CapturePoint LLC

Denver City Field

Subpart RR Monitoring, Reporting and Verification (MRV) Plan

July 2024

Contents

1 Introduction

CapturePoint LLC operates a Carbon Dioxide Enhanced Oil Recovery (CO_2-EOR) project in the Denver City Field (DCF) located in Gaines County, Texas, approximately four miles southwest of the town of Denver City, Texas and less than two miles west of the Denver Unit of the giant Wasson San Andres Fields for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO_2) with a subsidiary or ancillary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The DCF is comprised of the George Allen Unit (GAU) which contains the Ruth Hudson Lease (RH). Like Wasson production is from the San Andres formation at an average depth of 5,000 feet. The Monitoring, Reporting and Verification (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 Denver City Fields during a specified period of injection.

2 Facility Information

2.1 Reporter Number

576482 – Denver City Fields

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 DCF (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 (UIC) Class II program in the state for injection wells. All EOR injection wells in the DCF are currently classified as UIC Class II wells.

2.3 Existing Wells

Wells in the DCF are identified by name and 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 subpart RR submission.

3 Project Description

This project takes place in the DCF, an oil field located in West Texas that was first produced more than 60 years ago. The DCF is comprised of the GAU which contains the RH. The two are adjacent to each other, produce oil and gas from the same geologic formations and structure, and are under the sole operatorship of CapturePoint LLC. The geology, facilities/equipment, and operational procedures are similar for both in the DCF. In addition, the two properties share the same CO_2 recycle and water injection facilities as well as the injection piping system for both CO_2 and water. Because of these common facilities and common reservoir, one MRV Plan is being prepared for the two properties in the DCF and any important differences between the two properties will be noted in the MRV plan. CO_2 flooding was initiated in 2007 in the GAU and in 2012 in the RH. The field is well characterized and is suitable for secure geologic storage in the San Andres formation. CapturePoint LLC uses a water alternating with gas (WAG) injection process and maintains an injection to withdrawal ratio (IWR) at or near 1.

3.1 Project Characteristics

The DCF was discovered in 1956 and started production in the same year. The DCF consists of one unit (GAU) and one lease (RH). The GAU began to produce in May 1956 and the waterflood was initiated in September 1989. CO_2 flooding was initiated in December 2007, in both the Main Pay and Residual Oil Zone (ROZ). The RH initiated a waterflood in March 2008 and began to produce in November 2008. CO_2 flooding was initiated in December 2012, also in the Main Pay and ROZ.

A long-term forecast for both the GAU and RH was developed using a dimensionless performance curve (DPC) approach. Using this approach, approximately 2.0 million tonnes of stored CO_2 is forecasted over the life of the project. Figure 3-1 shows actual and projected CO_2 injection, production, and stored volumes in DCF.

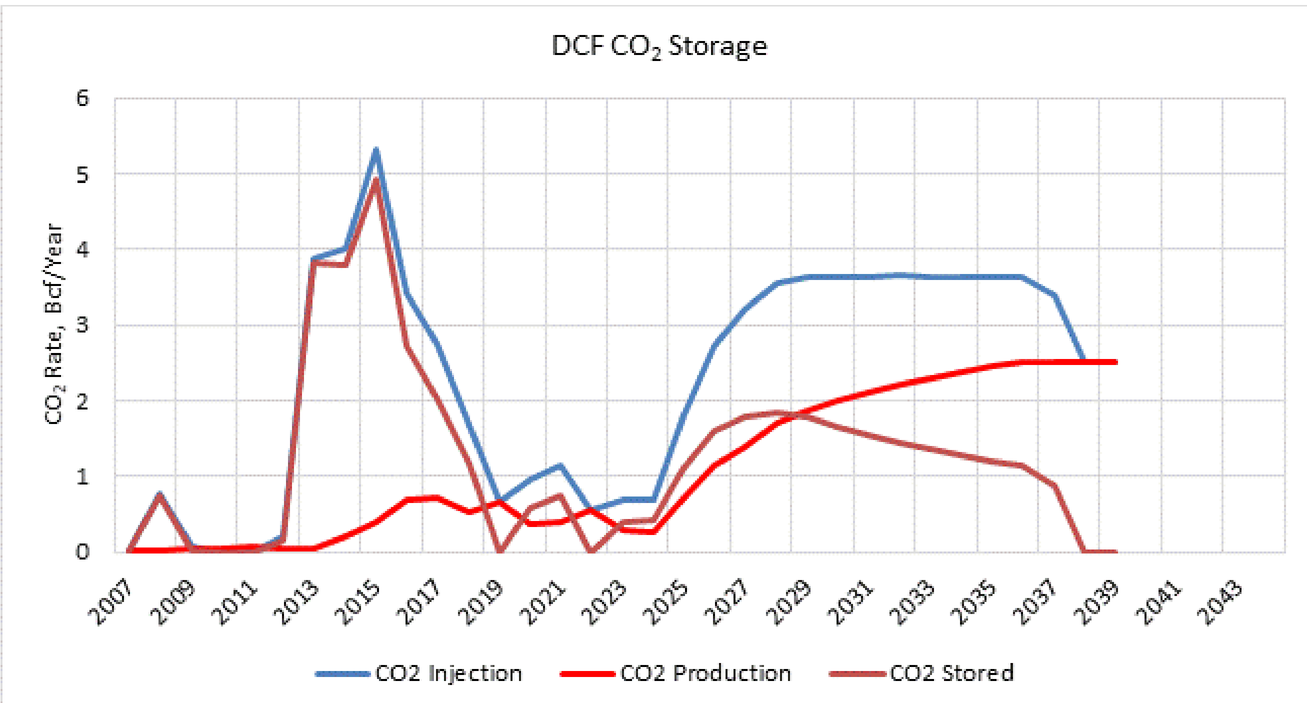

Figure 3-1 DCF Historic and Forecast CO_2 Injection, Production, and Storage

3.2 Environmental Setting

The DCF is located in the NE portion of the Central Basin Platform in West Texas (See Figure 3-2). This map also shows the location of the Denver Unit and other Wasson San Andres Units. The DCF is shown by the green dot.

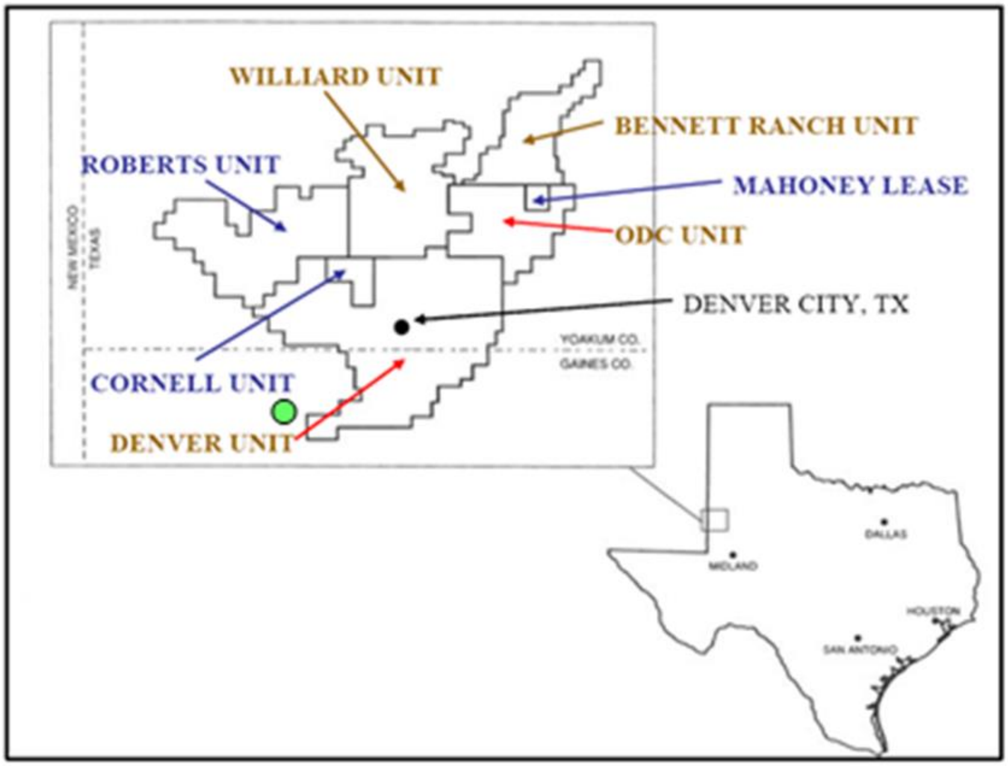

Figure 3-2 Location of DCF in West Texas

Like Wasson, the DCF produces from a San Andres dolomite reservoir at a depth of about 5,000 feet. In contrast to Wasson, DCF is a smaller oil accumulation with a thin mobile oil column trapped by a low relief anticlinal structure as shown in Figure 3-3. The Wasson field has produced over two billion barrels of oil to date from the San Andres while the DCF has produced 2.06 million barrels of oil to 2022.

