CapturePoint LLC

Wellman Field

Subpart RR Monitoring, Reporting and Verification (MRV) Plan

May 2024

Contents

1 Introduction

CapturePoint LLC operates a carbon dioxide (CO_2) enhanced oil recovery (EOR) project in the Wellman Field (WF) located in Terry County, Texas, approximately 10 miles southwest of the town of Brownfield for the primary purpose of EOR using CO_2 with a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The WF is comprised of the Wolfcamp Reef (WLFRF), the main producing reservoir. Production from the WLFRF is between 9,200-10,000 feet throughout the well-defined reef. The MRV plan was developed in accordance with 40 CFR §98.440-449 (Subpart RR) to provide for the monitoring, reporting, and verification of the quantity of CO_2 sequestered at the WF during a specified period of injection.

2 Facility Information

2.1 Reporter Number

544182 – WF

2.2 UIC Permit Class

The Oil and Gas Division of the Texas Railroad Commission (TRRC) regulates oil and gas activity in Texas. All wells in the WF (including production, injection, and monitoring wells) are permitted by TRRC through Texas Administrative Code (TAC) Title 16 Chapter 3. TRRC has primacy to implement the Underground Injection Control Class II program in the state for injection wells. All EOR injection wells in the WF are currently classified as UIC Class II wells.

2.3 Existing Wells

Wells in the WF are identified by Wellman Unit (WU) and their number, American Petroleum Institute (API) number, type, and status. The list of wells as of March 2023 is included in Section 12.1. Any changes in wells will be indicated in the annual report.

3 Project Description

This project takes place in the WF, an oil field located in West Texas that was first produced more than 70 years ago. WF is comprised of the WLFRF. The WLFRF is the main oil and gas producing unit, which is now under the sole operatorship of CapturePoint LLC. Water flooding was initiated in 1979 with CO_2 flooding beginning in 1983, in the WLFRF. The field is well characterized and is suitable for secure geologic storage. CapturePoint uses a continuous injection process to maintain a constant reservoir pressure. This is achieved with an injection to withdrawal ratio (IWR) at or near 1.

3.1 Project Characteristics

The WF was discovered in 1950 and started producing oil in the same year. The WLFRF began to produce in May 1950 and a waterflood was initiated in July 1979 in the flanks of the reef to push the oil column up towards the top of the structure. CO_2 flooding was then initiated in 1983 and was injected into the top of the structure for vertical CO_2 flooding. The entire reef is an oil-bearing zone that has been produced for years, swept by a waterflood, and is now CO_2 flooding from the top down for residual oil. This geologically well-defined reef system is an attractive target for EOR with CO_2 Capture and Sequestration.

A long-term CO_2 and hydrocarbon injection and production forecast for the WLFRF was developed using a dimensionless performance curve (DPC) approach. Using this approach, a total injection of approximately 100 million tonnes of CO_2 is forecasted over the life of the project ending in year 2061. Total injection is the volumes of stored CO_2 plus the volumes of CO_2 produced with oil. Figure 3-1 shows actual and projected CO_2 injection, production, and stored volumes in WF.

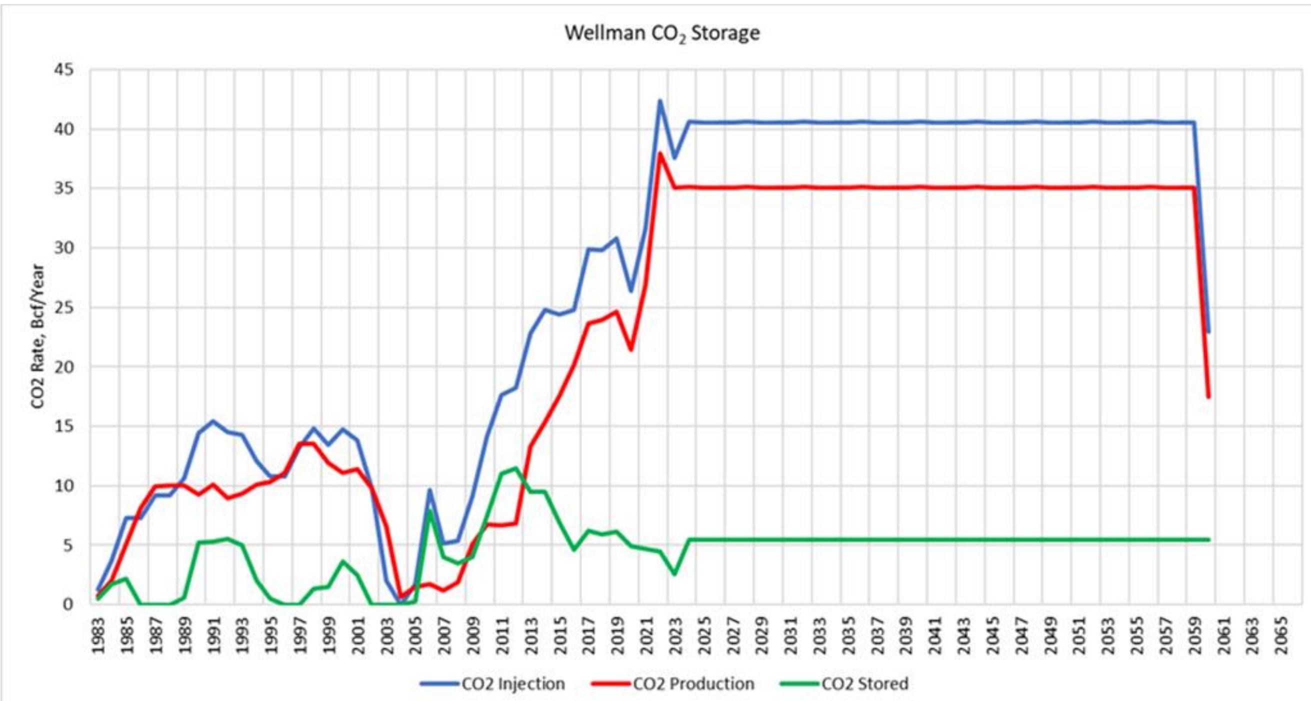
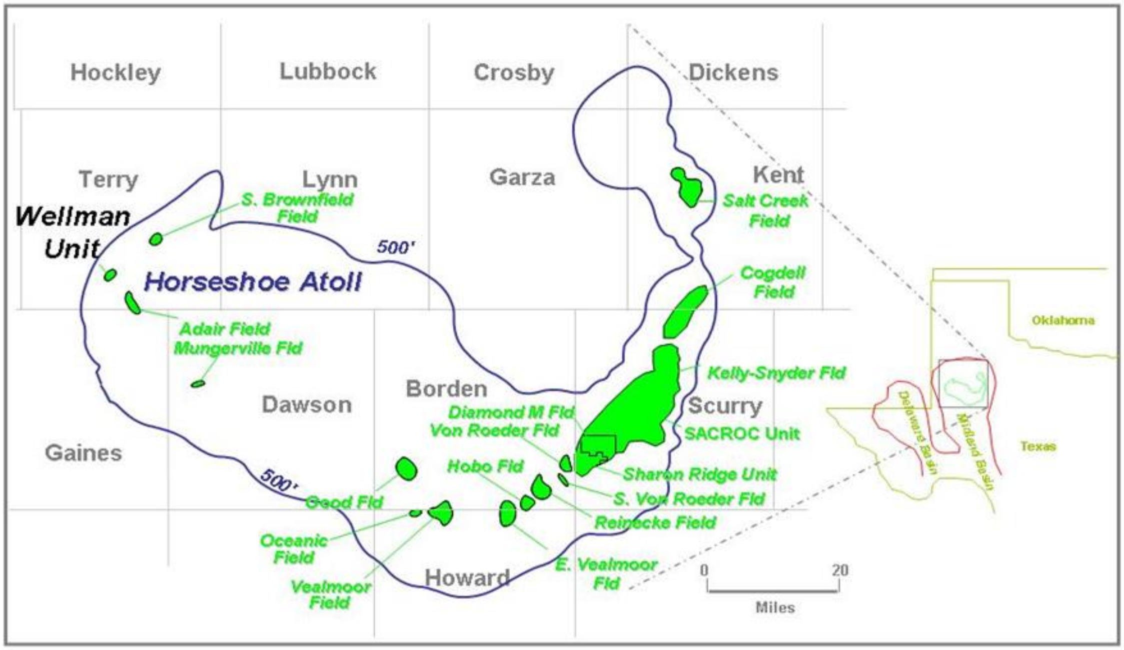


Figure 3-1 WF Historic and Forecast CO_2 Injection, Production, and Storage

3.2 Environmental Setting

The WF is in the NE portion of the Central Basin Platform in West Texas (See Figure 3-2). The productive portion of the WF is composed of the WLFRF.



Modified from Vest, 1970

Figure 3-2 Location of WF in West Texas

The WLFRF was developed on the far north-western edge of a larger Pennsylvanian reef trend known as the Horseshoe Atoll. The environment of deposition was shallow muddy (turbid) water with encroaching shales at the flank and eventually buried by terrigenous sediments (shales, siltstones, sands). Those sediments finally drowned out the reef and now form the primary seal for the reservoir. The structure is pinnacle reef like with two smaller bioherm buildups creating an overall structure oriented in a north to south direction (See Figure 3-4).

By the time the reef was deposited, the sinking of the Horseshoe Atoll was well underway, leaving a great deal of vertical accommodation space. As a result, the reef is steep-sided and slumping of the outer edges of the reef is common, as is mixing of the reef-slump (limestone) debris with shale from the overlying seal (Anderson, 1953). The peak of the reservoir occurs at approximately -5,900’SS and plunges below the original oil / water contact at -6,680’SS inside the boundaries of the Wellman Unit. Wolfcampian shales and siltstones, including the Hueco Formations, provide top and side seals for the Wellman oil trap. The Wolfcamp shales progress into the Spraberry series of siltstones, sands, and shales, with a few thin carbonate layers. This entire interval here is informally called the “Spraberry Group.” The Spraberry Group forms a cap of more than 1,400 feet of clastic rock above the reservoir (See Figure 3-3).

