NATIONAL PETROLEUM COUNCIL

Meeting the Dual Challenge

A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage

Appendix G

CO_2 Enhanced Oil Recovery Case Studies

December 12, 2019

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I. INTRODUCTION

Carbon dioxide (CO_2) enhanced oil recovery (EOR) has proven to be technically and economically viable in a variety of fields in the United States and abroad. The tools and knowledge to select and characterize reservoirs for CO_2 EOR application and to design successful projects are well established.

Three CO_2 EOR project examples are documented in this appendix, with case studies of the Denver Unit in the Permian Basin of West Texas, the Bell Creek Field in the Powder River Basin of Montana, and the Northern Niagaran Pinnacle Reef Trend in the Michigan Basin of Michigan are highlighted.

II. OXY PERMIAN DENVER UNIT

The Denver Unit is operated by Oxy and has the distinction of being the largest CO_2 EOR project in the world. The unit comprises 27,000 acres, and is the largest unit within the Wasson San Andres field. Tertiary CO_2 EOR in the Denver Unit began in 1984 with the completion of the Cortez pipeline, which supplies CO_2 from southwest Colorado. Original hydrocarbons in place for this unit included 3.16 billion barrels of oil, including residual oil zone (ROZ) volumes, and 675 billion cubic feet of free gas. Currently, the field injects 420 million cubic feet per day (MMCFD) of CO_2, including 200 MMCFD of new CO_2 and 220 MMCFD of recycled CO_2, into 609 active water-alternating-gas (WAG) injectors. The unit produces an average of 21,000 barrels of oil per day (BOPD), 249 thousand barrels of water per day, and 278 MMCFD of gas from 1,130 active producers. As of 2018, the field has safely stored more than 2.8 trillion cubic feet, or 147 million metric tons of CO_2 incidental to oil production during the CO_2 EOR operation.

A. Geology

The Denver Unit is a subdivision of the Wasson field. It is located in the southern part of the oil accumulation area. The boundaries of the Denver Unit are indicated in the Wasson field map in Figure G-1.

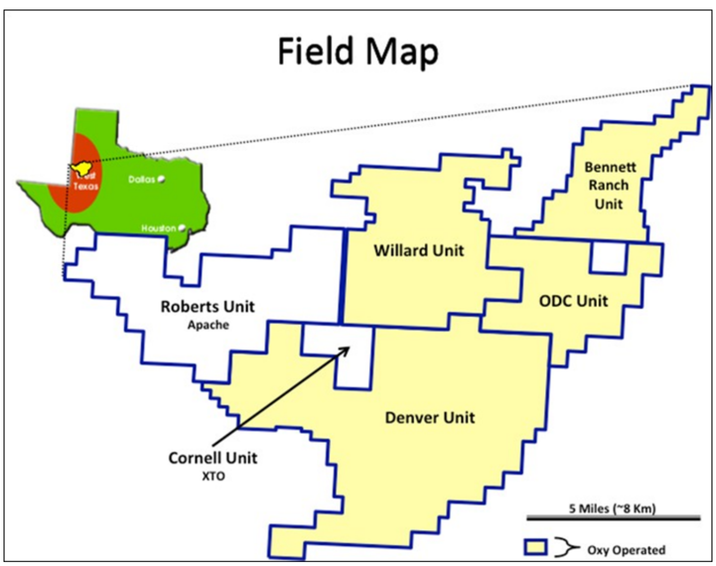

Figure G-1. *Wasson Field Map*

Source: Occidental Petroleum Corporation.

Discovered in 1936, the Wasson field is located in southwestern Yoakum and northwestern Gaines counties of West Texas in an area called the Northwest Shelf. It is approximately 5 miles east of the New Mexico state line and 100 miles north of Midland, Texas, as indicated with the red dot in Figure G-2. The field extends over a productive area of about 62,500 acres.

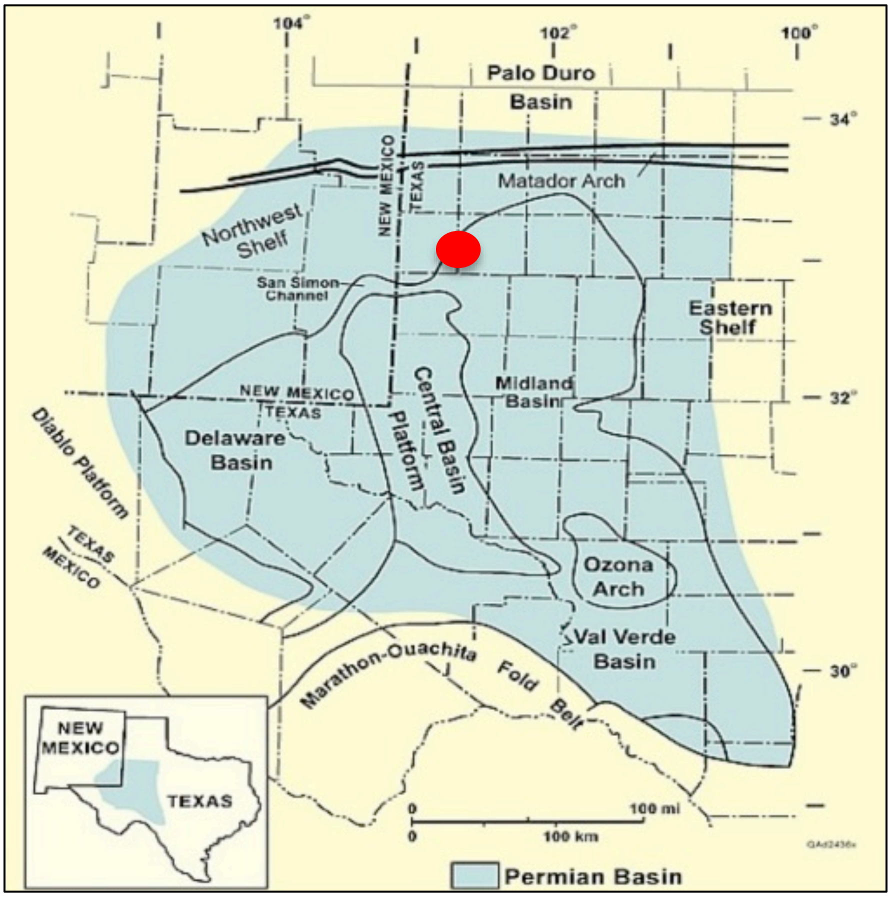

Figure G-2. *Permian Basin*
Source: Occidental Petroleum Corporation.

The Wasson field produces oil from the San Andres formation, a layer of permeable dolomites that were deposited in a shallow marine environment during the Permian period, some 250 to 300 million years ago. This depository created a wide sedimentary basin, called the Permian Basin, which covers the western part of Texas and the southeastern part of New Mexico. During the Permian period, this part of the central United States was under water. In the years following its deposition, the San Andres formation was buried under thick layers of impermeable rocks, and finally uplifted to form the current landscape. The process of burial and uplifting produced some unevenness in the geologic layers. Originally flat, there are now variations in elevation within the San Andres formation across the Permian Basin. The relative high spots, such as the Wasson field, have become the places where oil and natural gas have accumulated over the ensuing millions of years.

The San Andres formation is of Guadalupian age and exhibits several fourth-order shallowing-upward cycles (G1-G9). Deposition of the San Andres occurred along a gently dipping carbonate ramp in an open marine environment, with rapid sea level changes due to cyclic icehouse conditions. Figure G-2 is an aerial view of the structure of the Denver Unit showing the depth of the top of the San Andres. The reservoir is overlain and capped by ~600 feet of tight anhydrite tidal flat deposits, which serve as the top seal for the San Andres in the Wasson field area. In effect, these deposits form the hard ceilings of an upside-down bowl or dome. Below this seal, the formation consists of permeable dolomites containing oil and natural gas.

The reservoir rock in the San Andres is composed of dolomitized limestone, mostly wackestone to grain-dominated packstone. Average porosity of the reservoir rock in the Denver Unit San Andres is 10%, with the most common pore type being intercrystalline. With nearly 6,000 million barrels of original oil in place (OOIP), the Wasson San Andres field is one of the largest oilfields in North America.

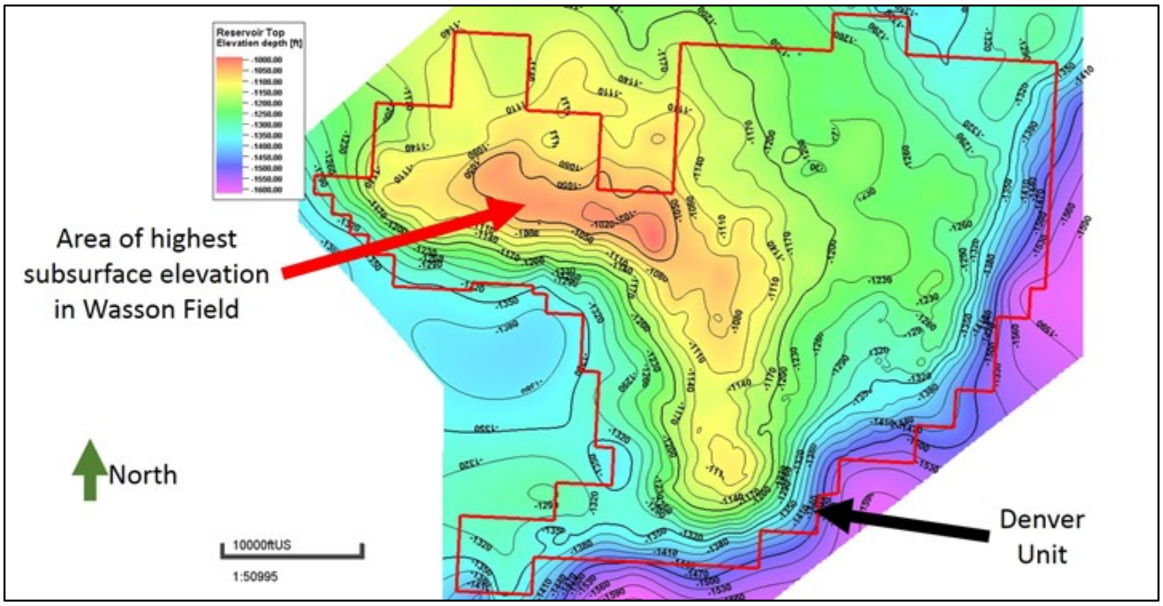

Figure G-3. *Structure Map on Top of San Andres Pay*
Source: Occidental Petroleum Corporation.

