natural Disasters (seismicity)	• Identify when the event occurred and the epicenter and magnitude of the event. If magnitude is greater than 2.0 (Richter magnitude scale): 1. Demonstrate all project wells have maintained mechanical integrity. 2. If a loss of CO_2 containment is determined, proceed as described above to evaluate, and if warranted, mitigate the loss of containment. • If a loss of CO_2 containment is determined, proceed as described above to evaluate, and if warranted, mitigate the loss of containment.

7.5 Response Personnel/Equipment and Training

7.5.1 Response Personnel and Equipment

GPSP personnel will have operations and emergency response training. In addition, DGC will consult with the Mercer County Local Emergency Planning Committee (LEPC) for inclusion in the county's multihazard mitigation plan. The emergency "out call" system, which is also referred to as the R911 system, is designed to notify those residents living or working within the pipeline corridor that a pipeline emergency has occurred with the potential to affect them.

Equipment needed in the event of an emergency and remedial response will vary, depending on the emergency event. Response actions (e.g., cessation of injection, transmission line, flowline, and/or well shut-in, and possible evacuation) will generally not require specialized equipment to implement. However, when specialized equipment (such as a workover rig, logging equipment, potable water hauling, etc.) is required, DGC planning superintendent shall be responsible for its procurement. Because of its historical operations in the area, DGC is uniquely qualified to respond to emergencies. Its existing GPSP is home to a fire station in addition to emergency technician and medical professionals.

7.5.2 Staff Training and Exercise Procedures

DGC will train personnel involved in the CO_2 geologic storage project on the proper emergency responses, maintenance, and operating procedures. The training efforts will be documented. DGC will also work with Mercer County LEPC to perform coordinated training exercises associated with potential emergency events.

7.6 Emergency Communications Plan

Prior to the commencement of CO_2 injection operations, DGC will communicate in writing with landowners living in and adjacent to the permitted storage area to provide a summary of the information contained within this ERRP, including, but not limited to, information about the nature of the operations, operator contact list, potential risks, and possible response approaches.

In the event of an emergency, the GPSP shift superintendent and Protection Services Control Center (PSCC) supervisor will be notified immediately. The DGC shift superintendent will assume the role of IC. The IC's responsibilities may include, but are not limited to, developing an incident action plan, managing incident operations, notifying proper plant personnel (as shown below), and properly applying all resources.

DGC Personnel and Contact Information

Position	DGC Employee	Office Phone Number
Shift Superintendent		701.873.6777
Communications Manager	Joan Dietz	701.557.5070
PSCC (business)		701.873.6677
PSCC (24-hour emergency)		701.873.6600
DGC Medical		701.873.6789
Safety and Industrial Hygiene Superintendent	Jeff Graney	701.873.6605
Planning Superintendent	Dave Knudson	701.873.6219

In addition to DGC personnel, the IC is responsible for establishing and maintaining communications with appropriate off-site persons and/or agencies, including, but not limited to, the following:

Beulah Police Department	701.873.5252
Beulah Fire Department	701.873.2121
Mercer County Ambulance	701.747.5558
Mercer County Emergency Manager	701.745.3302
Mercer County Sheriff's Office	701.745.3333
Hazen Police Department	701.747.2414
North Dakota Highway Patrol	701.327.2447
North Dakota Highway Department	701.327.9921
North Dakota Poison Control	800.222.1222
Hazen Fire Department	701.747.5550
Sakakawea Medical Center	701.747.2225
NDIC DMR UIC Program Director	701.327.8020
North Dakota Department of Emergency Services	833.997.7455

Lastly, the DGC plant emergency plan contains addresses and contact information for approximately 58 neighboring facilities and residences located within 4.5 miles of the GPSP. This information is based on DGC's latest population density survey. DGC will update this information to document any changes that may occur by conducting semi-annual surveys. DGC will utilize an emergency out call system which is designed to notify residents in the area if an emergency occurs.

7.7 ERRP Review and Updates

This ERRP shall be reviewed:

- At least annually following its approval by NDIC DMR.
- Within 1 year of an area of review (AOR) reevaluation.
- Within a prescribed period (to be determined by NDIC DMR) following any significant changes to the project, e.g., injection process, injection rate, etc.
- As required by NDIC DMR.

Should the operational monitoring (see Section 5.0, Testing and Monitoring Plan) of the geologic storage operations identify trends that warrant a modification to the ERRP prior to the scheduled annual review, DGC will move forward with revising the plan and submitting a revised ERRP to NDIC DMR within 6 months of that determination.

If the annual review indicates that no amendments to the ERRP are necessary, DGC will provide NDIC DMR with the documentation supporting a no-amendment-necessary determination. If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to NDIC DMR within 6 months following their identification.

8.0 WORKER SAFETY PLAN

8.0 WORKER SAFETY PLAN

The worker safety plan (WSP) describes the minimum safety programs and training requirements for DGC employees and contract personnel during the construction, operation, and postinjection site periods. DGC will give NDIC personnel sufficient access to perform wellsite inspections.

This WSP incorporates the existing occupational, safety, and industrial hygiene (OSIH) program utilized by DGC for employees and contractors and their personnel (including subcontractors) working at the Great Plains Synfuels Plant and other DGC facilities. The OSIH program is designed to prevent accidents, injuries, property losses, illnesses, and violations of government and company standards.

8.1 DGC Employee Safety Requirements and Training

DGC has established a process for employees to acquire the knowledge, skills, and abilities to competently operate the facility in accordance with DGC safe work practices, procedures, and operating manuals. The safety requirements for DGC employees include, but are not limited to, the following:

1. An orientation for all newly hired employees to ensure they are aware of company safety policies and procedures, safety and health hazards, safe work practices, and government safety regulations.

2. Instruction and training for each employee regarding:

    a. Safety expectations while on DGC property.

    b. What to do in an emergency, including evacuation routes and assembly points.

    c. Safety and industrial hygiene information about hazardous materials/conditions and immediate actions to take following an accidental exposure.

    d. When and how to report safety incidents.

    e. How to report unsafe conditions and behaviors.

    f. Safe work practices as defined by government and company standards.

8.1.2 DGC Contractor Safety Requirements and Training

The DGC OSIH program also establishes requirements for contractors to interface with DGC to ensure compliance with DGC safety procedures and federal, state, and local safety standards. The scope of the requirements covers all contractors and their personnel (including subcontractors) working at DGC's facilities.

The safety requirements and training required for a contractor to access and perform work at DGC facilities include, but are not limited to, the following:

1. Full compliance with all Energy Coalition for Contractor Safety (ECCS) guidelines for a "Class A contractor." (The ECCS guidelines can be found at the North Dakota Safety Council [NDSC] website at www.ndsc.org.).

2. Attendance at an annual DGC contractor safety orientation.

3. Negative drug test results within the last 12 months.

4. Availability of a contractor employee training record (CETR) within the last 12 months:

    a. Documents that the contractor has trained its personnel on DGC procedures and process descriptions.

    b. Ensures contractor employees are instructed in the known potential fire, explosion, or toxic release hazards and applicable provisions of the emergency response plan.

5. Documentation of a contractor employee background check within the last 5 years.

6. Successful completion of an Occupational Safety and Health Administration (OSHA) 10-hour class within the last 36 months.

7. A contractor safety manual evaluation completed by a third party, i.e., the North Dakota Safety Council (NDSC), to demonstrate compliance with federal, state, and DGC safety standards.

8. Demonstration of acceptable safety performance by submitting the last year's safety statistics to NDSC at www.ndsc.org.

9. Demonstration of qualification requirements for pipeline (off-site) contractors, which includes the following:

    a. Submision of a drug/alcohol plan that meets 49 Code of Federal Regulations (CFR) Part 40 and Part 199.

    b. Submission of an operator qualification plan in accordance with 49 CFR Part 192 and Part 195.

    c. Submission of qualification data for personnel performing operation, maintenance, or emergency response task(s) on the carbon dioxide (CO_2) pipeline.

    d. Other qualification requirements include:

        i. DGC access to drug/alcohol and operator qualification information for random record audits.

        ii. Submission of Department of Transportation (DOT) annual drug testing satistical data to DGC for inclusion in an annual DGC submittal to DOT.

Only DGC employees and contractor personnel who have been properly trained will participate in the project activities of drilling, construction, operations, and equipment repair.

9.0 WELL CASING AND CEMENTING PROGRAM

9.0 WELL CASING AND CEMENTING PROGRAM

Rampart Energy Company has drilled one well, Coteau 1 (NDIC File No. 38379) thus far on behalf of DGC. The well was permitted and drilled in June 2021 as a stratigraphic test well in compliance with Class VI underground injection control (UIC) injection well construction requirements. Application to convert Coteau 1 to a CO_2 storage injection well is being filed upon approval of this storage facility permit (SFP). The following information includes the current, as-constructed wellbore schematic (illustrated in Figure 9-1 and detailed in Tables 9-1 through 9-4) and a radial cement evaluation log summary for Coteau 1 (Figure 9-2). After drilling, the Broom Creek Formation was perforated with four shots at 5975 ft and a reservoir pressure and fluid sample were obtained. The perforations were then squeezed with 100 sacks of Class G cement and the casing pressured tested to 1600 psi with an inhibited brine solution.

Five additional injection wells are planned. Three of these, the proposed Coteau 2, Coteau 3, and Coteau 4, are expected to be drilled in the second quarter of 2022, followed by the proposed Coteau 5 and Coteau 6 in late 2025, to accommodate additional CO_2 injection volumes in the spring of 2026.

9.1 Coteau 1: As-Constructed CO_2 Injection Well Casing and Cementing Program

The as-constructed wellbore schematic for the Coteau 1 well is provided in Figure 9-1.

Tables 9-1 through 9-4 provide the casing and cement programs for the Coteau 1 well and have been updated according to the drilling performed in June 2021. The tables demonstrate compliance with North Dakota Administrative Code (NDAC) § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for conversion to a CO_2 storage injection well.

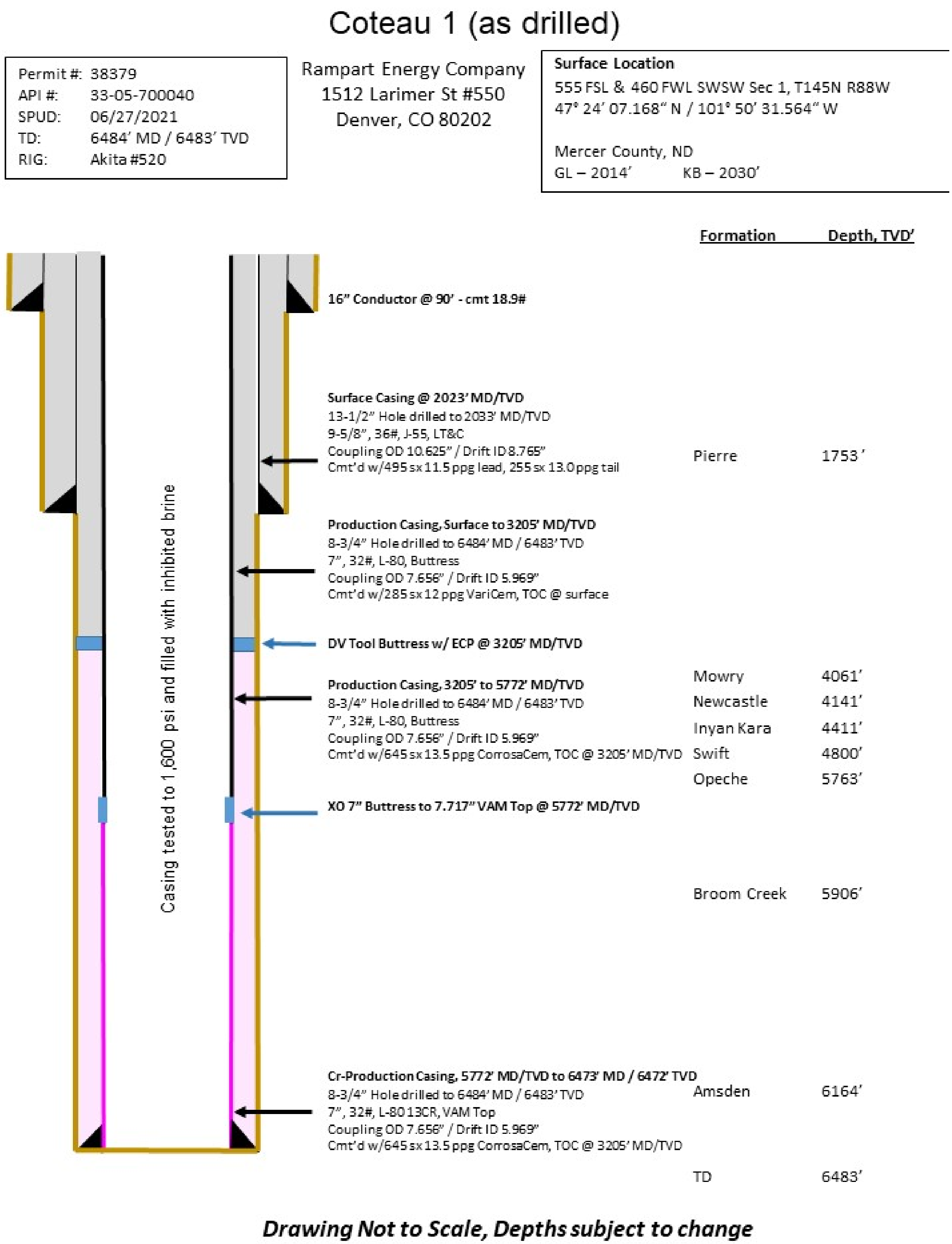


Figure 9-1. Coteau 1 as-constructed wellbore schematic.

Table 9-1. Coteau 1 As-Constructed Well Information

Well Name:	**Coteau 1**	**NDIC No.:**	**38379**	**API* No.:**	**33-057-00040**
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.1 T145N R88W	**Footages:**	555 FSL*, 60 FWL*	**Total Depth, ft:**	6484 MD

* API: American Petroleum Institute, FSL: from the south line, FWL: from the west line.

Table 9-2. Coteau 1 As-Constructed Casing Program

Section	Bit Size, in.	Casing OD*, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC*	Surface	2033	Cover freshwater aquifers
Production	8.75	7	32	L-80	Buttress	Surface	3205	Production casing
Production	8.75	DV* tool			Buttress	3205	3230	Stage collar with ECP*
Production	8.75	7	32	L-80	Buttress	3230	5772	Production casing
Production	8.75	7	32	13CR L80	VAM top*	5772	6474	CO_2-resistant production casing

* OD: outside diameter, LTC: long-thread and coupled, VAM top: premium thread and coupled, DV: differential valve: ECP: electrochemical pump.

Table 9-3. Coteau 1 As-Constructed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID*, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80	32	Buttress	6.094	5.969	9050	8610	745	791
7	13CR L80	32	VAM top	6.094	6.000	9060	8610	745	745

* ID: inside diameter.

Table 9-4. Coteau 1 As-Constructed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6474–3230	100	645
7	12.0 VariCem	3205–surface	OH 100	285

* The cement top was obtained from the radial cement evaluation. Figure 9.2 provides an evaluation of the isolation scanner performed on 9/17/2021. The top of cement is at the surface, while the top of CO_2-resistant cement is at 3205 ft.

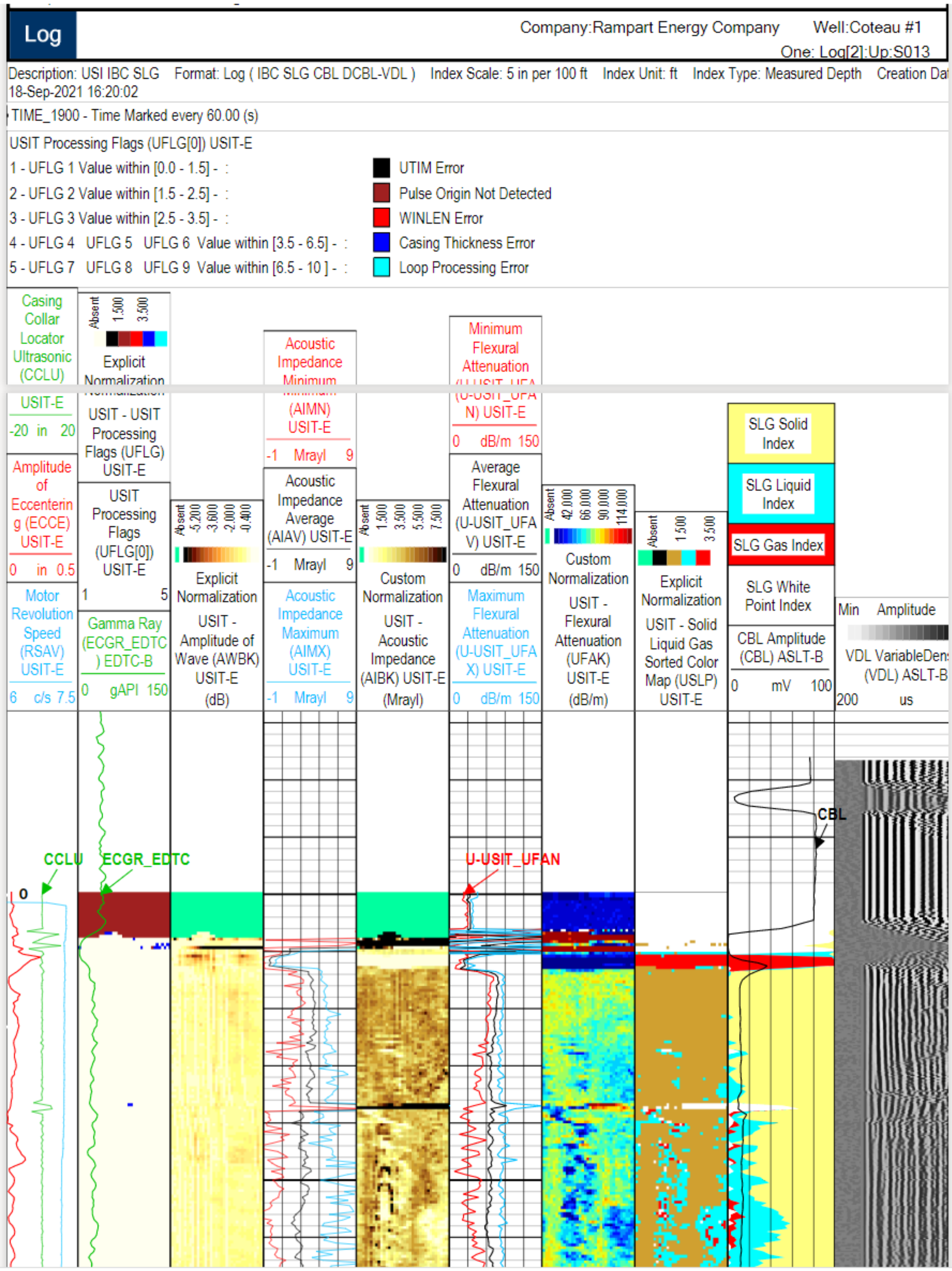


Figure 9-2. Coteau 1 isolation scanner results – radial cement evaluation log summary from Coteau 1 verifies the material behind the casing and the cement bond index. This enables the analyst to assess isolation in the CO_2 injection zone, confining zones, and underground sources of drinking water (USDWs) using a high-resolution image.

9.2 Coteau 2: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 2 well is expected to be drilled and completed in the second quarter of 2022. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-3.

Tables 9-5 through 9-8 include the proposed casing and cement programs for the Coteau 2 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

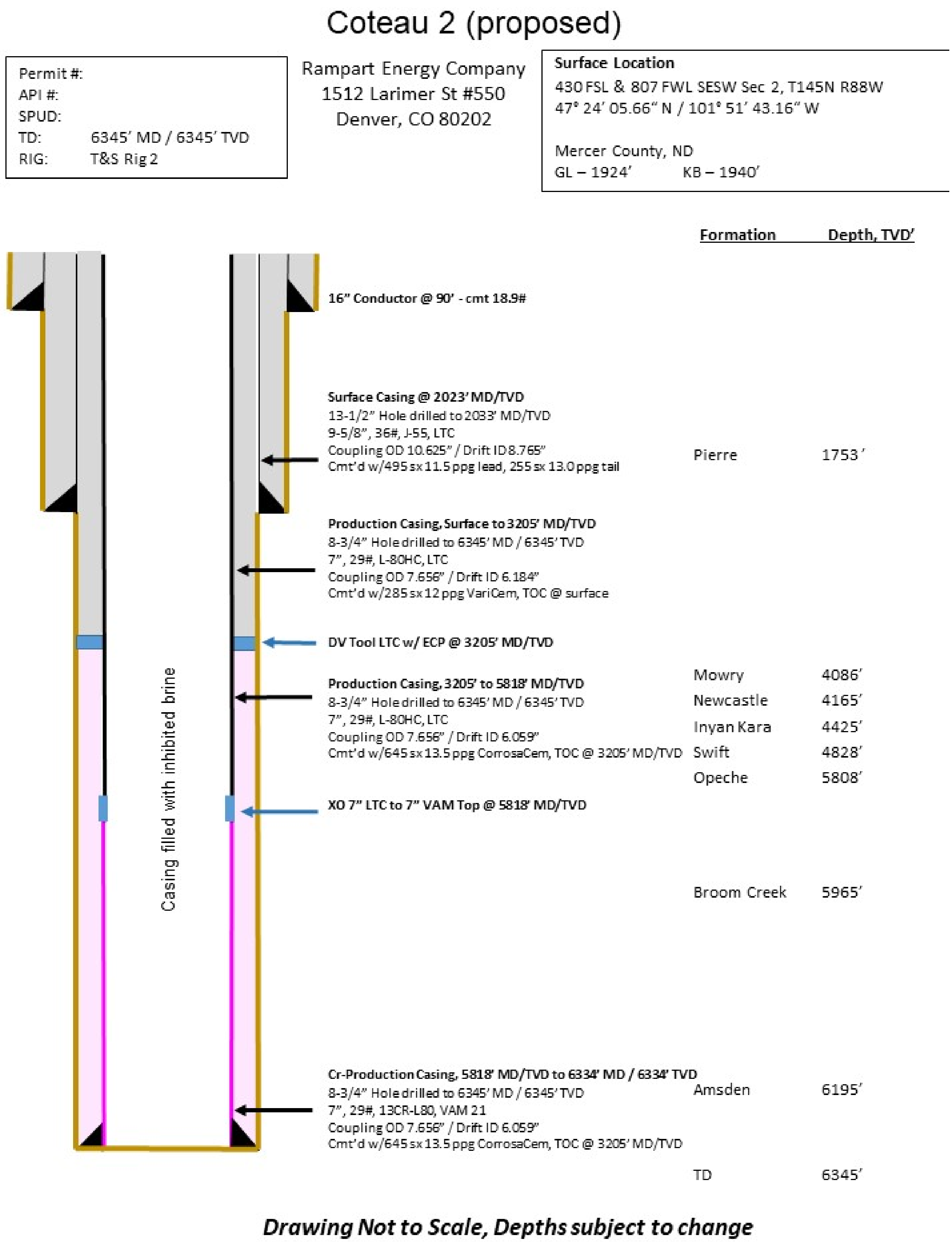


Figure 9-3. Coteau 2 proposed wellbore schematic.

Table 9-5. Coteau 2 Proposed Well Information

Well Name:	**Coteau 2**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.2 T145N R88W	**Footages:**	430 FSL, 807 FWL	**Total Depth, ft:**	6371 MD

Table 9-6. Coteau 2 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5829	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5829	6360	CO_2-resistant production casing

Table 9-7. Coteau 2 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7.717	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-8. Coteau 2 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6360–3205	100	625
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft.

9.3 Coteau 3: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 3 well is expected to be drilled and completed in the second quarter of 2022. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-4.

Tables 9-9 through 9-12 include the proposed casing and cement programs for the Coteau 3 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

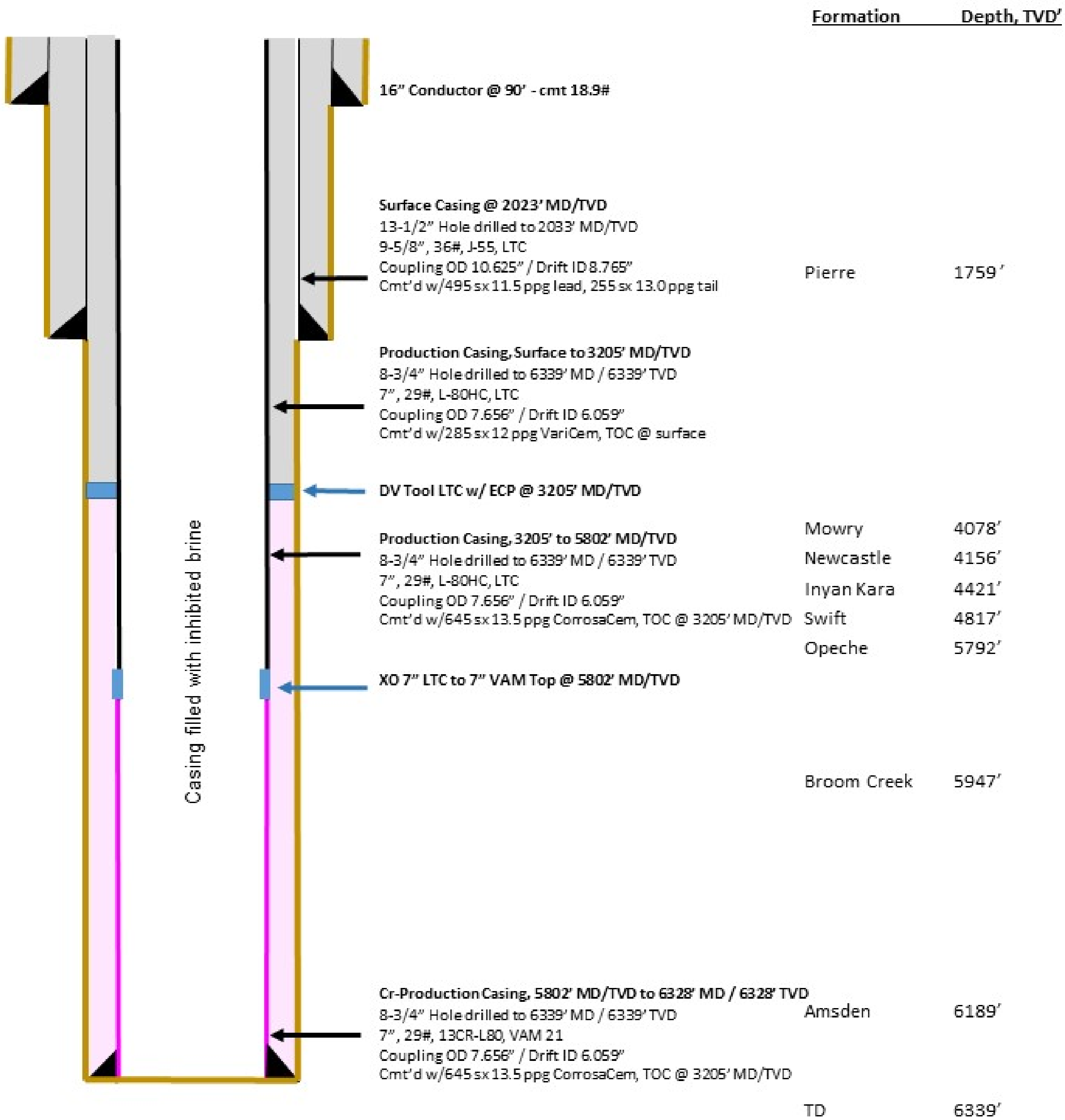
Coteau 3 (proposed)

Permit #:
API #:
SPUD:
TD: 6339' MD / 6339' TVD
RIG: T&S Rig 2

Rampart Energy Company
1512 Larimer St #550
Denver, CO 80202

Surface Location
2483 FSL & 2412 FEL SWNE Sec 2, T145N R88W
47° 24' 26.31" N / 101° 51' 13.02" W

Mercer County, ND
GL – 1988' KB – 2004'



Drawing Not to Scale, Depths subject to change

Figure 9-4. Coteau 3 proposed wellbore schematic.

Table 9-9. Coteau 3 Proposed Well Information

Well Name:	**Coteau 3**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.2 T145N R88W	**Footages:**	2483 FSL, 2412 FEL*	**Total Depth, ft:**	6361 MD

* FEL: from the east line.

Table 9-10. Coteau 3 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5815	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5815	6350	CO_2-resistant production casing

Table 9-11. Coteau 3 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7.717	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-12. Coteau 3 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6350–3205	100	620
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft.

9.4 Coteau 4: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 4 well is expected to be drilled and completed in the second quarter of 2022. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-5.

Tables 9-13 through 9-16 include the proposed casing and cement programs for the Coteau 4 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

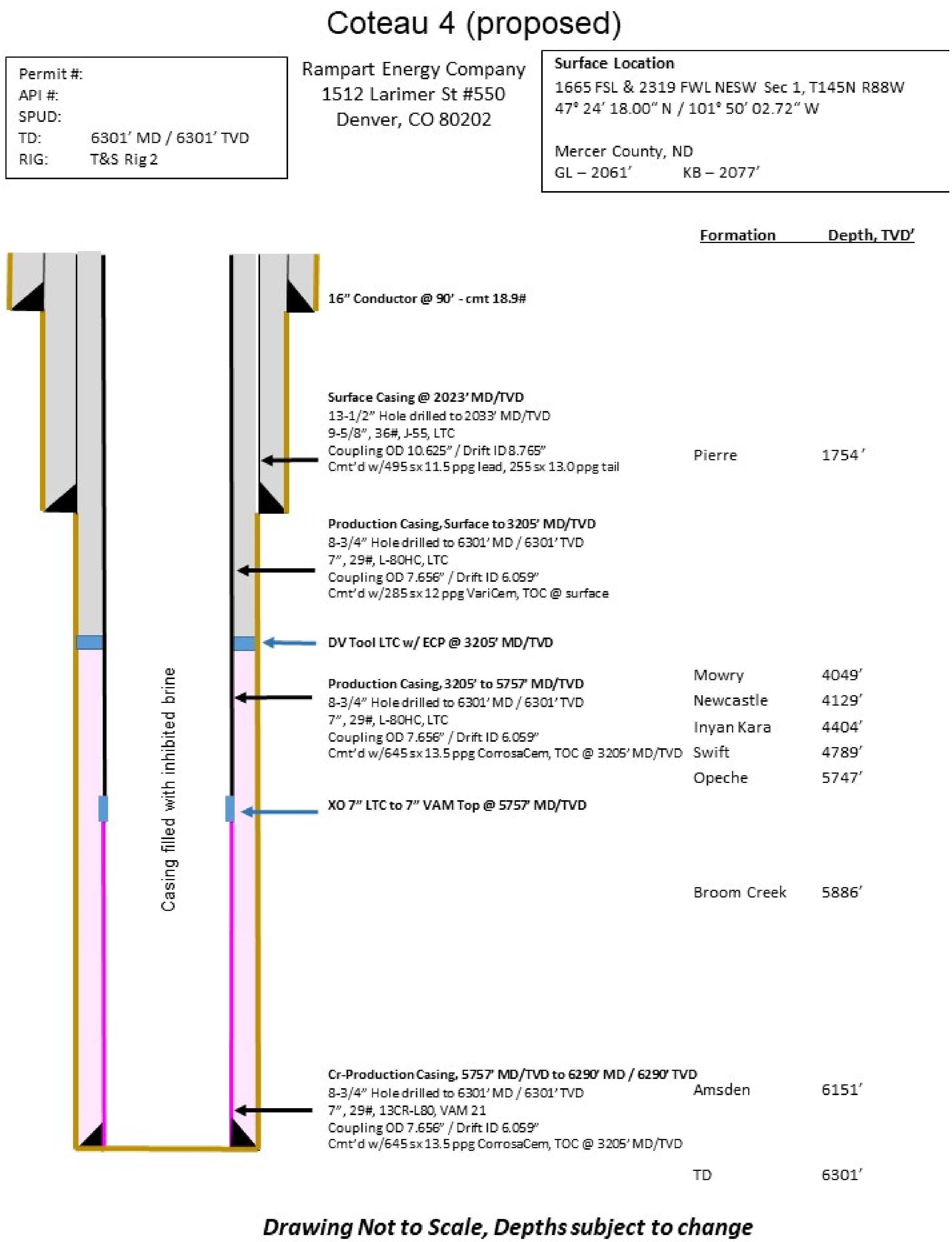


Figure 9-5. Coteau 4 proposed wellbore schematic.

Table 9-13. Coteau 4 Proposed Well Information

Well Name:	**Coteau 4**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.1 T145N R88W	**Footages:**	1665 FSL, 2319 FWL	**Total Depth, ft:**	6309 MD

Table 9-14. Coteau 4 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5769	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5769	6298	CO_2-resistant production casing

Table 9-15. Coteau 4 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-16. Coteau 4 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6298–3205	100	610
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft

9.5 Coteau 5: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 5 well is expected to be drilled and completed in late 2025. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-6.

Tables 9-17 through 9-20 include the proposed casing and cement programs for the Coteau 5 based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

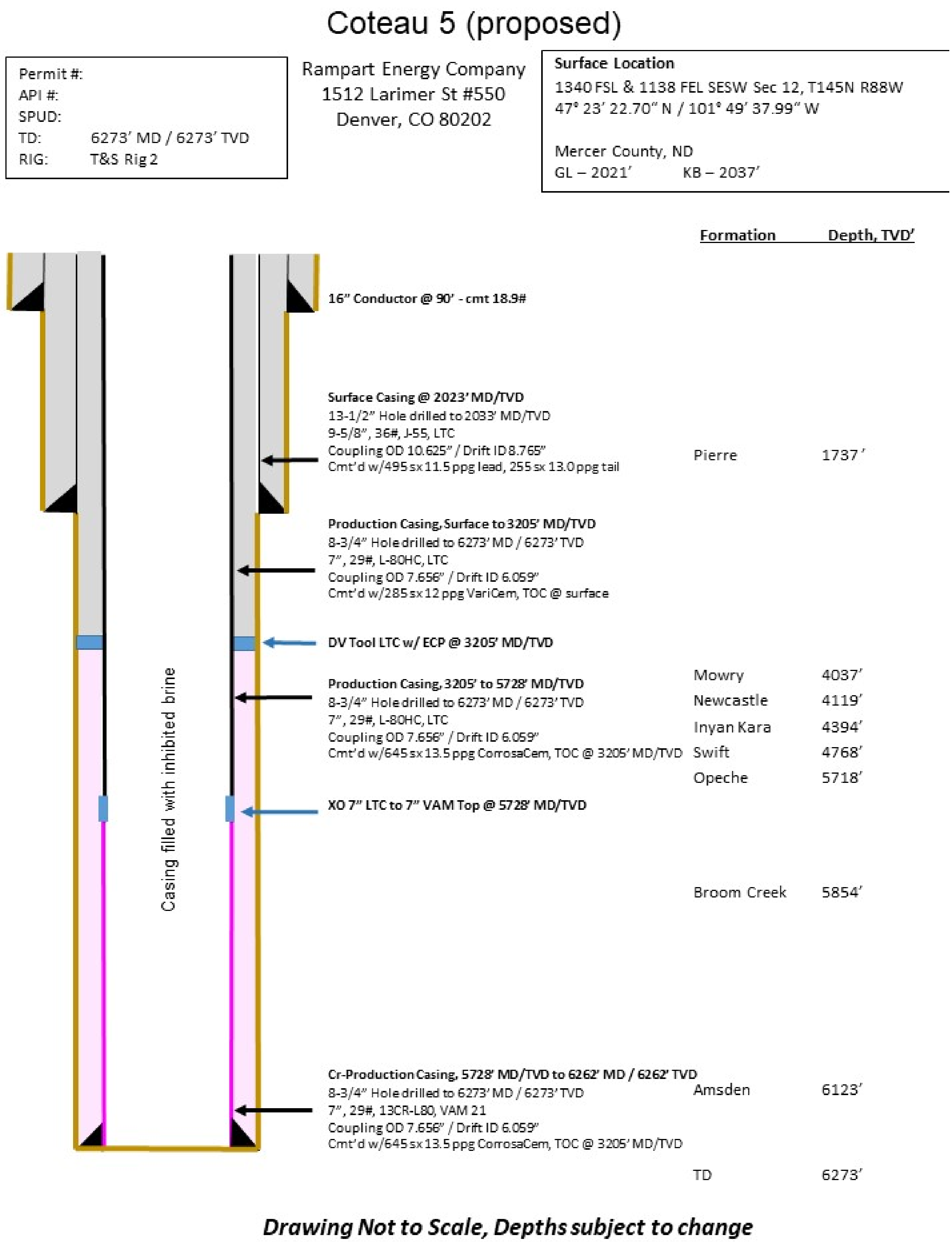


Figure 9-6. Coteau 5 proposed wellbore schematic.

Table 9-17. Coteau 5 Proposed Well Information

Well Name:	**Coteau 5**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.12 T145N R88W	**Footages:**	1340 FSL, 1138 FEL	**Total Depth, ft:**	6277 MD

Table 9-18. Coteau 5 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2023	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5741	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5741	6266	CO_2-resistant production casing

Table 9-19. Coteau 5 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-20. Coteau 5 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6266–3205	100	605
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3205 ft.

9.6 Coteau 6: Proposed CO_2 Injection Well Casing and Cementing Program

The Coteau 6 well is expected to be drilled and completed in late 2025. It will be drilled with identical casing and cementing parameters to those of the Coteau 1 well but with changes in specific depths based on electrical logs collected at the time. An approximate casing and cementing program is presented as Figure 9-7.

Tables 9-21 through 9-24 include the proposed casing and cement programs for the Coteau 6 well based on a surveyed surface elevation and modeled downhole geologic formation tops. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for a CO_2 storage injection well.

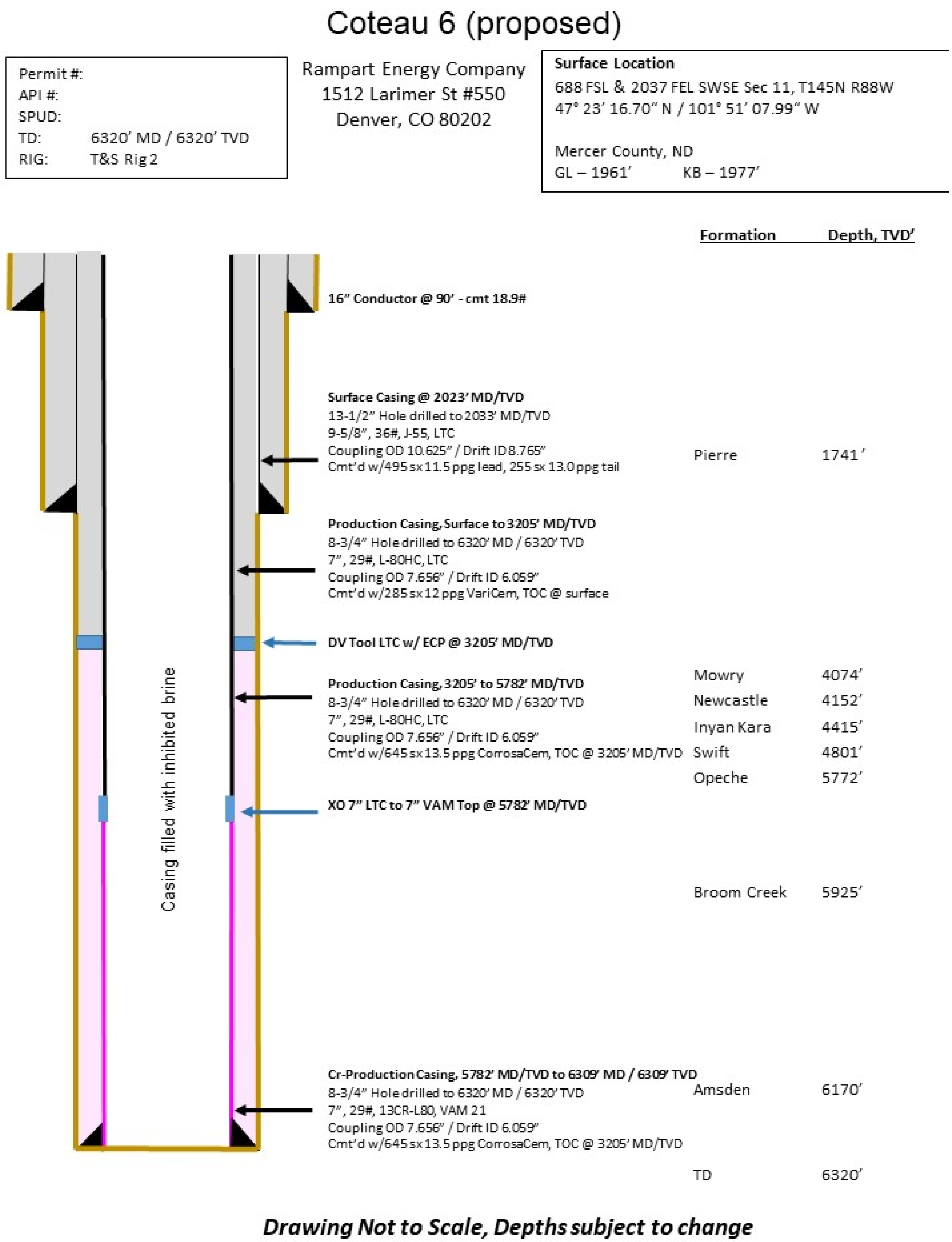


Figure 9-7. Coteau 6 proposed wellbore schematic.

Table 9-21. Coteau 6 Proposed Well Information

Well Name:	**Coteau 6**	**NDIC No.:**		**API No.:**	
County:	Mercer	**State:**	ND	**Operator:**	Rampart Energy Company
Location:	Sec.11 T145N R88W	**Footages:**	688 FSL, 2037 FEL	**Total Depth, ft:**	6335 MD

Table 9-22. Coteau 6 Proposed Casing Program

Section	Bit Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13.5	9.625	36	J-55	LTC	Surface	2033	Cover freshwater aquifers
Production	8.75	7	29	L-80HC	LTC	Surface	3205	Production casing
Production	8.75	DV tool			LTC	3205	3230	Stage collar with ECP
Production	8.75	7	29	L-80HC	LTC	3230	5794	Production casing
Production	8.75	7	29	13CR L80	VAM 21	5794	6324	CO_2-resistant production casing

Table 9-23. Coteau 6 Proposed Casing Properties

Casing OD, in.	Grade	Weight, lb/ft	Connection Type	ID, in.	Drift, in.	Burst Pressure, psi	Collapse Pressure, psi	Yield Strength, lb × 1000	
								Body	Connection
9.625	J-55	36	LTC	8.921	8.765	3520	2020	564	453
7	L-80HC	29	LTC	6.094	5.969	8460	8610	745	791
7	13CR L80	29	VAM 21	6.094	5.969	8460	8610	655	745

Table 9-24. Coteau 6 Proposed Cement Program

Casing OD, in.	Slurry Weight, lb/gal	Interval, ft	% Excess	Volume, sacks
9.625	13.0	2023–1066	100	255
9.625	11.5	1066–surface	100	495
7	13.5 CorrosaCem	6324–3230	100	615
7	12.0 VariCem	3205–surface	OH 100	285

* The proposed top of cement is at the surface, while the proposed top of CO_2-resistant cement is at 3,205 ft.

10.0 PLUGGING PLAN

10.0 PLUGGING PLAN FOR INJECTION WELLS

The plugging plans for all injection wells are intended to be interpreted as proposed conditions and do not reflect the current as-constructed state of a particular well. The schematics and procedure in this section illustrate what the estimated wellbore conditions will look like before and after the plugging and abandonment (P&A). The wells will be plugged and abandoned when CO_2 storage and injection operations cease.

The plugging plan will be provided to a representative from the NDIC, who will be present during the plugging operations. This will also be documented during workover reports. The plugging record will show that the material used will be compatible with CO_2 and isolate the injection zone.

10.1 Plugging & Abandonment (P&A) Program

A well schematic of the planned completion for the Coteau 1 well (NDIC File No. 38379) is provided in Figure 10-1 followed by a P&A procedure and a well-plugging schematic (Figure 10-2). The abandonment of subsequent injection wells, namely, the Coteau 2 through 6, will be performed in a manner consistent with that of the Coteau 1. The size and depths of the various plugs may vary as necessary to accomplish the zonal isolation, but in each instance, approval of specific P&A operations will be required from the NDIC prior to the initiation of fieldwork.

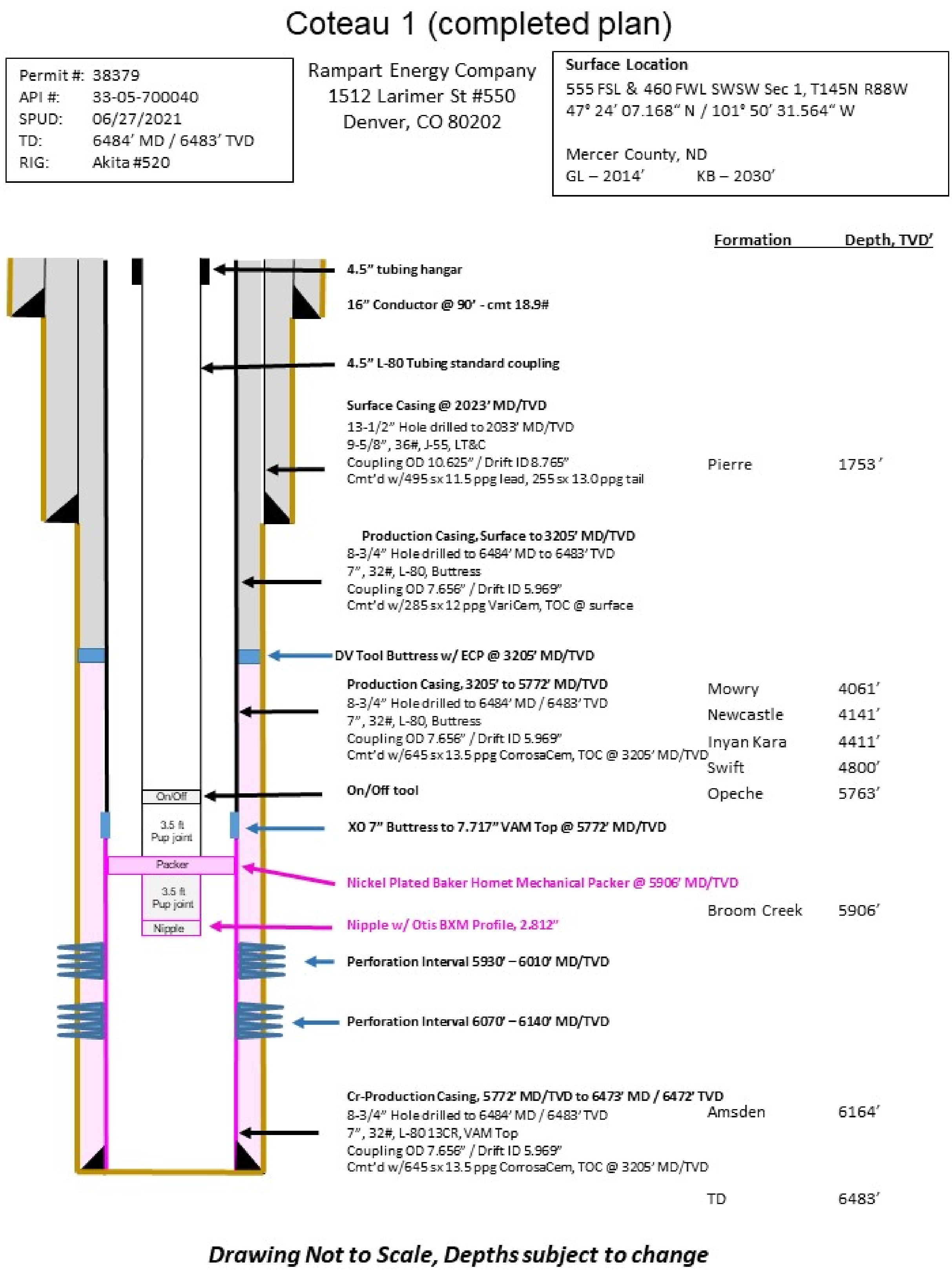


Figure 10-1. Coteau 1 CO_2 injection well schematic.

The NDIC will be contacted, and an intent to plug and abandon will be filed for approval. Final adjustments to the proposed P&A procedure will be made based on wellbore conditions at that time and NDIC field inspector recommendations. Currently, the proposed procedure for P&A of all wells is as follows.

The wellbore is to be plugged and abandoned at the end of the injection of CO_2. API standards, NDIC regulations, and best management practices will be employed to control the well at all times. Well work will be performed by experienced crews and contractors and supervised by Rampart Energy with other competent and experienced engineers and NDIC personnel on-site as necessary. Safety and environmental measures will be in place to ensure the well-being of all personnel and subsequent site reclamation. The protocol is as follows.