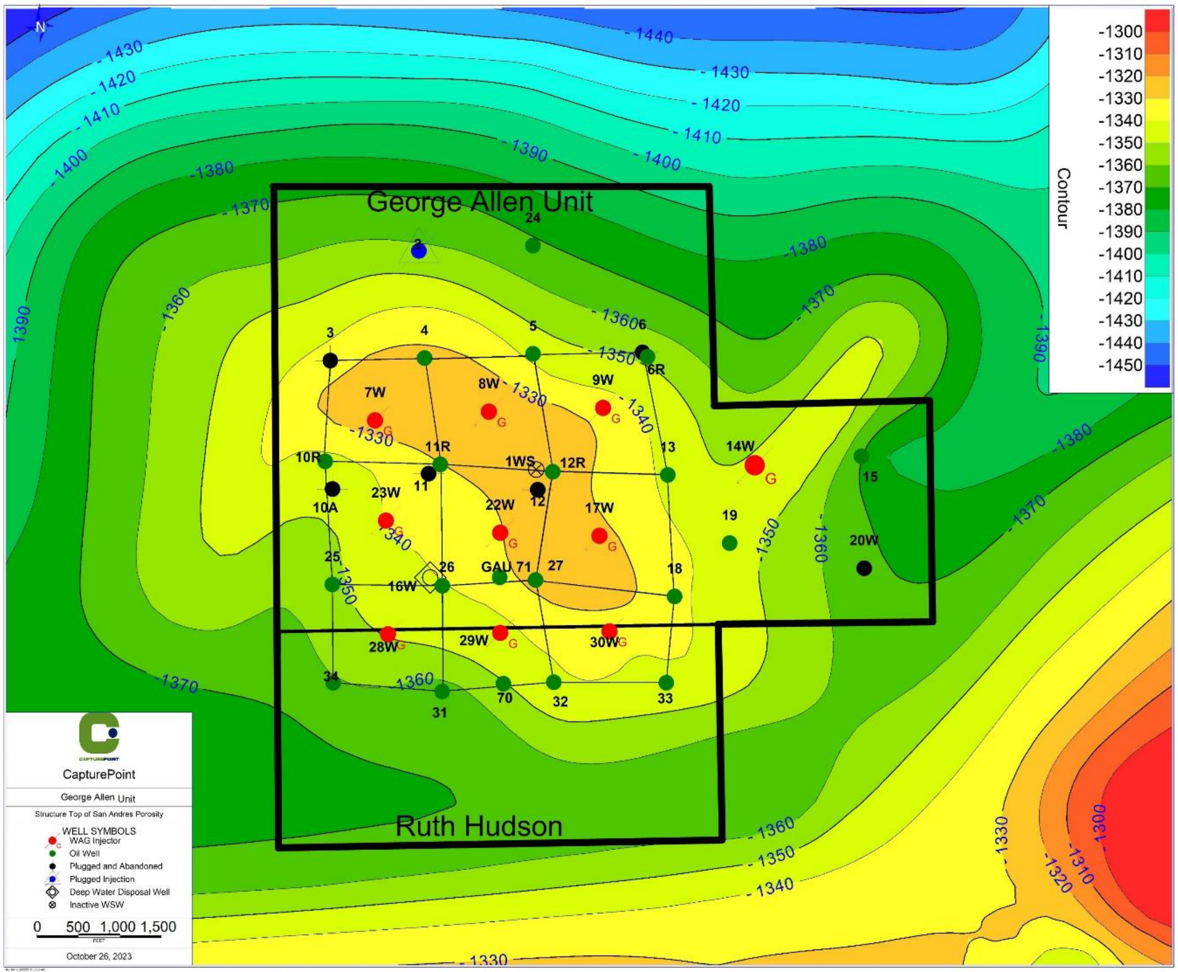

Figure 3-3 Local Area Structure on Top of San Andres for DCF

In the DCF there is a thin mobile oil column. Beneath the conventional oil column there is a thick, porous section with transition zone/residual oil (TZ/ROZ) that can only be produced via tertiary recovery methods, primarily CO_2 injection. This thick TZ/ROZ zone as found in the Wasson field gives a sizeable target for tertiary recovery (over 300 feet gross thickness).

Oil in the TZ/ROZ is currently being produced via CO_2 injection. Nine 40-acre patterns were prepared to inject CO_2 in this zone in the DCF. The presence of thick residual zones in the San Andres of the Permian Basin is widespread. Lindsay (2001), Melzer (2005), Melzer (2006), and Koperna and Kuuskraa (2006; 1&2) discuss the possible origins and the extent of residual oil zones in the Permian Basin. Brown (2001) discusses the ROZ in the area and its possible origin. The residual zone in the DCF has better porosity and permeability and is much thicker than the mobile oil zone which produced during primary and secondary (waterflood) recovery. This is often the case in residual oil zones, particularly those found in smaller fields with thinner oil columns. This gives us a large resource in which to economically sequester large volumes of CO_2, as CO_2 can both be stored and utilized for oil recovery in the extensive residual oil zones found in the San Andres in the Permian Basin.

The oil saturation profile found in the DCF/Wasson area is shown below in Figure 3-4 from Koperna and Kuuskraa (2006; 2):

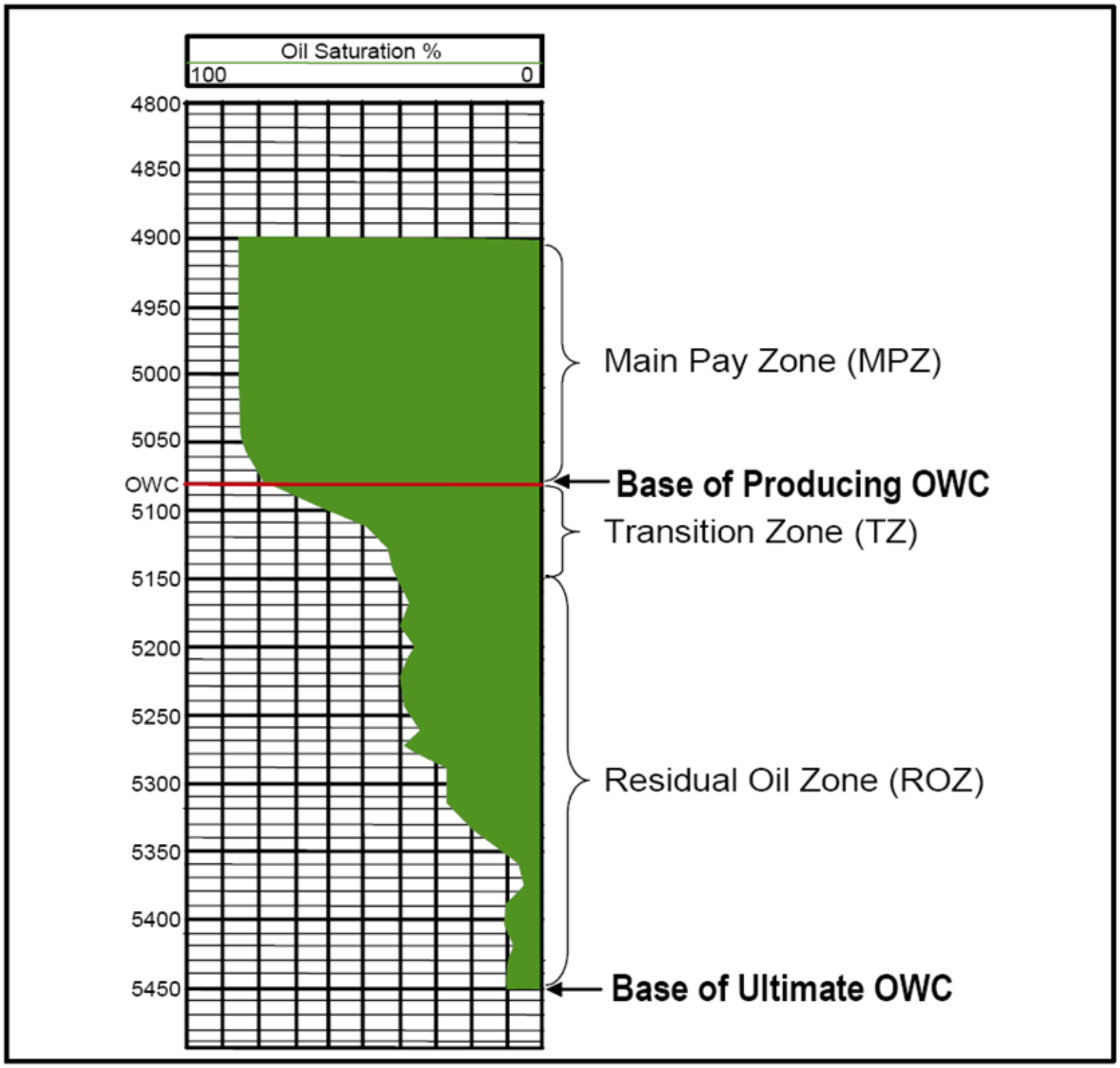

Figure 3-4 Saturation Profile of San Andres

Due to hydrodynamic flow in the San Andres aquifer, a ROZ was created and is under CO_2 flood along with the Main Pay Zone in the San Andres Formation.