The colors in the structure map in Figure G-3 indicate changes in elevation, with red and orange being the highest levels (i.e., the horizon closest to the surface), and blue and purple being lowest levels (i.e., deepest below the surface). The detailed geology available on this map and others comes from over 1,700 well penetrations, logs and other data points collected throughout development of the field. As indicated in the structure map, the Denver Unit is located at the highest elevation of the San Andres formation within the Wasson field, forming the top of the dome. The rest of the Wasson field slopes downward from this area, effectively forming the sides of the dome. The elevated area formed a natural trap for oil and natural gas that migrated from below over millions of years. In the Wasson field, this oil and natural gas has been trapped in the San Andres formation for 50 to 100 million years. Over time, Wasson field fluids, including CO_2, would rise vertically until meeting the ceiling of the dome and then would follow it to the highest elevation in the Denver Unit.

The San Andres in the Denver Unit is divided into three zones based on fluid contacts: the gas cap, the main oil column, and the ROZ. Up until the late Tertiary, the San Andres in the Wasson field was filled past the spill point, with the San Andres outcropping in the west. During this time of subaerial exposure of the San Andres in the west, fresh water migrated from surface recharge zones and began moving eastward through the San Andres formation, forming a massive hydraulic head. Over time, the fresh meteoric water driven by the hydraulic head from the west swept large volumes of oil out of the Wasson San Andres oil column, leaving behind a ROZ with an average thickness of 200 feet in the Denver unit.

Because the ROZ has oil saturations reduced to levels that are immobile relative to water, the residual oil requires tertiary recovery techniques to be mobilized.

Buoyancy dominates the mechanisms of oil and natural gas positioning in a reservoir. Gas, being lightest, rises to the top, and water, being heavier, sinks to the bottom. Oil, being heavier than gas but lighter than water, lies in between. The cross-section in **Figure** G-4 shows saturation levels in the oil-bearing layers of the Wasson field and illustrates this principle.

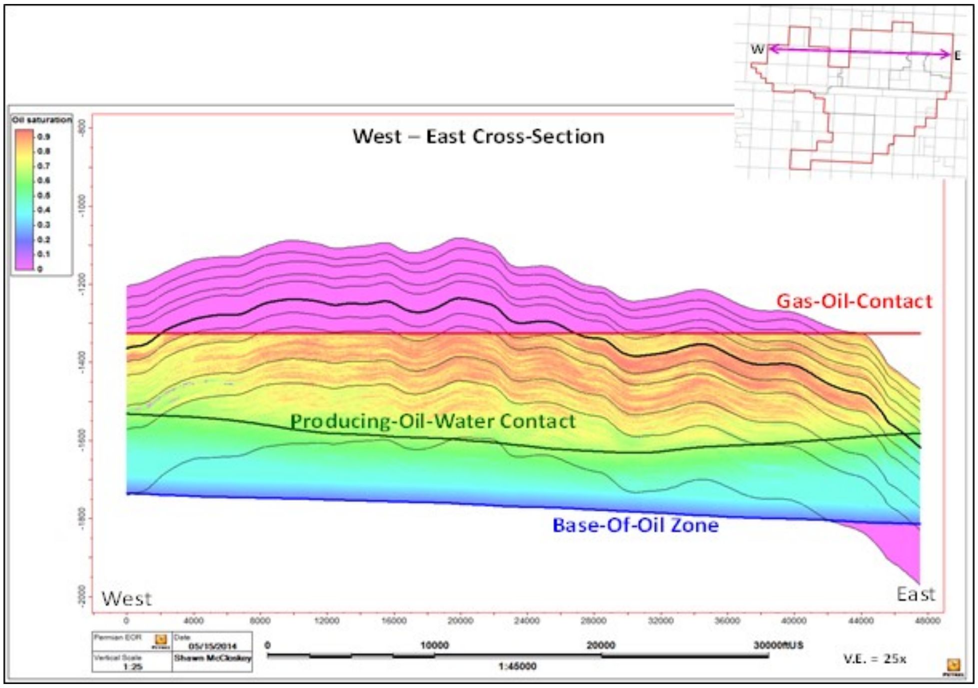

Figure G-4. *Wasson Field Cross-Section with Original Oil Saturation*
Source: Occidental Petroleum Corporation.

At the time of discovery, natural gas was trapped at the structural high point of the Wasson field, shown by the pink area above the red gas-oil contact line in Figure G-4. This interface is found approximately 5,000 feet below the surface (or at -1,325 feet subsea). Above the gas-oil interface is the volume known as a “gas cap.” The presence of a gas cap is evidence of the effectiveness of the seal formed by the upper San Andres. Gas is buoyant and highly mobile; if it could escape the Wasson field naturally through faults or fractures, it would have done so over the millennia.

Below the gas was an oil accumulation, which extended down to the producing oil-water contact (black line in Figure G-4). The producing oil-water contact (POWC) was determined through early drilling to be the maximum depth where 100% of the fluid produced was oil. The ROZ at Wasson is important in that it represents an additional CO_2 EOR target that is accessible by the relatively inexpensive deepening of existing wells. The ROZ interval is estimated to contain 2.5 billion barrels of OOIP in the Wasson field. A commercial CO_2EOR project in the ROZ is ongoing in the Denver Unit and in all other units except the Robertson Unit in the Wasson San Andres field.

B. Reservoir Development

1. Primary Production

The Denver Unit was discovered in 1936 by Shell Oil Company USA. The field produced from solution gas and gas cap drive (primary depletion) until it was unitized for waterflooding in 1964. Initial reservoir pressure was 1,850 psi, and initial solution gas/oil ratio, Rsi, was 450 standard cubic feet per barrel of oil (scf/bbl). Cumulative oil production (on primary depletion) prior to waterflood was ~10% of the original oil in place above the POWC from approximately 716 producing wells.

The free water level as defined by capillary pressure data in the Wasson field is approximately 200 feet deeper than the POWC, and it will be referred to throughout this appendix as the Paleo free water level, or PFWL. The ROZ lies between the POWC and the PFWL. This ROZ oil is a legitimate target for CO_2 EOR, but it was avoided during primary depletion and waterflood recovery because it contains no mobile oil and produces only water.

2. Waterflood

Waterflooding works most efficiently with regular patterns over a large area. The Wasson field was originally developed as numerous leases held by individuals and companies. To improve efficiency, a number of smaller leases were combined (or unitized) into larger legal entities (units), which can be operated without the operational restrictions imposed by the former lease boundaries. In 1964, six such units were formed at Wasson to enable waterflooding; the largest of these is the Denver Unit (see Figure G-1).

CO_2 flooding of the Denver Unit began in 1983 and has continued and expanded since that time. The experience of operating and optimizing the Denver Unit CO_2 flood over three decades has created a strong understanding of the reservoir and its capacity to store CO_2.

At the beginning of the waterflood, reservoir pressure was approximately 700 psi. The producing gas/oil ratio at the beginning of the waterflood was approximately 4,400 scf/bbl. The water injection project began with an injection rate of 550,000 barrels of water per day, for an injection throughput rate of 3% of the hydrocarbon pore volume per year. As reservoir pressure increased, the first clear signal of waterflood response was a dramatic decline in the producing gas/oil ratio, followed by an increase in oil production. At its peak, Denver Unit oil production was 150,000 BOPD under waterflood with 800 producers and 300 injectors.

3. CO_2 Enhanced Oil Recovery

a. Main Oil Column CO_2 EOR History

In 1978, a pilot program was implemented to evaluate the potential of enhanced oil recovery through CO_2 injection at the Denver Unit. The objectives were to assess interactions, if any, of CO_2 and water injection into a carbonate reservoir, measure CO_2 mobility compared to water, assess vertical and horizontal sweep, and determine residual oil saturation to CO_2 injection. The pilot consisted of an injector, a fluid observation well, and three logging observation wells placed about 100 feet from the injector. The configuration of the pilot wells is shown in Figure G-5.

