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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

October 20, 2022

Mr. Carl Thunem
700 Central Expwy South
Suite 405
Allen, Texas 75013

Re: Monitoring, Reporting and Verification (MRV) Plan for Seminole East Field (SEF)

Dear Mr. Thunem:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Seminole East Field (SEF), as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Seminole East Field on August 3, 2022, as the final MRV plan. The MRV Plan Approval Number is 1012091-1. This decision is effective October 25, 2022 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78.

If you have any questions regarding this determination, please contact me or Melinda Miller of the Greenhouse Gas Reporting Branch at miller.melinda@epa.gov.

Sincerely,

Julius Banks, Chief
Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for Seminole East Field (SEF)

October 2022

Contents

Appendices

Appendix A: Final MRV Plan
Appendix B: Submissions and Responses to Requests for Additional Information

This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) Subpart RR Monitoring, Reporting, and Verification (MRV) plan submitted for the carbon dioxide (CO_2)-enhanced oil recovery (EOR) project in the Permian-aged Seminole East Field (SEF) in Gaines County, Texas. Note that this evaluation pertains only to the Subpart RR MRV plan, and does not in any way replace, remove, or affect Underground Injection Control (UIC) permitting obligations.

1 Overview of Project

As is described in the MRV plan, CapturePoint currently operates CO_2-EOR project in the SEF located in Gaines County, Texas, approximately one and one-half miles northeast of the town of Seminole for the primary purpose of enhanced oil recovery using CO_2, with retention of CO_2 serving a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The SEF is comprised of the East Seminole San Andres Unit (ESSAU) and the Lindoss Unit. Production for both units is from the San Andres formation at an average depth of 5,500 feet. While the SEF first produced oil more than 60 years ago, the MRV plan states that CO_2 flooding was initiated in 2013 in both units. The MRV plan states that the geology, facilities/equipment, and operational procedures are similar for both units in the SEF. In addition, the two units 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 reservoir similarities, one MRV plan is being prepared for the two units that make up the SEF facility. Under this MRV plan, SEF plans to inject approximately 9 million metric tons of CO_2 over the duration of the project. This 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 SEF.

The MRV plan states that all EOR injection wells in the SEF are currently classified as UIC Class II wells permitted by the Texas Railroad Commissions (TRRC). TRRC has primacy to implement the Underground Injection Control (UIC) Class II program in the state for injection wells. Wells in the SEF are identified by name, American Petroleum Institute (API) number, type, and status. The list of wells as of February 2022 is included in Section 12.1 of the MRV plan. SEF recognizes that any and all changes to wells within the SEF will be indicated in the Subpart RR Annual Report.

The SEF is located in the northeast portion of the Central Basin Platform in West Texas. As explained in the MRV plan, the producing formation is the Upper Permian San Andres formation that consists of anhydritic dolomite with vuggy, moldic, and intercrystallite porosity. The thin, intertidal deposits of anhydrite carbonate mudstone layers result in effective vertical permeability barriers within this stratified reservoir. According to the MRV plan, the hydrodynamic flows in the San Andres aquifer caused a thick residual oil zone (ROZ). This ROZ is undergoing CO_2 flooding along with the main pay zone of the San Andres Formation. The structure of the field is an elliptical anticline oriented in a northwest to southeast direction, as shown in Figure 3-4 in the MRV plan.

According to the MRV plan, CO_2 is delivered to the ESSAU and Lindoss Unit via the Kinder Morgan CO_2 pipeline network. The CO_2 is a combination of natural and anthropogenic CO_2. The mass of CO_2 received at both units is metered and calculated through Custody Transfer Meters located at the pipeline delivery points. At both the ESSAU and at the Lindoss Unit, 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 water alternating gas (WAG) headers for injection into the injection wells according to the preprogrammed injection plan for each well pattern, where wells alternate 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.

The MRV plan states that the 18 active WAG injection wells are located across the SEF in 5-spot well patterns as seen in figure 3-7 of the MRV plan. CO_2 will be injected across the entire unit over the project life. The MRV plan states that SEF CO_2-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Additionally, reservoir pressure in the SEF is managed by maintaining an injection-to-withdrawal ratio (IWR) of approximately 1.0. 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.

The MRV plan states that produced fluids from both units (oil, hydrocarbon gas, water, CO_2, and other constituents) will be separated at a satellite test station (SAT). The produced gas, which is composed primarily of CO_2 and minor hydrocarbons, is sent to the recycle compression facility 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. The MRV plan states that there are no physical differences between the ESSAU and Lindoss Units.

The description of the project is acceptable and provides the necessary information for 40 CFR 98.448(a)(6).

2 Evaluation of the Delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA)

As part of the MRV plan, the reporter must identify and delineate both the maximum monitoring area (MMA) and active monitoring area (AMA), pursuant to 40 CFR 98.448(a)(1). Subpart RR defines maximum monitoring area as “the area that must be monitored under this regulation and 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.” Subpart RR defines active monitoring area as “the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) the area projected to contain the free phase CO_2 plume at the end of year t, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) the area projected to contain the free phase CO_2 plume at the end of year t + 5.” See 40 CFR 98.449.

The CO_2 storage volumes were forecasted using a dimensionless performance curve (DPC) approach. According to the MRV plan, this technique indicates that the flooded acreage still has significant additional storage potential. The maximum CO_2 storage (158 billion cubic feet (BCF)) is limited to the amount of pore space available by the removal of the produced hydrocarbon. However, the calculated projection used by SEF indicates that there is pore space available to store approximately 0.51 decimal fraction of hydrocarbon pore volume (HCPV), which amounts to 80.2 billion cubic feet (BCF).

According to the MRV plan, 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 80.2 BCF. A map detailing the estimated storage radius can be seen in Figure 4-1 of the MRV plan. The MRV plan explains that the storage area outlines in the original MRV plan submission slightly exceeded the ESSAU in the southwest corner. As a result, SEF elected to reduce the volume of CO_2 injected into this area, to increase CO_2 injected in the north-northeast wells, and the MRV plan. The MRV plan states that the MMA is defined by the ESSAU and Lindoss Unit boundaries plus the required half mile buffer. The MMA has the same boundary as the AMA since the plume location is less that the ESSAU and Lindoss unit areas.

The MMA, as it is defined in the MRV plan, is consistent with Subpart RR requirements because the defined MMA accounts for the expected free phase CO_2 plume, based on storage area modeling results, and incorporates the additional 0.5-mile or greater buffer area. The rationale used to delineate the MMA, as described in SEF's MRV plan, accounts for the existing operational and subsurface conditions at the site, along with any potential changes in future operations. Similarly, the AMA, as it is defined in the MRV plan, is consistent with Subpart RR requirements because the defined AMA is projected to contain the free phase CO2 plus an all-around buffer zone of one-half mile. Therefore, the designation of the AMA and MMA is acceptable.

The delineations of the MMA and AMA were determined to be acceptable per the requirements in 40 CFR 98.448(a)(1). The MMA and AMA described in the MRV plan are clearly and explicitly delineated in the plan and are consistent with the definitions in 40 CFR 98.449.

3 Identification of Potential Surface Leakage Pathways

As part of the MRV plan, the reporter must identify potential surface leakage pathways for CO_2 in the MMA, and that the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). SEF identified the following as potential leakage pathways in their MRV plan that required consideration:

1. Existing Well Bores
2. Faults and Fractures
3. Natural and Induced Seismicity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the SEF

7. Drilling Through the CO_2 Area
8. Diffuse Leakage Through the Seal

3.1 Leakage through Existing Wellbores

According to the MRV plan, an extensive review of all SEF penetrations was completed to determine the potential need for corrective action. This analysis showed that all penetrations have either been adequately plugged and abandoned or, if in use, do not require corrective action. The MRV plan also states that all wells in the SEF were constructed and are operated in compliance with TRRC rules. As part of routine risk management, SEF identified and evaluated the potential risk of CO_2 wellbore leakage occurring through CO_2 flood beam pumped producing wells, CO_2 flood electrical submersible pump (ESP) producing wells, and CO_2 WAG injector wells.

The risk assessment, as described in the MRV plan, classified the risk associated with leakage occurring through existing wellbores as low (less than 1% probability of occurrence). Furthermore, SEF states that they will mitigate the potential risk of wellbore CO_2 leakage through:

- Adhering to TRRC regulatory requirements for well drilling and testing,
- Implementing best practices that SEF has developed through its extensive operating experience,
- Monitoring injection/production performance, wellbores, and the surface; and,
- Maintaining surface equipment.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected through existing wellbores.

3.2 Leakage through Faults or Fractures

According to the MRV plan, there are no known faults or fractures that transect the San Andres reservoir in the project area. Therefore, the MRV plan claims there is little to no risk of leakage due to fracture or faults. Nevertheless, SEF will manage injection patterns so that injection pressures will not exceed the formation parting pressure (FPP). In addition, the IWR will be maintained to remain near 1.0. Both measures mitigate the potential for induing faults or fractures.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected through faults or fractures.

3.3 Leakage through Natural or Induced Seismicity

According to the MRV plan, 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 SEF. SEF reviewed the nature and location of seismic events in West Texas using the United States Geologic Survey (USGS) database on recorded earthquakes. Their review showed that no magnitude (M) 0.5 or greater earthquakes have occurred within the SEF since at least 1966. The closest earthquake over a M0.5 occurred approximately 30 miles away in 1992. SEF states that induced seismicity could lead to fractures in the seal, which would provide a pathway for CO_2 leakage to the surface. However, SEF is not aware of any reported loss of injectant to the surface associated with any seismic activity. Finally, the MRV plan states that SEF monitors the USGS earthquake monitoring Geological Information System (GIS) site for seismic signals that could indicate the creation of potential leakage pathways in the SEF.

In order to prevent induced seismicity, section 3.3.1 of the MRV plan states that they will keep injection pressure below the formation parting pressure (FPP). To do so, SEF will measure and monitor the injection pressure using step-rate tests.

Thus, the MRV plan provides an acceptable characterization of the CO_2 leakage that could be expected through natural or induced seismicity.

3.4 Leakage From Previous Operations

The MRV plan states that to obtain permits for CO_2 flooding, the AOR around all SEF CO_2 injector wells was evaluated to determine if there were any unknown penetrations and to assess if any corrective action was required at any wells. SEF found that no additional corrective action was needed to reduce the risk of leakage through previous well penetrations. Furthermore, SEF claims that its standard practice for drilling new wells at SEF includes a rigorous review of nearby wells to ensure that drilling will not cause damage to or interfere with existing wells. According to the MRV plan, these practices ensure that there are no unknown wells within SEF and that the potential risk of CO_2 migration from older wells has been sufficiently mitigated.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected from previous operations.

3.5 Leakage From Pipelines and Surface Equipment

The MRV plan states that the use of prevailing design and construction practices and compliance with applicable TRRC rules will reduce, to the maximum extent practicable, the risk of unplanned leakage from surface facilities at SEF. SEF states that they 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. Furthermore, field personnel are trained to look for and report potential leaks from pipeline and surface equipment as part of their routine activities.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected from pipeline and surface equipment.

3.6 Leakage From Lateral Migration Outside the SEF

The MRV plan states that it is highly unlikely that injected CO_2 will migrate downdip and laterally outside the SEF because of the nature of the geology and the approach used for injection. It explains that injected CO_2 will rise vertically towards the structurally highest point of the Upper San Andres formation within the SEF. Furthermore, the MRV plan asserts that the planned injection volumes and active fluid management during injection operations will prevent CO_2 from migrating laterally out of the structure. SEF employs continuous water curtain injection (WCI) methods during the CO_2-EOR operations to prevent CO_2 lateral migration out of the unit boundary. Finally, the MRV plan states that the total volume of stored CO_2 will be considerably less than the calculated capacity of the structure.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected from lateral migration outside the SEF.

3.7 Leakage From Drilling in the SEF

The MRV plan states that, in accordance with TRRC rules, well casings shall be securely anchored in the hole in order to effectively control the well at all times, all useable quality water zones shall be isolated and sealed off to effectively prevent contamination or harm, and all productive zones, potential flows zones, and zones with corrosive formation fluids shall be isolated and sealed off to prevent vertical migration of fluids, including gases, behind the casing. The MRV plan asserts that all well drilling activity at SEF is conducted in accordance with TRRC rules. Finally, SEF intends to operate SEF 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. SEF also asserts that the risks associated with third parties penetrating the SEF are negligible.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected from drilling in the SEF.

3.8 Leakage Through the Seal

The MRV plan states that diffuse leakage through the seal formed by the upper San Andres Formation is highly unlikely. They explain that there are several sections above the reservoir that are impermeable and serve as reliable barriers to prevent fluids from moving upwards towards the surface. SEF claims that their injection pattern monitoring program and the highly effective caprock assures there is minimal likelihood that a breach of the seal will be created.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through the seal.

The MRV plan concludes that, based on a careful assessment of the potential risk of release of CO2 from the subsurface, it has been determined that there are no leakage pathways at the SEF that are likely to result in significant loss of CO2 to the atmosphere. Thus, the MRV plan provides an acceptable characterization of potential CO2 leakage pathways as required by 40 CFR 98.448(a)(2).

4 Strategy for Detecting and Quantifying Surface Leakage of CO_2 and for Establishing Expected Baselines for Monitoring

40 CFR 98.448(a)(3) requires that an MRV plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring CO_2 surface leakage. Sections 5 and 6 of the MRV plan detail SEF's strategy for monitoring and quantifying CO_2 leakage, and section 7 of the MRV plan details strategies for establishing baselines for CO_2 leakage. SEF's approach for detecting and quantifying surface leakage of CO_2 primarily includes routine field inspections, SCADA system monitoring of wellhead pressures, monitoring of injection pressures, and monitoring of reservoir pressure through WAG headers.

As described in Section 5.9 of the MRV plan, 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 MRV plan explains that any volume of CO2 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.

A summary table of SEF's strategy for monitoring and responding to any possible CO_2 leakage can be found Table 5.1 of the MRV plan and reproduced below:

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, mechanical integrity tests (MITs) 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

Diffuse leakage through the seal	Injection pressure is continuously monitored and unexplained changes in injection pressure that might indicate leakage would trigger investigation as to the cause.	Conduct an injection radioactive tracer survey. If verified, well is shut in and workover crews respond within days.
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

4.1 Detection of Leakage from Existing Wellbores

Section 5.1 of the MRV plan states that SEF wells are supervised through daily 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.

Should anomalies in injection zone pressure warrant further investigation, section 6.1.5 of the MRV plan states that 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 SEF. 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.

Section 6.1.5 of the MRV plan states anomalies in annular pressure or other issues detected during routine maintenance inspections would be treated in the same way as anomalies in injection zone pressure. 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 SEF. 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.

As described in section 6.1.5 of the MRV plan, a visual inspection process in the area of the SEF is employed to detect unexpected CO_2 release from wellbores. Field personnel visit the surface facilities on a routine basis to check for bright white clouds or ice, which are indicators of CO_2 surface leakage. 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 they observe the facility for visible CO_2 or fluid line leaks.

Finally, section 6.1.5 of the MRV plan states that H_2S monitors will also be used to help detect CO_2 leakage from wellbores. All SEF field personnel wear H_2S monitors at all times. The H_2S monitor 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. Currently, the concentration of H_2S in the recycled or produced gas is in excess of 18,000 ppm, making leak detection viable. Thus, detected H_2S leaks will be investigated in order to quantify the potential CO_2 leakage source and quantities.

Thus, the MRV plan provides adequate characterization of SEF's approach to detect potential leakage from existing wellbores as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage through Faults or Fractures

As stated in the MRV plan, there is little to no risk of leakage due to fractures or faults. Even still, SEF routinely updates measurements to determine FPP and reservoir pressure of the SEF. This information is used to manage injection patterns so that the injection pressure will not exceed FPP. An IWR at or near 1.0 is also maintained. Both measures mitigate the potential for inducing faults or fractures. As a safeguard, WAG skids are continuously monitored to detect anomalies in CO_2 volumes and pressures.

Thus, the MRV plan provides adequate characterization of SEF's approach to detect potential leakage through faults or fractures as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage through Natural or Induced Seismicity

The MRV plan states that SEF 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 SEF. 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. SEF monitors the USGS earthquake monitoring Geological Information System (GIS) for seismic signals that could indicate the creation of potential leakage pathways in the SEF.

Thus, the MRV plan provides adequate characterization of SEF's approach to detect potential leakage through natural or induced seismicity as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage from Previous Operations

As stated in the MRV plan, SEF reviewed the identified penetrations and determined that no additional corrective action was needed to prevent CO_2 leakage. Requirements to construct wells with materials that are designed for CO_2 injection are adhered to at SEF. These practices ensure that that there are no unknown wells within SEF and that the risk of migration from older wells has been sufficiently mitigated.

Thus, the MRV plan provides adequate characterization of SEF's approach to detect potential leakage from previous operations as required by 40 CFR 98.448(a)(3).

4.5 Detection of Leakage from Pipelines and Surface Equipment

As stated in the MRV plan, SEF utilizes prevailing design and construction practices to mitigate the chances of CO_2 leakage through pipelines and surface equipment. 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. In preparation of any such leakage event, SEF field personnel are trained to look for and report potential leaks from pipeline and surface equipment as part of their routine activities. 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 EPA's GHGRP.

Thus, the MRV plan provides adequate characterization of SEF's approach to detect potential leakage from pipelines and surface equipment as required by 40 CFR 98.448(a)(3).

4.6 Detection of Leakage from Lateral Migration Outside the SEF

As described in the MRV plan, the nature of the geology and the approach used for injection at SEF makes it highly unlikely that injected CO_2 will migrate laterally outside the SEF. Reservoir pressure in WAG headers and high pressure found in new wells will be indicative of leakage due to lateral migration outside of the SEF.

Thus, the MRV plan provides adequate characterization of SEF's approach to detect potential leakage from lateral migration as required by 40 CFR 98.448(a)(3).

4.7 Detection of Leakage from Drilling in the SEF

As stated in the MRV plan, all well drilling activity at SEF is conducted in accordance with TRRC rules. As a result, CO_2 leakage from drilling in the SEF is unlikely. SEF's visual inspection process, including routine site visits, will identify unapproved drilling activity in the SEF. These inspections will also serve to monitor for leakage during future drilling in the SEF.

Thus, the MRV plan provides adequate characterization of SEF's approach to detect potential leakage from drilling as required by 40 CFR 98.448(a)(3).

4.8 Detection of Leakage through the Seal

As stated in the MRV plan, the multiple sections above the SEF injection reservoir are impermeable and are meant to serve as multiple reliable barriers to prevent fluids from moving upwards towards the surface. SEF claims that their injection monitoring program assures that no breach of the seal will be created. SEF injection pressure is continuously monitored and unexplained changes in injection pressure that might indicate leakage would trigger investigation as to the cause.

