Camrick Field Area (CFA)

MONITORING, REPORTING AND VERIFICATION PLAN (MRV)

CapturePoint LLC

April 2022

Contents

INTRODUCTION

CapturePoint, LLC (CapturePoint) operates the Camrick Field Area (CFA) located in Beaver and Texas Counties, Oklahoma and in Ochiltree County, Texas for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO_2) with retention of CO_2 serving a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The CFA was discovered in 1955 and is composed of three units, the Camrick Unit (CU) that was unitized by Humble Oil Company on October 14, 1969, the North Perryton Unit (NPU) that was unitized by Humble Oil Company on March 17, 1969, and the Northwest Camrick Unit (NWCU) that was unitized by Atlantic RichField Company on September 15, 1972. The Units were formed for the purpose of waterflooding with salt water sourced from the Wolfcamp formation. The field structure is a lenticular bedding sand trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. CapturePoint has been operating the CFA since 2017. CapturePoint acquired the CFA from Chaparral Energy LLC, which initiated the CO_2-EOR project in March 2001 for the CU and January 2007 for the NPU. No CO_2 has been injected in the NWCU. CapturePoint intends to continue CO_2-EOR operations until the end of the economic life of the CO_2-EOR program using various Class II injection wells as defined by Underground Injection Control (UIC) regulations and permitted under Texas Railroad Commission (TRRC) Rule 46 of the Texas Administrative Code (TAC) and the Oklahoma Corporation Commission (OCC) Title 165:10 of the Oklahoma Administrative Code (OAC). In this document, the term "gas" means a mixture of hydrocarbon light end components and the CO_2 component that can be produced as part of the EOR process.

CapturePoint has chosen to submit this Monitoring, Reporting, and Verification (MRV) plan to the EPA for approval according to 40 Code of Federal Regulations (CFR) 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code.

This MRV Plan contains ten sections:

Section 1 contains facility information.

Section 2 contains the project description including: a detailed description of the injection operation including the duration and volume of CO_2 to be injected; a detailed description of the geology and hydrogeology of the CFA located on the northwest shelf of the Anadarko basin; and a detailed characterization of the injection reservoir modeling techniques employed.

Section 3 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40 CFR 98.449 and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

Section 4 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP. This section also describes the strategy for detecting, verifying, and quantifying any surface leakage of CO_2 as required by 40 CFR 98.448(a)(3), Subpart RR of the GHGRP. Finally, this section also demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

Section 5 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

Section 6 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 7 provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 8 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.

Section 9 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.

Section 10 includes Appendices supporting the narrative of the MRV Plan.

1 Facility

1.1 Reporter Number

The CU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544678 and the NPU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544679. The EPA has been notified that the NPU will not be reporting for 2022, and that the facility has been merged into the Camrick Unit Facility Identification number 544678.

1.2 UIC Permit Class

For injection wells (see Appendix 2) that are the subject of this MRV plan, the OCC has rules governing UIC Class II injection wells. These OCC rules are OAC Title 165:10-5-1 through 165:10-5-15, OAC 165:5-7-27, OAC 165:5-7-30, the request for an exception to UIC rules under OAC 165:5-7-29, and other governing filing forms. Also, the TRRC has issued UIC Class II enhanced recovery permits under its Rule 46, TAC Title 16 Part 1 Chapter 3. All wells in the CFA, including both injection and production wells, are regulated by the OCC and the TRRC, which have primacy to implement the UIC Class II program.

1.3 UIC Injection Well Numbers

A list of the injection wells in the CFA is provided in Appendix 1. The details of the injection process are provided in Section 2.3.

2 Project Description

2.1 Project Characteristics

2.1.1 Estimated years of CO_2 injection

The CFA has been injecting CO_2 for the last 20+ years and it is currently projected that CapturePoint will inject CO_2 for an additional 12 years.

2.1.2 Estimated volume of CO_2 injected over lifetime of project

Historical and forecasted cumulative CO_2 retention volumes are approximately 100 billion standard cubic feet (Bscf) or 5.3 million metric tonnes (MMMT) from the start of CO_2

injection through October 2034. During the MRV plan, the period September 2022 through October 2034, 52.5 Bscf or 2.77 MMMT will be stored in the CFA. (See Figure 2.4-6)

2.2 Environmental Setting of MMA

2.2.1 Boundary of the MMA

CapturePoint has defined the boundary of the MMA as equivalent to the boundary of the CFA plus ½ mile beyond. A discussion of the methods used in delineating the MMA and the AMA are presented in Section 3.

2.2.2 Geology

The geological discussions in Sections 2.2.2 and 4.3-4.4 are based on analysis of logs from both the Farnsworth Unit, which is located 10 miles South-South-West of the CFA, and the CFA. Both areas have similar pay thickness, porosity values, permeability measurements, depositional environment, tectonic processes, and overburden strata layers. The descriptions of cores at the Farnsworth Unit included sections from overlying seals as well as the shale underlying the main reservoirs, petrographic thin section descriptions and point counts as well as a variety of special analytical techniques. These techniques included X-ray diffraction (XRD), which is the science of determining the atomic and molecular structure of rock crystals with an X-ray beam; scanning electron microscope (SEM) analysis, which uses a beam of electrons to define the surface of crystals; carbon isotope analysis to estimate the age of the CO_2 in the sample; and a variety of mechanical tests. Two dimensional (2D) and three dimensional (3D) geophysical surveys were also used as part of the Farnsworth Unit MRV Plan (2021). Details of recent geological investigations can be found in Gallagher (2014), Gragg (2016), Rasmussen et al (2019), Rose-Coss et al (2015), Trujillo (2018), Hobbs et al (2019), and Gragg et al (2018).

2.2.2.1 Tectonic Setting and Stratigraphy

The CFA is located on the northwest shelf of the Anadarko basin (Figure 2.2-1) and is one of many oil fields in the area that produce from a sequence of alternating sandstones and mudstones deposited during the late Pennsylvanian Morrowan period. Oil production and CO_2 injection at CFA is restricted to the operationally named Morrow B sandstone; the uppermost Morrow sandstone encountered below the Atokan Thirteen Finger limestone. The primary caprock intervals at CFA are comprised of the upper Morrow shale and the Thirteen Finger limestone (Figure 2.2-2). The Morrowan and Atokan intervals were deposited approximately 315-300 million years ago. Overlying stratigraphy includes late Pennsylvanian through the middle Permian shales and limestones, with lesser amounts of dolomite, sandstone and evaporites (Ball, 1991). The reservoir is approximately 60 feet thick throughout the field and lies at a depth of approximately 6,800-7,600 feet. The primary seal rocks of the Morrow shale and the Thirteen Finger Limestone comprise a package of approximately 180-200 feet thick in the field and are overlain by thousands of feet of Atokan and younger limestones and shales.

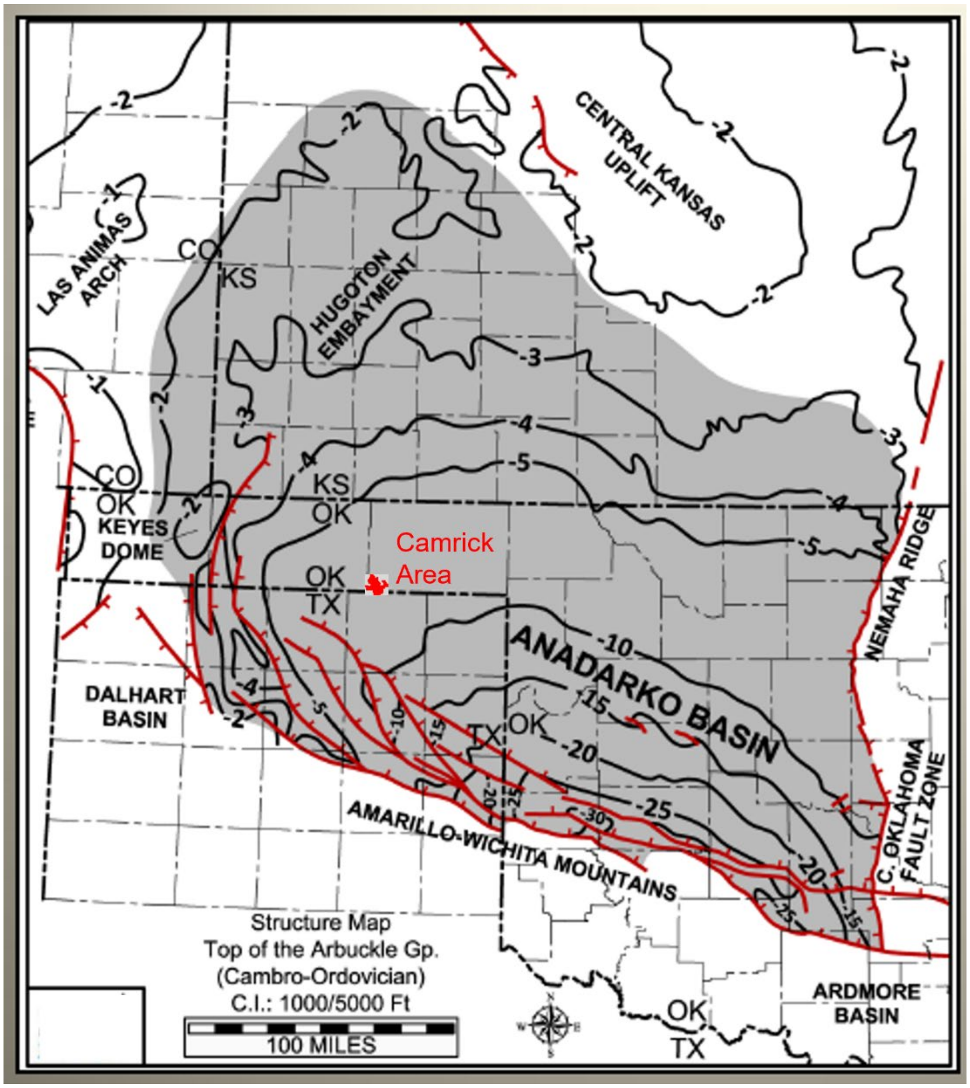

Figure 2.2-1. Location of the CFA on the Northwest Shelf of the Anadarko Basin in West Texas. Red lines are approximate locations of faults that have been documented in the region.

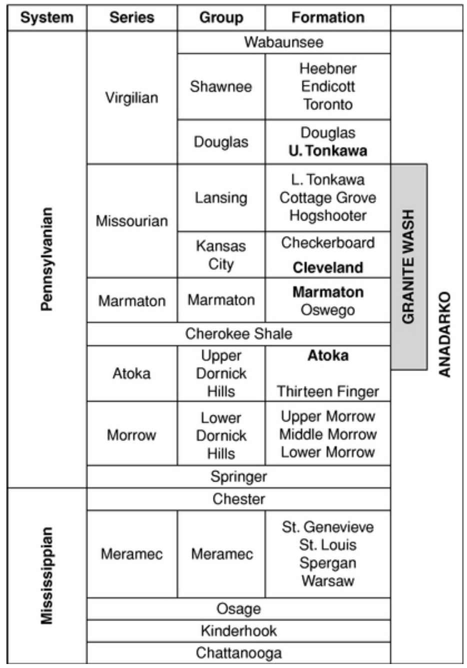

Figure 2.2-2. Stratigraphic section.

Tectonic Setting

From CFA's location on the western edge of the basin, the Anadarko Basin plunges to the southeast (Figure 2.2-3) where it reaches depths of over 40,000 feet (12,192 meters) adjacent to the Amarillo-Wichita Uplift (Perry, 1989). Maximum rates of subsidence occurred during Morrowan to Atokan times (Evans, 1979; Perry, 1989; Higley, 2014). Positive features that might have influenced deposition within the region include the Ancestral Rockies to the north, the Central Kansas uplift to the northeast, and the Wichita-Amarillo uplift to the south (Evans, 1979; Munson, 1989). Of note is the fact that during the Pennsylvanian time, the CFA was located on the basin shelf in an area that was not affected greatly by tectonic deformation. Although faults have been reported previously in the northwest Anadarko Basin, we found no direct evidence for tectonic faults within the CFA (see Section 4).

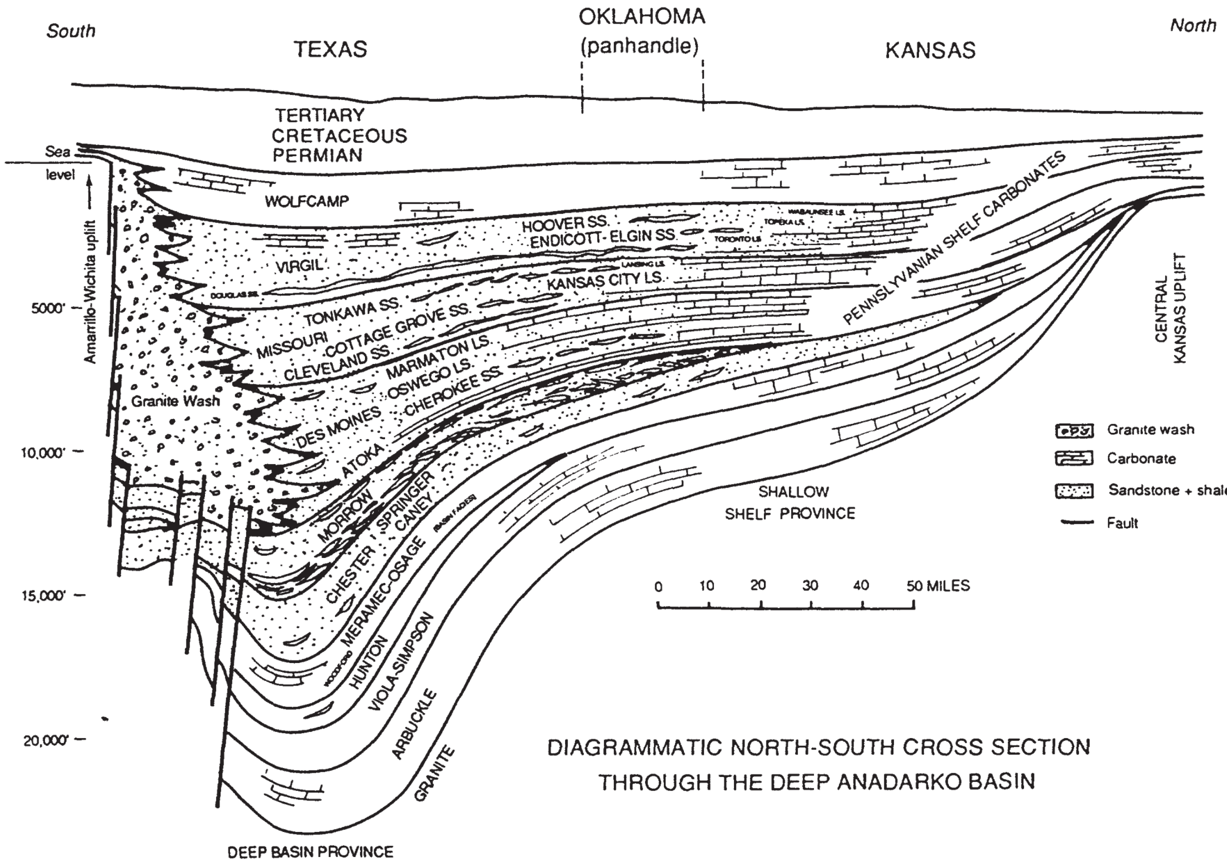

Figure 2.2-3. Diagrammatic North-South Section (Bottom) of the CFA.