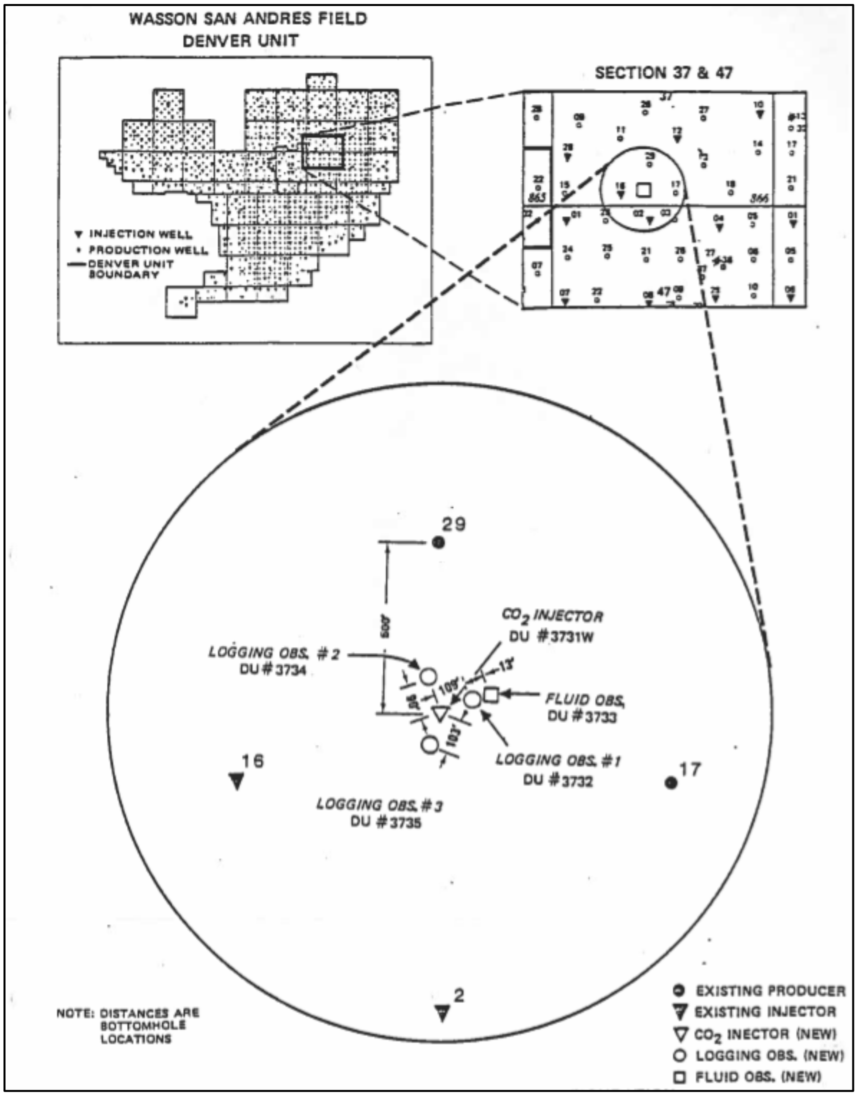

Figure G-5. *Denver Unit CO2 Flood Pilot*

Source: Occidental Petroleum Corporation.

A biweekly logging program was conducted at the observation wells to monitor the advancement of water in the pre-CO_2 injection brine flush, then of the oil bank and the CO_2. Pressurized cores were collected after the brine flush and again after a cumulative volume of 132 MMCF or 44% of the pilot area's pore volume was injected. The measured residual oil after waterflood and after the CO_2 flood are shown in Figure **G-6.**G-6. The pilot demonstrated that CO_2 enhanced oil recovery can range from 9% to 24% of the original oil in place, or 25% to 63% of the oil remaining after waterflood for the Denver Unit San Andres reservoir.

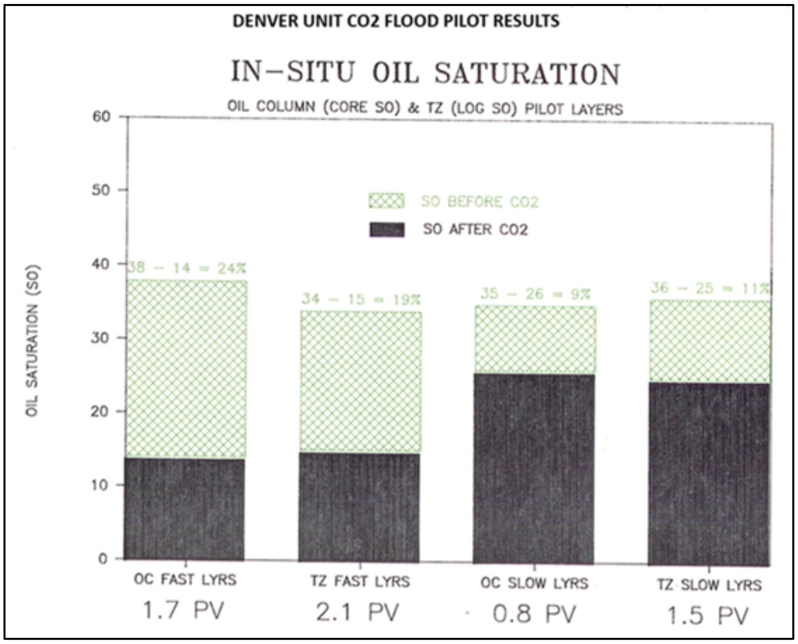

Figure G-6. *Residual Oil Saturation after CO_2 Injection from the Denver Unit CO2 EOR Pilot*

Source: Occidental Petroleum Corporation.

In 1984 upon completion of the Cortez Pipeline, CO_2 from the McElmo Dome CO_2 field in southwestern Colorado was transported to the Denver Unit at an initial CO_2 injection rate of 300 MCFD. The CO_2 project was implemented in phases, with the eastern and southern areas starting first. The initial project authorization called for a 40% hydrocarbon pore volume (HCPV) of CO_2 to be injected into all areas. As the CO_2 flood was implemented in each area of the field, patterns were standardized to 80-acre inverted nine-spots (~20 acres per well). Continuous CO_2 injection was used initially in the eastern portion of the unit, and WAG injection was done in the southern area to compare the two methods and determine the best injection process to be used for the remaining expansion areas. A 20% HCPV of continuous CO_2 injection followed by WAG injection was found to work best for the San Andres reservoir at the Denver Unit. Over a 5-year period from 1984 to 1989, the Denver Unit CO_2 project expanded from the sweet spot on the eastern side of the field, to the south and west to complete the CO_2 flood development. Figure G-7 presents the Denver Unit CO_2 flood patterns.

Cumulative enhanced oil recovery from the Denver Unit through 2018 is ~11% of the original oil in place. Associated CO_2 storage in the reservoir is more than 2.8 trillion cubic feet or 147 million metric tons. The peak oil response rate was 40,000 BOPD, and current production is approximately 21,000 BOPD. Figure G-8 depicts the Denver Unit historical production and injection data.

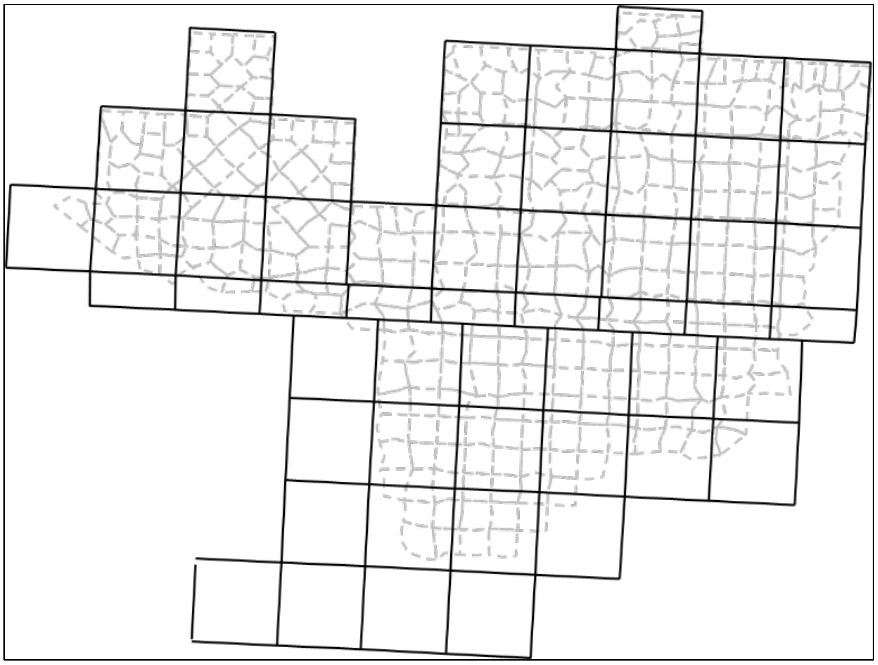

Figure G-7. *Denver Unit CO2 Flood Patterns Outline*
Source: Occidental Petroleum Corporation.

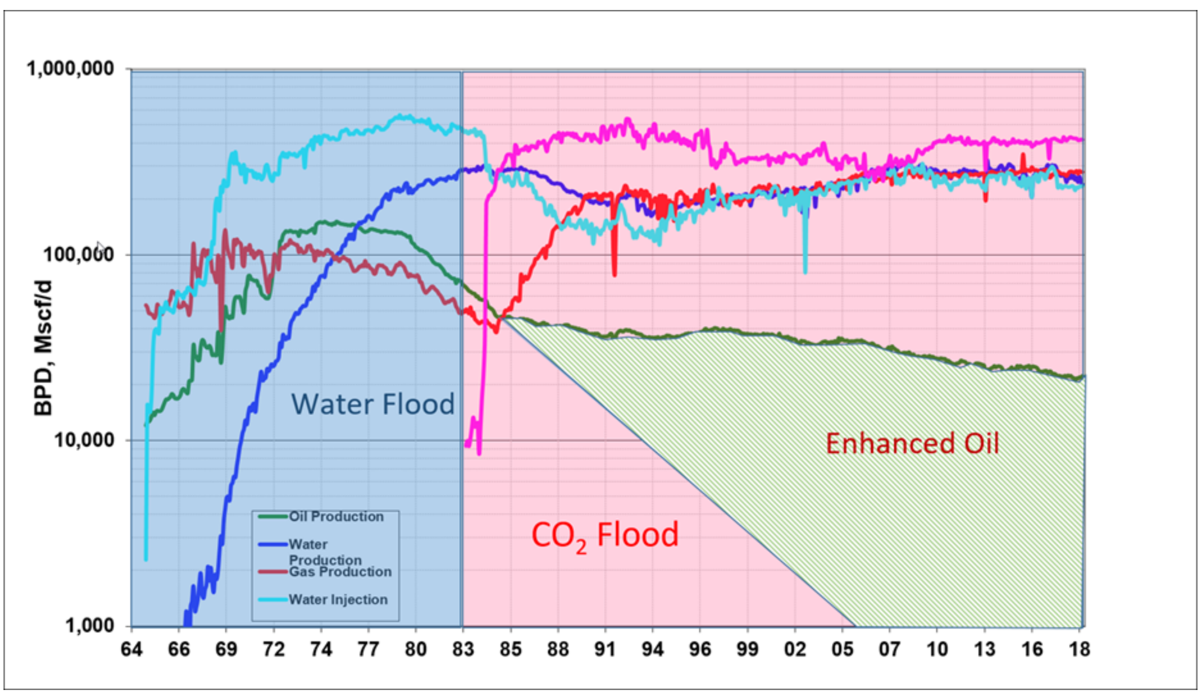

Figure G-8. *Denver Unit Historical Production and Injection*

Source: Occidental Petroleum Corporation.

b. TZ/ROZ Development

In 1992, a pilot program was developed to assess CO_2 EOR viability in the reservoir interval below the producing oil-water contact at the Denver Unit, typically referred to as the transition zone (TZ). The operator tested CO_2 recovery over a 75-feet interval below the POWC, where sponge core data indicated that residual oil saturation was above the irreducible level after a waterflood.