Thus, the MRV plan provides adequate characterization of SEF's approach to detect potential leakage through the seal as required by 40 CFR 98.448(a)(3).

4.9 Determination of Baselines and Quantification of Potential CO_2 Leakage

According to the MRV plan, ongoing operational monitoring has provided data for establishing historical baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO_2 leakage in the future. Data systems are used primarily for operational control and monitoring and as such are set to capture more information than is necessary for reporting in the Subpart RR Annual Report. For this, SEF will rely primarily on visual inspections, personal H_2S monitors, injection data, and production data.

Visual Inspections

The MRV plan states that the SEF field foreman is notified for maintenance activities that cannot be addressed on the spot by field operators. Examples of such incidents would 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. Furthermore, SEF will provide an estimate of CO_2 leakage for any such possible incidents in the Subpart RR Annual Report.

Personal H_2S Monitors

The MRV plan states that H_2S monitors have been and continually will be worn by all field personnel. The H_2S monitors detect concentrations of H_2S up to 500 ppm and will sound an alarm if the detection limit exceeds 10 ppm. Permanent H_2S monitors are also located throughout the field at ground level. 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. SEF considers H_2S to be a proxy for potential CO_2 leaks in the field. The Subpart RR Annual Report will provide an estimate the amount of CO_2 emitted from any such incidents.

Injection Rates, Pressures and Volumes

The MRV plan states that target injection rate and pressure for each injector is 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. Should the flag signify a substantial amount of CO_2 leakages, the Subpart RR Annual Report will provide an estimate of CO_2 emissions.

Production Volumes and Compositions

The MRV plan states that a general forecast of production volumes and composition is developed which is used to periodically evaluate performance and refine current and projected injection plans. Should leakage be detected via deviation from the forecasted production volumes, leakage volumes would be calculated using methods described in the MRV plan. Impact to Subpart RR reporting will be addressed, if deemed necessary.

Quantification

The MRV plan states that 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.

Thus, SEF provides an acceptable approach for establishing expected baselines for monitoring CO_2 surface leakage in accordance with 40 CFR 98.448(a)(4).

5 Considerations Used to Calculate Site-Specific Variables for the Mass Balance Equation

5.1 Calculation of Mass of CO_2 Received

Section 8 of the MRV plan states that 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 Kinder Morgan 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.

$$CO_2T{,}r = \sum_{p=1}^{4} (Q_{p,r} - S_{r,p}) * D * C_{CO2,r,p} \qquad \text{(Eq. RR-2)}$$

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 a site well in quarter p (standard cubic meters).

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

$C_{CO2,r,r}$ = 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.

SEF provides an acceptable approach to calculating the mass of CO_2 received is acceptable for the Subpart RR requirements.

5.2 Calculation of Mass of CO_2 Injected

Section 8 of the MRV plan states that the mass of CO_2 Injected into the Subsurface at the SEF is equal to the sum of the Mass of CO_2 Received as calculated in RR-2 of §98.443 and the mass of CO_2 recycled calculated using measurements taken from the flow meter located at the output of the RCF. The mass of CO_2 Recycled will be determined using equations RR-5 as follows:

$$CO_2u = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO2,p,u} \qquad \text{(Eq. RR-5)}$$

where:

CO_{2u} = Annual CO_2 mass recycled (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.

$C_{CO2,p,u}$ = 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-3) and Mass of CO_2 Recycled (modified RR-5).

$CO_{2I} = CO_2 + CO_{2u}$

SEF provides an acceptable approach to calculating the mass of CO_2 injected in accordance Subpart RR requirements.

5.3 Mass of CO_2 Produced

Section 8 of the MRV plan states that the mass of CO_2 Produced at the SEF 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. Equation RR-8 in §98.443 will be used to calculate the Mass of CO_2 Produced from all production wells as follows:

$$CO_{2w} = \sum_{p=1}^{4} Qp,w * D * C_{CO2,p,w} \qquad \text{(Eq. RR-8)}$$

where:

CO_{2W} = Annual CO_2 mass produced (metric tons).

$Q_{P,W}$ = Volumetric gas flow rate measurement for meter 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.

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

p = Quarter of the year.

w = Inlet meters to RCF

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

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

where:

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

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

Xoil = 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).

SEF provides an acceptable approach for calculating the mass of CO_2 produced under the Subpart RR requirements.

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage

Section 8 of the MRV Plan states that the total annual Mass of CO_2 emitted by Surface Leakage will be calculated and reported using an approach that is tailored to specific leakage events and relies on 40 CFR Part 98 Subpart W reports of equipment leakage. SEF 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 a number of sites 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 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 of the MRV plan. 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 Subpart RR Annual Report would be retained. Further, the Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.

Equation RR-10 in §98.433 will be used to calculate and report the Mass of CO_2 emitted by Surface Leakage:

$$CO_{2E} = \sum_{x=1}^{x} CO_{2x} \qquad \text{(Eq. RR-10)}$$

where:

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

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

SEF provides an acceptable approach for calculating the mass of CO_2 emitted by surface leakage under the Subpart RR requirements.

5.5 Calculation of Mass of CO_2 Sequestered

Section 8 of the MRV Plan states that the mass of CO_2 sequestered in subsurface geologic formations will be calculated based off Equation RR-11:

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \qquad \text{(Eq. RR-11)}$$

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) net of CO_2 entrained in oil 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 this part.

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 this part.

SEF provides an acceptable approach for calculating the mass of CO_2 sequestered under Subpart RR requirements.

6 Summary of Findings

The Subpart RR MRV plan for the Seminole East Field meets the requirements of 40 CFR 98.238. The regulatory provisions of 40 CFR 98.238(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the SEF MRV plan.

Subpart RR MRV Plan Requirement	SEF MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 4 of the MRV plan describes the MMA and AMA. The MMA and AMA share the same boundary. The MMA is defined by the ESSAU and Lindoss Unit boundaries plus the required ½ mile buffer.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 5 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: existing well bores; faults and fractures; natural and induced seismic activity; previous operations; pipeline/surface equipment; lateral migration outside the SEF; drilling through the CO_2 area; diffuse leakage through the seal; and leakage detection, verification, and quantification. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways. SEF determined that these leakage pathways are not likely at the Seminole East Field, and that it is unexpected that potential leakage conduits would result in significant loss of CO_2 to the atmosphere.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Sections 5 and 6 of the MRV plan describes a strategy for how the facility would detect and quantify potential CO_2 leakage to the surface should it occur, such as MITs, SCADA systems, field inspections, and the monitoring of WAG headers. Section 6 of the MRV plan

	also describes a strategy for how surface leakage would be quantified.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 7 of the MRV plan describes the strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage. Strategies include visual inspections; personal H_2S monitors; the monitoring of injection rates, pressures, and volumes; and the monitoring of production volumes and compositions.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 6 of the MRV plan describes SEF's approach to determining the amount of CO_2 sequestered using the Subpart RR mass balance equation, including as related to calculation of total annual mass emitted from equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 12 (Appendix) of the MRV plan provides well identification number for all active wells in the SEF. The MRV plan specifies that all of the injection wells at SEF are permitted by the TRRC as UIC Class II wells.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 7 of the MRV plan states that SEF's 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. The MRV plan also states that it will be implemented starting January 2023 or within 90 days of EPA approval, whichever occurs later.

Appendix A: Final MRV Plan

CapturePoint LLC Seminole East Field Subpart RR Monitoring, Reporting and Verification (MRV) Plan

August 2, 2022

Table of Contents

1. Introduction

CapturePoint LLC operates a carbon dioxide (CO_2)-enhanced oil recovery (EOR) project in the Seminole East Field (SEF) located in Gaines County, Texas, approximately one and one-half miles northeast of the town of Seminole for the primary purpose of enhanced oil recovery using CO_2 with a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The SEF is comprised of the East Seminole San Andres Unit (ESSAU) and the Lindoss Unit. Production is from the San Andres formation at an average depth of 5500 feet. 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 Seminole East Field during a specified period of injection.

2. Facility Information

2.1. Reporter Number

562518 – Seminole East Field

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 SEF (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 SEF are currently classified as UIC Class II wells.

2.3. Existing Wells

Wells in the SEF are identified by name and number, American Petroleum Institute (API) number, type, and status. The list of wells as of February 2022 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 SEF an oil field located in West Texas that was first produced more than 60 years ago. SEF is comprised of the ESSAU and the Lindoss Unit. The two units abut 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 units in the SEF. In addition, the two units 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 reservoir similarities, one MRV Plan is being prepared for the two units in the SEF and any important differences between the units will be noted in the MRV plan. CO_2 flooding was initiated in 2013 in both units. The field is well characterized and is suitable for secure geologic storage. CapturePoint uses a water alternating with gas (WAG) injection process and maintains an injection to withdrawal ratio (IWR) at or near 1.0.

3.1. Project Characteristics

The SEF was discovered in 1959 and started producing in the same year. The SEF consists of two units, the ESSAU and the Lindoss Unit. The ESSAU began to produce in May 1959 and waterflood was initiated in January 1983. CO_2 flooding was initiated in 2013, in both the Main Pay and Residual Oil Zone (ROZ). The ROZ is an oil-bearing zone that has been swept by water movement under hydrodynamic conditions over geologic time to a reduced oil saturation that is no longer mobile. The ROZs are attractive targets for EOR with CO_2 Capture and Sequestration. The Lindoss Unit began to produce in November 1979 and waterflood was initiated in July 1984. CO_2 flooding was initiated in October 2013, also in the Main Pay and ROZ.

A long-term CO_2 and hydrocarbon injection and production forecast for both ESSAU and Lindoss was developed using a performance dimensionless curve (DPC) approach. Using this approach, a total injection of approximately 9 million tonnes of 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 SEF.

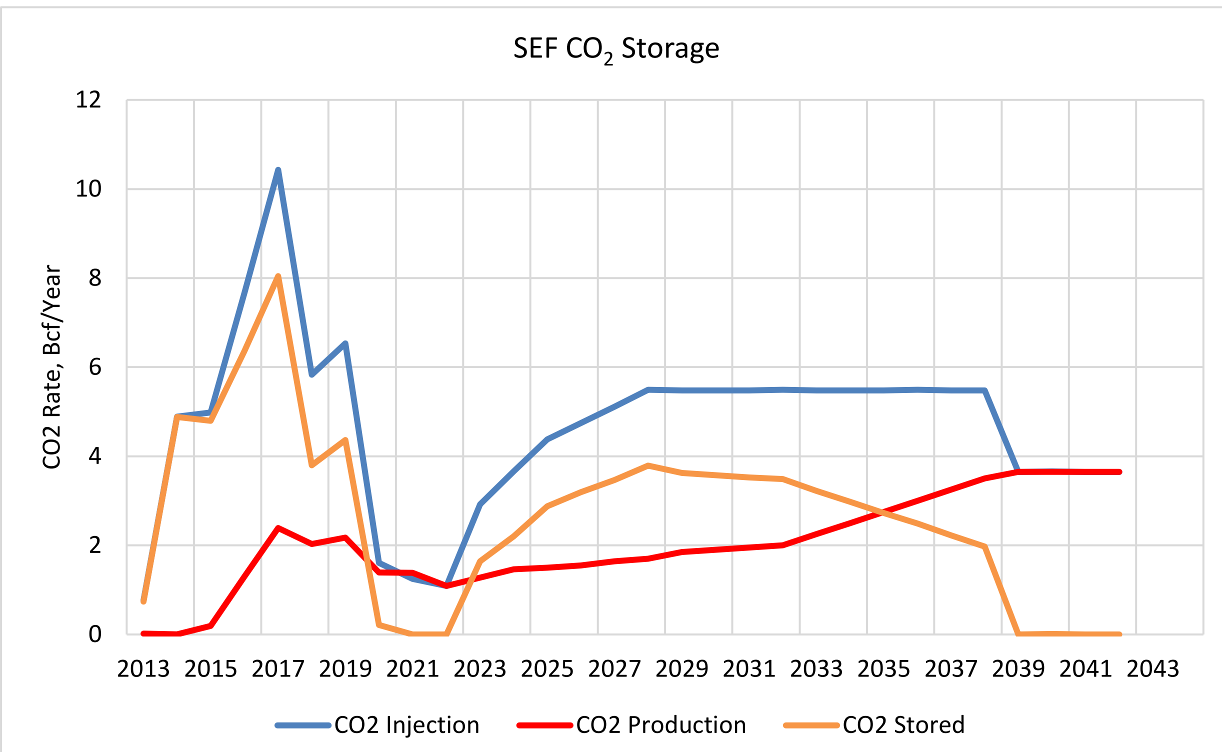

Figure 3-1 SEF Historic and Forecast CO_2 Injection, Production, and Storage

3.2. Environmental Setting

The SEF is located in the NE portion of the Central Basin Platform in West Texas (See Figure 3-2).

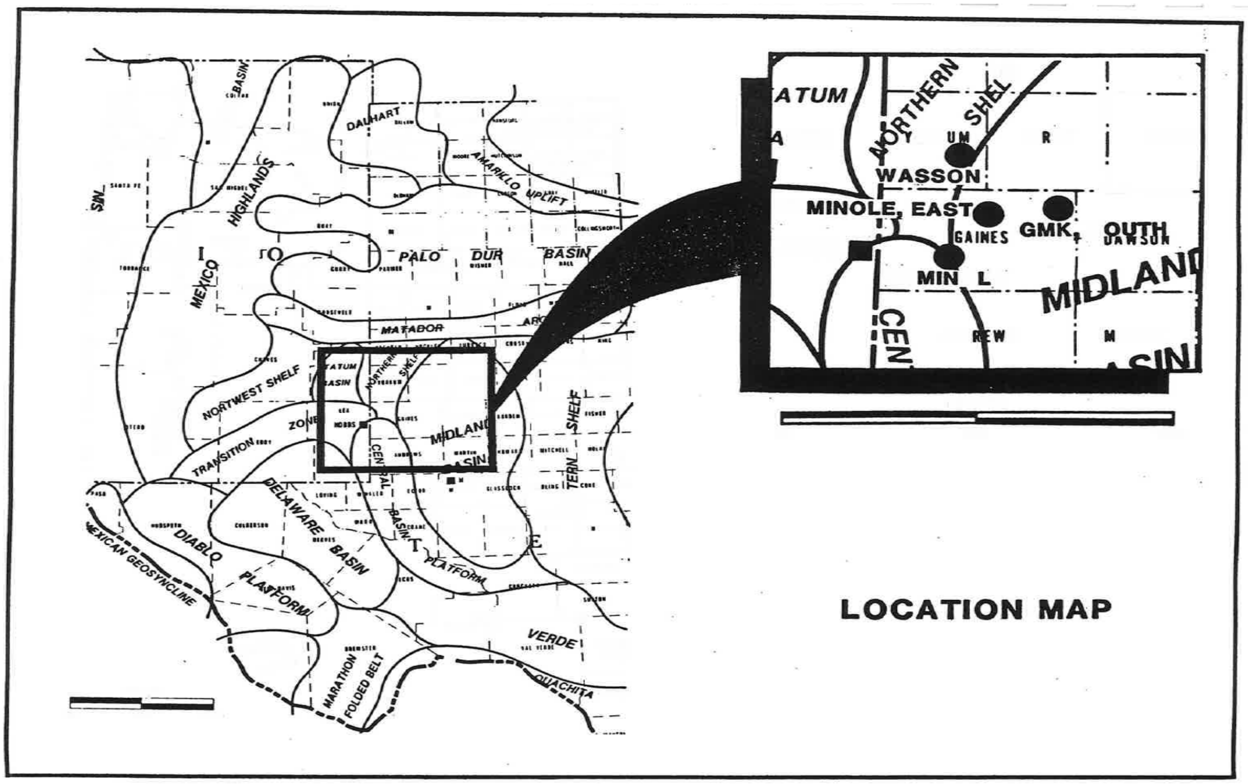

Figure 3-2 Location of SEF in West Texas

The productive formation is the Upper Permian San Andres and consists of anhydritic dolomite with vuggy, moldic, and intercrystalline porosity as seen in the Seminole East Generalized Stratigraphic Section Figure 3-3. The environment of deposition was shallow tidal water deposits with oolitic shoals ("carbonate sands") developed on tidal flats. Secondary porosity later developed from dolomitization.

The structure is an elliptical anticline oriented in a northwest to southeast direction (See Figure 3-4). The anticlinal structure is rimmed to the east and west by two arcuate shoals which merge toward the northwest and southeast to form an elliptical shaped structure with an intershoal "sag" in the center of the field. The east half of the field is the front, or "seaward," shoal and the west half is the back, or "landward" shoal.

The San Andres is a stratified reservoir. The stratification is due to tidal movements that occurred across the shoals. The tidal movements formed a stacked sequence of shoals with alternating thin intertidal deposits. The thin intertidal deposits are anhydritic carbonate mudstone layers and result in effective vertical permeability barriers (supported by core data). These barriers are continuous over the entire field and vary in thickness from two to ten feet with most averaging three to four feet in thickness. Detailed log analysis shows these barriers to be of very high-water saturation (+75%) with the adjacent zones of lower (+/- 24%) water saturation. The high-water saturation zones noted from log analysis are correlatable to very low permeability zones ("tight" and unproductive) in the available cores.