Stratigraphy

Reservoir

Upper Morrowan sandstones in the Anadarko Basin margins have long been recognized as fluvial deposits (Swanson, 1979; Sonnenberg, 1985; Munson, 1989; Krystinik and Blakeney, 1990; Bowen et al., 1990; Al-Shaieb et al., 1995; Mckay and Noah, 1996; Puckette et al., 1996; Bowen and Weimer, 2003, 2004; Devries 2005; Puckette et al., 2008; Gallagher, 2014). At the Farnsworth Unit and similarly at the CFA, the Morrow B is described as a relatively coarse-grained subarkosic sandstone. The upper Morrowan facies, with sequences of basal conglomerate, coarse-grained sandstone, and fine-grained sandstone appear to be typical of incised valley deposits, as described by Wheeler et al. (1990), Krystinik and Blakeney (1990), Bowen et al. (1990), Blakeney et al. (1990), Sonnenberg et al. (1990) and Puckette et al. (2008).

Primary Seals

The Morrow B sandstones are encased above and below by shales. Contacts with shale both below and above the sandstone are sharp and irregular. The Morrow shale generally fines upwards in a series of thin beds that alternate between upper fine sands and fine to medium muds. Sand content decreases upwards through the section.

The Thirteen Finger limestone formation has two different lithofacies: diagenetic limestone (cementstone) and pyrite and fossil bearing fine to medium mudstone and coal. The two facies are intercalated with each other but tend to cluster in layers dominated more by one or the other.

The entire Thirteen Finger interval is typically 130 feet (39.6 meters) thick, comprised of mudstone, coal, and limestone. The mudstone is calcite rich, with some dolomite, and is completely diagenetic in origin and probably formed relatively soon following deposition.

2.2.2.2 Hydrogeology

Information about Morrowan and Atokan formation water flow during oil operations has not been discovered in any oil or gas company published reports or academic research studies in the Anadarko Basin. Groundwater flow rates in confined deep Anadarko layers at present are considered to be low to no flow (Nelson and Gianoutsos, 2014). Their arguments are based on (1) restricted recharge in the western basin, (2) density barriers to flow in the east, and (3) an overpressure pocket inhibiting flow in the deep basin. Jorgenson (1989) suggested flow could be west to east, driven by potential recharge to elevated units in the west and discharge at lower elevation outcrops in the east. The CFA CO_2 injection and production operations have negligible likelihood of causing water to flow to outcrops of the late Carboniferous (Pennsylvanian) time period that extend from Brownwood, Texas, to the Jacksboro/Bowie, Texas, area, which are hundreds of miles away (The Paleontology Portal).

The Carboniferous is a geologic period and system that covers 60 million years from the Devonian Period 358.9 million years ago, to the beginning of the Permian Period, 298.9 million years ago. As noted in the Section 2.2.2.1, the Morrowan and Atokan intervals of the CFA were deposited approximately 315-300 million years ago and are contained in the Carboniferous period.

2.3 Description of the Injection Process

Figure 2.3-1 depicts a simplified flow diagram of the facilities and equipment within the boundaries of the CFA. CO_2 captured from the ethanol plant fermentation process is delivered via pipeline to the field for injection. The Arkalon plant in Liberal, Kansas is the only source of CO_2 to the field. The amount delivered is dependent on the production of CO_2 produced from the fermentation process. This amount will vary but should average 12 MMCFD. Once CO_2 enters the CFA there are three main processes involved in EOR operations. These processes are shown in Figure 2.3-1 and include:

1. CO_2 distribution and injection. Purchased CO_2 is combined with recycled CO_2 from the CFA central tank battery (CTB) and sent through the main CO_2 distribution system to various water alternating gas (WAG) injectors.

2. Produced Fluids Handling. Full well stream fluids are produced to the “all well test” (AWT) site. The AWT site has two major purposes; 1) to individually test a well’s performance by separating and metering oil, gas, and water, and 2) to separate all gas from liquid then send these two phases to the CTB for final separation; while only the gas from NPU is sent to the CTB the NPU oil and water remains in Texas.

3. Produced Gas Processing. All gases from the AWT sites are transferred to the CTB to separate the oil, gas, and water using a series of vessels and storage tanks.

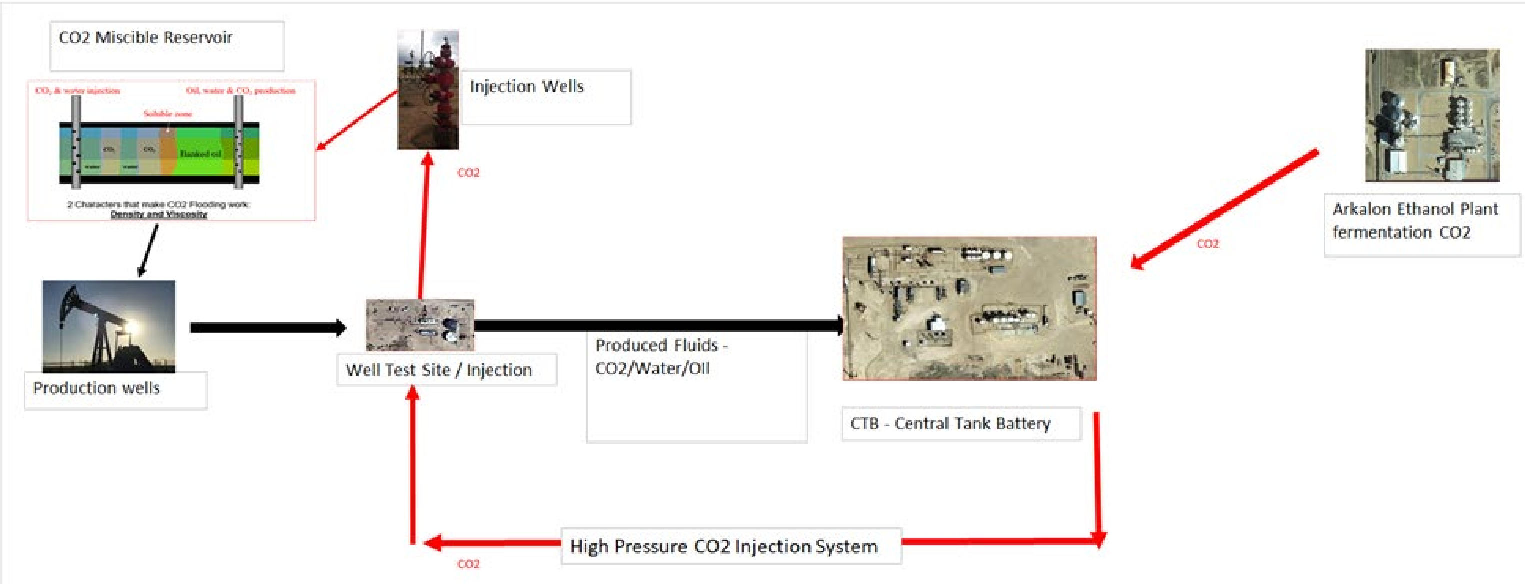

Figure 2.3–1. Simplified flow diagram of the facilities and equipment within the boundaries of the CFA.

2.3.1 CO_2 Distribution and Injection

CapturePoint purchases CO_2 from Conestoga Energy Partners, the parent company of the Arkalon Ethanol plant located in Liberal, Kansas. A custody transfer meter is located in the compression facility owned and operated by CapturePoint. The purchased CO_2 from the fermentation process is transported via a United States Department of Transportation (DOT) regulated pipeline to the CFA. A totalizer meter, for the purchased CO_2, is located in the field where instantaneous data is summed into a 24-hour flow rate which is recorded. A totalizer meter is a meter approved by the American Gas Association (AGA) Report #3 to measure the flowrate of gases. The actual measurements taken are temperature, line pressure, and differential pressure across the meter. Gas produced, which contains recycled CO_2, from the wells is compressed and metered by a similar totalizer meter as the purchase CO_2 meter and is recorded daily.

CapturePoint currently has seven active injection manifolds and approximately 29 active injection wells that the CO_2 is distributed through. When the MRV plan becomes active, the daily injection volume of the combined purchased CO_2 and recycled CO_2 will be approximately 24 MMCFD. Of this volume 12 MMCFD is purchased CO_2 and 12 MMCFD is recycled CO_2. This ratio of purchased CO_2 to recycled CO_2 is expected to change over time, with the percentage of recycled CO_2 increasing and purchased CO_2 decreasing. The current reservoir management plan projects that CO_2 purchases will remain constant at 12 MMCFD for 12 years and cease after 2034. A reservoir management plan is an integrated process using various surveillance techniques, economic evaluations, and accepted petroleum technical practices to efficiently operate enhanced oil recovery projects.

The seven injection manifolds currently in the field distribute the CO_2 to the field. These manifolds have valves to switch to water when the time is called for. Depending on the reservoir management plan, the WAG cycle will be adjusted to maximize oil recovery and minimize CO_2 utilization in each injection pattern. At each injection well pad there is a totalizer to measure the volumes injected every 24 hours. This data is collected daily by the field personnel and input into the data warehouse to be allocated for the pattern injection.

The two totalizer meters as described above will be used to determine the total volume injected used in section 7 for the mass balance equations necessary to determine annual and cumulative volumes of the stored CO_2.

2.3.2 Produced Fluids Handling

As injected CO_2 and water migrate through the reservoir; a mixture of oil, gas, and water (referred to as "produced fluids") flows to the production wells. Gathering lines bring the produced fluids from each production well to the AWT sites. CapturePoint has approximately 32 active production wells producing at any time. Each AWT has two separators. The first separator is used for testing individual wells to separate the gas, oil, and water produced from an individual well. This gas, oil, and water is subsequently measured and recorded for the well. Each producing well is production tested every 30 to 60 days after the last production test, or after the well is returned to production. Depending on the reservoir management plan, well testing can be more frequent to obtain data. The second separator is used to separate the gas from the oil/water mixture from the other wells producing into the AWT, and the gas and liquids are displaced from the vessel in separate lines. Leaving the AWT sites are two lines transporting produced fluids. One line is used for the liquid phase, a mixture of oil and water, and one line is used for the gas phase. However, the AWT in NPU does not transfer oil or gas to the CTB, it only transfers gas while reinjecting water with pumps at the NPU AWT and sells oil at the NPU AWT.

When gas and liquid lines enter the CTB, a series of vessels separate the oil, gas, and water to be accounted for and distributed for sales or reinjected. The liquid phase line has vessels to separate the oil from the water using density and residence time. The gas phase vessels collect any free liquids entrained with the gas. These free liquids are then combined back into the liquid phase line. All gas and water are reinjected, and the oil, which contains an estimated 2,360 ppm CO_2 (0.236%) for CU and 4,540 ppm CO_2 (0.454%) for NPU, is sold out of tanks. Annually, the oil from the stock tank is analyzed by a laboratory using ASTM crude oil analysis methods to determine the CO_2 content in the oil being sold.

After separation, the gas phase, which is approximately 92-95% CO_2, is mixed with reservoir volatile components, compressed, and distributed throughout the high-pressure distribution system using reciprocal compression and high-pressure horizontal pumps.

The water is transferred from the separation vessels to tanks for reinjection. After the water is conditioned, it is either reinjected at the WAG skids or disposed of into permitted disposal wells. Although CapturePoint is not required to determine or report the amount of dissolved CO_2 in the water as it is reinjected into the ground and not emitted to the atmosphere, the analyses have shown the water typically contains <690 ppm (0.069%) CO_2.

CFA production has trace amounts of hydrogen sulfide (H_2S), which is toxic. There are approximately 8-10 workers on the ground in the CFA at any given time, and all field and contractor personnel are always required to wear H_2S detectors. The primary purpose of the H_2S detectors is protecting people from the risk of being harmed. The detection limit of the H_2S detectors is quantified for readings in the range of 0-100 ppm and will sound an alarm above 10 ppm. The secondary purpose of the H_2S detectors would be to provide an indication of emissions of gas from a pipeline or surface equipment, which might go unnoticed by other observations or measurements. No gas volumes can be calculated based on the detector reading or alarm; only a H_2S leakage is detected and located. Once identified, a further response will be initiated and CO_2 volumes will be quantified as discussed in sections 4.5, 4.6, 5.4, and 8.1.5 of this MRV plan.

2.3.3 Produced Gas Handling

Produced gas separated at the CTB is stripped by a series of vessels of entrained and free water. The water content has been recorded to be < 20 pounds mass per MMCF, thus dehydration is not necessary. The gas is then sent to a centralized compression system to be compressed and placed in the high-pressure distribution system. This compression turns the CO_2 into a variable density liquid, which is then transported out via high pressure lines to the AWT sites where a manifold splits this dense CO_2 to the wells that are on CO_2 injection at that time.

2.3.4 Facilities Locations

The locations of the AWT sites are positioned in the field to access both injection distribution and production gathering. The CTB is where the final separation and injection equipment is maintained and operated. The water injection station is where the horizontal pumps are located to reinject the produced brine.