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 (188 million reservoir barrels (MRB) to sequester the planned CO_2 injection (27.8 million reservoir barrels). 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 Central Basin Platform is negligible. The volume of CO_2 storage is based on the estimated total pore space within the DCF. The total pore space within the DCF, from the top of the reservoir down to the base of the ROZ, is calculated to be 188 million reservoir barrels (MRB). 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 254 billion cubic feet (Bcf) (13.4 million tonnes) of CO_2 storage in the reservoir. CO_2 will occupy only 15% of the total calculated storage capacity by the year 2037 based on the projected forecast.

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

Top of Main Pay to Bottom of Residual Oil Zone (ROZ)	
Variables	DCF Outline
Pore Volume (**RB**)	188,396,478
BCO_2 (RB/MCF)	0.407
Swirr	0.35
Sor CO_2	0.10
Max CO_2 (MCF)	254,589,835
Max CO_2 (BCF)	254

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. A reservoir management strategy that is used in CO_2 floods is the implementation of water curtain injectors. This will be utilized in the DCF to create a pressure barrier or “curtain” to contain the injected CO_2 to the area selected for production. Water curtain injection is an efficient method of maintaining and controlling lateral migration of fluids to assure that CO_2 does not cross structurally deficient locations. Injected fluids (CO_2) stay in the reservoir within the DCF unit boundary and do not move to adjacent areas.

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

3.3 Geologic Setting/Stratigraphic Column

The George Allen/Wasson San Andres fields are located on the Northwest shelf of the Permian Basin (Figure 3-5).

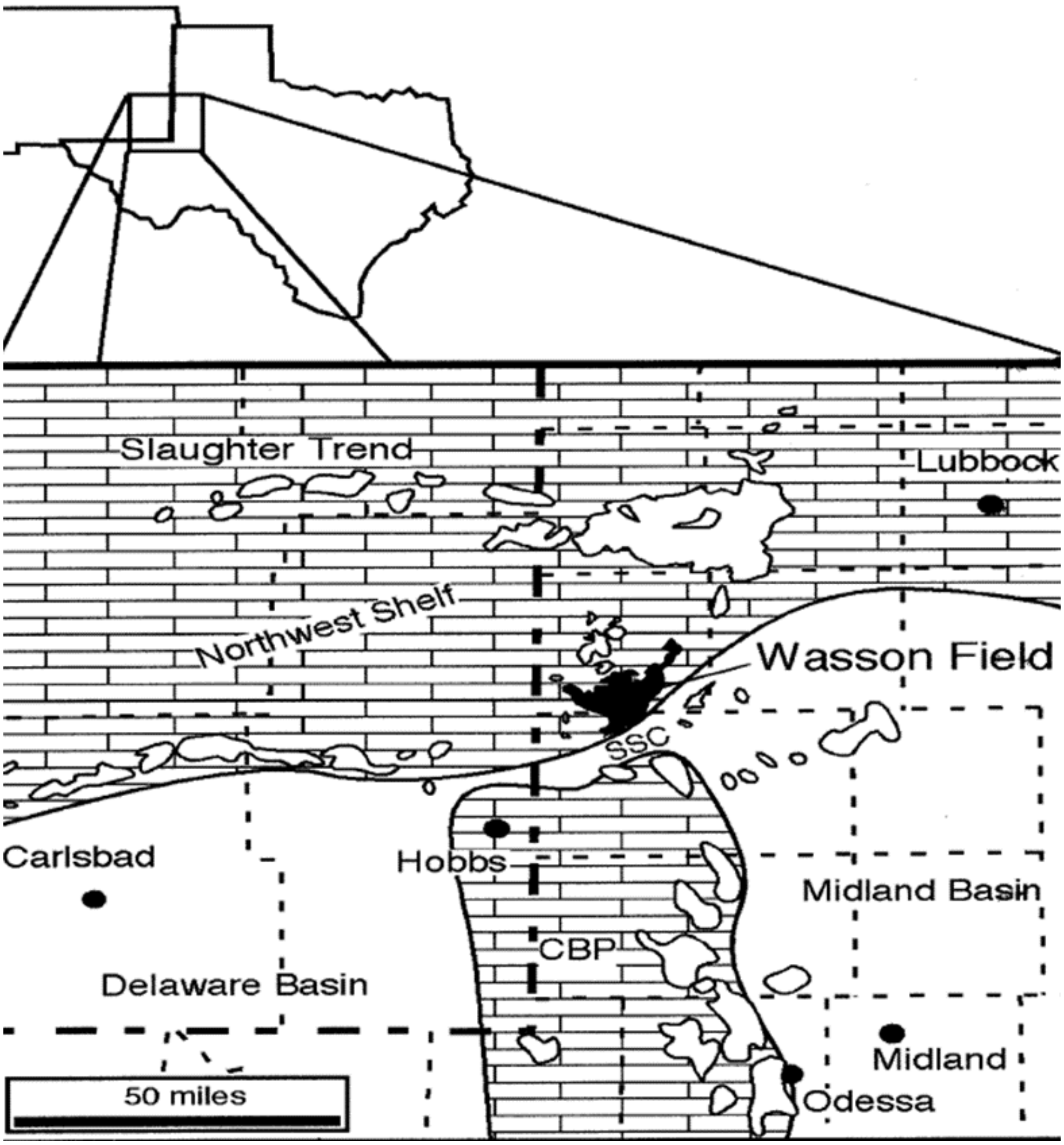

Figure 3-5 Map of Northwest shelf of the Permian Basin

The Wasson field is shown in black. Other San Andres fields are outlined. San Andres “shelf” facies are indicated by the brick pattern. “CBP” refers to the “Central Basin Platform” a major structural feature that separates the Delaware Basin from the Midland Basin. “SSC” refers to the “San Simon Channel” a feature which allowed seawater circulation between the shallow restricted shelf areas of the Northwest Shelf and the Central Basin Platform.

Figure 3-6 below shows the thickness and broad extent of the porous facies in the San Andres formation.

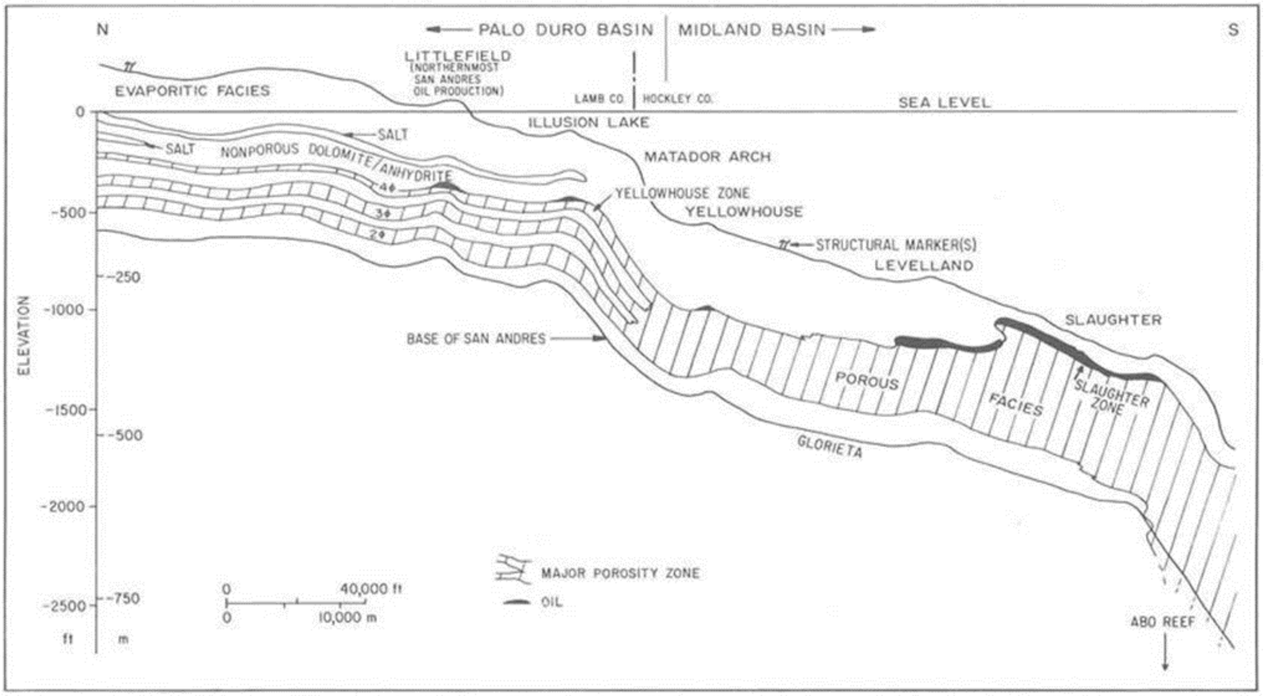

Figure 3-6 Cross section of lower San Andres Formation, Northern Shelf, showing porosity relationships.