WELLMAN FIELD TYPE LOG & GENERALIZED STRATIGRAPHIC SECTION

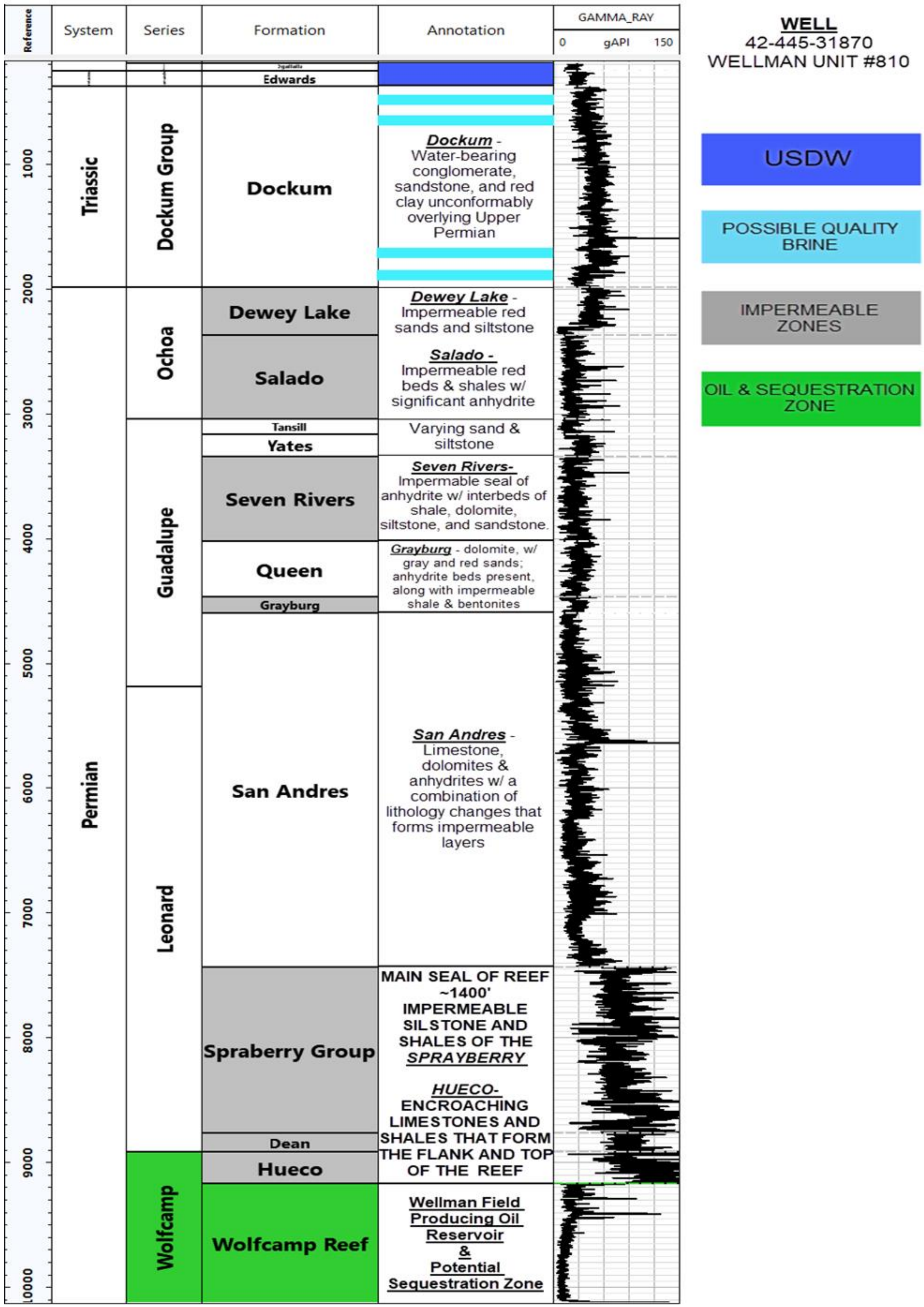


Figure 3-3 WF generalized stratigraphic section.

Wellman Field Stratigraphy

The Wellman Field produces from a Wolfcampian aged 299-280 million years ago (299-280 mya) limestone biohermal type reef. It was deposited on an isolated platform on the Pennsylvanian (320-299 mya) structure called the Horseshoe Atoll. The Horseshoe atoll is composed of bedded bioclastic limestone and limestone detritus that accumulated in the interior part of a developing intracratonic basin during late Paleozoic (355-280 mya) time. The reef environment was established early in the basin history and endured because of the lack of a significant terrigenous clastic source to fill the basin interior. Mixed types of bioclastic debris accumulated cyclically and the upper level of the reef complex was maintained near sea level as the basin subsided. About 1,800 ft of limestone accumulated during the Pennsylvanian (355-299 mya), with a primary dip as great as 8 percent that developed along the margins of the atoll. During early Permian time (299-280 mya) the reef was restricted to the southwest side of the atoll where more than 1,100 ft of additional limestone accumulated before death of the reef. The Horseshoe Atoll encompasses all or portions of 14 counties (Terry, Lynn, Garza, Kent, Scurry, Mitchell, Howard, Borden, Dawson, Gaines, Martin, Lubbock, Crosby, and Dickens); an area of approximately 8,100 square miles. The Wellman field is a pinnacle reef on the southwestern arm of the Horseshoe Atoll.

The following is a description of each formation in ascending order (Figure 3-3). All the formations are Permian (299-245 mya) in age through the Dewey Lake formation. The Dockum Group is Triassic (245-202 mya) in age and the Edwards and Ogalala are Late Tertiary (6-3 mya).

Wolfcamp Reef

The Wolfcampian (299-280 mya) Wolfcamp Reef is a fusilinid-algal packstone with vuggy and moldic porosity. With increasing depth, brachiopods, other bivalves, and crinoids are present. Bioturbation and some brecciated zones occur along with low amplitude stylolites.

Hueco Formation

The Late Wolfcampian (285-280 myo) Hueco Formation consists of interbedded limestones, sandstones, and shales. They interfinger to form the flank and caprock of the reef. Early deposition was almost exclusively shales and limestones. Influxes of clastics started with subsidence of the basin.

Dean

The Leonardian (280-279 mya) Dean Formation is a thin very fine-grained sandstone that grades upwards into laminated siltstones containing silty, bioturbated, mudstones.

Spraberry Group

The Early Leonardian (~281-278 mya) Spraberry Group consists of predominately silty mudstones and clay-rich siltstones with interfingering of sands and limestones. The siltstones and mudstones were deposited on a high stand carbonate ramp. During low sea level, the eolian sandstones increased when the shelf was exposed. It is fine-grained, low permeability with some bioturbation and organic rich shales. The sandstones are turbidites and channel deposits. The carbonates display turbidite with slump and debris flow characteristics.

San Andres

The Upper Leonardian - Lower Guadalupian (278-267 mya) San Andres Formation is predominantly dolomite with considerable amounts of anhydrite in the upper 300 feet. The depositional environment of the San Andres was shallow lagoon and sabkha complexes with an upward-shoaling, prograding-aggrading sequences.

Grayburg

The Guadalupian (267 mya) Grayburg Formation is a mixed carbonate-siliciclastic composite sequence with evaporites and halites deposited in a sabkha and tidal flat environment. The San Andres and Grayburg are frequently grouped together as they have similar depositional environments.

Queen

The Guadalupian (266-265 mya) Queen Formation is interbedded with siliclastic, carbonate mudstones, and evaporites. They were deposited in a fluvial depositional environment. Sandstones of the Queen formation are often reservoirs in the Permian basin.

Seven Rivers

The Guadalupian (265-262 mya) Seven Rivers Formation is composed of cyclically interbedded mudstones, salt, anhydrite, and dolomite.

Yates

The Guadalupian (262-261 mya) Yates Formation consists of sandstone, siltstone, and anhydrite. The sandstone is fine to very fine grained and contains scattered large rounded, frosted quartz grains.

Tansill

The Guadalupian (261-260 mya) Tansill Formation consists of interbedded salts and anhydrite.

Salado

The Ochoan (260-250 mya) Salado Formation is the dominant halite-bearing unit of the Midland Basin. The anhydrite contained in this formation represents the most-flooded, least-restricted conditions over the evaporite shelf where wind, storm, and seasonal circulation was adequate to maintain gypsum deposition. Overlying anhydrite beds contain halite, polyhalite, and mudstone beds.

Dewey Lake

The Ochoan (250-245 mya) Dewey Lake Formation contains orange-red, fine to very fine-grained sandstones and siltstones with anhydrite and gypsum cements.

Dockum

The Triassic (245-208 mya) Dockum Group consists mainly of terrigenous clastic red beds, mudstones and siltstones to conglomerates recording a change from the sabkha environments of Permian time to the humid continental environments of Triassic time.

There is an unconformity between the Dockum Group and the Edwards of approximately 98 million years. This was due to either non-deposition or uplift and erosion.

Edwards

The Cretaceous (142-68 mya) Edwards is a fine- to coarse-grained, thick-bedded to massive, light gray to grayish yellow limestone with abundant rudistids.

There is an unconformity between the Edwards and the Ogallala of approximately 45 million years.

Ogallala

The Miocene-Pliocene (23-2.5 mya) Ogallala Formation consists of gravel, sand, and finer grained clastic that were deposited in fluvial and upland eolian settings. Caliche and ash beds can also be found in the Ogallala.

The Ogallala and Edwards are USDWs in the Wellman Field.

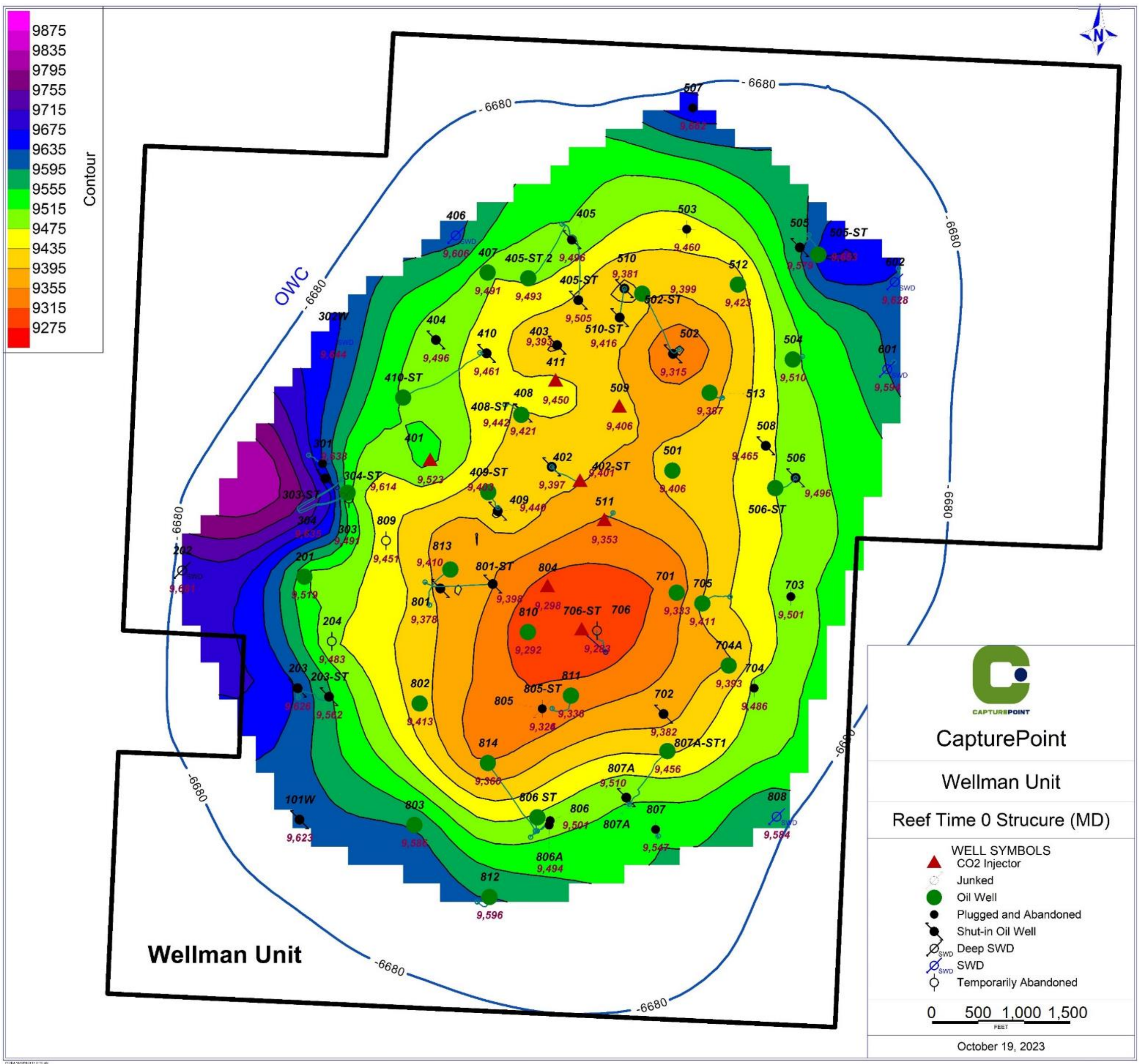


Figure 3-4 Local Area Structure on Top of the Wolfcamp Reef

Once the CO_2 flood is complete and injection ceases, the remaining mobile CO_2 will rise slowly upward, driven by buoyancy forces. There is more than enough pore space to sequester the volume of CO_2 planned for injection. The amount of CO_2 injected will not exceed the reservoir's secure storage capacity and, consequently, the risk that CO_2 could migrate to other reservoirs in the basin is negligible.

The volume of CO_2 storage is based on the estimated total pore space within WLFRF. The total pore space within WF, from the top of the reservoir down to the base of the WLFRF, is calculated to be 304.5 million reservoir barrels (RB). This is the volume of rock multiplied by porosity. Table 3-1 below shows the conversion of this amount of pore space into an estimated maximum volume of approximately 551 Billion Cubic Feet (BCF) (29 million tonnes) of CO_2 storage in the reservoir at original reservoir pressure conditions of 4100 psi. Based on the current project forecast, CO_2 will occupy only 66% (364 BCF) of the total calculated storage capacity by the year 2060. CO_2 currently occupies 29% (159 BCF) of the total calculated storage capacity.