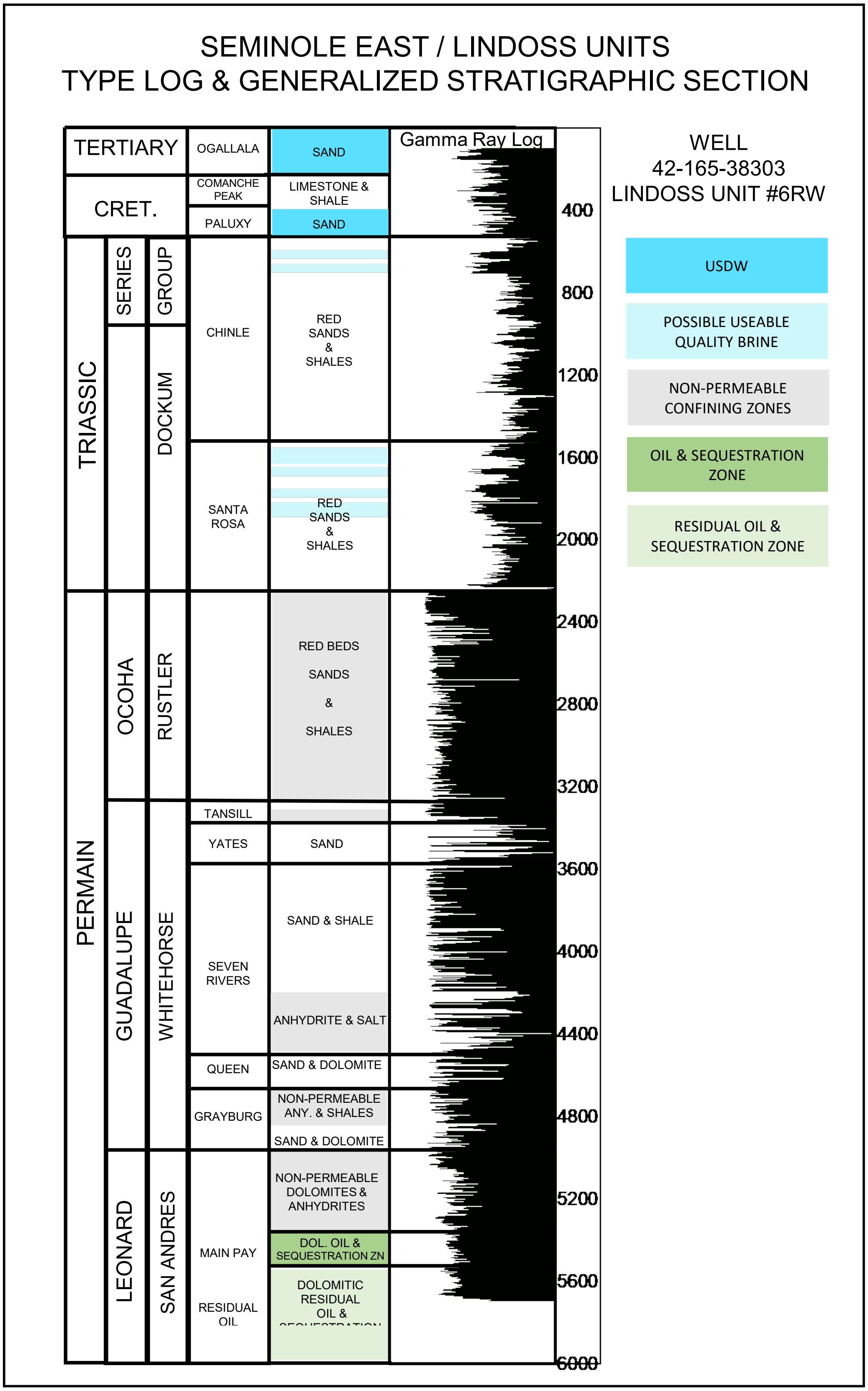

Figure 3-3 Local Area Structure on Top of San Andres

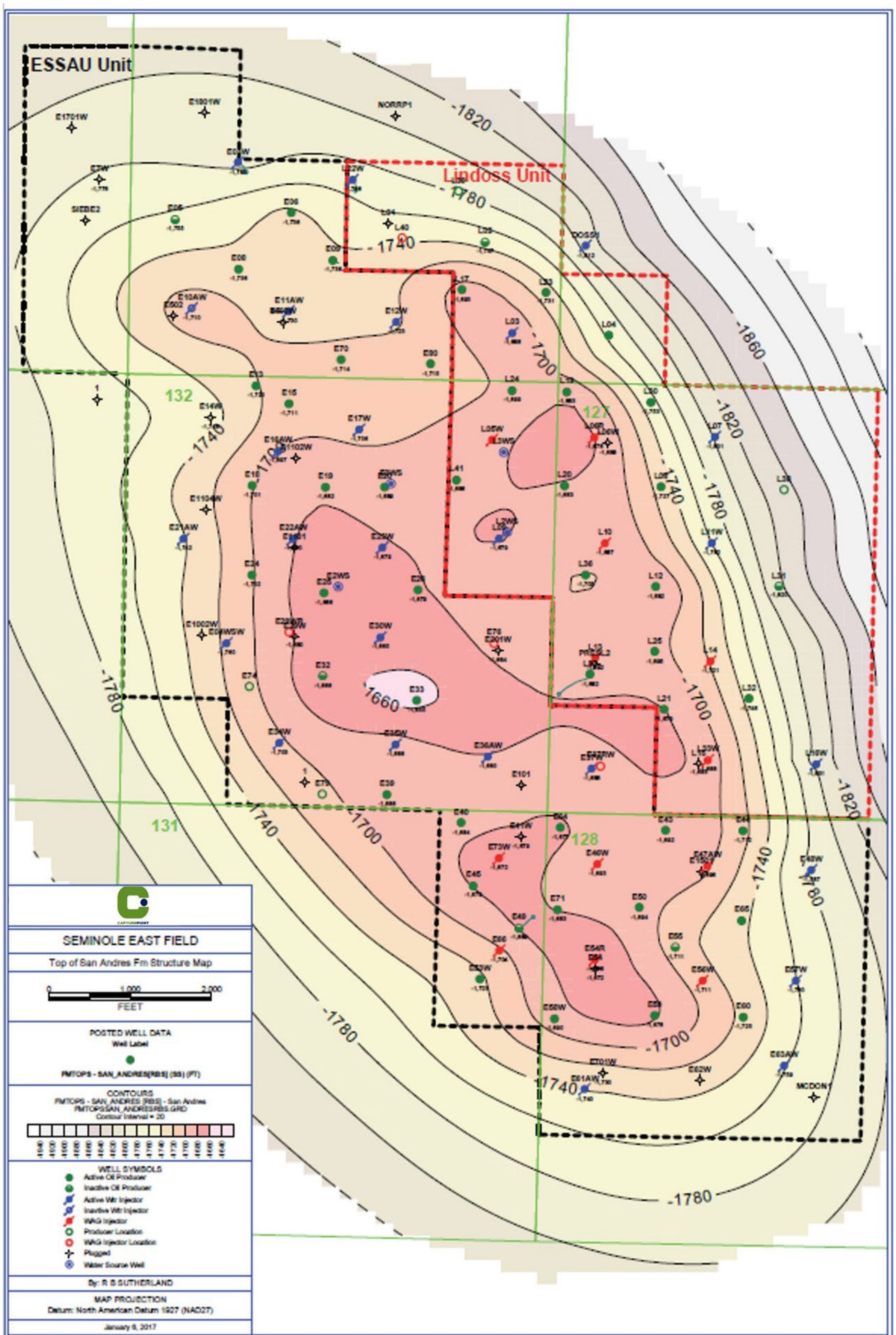

Figure 3-4 Local Area Structure on Top of San Andres

Log and core analyses identify seven major stratified zones in the SEF. The first porous zone or Main Pay is located nearly 400 feet into the San Andres Formation. Due to hydrodynamic flow in the San Andres aquifer, a thick residual oil zone 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 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 Central Basin Platform is negligible. The volume of CO_2 storage is based on the estimated total pore space within SEF. The total pore space within SEF, from the top of the reservoir down to the base of the residual oil zone, is calculated to be 104.2 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 158 Billion Cubic Feet (BCF) (9 million tonnes) of CO_2 storage in the reservoir. CO_2 will occupy only 50% of the total calculated storage capacity by the year 2042 based on the current project forecast.

Table 3-1 Calculation of Maximum Volume of CO_2 Storage Capacity at Seminole East Field (SEF)

Top of Main Pay to Bottom of Residual Oil Zone	
Variables	SEF Outline
Pore Volume (**RB**)	104,199,573
$\mathbf{B}_{CO2}$ (RB/MCF)	0.40
$\mathbf{S}_{wirr}$	0.24
$\mathbf{S}_{or\ CO2}$	0.15
Max CO_2 (MCF)	158,904,349
Max CO_2 (BCF)	158

$$\textbf{M}\text{ax } CO_2 = \text{Pore Volume} * (1 - \textbf{S}\text{wirr} - \textbf{S}\text{or}_{CO2}) / \textbf{B}_{CO2}$$

Where:

Max CO_2 = the maximum amount of storage capacity

Pore Volume = Total pore space in reservoir barrels (RB)

B_{CO2} = the formation volume factor for CO_2

S_{wirr} = the irreducible water saturation

Sor_{CO2} = 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 is being utilized in SEF 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 SEF unit boundary and do not move to adjacent areas.

Given that in SEF the confining zone has proved competent over both millions of years and in the current CO_2 flooding, and that the SEF 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 ESSAU. CO_2 is delivered to the ESSAU via the Kinder Morgan CO_2 pipeline network. The CO_2 is supplied by a number of different sources including both natural and anthropogenic CO_2 sources. Specified amounts are drawn from an outside source pipeline based on contractual arrangements among suppliers of CO_2, purchasers of CO_2, and the pipeline operator.

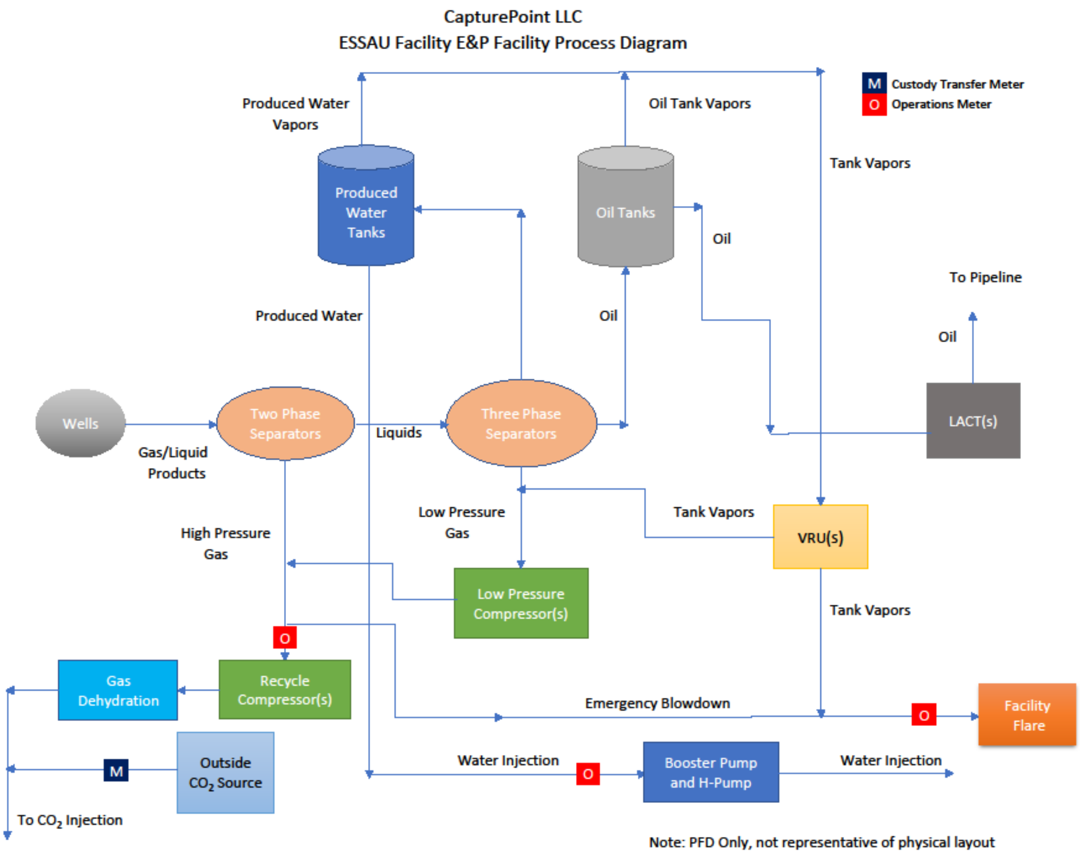

Figure 3-5 ESSAU Process Flow Diagram

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

i. CO_2 Distribution and Injection: The mass of CO_2 received at ESSAU 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 recycle compression facility 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 treatment and reinjection or disposal.

Figure 3-6 shows a simplified process flow diagram of the project facilities and equipment in the Lindoss Unit. CO_2 is delivered to the Lindoss Unit via the Kinder Morgan CO_2 pipeline network. The CO_2 is supplied by a number of different sources including both natural and anthropogenic CO_2 sources. Specified amounts are drawn from an outside source pipeline based on contractual arrangements among suppliers of CO_2, purchasers of CO_2, and the pipeline operator.

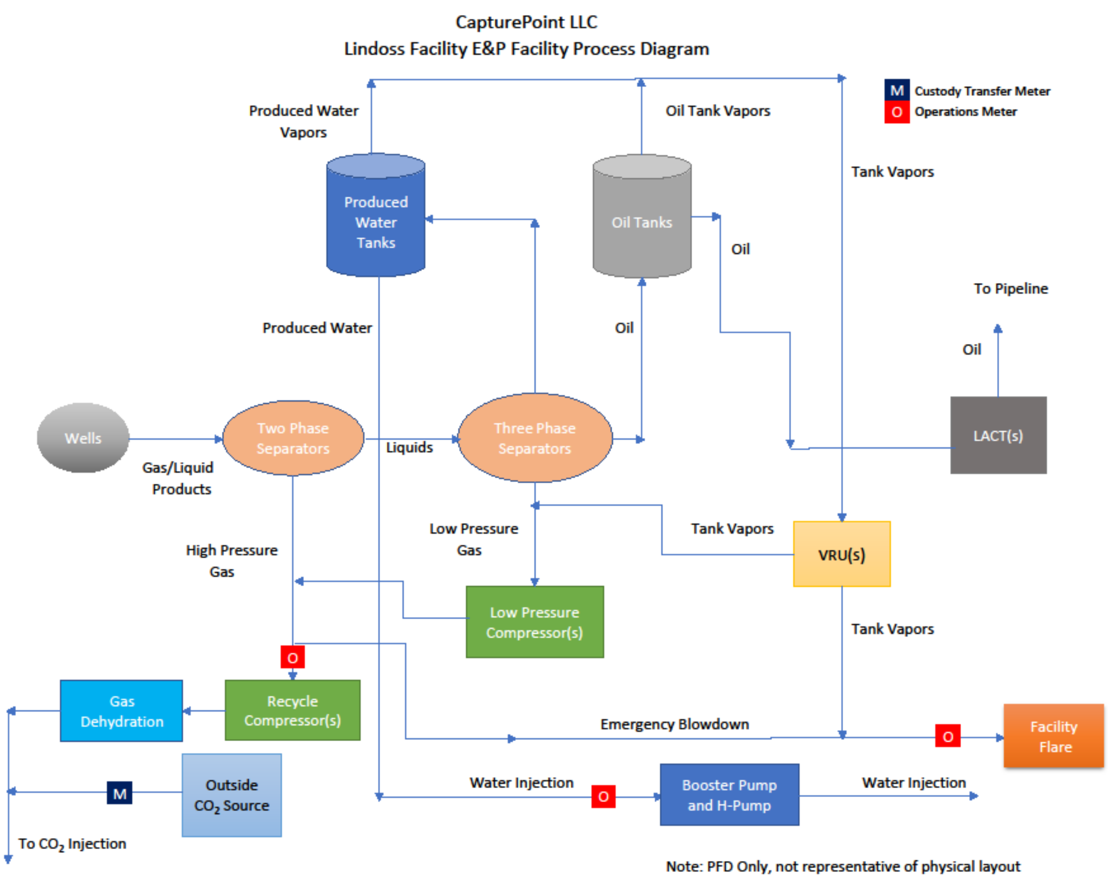

Figure 3-6 Lindoss Process Flow Diagram

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

i. CO_2 Distribution and Injection: The mass of CO_2 received at Lindoss 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 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.

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 H_2S as discussed in Section 7. They are gathered and sent to SATs 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 recycle compression facility 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 treatment and reinjection or disposal.

There are no physical differences between the ESSAU and Lindoss facilities.

3.3.1 Wells in the Seminole East Field

The TRRC has broad authority over oil and gas operations including primacy to implement UIC Class II wells. The rules are found in Texas Administrative Code 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 they 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 3.1 provides a well count by type and status. All these wells are in material compliance with TRRC rules.

Table 3.1 SEF Well Penetrations by Type and Status

TYPE	ACTIVE	INACTIVE	P & A	Total
PROD_OIL	32	16	0	**48**
INJ_WTR	16	4	0	**20**
INJ_WAG	18	0	0	**18**
INJ_SWD*	1	0	0	**1**
WSW**	1	4	0	**5**
P&A***	0	0	28	**28**
TOTAL	**68**	**24**	**28**	**120**

*INJ_SWD = Saltwater disposal wells
**WSW= Water source wells
***P&A = Plugged and Abandoned wells

As indicated in Figure 3-7, wells are distributed across the SEF. The well patterns currently undergoing CO_2 flooding are identified by black 5-spot pattern outlines and red symbols. CO_2 will be injected across the entire unit over the project life.

SEF CO_2-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Reservoir pressure in the SEF 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.

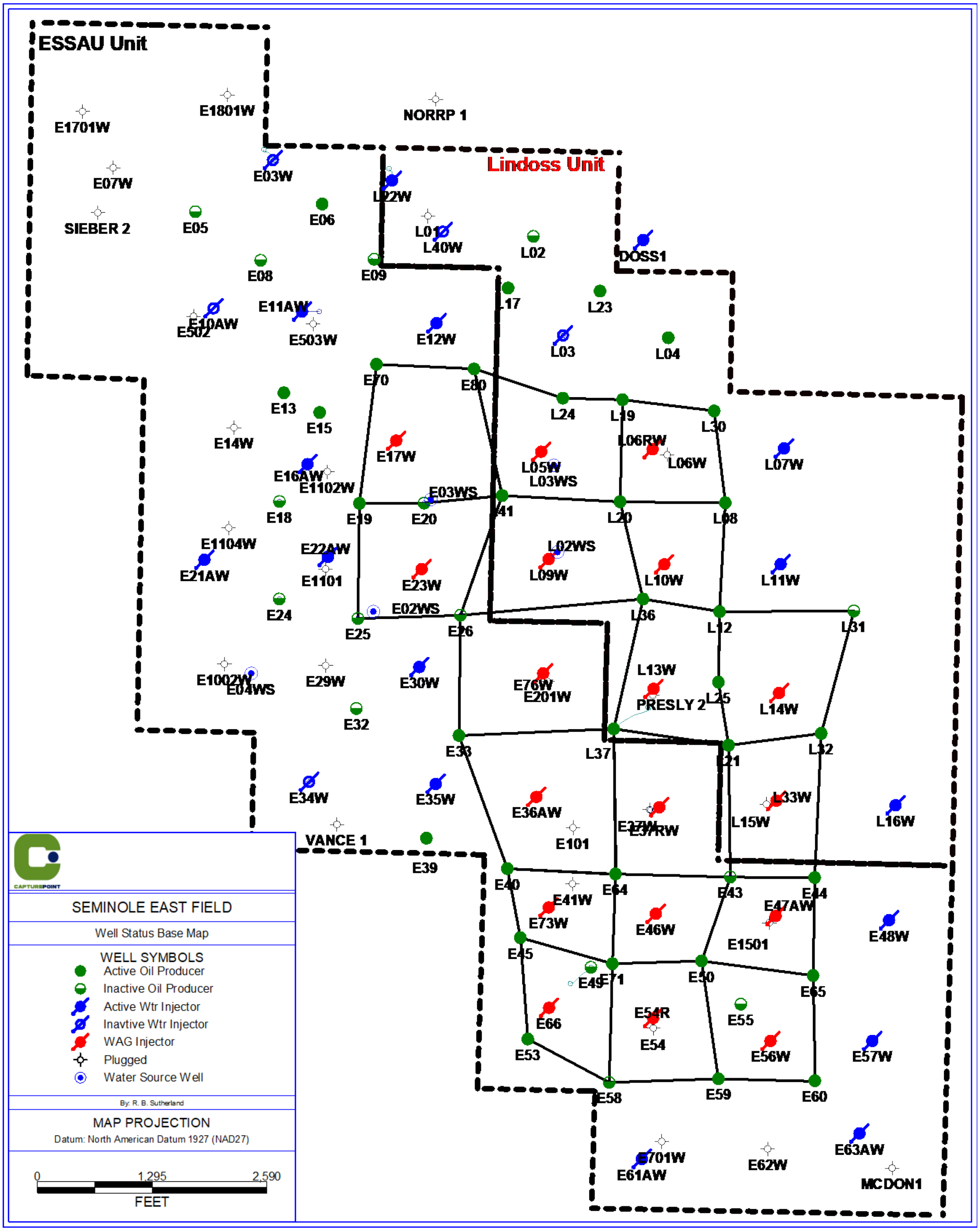

Figure 3-7 SEF Wells and Injection Patterns

3.4 Reservoir Forecasting

DPCs derived from analogous fields were used to project carbon dioxide enhanced oil recovery in the Seminole East Field. Most DPCs are derived from geologic and reservoir models. In the SEF case the DPC was derived from actual field performance from an analogous field.