A typical stratigraphic section for the area is shown below in Figure 3-7.

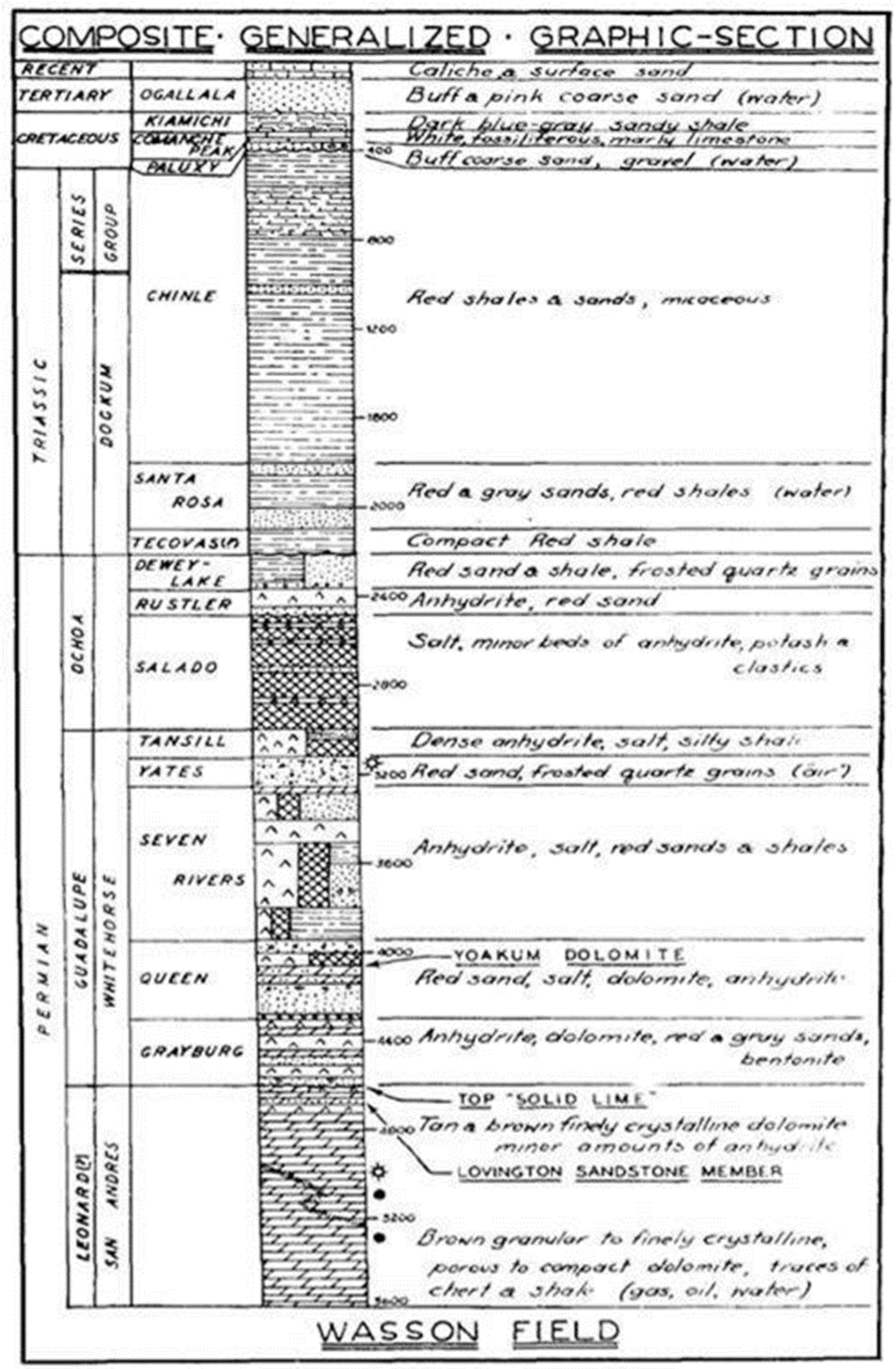

Figure 3-7 Composite generalized stratigraphic section.

The stratigraphy and facies of the Upper Permian on the Northwest Shelf and Central Basin Platform is quite uniform. The Upper Permian consists of a dominate thick and porous shallow marine carbonate facies that was later dolomitized as the San Andres Group prograded out into the basin. Continuation of the regressive sequence during the Upper Permian, defined as the Whitehorse group, caps the San Andres Group with tidal flat muds and tight exposed shelf carbonates, along with restricted evaporites. These facies within the Grayburg, Queen and Seven Rivers formation serve as widespread and efficient seals for both hydrocarbons and CO_2 trapping.

The notable thing about the Upper Permian rocks described here is that there are multiple and thick intervals that should eliminate the possibility of any vertical migration of fluids or gases from the San Andres reservoir to the surface.

The first seal is the Upper San Andres which consists of dense, fine crystalline dolomite and anhydrite, devoid of any porosity or permeability, deposited on the tidal flats of a broad, restricted shelf. Where the porous, shallow water carbonate facies of the Lower San Andres pinch out and interfinger with these rocks a series of stratigraphic traps is formed in the northern part of the Northwest Shelf. The Levelland-Slaughter-Chaveroo-Cato San Andres fields are found in this trend. A similar porosity pinches out, on the interior of the Central Basin platform, controls the widespread San Andres production found on the eastern margin of the Central Basin platform. These widespread producing trends attest to sealing capacity of the Upper San Andres anhydrous dolomite facies both vertically and laterally.

Above the San Andres are a series of restricted/exposed shelf facies consisting of tight, anhydrous dolomite, anhydrite, salt, and thin sandstones of the Upper Guadalupian Grayburg, Queen, Seven Rivers, Yates and Tansill formations. The sandstones sometimes have porosity and permeability but are often cemented by salt and are non-permeable. Where permeable, they offer no chance for vertical migration of fluids or gases as they are inter-layered with impermeable salt, anhydrite, and anhydrous dolomite.

Following the Tansill, the Ochoan, Upper Permian evaporites of the Salado and Rustler formations exist. The Salado is roughly 600-700 feet thick in the Wasson/George Allen area and consists dominantly of halite with some thin beds of potash and anhydrite and a few very thin layers of red mud, silt, and fine sand. Being widespread, thick, and impermeable, this formation alone should certainly stop the vertical migration of any fluids or gases from the subsurface to the surface. Even if fractured, the salt will flow and seal any open cracks. It is followed by the Rustler formation; 60 feet of dense, white anhydrite at the top overlying 30 feet of red shale interbedded with anhydrite; another capstone, on top a over 2,500 feet of mostly impermeable rock.

The Permian ends with the Dewey Lake formation which consists of red gypsum cemented sandstone and red shales.

Above the Permian unconformity are the Triassic Tecovas red shale and then the Santa Rosa formation which contains fresh water bearing sandstones. These deposits are followed by the micaceous red shales and sands of the Chinle formation. A major unconformity separates the Triassic Chinle from the overlying Cretaceous sediments that consists of coarse sand and gravel, white marly limestone, and dark, blue-gray sandy shale.

An important aquifer, the Tertiary Ogallala formation overlies these Cretaceous sediments. It consists of course sands and vari-colored gravels, all loose or poorly consolidated, which are followed by recent wind-blown sand and caliche.

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

Figure 3-8 shows a simplified process flow diagram of the project facilities and equipment in the DCF. CO_2 will be delivered to the DCF from Trinity, via the Kinder Morgan CO_2 pipeline network. The CO_2 will be supplied by several different sources including both natural and anthropogenic CO_2 sources. Specified amounts will be drawn from an outside source pipeline based on contractual arrangements among suppliers of CO_2, purchasers of CO_2, and the pipeline operator. The Specified amount of CO_2 required in addition to the produced gas to meet target CO_2 injection rates are forecasted using the DPC approach.