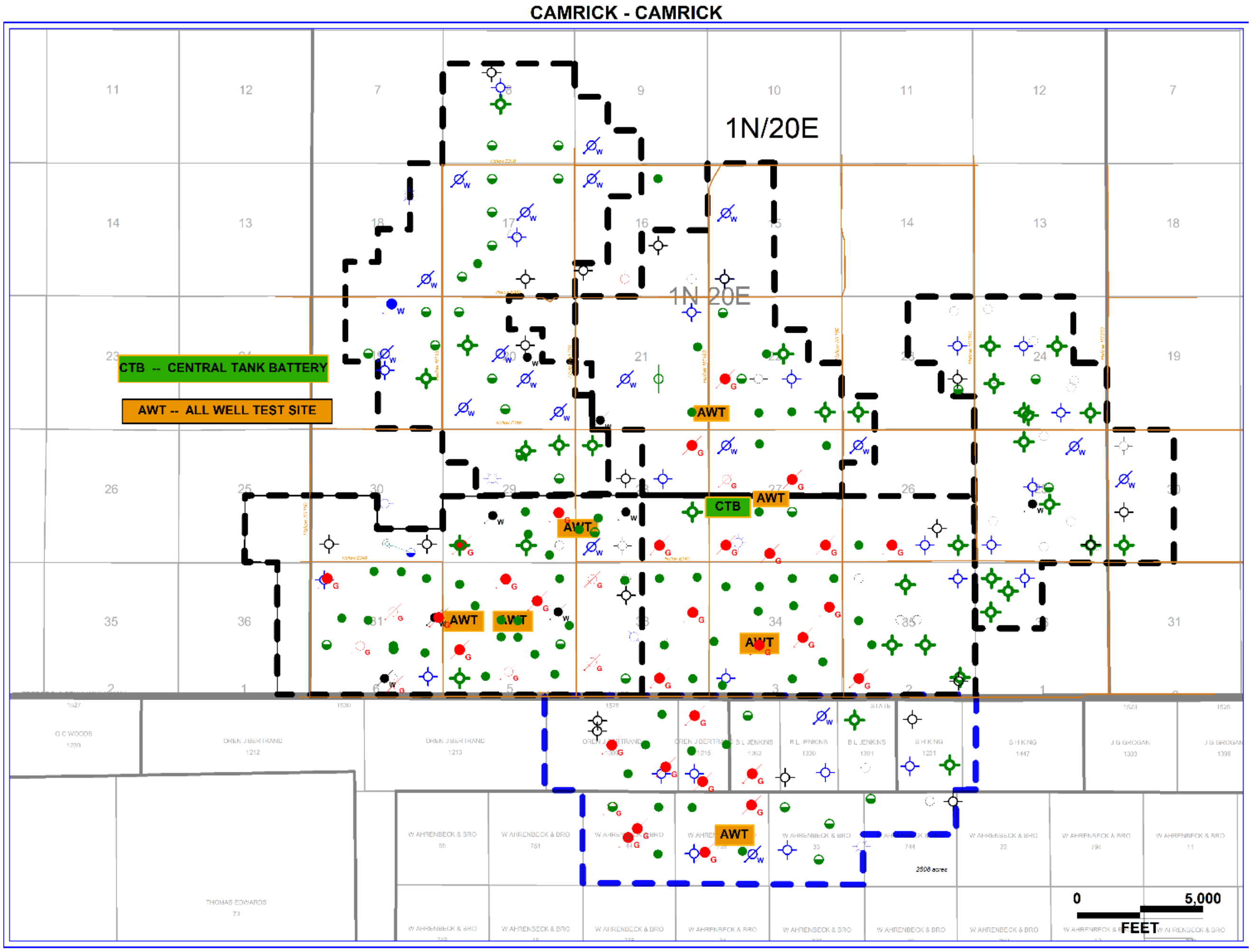

Figure 2.3-2. Location of AWT sites and CTB in the CFA

2.3.5 Water Conditioning and Injection

Produced water collected at the CTB is collected in a series of vessels and tanks in a cascade system. This allows any entrained oil to further separate to the top of the tanks because of the density difference. This oil is skimmed off and put back in the oil separation system. The clean water is then transferred to the water injection system where it is boosted in pressure and sent out to the AWT sites for distribution to all wells that are currently on water injection.

2.3.6 Well Operation and Permitting

The OCC and TRRC rules (Appendix 2) govern well location, construction, operation, maintenance, and plugging for all wells in permitted units and wells. CapturePoint follows these rules and regulations to maintain safe and efficient operations. This includes complying with all current and updated information for mechanical integrity testing, well repairs for injection wells, drilling and completion, permitting, and reporting.

Briefly, the following bulleted list is what the current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface waters.
- That wells file a completion report including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore).
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.
- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location, and setting of plugs.

2.3.7 Number, Location, and Depth of Wells

CapturePoint's CFA injection wells are listed in Appendix 1. Injection is into the Upper Morrowan, a lenticular bedded sandstone trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. The Upper Morrowan is described in section 2.2.2.1 above.

2.4 Reservoir Characterization

2.4.1 Reservoir Description

The target reservoir CFA Morrow B is a sandstone formation overlain by the Morrow shale and the Thirteen Finger limestone, which serve as excellent seals for injected CO_2 as determined by Farnsworth data (Ampomah et al., 2016a). The Morrow B sandstone reservoir is at a depth between 6,800 feet and 7,600 feet subsurface with an average dip of less than one degree (Figure 2.4-1). The productive limit of the CFA is about 80 to 90 percent of the total operated surface acreage, which is 14,652.315 acres. The maximum pay thickness is 56 feet with an average of 15 feet and does diminish to zero in spots.

The CFA is approximately eight miles by seven miles with areas that exhibit different reservoir behavior. The southwest portion of CU was most prolific oil producing area of the CFA under primary and secondary production; whereas the western portion of NPU is now responding to CO_2 better than historical operations would have indicated.

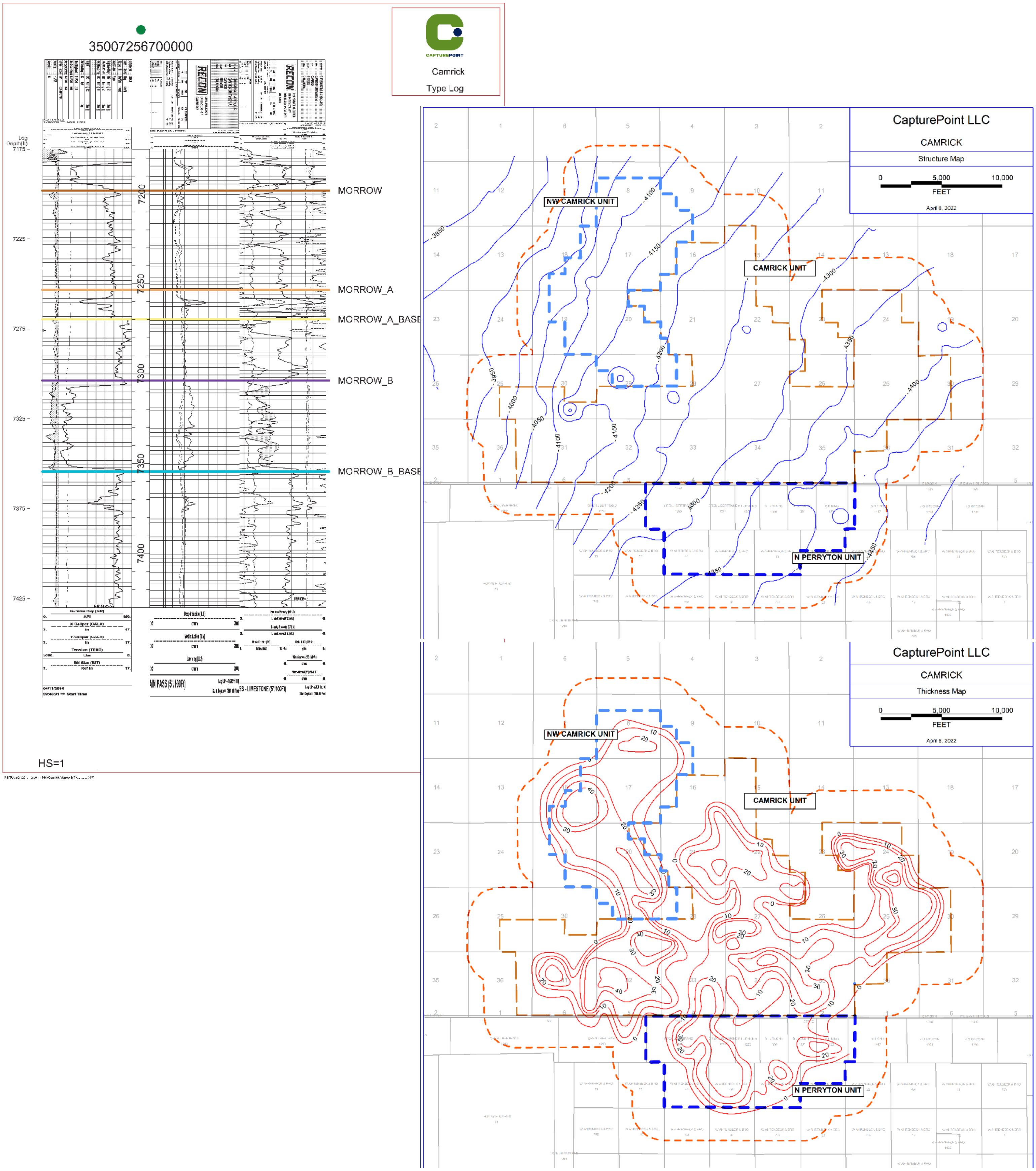

Figure 2.4-1. (Left) Type log of CFA caprock and reservoir, (Upper Right) Surface contour of Morrow top, (Lower Right) Thickness map of Morrow sands.

2.4.2 Reservoir Fluid Modeling

The compositional fluid model was constructed for the CapturePoint operated Farnsworth Unit. From laboratory compositional analysis an equation of state was tuned (Gunda et al., 2015). The minimum miscibility pressure (MMP) experiment was then simulated using a one-dimensional model. The simulated Farnworth Unit MMP of 4,009 psia compared to an MMP value of 4,200 psia derived from laboratory experiments provided by the operator represents a less than 5% error (Gunda et al., 2015).

The reservoir temperature in the CFA is 152 degrees Fahrenheit or 16 degrees lower than the temperature at Farnsworth Unit of 168 degrees. Using parameters of the Alston empirical correlation (1985), the MMP would be 170 psia lower at the CFA or 3,510 psia compared to 3,680 psia at the Farnsworth Unit (Figure 2.4-2).

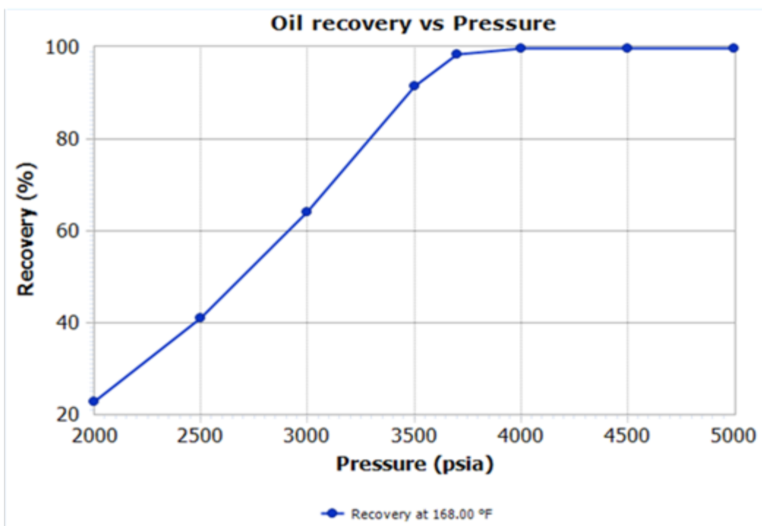

Figure 2.4-2. Oil recovery plot for 1D slim tube test for Farnsworth Unit.

2.4.3 CO_2 Analogy Field Study

Based on similar geologic, petrophysical, engineering, and operational parameters between the Farnsworth Unit and the CFA, the oil recovery performance of both fields is expected to be similar. Due to the stratigraphic nature of the Morrow channel sands, the potential movement of CO_2 is severely limited. The CFA area has contained the free phase CO_2 plume in a very confined area since March 2001 as exhibited by oil, water, and CO_2 recovery performance. Also, during CFA drilling and production operations, no reports exist which would indicate any plume has moved outside of the MMA. The Farnsworth Unit MRV and the CFA data justifies the conclusion that CO_2 will continue to be contained inside the MMA at the end of the CO_2 injection year t + 5, per §98.449 definitions.

2.4.4 CO_2 – EOR Performance Projections

For years, the oil industry has used dimensionless equations to predict the amount of oil that can be recovered using CO_2 for flooding oil reservoirs (Lee et al, 2018, Stell 2010). The amount of oil recovered from projects is plotted as a decimal fraction of the original-oil-in-place versus the decimal fraction of the hydrocarbon pore volume (HPV) of CO_2 injected into the oil reservoir as measured in reservoir barrels (RB).

The CFA has been injecting CO_2 since March 2001. The dimensionless curves were matched to historical performance through early 2020 (Figure 2.4-3). The supply of CO_2 was curtailed from March 2020 until present, due to oil price uncertainty, and will resume after the Arkalon Plant upgrade that will be finished in the 4th quarter of 2022.

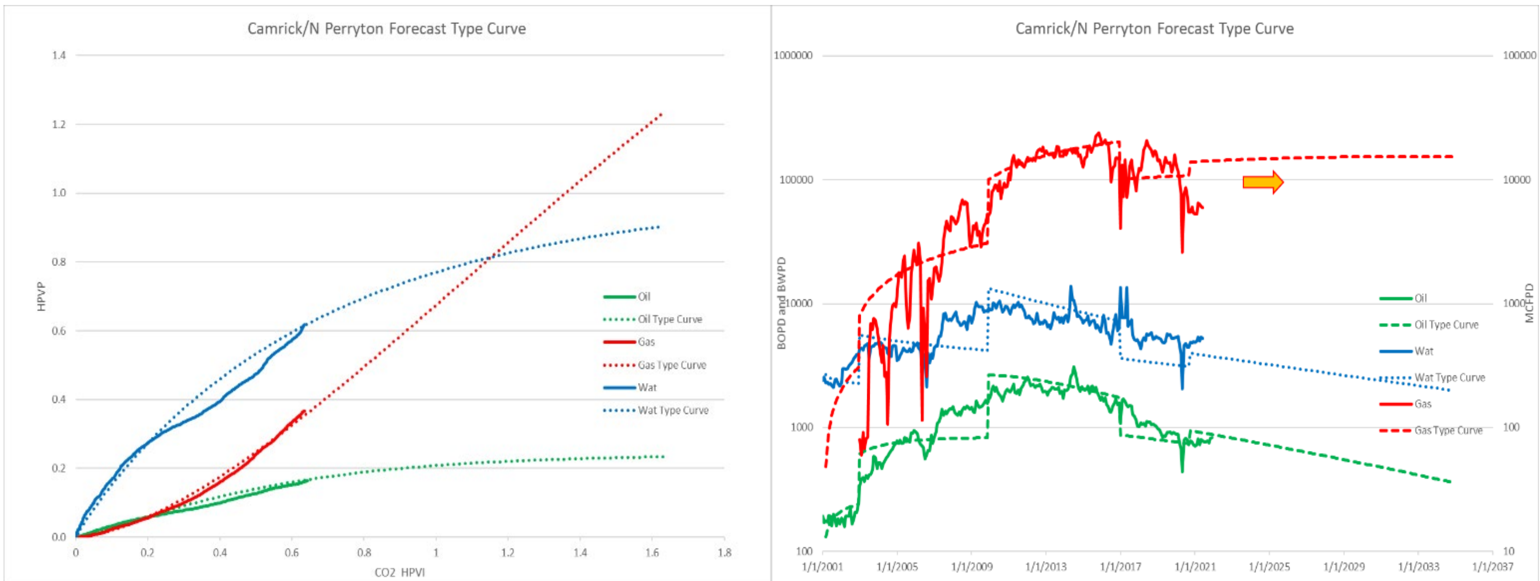

Figure 2.4-3. Dimensionless curves for CO_2 injection (left) with rate time curves (right).