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 3-8. The dimensioned projections of oil, CO_2 and water production, and CO_2 and water injection are made from DPCs using the original oil in place of an area of interest.

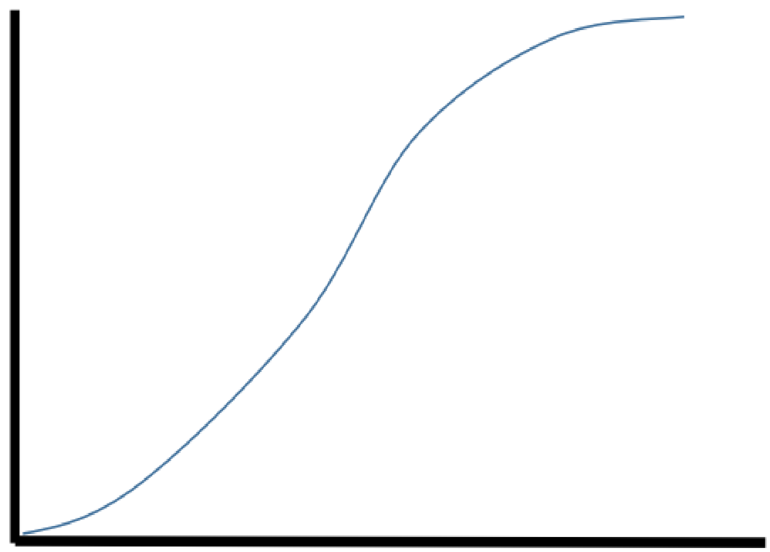

Figure 3-8 Dimensionless performance curve plot

The SEF DPC was calculated from the cumulative production and injection from an analogous field. The SEF DPC was used on each pattern in the SEF 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 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 laterally or vertically 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 ESSAU and Lindoss Unit boundaries.

Figure 3-7 displays wells that have CO_2 retention on the 680 acres that have been under CO_2 injection since project initialization. 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 (158 BCF) is limited to the amount of space available by the removal of the produced hydrocarbon. The projection indicates that there is pore space available to store approximately .51 decimal fraction of HCPV amounting to 32 MMRB (80.2 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 80.2 BCF. Initially, the storage area outline slightly exceeded the ESSAU in the southwest corner by less than 150 ft. To keep the CO_2 within the unit boundaries in the southwest corner less CO_2 will be injected into that area of the unit thus reducing the storage radius for each well. The extra CO_2 would be injected into the north – northeast wells. Figure 4-1 shows the map of the revised storage area outline (dashed red line). This calculation showed 1000 acres would be needed to store the 80.2 BCF. This is significantly less than the 2045 acres in the SEF outline.

4.2. Maximum Monitoring Area

The Maximum Monitoring Area (MMA) is defined by the ESSAU and Lindoss Unit boundaries plus the required ½ mile buffer as required by 40 CFR §98.440-449 (Subpart RR). The MMA would be the same as the AMA since the plume location is less than the Unit area.

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 SEF. The Specified Period will be shorter than the period of production from the SEF.

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 SEF is collected for use in operations management. Reservoir pressure is not forecasted to change appreciably since the IWR will be maintained at approximately 1.0. 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).

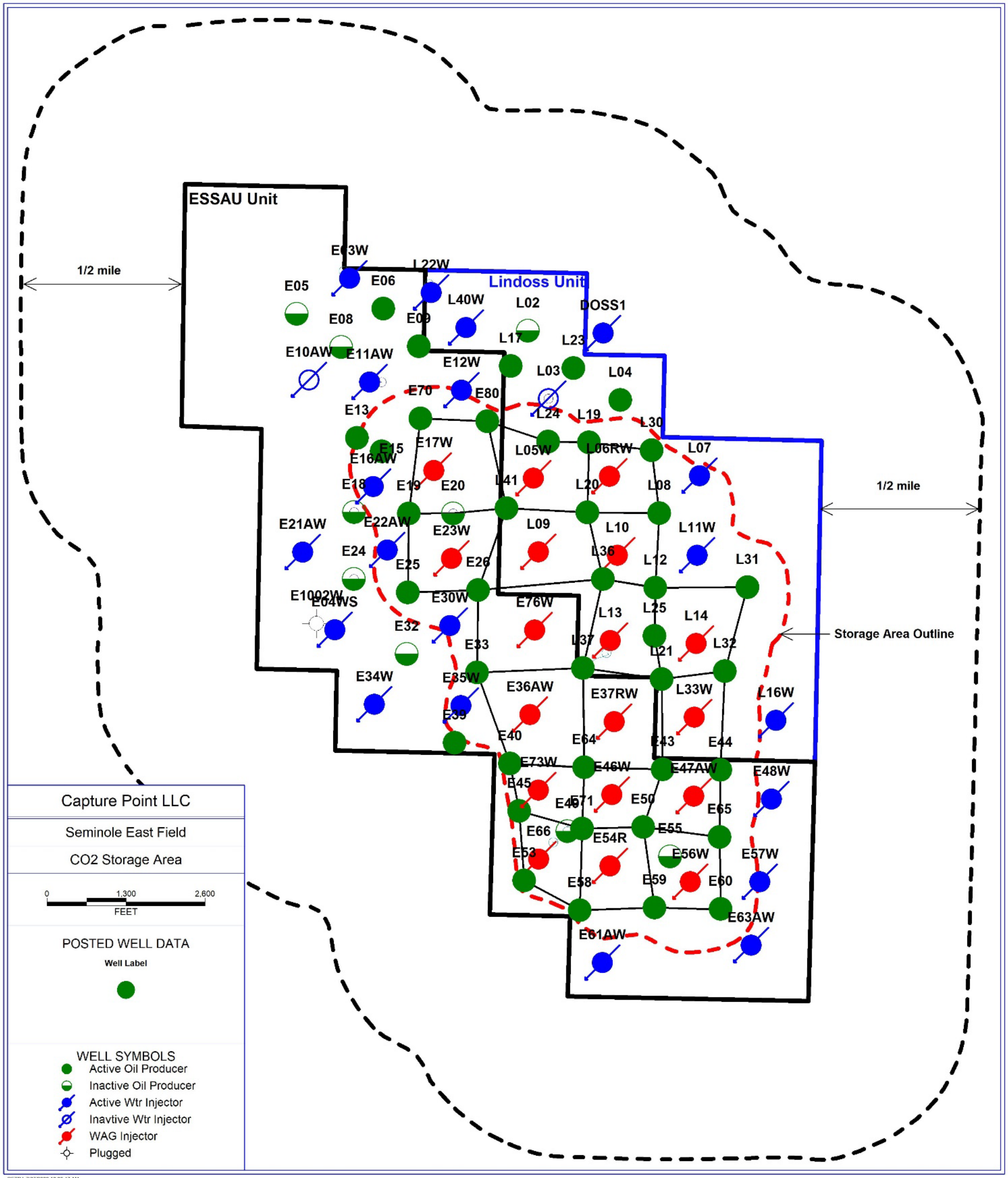

Figure 4-1 Projected CO2 storage area

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

In the roughly 60 years since the SEF 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 Well Bores
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the SEF
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 Wellbores

As part of the TRRC requirement to initiate CO_2 flooding, an extensive review of all SEF 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 SEF 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 beam pumped producing wells,
- CO_2 flood electrical submersible pump (ESP) producing wells, and
- CO_2 WAG 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 SEF 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 SEF 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 are investigated and addressed. CapturePoint's experience, from over 10 years of operating CO_2-EOR projects, is that such leakage is very rare.

- 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 the 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 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 and reported and quantified.

Based on ongoing monitoring activities and review of the potential leakage risks posed by well bores, it is concluded that the risk of CO_2 leakage through well bores is being mitigated by detecting problems as they arise and quantifying any leakage that does occur.

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 little to no risk 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 1.0 is also maintained. Both measures mitigate the potential for inducing faults or fractures. As a safeguard, WAG skids are continuously monitored.

5.3. Natural or 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 SEF.

To evaluate this potential risk at SEF, CapturePoint has reviewed the nature and location of seismic events in West Texas. Some of the recorded earthquakes in West Texas are far removed from any injection operation. These 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 M0.5 or greater in the Permian Basin since 1966 indicates that none have occurred in the SEF; the closest took place in 1992 approximately 30 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 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 SEF. 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 (GIS) site[3] for seismic signals that could indicate the creation of potential leakage pathways in the SEF.

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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/

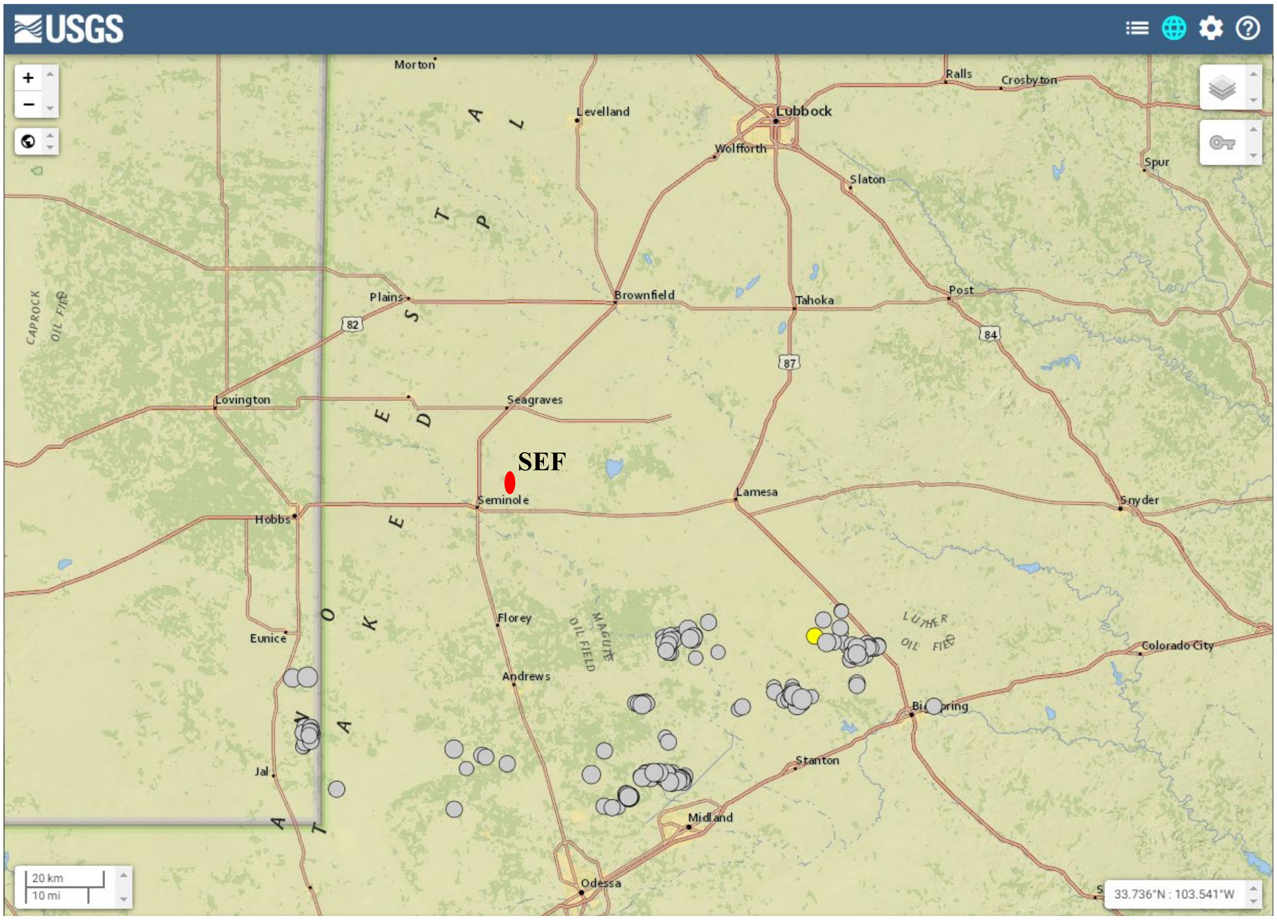

Figure 5-1 USGS earthquakes (+1.0 magnitude) for last 56 years)

5.4. Previous Operations

CO_2 flooding was initiated in SEF in 2013. 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 SEF. These practices ensure that that there are no unknown wells within SEF and that the risk of migration from older wells has been sufficiently mitigated. The successful experience with CO_2 flooding in SEF demonstrates that the confining zone has not been impaired by previous operations.

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 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. 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).

5.6. Lateral Migration Outside the Seminole East Field

It is highly unlikely that injected CO_2 will migrate downdip and laterally outside the SEF because of the nature of the geology and the approach used for injection. Over long periods of time, injected CO_2 will tend to rise vertically towards the Upper San Andres and continue towards the point in the SEF 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. Water Curtain Injection (WCI) methods are employed during CO_2-EOR operations to prevent CO_2 lateral migration out of the unit boundary. Continuous WCI operations are conducted at the SEF unit boundaries to create a pressure barrier to contain injected fluids within the SEF. Finally, the total volume of fluids contained in the SEF will stay relatively constant. Based on site characterization and planned and projected operations it is estimated that the total volume of stored CO_2 will be considerably less than calculated capacity.

5.7. Drilling in the Seminole East 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 SEF is conducted in accordance with TRRC rules. CapturePoint's visual inspection process, including routine site visits, will identify unapproved drilling activity in the SEF.

In addition, CapturePoint intends to operate SEF 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 SEF 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 into the formations beneath them. As mentioned in Section 3.2 "The San Andres is a stratified reservoir. The stratification is due to tidal movements that occurred across the shoals. The tidal movements formed a stacked sequence of shoals with alternating thin intertidal

deposits. The thin intertidal deposits are anhydritic carbonate mudstone layers and result in effective vertical permeability barriers (supported by core data). These barriers are continuous over the entire field and vary in thickness from two to ten feet with most averaging three to four feet in thickness."

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.

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 (well bores), 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.

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 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 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
Diffuse leakage through the seal	Injection pressure is continuously monitored and unexplained changes in injection pressure that might indicate leakage would trigger investigation as to the cause.	Conduct an injection radioactive tracer survey. If verified, well is shut in and workover crews respond within days.
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

5.10. Summary

The structure and stratigraphy of the San Andres reservoir in the SEF 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 SEF 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 SEF 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 SEF follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), 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 & 3-6, 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 SEF. 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 inlet to the RCF.
- CO_2 that is entrained in produced oil, as indicated in Figure 3-5 & 3-6, is calculated using volumetric flow through the custody transfer 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 SEF. 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. The Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.

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, 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 SEF. 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

SEF 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 SEF. 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 SEF. 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 Greenhouse 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 SEF 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 worn by all field personnel at all times and are permanent throughout the field at ground level, is used as a last method to detect leakage from wellbores. The H_2S monitor 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. Currently the concentration of H_2S in the recycled or produced gas is in excess of 18,000 ppm making leak detection viable. Thus, detected H_2S leaks will be investigated in order 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, 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 equipment, the CO_2 content of produced oil, and 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 equipment, the CO_2 content of produced oil, and vented CO_2, as required under 40 CFR Part 98 Subpart W.

6.2. To Demonstrate that Injected CO2 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 SEF 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 reservoir pressure that 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 and as such 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 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 H_2S monitors throughout the field at ground level to detect H_2S 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 and 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

To account for the potential propagation of error that would result if volume data from flow meters at each injection and production well were utilized, it is proposed to use the data from custody and operations meters on the main system pipelines to determine injection and production volumes used in the mass balance. 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 of the well head meters within the SEF.

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 Kinder Morgan 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.

$$CO_2T,r = \sum_{p=1}^{4} (Q_{p,r} - S_{r,p}) * D * C_{CO2,r,p} \qquad \text{(Eq. RR-2)}$$

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 a site well in quarter p (standard cubic meters).

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

$C_{CO2,r,r}$ = 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 SEF's method of receiving CO_2 and requirements at Subpart RR §98.444(a):

- All delivery to the SEF is used within the unit so no quarterly flow redelivered, and Sr,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 SEF 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 output of the RCF (see Figure 3-5). 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:

$$CO_2u = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO2,p,u} \qquad \text{(Eq. RR-5)}$$

where:

CO_2u = Annual CO_2 mass recycled (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.

$C_{CO2,p,u}$ = 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-3) and Mass of CO_2 Recycled (modified RR-5).

$CO_{2I} = CO_2 + CO_2u$

8.3. Mass of CO_2 Produced

The Mass of CO_2 Produced at the SEF 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:

$$CO_{2w} = \sum_{p=1}^{4} Qp,w * D * C_{CO2,p,w} \qquad \text{(Eq. RR-8)}$$

where:

CO_{2W} = Annual CO_2 mass produced (metric tons).

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

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

$C_{CO2,pw}$ = CO_2 concentration measurement in flow for meter w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Inlet meters to RCF

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

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

where:

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

CO_2w = Annual CO_2 mass produced (metric tons) through all separators in the reporting year.