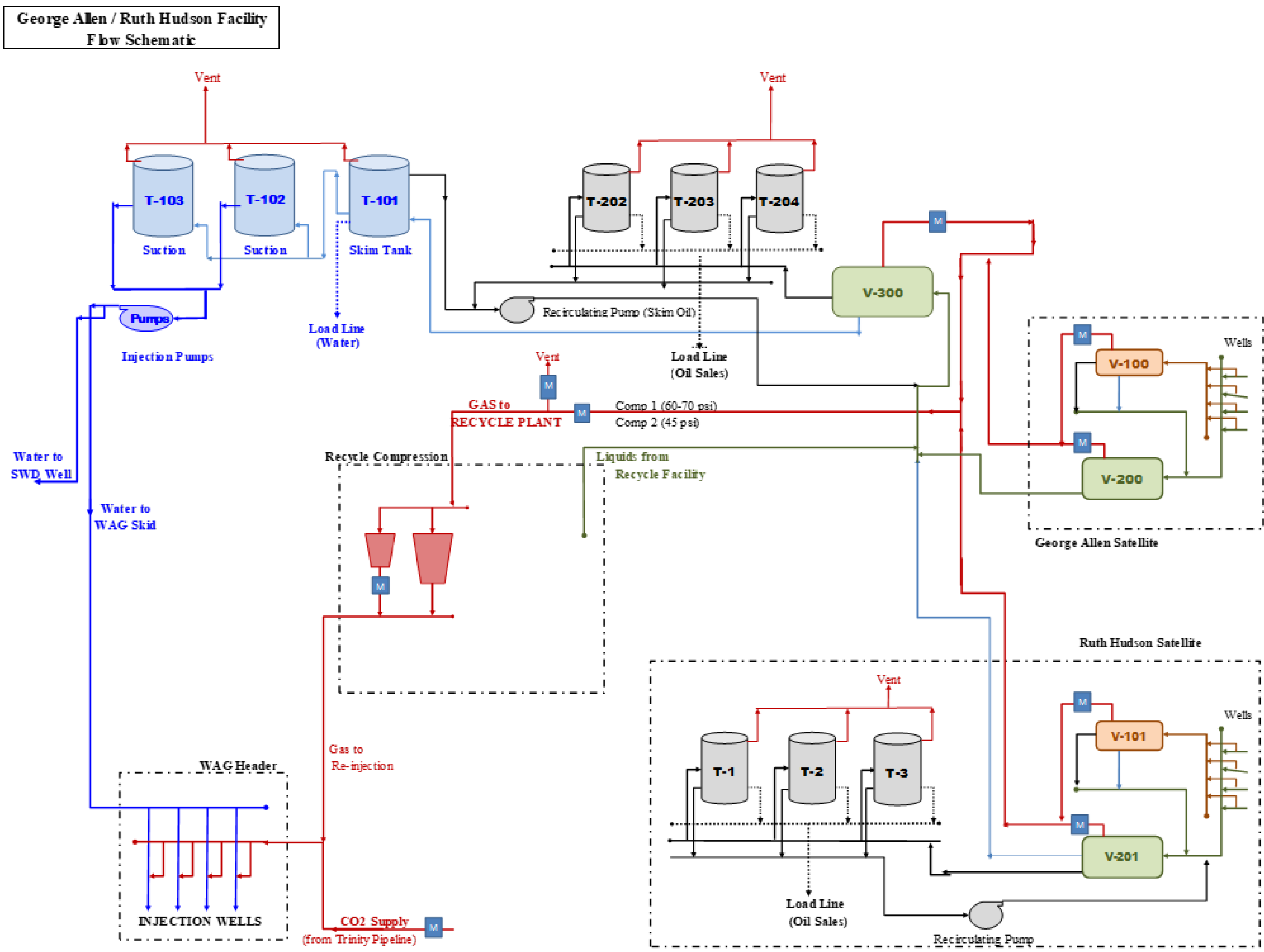

Figure 3-8 DCF Process Flow Diagram

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

i. CO_2 Distribution and Injection: The mass of CO_2 received at the DCF 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 WAG headers for injection into the injection wells according to the pre-programmed injection plan for each well pattern which alternates between water and CO_2 injection. WAG headers are manually operated and can inject either CO_2 or water at various rates and injection pressures as specified in the injection plans. 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. They are gathered and sent to Satellite Test Stations (SAT) for separation into a gas/CO_2 mix and a produced fluids mix of water, oil, 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 sent to two separate tanks (one at GAU and one at RH) where is then sold via truck.

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

3.4.1 Wells in the Denver City Fields

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 DCF Well Penetrations by Type and Status

TYPE	ACTIVE	INACTIVE	P & A	Total
PROD_OIL	16	3		19
INJ_WTR	0	1		1
INJ_WAG	8	0		8
INJ_SWD*	0	0		0
WSW	0	0		0
P&A			3	3
TOTAL	24	4	3	31

PROD_OIL = Production Wells
INJ_WRT = Water injection wells
INJ_WAG = WAG injection wells
INJ_SWD = Saltwater disposal wells
WSW = Water source wells
P&A = Plugged and Abandoned wells.

As indicated in Figure 3-9, wells are distributed across the DCF. The well patterns currently undergoing CO_2 flooding are identified by black 5-spot pattern outlines and CO_2 will be injected across the entire unit over the project life.

DCF CO_2-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Reservoir pressure in the DCF is managed by maintaining an IWR of approximately 1.0. To maintain the IWR, fluid injection and production are monitored and managed to ensure that reservoir pressure does not increase to a level that would compromise the reservoir seal or otherwise damage the integrity of the oil field.