The pilot was a success, and full field ROZ development began as CO_2 supply became available, due to the mature main oil column (MOC) patterns being placed on the WAG injection scheme. The early TZ projects involved deepening existing injectors and producers to only 75 feet below the POWC, and TZ injection and production streams were commingled with the MOC. As full field TZ development continued, based on early successes, injectors and producers were deepened through both the TZ and ROZ, stopping short of the base of the zone. Drilling dedicated TZ/ROZ injectors was sometimes necessary to avoid preferential injection into the CO_2-flushed MOC, thereby giving the TZ/ROZ a higher chance of success technically and economically. However, the producers remained commingled with the MOC.

The TZ/ROZ CO_2 enhanced oil recovery behaves just like CO_2 EOR in the MOC, with incremental oil being produced from a previously water swept zone, because the TZ/ROZ interval had simply been waterflooded naturally over geologic time.

C. Denver Unit Facilities and Closed Loop Process

New CO_2 is delivered to the Wasson field via the Permian pipeline delivery system. Once CO_2 enters the Denver Unit, it becomes part of a closed loop system within three main EOR processes and becomes stored incidental to the overall EOR operation. These processes include CO_2 distribution and injection, produced fluids handling, produced gas processing, and water treatment and injection. These processes are described in the following sections:

1. CO_2 Distribution and Injection

New CO_2 is combined with recycled CO_2 from the Denver Unit CO_2 Recovery Plant (DUCRP) and sent through the main CO_2 distribution system to various CO_2 injectors throughout the field.

New CO_2 and recycled CO_2 are combined and sent through the CO_2 trunk lines to injection manifolds. These manifolds are complexes of pipes that have no valves and do not exercise any control function. At the manifolds, the CO_2 is split into multiple streams and sent through distribution lines to individual WAG skids. Currently, the Denver Unit has 16 injection manifolds and 609 injection wells. As of 2019, 420 million standard cubic feet of CO_2 is injected each day, of which approximately 47% is new, and the balance (53%) is recycled.

Each injection well has an individual WAG skid located near the wellhead (typically 150 to 200 feet away). WAG skids are remotely operated and can inject either CO_2 or water at various rates and injection pressures, as specified in the injection plans. The length of time spent injecting each fluid is a matter of continual optimization, designed to maximize oil recovery and minimize CO_2 utilization in each injection pattern. The WAG skid control system consists of a dual-purpose flow meter used to measure the injection rate of water or CO_2, depending on what is being injected as defined from a control center.

2. Produced Fluids Handling

As injected CO_2 and water move through the reservoir, a mixture of oil, gas, and water (referred to as "produced fluids") flows to the production wells where the fluids mixture is produced to the surface. Gathering lines bring the produced fluids from each production well to satellite tank batteries. The Denver Unit has 1,120 production wells, and production from each is sent to one of 32 satellite tank batteries, each containing a large vessel that performs a gas-liquid separation. Each satellite battery also has well test equipment to measure production rates of oil, water, and gas from individual production wells.

The gas phase, which is approximately 80% to 85% CO_2, is transported by pipeline to DUCRP for processing.

The water/oil (liquid) mix is sent to one of six centralized tank batteries, where the oil is separated from the water. Produced oil is metered and sold; the water is sent to a water treatment facility. Any gas released from the liquid phase rises to the top of the tanks, as part of the closed loop system, and is collected by a vapor recovery unit, which compresses the gas and sends it to DUCRP for processing.

3. Produced Gas Processing

The hydrocarbon natural gas and CO_2 gas mixture separated at the satellite and centralized tank batteries goes to the DUCRP where the natural gas (NG), natural gas liquids (NGL), and CO_2 streams are separated. The NG and NGL move to commercial pipelines for sale. The remaining CO_2 is recycled within the closed loop system through the CO_2 distribution system for reinjection around the field, where it becomes trapped in the reservoir.

D. Monitoring

Oxy reports the amount of anthropogenic CO_2 it receives at the Denver Unit under Subpart RR of the Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program, in order to quantify the amount of CO_2 that is stored during CO_2 EOR operations. The Denver Unit has in place a monitoring, reporting and verification plan, which describes the operations, the monitoring program, and its CO_2 material balance quantification process. This plan has been approved by the EPA.

E. Summary

CO_2 EOR has successfully enhanced the recovery of hydrocarbons from the well characterized natural geologic trap in the Denver Unit while inherently storing CO_2 in that same geologic system continuously since CO_2 EOR operations were begun in 1984. To date, more than 2.8 trillion cubic feet, or 147 million metric tons of CO_2 have been stored in the reservoir of the Denver Unit. This project encompasses CO_2 EOR and associated storage in not only the main oil column of the field, but also in the transition zone and residual oil zone areas with equal success.

III. DENBURY BELL CREEK FIELD

The Bell Creek oil field is in southeastern Montana near the northeastern edge of the Powder River Basin (Figure G-9). The Bell Creek unit is operated by Denbury Resources. The field has been under CO_2 flood since May 2013, and under some form of development for nearly 60 years prior to that. Oil has been produced in the field via primary, secondary (waterflood), and now tertiary (CO_2 EOR) recovery methods. The cumulative recovery prior to CO_2 flooding is 135 million barrels (38.2% of original oil in place). CO_2 flooding through 2018 has recovered nearly 6 million barrels of incremental oil production through injection of more than 180 billion cubic feet of CO_2 (10 million tons).

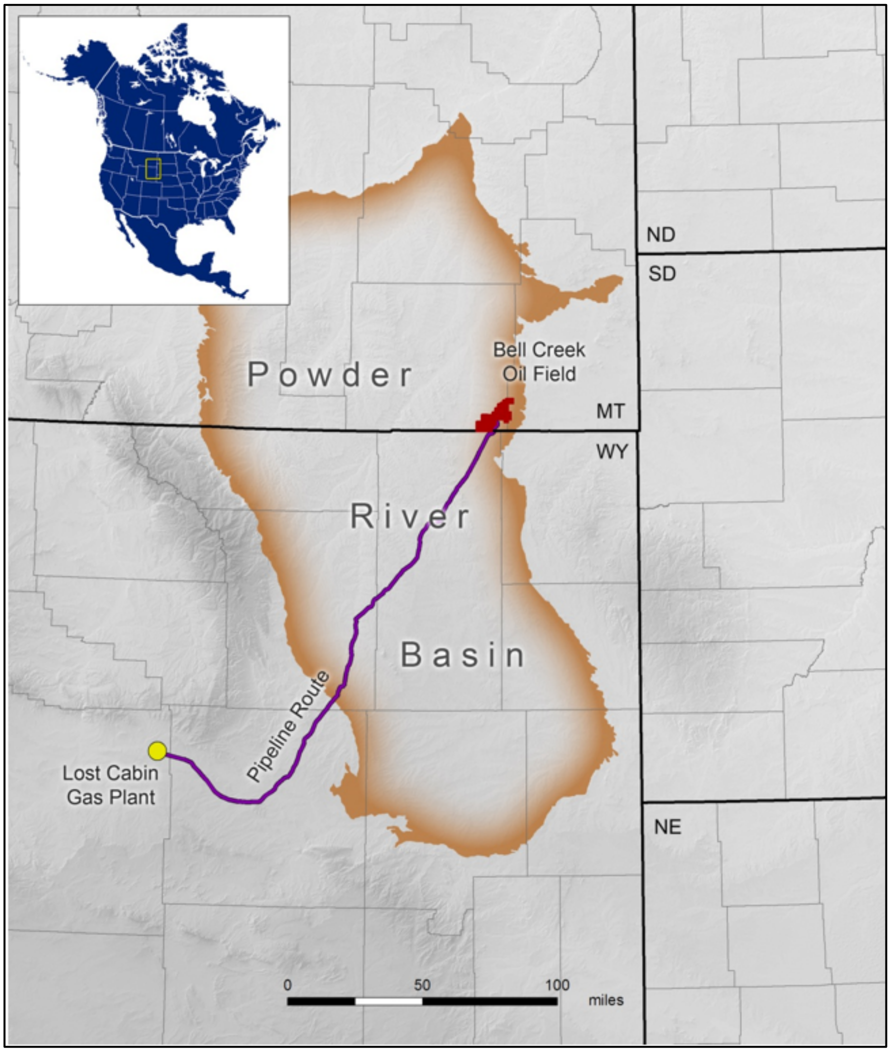

Figure G-9. *Regional View of Bell Creek in Relation to Lost Cabin Gas Plant*

Source: Denbury Resources.

A. Geology

The producing formation in Bell Creek is the Lower Cretaceous Muddy (Newcastle) formation at a depth of 4,300 to 4,500 feet. The Muddy formation is characterized by clean, high-porosity (25% to 35%), and high-permeability (100 to 1175 md) sandstones deposited in a nearshore marine environment. The Muddy formation in Bell Creek features an updip facies change from sand to shale that serves as a trap. The estimated original oil in place is 353 million barrels distributed between three main pay sands: B10, BC20, and BC30. The field is split up areally into phases that are stratigraphically defined in most cases by erosional channels and reservoir quality transitions. The primary seal for the formation is provided by the overlying Mowry shale formation. On top of the Mowry shale are several thousand feet of low-permeability shale formations, including the Belle Fourche, Greenhorn, Niobrara, and Pierre shales, which provide redundant layers of protection in the unlikely event that the primary seal fails (Figure G-10).