Xoil = 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).

8.4. Mass of CO_2 Emitted by Surface Leakage

The total annual Mass of CO_2 emitted by Surface Leakage will be calculated and reported using an approach that is tailored to specific leakage events and relies on 40 CFR Part 98 Subpart W reports of equipment leakage. 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 a number of 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 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. Further, the Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.

Equation RR-10 in §98.433 will be used to calculate and report the Mass of CO_2 emitted by Surface Leakage:

$$CO_{2E} = \sum_{x=1}^{x} CO_{2}x \qquad \text{(Eq. RR-10)}$$

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 Sequestered in Subsurface Geologic Formation

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

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \qquad \text{(Eq. RR-11)}$$

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) net of CO_2 entrained in oil 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 this part.

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 this part.

8.6. Cumulative Mass of CO_2 Reported as Sequestered in Subsurface Geologic Formation

The total annual volumes obtained using equation RR-11 in §98.443 will be summed to arrive at the Cumulative Mass of CO_2 Sequestered in Subsurface Geologic Formations.

9. MRV Plan Implementation Schedule

This MRV plan will be implemented starting January 2023 or within 90 days of EPA approval, whichever occurs later. Other GHG 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 program will be in effect during the Specified Period, during which time the SEF 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 SEF. 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 Program

10.1. Monitoring QA/QC

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.
- The quarterly flow rate of the produced gas is measured at the flow meters located at the RCF inlet.

CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2

These volumes are measured in conformance with the monitoring and QA/QC 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 nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.
- The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

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 SEF 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 and number, API number, type, and status for active wells in the SEF as of August 2021. 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_WTR refers to wells that inject water
  - INJ_WAG refers to wells that inject water and CO_2 Gas
  - INJ_SWD refers to wells that inject water for disposal
  - SWS refers to wells that supply water
  - 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

Well Name	API Number	Well Type	Status
DCB Doss 1 (INJ)	4216534180	INJ_WTR	ACTIVE
ESSAU 02WS	4216530590	WSW	SHUT_IN
ESSAU 03W (INJ)	4216534370	INJ_WTR	SHUT_IN
ESSAU 03WS	4216534343	WSW	ACTIVE
ESSAU 04WS	4216532191	WSW	SHUT_IN
ESSAU 05	4216581203	PROD_OIL	SHUT_IN
ESSAU 06	4216533021	PROD_OIL	ACTIVE
ESSAU 07W (INJ)	4216530591	P&A	INACTIVE
ESSAU 08	4216533913	PROD_OIL	SHUT_IN
ESSAU 09	4216534600	PROD_OIL	SHUT_IN
ESSAU 1002W	4216510149	P&A	INACTIVE
ESSAU 101	4216501006	P&A	INACTIVE
ESSAU 10AW (INJ)	4216533614	INJ_WTR	SHUT_IN
ESSAU 1101	4216510058	P&A	INACTIVE
ESSAU 1102W (INJ)	4216510079	P&A	INACTIVE
ESSAU 1104W (INJ)	4216510241	P&A	INACTIVE
ESSAU 11AW (INJ)	4216533615	INJ_WTR	ACTIVE
ESSAU 12W (INJ)	4216533403	INJ_WTR	ACTIVE

Well Name	API Number	Well Type	Status
ESSAU 13	4216534028	PROD_OIL	ACTIVE
ESSAU 14W (INJ)	4216510072	P&A	INACTIVE
ESSAU 15	4216534110	PROD_OIL	ACTIVE
ESSAU 1501	4216510413	P&A	INACTIVE
ESSAU 16AW (INJ)	4216534371	INJ_WTR	ACTIVE
ESSAU 1701W (INJ)	4216510246	P&A	INACTIVE
ESSAU 17W (INJ)	4216534108	INJ_WAG	ACTIVE
ESSAU 18	4216533910	PROD_OIL	SHUT_IN
ESSAU 1801W (INJ)	4216510250	P&A	INACTIVE
ESSAU 19	4216533912	PROD_OIL	ACTIVE
ESSAU 20	4216534111	PROD_OIL	SHUT_IN
ESSAU 201W (INJ)	4216500168	P&A	INACTIVE
ESSAU 21AW (INJ)	4216533819	INJ_WTR	ACTIVE
ESSAU 22AW (INJ)	4216533908	INJ_WTR	ACTIVE
ESSAU 23W (INJ)	4216501005	INJ_WAG	ACTIVE
ESSAU 24	4216533906	PROD_OIL	SHUT_IN
ESSAU 25	4216533914	PROD_OIL	SHUT_IN
ESSAU 26	4216534112	PROD_OIL	SHUT_IN
ESSAU 29W (INJ)	4216501019	P&A	INACTIVE
ESSAU 30W (INJ)	4216501007	INJ_WTR	ACTIVE
ESSAU 32	4216533909	PROD_OIL	SHUT_IN
ESSAU 33	4216534031	PROD_OIL	ACTIVE
ESSAU 34W (INJ)	4216534109	INJ_WTR	SHUT_IN
ESSAU 35W (INJ)	4216501008	INJ_WTR	ACTIVE
ESSAU 36AW (INJ)	4216530147	INJ_WAG	ACTIVE
ESSAU 37RW (INJ)	4216538478	INJ_WAG	ACTIVE
ESSAU 37W (INJ)	4216502594	P&A	INACTIVE
ESSAU 39	4216534106	PROD_OIL	ACTIVE
ESSAU 40	4216534104	PROD_OIL	ACTIVE
ESSAU 41W (INJ)	4216501012	P&A	INACTIVE
ESSAU 43	4216534601	PROD_OIL	SHUT_IN
ESSAU 44	4216534652	PROD_OIL	ACTIVE
ESSAU 45	4216534107	PROD_OIL	ACTIVE
ESSAU 46W (INJ)	4216500002	INJ_WAG	ACTIVE
ESSAU 47AW (INJ)	4216533014	INJ_WAG	ACTIVE
ESSAU 48W (INJ)	4216533015	INJ_WTR	ACTIVE
ESSAU 49	4216534049	PROD_OIL	SHUT_IN
ESSAU 50	4216533907	PROD_OIL	ACTIVE
ESSAU 502	4216510251	P&A	INACTIVE
ESSAU 503W (INJ)	4216530452	P&A	INACTIVE
ESSAU 53	4216533911	PROD_OIL	SHUT_IN
ESSAU 54	4216502901	P&A	INACTIVE
ESSAU 54R (INJ)	4216538339	INJ_WAG	ACTIVE

Well Name	API Number	Well Type	Status
ESSAU 55	4216501046	PROD_OIL	SHUT_IN
ESSAU 56W (INJ)	4216534030	INJ_WAG	ACTIVE
ESSAU 57W (INJ)	4216510252	INJ_WTR	ACTIVE
ESSAU 58	4216534105	PROD_OIL	SHUT_IN
ESSAU 59	4216533905	PROD_OIL	ACTIVE
ESSAU 60	4216534048	PROD_OIL	ACTIVE
ESSAU 61AW (INJ)	4216533820	INJ_WTR	ACTIVE
ESSAU 62W (INJ)	4216502902	P&A	INACTIVE
ESSAU 63AW (INJ)	4216534029	INJ_WTR	ACTIVE
ESSAU 64	4216534027	PROD_OIL	ACTIVE
ESSAU 65	4216534026	PROD_OIL	ACTIVE
ESSAU 66W (INJ)	4216501003	INJ_WAG	ACTIVE
ESSAU 70	4216537356	PROD_OIL	ACTIVE
ESSAU 701W (INJ)	4216501011	P&A	INACTIVE
ESSAU 71	4216537747	PROD_OIL	ACTIVE
ESSAU 73W (INJ)	4216537748	INJ_WAG	ACTIVE
ESSAU 76W (INJ)	4216538479	INJ_WAG	ACTIVE
ESSAU 80	4216538294	PROD_OIL	ACTIVE
Lindoss 01	4216533392	P&A	INACTIVE
Lindoss 02	4216533467	PROD_OIL	SHUT_IN
Lindoss 02WS	4216534452	WSW	SHUT_IN
Lindoss 03 (INJ)	4216533284	INJ_WTR	SHUT_IN
Lindoss 03WS	4216534453	WSW	SHUT_IN
Lindoss 04	4216533041	PROD_OIL	ACTIVE
Lindoss 05W (INJ)	4216532364	INJ_WAG	ACTIVE
Lindoss 06RW (INJ)	4216538303	INJ_WAG	ACTIVE
Lindoss 06W (INJ)	4216532733	P&A	INACTIVE
Lindoss 07W (INJ)	4216532883	INJ_WTR	ACTIVE
Lindoss 08	4216533452	PROD_OIL	ACTIVE
Lindoss 09W (INJ)	4216532200	INJ_WAG	ACTIVE
Lindoss 10W (INJ)	4216532606	INJ_WAG	ACTIVE
Lindoss 11W (INJ)	4216532757	INJ_WTR	ACTIVE
Lindoss 12	4216533453	PROD_OIL	ACTIVE
Lindoss 13W (INJ)	4216533422	INJ_WAG	ACTIVE
Lindoss 14W (INJ)	4216531826	INJ_WAG	ACTIVE
Lindoss 15 (INJ)	4216531527	P&A	INACTIVE
Lindoss 16W (INJ)	4216532025	INJ_WTR	ACTIVE
Lindoss 17	4216534440	PROD_OIL	ACTIVE
Lindoss 19	4216534442	PROD_OIL	ACTIVE
Lindoss 20	4216534441	PROD_OIL	ACTIVE
Lindoss 21	4216534602	PROD_OIL	ACTIVE
Lindoss 22W (INJ)	4216534604	INJ_WTR	ACTIVE
Lindoss 23	4216536582	PROD_OIL	ACTIVE

Well Name	API Number	Well Type	Status
Lindoss 24	4216536583	PROD_OIL	ACTIVE
Lindoss 25	4216536581	PROD_OIL	ACTIVE
Lindoss 30	4216537352	PROD_OIL	ACTIVE
Lindoss 31	4216537345	PROD_OIL	SHUT_IN
Lindoss 32	4216537341	PROD_OIL	ACTIVE
Lindoss 33W (INJ)	4216537346	INJ_WAG	ACTIVE
Lindoss 36	4216537772	PROD_OIL	ACTIVE
Lindoss 37	4216538297	PROD_OIL	ACTIVE
Lindoss 40W (SWD)	4216538466	INJ_SWD	SHUT_IN
Lindoss 41	4216538296	PROD_OIL	ACTIVE
McDonald 1	4216502903	P&A	INACTIVE
Norrp 1	4216533505	P&A	INACTIVE
Presely 2	4216531620	P&A	INACTIVE
Sieber 2	4216510247	P&A	INACTIVE
Vance 1	4216501018	P&A	INACTIVE

12.2 Regulatory References

Regulations cited in this plan:

- Texas Administrative Code 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

AGA - American Gas Association

AMA - Active Monitoring Area

API - American Petroleum Institute

AoR - Area of Review

Bcf – 1 Billion Cubic Feet of Gas

CO_2 - Carbon Dioxide

DPC - Dimensionless Performance Curve

EPA - Environmental Protection Agency

EOR - Enhanced Oil Recovery

ESP - Electrical Submersible Pump

ESSAU - East Seminole San Andres Unit

FPP - Formation Parting Pressure (psi)

GHG - Greenhouse Gas

GHGRP - Greenhouse Gas Reporting Program

GIS - Geographical Information System

GPA - Gas Processors Association

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 – 1,000 Cubic Feet of Gas

NIST - National Institute of Standards and Technology

RB - Reservoir Barrels

RCF - Recycle Compression Facility

ROZ - Residual Oil Zone

SAT - Satellite Test Stations

SEF - Seminole East Field

TAC - Texas Administrative Code

TRRC - Texas Railroad Commission - Oil and Gas Division

UIC - Underground Injection Control

USGS - United States Geological Survey

WAG - Water Alternating with Gas

WCI - Water Curtain Injection

Appendix B: Submissions and Responses to Requests for Additional Information

CapturePoint LLC Seminole East Field Subpart RR Monitoring, Reporting and Verification (MRV) Plan

August 2, 2022

Table of Contents

1. Introduction

CapturePoint LLC operates a carbon dioxide (CO_2)-enhanced oil recovery (EOR) project in the Seminole East Field (SEF) located in Gaines County, Texas, approximately one and one-half miles northeast of the town of Seminole for the primary purpose of enhanced oil recovery using CO_2 with a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The SEF is comprised of the East Seminole San Andres Unit (ESSAU) and the Lindoss Unit. Production is from the San Andres formation at an average depth of 5500 feet. 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 Seminole East Field during a specified period of injection.

2. Facility Information

2.1. Reporter Number

562518 – Seminole East Field

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 SEF (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 SEF are currently classified as UIC Class II wells.

2.3. Existing Wells

Wells in the SEF are identified by name and number, American Petroleum Institute (API) number, type, and status. The list of wells as of February 2022 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 SEF an oil field located in West Texas that was first produced more than 60 years ago. SEF is comprised of the ESSAU and the Lindoss Unit. The two units abut 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 units in the SEF. In addition, the two units 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 reservoir similarities, one MRV Plan is being prepared for the two units in the SEF and any important differences between the units will be noted in the MRV plan. CO_2 flooding was initiated in 2013 in both units. The field is well characterized and is suitable for secure geologic storage. CapturePoint uses a water alternating with gas (WAG) injection process and maintains an injection to withdrawal ratio (IWR) at or near 1.0.

3.1. Project Characteristics

The SEF was discovered in 1959 and started producing in the same year. The SEF consists of two units, the ESSAU and the Lindoss Unit. The ESSAU began to produce in May 1959 and waterflood was initiated in January 1983. CO_2 flooding was initiated in 2013, in both the Main Pay and Residual Oil Zone (ROZ). The ROZ is an oil-bearing zone that has been swept by water movement under hydrodynamic conditions over geologic time to a reduced oil saturation that is no longer mobile. The ROZs are attractive targets for EOR with CO_2 Capture and Sequestration. The Lindoss Unit began to produce in November 1979 and waterflood was initiated in July 1984. CO_2 flooding was initiated in October 2013, also in the Main Pay and ROZ.

A long-term CO_2 and hydrocarbon injection and production forecast for both ESSAU and Lindoss was developed using a performance dimensionless curve (DPC) approach. Using this approach, a total injection of approximately 9 million tonnes of 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 SEF.

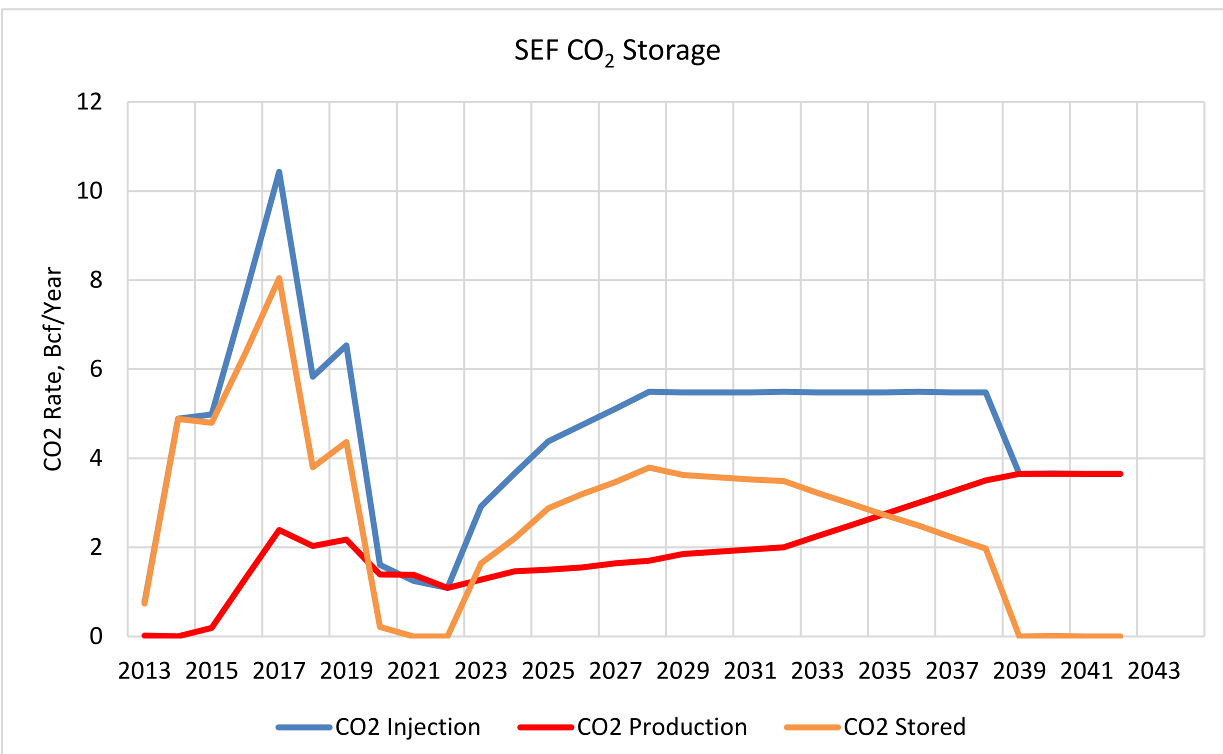

Figure 3-1 SEF Historic and Forecast CO_2 Injection, Production, and Storage

3.2. Environmental Setting

The SEF is located in the NE portion of the Central Basin Platform in West Texas (See Figure 3-2).