1. Capture and record bottomhole reservoir pressure for Broom Creek Formation using an electronic recording pressure gauge – NDAC § 43-05-01-11.5(2a).
   Note: calculate the required corrosion-inhibited kill fluid weight based on bottomhole reservoir pressure plus 100–300 psi for overbalanced pressure. Appropriate storage volume of weighted kill fluid will be stored in portable tanks on location.

2. Move in and rig up (MIRU) workover rig with 2⅞", work string.

3. Kill well by pumping calculated weight and volume of corrosion-inhibited kill fluid down 4.5" injection tubing. Ensure wellhead, tubing, and annular/casing pressures are showing 0 psi and stable.

4. Nipple down (ND) wellhead. Install blowout preventer (BOP), and test low/high 250 psi/ 4,000 psi.

5. While maintaining a hole full of kill fluid, trip out of hole (TOOH) with 4.5" injection tubing, seal assembly, and locator sub, and lay down 4.5" tubing with thread protectors. Also, remove injection packer at 5,906' ft.

6. MIRU wireline services to perform external mechanical integrity test, and set 7-in. cast iron cement retainer (CICR).

7. Install lubricator and pressure-test to 4,000 psi for 10 minutes.

8. Make up and run in hole (RIH) with ultrasonic log–variable-density log (VDL)–casing collar locator (CCL)–temperature–GR log from plug back total depth (PBTD) (anticipated at ~6,280 ft from GR–CCL log run September 17, 2021, to surface for external mechanical integrity test – NDAC § 43-05-01-11.5(2b).
   Note: The proposed logs satisfy requirements for determining external mechanical integrity – NDAC § 43-05-01-11.2(1d).

9. Make up and RIH with CICR. Set CICR at 5,906 ft or 25 ft above top perforation.

10. Rig down and move out (RDMO) wireline unit and crew.

Isolate Broom Creek Formation

Perforations will be isolated pursuant to NDAC § 43-05-01-11.5. They will be isolated with a CO_2-resistant cement.

11. RIH with 2⅞-in. L-80 work string and sting-in into the CICR.

12. Rig up (RU) cementing equipment. Mix and pump 75 sacks (sx) of CO_2-resistant cement to squeeze from 5,906 to 6,141 ft. Displace with corrosion-inhibited spacer fluid.
Note: Assumptions on the cement properties are 14.2 ppg, 100% excess, and a yield of 1.33 ft^3*/sack.*

13. Unsting 2⅞-in. work string from CICR.

14. TOOH and lay down with work string to ± 5,906 ft. Mix and pump a cement plug of 51 sx CO_2-resistant cement to plug interval of 206 ft. Displace with corrosion-inhibited spacer fluid.
Note: Assumptions on the cement properties are 14.2 ppg, 50% excess, and a yield of 1.33 ft^3*/sack.*

Isolate Dakota Group

The Inyan Kara Formation will be isolated pursuant to NDAC § 43-05-01-11.5. The method of isolation will be a CO_2-resistant cement plug placed inside of the casing.

15. TOOH and lay down with work string to ±4,841 ft. Mix and pump a balanced plug of 188 sx CO_2-resistant cement to plug interval of 820 ft. Displace with corrosion-inhibited spacer fluid.
Note: Assumptions on the cement properties are 14.2 ppg, 50% excess, and a yield of 1.33 ft^3*/sack.*

Isolate Surface Casing Shoe

16. TOOH and lay down with work string to ±2,100 ft. Mix and pump a balanced plug of 131 sx Class G cement to plug interval of 500 ft. Displace with corrosion-inhibited spacer fluid.
Note: Assumptions on the cement properties are 15.8 ppg, 50% excess, and a yield of 1.16 ft^3*/sack.*

Isolate Surface

17. TOOH and lay down with work string to ±120 ft. Mix and pump a balanced plug of 21 sx Class G cement to plug interval of 80 ft. Displace with corrosion-inhibited spacer fluid.
Note: Assumptions on the cement properties are 15.8 ppg, 50% excess, and a yield of 1.16 ft^3*/sack.*

18. TOOH and lay down remainder of work string.

19. RD cementing equipment.

20. ND BOP and RDMO workover rig.

21. Dig out wellhead and cut off casing 5 ft below ground level (GL). Weld ½-in. steel cap on casing with well name, date inscribed (confined space entry), and information that it was used for CO_2 injection. Dig out deadmen if applicable – NDAC § 43-05-01-19(6).

22. Within 60 days, submit Form 7 plugging report after plugging operations are complete – NDAC § 43-05-01-11.5(4).

23. Submit notice of intent to reclaim to NDIC 30 days in advance prior to reclamation – NDAC § 43-05-01-18(10d).

The proposed P&A plan for the Coteau 1 is summarized in Table 10-1 and provided in Figure 10-2.

Table 10-1. Summary of P&A Plan

Cement Plug No.	Interval Range, ft		Thickness ft	Volume sacks	Note
1 Squeeze	5,906	6,141	235	75	CO_2-resistant cement plug from CICR to bottom perf. Squeezed cement will isolate perforations in the Broom Creek.
2	5,700	5,906	206	51	CO_2-resistant cement plug isolates the Broom Creek Formation and 50' above the top of the Opeche Formation.
3	4,021	4,841	820	188	CO_2-resistant cement plug isolates from 50' above the top of the Inyan Kara Formation to 50' below the base of the Inyan Kara Formation
4	1,600	2,100	500	131	Class G balanced plug to isolate the 9 ⅝" casing shoe
5	40	120	80	21	Class G balanced surface cement plug

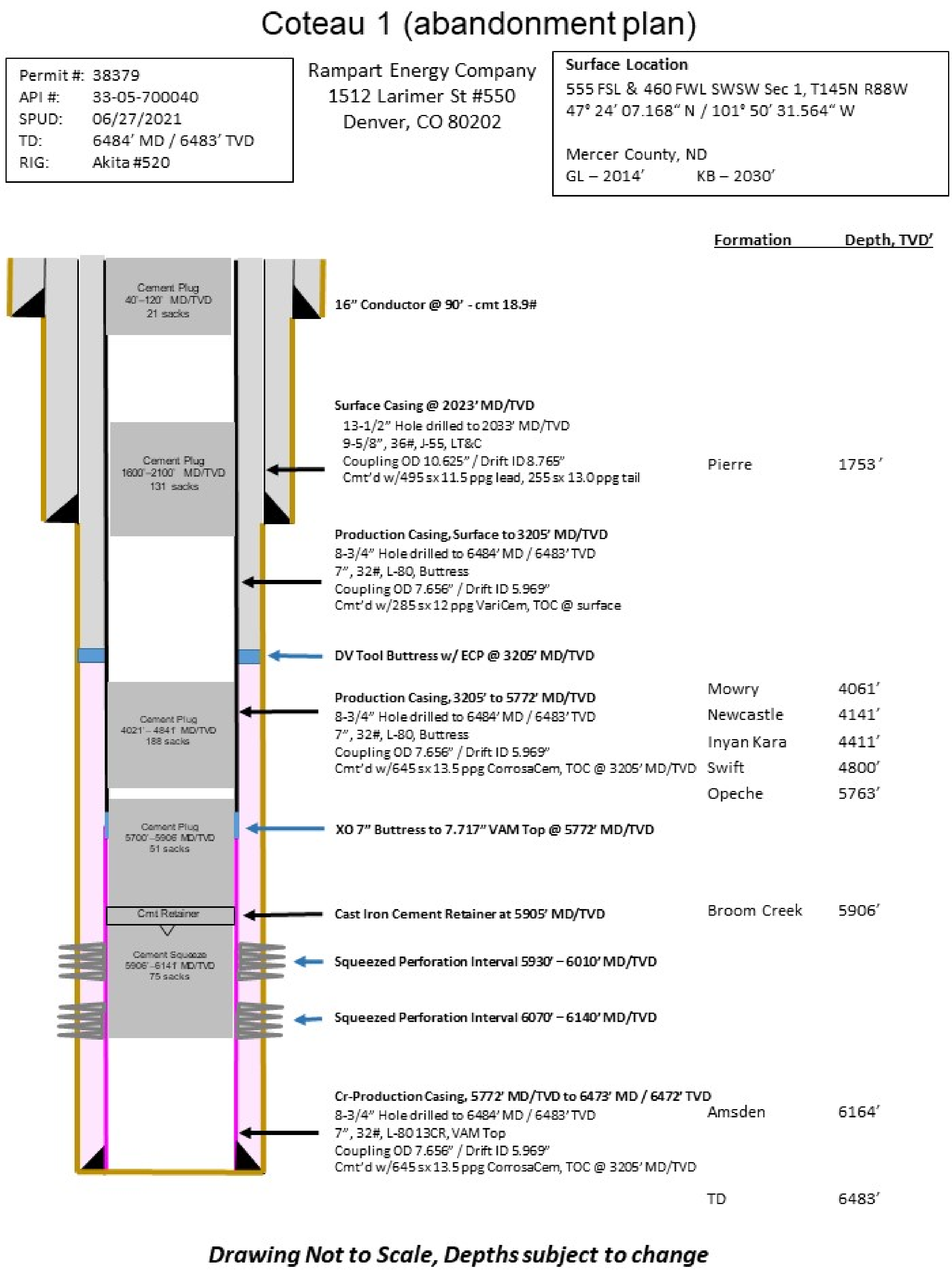


Figure 10-2. Schematic of proposed abandonment plan for each injection well.

11.0 INJECTION WELL AND STORAGE OPERATIONS

11.0 INJECTION WELL AND STORAGE OPERATIONS

This section of the storage facility permit (SFP) application presents the engineering criteria for completing and operating the injection wells in a manner that protects underground sources of drinking water (USDWs). The information that is presented meets the permit requirements for injection wells and storage operations as presented in North Dakota Administrative Code (NDAC) § 43-05-01-05 (SFP, Table 11-1) and NDAC § 43-05-01-11.3

Table 11-1. Proposed Injection Well Operating Parameters

Item	Coteau 1	Coteau 2	Coteau 3	Coteau 4	Coteau 5	Coteau 6	Total/Avg
Injected Volumes							
Total Injected Volume[1]	96.0 Bcf (4.9 MMt)	67.2 Bcf (3.4 MMt)	96.0 Bcf (4.9 MMt)	96.0 Bcf (4.9 MMt)	73.2 Bcf (3.7 MMt)	73.2 Bcf (3.7 MMt)	501.6 Bcf (25.6 MMt)
Injection Rates							
Predicted Average Injection Rate[2]	21.9 MMcfd (1,119 t/d)	15.3 MMcfd (783 t/d)	21.9 MMcfd (1,119 t/d)	21.9 MMcfd (1,119 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	114.5 MMcfd (5,845 t/d)
Predicted Maximum Injection Rate[2]	24.6 MMcfd (1,254 t/d)	17.2 mmcfd (878 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	140.0 MMcfd (7,146 t/d)
Injection Pressures							
Estimated Depth of Top Perforation (feet)[3]	5,930	5,998	5,981	5,928	5,901	5,961	5,950
Formation Fracture Pressure at Top Perforation (psi)[4]	4,210	4,259	4,247	4,209	4,190	4,232	4,224
Projected Avg Surface Injection Pressure (psi)[2]	1,628	1,597	1,644	1,604	1,682	1,677	1,639
Max Allowable Surface Injection Pressure (psi)[5]	1,976	1,998	1,993	1,975	1,966	1,986	1,982
Projected Avg Bottomhole Injection Pressure (psi)[2]	3,315	3,335	3,349	3,297	3,284	3,295	3,313
Projected Max. Bottomhole Injection Pressure (psi)[2]	3,430	3,445	3,462	3,414	3,424	3,426	3,434
Max. Bottomhole Pressure at Top Perforation (psi)[6]	3,801	3,845	3,834	3,800	3,782	3,821	3,814

[1] Assumes 55 MMcfd distributed between four wells (Coteau 1–4) from July/22 thru Dec/24, 70 MMcfd distributed between these same wells Jan/25 thru Apr/26, and 140 MMcfd distributed between six wells (Coteau 1–6) from May/26 through Jun/34.
[2] Per simulation modeling.
[3] Top perf. assumed to be 23 ft below the top of the Broom Creek Formation in all instances based on log results from Couteau 1.
[4] Based on a fracture pressure gradient of 0.71 psi/ft as calculated via CoreLabs D-Code algorithm.
[5] Based on a maximum allowable BHP equal to 90% of frac pressure and a CO_2 density of 0.306 psi/ft.
[6] Based on a maximum allowable BHP equalt to 90% of fracture pressure gradient at estimated depth of top perforation.

11.1 Coteau 1 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of the Dakota Gasification Company [DGC]) drilled and cased the Coteau 1 (Figure 9-1 and Tables 9-1 through 9-4) with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. The following proposed completion procedure outlines the steps necessary to complete the Coteau 1 well for injection purposes.

<u>Site and Well Work Preparation</u>

- Contact the NDIC and provide schedule to perform well work.
- Work road and location as needed for safe operations.
- Conduct safety meetings prior to shifts and treatments.
- Two 500-bbl tanks of 2% KCl water will be required for the step rate test.
- Well was left with no equipment in the hole, no open perforations, and filled with 2% KCl water (to a depth of 20' to avoid winter freezing).

<u>Clean Wellbore and Test Production Casing</u>

1. Move in and rig up (MIRU) workover rig.

2. Confirm zero pressure on wellhead gauges prior to removing night cap.

3. Nipple down 4-1/16" top valve and night cap.

4. Nipple up (NU) blowout preventer (BOP). Record BOP test with a low/high pressure of 250 psi/4,000 psi.

5. Pick up 2⅞" work string.

6. Trip in hole (TIH) open ended, confirm plug back total depth (PBTD). Trip out of hole (TOH).

7. Pressure-test production casing to 1,500 psi.
   a. Top off production casing with 2% KCl water.
   b. Pressure-test casing to 1,500 psi, record pressure for a minimum of 30 minutes.
   c. If casing pressure drops more than 10% variance (NDAC § 43-02-03-21), contact field engineer and DGC representative for further instructions.

<u>Run Cased-Hole Logs</u>

8. MIRU wireline service company.

9. RU wireline lubricator and pressure-test to 1,000 psi.

10. Run in hole (RIH) with temperature/gamma ray log and survey from PBTD to surface.

Perforate Broom Creek Formation

11. RIH with perforating guns and perforate the Broom Creek Formation from 5,930'–6,010' and 6,070'–6,140' (4 shots per foot, 90-degree phasing) utilizing the triple combo openhole log dated July 12, 2021, for correlation, Figure 11-1.

12. Rig down wireline service company.

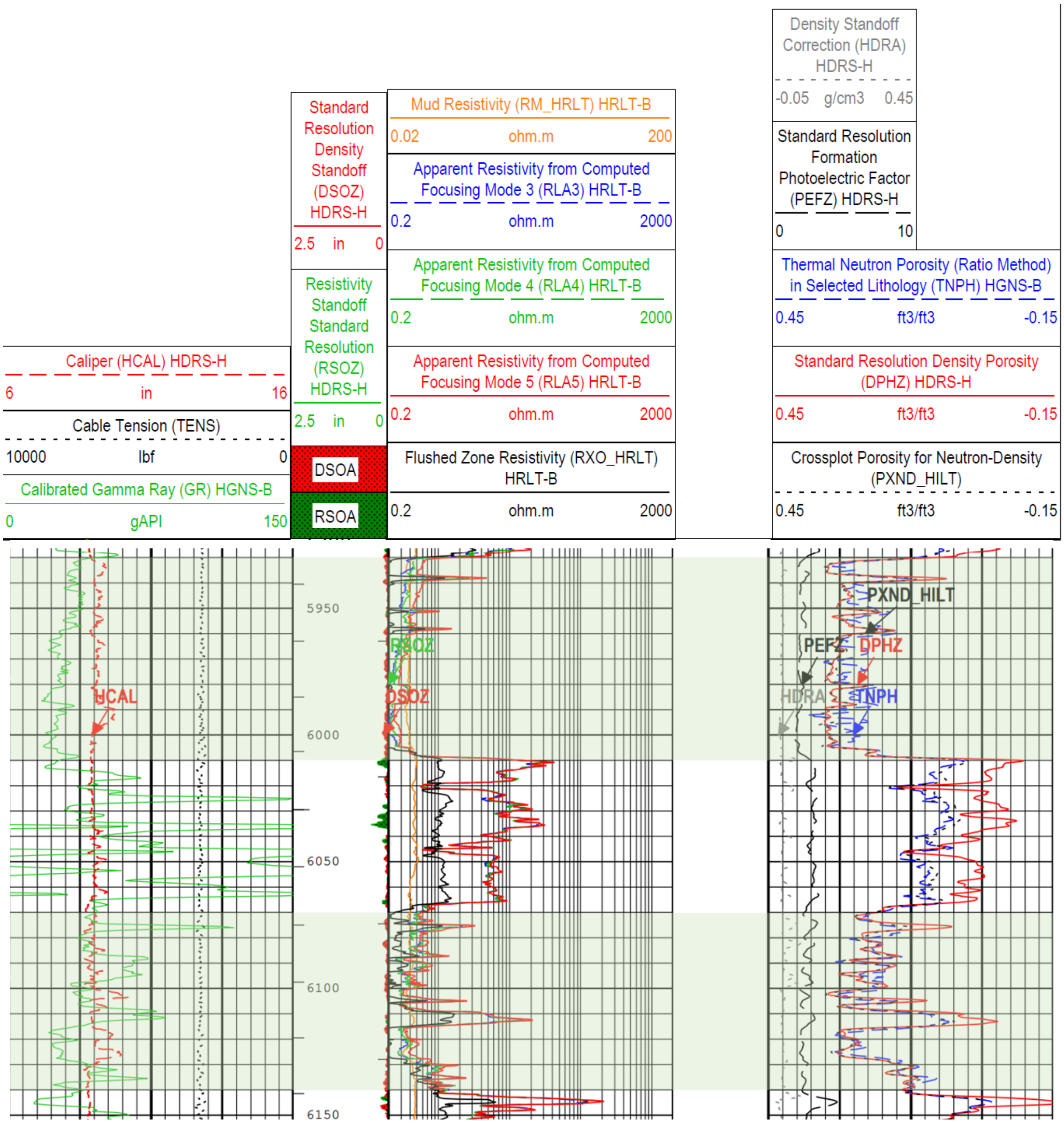


Figure 11-1. Coteau 1 proposed perforation intervals of the Broom Creek Formation (green-shaded sections based on the Coteau 1 triple combo openhole log July 2021).

Perform Step Test

13. PU 7" test packer on 2 7/8" work string, TIH, and set at ±5,900'.

14. Pressure-test packer via annulus to 2,000 psi for 30 minutes. If greater than 10% variance, contact field engineer and DGC representative for further instructions.

15. RU pump service company
    a. Pressure-test surface lines to 2,000 psi.
    b. Set pressure relief valve (PRV) at 2,000 psi or the maximum surface treating pressure.
    c. Monitor annulus with annular pressure gauge for communication.
    d. Perform proposed step rate injection test as follows:
        i. Inject at step rates of 1 barrel per minute.
        ii. Inject at constant rate for 15-min increments.
    e. After indication of formation breakdown (change in pressure slope):
        i. Continue to inject at breakdown rate for an additional 15 min.
        ii. Increase rate by 0.5 bpm for an additional 15 min.
    f. Continuously record rate vs. pressure data throughout the entire test.
    g. Shut down and record instant shut-in pressure (ISIP), 5-, 10-, and 15-min pressure readings.
    h. Shut-in well via master valve, and bleed pressure off surface lines back to pump truck.
    i. Monitor and record all pressures for initial reservoir radial flow, and continue to monitor for stable radial flow as required (NDAC § 43-05-01-11.2) and for pressure fall-off testing.
    j. RD pump service company.

16. TOH and lay down test packer and work string.

Run CO_2 Injection String

17. Change out the pipe rams from 2⅞" to 4½" and pressure-test (test low/high 250 psi/4,000 psi).

18. RU wireline service company.

19. Set 7" nickel-plated injection packer at ±5,905'.

20. Pressure-test packer to 1,500 psi.

21. RD wireline service company.

22. Make up seal assembly, locator subs, and necessary connections. RIH with 4½" L-80 tubing.

23. Pump 100 bbl corrosion-inhibited packer fluid down 4½" tubing and displace with 89 bbl 2% KCl water to displace packer fluid into the annulus.

24. Gently tag on/off tool, latch onto the on/off tool as directed by the tool hand. Verify the connection is made by slight overpull and by pumping into the tubing string. Space out and stack ±15,000-lb compression on packer, lock down, and secure. Pre-pressure-test annulus, packer, and seal bore to 1,000 psi for 30 min with rig pump. Record pressure readings every 5 min.

25. Contact NDIC to witness mechanical integrity test (MIT) 24 hr prior to official testing.
    a. Pressure well to 1,000 psi for 30 min, or as directed by NDIC while charting entire pressure test.
    b. NDIC must witness MIT in accordance with state regulations.

26. ND BOP and NU wellhead.

27. Pressure up tubing to ±2,250 psi to pump out the plug using the rig pump.

28. RDMO workover rig, continuing to be careful of wellhead equipment. Load out surplus equipment. Clear and clean location.

29. Well is to begin injection operations after NDIC approval, including approved MIT.

30. Well is completed as illustrated in Figure 11-2 and is ready for installation of surface equipment for injection operations.

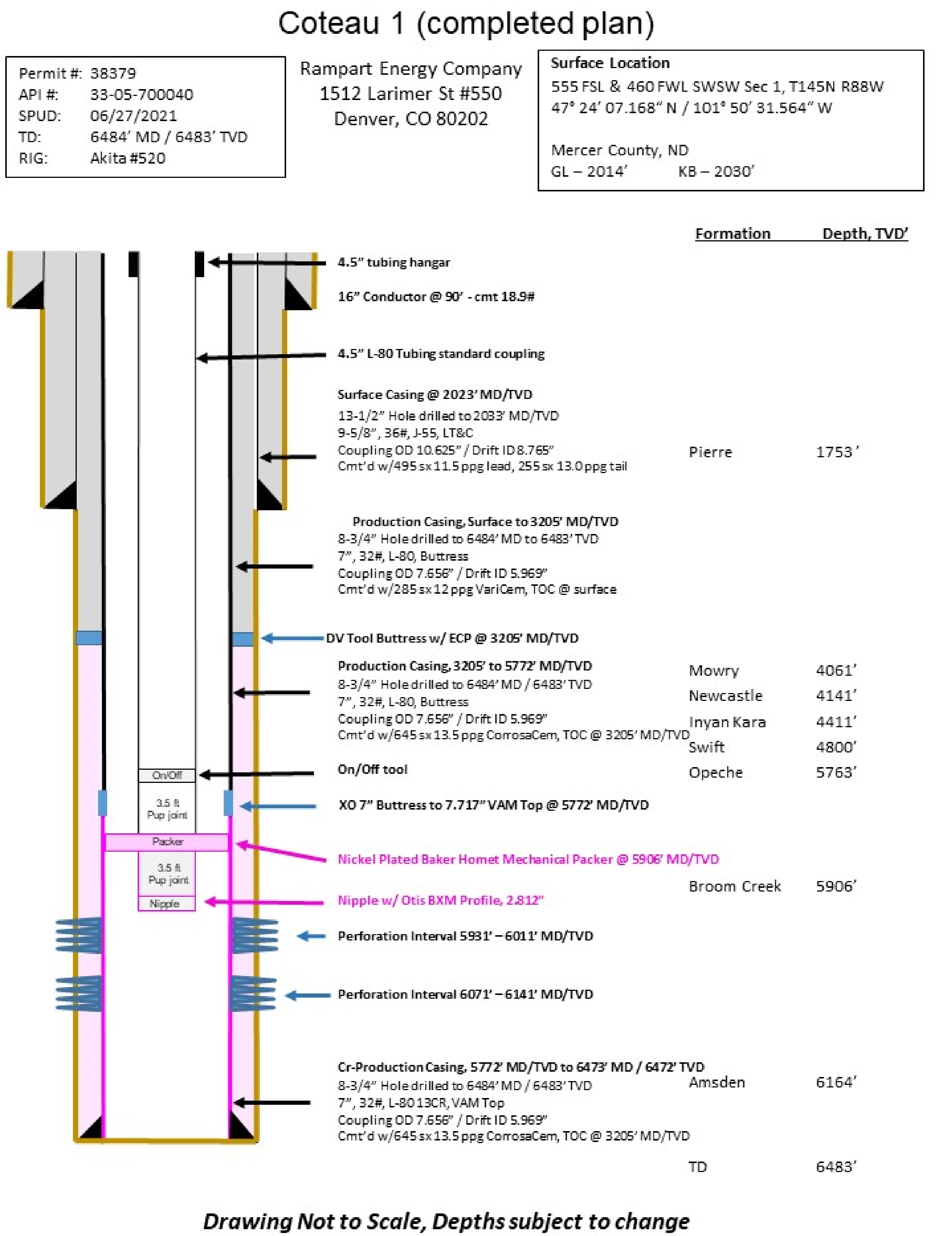


Figure 11-2. Coteau 1 proposed completed wellbore schematic.

11.2 Coteau 2 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 2 (Figure 9-3 and Tables 9-5 through 9-8) prior to project start-up in 2022, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 2 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 2 completed wellbore is shown in Figure 11-3.

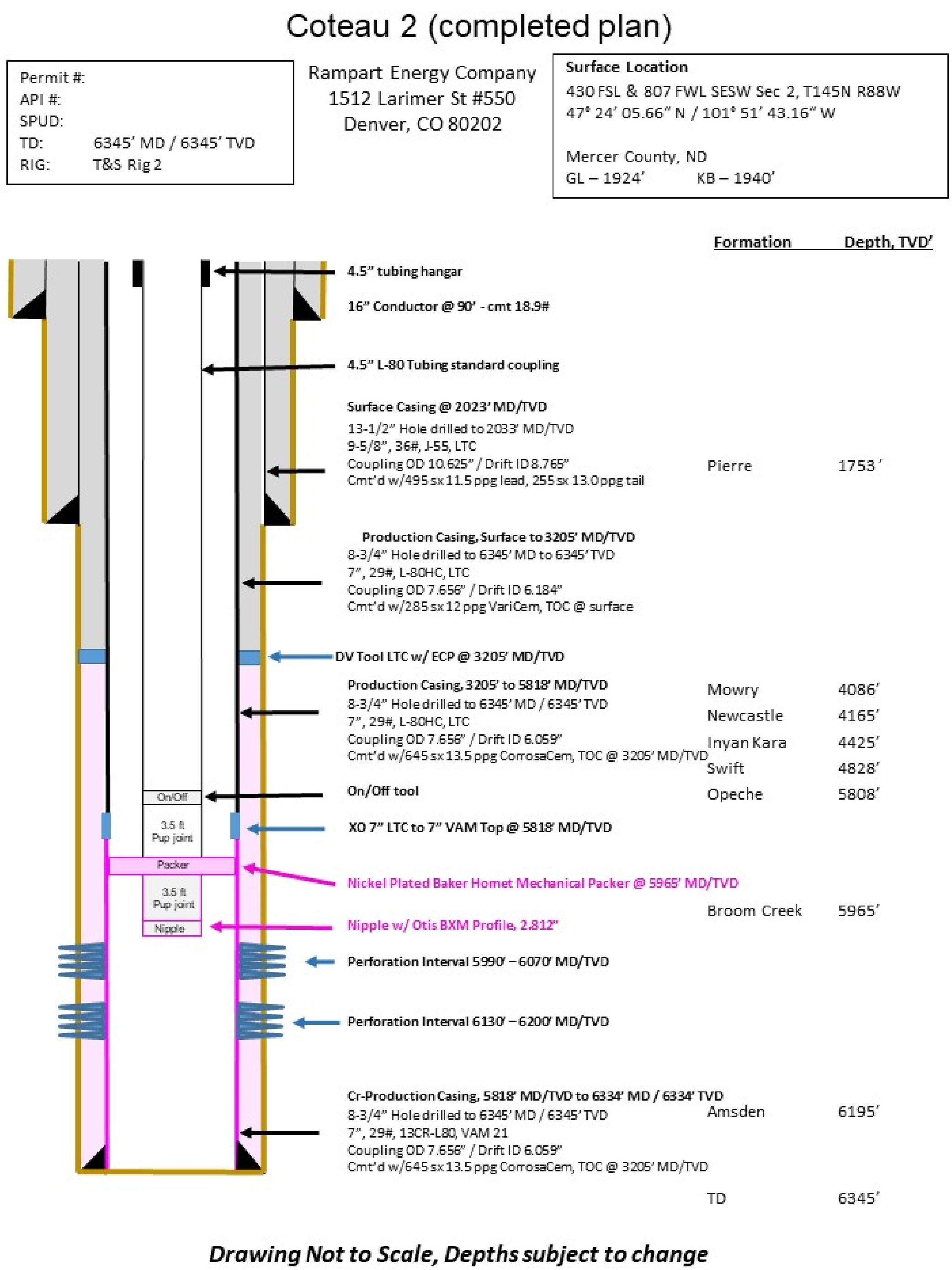


Figure 11-3. Coteau 2 proposed completed wellbore schematic.

11.3 Coteau 3 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 3 (Figure 9-4 and Tables 9-9 through 9-12) prior to project start-up in 2022, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 3 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 3 completed wellbore is shown in Figure 11-4.

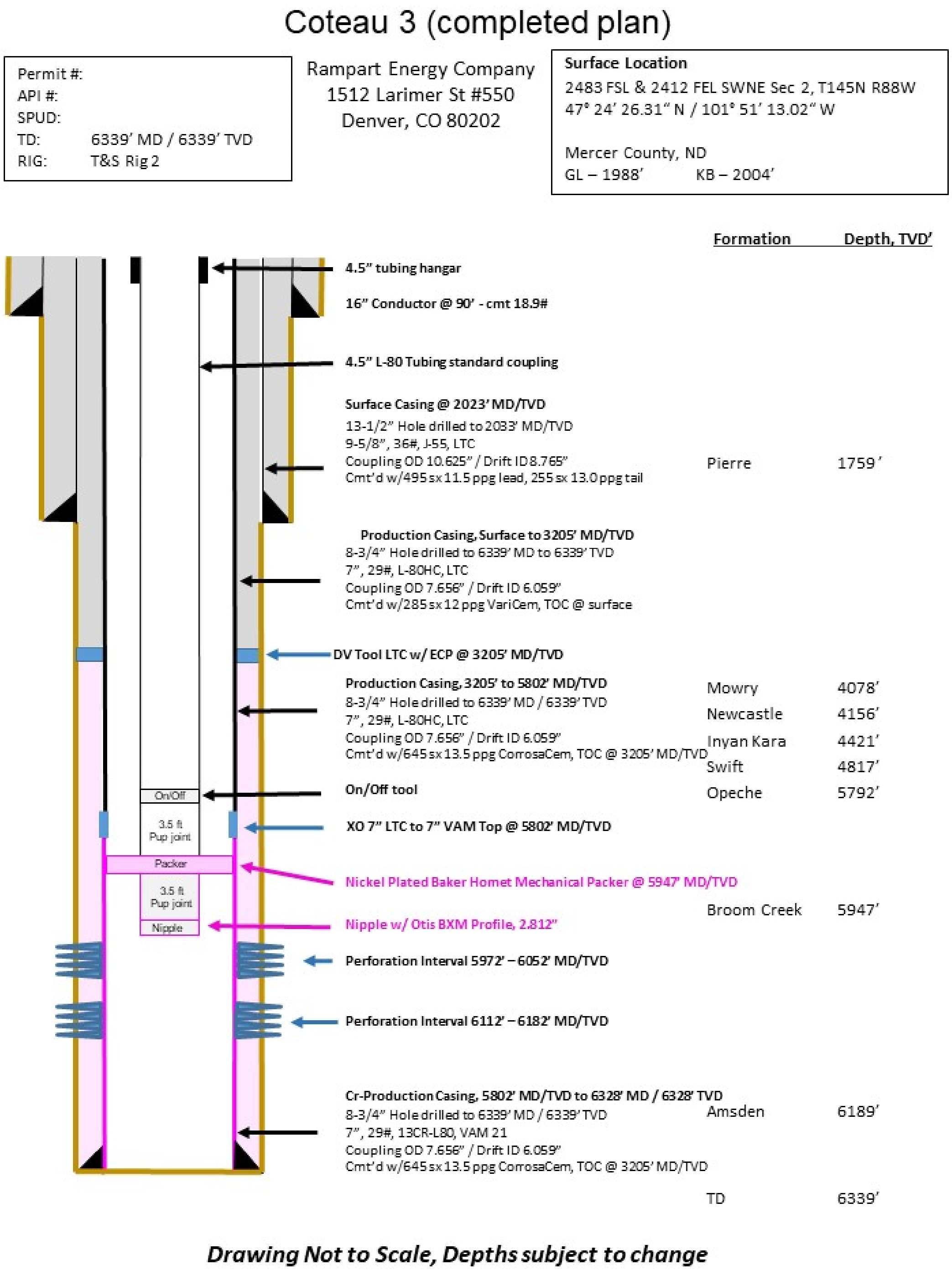


Figure 11-4. Coteau 3 proposed completed wellbore schematic.

11.4 Coteau 4 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 4 (Figure 9-5 and Tables 9-13 through 9-16) prior to project start-up in 2022, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 4 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 4 completed wellbore is shown in Figure 11-5.

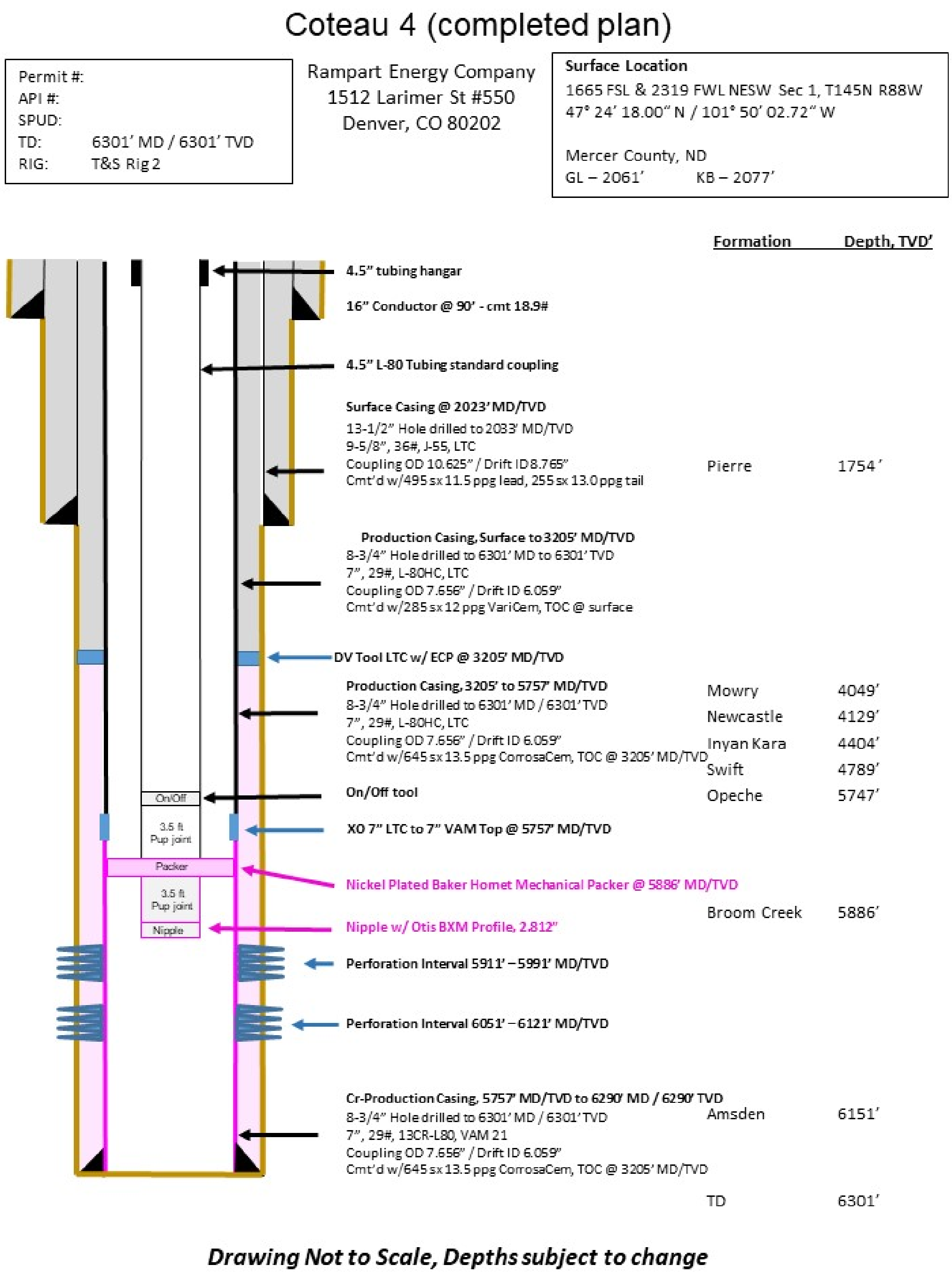


Figure 11-5. Coteau 4 proposed completed wellbore schematic.

11.5 Coteau 5 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 5 (Figure 9-6 and Tables 9-17 through 9-20) prior to an anticipated ramp-up in injection rates in 2026, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 5 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 5 completed wellbore is shown in Figure 11-6.

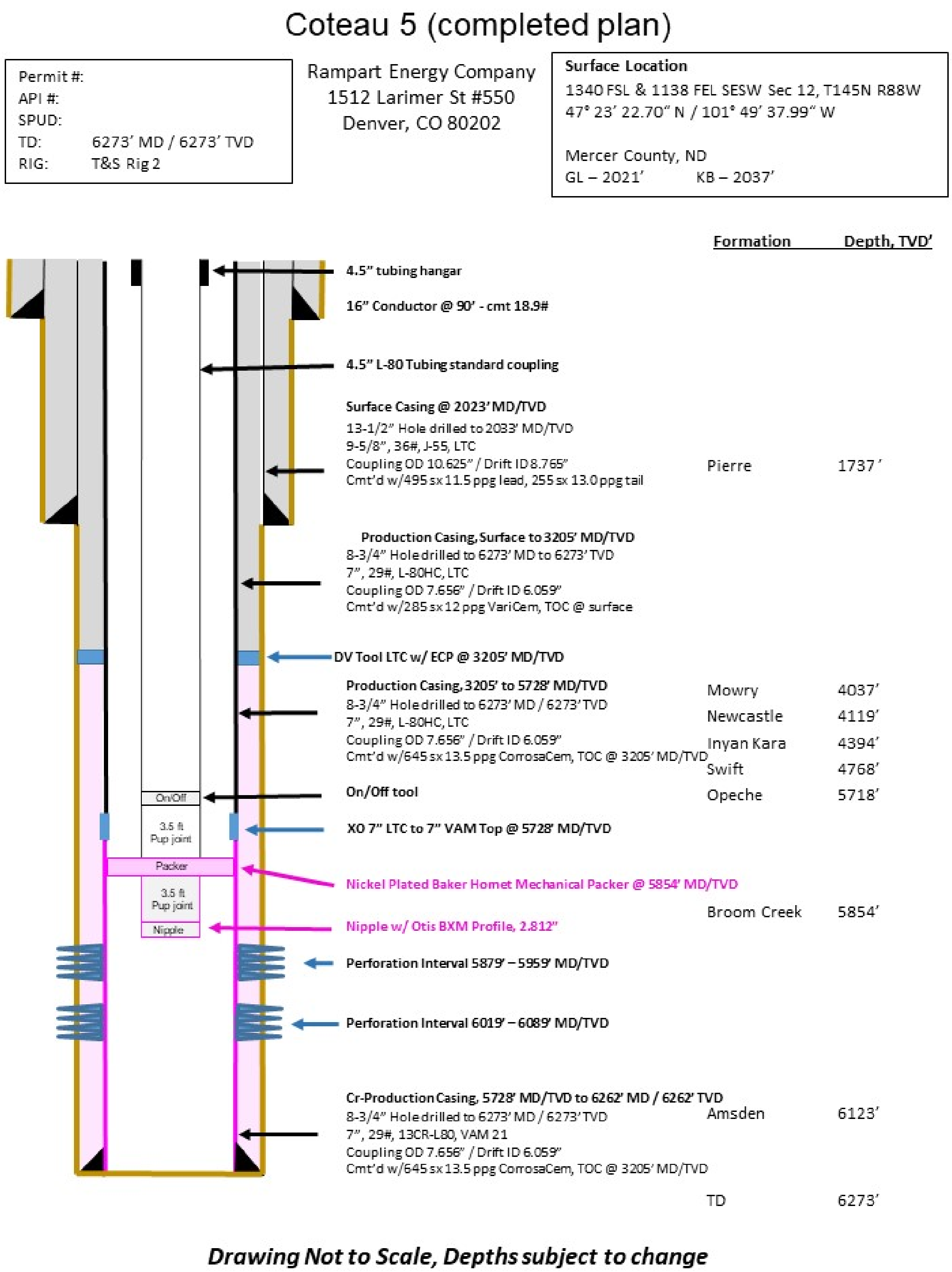


Figure 11-6. Coteau 5 proposed completed wellbore schematic.

11.6 Coteau 6 Well – Proposed Completion Procedure to Conduct Injection Operations

Rampart Energy (on behalf of DGC) intends to drill and complete Coteau 6 (Figure 9-7 and Tables 9-21 through 9-24) prior to an anticipated ramp-up in injection rates in 2026, with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. Coteau 6 will be completed and equipped in a manner consistent with that of Coteau 1. A schematic of the anticipated Coteau 6 completed wellbore is shown in Figure 11-7.

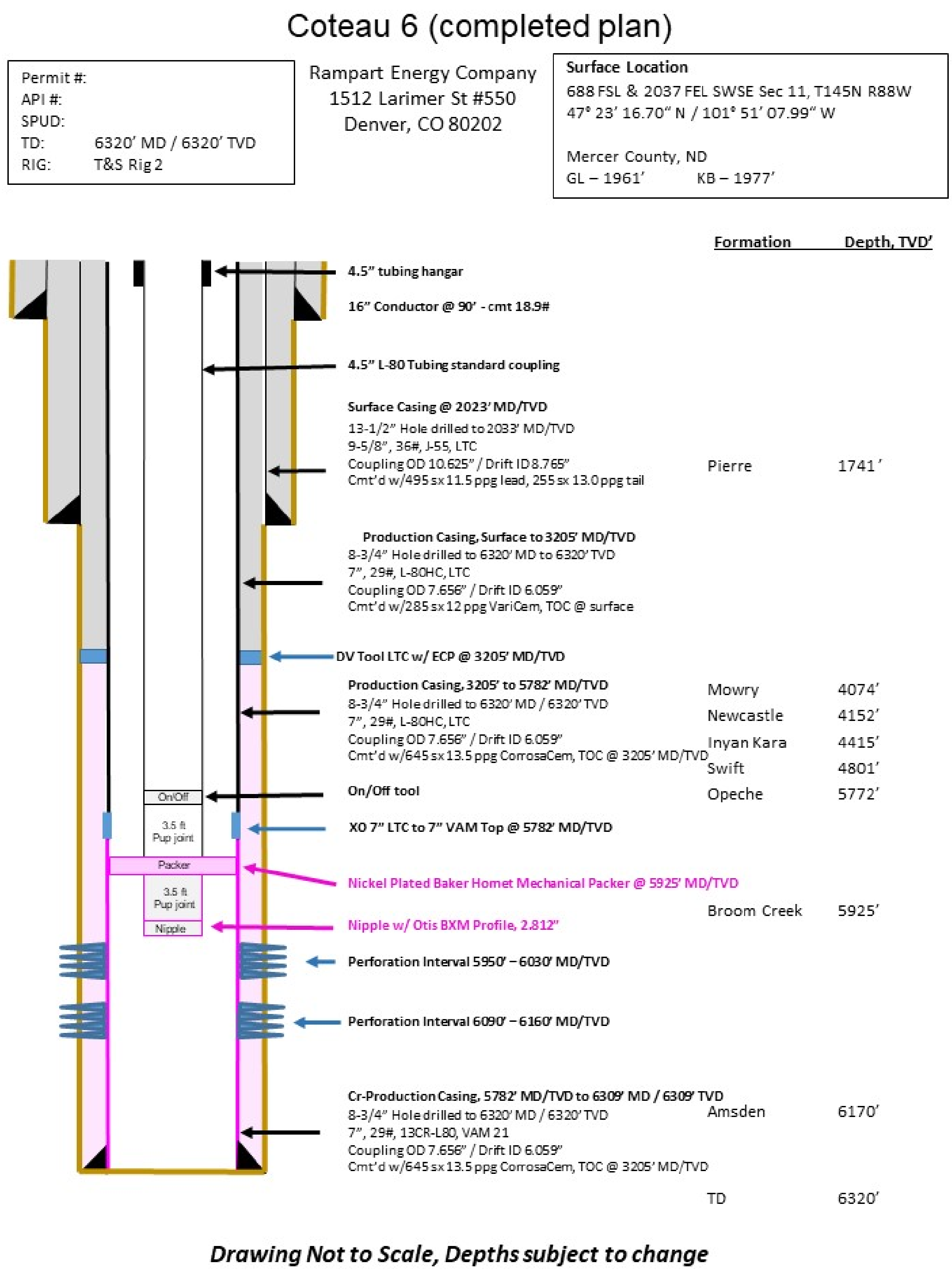


Figure 11-7. Coteau 6 proposed completed wellbore schematic.

11.7 Surface and Downhole Equipment Detail

Common packer and wellhead configurations are planned for each of the six injectors in the Great Plains CO_2 Sequestration Project (Figures 11-8 and 11-9).

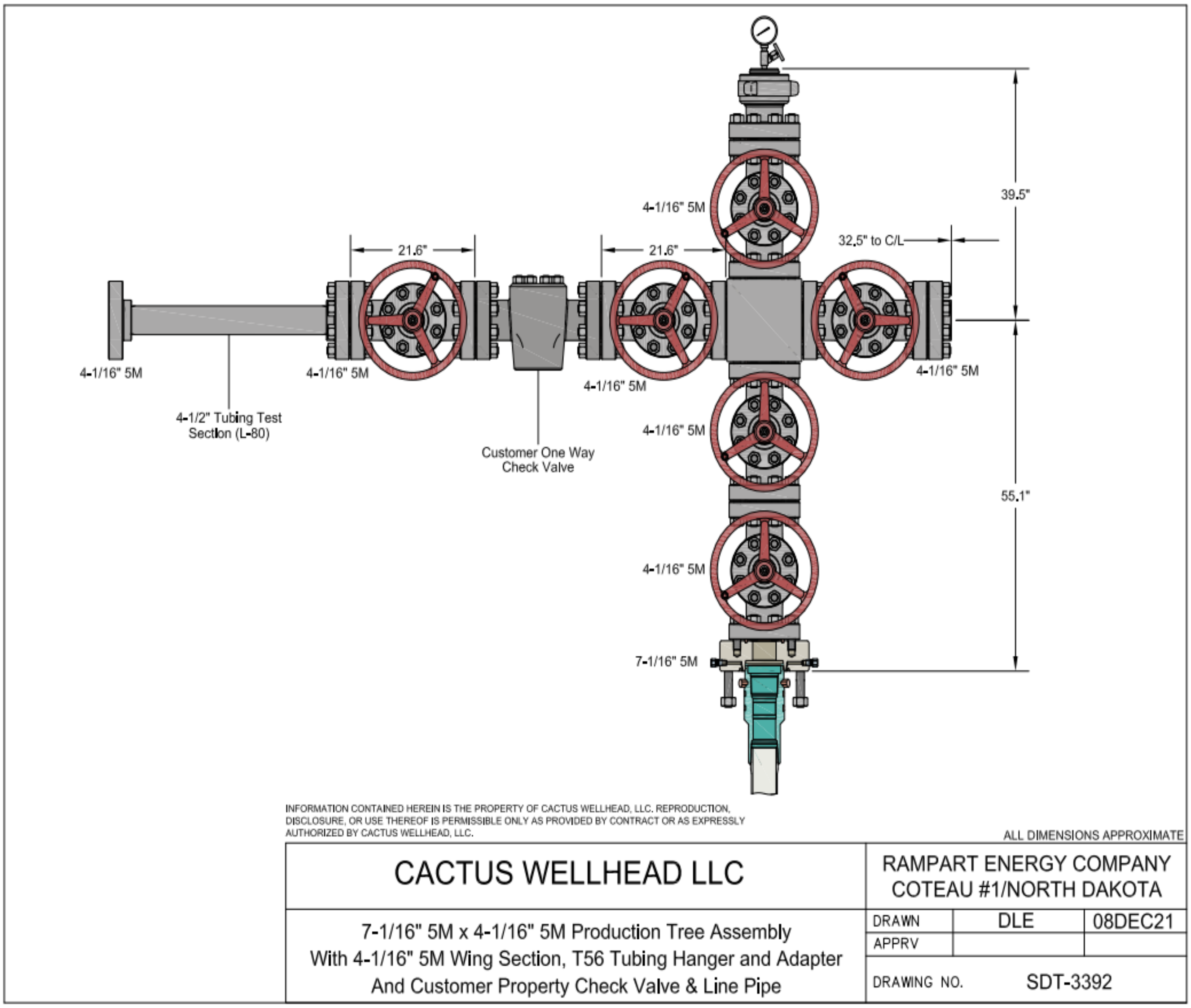


Figure 11-8. Proposed wellhead configuration for Coteau 1 through 6.