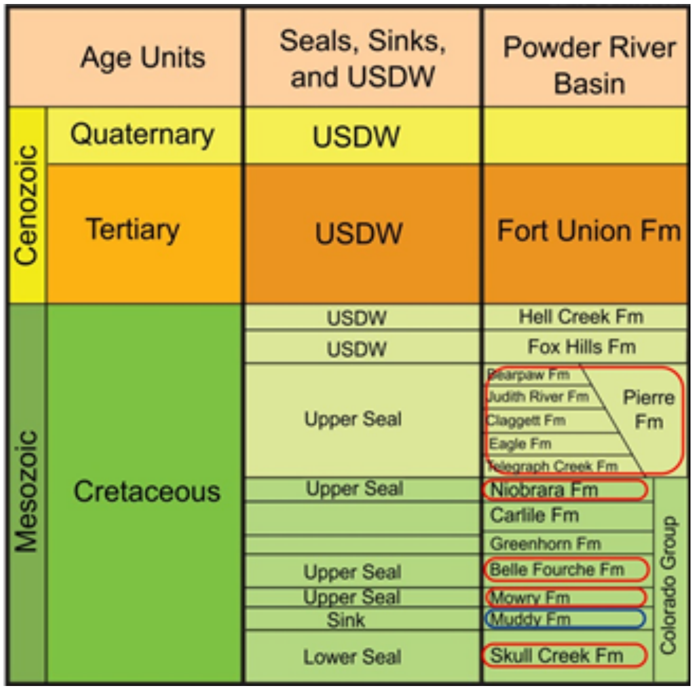

Figure G-10. *Geologic Description of Reservoir and Overlying Formations*
Source: Denbury Resources.

The reservoir is subnormally pressured with an initial reservoir pressure of only 1,200 pounds per square inch (psi) (hydrostatic pressure for this horizon would be 2,100 psi). The CO_2 miscibility pressure is estimated at 1,342 psi, as per slim tube and PVT study results. The field is currently operated at 3,100 psi to keep CO_2 in the dense phase and the EOR process largely miscible. The pressure is well below the fracture pressure of the reservoir and overlying seal. This operating pressure also allows the wells to flow, reducing the requirement for artificial lift.

B. Reservoir Development

Bell Creek CO_2 flood was developed in nine phases that covered the areal extent of the unit (Figure G-11). The initial development areas (Phases 1 through 4) were developed at 80-acre pattern spacing with five-spot pattern orientation (injector located in the center of four producers). A combination of previous existing wells and new drills were used to complete the patterns, and most of the OOIP in each of the phases is covered with patterns.

The central injector in each pattern is set up to inject either CO_2 or water. The producers do not have artificial lift equipment because the field is kept at elevated reservoir pressure and therefore the wells flow naturally. The field achieved this elevated reservoir pressure through fill-up with water injection once the injection wells were in place.

Phases 5 and 6 are the most recent developments. They are also completed with five-spot patterns but are more widely spaced at 160 acres. The Phase 5 development recently responded to CO_2 injection, and the Phase 6 development is underway with first injection expected to start in Q1 of 2019. Phases 5 and 6 are more centrally located in the field and represent the areas with some of the highest expected recoveries (and best rock qualities). Additional development phases will be brought online as compression capacity becomes available.

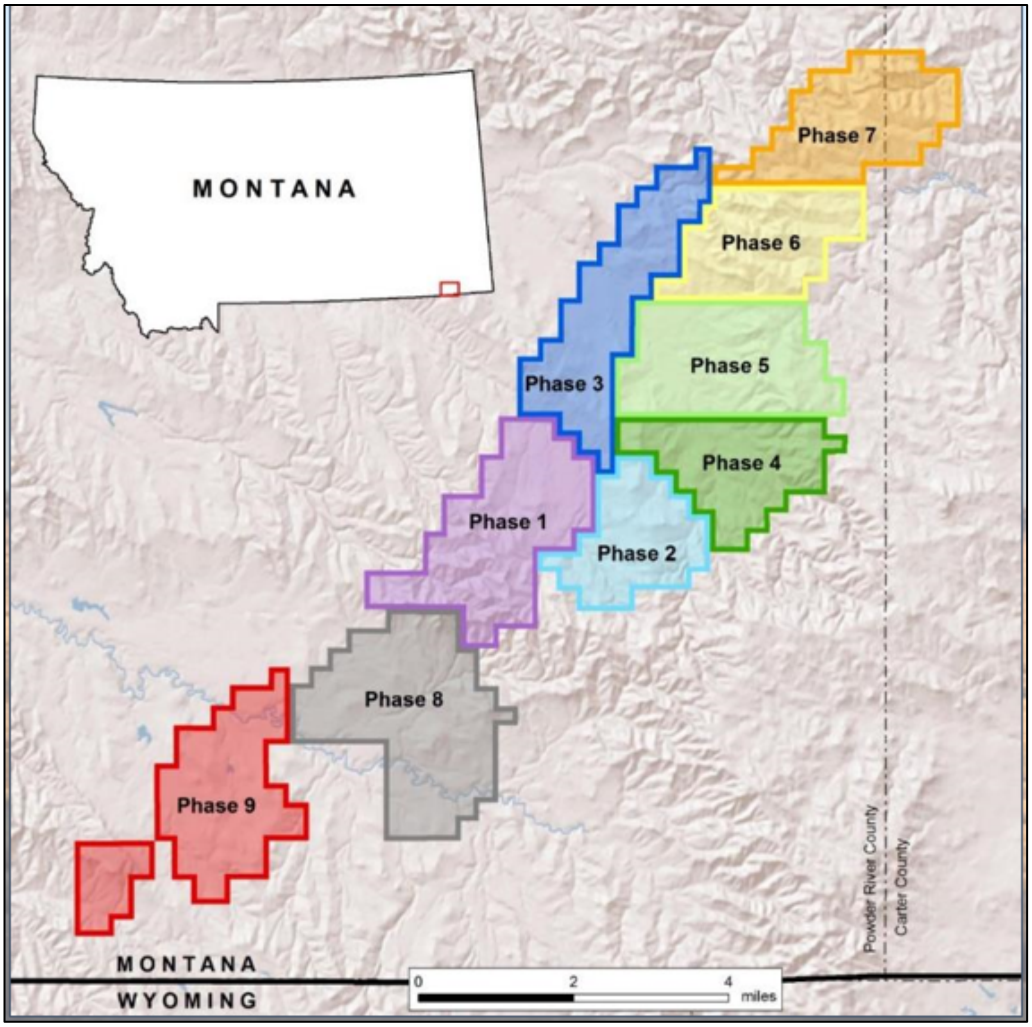

Figure G-11. *Phases of Development at Bell Creek*
Source: Denbury Resources.

C. CO_2 Supply

The CO_2 for field injection is from the ExxonMobil LaBarge gas plant and the ConocoPhillips Lost Cabin gas processing plant in Wyoming. Total CO_2 delivered to the field is approximately 115 million cubic feet per day. The Lost Cabin facility initially generated about 50 million cubic feet per day, but declined to a rate of 35 million cubic feet per day by the end of 2018. The CO_2 is transported to the site via a 232-mile pipeline and is compressed to 2200 psi for injection. New CO_2 acquired to date is more than 180 billion cubic feet. New CO_2 acquisition is scheduled to continue at declining rates as the field matures and full development is reached. An ultimate CO_2 volume of 220 billion cubic feet (12 million tons) is estimated to remain in the field at project completion.

D. CO_2 System Material Balance

A key element to demonstrating containment of CO_2 in an EOR process is through the identification of incoming, injected, and any emitted gasses. Figure G-12 illustrates this process and includes the values for the Bell Creek process in 2018. All values in the figure are in billion cubic feet.

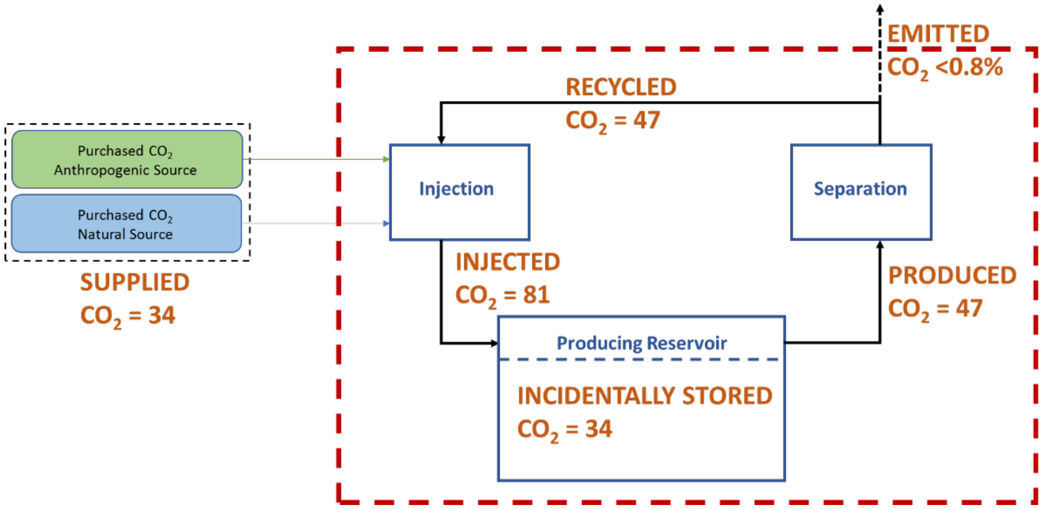

Figure G-12. *Material Balance of the CO2 System at Bell Creek*

Source: Denbury Resources.

The accounting of the system indicates that less than 0.8% of the CO_2 supplied to the Bell Creek EOR system is emitted to the atmosphere. The closed loop system allows for the gas to be produced, compressed, and reinjected for additional oil recovery.