Table 3-1 Calculation of Maximum Volume of CO_2 Storage Capacity at WF

Top of Main Pay to Original Oil/Water Contact	
Variables	WF Outline in Figure 3-4
Pore Volume (**RB**)	304,516,542
BCO_2 (RB/MCF)	0.42
Swirr	0.15
Sor CO_2	0.09
Max CO_2 (MCF)	551,029,933
Max CO_2 (BCF)	551

*Max CO_2 = Pore Volume * (1 – Swirr – Sor CO_2) / BCO_2*

Where:

Max CO_2 = the maximum amount of storage capacity
Pore Volume = Total pore space in reservoir barrels (RB)
BCO_2 = the formation volume factor for CO_2
Swirr = the irreducible water saturation
Sor CO_2 = the irreducible oil saturation

Reservoir management is employed on a constant basis to obtain the maximum possible economic recovery from a reservoir based on facts, information, and knowledge. As WF is a vertical displacement flood, long-term storage utilizes the natural buoyancy of CO_2 to oil and water, along with the existing reservoir seal, to contain the CO_2. In this scenario, there is no lateral migration and injected fluids (CO_2) will stay in the reservoir within the WF unit boundary and not move laterally to adjacent areas.

Given that in WF the confining zone has proved competent over millions of years, has remained intact with the current CO_2 flooding, and that the WF has ample storage capacity, there is confidence that stored CO_2 will be contained securely within the reservoir.

3.3 Description of CO_2-EOR Project Facilities and the Injection Process

Figure 3-5 shows a simplified process flow diagram of the project facilities and equipment in WF. CO_2 is delivered to the WLFRF via the Trinity CO_2 pipeline network. CO_2 is supplied by anthropogenic CO_2 sources. Available amounts of CO_2 are drawn from an outside source pipeline based on contractual arrangements among suppliers of CO_2, purchasers of CO_2, and the pipeline operator. These amounts will vary over time and be added to the recycled CO_2 for injection into the reservoir.

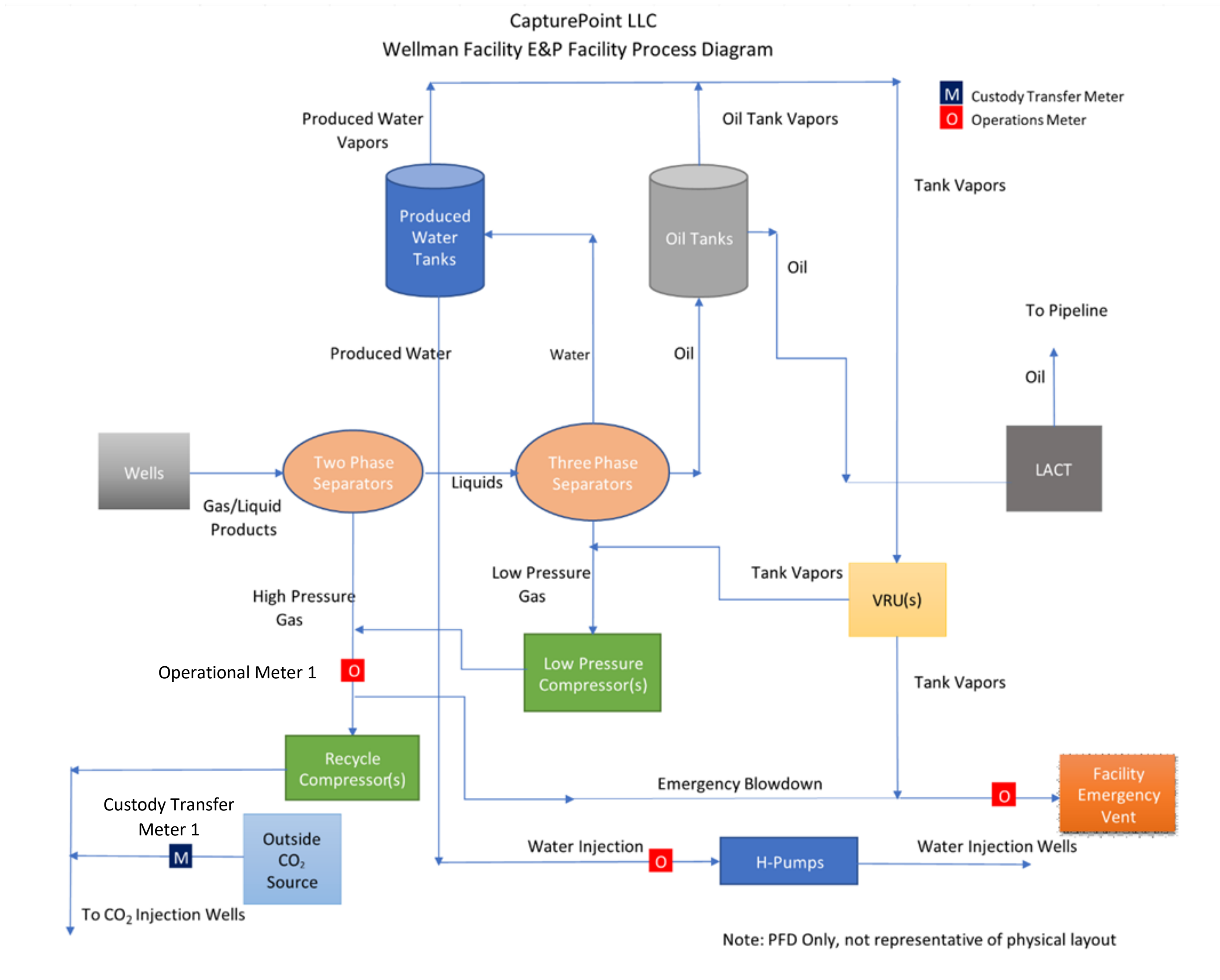


Figure 3-5 Wellman Process Flow Diagram

Once CO_2 enters the WLFRF there are three main processes involved in EOR operations:

i. CO_2 Distribution and Injection: The mass of CO_2 received at WF is metered and calculated through the Custody Transfer Meter located at the pipeline delivery point. The mass of CO_2 received is combined with recycled CO_2 / hydrocarbon gas mix from the recycle compression facility (RCF) and distributed to the wellheads for injection into the injection wells according to the injection plan for the reservoir. This is an EOR project and reservoir pressure must be maintained above minimum miscibility pressure. Therefore, injection pressure must be sufficiently high to allow injectants to enter the reservoir, but below formation parting pressure (FPP).

ii. Produced Fluids Handling: Produced fluids from the production wells are a mixture of oil, hydrocarbon gas, water, CO_2, and trace amounts of other constituents in the field including nitrogen and hydrogen sulfide (H_2S) as discussed in Section 7. The fluids are transported via flowlines to the Central Tank Battery (CTB) for separation into a gas/CO_2 mix and produced liquids that are a mix of water and oil, with entrained gas and CO_2. The produced gas, which is composed primarily of CO_2 and minor hydrocarbons, is sent to the RCF for dehydration and recompression before reinjection into the reservoir. An operations meter at the RCF is used to determine the total volume of produced gas that is reinjected. The separated oil is metered through the Custody Transfer Meter located at the central tank battery and sold into a pipeline.

iii. Water Treatment and Injection: Water is recovered for reuse and forwarded to the water injection station for reinjection or disposal.

3.3.1 Wells in the Wellman Field

The TRRC has broad authority over oil and gas operations including primacy to implement UIC Class II wells. The rules are found in TAC Title 16, Part 1, Chapter 3 and are also explained in a TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual (See Appendix 12-2). TRRC rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields.

Briefly, TRRC rules include the following requirements:

- Fluids must be constrained in the strata in which they are encountered,
- activities cannot result in the pollution of subsurface or surface water,
- wells must adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata that are encountered into other strata with oil and gas, or into subsurface and surface waters,
- completion report for each well including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore) must be prepared,
- operators must follow plugging procedures that require advance approval from the TRRC Director and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs; and,
- injection well operators must identify an Area of Review (AoR), use compatible materials and equipment, test, and maintain well records.

Table 3-2 provides a well count by type and status. All these wells are in material compliance with TRRC rules.

Table 3-2 WF Well Penetrations by Type and Status

TYPE	**ACTIVE**	**INACTIVE**	**P & A**	**Total**
PROD_OIL	27	6	0	**33**
INJ_SWD	6	0	0	**6**
INJ_CO_2	7	0	0	**7**
P&A	0	0	8	**8**
TOTAL	**40**	**6**	**8**	**54**

PROD_OIL = Production Wells
INJ_SWD = Saltwater disposal wells
INJ_CO_2 = CO_2 injection wells
P&A = Plugged and Abandoned wells.
(P&A for sidetracks are not included in the P&A count)

WF CO_2-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Reservoir pressure in the WF is managed by monitoring reservoir pressures and ensuring these remain constant. This is achieved by maintaining an IWR of approximately 1.

Injection pressure is also maintained below the FPP, which is measured using step-rate tests.

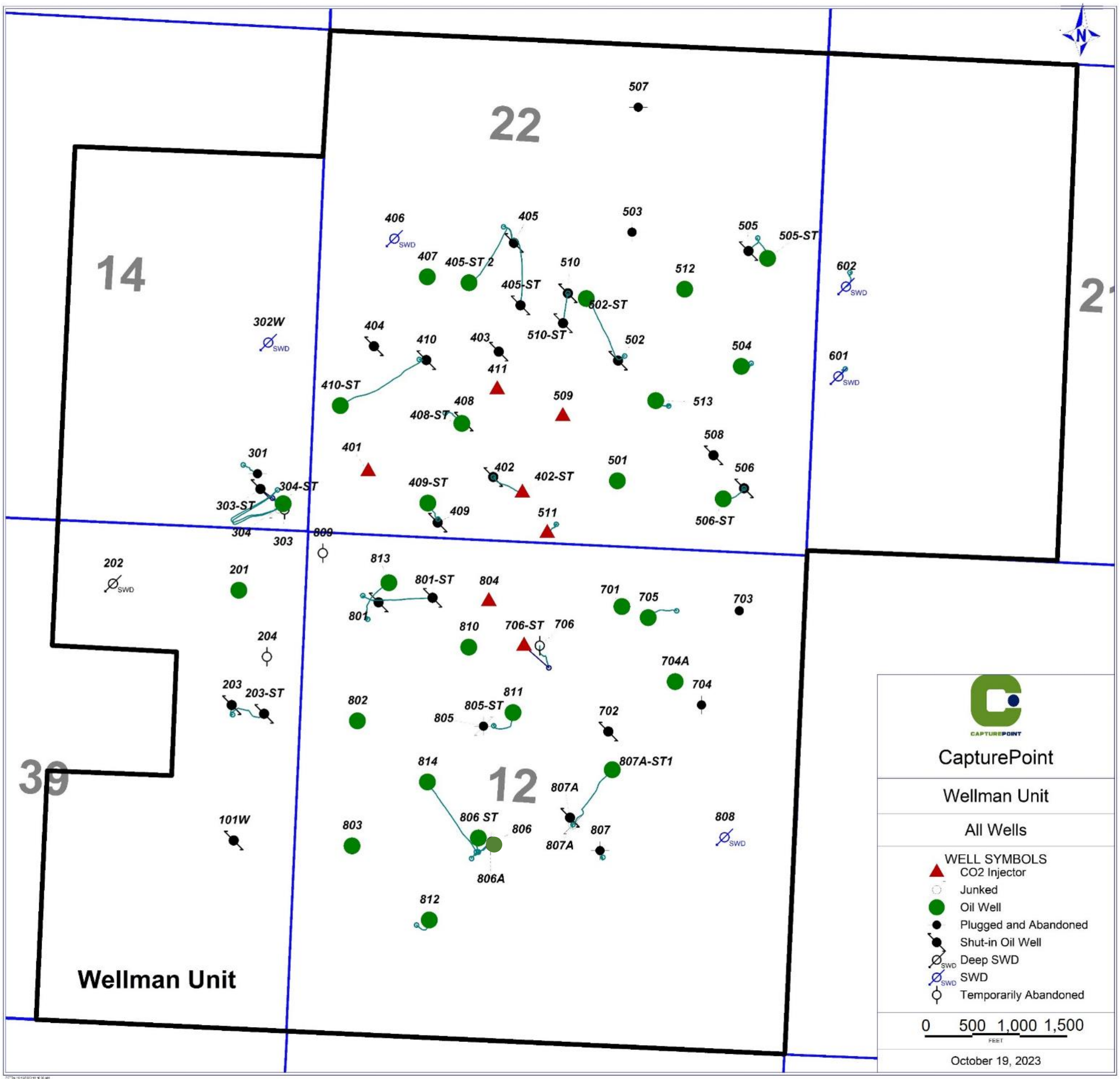


Figure 3-6 WF Wells and Injection Patterns

3.4 Reservoir Forecasting

DPCs derived from actual field performance were used to project CO_2-EOR in the WF. Most DPCs are derived from geologic and reservoir models or actual field performance. In the WF case the DPC was derived from actual field performance in the WF. The WF has 40 years of actual CO_2 history which is more than enough data to develop a DPC to forecast reservoir performance. Initial oil recovery and CO_2 injection results were obtained from lab experiments performed with CO_2. The DPC's project recoveries are close to what the lab experiments concluded.