Proposed Completion Schematic

Baker Hughes

District: Minot- Bakken
District Ph:

Date Prepared: 19-Nov-2021
Prepared By: Kevin Harding

Proposal:
Revision:
Rev Date: 11/19/2021

Customer/Project	Field/Block	Lease	Well	County/Parish	State/Province
Nickel Coated Hornet Packer					

Customer Rep(s)	Rig Name	Fluid Type	Fluid Weight	BHP	BHT	Max Dev	PBTD
Bill Minnett							

Tubulars	OD (in)	Weight (lbs/ft)	ID (in)	Drift (in)	Grade	Thread	Top Depth	Bottom Depth	Comments
Casing 1	7	32.00	6.094	5.969	13Cr80	Vam Top			
Tubing 1	4 1/2				L-80				

Open Hole ID: **Hole Length:** **Casing Shoe Depth:**

No	Description	OD (in)	ID (in)	Length (ft)	Depth (ft)
1	3-1/2 EUE Pin X TBD Thread Box Nickel Plated	TBD	TBD	TBD	
2	ON/OFF TL, L-10 3.500 2.813 X Profile Nickel Plated	5.500	2.810	2.48	
3	HORNET Wireline PACKER 600-292 07.000 IN 23.0-29.0 Nickel Plated	6.000	2.920	9.71	
4	COUPLING 3.5 Nickel Plated	4.479	N/A	0.48	
5	6' PUP JOINT 3.5 IN EU 8RD Nickel Plated	3.507	2.956	5.54	
6	SEATING NIPPLE W/OTIS PROFILE 2.812 BXN PROFILE 3.5 EUE BXP 9 CHROME	4.911	3.725	1.50	
7	WLEG W/ POP Pinned 2000 PSI , 3.5" 9.2# EU B Nickel Plated	4.511	3.025	0.50	

Figure 11-9. Proposed packer assembly for Coteau 1 through 6.

12.0 FINANCIAL ASSURANCE AND DEMONSTRATION PLAN

12.0 FINANCIAL ASSURANCE AND DEMONSTRATION PLAN

This financial assurance demonstration plan (FADP) is provided to meet the regulatory requirements for the geologic storage of carbon dioxide (CO_2) as prescribed by the state of North Dakota in North Dakota Administrative Code (NDAC) § 43-05-01-09.1. The storage facility permit application must demonstrate that a financial instrument is in place that is sufficient to cover the costs associated with the following actions:

- Pursuant to NDAC § 43-05-01-05.1, corrective action on all active and abandoned wells, which are within the area of review (AOR) and penetrate the confining zone, that have the potential to endanger underground sources of drinking water (USDWs) through the subsurface movement of the injected CO_2 or other fluids.

- Pursuant to NDAC § 43-05-01-11.5, plugging of injection wells.

- Pursuant to NDAC § 43-05-01-19, implementation of postinjection site care (PISC) and facility closure activities, which includes the 10-year PISC monitoring program.

- Pursuant to NDAC § 43-05-01-13, implementation of emergency and remedial response plan (ERRP) actions.

This FADP identifies the financial instruments that will be established (Section 12.2) and provides cost estimates for each of the above actions (Section 12.3) based on the information that is provided in the storage facility permit application.

12.1 Facility Information

The facility name, facility contact, and injection well locations are provided below:

Facility Name:	Dakota Gasification Company (DGC) Great Plains Synfuels Plant
Facility Contact:	Dale Johnson, Vice President and Plant Manager
Injection Well Locations:	Coteau 1 (North Dakota Industrial Commission [NDIC] File No. 38379) SW/SW of Section 01 T145N, R88W (47.401991, -101.842101) Coteau 2 (NDIC File No. TBD) SW/SW of Section 02 T145N, R88W (47.401572, -101.861988) Coteau 3 (NDIC File No. TBD) NW/SE of Section 02 T145, R88W (47.407308, -101.853618) Coteau 4 (NDIC File No. TBD) NE/SE of Section 01 T145N, R88W (47.406940, -101.835330) Coteau 5 (NDIC File No. TBD) NE/SE of Section 12 T145N, R88W (47.389640, -101.827219) Coteau 6 (NDIC File No. TBD) SW/SE of Section 11 T145N, R88W (47.405000, -101.834090)

12.2 Financial Instruments

DGC is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments:

- DGC will establish an escrow account to cover the costs of corrective action in accordance with NDAC § 43-05-01-05.1, plug injection wells in accordance with NDAC § 43-05-01-11.5, and implement PISC and facility closure activities in accordance with NDAC § 43-05-01-19. DGC will make four annual payments of $1 million to the escrow account. The first payment will occur on or before the first day of operations, and the final payment will occur in 2025, bringing the account balance to $4 million.

- A third-party pollution liability insurance policy with an aggregate limit of $16 million will be secured to cover the costs of implementing emergency and remedial response actions, if warranted, in accordance with NDAC § 43-05-01-13.

The estimated total costs of these activities are presented in Table 12-1. Section 12.3 of this FADP provides additional details of the financial responsibility cost estimates for each activity.

Table 12-1. Cost Estimates for Activities to Be Covered

Activity	Estimated Total Cost
Corrective Action on Wells in the AOR	$0
Plugging of Injection Wells	$1,000,000
PISC and Facility Closure	$3,000,000
Emergency and Remedial Response (including endangerment to USDWs)	$16,000,000
Total	$20,000,000

The third-party insurance, which will identify DGC as the principal, will be provided by one or a combination of companies shown below. The companies meet all of the following criteria:

1. The company is authorized to transact business in North Dakota.

2. The company has either passed the specified financial strength requirements based on credit ratings or has met a minimum rating, minimum capitalization, and ability to pass the rating, when applicable.

3. The third-party insurance can be maintained until such time that NDIC determines that the storage operator has fulfilled its financial obligations.

The third-party insurance, which identifies DGC as the covered party, will be provided by one or a combination of the companies shown below. The coverage limits of the policy are summarized below:

DGC has procured indicated terms for commercial environmental impairment liability (EIL) insurance coverage to fund covered emergency and remedial response actions to protect USDWs arising out of sequestration operations. Coverage terms are of an estimated nature only at this time, as firm and bindable terms are not possible this far in advance of commencement of sequestration operations. At this time, a coverage limit of $25 million per occurrence/aggregate is contemplated and expected to be provided by one or a combination of the following insurers:

- Ascot Insurance Group – AM Best-Rated A (excellent)
- Aspen Insurance Group – AM Best-Rated A (excellent)
- W.R. Berkley Insurance Group – AM Best-Rated A+ (superior)

Final coverage terms and costs will be determined upon full underwriting and firm/bindable quotations to be issued by insurers 30 to 60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations.

The third-party insurance companies listed above meet both of the following criteria, as specified in NDAC §43-05-01-09.1(1)(g):

1. The companies satisfy financial strength requirements based on credit ratings in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa).

2. The companies meet a minimum rating (minimum rating based on an issuer, credit, securities, or financial strength rating as a demonstration of financial stability) and minimum capitalization (i.e., demonstration that minimum thresholds are met for the following financial ratios: debt–equity, assets–liabilities, cash return on liabilities, liquidity, and net profit) and are able to pass bond rating in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa), when applicable.

12.3 Financial Responsibility Cost Estimates

12.3.1 Corrective Action

DGC implemented the following workflow to estimate costs associated with corrective action activities: 1) delineate the AOR and 2) identify and evaluate active and abandoned legacy wells within the AOR (i.e., ANG#1 and ANG#2) to ensure they meet the minimum completion standards for geologic storage of CO_2 and need no corrective action. Based on the results of the well evaluations, no correction action was needed.

12.3.2 Plugging of Injection Wells

DGC implemented the following approach to estimate costs associated with the plugging of injection wells: assume plugging of six Class VI injection wells at a total cost of $1 million, or $167,000 per well.

12.3.3 Implementation of PISC and Facility Closure Activities

The breakdown of estimated costs totaling $3 million for implementing the PISC as described in the PISC and facility closure plan is provided in Table 12-2, which includes the following: a) near-surface monitoring (i.e., soil gas and Fox Hills Formation testing), b) formation monitoring (i.e., downhole pressure and temperature surveys, pulsed-neutron logs) and mechanical integrity well tests (i.e., injection well annulus pressure, ultrasonic logs), c) coordinated repeat 2D seismic, and d) estimated cost of site closure activities, which has been estimated at $100K based on the integrated environmental control.

Table 12-2. Cost Estimates for 10-year PISC Monitoring Efforts

Monitoring Type	Comments	Total Estimated Cost
Near-Surface Monitoring		
Soil Gas Sampling and Analysis	10 years at $25,000 per year	$250,000
Fox Hills Sampling and Analysis	10 years at $25,000 per year plus $300,000 for site closure activities	$550,000
Geophysical Monitoring		
2D Seismic Data Acquisition	Perform four 2D seismic surveys (PISC years 1, 3, 5, and 10) at $550,000 per survey	$2,200,000
	Total	**$3,000,000**

12.3.4 Implementation of Emergency and Remedial Response Actions

12.3.4.1 Emergency Response Actions

A review of the technical risk categories for DGC's Great Plains CO_2 Sequestration Project identified a list of events that could potentially result in the movement of injected CO_2 or formation fluids in a manner that may endanger a USDW and require an emergency response. These events are as follows:

- Failure of the surface equipment
- Integrity failure of injection well
- Injection well-monitoring equipment failure
- Storage reservoir is unable to contain the formation fluid or stored CO_2
- Natural disasters

If it is determined that one or more of these events have occurred, the emergency response actions that will be implemented are described in the ERRP (Section 7). These response actions are summarized in Table 12-3.

Table 12-3. Response Actions for Potential Emergency Events

Emergency Event	Response Action
Failure of CO_2 Transmission Line or Flow Lines from DGC CO_2 Capture System to CO_2 Injection Wellheads	• The CO_2 stream release and its location will be detected by the leak detection system, which will trigger an alarm and result in the automated shutdown of the transmission line and wellsite flow line. • If warranted, initiate an evacuation plan. • The transmission line and/or flow line failure will be inspected to determine the root cause of the failure. • Repair/replace the damaged transmission line or flow line, and if warranted, put in place the measures necessary to eliminate such events in the future.
Integrity Failure of Injection Well	• Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure. • Stop CO_2 injection, and purge CO_2 from surface facilities. • Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the NDIC Department of Mineral Resources (DMR) underground injection control (UIC) program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).
Injection Well-Monitoring Equipment Failure	• Monitor well pressure, temperature, and annulus pressure (manually if necessary) to determine the cause and extent of failure. • Stop CO_2 injection, and purge CO_2 from surface facilities. • Identify and, if necessary, implement appropriate remedial actions to repair/replace well-monitoring equipment (in consultation with the NDIC DMR UIC program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).

Continued . . .

Table 12-3. Response Actions for Potential Emergency Events (continued)

Emergency Event	Response Action
Storage Reservoir Unable to Contain Formation Fluid or Stored CO_2	• Collect confirmation sample(s) of groundwater, soil gas, ambient air, and/or surface water, and analyze them for indicator parameters (see testing and monitoring plan of the supporting plans of the storage facility permit application). • If the presence of indicator parameters is confirmed, develop (in consultation with the NDIC DMR UIC program director) a case-specific work plan to: 1. Install additional monitoring points near the impacted area to delineate the extent of impact. a. If a USDW is impacted above drinking water standards, arrange for an alternative potable water supply for all users of that USDW. b. If a surface release of CO_2 to the atmosphere is confirmed, initiate an evacuation plan, if warranted, in tandem with an appropriate workspace and/or ambient air-monitoring program at the plant boundary to monitor the presence of CO_2 and its natural dispersion following the termination of CO_2 injection, following practices similar to those described in the DGC risk management plan for analyzing the potential impacts of other chemical releases from the DGC plant. c. If surface release of CO_2 to surface waters is confirmed, implement appropriate surface water-monitoring program to determine if water quality standards are being exceeded. 2. Proceed with efforts, if necessary, to 1) remediate the USDW to achieve compliance with drinking water standards (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to air-strip CO_2 from the impacted water or implement other active remediation processes) and reinject treated water into the subsurface, 2) monitor CO_2 concentrations in the workspace and ambient air to

Continued . . .

Table 12-3. Response Actions for Potential Emergency Events (continued)

Emergency Event	Response Action
Storage Reservoir Unable to Contain Formation Fluid or Stored CO_2 (continued)	document reduction of CO_2 concentrations to background levels over time, and 3) monitor the reduction of impacts to surface waters to background levels as a result of natural attenuation processes or implement active/passive remediation of surface waters to achieve acceptable background levels of impacts. • Continue all remediation and monitoring at an appropriate frequency (as determined by DGC and the NDIC DMR UIC program director) until the unacceptable, adverse impacts have been fully addressed.
Natural Disasters (seismic event)	• Identify where (i.e., the epicenter) and when the event occurred. • Determine whether there is a connection with injection activities. • Determine mechanical integrity of all project wells and formation seals. • If warranted, stop CO_2 injection, purge CO_2 from surface facilities, and implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).
Natural Disasters (other)	• Monitor well pressure, temperature, and annulus pressure to verify status of wells and determine the cause and extent of any failure. • If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate extent of any impacts. • If impacts or endangerment of USDWs are detected, identify and implement appropriate response actions in accordance with the DGC emergency action plan (in consultation with the NDIC DMR UIC program director).

12.3.4.2 Estimation of Costs of Emergency Response Actions

Estimating the costs of implementing the emergency response actions in Table 12-3 is challenging since remediation measures specifically dedicated to CO_2 storage impacts are poorly documented, with one of the more important data gaps being the lack of precise knowledge of the leakage mechanisms and associated impacts (Manceau and others, 2014). Without this knowledge, it is not possible to design appropriate remedial measures. Furthermore, to date, no remediation action following CO_2 leakage after geologic storage has ever been implemented mainly because of the absence of established impacts (Manceau and others, 2014). Consequently, the degree of maturity of remediation measures in the carbon capture and storage (CCS) field is low, making it necessary to rely on literature that is primarily based on modeling or analogies with other pollutants, e.g., the analogy between CO_2 and volatile organic compounds, the latter having been addressed extensively in the literature. Additionally, for the remedial measures, costs and time for adequate removal are generally site-dependent, and no information is specifically available in this area in the CCS field.

Based on this current situation, two key technical manuscripts were relied upon to identify and estimate the costs of mitigation/remediation technologies to address undesired migration of CO_2 from a geological storage unit (Manceau and others, 2014, and Bielicki and others, 2014).

<u>12.3.4.2.1 Identification of Remediation Technologies</u>

Manceau and others (2014) identified several remediation technologies/strategies that are available to address the potential impacted media that may result from an emergency event. These impacted media and remediation measures are listed in Table 12-4. The impacted media in Table 12-4 include surface and groundwater/USDWs, vadose zone, indoor settings, and atmosphere; the remedial measures include a combination of active (e.g., air sparging) and passive (e.g., dispersion, natural attenuation) systems. However, it is important to note that, at this time, there is no widely accepted methodology for designing intervention and remediation plans for CO_2 geologic storage projects. Consequently, there remains a need for establishing the best field-applied and test practices for mitigating an undesired CO_2 migration. This effort will be based on a combination of available literature and experience that is gained over time in existing CO_2 storage projects.

Table 12-4. Proposed Technologies/Strategies for Remediation of Potential Impacted Media

Impacted Media	Potential Remedial Measures
Groundwater/USDW	Monitored natural attenuation
	Pump-and-treat
	Air sparging
	Permeable reactive barrier
	Extraction/injection
	Biological remediation
Vadose Zone	Monitored natural attenuation
	Soil vapor extraction
	pH adjustment (via spreading of alkaline supplements, irrigation, and drainage)
Surface Water	Passive systems, e.g., natural attenuation
	Active treatment systems
Atmosphere	Passive systems, e.g., natural mixing, dispersion
Indoor/Workplace Settings	Sealing of leak points
	Depressurization
	Ventilation

12.3.4.2.2 Estimation of Costs for Implementing Emergency Event Responses

Given the lack of a site-specific estimate of implementing the emergency event responses at the CO_2 geologic storage site of DGC, cost estimates developed by Bielicki and others (2014) were used to derive a cost range for the project related to the undesired migration of CO_2 from a geologic storage unit. Extrapolating these literature costs, which were based on a case study site in the Michigan Sedimentary Basin, to DGC's Great Plains CO_2 Sequestration Project only provides an order-of-magnitude estimate of the potential costs due to the significant site-specific differences in the storage projects; however, the range of costs estimated in this manner are believed to be conservatively high in nature, making them more than sufficient for informing the value of the financial instrument that must be secured for the project, as described in the financial responsibility demonstration plan.

Case Study Description

Bielicki and others (2014) examined the costs associated with remediating undesired migration of CO_2 from a geologic storage unit as part of a case study of an extreme leakage situation. The case study involved the continuous annual injection of 9.5 Mt (9,500,000 metric tons) of CO_2 into the Mt. Simon sandstone of the Michigan Sedimentary Basin over a period of 30 years. It assumed every well in the basin was a potential leakage pathway and that no action was taken to mitigate any of these leakage pathways. In addition, eight UIC Class I injection wells, which were located within approximately 1 mile of the CO_2 injection well, were also identified as leakage pathways. Four hundred probabilistic simulations of the CO_2 injection were performed and produced estimates of the area of the CO_2 plume as well as leakage rates of CO_2 from the storage reservoir to four aquifers as well as to the surface.

Cost Estimates

Story lines were developed for the site based on 1) risk assessments for the geologic storage of CO_2; 2) consequences of leakage; 3) lay and expert opinion of leakage risk; 4) modeling of CO_2 injection and leakage for the case study; and 5) input from local experts, oil and gas engineers, academics, attorneys, and other environmental professionals familiar with the Michigan Sedimentary Basin. Cost estimates for managing leakage events were then generated for first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) projects based on a low-cost and high-cost story line. These cost estimates provided a breakdown of the costs into the following categories:

- Find and fix a leak
- Environmental remediation
- Injection interruption
- Technical remedies for damages
- Legal costs
- Business disruption to others, e.g., natural gas storage
- Labor burden to others

Of interest for the financial responsibility demonstration plan is the environmental remediation cost estimate, which was provided for a leak scenario where there was interference with groundwater as well as a scenario where there was groundwater interference combined with CO_2 migration to the surface.

Environmental Remediation – Low-Cost and High-Cost Story Line

The low-cost and high-cost story lines for the two components of environmental remediation, groundwater interference and migration to the surface, are summarized in Table 12-5. As shown in Table 12-5, the low-cost story lines are characterized by independent leak scenarios that either result in interference with groundwater or CO_2 migration to the surface. On the other hand, the high-cost story lines are interrelated, where it is assumed that the high-cost story line for CO_2 migration to the surface is conditional upon the existence of the high-cost story line for groundwater interference.

Estimated Environmental Remediation Costs – FOAK and NOAK Projects

Based on the above story lines, the estimated environmental remediation costs for the high-cost story lines are basically the same for both FOAK and NOAK projects:

- High-cost story line – Groundwater interference alone: ~ \$13MM
- High-cost story line – Groundwater interference with CO_2 migration to the surface: \$15MM to \$16MM

12.3.4.2.3 Input for the Financial Responsibility Demonstration Plan

The estimated costs for the environmental remediation of the high-cost story line for the case study, \$15MM to \$16MM, likely represents a conservatively high estimate of similar costs for DGC's Great Plains CO_2 Sequestration Project. This statement is based primarily on the fact that the quantity of CO_2 injection of the case study (9,500,000 metric tons of CO_2 per year) is significantly larger than the planned injection quantity of DGC's Great Plains CO_2 Sequestration Project (from 1.1 to 2.7 million metric tons of CO_2 per year). Furthermore, the case study site had 450,000 active and abandoned wells, 400,000 of which penetrate the shallow subsurface to provide for drinking water, irrigation, and industrial uses. In contrast, there are six proposed CO_2 injection wells and two wastewater disposal wells (ANG#1 and ANG#2) located in the area of DGC's Great Plains CO_2 Sequestration Project. As such, the extreme leakage scenario of the case study represents a more extensive leakage scenario that could exist at the DGC site. Accordingly, even though the same remedial technologies and strategies may be used at both sites to address CO_2 migration, it is assumed that the cost estimates provided for the case study represent a conservatively high maximum cost for DGC's Great Plains CO_2 Sequestration Project. It is on this basis that the value of $16MM has been used as one of the cost inputs into the determination of the financial instrument that will be put in place for DGC's Great Plains CO_2 Sequestration Project.

Table 12-5. Low-Cost and High-Cost Story Line for Environmental Remediation

Low-Cost Story Line	
Groundwater Interference	• A small amount of CO_2 migrates into a deep formation that has a total dissolved solids concentration of ~9000 ppm. By definition, this unit is a USDW, but the state has abundant water resources, and there are no foreseeable uses for water from this unit. • Regulators require that two monitoring wells be drilled into the affected USDW and three monitoring wells be drilled into the lowermost potable aquifer (total dissolved solids concentration of <1000 ppm) to verify the extent of the impacts of the leak. No legal action is taken. • Injection is halted from the time that the leak is discovered until monitoring confirms that containment is effective (9 months). • The UIC regulator determines that no additional remedial actions are necessary.
CO_2 Migration to the Surface	• A leaking well provides a pathway whereby CO_2 discharges directly to the atmosphere. • Neither CO_2 nor brine leaks into the subsurface formation outside the injection formation in significant quantities. • The CO_2 injection is halted for 5 days, and the leaking well is promptly plugged.
High-Cost Story Line	
Groundwater Interference	• A community water system reports elevated arsenic. Monitoring suggests that the native arsenic in the formation may have been mobilized by pH changes in the aquifer caused by CO_2 impacts to the aquifer. • A new water supply well is installed to serve the community, and the former water supply wells are plugged and capped. • Potable water is provided to the affected households during the 6 months required to drill the new water supply wells. • Groundwater regulators take legal action on the geologic storage operator to force remediation of the affected USDW using pump-and-treat technology. • UIC regulators require remedial action to remove, through a CO_2 extraction well, an accumulation of CO_2 that has the potential to affect the drinking water. • CO_2 injection is halted for 1 year during these remediation activities.
CO_2 Migration to the Surface	• The high-cost story line for groundwater is required. • A hyperspectral survey completed during the diagnostic monitoring program identifies surface leakage in a sparsely populated area. • Elevated CO_2 concentrations are detected by a soil gas survey and by indoor air quality sampling in the basements of several residences. • Affected residents are housed in a local hotel for several nights while venting systems are installed in their basements. • A soil-venting system is installed at the site. • CO_2 injection is halted for a year during these remediation activities.

To provide additional perspective for this $16MM cost estimate for environmental remediation, two other cost estimates for the remediation of potential environmental impacts associated with the geologic storage of CO_2 were found in the literature. These costs ranged from $9MM to $34MM. The source of the lower limit ($9MM) was a 2012 study (Trabucchi and others, 2012) which estimated the damages, i.e., dollars necessary to remediate or compensate for harm should a release occur at a commercial storage site (i.e., FutureGen 1.0 located in Jewett, Texas) that planned to inject 1,000,000 metric tons of CO_2 per year. This study estimated the "most likely (50th percentile)" total damages to be approximately $8.7MM and the "upper end (95th and 99th percentiles)" of the total damages to be approximately $20.1MM and $26.2MM, respectively (all estimates in 2020 dollars).

The upper limit of the range ($34MM) came from a Class VI UIC permit, which was issued to Archer Daniels Midland (ADM) by the U.S. Environmental Protection Agency (Underground Injection Control Permit – Class VI, Permit No. IL-115-6A-0001). As part of the financial responsibility demonstration plan of the ADM permit, a cost estimate of $33.8MM was provided for the cost element, emergency and remedial response, which is slightly higher than the 99th percentile cost estimate of $26.2MM for the FutureGen 1.0 site. The planned injection rate for the ADM geologic storage project was ~1,200,000 metric tons per year.[1]

12.4 References

Bielicki, J.M., Pollak, M.F., Fitts, J.P., Peters, C.A., and Wilson, E.J., 2013, Causes and financial consequences of geologic CO_2 storage reservoir leakage and interference with other subsurface resources: International Journal of Greenhouse Gas Control, v. 20, p. 272–284.

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Trabucchi, C., Donlan, M., Huguenin, M, Konopka, M., and Bolthrunis, S., 2012, Valuation of potential risks arising from a model, commercial-scale CCS project site: Prepared for CCS Valuation Sponsor Group, June 1, 2012.

[1] It should be noted that both of these examples are injecting CO_2 at a rate that is approximately the same planned injection at the DGC Great Plains Synfuels Plant CO_2 facility, which suggests that these cost estimates are likely similar to the costs that will be required for DGC's Great Plains CO_2 Sequestration Project.

APPENDIX A

COTEAU 1 FORMATION FLUID SAMPLING

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 14 Oct 21
Lab Number: 21-W3667
Work Order #:82-2651
Account #: 72540
Date Sampled: 28 Sep 21 19:35

Bill Minnett
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Date Received: 29 Sep 21 7:44
Sampled By: MVTL Field Service

Project Name: Coteau #1
Sample Description: Broom Creek

Temp at Receipt: 4.1C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	29 Sep 21	AC
pH	* 6.7	units	N/A	SM4500-H+-B-11	29 Sep 21 17:00	EMS
Conductivity (EC)	62019	umhos/cm	N/A	SM2510B-11	29 Sep 21 17:00	EMS
pH - Field	7.04	units	NA	SM 4500 H+ B	28 Sep 21 19:35	JSM
Temperature - Field	20.2	Degrees C	NA	SM 2550B	28 Sep 21 19:35	JSM
Total Alkalinity	853	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Bicarbonate	853	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	29 Sep 21 17:00	EMS
Conductivity - Field	48194	umhos/cm	1	EPA 120.1	28 Sep 21 19:35	JSM
Cation Summation	701	meq/L	NA	SM1030-F	5 Oct 21 13:41	Calculated
Anion Summation	729	meq/L	NA	SM1030-F	1 Oct 21 14:38	Calculated
Percent Error	-2.00	%	NA	SM1030-F	5 Oct 21 13:41	Calculated
Total Organic Carbon	98.0	mg/l	0.5	SM5310C-11	1 Oct 21 16:29	NAS
Sulfate	469	mg/l	5.00	ASTM D516-11	1 Oct 21 14:38	SD
Chloride	24900	mg/l	2.0	SM4500-Cl-E-11	29 Sep 21 15:49	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	30 Sep 21 12:06	SD
Ammonia-Nitrogen as N	111	mg/l	0.20	EPA 350.1	5 Oct 21 13:41	SD
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	6 Oct 21 14:13	MDE
Total Dissolved Solids	42800	mg/l	10	USGS I1750-85	1 Oct 21 14:57	AC
Calcium - Total	1860	mg/l	1.0	6010D	4 Oct 21 11:34	SZ
Magnesium - Total	212	mg/l	1.0	6010D	4 Oct 21 11:34	SZ
Sodium - Total	12800	mg/l	1.0	6010D	4 Oct 21 11:34	SZ
Potassium - Total	516	mg/l	1.0	6010D	4 Oct 21 11:34	SZ
Iron - Total	392	mg/l	0.10	6010D	1 Oct 21 11:03	SZ
Manganese - Total	3.94	mg/l	0.05	6010D	1 Oct 21 11:03	SZ
Barium - Dissolved	4.58	mg/l	0.10	6010D	14 Oct 21 8:48	SZ
Strontium - Dissolved	70.8	mg/l	0.10	6010D	14 Oct 21 8:48	SZ
Arsenic - Dissolved	< 0.008 @	mg/l	0.0020	6020B	13 Oct 21 11:45	MDE
Cadmium - Dissolved	< 0.002 @	mg/l	0.0005	6020B	13 Oct 21 11:45	MDE
Chromium - Dissolved	0.0117	mg/l	0.0020	6020B	13 Oct 21 11:45	MDE
Copper - Dissolved	< 0.02 @	mg/l	0.0020	6020B	13 Oct 21 11:45	MDE
Lead - Dissolved	0.0042	mg/l	0.0005	6020B	13 Oct 21 11:45	MDE
Molybdenum - Dissolved	0.7754	mg/l	0.0020	6020B	13 Oct 21 11:45	MDE
Selenium - Dissolved	0.0277	mg/l	0.0050	6020B	13 Oct 21 11:45	MDE
Silver - Dissolved	< 0.002 @	mg/l	0.0005	6020B	13 Oct 21 11:45	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL guarantees the accuracy of the analysis done on the sample submitted for testing. It is not possible for MVTL to guarantee that a test result obtained on a particular sample will be the same on any other sample unless all conditions affecting the sample are the same, including sampling by MVTL. As a mutual protection to clients, the public and ourselves, all reports are submitted as the confidential property of clients, and authorization for publication of statements, conclusions or extracts from or regarding our reports is reserved pending our written approval.

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 14 Oct 21
Lab Number: 21-W3667
Work Order #:82-2651
Account #: 72540
Date Sampled: 28 Sep 21 19:35

Bill Minnett
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Date Received: 29 Sep 21 7:44
Sampled By: MVTL Field Service

Project Name: Coteau #1
Sample Description: Broom Creek

Temp at Receipt: 4.1C ROI

	As Received Result	Method RL	Method Reference	Date Analyzed	Analyst

* Holding time exceeded

Approved by: Claudette K. Carroll 14OCT21 CC

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
\# = Due to concentration of other analytes
\+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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A-3

MVTL
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Chain of Custody Record

Project Name: Coteau #1	Event:	Work Order Number: 82-2651
Report To: Rampart Energy Company Attn: Bill Minnett Address: 1512 Larimer St, Suite 550 Denver, CO 80202 Phone: 303-618-2696 Email: bminnett@earthlink.net	CC:	Collected By:

Lab Number	Sample ID	Date	Time	Sample Type	1 Liter Raw	500 mL Nitric	500 mL Nitric (filtered)	250 mL Sulfuric	3 VOC	4 TOC	1 Liter Amber	1 Liter Amber HCL	Temp (°C)	Spec. Cond.	pH	Analysis Required
W31607	**Broom Creek**	28 Sept21	1935	GW	2	X	X	X		X			20.18	48194	7.04	See Attachment

Comments:

Field Readings	Time	Temp (°C)	Cond.	pH
	1903	24.03	57300	6.84
	1929	21.31	53589	6.93
	1935	20.18	48194	7.04

Sample Appearance
Turbid Brown

	Relinquished By		Sample Condition	
	Name	Date/Time	Location	Temp (°C)
1		29 Sept21 0744	~~Log In~~ Walk In #2	4.1 R02 TM562 / ~~TM805~~
2				

Received By	
Name	Date/Time
	29Sept21 0744

APPENDIX B

FRESHWATER WELL FLUID SAMPLING

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4509
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 12:00

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Temp at Receipt: 3.4C ROI

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Oberlander

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	17 Nov 21	RAA
pH	* 8.5	units	N/A	SM4500-H+-B-11	17 Nov 21 18:00	AC
Conductivity (EC)	2519	umhos/cm	N/A	SM2510B-11	17 Nov 21 18:00	AC
pH - Field	8.37	units	NA	SM 4500 H+ B	17 Nov 21 12:00	JSM
Temperature - Field	6.69	Degrees C	NA	SM 2550B	17 Nov 21 12:00	JSM
Total Alkalinity	1020	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Bicarbonate	987	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Carbonate	33	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Conductivity - Field	2574	umhos/cm	1	EPA 120.1	17 Nov 21 12:00	JSM
Tot Dis Solids(Summation)	1470	mg/l	12.5	SM1030-F	22 Nov 21 14:48	Calculated
Percent Sodium of Cations	101	%	NA	N/A	22 Nov 21 13:09	Calculated
Total Hardness as CaCO3	9.49	mg/l	NA	SM2340B-11	22 Nov 21 13:09	Calculated
Hardness in grains/gallon	0.55	gr/gal	NA	SM2340-B	22 Nov 21 13:09	Calculated
Cation Summation	25.7	meq/L	NA	SM1030-F	22 Nov 21 13:09	Calculated
Anion Summation	27.4	meq/L	NA	SM1030-F	22 Nov 21 14:48	Calculated
Percent Error	-3.15	%	NA	SM1030-F	22 Nov 21 14:48	Calculated
Sodium Adsorption Ratio	70.7		NA	USDA 20b	22 Nov 21 13:09	Calculated
Bromide	1.86	mg/l	0.100	EPA 300.0	24 Nov 21 17:55	RMV
Total Organic Carbon	2.1	mg/l	0.5	SM5310C-11	19 Nov 21 16:46	NAS
Dissolved Organic Carbon	2.1	mg/l	0.5	SM5310C-96	19 Nov 21 16:46	NAS
Fluoride	1.81	mg/l	0.10	SM4500-F-C	19 Nov 21 17:00	RAA
Sulfate	< 5	mg/l	5.00	ASTM D516-11	19 Nov 21 16:05	SD
Chloride	248	mg/l	2.0	SM4500-Cl-E-11	22 Nov 21 14:48	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 16:44	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 11:26	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 9:35	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 14:00	MDE
Total Dissolved Solids	1560	mg/l	10	USGS I1750-85	19 Nov 21 12:14	RAA
Calcium - Total	3.8	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Magnesium - Total	< 1	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Sodium - Total	599	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Potassium - Total	3.0	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Lithium - Total	0.076	mg/l	0.020	6010D	18 Nov 21 11:06	SZ

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix # = Due to concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4509
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 12:00

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Project Name: Coteau #1
Sample Description: Oberlander

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Aluminum - Total	< 0.1	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Iron - Total	0.29	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Silicon - Total	4.17	mg/l	0.10	6010D	29 Nov 21 14:40	MDE
Strontium - Total	0.14	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Zinc - Total	0.41	mg/l	0.05	6010D	19 Nov 21 11:52	SZ
Boron - Total	1.97	mg/l	0.10	6010D	24 Nov 21 11:57	SZ
Calcium - Dissolved	3.8	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Sodium - Dissolved	585	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Potassium - Dissolved	3.2	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Lithium - Dissolved	0.077	mg/l	0.020	6010D	18 Nov 21 11:06	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Iron - Dissolved	0.19	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Silicon - Dissolved	4.12	mg/l	0.10	6010D	29 Nov 21 14:40	MDE
Strontium - Dissolved	0.14	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Zinc - Dissolved	0.33	mg/l	0.05	6010D	19 Nov 21 13:52	SZ
Boron - Dissolved	1.95	mg/l	0.10	6010D	24 Nov 21 15:57	SZ
Antimony - Total	< 0.006 @	mg/l	0.0010	6020B	24 Nov 21 12:32	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Barium - Total	0.1168	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Lead - Total	0.0011	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Manganese - Total	0.0033	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	24 Nov 21 12:32	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Antimony - Dissolved	< 0.006 @	mg/l	0.0010	6020B	29 Nov 21 11:36	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Barium - Dissolved	0.1064	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	3 Dec 21 13:23	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix # = Due to concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4509
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 12:00

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Project Name: Coteau #1
Sample Description: Oberlander

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Lead - Dissolved	0.0007	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Manganese - Dissolved	0.0028	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 Nov 21 11:36	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 7 Dec 21

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4510
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 14:08

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Helmuth

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	17 Nov 21	RAA
Preservation Flag					17 Nov 21	RAA
pH	* 8.4	units	N/A	SM4500-H+-B-11	17 Nov 21 18:00	AC
Conductivity (EC)	2347	umhos/cm	N/A	SM2510B-11	17 Nov 21 18:00	AC
pH - Field	8.51	units	NA	SM 4500 H+ B	17 Nov 21 14:08	JSM
Temperature - Field	5.16	Degrees C	NA	SM 2550B	17 Nov 21 14:08	JSM
Total Alkalinity	1280	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Bicarbonate	1272	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	17 Nov 21 18:00	AC
Conductivity - Field	2353	umhos/cm	1	EPA 120.1	17 Nov 21 14:08	JSM
Tot Dis Solids(Summation)	1500	mg/l	12.5	SM1030-F	22 Nov 21 14:48	Calculated
Percent Sodium of Cations	102	%	NA	N/A	22 Nov 21 13:09	Calculated
Total Hardness as CaCO3	10.4	mg/l	NA	SM2340B-11	22 Nov 21 13:09	Calculated
Hardness in grains/gallon	0.61	gr/gal	NA	SM2340-B	22 Nov 21 13:09	Calculated
Cation Summation	28.1	meq/L	NA	SM1030-F	22 Nov 21 13:09	Calculated
Anion Summation	27.6	meq/L	NA	SM1030-F	22 Nov 21 14:48	Calculated
Percent Error	0.88	%	NA	SM1030-F	22 Nov 21 14:48	Calculated
Sodium Adsorption Ratio	89.2		NA	USDA 20b	22 Nov 21 13:09	Calculated
Bromide	0.580	mg/l	0.100	EPA 300.0	24 Nov 21 18:16	RMV
Total Organic Carbon	4.8	mg/l	0.5	SM5310C-11	19 Nov 21 16:46	NAS
Dissolved Organic Carbon	4.8	mg/l	0.5	SM5310C-96	19 Nov 21 16:46	NAS
Fluoride	1.99	mg/l	0.10	SM4500-F-C	19 Nov 21 17:00	RAA
Sulfate	< 5	mg/l	5.00	ASTM D516-11	19 Nov 21 16:27	SD
Chloride	70.1	mg/l	2.0	SM4500-Cl-E-11	22 Nov 21 14:48	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 16:44	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 11:26	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 9:35	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 14:00	MDE
Total Dissolved Solids	1530	mg/l	10	USGS I1750-85	19 Nov 21 12:14	RAA
Calcium - Total	2.5	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Magnesium - Total	1.0	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Sodium - Total	660	mg/l	1.0	6010D	22 Nov 21 10:09	SZ
Potassium - Total	3.0	mg/l	1.0	6010D	22 Nov 21 10:09	SZ

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4510
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 14:08

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Project Name: Coteau #1
Sample Description: Helmuth

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lithium - Total	0.082	mg/l	0.020	6010D	18 Nov 21 11:06	SZ
Aluminum - Total	0.13	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Iron - Total	0.92	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Silicon - Total	5.01	mg/l	0.10	6010D	29 Nov 21 14:40	MDE
Strontium - Total	0.15	mg/l	0.10	6010D	19 Nov 21 11:52	SZ
Zinc - Total	0.43	mg/l	0.05	6010D	19 Nov 21 11:52	SZ
Boron - Total	1.76	mg/l	0.10	6010D	24 Nov 21 11:57	SZ
Calcium - Dissolved	2.4	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Sodium - Dissolved	640	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Potassium - Dissolved	3.2	mg/l	1.0	6010D	22 Nov 21 13:09	SZ
Lithium - Dissolved	0.077	mg/l	0.020	6010D	18 Nov 21 11:06	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Iron - Dissolved	0.54	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Silicon - Dissolved	4.34	mg/l	0.10	6010D	29 Nov 21 14:40	MDE
Strontium - Dissolved	0.14	mg/l	0.10	6010D	19 Nov 21 13:52	SZ
Zinc - Dissolved	0.06	mg/l	0.05	6010D	19 Nov 21 13:52	SZ
Boron - Dissolved	1.70	mg/l	0.10	6010D	24 Nov 21 15:57	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	24 Nov 21 12:32	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Barium - Total	0.1308	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Copper - Total	0.0036	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Lead - Total	0.0221	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Manganese - Total	0.0134	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Molybdenum - Total	0.0164	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	24 Nov 21 12:32	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	24 Nov 21 12:32	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	24 Nov 21 12:32	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	29 Nov 21 11:36	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Barium - Dissolved	0.1186	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE

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@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 6 Dec 21
Lab Number: 21-W4510
Work Order #:82-3203
Account #: 72540
Date Sampled: 17 Nov 21 14:08

Date Received: 17 Nov 21 15:43
Sampled By: MVTL Field Services

Rich McClure
Rampart Energy Company
1512 Larimer St
Suite 550
Denver CO 80202

Project Name: Coteau #1
Sample Description: Helmuth

Temp at Receipt: 3.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	3 Dec 21 13:23	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Lead - Dissolved	0.0019	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Manganese - Dissolved	0.0064	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Molybdenum - Dissolved	0.0153	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 Nov 21 11:36	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE

This sample was either unpreserved or needed additional preservation upon receipt at the laboratory. The following preservation was added by MVTL: sulfuric acid.

* Holding time exceeded

Approved by: Claudette K. Carroll CC 7 Dec 21

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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B-7

MVTL
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Chain of Custody Record

Project Name: Coteau #1	Event:	Work Order Number: 82-3203
Report To: Rampart Energy Attn: Rich McClure Address: Phone: 720-635-1555 Email: rfm@carbon-vault.com	CC: **Rampart Energy** Shawna Harrison 1512 Larimer St. Suite 550 Denver, CO 80202	Collected By:

Lab Number	Sample ID	Date	Time	Sample Type	1 Liter Raw	1 Liter Raw (filtered)	500 mL Nitric	500 mL Nitric (filtered)	250 mL Sulfuric	250 mL Sulfuric (filtered)	3 TOC	3 TOC (filtered)	125 mL Raw	Temp (°C)	Spec. Cond.	pH	Analysis Required
W4509	Oberlander	17 Nov 21	1200	GW	3	X	X	X	X	X	X	X	2	6.69	2574	8.37	see attachment
W4510	Helmuth	17Nov21	1408	GW	3	X	X	X	X	X	X	X	2	5.16	2353	8.51	

Comments:

	Relinquished By		Sample Condition		Received By	
	Name	Date/Time	Location	Temp (°C)	Name	Date/Time
1		17Nov21 1543	~~Log In~~ Walk In #2	Rol 3.4 ~~TM562~~/ TM805		17Nov21 1543
2						

MVTL LABORATORIES, Inc.
PO BOX 1673
BISMARCK, ND 58504-1673
PHONE (701) 258-9720 FAX (701) 258-9724

28 SEP 1990

FINAL ANALYSIS REPORT

Sample Number: 90-W1115
Client: Water Supply Inc.
P.O. Box 1191
Bismarck ND 58502

Report Date: 9/27/90
Work Order #: 82-980
PO #:
Payment Type::

Attn: Roger Schmid
(DAS 3/6/97)
FRED/ART OBERLANDER #1
~~Fred Oberlander #1~~

#1

Collection Date: 8/30/90
Collection Time: 16:12
Date Received: 8/31/90

Analyte	Result	Units	Comments
pH	8.5	units	
Specific Conductance	2585.	umhos/cm	
Total Alkalinity	980.	mg/l CaCO3	
Phenolphthalein Alk	14.0	mg/l CaCO3	
Bicarbonate	952.	mg/l CaCO3	
Carbonate	28.0	mg/l CaCO3	
Total Dissolved Solids	1520	mg/l	
Sulfate	9.00	mg/l	
Chloride	272.	mg/l	
Nitrate-Nitrite	< 1	mg/l	
Fluoride	4.70	mg/l	
Calcium - Total	5.2	mg/l	
Magnesium-Total	1.8	mg/l	
Sodium - Total	640.	mg/l	
Potassium - Total	3.8	mg/l	
Total Hardness as CaCO3	20.4	mg/l	
Hardness in grains/gallon	1.19	gr/gal	
Cation Summation	28.4		
Anion Summation	27.5		
Percent Error	1.61	%	
Sodium Adsorption Ratio	61.7		
Iron - Total	0.30	mg/l	
Manganese - Total	< 0.05	mg/l	

Approved by:
C-Leach

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ENERGY LABORATORIES

ENERGY LABORATORIES, INC.

P.O. BOX 30916 • 1107 SOUTH BROADWAY • BILLINGS, MT 59107-0916 • PHONE (406) 252-6325

LABORATORY REPORT

Lab. No. 82-6424

To Coteau Properties Date 11-9-82 CB

Address Kirkwood Office Tower Bismarck, North Dakota 58501

WATER ANALYSIS (DAS 3/6/97)

~~A. Oberlander #1~~ FRED/ART OBERLANDER #1

Sampled 10-14-82 @ 12:00

Sample Submitted 10-22-82

P.O. #12531

CONSTITUENT	MILLIGRAMS PER LITER	
Potassium	1	
Sodium	657	
Calcium	4	
Magnesium	1	
Sulfate	13	
Chloride	265	
Carbonate	0	
Bicarbonate	1,240	
Total Dissolved Solids @ 180°C	1,520	
Total Hardness as $CaCO_3$	13	
Total Alkalinity as $CaCO_3$	1,020	
Sum of Anions	28.1	meq/l
Sum of Cations	28.9	meq/l
Cation-Anion Balance, % difference	1.40	
Specific Conductance @ 25°C	2,480	micromhos/cm
pH	8.2	
Phenolphthalein Alkalinity as $CaCO_3$	0	
Nitrate as N	0.05	
Total Iron	0.50	
Manganese	<0.02	

Certified by:

[signature]

Chief Chemist

ANALYTICAL SERVICES — WATER, SOIL, PETROLEUM, COAL

MVTL LABORATORIES, Inc.
P.O. BOX 1873, 1411 S. 12th STREET
BISMARCK, ND 58502
PHONE (701) 258-9720 WATS (800) 279-6885 FAX (701) 258-9724

WE ARE AN EQUAL OPPORTUNITY EMPLOYER

FINAL ANALYSIS REPORT

Sample Number: 94-W4482

Report Date: 11/10/94

Les Morgenstern
Braun Intertec Corporation
PO Box 2379
Bismarck ND 58502

Work Order #: 82-1398
PO #: CFEX-91-0014

Date Received 10/28/94

Sample Description: Standard Water Sample
Sample Site: H Pfennig #2
Sample Location: Rural Beulah, ND

Collection Date 10/27/94
Collection Time 18:34

Analyte	Results	Units
pH	8.4	units
Specific Conductance	2360	umhos/cm
Total Alkalinity	1267	mg/l CaCO3
Phenolphthalein Alk	32	mg/l CaCO3
Bicarbonate	1203	mg/l CaCO3
Bicarb as HCO3	1470	mg/l HCO3
Carbonate	64	mg/l CaCO3
Hydroxide	0.0	mg/l CaCO3
Total Dissolved Solids	1460	mg/l
Sulfate	10.0	mg/l
Chloride	59.1	mg/l
Nitrate-Nitrite as N	< 1	mg/l
Calcium - Total	3.5	mg/l
Magnesium - Total	0.8	mg/l
Sodium - Total	620	mg/l
Potassium - Total	2.3	mg/l
Total Hardness as CaCO3	12.0	mg/l
Cation Summation	27.3	
Anion Summation	27.2	
Percent Error	0.11	%
Sodium Adsorption Ratio	77.8	
Iron - Dissolved	0.16	mg/l
Manganese - Dissolved	< 0.05	mg/l

Approved By: AKoel

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LABORATORY REPORT

Lab. No. 82-6176

To Coteau Properties Company Date 10-21-82 pb

Address Kirkwood Office Tower Bismarck, North Dakota 58501

WATER ANALYSIS
P.O. No. 12531
F. Weigum #1
Sampled 10-11-82 @ 10:00 a.m.
Sample received 10-12-82

CONSTITUENT	MILLIGRAMS PER LITER	
Potassium	5	
Sodium	617	
Calcium	3	
Magnesium	-1	
Sulfate	22	
Chloride	184	
Carbonate	15	
Bicarbonate	1,320	
Total Dissolved Solids @ 180°C	1,410	
Total Solids, calculated	1,500	
Total Hardness as $CaCO_3$	9	
Total Alkalinity as $CaCO_3$	1,100	
Sum of Anions	27.7	meq/l
Sum of Cations	27.1	meq/l
Cation-Anion Balance, % difference	1.09	
Specific Conductance @ 25°C	2,330	micromhos/cm
pH 8.4		
Phenolphthalein Alkalinity as $CaCO_3$	0	
Nitrate as N	-0.05	
Total Iron	0.84	
Manganese	-0.02	

Certified by:

Chief Chemist

a minus sign (-) indicates less than

ANALYTICAL SERVICES – WATER, SOIL, PETROLEUM, COAL

The Coteau Properties Company (CPC), a wholly owned subsidiary of North American Coal Corporation, has implemented a shallow groundwater monitoring program since 1979 as part of its operations at the Freedom Mine, thereby establishing a baseline water quality database for select shallow freshwater aquifers within the area of review (AOR).

More than 500 monitoring site locations have been drilled by CPC over an area of about 84 square miles around the Freedom Mine. A total of 460 of the monitoring sites have at least one water quality test date in the database, and approximately 100 of the sites are currently active. The monitoring sites sample from either surficial glacial aquifers of the Coleharbor Group (Pleistocene) or water-bearing coalbed (lignite) horizons of the Sentinel Butte Formation of the Fort Union Group (Paleocene). Figure B-1 summarizes the stratigraphy and freshwater aquifers present within the AOR. Lignite beds of the Sentinel Butte Formation are among the most tapped water resources (Croft, 1973), as they are the primary supply of domestic and stock water resources to the local area (U.S. Department of the Interior, 2016).