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

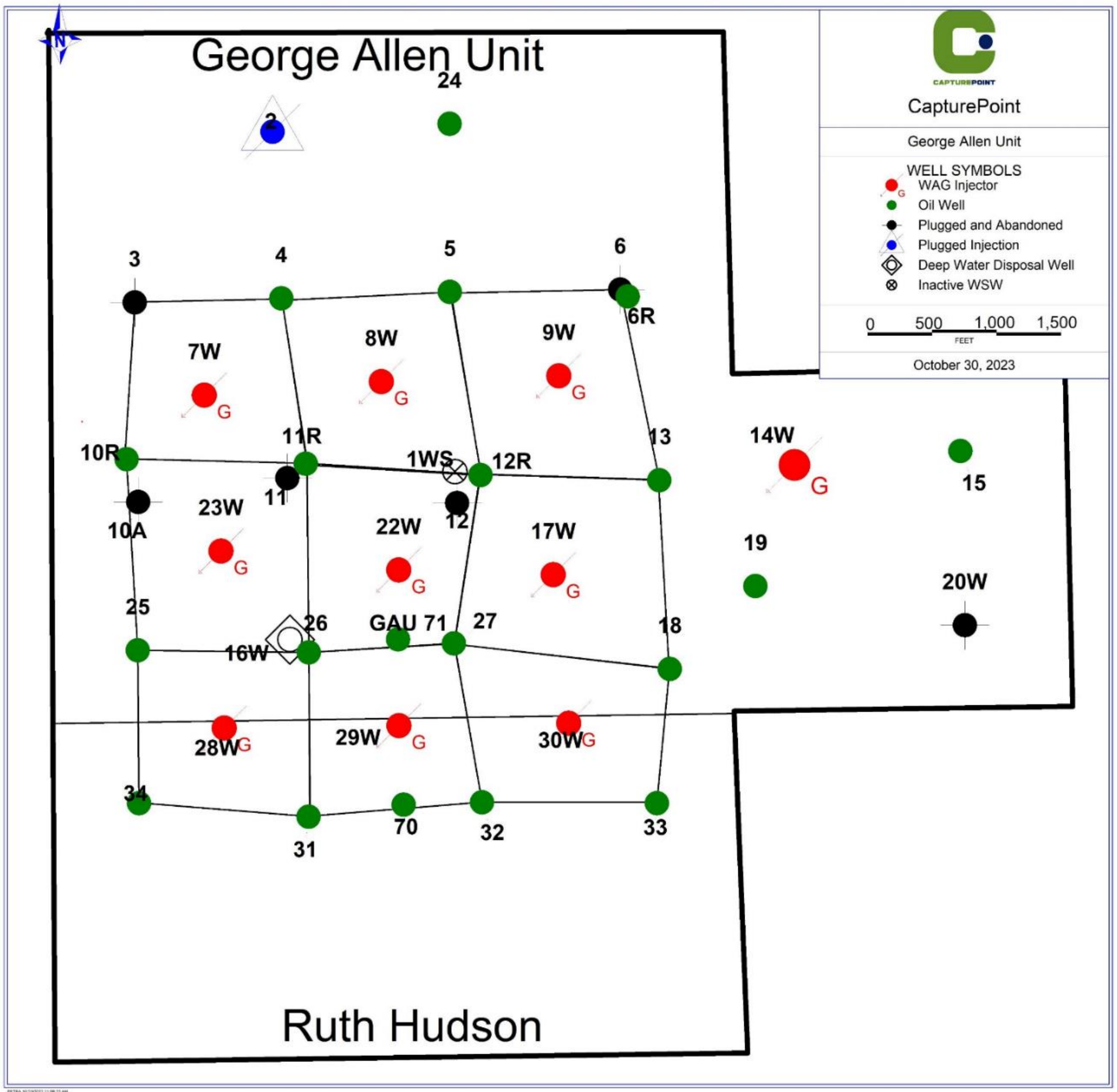

Figure 3-9 DCF Wells and Injection Patterns

3.5 Reservoir Forecasting

DPCs derived from the analogous Wasson San Andres field were used to project CO_2-EOR in the Denver City Field. Most DPCs are derived from geologic and reservoir models. In the DCF case the DPC was derived from actual field performance from the Wasson San Andres field. Like Wasson, the DCF is located on the Northwest shelf of the Permian Basin and produces from the San Andres dolomite reservoir at a depth of about 5,000 feet making them analogous.

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 3-10. 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.

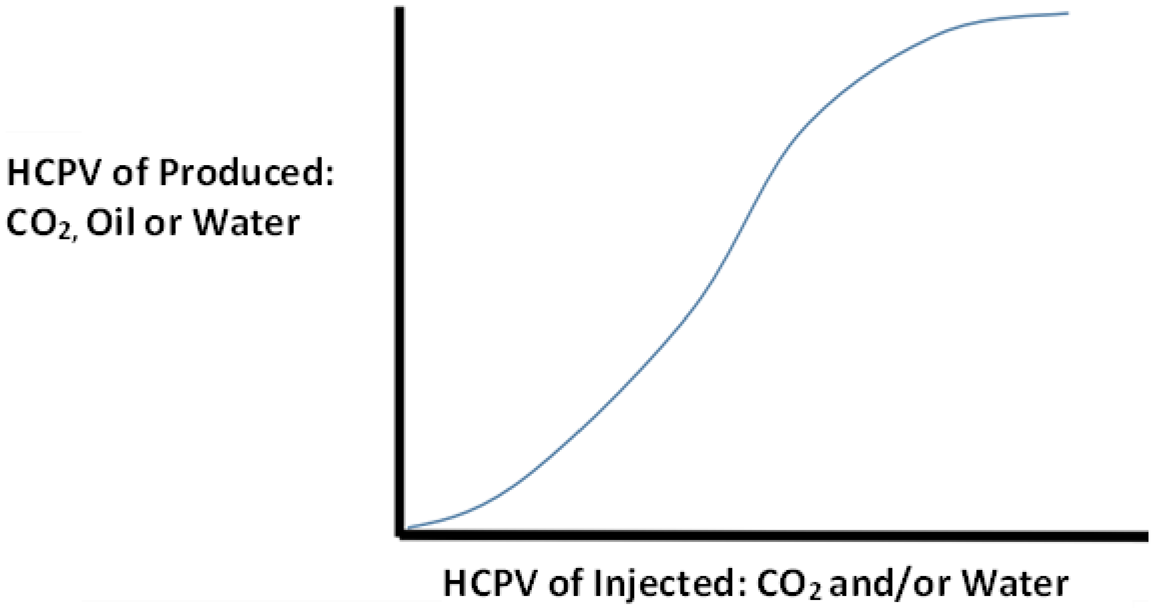

Figure 3-10 DPC plot

The DCF DPC was calculated from the cumulative production and injection from an analogous field. This DPC was used on each pattern in the DCF and then summed up to full field. This method allows you to use different start times and implement different field implementation speeds.

The DPCs are the basis for future 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 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 the GAU and RH boundaries plus the required ½ mile zone. Based on our projections, CapturePoint expects the free phase CO_2 plume to remain within the GAU and RH boundaries for the entire length of the project and through year [t+5]. The CO_2 storage volume calculations show the CO_2 to remain within the unit boundaries in the period associated with the AMA, which is year 2037.

The AMA is shown in Figure 4-1. It is an area defined by the boundary of the DCF plus the required ½ mile buffer. The AMA is consistent with the requirements in 40 CFR 98.449 because it is the area projected:

1 to contain the free phase CO_2 plume for the duration of the project (year t), plus an all-around buffer zone of one-half mile.

2 to contain the free phase CO_2 plume for at least 5 years after injection ceases (year t + 5).

4.1.1 Discussion of CO_2 Storage Volumes in AMA

The CO_2 injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO_2-EOR. Maintenance of an Injection to Withdrawal ratio of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.

Figure 3-9 displays wells that have CO_2 retention on the 370 acres that have been under CO_2 injection since project initialization. The CO_2 storage volumes were forecasted using the DPC approach. This technique indicates that the flooded acreage still has significant storage potential. The maximum CO_2 storage (254 BCF) is limited to the amount of space available by the removal of the produced hydrocarbon and water. The projection indicates that there is pore space available to store approximately 0.15 decimal fraction of HCPV amounting to 27.8 million reservoir barrels of oil (MMRB) (37.5 BCF).

The lateral extent of CO_2 in the injection zone or the CO_2 storage radius for each well was estimated by calculating a storage radius based on the forecasted CO_2 storage volume of 37.5 BCF. Figure 4-1 shows the map of the storage area outline for each pattern (dashed red line). This calculation showed 166 acres (this calculates to 18 acres per pattern) would be needed to store 37.5 BCF. This is significantly less than the 1133 acres in the DCF outline.

CO_2 injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO_2-EOR. Namely, maintenance of an IWR of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.

4.2 Maximum Monitoring Area

The Maximum Monitoring Area (MMA) is defined by the GAU and RH boundaries plus the required ½ mile buffer as required by 40 CFR §98.440-449 (Subpart RR). The CO_2 plume (Figure 4-1) is expected to be contained within the GAU and RH boundaries which will be actively monitored. Therefore, CapturePoint defines the MMA as the same as the AMA since the plume location is less than the unit area. 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 FR 98.448(d)(1).

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 DCF. The Specified Period is the timeframe that CO_2 storage will occur. In the DCF, CO_2 storage will occur until 2037 at which point CO_2 injection will equal CO_2 production. Specified Period will be shorter than the period of production from the DCF.

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 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 DCF 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.