The dimensionless water oil ratio and the gas oil ratio trends (Figure 2.4-4) for the CFA flooded acreage are very similar to what was forecasted by simulation in the Farnsworth Field as expected because of the porosity, permeability, and sand similarities.

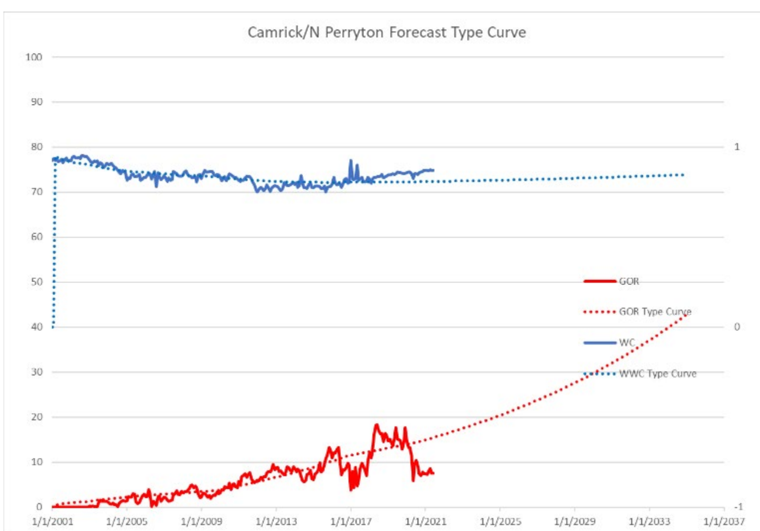

Figure 2.4-4. Dimensionless water cut and GOR vs. observed EOR data.

The CO_2 storage volumes for Arkalon fermentation CO_2 were also forecasted (Figure 2.4-5) using the same dimensionless technique. This technique indicates that the flooded acreage still has significant additional storage potential. The maximum CO_2 storage is limited to the amount of space available by the removal of the produced hydrocarbon. The projection indicates that there is pore space available to store approximately 0.4 to 0.5 decimal fraction of HPV amounting to 30 to 40 MMB.

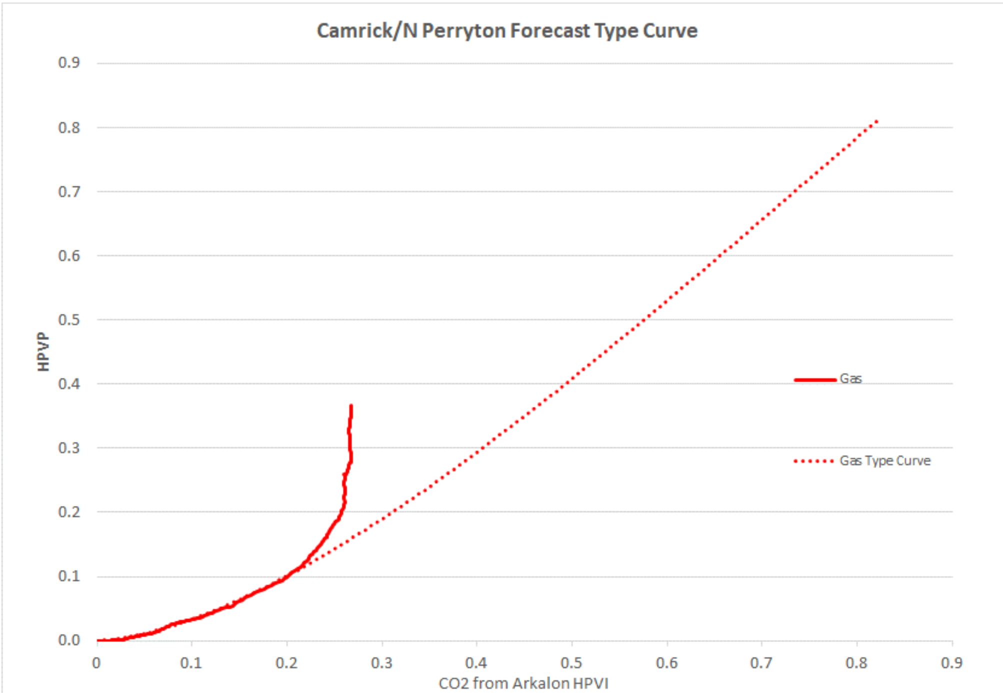

Figure 2.4-5. Dimensionless CO_2 Purchase (Fermentation) Curves

The barrels of reservoir volume were converted to standard cubic feet of gas and is displayed in the CFA Purchase CO_2, or Fermentation CO_2, vs Time chart (Figure 2.4-6).

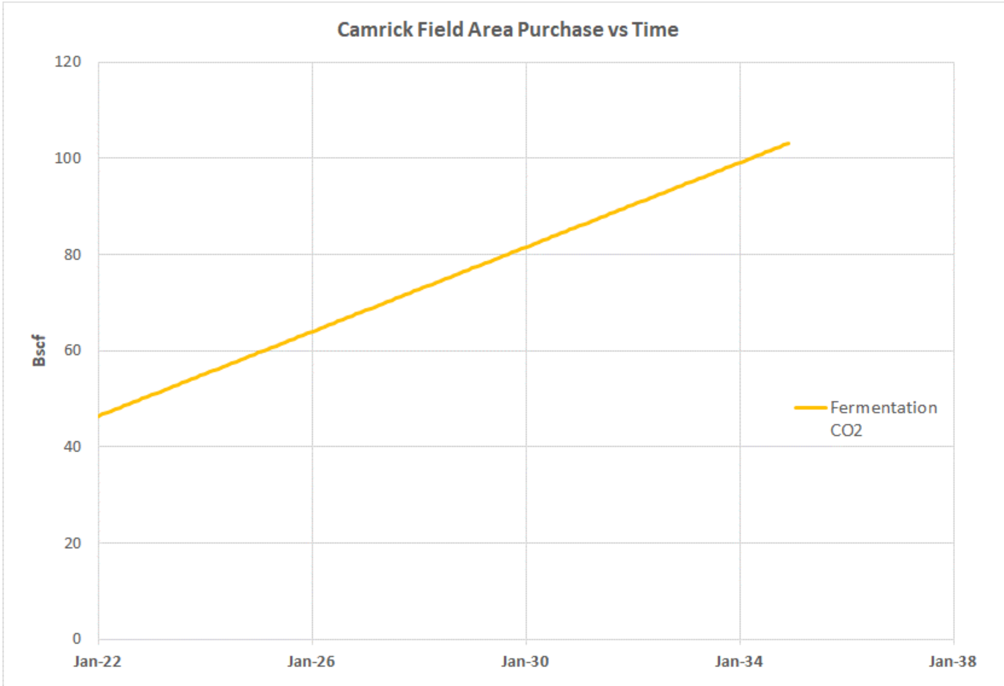

Figure 2.4-6. CO_2 Purchase (Fermentation) Volume.

3 Delineation of Monitoring Area

3.1 MMA

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The purchase volumes that are displayed in Figure 2.4-6 were mapped and are displayed in Section 3.1.1 indicating that CO_2 storage pore space is available, barring unforeseen future operational issues. Therefore, CapturePoint is defining the MMA as the boundary of the CFA plus an additional one-half mile buffer zone. This will allow for operational expansion throughout the CFA for the next 12 years, the anticipated life of the project.

3.1.1 Determination of Storage Volumes

Figure 3.1-1 displays wells that have CO_2 retention on the developed 4,800 acres that have been under CO_2 EOR injection in the CFA since project initialization (14,652.315 acres are in the CFA). The volume of the oil recovered since August 1955, resulted in a voidage space of 36 MMscf of CO_2 per acre of surface area that was later filled with water during waterflood operations. The average decimal fraction of CO_2 injection to hydrocarbon pore volume left in the ground after accounting for CO_2 production through 2021 is 0.29. The lateral extent of CO_2 in the injection zone or the CO_2 storage radius for each well was estimated based on cumulative CO_2 injected times the decimal fraction of CO_2 remaining divided by the voidage space. The largest CO_2 storage areas are around wells that injected the largest volume CO_2.

Figure 3.1-2 displays the potential area of the reservoir that can be filled with CO_2 with the existing injection wells. This assumed that only 78 percent of the average injection pattern area or 80 acres per pattern can be filled. The volumetric storage capacity calculated for the 49 patterns identified for continued injection indicates an additional 90 Bscf of CO_2 can be stored and with 50 Bscf already stored results in 140 Bscf of total storage. With the anticipated 12 MMCFD rate of purchased CO_2, this storage volume will only be 60 percent utilized. As delineated in this MRV plan, the MMA account for an injected volume of up to 140 Bscf and includes all areas of the CFA that could be utilized in the future for CO_2 injection. The MMA will contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. If there are any material changes to the monitoring/operational parameters not outlined in this MRV plan, the plan will be resubmitted in accordance with 40 CFR 98.448(d)(1).

Areas that do not have CO_2 storage posted on Figure 3.1-2 will be evaluated if existing CO_2 injection operations experience any rate restriction or develop any operational issues in the future. If necessary, replacement wells or additional injection locations in inactive areas of the CFA will be drilled or activated. This will be accomplished by utilizing existing plugged and abandoned wells or redrilling old locations as described in Section 3.2.

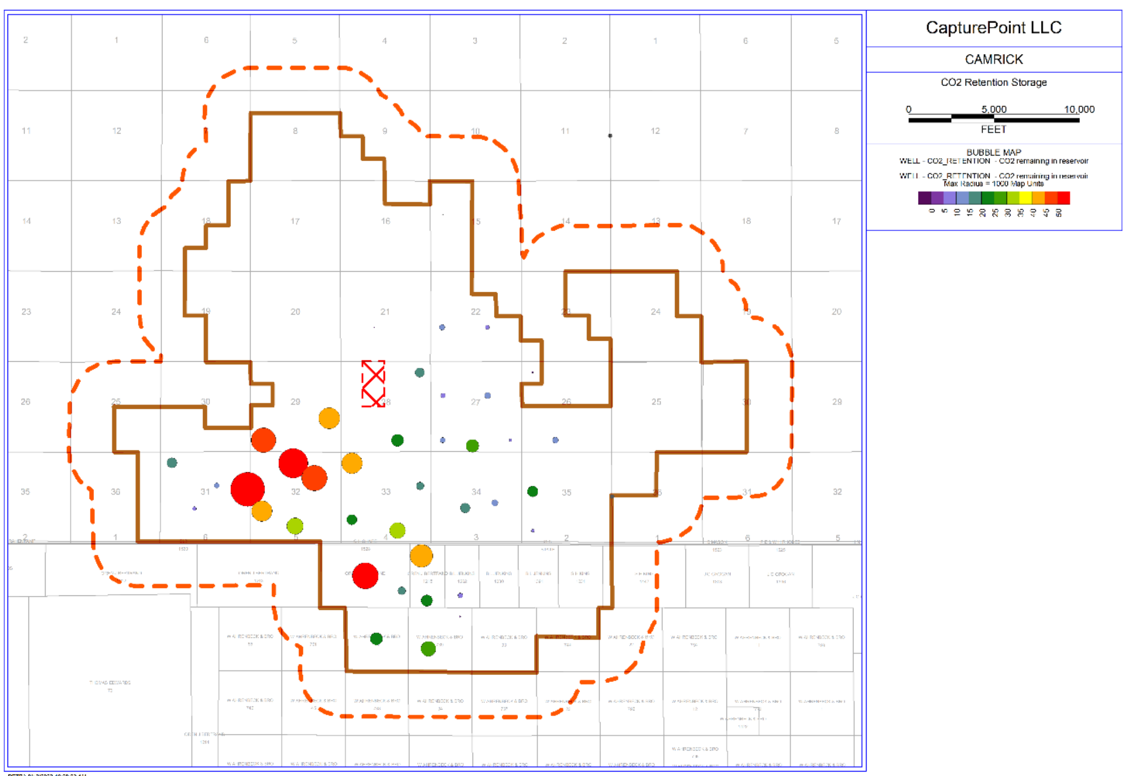

Figure 3.1-1. Estimated CO_2 storage as of 2021 in CFA.
The AMA is the land area inside the solid line polygon except for the red hashed rectangle.
The MMA extends to dotted red line and includes the red hashed rectangle.

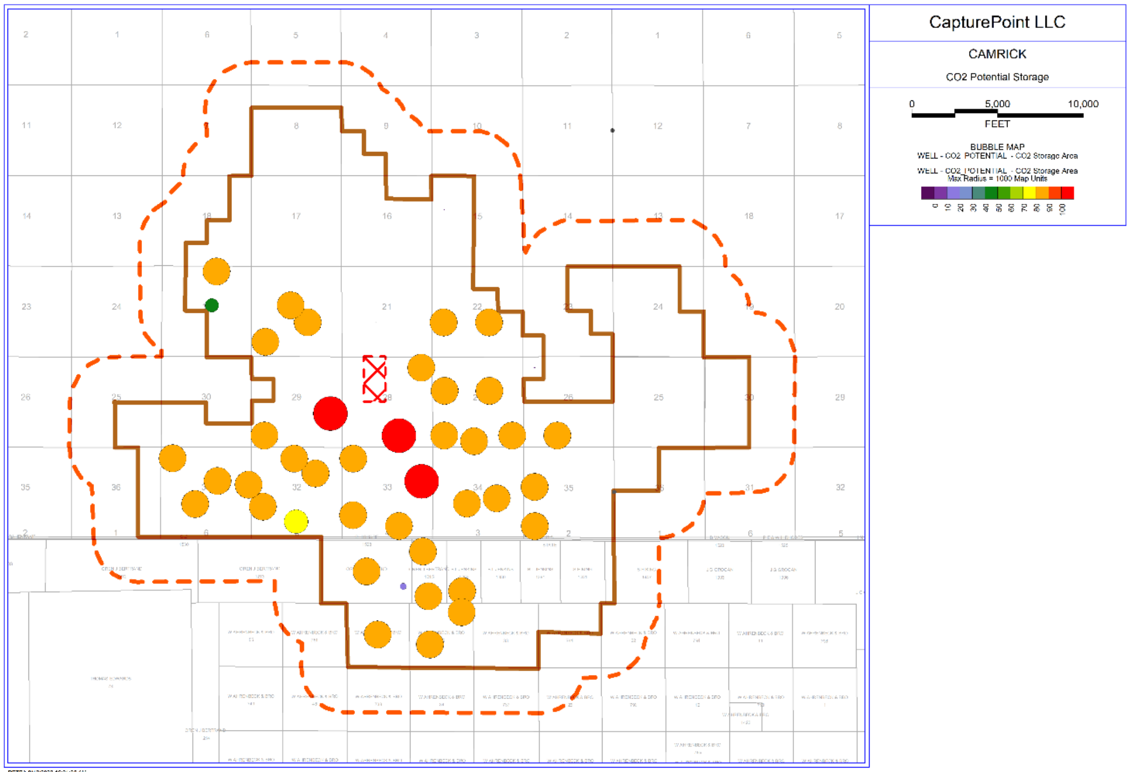

Figure 3.1-2. Potential Total CO_2 Storage in the CFA.
The AMA is the land area inside the solid line polygon except for the red hashed rectangle.
The MMA extends to dotted red line and includes the red hashed rectangle.