A description of the locations, sampling horizon, screen depth, and well status of 19 wells from the CPC shallow groundwater database is provided in Table B-1. Figure B-2 provides a map of the 19 selected monitoring sites. The 19 monitoring sites were selected based on the following criteria and considerations:

The Beulah, Spaer, and Stanton coalbed sampling horizons were selected because they are the primary sources of groundwater within the AOR and also have the greatest areal extent over the CO_2 plume area (U.S. Department of the Interior, 2016).

The monitoring site locations fall within the predicted 12-yr CO_2 plume extent. This was done to identify the most relevant sampling location to this geologic storage project.

Monitoring sites within a quarter mile of one another were eliminated to limit redundancy of individual data points.

The bed screen depth was required to be greater than 100 feet. This was done to help ensure consistent geochemical results and avoid surficial effects from previous mining operations or farming activities.

If two or more locations had water quality test data in the same location, the monitoring site with the deeper screen depth was selected and included in the final data set. This was done to limit the redundancy of individual data points.

Summaries of the geochemical analyses from the 19 monitoring sites, including pH, alkalinity, and total dissolved solids, is provided in Table B-2. Just two of the 19 sites had trace metal analyses conducted on them, provided in Table B-3.

ERATHEM	SYSTEM		SERIES	ROCK UNIT: GROUP	ROCK UNIT: FORMATION	FRESHWATER AQUIFER(S)	FRESHWATER AQUIFER(S) UNDER SURVEILLANCE
CENOZOIC	Quaternary		Holocene		Oahe	No	
			Pleistocene	Coleharbor	"Glacial Drift"	Yes	Antelope Creek
	Tertiary	Neogene	Pliocene		(Unnamed)	Yes	
			Miocene		Arikaree	No	
		Paleogene	Oligocene	White River	Brule	No	
			Eocene		Chadron	No	
					Golden Valley	No	
			Paleocene	Fort Union	Sentinel Butte	Yes	Beulah, Spaer, and Stanton coalbed horizons
					Tongue River: Bullion Creek	Yes	
					Tongue River: Slope	No	
					Cannonball	Yes	
					Ludlow	Yes	
MESOZOIC	Cretaceous		Upper	Montana	Hell Creek	Yes	
					Fox Hills	Yes	Lowest USDW
					Pierre	No	

Modified from Murphy et al., 2009, NDGS MS 91

Figure B-1. Stratigraphic column of the major freshwater aquifer systems of North Dakota, with the aquifer systems under surveillance within the geologic storage project indicated.

Table B-1. Names, Locations, Sampling Horizons, Screen Depths, and Well Status of Selected Monitoring Sites

Monitoring Site Location	Quarter Call	S-T-R	Latitude NAD 83	Longitude NAD 83	Sampling Horizon	Screen Depth (ft)	Well Status
MP81-P21	BBB	14-145N-88W	47.3853676	−101.86519	Beulah	123–137	Active
MP81-P32*	CBC	15-145N-88W	47.3748245	−101.88645	Beulah	170–180	Active
MP93-P07A	BAA	31-146N-87W	47.4291821	−101.81276	Spaer	160–165	Inactive
MP03-RP01A	ABB	06-145N-87W	47.4146862	−101.81177	Spaer	184–189	Inactive
MP81-P01	DDA	01-145N-88W	47.4028258	−101.82273	Spaer	235–242	Inactive
MP81-P07	BBB	02-145N-88W	47.4145552	−101.86515	Spaer	181–188	Inactive
MP81-P22	DAA	14-145N-88W	47.3781632	−101.84589	Spaer	115–119	Inactive
MP81-P24*	AAD	23-145N-88W	47.3681521	−101.84585	Spaer	111–115	Active
MP93-RP01A	ACD	12-145N-88W	47.3925468	−101.8291	Spaer	187–192	Inactive
MP16-P01A	CAD	11-145N-88W	47.3911977	−101.85454	Spaer	179–181	Active
MP16-P02A	BCB	11-145N-88W	47.3947722	−101.86503	Spaer	196–197	Active
MP95-RP03A	DDD	06-145N-87W	47.4005739	−101.80184	Spaer	241–246	Active
MP95-RP04A	BCC	08-145N-87W	47.39329	−101.8013	Spaer	184–189	Inactive
M77-P01	DDD	18-145N-87W	47.3715152	−101.80157	Stanton	131–141	Inactive
M77-P18	DCD	07-145N-87W	47.3860116	−101.80748	Stanton	233–238	Inactive
M77-P22	CCC	07-145N-87W	47.3860271	−101.82205	Stanton	213–218	Inactive
MP81-P12	DAA	02-145N-88W	47.4023753	−101.84407	Stanton	246–251	Inactive
MP83-P01	BAA	22-145N-88W	47.3713922	−101.87622	Stanton	278–283	Active
MP03-RP03A*	BCC	31-146N-87W	47.422307	−101.82244	Stanton	191–196	Active

* Monitoring site locations with recent laboratory reports provided in Appendix B.

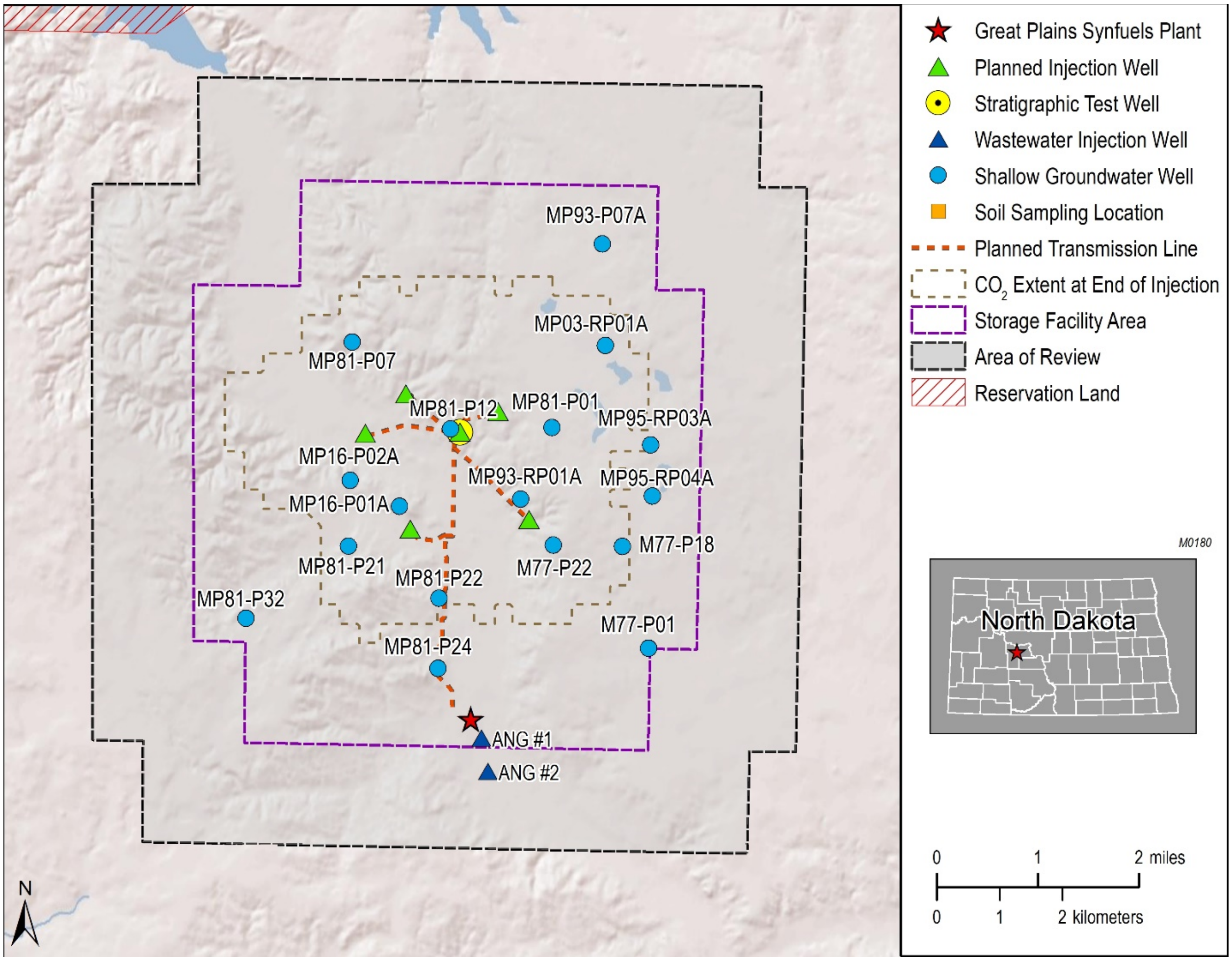

Figure B-2. Locations of the 19 monitoring sites operated by CPC.

Table B-2. Summarized Water Quality Test Results for 19 Monitoring Sites

Monitoring Site Location	Sampling Horizon	Mean* pH	pH Range	Mean* Alkalinity (mg/L $CaCO_3$)	Alkalinity Range (mg/L $CaCO_3$)	Mean* TDS (mg/L)	Range TDS (mg/L)
MP81-P21	Beulah	6.9	6.6–7.2	443	406–488	1,029	551–1,540
MP81-P32	Beulah	7.7	7.2–8.2	720	565–815	992	826–1,140
MP93-P07A	Spaer	7.8	6.7–8.2	1,593	950–1,770	3,160	2,910–5,070
MP03-RP01A	Spaer	8.2	8.1–8.3	1,755	1,740–1,770	3,278	3,180–3,380
MP81-P01	Spaer	8.1	7.8–8.5	1,670	1,488–1,750	1,917	1,680–2,270
MP81-P07	Spaer	7.4	7.2–7.9	577	543–648	1,402	1,291–1,480
MP81-P22	Spaer	7.5	7.1–8.8	476	252–574	929	603–1,170
MP81-P24	Spaer	8.2	7.7–8.9	637	333–810	1,250	620–1,708
MP93-RP01A	Spaer	8.2	7.9–8.7	882	817–992	1,507	1,350–1,670
MP16-P01A	Spaer	8.3	8.1–8.4	1,068	1,030–1,110	1,351	1,280–1,420
MP16-P02A	Spaer	8.4	8.2–8.6	880	843–928	1,243	1,190–1,300
MP95-RP03A	Spaer	8.0	7.6–8.3	1,537	512–1,820	2,070	894–2,460
MP95-RP04A	Spaer	8.2	7.8–8.4	1,574	1,420–1,680	1,819	1,600–2,160
M77-P01	Stanton	8.2	7.4–8.6	1,072	218–1,550	1,286	309–1,880
M77-P18	Stanton	8.0	7.6–8.3	1,129	256–1,492	1,373	372–1,720
M77-P22	Stanton	7.8	6.8–8.4	646	232–872	877	296–1,270
MP81-P12	Stanton	8.1	7.8–8.5	1,700	1,380–1,862	1,917	1,660–2,090
MP83-P01	Stanton	8.2	7.9–8.5	1,234	991–1,400	1,447	1,160–1,610
MP03-RP03A	Stanton	8.3	8.0–8.5	1,511	1,360–1,610	1,777	1,690–1,860

* Geometric mean.

Table B-3. Results of Trace Metal Analyses* (in mg/L) for Monitoring Sites in Table B-2

Monitoring Site Location	Sampling Horizon	Arsenic	Barium	Boron	Iron	Lead	Silver	Strontium
MP81-P01	Spaer	0.01	0.12	0.10	0.45	0.02	0.00	0.24
M77-P22	Stanton	0.00	0.21	0.53	0.80	0.25	0.01	0.25

* All water samples came back negative for Cd, Cr, Hg, Mo, and Se.

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Croft, M.G., 1973, Ground-water resources, Mercer and Oliver Counties, North Dakota: North Dakota Geological Survey Bulletin 56(III).

U.S. Department of the Interior, 2016, Environmental assessment for the Freedom Mine, West Mine Area, February 2016: U.S. Department of the Interior Office of Surface Mining Reclamation and Enforcement Report.

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
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MEMBER ACIL

Report Date: 30 Jun 21
Lab Number: 21-W1761
Work Order #: 82-1480
Account #: 002212
Date Sampled: 17 Jun 21 11:20
Date Received: 18 Jun 21 8:00
Sampled By: MVTL Field Services

Coteau Properties Company
204 County Road 15
Beulah ND 58523

Project Name: 2021 Coteau Groundwater

PO #: 570610 OP

Sample Description: GS21CW-52
Sample Site: MP81-P24
Event and Year: 2021

Temp at Receipt: 0.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	18 Jun 21	CC
pH	* 8.5	units	N/A	SM4500-H+-B-11	18 Jun 21 17:00	RAA
Conductivity (EC)	2172	umhos/cm	N/A	SM2510B-11	18 Jun 21 17:00	RAA
pH - Field	8.5	units	NA	4500 H+ B	17 Jun 21 11:20	DJN
Temperature - Field	11.2	Degrees C	NA	SM 2550B	17 Jun 21 11:20	DJN
Total Alkalinity	512	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Bicarbonate	487	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Carbonate	25	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	18 Jun 21 17:00	RAA
Conductivity - Field	2123	umhos/cm	1	EPA 120.1	17 Jun 21 11:20	DJN
Tot Dis Solids(Summation)	1320	mg/l	12.5	SM1030-F	23 Jun 21 14:09	Calculat
Total Hardness as CaCO3	18.4	mg/l	NA	SM2340B-11	23 Jun 21 11:37	Calculat
Cation Summation	23.0	meq/L	NA	SM1030-F	24 Jun 21 13:24	Calculat
Anion Summation	20.5	meq/L	NA	SM1030-F	23 Jun 21 14:09	Calculat
Percent Error	5.57	%	NA	SM1030-F	24 Jun 21 13:24	Calculat
Sodium Adsorption Ratio	52.5		NA	USDA 20b	23 Jun 21 11:37	Calculat
Sulfate	480	mg/l	5.00	ASTM D516-11	21 Jun 21 14:46	SD
Chloride	10.8	mg/l	2.0	SM4500-Cl-E-11	18 Jun 21 15:38	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	23 Jun 21 14:09	SD
Calcium - Total	3.4	mg/l	1.0	6010D	23 Jun 21 11:37	MDE
Magnesium - Total	2.4	mg/l	1.0	6010D	23 Jun 21 11:37	MDE
Sodium - Total	517	mg/l	1.0	6010D	23 Jun 21 11:37	MDE
Potassium - Total	4.1	mg/l	1.0	6010D	23 Jun 21 11:37	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	24 Jun 21 13:24	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	24 Jun 21 13:24	MDE

* Holding time exceeded

Approved by: Claudette K. Carroll CC 1 JUL 21

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 15 Jun 21
Lab Number: 21-W1599
Work Order #: 82-1362
Account #: 002212
Date Sampled: 8 Jun 21 11:01
Date Received: 9 Jun 21 8:00
Sampled By: MVTL Field Service

PO #: 570610 OP

Temp at Receipt: 3.4C

Coteau Properties Company
204 County Road 15
Beulah ND 58523

Project Name: 2021 Coteau Groundwater

Sample Description: GS20CW-11
Sample Site: MP81-P32
Event and Year: 2021

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	9 Jun 21	RAA
pH	* 7.8	units	N/A	SM4500-H+-B-11	9 Jun 21 18:00	RAA
Conductivity (EC)	1836	umhos/cm	N/A	SM2510B-11	9 Jun 21 18:00	RAA
pH - Field	7.2	units	NA	4500 H+ B	8 Jun 21 11:01	DJN
Temperature - Field	12.3	Degrees C	NA	SM 2550B	8 Jun 21 11:01	DJN
Total Alkalinity	676	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Bicarbonate	676	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	9 Jun 21 18:00	RAA
Conductivity - Field	1811	umhos/cm	1	EPA 120.1	8 Jun 21 11:01	DJN
Tot Dis Solids(Summation)	1170	mg/l	12.5	SM1030-F	14 Jun 21 12:14	Calculat
Total Hardness as CaCO3	35.3	mg/l	NA	SM2340B-11	14 Jun 21 12:14	Calculat
Cation Summation	20.6	meq/L	NA	SM1030-F	14 Jun 21 12:14	Calculat
Anion Summation	19.7	meq/L	NA	SM1030-F	11 Jun 21 11:32	Calculat
Percent Error	2.37	%	NA	SM1030-F	14 Jun 21 12:14	Calculat
Sodium Adsorption Ratio	33.3		NA	USDA 20b	14 Jun 21 12:14	Calculat
Sulfate	285	mg/l	5.00	ASTM D516-11	11 Jun 21 11:32	SD
Chloride	7.8	mg/l	2.0	SM4500-Cl-E-11	10 Jun 21 11:22	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	10 Jun 21 15:04	SD
Calcium - Total	6.4	mg/l	1.0	6010D	14 Jun 21 12:14	SZ
Magnesium - Total	4.7	mg/l	1.0	6010D	14 Jun 21 12:14	SZ
Sodium - Total	455	mg/l	1.0	6010D	14 Jun 21 12:14	SZ
Potassium - Total	5.1	mg/l	1.0	6010D	14 Jun 21 12:14	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	11 Jun 21 12:06	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	11 Jun 21 12:06	SZ

* Holding time exceeded

Approved by: Claudette K. Carroll cc 16 Jun 21

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

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MEMBER ACIL

Report Date: 29 Jun 20
Lab Number: 20-W1914
Work Order #: 82-1555
Account #: 002212
Date Sampled: 17 Jun 20 16:38
Date Received: 19 Jun 20 8:00
Sampled By: MVTL Field Services

Coteau Properties Company
204 County Road 15
Beulah ND 58523

Project Name: 2020 Coteau Groundwater

PO #: 556847

Sample Description: GS20CW-36
Sample Site: MP03-RP03A
Event and Year: 2020

Temp at Receipt: 3.0C

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	19 Jun 20	JD
pH	* 8.4	units	N/A	SM4500 H+ B	19 Jun 20 18:00	HT
Conductivity (EC)	2780	umhos/cm	N/A	SM2510-B	19 Jun 20 18:00	HT
pH - Field	8.0	units	NA	4500 H+ B	17 Jun 20 16:38	DJN
Temperature - Field	10.4	Degrees C	NA	SM 2550B	17 Jun 20 16:38	DJN
Total Alkalinity	1590	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Bicarbonate	1566	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Carbonate	24	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	19 Jun 20 18:00	HT
Conductivity - Field	2817	umhos/cm	1	EPA 120.1	17 Jun 20 16:38	DJN
Tot Dis Solids(Summation)	1850	mg/l	12.5	SM1030-F	25 Jun 20 14:04	Calculated
Total Hardness as CaCO3	26.4	mg/l	NA	SM2340-B	23 Jun 20 15:29	Calculated
Cation Summation	35.7	meq/L	NA	SM1030-F	25 Jun 20 12:24	Calculated
Anion Summation	33.6	meq/L	NA	SM1030-F	25 Jun 20 14:04	Calculated
Percent Error	2.93	%	NA	SM1030-F	25 Jun 20 14:04	Calculated
Sodium Adsorption Ratio	68.2		NA	USDA 20b	23 Jun 20 15:29	Calculated
Sulfate	38.5	mg/l	5.00	ASTM D516-11	25 Jun 20 9:08	EV
Chloride	37.1	mg/l	1.0	SM4500-Cl-E	22 Jun 20 9:48	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	25 Jun 20 14:04	EV
Calcium - Total	4.8	mg/l	1.0	6010D	23 Jun 20 15:29	MDE
Magnesium - Total	3.5	mg/l	1.0	6010D	23 Jun 20 15:29	MDE
Sodium - Total	805	mg/l	1.0	6010D	23 Jun 20 15:29	MDE
Potassium - Total	5.0	mg/l	1.0	6010D	23 Jun 20 15:29	MDE
Iron - Dissolved	0.30	mg/l	0.10	6010D	25 Jun 20 12:24	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	25 Jun 20 12:24	MDE

* Holding time exceeded

cc

Approved by: Claudette K. Carroll 9 JUL 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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APPENDIX C

QUALITY ASSURANCE SURVEILLANCE PLAN

1.0 QUALITY ASSURANCE AND SURVEILLANCE PLAN

The primary goal of the testing and monitoring plan of this storage facility permit application is to ensure that the geologic sequestration project is operating as permitted and is not endangering USDWs. In compliance with North Dakota Administrative Code (NDAC) § 43-05-01-11.4 (Testing and Monitoring Requirements), this Quality Assurance and Surveillance Plan (QASP) was developed and is being provided as part of the testing and monitoring program.

The testing and monitoring program for the project includes the analysis of the injected CO_2 stream, periodic testing of the injection wells, a corrosion monitoring plan for the CO_2 injection well components and surface facilities, a leak detection and monitoring plan for surface components of the CO_2 injection system, and a leak detection plan to monitor any movement of the CO_2 outside of the storage reservoir (see Table 5-1). The latter consists of a combination of soil gas and groundwater monitoring, storage reservoir monitoring, downhole monitoring, and geophysical monitoring. The quality assurance and surveillance procedures for this testing and monitoring plan are provided in the remainder of this QASP.

1.1 CO_2 Stream Analysis and Injection Well Mechanical Integrity Testing

1.1.1 CO_2 Stream Analysis

NDAC § 43-05-01-11.4(1a) requires analysis of the CO_2 stream in compliance with applicable analytical methods and standards generally accepted by industry and with sufficient frequency to yield data representative of its chemical and physical characteristics. DGC will collect samples of the injected CO_2 stream daily at the capture facility and analyze them to determine the concentrations of CO_2, nitrogen, oxygen, hydrogen, water, hydrogen sulfide, carbon monoxide, and a suite of hydrocarbons (e.g., ethane, propane, n-butane, and methane). This is consistent with the daily analysis DGC has performed on volumes delivered to Canadian oil fields since 1998. DGC uses an Agilent gas chromatograph with flame ionization and thermal conductivity detectors and complies with American Society for Testing and Materials Standards D7833, D1946, D2163, and UOP 539. Selected stable and radiogenic isotopes (i.e., isotopes of carbon dioxide [^{13}C and ^{14}C], methane [^{13}C and ^{14}C], and deuterium [^{2}H]) will also be sampled three to four times in the first year to establish a baseline. The isotopic analyses will be outsourced to commercial laboratories that will employ standard analytical quality assurance/quality control (QA/QC) protocols used in the industry.

1.1.2 Injection Well Mechanical Integrity Testing

The external mechanical integrity of the injection wells will be established prior to injection with a USIT (ultrasonic imager tool) in combination with variable density (VDL) and cement bond logs (CBL). The USIT (includes the VDL and CBL) will be performed during well workovers not more frequently than once every 5 years. It will also be useful for assessing the internal mechanical integrity of the injection wells. In addition, the injection wells will be monitored with a pulsed neutron log tool (PNX), to include temperature and pressure readings, using the phased approach described in Section 5.1.2 of this storage facility permit. The tool specifications of the USIT and the PNX are provided in Attachments A-1 and A-2, respectively.

Internal mechanical integrity of the injection wells will be demonstrated via tubing-casing annulus pressure tests prior to injection and during well workovers but not more frequently than

once every 5 years. A detailed description of this test is provided in Attachment A-3. Pressure falloff tests will be performed in the injection wells prior to injection. During injection operations, pressure falloff testing will be carried out via surface pressure monitoring at least once every 5 years to demonstrate storage reservoir injectivity. In addition, the injection wells will be continuously monitored for surface and annular pressure anomalies by maintaining a consistent 200 pounds per square inch (psi) on the annulus with a nitrogen cushion that will be added on top of the packer fluid.

1.2 Corrosion Monitoring and Prevention Plan

1.2.1 Corrosion Monitoring

DGC will install a 3-foot test section of 4½-inch L-80 tubing in the flowlines near each wellhead for regular testing and corrosion monitoring of the well material (Figure 5-1 or the storage facility permit). The tubing joints will be inspected monthly via ultrasound equipment during the first quarter, then quarterly thereafter for the first 2 years. If the well materials (i.e., tubing) show no sign of corrosion within the first 2 years of the injection period, future internal monitoring of the tubing will be accomplished through a platform multifinger imaging tool (PMIT), or in the event a downhole tubing string is pulled for any reason, it will be inspected at the surface for corrosion and mechanical integrity. Wireline monitoring using the USIT, which will be run during workovers (including when tubing is pulled) but not more frequently than once every 5 years, will also be considered for assessing the corrosion of the casing in the injection wells. Details related to the PMIT and Tuboscope wellsite injection services are provided as Attachments A-4 and A-5, respectively.

1.2.2 Corrosion Prevention

To prevent corrosion of the well materials, the following preemptive measures will be taken: 1) cement in the injection wells opposite the injection interval and extending more than 2,000 feet uphole, will be CO_2-resistant, 2) the well casing (L-80 13Cr) will also be CO_2-resistant from the bottomhole to a depth just above the Opeche Formation, and 3) the packer fluid will be an industry standard corrosion inhibitor. In addition, the chemical composition of the CO_2 stream is highly pure (Table 5-2) and dry, with a moisture level for the CO_2 stream typically less than 2.00 parts per million by volume, both of which help prevent corrosion of the surface and well materials.

1.3 Surface Leak Detection and Monitoring Plan

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 (Attachment A-6) located inside each gas meter and wellhead enclosure. Another H_2S detection station will be installed on the exterior of each wellhead enclosure to monitor atmospheric conditions on the pad. This leak detection equipment will be integrated with automated warning systems capable of immediately notifying personnel in DGC's pipeline control center in the event of an anomalous reading. As an added measure for safety, field personnel will have multi gas detectors with them to monitor for H_2S (Attachment A-7). Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

1.4 Subsurface Leak Detection and Monitoring Plan

The monitoring plan for detecting subsurface leaks comprises "surface/near-surface" and deep subsurface monitoring programs. In this document, QA/QC information regarding the near-surface monitoring program is presented in Section 1.5, and QA/QC information regarding the deep subsurface monitoring programs is broken into Sections 1.6 and 1.7.

1.5 Near-Surface Soil Gas and Groundwater Monitoring

Near-surface sampling discussed herein comprises 1) sampling of soil gas in the shallow vadose zone and 2) sampling groundwater aquifers (lowest USDW). Sampling and chemical analysis of these zones provide concentrations of chemical constituents, including stable carbon isotopes [^{13}C and ^{12}C] of CO_2, which are focused on detecting movement of the CO_2 out of the reservoir. These monitoring efforts will provide data to confirm that near-surface environments are not adversely impacted by CO_2 injection and storage operations.

1.5.1 Soil Gas

Vadose zone soil gas monitoring directly measures the characteristics of the air space between soil components and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. A total of 11 soil gas sampling sites were drilled and installed in the storage facility area (SG01 through SG11 as shown in Figures 5-1, 5-2, and 5-3). All eleven locations (SG01 through SG11) are located on Coteau property.

1.5.1.1 Soil Gas Sampling and Analysis Protocol

<u>Soil Gas Locations: SG01 to SG11</u>

Fixed soil gas profile stations were installed for the sampling of soil gas at locations SG01 through SG11 prior to the initiation of CO_2 injection. Schematics of these soil gas profile stations are shown below in Figures C-1 and C-2. As shown, soil profile stations contain up to two isolated gas sampling intervals from which individual soil gas samples will be obtained.

Prior to the collection of each sample, a minimum of three casing volumes were removed, and the representativeness of the gas flow was determined by analyzing the soil gas for CO_2, hydrogen sulfide (H_2S), methane (CH_4), and O_2 using a Landtec GEM 5000 gas meter handheld multigas meter, which was calibrated daily based on manufacturer instructions. After these measurements of the soil gas composition stabilized, two soil gas samples were collected for characterization at each location using a Tedlar® bag, which was labeled with the appropriate sample number and site information and transported to the Dolan Integration Group (DIG) (Westminster, Colorado) for compositional and isotopic analysis. The target analytes for these analyses are shown below in Table C-1 and Table C-2, respectively.

Vista GeoScience

NESTED VAPOR WELL CONSTRUCTION DETAILS

Project Name: CCS Soil Gas Minitoring Well Installation
Vista GeoScience Project #: 21215.01
Address: N/A
City: Beulah
State: North Dakota

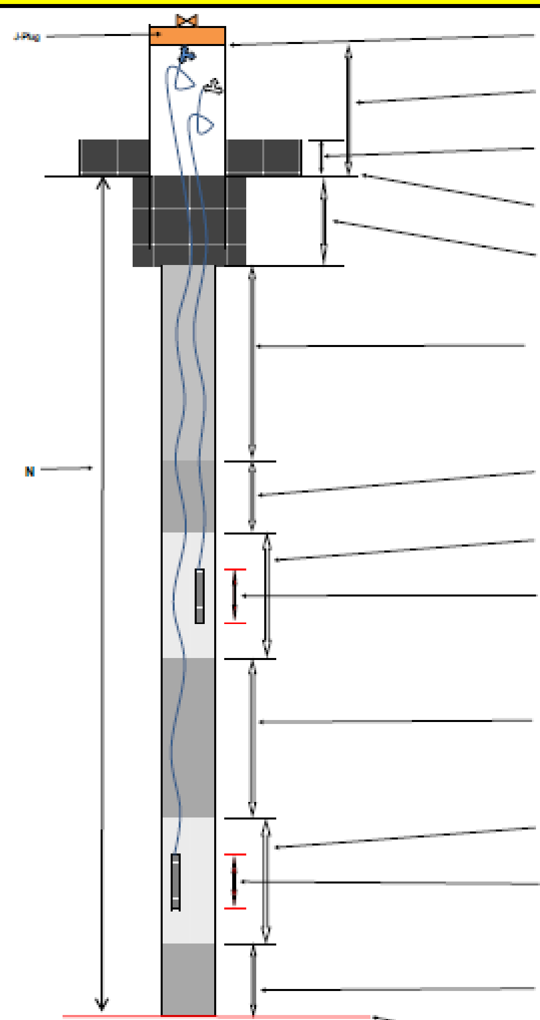
Permit No.:

Type of Well: Nested Vapor Well
Type of Screen: 21" Stainless Steel Implant
Tubing Type: NYLAFLOW Nylon Tubing   ID Tubing: 0.19 inches
Boring Diameter: 2.5 inches   OD Tubing: 0.25 inches

Location ID: SG-01
Shallow Vapor Well ID: SG-01S
Deep Vapor Well ID: SG-01D

D Ground Surface Elevation: ______ feet MSL
A Top of Stick Up Elevation: ______ feet MSL
Northing: 47.40171198   Easting: -101.841981

Driller #1 Name: Davis Henschel
Driller #2 Name: David Fontana
Date Drilled: 10/24/2021   Date Installed: 10/24/2021



A Top of Well Vault

B Stick Up: Bot. 0 ags Top 2' ags Interval 2 ft
Material: 4" diameter PVC

C Well Pad: Bot. 0 ags Top 0.29' ags Interval 0.29 ft
Well Pad Material Description: 2' x 2' concrete pad with wood 2x4 frame

D Ground Surface

E Surface Seal: Bot. 3' bgs Top 0 bgs Interval 3 ft
Material Type: Concrete

F Bentonite Seal: Bot. 8' bgs Top 3' bgs Interval 5 ft
Material Type: Hyrdrated Bentonite Crumbles

G Bentonite Seal: Bot. 11' bgs Top 8' bgs Interval 3 ft
Material Type: Hydrated Bentonite Crumbles

H Filter Pack: Bot. 16' bgs Top 11' bgs Interval 5 ft
Material Type: 10-20 mesh sand

I Shallow Screen Interval: Bot. 14.3' bgs Top 12.55 bgs Interval 1.75 ft
Type: 21" Stainless Steel Implant Slot Size: n/a

J Bentonite Seal: Bot. 19.5' bgs Top 16' bgs Interval 3.5 ft
Material Type: Hydrated Bentonite Crumbles

K Filter Pack: Bot. 25' bgs Top 19.5' bgs Interval 5.5 ft
Material Type: 10-20 mesh sand

L Deep Screen Interval: Bot. 23.3' bgs Top 21.55' bgs Interval 1.75 ft
Type: 21" Stainless Steel Implant Slot Size: n/a

M Backfill Material: Bot. n/a bgs Top n/a bgs Interval n/a ft
Material Type: none

N Total Boring Depth: 25 ft bgs

Drilled By: Davis Henschel
Logged By: David Fontana

Drilling Method: H.S.A. ☐ S.S.A. ☐ D.P.T. ☒

Drilling Tooling Max. Diameter: 2.5 inches

General Notes:
Deep and Shallow wells are labeled with separate aluminum tags.
Each vapor well tubing is capped with a 3-way valve that has been left in the position which closes off the downhole opening of the valve.
Deep vapor wells have a blue 3-way valve and shallow vapor wells have a white 3-way valve.
Well Vault is capped with a 4" J-plug.
Vapor implant and tubing were centered in the borehole, filter pack, and bentonite seal as best as possible.

I hearby certify that the information on this form is true and correct to the best of my knowledge
Signature:

Printed Name: David Fontana

Figure C-1. Schematic of Soil Gas Profile Station SG01. Well design is the same for all stations except SG02 and SG11 (shown in Figure C-2).

Vista GeoScience

VAPOR WELL CONSTRUCTION DETAILS

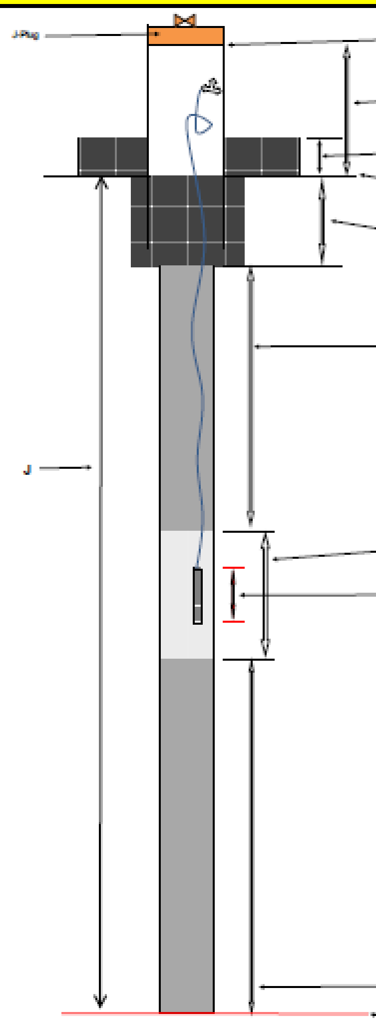
Project Name: CCS Soil Gas Minitoring Well Installation
Vista GeoScience Project #: 21215.01
Address: N/A
City: Beulah
State: North Dakota
Permit No.:

Location ID: SG-02
Shallow Vapor Well ID: SG-02S
Deep Vapor Well ID: n/a

D Ground Surface Elevation: feet MSL
A Top of Stick Up Elevation: feet MSL
Northing 47.40115902 Easting -101.861667

Type of Well: Vapor Well
Type of Screen: 21" Stainless Steel Implant
Tubing Type: NYLAFLOW Nylon Tubing ID Tubing 0.19 inches
Boring Diameter: 2.5 inches OD Tubing 0.25 inches

Driller #1 Name: Davis Henschel
Driller #2 Name: David Fontana
Date Drilled: 10/21/2021 Date Installed: 10/21/2021



A Top of Well Vault

B Stick Up: Bot. 0 ags Top 3.25' ags Interval 3.25 ft
Material: 4" diameter PVC

C Well Pad: Bot. 0 ags Top 0.29' ags Interval 0.29 ft
Well Pad Material Description: 2' x 2' concrete pad with wood 2x4 frame

D Ground Surface

E Surface Seal: Bot. 1.75' bgs Top 0 bgs Interval 1.75 ft
Material Type: Concrete

F Bentonite Seal: Bot. 4' bgs Top 1.75' bgs Interval 2.25 ft
Material Type: Hyrdrated Bentonite Crumbles

G Filter Pack: Bot. 6' bgs Top 4' bgs Interval 2 ft
Material Type: 10-20 mesh sand

H Deep Screen Interval: Bot. 5.85 bgs Top 4.1 bgs Interval 1.75 ft
Type: 21" Stainless Steel Implant Slot Size: n/a

I Backfill Material: Bot. 15' bgs Top 6' bgs Interval 9 ft
Material Type: Bentonite chips and native material that collapsed into the borehole.

J Total Boring Depth: 15 ft bgs

Drilled By: Davis Henschel
Logged By: David Fontana

Drilling Method: H.S.A. ☐ S.S.A. ☐ D.P.T. ☒

Drilling Tooling Max. Diameter: 2.5 inches

General Notes:
The vapor well tubing is capped with a 3-way valve that has been left in the position which closes off the downhole opening of the valve.
Well Vault is capped with a 4" J-plug.
Vapor implant and tubing were centered in the borehole, filter pack, and bentonite seal as best as possible.
While backfilling the borehole collapsed to 6' bgs.
Groundwater was noted between 8 and 10' bgs and logged at 10.10' BGS during drilling.

I hearby certify that the information on this form is true and correct to the best of my knowledge
Signature:
Printed Name: David Fontana

Figure C-2. Schematic of Soil Gas Profile Station SG02. Well design is the same for SG11.

Table C-1. Soil Gas Analytes Identified with Field and Laboratory Instruments

Landtec GEM 5000	*U.S. EPA Method TO-17*
Analyte	**Analyte**
CO_2	1,1,1,2-Tetrachloroethane
O_2	1,1,1-Trichloroethane
H_2S	1,1,2,2-Tetrachloroethane
CH_4	1,1,2-Trichloroethane
	1,1,2-Trichlorotrifluoroethane (Fr_113)
	1,1-Dichloroethane
	1,1-Dichloroethene
	1,2,3-Trichlorobenzene
	1,2,3-Trichloropropane
	1,2,4-Trichlorobenzene
	1,2,4-Trimethylbenzene
	1,2-Dibromoethane (EDB)
	1,2-Dichlorobenzene
	1,2-Dichloroethane
	1,3,5-Trimethylbenzene
	1,3-Dichlorobenzene
	1,4-Dichlorobenzene
	1,4-Dioxane
	2-Methylnaphthalene
	Benzene
	Carbon tetrachloride
	Chlorobenzene
	Chloroform
	cis-1,2-Dichloroethene
	Ethylbenzene
	Isopropylbenzene
	Methyl-t-butyl ether
	Naphthalene
	o-Xylene
	p and m-Xylene
	Tetrachloroethene
	Toluene
	trans-1,2-Dichloroethene
	Trichloroethene
	Vinyl chloride

Table C-2. Isotope Measurements of Soil Gas Samples

Isotope	Units
$\delta^{13}C$ of CO_2*	‰ (per mil)
$\delta^{13}C$ of CH_4*	‰ (per mil)
δD of CH_4*	‰ (per mil)

* Only measured if high enough concentration detected.

1.5.1.2 Quality Assurance/Quality Control Procedures

Soil Gas Locations: SG01 to SG11

The standard sampling and analytical QA/QC protocols that will be applied by DIG at sample locations SG01 through SG11 were provided earlier in Section C.6.1.1 of this QASP (see also https://digforenergy.com/geochemical-laboratory/).

1.5.2 Groundwater/USDW

Groundwater/USDW monitoring measures the water's chemical components and characteristics of soil components and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. A total of six Fox Hills groundwater sampling sites were drilled and installed in the storage facility area (Figure 5-4). All six locations are located on Coteau property. In addition, DGC will add one Fox Hills groundwater monitoring well near the Herrmann 1 (NDIC File No. 4177) and obtain a baseline sample prior to the start of injection operations (Figure 5-14).

1.5.2.1 Groundwater Sampling and Analysis Protocol

Baseline Groundwater Wells (Fred Art/Oberlander 1 and Helmuth Pfenning 2)

Groundwater samples were collected by Minnesota Valley Testing Laboratories (MVTL) (Bismarck, North Dakota) from these wells using the wells' submersible pumps. MVTL applied the following standard procedure for sampling the wells:

1. Determine use of well prior to sample collection, (e.g., domestic, livestock, irrigation, municipal)

2. Purge the well, using a measured bucket to determine the pumping rate when the valve is fully open.

   a. The longer that the well has not been in use, the longer the well will need to be purged before sample collection. Purge time will also depend on the total depth of the well.
   b. For wells used daily, purge the well for 1–2 minutes. For wells used on a seasonal basis, such as livestock or irrigation, purge the well for 15 minutes, or longer if the well is over 100 feet deep. If the well has not been in use in the past year, three well volumes may need to be removed to ensure a freshwater sample can be collected.

3. Collect the sample.
   a. Once the well has been sufficiently purged, sample collection can proceed.

b. Record location of sample point.
c. Record pumping rate and volume purged.
d. Collect field readings: temperature, conductivity, and pH.
e. Fill appropriate sample containers for analysis.

Two laboratories were used to analyze the water samples: 1) MVTL analyzed samples for general parameters, anions, cations, metals (dissolved and total), and nonmetals (Tables C-3 and C-4) and 2) the Dolan Integration Group (DIG) laboratory analyzed samples for dissolved gas composition (Table C-5) and the stable isotopes (Table C-6).

The standard sampling and analytical QA/QC protocols that will be applied by MVTL and DIG as part of the monitoring efforts at these sample locations were provided earlier in this QASP (www.mvtl.com/QualityAssurance and https://digforenergy.com/geochemical-laboratory/).

Table C-3. Measurements of General Parameters for Groundwater Samples

Parameter	Method
pH	SM4500-H+-B-11
Conductivity	SM2510B-11
Alkalinity	SM[1] 2320B
Temperature	SM2550B
Total Dissolved Solids	SM 2540C
Total Inorganic Carbon	EPA[2] 9060
Dissolved Inorganic Carbon (DIC)	EPA 9060
Total Organic Carbon	SM 5310B
Dissolved Organic Carbon	SM 5310B
Total Mercury	EPA 7470A
Dissolved Mercury	EPA 245.2
Total Metals[3] (26 metals)	EPA 6010B/6020
Dissolved Metals[3] (26 metals)	EPA 200.7/200.8
Bromide	EPA 300.0
Chloride	EPA 300.0
Fluoride	EPA 300.0
Sulfate	EPA 300.0
Nitrite	EPA 353.2

[1] Standard method; American Public Health Association (2017).
[2] U.S. Environmental Protection Agency.
[3] See Table B-2 for entire sampling list of total and dissolved metals.

Table C-4. Total and Dissolved Metals and Cation Measurements for Groundwater Samples

Metals	Major Cations	Trace Metals
Antimony	Barium	Aluminum
Arsenic	Boron	Cobalt
Beryllium	Calcium	Lithium
Cadmium	Iron	Molybdenum
Chromium	Magnesium	Vanadium
Copper	Manganese	
Lead	Potassium	
Mercury	Silicon	
Nickel	Sodium	
Selenium	Strontium	
Silver	Phosphorus	
Thallium		
Zinc		

Table C-5. Gas Compositional Analysis – Dissolved Gas in Water

Dissolved Gases*
N_2
O_2 + Ar
CO_2
C_1 Methane
Ethane
Propane
iso-Butane
nor-Butane
iso-Pentane
nor-Pentane
Helium
H_2

* EPA RSK-175 – Sample Preparation and Calculations for Dissolved Gas Analysis in Water Samples Using a GC Headspace Equilibration Technique.

Table C-6. Stable Isotope Measurements and Dissolved Gases in Groundwater

Isotope	Units
δD H_2O	‰ (per mil)
$\delta^{18}O$ H_2O	‰ (per mil)
$\delta^{13}C$ DIC	‰ (per mil)
$\delta^{13}C$ Methane (if present)	‰ (per mil)
$\delta^{13}C$ Ethane (if present)	‰ (per mil)
$\delta^{13}C$ Propane (if present)	‰ (per mil)
δD Methane (if present)	‰ (per mil)
$\delta^{13}C$ CO_2 (if present)	‰ (per mil)

Operational and PISC Groundwater Wells

The operational and PISC groundwater wells that will be monitored include sampling of the six dedicated groundwater Fox Hills Formation monitoring wells installed at each of the injection wells. DIG will assist with the sampling of the wells to provide two samples for analysis from each well. One sample will be analyzed by a state-certified laboratory for the general parameters, anions, cations, metals (dissolved and total), and nonmetals listed in Tables C-3 and C-4; the other sample will be sent to DIG for the determination of the dissolved gases and isotopic signatures (see Table C-6).

1.5.2.2 Quality Assurance/Quality Control

Baseline Groundwater Wells (Fred Art/Oberlander 1 and Helmuth Pfenning 2)

The laboratory analyses conducted by MVTL and DIG were performed in accordance with their internal QA/QC procedures (Table C-3 and www.mvtl.com/QualityAssurance). In addition, duplicate samples were taken to assess the combined accuracy of the field sampling and laboratory analysis methods. These duplicate samples were collected at the same time and location for each of the groundwater wells.

Operational and PISC Groundwater Wells

The standard sampling and analytical QA/QC protocols that will be applied by MVTL and DIG as part of the monitoring efforts at these sample locations were provided earlier in this QASP.

1.6 Storage Reservoir Monitoring

Monitoring of the storage reservoir during the injection operation includes monitoring of the injection flow rates and volumes, wellhead injection temperatures and pressures, bottomhole injection pressures, temperature, and saturation profiles from the storage reservoir to the AZMI (above-zone monitoring interval), and the tubing-casing annulus pressure or casing pressure.

The storage monitoring will be accomplished using flowmeters and surface digital pressure and temperature gauges. Surface measurements will be taken at the flowmeter and the wellhead (tubing and casing). These readings will be recorded in real-time. These pressure/temperature data will be continuously recorded as part of the supervisory control and data acquisition (SCADA) (see Attachment A-8) system that is employed on-site. All data collected by the SCADA system is routed to DGC's pipeline control center.

1.7 Wireline Logging and Retrievable Monitoring

The wireline logging and retrievable monitoring that will be performed comprise pulsed-neutron logs (PNLs), which include temperature and pressure data, ultrasonic logs, injection zone pressure falloff tests, and corrosion monitoring. The information provided by these monitoring efforts is as follows:

- PNL: provides information regarding gas saturation in the formations, which can be used to determine if the injected CO_2 is contained within the storage formation as well as ground-truth information provided by the seismic surveys. The PNL is also capable of gathering downhole pressure and temperature data.

- USIT (ultrasonic imaging tool): provides an assessment of the external and internal mechanical integrity and assessment of corrosion of the wellbore.

- PMIT: provides a measure of change in thickness of the wellbore materials over time due to interaction of the wellbore with the injected CO_2 and formation fluids.

- Pressure falloff test: provides an assessment of the storage reservoir injectivity.

All wireline logging events will follow API (American Petroleum Institute) guidelines along with the standard operating procedures of a third-party wireline operator. More details regarding each of these monitoring techniques is provided below.

1.7.1 Pulsed-Neutron Logs

PNLs provide formation evaluation and reservoir monitoring in cased holes. PNL is deployed as a wireline logging tool with an electronic pulsed neutron source and one or more detectors that typically measure neutrons or gamma rays (Rose and others, 2015). High-speed digital signal electronics process the gamma ray response and its time of arrival relative to the start of the neutron pulse. Spectral analysis algorithms translate the gamma ray energy and time relationship into concentrations of elements (Schlumberger, 2017).

Schlumberger's Pulsar Multifunction Spectroscopy Service (PNX) tool is a slim tool with an outer diameter (o.d.) of 1.72 in. for through-tubing access in cased hole environments. The housing is corrosion-resistant, allowing deployment in wellbore environments such as CO_2. The PNX tool can provide a direct volumetric measurement of gas-filled porosity and differentiate between gas-filled porosity, liquid-filled, and tight zones (Schlum20berger, 2017). Detection limits for CO_2 saturation for the PNX tool vary with the logging speed as well as the formation porosity as shown in Table C-7 below. Detailed measurement and mechanical specifications for the PNX tool are provided in Attachment A-2. The wireline operator will provide QA/QC procedures and tool calibration for their equipment.

Table C-7. Gas Saturation Detection Limits for PNL – PNX Tool

	Gas Saturation Detection Limit (%)	
Porosity Value (%)	**Minimum at Logging Speed of 1000 feet/hour**	**Minimum at Logging Speed of 200 feet/hour**
10	~39	~18
15	~22	~10
20	~18	~8

1.7.1.1 Description of Regular PNL Protocol

After the drilling and before CO_2 injection, a PNL will be run in each injector to confirm cement integrity and provide a baseline to which future PNL logging runs will be compared. Since the PNL tool also includes temperature and pressure measurements, profiles of both temperature and pressure will be constructed. The injection wells will be logged following the phased approach defined in Section 5.1.2 of this storage facility permit.