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

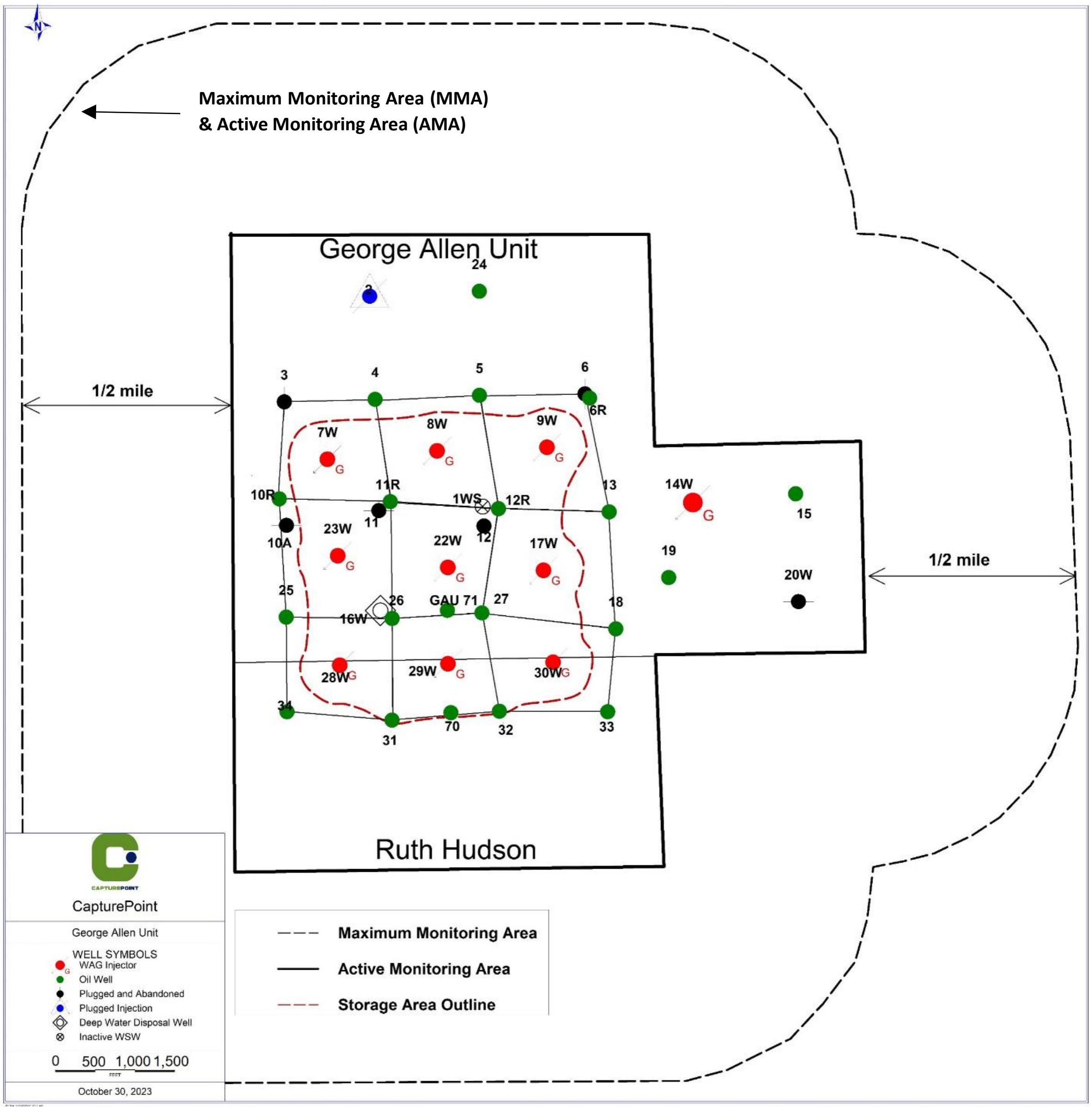

Figure 4-1 Projected CO_2 Storage area

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

In the roughly 60 years since the DCF 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 DCF
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 the DCF 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 DCF 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 beam pumped producing 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 DCF 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 DCF 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 a SAT. There is a routine well testing cycle for each SAT, 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 at the SAT 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 off 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. Further, the personal H_2S monitors are designed to detect leaked fluids around production wells during well inspections as well as various permanent H_2S monitors throughout the field at ground level.
- 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. If leakage did occur, the magnitude of leaks will range from 5 to 20 MT once every 50 years and will be addressed within 2 to 6 months of discovery to allow for obtaining drilling permits and contractor equipment mobilization.

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 San Andres reservoir in the project area. As a result, there is minimal risk (less than 1%) of leakage due to fractures or faults. This low risk therefore infers a very low magnitude if leaked.

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. Both procedures mitigate the potential for inducing faults or fractures. As a safeguard, WAG skids are continuously monitored.

5.3 Natural and Induced Seismicity

After reviewing the literature 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 DCF. 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 DCF 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 and less than 1% and of a very low magnitude.

To evaluate this potential risk at the DCF, CapturePoint has reviewed the nature and location of seismic events in West Texas. While some of the recorded earthquakes in West Texas are judged to be from natural causes, others are near oil fields or water disposal wells and are placed in the category of "quakes in close association with human enterprise."[2] A review of the United States Geological Survey (USGS) database of recorded earthquakes at M1.0 or greater in the Permian Basin since 1956 indicates that none have occurred in the DCF; the closest took place in 2020 approximately 38 miles away. See Figure 5-1.

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 induced seismic activity. There is no direct evidence to suggest that induced seismic activity poses a significant risk for loss of CO_2 to the surface in the Permian Basin, and specifically in the DCF. RRC approved injection pressures are kept well below the reservoir fracture gradient to ensure seismicity is not induced. 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.

[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.

CapturePoint monitors the USGS earthquake monitoring Geographical Information System (GIS) site[3] for seismic signals that could indicate the creation of potential leakage pathways in the DCF.

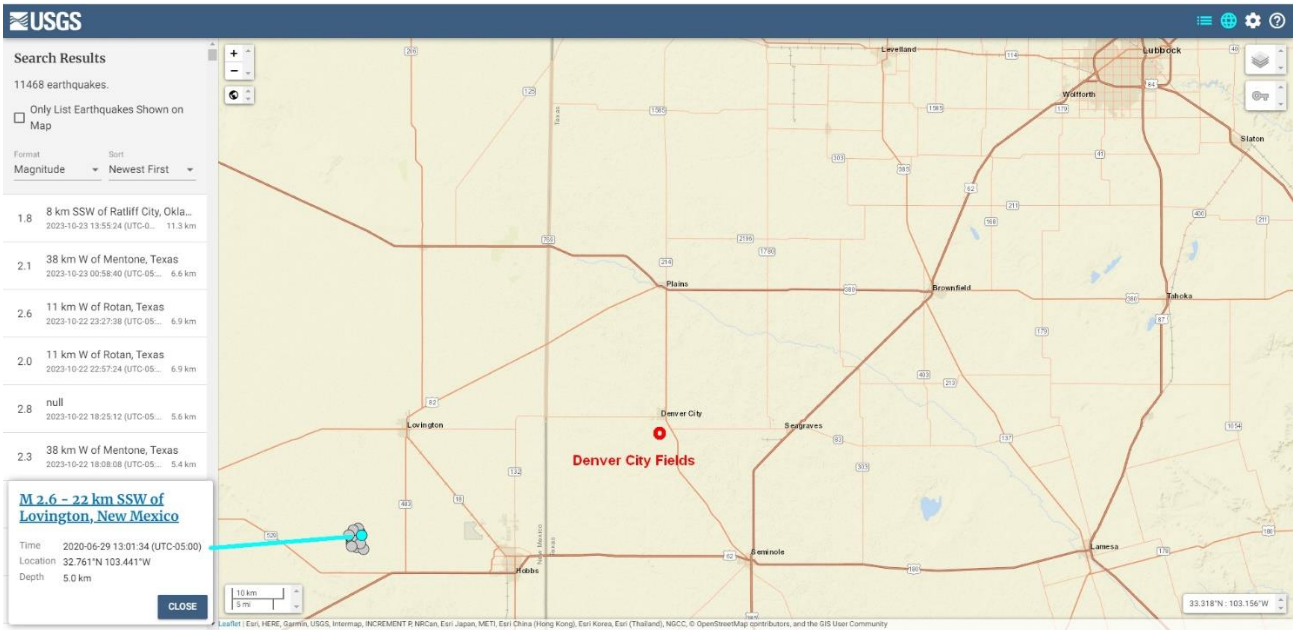

Figure 5-1 USGS earthquakes (+1.0 magnitude) for last 57 years)

5.4 Previous Operations

CO_2 flooding was initiated in the DCF in 2007. 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 5.1, 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 the DCF. These practices ensure that there are no unknown wells within the DCF and that the risk of migration from older wells has been sufficiently mitigated via location identification and daily on-site monitoring of rates and pressures. The successful experience with CO_2 flooding in the DCF demonstrates that the confining zone has not been impaired by previous operations. 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 and construction practices and compliance with applicable laws will reduce to the maximum extent practicable the risk of

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

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. Surface equipment leaks have a low risk of occurring based on design standards that are followed, and any leak would have insubstantial results. The magnitude of surface equipment leaks will range from 0.1 to 2 MT yearly and are addressed within 6-12 hours of occurring. 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 the Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP). 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 Denver City Fields

It is highly unlikely that injected CO_2 will migrate downdip and laterally outside the DCF because of the nature of the geology and the approach used for injection. Over prolonged periods of time, injected CO_2 will tend to rise vertically towards the Upper San Andres and continue towards the point in the DCF with the highest elevation. Second, the planned injection volumes and active fluid management during injection operations will prevent CO_2 from migrating laterally out of the structure. Finally, the total volume of fluids contained in the DCF will stay constant. Based on site characterization and planned and projected operations it is estimated that the total volume of stored CO_2 will be less than the calculated capacity. Since the stored volume is less than the calculated capacity, the likelihood and magnitude of lateral migration are very low and would happen only in the late life of injection.

5.7 Drilling in the Denver City Fields

The TRRC regulates well drilling activity in Texas. Pursuant to TRRC rules, well casing shall be securely anchored in the hole 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. The TRRC requires applications and approvals before a well is drilled, recompleted, or reentered. Well drilling activity at the DCF is conducted in accordance with TRRC rules. CapturePoint's visual inspection process, including routine site visits, will identify unapproved drilling activity in the DCF. 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 the DCF 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, the risks associated with third parties penetrating the DCF are negligible.

5.8 Diffuse Leakage Through the Seal

Diffuse leakage through the seal formed by the upper San Andres is highly unlikely. There are a number of 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.