3.1.2 Determination of Buffer Zone

CapturePoint intends to implement a buffer zone of one-half mile around the CFA, the minimum required by Subpart RR, because the site characterization and stratigraphic trapping of the Morrow did not reveal any leakage pathways that would allow free-phase CO_2 to migrate laterally thereby warranting a buffer zone greater than one-half mile.

3.2 AMA

The Active Monitoring Area (AMA) is defined by CapturePoint's exclusive right to operate the CFA unitized leases, as described in the INTRODUCTION and Section 2.2.1. Currently, CapturePoint's operations are focused on the western portion of the CU and the entire NPU. However, it is anticipated as time passes, or additional CO_2 volumes become available additional areas within the CFA may be developed. Additional development is driven by the market price of oil coupled with the availability of sufficient CO_2 volumes and thus the timing of additional development is uncertain at this time. As CO_2 injection operations are expanded beyond the currently active CO_2 EOR portion of the CFA, all additional CO_2 injection wells will be permitted under the UIC program and will be included in the annual submittal per 40 CFR 98.446(f)(13). All future CO_2 injection wells permitted will be within the AMA. Based on our projections, CapturePoint expects the free phase CO_2 plume to remain within the CFA for the entire length of the project and through year [t + 5]. Therefore, CapturePoint is defining the AMA as the CFA plus an all-around one-half mile buffer, consistent with the definitions in 40 CFR 98.449. If there are any material changes to the monitoring/operational parameters not outlined in this MRV plan, the plan will be resubmitted in accordance with 40 CFR 98.448(d)(1).

Therefore, for the purposes of this MRV plan, CapturePoint is continuously monitoring the entire CFA, which is the AMA.

4 Identification and Evaluation of Leakage Pathways

Since its discovery in 1955, the unitization of the different units from 1969 to 1972, and the commencement of CO_2 EOR in 2001; the CFA is an analogous field to the Farnsworth Unit, which has undergone extensive investigation and documentation as indicated in Section 2. From this body of work, CapturePoint has identified the following potential pathways of CO_2 leakage to the surface. This section will also address detection, verification, and quantification of leakage from each pathway.

4.1 Leakage from Surface Equipment

The surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO_2 EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment via personnel instructed on how to detect surface leaks and other equipment failure minimizes releases. In addition, the Oil and Gas Division requirements of the OAC rules of the OCC and the TAC rules of the TRRC to report and quantify leaks, both serve to minimize leakage of GHG from surface equipment. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. As described in Section 6.4 below, should leakage from surface equipment occur it will be quantified according to the procedures in Subpart W of the GHGRP.

4.2 Leakage from Wells

CapturePoint has identified 68 abandoned wells, 49 injection wells (29 active) and 94 production wells (59 active) within the MMA and assessed their potential for leakage of CO_2 to the surface as listed in Appendix 1.

4.2.1 Abandoned Wells

Figure 4.2-1 shows all wells plugged and abandoned in the CFA. Because the CFA was unitized in 1969 to 1972, all plugging and abandonment activities of wells within the CFA have been conducted under the regulations of the OCC and the TRRC for plugging wells. The cement used to plug wells when exposed to CO_2 will form colloidal gels that further reduce any flow. CapturePoint concludes that leakage of CO_2 to the surface through abandoned wells is unlikely. However, strategies for leak detection are in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

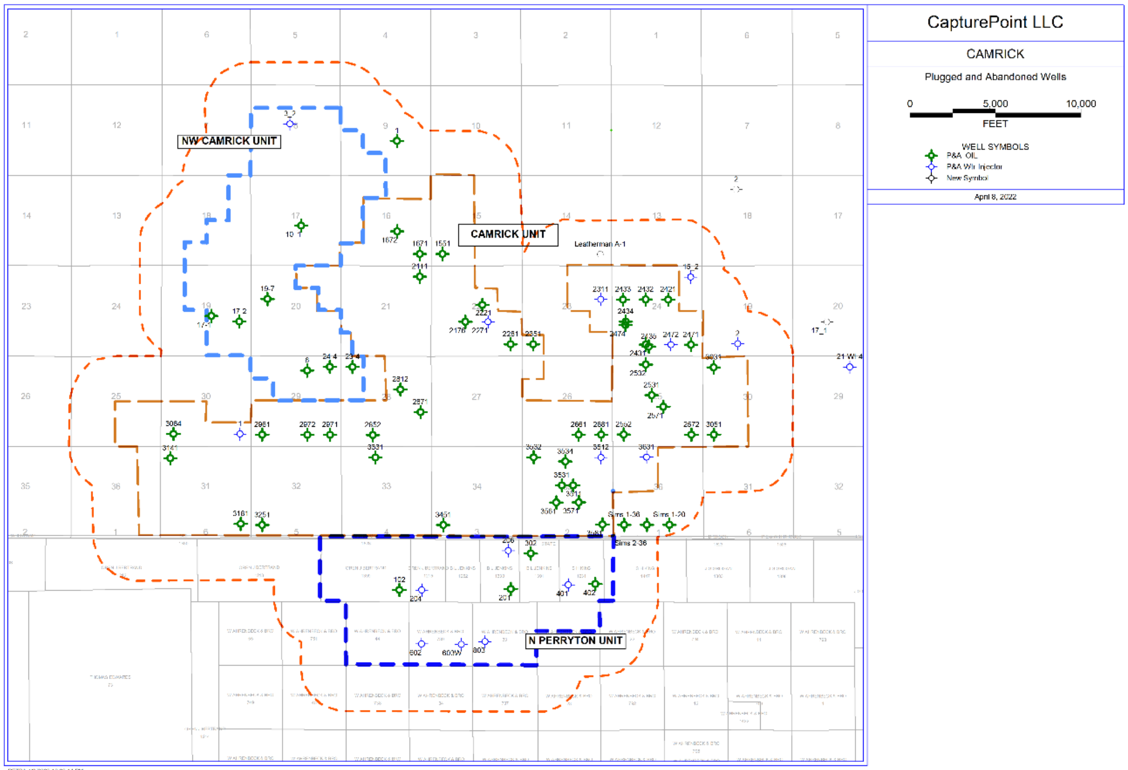

Figure 4.2-1. Plugged and Abandoned Wells in the CFA.

4.2.2 Injection Wells

Mechanical integrity testing (MIT) is an essential requirement of the UIC program in demonstrating that injection wells themselves do not act as conduits for leakage into underground sources of drinking water (USDW) and to the surface environment. TRRC Rule 46 requirements include special equipment requirements (e.g., tubing and packer) and modification; records maintenance; monitoring and reporting; testing; plugging; and penalties for violations of the rule. Permit revocation may result as a consequence of noncompliance. (See Section 2.3.6) The TRRC and the OCC detail all the requirements for the Class II permits issued to CapturePoint. These rules ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Figure 4.2-2 shows the active injection wells in the CFA. CapturePoint concludes that leakage of CO_2 to the surface through active injection wells is unlikely.

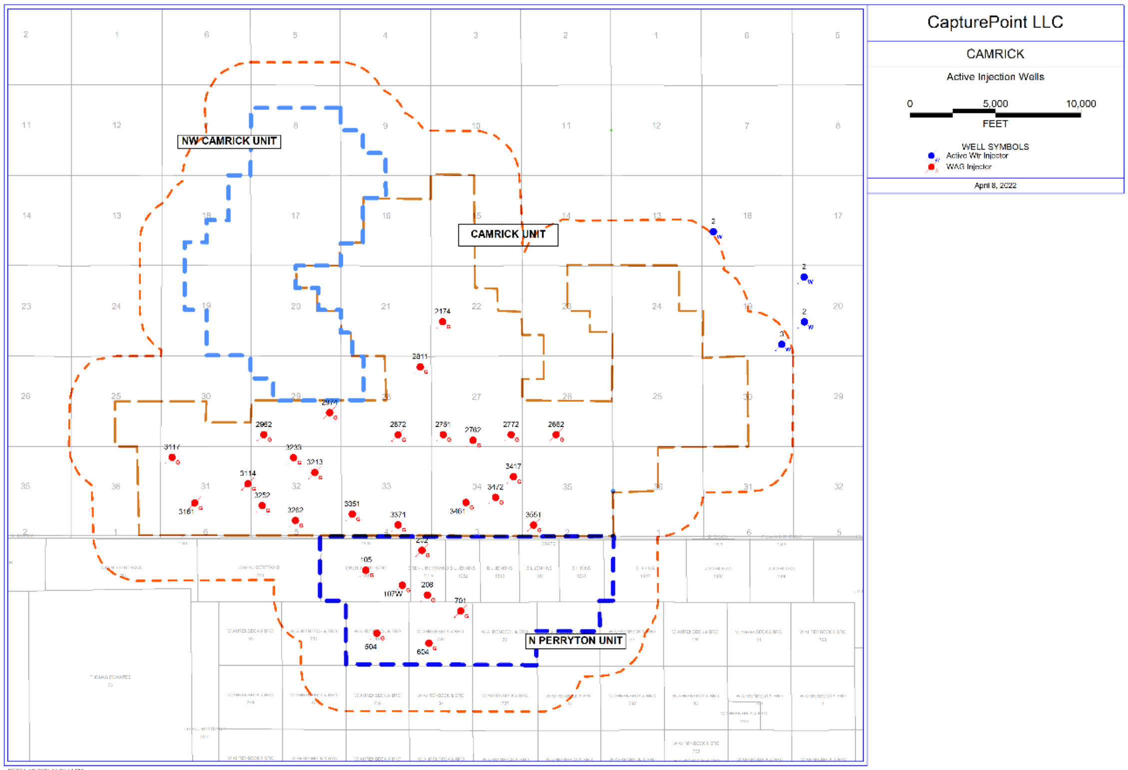

Figure 4.2-2. Active Injection Wells in the CFA.

4.2.3 Production Wells

Some of the original field wells drilled as oil wells were reclassified, administratively, to gas wells per OAC Title 165:10-1-6 paragraph (d), because of the gas-oil ratio growth due to reservoir depletion. Hence, there is no difference in well construction. (See Section 2.3.6) As the field is being further developed for enhanced oil recovery, these gas wells have been reclassified to oil wells per OCC regulations and will be monitored for leakage. (See Section 4.7) Figure 4.2-3 shows the active oil production wells in the CFA. Once EOR operations commence, the energy content of the produced gas drops and cannot be sold; therefore, any inactive gas wells are either reclassified to oil producers, or activated to WAG injectors, as described earlier. (See Section 4.2.2) However, as the project develops in the CFA additional production wells may be added and will be constructed according to the relevant rules of the OCC and the TRRC. Additionally, inactive wells may become active according to the rules of the OCC and the TRRC.

During production, oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by a differential pressure where the bottom hole wellbore pressure is less than the reservoir pressure. These lower pressure fluids, which also contains CO_2, are contained by the casing, tubing, wellhead, and flowline all the way to the CTB. CapturePoint concludes that leakage of CO_2 to the surface through production wells is unlikely.

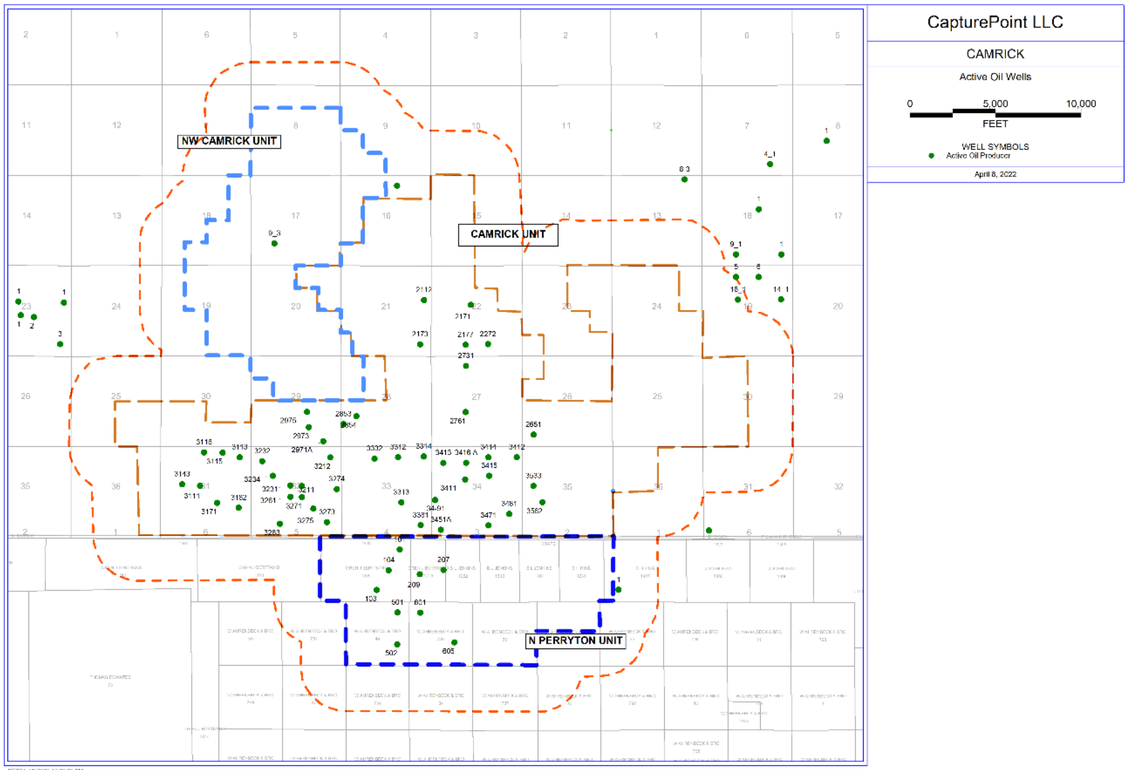

Figure 4.2-3. Active Oil Production Wells in the CFA.

4.2.4 Inactive Wells

Figure 4.2-4 shows all of the inactive wells in the CFA. The OCC has regulations for temporally abandoned/not plugged (TA) and terminated order wells/UIC not plugged (TM) and likewise the TRRC has regulations for inactive wells.

Inactive wells have a cast iron bridge plug set or long cement plugs placed above the existing perforations to isolate the reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change. CapturePoint concludes that leakage of CO_2 to the surface through inactive wells is unlikely.