E. PCOR Partnership

The Plains CO_2 Reduction (PCOR) Partnership, led by the Energy & Environmental Research Center (EERC) and supported by the Department of Energy, is working with Denbury Onshore LLC (Denbury) to determine the effect of a large-scale injection of CO_2 into a deep clastic reservoir for simultaneous CO_2 enhanced oil recovery (EOR) and associated or incidental CO_2 storage at the Bell Creek oil field.[1] Denbury owns and operates the field, while a technical team that includes Denbury, the EERC, and others conducts a variety of activities to determine baseline reservoir characteristics, build out the development plan and frame out a testing program for monitoring strategies around the EOR activities. The partnership with PCOR should also extend the learnings from site characterization, risk assessments and monitoring programs to applicability in other EOR or deep saline formation projects.

1. Site Characterization, Modeling and Simulation

The more than 60 years of development and operational performance at Bell Creek offer a wealth of well, geologic, and dynamic production and injection data to a build a thorough site characterization. This characterization is undertaken at a variety of levels from regional, field level, and phase level. These levels allow for different reference frames that may emphasize different characteristics.

Regional site characterization involves review of other Muddy fields in the Powder River basin and any characteristics of Bell Creek that may be transferrable. This level of analysis also involves reviewing the extent of the Mowry shale seal and other overlying shale layers. The field level characterization integrates the geologic information into a full field geomodel that honors the log, seismic, and core data. This

[1] Hamling, J.A, Gorecki, C.D, Klapperich, R.J., Saini, D., and Steadman, E.N. (2013). "Overview of the Bell Creek combined CO2 storage and CO2 enhanced oil recovery project," Greenhouse Gas Control Technologies.

geologic model covers the target Muddy formation and incorporates the stratigraphic features that may bank or trap CO_2.

The field level model is integrated with all the well perforations and dynamic data to build a simulation history match. Because the field is so large, this simulation history match is undertaken by development phase level. The first two phases (Phase 1 and 2) were completed as a connected geomodel as the pressure data indicate that the two phases communicate and exchange fluids. Integration of the dynamic data increases the likelihood of proper characterization and gives more clarity to the key drivers of success.

Site characterization is further enhanced by the gathering of pre-injection baseline information at the surface and near-surface levels to understand the fluctuations of natural CO_2 present in the soil, air, and water. The data gathered can help clarify whether CO_2 operations have impacted surface conditions. Site characterization is a foundational step in the progressing of a CO_2 EOR project that also confirms associated CO_2 storage.

Time and energy spent on this step can improve project economic viability while pointing to key early indicators of success or challenge.

2. Risk Assessment and Mitigation

Risk assessment plays and integral role in the formation of effective site characterization and monitoring plans. Identification of risks helps the operator tailor the monitoring plan to areas with greatest uncertainty. Primary risks identified for the Bell Creek CO_2 project include wellbore leakage, out-of-zone fluid migrations, and early breakthrough or CO_2 channeling during the injection project.

Bell Creek has more than 450 wellbore penetrations that could provide potential pathways for CO_2 out of the target zone. Periodic collection and analysis of soil gas, surface water, and groundwater samples, along with continuous pressure monitoring at active injection and production wells, will allow for the early identification of potential injectivity or wellbore integrity issues. These anomalies can then be addressed via remediation activities, if necessary.

Out-of-zone flow, whether laterally or vertically, results in storage retention and economic challenges for the project. If CO_2 is not staying in the designated target zone, it is not being used effectively or economically. Early simulation work and detailed geomodeling enables a development team to build a plan that minimizes the likelihood of this occurrence. Incorporation of previous flood history (including waterflood and the polymer flood pilots) helps to increase the voracity of the modeling process. Baseline and periodic monitoring can provide early indicators to potential issues. The techniques used at Bell Creek include #repeat 3D seismic surveys over time (also called 4D seismic), pressure and temperature data, and pulsed neutron lifetime (PNL) logs to quantify near wellbore fluid saturations.

Early breakthrough represents a challenge to flood's economic performance as it limits contact of the CO_2 with the remaining oil saturation, thereby reducing the efficiency of the flood. Early breakthrough can be monitored with the same methods as out-of-zone flow with emphasis on production pressure, temperature and gas flow rates as key indicators. Early breakthrough risks can be somewhat mitigated by utilization of a WAG injection process, where water is injected in alternating cycles with CO_2 injection into the same well. The injected water cycles serve to "plug" off higher permeability zones and redirect the CO_2 to lower permeability zones with often higher residual oil saturations. WAG has been implemented in all phases of Bell Creek and supports better utilization of the CO_2 limited volumes that are available for injection.

3. Monitoring Plan

The monitoring plan for Bell Creek was developed to address findings from risk assessment and site characterization processes. A wide variety of techniques have been employed to test a range of technologies for this application. The plan includes a program of baseline monitoring followed by periodic repeat surveys and updates to test the integrity of the project.[2]

Monitoring techniques cover the range from surface to the reservoir formation at 4,500 feet (Figure G-13). Surface monitoring technologies include groundwater wells, surface water samples, and soil gas profile stations and probes. Surface monitoring data must identify and quantify baseline CO_2 concentrations (and fluctuations) under normal conditions so that any operational variances to this baseline may be detected. To date, no variances in baseline CO_2 concentrations have been observed as a result of Bell Creek CO_2 EOR flood operations.

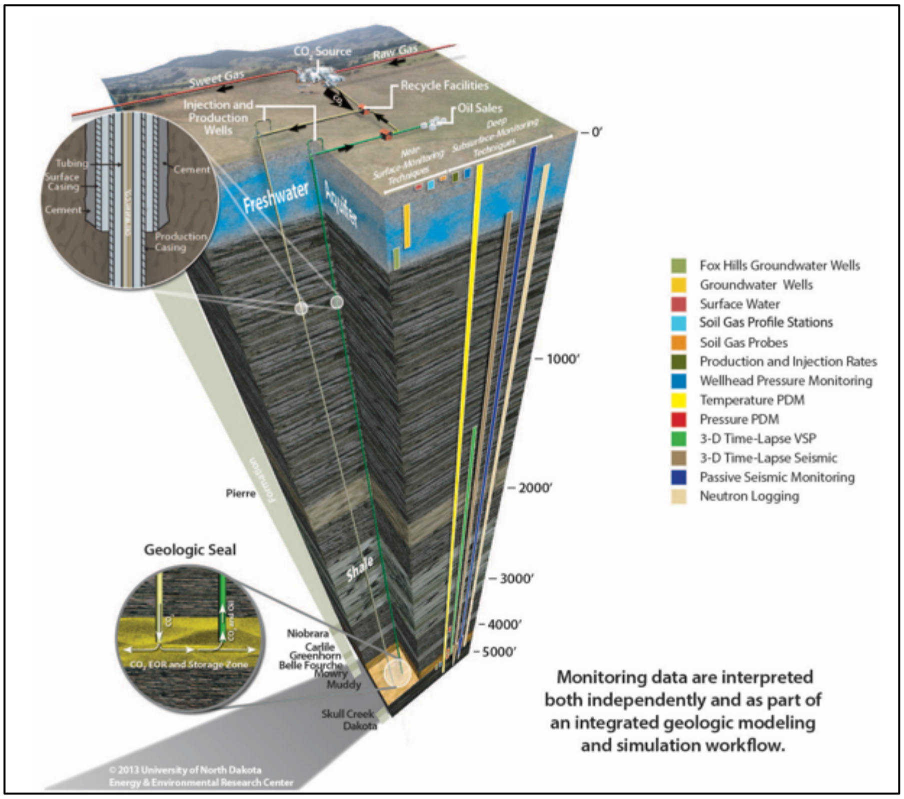

Figure G-13. *Illustration of Monitoring Techniques at Bell Creek*

Source: Energy & Environmental Research Center.

Surface and subsurface monitoring is a standard practice of oil and natural gas operations, undertaken for a variety of reasons including economic, environmental, safety, and regulatory. While the partnership with PCOR at Bell Creek enabled testing of newer monitoring technologies, it did not change the fundamental focus of the monitoring activities—to ensure that the CO_2 injected stays in the reservoir and used as efficiently as possible in the oil recovery process. The surface and subsurface monitoring techniques employed include wellhead pressure, production and injection rates, neutron logs, 3D seismic (initial and time-lapse), and one monitoring well. This combination of the data yields information on the

[2] Gorecki C. D., Hamling J. A., Klapperich R. J., Steadman E. N., and Harju J. A. "Integrating CO_2 EOR and CO_2 storage in the Bell Creek oil field," Carbon Management Technology Conference Paper 151476, February 2012.

areal and vertical location and characteristics of the CO_2 flood front and identifies production wells that are affected by CO_2 breakthrough at the wellbore.[3]

Many of the monitoring strategies utilized at Bell Creek and other typical oil and natural gas operations will have direct application in carbon capture, use and storage activities as well, whether it be associated or incidental storage resulting from CO_2 EOR operations, or dedicated CO_2 storage in deep saline formations.

F. Summary

Denbury anticipates that the Bell Creek field will recover between 30 and 50 million barrels of oil through application of CO_2 EOR over the project life, for an incremental 8% to 14% of original oil in place[4] as a result of injection of more than 13 million tons of CO_2 over the project's life.

The project is providing a means to test and validate a range of site characterization, risk analysis, and monitoring techniques, methods and techniques that will be useful in ensuring the long-term and secure storage of CO_2 that is incidentally trapped as part of the project.

IV. CORE ENERGY MICHIGAN NORTHERN NIAGARAN PINNACLE REEF TREND

Core Energy LLC (Core Energy) operates an integrated CO_2 capture and EOR facility in the upper north portion of Michigan in what is known as the Northern Niagaran Pinnacle Reef Trend (NNPRT) (Figure G-14). The Core Energy facility includes equipment to capture CO_2 from various sources nearby, dedicated pipelines to deliver the CO_2 to the field and wells, a set of subsurface geologic reef formations, and equipment to process oil.