The following procedure will be followed when running a PNL in an injection well:

1. Hold a safety meeting and ensure that all personnel are wearing breathing equipment as the injection fluid contains H_2S:
   a. Rig up H_2S monitoring equipment
   b. Ensure that all safety precautions are taken

2. Shut well in by closing the outside wing valve and upper master valve.

3. Rig up lubricator, and pressure-test connections and seals to 2,000 pounds per square inch.

4. Open crown valve.

5. Open top master valve and proceed downhole to the injection packer with the PNL logging tool.

6. Make a 30-minute stop at the bottom of the hole, and record a static bottomhole pressure.

7. Proceed with running the PNL log making stops every 500' (approximately 12 stops) for 5 minutes each to record a static fluid pressure.

8. Once the logging tool is at the surface and in the lubricator, make a 5-minute stop to record the surface pressure in the tubing.

9. Close the crown valve and top master valve. Bleed pressure from the tree and lubricator.

10. Remove lubricator and replace the top cap and pressure gauge.

11. Open the top master valve, and again record the tubing and annular pressures.

12. Rig down the wireline company and clean the location.

13. Return the well to injection service by opening the outside wing valve.

1.7.2 Ultrasonic Imaging Tool

The USIT indicates the quality of the cement bond at the cement–casing interface and provides casing inspection (corrosion detection, monitoring, and casing thickness analysis). The tool is deployed on wireline with a transmitter emitting ultrasonic pulses and measuring the reflected ultrasonic waveforms received from the internal and external casing interfaces. The entire circumference of the casing is scanned, enabling the evaluation of the radial cement bond and the detection of internal and external casing damage or deformation. The high angular and vertical tool resolutions can detect cement channels as narrow as 1.2 inches (Attachment A-1). Detailed measurement and mechanical specifications for the USIT tool are provided in Attachment A-1. The wireline operator will provide QA/QC procedures and tool calibration for this equipment.

1.7.3 Platform Multifinger Tool

In instances where an individual tubing string has not been pulled for workover purposes, and thus made available for inspection at the surface, it may be useful to instead run a PMIT. The PMIT is a multifingered caliper tool that makes highly accurate radial measurements of the internal diameter of tubing and casing strings. In so doing it can quantify surface pitting and/or internal wall loss. Detailed measurements and mechanical specifications for the PMIT tool are provided in Attachment A-4.

1.7.4 Injection Zone Pressure Falloff Test

The injection zone pressure falloff test will be performed in the injection well prior to initiation of CO_2 injection activities and at least once every 5 years thereafter to demonstrate storage reservoir injectivity. Pressure data will be recorded during the pressure falloff test at the bottomhole.

1.8 Geophysical Monitoring Methods

The geophysical monitoring that is planned for the project includes time-lapse seismic surveys. This indirect monitoring method will characterize attributes associated with the injected CO_2, including the plume extents, mass changes, pressure changes, and potential seismicity. Details regarding the application and quality of this method are provided in the remainder of this section:

- Time-lapse seismic surveys: provide a measurement of the change in acoustic properties of the storage formation as injected CO_2 saturates the storage interval.

1.8.1 Time Lapse Seismic Surveys

Application of time-lapse seismic surveys for monitoring changes in acoustic properties requires a quality preoperational seismic survey for baseline conditions. The monitor survey should be repeated as closely to the baseline conditions and parameters as possible. The seismic monitor data should be reprocessed simultaneously with the original baseline data or processed with the same steps and workflow to ensure repeatability. Repeatability is a measure of 4D seismic quality (Lumley and others, 1997, 2000) that can be quantified once the processed data are analyzed by an experienced 4D seismic interpreter.

1.9 Completed Well Logging

Several continuous measurements of the storage formation properties were made in the Coteau 1 wellbore using wireline logging techniques. These logs, which are identified along with the justification for their use in Table 5-7, are listed below:

- Ultrasonic log
- Casing collar locator (CCL) log
- VDL
- CBL
- Gamma ray log
- Triple combo logs (i.e., resistivity, density, porosity, caliper, and spontaneous potential)
- Combinable magnetic resonance (CMR) log
- Spectral gamma ray log
- Dipole sonic log
- Fracture finder log

1.10 Perforation/Flowback Test (formation fluid and reservoir pressure)

Upon completion of initial drilling, casing, and cementing operations at the Coteau 1, the well was allowed to stand idle for a period of 3 months. Subsequently, the well was reentered, and a USIT was run to evaluate the cement bond to surface. A single foot of perforations was shot at 5,975 feet in the well in order to obtain a Broom Creek fluid sample and current reservoir pressure (Attachment A-9). The well was swabbed briefly and then began flowing back on its own. After the recovery of 50 barrels of formation fluid, multiple surface readings were taken to confirm consistent total dissolved solids readings. A fluid sample was then obtained for evaluation. After recording the bottomhole pressure, the perforations were squeeze-cemented. This cement was later drilled out, and the casing was tested to 1600 psi.

For future wells, namely, the Coteau 2 through 6, the flowback and pressure recording will be performed as part of their completion as CO_2 injection wells.

1.11 References

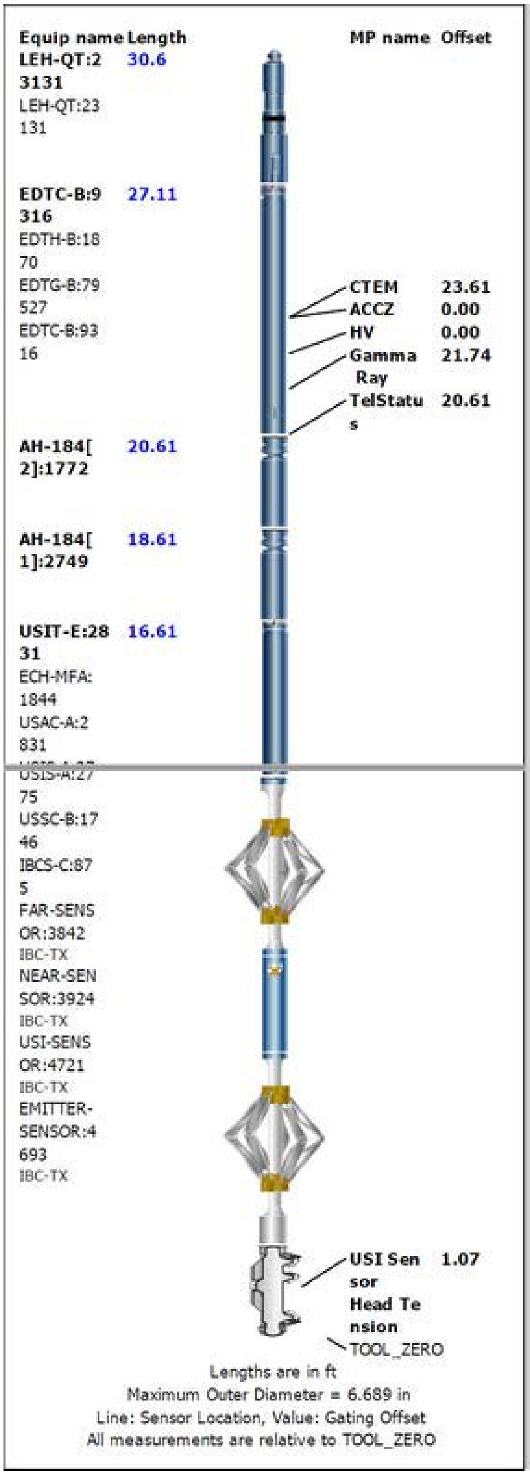
Lumley, D.E., Behrens, R.A., and Wang, Z., 1997, Assessing the technical risk of a 4-D seismic project: The Leading Edge, v. 16, p. 1287–1292, doi: 10.1190/1.1437784.

Lumley, D.E., Cole, S., Meadows, M.A., Tura, A., Hottman, B., Cornish, B., Curtis, M., and Maerefat, N., 2000, A risk analysis spreadsheet for both time-lapse VSP and 4D seismic reservoir monitoring: 70th Annual International Meeting, SEG, Expanded Abstracts, p. 1647–1650.

Rose D., Zhou, T., Beekman, S., Quinlan T., Delgadillo, M., Gonzalez, G., Fricke, S., Thornton, J., Clinton, D., Gicquel, F., Shestakova, I., Stephenson, K., Stoller, C., Philip, O., Miguel La Rotta Marin, J., Mainier, S., Perchonok, B., and Bailly, J.P., 2015, An innovative slim pulsed neutron logging tool: Society of Petrophysicists and Well Log Analysts 56th Annual Logging Symposium, Long Beach, California, July 2015.

Schlumberger, 2017, Pulsar multifunction spectroscopy tool: Society of Petrophysicists and Well Log Analysts 58th Annual Logging Symposium, Oklahoma City, Oklahoma, June 2017.

Attachment A-1 – Ultrasonic Imaging Tool



Measurement Specifications

	Isolation Scanner Tool
Output†	Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image
Max. logging speed	Standard resolution (6 in, 10° sampling): 823 m/h [2,700 ft/h] High resolution (0.6 in, 5° sampling): 172 m/h [563 ft/h]
Range of measurement	Min. casing thickness: 0.38 cm [0.15 in] Max. casing thickness: 2.01 cm [0.79 in]
Vertical resolution	High resolution: 1.52 cm [0.6 in] High speed: 15.24 cm [6 in]
Acoustic impedance‡	Range: 0 to 10 Mrayl Resolution: 0.2 Mrayl Accuracy: 0 to 3.3 Mrayl = ±0.5 Mrayl, >3.3 Mrayl = ±15%
Flexural attenuation	Range: 0 to 2 dB/cm§ Resolution: 0.05 dB/cm§ Accuracy: 0.01 dB/cm§
Min. quantifiable channel width	30 mm [1.2 in]
Depth of investigation†	Casing and annulus up to 7.62 cm [3 in]
Mud type or weight limitation††	Conditions simulated before logging
Combinability	Bottom only, combinable with most wireline tools Telemetry: fast transfer bus (FTB) or enhanced FTB (EFTB)
Special applications	H_2S service

† Investigation of annulus width depends on the presence of third-interface echoes. Analysis and processing beyond cement evaluation can yield additional answers through additional outputs, including the Variable Density log (VDL) of the annulus waveform and polar movies in AVI format.

‡ Differentiation of materials by acoustic impedance alone requires a minimum gap of 0.5 MRayl between the fluid behind the casing and a solid.

§ For 8-mm [0.3-in] casing thickness.

†† Max. mud weight depends on the mud formulation, sub used, and casing size and weight, which are simulated before logging.

Mechanical Specifications

	Isolation Scanner Tool
Max. temperature	177 degC [350 degF]
Pressure range	1 to 138 MPa [145 to 20,000 psi]
Casing size—min.†	4½ in (min. pass-through restriction: 4 in)
Casing size—max.†	9⅝ in
Outside diameter	IBCS-A: 8.57 cm [3.375 in] IBCS-B: 11.36 cm [4.472 in] IBCS-C: 16.91 cm [6.657 in]
Length without sub	6.01 m [19.73 ft]
Weight without sub	151 kg [333 lbm]
Sub length, weight	IBCS-A: 61.22 cm [24.10 in], 7.59 kg [16.75 lbm] IBCS-B: 60.32 cm [23.75 in], 9.36 kg [20.64 lbm] IBCS-C: 60.32 cm [23.75 in], 10.73 kg [23.66 lbm]
Sub max. tension	10,000 N [2,250 lbf]
Sub max. compression	50,000 N [12,250 lbf]

† Limits for casing size depend on the sub used. Data can be acquired in casing larger than 9⅝ in with low-attenuation mud (e.g., water, brine).

Attachment A-1. Schlumberger's isolation scanner USIT used to provide evidence of external mechanical integrity in injection wells Coteau 1 through Coteau 6.

Attachment A-2 – Through-Tubing Pulsed Neutron Tool

Pulsar

Multifunction spectroscopy service

Measurement Specifications	
Acquisition	Real time with surface readout
Output	
Time domain	Sigma (SIGM), porosity (TPHI), fast-neutron cross section (FNXS)
Energy domain	Inelastic and capture yields of various elements, carbon/oxygen ratio, total organic carbon
Logging speed†	
Inelastic capture mode	200 ft/h [61 m/h]
Inelastic gas, sigma, and hydrogen index (GSH) mode	3,600 ft/h [1,097 m/h]
Sigma lithology mode	1,000 ft/h [305 m/h]
Range of measurement	Porosity: 0 to 60 pu
Mud type or weight limitations	None
Combinability	Combinable with tools that use the PS Platform production services platform's telemetry system and ThruBit through-the-bit logging services
Special application	Qualified per the requirements of NACE MR0175 H_2S and CO_2 resistance

† Logging speed determined using the tool planner

Mechanical Specifications	
Temperature rating	350 degF [175 degC]
Pressure rating	15,000 psi [103.4 MPa]
Casing size—min.	2⅜ in [6.03 cm]
Casing size—max.	9⅝ in [24.45 cm]
Outside diameter	1.72 in [4.37 cm]
Length	18.3 ft [5.58 m]
Weight	88 lbm [40 kg]
Tension	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N]

*Mark of Schlumberger
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Attachment A-2. Measurement and mechanical specifications for Schlumberger's PNX (through-tubing pulsed neutron) tool.

Attachment A-3 – Standard Annulus Pressure Test Procedure

The tubing/casing annular pressure test provides an assessment of the internal mechanical integrity of the wellbore between the tubing-casing annulus. The pressure test procedure will be generated following the North Dakota Industrial Commission (NDIC) Injection Well Construction and Completion Standards (NDAC § 43-05-01-11), which state the pressure must be applied for a period of 30 minutes and must have no decrease in pressure greater than 10% of the required minimum test pressure.

Pursuant to Section 43-05-01-11.1

1. Contact NDIC to witness mechanical integrity test (MIT) procedure a minimum of 24 hours prior to test.

2. Completely fill the tubing/casing annulus with corrosion-inhibited packer fluid. Temperature stabilization of the well and annulus fluid is necessary; therefore, injection shall either be ceased, or a stabilized injection rate and temperature will be maintained.

3. After stabilization, the annulus will be pressurized to the maximum allowable injection pressure or an alternate pressure approved by NDIC. A positive pressure differential between the annulus and the injection string shall be maintained throughout the entire annulus.

4. Following pressurization, the annulus will be isolated from the source of pressure by a closed valve.

5. The annulus will remain isolated for a period no less than 30 minutes or as otherwise approved by NDIC. Pressure measurements will be recorded every 5 minutes, as well as continuously charted.

6. If the pressure deviates more than 10% of the required minimum test pressure, check for seal leaks, otherwise repeat steps. If failure occurs, well will be shut in, report of the failure will be sent to NDIC, and isolation and repair of the leak will commence within 90 days, unless otherwise approved by NDIC.

Attachment A-4 – Platform Multifinger Imaging Tool

Schlumberger

PS Platform Multifinger Imaging Tool

APPLICATIONS

- Identification and quantification of corrosion damage
- Identification of scale, wax, and solids accumulation
- Monitoring of anticorrosion systems
- Location of mechanical damage
- Evaluation of corrosion increase through periodic logs
- Determination of absolute inside diameter (ID)

The PS Platform* Multifinger Imaging Tool (PMIT) is a multifinger caliper tool that makes highly accurate radial measurements of the internal diameter of tubing and casing strings. The tool is available in three sizes to address a wide range of through-tubing and casing size applications.

The tool deploys an array of hard-surfaced fingers, which accurately monitor the inner pipe wall. Eccentricity effects are minimized by equal azimuthal spacing of the fingers and a special processing algorithm. The PMIT-B and PMIT-C tools incorporate powerful motorized centralizers to ensure effective centering force even in highly deviated intervals. The centralizers are equipped with rollers to prevent casing and tubing damage. The inclinometer in the tool provides information on well deviation and tool rotation. The PMIT-C tool can be fitted with special extended fingers for logging large-diameter casings. The PMIT-A is similarly fitted with special extended fingers for logging casing through tubing. All versions of the PMIT can be run in either real-time or memory mode.

The PMIT is available in three sizes for radially measuring the internal diameter of tubing and casing strings.

Attachment A-4. Schlumberger's PMIT used as a possible alternative to surface tubing inspection in the Coteau 1 through Coteau 6 (continued).

PS Platform Multifinger Imaging Tool

Measurement Specifications			
	PMIT-A	**PMIT-B**	**PMIT-C**
Output	Internal casing image from multiple internal radius measurements	Internal casing image from multiple internal radius measurements	Internal casing image from multiple internal radius measurements
Logging speed, m/h [ft/h]	Standard: 549 [1,800] Max.: 1,829 [6,000]	Standard: 549 [1,800] Max.: 1,829 [6,000]	Standard: 549 [1,800] Max.: 1,829 [6,000]
Minimum measurable casing ID, cm [in]	Standard or extended fingers: 5.08 [2]	7.62 [3]	Standard fingers: 12.7 [5] Extended fingers: 20.32 [8]
Maximum measurable casing ID, cm [in]	Standard fingers: 11.43 [4.5] Extended fingers: 17.78 [7]	17.78 [7]	Standard fingers: 25.4 [10] Extended fingers: 33.02 [13]
Vertical resolution at 529 m/h [1,800 ft/h], mm [in]	2.1 [0.082]	2.8 [0.11]	4.24 [0.167]
Radial resolution, mm [in]	Standard fingers: 0.10 [0.004] Extended fingers: 0.18 [0.007]	0.13 [0.005]	Standard fingers: 0.18 [0.007] Extended fingers: 0.23 [0.009]
Accuracy, mm [in]	Standard fingers: ±0.76 [±0.030] Extended fingers: ±1.07 [±0.042]	±0.76 [±0.030]	Standard fingers: ±0.76 [±0.030] Extended fingers: ±1.3 [±0.050]
Relative bearing accuracy, °	±5	±5	±5
Deviation accuracy at up to 70° deviation, °	±5	±5	±5
Depth of investigation	Casing inside surface	Casing inside surface	Casing inside surface
Borehole fluid limitations	None	None	None
Combinability	Real time: combinable with all PS Platform tools Memory mode: stand alone	Real time: combinable with all PS Platform tools Memory mode: stand alone	Real time: combinable with all PS Platform tools Memory mode: stand alone Bottom-only tool Extra centralizers required for casing larger than 9⅝ in
Special applications	H_2S service	H_2S service	H_2S service

Mechanical Specifications			
	PMIT-A	**PMIT-B**	**PMIT-C**
Temperature rating, degF [degC]	302 [150]	302 [150]	PMIT-CA: 302 [150] PMIT-CB: 350 [177]
Pressure rating, MPa [psi]	103 [15,000]	103 [15,000]	PMIT-CA: 103 [15,000] PMIT-CB: 138 [20,000]
Outside diameter, cm [in]	Standard or extended fingers: 4.29 [1.6875]	6.99 [2.75]	Standard fingers: 10.16 [4] Extended fingers: 13.97 [5.5]
Fingers	24	40	60
Fingertip radius, mm [in]	1.5 [0.06]	1.27 [0.05]	1.52 [0.06]
Finger width, mm [in]	1.6 [0.063]	1.6 [0.063]	1.6 [0.063]
Length, m [ft]	3.62 [11.88] (with centralizers)	2.70 [8.86]	3.15 [10.34]
Weight, kg [lbm]	26 [56.5] (with centralizers)	40 [87.4]	54 [120]
Max. tensile strength, N [lbf]	44,480 [10,000]	44,480 [10,000]	44,480 [10,000]
Max. compressive strength, N [lbf]	8,230 [1,850]	11,120 [2,500]	11,120 [2,500]

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Schlumberger

*Mark of Schlumberger
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Attachment A-4 (continued). Schlumberger's PMIT used as a possible alternative to surface tubing inspection in the Coteau 1 through Coteau 6.

Attachment A-5 – Tuboscope Wellsite Tubing Inspection System

TuboChek™$_{C1D1}$ — Non Gamma Wellsite Tubing Inspection System

Tuboscope is pleased to announce the introduction of the TuboChek$_{C1D1}$ inspection system. This unit is certified and meets Class-1 Div-1 safety standards with intrinsically safe electronics and includes an encapsulated coil housing.

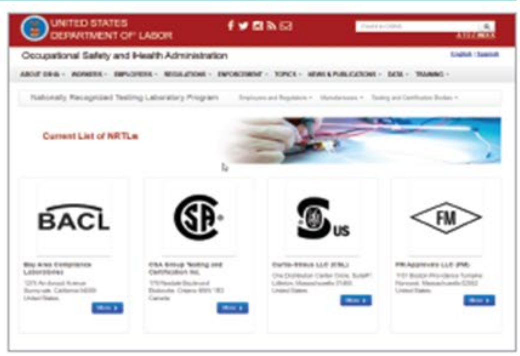
Similar to our WellChek system, TuboChek$_{C1D1}$ utilizes the same reporting and database soft-ware, providing you real-time tubing inspection, data management and evaluation of your used tubing.

This new system delivers an accurate evaluation of each tube using the same proven eddy current based split detection and Sonoscope EMI inspection for pitting and corrosion detection. Unique to this system, a flux integration method is used for cross-sectional area, calculated rod-wear and a flux leakage technique for magnetic field discrimination to determine rod strokes.

TuboChek$_{C1D1}$ increases the size range capabilities of inspected tubing to include: 2 ⅜" , 2 ⅞", 3 ½", 4" and 4 ½"

Benefits
- Professionally trained crew for efficient and safe operations
- Records exact defect and joint location in the well
- Real time usable information
- On-site inspection eliminates need for trucking to inspection facilities
- Immediate re-use of good tubing

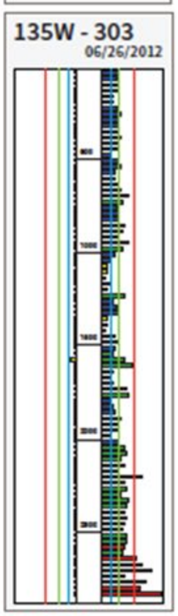
Defect Detection
- Corrosion pitting
- Rod wear
- Wall loss
- Cracks
- Erosion
- Splits
- Cuts
- Holes
- 3-Dimensional Transverse Defects



Tuboscope | NOV Wellbore Technologies 2835 Holmes Road Houston, Texas 77051, USA Phone 346 223 6100 tuboscopesales@nov.com nov.com/tuboscope

Attachment A-5. Tuboscope's wellsite tubing inspection service. This (or its equivalent) can be utilized for surface inspection of the Coteau 1 thru 6 tubing strings in the event they need to be pulled for any reason (continued).

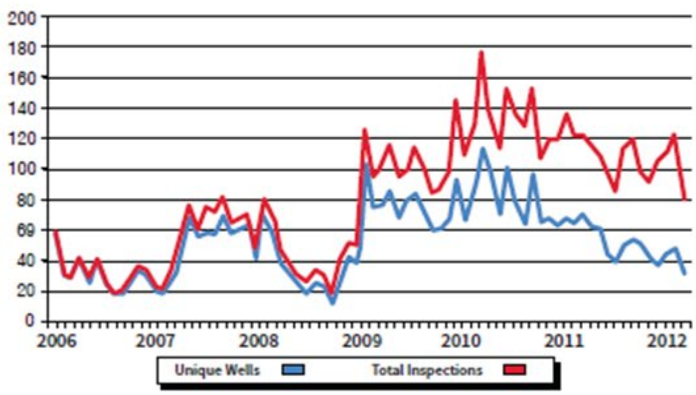
TuboChek™ $_{C1D1}$ — Non Gamma Wellsite Tubing Inspection System



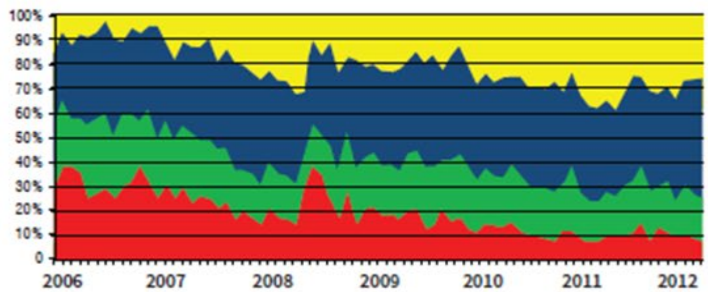
Sample Well
Well profiles show the rate of corrosion *(left bars)* and wall loss *(right bars)* by joint at precise depths.

WellTrak Tubing Data Management and Evaluation System provides production engineers, well managers, rig supervisors and others in tubing management programs access to TuboChek™ $_{C1D1}$ inspection reports. The reports provide critical data at precise depths where string wear, corrosion, or failures have occurred.

Tubing Management decisions based on WellTrak's online historical database of well/field conditions can greatly assist in string design, treatments or mitigation techniques before the well is put back on production. This valuable information helps extend the run life of wells, measure the effectivenes of changes, and reduce overall tubing failures.



Inspections per month



Reject Rates per month
Continued application of on-site inspection at this field resulted in reduced reject rates and reduced tubing failures.

Benefits:

- Individual full inspection history
- Online access to well records
- Identify patterns or correlations among historical inspections
- Quick rod guide assessment can be established in conjunction with rod design programs
- Generalized statistics for inspections performed

The exclusive Tuboscope TuboChek™ $_{C1D1}$ inspection coupled with WellTrak's data management system maximizes the potential of your tubing string, preventing future problems while reducing operating costs.

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Houston, Texas 77051, USA
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Attachment A-5 (continued). Tuboscope's wellsite tubing inspection service. This (or its equivalent) can be utilized for surface inspection of the Coteau 1 through 6 tubing strings in the event they need to be pulled for any reason.

Honeywell

Sensepoint XCD SPECIFICATIONS

Flammable, toxic and oxygen gas detector for industrial applications

Use	3 wire, 4-20mA and RS485 MODBUS output fixed point detector with in-built alarm and fault relays for the protection of personnel and plant from flammable, toxic and Oxygen hazards. Incorporates a transmitter with local display and fully configurable via non-intrusive magnetic switch interface.
Electrical	
Input Voltage Range	12 to 32VDC (24VDC nominal)
Max Power Consumption	Maximum power consumption is dependent on the type of gas sensor being used. Electrochemical cells = 3.7W, IR = 3.7W and catalytic = 4.9W. Maximum inrush current = 800mA at 24VDC
Current Output	Sink or source
Relays	3 x 5A@250VAC. Selectable normally open or normally closed (switch) and energized/de-energised (programmable) Alarm relays default normally open/de-energized. Fault relay default normally open/energized
Communication	RS485, MODBUS RTU
Construction	
Material	Housing: Epoxy painted aluminium alloy ADC12 or 316 stainless steel Sensor: 316 stainless steel
Weight (approx)	Aluminium Alloy LM25: 4.4lbs 316 Stainless Steel: 11lbs
Mounting	Integral mounting plate with 4 x mounting holes suitable for M8 bolts. Optional pipe mounting kit for horizontal or vertical pipe Ø1.5 to 3" (2" nominal)
Cable Entries	UL\cUL versions: 2 x ¾"NPT conduit entries. Suitable blanking plug supplied for use if only 1 entry used. Seal to maintain IP rating; ATEX/IECEx versions: 2 x M20 cable entries
Environmental	
IP Rating	IP66 in accordance with EN60529:1992
Certified Temperature Range	-40ºF to +149ºF (-40ºC to +65ºC)

Detectable Gases and XCD Sensor Performance

Gas	User Selectable Full Scale Range	Default Range	Steps	User Selectable Cal Gas Range	Default Cal Point	Response Time (T90) Secs	Accuracy	Operating Temperature Min	Operating Temperature Max	Default Alarm Points A1	Default Alarm Points A2
Electrochemical Sensors											
Oxygen	25.0%Vol. only	25.0%Vol.	n/a	20.9%Vol. (Fixed)	20.9%Vol.	<30	<±0.5%Vol.	-20°C / -4°F	55°C / 131°F	19.5%Vol. ▼	23.5%Vol. ▲
Hydrogen Sulfide*	10.0 to 100.0ppm	50.0ppm	0.1ppm	30 to 70% of selected full scale range	25ppm	<50	<±1ppm	-20°C / -4°F	55°C / 131°F	10ppm ▲	20ppm ▲
Carbon Monoxide**	100 to 1,000ppm	300ppm	100ppm		100ppm	<30	<±6ppm	-20°C / -4°F	55°C / 131°F	30ppm ▲	100ppm ▲
Hydrogen	1,000ppm only	1,000ppm	n/a		500ppm	<65	<±25ppm	-20°C / -4°F	55°C / 131°F	200ppm ▲	400ppm ▲
Nitrogen Dioxide***	10.0 to 50.0ppm	10.0ppm	5.0ppm		5.0ppm	<40	<±3ppm	-20°C / -4°F	55°C / 131°F	5.0ppm ▲	10.0ppm ▲
* Lowest Alarm Limit = 1ppm; Lowest Detection Limit = .5ppm ** Lowest Alarm Limit = 15 ppm; Lowest Detection Limit = 10ppm *** Lowest Alarm Limit = 0.6 ppm; Lowest Detection Limit = 0.3ppm											
Catalytic Bead Sensors											
Flammable 1 to 8	20.0 to 100.0%LEL	100%LEL	10%LEL		50%LEL	<25	<±1.5%LEL	-20°C / -4°F	55°C / 131°F	20%LEL ▲	40%LEL ▲
Infrared Sensors											
Methane	20.0 to 100.0%LEL	100%LEL	10%LEL		50%LEL	<30	<±1.5%LEL	-20°C / -4°F	50°C / 122°F	20%LEL ▲	40%LEL ▲
Propane	20 to 100%LEL	100%LEL	10%LEL		50%LEL	<30	<±1%LEL	-20°C / -4°F	50°C / 122°F	20%LEL ▲	40%LEL ▲
Carbon Dioxide	2%Vol. only	2%Vol.	n/a		1%Vol.	<30	<±0.04%Vol.	-20°C / -4°F	50°C / 122°F	0.4%Vol. ▲	0.8%Vol. ▲

NOTE: For Cat Bead and Infrared sensors, Lowest Detectable Limit is 5% LEL and Lowest Alarm Level is 10% LEL.

▲ - Rising Alarm ▼ - Falling Alarm

Certification	
US, Latin America, Canada	UL/c-UL - Class I, Division 1, Groups B, C and D, Class I, Division 2, Groups B, C & D, Class II, Division 1, Groups E, F & G, Class II, Division 2, Groups F & G. -40°C to +65°C
European	ATEX Ex II 2 GD Ex d IIC Gb T6 (Ta -40°C to +65°C) Ex tb IIIC T85°C Db IP66
International	IEC Ex d IIC Gb T6 (Ta -40ºC to +65ºC) Ex tb IIIC T85°C Db IP66
EMC	CE: EN50270:2006 EN6100-6-4:2007
Performance	UL508; CSA 22.2 No. 152 (flammable gasses, excludes infrared sensors); ATEX, IEC/EN60079-29-1:2007, EN45544, EN50104, EN50271; China: PA Pattern Measurement (for transmitter and toxic gas sensors) "CCCF" Shenyang for Flammable (fire dept approval)

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Please Note:

While every effort has been made to ensure accuracy in this publication, no responsibility can be accepted for errors or omissions. Data may change, as well as legislation, and you are strongly advised to obtain copies of the most recently issued regulations, standards, and guidelines. This publication is not intended to form the basis of a contract.

SS01082_v4 3/14

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Attachment A-7A – H_2S Detection Personnel Equipment

iBRID® MX6

- 24 "Plug-and-Play" field-replaceable sensors including PID and Infrared options
- Up to 6 gases monitored simultaneously
- Simple, user-friendly, customizable, menu-driven navigation
- Five-way navigation button
- Durable, concussion-proof overmold
- Optional integral sampling pump with strong 30.5 meter (100 feet) sample draw
- Full-color graphic LCD is highly visible in a variety of lighting conditions
- Powerful, 95 dB audible alarm

Get ready to see hazardous levels of oxygen, toxic and combustible gas, and volatile organic compounds (VOCs) like never before.

The MX6 iBrid® is more than an intelligent hybrid of Industrial Scientific's best monitoring technologies—it's the most adaptable six-gas monitor on the market. With hundreds of possible sensor combinations, and a robust list of available configuration settings, the MX6 iBrid is ready to monitor oxygen, toxic and combustible gas, and volatile organic compounds (VOCs).

As your work changes, so can your MX6 iBrid. It uses five sensor slots to detect up to six gases. Each of those sensor slots accepts a variety of sensors, which means you can use the instrument with a PID sensor one day and an infrared sensor the next. What's more, settings allow you to adapt the instrument's behavior for your application. If you need to use a benzene PID response factor for one application, and butadiene for others, the familiar menu structure will allow you to quickly change settings.

The rugged MX6 iBrid carries our Guaranteed for Life™ warranty and is compatible with DSX™ Docking Stations. With a DSX Docking Station, maintenance is simplified and data becomes more than a spreadsheet filled with logged readings. Proactively manage your gas detection fleet—track trends, know when instrument maintenance will be required, and understand how your MX6 iBrid instruments are being used.

INDUSTRIAL SCIENTIFIC

Continued…

Attachment A-7A – H_2S Detection Personnel Equipment (continued)

SPECIFICATIONS*

INSTRUMENT WARRANTY
Warranted for as long as the instrument is supported by Industrial Scientific

CASE MATERIAL
Lexan/ABS/Stainless Steel with protective rubber overmold

DIMENSIONS
135 x 77 x 48 mm (5.3 x 3.05 x 1.9 in) without Pump
193 x 77 x 56 mm (7.6 x 3.1 x 2.2 in) with Pump

WEIGHT
409 g (14.4 oz) typical, without Pump
511 g (18.0 oz) typical, with Pump

DISPLAY/READOUT
Color Graphic Liquid Crystal Display

POWER SOURCE/RUN TIMES
Rechargeable, Extended-Range Lithium-ion Battery Pack (36 hours) without Pump
Rechargeable, Extended-Range Lithium-ion Battery Pack (20 hours) with Pump
Replaceable AA Alkaline Battery Pack (10.5 hours) without Pump

OPERATING TEMPERATURE RANGE
-20 °C to 55 °C (-4 °F to 131 °F)

OPERATING HUMIDITY RANGE
15% to 95% non-condensing (continuous)

CERTIFICATIONS
INGRESS PROTECTION IP64

ANZEx:	Ex ia s Zone 0 I; Ex ia s Zone 0 IIC T4
ATEX:	Ex ia IIC T4 Ga; II 1G (or Ex d ia IIC T4 Gb IR sensor); Ex ia I; Equipment Group and Category: I M1/II 1G
China CPC:	Metrology Approval
China Ex:	Ex ia d I/IIC T4
CMA:	Approval for Mining Products: CH_4, O_2, CO, CO_2
CSA:	Cl I, Gr A-D T4; Ex d ia IIC T4
EAC:	PBExiadI X; 1ExiadIICT4 X
IECEx:	Ex ia I (Ex ia d I IR sensor); Ex ia IIC T4 Ga; Ex d ia IIC T4 Gb
INMETRO:	Ex ia IIC T4 Ga
KC:	Ex d ia IIC T4
KIMM:	Ex d ia IIC T4
MDR:	Registration of Plant Design: CH_4, O_2, CO, H_2S, NO_2
MSHA:	30 CRF, Part 22, Intrinsically safe for methane/air mixtures
PA-DEP:	BFE 114-08 Permissible for PA Bituminous Underground Mines
UL:	Cl I, Div 1, Gr A-D, T4; Cl II, Groups F G; Cl I, Zone LEL 0, AEx ia d IIC T4 (or AEx ia d IIC T4 IR sensor)

MEASURING RANGES SENSOR	RANGE	RESOLUTION
CATALYTIC BEAD		
Combustible Gas	0-100% LEL	1%
Methane	0-5% vol	0.01%
ELECTROCHEMICAL		
Ammonia	0-500 ppm	1
Carbon Monoxide	0-1,500 ppm	1
Carbon Monoxide (High Range)	0-9,999 ppm	1
Carbon Monoxide/Hydrogen low	0-1,000 ppm	1
Chlorine	0-50 ppm	0.1
Chlorine Dioxide	0-1 ppm	0.01
Carbon Monoxide/ Hydrogen Sulfide (COSH)	CO: 0-1,500 ppm H_2S: 0-500 ppm	1 0.1
Hydrogen	0-2,000 ppm	1
Hydrogen Chloride	0-30 ppm	0.1
Hydrogen Cyanide	0-30 ppm	0.1
Hydrogen Sulfide	0-500 ppm	0.1
Nitric Oxide	0-1,000 ppm	1
Nitrogen Dioxide	0-150 ppm	0.1
Oxygen	0-30% vol	0.1%
Phosphine	0-5 ppm	0.01
Phosphine (High Range)	0-1,000 ppm	1
Sulfur Dioxide	0-150 ppm	0.1
INFRARED		
Hydrocarbons	0-100% LEL	1%
Methane (% vol)	0-100% vol	1%
Methane (% LEL)	0-100% LEL	1%
Carbon Dioxide	0-5% vol	0.01%
PHOTOIONIZATION		
VOC	0-2,000 ppm	0.1

* These specifications are based on performance averages and may vary by instrument.

AVAILABLE FOR RENT

For a list of classes, videos, or to download the GDME App, visit www.indsci.com/training

Which Accessories Will You Need?

CHECKLIST

- [ ] Docking Stations
- [ ] Calibration Stations
- [ ] Compliance Tracking Software (iNet Control)
- [ ] Probes
- [ ] Sample Tubing
- [ ] Confined Space Kits
- [ ] Spare Batteries
- [ ] Replacement Sensors
- [ ] Desktop Chargers
- [ ] Vehicle Chargers
- [ ] Multi-Unit Chargers
- [ ] Carrying Cases
- [ ] Filters

For a list of all accessories, visit: www.indsci.com/mx6

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Fax: +33 (0)1 57 32 92 67 | info@eu.indsci.com

Attachment A-7B – H_2S Detection Personnel Equipment

VENTIS MX4

The Ventis® MX4 is a four-gas monitor with the portability and size of a single-gas monitor. Eliminate the need for extra monitors and transition seamlessly from personal monitoring to confined space entry with the Ventis® Slide-on Pump—ideal for operators who wear their gas monitors primarily for personal protection but occasionally require a pump for confined space entries.

- Detect up to four gases with a wide range of sensor options
- Select alarm set points, set latch alarms, disable instrument shutdown while in alarm, and more
- Save time and reduce human error with maintenance and usage data available from iNet Control software
- Available with or without an integral pump, or with the Ventis Slide-on Pump for ultimate flexibility
- Non-pumped instruments compatible with 12-hour, 18-hour, or 20-hour batteries

The Ventis® Slide-on Pump

The Ventis® Slide-on Pump is ideally suited for operators who wear their gas monitors primarily for personal protection but occasionally require a pump for confined space entries. Available in black or safety orange and powered by its own battery, the slide-on pump is compatible with the Ventis MX4 and Ventis® Pro5 Multi-Gas Monitor.

- **Convenient Sampling** – Sample draw distance of up to 50 feet provides convenient sampling in a wide range of applications
- **Easy to Attach** – No tools are required to attach or remove the Ventis Slide-on Pump to or from the monitor
- **Uses Same Batterys and Chargers as Ventis** – Monitor and pump each use the same batterys, and can easily be exchanged between instruments
- **Flexible Battery Options** – Three available battery options make this pump extremely flexible in the field

Build and price your Ventis MX4 online
with the instrument builder
https://www.indsci.com/ventis-mx4-builder

Continued…

Attachment A-7B – H_2S Detection Personnel Equipment (continued)

SPECIFICATIONS*

WARRANTY
The following components are warranted for four (4) years from the device's date of manufacture: monitor, pump, and CO/H_2S/O_2/LEL sensors. All other components are warranted for two (2) years from the device's date of manufacture.**

CASE MATERIAL
Polycarbonate with protective rubber overmold

DIMENSIONS
103 x 58 x 30 mm (4.1 x 2.3 x 1.2 in) without pump, lithium-ion battery version
172 x 67 x 66 mm (6.8 x 2.6 x 2.6 in) with pump, lithium-ion battery version

WEIGHT
182 g (6.4 oz) without Pump, lithium-ion battery version
380 g (13.4 oz) with Pump, lithium-ion battery version

POWER SOURCE/RUN TIME
Rechargeable slim extended lithium-ion battery
(18 hours typical @ 20 °C) without Pump
Rechargeable lithium-ion battery
(12 hours typical @ 20 °C) without Pump
Rechargeable extended-range lithium-ion battery
(20 hours typical @ 20 °C) without Pump
(12 hours typical @ 20 °C) with Pump
Replaceable AAA alkaline battery
(8 hours typical @ 20 °C) without Pump
(4 hours typical @ 20 °C) with Pump

ALARMS
Ultra-bright LEDs, loud audible alarm (95 dB at 30 cm) and vibrating alarm

DISPLAY/READOUT
Backlit liquid crystal display (LCD)

TEMPERATURE RANGE
-20 °C to 50 °C (-4 °F to 122 °F) ***

HUMIDITY RANGE
15% to 95% Non-condensing (continuous)

SENSORS
Combustible gases/methane – Catalytic Bead
O_2, CO, CO/H_2 low, H_2S, NO_2, SO_2 – Electrochemical

MEASURING RANGES

Combustible Gases:	0-100% LEL in 1% increments
Methane (CH_4):	0-5% of vol in 0.01% increments
Oxygen (O_2):	0-30% of vol in 0.1% increments
Carbon Monoxide (CO/H_2 low):	0-1,000 ppm in 1 ppm increments
Carbon Monoxide (CO):	0-1,000 ppm in 1 ppm increments
Hydrogen Sulfide (H_2S):	0-500 ppm in 0.1 ppm increments
Nitrogen Dioxide (NO_2):	0-150 ppm in 0.1 ppm increments
Sulfur Dioxide (SO_2):	0-150 ppm in 0.1 ppm increments

CERTIFICATIONS
INGRESS PROTECTION IP66/67

ANZEx:	Ex ia s Zone 0 I/IIC T4
ATEX:	Ex ia IIC T4 Ga and Ex ia I Ma; Equipment Group and Category II 1G/I M1
China CMC:	Metrology approval
China CPC:	CPA 2017-C103
China Ex:	Ex ia IIC T4 Ga; Ex ia d I Mb
China KA:	Approved for Underground Mines with CO, H_2S, O_2 and CH_4
China MA:	Approved for Underground Mines with CO, H_2S, O_2 and CH_4 (Note: Diffusion 17144453 pack only)
CSA:	Cl I, Div 1, G A-D, T4; Ex d ia IIC T4
EAC:	PB Ex d ia I X/1Ex d ia IIC T4 X
IECEx:	Ex ia IIC T4 Ga
INMETRO:	Ex ia IIC T4 Ga
KC:	Ex d ia IIC T4
KIMM:	Ex d ia IIC T4
MSHA:	30 CFR Part 22; Permissible for underground mines; Li-ion
PA-DEP:	BFE 46-12 Permissible for PA Bituminous Underground Mines; Charger/docking station accessories; Category 1
SANS:	SANS 1515-1; Type A; Ex ia I/IIC T4; Li-ion
TIIS:	Ex ia IIC T4 X
UL:	Cl I, Div 1, Groups A-D, T4; Zone 0, AEx ia IIC T4; Cl II, Gr F-G (Carbonaceous and Grain dust)

SUPPLIED WITH MONITOR
Calibration Cup (without pump), Sample Tubing (with pump), Reference Guide

LANGUAGE
English (1), French (2), Spanish (3), German (4), Italian (5), Dutch (6), Portuguese (7), Russian (9), Polish (A), Czech (B), Chinese (C), Danish (D), Norwegian (E), Finnish (F), Swedish (G), Japanese (J)

* These specifications are based on performance averages and may vary by instrument.

**The 4-year warranty is strictly limited to the enumerated components in devices manufactured after December 31, 2019. Warranted components in devices manufactured before January 1st, 2020 are warranted for two (2) years from the device's date of manufacture.

*** Operating temperatures above 50 °C (122 °F) may cause reduced instrument accuracy. Operating temperatures below -20 °C (-4 °F) may cause reduced instrument accuracy and affect display and alarm performance. See Product Manual for details.

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Attachment A-8 – Supervisory Control and Data Acquisition (SCADA) System

The SCADA system is a computer-based system or systems used by personnel in a control room that aims to collect and display information about the Dakota Gasification Company (DGC) CO_2 storage injection operations in real time. This supervisory system collects data at an assigned time interval and stores the data in the historian server. Using DGC operator process control selections, the SCADA will have the ability to send commands and control the storage injection network (i.e., start or stop pumps, open or close valves, control process equipment remotely, etc.).

In addition to monitoring and control ability, the SCADA system will include warnings, both audible and visual, to alert the DGC control room, which is staffed 24/7, of near or excessive violations of set parameters within the system.

Attachment A-9 – Bottomhole Pressure Survey

Pressure Survey Report

EVOLUTION COMPLETIONS INC.

Williston, ND
(701) 572-2069
info@evolutioncompletions.com
www.evolutioncompletions.com

RAMPART ENERGY

COTEAU 1
COTEAU 1

SEP 27 - 28, 2021

Bottom Hole - Build-Up

Report Prepared by

E.S. KYLE INSTRUMENT LTD.

Red Deer, AB
PH 403.309.0980
Scott Brilz
Ref #: RD21-0365

EVOLUTION COMPLETIONS

Well Information

RAMPART ENERGY
COTEAU 1
COTEAU 1

SEP 27 - 28, 2021

Bottom Hole - Build-Up

AER Well License Number:
Test Purpose:

Field: WILDCAT
Formation Name:

Well Fluid Status: (01) Oil — H2S: N
Well Type: Vertical

KB Elevation: 17.00 — Open Hole: N
CF Elevation: 0.00

Production Interval:
Mid Point Perfs.: ft KB-TVD

Producing Through: Casing

in Tbg. — ft KB
7.00 in Csg. — ft KB

PBTD: ft KB

Test Summary

Start of Test: 2021 09 27 1557
Well Shut-In: Hrs
Final Test Time: 2021 09 28 2338

Initial Tubing Pressure:		Final Tubing Pressure:		PSIA
Initial Casing Pressure:	300.0	Final Casing Pressure:	300.0	

Run Depth: 5975.00 ft KB-TVD

Primary Gauge (1):

Final Pressure: 2937.09 PSIA
Final Temperature: 151.85 Deg. F

Gradient at Run Depth: PSIA/ft
Calculated Pressure at MPP: PSIA

Gauge Program: 5 SEC

Report Prepared by:

E.S. KYLE INSTRUMENT LTD. — Ref. #: RD21-0365

EVOLUTION COMPLETIONS INC.