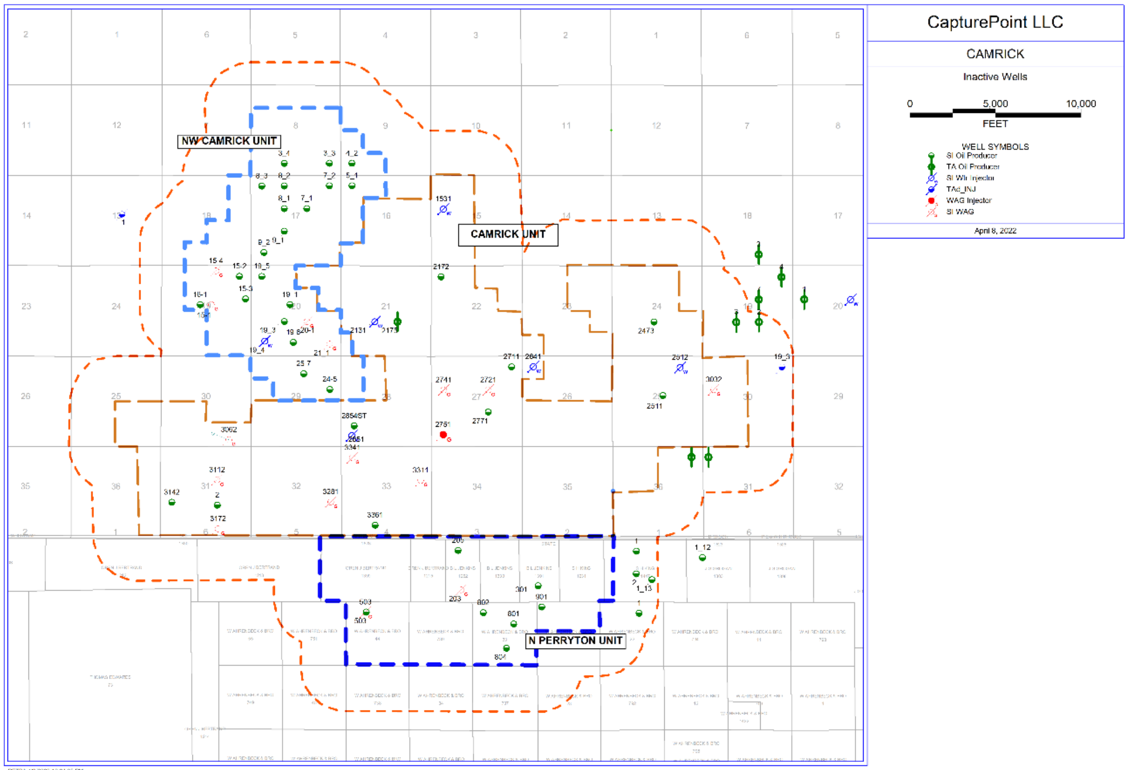

Figure 4.2-4. Inactive wells in the CFA

4.2.5 New Wells

As the project develops, new production wells and injection wells may be added to the CFA. All new wells will be constructed according to the relevant rules for the OCC and the TRRC which ensure protection of subsurface and surface resources, and the environment.

All wells in Oklahoma oilfields and all wells in Texas oilfields, including both injection and production wells, are regulated by the OCC and the TRRC, respectively, which has primacy to implement the UIC Class II programs.

Rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. Briefly current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface water.
- That wells file a completion report including basic electric logs.
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.

- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs.

New well construction is based on existing best practices, established during the drilling of existing wells in CFA and follows the OCC and the TRRC rules, which significantly limits any potential leakage from well pathways. Additionally, the existing wells followed the OCC and the TRRC rules.

In public databases, the area of CFA plus one mile past the unit boundary contains over 100 wells that were drilled deeper than the Morrow formation and none of these wells were productive in reservoirs deeper than the Morrow. Therefore, it is very unlikely that anyone will ever drill through the AMA reservoir in the future. In the event a well is drilled within the AMA, the operator would be required to follow all the OCC and the TRRC rules and procedures in the drilling the well and the potential for leakage would be similar to any well that CapturePoint drills within the AMA. In addition, CapturePoint's visual inspection process during routine field operation will identify any unapproved drilling activity in the CFA.

4.3 Leakage from Faults and Bedding Plane Partings

Primary seals at CFA have been demonstrated to be mechanically very competent (see Section 2.2.2), thus the main concern of CO_2 migration at CFA is via seal bypass systems along fracture networks. The following lines of analysis have been used to assess this risk in the area.

4.3.1 Prescence of Hydrocarbons

The first and foremost argument against present day up-fault transmissibility is the 75 MMB of oil that was found trapped in the reservoir. If significant escape pathways existed, oil would have drained from the reservoir prior to the current day.

4.3.2 Fracture analysis

At the CFA, the work done at the Farnsworth Unit is analogous, where small aperture fractures were noted but not common in most of the reservoir cores examined but most of these fractures appear to be drilling induced. Fractures in the Thirteen Finger limestone caprock were described using an industry-standard format for fracture class type, orientation, fracture dip, type of mineral fill, fracture porosity, fracture spacing, and intensity. Again, drilling induced fractures are most common. Natural mineral-filled fractures are quite rare, were formed during diagenesis at shallow depths, and are of late Carboniferous age. Unless significantly damaged by large changes in reservoir pressure, they are highly unlikely to provide migration pathways.

In the unlikely event CO_2 leakage occurs as a result of leakage through the faults and fractures, it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.4 Lateral Fluid Movement

The Morrow strata in the Oklahoma and Texas Panhandle was primarily a deltaic sequence that prograded toward the southeast, resulting in deposition of mainly shales with lenticular, discontinuous coarse sandstones separated with very fine sandstone, minor conglomerates, and shale. The likelihood of any extensive migration of fluid outside of the AMA is very low.

Since CO_2 is lighter than the water remaining in the reservoir, it will migrate to the top of each lenticular structure as it is filled. The producing wells, which create low pressure points in the field, will drain the water and keep the CO_2 within each discontinuous sandstone.

4.5 Leakage through Confining/Seal system

At the CFA, the work done at the Farnsworth Unit will apply, where a variety of analytical methods were used for caprock (confining system) analysis, and the results should be the same for the CFA. Petrologic examination included standard thin section petrography and backscattered electron microscopy. Petrophysical analytical methods include retort analysis, pulse-decay permeability measurement, pressure decay permeability analysis for tight rocks, and mercury injection porosimetry, which is also known as mercury injection capillary pressure (MICP). Geomechanical analysis involved a standard series of mechanical tests: Brazil tension, unconfined compression, triaxial compression, and multi-stress compression.

Results of the MICP analysis show that the mudstone lithologies in the Morrow Shale and Thirteen Finger Limestone can support CO_2 column heights of ~1,000 to 10,000 feet. At an order of magnitude over the thickness of the Morrow reservoir, this should prove an effective seal for CO_2 storage in the Morrow B injection horizon.

Failure analyses show that the Morrow B sands are weaker than overlying lithologies, so that any fracture initiation around the injection well would not be expected to propagate into the overlying sealing units. Mechanical properties of the overlying shale and limestones provide an interesting and effective combination of strength and elasticity. Limestone layers are strong but brittle, while the shale layers are weaker but sufficiently ductile to prevent extensive fracture propagation.

It is unlikely for hydrocarbon migration pathways that charged the Morrow reservoir to be potential CO_2 migration pathways via primary pore networks today. Any potential CO_2 migration would be most likely due to leakage from wellbores or bypass through fault and fracture networks, discussed in Sections 4.2 and 4.3.

In the unlikely event CO_2 leakage occurs as a result of leakage through the confining seal it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.6 Natural and Induced Seismic Activity

Figure 4.6-1 shows the map of earthquakes with magnitudes measured at greater than 2.5 as defined by the United States Geological Survey (USGS). While past earthquake data cannot predict future earthquakes, the small number of events near CFA after the waterflood operations were initiated in 1969 implies the area is not seismically sensitive to injection. Also, no documentation exists that any of the distant earthquake events caused a disruption in injectivity or damage to any of the wellbores in CFA.

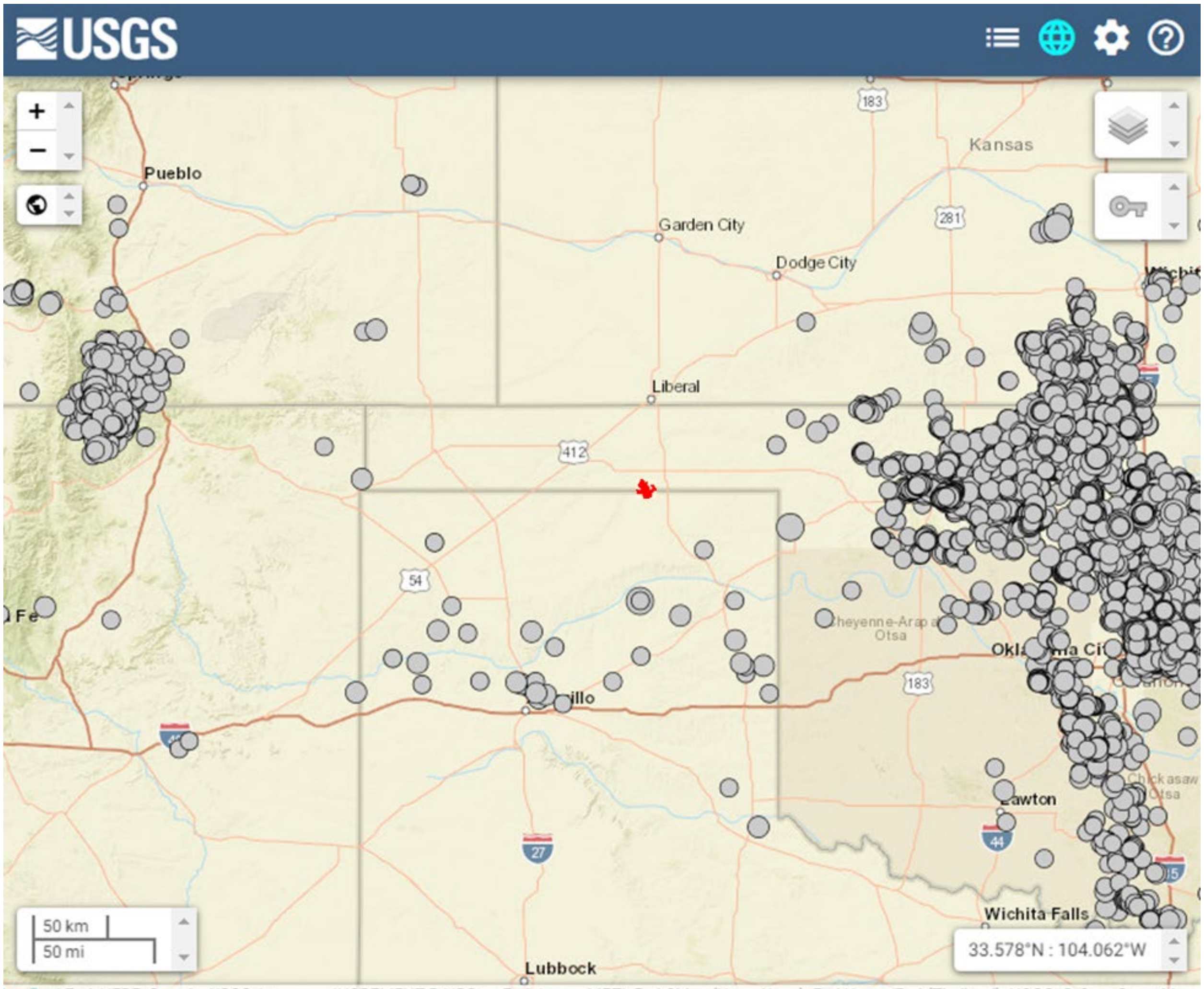

Figure 4.6-1. USGS earthquakes (+2.5 magnitude) for last 40 years with CFA highlighted red.

There is no direct evidence that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the CFA.

In the unlikely event that induced seismicity resulted in a pathway for material amounts of CO_2 to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would lead to further investigation.

4.7 Strategy for Detection and Response to CO_2 loss

As discussed above, the potential sources of leakage include fairly routine issues, such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment (well bores), and unique events such as induced fractures. Table 1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, CapturePoint's standard response, and other applicable regulatory programs requiring similar reporting.

The potential CO_2 losses discussed in the table are identified by type. Once the type is reported to a response manager the correct resources and personnel can be mobilized to develop the optimal response procedure. The procedure will address and mitigate further CO_2 leakage.

Table 1 Response Plan for CO_2 Loss

Known Potential Leakage Risks	Monitoring Methods and Frequency	Anticipated Response Plan
Tubing Leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days
Casing Leak	Weekly field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days
Wellhead Leak	Weekly field inspection	Workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations (weekly inspection but field personnel present daily)	Maintain well kill procedures
Unplanned wells drilled through Morrow	Weekly field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Re-enter and reseal abandoned wells
Pumps, values, etc.	Weekly field inspection	Workover crews respond within days
Leakage along faults	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near faults
Leakage laterally	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Fluid management along lease lines
Leakage through induced fractures	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near seismic event

4.8 Strategy for Quantifying CO_2 loss

Major CO_2 losses are typically event-driven and require a process to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. CapturePoint will use Subpart W techniques to estimate leakages only on equipment and ensure those results are consistently represented in the Subpart RR report. Any event-driven leakage quantification reported in Subpart RR for surface leaks will use other techniques.

Given the uncertainty concerning the nature and characteristics of leaks that will be encountered, it is not clear the method for quantifying the volume of leaked CO_2 that would be most appropriate. In the event leakage occurs, CapturePoint will determine the most appropriate method for quantifying the volume leaked and will report the methodology used as required as part of the annual Subpart RR submission.

Any volume of CO_2 detected leaking to the surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 Subpart W or engineering estimates of leak amounts based on measurements in the subsurface, CapturePoint's field experience, and other factors such as the frequency of inspection. As indicated in Section 6.4, leaks will be documented, and the records of leakage events will be retained in the electronic environmental documentation and reporting system, which consists of reports stored on servers, with information uploaded into third party software.

Available studies of actual well leaks and natural analogs (e.g., naturally occurring CO_2 geysers) suggest that the amount released from routine leaks would be small as compared to the amount of CO_2 that would remain stored in the formation.

5 Strategy for Determining CO_2 Baselines for CO_2 Monitoring

Atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values for soil measurement in the CFA area, per the characterization, monitoring and well data collected by the Southwest Regional Partnership on Carbon Sequestration (SWP) in the analogous Farnsworth Unit.

5.1 Site Characterization and Monitoring

As described in Sections 2.2.2 and 2.4, the Morrow B sandstone is isolated both above and below by shale units of the Morrow. The primary seal consists of 180 – 200 ft of Morrow shale and Thirteen Finger Limestone which in turn is overlain by over a thousand feet of younger shale and limestone. These units provide a suitable seal to prevent the migration of CO_2 out of the injection reservoir. Additionally, no significant faults or fracture zones that cut across the seal units have been identified in the CFA, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented.