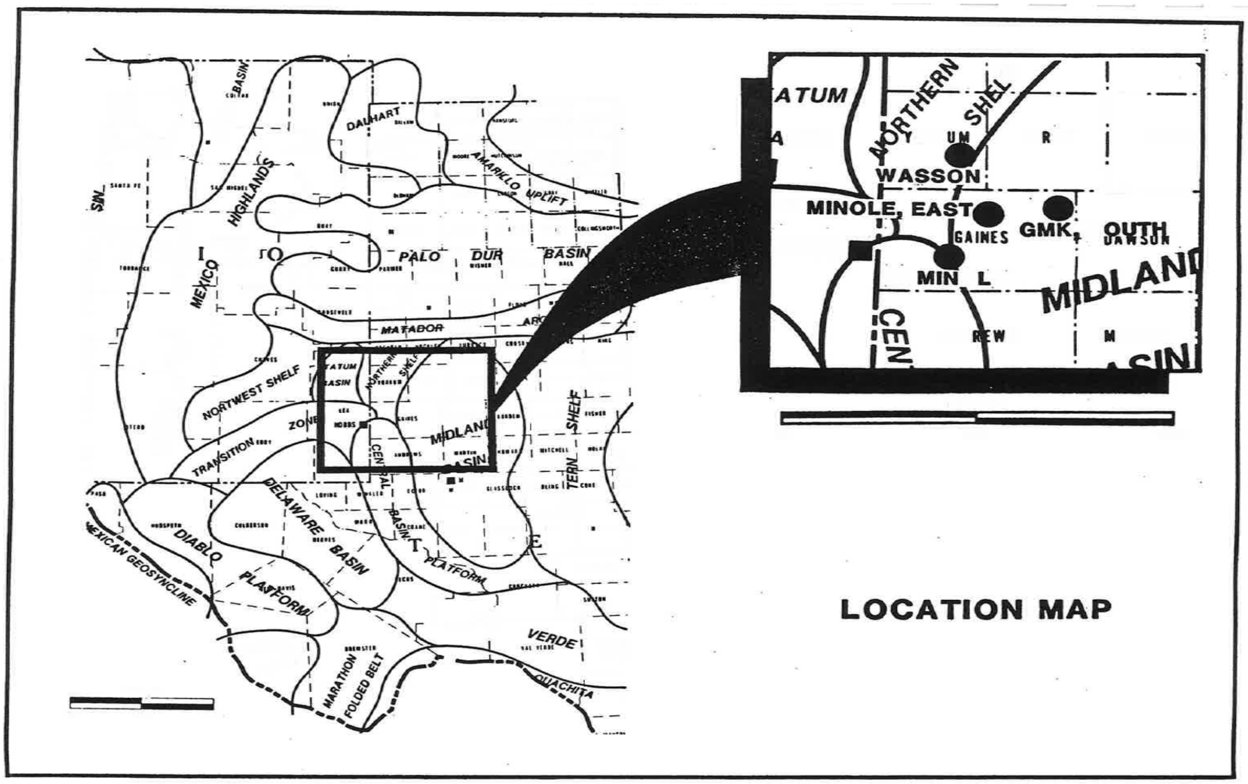

Figure 3-2 Location of SEF in West Texas

The productive formation is the Upper Permian San Andres and consists of anhydritic dolomite with vuggy, moldic, and intercrystalline porosity as seen in the Seminole East Generalized Stratigraphic Section Figure 3-3. The environment of deposition was shallow tidal water deposits with oolitic shoals ("carbonate sands") developed on tidal flats. Secondary porosity later developed from dolomitization.

The structure is an elliptical anticline oriented in a northwest to southeast direction (See Figure 3-4). The anticlinal structure is rimmed to the east and west by two arcuate shoals which merge toward the northwest and southeast to form an elliptical shaped structure with an intershoal "sag" in the center of the field. The east half of the field is the front, or "seaward," shoal and the west half is the back, or "landward" shoal.

The San Andres is a stratified reservoir. The stratification is due to tidal movements that occurred across the shoals. The tidal movements formed a stacked sequence of shoals with alternating thin intertidal deposits. The thin intertidal deposits are anhydritic carbonate mudstone layers and result in effective vertical permeability barriers (supported by core data). These barriers are continuous over the entire field and vary in thickness from two to ten feet with most averaging three to four feet in thickness. Detailed log analysis shows these barriers to be of very high-water saturation (+75%) with the adjacent zones of lower (+/- 24%) water saturation. The high-water saturation zones noted from log analysis are correlatable to very low permeability zones ("tight" and unproductive) in the available cores.

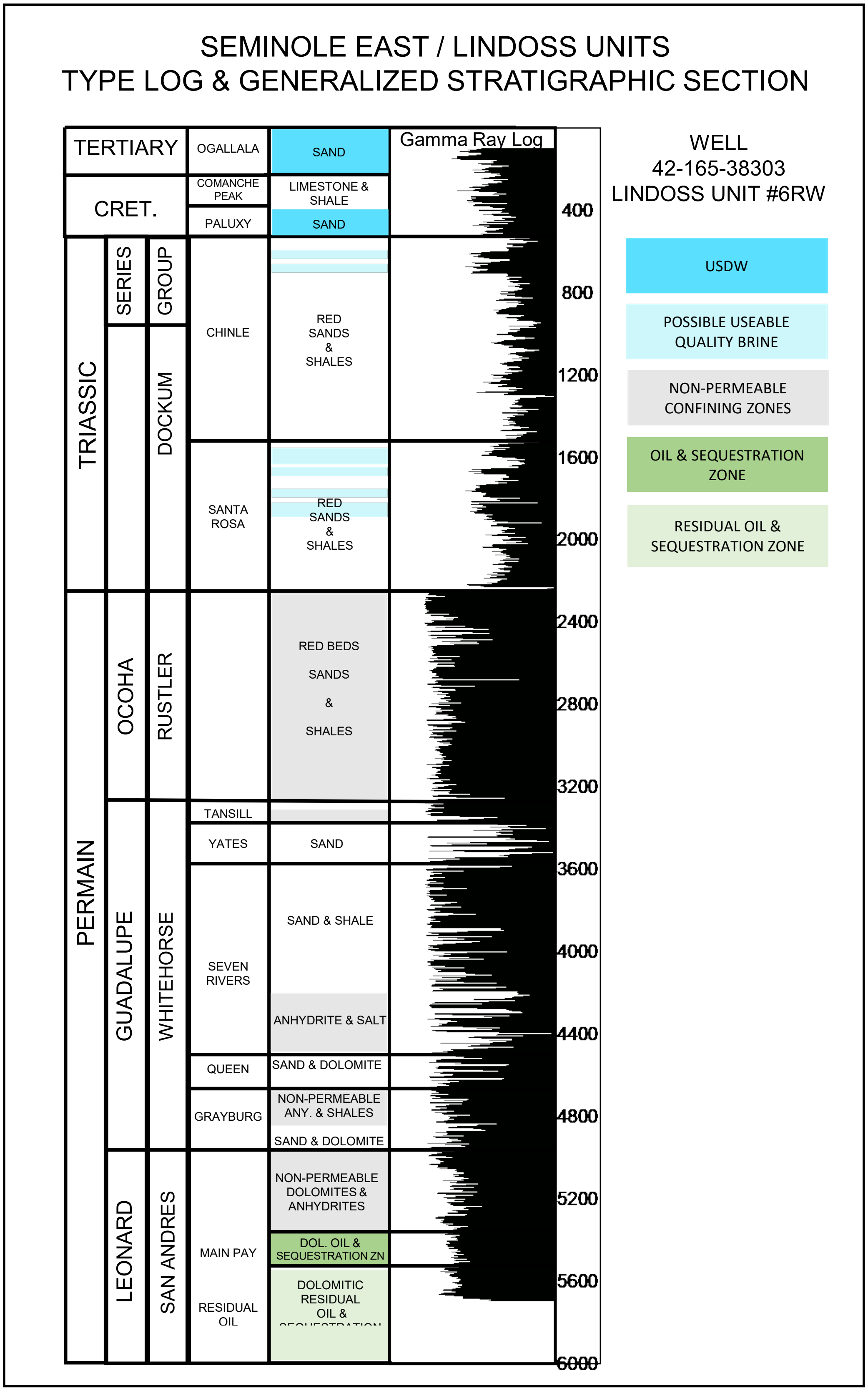

Figure 3-3 Local Area Structure on Top of San Andres

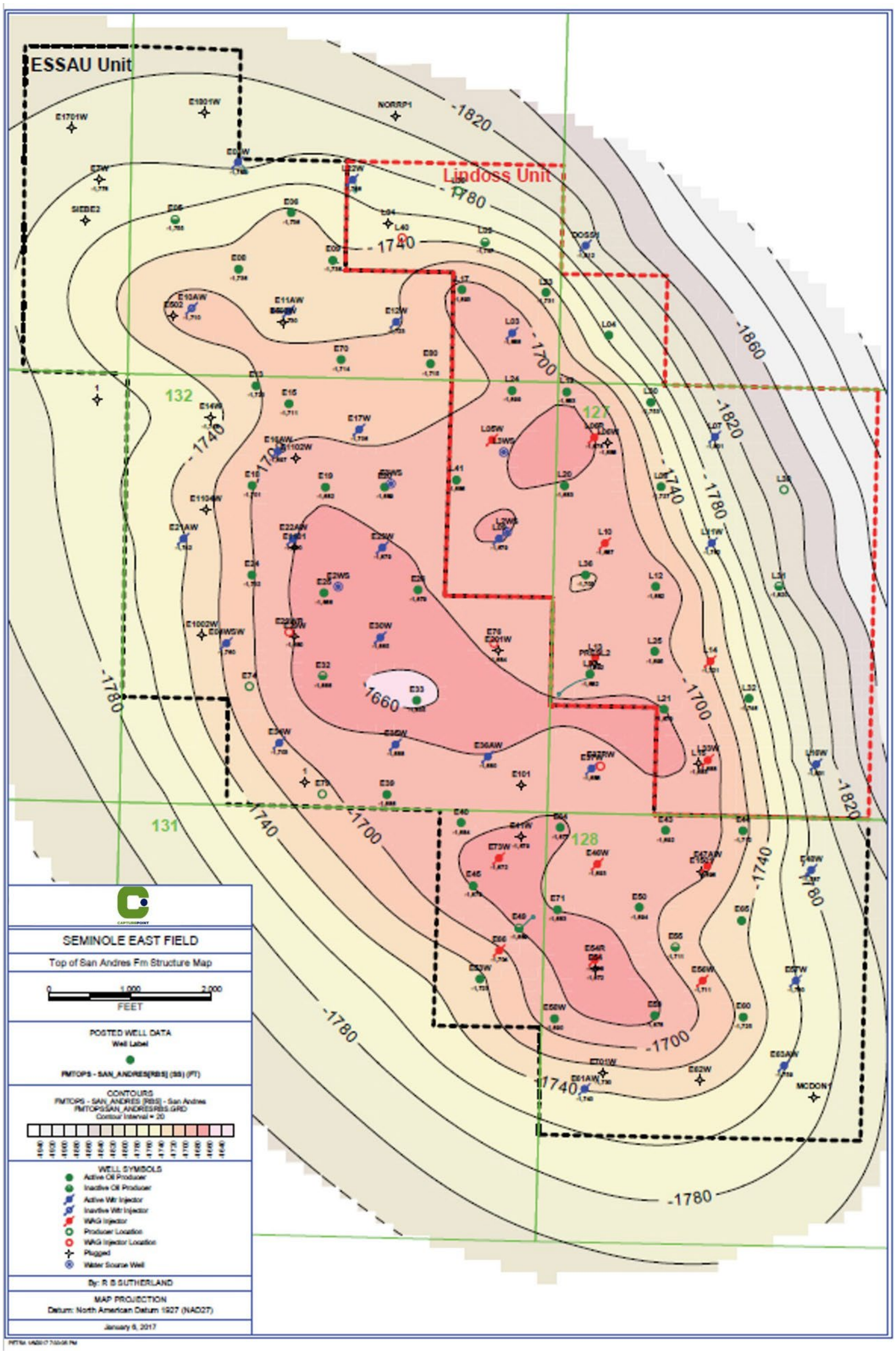

Figure 3-4 Local Area Structure on Top of San Andres

Log and core analyses identify seven major stratified zones in the SEF. The first porous zone or Main Pay is located nearly 400 feet into the San Andres Formation. Due to hydrodynamic flow in the San Andres aquifer, a thick residual oil zone 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 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 Central Basin Platform is negligible. The volume of CO_2 storage is based on the estimated total pore space within SEF. The total pore space within SEF, from the top of the reservoir down to the base of the residual oil zone, is calculated to be 104.2 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 158 Billion Cubic Feet (BCF) (9 million tonnes) of CO_2 storage in the reservoir. CO_2 will occupy only 50% of the total calculated storage capacity by the year 2042 based on the current project forecast.

Table 3-1 Calculation of Maximum Volume of CO_2 *Storage Capacity at Seminole East Field (SEF)*

Top of Main Pay to Bottom of Residual Oil Zone	
Variables	SEF Outline
Pore Volume (**RB**)	104,199,573
$\mathbf{B}_{CO2}$ (RB/MCF)	0.40
$\mathbf{S}_{wirr}$	0.24
$\mathbf{S}_{or\ CO2}$	0.15
Max CO_2 (MCF)	158,904,349
Max CO_2 (BCF)	158

$$\mathbf{M}\text{ax } CO_2 = \text{Pore Volume} * (1 - \mathbf{S}\text{wirr} - \mathbf{S}\text{or}_{CO2}) / \mathbf{B}_{CO2}$$

Where:

Max CO_2 = the maximum amount of storage capacity

Pore Volume = Total pore space in reservoir barrels (RB)

B_{CO2} = the formation volume factor for CO_2

S_{wirr} = the irreducible water saturation

Sor_{CO2} = 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 is being utilized in SEF 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 SEF unit boundary and do not move to adjacent areas.

Given that in SEF the confining zone has proved competent over both millions of years and in the current CO_2 flooding, and that the SEF 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 ESSAU. CO_2 is delivered to the ESSAU via the Kinder Morgan CO_2 pipeline network. The CO_2 is supplied by a number of different sources including both natural and anthropogenic CO_2 sources. Specified amounts are drawn from an outside source pipeline based on contractual arrangements among suppliers of CO_2, purchasers of CO_2, and the pipeline operator.

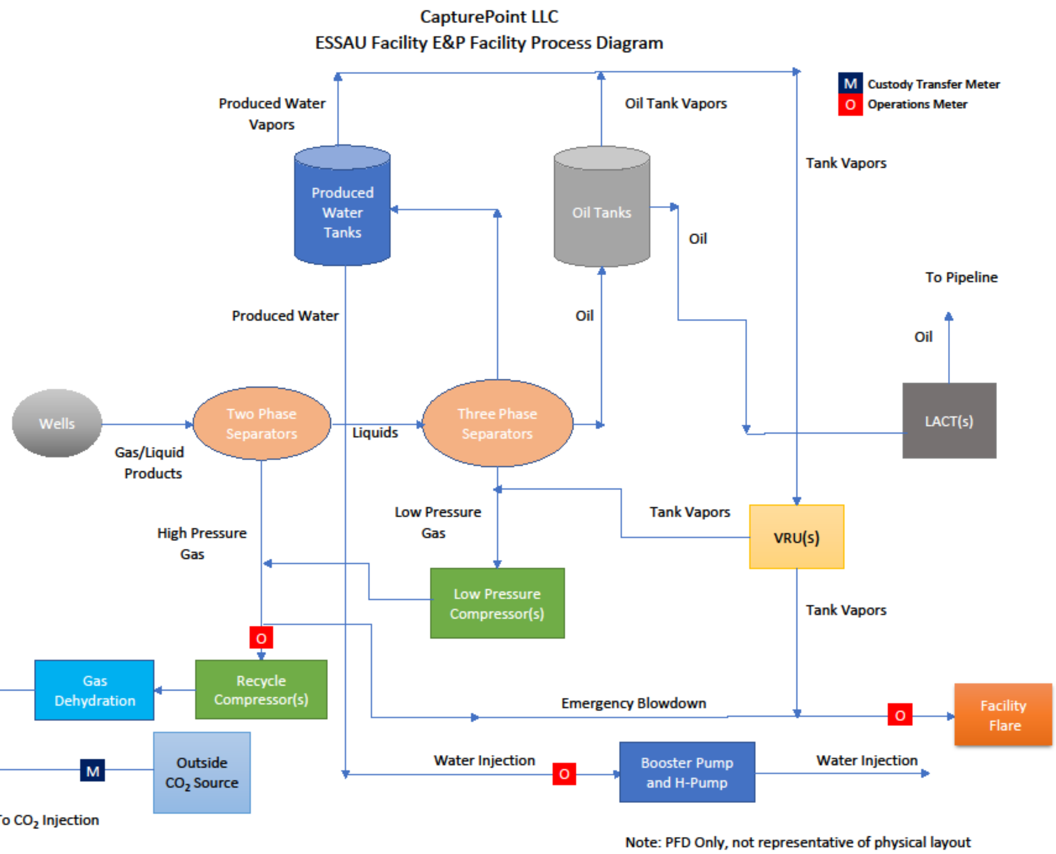

Figure 3-5 ESSAU Process Flow Diagram

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

i. CO_2 Distribution and Injection: The mass of CO_2 received at ESSAU 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 recycle compression facility 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 treatment and reinjection or disposal.

Figure 3-6 shows a simplified process flow diagram of the project facilities and equipment in the Lindoss Unit. CO_2 is delivered to the Lindoss Unit via the Kinder Morgan CO_2 pipeline network. The CO_2 is supplied by a number of different sources including both natural and anthropogenic CO_2 sources. Specified amounts are drawn from an outside source pipeline based on contractual arrangements among suppliers of CO_2, purchasers of CO_2, and the pipeline operator.

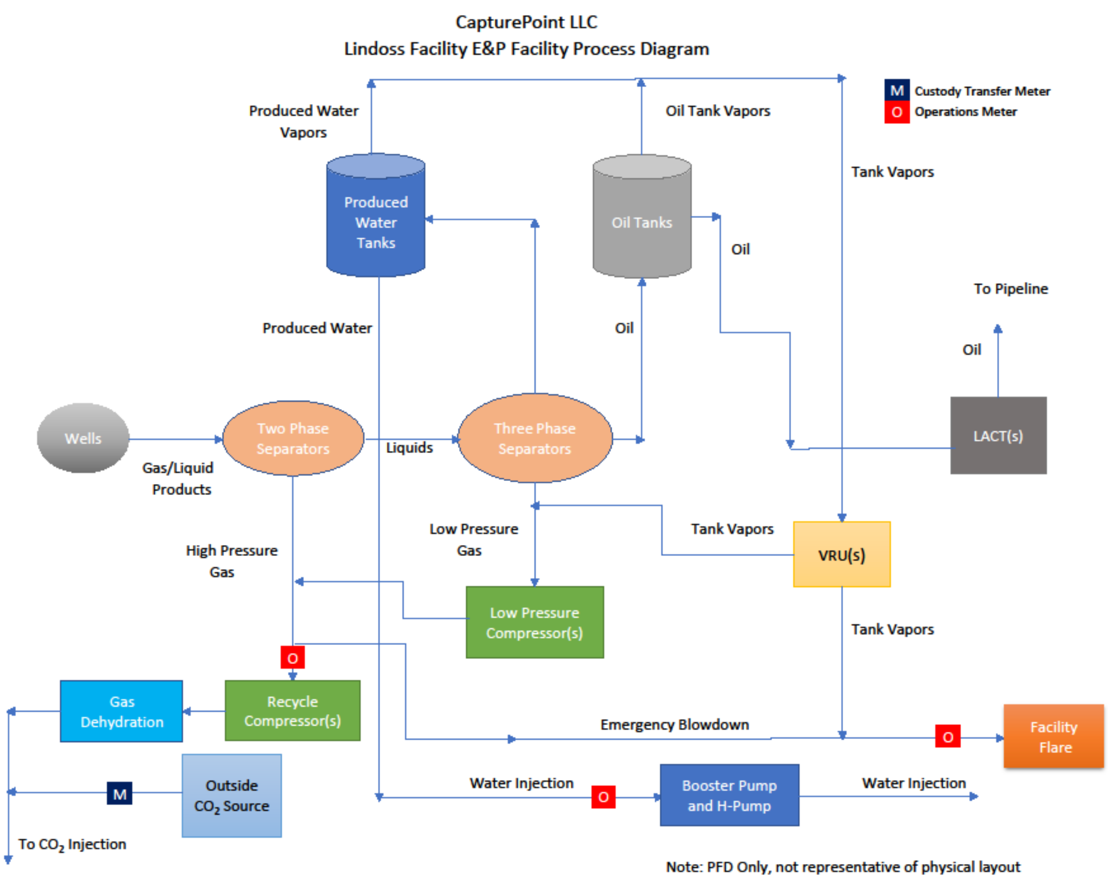

Figure 3-6 Lindoss Process Flow Diagram

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

i. CO_2 Distribution and Injection: The mass of CO_2 received at Lindoss 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 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.