Extended Test Data

RAMPART ENERGY
COTEAU 1
COTEAU 1

SEP 27 - 28, 2021

Formation:

Test Type: Bottom Hole - Build-Up

Initial Tubing Pressure:		PSIA	Final Tubing Pressure:		PSIA
Initial Casing Pressure:	300.0		Final Casing Pressure:	300.0	

Top Gauge					Bottom Gauge			
			253	Gauge Serial #	254			
% Acc.	0.024	KPAA	41369	Range	41369	KPAA	0.024	% Acc.
% Res.	0.0003		09/15/2021	Calibration Date	09/15/2021		0.0003	% Res.
			Cal-Scan Recorder - Strain	Gauge Type	Cal-Scan Recorder - Strain			
			09/27/21 15:57:00	Gauge Start Time	09/27/21 15:57:00			
		ft KB-TVD	5974.70	Run Depth	5975.00	ft KB-TVD		
		PSIA	2936.41	Pressure	2937.09	PSIA		
		Deg. F	151.79	Temperature	151.85	Deg. F		
		PSIA/ft		Gradient		PSIA/ft		

Gauge Event	Temp Deg. F	Pressure PSIA	Real Time (mm/dd/yy hh:mm:ss)	Temp Deg. F	Pressure PSIA	Duration of Event Hours
On Bottom	152.20	2932.03	09/27/21 16:55:50	152.15	2932.70	
Open to Flow						
Shut-In						
Off Bottom	151.79	2936.41	09/28/21 18:53:25	151.85	2937.09	26.0

Pressure Corrected to Run Depth

PSIA	2936.41	5975.00	2937.09	PSIA

Calculated Pressure at MPP

PSIA				PSIA

Remarks:

		Top Gauge			Bottom Gauge		
##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
912	2021 09 27 15:59:00	0.0333	13.46	95.18	0.0333	13.25	95.77
960	2021 09 27 16:03:00	0.1000	305.92	58.07	0.1000	309.82	58.60
					0.00 ft KB-TVD- Initial Surface		
1008	2021 09 27 16:07:00	0.1667	525.62	59.15	0.1667	526.31	59.02
1056	2021 09 27 16:11:00	0.2333	749.94	65.65	0.2333	750.88	65.53
1104	2021 09 27 16:15:00	0.3000	976.96	73.27	0.3000	977.55	73.00
1152	2021 09 27 16:19:00	0.3667	1201.53	82.84	0.3667	1202.26	82.63
1200	2021 09 27 16:23:00	0.4333	1426.41	91.98	0.4333	1427.25	91.92
1248	2021 09 27 16:27:00	0.5000	1655.05	103.44	0.5000	1655.59	101.99
1296	2021 09 27 16:31:00	0.5667	1852.01	114.18	0.5667	1852.03	113.02
1344	2021 09 27 16:35:00	0.6333	2074.32	127.18	0.6333	2075.26	125.48
1392	2021 09 27 16:39:00	0.7000	2286.38	135.12	0.7000	2287.18	134.43
1440	2021 09 27 16:43:00	0.7667	2538.85	140.96	0.7667	2539.50	140.06
1488	2021 09 27 16:47:00	0.8333	2736.96	147.66	0.8333	2738.49	146.99
1536	2021 09 27 16:51:00	0.9000	2889.52	151.95	0.9000	2889.52	151.81
1584	2021 09 27 16:55:00	0.9667	2932.92	152.17	0.9667	2933.57	152.13
1594	2021 09 27 16:55:50	0.9806	2932.03	152.20	0.9806	2932.70	152.15
					5975.00 ft KB-TVD- On Bottom		
1632	2021 09 27 16:59:00	1.0333	2931.99	152.23	1.0333	2932.58	152.21
1680	2021 09 27 17:03:00	1.1000	2932.26	152.23	1.1000	2932.89	152.25
1728	2021 09 27 17:07:00	1.1667	2932.53	152.23	1.1667	2933.16	152.26
1776	2021 09 27 17:11:00	1.2333	2932.80	152.23	1.2333	2933.38	152.26
1824	2021 09 27 17:15:00	1.3000	2933.03	152.22	1.3000	2933.60	152.27
1872	2021 09 27 17:19:00	1.3667	2933.25	152.23	1.3667	2933.87	152.27
1920	2021 09 27 17:23:00	1.4333	2933.49	152.23	1.4333	2934.10	152.27
1968	2021 09 27 17:27:00	1.5000	2933.70	152.23	1.5000	2934.35	152.27
2016	2021 09 27 17:31:00	1.5667	2933.94	152.23	1.5667	2934.54	152.27
2064	2021 09 27 17:35:00	1.6333	2934.13	152.23	1.6333	2934.76	152.27
2112	2021 09 27 17:39:00	1.7000	2934.33	152.23	1.7000	2934.94	152.27
2160	2021 09 27 17:43:00	1.7667	2934.50	152.22	1.7667	2935.14	152.27
2208	2021 09 27 17:47:00	1.8333	2934.71	152.22	1.8333	2935.30	152.26
2256	2021 09 27 17:51:00	1.9000	2934.84	152.22	1.9000	2935.53	152.26
2304	2021 09 27 17:55:00	1.9667	2935.04	152.22	1.9667	2935.68	152.26
2352	2021 09 27 17:59:00	2.0333	2935.17	152.22	2.0333	2935.89	152.26
2400	2021 09 27 18:03:00	2.1000	2935.33	152.21	2.1000	2936.01	152.25
2448	2021 09 27 18:07:00	2.1667	2935.51	152.21	2.1667	2936.09	152.25
2496	2021 09 27 18:11:00	2.2333	2935.62	152.21	2.2333	2936.24	152.24
2544	2021 09 27 18:15:00	2.3000	2935.74	152.20	2.3000	2936.32	152.24
2592	2021 09 27 18:19:00	2.3667	2935.79	152.20	2.3667	2936.45	152.23
2640	2021 09 27 18:23:00	2.4333	2935.84	152.20	2.4333	2936.48	152.23

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
2688	2021 09 27 18:27:00	2.5000	2935.87	152.19	2.5000	2936.49	152.23
2736	2021 09 27 18:31:00	2.5667	2935.88	152.19	2.5667	2936.52	152.22
2784	2021 09 27 18:35:00	2.6333	2935.92	152.18	2.6333	2936.52	152.22
2832	2021 09 27 18:39:00	2.7000	2935.92	152.17	2.7000	2936.56	152.21
2880	2021 09 27 18:43:00	2.7667	2935.93	152.16	2.7667	2936.53	152.21
2928	2021 09 27 18:47:00	2.8333	2935.94	152.14	2.8333	2936.61	152.20
2976	2021 09 27 18:51:00	2.9000	2935.95	152.11	2.9000	2936.58	152.20
3024	2021 09 27 18:55:00	2.9667	2935.94	152.08	2.9667	2936.58	152.19
3072	2021 09 27 18:59:00	3.0333	2935.97	152.06	3.0333	2936.61	152.19
3120	2021 09 27 19:03:00	3.1000	2935.97	152.03	3.1000	2936.65	152.18
3168	2021 09 27 19:07:00	3.1667	2936.00	152.01	3.1667	2936.62	152.17
3216	2021 09 27 19:11:00	3.2333	2935.95	152.00	3.2333	2936.60	152.17
3264	2021 09 27 19:15:00	3.3000	2936.00	151.98	3.3000	2936.59	152.16
3312	2021 09 27 19:19:00	3.3667	2936.01	151.97	3.3667	2936.63	152.16
3360	2021 09 27 19:23:00	3.4333	2936.05	151.96	3.4333	2936.69	152.15
3408	2021 09 27 19:27:00	3.5000	2935.99	151.95	3.5000	2936.65	152.14
3456	2021 09 27 19:31:00	3.5667	2936.01	151.94	3.5667	2936.66	152.11
3504	2021 09 27 19:35:00	3.6333	2936.04	151.94	3.6333	2936.66	152.08
3552	2021 09 27 19:39:00	3.7000	2936.08	151.94	3.7000	2936.65	152.05
3600	2021 09 27 19:43:00	3.7667	2936.04	151.93	3.7667	2936.68	152.03
3648	2021 09 27 19:47:00	3.8333	2936.05	151.93	3.8333	2936.71	152.01
3696	2021 09 27 19:51:00	3.9000	2936.06	151.93	3.9000	2936.70	152.00
3744	2021 09 27 19:55:00	3.9667	2936.08	151.92	3.9667	2936.66	151.99
3792	2021 09 27 19:59:00	4.0333	2936.08	151.92	4.0333	2936.66	151.99
3840	2021 09 27 20:03:00	4.1000	2936.04	151.92	4.1000	2936.71	151.98
3888	2021 09 27 20:07:00	4.1667	2936.07	151.91	4.1667	2936.70	151.98
3936	2021 09 27 20:11:00	4.2333	2936.05	151.91	4.2333	2936.70	151.98
3984	2021 09 27 20:15:00	4.3000	2936.07	151.91	4.3000	2936.68	151.97
4032	2021 09 27 20:19:00	4.3667	2936.11	151.91	4.3667	2936.70	151.97
4080	2021 09 27 20:23:00	4.4333	2936.11	151.91	4.4333	2936.72	151.97
4128	2021 09 27 20:27:00	4.5000	2936.08	151.91	4.5000	2936.72	151.96
4176	2021 09 27 20:31:00	4.5667	2936.09	151.91	4.5667	2936.72	151.96
4224	2021 09 27 20:35:00	4.6333	2936.09	151.90	4.6333	2936.72	151.96
4272	2021 09 27 20:39:00	4.7000	2936.09	151.90	4.7000	2936.76	151.96
4320	2021 09 27 20:43:00	4.7667	2936.08	151.90	4.7667	2936.70	151.96
4368	2021 09 27 20:47:00	4.8333	2936.13	151.90	4.8333	2936.74	151.95
4416	2021 09 27 20:51:00	4.9000	2936.09	151.89	4.9000	2936.76	151.95
4464	2021 09 27 20:55:00	4.9667	2936.14	151.89	4.9667	2936.76	151.95
4512	2021 09 27 20:59:00	5.0333	2936.10	151.89	5.0333	2936.75	151.95
4560	2021 09 27 21:03:00	5.1000	2936.14	151.89	5.1000	2936.75	151.95
4608	2021 09 27 21:07:00	5.1667	2936.14	151.89	5.1667	2936.77	151.95
4656	2021 09 27 21:11:00	5.2333	2936.14	151.89	5.2333	2936.76	151.94

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
4704	2021 09 27 21:15:00	5.3000	2936.15	151.88	5.3000	2936.73	151.94
4752	2021 09 27 21:19:00	5.3667	2936.08	151.88	5.3667	2936.78	151.94
4800	2021 09 27 21:23:00	5.4333	2936.14	151.88	5.4333	2936.82	151.94
4848	2021 09 27 21:27:00	5.5000	2936.11	151.88	5.5000	2936.75	151.93
4896	2021 09 27 21:31:00	5.5667	2936.12	151.88	5.5667	2936.75	151.93
4944	2021 09 27 21:35:00	5.6333	2936.08	151.87	5.6333	2936.77	151.93
4992	2021 09 27 21:39:00	5.7000	2936.11	151.87	5.7000	2936.75	151.93
5040	2021 09 27 21:43:00	5.7667	2936.13	151.87	5.7667	2936.77	151.93
5088	2021 09 27 21:47:00	5.8333	2936.12	151.87	5.8333	2936.79	151.93
5136	2021 09 27 21:51:00	5.9000	2936.12	151.87	5.9000	2936.78	151.93
5184	2021 09 27 21:55:00	5.9667	2936.16	151.87	5.9667	2936.79	151.93
5232	2021 09 27 21:59:00	6.0333	2936.09	151.87	6.0333	2936.77	151.92
5280	2021 09 27 22:03:00	6.1000	2936.11	151.87	6.1000	2936.75	151.92
5328	2021 09 27 22:07:00	6.1667	2936.10	151.86	6.1667	2936.76	151.92
5376	2021 09 27 22:11:00	6.2333	2936.17	151.86	6.2333	2936.80	151.92
5424	2021 09 27 22:15:00	6.3000	2936.10	151.86	6.3000	2936.79	151.92
5472	2021 09 27 22:19:00	6.3667	2936.16	151.86	6.3667	2936.76	151.92
5520	2021 09 27 22:23:00	6.4333	2936.15	151.86	6.4333	2936.75	151.92
5568	2021 09 27 22:27:00	6.5000	2936.13	151.86	6.5000	2936.81	151.92
5616	2021 09 27 22:31:00	6.5667	2936.18	151.86	6.5667	2936.77	151.92
5664	2021 09 27 22:35:00	6.6333	2936.14	151.86	6.6333	2936.79	151.91
5712	2021 09 27 22:39:00	6.7000	2936.15	151.86	6.7000	2936.80	151.91
5760	2021 09 27 22:43:00	6.7667	2936.15	151.86	6.7667	2936.77	151.91
5808	2021 09 27 22:47:00	6.8333	2936.15	151.85	6.8333	2936.81	151.91
5856	2021 09 27 22:51:00	6.9000	2936.18	151.85	6.9000	2936.85	151.91
5904	2021 09 27 22:55:00	6.9667	2936.17	151.85	6.9667	2936.81	151.91
5952	2021 09 27 22:59:00	7.0333	2936.15	151.85	7.0333	2936.83	151.91
6000	2021 09 27 23:03:00	7.1000	2936.18	151.85	7.1000	2936.80	151.91
6048	2021 09 27 23:07:00	7.1667	2936.13	151.85	7.1667	2936.81	151.90
6096	2021 09 27 23:11:00	7.2333	2936.18	151.85	7.2333	2936.79	151.90
6144	2021 09 27 23:15:00	7.3000	2936.16	151.85	7.3000	2936.79	151.90
6192	2021 09 27 23:19:00	7.3667	2936.15	151.84	7.3667	2936.82	151.90
6240	2021 09 27 23:23:00	7.4333	2936.19	151.85	7.4333	2936.85	151.90
6288	2021 09 27 23:27:00	7.5000	2936.18	151.84	7.5000	2936.82	151.90
6336	2021 09 27 23:31:00	7.5667	2936.19	151.85	7.5667	2936.82	151.90
6384	2021 09 27 23:35:00	7.6333	2936.19	151.84	7.6333	2936.84	151.90
6432	2021 09 27 23:39:00	7.7000	2936.20	151.84	7.7000	2936.80	151.90
6480	2021 09 27 23:43:00	7.7667	2936.18	151.84	7.7667	2936.82	151.90
6528	2021 09 27 23:47:00	7.8333	2936.17	151.84	7.8333	2936.84	151.90
6576	2021 09 27 23:51:00	7.9000	2936.18	151.84	7.9000	2936.80	151.90
6624	2021 09 27 23:55:00	7.9667	2936.18	151.84	7.9667	2936.84	151.90
6672	2021 09 27 23:59:00	8.0333	2936.19	151.84	8.0333	2936.80	151.89

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
6720	2021 09 28 00:03:00	8.1000	2936.20	151.84	8.1000	2936.87	151.89
6768	2021 09 28 00:07:00	8.1667	2936.19	151.84	8.1667	2936.85	151.89
6816	2021 09 28 00:11:00	8.2333	2936.20	151.84	8.2333	2936.83	151.89
6864	2021 09 28 00:15:00	8.3000	2936.18	151.83	8.3000	2936.87	151.89
6912	2021 09 28 00:19:00	8.3667	2936.19	151.83	8.3667	2936.86	151.89
6960	2021 09 28 00:23:00	8.4333	2936.20	151.84	8.4333	2936.82	151.89
7008	2021 09 28 00:27:00	8.5000	2936.19	151.83	8.5000	2936.82	151.89
7056	2021 09 28 00:31:00	8.5667	2936.22	151.83	8.5667	2936.84	151.89
7104	2021 09 28 00:35:00	8.6333	2936.20	151.83	8.6333	2936.86	151.89
7152	2021 09 28 00:39:00	8.7000	2936.19	151.83	8.7000	2936.85	151.89
7200	2021 09 28 00:43:00	8.7667	2936.20	151.83	8.7667	2936.81	151.89
7248	2021 09 28 00:47:00	8.8333	2936.21	151.83	8.8333	2936.86	151.89
7296	2021 09 28 00:51:00	8.9000	2936.21	151.83	8.9000	2936.85	151.89
7344	2021 09 28 00:55:00	8.9667	2936.20	151.83	8.9667	2936.87	151.89
7392	2021 09 28 00:59:00	9.0333	2936.19	151.83	9.0333	2936.84	151.88
7440	2021 09 28 01:03:00	9.1000	2936.19	151.83	9.1000	2936.85	151.89
7488	2021 09 28 01:07:00	9.1667	2936.20	151.83	9.1667	2936.88	151.88
7536	2021 09 28 01:11:00	9.2333	2936.21	151.83	9.2333	2936.87	151.88
7584	2021 09 28 01:15:00	9.3000	2936.16	151.83	9.3000	2936.84	151.88
7632	2021 09 28 01:19:00	9.3667	2936.22	151.83	9.3667	2936.82	151.88
7680	2021 09 28 01:23:00	9.4333	2936.17	151.83	9.4333	2936.86	151.88
7728	2021 09 28 01:27:00	9.5000	2936.23	151.82	9.5000	2936.85	151.88
7776	2021 09 28 01:31:00	9.5667	2936.18	151.82	9.5667	2936.85	151.88
7824	2021 09 28 01:35:00	9.6333	2936.22	151.83	9.6333	2936.85	151.88
7872	2021 09 28 01:39:00	9.7000	2936.20	151.82	9.7000	2936.85	151.88
7920	2021 09 28 01:43:00	9.7667	2936.19	151.82	9.7667	2936.87	151.88
7968	2021 09 28 01:47:00	9.8333	2936.20	151.82	9.8333	2936.90	151.88
8016	2021 09 28 01:51:00	9.9000	2936.22	151.82	9.9000	2936.88	151.88
8064	2021 09 28 01:55:00	9.9667	2936.22	151.82	9.9667	2936.86	151.88
8112	2021 09 28 01:59:00	10.0333	2936.24	151.82	10.0333	2936.86	151.88
8160	2021 09 28 02:03:00	10.1000	2936.21	151.82	10.1000	2936.89	151.88
8208	2021 09 28 02:07:00	10.1667	2936.22	151.82	10.1667	2936.88	151.88
8256	2021 09 28 02:11:00	10.2333	2936.22	151.82	10.2333	2936.83	151.88
8304	2021 09 28 02:15:00	10.3000	2936.27	151.82	10.3000	2936.87	151.88
8352	2021 09 28 02:19:00	10.3667	2936.22	151.82	10.3667	2936.90	151.88
8400	2021 09 28 02:23:00	10.4333	2936.20	151.82	10.4333	2936.92	151.88
8448	2021 09 28 02:27:00	10.5000	2936.22	151.82	10.5000	2936.88	151.88
8496	2021 09 28 02:31:00	10.5667	2936.24	151.82	10.5667	2936.89	151.87
8544	2021 09 28 02:35:00	10.6333	2936.24	151.82	10.6333	2936.90	151.87
8592	2021 09 28 02:39:00	10.7000	2936.22	151.82	10.7000	2936.91	151.87
8640	2021 09 28 02:43:00	10.7667	2936.26	151.82	10.7667	2936.87	151.87
8688	2021 09 28 02:47:00	10.8333	2936.22	151.82	10.8333	2936.91	151.87

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
8736	2021 09 28 02:51:00	10.9000	2936.19	151.82	10.9000	2936.86	151.87
8784	2021 09 28 02:55:00	10.9667	2936.20	151.82	10.9667	2936.90	151.87
8832	2021 09 28 02:59:00	11.0333	2936.25	151.82	11.0333	2936.87	151.87
8880	2021 09 28 03:03:00	11.1000	2936.23	151.82	11.1000	2936.91	151.87
8928	2021 09 28 03:07:00	11.1667	2936.25	151.82	11.1667	2936.88	151.87
8976	2021 09 28 03:11:00	11.2333	2936.23	151.81	11.2333	2936.90	151.87
9024	2021 09 28 03:15:00	11.3000	2936.23	151.81	11.3000	2936.89	151.87
9072	2021 09 28 03:19:00	11.3667	2936.25	151.82	11.3667	2936.91	151.87
9120	2021 09 28 03:23:00	11.4333	2936.25	151.81	11.4333	2936.88	151.87
9168	2021 09 28 03:27:00	11.5000	2936.23	151.81	11.5000	2936.88	151.87
9216	2021 09 28 03:31:00	11.5667	2936.29	151.82	11.5667	2936.90	151.87
9264	2021 09 28 03:35:00	11.6333	2936.25	151.81	11.6333	2936.91	151.87
9312	2021 09 28 03:39:00	11.7000	2936.24	151.81	11.7000	2936.93	151.87
9360	2021 09 28 03:43:00	11.7667	2936.23	151.81	11.7667	2936.88	151.87
9408	2021 09 28 03:47:00	11.8333	2936.21	151.81	11.8333	2936.90	151.87
9456	2021 09 28 03:51:00	11.9000	2936.23	151.81	11.9000	2936.91	151.87
9504	2021 09 28 03:55:00	11.9667	2936.25	151.81	11.9667	2936.88	151.87
9552	2021 09 28 03:59:00	12.0333	2936.27	151.81	12.0333	2936.90	151.87
9600	2021 09 28 04:03:00	12.1000	2936.25	151.81	12.1000	2936.90	151.87
9648	2021 09 28 04:07:00	12.1667	2936.28	151.81	12.1667	2936.91	151.87
9696	2021 09 28 04:11:00	12.2333	2936.23	151.81	12.2333	2936.91	151.87
9744	2021 09 28 04:15:00	12.3000	2936.24	151.81	12.3000	2936.93	151.87
9792	2021 09 28 04:19:00	12.3667	2936.23	151.81	12.3667	2936.89	151.87
9840	2021 09 28 04:23:00	12.4333	2936.25	151.81	12.4333	2936.91	151.87
9888	2021 09 28 04:27:00	12.5000	2936.24	151.81	12.5000	2936.89	151.87
9936	2021 09 28 04:31:00	12.5667	2936.25	151.81	12.5667	2936.88	151.87
9984	2021 09 28 04:35:00	12.6333	2936.27	151.81	12.6333	2936.93	151.86
10032	2021 09 28 04:39:00	12.7000	2936.24	151.81	12.7000	2936.93	151.87
10080	2021 09 28 04:43:00	12.7667	2936.24	151.81	12.7667	2936.95	151.86
10128	2021 09 28 04:47:00	12.8333	2936.27	151.81	12.8333	2936.96	151.87
10176	2021 09 28 04:51:00	12.9000	2936.26	151.81	12.9000	2936.92	151.87
10224	2021 09 28 04:55:00	12.9667	2936.27	151.81	12.9667	2936.94	151.86
10272	2021 09 28 04:59:00	13.0333	2936.25	151.81	13.0333	2936.97	151.87
10320	2021 09 28 05:03:00	13.1000	2936.26	151.81	13.1000	2936.96	151.87
10368	2021 09 28 05:07:00	13.1667	2936.27	151.81	13.1667	2936.96	151.86
10416	2021 09 28 05:11:00	13.2333	2936.28	151.81	13.2333	2936.93	151.87
10464	2021 09 28 05:15:00	13.3000	2936.24	151.81	13.3000	2936.94	151.87
10512	2021 09 28 05:19:00	13.3667	2936.25	151.81	13.3667	2936.94	151.86
10560	2021 09 28 05:23:00	13.4333	2936.26	151.81	13.4333	2936.94	151.86
10608	2021 09 28 05:27:00	13.5000	2936.24	151.81	13.5000	2936.97	151.86
10656	2021 09 28 05:31:00	13.5667	2936.28	151.81	13.5667	2936.98	151.86
10704	2021 09 28 05:35:00	13.6333	2936.24	151.81	13.6333	2936.96	151.86

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
10752	2021 09 28 05:39:00	13.7000	2936.26	151.81	13.7000	2936.97	151.86
10800	2021 09 28 05:43:00	13.7667	2936.26	151.81	13.7667	2936.95	151.86
10848	2021 09 28 05:47:00	13.8333	2936.29	151.81	13.8333	2936.98	151.86
10896	2021 09 28 05:51:00	13.9000	2936.30	151.81	13.9000	2936.94	151.86
10944	2021 09 28 05:55:00	13.9667	2936.27	151.81	13.9667	2936.95	151.86
10992	2021 09 28 05:59:00	14.0333	2936.31	151.81	14.0333	2936.94	151.86
11040	2021 09 28 06:03:00	14.1000	2936.32	151.81	14.1000	2936.99	151.86
11088	2021 09 28 06:07:00	14.1667	2936.30	151.81	14.1667	2936.95	151.86
11136	2021 09 28 06:11:00	14.2333	2936.29	151.81	14.2333	2936.96	151.86
11184	2021 09 28 06:15:00	14.3000	2936.28	151.80	14.3000	2936.95	151.86
11232	2021 09 28 06:19:00	14.3667	2936.30	151.80	14.3667	2936.99	151.86
11280	2021 09 28 06:23:00	14.4333	2936.28	151.80	14.4333	2936.97	151.86
11328	2021 09 28 06:27:00	14.5000	2936.33	151.80	14.5000	2936.94	151.86
11376	2021 09 28 06:31:00	14.5667	2936.30	151.80	14.5667	2936.98	151.86
11424	2021 09 28 06:35:00	14.6333	2936.27	151.80	14.6333	2936.97	151.86
11472	2021 09 28 06:39:00	14.7000	2936.32	151.80	14.7000	2936.96	151.86
11520	2021 09 28 06:43:00	14.7667	2936.27	151.80	14.7667	2936.98	151.86
11568	2021 09 28 06:47:00	14.8333	2936.29	151.80	14.8333	2936.98	151.86
11616	2021 09 28 06:51:00	14.9000	2936.31	151.80	14.9000	2936.98	151.86
11664	2021 09 28 06:55:00	14.9667	2936.29	151.80	14.9667	2936.95	151.86
11712	2021 09 28 06:59:00	15.0333	2936.32	151.80	15.0333	2936.97	151.86
11760	2021 09 28 07:03:00	15.1000	2936.29	151.80	15.1000	2936.98	151.86
11808	2021 09 28 07:07:00	15.1667	2936.29	151.80	15.1667	2936.99	151.86
11856	2021 09 28 07:11:00	15.2333	2936.29	151.80	15.2333	2936.98	151.86
11904	2021 09 28 07:15:00	15.3000	2936.33	151.80	15.3000	2936.97	151.86
11952	2021 09 28 07:19:00	15.3667	2936.32	151.80	15.3667	2936.97	151.86
12000	2021 09 28 07:23:00	15.4333	2936.30	151.80	15.4333	2936.98	151.86
12048	2021 09 28 07:27:00	15.5000	2936.32	151.80	15.5000	2936.98	151.86
12096	2021 09 28 07:31:00	15.5667	2936.31	151.80	15.5667	2937.00	151.86
12144	2021 09 28 07:35:00	15.6333	2936.31	151.80	15.6333	2936.99	151.86
12192	2021 09 28 07:39:00	15.7000	2936.33	151.80	15.7000	2936.99	151.86
12240	2021 09 28 07:43:00	15.7667	2936.30	151.80	15.7667	2936.98	151.86
12288	2021 09 28 07:47:00	15.8333	2936.30	151.80	15.8333	2937.00	151.86
12336	2021 09 28 07:51:00	15.9000	2936.35	151.80	15.9000	2937.00	151.86
12384	2021 09 28 07:55:00	15.9667	2936.33	151.80	15.9667	2936.99	151.85
12432	2021 09 28 07:59:00	16.0333	2936.32	151.80	16.0333	2936.99	151.86
12480	2021 09 28 08:03:00	16.1000	2936.32	151.80	16.1000	2936.98	151.85
12528	2021 09 28 08:07:00	16.1667	2936.33	151.80	16.1667	2937.00	151.86
12576	2021 09 28 08:11:00	16.2333	2936.34	151.80	16.2333	2937.00	151.86
12624	2021 09 28 08:15:00	16.3000	2936.31	151.80	16.3000	2936.98	151.86
12672	2021 09 28 08:19:00	16.3667	2936.33	151.80	16.3667	2936.99	151.86
12720	2021 09 28 08:23:00	16.4333	2936.34	151.80	16.4333	2936.99	151.86

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
12768	2021 09 28 08:27:00	16.5000	2936.35	151.79	16.5000	2936.96	151.86
12816	2021 09 28 08:31:00	16.5667	2936.35	151.80	16.5667	2937.00	151.86
12864	2021 09 28 08:35:00	16.6333	2936.33	151.80	16.6333	2937.02	151.86
12912	2021 09 28 08:39:00	16.7000	2936.36	151.80	16.7000	2936.99	151.86
12960	2021 09 28 08:43:00	16.7667	2936.33	151.80	16.7667	2936.98	151.85
13008	2021 09 28 08:47:00	16.8333	2936.34	151.80	16.8333	2936.98	151.86
13056	2021 09 28 08:51:00	16.9000	2936.32	151.80	16.9000	2937.01	151.85
13104	2021 09 28 08:55:00	16.9667	2936.32	151.80	16.9667	2936.99	151.86
13152	2021 09 28 08:59:00	17.0333	2936.34	151.80	17.0333	2937.01	151.86
13200	2021 09 28 09:03:00	17.1000	2936.30	151.80	17.1000	2936.99	151.85
13248	2021 09 28 09:07:00	17.1667	2936.34	151.80	17.1667	2937.00	151.86
13296	2021 09 28 09:11:00	17.2333	2936.34	151.80	17.2333	2936.97	151.85
13344	2021 09 28 09:15:00	17.3000	2936.31	151.79	17.3000	2937.02	151.85
13392	2021 09 28 09:19:00	17.3667	2936.32	151.80	17.3667	2937.00	151.85
13440	2021 09 28 09:23:00	17.4333	2936.34	151.80	17.4333	2937.02	151.85
13488	2021 09 28 09:27:00	17.5000	2936.34	151.79	17.5000	2936.99	151.85
13536	2021 09 28 09:31:00	17.5667	2936.37	151.79	17.5667	2937.04	151.85
13584	2021 09 28 09:35:00	17.6333	2936.35	151.80	17.6333	2936.99	151.85
13632	2021 09 28 09:39:00	17.7000	2936.32	151.79	17.7000	2937.02	151.85
13680	2021 09 28 09:43:00	17.7667	2936.33	151.79	17.7667	2936.99	151.85
13728	2021 09 28 09:47:00	17.8333	2936.34	151.79	17.8333	2937.00	151.85
13776	2021 09 28 09:51:00	17.9000	2936.34	151.79	17.9000	2937.01	151.85
13824	2021 09 28 09:55:00	17.9667	2936.31	151.80	17.9667	2936.99	151.85
13872	2021 09 28 09:59:00	18.0333	2936.35	151.79	18.0333	2937.02	151.85
13920	2021 09 28 10:03:00	18.1000	2936.34	151.79	18.1000	2937.02	151.85
13968	2021 09 28 10:07:00	18.1667	2936.33	151.79	18.1667	2937.03	151.86
14016	2021 09 28 10:11:00	18.2333	2936.32	151.79	18.2333	2937.03	151.86
14064	2021 09 28 10:15:00	18.3000	2936.31	151.79	18.3000	2937.03	151.86
14112	2021 09 28 10:19:00	18.3667	2936.36	151.80	18.3667	2937.00	151.85
14160	2021 09 28 10:23:00	18.4333	2936.34	151.79	18.4333	2937.05	151.85
14208	2021 09 28 10:27:00	18.5000	2936.36	151.80	18.5000	2937.01	151.85
14256	2021 09 28 10:31:00	18.5667	2936.33	151.79	18.5667	2937.02	151.85
14304	2021 09 28 10:35:00	18.6333	2936.34	151.79	18.6333	2936.99	151.85
14352	2021 09 28 10:39:00	18.7000	2936.34	151.79	18.7000	2937.00	151.85
14400	2021 09 28 10:43:00	18.7667	2936.33	151.79	18.7667	2937.04	151.85
14448	2021 09 28 10:47:00	18.8333	2936.35	151.79	18.8333	2937.04	151.85
14496	2021 09 28 10:51:00	18.9000	2936.33	151.79	18.9000	2936.99	151.85
14544	2021 09 28 10:55:00	18.9667	2936.35	151.79	18.9667	2937.01	151.85
14592	2021 09 28 10:59:00	19.0333	2936.36	151.79	19.0333	2937.01	151.85
14640	2021 09 28 11:03:00	19.1000	2936.39	151.80	19.1000	2937.03	151.85
14688	2021 09 28 11:07:00	19.1667	2936.36	151.79	19.1667	2937.01	151.85
14736	2021 09 28 11:11:00	19.2333	2936.33	151.79	19.2333	2937.04	151.85

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
14784	2021 09 28 11:15:00	19.3000	2936.39	151.79	19.3000	2937.00	151.85
14832	2021 09 28 11:19:00	19.3667	2936.34	151.79	19.3667	2937.01	151.85
14880	2021 09 28 11:23:00	19.4333	2936.35	151.79	19.4333	2937.04	151.85
14928	2021 09 28 11:27:00	19.5000	2936.35	151.79	19.5000	2937.06	151.85
14976	2021 09 28 11:31:00	19.5667	2936.33	151.79	19.5667	2937.02	151.85
15024	2021 09 28 11:35:00	19.6333	2936.33	151.79	19.6333	2937.03	151.85
15072	2021 09 28 11:39:00	19.7000	2936.38	151.79	19.7000	2937.05	151.85
15120	2021 09 28 11:43:00	19.7667	2936.34	151.79	19.7667	2937.00	151.85
15168	2021 09 28 11:47:00	19.8333	2936.37	151.79	19.8333	2937.03	151.85
15216	2021 09 28 11:51:00	19.9000	2936.36	151.79	19.9000	2937.02	151.85
15264	2021 09 28 11:55:00	19.9667	2936.37	151.79	19.9667	2937.05	151.85
15312	2021 09 28 11:59:00	20.0333	2936.32	151.79	20.0333	2937.03	151.85
15360	2021 09 28 12:03:00	20.1000	2936.35	151.79	20.1000	2937.04	151.85
15408	2021 09 28 12:07:00	20.1667	2936.36	151.79	20.1667	2937.04	151.85
15456	2021 09 28 12:11:00	20.2333	2936.34	151.79	20.2333	2937.03	151.85
15504	2021 09 28 12:15:00	20.3000	2936.35	151.79	20.3000	2937.03	151.85
15552	2021 09 28 12:19:00	20.3667	2936.34	151.79	20.3667	2937.03	151.85
15600	2021 09 28 12:23:00	20.4333	2936.35	151.79	20.4333	2937.01	151.86
15648	2021 09 28 12:27:00	20.5000	2936.36	151.79	20.5000	2937.00	151.85
15696	2021 09 28 12:31:00	20.5667	2936.37	151.79	20.5667	2937.00	151.85
15744	2021 09 28 12:35:00	20.6333	2936.38	151.80	20.6333	2937.04	151.85
15792	2021 09 28 12:39:00	20.7000	2936.38	151.79	20.7000	2937.06	151.85
15840	2021 09 28 12:43:00	20.7667	2936.31	151.79	20.7667	2937.02	151.85
15888	2021 09 28 12:47:00	20.8333	2936.33	151.79	20.8333	2937.02	151.85
15936	2021 09 28 12:51:00	20.9000	2936.36	151.79	20.9000	2937.05	151.85
15984	2021 09 28 12:55:00	20.9667	2936.35	151.79	20.9667	2937.03	151.85
16032	2021 09 28 12:59:00	21.0333	2936.36	151.79	21.0333	2937.03	151.85
16080	2021 09 28 13:03:00	21.1000	2936.36	151.79	21.1000	2937.04	151.85
16128	2021 09 28 13:07:00	21.1667	2936.33	151.79	21.1667	2937.00	151.85
16176	2021 09 28 13:11:00	21.2333	2936.36	151.79	21.2333	2937.01	151.85
16224	2021 09 28 13:15:00	21.3000	2936.38	151.79	21.3000	2937.04	151.85
16272	2021 09 28 13:19:00	21.3667	2936.34	151.79	21.3667	2937.03	151.85
16320	2021 09 28 13:23:00	21.4333	2936.37	151.79	21.4333	2937.03	151.85
16368	2021 09 28 13:27:00	21.5000	2936.36	151.79	21.5000	2937.03	151.85
16416	2021 09 28 13:31:00	21.5667	2936.35	151.79	21.5667	2937.03	151.85
16464	2021 09 28 13:35:00	21.6333	2936.36	151.79	21.6333	2937.03	151.85
16512	2021 09 28 13:39:00	21.7000	2936.38	151.79	21.7000	2937.01	151.85
16560	2021 09 28 13:43:00	21.7667	2936.37	151.79	21.7667	2937.05	151.85
16608	2021 09 28 13:47:00	21.8333	2936.37	151.79	21.8333	2937.03	151.85
16656	2021 09 28 13:51:00	21.9000	2936.37	151.79	21.9000	2937.06	151.85
16704	2021 09 28 13:55:00	21.9667	2936.39	151.79	21.9667	2937.05	151.85
16752	2021 09 28 13:59:00	22.0333	2936.35	151.79	22.0333	2937.02	151.85

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
16800	2021 09 28 14:03:00	22.1000	2936.36	151.79	22.1000	2937.02	151.85
16848	2021 09 28 14:07:00	22.1667	2936.40	151.79	22.1667	2937.02	151.85
16896	2021 09 28 14:11:00	22.2333	2936.39	151.79	22.2333	2937.07	151.85
16944	2021 09 28 14:15:00	22.3000	2936.37	151.79	22.3000	2937.04	151.85
16992	2021 09 28 14:19:00	22.3667	2936.36	151.79	22.3667	2937.03	151.85
17040	2021 09 28 14:23:00	22.4333	2936.38	151.79	22.4333	2937.04	151.85
17088	2021 09 28 14:27:00	22.5000	2936.38	151.79	22.5000	2937.05	151.85
17136	2021 09 28 14:31:00	22.5667	2936.37	151.79	22.5667	2937.04	151.85
17184	2021 09 28 14:35:00	22.6333	2936.40	151.79	22.6333	2937.03	151.85
17232	2021 09 28 14:39:00	22.7000	2936.35	151.79	22.7000	2937.05	151.85
17280	2021 09 28 14:43:00	22.7667	2936.37	151.79	22.7667	2937.04	151.85
17328	2021 09 28 14:47:00	22.8333	2936.36	151.79	22.8333	2937.03	151.85
17376	2021 09 28 14:51:00	22.9000	2936.39	151.79	22.9000	2937.07	151.85
17424	2021 09 28 14:55:00	22.9667	2936.37	151.79	22.9667	2937.03	151.85
17472	2021 09 28 14:59:00	23.0333	2936.37	151.79	23.0333	2937.02	151.85
17520	2021 09 28 15:03:00	23.1000	2936.37	151.79	23.1000	2937.05	151.85
17568	2021 09 28 15:07:00	23.1667	2936.33	151.79	23.1667	2937.04	151.85
17616	2021 09 28 15:11:00	23.2333	2936.33	151.79	23.2333	2937.02	151.85
17664	2021 09 28 15:15:00	23.3000	2936.38	151.79	23.3000	2937.02	151.85
17712	2021 09 28 15:19:00	23.3667	2936.37	151.79	23.3667	2937.02	151.85
17760	2021 09 28 15:23:00	23.4333	2936.35	151.79	23.4333	2937.04	151.85
17808	2021 09 28 15:27:00	23.5000	2936.35	151.79	23.5000	2937.03	151.85
17856	2021 09 28 15:31:00	23.5667	2936.37	151.79	23.5667	2937.05	151.85
17904	2021 09 28 15:35:00	23.6333	2936.38	151.80	23.6333	2937.01	151.85
17952	2021 09 28 15:39:00	23.7000	2936.35	151.80	23.7000	2937.08	151.86
18000	2021 09 28 15:43:00	23.7667	2936.37	151.79	23.7667	2937.06	151.85
18048	2021 09 28 15:47:00	23.8333	2936.36	151.79	23.8333	2937.03	151.86
18096	2021 09 28 15:51:00	23.9000	2936.37	151.79	23.9000	2937.02	151.86
18144	2021 09 28 15:55:00	23.9667	2936.35	151.79	23.9667	2937.01	151.85
18192	2021 09 28 15:59:00	24.0333	2936.36	151.79	24.0333	2937.07	151.86
18240	2021 09 28 16:03:00	24.1000	2936.38	151.80	24.1000	2937.00	151.85
18288	2021 09 28 16:07:00	24.1667	2936.36	151.79	24.1667	2937.03	151.85
18336	2021 09 28 16:11:00	24.2333	2936.37	151.79	24.2333	2937.02	151.85
18384	2021 09 28 16:15:00	24.3000	2936.39	151.79	24.3000	2936.99	151.85
18432	2021 09 28 16:19:00	24.3667	2936.39	151.79	24.3667	2937.02	151.85
18480	2021 09 28 16:23:00	24.4333	2936.38	151.79	24.4333	2937.05	151.85
18528	2021 09 28 16:27:00	24.5000	2936.35	151.79	24.5000	2937.02	151.85
18576	2021 09 28 16:31:00	24.5667	2936.37	151.79	24.5667	2937.04	151.85
18624	2021 09 28 16:35:00	24.6333	2936.37	151.79	24.6333	2937.04	151.85
18672	2021 09 28 16:39:00	24.7000	2936.36	151.79	24.7000	2937.07	151.85
18720	2021 09 28 16:43:00	24.7667	2936.36	151.79	24.7667	2937.03	151.85
18768	2021 09 28 16:47:00	24.8333	2936.34	151.79	24.8333	2937.02	151.85

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
18816	2021 09 28 16:51:00	24.9000	2936.37	151.79	24.9000	2937.02	151.85
18864	2021 09 28 16:55:00	24.9667	2936.36	151.79	24.9667	2937.01	151.85
18912	2021 09 28 16:59:00	25.0333	2936.35	151.79	25.0333	2937.06	151.85
18960	2021 09 28 17:03:00	25.1000	2936.37	151.79	25.1000	2937.01	151.85
19008	2021 09 28 17:07:00	25.1667	2936.39	151.79	25.1667	2937.04	151.85
19056	2021 09 28 17:11:00	25.2333	2936.36	151.79	25.2333	2937.04	151.85
19104	2021 09 28 17:15:00	25.3000	2936.38	151.79	25.3000	2937.01	151.85
19152	2021 09 28 17:19:00	25.3667	2936.39	151.79	25.3667	2937.02	151.85
19200	2021 09 28 17:23:00	25.4333	2936.36	151.79	25.4333	2937.07	151.85
19248	2021 09 28 17:27:00	25.5000	2936.37	151.79	25.5000	2937.04	151.85
19296	2021 09 28 17:31:00	25.5667	2936.38	151.79	25.5667	2937.02	151.85
19344	2021 09 28 17:35:00	25.6333	2936.39	151.79	25.6333	2937.04	151.85
19392	2021 09 28 17:39:00	25.7000	2936.31	151.79	25.7000	2937.03	151.85
19440	2021 09 28 17:43:00	25.7667	2936.35	151.80	25.7667	2937.05	151.85
19488	2021 09 28 17:47:00	25.8333	2936.39	151.79	25.8333	2937.04	151.85
19536	2021 09 28 17:51:00	25.9000	2936.36	151.79	25.9000	2937.03	151.85
19584	2021 09 28 17:55:00	25.9667	2936.34	151.79	25.9667	2937.06	151.86
19632	2021 09 28 17:59:00	26.0333	2936.38	151.79	26.0333	2937.06	151.86
19680	2021 09 28 18:03:00	26.1000	2936.38	151.79	26.1000	2937.02	151.85
19728	2021 09 28 18:07:00	26.1667	2936.35	151.79	26.1667	2937.02	151.85
19776	2021 09 28 18:11:00	26.2333	2936.37	151.80	26.2333	2937.05	151.85
19824	2021 09 28 18:15:00	26.3000	2936.36	151.79	26.3000	2937.02	151.85
19872	2021 09 28 18:19:00	26.3667	2936.42	151.79	26.3667	2937.07	151.85
19920	2021 09 28 18:23:00	26.4333	2936.37	151.79	26.4333	2937.05	151.85
19968	2021 09 28 18:27:00	26.5000	2936.37	151.79	26.5000	2937.00	151.85
20016	2021 09 28 18:31:00	26.5667	2936.33	151.79	26.5667	2937.04	151.85
20064	2021 09 28 18:35:00	26.6333	2936.35	151.79	26.6333	2937.03	151.85
20112	2021 09 28 18:39:00	26.7000	2936.39	151.79	26.7000	2937.03	151.85
20160	2021 09 28 18:43:00	26.7667	2936.36	151.79	26.7667	2937.04	151.85
20208	2021 09 28 18:47:00	26.8333	2936.38	151.79	26.8333	2937.03	151.85
20256	2021 09 28 18:51:00	26.9000	2936.34	151.79	26.9000	2936.99	151.85
20285	2021 09 28 18:53:25	26.9403	2936.41	151.79	26.9403	2937.09	151.85
					5975.00 ft KB-TVD- Off Bottom		
20304	2021 09 28 18:55:00	26.9667	2747.35	151.77	26.9667	2744.93	151.83
20352	2021 09 28 18:59:00	27.0333	2749.31	151.41	27.0333	2750.07	151.75
20400	2021 09 28 19:03:00	27.1000	2756.42	151.66	27.1000	2757.00	151.68
20448	2021 09 28 19:07:00	27.1667	2760.81	151.85	27.1667	2761.73	151.84
20496	2021 09 28 19:11:00	27.2333	2765.82	152.20	27.2333	2766.91	152.12
20544	2021 09 28 19:15:00	27.3000	2771.30	152.32	27.3000	2772.51	152.30
20592	2021 09 28 19:19:00	27.3667	2776.23	152.38	27.3667	2777.10	152.39
20640	2021 09 28 19:23:00	27.4333	2787.46	152.41	27.4333	2787.91	152.44
20688	2021 09 28 19:27:00	27.5000	2788.15	152.41	27.5000	2788.71	152.46

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
20736	2021 09 28 19:31:00	27.5667	2774.81	152.40	27.5667	2776.09	152.46
20784	2021 09 28 19:35:00	27.6333	2758.56	152.41	27.6333	2759.35	152.46
20832	2021 09 28 19:39:00	27.7000	2932.95	152.50	27.7000	2933.61	152.52
20880	2021 09 28 19:43:00	27.7667	2963.61	150.81	27.7667	2968.84	151.69
20928	2021 09 28 19:47:00	27.8333	2997.88	145.44	27.8333	3005.66	146.70
20976	2021 09 28 19:51:00	27.9000	3040.78	141.64	27.9000	3049.71	142.64
21024	2021 09 28 19:55:00	27.9667	2949.47	139.42	27.9667	2949.36	139.99
21072	2021 09 28 19:59:00	28.0333	2936.38	140.69	28.0333	2936.53	140.56
21120	2021 09 28 20:03:00	28.1000	2935.76	141.33	28.1000	2935.94	141.14
21168	2021 09 28 20:07:00	28.1667	2935.53	141.77	28.1667	2935.78	141.60
21216	2021 09 28 20:11:00	28.2333	2935.64	142.28	28.2333	2935.89	142.07
21264	2021 09 28 20:15:00	28.3000	2935.37	142.69	28.3000	2935.60	142.50
21312	2021 09 28 20:19:00	28.3667	2935.30	143.09	28.3667	2935.51	142.89
21360	2021 09 28 20:23:00	28.4333	2935.22	143.38	28.4333	2935.47	143.22
21408	2021 09 28 20:27:00	28.5000	2935.18	143.63	28.5000	2935.40	143.49
21438	2021 09 28 20:29:30	28.5417	2935.17	143.79	28.5417	2935.19	143.65
						Pulled Off Bottom	
21456	2021 09 28 20:31:00	28.5667	2908.06	144.95	28.5667	2908.44	144.46
21504	2021 09 28 20:35:00	28.6333	2907.48	145.88	28.6333	2908.00	145.73
21552	2021 09 28 20:39:00	28.7000	2878.16	146.01	28.7000	2875.12	145.99
21600	2021 09 28 20:43:00	28.7667	2798.66	144.65	28.7667	2799.14	144.84
21648	2021 09 28 20:47:00	28.8333	2719.79	142.78	28.8333	2714.63	143.16
21696	2021 09 28 20:51:00	28.9000	2629.59	140.11	28.9000	2630.01	140.93
21744	2021 09 28 20:55:00	28.9667	2515.15	137.19	28.9667	2509.25	138.01
21792	2021 09 28 20:59:00	29.0333	2432.27	134.64	29.0333	2432.47	135.49
21840	2021 09 28 21:03:00	29.1000	2315.63	131.83	29.1000	2320.02	132.32
21888	2021 09 28 21:07:00	29.1667	1946.30	130.35	29.1667	1939.87	130.18
21936	2021 09 28 21:11:00	29.2333	2116.73	128.61	29.2333	2117.35	128.81
21984	2021 09 28 21:15:00	29.3000	1863.48	131.17	29.3000	1864.03	130.87
22032	2021 09 28 21:19:00	29.3667	1715.35	131.94	29.3667	1709.50	131.28
22080	2021 09 28 21:23:00	29.4333	1674.00	131.87	29.4333	1674.16	130.67
22128	2021 09 28 21:27:00	29.5000	1314.92	130.24	29.5000	1241.41	130.20
22176	2021 09 28 21:31:00	29.5667	1161.92	124.85	29.5667	1215.69	124.95
22224	2021 09 28 21:35:00	29.6333	1334.67	119.26	29.6333	1335.20	119.56
22272	2021 09 28 21:39:00	29.7000	1231.57	119.61	29.7000	1224.47	119.71
22320	2021 09 28 21:43:00	29.7667	1194.94	112.92	29.7667	1195.07	113.29
22368	2021 09 28 21:47:00	29.8333	1080.17	109.49	29.8333	1080.05	109.77
22416	2021 09 28 21:51:00	29.9000	1069.25	106.48	29.9000	1069.57	106.57
22464	2021 09 28 21:55:00	29.9667	1036.89	106.12	29.9667	1037.06	105.87
22512	2021 09 28 21:59:00	30.0333	1005.20	104.25	30.0333	1005.45	104.17
22560	2021 09 28 22:03:00	30.1000	1005.50	103.01	30.1000	1005.68	103.10
22608	2021 09 28 22:07:00	30.1667	1005.54	101.93	30.1667	1005.69	102.12

##	Real Time (yyyy mm dd hh:mm:ss)	Time (Hrs)	Pressure PSIA	Temp Deg. F	Time (Hrs)	Pressure PSIA	Temp Deg. F
22656	2021 09 28 22:11:00	30.2333	940.81	101.03	30.2333	941.01	100.93
22704	2021 09 28 22:15:00	30.3000	941.00	99.90	30.3000	941.18	99.88
22752	2021 09 28 22:19:00	30.3667	909.14	96.90	30.3667	909.28	97.07
22800	2021 09 28 22:23:00	30.4333	875.94	94.53	30.4333	876.07	94.78
22848	2021 09 28 22:27:00	30.5000	848.54	94.37	30.5000	848.04	94.48
22896	2021 09 28 22:31:00	30.5667	752.92	93.91	30.5667	764.76	93.49
22944	2021 09 28 22:35:00	30.6333	333.72	89.26	30.6333	564.03	89.12
22992	2021 09 28 22:39:00	30.7000	549.23	84.36	30.7000	539.07	84.07
23040	2021 09 28 22:43:00	30.7667	491.26	79.56	30.7667	490.68	79.56
23088	2021 09 28 22:47:00	30.8333	523.88	78.96	30.8333	516.81	79.11
23136	2021 09 28 22:51:00	30.9000	594.72	73.26	30.9000	595.80	72.92
23184	2021 09 28 22:55:00	30.9667	1716.90	70.66	30.9667	1709.33	71.12
23232	2021 09 28 22:59:00	31.0333	457.19	70.66	31.0333	456.41	71.04
23280	2021 09 28 23:03:00	31.1000	466.16	71.17	31.1000	467.09	71.29
23328	2021 09 28 23:07:00	31.1667	461.42	72.58	31.1667	461.52	72.51
23376	2021 09 28 23:11:00	31.2333	464.67	73.80	31.2333	465.66	73.58
23424	2021 09 28 23:15:00	31.3000	305.66	75.13	31.3000	294.68	75.07
23472	2021 09 28 23:19:00	31.3667	251.09	73.74	31.3667	251.38	74.05
23520	2021 09 28 23:23:00	31.4333	158.63	74.22	31.4333	158.81	73.96
23568	2021 09 28 23:27:00	31.5000	44.59	76.96	31.5000	43.58	76.84
23616	2021 09 28 23:31:00	31.5667	43.04	74.38	31.5667	43.78	74.16
23664	2021 09 28 23:35:00	31.6333	13.55	74.74	31.6333	13.42	74.72