A DPC is a plot where injection and production volumes for CO_2, water, and hydrocarbon phases are normalized by dividing by Hydrocarbon Pore Volume (HCPV). See Figure 3-7. The dimensioned projections for the oil, CO_2, and water production are relative to the CO_2 and water injection and are calculated using the original oil in place of an area of interest.

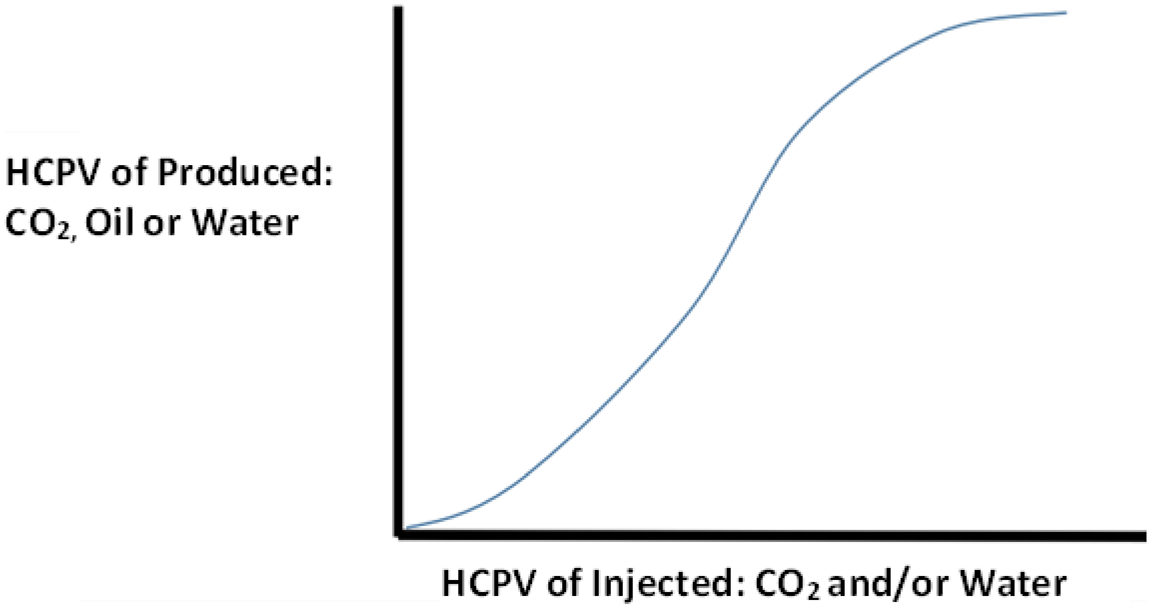


Figure 3-7 DPC plot

The WF DPC was calculated from the cumulative production and injection using 40 years of WF history. This method allows you to use different field implementation speeds.

The DPCs are the basis for future reservoir performance prediction scenarios but are additionally a means of evaluating the reservoir process efficiencies. In a similar manner to history matching in reservoir simulation, deviations from the expected performance can indicate errors in the geologic model of the pore volume, growth of the CO_2 plume, or metering and production allocation errors.

4 Delineation of Monitoring Area and Timeframes

4.1 Active Monitoring Area

The Active Monitoring Area (AMA) is defined by a ½ mile buffer surrounding the WLFRF storage area boundary (as indicated by the red dashed line on Figure 4-1) which serves to trap the CO_2 and keep it from migrating laterally and allowing the plume to stabilize within the WLFRF impermeable seal.

Figure 3-6 displays wells that have CO_2 retention on the 2,100 acres that have been under CO_2 injection since project initialization as well as SWD wells to support field operations. The CO_2 storage volumes were forecasted (Figure 3-1) using the DPC approach. This technique indicates that the flooded acreage still has significant additional storage potential. The maximum CO_2 storage (551 BCF) is limited to the amount of space available by the removal of the produced fluids. The projection indicates that there is pore space available to store approximately 0.66 decimal fraction of HCPV amount to 151.9 million RB (364 BCF).

The lateral extent of CO_2 in the injection zone or the CO_2 storage radius was estimated by calculating a storage radius based on the forecasted CO_2 volume of 364 BCF. Figure 4-1 shows the map of the storage area outline (dashed red line). This calculation showed approximately 1,043 acres would be needed to store 364 BCF. The CO_2 plume is anticipated to stay within the storage area depicted by the dashed red line. Therefore, the CO_2 plume would remain contained in the WF unit at the end of year 2066 (t+5).

4.2 Maximum Monitoring Area

The Maximum Monitoring Area (MMA) is defined as 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 CO_2 plume will stabilize within the WLFRF storage area boundary (as indicated by the red dashed line on Figure 4-1) which serves to trap the CO_2 and keep it from migrating laterally beyond the reservoir's impermeable seal. In this instance the MMA is the same as the AMA. Since the MMA is depicted to be ½ mile beyond the stabilized plume boundary, the MMA meets the definition found in 40 CFR 98.449.

4.3 Monitoring Timeframes

The primary purpose for injecting CO_2 is to produce oil that would otherwise remain trapped in the reservoir and not, as in UIC Class VI, "specifically for the purpose of geologic storage."[1] During a Specified Period, there will be a subsidiary purpose of establishing the long-term containment of CO_2 in the WF. The Specified Period will be shorter than the period of production from the WF.

At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted with a demonstration that current monitoring and model(s) show that the cumulative mass of CO_2 reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It

[1] EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b).

is expected that it will be possible to make this demonstration after the Specified Period ends based upon monitoring data.

The reservoir pressure in the WF is collected for use in operations management. Reservoir pressure is not forecasted to change appreciably since the IWR will be maintained at approximately 1. Once injection ceases, reservoir pressure is predicted to stabilize within one year.

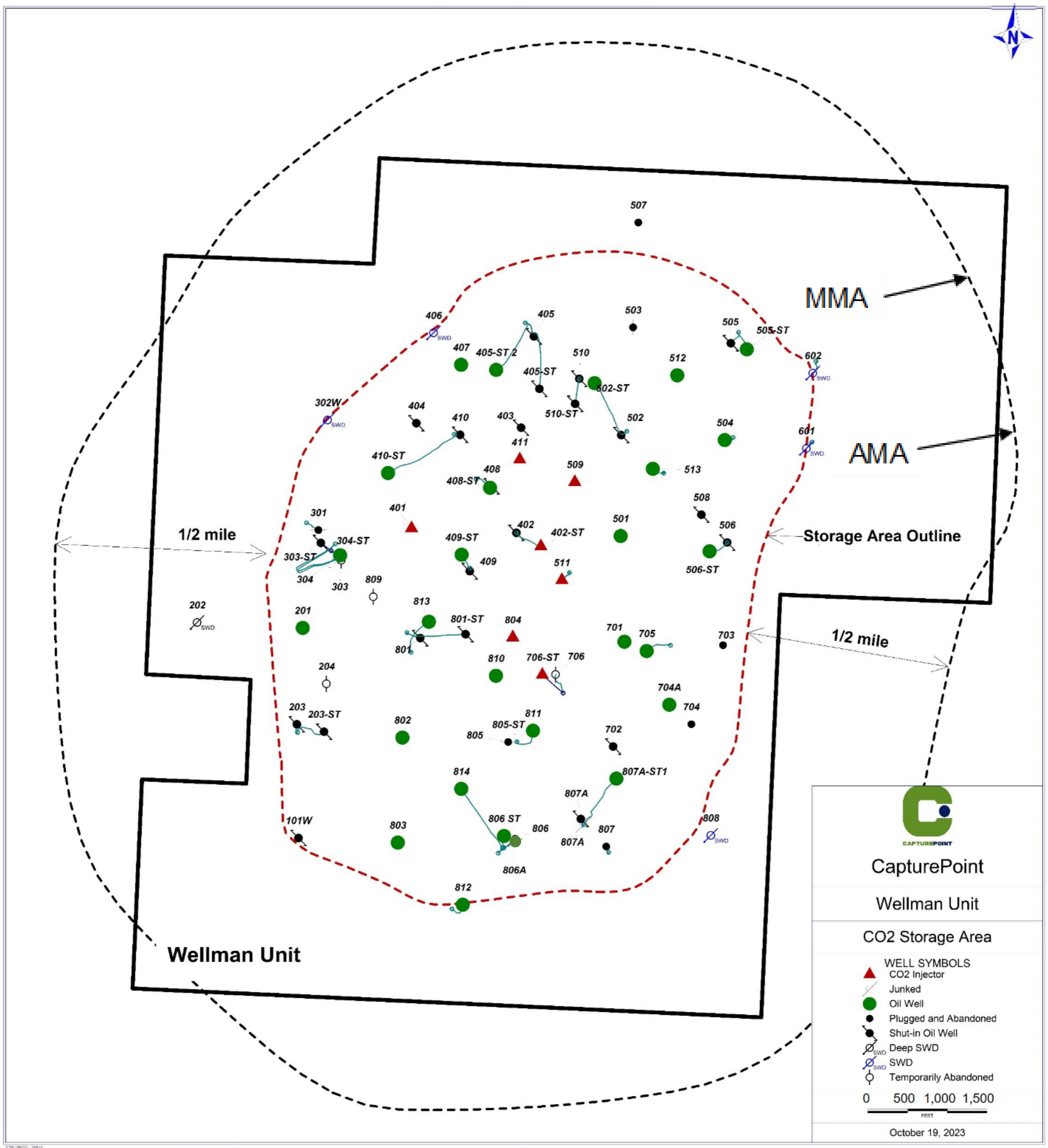


Figure 4-1 Projected CO_2 Storage area

5 Evaluation of Potential Pathways for Leakage to the Surface, Leakage Detection, Verification, and Quantification

In the roughly 70 years since the Wellman oil field was discovered, the reservoir has been studied extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO_2 to the surface including:

1. Existing Wells
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the WF
7. Drilling Through the CO_2 Area
8. Diffuse Leakage Through the Seal
9. Leakage Detection, Verification, and Quantification

This analysis shows that leakage through wellbores and surface equipment pose the only meaningful potential leakage pathways. The monitoring program to detect and quantify leakage is based on this assessment as discussed below.

5.1 Existing Wells

As part of the TRRC requirement to initiate CO_2 flooding, an extensive review of all WF penetrations was completed to determine the need for corrective action. That analysis showed that all penetrations have either been adequately plugged and abandoned or, if in use, do not require corrective action. All wells in the WF were constructed and are operated in compliance with TRRC rules.

As part of routine risk management, the potential risk of leakage associated with the following were identified and evaluated:

- CO_2 flood electrical submersible pump (ESP) producing wells,
- CO_2 Flood flowing production wells, and
- CO_2 injector wells.