Our injection pattern 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 using all metering and measurement equipment from each wellhead through the output of the tanks and recycle. 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.

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

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.

Records of leakage events will be retained in an 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 pressure; MIT for injectors	Well is shut in and workover crews respond within days
Casing Leak	Routine Field inspection; Monitor changes in annulus pressure, MIT for injectors; extra attention to high risk wells	Well is shut in and workover crews respond within days
Wellhead Leak	Routine Field inspection, SCADA system monitors wellhead pressure	Well is shut in and workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations	Maintain well kill procedures
Unplanned wells drilled through San Andres	Routine Field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells.	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Reservoir pressure in WAG headers; high pressure found in new wells	Re-enter and reseal abandoned wells
Pumps, valves, etc.	Routine Field inspection, SCADA	Workover crews respond within days
Overfill beyond spill points	Reservoir pressure in WAG headers; high pressure found in new wells	Fluid management along lease lines
Leakage through induced fractures	Reservoir pressure in WAG headers; high pressure found in new wells	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Reservoir pressure in WAG headers; high pressure found in new wells	Shut in injectors near seismic event
Diffuse leakage through the seal	Monitor injection pressure for unexplained changes in injection pressure that might indicate leakage	Investigate to determine if cement and steel construction is the issue. Well is shut in and workover crews respond within days.

5.10 Summary

The structure and stratigraphy of the San Andres reservoir in the DCF is ideally suited for the injection and storage of CO_2. The stratigraphy 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 DCF 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.

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 DCF 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 DCF 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 3-8, 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 Kinder Morgan CO_2 pipeline delivery system is transferred to the DCF. 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 RCF and the custody transfer meter at the CO_2 off-take point from the Kinder Morgan 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 the outlet of the separation facility (Figure 3-8 vessels, V-100, V-101, V-200, V-201, and V-300),
- CO_2 that is entrained in produced oil, as indicated in Figure 3-8, is calculated from routinely captured samples and volume is measured by the truck flow meter,
- Recycled CO_2 is calculated using the volumetric flow meter at the outlet of the RCF, which is an operations 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 DCF. Subpart W uses a factor-driven approach to estimate equipment leakage. An event-driven process to assess, address, track, and if applicable quantify potential CO_2 leakage to the surface is used. Additionally, CapturePoint uses 40 CFR Part 98 Subpart RR to report equipment leaks and vented emissions separately for injection and production.

The multi-layered, 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, 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 SAT 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 as well as the various permanent H_2S monitors throughout the field at ground level. Such a diffuse leak from the subsurface has not occurred in the DCF. 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

DCF 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 and various permanent H_2S monitors throughout the field at ground level.

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 DCF. 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 DCF. 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 Green House Gas (GHG) reporting.

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 area of the DCF 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 check that injectors are on the proper WAG schedule and observe the facility for visible CO_2 or fluid line leaks.

Finally, the data collected by the H_2S monitors, which are always worn by field personnel and are located permanently throughout the field at ground level, is used as a last method to detect leakage from wellbores. The H_2S monitor's detection limit is 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 CO_2 leaks in the field. Thus, detected H_2S leaks will be investigated to determine and, if needed, quantify potential CO_2 leakage.

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, ensuring that injectors are on the proper WAG schedule, and also 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 and the permanent H_2S monitors throughout the field at ground level 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 DCF 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. The current H2S concentration in the produced gas is 5,709 ppm taken from the recycle compressor inlet and 205 ppm in the produced oil. 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.

As stated before, there are various permanent H2S monitors throughout the field at ground level to detect H2S and alarm if a limit is reached.

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

Per subpart RR requirements, all flow meters for CO_2 and oil measurement are located directly downstream of each separation point. To account for the potential error that would result if volume data from flow meters at each injection and production well were utilized, the data from custody transfer meters, operations meters on the main system pipelines, and at all points of separation, is used to determine injection and production volumes used in the mass balance of the system. This issue arises because while each meter has a small but acceptable margin of error, this error would become significant if data were taken from all the well head meters within the DCF (See Figure 3-8).

The following sections describe how each element of the mass-balance equation (Equation RR-11) will be calculated.

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:

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

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

- All delivery to the DCF 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 DCF 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 at the outlet of the RCF (see Figure 3-8). As previously explained, using data at each injection well would give an inaccurate estimate of total injection volume due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

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.

$C_{CO_{2,p,u}}$= 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:

$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$ (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

The Mass of CO_2 Produced at the DCF will be calculated using the measurements from the flow meters at the inlet to RCF and the custody transfer meter for oil sales rather than the metered data from each production well. Again, using the data at each production well would give an inaccurate estimate of total injection due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

Equation RR-8 in §98.443 will be used to calculate the Mass of CO_2 Produced from all production wells 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.

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 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

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. Volumes for CO_{2E} (surface leakage) and CO_{2FI} (equipment leakage and vented emissions) are calculated separately and differently.

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

$CO_{2E} = \sum_{x=1}^{X} \mathrm{CO}_{2,\mathrm{x}}$ (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 DCF 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:

$CO_{2w} = \sum_{p=1}^{4}(\mathrm{Q}_{\mathrm{p,w}}) * \mathrm{D} * \mathrm{C}_{\mathrm{CO}_{2,\mathrm{p,w}}}$ (Eq. RR-8)

Where:

CO_{2w} = 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 DCF 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 DCF. 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 flow meter located at the RCF outlet.

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 DCF 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 DCF 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:

- SWS refers to wells that supply water.
- PROD_OIL refers to wells that produce oil.
- INJ_WAG refers to wells that inject water or 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
GAU #1WS	42165339890000	SWS	INACTIVE
GAU #2W	42165106400000	P&A	INACTIVE
GAU #3	42165106340000	P&A	INACTIVE
GAU #4	42165103790000	PROD_OIL	SHUT_IN
GAU #5	42165106070000	PROD_OIL	INACTIVE
GAU #6	42165106530000	P&A	INACTIVE
GAU #6R	42165367760000	PROD_OIL	INACTIVE
GAU #7W	42165339900000	INJ_WAG	ACTIVE
GAU #8W	42165339910000	INJ_WAG	SHUT_IN
GAU #9W	42165339920000	INJ_WAG	ACTIVE
GAU #10	42165106510000	P&A	INACTIVE
GAU #10R	42165367820000	PROD_OIL	ACTIVE
GAU #11	42165106060000	P&A	INACTIVE
GAU #11R	42165367490000	PROD_OIL	ACTIVE
GAU #12	42165102070000	P&A	INACTIVE
GAU #12R	42165367510000	PROD_OIL	ACTIVE
GAU #13	42165003830000	PROD_OIL	ACTIVE

Well Name	API Number	Well Type	Status
GAU #14W	42165317930000	INJ_WAG	SHUT_IN
GAU #15	42165101300000	PROD_OIL	INACTIVE
GAU #16W	42165106270000	INJ_SWD	ACTIVE
GAU #17W	42165339930000	INJ_WAG	ACTIVE
GAU #18	42165103780000	PROD_OIL	ACTIVE
GAU #19	42165106460000	PROD_OIL	SHUT_IN
GAU #20W	42165008790000	P&A	INACTIVE
GAU #22W	42165352720000	INJ_WAG	ACTIVE
GAU #23W	42165367500000	INJ_WAG	ACTIVE
GAU #24	42165106440000	PROD_OIL	INACTIVE
GAU #25	42165367550000	PROD_OIL	ACTIVE
GAU #26	42165367530000	PROD_OIL	ACTIVE
GAU #27	42165367540000	PROD_OIL	ACTIVE
GAU #71	42165384590000	PROD_OIL	ACTIVE
RH #28W	42165367610000	INJ_WAG	ACTIVE
RH #29W	42165367620000	INJ_WAG	ACTIVE
RH #30W	42165367630000	INJ_WAG	ACTIVE
RH #31	42165367660000	PROD_OIL	ACTIVE
RH #32	42165367670000	PROD_OIL	ACTIVE
RH #33	42165367520000	PROD_OIL	ACTIVE
RH #34	42165367890000	PROD_OIL	SHUT_IN
RH #70	42165384430000	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

DCF – Denver City Fields

DPC - Dimensionless Performance Curve

EPA - Environmental Protection Agency

EOR - Enhanced Oil Recovery

ESP - Electrical Submersible Pump

FPP - Formation Parting Pressure (psi)

GAU - George Allen Unit

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

RH - Ruth Hudson Lease

SAT – Satellite Test

TAC - Texas Administrative Code

TRRC - Texas Railroad Commission - Oil and Gas Division

UIC – Underground Injection Control

USGS - United States Geological Survey

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.