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 H_2S as discussed in Section 7. They are gathered and sent to SATs 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 recycle compression facility 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 treatment and reinjection or disposal.

There are no physical differences between the ESSAU and Lindoss facilities.

3.3.1 Wells in the Seminole East Field

The TRRC has broad authority over oil and gas operations including primacy to implement UIC Class II wells. The rules are found in Texas Administrative Code 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 they 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 3.1 provides a well count by type and status. All these wells are in material compliance with TRRC rules.

Table 3.1 SEF Well Penetrations by Type and Status

TYPE	ACTIVE	INACTIVE	P & A	Total
PROD_OIL	32	16	0	**48**
INJ_WTR	16	4	0	**20**
INJ_WAG	18	0	0	**18**
INJ_SWD*	1	0	0	**1**
WSW**	1	4	0	**5**
P&A***	0	0	28	**28**
TOTAL	**68**	**24**	**28**	**120**

*INJ_SWD = Saltwater disposal wells
**WSW= Water source wells
***P&A = Plugged and Abandoned wells

As indicated in Figure 3-7, wells are distributed across the SEF. The well patterns currently undergoing CO_2 flooding are identified by black 5-spot pattern outlines and red symbols. CO_2 will be injected across the entire unit over the project life.

SEF CO_2-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Reservoir pressure in the SEF 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.

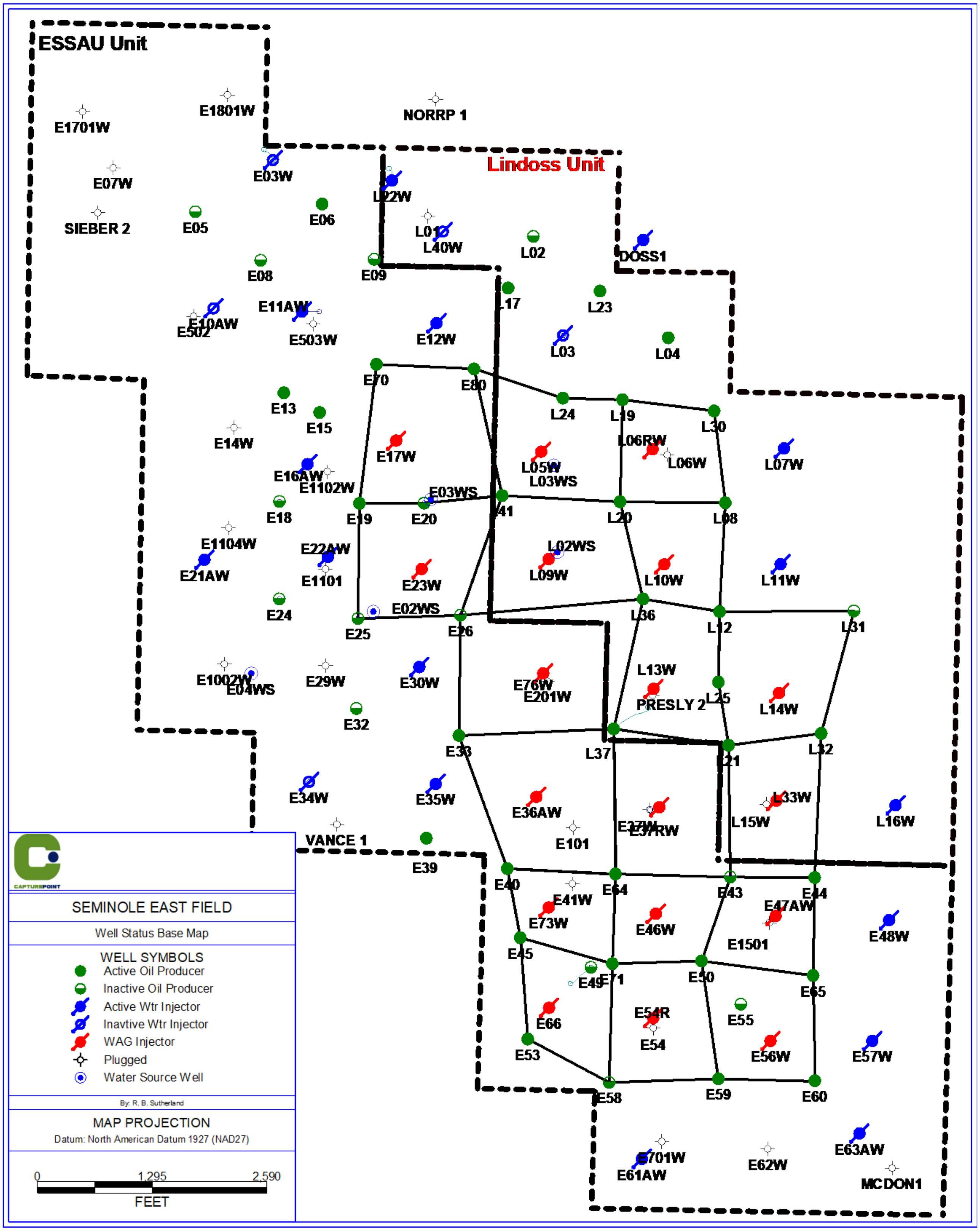

Figure 3-7 SEF Wells and Injection Patterns

3.4 Reservoir Forecasting

DPCs derived from analogous fields were used to project carbon dioxide enhanced oil recovery in the Seminole East Field. Most DPCs are derived from geologic and reservoir models. In the SEF case the DPC was derived from actual field performance from an analogous field.

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 3-8. The dimensioned projections of oil, CO_2 and water production, and CO_2 and water injection are made from DPCs using the original oil in place of an area of interest.

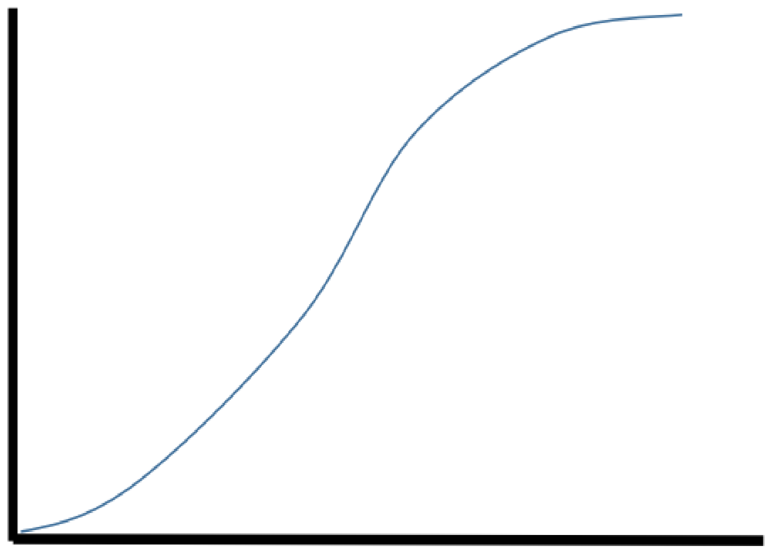

Figure 3-8 Dimensionless performance curve plot

The SEF DPC was calculated from the cumulative production and injection from an analogous field. The SEF DPC was used on each pattern in the SEF 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 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 laterally or vertically 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 ESSAU and Lindoss Unit boundaries.

Figure 3-7 displays wells that have CO_2 retention on the 680 acres that have been under CO_2 injection since project initialization. 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 (158 BCF) is limited to the amount of space available by the removal of the produced hydrocarbon. The projection indicates that there is pore space available to store approximately .51 decimal fraction of HCPV amounting to 32 MMRB (80.2 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 80.2 BCF. Initially, the storage area outline slightly exceeded the ESSAU in the southwest corner by less than 150 ft. To keep the CO_2 within the unit boundaries in the southwest corner less CO_2 will be injected into that area of the unit thus reducing the storage radius for each well. The extra CO_2 would be injected into the north – northeast wells. Figure 4-1 shows the map of the revised storage area outline (dashed red line). This calculation showed 1000 acres would be needed to store the 80.2 BCF. This is significantly less than the 2045 acres in the SEF outline.

4.2. Maximum Monitoring Area

The Maximum Monitoring Area (MMA) is defined by the ESSAU and Lindoss Unit boundaries plus the required ½ mile buffer as required by 40 CFR §98.440-449 (Subpart RR). The MMA would be the same as the AMA since the plume location is less than the Unit area.

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 SEF. The Specified Period will be shorter than the period of production from the SEF.

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 SEF is collected for use in operations management. Reservoir pressure is not forecasted to change appreciably since the IWR will be maintained at approximately 1.0. 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).

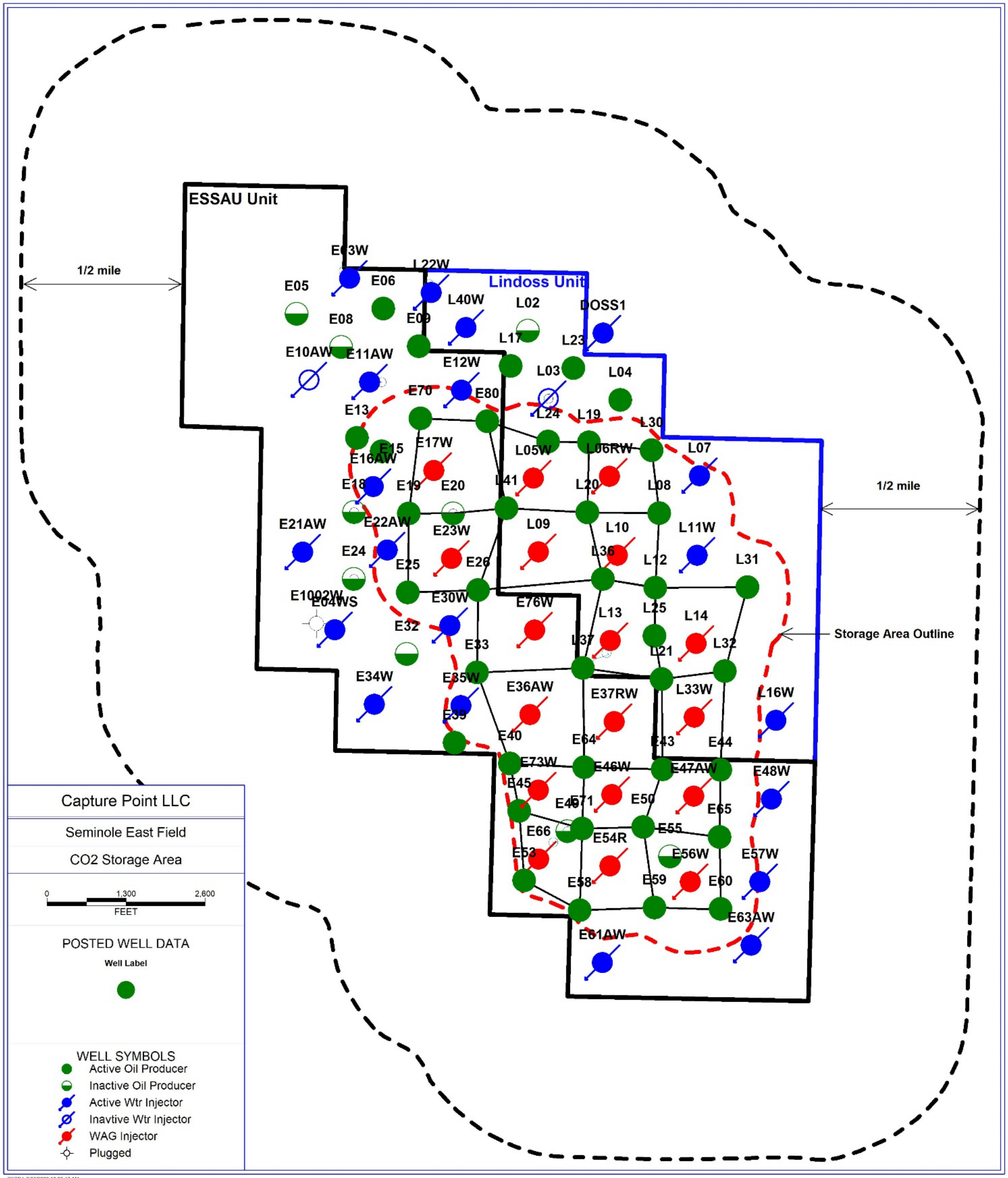

Figure 4-1 Projected CO2 storage area

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

In the roughly 60 years since the SEF 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 Well Bores
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the SEF
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 Wellbores

As part of the TRRC requirement to initiate CO_2 flooding, an extensive review of all SEF 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 SEF 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 beam pumped producing wells,
- CO_2 flood electrical submersible pump (ESP) producing wells, and
- CO_2 WAG 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 SEF 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 SEF 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 are investigated and addressed. CapturePoint's experience, from over 10 years of operating CO_2-EOR projects, is that such leakage is very rare.

- 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 the 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 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 and reported and quantified.

Based on ongoing monitoring activities and review of the potential leakage risks posed by well bores, it is concluded that the risk of CO_2 leakage through well bores is being mitigated by detecting problems as they arise and quantifying any leakage that does occur.

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 little to no risk 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 1.0 is also maintained. Both measures mitigate the potential for inducing faults or fractures. As a safeguard, WAG skids are continuously monitored.

5.3. Natural or 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 SEF.

To evaluate this potential risk at SEF, CapturePoint has reviewed the nature and location of seismic events in West Texas. Some of the recorded earthquakes in West Texas are far removed from any injection operation. These 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 M0.5 or greater in the Permian Basin since 1966 indicates that none have occurred in the SEF; the closest took place in 1992 approximately 30 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 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 SEF. 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 (GIS) site[3] for seismic signals that could indicate the creation of potential leakage pathways in the SEF.

[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/

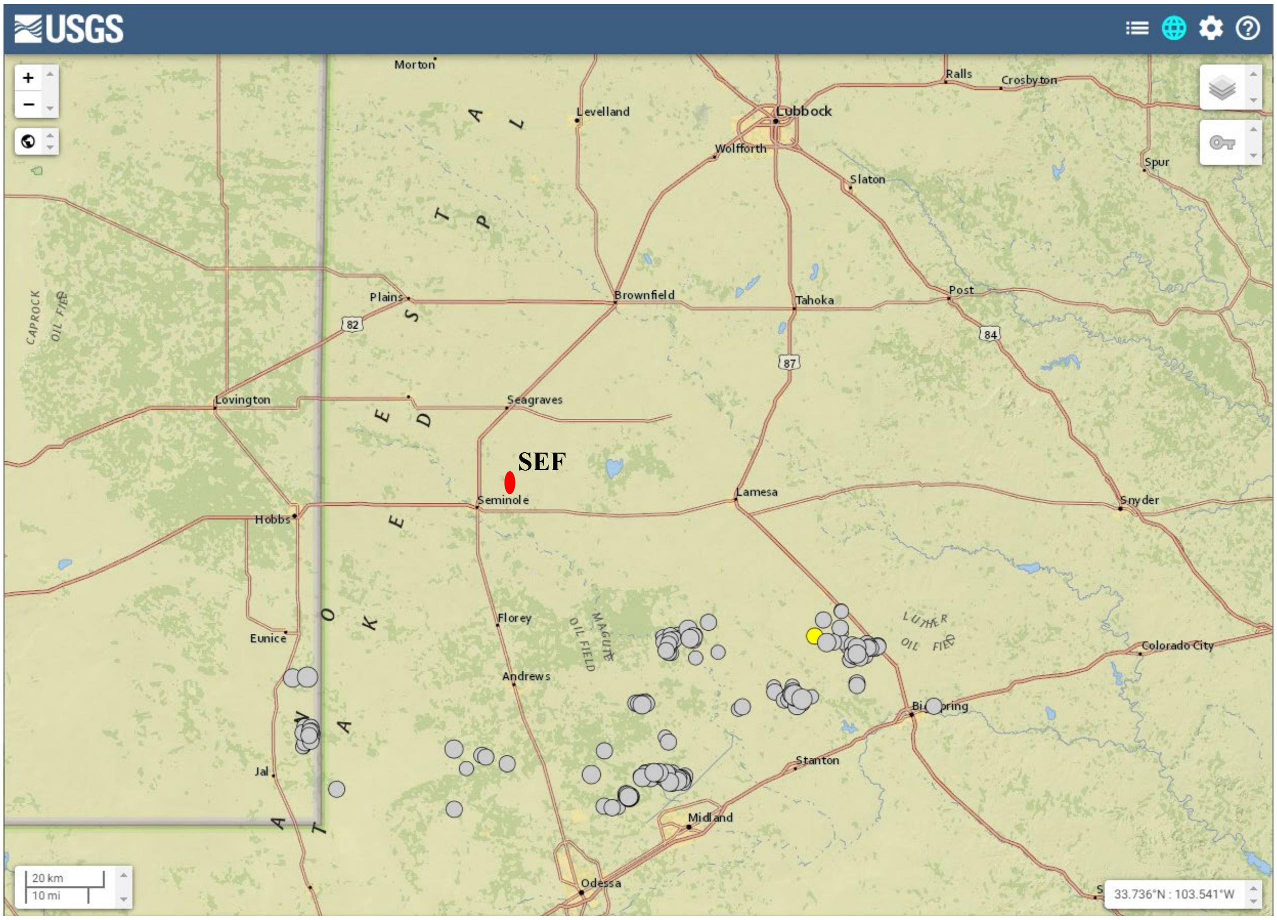

Figure 5-1 USGS earthquakes (+1.0 magnitude) for last 56 years)

5.4. Previous Operations

CO_2 flooding was initiated in SEF in 2013. 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 SEF. These practices ensure that that there are no unknown wells within SEF and that the risk of migration from older wells has been sufficiently mitigated. The successful experience with CO_2 flooding in SEF demonstrates that the confining zone has not been impaired by previous operations.