APPENDIX D

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

Permit Item	NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
Pore Space Amalgamation	NDCC 38-22-06 §3 & 4 NDAC 43-05-01-08 §1 & 2	**NDCC 38-22-06** 3. Notice of the hearing must be given to each mineral lessee, mineral owner, and pore space owner within the storage reservoir and within one-half mile of the storage reservoir's boundaries. 4. Notice of the hearing must be given to each surface owner of land overlying the storage reservoir and within one-half mile of the reservoir's boundaries. **NDAC 43-05-01-08** 1. The commission shall hold a public hearing before issuing a storage facility permit. At least forty-five days prior to the hearing, the applicant shall give notice of the hearing to the following: a. Each operator of mineral extraction activities within the facility area and within one-half mile [.80 kilometer] of its outside boundary; b. Each mineral lessee of record within the facility area and within one-half mile [.80 kilometer] of its outside boundary; c. Each owner of record of the surface within the facility area and one-half mile [.80 kilometer] of its outside boundary; d. Each owner of record of minerals within the facility area and within one-half mile [.80 kilometer] of its outside boundary; e. Each owner and each lessee of record of the	a. An affidavit of mailing certifying that all pore space owners and lessees within the storage reservoir boundary and within one-half mile outside of its boundary have been notified of the proposed carbon dioxide storage project;	**1.0 PORE SPACE ACCESS (2nd paragraph, p. 1-1)** Dakota Gasification Company (DGC) has identified the owners (surface and mineral). In addition, with the exception of coal extraction, there are no mineral lessees or operators of mineral extraction activities within the facility area or within 0.5 miles of its outside boundary. DGC will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made.	N/A
			b. A map showing the extent of the pore space that will be occupied by carbon dioxide over the life of the project;	**1.0 PORE SPACE ACCESS (p. 1-1)** North Dakota law explicitly grants title of the pore space in all strata underlying the surface of lands and waters to the overlying surface estate, i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] Chapter 47-31 – Subsurface Pore Space Policy). Prior to issuance of the storage facility permit (SFP), the storage operator is mandated by the North Dakota statute governing geologic storage of carbon dioxide (CO_2) to obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir. The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are or will be equitably compensated. North Dakota law grants the North Dakota Industrial Commission (NDIC) the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation. Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application (NDCC §§ 38-22-06[3] and 38-22-06[4] and North Dakota Administrative Code [NDAC] §§ 43-05-01-08[1] and 43-05-01-08[2]). Dakota Gasification Company (DGC) has identified the owners (surface and mineral). In addition, with the exception of coal extraction, there are no mineral lessees or operators of mineral extraction activities within the facility area or within 0.5 miles of its outside boundary. DGC will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made. All owners, lessees, and operators that require notification have been identified in accordance with North Dakota law, which vests the title to the pore space in all strata underlying the surface of lands and water to the owner of the overlying surface estate (NDCC Chapter 47-31). The identification of pore space owners indicates that there was no severance of pore space or leasing of pore space to a third-party from the surface estate prior to 2009. Maps showing the extent of the pore space that will be occupied by CO_2 over the life of the project, including the storage reservoir boundary and 0.5 miles (0.8 kilometers) outside of the storage reservoir boundary with a description of pore space ownership, surface owner, and pore space lessees of record are illustrated in Figures 1-1 and 1-2.	Figure 1-1. Storage facility area map showing pore space ownership and Figure 1-2 (p. 1-2) Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area. (p. 1-3)
			c. A map showing the storage reservoir boundary and one-half mile outside of the storage reservoir boundary with a description of pore space ownership;		Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area. (p. 1-3).
			d. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each operator of mineral extraction activities;		Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area. (p. 1-3).
			e. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each mineral lessee of record;		
			f. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each surface owner of record;		Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area. (p 1-3).
			g. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each owner of record of minerals.		Figure 1-2. Hearing notification area for landowners within ½ mile of

		pore space within the storage reservoir and within one-half mile [.80 kilometer] of the reservoir's boundary; and f. Any other persons as required by the commission. 2. The notice given by the applicant must contain: a. A legal description of the land within the facility area. b. The date, time, and place that the commission will hold a hearing on the permit application. c. A statement that a copy of the permit application and draft permit may be obtained from the commission.			the storage facility area. (p. 1-3).
Geologic Exhibits	NDAC 43-05-01-05 §1b(1)	**NDAC 43-05-01-05 §1b(1)** (1) The name, description, and average depth of the storage reservoirs;	a. Geologic description of the storage reservoir: Name Lithology Average depth Average thickness	**2.1 Overview of Project Area Geology (p. 2-1)** The proposed DGC Great Plains CO_2 Sequestration Project will be situated near Beulah, North Dakota (Figure 2-1). This project site is on the central portion of the Williston Basin. The Williston Basin is an intracratonic sedimentary basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted via the PCOR Partnership, the Williston Basin has been identified as an excellent candidate for long-term CO_2 storage because of, in part, the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structure character and tectonic stability (Peck and others, 2014; Glazewski and others, 2015). The target CO_2 storage reservoir for the Great Plains CO_2 Sequestration Project is the Broom Creek Formation, a predominantly sandstone horizon lying about 5,900 ft below DGC's Great Plains Synfuels Plant (Figure 2-2). Mudstones, siltstones, and interbedded evaporites of the Opeche Formation unconformably overly the Broom Creek and serve as the primary confining zone (Figure 2-3). The Amsden Formation (dolostone, limestone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-3). Together, the Opeche, Broom Creek, and Amsden comprise the CO_2 storage complex for the Great Plains CO_2 Sequestration Project (Table 2-1). Including the Opeche Formation, there is ~1,100 ft of impermeable formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation. An additional ~2,700 ft of impermeable intervals separates the Inyan Kara and the lowest USDW, the Fox Hills Formation (Figure 2-3).	Figure 2-1. Topographic map of the Great Plains CO_2 Sequestration Project area showing well locations and the Great Plains Synfuels Plant (p. 2-2) Figure 2-2. Map of the proposed CO_2 injection wells (p. 2-3) Figure 2-3. Stratigraphic column identifying the storage reservoir, confining zones, and lowest USDW addressed in this permit application for the Great Plains CO_2 Sequestration Project (p. 2-4) Table 2-1. Formations Comprising the Great Plains CO2 Sequestration Project Storage Complex (p. 2-5)

Table 2-1. Formations Comprising the Great Plains CO_2 Sequestration Project Storage Complex (average values calculated from the simulation model and well log data)

	Formation	Purpose	Average Thickness, ft	Average Measured Depth (MD), ft	Lithology
Storage Complex	Opeche	Upper confining zone	150	4,887	Mudstone, siltstone, evaporites
	Broom Creek	Storage reservoir (i.e., injection zone)	248	5,348	Sandstone, dolostone, dolomitic sandstone, anhydrite
	Amsden	Lower confining zone	268	5,558	Dolostone, limestone, anhydrite

NDAC 43-05-01-05 §1b(2)(k)

NDAC 43-05-01-05 §1b(2)(k)
(k) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;

b. Data on the injection zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:
- Depth
- Areal extent
- Thickness
- Mineralogy
- Porosity
- Permeability
- Capillary pressure
- Facies changes

SOURCE OF THE DATA:
***2.2.1 Existing Data* (p. 2-3)**
The existing data used to characterize the geology beneath the Great Plains CO_2 Sequestration Project site included publicly available well logs and formation top depths acquired from the North Dakota Industrial Commission's (NDIC's) online database. Well log data and interpreted formation top depths were acquired for 120 wellbores within a 5472-mi^2 (72 × 76-mi) area centered on the proposed storage site (Figure 2-4). Well data were used to characterize the depth, thickness, and extent of the subsurface geologic formations.

Existing laboratory measurements from Broom Creek Formation core samples were available from five wells shown in Figure 2-5: Coteau 1 (NDIC File No. 38379), Flemmer 1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), J-LOC1 (NDIC File No. 37380), J-ROC1 (NDIC File No. 37672), and ANG #1 (North Dakota Department of Environmental Quality [NDEQ] No. 11308). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and integrated with newly acquired site-specific data.

Ten square miles of legacy 3D seismic data from Mercer County, encompassing the Flemmer 1 wellsite, and twenty-eight miles of legacy 2D seismic data were licensed and examined to understand the heterogeneity and geologic structure of the Broom Creek Formation interval. Additionally, publicly available seismic interpretation products for the Broom Creek from a 3D seismic survey in Oliver County were used to inform structure and variogram distributions (Section 3.2). The structural configurations of the formations of interest generated from the interpretation of the two 3D seismic data sets along with formation tops interpreted from well log data were used to construct the geologic model. Variogram distributions derived from inversion volumes generated using the 3D seismic data were used to inform property distribution in the geologic model which was, in turn, used to simulate migration of the CO_2 plume. These simulated CO_2 plumes were used to inform the testing and monitoring plan (Section 5).

DATA ON THE INJECTION ZONE:
2.3 Storage Reservoir (injection zone) (p. 2-12)
Locally, the Broom Creek Formation is laterally extensive (Figure 2-7) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers).

2.3 Storage Reservoir (injection zone) (p. 2-12)
Locally, the Broom Creek Formation is laterally extensive (Figure 2-7) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone, siltstones, and evaporites of the Opeche Formation (Figure 2-3).

Figure 2-4. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones (p. 2-5)

Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (modified from Rygh and others [1990]). Based on new well control shown outside of the green dashed line. (p. 2-13)

At Coteau 1, the Broom Creek Formation is 258 ft thick; is made up of 134 ft of sandstone, 35 ft of dolostone, 24 ft of anhydrite, and 65 ft of dolomitic sandstone; and is located at a depth of 5,906 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 163 to 322 ft (Figure 2-8), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 24 to 205 ft, with an average of 99 ft.

The top of the Broom Creek Formation was picked across the model area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-9). The top of the Amsden Formation was placed at the bottom of a relatively high GR signature representing an argillaceous dolostone that can be correlated across the entirety of the Great Plains CO2 Sequestration Project Area. 2D seismic data collected as part of site characterization efforts were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and analyses indicate that there should be few-to-no major reservoir stratigraphic discontinuities near the Coteau 1 well (Figures 2-10 and 2-11). The Broom Creek Formation is estimated to pinch out ~34 miles to the east of the Coteau 1 wellsite. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Great Plains CO2 Sequestration Project Area (Figure 2-12 and Figure 2-13). (p. 2-14)

Twenty-two 1-inch-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the Coteau 1 well. From the twenty-two samples, three samples at 5,941.95', 5,969.9', and 5,994.4' were duplicated and oriented 90 degrees compared to the original core plug to investigate the possibility of any orientation-dependent permeability existing in the reservoir. The remaining nineteen core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the Coteau 1 Broom Creek Formation core samples have porosity values ranging from 1.41% to 34.39% at 800 psi and 7.88% to 30.34% at 2400 psi. Permeabilities range from 0.13 to 12,300 mD at 800 psi and 0.118 to 3,990 mD at 2400 psi (Table 2-7). The wide range in porosity and permeability reflects the differences between the sandstone and dolostone lithofacies in the Broom Creek Formation. Portions of the Broom Creek Formation core revealed unconsolidated or poorly consolidated sandstone.

***2.3.1 Mineralogy* (p. 2-23)**

XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek Formation core primarily comprises quartz, feldspar, carbonates, anhydrite, clay, and other minor minerals (Figure 2-19) .

XRF data are shown in Figure 2-20 for the Broom Creek Formation. Sandstone and dolomite intervals are confirmed through the high percentages of SiO_2 (71%–98%), CaO (19%–36%), and MgO (13%–21%). The high percentage of CaO and SO_3 at 5,908.1, 6,141, and 6,154.2 ft indicate a presence of anhydrite beds. The formation shows little volumes of clay, with a range of 0.04% to 10.54% for all samples.

Table 2-9. XRD Results for Coteau 1 Broom Creek Core Sample

Mineral Data	%
Albite	2.25
Anhydrite	15.17
Anorthite	1.96
Dolomite	23.91
Illite	2.85
Pyrite	0.13
Quartz	54.15

Figure 2-3. Stratigraphic column identifying the storage reservoir, confining zones, and lowest USDW addressed in this permit application for the Great Plains CO_2 Sequestration Project (p. 2-4)

Figure 2-8. Isopach map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project Area (p. 2-14)

Figure 2-9. Well log display of the interpreted lithologies of the Opeche, Broom Creek, and upper Amsden Formations in the Coteau 1 well (p. 2-15)

Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-16)

Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-17)

Figure 2-12. Structure map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops). (p. 2-18)

Figure 2-13. Cross section of the Great Plains CO_2 Sequestration Project storage complex from the geologic

Table 2-7. Description of CO_2 Storage Reservoir (injection zone) at the Coteau 1 Well Injection Zone Properties

Property	Description		
Formation Name	Broom Creek		
Lithology	Sandstone, dolostone, dolomitic sandstone, anhydrite		
Formation Top Depth, ft	5,906		
Thickness, ft	Sandstone 134 Dolostone 35 Dolomitic sandstone 65 Anhydrite 24		
Capillary Entry Pressure (CO_2/brine), psi	0.72		
Geologic Properties			
Formation	**Property**	**Laboratory Analysis**	**Simulation Model Property Distribution**
Broom Creek (sandstone)	Porosity, %*	21.28 (7.88–30.34)	23.64 (3.65–35.77)
	Permeability, mD**	221.84 (2.92–3,990)	246.74 (0.001–3,379)
Broom Creek (dolostone)	Porosity, %	8.79 (8.66–8.94)	5.68 (0.1–25.99)
	Permeability, mD	0.180 (0.118–0.361)	0.02 (0–220)

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses.
** Permeability values are reported as the geometric mean followed by the range of values in parentheses.

2.3.3 Geochemical Information of Injection Zone

Geochemical simulation has been performed to calculate the effects of introducing the CO_2 stream to the injection zone.

The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in the Computer Modelling Group Ltd. (CMG) compositional simulation software package GEM. GEM is also the primary simulation software used for evaluation of the reservoir's dynamic behavior resulting from the expected CO_2 injection. For this geochemical modeling study, the injection scenario consisted of a single injection well injecting for a 12-year period with maximum BHP and maximum gas injection rate (STG) constraints of 3,833 psi and 25 MMcfd (468,000 tonnes/year), respectively. A postinjection period of 25 years was run in the model to evaluate any dynamic behavior and/or geochemical reaction after the CO_2 injection is stopped. This geochemical scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared (Figure 2-21).

model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level. (p. 2-20)

Table 2-7. Description of CO_2 Storage Reservoir (injection zone) at the Coteau 1 Well Injection Zone Properties (p. 2-19)

Figure 2-19. Described core and laboratory-derived mineralogic characteristics of the Opeche, Broom Creek, and Amsden Formations (p. 2-26)

Figure 2-20. XRF data from the Broom Creek Formation from the Coteau 1 (p. 2-27)

Table 2-9. XRD Results for Coteau 1 Broom Creek Core Sample (p. 2-31)

Figure 2-21. Upper graph shows cumulative injection vs. time; the bottom figure shows the gas injection rate vs. time. There is no observable difference in injection due to geochemical reactions (p. 2-29)

Figure 2-22. 2D map showing the water salinity plume from the disposal wells, ANG #1 and ANG #2, and the gas mole fraction (CO_2) for the expected injection scenario for this project described in Section 3 consisting of six CO_2 injection wells. The lower map shows the stabilized CO_2 plume vs. the salinity plume extent after 10 years postinjection, in July 2044. (p. 2-30)

Table 2-9. XRD Results for Coteau 1 Broom Creek Core Sample (p. 2-31)

Table 2-10. Broom Creek Water Ionic Composition, expressed in molality (p. 2-31)

				Simulation results indicate that the low-salinity plume (TDS 8,050 ppm) associated with the ANG #1 and ANG #2 disposal water and the injected CO_2 plume for the six-well injection scenario discussed in Section 3 may have little interaction after 10 years of postinjection (Figure 2-22). Based on this limited interaction of the injected CO_2 and the injected disposal water and the chemical composition of the disposal water, the ANG disposal well injection was not included as part of the geochemical modeling for computational efficiency. The historical ANG well injection up to August 2021 was included during the modeling. Geochemical alteration effects were seen in the geochemistry case, as described below. However, these effects were not significant enough to cause meaningful changes to the storage reservoir performance of the storage formation. For more details regarding the geochemical information of injection zone, see Section 2.3.3 on page 2-27.	Table 2-11. ANG #1 Water Ionic Composition, expressed in molality (p. 2-31) Figure 2-23. BHP and WHP vs. time. There is no observable difference in injection pressure due to geochemical reactions as compared to the results without the geochemical model. (p. 2-32) Figure 2-24a. CO_2 molality for the geochemistry case simulation results after 12 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east and right upper are north-south cross sections. Lower image is a planar view of simulation in layer k = 11. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-33) Figure 2-24b. CO2 molality for the non-geochemistry model (bottom) results after 12 years of injection + 25 years postinjection showing the distribution of CO_2 molality in log scale. Left upper images are west-east and right upper are north-south cross sections. Lower image is a planar view of simulation in layer k = 11. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-34) Figure 2-25. Geochemistry case simulation results after 12 years of injection + 25 years postinjection showing the pH of formation brine in log scale. White grid cells correspond to cells omitted from calculations because of having porosity

					and/or permeability values that round to zero. (p. 2-35) Figure 2-26. Dissolution and precipitation quantities of reservoir minerals because of CO_2 injection. Dissolution of anorthite with precipitation of pyrite, albite, and dolomite was observed. Upper figure shows all the minerals; the lower figure is rescaled for better view of the minerals mass change except pyrite. (p. 2-36) Figure 2-27. Change in molar distribution of anorthite, the most prominent dissolved mineral at the end of the 12-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-37) Figure 2-28. Change in molar distribution of albite, a precipitated mineral at the end of the 12-year injection + 25 years postinjection period in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-38) Figure 2-29. Change in molar distribution of dolomite, a precipitated mineral at the end of the 12-year injection + 25 years postinjection period in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-39) Figure 2-30. Change in molar distribution of pyrite, the most prominent precipitated mineral at the end of the 12-year injection + 25 years

<table>
<tr><td></td><td></td><td></td><td></td><td></td><td>postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-40)</td></tr>
<tr><td></td><td></td><td></td><td>c. Data on the confining zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:
Depth
Areal extent
Thickness
Mineralogy
Porosity
Permeability
Capillary pressure
Facies changes</td><td>SOURCE OF THE DATA:
See discussion above under 2.2.1 Existing Data (p. 2-3 and 2-6)

DATA ON THE CONFINING ZONE:
See Figures 2-10 through 2-12 and Figure 2-19

AND

2.4 Confining Zones (p. 2-41)
The confining zones for the Broom Creek Formation are the Opeche interval and underlying Amsden Formation (Figure 2-3, Table 2-12). Both the Amsden and Opeche intervals consist of impermeable rock layers.

Table 2-12. Properties of Upper and Lower Confining Zones in Simulation Area (data based on the Coteau 1 well)
<table>
<tr><th>Confining Zone Properties</th><th>Upper Confining Zone</th><th>Lower Confining Zone</th></tr>
<tr><td>Formation Name</td><td>Opeche</td><td>Amsden</td></tr>
<tr><td>Primary Lithology</td><td>Silty mudstone</td><td>Dolostone</td></tr>
<tr><td>Formation Top Depth, ft</td><td>5,763</td><td>6,164</td></tr>
<tr><td>Thickness, ft</td><td>143</td><td>300</td></tr>
<tr><td>Porosity, % (core data) *</td><td>6.93</td><td>2.40</td></tr>
<tr><td>Permeability, mD (core data) **</td><td>0.002878</td><td>0.00116</td></tr>
<tr><td>Capillary Entry Pressure (CO_2/brine), psi</td><td>138.68</td><td>251.27</td></tr>
<tr><td>Depth below Lowest Identified USDW, ft</td><td>4,658</td><td>5,059</td></tr>
</table>
* Porosity values are reported as the arithmetic mean.
** Permeability values are reported as the geometric mean.

2.4.1 Upper Confining Zone (p. 2-41)
In the Great Plains CO_2 Sequestration Project area, the Opeche Formation consists of silty mudstone and anhydrite. The upper confining zone (Opeche) is laterally extensive across the Great Plains CO_2 Sequestration Project area (Figure 2-31). The upper</td><td>Table 2-12. Properties of Upper and Lower Confining Zones in Simulation Area (p. 2-41)

Figure 2-31. Areal extent of the Opeche Formation in North Dakota (p. 2-42)

Figure 2-32. Structure map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (p. 2-43)

Figure 2-33. Isopach map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (p. 2-44)

Figure 2-34. Well log display of the upper confining zone at the Coteau 1 well (p. 2-45)

Figure 2-38. XRD data for the Opeche Formation from the Coteau 1 (p. 2-49)</td></tr>
</table>

				confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche interval is 5,763 ft below the land surface and 143 ft thick at the Coteau 1 wellsite (Table 2-12, Figures 2-32 and 2-33). The contact between the upper confining zone and underlying Broom Creek sandstone is an unconformity that can be correlated across the formation's extent where the resistivity and GR logs show a significant change across the contact (Figure 2-34). Microfracture in situ stress tests were not performed within the Opeche Formation in the Coteau 1 well. Microfracture in situ tests were performed using the MDT tool in the Flemmer 1 well, in the Opeche Formation, at a depth of 6,262 ft, which yielded results within good confidence. The MDT tool was able to cause breakdown in the formation at 8,157 psi. Propagation pressure for two cycles in close agreement were 4,879 and 5,085 psi, resulting in an average propagation pressure gradient of 0.80 psi/ft (Figure 2-35). In situ fluid pressure testing was not performed in the Opeche Formation with the MDT tool. The CMR log shown in Figure 2-36 suggests that because of the low to almost zero permeability the fluid within the Opeche is pore- and capillary-bound fluid and not mobile. This is confirmed by unsuccessful attempts by others to extract fluid samples from the Opeche. The Tundra SGS (secure geologic storage) and Red Trail Energy storage facility permit applications describe unsuccessful attempts to draw down reservoir fluid in order to determine the reservoir pressure or to collect an in situ fluid sample; the formation was unable to rebound (build pressure) because of low to almost zero permeability (NDIC, 2021a, b). These unsuccessful attempts provide further evidence of the confining properties of the Opeche Formation, ensuring sufficient geologic integrity to contain the injected carbon dioxide stream. Laboratory measurements from the Opeche Formation core samples taken from the Coteau 1 well indicate a porosity value of 6.93% at 800 psi and 6.62% at 2,400 psi and geometric average permeability values of 0.002878 mD at 800 psi and 0.002083 mD at 2,400 psi. The lithology of the cored sections of the Opeche is primarily silty mudstone. *2.4.1.1 Mineralogy* (p. 2-48) Thin-section investigation shows that the Opeche Formation comprises alternating intervals of very fine silty mudstone and mudstone. In all, five thin sections were created over the 73 ft of core collected from the Opeche Formation. The mineral components present are clay, quartz, anhydrite, feldspar, dolomite, and iron oxides. The coarser grains are almost always surrounded by anhydrite or clay as cement or matrix. The observable porosity is very low and is due to the dissolution of quartz and feldspar. The porosity ranges between 5% and 9%. Permeability is very poor and ranges between 0.00026 to 0.0227 mD. Figure 2-37 shows examples of the texture, fabric, and nature of observable porosity for the intervals where thin sections were created. As shown, observable porosity (shown in blue) is generally isolated and not well connected throughout. Additionally, thin-section analysis shows the fine-grained, well-compacted nature of the intervals evaluated. XRD data from the five Opeche samples of the Coteau 1 core supported facies interpretations from core descriptions and thin-section analysis. The Opeche Formation mainly comprises clay, quartz, feldspar, dolomite, and anhydrite. Figure 2-38 shows the mineralogy determined from XRD data for the five samples tested through the cored interval of the Opeche Formation. XRF analysis of the Opeche Formation shown in Figure 2-39 identifies SiO_2 (44%–57%), Al_2O_3 (6%–18%), CaO (5%–15%), and MgO (3%–9%) as the major chemical constituents, correlating well with the silicate, carbonate, and aluminum-rich mineralogy determined by XRD. This is in good agreement with XRD, core description, and thin-section analysis. *2.4.1.2 Geochemical Interaction (p. 2-50)* Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected CO2 stream on the Opeche Formation, the primary confining zone. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to CO_2 and minor amounts of H2S at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Opeche by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the Opeche Formation. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock –CO_2/H_2S exposure boundary. The mineralogical composition of the Opeche Formation was honored (Table 2-13). The XRD data used to define mineral composition in the model correspond to a mudstone sample from the Opeche Formation. Formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone below (Table 2-14). The CO_2 stream composition was as described in Table 2-15. 96.45 mol% of the stream is CO_2, and the rest represents other components, including H_2S, the second major component of the stream. 96 mol% of CO_2 was used in the simulation instead of 96.45 mol% to keep the model input simple (Table 2.15). The 4 mol% H2S used for this simulation represents the sum of all other components (CH_4, C_2H_6, C_3H_8, N_2) and thus overstates the actual H2S fraction of 1.23 mol% (Table 2-15). The exposure level, expressed in moles per year, of the CO_2 stream to the cap rock used was 4.5 moles/yr.	Figure 2-39. XRF data for the Opeche Formation from the Coteau 1 (p. 2-49) Table 2-13. Mineral Composition of the Opeche Derived from XRD Analysis of Coteau 1 Core Samples (p. 2-50) Table 2-14. Formation Water Chemistry from Broom Creek Fluid Samples from Coteau 1 (p. 2-50) Table 2-15. Composition of the Injection Stream (p. 2-51) Table 2-16. Description of Zones of Confinements above the Immediate Upper Confining Zone (Opeche) (p. 2-50) Figure 2-46. Structure map of the Amsden Formation across the greater Great Plains CO_2 Sequestration Project area (p. 2-57) Figure 2-47. Isopach of the Amsden Formation across the greater Great Plains CO_2 Sequestration Project area (p. 2-58) Figure 2-48. XRD data for the Amsden Formation from the Coteau 1 (p. 2-60) Figure 2-49. XRF data for the Amsden Formation from the Coteau 1 (p. 2-60)

This value is considerably higher than the expected actual exposure level of 2.3 moles/year (Espinoza and Santamarina, 2017). This overestimate was done to ensure that the degree and pace of geochemical change would not be underestimated. This geochemical simulation was run for 37 years to match the reservoir injection zone geochemical model and represent 12 years of injection plus 25 years of postinjection. The simulation was performed at reservoir pressure and temperature conditions.

For more details on Geochemical interaction of the confining zone, refer to section 2.4.1.2 on page 2-51.

2.4.2 Additional Overlying Confining Zones **(p. 2-54)**
Several other formations provide additional confinement above the Opeche interval. Impermeable rocks above the primary seal include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-16). Together with the Opeche interval, these formations are 1,106 ft thick and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-44). Above the Inyan Kara Formation, 2,657 ft of impermeable rocks act as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (Figure 2-44). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-16).

Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (Opeche) (data based on the Coteau 1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,753	1,931	0
Greenhorn	Shale	3,685	376	1,931
Mowry	Shale	4,061	94	2,307
Skull Creek	Shale	4,156	254	2,402
Swift	Shale	4,800	411	3,046
Rierdon	Shale	5,212	205	3,458
Piper (Kline Member)	Limestone	5,417	112	3,663
Piper (Picard Member)	Shale	5,529	233	3,775

2.4.3 Lower Confining Zones **(p. 2-57)**
The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, mudstone, and anhydrite. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, with relatively high GR character that can be correlated across the Great Plains CO_2 Sequestration Project area (Figure 2-6). The Amsden Formation is 6,164 ft below land surface and approximately 300 ft thick at the Coteau 1 well (Figures 2-46 and 2-47, Table 2-12).

The contact between the overlying Broom Creek and Amsden Formations is evident on wireline logs as there is a lithological change from the porous sandstones of the Broom Creek Formation to the dolostone and anhydrite beds of the Amsden Formation. This lithologic change is recognized in the core from the Coteau 1 well. The lithology of the cored section of the Amsden Formation from the Coteau 1 well is dolostone, anhydrite, and mudstone with laminated, fine-grained sandstone and siltstone. Data acquired from the six core plug samples taken from the Amsden Formation show porosity values ranging from 1.00% to 5.27% at 800 psi and 0.91% to 4.54% at 2,400 psi. Permeability values range from 0.0000557 to 1.2 mD at 800 psi and 0.0000642 to 0.215 mD at 2,400 psi (Table 2-17).

2.4.3.1 Mineralogy (p. 2-59)
Thin-section analysis shows that the Amsden Formation comprises dolomite, anhydrite, sandy dolomite, and shaly sand. Six thin sections were created and described for the 83-ft cored Amsden section. The dolomite is expressed by very fine to fine-sized

				dolomite crystals with the presence of quartz of variable size and shape, feldspar, clay, anhydrite, and iron oxides. The porosity is very low and is mainly intragranular because of dissolution with an average of 2%. Anhydrite is present as beds, nodules, and laminations in association with the dolomite intervals. Minor iron oxides inclusions are present. The porosity is almost nonexistent. The dolomite is mainly composed of dolomite crystals and grains of quartz. Minor iron oxides and feldspar are present, with rare occurrence of anhydrite observed. The grains of quartz are almost always separated by dolomite matrix. The porosity is mainly due to the dissolution of feldspar and averages 1%. Finally, the anhydritic sandstone interval is composed of quartz, clay, carbonates, and anhydrite. Iron oxides are present in some parts of the rock matrix as rims around some quartz grains and mostly fill the stylolite surfaces and some rare fractures. The grains of quartz are almost always separated by carbonate cement, clay minerals and, specifically, anhydrite cement. In this lithofacies, anhydrite acts as cement in most parts of the interval by connecting sand grains together and decreasing the overall porosity of the lithofacies. The porosity averages 3% and is mainly due to the dissolution of feldspar and quartz (Figure 2-48). XRD was performed (Figure 2-49), and the results confirm the observations made during core analyses and thin-section description. XRF data shows that the Amsden Formation at the contact with the Broom Creek is dominated by CaO and MgO (major chemical components of dolomite). Deeper samples are more anhydrite-rich, fine- to medium-grained sandstones, as shown by the high percentage of SiO_2, CaO, and SO_3 (Figure 2-50).	
	NDAC 43-05-01-05 §1b(2) ¶	**NDAC 43-05-01-05 §1b(2)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or	d. A description of the storage reservoir's mechanisms of geologic confinement characteristics with regard to preventing migration of carbon dioxide beyond the proposed storage reservoir, including: Rock properties Regional pressure gradients Adsorption processes	*2.2.2.3 Formation Temperature and Pressure* (2nd paragraph, p. 2-9) Temperature data recorded from logging the Coteau 1 and Flemmer 1 wellbores were used to derive a temperature gradient for the proposed injection site (Tables 2-2 and 2-3). In combination with depth, the temperature gradient was used to distribute a temperature property throughout the geologic model of the Great Plains CO2 Sequestration Project area. The temperature property was used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for the geochemical modeling. The formation pressure and temperature at Coteau 1 were collected with a bottomhole pressure (BHP) gauge. In the Coteau 1 well, the Broom Creek was perforated at 5975 ft (1 foot, 4 shots per foot). After perforating, the BHP gauge was run to the perforation depth where temperature and pressure measurements were collected (Appendix C, "Pressure Survey Report"). The pressure data recorded in the Coteau 1 well are shown in Table 2-4. (p. 2-9) ***2.3.2 Mechanism of Geologic Confinement*** 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. 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). After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period of time (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation and, therefore, is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.	Table 2-4. Description of Coteau 1 Formation Pressure Measurements and Calculated Pressure Gradients (p. 2-11) Table 2-5. Description of Flemmer 1 Formation Pressure Measurements and Calculated Pressure Gradients (p. 2-11)

		potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:			
	NDAC 43-05-01-05 §1b(2)(g)	**NDAC 43-05-01-05 §1b(2)(g)** (g) Identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir;	e. Identification of all characteristics controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir, including: Structural spill points Stratigraphic discontinuities	*2.2.2.6 Seismic Survey* (p. 2-12) The proximity of the site to an active coal mine and industrial facilities makes acquisition of 3D seismic data problematic. Placement of seismic source and receiver locations required for a 3D seismic survey would be restricted because of these surface uses potentially resulting in insufficient data quality to image the subsurface for characterization and monitoring purposes. Interpretation of 2D seismic data provides a practical alternative to acquiring and interpreting 3D seismic data. 2D seismic surveys can be used to evaluate the subsurface across large tracts of land, can be oriented to avoid surface obstacles such as those found at this site, can be acquired more frequently for future site monitoring, and eliminates the need to overshoot areas that have already been swept with CO_2. Twenty-eight miles of 2D seismic lines that traverse the storage facility area and intersect the Coteau 1 well were licensed and interpreted (Figure 2-4). The 2D seismic lines were tied to the Coteau 1 well and used to evaluate the thickness and structure of the Broom Creek and upper and lower confining zones within the storage facility area. The interpreted surfaces for the formations of interest derived from the 2D seismic lines were used to confirm that the geologic model is representative of the reservoir thickness and structure within the storage facility area. The 2D seismic data suggest there are no major stratigraphic pinch-outs or structural features with associated spill points in the Great Plains CO_2 Sequestration Project area. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the lowest USDW, the Fox Hills Formation, were observed in the seismic data. Twenty-eight miles of new 2D seismic data centered around the Coteau 1 well was acquired in January 2022 and will be used to confirm these interpretations. **2.3 Storage Reservoir (injection zone) (last sentence in paragraph, p. 2-14)** The top of the Broom Creek Formation was picked across the model area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-9). The top of the Amsden Formation was placed at the bottom of a relatively high GR signature representing an argillaceous dolostone that can be correlated across the entirety of the Great Plains CO_2 Sequestration Project Area. 2D seismic data collected as part of site characterization efforts were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and analyses indicate that there should be few-to-no major reservoir stratigraphic discontinuities near the Coteau 1 well (Figures 2-10 and 2-11). The Broom Creek Formation is estimated to pinch out ~34 miles to the east of the Coteau 1 wellsite. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Great Plains CO_2 Sequestration Project Area (Figure 2-12 and Figure 2-13). ***2.3.2 Mechanism of Geologic Confinement*** 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. 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). After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period of time (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation and, therefore, is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.	Figure 2-9. Well log display of the interpreted lithologies of the Opeche, Broom Creek, and upper Amsden Formations in the Coteau 1 well (p. 2-15) Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-16) Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-17) Figure 2-12. Structure map of the Broom Creek Formation across the greater Great Plains CO2 Sequestration Project area (generated using 3D seismic horizons and well log tops). (p. 2-18) Figure 2-13. Cross section of the Great Plains CO2 Sequestration Project storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations

					are referenced to mean sea level. (p. 2-20)
	NDAC 43-05-01-05 §1b(2)c	**NDAC 43-05-01-05 §1b(2)c** (c) Any regional or local faulting;	f. Any regional or local faulting;	**2.5 Faults, Fractures, and Seismic Activity (First two paragraphs on p. 2-87)** In the Great Plains CO_2 Sequestration Project area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. The absence of transmissive faults is supported by fluid sample analysis results from Coteau 1 that suggest the injection interval, Broom Creek Formation (42,800 mg/L) is isolated from the next permeable interval, the Inyan Kara Formation (22,800 mg/L). The Williston Basin is a tectonically stable region of the North American Craton. Zhou and others (2008) summarize that "the Williston Basin as a whole is in an overburden compressive stress regime," which could be attributed to the general stability of the North American Craton. Interpreted structural features associated with tectonic activity in the Williston Basin in North Dakota include anticlinal and synclinal structures in the western half of the state, lineaments associated with Precambrian basement block boundaries, and faults (North Dakota Industrial Commission, 2019).	Figure 2-73. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (p. 2-89)
	NDAC 43-05-01-05 §1b(2)(j)	**NDAC 43-05-01-05 §1b(2)(j)** (j) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone in the area of review, and a determination that they would not interfere with containment;	g. Properties of known or suspected faults and fractures that may transect the confining zone in the area of review: Location Orientation Determination of the probability that they would interfere with containment	**2.5 Faults, Fractures, and Seismic Activity (1st paragraph, p. 2-87)** In the Great Plains CO2 Sequestration Project area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. The absence of transmissive faults is supported by fluid sample analysis results from Coteau 1 that suggest the injection interval, Broom Creek Formation (42,800 mg/L) is isolated from the next permeable interval, the Inyan Kara Formation (22,800 mg/L).	N/A
	NDAC 43-05-01-05 §1b(2) ¶ & §1b(2)(m)	**NDAC 43-05-01-05 §1b(2)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any	h. Information on any regional tectonic activity, and the seismic history, including: The presence and depth of seismic sources; Determination of the probability that seismicity would interfere with containment;	**2.5 Faults, Fractures, and Seismic Activity (3rd paragraph, p. 2-87 and p. 2-89)** Between 1870 and 2015, 13 earthquakes were detected within the North Dakota portion of the Williston Basin (Table 2-21) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-73). The seismic event recorded closest to the Great Plains CO_2 Sequestration Project storage facility area occurred 29.6 mi from the Coteau 1 well near Fort Berthold in southwestern North Dakota (Table 2-21). The magnitude of this seismic event is estimated to have been 1.9. Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging earthquake events occurring in North Dakota, with less than two damaging earthquake events predicted to occur over a 10,000-year time period (Figure 2-74) (U.S. Geological Survey, 2019). A 1-year seismic forecast (including both induced and natural seismic events) released by 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 that could be associated with nearby 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 containment is low.	Table 2-21. Summary of Earthquakes Reported to Have Occurred in North Dakota Figure 2-74. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (p. 2-90)

		productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following: **NDAC 43-05-01-05 §1b(2)(m)** (m) Information on the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment;			
	NDAC 43-05-01-05 §1b(2) ¶ NDAC 43-05-01-05 §1b(2)(n)	**NDAC 43-05-01-05 §1b(2)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include	i. Illustration of the regional geology, hydrogeology, and the geologic structure of the storage reservoir area: Geologic maps Topographic maps Cross sections	**2.1 Overview of Project Area Geology (1st paragraph, p. 2-1)** The proposed Dakota Gasification Company (DGC) Great Plains CO_2 Sequestration Project will be situated near Beulah, North Dakota (Figure 2-1). This project site is on the central portion of the Williston Basin. The Williston Basin is an intracratonic sedimentary basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. See also Figure 2-7 on p. 2-13, Figure 2-10 on p. 2-16, Figure 2-11 on p. 2-17, Figure 2-13 on p. 2-20, Figure 2-31 on p. 2-43, and Figure 2-72 on p. 2-88. ***4.4.3 Hydrology of USDW Formations* (p. 4-21)** Groundwater is obtained from both glacial drift and bedrock aquifers, with most of the water obtained from bedrock. Lignite beds and sands in the Sentinel Butte and Tongue River Formations provide shallow bedrock aquifers in most areas of Mercer County. Sandstones near the base of the Tongue River Formation and within the Hell Creek and Fox Hills Formations provide deeper artesian aquifers in many areas. Glacial drift is generally too thin or impermeable to provide good aquifers in the upland areas. However, in the valleys of the major streams and in the diversion channels, the glacial and alluvial fill provides adequate supplies of groundwater (Carlson, 1973). The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the area of investigation is to the east (Figure 4-13). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,530 mg/L near the Great Plains CO2 Sequestration Project area. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Trapp and Croft, 1975). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering. See also Figure 4-15 on p. 4-24.	Figure 2-1. Topographic map of the Great Plains CO_2 Sequestration Project area showing well locations and the Great Plains Synfuels Plant Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (modified from Rygh and others [1990]). Based on new well control shown outside of the green dashed line. (p. 2-13) Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-16) Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-17)

		exhibits and plan view maps showing the following: **NDAC 43-05-01-05 §1b(2)(n)** (n) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the facility area; and			Figure 2-13. Cross section of the Great Plains CO_2 Sequestration Project storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level. (p. 2-20) Figure 2-32. Structure map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (p. 2-43) Figure 2-73. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (p. 2-89) Figure 4-13. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in Mercer County (modified from Fischer, 2013). (p. 4-22) Figure 4-15. West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the locations of the water wells illustrated on the cross section. (p. 4-24)
	NDAC 43-05-01-05 §1b(2)(d)	**NDAC 43-05-01-05 §1b(2)(d)** (d) An isopach map of the storage reservoirs;	j. An isopach map of the storage reservoir(s);	See Figure 2-8 on p. 2-14	Figure 2-8. Isopach map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project Area (p. 2-14)
	NDAC 43-05-01-05 §1b(2)(e)	**NDAC 43-05-01-05 §1b(2)(e)** (e) An isopach map of the primary and any secondary containment barrier for the storage reservoir;	k. An isopach map of the primary containment barrier for the storage reservoir;	See Figure 2-33 on p. 2-44	Figure 2-33. Isopach map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area. (p. 2-44)

			l. An isopach map of the secondary containment barrier for the storage reservoir;	See Figure 2-44 on p. 2-55 and Figure 2-45 on p. 2-56	Figure 2-44. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. (p. 2-55) Figure 2-45. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone. (p. 2-56)
	NDAC 43-05-01-05 §1b(2)(f)	**NDAC 43-05-01-05 §1b(2)(f)** (f)A structure map of the top and base of the storage reservoirs;	m. A structure map of the top of the storage formation;	See Figure 2-12 on p. 2-18	Figure 2-12. Structure map of the Broom Creek Formation across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops). (p. 2-18)
			n. A structure map of the base of the storage formation;	See Figure 2-32 on p. 2-43	Figure 2-32. Structure map of the Opeche interval of the upper confining zone across the greater Great Plains CO_2 Sequestration Project area (generated using 3D seismic horizons and well log tops). (p. 2-43)
	NDAC 43-05-01-05 §1b(2)(i)	**NDAC 43-05-01-05 §1b(2)(i)** (i) Structural and stratigraphic cross sections that describe the geologic conditions at the storage reservoir;	o. Structural cross sections that describe the geologic conditions at the storage reservoir;	See Figure 2-11 on p. 2-17 and Figure 2-13 on p. 2-20	Figure 2-11. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-17) Figure 2-13. Cross section of the Great Plains CO_2 Sequestration Project storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level. (p. 2-20)
			p. Stratigraphic cross sections that describe the geologic conditions at the storage reservoir;	See Figure 2-10 on p. 2-16	Figure 2-10. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top

					of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) neutron porosity (blue), and 3) interpreted lithology log. (p. 2-16)
	NDAC 43-05-01-05 §1b(2)(h)	**NDAC 43-05-01-05 §1b(2)(h)** (h) Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any;	q. Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any;	**3.4 Simulation Results (p. 3-22)** The pressure front (Figure 3-20) shows the distribution of pressure increase throughout the Broom Creek Formation at the end of the 12-year injection period. A maximum increase of 436.53 psi is estimated in the near wellbore area. ***6.1.1 Pre- and Postinjection Pressure Differential*** **(p. 6-1)** Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of CO_2 injection. The simulations were conducted for 12 years of CO_2 injection at rates between 1.1 and 2.7 million metric tons per year, followed by a postinjection period of 10 years. Figure 6-1 illustrates the predicted pressure differential at the conclusion of 12 years of CO_2 injection. At the time that CO_2 injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of 350 to 400 psi at the location of the injection wells, which is insufficient to move formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the AOR delineation of this permit application (Section 3). An illustration of the predicted decrease in this pressure profile over the 10-year postinjection period is provided in Figure 6-2. The pressure in the reservoir gradually decreases over time following the cessation of CO_2 injection, with the pressure at the injection well after 10 years of postinjection predicted to decrease 300 to 350 psi as compared to the pressure at the time CO_2 injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions.	Figure 3-20. Average pressure increases within the Broom Creek Formation at the end of a simulated 12-year CO_2 injection operation (p. 3-22) Figure 6-1. Predicted pressure differential in storage reservoir following 12 years of CO_2 injection at rates between 1.1 and 2.7 million metric tons per year (p. 6-2) Figure 6-2. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection (p. 6-3)
	NDAC 43-05-01-05 §1b(2)(l)	**NDAC 43-05-01-05 §1b(2)(l)** (l) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream;	r. Geomechanical information on the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide: Fractures Stress Ductility Rock strength In situ fluid pressure	*2.4.4.1 Fracture Analysis (p. 2-66)* Fractures within the Opeche Formation, the overlying confining zone, and the Amsden Formation, the underlying confining zone, have been assessed during the description of the Coteau 1 well core. Observable fractures were categorized by attributes including morphology, orientation, aperture, and origin. Secondly, natural fractures and in situ stresses were assessed by Schlumberger through the interpretation of the fullbore formation microimager (FMI), bulk density (RHOB), dipole shear sonic (DTS), and dipole compressional sonic (DTC) logs acquired during the drilling of the Coteau 1 well. *2.4.4.2 Fracture Analysis Core Description* (p. 2-66) Fractures within the Opeche Formation are primarily litho-bound resistive fractures. They are commonly filled with anhydrite. However, some litho-bound conductive fractures are highlighted. The presence of microfaults is underlined mainly in the lower part of the Opeche Formation. The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. The aperture varies from closed to, in rare cases, centimeter-scale. The Amsden Formation could be considered as a nonfractured interval. However, few litho-bound conductive fractures are commonly coincident with the horizontal compaction features (stylolite) observed. *2.4.4.3 Borehole Image Fracture Analysis (FMI)* Schlumberger's FMI log was chosen to evaluate the geomechanical condition of the formation in the subsurface. This log provides a 360-degree image of the formation of interest and can be oriented to provide an understanding of the general direction of features observed. Figure 2-57 showsFigure 2-57 The far-right track on Figure 2-57 provides information on surface boundaries, slump deformed, and notes the presence of electrically conductive and resistive features. The latter are interpreted as minor anhydrite-filled fractures. Figure 2-58 shows two sections of the interpreted borehole imagery and primary features observed. Figure 2-58 demonstrates that the tool provides information on slump deformation, conductive fractures, and microfaults. These microfaults are identified in Figure 2-58 and are likely clay-filled because of their electrically conductive signal. Figure 2-59 and Figure 2-60 show two thin-section images and give an indication of different minerals within the reservoir with observed changes in the electrical response shown on the FMI log. Also, some drilled-induced fractures are highlighted in the upper part of the Opeche Formation.	Table 2-19 Triaxial Testing Results Showing the Calculated Static Young's Modulus, Poisson's Ratio, and Compressive Strength. The confining zone pressure was set at 1,180 psi for testing. The pore pressure used for calculations was assumed to be 0 psi. (p. 2-82) Table 2-20 Triaxial Testing Results Showing the Measured Acoustic Velocities and Calculated Dynamic Bulk Modulus, Young's Modulus, Poisson's Ratio, and Compressive Strength. The confining zone pressure was set at 1,180 psi for testing. (p. 2-83) Figure 2-70. Calibrated geomechanical rock properties model in Opeche Formation (p. 2-84)