5.2 Groundwater monitoring

CapturePoint does not routinely pull water samples from the Ogallala water wells. However, samples are pulled when OCC injection permits are submitted in Oklahoma. No indication of fluid leakage has been identified from any of these in the CFA area. CapturePoint is unlikely to continue monitoring USDW wells for CO_2 or brine contamination, as characterization of the Morrow (see section 5.1) has suggested minimal risk of groundwater contamination from CO_2 leakage from this depth.

5.3 Soil CO_2 monitoring

Atmospheric CO_2 values at the Farnsworth Unit have been determined by a SWP eddy tower installation. In winter 2019, the eddy system malfunctioned and has not been repaired due to COVID travel restrictions. However, the atmospheric CO_2 concentration data from the eddy tower were in very good agreement with values obtained from the NOAA Global Monitoring Laboratory station in Moody, Texas (Station: WKT). Since the CFA area is in close proximity to the Farnsworth Unit, atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values.

5.4 Visual Inspection

CapturePoint operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage.

5.5 Well Surveillance

CapturePoint adheres to the requirements of OAC Title 165:10-5 for the OCC and of TAC Rule 46 for the TRRC governing fluid injection into productive reservoirs. Rule 46 includes requirements for monitoring, reporting, and testing of Class II injection wells. Furthermore, the OCC and the TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well if they are deemed necessary.

CapturePoint also adheres to the requirements of OAC Title 165:10-7 for the OCC and TAC Rule 20 for the TRRC governing the notification of fires, breaks, leaks, or escapes. Rule 20 requires that all operators report leaks to the OCC or the TRRC including measured or estimated quantities of product leaked.

6 Site specific considerations for determining the Mass of CO_2 Sequestered

Of the twelve RR equations in 98.443 of Subpart RR, the following are relevant to CapturePoint's operations.

6.1 Determining Mass of CO_2 received

CapturePoint currently receives CO_2 at its CFA facility through its own pipeline from the Arkalon Ethanol plant in Liberal, Kansas. CapturePoint also recycles CO_2 from its production wells in the CFA.

$$_{2T\ ,r} = \sum_{p\ =1}^{4} (Q_{\ r\ ,p} - S_{\ r\ ,p}) * D \ * C_{\ 2,p\ ,r}$$ (Equation RR-2)

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into the well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

6.2 Determining Mass of CO_2 Injected

CapturePoint injects CO_2 into the injection wells listed in Appendix 1.

$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$ (Equation RR-5)

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

6.3 Determining Mass of CO_2 produced from Oil Wells

CapturePoint also recycles CO_2 from its production wells which are part of its operations in the CFA. Therefore, the following equation is relevant to its operations.

$$CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} * D * C_{CO_{2,p,w}} \quad \text{(Equation RR-8)}$$

Where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Volumetric gas flow rate measurement for separator w in quarter p at standard conditions (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,w}}$ = CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator.

To aggregate production data, CapturePoint will sum the mass of all of the CO_2 separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 below:

$$CO_{2P} = (1 + X) * \sum_{w=1}^{W} CO_{2,w} \quad \text{(Equation RR-9)}$$

Where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) through all separators in the reporting year.

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2, expressed as a decimal fraction), CU is 0.00236 and NPU is 0.00454 at the last sample.

w = Separator.

6.4 Determining Mass of CO_2 emitted by Surface Leakage

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations.

CapturePoint will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 below:

$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$ (Equation RR-10)

where:

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

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

x = Leakage pathway.

6.5 Determining Mass of CO_2 sequestered

The following Equation RR-11 pertains to facilities that are actively producing oil or natural gas.

$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP}$ (Equation RR-11)

Where:

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

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

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

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

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

CO_{2FP} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W of the GHGRP.

7 Estimated Schedule for Implementation of MRV plan

CapturePoint expects to begin implementing the approved MRV plan when the new CO_2 capture facility is operational, September 1, 2022.

8 GHG monitoring and Quality Assurance Program

CapturePoint will meet the monitoring and QA/QC requirements of 98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 98.444 (d).

8.1 GHG monitoring

As required by 40 CFR 98.3(g)(5)(i), CapturePoint's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

8.1.1 General

Measurement of CO_2 *Concentration* – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GSA) standards.

Measurement of CO_2 *Volume* – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. CapturePoint will adhere to the American Gas Association (AGA) Report #3 – (ORIFICE METERING OF NATURAL GAS AND OTHER RELATED HYDROCARBON FLUIDS)

8.1.2 CO_2 Received

Daily fermentation CO_2 purchased is received via the pipeline from the Arkalon ethanol plant in Liberal, Kansas, and is measured using a volumetric totalizer, which uses accepted flow calculations for CO_2 according to the AGA Report #3.

8.1.3 CO_2 Injected

Daily CO_2 injection is recorded by combining the totals for the recycle compressor meter and the received CO_2 meter from Arkalon based on what's delivered on a 24-hour basis. This data is taken from the meter daily and stored in CapturePoint's data warehouse for records and reservoir management.

8.1.4 CO_2 Produced

The point of produced gas measurement is from a meter downstream of the compressors prior to being combined with purchase CO_2. The produced gas is sampled at least quarterly for the CO_2 content.

8.1.5 CO_2 Emissions from equipment leaks and vented emissions of CO_2

As required by 98.444 (d), CapturePoint will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead and between the flow meter used to measure production quantity and the production wellhead.

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations. The default emission factors for production equipment are applied to the carbon capture utilization and storage (CCUS) injection operations reporting under Subpart RR.

8.1.6 Measurement Devices

As required by 40 CFR 98.444(e), CapturePoint will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration.
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meters are National Institute of Standards and Technology (NIST) traceable.

8.2 QA/QC procedures

CapturePoint will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

8.3 Estimating missing data

CapturePoint will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

A quarterly flow rate of CO_2 received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.

A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.

A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

8.4 Revisions of the MRV plan

CapturePoint will revise the MRV Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

9 Records Retention

CapturePoint will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, CapturePoint will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.
(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:
    (i) The GHG emissions calculations and methods used.
    (ii) Analytical results for the development of site-specific emissions factors, if applicable.
    (iii) The results of all required analyses.
    (iv) Any facility operating data or process information used for the GHG emission calculations.
(3) The annual GHG reports.
(4) Missing data computations. For each missing data event, CapturePoint will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
(5) A copy of the most recent revision of this MRV Plan.
(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(9) Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(10) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(11) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
(12) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
(13) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.
(14) Any other records as specified for retention in this EPA-approved MRV plan.

10 Appendices

Appendix 1 – CFA Wells

Table A1.1 – Production Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2112	35007353570000	Oil Prod	Active	CO_2	1	0
CU 2171	35007354120000	Oil Prod	Active	CO_2	1	0
CU 2173	35007354140000	Oil Prod	Active	CO_2	1	0
CU 2177	35007222340000	Oil Prod	Active	CO_2	1	0
CU 2272	35007224530000	Oil Prod	Active	CO_2	1	0
CU 2651	35007362650000	Oil Prod	Active	CO_2	1	0
CU 2731	35007359750000	Oil Prod	Active	CO_2	1	0
CU 2761	35007350590000	Oil Prod	Active	CO_2	1	0
CU 2853	35007250840000	Oil Prod	Active	CO_2	1	0
CU 2854	35007250850000	Oil Prod	Active	CO_2	1	0
CU 2971A	35007256700000	Oil Prod	Active	CO_2	1	0
CU 2973	35007213750000	Oil Prod	Active	CO_2	1	0
CU 2975	35007223730000	Oil Prod	Active	CO_2	1	0
CU 3111	35007350600000	Oil Prod	Active	CO_2	1	0
CU 3113	35007359460000	Oil Prod	Active	CO_2	1	0
CU 3115	35007251710000	Oil Prod	Active	CO_2	1	0
CU 3116	35007252570000	Oil Prod	Active	CO_2	1	0
CU 3143	35007250860000	Oil Prod	Active	CO_2	1	0
CU 3171	35007359600000	Oil Prod	Active	CO_2	1	0
CU 3182	35007249250000	Oil Prod	Active	CO_2	1	0
CU 3211	35007352150000	Oil Prod	Active	CO_2	1	0
CU 3212	35007352690000	Oil Prod	Active	CO_2	1	0
CU 3231	35007001820000	Oil Prod	Active	CO_2	1	0
CU 3232	35007352720000	Oil Prod	Active	CO_2	1	0
CU 3234	35007212010000	Oil Prod	Active	CO_2	1	0
CU 3261	35007352170000	Oil Prod	Active	CO_2	1	0
CU 3263	35007251640000	Oil Prod	Active	CO_2	1	0
CU 3271	35007352160000	Oil Prod	Active	CO_2	1	0
CU 3273	35007252580000	Oil Prod	Active	CO_2	1	0
CU 3274	35007253140000	Oil Prod	Active	CO_2	1	0
CU 3275	35007254040000	Oil Prod	Active	CO_2	1	0
CU 3312	35007360800000	Oil Prod	Active	CO_2	1	0
CU 3313	35007254370000	Oil Prod	Active	CO_2	1	0
CU 3314	35007254030000	Oil Prod	Active	CO_2	1	0
CU 3332	35007254020000	Oil Prod	Active	CO_2	1	0
CU 3381	35007360780000	Oil Prod	Active	CO_2	1	0
CU 3411	35007351700000	Oil Prod	Active	CO_2	1	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3412	35007351720000	Oil Prod	Active	CO_2	1	0
CU 3413	35007351730000	Oil Prod	Active	CO_2	1	0
CU 3414	35007005220000	Oil Prod	Active	CO_2	1	0
CU 3415	35007211170000	Oil Prod	Active	CO_2	1	0
CU 3416A	35007252590000	Oil Prod	Active	CO_2	1	0
CU 3451A	35007256710000	Oil Prod	Active	CO_2	1	0
CU 3471	35007351750000	Oil Prod	Active	CO_2	1	0
CU 3481	35007351710001	Oil Prod	Active	CO_2	1	0
CU 3491	35007254330000	Oil Prod	Active	CO_2	1	0
CU 3533	35007206880000	Oil Prod	Active	CO_2	1	0
CU 3562	35007255050000	Oil Prod	Active	CO_2	1	0
NPU 101	42357010440000	Oil Prod	Active	CO_2	1	0
NPU 103	42357010060000	Oil Prod	Active	CO_2	1	0
NPU 104	42357000050000	Oil Prod	Active	CO_2	1	0
NPU 207	42357302000000	Oil Prod	Active	CO_2	1	0
NPU 209	42357333830000	Oil Prod	Active	CO_2	1	0
NPU 501	42357009140000	Oil Prod	Active	CO_2	1	0
NPU 502	42357024100000	Oil Prod	Active	CO_2	1	0
NPU 601	42357008420000	Oil Prod	Active	CO_2	1	0
NPU 605	42357333840000	Oil Prod	Active	CO_2	1	0
NWCU 3-1	35007360850000	Gas Prod	Active	CO_2	1	0
NWCU 9-3	35007249430000	Oil Prod	Active	CO_2	1	0
CU 2172	35007354130000	Oil Prod	Inactive	CO_2	0	0
CU 2175	35007354160000	Oil Prod	Inactive	CO_2	0	0
CU 2473	35007211990000	Oil Prod	Inactive	CO_2	0	0
CU 2511	35007350790000	Oil Prod	Inactive	CO_2	0	0
CU 2711	35007359260000	Oil Prod	Inactive	CO_2	0	0
CU 2771	35007359850000	Oil Prod	Inactive	CO_2	0	0
CU 3142	35007222350000	Oil Prod	Inactive	CO_2	0	0
CU 3361	35007352670000	Oil Prod	Inactive	CO_2	0	0
NPU 205	42357008070000	Oil Prod	Inactive	CO_2	0	0
NPU 301	42357022080000	Oil Prod	Inactive	CO_2	0	0
NPU 801	42357004630000	Oil Prod	Inactive	CO_2	0	0
NPU 802	42357004620000	Oil Prod	Inactive	CO_2	0	0
NPU 804	42357201730000	Oil Prod	Inactive	CO_2	0	0
NPU 901	42357000660000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-2	35007350870000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-3	35007210790000	Oil Prod	Inactive	CO_2	0	0
NWCU 16-1	35007350720000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-1	35007360900000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-3	35007360920000	Oil Prod	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
NWCU 19-4	35007360930000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-5	35007360940000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-6	35007211250000	Oil Prod	Inactive	CO_2	0	0
NWCU 24-5	35007222710000	Oil Prod	Inactive	CO_2	0	0
NWCU 25-7	35007228000000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-3	35007360870000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-4	35007360880000	Oil Prod	Inactive	CO_2	0	0
NWCU 4-2	35007360740000	Oil Prod	Inactive	CO_2	0	0
NWCU 5-1	35007361050000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-1	35007360980000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-2	35007360990000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-1	35007360810000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-2	35007360820000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-3	35007208260000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-1	35007360950000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-2	35007360960000	Oil Prod	Inactive	CO_2	0	0
CU 1551	35007350740000	Oil Prod	P&A	CO_2	0	0
CU 1671	35007352180000	Oil Prod	P&A	CO_2	0	0
CU 2111	35007353560000	Oil Prod	P&A	CO_2	0	0
CU 2176	35007358870000	Oil Prod	P&A	CO_2	0	0
CU 2221	35007000490000	Oil Prod	P&A	CO_2	0	0
CU 2281	35007359220000	Oil Prod	P&A	CO_2	0	0
CU 2421	35007359350000	Oil Prod	P&A	CO_2	0	0
CU 2431	35007350330000	Oil Prod	P&A	CO_2	0	0
CU 2432	35007350340000	Oil Prod	P&A	CO_2	0	0
CU 2433	35007350350000	Oil Prod	P&A	CO_2	0	0
CU 2434	35007350360000	Oil Prod	P&A	CO_2	0	0
CU 2435	35007218800000	Oil Prod	P&A	CO_2	0	0
CU 2471	35007359080000	Oil Prod	P&A	CO_2	0	0
CU 2531	35007361090000	Oil Prod	P&A	CO_2	0	0
CU 2532	35007361100000	Oil Prod	P&A	CO_2	0	0
CU 2552	35007359760000	Oil Prod	P&A	CO_2	0	0
CU 2571	35007350730000	Oil Prod	P&A	CO_2	0	0
CU 2572	35007359320000	Oil Prod	P&A	CO_2	0	0
CU 2661	35007361990000	Oil Prod	P&A	CO_2	0	0
CU 2681	35007350320000	Oil Prod	P&A	CO_2	0	0
CU 2852	35007301360000	Oil Prod	P&A	CO_2	0	0
CU 2961	35007358760000	Oil Prod	P&A	CO_2	0	0
CU 2971	35007358750000	Oil Prod	P&A	CO_2	0	0
CU 2972	35007358780000	Oil Prod	P&A	CO_2	0	0
CU 3031	35007359560000	Oil Prod	P&A	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3051	35007300380000	Oil Prod	P&A	CO_2	0	0
CU 3064	35007254270000	Oil Prod	P&A	CO_2	0	0
CU 3141	35007359610000	Oil Prod	P&A	CO_2	0	0
CU 3181	35007359470000	Oil Prod	P&A	CO_2	0	0
CU 3251	35007352710000	Oil Prod	P&A	CO_2	0	0
CU 3331	35007200750000	Oil Prod	P&A	CO_2	0	0
CU 3451	35007351690000	Oil Prod	P&A	CO_2	0	0
CU 3511	35007359730000	Oil Prod	P&A	CO_2	0	0
CU 3531	35007350850000	Oil Prod	P&A	CO_2	0	0
CU 3532	35007359950000	Oil Prod	P&A	CO_2	0	0
CU 3534	35007211180000	Oil Prod	P&A	CO_2	0	0
CU 3561	35007359830000	Oil Prod	P&A	CO_2	0	0
CU 3571	35007359980000	Oil Prod	P&A	CO_2	0	0
CU 3581	35007359970000	Oil Prod	P&A	CO_2	0	0
CU 3631	35007301000000	Oil Prod	P&A	CO_2	0	0
CU 1672	35007352190000	Oil Prod	P&A	CO_2	0	0
CU 2351	35007350370000	Oil Prod	P&A	CO_2	0	0
CU 2474	35007228200000	Oil Prod	P&A	CO_2	0	0
CU 2812	35007352340000	Oil Prod	P&A	CO_2	0	0
CU 2871	35007359060000	Oil Prod	P&A	CO_2	0	0
NPU 102	42357021420000	Oil Prod	P&A	CO_2	0	0
NPU 201	42357001280000	Oil Prod	P&A	CO_2	0	0
NPU 302	42357022290000	Oil Prod	P&A	CO_2	0	0
NPU 402	42357022300000	Oil Prod	P&A	CO_2	0	0
NWCU 17-2	35007359620000	Oil Prod	P&A	CO_2	0	0
NWCU 10-1	35007361010000	Oil Prod	P&A	CO_2	0	0
NWCU 17-1	35007350710000	Oil Prod	P&A	CO_2	0	0
NWCU 19-7	35007224520000	Oil Prod	P&A	CO_2	0	0
NWCU 24-4	35007358770000	Oil Prod	P&A	CO_2	0	0
NWCU 25-6	35007358790000	Oil Prod	P&A	CO_2	0	0