The Core Energy CO_2 EOR facility includes a total of 10 subsurface reef reservoirs that are in various stages of development. Core Energy has already produced 2.45 million barrels of oil and incidentally stored 46.08 billion cubic feet of CO_2 (2.42 million metric tonnes). The company estimates that as many as 250 million additional barrels of oil could be economically recovered through CO_2 EOR, and there is the potential to store hundreds of millions of tonnes of CO_2 through ancillary CO_2 EOR storage across the state of Michigan. Core Energy anticipates that it will be limited in the future by the amount of available CO_2, not by the amount of economically viable CO_2 EOR opportunities.

A. Geology

The NNPRT is part of an extensive paleo shallow shelf carbonate depositional system that forms a circular belt along the platform margin that rings the Michigan Basin. Most of the oil- and gas-producing reefs along the NNPRT are at depths of approximately 3,500 to 5,500 feet. While individual reef complexes are localized (averaging 50 to 400 acres in projected surface area), they may be up to 2,000 acres in total areal extent and 150 to 700 feet in vertical relief with steeply dipping flanks. Reef height, pay thickness, burial depth, and reservoir pressure increase toward the basin center.[5] Currently, there are approximately 800 fields in the NNPRT and another approximately 400 in the Southern Niagaran Pinnacle Reef Trend of the Michigan Basin.

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[3] Gorecki, Charles. (August 2016). "Plains CO_2 Reduction Partnership: Bell Creek Field Project." Mastering the Subsurface Through Technology Innovation & Collaboration: Carbon Storage & Oil & Natural Gas Technologies Review Meeting.

[4] Peck, Wes. (April 2016). "Implementing Carbon Capture and Storage: An Overview of the Plains CO_2 Reduction Partnership's Bell Creek Project," North American Energy Minsters Trilateral Meeting.

[5] Gill 1979

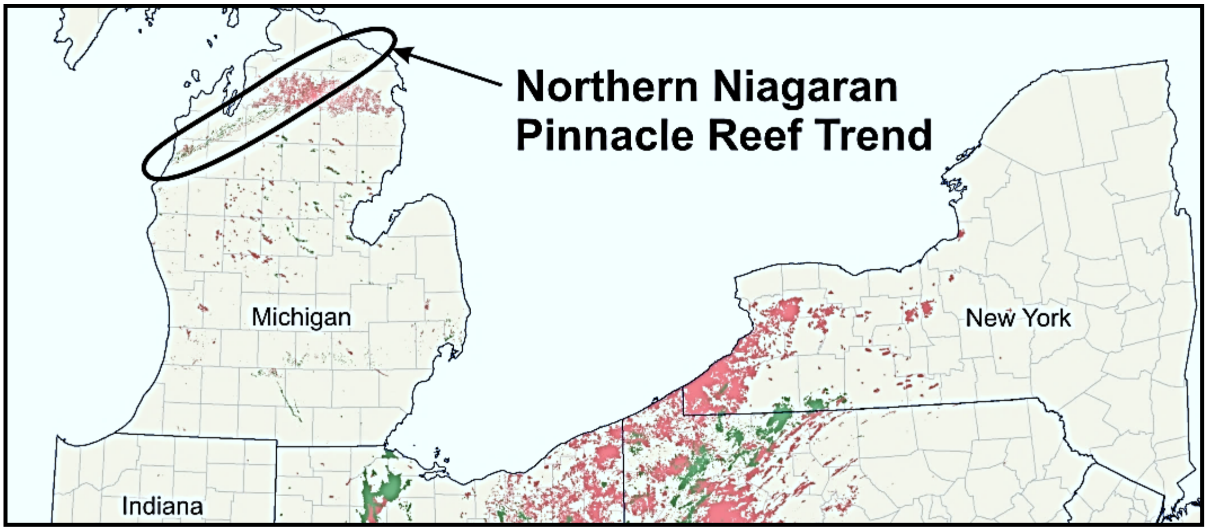

Figure G-14. *General Location of Core Energy Operations*
Source: Core Energy LLC.

The NNPRT is generally divided in then updip direction into gas, oil, and water-saturated zones. The reservoir facies consist primarily of porous and permeable dolomite and limestone. Some reefs are completely dolomitized, while others are essentially all limestone. Dolomitization of reefs increases as the reefs become shallower, and salt and anhydrite plugging of porosity occurs in the deeper reefs.[6] Effective porosity intervals for the reservoir range from only a few feet to several hundred feet from reef to reef and location within the Trend. Porosity values extend to 35%, but typically average 3% to 12%; the best porosity and permeability are associated with dolomitized reef core and flank facies. The best reservoir rocks are characterized by well-developed intercrystalline and vuggy porosity with average permeability values of 3 to 10 millidarcies. Secondary porosity can significantly enhance permeability within the reservoir. The seals for the Niagaran reefs consist of a series of evaporites and salt-plugged carbonates that encase the flanks and top of the reefs, forming regional seals over the entire reef complex.

Figure G-15 illustrates the internal structure and geometry of reefs as well as their development cycle. This knowledge is important for predicting areas of best reservoir within the reef. The building of a Niagaran reef was initiated by carbonate mud-rich bioherm accumulation in warm, calm, shallow waters. The bioherm grew as sea level rose, following the prime conditions where biohermal organisms thrive (Stage 1). As sea level continued to rise, the reef core developed, dominated by corals and stromatoporoids. The wind direction during time of reef building was important because it created asymmetry within the reef.[7] The windward direction developed reef rubble where pieces of the reef core broke off and reduced in size by wave water impact. The leeward side developed a muddy detrital grain apron as fine-grained material sloughed off the reef (Stage 2). When relative sea level stabilized, stromatolitic algal caps formed over top of the reef and created an intertidal, depositional environment. Next, as sea level fell within the Michigan Basin, the reef complex was exposed (Stage 3), and the living reef was killed. Evaporites such as salt and anhydrites were deposited along the flanks of the reefs and diagenesis occurred within the reef core. As post-Niagaran sea level rose and fell, layers of carbonates and evaporites were deposited over the reef complex (Stage 4).

6 (Gill 1979)

7 Rine 2015

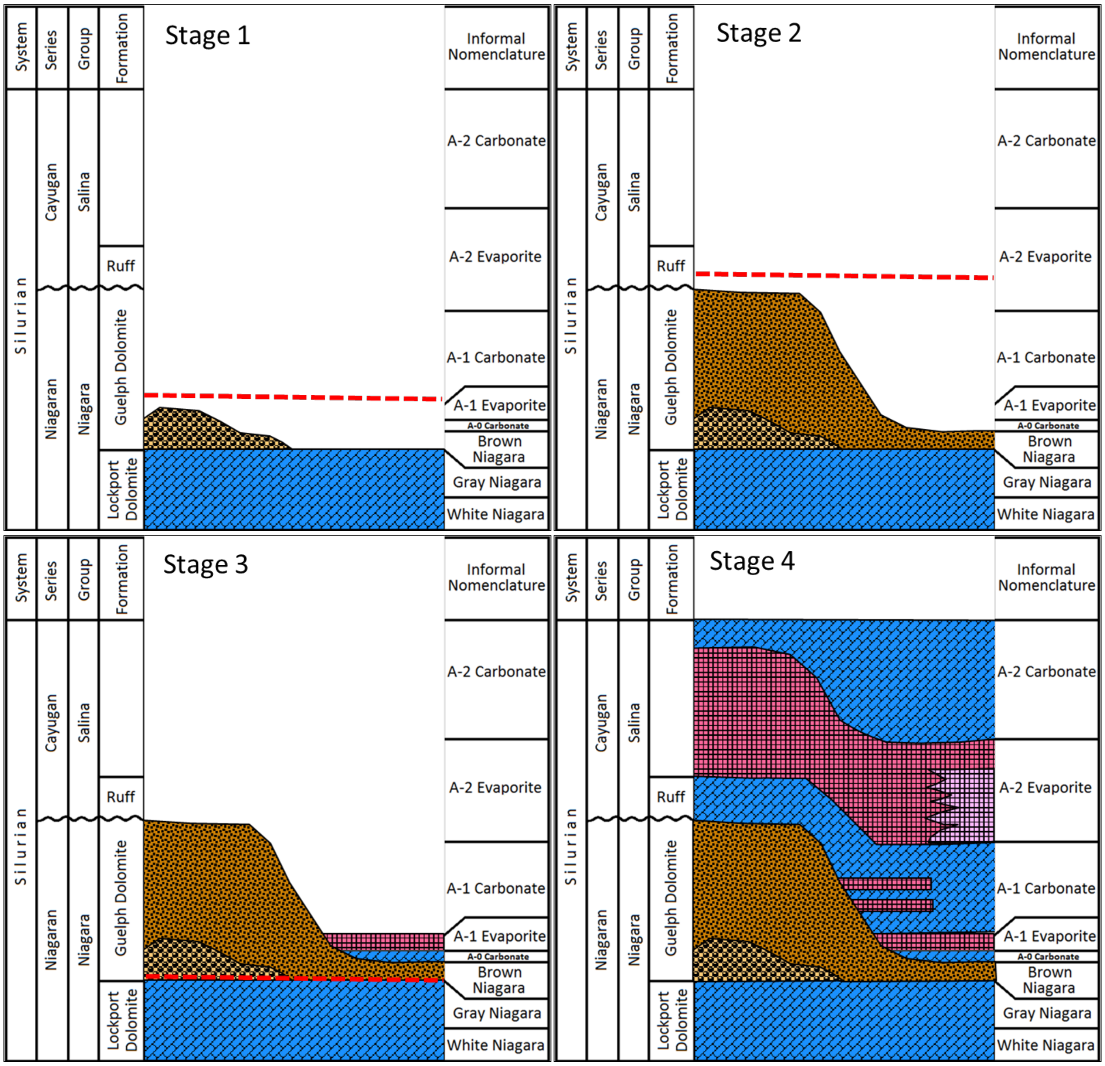

Figure G-15. *Simplified Diagrams of the Stages of Niagaran Reef Development (Red dashed line denotes approximate sea level relative to reef growth.)*

Source: Core Energy LLC.