The risk assessment classified all risks associated with subsurface as low risk, i.e., less than 1% likelihood to occur and having a consequence that is insubstantial. The risks were classified as low risk because the WF geology is well suited to CO_2 sequestration with an extensive confining zone that is free of fractures and faults that could be potential conduits for CO_2 migration. Any risks are further mitigated because the WF is operated in a manner that maintains, monitors, and documents the integrity of the reservoir.

The risk of well leakage is mitigated through:

- Adhering to regulatory requirements for well drilling and testing,
- implementing best practices that CapturePoint has developed through its extensive operating experience,
- monitoring injection/production performance, wellbores, and the surface; and,
- maintaining surface equipment.

Continual and routine monitoring of the wellbores and site operations will be used to detect leaks or other potential well problems, as follows:

- Pressure in injection wells is monitored daily. The injection plans for each pattern are provided to field operations to govern the rate, pressure, and duration of either water or CO_2 injection. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such events occur, they would be investigated and addressed. CapturePoint's experience, from over 10 years of operating CO_2-EOR projects, is that such leakage has not occurred.
- Production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to test vessels. There is a routine well testing cycle, with each well being tested approximately once every month. During this cycle, each production well is diverted to the well test equipment for a period sufficient to measure and sample produced fluids (generally 12-24 hours). These tests are the basis for allocating a portion of the produced fluids measured to each production well, assessing the composition of produced fluids by location, and assessing the performance of each well. Performance data are reviewed on a routine basis to ensure that CO_2 flooding efficiency is optimized. If production is different from the expected plan, it is investigated, and any identified issues addressed. Leakage to the outside of production wells is not considered a major risk because of the reduced pressure in the casing. All personnel are equipped with personal H_2S monitors. These personal H_2S monitors are designed to detect leaked fluids around production wells during well and equipment inspections.
- Field inspections are conducted on a routine basis by field personnel. Leaking CO_2 is very cold and leads to the formation of bright white clouds and ice that are easily spotted. All field personnel are trained to identify leaking CO_2 and other potential problems at wellbores and in the field. Any CO_2 leakage detected will be documented, quantified, and reported.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, it is concluded that the risk of CO_2 leakage through wellbores is being mitigated by detecting problems as they arise and quantifying any leakage that does occur. As mentioned before, leakage from wellbores is considered low but possible. It would most likely occur during the workover operations of installing the blowout preventer or wellhead. This release would be limited in nature to only a few MCF.

5.2 Faults and Fractures

After reviewing geologic, seismic, operating, and other evidence, it has been concluded that there are no known faults or fractures that transect the WLFRF reservoir into overlying formations in the project area. There have not been any fracture treatments performed on WF wells and there are no future fracture treatments contemplated and thus induced fracture risk is eliminated. Seismic evaluation has eliminated the existence of faults. As a result, there is little to no risk (less than 1%) of leakage due to fractures or faults.

Measurements to determine FPP and reservoir pressure are routinely updated. This information is used to manage injection patterns so that the injection pressure will not exceed FPP. An IWR at or near 1 is also maintained based on consistent reservoir pressure measurements. Both activities mitigate the potential for inducing faults or fractures.

5.3 Natural and Induced Seismicity

After reviewing the literature[2] and actual operating experience, it is concluded that there is no direct evidence that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the Permian Basin, and specifically in the WF. There is no indication of seismic activity posing a risk for loss of CO_2 to the surface within the MMA. The TRRC approved injection pressures in the WF are maintained and monitored so that injection pressure is kept well below the TRRC approved injection pressures which are significantly below the fracture initiation pressure. This ensures that there will be no induced seismicity. Therefore, CapturePoint concludes that leakage of sequestered CO_2 through seismicity is unlikely.

To evaluate this potential risk at WF, CapturePoint has reviewed the nature and location of seismic events in West Texas. A review of the United States Geological Survey (USGS) database of recorded earthquakes of magnitude 1.0 or greater on the Richter Scale in the Permian Basin since 1956, indicates very little seismic activity with a magnitude 2.5 earthquake 38 miles to the south of the WF.

The concern about induced seismicity is that it could lead to fractures in the seal providing a pathway for CO_2 leakage to the surface. CapturePoint is not aware of any reported loss of injectant (brine water or CO_2) to the surface associated with any seismic activity. There is no direct evidence to suggest that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the Permian Basin, and specifically in the WF. If 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 detect the migration and lead to further investigation. CapturePoint monitors the USGS earthquake monitoring Geological Information System site[3] for seismic signals that could indicate the creation of potential leakage pathways in the WF.

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[2] Frohlich, Cliff (2012) "Induced or Triggered Earthquakes in Texas: Assessment of Current Knowledge and Suggestions for Future Research", Final Technical Report, Institute for Geophysics, University of Texas at Austin, Office of Sponsored Research.

[3] https://earthquake.usgs.gov/earthquakes/map/

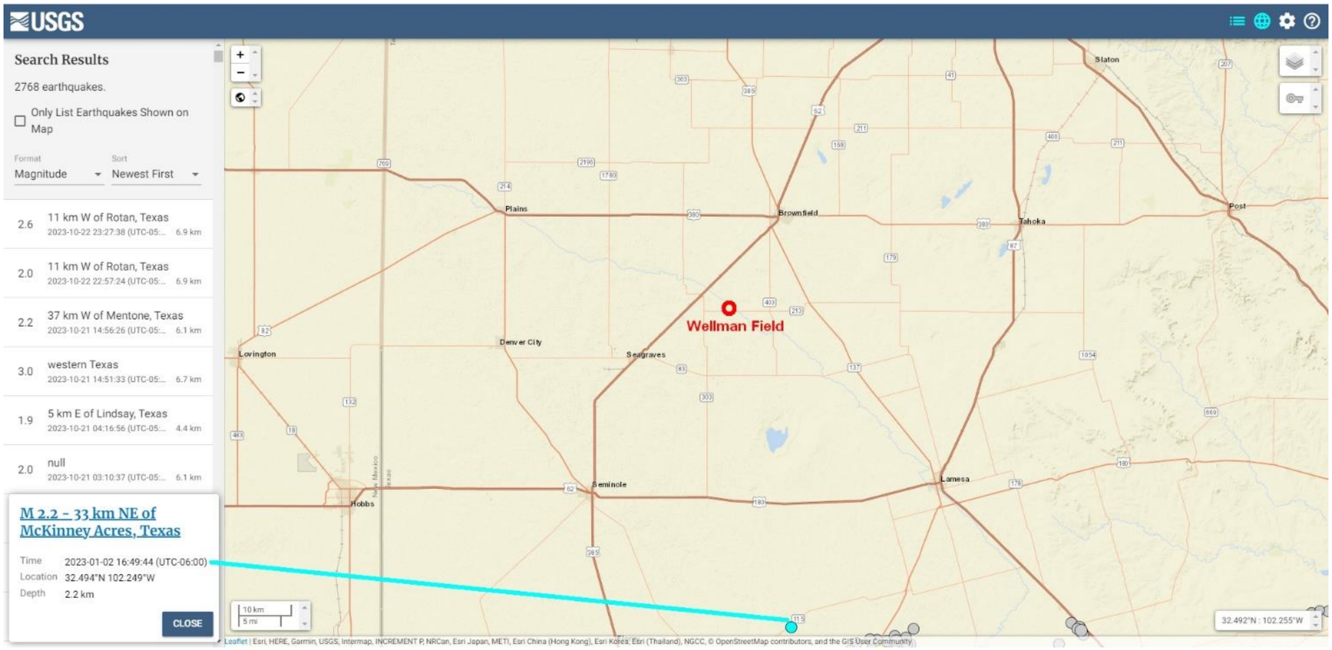

Figure 5-1 USGS earthquakes (+0.5 magnitude) for last 53 years)

5.4 Previous Operations

CO_2 flooding was initiated in WF in 1983. To obtain permits for CO_2 flooding, the AoR around all CO_2 injector wells was evaluated to determine if there were any unknown penetrations and to assess if corrective action was required at any wells. As indicated in Section 5.9, this evaluation reviewed the identified penetrations and determined that no additional corrective action was needed. Further, CapturePoint's standard practice for drilling new wells includes a rigorous review of nearby wells to ensure that drilling will not cause damage to or interfere with existing wells. Additionally, requirements to construct wells with materials that are designed for CO_2 injection are adhered to at WF. These practices ensure that that there are no unknown wells within WF and that the risk of migration from older wells has been sufficiently mitigated. The wells were designed to prevent migration from the injection interval to the surface through the casing and cement placed in the well. Mechanical integrity tests (MIT), required under TAC Rule §3.46 [40 CFR §146.23 (b)(3)], will take place every five years to verify that the well and wellhead can contain the appropriate operating pressures. If an MIT were to indicate a leak, the well would be isolated, and the leak mitigated to prevent leakage of the injectate to the atmosphere. The successful experience with CO_2 flooding in WF demonstrates that the confining zone has not been impaired by previous operations. As evidenced by the 40 years of CO_2 injection without leakage previous operations do not present a risk of leakage to the atmosphere. Well construction requirements all but eliminate this leakage potential. If leakage were to occur, well intervention methods would address the failure in a matter of hours to days limiting the volume of leakage to a range of a few MCF to a few MMCF. Based on this history of no leakage events and well construction requirements, the likelihood is less the 1% and the magnitude would be low with a timely response and remediation.

5.5 Pipelines and Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2. CapturePoint anticipates that the use of prevailing design, construction practices, and compliance with applicable laws will reduce to the maximum extent possible, the risk of unplanned leakage from surface facilities. The facilities and pipelines currently utilize, and will continue to utilize, materials of construction and control processes that are standard for CO_2-EOR projects in the oil and gas industry. Operating and maintenance practices currently follow, and will continue to follow, demonstrated industry standards. Field personnel are trained to look for and report potential leaks from pipeline and surface equipment as part of their routine activities. All equipment is designed with isolation valving to reduce the leakage from any failed equipment resulting in the potential leakage limited from the MCF to hundreds of MCF range. The Facility Emergency Vent is included in the surface equipment. It is a planned relief system that has the potential to release unplanned CO_2. That volume is measured by an operations meter and recorded for reporting purposes. Should leakage be detected from pipeline or surface equipment, the volume of released CO_2 will be quantified following the requirements of Subpart W of Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP). The magnitude of these releases is usually small within only a few MCF as they are easily identified and isolated. Because of materials selection, the risk is once again low and CapturePoint concludes that leakage of CO_2 through the surface equipment is unlikely.

5.6 Lateral Migration Outside the Wellman Field

It is highly unlikely that injected CO_2 will migrate downdip and laterally outside the WF because of the nature of the geology and the approach used for injection. The reef is completely encased with impermeable sediments, which is what created such a defined reservoir that trapped oil over millions of years. With water flooding from the edges, combined with vertical CO_2 flooding from the top of the reef, the CO_2 will be contained to the upper portions of the reef (See Figure 5-2). Finally, the total volume of fluids contained in the WF will stay relatively constant. Based on site characterization along with the planned and projected operations, it is estimated that the total volume of stored CO_2 will be considerably less than the calculated capacity. Based on the above statement, the storage capacity down to the spill-point is greater than the stored volume, so no CO_2 would be leaked laterally.

5.7 Drilling in the Wellman Field

The TRRC regulates well drilling activity in Texas. Pursuant to TRRC rules, wells casing shall be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones shall be isolated and sealed off to effectively prevent contamination or harm, and all productive zones, potential flow zones, and zones with corrosive formation fluids shall be isolated and sealed off to prevent vertical migration of fluids, including gases, behind the casing. Where TRRC rules do not detail specific methods to achieve these objectives, operators shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology (TAC Title 16 Part1 Chapter 3 Rule §3.13). The TRRC requires applications and approvals before a well is drilled, recompleted, or reentered. Well drilling activity at WF is conducted in accordance with TRRC rules. CapturePoint's visual inspection process, including routine site visits, will identify unapproved drilling activity in the WF. Leakage during drilling operations is unlikely but possible. It would occur when reservoir pressure is high. Drilling mud weight is designed to control that leakage therefore making the potential very low with volumes leaked kept at low levels.