Table A1.2 – Water Alternating Gas (WAG) Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 2662 (INJ)	35007362010000	WAG Inj	Active	CO_2	0	1
CU 2751 (INJ)	35007359440002	WAG Inj	Active	CO_2	0	1
CU 2762 (INJ)	35007213660000	WAG Inj	Active	CO_2	0	1
CU 2772 (INJ)	35007359860001	WAG Inj	Active	CO_2	0	1
CU 2811 (INJ)	35007352200000	WAG Inj	Active	CO_2	0	1
CU 2872 (INJ)	35007359070000	WAG Inj	Active	CO_2	0	1
CU 2962 (INJ)	35007212000000	WAG Inj	Active	CO_2	0	1
CU 2974 (INJ)	35007220770000	WAG Inj	Active	CO_2	0	1
CU 3114 (INJ)	35007206540000	WAG Inj	Active	CO_2	0	1
CU 3117 (INJ)	35007254000000	WAG Inj	Active	CO_2	0	1
CU 3161 (INJ)	35007359590002	WAG Inj	Active	CO_2	0	1
CU 3213 (INJ)	35007224570000	WAG Inj	Active	CO_2	0	1
CU 3233 (INJ)	35007206890000	WAG Inj	Active	CO_2	0	1
CU 3252 (INJ)	35007211020000	WAG Inj	Active	CO_2	0	1
CU 3262 (INJ)	35007206870000	WAG Inj	Active	CO_2	0	1
CU 3351 (INJ)	35007352680000	WAG Inj	Active	CO_2	0	1
CU 3371 (INJ)	35007360770000	WAG Inj	Active	CO_2	0	1
CU 3417 (INJ)	35007255060000	WAG Inj	Active	CO_2	0	1
CU 3461 (INJ)	35007351680000	WAG Inj	Active	CO_2	0	1
CU 3472 (INJ)	35007206940000	WAG Inj	Active	CO_2	0	1
CU 3551 (INJ)	35007359840000	WAG Inj	Active	CO_2	0	1
NPU 105 (INJ)	42357000030000	WAG Inj	Active	CO_2	0	1
NPU 107W (INJ)	42357333770000	WAG Inj	Active	CO_2	0	1
NPU 202WI (INJ)	42357021500000	WAG Inj	Active	CO_2	0	1
NPU 208 (INJ)	42357327410000	WAG Inj	Active	CO_2	0	1
NPU 701 (INJ)	42357008410000	WAG Inj	Active	CO_2	0	1
NPU 504 (INJ)	42357329480000	WAG Inj	Active	CO_2	0	1
NPU 604W (INJ)	42357330870000	WAG Inj	Active	CO_2	0	1
CU 1531 (INJ)	35007359990000	WAG Inj	Inactive	CO_2	0	0
CU 2131 (INJ)	35007362700000	WAG Inj	Inactive	CO_2	0	0
CU 2512 (INJ)	35007350780000	WAG Inj	Inactive	CO_2	0	0
CU 2641 (INJ)	35007359250001	WAG Inj	Inactive	CO_2	0	0
CU 2721 (INJ)	35007359870001	WAG Inj	Inactive	CO_2	0	0
CU 2741 (INJ)	35007359430000	WAG Inj	Inactive	CO_2	0	0
CU 2851 (INJ)	35007355420001	WAG Inj	Inactive	CO_2	0	0
CU 3032 (INJ)	35007359580000	WAG Inj	Inactive	CO_2	0	0
CU 3062 (INJ)	35007253090000	WAG Inj	Inactive	CO_2	0	0
CU 3112 (INJ)	35007359450001	WAG Inj	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 3172 (INJ)	35007251690000	WAG Inj	Inactive	CO_2	0	0
CU 3281 (INJ)	35007352700003	WAG Inj	Inactive	CO_2	0	0
CU 3311 (INJ)	35007360790000	WAG Inj	Inactive	CO_2	0	0
CU 3341 (INJ)	35007353530000	WAG Inj	Inactive	CO_2	0	0
NPU 203W (INJ)	42357008270000	WAG Inj	Inactive	CO_2	0	0
NPU 503 (INJ)	42357009150001	WAG Inj	Inactive	CO_2	0	0
NWCU 15-1 (INJ)	35007350860000	WAG Inj	Inactive	CO_2	0	0
NWCU 15-4 (INJ)	35007224510000	WAG Inj	Inactive	CO_2	0	0
NWCU 20-1 (INJ)	35007360760000	WAG Inj	Inactive	CO_2	0	0
NWCU 21-1 (INJ)	35007361020000	WAG Inj	Inactive	CO_2	0	0
CU 2271 (INJ)	35007359230000	WAG Inj	P&A	CO_2	0	0
CU 2311 (INJ)	35007362000000	WAG Inj	P&A	CO_2	0	0
CU 2472 (INJ)	35007359090000	WAG Inj	P&A	CO_2	0	0
CU 3061 (INJ)	35007359820000	WAG Inj	P&A	CO_2	0	0
CU 3512 (INJ)	35007359740000	WAG Inj	P&A	CO_2	0	0
NPU 204W (INJ)	42357022520000	WAG Inj	P&A	CO_2	0	0
NPU 206W (INJ)	42357022510000	WAG Inj	P&A	CO_2	0	0
NPU 401W (INJ)	42357004520000	WAG Inj	P&A	CO_2	0	0
NPU 602W (INJ)	42357020230000	WAG Inj	P&A	CO_2	0	0
NPU 603W (INJ)	42357201720001	WAG Inj	P&A	CO_2	0	0
NPU 803W (INJ)	42357201710000	WAG Inj	P&A	CO_2	0	0
NWCU 14-1 (INJ)	35007350530000	WAG Inj	P&A	CO_2	0	0
NWCU 3-2 (INJ)	35007360860000	WAG Inj	P&A	CO_2	0	0

Table A1.3 – Water Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU WSW 1	35007355430001	Wtr Inj	Active	CO_2	0	1
NPU W 1W	42357300050002	Wtr Inj	Inactive	CO_2	0	0
CU 2551	35007350750000	Wtr Inj	P&A	CO_2	0	0

Appendix 2 – Referenced Regulations

U.S. Code > Title 26, INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1, NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits >

Section 45Q ..... Credit for carbon oxide sequestration

OCC > Title 165: CORPORATION COMMISSION > UNDERGROUND INJECTION CONTROL

Section

165:10-5-1 .... Classification of underground injection wells
165:10-5-2 .... Approval of injection wells or disposal wells
165:10-5-3 .... Authorization for existing enhanced recovery injection wells and existing disposal wells
165:10-5-4 .... Application for approval of enhanced recovery projects
165:10-5-5 .... Application for approval of injection and disposal operations
165:10-5-6 .... Testing and monitoring requirements for injection wells and disposal wells
165:10-5-7 .... Monitoring and reporting requirements for wells covered by 165:10-5-1
165:10-5-8 .... Liquid hydrocarbon storage wells
165:10-5-9 .... Duration of underground injection well orders or permits
165:10-5-10 ..... Transfer of authority to inject
165:10-5-11 ..... Notarized reports
165:10-5-12 ..... Application for administrative approval for the subsurface injection of onsite reserve pit fluids
165:10-5-13 ..... Application for permit for one time injection of reserve pit fluids
165:10-5-14 ..... Exempt aquifers
165:10-5-15 ..... Application for permit for simultaneous injection well

165:5-7-27 .... Application for approval of injection and disposal wells
165:5-7-29 .... Request for exception to certain underground injection well requirements
165:5-7-30 .... Amending existing orders or permits authorizing injection for injection, disposal, or LPG storage wells

TAC > Title 16 - Economic Regulation> Part 1 TRRC > Chapter 3 – Oil and Gas Division >

Rules

§3.37................ Statewide Spacing Rule
§3.38................ Well Densities
§3.39................ Proration and Drilling Units: Contiguity of Acreage and Exception Thereto
§3.40................ Assignment of Acreage to Pooled Development and Proration Units
§3.41................ Application for New Oil or Gas Field Designation and/or Allowable
§3.42................ Oil Discovery Allowable
§3.43................ Application for Temporary Field Rules
§3.45................ Oil Allowables
§3.46................ Fluid Injection into Productive Reservoirs
§3.47................ Allowable Transfers for Saltwater Injection Wells
§3.48................ Capacity Oil Allowables for Secondary or Tertiary Recovery Projects
§3.49................ Gas-Oil Ratio
§3.50................ Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive
§3.51................ Oil Potential Test Forms Required
§3.52................ Oil Well Allowable Production
§3.53................ Annual Well Tests and Well Status Reports Required
§3.54................ Gas Reports Required
§3.55................ Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering
§3.56................ Scrubber Oil and Skim Hydrocarbons
§3.57................ Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials
§3.58................ Certificate of Compliance and Transportation Authority; Operator Reports
§3.59................ Oil and Gas Transporter's Reports
§3.60................ Refinery Reports
§3.61................ Refinery and Gasoline Plants
§3.62................ Cycling Plant Control and Reports
§3.63................ Carbon Black Plant Permits Required
§3.70................ Pipeline Permits Required
§3.71................ Pipeline Tariffs
§3.72................ Obtaining Pipeline Connections
§3.73................ Pipeline Connection; Cancellation of Certificate of Compliance; Severance
§3.76................ Commission Approval of Plats for Mineral Development
§3.78................ Fees and Financial Security Requirements
§3.79................ Definitions
§3.80................ Commission Oil and Gas Forms, Applications, and Filing Requirements
§3.81................ Brine Mining Injection Wells
§3.83................ Tax Exemption for Two-Year Inactive Wells and Three-Year Inactive Wells
§3.84................ Gas Shortage Emergency Response
§3.85................ Manifest to Accompany Each Transport of Liquid Hydrocarbons by Vehicle
§3.86................ Horizontal Drainhole Wells
§3.91................ Cleanup of Soil Contaminated by a Crude Oil Spill
§3.93................ Water Quality Certification Definitions

Appendix 3 – References

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Appendix 4 – Abbreviations and Acronyms

2D – 2 dimensional
3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
ANSI – American National Standards Institute
API – American Petroleum Institute
AWT – All Well Test
ASTM - American Society for Testing and Materials
Bscf – billion standard cubic feet
B/D – barrels per day
bopd – barrels of oil per day
C4 – butane
C5 – pentane
C7 – heptane
C7+ - standard heptane plus
CCE – constant composition expansion
CCUS – carbon capture utilization and storage
CFA – Camrick Field Area
CFR – Code of Federal Regulations
cf – cubic feet
CH4 – methane
CO_2 – carbon dioxide
EOR – Enhanced Oil Recovery
EOS – Equation of State
EPA – US Environmental Protection Agency
ESD – Emergency Shutdown Device
GHG – Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
H_2S – hydrogen sulfide
lb – pound
mD – millidarcy(ies)
MICP – mercury injection capillary pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MMB – million barrels
MMP – minimum miscible pressure
MMscf – million standard cubic feet
MMstb – million stock tank barrels
MRV – Monitoring, Reporting, and Verification
MMMT – Million metric tonnes
MT – Metric tonne

NIST – National Institute of Standards and Technology
NAESB – North American Energy Standards Board
OAC – Oklahoma Administrative Code
OCC – Oklahoma Corporation Commission
OOIP – Original Oil-In-Place
OWC – oil water contact
PPM – Parts Per Million
psia – pounds per square inch absolute
PVT – pressure, volume, temperature
QA/QC – quality assurance/quality control
RMS – root mean square
SEM – scanning electron microscope
SWP - Southwest Regional Partnership on Carbon Sequestration
TAC – Texas Administrative Code
TA – Temporally Abandoned/not plugged
TD – total depth
TM – Terminated order wells/UIC not plugged
TRRC – Texas Railroad Commission
TSD – Technical Support Document
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water
WAG – Water Alternating Gas (Gas is recycled CO_2 and purchase CO_2)
XRD – x-ray diffraction

Appendix 5 – Conversion Factors

CapturePoint reports CO_2 at standard conditions of temperature and pressure as defined in the State of Texas in the Texas Administrative Code for the Oil and Gas Division, Rule 3.79 as follows:

> Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit.

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST). This online database is available at:

https://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner equation of state (EOS) at a wide range of temperature and pressures.

At State of Texas standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.002641684 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb - moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2{,}204.62\ lbs}$$

Where:

$$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$$

$$Density_{CO2} = 0.002641684$$

$$MW_{CO2} = 44.0095$$

$$Density_{CO2} = 5.2734\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.2734\ x\ 10^{-2}\frac{MT}{Mcf}$$

The conversion factor 5.2734×10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.