B. Field Development

The NNPRT reefs were originally developed in the 1970s to 1980s and have undergone primary production and, in some cases, secondary recovery through water flood and other methods. After primary production in the reefs, secondary recovery methods were tried on a limited basis and abandoned due to limited success. In the late 1990s, CO_2 flooding was initiated in two reefs. In 2003, Core Energy was founded and took over operations in these two reefs. Since then the company has revitalized oil production from these reefs through application of CO_2 EOR.

The drive mechanisms for the reef reservoirs under primary recovery is pressure depletion and the development of secondary gas caps. When CO_2 is injected into the reefs, it contacts the oil trapped in the pore space while simultaneously increasing the reservoir pressure from its depleted level toward the initial reservoir pressure. As contact and reservoir pressure increase, the minimum miscibility pressure for CO_2 in this oil is exceeded, and the CO_2 becomes miscible with the oil, improving its flow toward a designed production well. Figure G-16 illustrates the CO_2 EOR process in a reef field for a CO_2 injection well and the associated production well. Figure G-17 shows the reefs currently operated by Core Energy. Core Energy continues to explore and develop new reefs in the NNPRT.

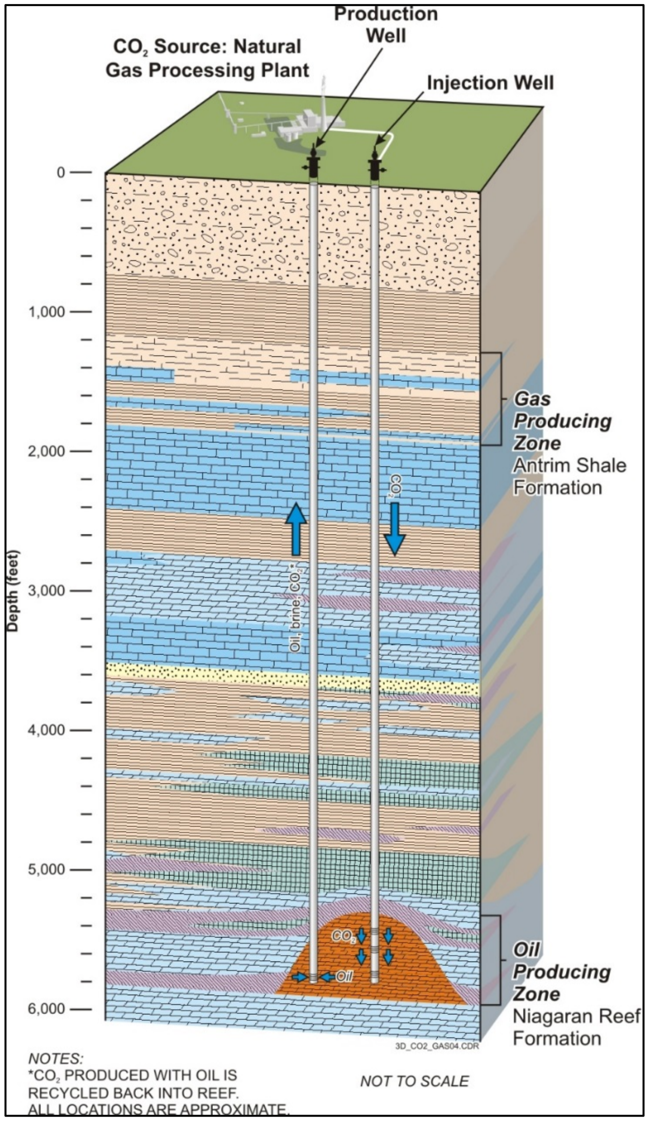

Figure G-16. *Simplified Diagram Illustrating CO2-EOR Process in a Reef*

Source: Core Energy LLC.

C. CO_2 Supply

The original source of CO_2 for the Core Energy EOR Facility is a natural gas processing facility that treats gas produced from the Antrim Shale, as indicated at a depth of approximately 1,800 feet, also in Figure G-17. This source of CO_2 is expected to continue to be available and operating for another 10 to 20 years, depending on market conditions. Therefore, Core Energy is exploring options for new sources of CO_2, even as it exploits the flexibility inherent in the modular structure of its EOR facility to take as much CO_2 as it can from the current source.

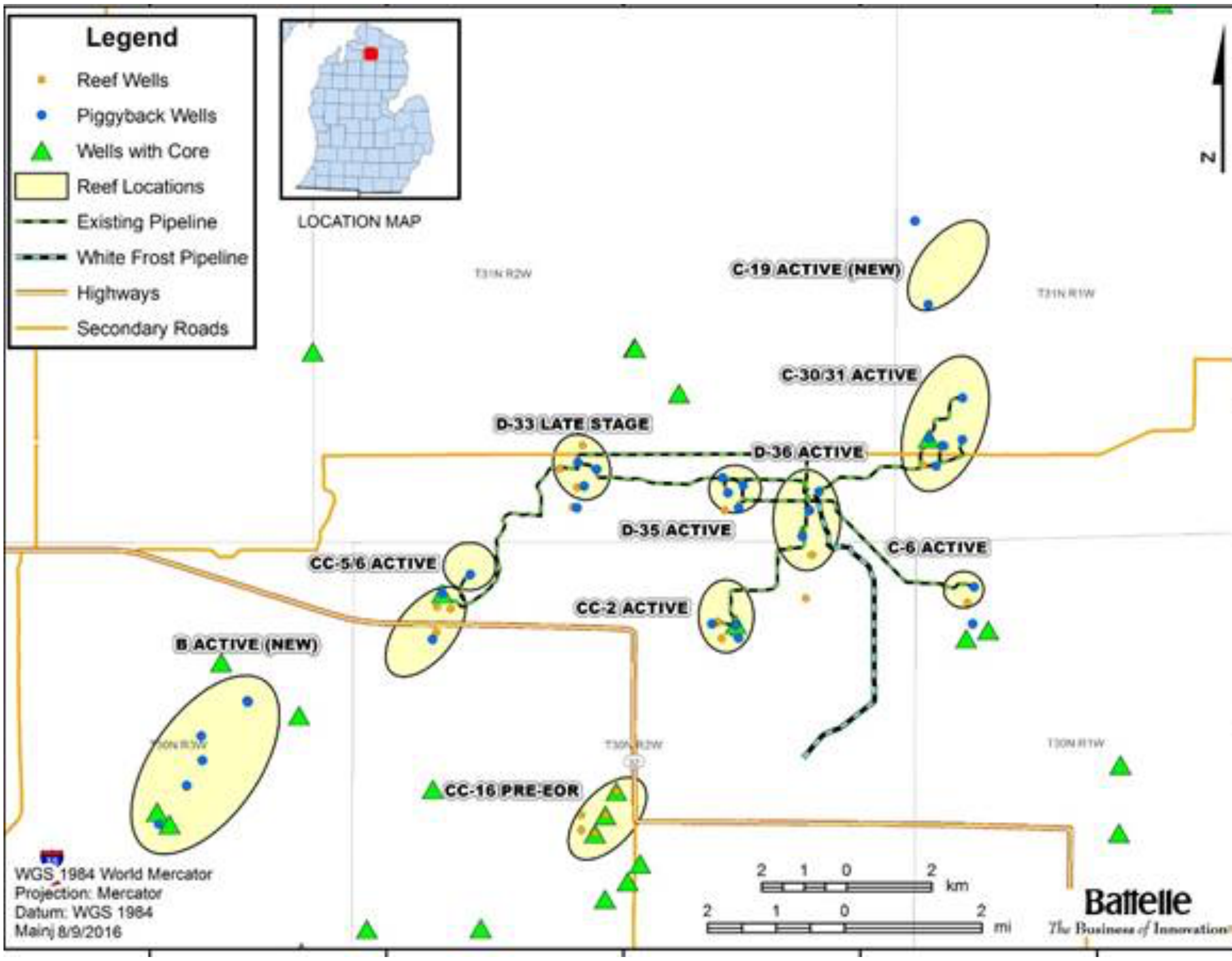

Figure G-17. *Active Reefs Operated by Core Energy*

Source: Core Energy LLC.

D. Midwest Regional Carbon Sequestration Partnership

In 2005, Core Energy joined the Midwest Regional Carbon Sequestration Partnership (MRCSP). Research conducted under the auspices of the MRCSP effort have expanded Core Energy's knowledge of the NNPRT geology and informed reservoir modeling for the reefs. This work demonstrates the integrity of the reef structures, informs the operational plans, and helped to create a data collection system to track the amount of CO_2 stored in the project as a result of CO_2 EOR operations.

E. Monitoring

As with other CO_2 EOR projects, permits for CO_2 injection have been issued under the Underground Injection Control Class II program of the U.S. Environmental Protection Agency. Early on, Core Energy reported the amount of CO_2 it receives under Subpart UU of the EPA's Greenhouse Gas Reporting Program (GHGRP). In 2018, Core Energy opted into the GHGRP Subpart RR program so that it could quantify the amount of CO_2 storage achieved as a result of its CO_2 EOR operations.

As an initial step, Core Energy developed a monitoring, verification, and reporting (MRV) plan to describe the operations, the monitoring program, and its CO_2 material balance quantification plan. The

MRV plan was approved in late fall of 2018, and Core Energy is assembling its first report, which is expected to be submitted in 2019.

F. Summary

The Core Energy CO_2 EOR Facility demonstrates the diversity and value of potential CO_2 EOR projects. The reefs have proven to be an excellent geologic setting for oil production and CO_2 storage. The use of oil fields that had been developed and depleted previously, or that have been completely abandoned, is an approach that can be repeated elsewhere in the United States. The revitalization of these fields further optimizes the natural resource, provides economic development, and ultimately stores CO_2 that would otherwise be emitted to the atmosphere. It is estimated that in northern Michigan alone, the reefs in the NNPRT could sequester several hundred million tonnes of CO_2.