In addition, CapturePoint intends to operate WF for several more years and will continue to be vigilant about protecting the integrity of its assets and maximizing the potential of its resources, including oil, gas, and CO_2. Consequently, as CapturePoint owns the rights at all depths, the risks associated with third parties penetrating the WF are negligible.

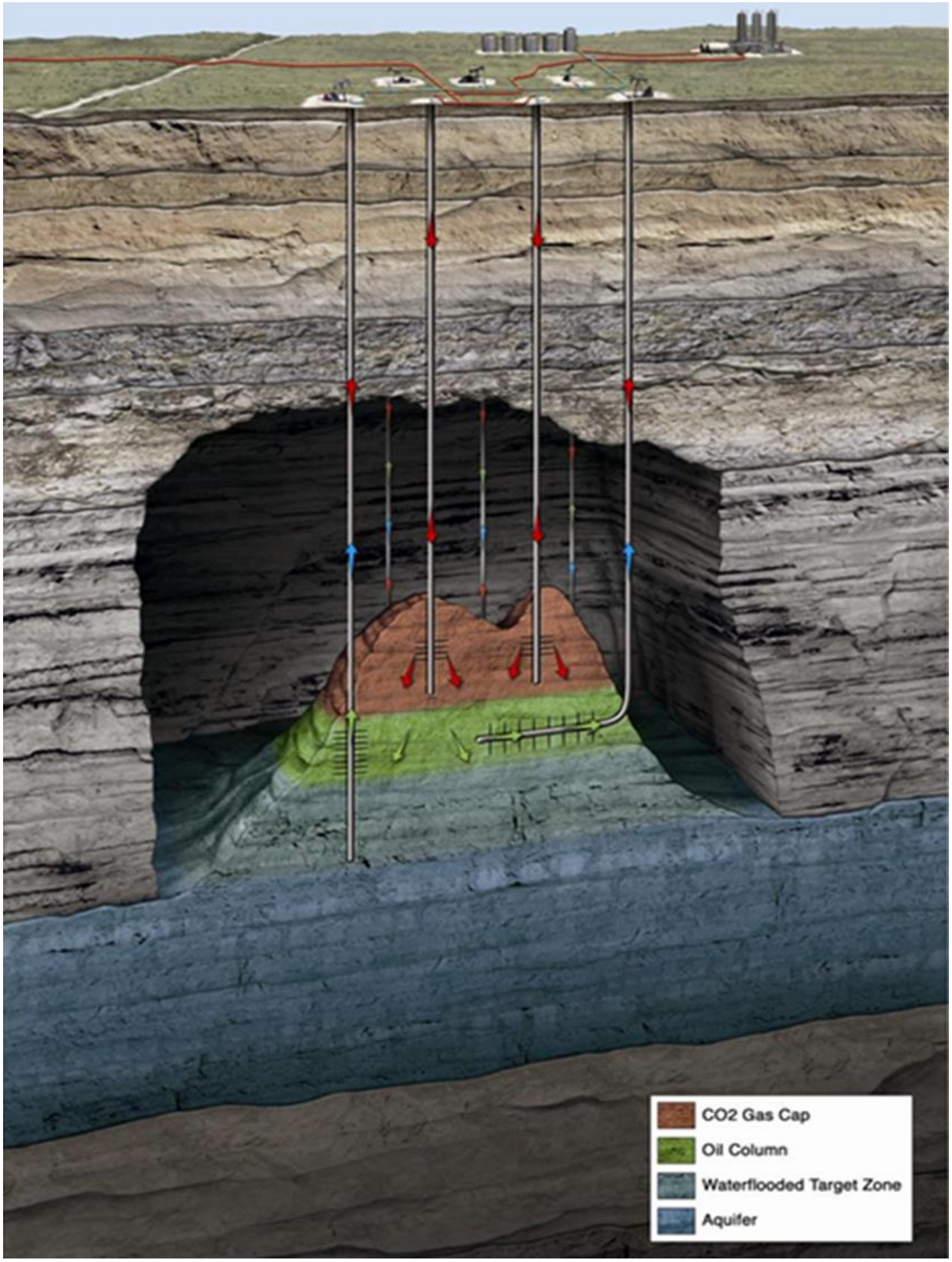

Figure 5-2 Schematic of WF vertical $C0_2$ flood

5.8 Diffuse Leakage Through the Seal

Diffuse leakage through the seal formed by the upper Wolfcamp is highly unlikely. There are several sections above the reservoir that are impermeable and serve as reliable barriers to prevent fluids from moving upwards towards the surface. These barriers are referred to as seals because they effectively seal fluids within the formations beneath them. As mentioned in Section

3.2, “Wolfcampian shales and siltstones, including the Hueco Formation, provide top and side seals for the Wellman oil trap. The Wolfcamp shales progress into the Spraberry series of siltstones, sands, and shales, with a few thin carbonate layers. This entire interval is informally called the “Spraberry Series.” The Spraberry Series forms a cap of more than 1,400 feet of clastics above the reservoir.”

Our injection monitoring program assures that no breach of the seal will be created. The seal is highly impermeable. Wellbores that penetrate the seal make use of cement and steel construction that is closely regulated to ensure that no leakage takes place. Injection pressure is continuously monitored and unexplained changes in injection pressure that might indicate leakage would trigger investigation as to the cause. The potential for leakage again is very low (less than 1%) the magnitude of which would be in the several MCF range into other formations but not to the surface.

5.9 Leakage Detection, Verification, and Quantification

As discussed above, the potential sources of leakage include issues, such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment (wellbores), and unique events such as induced fractures. An event-driven process to assess, address, track, and if applicable quantify potential CO_2 leakage is used. Table 5.1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, the standard response, and other applicable regulatory programs requiring similar reporting.

Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods for quantifying the volume of leaked CO_2 will be determined on a case-by-case basis. In the event leakage occurs, the most appropriate methods for quantifying the volume leaked will be determined and it will be reported as required as part of the annual Subpart RR submission. The potential quantification methods may include, but are not limited to:

- For leakage through wellbores, continuous SCADA monitoring data provide the basis to determine duration and the amount of any CO_2 loss;
- For leakage from surface equipment and pipelines, continuous SCADA monitoring data and acceptable emission factors, such as those in 40 CFR Part §98 Subpart W, provide the basis to determine duration and the amount of any CO_2 loss;
- For leakage related to the competency of the confining layer, reservoir modeling and engineering estimates provide the basis for determining the amount of any CO_2 losses.

Any volume of CO_2 detected leaking to 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, field experience, and other factors such as the frequency of inspection. Leaks will be documented, evaluated, and addressed in a timely manner.

In the unlikely event that CO_2 was released because of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

$CO_{2E} = \sum_{x=1}^{X} CO_{2x}$ (Eq. 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

Calculation methods using equations from subpart W will be used to calculate CO_2 emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead. Records of leakage events will be retained in the electronic environmental documentation and reporting system. The Field Foreman is notified for maintenance activities that cannot be addressed on the spot.

Table 5-1 Response Plan for CO_2 Loss

Risk	Monitoring Plan	Response Plan
Tubing Leak	Monitor changes in tubing and annulus pressures;	The well is shut in and workover crews respond within days. Magnitude could be thousands of cubic feet.
Casing Leak	Routine Field inspection; Monitor changes in annulus pressure, MIT for injectors; extra attention to high-risk wells	The well is shut in and workover crews respond within days. Magnitude could be thousands of cubic feet.
Wellhead Leak	Routine Field inspection, SCADA system monitors wellhead pressure	The well is shut in and workover crews respond within days. Magnitude could be thousands of cubic feet.
Loss of Bottom-hole pressure control	Blowout during well operations	Maintain well kill procedures. Magnitude would be millions of cubic feet.
Unplanned wells drilled through WLFRF	Routine Field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells.	Assure compliance with TRRC regulations is maintained.
Diffuse leakage through the seal	Reservoir pressure is continuously monitored and unexplained changes in reservoir pressure that might indicate leakage would trigger investigation as to the cause.	Conduct an injection radioactive tracer survey. If verified, the well is shut in and workover crews respond within days. Magnitude could be thousands of cubic feet.
Loss of seal in abandoned wells	Routine field inspections of abandoned well locations	Re-enter and reseal abandoned wells. Magnitude could be millions of cubic feet.
Pumps, valves, etc.	Routine Field inspection, Monitor SCADA	Repair crews respond within hours to days. Magnitude could be thousands of cubic feet.
Overfill beyond spill points	Monitor reservoir pressure in injector headers; high pressure discovered in new wells	Fluid management along into the reservoir by reduction of injection. This reservoir is a well-defined tank. Volumetric evaluation will direct fluid volume injection.
Leakage through induced fractures	Monitor reservoir pressure in injector headers; Reservoir pressure is continuously monitored and unexplained changes in reservoir pressure that might indicate leakage would trigger investigation as to the cause. High pressure discovered in new wells	Comply with TRRC approved injection pressures below parting pressure.

Leakage due to seismic event	Reservoir pressure is continuously monitored and unexplained changes in reservoir pressure that might indicate leakage would trigger investigation as to the cause.	Shut in injectors near seismic event. Inject water near seismic event to stop leakage.

5.10 Summary

The structure and stratigraphy of the WLFRF reservoir in the WF is ideally suited for the injection and storage of CO_2. The carbonate reef within the CO_2 injection zones is porous, permeable, and thick, providing ample capacity for long-term CO_2 storage. The reservoir is overlain by several intervals of impermeable geologic zones that form effective seals or “caps” to fluids in the reservoir.

In summary, based on a careful assessment of the potential risk of release of CO_2 from the subsurface, it has been determined that there are no leakage pathways at the WF that are likely to result in significant loss of CO_2 to the atmosphere. Further, given the detailed knowledge of the field and its operating protocols, it is concluded that any CO_2 leakage to the surface that could arise through either identified or unexpected leakage pathways would be detected and quantified as required by 40 CFR 98.448.

6 Monitoring and Considerations for Calculating Site Specific Variables

Monitoring will also be used to determine the quantities in the mass balance equation and to make the demonstration that the CO_2 plume will not migrate to the surface after the time of discontinuation.

6.1 For the Mass Balance Equation

6.1.1 General Monitoring Procedures

Flow rate, pressure, and gas composition data are monitored and collected from the WF in centralized data management systems as part of ongoing operations. This data is monitored by qualified technicians who follow response and reporting protocols when the systems deliver notifications that data exceed statistically acceptable boundaries.

Metering protocols used at WF follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association, and the Gas Processors Association, as appropriate. This approach is consistent with EPA GHGRP’s Subpart RR, section §98.444(e)(3). These meters will be maintained routinely, operated continually, and will feed data directly to the centralized data collection systems. The meters meet the industry standard for custody transfer meter accuracy and calibration frequency.

6.1.2 CO_2 Received

As indicated in Figure 3-5, the volume of received CO_2 is measured using a commercial custody transfer meter at the point at which custody of the CO_2 from the Trinity CO_2 pipeline delivery system is transferred to the WF. This meter measures flow rate continually. The transfer is a commercial transaction that is documented. CO_2 composition is governed by contract and the gas is routinely sampled. Fluid composition will be determined, at a minimum, quarterly, consistent with EPA GHGRP's Subpart RR, section §98.447(a). All meter and composition data are documented, and records will be retained for at least three years. No CO_2 is received in containers.

6.1.3 CO_2 Injected in the Subsurface

Injected CO_2 will be calculated using the flow meter volumes at the operations meter at the outlet of the central tank battery separators less vent and equipment losses plus, the custody transfer meter at the CO_2 off-take point from the Trinity CO_2 pipeline delivery system.

6.1.4 CO_2 Produced, Entrained in Products, and Recycled

The following measurements are used for the mass balance equations in Section 8:

- CO_2 produced in the gaseous stage is calculated using the volumetric flow meters at central production battery. These meters are located immediately downstream of the separation facilities.
- CO_2 that is entrained in produced oil, as indicated in Figure 3-5, is calculated using volumetric flow through the custody transfer meter and annual analysis of CO_2 content in the oil which has typically 0.3797 volume percent (1.2692 Mol%).
- Recycled CO_2 is calculated using the volumetric flow meter at the outlet of the central production battery separators feeding the inlet of the RCF, which is an operations meter. Only gaseous CO_2 flows through this meter.