				Figure 2-61 shows the logged interval for the lower Opeche Formation at Coteau 1 well. As shown, the section closest to the Broom Creek Formation is dominated by litho-bound fractures and microfaults which are electrically conductive features likely due to the presence of clay. The rose diagrams shown in Figures 2-62 through 2-65 provide the orientation of the conductive, resistive, microfault, and drilling-induced features in the Opeche Formation. The drilling-induced fractures are oriented NE-SW and N-S which give an orientation of N060 and N000 to the maximum horizontal stress (Shmax), respectively. The logged interval of the Amsden Formation shows that the main features present are bed boundaries and slump deformation features (Figure 2-66). The depths 6,201.6 and 6,213.7 ft show some evidence of conductive fracture and drilling-induced fractures, respectively (Figure 2-67). The rose diagrams shown in Figures 2-67 and 2-68 provide the orientation of the conductive and drilling-induced fractures in the Amsden Formation. The drilling-induced fractures are oriented NE-SW which gives an orientation of N060 to the maximum horizontal stress (Shmax). *2.4.4.4 Stress* (p. 2-81) The 1D Mechanical Earth Model (MEM) for Opeche, Broom Creek, and Amsden Formations in Coteau 1 well was generated by Core Laboratories (Figures 2-70, 2-71, and 2-72). During construction of the 1D MEM, the effect of pore pressure on sonic transit time, accurate calculation of stress, and rock properties required corrections based on this effect. Dipole sonic logs (DTC, DTS) were corrected for formation pressure impedance and tool radius of investigation. The log corrections allow for a better match to core measurements and more robust geomechanical models. The output data for the 1D MEM are vertical stress (Sv), pore pressure, pore pressure gradient, dynamic Poisson's ratio, dynamic Young's modulus, Biot factor, fracture closure pressure, fracture closure pressure gradient, fracture propagation pressure, fracture propagation pressure gradient, fracture breakdown pressure, and fracture breakdown pressure gradient. Laboratory-derived core measurements were used from the Coteau 1 well. The static and dynamic parameters from core including DTS, DTC, compressional wave velocity (Vp), shear wave velocity (Vs), dynamic Young's modulus, and dynamic Poisson's ratio were estimated for the Opeche, Broom Creek, and Amsden Formations and used to calibrate the geomechanical rock properties model. The isotropic (dynamic) properties from well logs (Young's modulus and dynamic Poisson's ratio) were calculated based on the corrected DTC and DTS well logs and calibrated with core measurements. Pore pressure, pore pressure gradient, fracture closure pressure, fracture closure pressure gradient, fracture propagation pressure, fracture propagation fracture gradient, fracture breakdown pressure, and fracture breakdown pressure gradient were also estimated. Pore pressure was calibrated using the pressure and temperature data from the Coteau 1 well. Triaxial tests were performed on 15 vertical samples: three in Opeche, nine in Broom Creek, and three in Amsden (Table 2-19 and 2-20). Static Young's modulus, Poisson's ratio, and compressive strength were measured at the confining pressure of 1180 psi. Also, acoustic velocities (Vp, Vs) and dynamic moduli (Bulk modulus, Young's modulus, shear modulus, Poisson's ratio) were estimated under a confining pressure of 1,180 psi The triaxial outputs were calibrated with the estimated parameters using well logs. Figures 2-70–2-72 show the outputs of the 1D MEM for the Opeche, Broom Creek, and Amsden Formations. In situ stresses such as vertical stress (Sv), maximum horizontal stress (Shmax), and minimum horizontal stress (Shmin) were calculated. The vertical stress is calculated using the density log (RHOB) and assumes 1 psi/ft above 1,500 ft where the RHOB data were not available. The minimum horizontal stress is estimated from a modified Eaton calculation method. Shmax is estimated from Shmin and process zone stress as a function of porosity. Based on the calculated stresses, the stress regime of the Opeche, Broom Creek, and Amsden Formations is considered a normal stress regime where Sv > Shmax > Shmin. ***4.1.1 Written Description* (p. 4-1 and p. 4-2)** An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.	Figure 2-71. Calibrated geomechanical rock properties model in Broom Creek Formation (p. 2-85) Figure 2-72. Calibrated geomechanical rock properties model in the Amsden Formation (p. 2-86)

	NDAC 43-05-01-05 §1b(2)(o)	**NDAC 43-05-01-05 §1b(2)(o)** (o) Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement, are free of transmissive faults or fractures, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	s. Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement: Free of transmissive faults Free of transmissive fractures Effect on pressure dissipation Utility for monitoring, mitigation, and remediation.	***2.4.2 Additional Overlying Confining Zones* (p. 2-54 and p. 2-57)** Several other formations provide additional confinement above the Opeche interval. Impermeable rocks above the primary seal include the Picard, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-16). Together with the Opeche interval, these formations are 1,106 ft thick and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-44). Above the Inyan Kara Formation, 2,657 ft of impermeable rocks act as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (Figure 2-44). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-16). These formations between the Broom Creek and Inyan Kara and between the Inyan Kara and the lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin (Downey, 1986; Downey and Dinwiddie, 1988). Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Inyan Kara Formation represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring using annual temperature and pulse neutron logging of the Inyan Kara Formation provides an additional opportunity for mitigation and remediation (Section 4). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at the Coteau 1 well is 4,512 ft, and the formation itself is 378 ft thick.	Table 2-16 (p. 2-55) Figure 2-44. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation (p. 2-55) Figure 2-45. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation (p. 2-56)
Area of Review Delineation	NDAC 43-05-01-05 §1j & §1b(3)	**NDAC 43-05-01-05 §1j** j. An area of review and corrective action plan that meets the requirements pursuant to section 43-05-01-05.1; **NDAC 43-05-01-05 §1b(3)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following:	The carbon dioxide storage reservoir area of review includes the areal extent of the storage reservoir and one mile outside of the storage reservoir boundary, plus the maximum extent of the pressure front caused by injection activities. The area of review delineation must include the following:	***4.1.1 Written Description*** North Dakota geologic storage of CO_2 regulations require that each storage facility permit delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO_2 plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the Coteau 1 well (NDIC File No. 38379) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-7]). Section 3 includes a detailed discussion on the computational modeling and simulations (e.g., storage facility area, pressure front, AOR boundary, etc.), assumptions, and justification used to delineate the AOR and method for delineation of the AOR. NDAC § 43-05-01-05 subsection 1b(3) requires, "A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 4-1), the resulting AOR for the Great Plains CO_2 Sequestration Project is delineated as being 1 mile from the storage facility permit (SFP) boundary. This extent ensures compliance with existing state regulations. All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 4-2 through 4-5) by a professional engineer pursuant to NDAC § 43- 05-01-05 subsection 1b(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected CO2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 through 4-6 and Figures 4-6 through 4-9). An extensive geologic and hydrogeologic characterization performed by a team of geologists from the EERC resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.	Figure 4-2. Final AOR map showing the Great Plains CO_2 Sequestration Project storage facility area, the storage facility area (dashed purple boundary), and the AOR (dashed black boundary). Pink squares represent occupied dwellings, teal squares represent vacant buildings, and blue squares represent commercial buildings. (p. 4-3) Figure 4-3. AOR map in relation to nearby legacy wells and groundwater wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR, and the light-orange triangles represent Class I ANG #1 and ANG #2 wells. All groundwater wells in the AOR are identified above. All observation/monitoring wells are shallow groundwater wells associated with the mine activities. No springs are present in the AOR. (p. 4-4)

				This section of the SFP application is accompanied by maps and tables that include information required and in accordance with NDAC § 43-05-01-05 subsections 1(a) and 1(b) and 43-05-01-05.1 subsection 2, such as the storage facility area, location of any proposed injection wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05 subsections 1a and 1b(3) and 43-05-01-05.1 subsection 2. Surface features that were investigated but not found within the AOR boundary were identified in Table 4-1. See Figure 4-2 on p. 4-3, Figure 4-3 on p. 4-4, and Figure 4-4 on p. 4-5.	Figure 4-4. AOR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR and the Class I ANG #1 and ANG #2 wells are represented by blue triangles. (p. 4-5)
	NDAC 43-05-01-05 §1b(3) & §1a	**NDAC 43-05-01-05 §1b(3)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: **NDAC 43-05-01-05 §1a** a. A site map showing the boundaries of the storage reservoir and the location of all proposed wells, proposed cathodic protection boreholes, and surface facilities within the carbon dioxide storage facility area;	a. A map showing the following within the carbon dioxide reservoir area: i. Boundaries of the storage reservoir ii. Location of all proposed wells iii. Location of proposed cathodic protection boreholes iv. Any existing or proposed above ground facilities;	**4.1.2 Supporting Maps (p. 4-2)** See Figure 4-2 on p. 4-3	Figure 4-2 Final AOR map showing the Great Plains CO_2 Sequestration Project storage facility area, the storage facility area (dashed purple boundary), and the AOR (dashed black boundary). Pink squares represent occupied dwellings, teal squares represent vacant buildings, and blue squares represent commercial buildings. (p. 4-3)
	NDAC 43-05-01-05 §1b(2)(a)	**NDAC 43-05-01-05 §1b(2)(a)** (a) All wells, including water, oil, and natural gas exploration and development wells, and other manmade subsurface structures and activities, including coal mines, within the facility area and within one mile [1.61 kilometers] of its outside boundary;	b. A map showing the following within the storage reservoir area and within one mile outside of its boundary: i. All wells, including water, oil, and natural gas exploration and development wells ii. All other manmade subsurface structures and activities, including coal mines;	**4.1.2 Supporting Maps (p. 4-2)** See Figure 4-3 on p. 4-4 and Figure 4-4 on p. 4-5	Figure 4-3 AOR map in relation to nearby legacy wells and groundwater wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR, and the light-orange triangles represent Class I ANG #1 and ANG #2 wells. All groundwater wells in the AOR are identified above.

					All observation/monitoring wells are shallow groundwater wells associated with the mine activities. No springs are present in the AOR. (p. 4-4) Figure 4-4 AOR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR and the Class I ANG #1 and ANG #2 wells are represented by blue triangles. (p. 4-5)
	NDAC 43-05-01-05 §1c NDAC 43-05-01-05.1 §1a	**NDAC 43-05-01-05 §1c** c. The extent of the pore space that will be occupied by carbon dioxide as determined by utilizing all appropriate geologic and reservoir engineering information and reservoir analysis, which must include various computational **NDAC 43-05-01-05.1 §1a** a. The method for delineating the area of review, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	c. A description of the method used for delineating the area of review, including: i. The computational model to be used ii. The assumptions that will be made iii. The site characterization data on which the model will be based;	**3.5 Delineation of the Area of Review (p. 3-25)** The North Dakota Administrative Code (NDAC) defines the AOR as the region surrounding the geologic storage project where USDWs may be endangered by CO_2 injection activity (NDAC § 43-05-01-05). The primary endangerment risk is the potential for vertical migration of CO_2 and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the CO_2 plume within the storage reservoir. However, the CO_2 plume has an associated pressure front where CO_2 injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the CO_2 plume. Therefore, the AOR encompasses both the areal extent of the CO_2 plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the CO_2 plume, AOR delineation focuses on the pressure front. The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. U.S. Environmental Protection Agency (EPA) guidance for AOR delineation under the Underground Injection Control (UIC) Program for Class VI wells provides several methods for estimating the critical threshold pressure increase and resulting critical threshold pressure. In this document, "storage reservoir" refers to the Broom Creek Formation (the injection zone), and the "lowest USDW" refers to the Fox Hills Formation.	
	NDAC 43-05-01-05.1 §1b(1-4)	**NDAC 43-05-01-05.1 §1b(1-4)** b. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review; (2) The monitoring and operational conditions	d. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review; (2) Any monitoring and operational conditions that would warrant a reevaluation of the area of	**4.3 Reevaluation of AOR and Corrective Action Plan (p. 4-17)** DGC will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place not later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following: • Any changes to the monitoring and operational data prior to the scheduled reevaluation date. • Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and operational data to be utilized as the basis for that update will be identified.	N/A

		that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date; (3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and (4) How corrective action will be conducted to meet the requirements of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	review prior to the next scheduled reevaluation date; (3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; (4) How corrective action will be conducted if necessary, including: a. What corrective action will be performed prior to injection b. How corrective action will be adjusted if there are changes in the area of review;	• The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR.	
	NDAC 43-05-01-05 §1b(2)(b)	**NDAC 43-05-01-05 §1b(2)(b)** (b) All manmade surface structures that are intended for temporary or permanent human occupancy within the facility area and within one mile [1.61 kilometers] of its outside boundary;	e. A map showing the areal extent of all manmade surface structures that are intended for temporary or permanent human occupancy within the storage reservoir area, and within one mile outside of its boundary;	**4.1.2 Supporting Maps (p. 4-2)** See Figure 4-2 on p. 4-3	Figure 4-2 Final AOR map showing the Great Plains CO_2 Sequestration Project storage facility area, the storage facility area (dashed purple boundary), and the AOR (dashed black boundary). Pink squares represent occupied dwellings, teal squares represent vacant buildings, and blue squares represent commercial buildings. (p. 4-3)
	NDAC 43-05-01-05 §1b(2) ¶	**NDAC 43-05-01-05 §1b(2)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any	f. A map and cross section identifying any productive existing or potential mineral zones occurring within the storage reservoir area and within one mile outside of its boundary;	**2.6 Potential Mineral Zones (p. 2-89 through 2-91)** There are no known producible accumulations of hydrocarbons in the storage facility area. The North Dakota Geological Survey recognizes the Spearfish Formation as the only potential oil-bearing formation above the Broom Creek Formation. However, production from the Spearfish Formation is limited to the northern tier of counties in western North Dakota (Figure 2-75). There has been no exploration for, nor development of, a hydrocarbon resource from the Spearfish Formation in the Great Plains CO_2 Sequestration Project area. There has been no historic hydrocarbon exploration in, or production from, formations below the Broom Creek Formation in the storage facility area. The Herrmann 1 well (NDIC File No. 4177), the closest hydrocarbon exploration well to the storage facility area, located 4.1 miles from the Coteau 1 well, was drilled in 1966 to explore potential hydrocarbons in the Madison Group. The well was dry and did not suggest the presence of hydrocarbons. The closest hydrocarbon producing well is Traxel 1-31H (NDIC File No. 17877), located 10.8 miles east from the Coteau 1 well (NDIC 38379). The Traxel 1-31H well was drilled in August 2009,	Figure 2-75. Drillstem test results indicating the presence of oil in the Spearfish Formation (modified from Stolldorf, 2020). (p. 2-91)

		regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:		producing a cumulative total of 12,021 bbl until December 2013. The well's current status is producer now abandoned (PNA) as of November 2014. Published studies suggest there are no economic deposits of hydrocarbons in the Bakken Formation in the storage facility area (Bergin, 2012; Theloy, 2016). In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a 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 (Figure 3-20). Pressure increases will relax postinjection as the area returns to its preinjection 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 placed across the storage reservoir, with CO_2-resistant cement used to anchor the casing in place. Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations (NDCC 57-51-01) define shallow gas resources as "gas produced from a zone that consists of strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1,524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation (Jurassic), from which gas may be produced." Lignite reserves in the Sentinel Butte Formation of the Fort Union Group (the Beulah of the Beulah-Zap interval and Twin Butte coal beds) are mined to be used as feedstock for the GPSP coal gasification process and power generation feedstock at Basin Electric Power Cooperative's Antelope Valley Station, located about 0.5 miles north of DGC's GPSP. The lignite is obtained from the Freedom Mine, which is operated by Coteau Properties Company, a wholly owned subsidiary of North American Coal Corporation. The thickness of the Beulah–Zap averages between 18 to 22 feet in thickness (Figure 2-76). Above the Beulah horizon are several thin beds of lignite. In ascending order, these are the Schoolhouse and Twin Butte beds. Overburden on top of the Beulah ranges from 95 to 145 feet (Figure 2-77). The Twin Butte has an average thickness of about 6 feet under 25–30 feet of overburden where it is actively mined (Zygarlicke and others, 2019). The Beulah, Twin Butte, and other coal seams thicken and deepen to the west. The Beulah–Zap and Twin Butte seams pinch out to the east. The underlying Hagel coal seam is mined farther to the east at the BNI Coal Mine near Center, North Dakota, and the Falkirk Mine near Falkirk, North Dakota.	Figure 2-76. Beulah net coal isopach map (modified from Ellis and others, 1999). (p. 2-93) Figure 2-77. Beulah overburden isopach map (modified from Ellis and others, 1999). (p. 2-94)
	NDAC 43-05-01-05 §1b(3) NDAC 43-05-01-05.1 §2b	**NDAC 43-05-01-05 §1b(3)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following:	g. A map identifying all wells within the area of review, which penetrate the storage formation or primary or secondary seals overlying the storage formation.	See Figure 4-4 on p. 4-5	Figure 4-4 AOR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (dashed orange boundary), the storage facility area (dotted purple boundary), and the 1-mile AOR (dashed black boundary). Orange solid circles represent nearby legacy wells near the project area outside of the 1-mile AOR and the Class I ANG #1 and ANG #2 wells are represented by blue triangles. (p. 4-5)

		NDAC 43-05-01-05.1 §2b b. Using methods approved by the commission, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone. Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the commission may require;			
	NDAC 43-05-01-05 §1b(3)(a) NDAC 43-05-01-05 §1b(3)(b) NDAC 43-05-01-05 §1b(3)(c)	**NDAC 43-05-01-05 §1b(3)(a)** (a) A determination that all abandoned wells have been plugged and all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping from the storage reservoir; **NDAC 43-05-01-05 §1b(3)(b)** (b) A description of each well's type, construction, date drilled, location, depth, record of plugging, and completion; **NDAC 43-05-01-05 §1b(3)(c)** (c) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all underground sources of drinking water, water wells, and springs within	h. A review of these wells must include the following: (1) A determination that all abandoned wells have been plugged in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation; (2) A determination that all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation; (3) A description of each well: a. Type b. Construction c. Date drilled d. Location e. Depth f. Record of plugging g. Record of completion (4) Maps and stratigraphic cross sections of all underground sources of drinking water within the area of review indicating the following: a. Their positions relative to the injection zone	**4.1.1 Written Description (4th paragraph, p. 4-1)** All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated by a professional engineer pursuant to NDAC § 43- 05-01-05 subsection 1b(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected CO_2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 through 4-6 and Figures 4-6 through 4-9). 4.1.2 Supporting Maps See Figure 4-3 on p. 4-4. **4.2 Corrective Action Evaluation (p. 4-8)** See Table 4-2 on p. 4-8, Table 4-3 on p. 4-9, Table 4-4 on p. 4-10, Table 4-5 on p. 4-11, and Table 4-6 on p. 4-12. See Figure 4-6 on p. 4-13, Figure 4-7 on p. 4-14, Figure 4-8 on p. 4-15, and Figure 4-9 on p. 4-16.	Table 4-2. Wells in AOR Evaluated for Corrective Action (p. 4-8) Table 4-3. Hermann 1 (NDIC File No. 4177) Well Evaluation (p. 4-9) Table 4-4. ANG 1 (NDEQ File No. NDOH11308) Well Evaluation (p. 4-10) Table 4-5. ANG 2 (NDEQ File No. NDOH11309) Well Evaluation (p. 4-11) Table 4-6. Coteau 1 (NDIC File No. 38379) Well Evaluation (p. 4-12) Figure 4-3 (p. 4-4) Figure 4-6 Hermann 1 (NDIC File No. 4177) well schematic showing the location and thickness of cement plugs (p. 4-13) Figure 4-7. ANG 1 (NDEQ File No. NDOH11308) well schematic showing the location

	NDAC 43-05-01-05 §1b(3)(d) NDAC 43-05-01-05 §1b(3)(e) NDAC 43-05-01-05 §1b(3)(b)(f)	the area of review; their positions relative to the injection zone; and the direction of water movement, where known; **NDAC 43-05-01-05 §1b(3)(d)** (d)Maps and cross sections of the area of review; **NDAC 43-05-01-05 §1b(3)(e)** (e) A map of the area of review showing the number or name and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, state-approved or United States environmental protection agency-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features, including structures intended for human occupancy, state, county, or Indian country boundary lines, and roads;	b. The direction of water movement, where known c. General vertical and lateral limits d. Water wells e. Springs (5) Map and cross sections of the area of review; (6) A map of the area of review showing the following: a. Number or name and location of all injection wells b. Number or name and location of all producing wells c. Number or name and location of all abandoned wells d. Number of name and location of all plugged wells or dry holes e. Number or name and location of all deep stratigraphic boreholes f. Number or name and location of all state-approved or United States Environmental Protection Agency-approved subsurface cleanup sites g. Name and location of all surface bodies of water h. Name and location of all springs i. Name and location of all mines (surface and subsurface) j. Name and location of all quarries k. Name and location of all water wells l. Name and location of all other pertinent surface features m. Name and location of all structures intended for human occupancy n. Name and location of all state, county, or Indian country boundary lines o. Name and location of all roads		and thickness of cement plugs (p. 4-14) Figure 4-8. ANG 2 (NDEQ File No. NDOH11309) well schematic showing the location and thickness of cement plugs (p. 4-15) Figure 4-9. Coteau 1 (NDIC File No. 38379) well schematic showing the location and thickness of cement plugs (p. 4-16)

		NDAC-43-05-01-05 §1b(3)(b)(f) (f) A list of contacts, submitted to the commission, when the area of review extends across state jurisdiction boundary lines;	(7)A list of contacts, submitted to the Commission, when the area of review extends across state jurisdiction boundary lines.		
	NDAC 43-05-01-05 §1b(3)(g)	**NDAC 43-05-01-05 §1b(3)(g)** (g) Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review; and	i. Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review.	***5.5.2 Groundwater Baseline Sampling* (p. 5-13)** Two Fox Hills Formation samples were obtained in November 2021 from the Fred Art/Oberlander #1 and Helmuth Pfenning #2 wells. State-certified laboratory results for these two wells found in Appendix B show little variation among the reports. The locations of the wells investigated for establishing baseline conditions are shown in Figure 5-3, and the results of the baseline measurements for pH, specific conductivity, and alkalinity are provided in Table 5-5, with state-certified laboratory results for each sampling event provided in Appendix B. In addition, DGC plans to obtain a baseline water sample from the Fox Hills monitoring well that will be drilled near the Herrmann 1 well (NDIC File No. 4177) prior to injection operations. **Appendix B - FRESHWATER WELL FLUID-SAMPLING LABORATORY ANALYSIS** See Appendix B for detailed laboratory reports of geochemical data collected during the initial baseline sampling program	Figure 5-3. DGC's initiated baseline sampling program for vadose zone soil gas and groundwater in the Fox Hills Formation (p. 5-12) Table 5-4. DGC's Initial Baseline Groundwater Sampling Results – November 2021 (p. 5-13)
Required Plans	NDAC 43-05-01-05 §1k	**NDAC 43-05-01-05 §1k** k. The storage operator shall comply with the financial responsibility requirements pursuant to section 43-05-01-9.1;	a. Financial Assurance Demonstration	**12.2 Financial Instruments (p. 12-1 and p. 12-2)** DGC is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments: • DGC will establish an escrow account to cover the costs of corrective action in accordance with NDAC § 43-05-01-05.1, plugging of injection wells in accordance with NDAC § 43-05-01-11.5, and implementing postinjection site care and facility closure activities in accordance with NDAC § 43-05-01-19. DGC will make four annual payments of $1 million to the escrow account. The first payment will occur on or before the first day of operations, and the final payment will occur in 2025, bringing the account balance to $4 million. • A third-party pollution liability insurance policy with an aggregate limit of $16 million will be secured to cover the costs of implementing emergency and remedial response actions, if warranted, in accordance with NDAC § 43-05-01-13. The estimated total costs of these activities are presented in Table 12-1. Section 12.3 of this FADP provides additional details of the financial responsibility cost estimates for each activity.	Table 12-1. Cost estimates for Activities to Be Covered (p. 12-2)
	NDAC 43-05-01-05 §1d	**NDAC 43-05-01-05 §1d** d. An emergency and remedial response plan pursuant to section 43-05-01-13;	b. An emergency and remedial response plan;	**7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN (p. 7-1)** This emergency and remedial response plan (ERRP) 1) describes the local resources and infrastructure in proximity to the site; 2) identifies events that have the potential to endanger all underground sources of drinking water (USDWs) during the construction, operation, and postinjection site care periods of the geologic storage project; and 3) describes the response actions that are necessary to manage these risks to USDWs. In addition, the integration of the ERRP with the existing plant emergency plan and risk management plan of Dakota Gasification Company's (DGC's) Great Plains Synfuels Plant (GPSP) is described, emphasizing the command structure of DGC, the evacuation plan, hazmat (hazardous material) capabilities, and the emergency communication plan of the GPSP. Lastly, procedures are presented for regularly conducting and evaluating the adequacy of the ERRP and updating it, if warranted, over the lifetime of the Great Plains CO2 Sequestration Project. Note: Refer to the following key tables instead: Table 7-2 on p. 7-6 and Table 7-3 on p. 7-8 through 7-10.	Table 7-2. Potential Project Emergency Events and Their Detection (p. 7-6) Table 7-3 Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (p. 7-8 through 7-10)
	NDAC 43-05-01-05 §1e	**NDAC 43-05-01-05 §1e** e. A detailed worker safety plan that addresses carbon	c. A detailed worker safety plan that addresses the following:	**8.1 DGC Employee Safety Requirements and Training (p. 8-1)**	N/A

		dioxide safety training and safe working procedures at the storage facility pursuant to section 43-05-01-13;	i. Carbon dioxide safety training ii. Safe working procedures at the storage facility;	DGC has established a process for employees to acquire the knowledge, skills, and abilities to competently operate the facility in accordance with DGC safe work practices, procedures, and operating manuals. The safety requirements for DGC employees include, but are not limited to, the following: 1. An orientation for all newly hired employees to ensure they are aware of company safety policies and procedures, safety and health hazards, safe work practices, and government safety regulations. 2. Instruction and training for each employee regarding: a. Safety expectations while on DGC property. b. What to do in an emergency, including evacuation routes and assembly points. c. Safety and industrial hygiene information about hazardous materials/conditions and immediate actions to take following an accidental exposure. d. When and how to report safety incidents. e. How to report unsafe conditions and behaviors. f. Safe work practices as defined by government and company standards. ***8.1.2 DGC Contractor Safety Requirements and Training*** **(p. 8-1 and p. 8-2)** The DGC OSIH program also establishes requirements for contractors to interface with DGC to ensure compliance with DGC safety procedures and federal, state, and local safety standards. The scope of the requirements covers all contractors and their personnel (including subcontractors) working at DGC's facilities. The safety requirements and training required for a contractor to access and perform work at DGC facilities include, but are not limited to, the following: 1. Full compliance with all Energy Coalition for Contractor Safety (ECCS) guidelines for a "Class A contractor." (The guidelines can be found at the North Dakota Safety Council [NDSC] website at www.ndsc.org.) 2. Attendance at an annual DGC contractor safety orientation. 3. Negative drug test results within the last 12 months. 4. Availability of a contractor employee training record (CETR) within the last 12 months: a. Documents that the contractor has trained its personnel on DGC procedures and process descriptions. b. Ensures contractor employees are instructed in the known potential fire, explosion, or toxic release hazards and applicable provisions of the emergency response plan. 5. Documentation of a contractor employee background check within the last 5 years. 6. Successful completion of an Occupational Safety and Health Administration (OSHA) 10-hour class within the last 36 months. 7. A contractor safety manual evaluation completed by a third party, i.e., the North Dakota Safety Council (NDSC), to demonstrate compliance with federal, state, and DGC safety standards. 8. Demonstration of acceptable safety performance by submitting the last year's safety statistics to NDSC at www.ndsc.org. 9. Demonstration of qualification requirements for pipeline (off-site) contractors, which includes the following: a. Submission of a drug/alcohol plan that meets 49 Code of Federal Regulations (CFR) Part 40 and Part 199. b. Submission of an operator qualification plan in accordance with 49 CFR Part 192 and Part 195. c. Submission of qualification data for personnel performing operation, maintenance, or emergency response task(s) on the carbon dioxide (CO_2) pipeline. d. Other qualification requirements include: i. DGC access to drug/alcohol and operator qualification information for random record audits. ii. Submission of Department of Transportation (DOT) annual drug testing statistical data to DGC for inclusion in an annual DGC submittal to DOT. Only DGC employees and contractor personnel who have been properly trained will participate in the project activities of drilling, construction, operations, and equipment repair.	
	NDAC 43-05-01-05 §1f	**NDAC 43-05-01-05 §1f** f. A corrosion monitoring and prevention plan for all wells and surface facilities pursuant to section 43-05-01-15;	d. A corrosion monitoring and prevention plan for all wells and surface facilities;	**5.2 Corrosion Monitoring and Prevention Plan (p. 5-4)** The purpose of the corrosion monitoring and prevention plan is to monitor the surface facilities and injection well components during the operational phase of the Great Plains CO_2 Sequestration Project to ensure that the materials meet the minimum standards for material strength and performance. Figure 5-1 illustrates the pad drawings for the Coteau 1 through Coteau 4 wells. DGC permitted a new 6.8-mile-long transmission line through the North Dakota Public Service Commission (PSC) in July 2021 (PU-21-150). The transmission line implements a corrosion monitoring and prevention strategy that was approved by PSC and is not discussed in this storage facility permit application. At the transition from transmission line to flowline (Figure 5-2), DGC's efforts	Figure 5-1A. Well pad drawing of the Coteau 1 well location (p. 5-5) Figure 5-1B. Well pad drawing of the Coteau 2 well location (p. 5-6)

				to monitor and prevent corrosion of the flowline and well materials at the injection wellsites are presented in Sections 5.2.1 and 5.2.2. ***5.2.1 Corrosion Monitoring* (p. 5-4)** DGC will install a 3-foot test section of 4½-inch L-80 tubing in the flowlines near each wellhead for regular testing and corrosion monitoring of the well material. The tubing joints will be inspected monthly via ultrasound equipment during the first quarter, then quarterly thereafter for the first 2 years. If the well materials (i.e., tubing) show no sign of corrosion within the first 2 years of the injection period, future internal monitoring of the tubing will be accomplished through a PMIT, or in the event a downhole tubing string is pulled for any reason, it will be inspected at the surface for corrosion and mechanical integrity. USITs may also be run during workovers (including when tubing is pulled), but not more frequently than once every 5 years, to further assess any corrosion of the injection string. ***5.2.2 Corrosion Prevention* (p. 5-9)** To prevent corrosion of the well materials, the following preemptive measures will be taken: 1) cement in the injection wells opposite the injection interval and extending more than 2,000 feet uphole will be CO_2-resistant, 2) the well casing (L-80 13Cr) will also be CO_2-resistant from the bottomhole to a depth just above the Opeche Formation in the injection wells, and 3) the packer fluid will be an industry standard corrosion inhibitor. In addition, the chemical composition of the CO_2 stream is highly pure (Table 5-2) and dry, with a moisture level for the CO_2 stream typically less than two parts per million by volume, both factors of which help to prevent corrosion of the surface and well materials.	Figure 5-1C. Well pad drawing of the Coteau 3 well location (p. 5-7) Figure 5-1D. Well pad drawing of the Coteau 4 well location Figure 5-2. Diagram of surface connections at the Coteau 1 wellsite (p. 5-9) Table 5-2. Chemical Content of the CO_2 Stream (p. 5-3)
	NDAC 43-05-01-05 §1g	**NDAC 43-05-01-05 §1g** g. A leak detection and monitoring plan for all wells and surface facilities pursuant to section 43-05-01-14. The plan must: (1) Identify the potential for release to the atmosphere; (2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.	e. A surface leak detection and monitoring plan for all wells and surface facilities pursuant to North Dakota Administrative Code (NDAC) Section 43-05-01-14;	**5.3 Surface Leak Detection and Monitoring Plan (p. 5-10)** 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. Performance targets designed for the Great Plains CO_2 Sequestration Project to detect potential leaks in the flowline are provided in Table 5-3. The performance targets are dependent upon the actual performance of instrumentation (e.g., pressure gauges) and the supervisory control and data acquisition (SCADA) system, which uses software to track the status of the pipeline system in real time by comparing live pressure and flow rate data to a comprehensive predictive model. The performance targets assume a flow rate of 200 million standard cubic feet per day (MMSCFD) of CO_2. An alarm will trigger on the SCADA system if a volume deviation of more than 2% is registered. H2S detection stations will also be mounted on the inside and outside of wellhead enclosures to detect any potential indoor and atmospheric leaks at the well pad locations, respectively. The stations can detect H2S concentrations as low as 1 part per million (ppm) and have an integrated alarm system if a 10 ppm threshold is crossed. The stations are further described in Appendix C (Attachment A-7). Field personnel will have multi gas detectors with them for wellsite visits or flowline inspections to detect potential leaks from the equipment. The multi gas detectors will primarily monitor for CH_4, CO, O_2, and H_2S up to 100 feet from a surface leakage source. The multi gas detector will measure H2S as low as 0.1 ppm with an incremental resolution of 0.1 ppm and has built-in alarms. Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.	N/A
	NDAC 43-05-01-05 §1h	**NDAC 43-05-01-05 §1h** h. A leak detection and monitoring plan to monitor any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile [1.61 kilometers] of the facility area's outside	f. A subsurface leak detection and monitoring plan to monitor for any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile of the facility area's outside boundary;	**5.4 Subsurface Leak Detection and Monitoring Plan (p. 5-10)** The monitoring plan for detecting subsurface leaks comprises "surface/near-surface" and deep subsurface monitoring programs. "Surface/near-surface" refers to the region from ground surface down to, and including, the lowest USDW as well as surface waters, soil gas (vadose zone), and shallow groundwater (e.g., stock wells, residential drinking water wells, etc.). The deep subsurface zone extends from the base of the lowest USDW to the base of the injection zone of the storage reservoir. Subsurface leak detection will include multiple approaches to ensure confidence that surface (i.e., ambient and workspace atmospheres and surface waters) and near-surface (i.e., vadose zone, groundwater wells, and the lowest USDW) environments are protected, and the CO_2 is safely and permanently stored in the storage reservoir. More specifically, for DGC's geologic storage project, near-surface monitoring will include 11 soil gas profile stations and seven dedicated Fox Hills Formation monitoring wells within the AOR to detect if the lowest USDW is being impacted by operations. These monitoring efforts will provide additional	

		boundary. Provisions in the plan will be dictated by the site characteristics as documented by materials submitted in support of the permit application but must: (1) Identify the potential for release to the atmosphere; (2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.		lines of evidence to assess whether the surface/near-surface environment is being protected and whether the CO_2 is being safely and permanently stored in the storage reservoir. To complement surface/near-surface monitoring, additional monitoring of the subsurface will ensure CO_2 is staying in the targeted storage reservoir. Operational monitoring at the injection wells, including injection rates, pressures, and temperatures will provide data to inform the monitoring approaches. Internal and external mechanical integrity of the injection wells will also be demonstrated to ensure no leakage pathway exist that may allow vertical movement of the CO_2. Additionally, geophysical (seismic) surveys conducted over regular intervals will monitor subsurface CO_2 plume movement. More details regarding the surface, near-surface, and deep subsurface monitoring efforts are provided in sections 5.5 through 5.7.	
	NDAC 43-05-01-05 §1l	**NDAC 43-05-01-05 §1l** l. A testing and monitoring plan pursuant to section 43-05-01-11.4;	g. A testing and monitoring plan pursuant to NDAC Section 43-05-01-11.4;	See Section 5.0 Testing and Monitoring Plan and Appendix C: Quality Assurance Surveillance Plan Note: See Table 5-1 on p. 5-2 Table 5-5 on p.5-11, Table 5-6 on p. 5-13 and 5-14, Table 5-7 on p. 5-15 for detailed summaries of the testing and monitoring plan.	Table 5-1. Overview of DGC's Testing and Monitoring Plan (p. 5-2) Table 5-5. Baseline, Operational, and Postoperational Monitoring Duration and Frequency for Soil Gas and Groundwater (p. 5-13) Table 5-6. Description of DGC's Deep Subsurface Monitoring Program (p. 5-16) Table 5-7. Testing and Logging Program for the Coteau 1 Wellbore (p. 5-18)
	NDAC 43-05-01-05 §1i	**NDAC 43-05-01-05 §1i** i. The proposed well casing and cementing program detailing compliance with section 43-05-01-09;	h. The proposed well casing and cementing program;	**9.0 WELL CASING AND CEMENTING PROGRAM (p. 9-1)** Rampart Energy Company has drilled one well, Coteau 1 (NDIC File No. 38379) thus far on behalf of DGC. The well was permitted and drilled in June 2021 as a stratigraphic test well in compliance with Class VI underground injection control (UIC) injection well construction requirements. Application to convert Coteau 1 to a CO_2 storage injection well is being filed upon approval of this storage facility permit (SFP). The following information includes the current, as-constructed wellbore schematic (illustrated in Figure 9-1 and detailed in Tables 9-1 through 9-4) and a radial cement evaluation log summary for Coteau 1 (Figure 9-2). After drilling, the Broom Creek Formation was perforated with four shots at 5975 ft and a reservoir pressure and fluid sample were obtained. The perforations were then squeezed with 100 sacks of Class G cement and the casing pressured tested to 1600 psi with an inhibited brine solution.	Figure 9-1. Coteau 1 as-constructed wellbore schematic (p. 9-2) Table 9-1. Coteau 1 As-Constructed Well Information (p. 9-3) Table 9-2. Coteau 1 As-Constructed Casing Program (p. 9-3)

				Five additional injection wells are planned. Three of these, the proposed Coteau 2, Coteau 3, and Coteau 4, are expected to be drilled in the second quarter of 2022, followed by the proposed Coteau 5 and Coteau 6 in late 2025, to accommodate additional CO2 injection volumes in the spring of 2026. Note: See also the proposed casing and cementing program details for the Coteau 2 through 6 wells on p. 9-7 through 9-20.	Table 9-3. Coteau 1 As-Constructed Casing Properties (p. 9-4) Table 9-4. Coteau 1 As-Constructed Cement Program (p. 9-4) Figure 9-2. Coteau 1 isolation scanner results (p. 9-5)
	NDAC 43-05-01-05 §1m	**NDAC 43-05-01-05 §1m** m. A plugging plan that meets requirements pursuant to section 43-05-01-11.5;	i. A plugging plan;	**10.1 Plugging & Abandonment (P&A) Program (p. 10-1)** A well schematic of the planned completion for the Coteau 1 well (NDIC File No. 38379) is provided in Figure 10-1 followed by a P&A procedure and a well-plugging schematic (Figure 10-2). The abandonment of subsequent injection wells, namely, the Coteau 2 through 6, will be performed in a manner consistent with that of the Coteau 1. The size and depths of the various plugs may vary as necessary to accomplish the zonal isolation, but in each instance, approval of specific P&A operations will be required from the NDIC Department of Mineral Resources (DMR) prior to the initiation of fieldwork.	Figure 10-1. Coteau 1 CO_2 injection well schematic (p. 10-2) Figure 10-2. Schematic of proposed abandonment plan for each injection well (p. 10-6)
	NDAC 43-05-01-05 §1n	**NDAC 43-05-01-05 §1n** n. A postinjection site care and facility closure plan pursuant to section 43-05-01-19; and	j. A post-injection site care and facility closure plan.	**6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN (p. 6-1)** This postinjection site care (PISC) and facility closure plan describes the activities that DGC will perform following the cessation of CO_2 injection to achieve final closure of the site. A primary component of this plan is a postinjection monitoring program that will provide evidence that the injected CO_2 plume is stable (i.e., CO_2 migration will be unlikely to move beyond the boundary of the storage facility area). Based on simulations of the predicted CO_2 plume movement following the cessation of CO_2 injection, it is projected that the CO_2 plume will stabilize within the storage facility area boundary (Section 3). Based on these observations, a minimum postinjection monitoring period of 10 years is planned to confirm these current predictions of the CO_2 plume extent and postinjection stabilization. However, monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable CO_2 plume. The nature and duration of that extension will be determined based on an update of this plan and NDIC approval. In addition to DGC executing the postinjection monitoring program, the Class VI injection wells will be plugged as described in the plugging plan of this permit application (Section 10), all surface equipment not associated with long-term monitoring will be removed, and the surface land of the site will be reclaimed to as close as is practical to its original condition. Following the plume stability demonstration, a final assessment will be prepared to document the status of the site and submitted as part of a site closure report. Note: Refer to Table 6-1 on p. 6-4 for a summary of the postinjection site care monitoring plan.	Table 6-1. Summary of 10-year Postinjection Site Care Monitoring Plan (p. 6-4)
Storage Facility Operations	NDAC 43-05-01-05 §1b(4)	**NDAC 43-05-01-05 §1b(4)** (4) The proposed calculated average and maximum daily injection rates, daily volume, and the total anticipated volume of the carbon dioxide stream using a method acceptable to and filed with the commission;	The following items are required as part of the storage facility permit application: a. The proposed average and maximum daily injection rates; b. The proposed average and maximum daily injection volume; c. The proposed total anticipated volume of the carbon dioxide to be stored;	**11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)** This section of the storage facility permit (SFP) application presents the engineering criteria for completing and operating the injection wells in a manner that protects underground sources of drinking water (USDWs). The information that is presented meets the permit requirements for injection wells and storage operations as presented in North Dakota Administrative Code (NDAC) § 43-05-01-05 (SFP, Table 11-1) and NDAC § 43-05-01-11.3	Table 11.1. Proposed Injection Well Operating Parameters (p. 11-1)

NDAC 43-05-01-05 §1b(5)

NDAC 43-05-01-05 §1b(5)
(5) The proposed average and maximum bottom hole injection pressure to be utilized at the reservoir. The maximum allowed injection pressure, measured in pounds per square inch gauge, shall be approved by the commission and specified in the permit. In approving a maximum injection pressure limit, the commission shall consider the results of well tests and other studies that assess the risks of tensile failure and shear failure. The commission shall approve limits that, with a reasonable degree of certainty, will avoid initiating a new fracture or propagating an existing fracture in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water;

d. The proposed average and maximum bottom hole injection pressure to be utilized;

e. The proposed average and maximum surface injection pressures to be utilized;

Table 11-1. Proposed Injection Well Operating Parameters

Item	Coteau 1	Coteau 2	Coteau 3	Coteau 4	Coteau 5	Coteau 6	Total/Avg
Injected Volumes							
Total Injected Volume[1]	96.0 Bcf (4.9 MMt)	67.2 Bcf (3.4 MMt)	96.0 Bcf (4.9 MMt)	96.0 Bcf (4.9 MMt)	73.2 Bcf (3.7 MMt)	73.2 Bcf (3.7 MMt)	501.6 Bcf (25.6 MMt)
Injection Rates							
Predicted Average Injection Rate[2]	21.9 MMcfd (1,119 t/d)	15.3 MMcfd (783 t/d)	21.9 MMcfd (1,119 t/d)	21.9 MMcfd (1,119 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	114.5 MMcfd (5,845 t/d)
Predicted Maximum Injection Rate[2]	24.6 MMcfd (1,254 t/d)	17.2 mmcfd (878 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	24.6 MMcfd (1,254 t/d)	140.0 MMcfd (7,146 t/d)
Injection Pressures							
Estimated Depth of Top Perforation (feet)[3]	5,930	5,998	5,981	5,928	5,901	5,961	5,950
Formation Fracture Pressure at Top Perforation (psi)[4]	4,210	4,259	4,247	4,209	4,190	4,232	4,224
Projected Avg Surface Injection Pressure (psi)[2]	1,628	1,597	1,644	1,604	1,682	1,677	1,639
Max Allowable Surface Injection Pressure (psi)[5]	1,976	1,998	1,993	1,975	1,966	1,986	1,982
Projected Avg Bottomhole Injection Pressure (psi)[2]	3,315	3,335	3,349	3,297	3,284	3,295	3,313
Projected Max. Bottomhole Injection Pressure (psi)[2]	3,430	3,445	3,462	3,414	3,424	3,426	3,434
Max. Bottomhole Pressure at Top Perforation (psi)[6]	3,801	3,845	3,834	3,800	3,782	3,821	3,814

1 Assumes 55 MMcfd distributed between four wells (Coteau 1–4) from July/22 thru Dec/24, 70 MMcfd distributed between these same wells Jan/25 thru Apr/26, and 140 MMcfd distributed between six wells (Coteau 1–6) from May/26 through Jun/34.
2 Per simulation modeling.
3 Top perf. assumed to be 23 ft below the top of the Broom Creek Formation in all instances based on log results from Couteau 1.
4 Based on a fracture pressure gradient of 0.71 psi/ft as calculated via CoreLabs D-Code algorithm.
5 Based on a maximum allowable BHP equal to 90% of frac pressure and a CO_2 density of 0.306 psi/ft.
6 Based on a maximum allowable BHP equalt to 90% of fracture pressure gradient at estimated depth of top perforation

	NDAC 43-05-01-05 §1b(6)	**NDAC 43-05-01-05 §1b(6)** (6) The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone and confining zone pursuant to section 43-05-01-11.2;	f. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone;	See Table 5-7 on p. 5-18 See Appendix A: WELL AND WELL FORMATION FLUID SAMPLING LABORATORY ANALYSIS	Table 5-7 (p. 5-18)
			g. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the confining zone;	See Table 5-7 on p. 5-18	
	NDAC 43-05-01-05 §1b(7)	**NDAC 43-05-01-05 §1b(7)** (7) The proposed stimulation program, a description of stimulation fluids to be used, and a determination that stimulation will not interfere with containment; and	h. The proposed stimulation program: 1. A description of the stimulation fluids to be used 2. A determination of the probability that stimulation will interfere with containment;	**11.1 Coteau 1 Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-2)** Rampart Energy (on behalf of the Dakota Gasification Company [DGC]) drilled and cased the Coteau 1 with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. The following proposed completion procedure outlines the steps necessary to complete the Coteau 1 well for injection purposes. Note: See a full procedure provided from p. 11-3.	N/A
	NDAC 43-05-01-05 §1b(8)	**NDAC 43-05-01-05 §1b(8)** (8) The proposed procedure to outline steps necessary to conduct injection operations.	i. Steps to begin injection operations	**11.1 Coteau 1 Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-2)** Rampart Energy (on behalf of the Dakota Gasification Company [DGC]) drilled and cased the Coteau 1 with intentions to conduct $CO2_2$ stream injection operations, as referenced in previous sections. The following proposed completion procedure outlines the steps necessary to complete the Coteau 1 well for injection purposes. Note: See a full procedure provided from p. 11-3.	

Mercer

NORTH DAKOTA NEWSPAPER ASSOCIATION

Affidavit of Publication

Hannah Hertz, being duly sworn, states as follows:

1. I am the designated agent, under the provisions and for the purposes of, Section 31-04-06, NDCC, for the newspapers listed on the attached exhibits.

2. The newspapers listed on the exhibits published the advertisement of: **Oil and Gas Division, Case No. 29450, 1** time(s) as required by law or ordinance.

3. All of the listed newspapers are legal newspapers in the State of North Dakota and, under the provisions of Section 46-05-01, NDCC, are qualified to publish any public notice or any matter required by law or ordinance to be printed or published in a newspaper in North Dakota.

Signed: ____________________

State of North Dakota

County of Burleigh

Subscribed and sworn to before me this 16th day of June, 2022.

Kelli Richey

KELLI RICHEY
Notary Public
State of North Dakota
My Commission Expires Oct 13, 2022

NOTICE OF HEARING
N.D. INDUSTRIAL COMMISSION
OIL AND GAS DIVISION

The North Dakota Industrial Commission will hold a public hearing at 09:00 AM Wednesday, July 20, 2022 at N.D. Oil & Gas Division 1000 East Calgary Avenue Bismarck, North Dakota. At the hearing the Commission will receive testimony and exhibits. Persons with any interest in the cases listed below, take notice.

PERSONS WITH DISABILITIES: If at the hearing you need special facilities or assistance, contact the Oil and Gas Division at 701-328-8038 by Wednesday, July 08, 2022.

STATE OF NORTH DAKOTA TO:

Case No. 29450: Application of Dakota Gasification Company requesting consideration for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Dakota Gasification Company intends to capture carbon dioxide from the Great Plains Synfuels Plant and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT July 19, 2022. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Steve Fried, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Dakota Gasification Company, 1717 East Interstate Avenue, Bismarck, ND 58503.

Case No. 29451: Application of Dakota Gasification Company to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Dakota Gasification Company storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code Section 38-22-10.

Case No. 29452: Application of Dakota Gasification Company for an order of the Commission determining the amount of financial responsibility for the geologic storage of carbon dioxide from the Great Plains Synfuels Plant in the storage facility located in Sections 5, 6, 7, 8, 17, 18, 19, Township 145 North, Range 87 West, Sections 1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 16, 22, 23, 24, Township 145 North, Range 88 West, Sections 30, 31, 32, Township 146 North, Range 87 West, Sections 25, 26, 27, 33, 34, 35, 36, Township 146 North, Range 88 West, Mercer County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.

Signed by,
Doug Burgum, Governor
Chairman, NDIC

(6-9-22)

*** Proof of Publication ***

State of North Dakota)
) SS:
County of Burleigh)

RECEIVED
JUL 22 2022
N.D. INDUSTRIAL COMMISSION

Before me, a Notary Public for the State of North Dakota personally appeared Jill Lindsay who being duly sworn, deposes and says that he (she) is the Clerk of Bismarck Tribune Co., and that the publication(s) were made through the

Bismarck Tribune on the following dates:

6/8/2022

Signed Jill Lindsay

OIL & GAS DIVISION

600 E BLVD AVE #405
BISMARCK, ND 58505

ORDER NUMBER 47874

Sworn and subscribed to before me this 20 day of July 20 22

Sharon L. Peterson
Notary Public in and for the State of North Dakota

SHARON L. PETERSON
NOTARY PUBLIC
STATE OF NORTH DAKOTA
MY COMMISSION EXPIRES NOV. 08, 2025

Section: Legals
Category: 5380 Public Notices
PUBLISHED ON: 06/08/2022

TOTAL AD COST:	117.60
FILED ON:	6/13/2022

*** Proof of Publication ***

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Signed by,
Doug Burgum, Governor
Chairman, NDIC

6/8 - 47874