6.1.5 CO_2 Emitted by Surface Leakage

CapturePoint uses 40 CFR Part 98 Subpart W to estimate surface leaks from equipment at the WF. Subpart W uses a factor-driven approach to estimate equipment leakage. In addition, an event- driven process to assess, address, track, and if applicable quantify potential CO_2 leakage to the surface is used.

In accordance with §98.444(d), CP uses Equation RR-10 in §98.443 to calculate and report the Mass of CO_2 emitted by Surface Leakage from WF. In accordance with §98.443(f)(2), CP will separately calculate and report CO_{2FI} and CO_{2E} emissions.

The multi-layered and risk-based monitoring program for event-driven incidents has been designed to meet two objectives: 1) to detect problems before CO_2 leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the volumes of CO_2 leaked to the surface.

Monitoring for Potential Leakage from the Injection/Production Zone

In addition to the measures discussed in Section 5.9, both injection into and production from the reservoir will be monitored as a means of early identification of potential anomalies that could indicate leakage from the subsurface.

Injection plans (fluid rate, pressure, volume) are given to operations on a weekly basis. If injection pressure or rate measurements are outside the specified set points determined as part of each pattern injection plan, reservoir engineering will notify field personnel and they will investigate and resolve the problem. These excursions will be reviewed by well management personnel to determine if CO_2 leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or some other minor action is required), and there is no threat of CO_2 leakage. In the case of issues that are not readily resolved, a more detailed investigation and response would be initiated, and support staff would provide additional assistance and evaluation.

Likewise, a forecast of the rate and composition of produced fluids is developed. Each producer well is assigned to a specific test vessel and is isolated during each cycle for a well production test. This data is reviewed on a periodic basis to confirm that production is at the level forecasted. If there is a significant deviation from the plan, well management personnel investigate. If the issue cannot be resolved quickly, a more detailed investigation and response would be initiated. If leakage in the flood zone were detected, an appropriate method would be used to quantify the involved volume of CO_2. This might include use of material balance equations based on known injected quantities and monitored pressures in the injection zone to estimate the volume of CO_2 involved.

A subsurface leak might not lead to a surface leak. In the event of a subsurface leak, CapturePoint would determine the appropriate approach for tracking subsurface leakage to determine and quantify leakage to the surface. To quantify leakage, the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be estimated to quantify the leak volume. Depending on specific circumstances, these determinations may rely on engineering estimates.

In the event leakage from the subsurface occurred diffusely through the seals, the leaked gas would include H_2S, which would trigger the alarm on the personal monitors worn by field personnel. Such a diffuse leak from the subsurface has not occurred in the WF. In the event such a leak was detected, personnel would determine how to address the problem. The personnel might use modeling, engineering estimates, and direct measurements to assess, address, and quantify the leakage.

Monitoring of Wellbores

WF wells are monitored through daily pressure monitoring of the injection zone, monitoring of the annular pressure in wellheads, and routine maintenance and inspection.

Leaks from wellbores would be detected through the follow-up investigation of pressure anomalies, visual inspection, or the use of personal H_2S monitors.

Anomalies in injection zone pressure may not indicate a leak, as discussed above. However, if an investigation leads to a need for further study, field personnel would inspect the equipment in question and determine the nature of the problem. If it is a simple matter, the repair would be made, and the volume of leaked CO_2 would be included in the 40 CFR Part 98 Subpart W report for the WF. If more extensive repair were needed, the appropriate approach for quantifying leaked CO_2 using the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be determined.

Anomalies in annular pressure or other issues detected during routine maintenance inspections would be treated in the same way. Field personnel would inspect the equipment in question and determine the nature of the problem. For simple matters the repair would be made at the time of inspection and the volume of leaked CO_2 would be included in the 40 CFR Part 98 Subpart W report for the WF. If more extensive repairs were needed, the well would be shut in, a work order would be generated and the appropriate approach for quantifying leaked CO_2 using the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be determined. The work order would serve as the basis for tracking the event for GHGRP.

Because leaking CO_2 at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a visual inspection process in the WF area is employed to detect unexpected releases from wellbores. Field personnel visit the surface facilities on a routine basis. Inspections may include tank levels, equipment status, lube oil levels, pressures and flow rates in the facility, and valves. Field personnel also observe the facility for visible CO_2 or fluid line leaks.

Finally, the H_2S monitors, which are always worn by all field personnel are used as a last method to detect leakage from wellbores. The H_2S monitor detects concentrations greater than 10 ppm. If an H_2S alarm is triggered, the first response is to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. As noted previously, H_2S is considered a proxy for potential gas leaks including CO_2 in the field. Currently the concentration of H_2S in the recycled or produced gas is approximately 130 ppm while in the produced fluid the concentration is 77 ppm making leak detection viable. Thus, detected H_2S leaks will be investigated to quantify the potential CO_2 leakage source and quantities.

Other Potential Leakage at the Surface

The same visual inspection process and H_2S monitoring system will be used to detect other potential leakage at the surface as it does for leakage from wellbores. Routine visual inspections are used to detect significant loss of CO_2 to the surface. Field personnel routinely visit surface facilities to conduct a visual inspection. Inspections may include review of tank level, equipment status, lube oil levels, pressures and flow rates in the facility, valves, and conducting a general observation of the facility for visible CO_2 or fluid line leaks. If problems are detected, field personnel would investigate, and complete any maintenance that is required. In addition to these visual inspections, the results of the personal H_2S monitors worn by field personnel will be used as a supplement for smaller leaks that may escape visual detection.

If CO_2 leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, steps are taken to prevent further leaks.

6.1.6 CO_2 emitted from equipment leaks and vented emissions of CO_2 from surface equipment located between the injection flow meter and the injection wellhead

CapturePoint evaluates and estimates leaks from injection equipment and the CO_2 content of any vented CO_2, as required under 40 CFR Part 98 Subpart W.

6.1.7 CO_2 emitted from equipment leaks and vented emissions of CO_2 from surface equipment located between the production flow meter and the production wellhead

CapturePoint evaluates and estimates leaks from production equipment and the CO_2 content of produced oil, and any vented CO_2, as required under 40 CFR Part 98 Subpart W.

6.2 To Demonstrate that Injected CO_2 is not Expected to Migrate to the Surface

At the end of the Specified Period, injecting CO_2 for the subsidiary purpose of establishing the long-term storage of CO_2 in the WF will cease. Sometime after the end of the Specified Period, a request to discontinue monitoring and reporting will be submitted. The request will demonstrate that the amount of CO_2 reported under 40 CFR §98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage.

At that time, the request will be supported with years of data collected during the Specified Period. This demonstration will provide the information necessary for the EPA Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

- Data comparing actual performance to predicted performance (purchase, injection, production) over the monitoring period,
- An assessment of the CO_2 leakage detected, including the discussion of the estimated amount of CO_2 leaked and the distribution of emissions by leakage pathway,
- A demonstration that future operations will not release the volume of stored CO_2 to the surface,
- A demonstration that there has been no significant leakage of CO_2; and,
- An evaluation of the reservoir pressure demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

7 Determination of Baselines

Ongoing operational monitoring has provided data for establishing baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO_2 leakage. Data systems are used primarily for operational control and monitoring, which are set to capture more information than is necessary for reporting in the Annual Subpart RR Report. The necessary system guidelines to capture the information that is relevant to identify possible CO_2 leakage will be developed. The following describes the approach to collecting this information.

Visual Inspections

As field operators conduct routine inspections and repairs, the Field Foreman is notified for maintenance activities that cannot be addressed on the spot. Examples include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation (the responsible party will be provided in the monitoring plan, as required under Subpart A, §98.3(g)).

The Annual Subpart RR Report will provide an estimate of CO_2 emissions. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

Personal H_2S Monitors

H_2S monitors are worn by all field personnel. The H_2S monitors detect concentrations of H_2S up to 500 ppm in 0.1 ppm increments and will sound an alarm if the detection limit exceeds 10 ppm. If an H_2S alarm is triggered, the immediate response is to protect the safety of the personnel, and the next step is to safely investigate the source of persistent alarms. CapturePoint considers H_2S to be a proxy for potential CO_2 leaks in the field. The person responsible for MRV documentation will receive notice of all incidents where H_2S is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO_2 emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

Injection Rates, Pressures and Volumes

Target injection rate and pressure for each injector are developed within the permitted limits based on the results of ongoing pattern balancing. The injection targets are submitted to field operations. Field operations flags whenever statistically significant deviations from the targeted ranges are identified. The set points are designed to be conservative, because it is preferable to have too many flags rather than too few. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO_2 leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions. The Annual Subpart RR Report will provide an estimate of CO_2 emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

Production Volumes and Compositions

A general forecast of production volumes and composition is developed which is used to periodically evaluate performance, refine current and projected injection plans, and the forecast. This information is used to make operational decisions but is not recorded in an automated data system. The MRV plan implementation lead will review the data and identify those that could result in CO_2 leakage. Should such events occur, leakage volumes would be calculated following the approaches described in Sections 5 and 6. Impact to Subpart RR reporting will be addressed, if deemed necessary.

8 Determination of Sequestration Volumes Using Mass Balance Equations

This section describes how CP uses the equations in Subpart RR §98.443 to calculate the mass of CO_2 received using equations RR-2 and RR-3, the mass of CO_2 injected using equations RR-5and RR-6, the amount of CO_2 produced using equations RR-8 and RR-9, the mass of CO2 Surface Leakage using equation RR-10, and the mass of CO_2 sequestered using equation RR-11.

8.1 Mass of CO_2 Received

Equation RR-2 will be used as indicated in Subpart RR §98.443 to calculate the mass of CO_2 at the receiving custody transfer meter from the Trinity CO_2 pipeline delivery system. The volumetric flow at standard conditions will be multiplied by the CO_2 concentration and the density of CO_2 at standard conditions to determine mass.

The Mass of the CO_2 Received will be determined using Equation RR-2 as follows:

$CO_{2T,r} = \sum_{p=1}^{4}(Q_{p,r} - S_{r,p}) * D * C_{CO_{2,p,r}}$ (Eq. 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 your 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 meters.

Given WF's method of receiving CO_2 and requirements at Subpart RR §98.444(a):

- All delivery to the WF is used within the unit so no quarterly flow redelivered, and $S_{r,p}$ will be zero ("0").
- Quarterly CO_2 concentration will be taken from the gas measurements.

8.2 Mass of CO_2 Injected into the Subsurface

The equation for calculating the Mass of CO_2 Injected into the Subsurface at the WF is equal to the sum of the Mass of CO_2 Received as calculated in RR-2 of §98.443 (section 8.1 above) and the Mass of CO_2 Recycled calculated using measurements taken from the flow meter located directly downstream of the separation facilities (see Figure 3-5).

The Mass of CO_2 Recycled will be determined using equations RR-5 as follows:

$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$ (Eq. 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.

$C_{CO_{2,p,u}}$= Quarterly 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.

The total Mass of CO_2 Injected will be the sum of the Mass of CO_2 Received (RR-2) and Mass of CO_2 Recycled (RR-5).

The Mass of CO_2 Injected will be determined using equations RR-6 as follows:

$CO_{2I} = \sum_{u=1}^{U} CO_{2u}$ (Eq. RR-6)

where:

CO_{2I}. = Total annual CO_2 mass injected (metric tons) through all injection wells.

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

u = Flow meter.

8.3 Mass of CO_2 Produced

In accordance with §98.443, Equation RR-8 will be used the calculate the Mass of CO_2 Produced at the flow meter (Operational Meter 1) on Figure 3-5, as described in Section 6.1.4. Quarterly CO_2 concentration will be taken from the gas measurement database. The volumetric flow at standard conditions will be multiplied by the CO_2 concentration and the density of CO_2 at standard conditions to determine net Annual Mass of CO_2 Received.

$CO_{2,w} = \sum_{p=1}^{4}(Q_{p,w}) * D * C_{CO_{2,p,w}}$ (Eq. 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.

$CCO_{2,p,w}$ = 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.

For Equation RR-9 in §98.443 the variable X will be measured as follows:

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

Where:

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

$CO_{2,w}$ = Annual CO2 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

w = Separator

8.4 Mass of CO_2 Emitted by Surface Leakage

Surface Leakage will be calculated and reported using an approach that is tailored to specific leakage events including calculation methodologies in 40 CFR Part 98 Subpart W for emissions and leaks from equipment. CapturePoint is prepared to address the potential for leakage in a variety of settings. Estimates of the amount of CO_2 leaked to the surface will depend on several site- specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

The process for quantifying leakage will entail using the best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are described in Sections 5.9 and 6. In the event leakage to the surface occurs, leakage amounts would be quantified and reported, and records that describe the methods used to estimate or measure the volume leaked as reported in the Annual Subpart RR Report would be retained.

Equation RR-10 in §98.443 will be used to calculate and report the Mass of CO_2 emitted by Surface Leakage:

$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$ (Eq. 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

8.5 Mass of CO_2 Emitted by Facility Emergency Vent

The Mass of CO_2 emitted by the Emergency Vent at the WF will be calculated using the measurements from the flow meter at the vent. That volume will be added to CO_{2FI} which is the 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 part 98 of Mandatory Greenhouse Reporting.

Equation RR-8 in §98.443 will be used to calculate the Mass of CO_2 emitted through the emergency vent as follows:

$CO_{2,w} = \sum_{p=1}^{4} (Q_{p,w}) * D * C_{CO_{2,p,w}}$ (Eq. 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.

$CCO_{2,p,w}$ = 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

8.6 Mass of CO_2 Sequestered and Reported in Subsurface Geologic Formation

Equation RR-11 in §98.443 will be used to calculate the Mass of CO_2 Sequestered and Reported in Subsurface Geologic Formations in the Reporting Year as follows:

$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP}$ (Eq. 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 covered by this source category 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 part 98 of Mandatory Greenhouse Reporting.

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 part 98 of Mandatory Greenhouse Reporting.

9 MRV Plan Implementation Schedule

This MRV plan will be implemented starting October 2023 or within 90 days of EPA approval, whichever occurs later. Other GHGRP reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. It is anticipated that the MRV plan will be in effect during the Specified Period, during which time the WF will be operated with the subsidiary purpose of establishing long-term containment of a measurable quantity of CO_2 in subsurface geological formations at the WF. It is anticipated to establish that a measurable amount of CO_2 injected during the Specified Period will be stored in a manner not expected to migrate resulting in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be prepared and a request to discontinue monitoring and reporting under this MRV plan will be submitted. See 40 C.F.R. §98.441(b)(2)(ii).

10 Quality Assurance (QA) Program

10.1 QA Procedures

The requirements of §98.444 (a) – (d) have been incorporated in the discussion of mass balance equations. These include the following provisions.

CO_2 Received and Injected

- The quarterly flow rate of CO_2 received by pipeline is measured at the receiving custody transfer meters.
- The quarterly CO_2 flow rate for recycled CO_2 is measured at the outlet of the central production battery separators feeding the inlet of the RCF.

CO_2 Produced

- The point of measurement for the quantity of CO_2 produced from oil or other fluid production wells is a flow meter directly downstream of each separator that sends a stream of gas into a recycle or end use system.
- The produced gas stream is sampled annually downstream of the flow meter used to measure flow rate of that gas stream and measure the CO_2 concentration of the sample.

CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2

These volumes are measured in conformance with the monitoring and QA requirements specified in subpart W of 40 CFR Part 98.

Flow Meter Provisions

The flow meters used to generate date for the mass balance equations are:

- Operated continuously except as necessary for maintenance and calibration.
- Operated using the calibration and accuracy requirements in 40 CFR §98.3(i).
- Operated in conformance with API standards.
- National Institute of Standards and Technology (NIST) traceable.

Concentration of CO_2

CO_2 concentration is measured using an appropriate standard method. Further, all measured volumes of CO_2 have been converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere, including those used in Equations RR-2, RR-5, and RR-8 in Section 8.

10.2 Missing Data Procedures

In the event data needed for the mass balance calculations cannot be collected, procedures for estimating missing data in §98.445 will be used as follows:

- 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 previous measured 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 previous measured period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the previous measured period 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 previous measured period.

10.3 MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters of the CO_2-EOR operations in the WF that is not anticipated in this MRV plan, the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in §98.448(d).

11 Records Retention

The record retention requirements specified by §98.3(g) will be followed. In addition, the requirements in Subpart RR §98.447 will be met by maintaining the following records for at least three years:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of produced CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of injected CO_2 including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
- 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.

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

12 Appendix

12.1 Well Identification Numbers

The following table presents the well name, API number, type, and status for active wells in the WF as of March 2023. The table is subject to change over time as new wells are drilled, existing wells change status, or existing wells are repurposed.

The following terms are used:

Well Type:

- PROD_OIL refers to wells that produce oil.
- INJ_CO_2 refers to wells that inject CO_2.
- INJ_SWD refers to wells that inject water for disposal.
- P&A refers to plugged and abandoned wells.

Well Status:

- ACTIVE refers to active wells.
- INACTIVE refers to wells that have been completed but are not in use.
- SHUT_IN refers to wells that have been temporarily idled or shut in.
- TEMP_AB refers to wells that have been temporarily abandoned.

Table 12-1 Well Status Table

Well Name	API Number	Well Type	Status
WU 101W	4244500076	INJ_SWD	SHUT_IN
WU 201	4244500072	PROD_OIL	ACTIVE
WU 202	4244500073	INJ_SWD	ACTIVE
WU 203	4244500074	P&A	INACTIVE
WU 203-ST	424450007401	P&A	INACTIVE
WU 204	4244530234	P&A	INACTIVE
WU 301	4244500575	P&A	INACTIVE
WU 302W	4244500576	INJ_SWD	ACTIVE
WU 303	4244530070	PROD_OIL	TEMP_AB
WU 303-ST	4216533912	PROD_OIL	SHUT_IN
WU 304	4244532434	P&A	INACTIVE
WU 304-ST	424453243401	PROD_OIL	ACTIVE
WU 401	4244500083	INJ CO_2	ACTIVE
WU 402	4244500084	P&A	INACTIVE
WU 402-ST	424450008401	INJ_CO_2	ACTIVE
WU 403	4244500085	P&A	INACTIVE
WU 404	4244500086	PROD_OIL	SHUT_IN
WU 405	4244500087	P&A	INACTIVE
WU 405-ST	424450008701	P&A	INACTIVE

Well Name	API Number	Well Type	Status
WU 405-ST2	424450008702	PROD_OIL	ACTIVE
WU 406	4244500088	INJ_SWD	ACTIVE
WU 407	4244530288	PROD_OIL	ACTIVE
WU 408	4244531435	P&APROD_OIL	INACTIVESHUT_IN
WU 408-ST	424453143501	PROD_OIL	ACTIVE
WU 409	4244531456	P&APROD_OIL	INACTIVESHUT_IN
WU 409-ST	424453145601	PROD_OIL	ACTIVE
WU 410	4244531825	P&APROD_OIL	INACTIVESHUT_IN
WU 410-ST	424453182501	PROD_OIL	ACTIVE
WU 411	4244531858	INJ_CO_2	ACTIVE
WU 501	4244500578	PROD_OIL	ACTIVE
WU 502	4244500579	P&APROD_OIL	INACTIVESHUT_IN
WU 502-ST	424450057901	PROD_OIL	ACTIVE
WU 503	4244500580	P&A	INACTIVE
WU 504	4244500581	PROD_OIL	ACTIVE
WU 505	4244500582	P&APROD_OIL	INACTIVESHUT_IN
WU 505-ST	424450058202	PROD_OIL	ACTIVE
WU 506	4244500583	P&APROD_OIL	INACTIVESHUT_IN
WU 506-ST	424450058301	PROD_OIL	ACTIVE
WU 507	4244500584	P&A	INACTIVE
WU 508	4244530105	PROD_OIL	TEMP_AB
WU 509	4244531117	INJ_CO_2	ACTIVE
WU 510	4244531434	P&APROD_OIL	INACTIVEACTIVE
WU 510-ST	424453143401	PROD_OIL	ACTIVE
WU 511	4244531457	INJ_CO_2	ACTIVE
WU 512	4244531769	PROD_OIL	ACTIVE
WU 513	4244531872	PROD_OIL	ACTIVE
WU 601	4244500569	INJ_SWD	ACTIVE
WU 602	4244500570	INJ_SWD	ACTIVE
WU 701	4244500163	PROD_OIL	ACTIVE
WU 702	4244500089	PROD_OIL	TEMP_AB
WU 703	4244500090	P&A	INACTIVE
WU 704	4244500091	P&A	INACTIVE
WU 704A	4244530314	PROD_OIL	ACTIVE
WU 705	4244530125	PROD_OIL	ACTIVE
WU 706	4244530864	P&A	INACTIVE
WU 706-ST	424453086401	INJ_CO_2	ACTIVE
WU 801	4244500418	P&A	INACTIVE
WU 801-ST	424450041801	PROD_OIL	SHUT_IN
WU 802	4244500419	PROD_OIL	ACTIVE
WU 803	4244500420	PROD_OIL	ACTIVE
WU 804	4244500421	INJ_CO_2	ACTIVE
WU 805	4244500422	P&A	INACTIVE
WU 805-ST	424450042201	P&A	INACTIVE
WU 806	4244500423	P&A	INACTIVE

Well Name	API Number	Well Type	Status
WU 806A	4244532445	PROD_OIL	ACTIVE
WU 806-ST	424450042301	PROD_OIL	ACTIVE
WU 807	4244500424	P&A	INACTIVE
WU 807A	4244500425	P&A	INACTIVE
WU 807A-ST1	424450042501	PROD_OIL	ACTIVE
WU 808	4244530741	INJ_SWD	ACTIVE
WU 809	4244531824	PROD_OIL	TEMP_AB
WU 810	4244531870	PROD_OIL	ACTIVE
WU 811	4244532428	PROD_OIL	ACTIVE
WU 812	4244532435	PROD_OIL	ACTIVE
WU 813	4244532446	PROD_OIL	ACTIVE
WU 814	4244532467	PROD_OIL	ACTIVE

12.2 Regulatory References

Regulations cited in this plan:

- TAC Title 16 Part 1 Chapter 3 Oil & Gas Division

https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y

- TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual

https://www.rrc.texas.gov/oil-and-gas/publications-and-notices/manuals/injection-storage-manual/

12.3 Abbreviations and Acronyms

AMA - Active Monitoring Area

API - American Petroleum Institute

AoR - Area of Review

Bcf – 1 Billion Standard Cubic Feet of Gas

CO_2 - Carbon Dioxide

CTB – Central Tank Battery

DPC - Dimensionless Performance Curve

EPA - Environmental Protection Agency

EOR - Enhanced Oil Recovery

ESP - Electrical Submersible Pump

FPP - Formation Parting Pressure (psi)

GHGRP - Greenhouse Gas Reporting Program

H_2S – Hydrogen Sulfide

HCPV - Hydrocarbon Pore Volume

IWR - Injection to Withdrawal Ratio

MMA - Maximum Monitoring Area

MRV Plan - Monitoring, Reporting and Verification Plan

MCF – 1 Thousand Standard Cubic Feet of Gas

MIT – Mechanical Integrity Test

MMCF – 1 Million Standard Cubic Feet of Gas

NIST - National Institute of Standards and Technology

QA – Quality Assurance

RB - Reservoir Barrels

RCF - Recycle Compression Facility

TAC - Texas Administrative Code

TRRC - Texas Railroad Commission - Oil and Gas Division

USGS - United States Geological Survey

UIC – Underground Injection Control

WF – Wellman Field

WLFRF – Wolfcamp Reef

12.4 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 CO2 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 CO2 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 x 10-2 MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.