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 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. 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).

5.6. Lateral Migration Outside the Seminole East Field

It is highly unlikely that injected CO_2 will migrate downdip and laterally outside the SEF because of the nature of the geology and the approach used for injection. Over long periods of time, injected CO_2 will tend to rise vertically towards the Upper San Andres and continue towards the point in the SEF 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. Water Curtain Injection (WCI) methods are employed during CO_2-EOR operations to prevent CO_2 lateral migration out of the unit boundary. Continuous WCI operations are conducted at the SEF unit boundaries to create a pressure barrier to contain injected fluids within the SEF. Finally, the total volume of fluids contained in the SEF will stay relatively constant. Based on site characterization and planned and projected operations it is estimated that the total volume of stored CO_2 will be considerably less than calculated capacity.

5.7. Drilling in the Seminole East 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 SEF is conducted in accordance with TRRC rules. CapturePoint's visual inspection process, including routine site visits, will identify unapproved drilling activity in the SEF.

In addition, CapturePoint intends to operate SEF 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 SEF 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 into the formations beneath them. As mentioned in Section 3.2 "The San Andres is a stratified reservoir. The stratification is due to tidal movements that occurred across the shoals. The tidal movements formed a stacked sequence of shoals with alternating thin intertidal

deposits. The thin intertidal deposits are anhydritic carbonate mudstone layers and result in effective vertical permeability barriers (supported by core data). These barriers are continuous over the entire field and vary in thickness from two to ten feet with most averaging three to four feet in thickness."

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.

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 (well bores), 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.

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 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 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
Diffuse leakage through the seal	Injection pressure is continuously monitored and unexplained changes in injection pressure that might indicate leakage would trigger investigation as to the cause.	Conduct an injection radioactive tracer survey. If verified, well is shut in and workover crews respond within days.
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

5.10. Summary

The structure and stratigraphy of the San Andres reservoir in the SEF 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 SEF 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 SEF 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 SEF follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), 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 & 3-6, 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 SEF. 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 inlet to the RCF.
- CO_2 that is entrained in produced oil, as indicated in Figure 3-5 & 3-6, is calculated using volumetric flow through the custody transfer 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 SEF. 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. The Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.

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, 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 SEF. 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

SEF 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 SEF. 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 SEF. 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 Greenhouse 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 SEF 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 worn by all field personnel at all times and are permanent throughout the field at ground level, is used as a last method to detect leakage from wellbores. The H_2S monitor 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. Currently the concentration of H_2S in the recycled or produced gas is in excess of 18,000 ppm making leak detection viable. Thus, detected H_2S leaks will be investigated in order 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, 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 equipment, the CO_2 content of produced oil, and 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 equipment, the CO_2 content of produced oil, and vented CO_2, as required under 40 CFR Part 98 Subpart W.

6.2. To Demonstrate that Injected CO2 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 SEF 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 reservoir pressure that 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 and as such 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 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 H_2S monitors throughout the field at ground level to detect H_2S 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 and 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

To account for the potential propagation of error that would result if volume data from flow meters at each injection and production well were utilized, it is proposed to use the data from custody and operations meters on the main system pipelines to determine injection and production volumes used in the mass balance. 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 of the well head meters within the SEF.

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 Kinder Morgan 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.

$$CO_2T,r = \sum_{p=1}^{4} (Q_{p,r} - S_{r,p})*D*C_{CO2,r,p} \qquad \text{(Eq. RR-2)}$$

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 a site well in quarter p (standard cubic meters).

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

$C_{CO2,r,r}$ = 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 SEF's method of receiving CO_2 and requirements at Subpart RR §98.444(a):

- All delivery to the SEF is used within the unit so no quarterly flow redelivered, and Sr,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 SEF 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 output of the RCF (see Figure 3-5). 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:

$$CO_2u = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO2,p,u} \qquad \text{(Eq. RR-5)}$$

where:

CO_2u = Annual CO_2 mass recycled (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.

$C_{CO2,p,u}$ = 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-3) and Mass of CO_2 Recycled (modified RR-5).

$$CO_{2I} = CO_2 + CO_2u$$

8.3. Mass of CO_2 Produced

The Mass of CO_2 Produced at the SEF 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:

$$CO_{2w} = \sum_{p=1}^{4} Qp,w * D * C_{CO2,p,w} \qquad \text{(Eq. RR-8)}$$

where:

CO_{2W} = Annual CO_2 mass produced (metric tons).

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

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

$C_{CO2,pw}$ = CO_2 concentration measurement in flow for meter w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Inlet meters to RCF

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

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

where:

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

CO_2w = Annual CO_2 mass produced (metric tons) through all separators in the reporting year.

Xoil = 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).

8.4. Mass of CO_2 Emitted by Surface Leakage

The total annual Mass of CO_2 emitted by Surface Leakage will be calculated and reported using an approach that is tailored to specific leakage events and relies on 40 CFR Part 98 Subpart W reports of equipment leakage. 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 a number of 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 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. Further, the Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.

Equation RR-10 in §98.433 will be used to calculate and report the Mass of CO_2 emitted by Surface Leakage:

$$CO_{2E} = \sum_{x=1}^{x} CO_{2}x \qquad \text{(Eq. RR-10)}$$

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 Sequestered in Subsurface Geologic Formation

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

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \qquad \text{(Eq. RR-11)}$$

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) net of CO_2 entrained in oil 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 this part.

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 this part.

8.6. Cumulative Mass of CO_2 Reported as Sequestered in Subsurface Geologic Formation

The total annual volumes obtained using equation RR-11 in §98.443 will be summed to arrive at the Cumulative Mass of CO_2 Sequestered in Subsurface Geologic Formations.

9. MRV Plan Implementation Schedule

This MRV plan will be implemented starting January 2023 or within 90 days of EPA approval, whichever occurs later. Other GHG 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 program will be in effect during the Specified Period, during which time the SEF 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 SEF. 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 Program

10.1. Monitoring QA/QC

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.
- The quarterly flow rate of the produced gas is measured at the flow meters located at the RCF inlet.

CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2

These volumes are measured in conformance with the monitoring and QA/QC 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 nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.
- The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

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 SEF 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 and number, API number, type, and status for active wells in the SEF as of August 2021. 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_WTR refers to wells that inject water
  - INJ_WAG refers to wells that inject water and CO_2 Gas
  - INJ_SWD refers to wells that inject water for disposal
  - SWS refers to wells that supply water
  - 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

Well Name	API Number	Well Type	Status
DCB Doss 1 (INJ)	4216534180	INJ_WTR	ACTIVE
ESSAU 02WS	4216530590	WSW	SHUT_IN
ESSAU 03W (INJ)	4216534370	INJ_WTR	SHUT_IN
ESSAU 03WS	4216534343	WSW	ACTIVE
ESSAU 04WS	4216532191	WSW	SHUT_IN
ESSAU 05	4216581203	PROD_OIL	SHUT_IN
ESSAU 06	4216533021	PROD_OIL	ACTIVE
ESSAU 07W (INJ)	4216530591	P&A	INACTIVE
ESSAU 08	4216533913	PROD_OIL	SHUT_IN
ESSAU 09	4216534600	PROD_OIL	SHUT_IN
ESSAU 1002W	4216510149	P&A	INACTIVE
ESSAU 101	4216501006	P&A	INACTIVE
ESSAU 10AW (INJ)	4216533614	INJ_WTR	SHUT_IN
ESSAU 1101	4216510058	P&A	INACTIVE
ESSAU 1102W (INJ)	4216510079	P&A	INACTIVE
ESSAU 1104W (INJ)	4216510241	P&A	INACTIVE
ESSAU 11AW (INJ)	4216533615	INJ_WTR	ACTIVE
ESSAU 12W (INJ)	4216533403	INJ_WTR	ACTIVE

Well Name	API Number	Well Type	Status
ESSAU 13	4216534028	PROD_OIL	ACTIVE
ESSAU 14W (INJ)	4216510072	P&A	INACTIVE
ESSAU 15	4216534110	PROD_OIL	ACTIVE
ESSAU 1501	4216510413	P&A	INACTIVE
ESSAU 16AW (INJ)	4216534371	INJ_WTR	ACTIVE
ESSAU 1701W (INJ)	4216510246	P&A	INACTIVE
ESSAU 17W (INJ)	4216534108	INJ_WAG	ACTIVE
ESSAU 18	4216533910	PROD_OIL	SHUT_IN
ESSAU 1801W (INJ)	4216510250	P&A	INACTIVE
ESSAU 19	4216533912	PROD_OIL	ACTIVE
ESSAU 20	4216534111	PROD_OIL	SHUT_IN
ESSAU 201W (INJ)	4216500168	P&A	INACTIVE
ESSAU 21AW (INJ)	4216533819	INJ_WTR	ACTIVE
ESSAU 22AW (INJ)	4216533908	INJ_WTR	ACTIVE
ESSAU 23W (INJ)	4216501005	INJ_WAG	ACTIVE
ESSAU 24	4216533906	PROD_OIL	SHUT_IN
ESSAU 25	4216533914	PROD_OIL	SHUT_IN
ESSAU 26	4216534112	PROD_OIL	SHUT_IN
ESSAU 29W (INJ)	4216501019	P&A	INACTIVE
ESSAU 30W (INJ)	4216501007	INJ_WTR	ACTIVE
ESSAU 32	4216533909	PROD_OIL	SHUT_IN
ESSAU 33	4216534031	PROD_OIL	ACTIVE
ESSAU 34W (INJ)	4216534109	INJ_WTR	SHUT_IN
ESSAU 35W (INJ)	4216501008	INJ_WTR	ACTIVE
ESSAU 36AW (INJ)	4216530147	INJ_WAG	ACTIVE
ESSAU 37RW (INJ)	4216538478	INJ_WAG	ACTIVE
ESSAU 37W (INJ)	4216502594	P&A	INACTIVE
ESSAU 39	4216534106	PROD_OIL	ACTIVE
ESSAU 40	4216534104	PROD_OIL	ACTIVE
ESSAU 41W (INJ)	4216501012	P&A	INACTIVE
ESSAU 43	4216534601	PROD_OIL	SHUT_IN
ESSAU 44	4216534652	PROD_OIL	ACTIVE
ESSAU 45	4216534107	PROD_OIL	ACTIVE
ESSAU 46W (INJ)	4216500002	INJ_WAG	ACTIVE
ESSAU 47AW (INJ)	4216533014	INJ_WAG	ACTIVE
ESSAU 48W (INJ)	4216533015	INJ_WTR	ACTIVE
ESSAU 49	4216534049	PROD_OIL	SHUT_IN
ESSAU 50	4216533907	PROD_OIL	ACTIVE
ESSAU 502	4216510251	P&A	INACTIVE
ESSAU 503W (INJ)	4216530452	P&A	INACTIVE
ESSAU 53	4216533911	PROD_OIL	SHUT_IN
ESSAU 54	4216502901	P&A	INACTIVE
ESSAU 54R (INJ)	4216538339	INJ_WAG	ACTIVE

Well Name	API Number	Well Type	Status
ESSAU 55	4216501046	PROD_OIL	SHUT_IN
ESSAU 56W (INJ)	4216534030	INJ_WAG	ACTIVE
ESSAU 57W (INJ)	4216510252	INJ_WTR	ACTIVE
ESSAU 58	4216534105	PROD_OIL	SHUT_IN
ESSAU 59	4216533905	PROD_OIL	ACTIVE
ESSAU 60	4216534048	PROD_OIL	ACTIVE
ESSAU 61AW (INJ)	4216533820	INJ_WTR	ACTIVE
ESSAU 62W (INJ)	4216502902	P&A	INACTIVE
ESSAU 63AW (INJ)	4216534029	INJ_WTR	ACTIVE
ESSAU 64	4216534027	PROD_OIL	ACTIVE
ESSAU 65	4216534026	PROD_OIL	ACTIVE
ESSAU 66W (INJ)	4216501003	INJ_WAG	ACTIVE
ESSAU 70	4216537356	PROD_OIL	ACTIVE
ESSAU 701W (INJ)	4216501011	P&A	INACTIVE
ESSAU 71	4216537747	PROD_OIL	ACTIVE
ESSAU 73W (INJ)	4216537748	INJ_WAG	ACTIVE
ESSAU 76W (INJ)	4216538479	INJ_WAG	ACTIVE
ESSAU 80	4216538294	PROD_OIL	ACTIVE
Lindoss 01	4216533392	P&A	INACTIVE
Lindoss 02	4216533467	PROD_OIL	SHUT_IN
Lindoss 02WS	4216534452	WSW	SHUT_IN
Lindoss 03 (INJ)	4216533284	INJ_WTR	SHUT_IN
Lindoss 03WS	4216534453	WSW	SHUT_IN
Lindoss 04	4216533041	PROD_OIL	ACTIVE
Lindoss 05W (INJ)	4216532364	INJ_WAG	ACTIVE
Lindoss 06RW (INJ)	4216538303	INJ_WAG	ACTIVE
Lindoss 06W (INJ)	4216532733	P&A	INACTIVE
Lindoss 07W (INJ)	4216532883	INJ_WTR	ACTIVE
Lindoss 08	4216533452	PROD_OIL	ACTIVE
Lindoss 09W (INJ)	4216532200	INJ_WAG	ACTIVE
Lindoss 10W (INJ)	4216532606	INJ_WAG	ACTIVE
Lindoss 11W (INJ)	4216532757	INJ_WTR	ACTIVE
Lindoss 12	4216533453	PROD_OIL	ACTIVE
Lindoss 13W (INJ)	4216533422	INJ_WAG	ACTIVE
Lindoss 14W (INJ)	4216531826	INJ_WAG	ACTIVE
Lindoss 15 (INJ)	4216531527	P&A	INACTIVE
Lindoss 16W (INJ)	4216532025	INJ_WTR	ACTIVE
Lindoss 17	4216534440	PROD_OIL	ACTIVE
Lindoss 19	4216534442	PROD_OIL	ACTIVE
Lindoss 20	4216534441	PROD_OIL	ACTIVE
Lindoss 21	4216534602	PROD_OIL	ACTIVE
Lindoss 22W (INJ)	4216534604	INJ_WTR	ACTIVE
Lindoss 23	4216536582	PROD_OIL	ACTIVE

Well Name	API Number	Well Type	Status
Lindoss 24	4216536583	PROD_OIL	ACTIVE
Lindoss 25	4216536581	PROD_OIL	ACTIVE
Lindoss 30	4216537352	PROD_OIL	ACTIVE
Lindoss 31	4216537345	PROD_OIL	SHUT_IN
Lindoss 32	4216537341	PROD_OIL	ACTIVE
Lindoss 33W (INJ)	4216537346	INJ_WAG	ACTIVE
Lindoss 36	4216537772	PROD_OIL	ACTIVE
Lindoss 37	4216538297	PROD_OIL	ACTIVE
Lindoss 40W (SWD)	4216538466	INJ_SWD	SHUT_IN
Lindoss 41	4216538296	PROD_OIL	ACTIVE
McDonald 1	4216502903	P&A	INACTIVE
Norrp 1	4216533505	P&A	INACTIVE
Presely 2	4216531620	P&A	INACTIVE
Sieber 2	4216510247	P&A	INACTIVE
Vance 1	4216501018	P&A	INACTIVE

12.2 Regulatory References

Regulations cited in this plan:

- Texas Administrative Code 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

AGA - American Gas Association

AMA - Active Monitoring Area

API - American Petroleum Institute

AoR - Area of Review

Bcf – 1 Billion Cubic Feet of Gas

CO_2 - Carbon Dioxide

DPC - Dimensionless Performance Curve

EPA - Environmental Protection Agency

EOR - Enhanced Oil Recovery

ESP - Electrical Submersible Pump

ESSAU - East Seminole San Andres Unit

FPP - Formation Parting Pressure (psi)

GHG - Greenhouse Gas

GHGRP - Greenhouse Gas Reporting Program

GIS - Geographical Information System

GPA - Gas Processors Association

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 – 1,000 Cubic Feet of Gas

NIST - National Institute of Standards and Technology

RB - Reservoir Barrels

RCF - Recycle Compression Facility

ROZ - Residual Oil Zone

SAT - Satellite Test Stations

SEF - Seminole East Field

TAC - Texas Administrative Code

TRRC - Texas Railroad Commission - Oil and Gas Division

UIC - Underground Injection Control

USGS - United States Geological Survey

WAG - Water Alternating with Gas

WCI - Water Curtain Injection

Request for Additional Information: Seminole East Field (SEF)
July 27, 2022

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	4	16-17	Per 40 CFR 98.449, "Active monitoring area" is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase CO2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile. (2) The area projected to contain the free phase CO2 plume at the end of year t + 5. Per 40 CFR 98.449, "Maximum monitoring area" means the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO2 plume until the CO2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Section 4.1 of the MRV plan states that, "The Active Monitoring Area (AMA) is defined by the ESSAU and Lindoss Unit boundaries plus the required ½ mile buffer." Section 4.2 of the MRV plan states that, "The Maximum Monitoring Area (MMA) is defined by the ESSAU and Lindoss Unit boundaries plus the required ½ mile buffer as required by 40 CFR §98.440-449 (Subpart RR). The MMA would be the same as the AMA since the plume location is less than the Unit area." However, Figure 4.1 in the MRV plan shows that the storage area outline exceeds the ESSAU unit in the southwest corner. This seems to conflict with the earlier statement that the storage area/plume would be within the unit boundaries. Please clarify the delineations of the AMA and MMA and update the MRV plan as necessary.	We re-examined the storage area outline and clarified the delineations of the AMA and MMA. The MRV plan was updated accordingly.

CapturePoint LLC Seminole East Field Subpart RR Monitoring, Reporting and Verification (MRV) Plan

June 13, 2022

Table of Contents

1. Introduction

CapturePoint LLC operates a carbon dioxide (CO_2)-enhanced oil recovery (EOR) project in the Seminole East Field (SEF) located in Gaines County, Texas, approximately one and one-half miles northeast of the town of Seminole for the primary purpose of enhanced oil recovery using CO_2 with a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The SEF is comprised of the East Seminole San Andres Unit (ESSAU) and the Lindoss Unit. Production is from the San Andres formation at an average depth of 5500 feet. 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 Seminole East Field during a specified period of injection.

2. Facility Information

2.1. Reporter Number

562518 – Seminole East Field

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 SEF (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 SEF are currently classified as UIC Class II wells.

2.3. Existing Wells

Wells in the SEF are identified by name and number, American Petroleum Institute (API) number, type, and status. The list of wells as of February 2022 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 SEF an oil field located in West Texas that was first produced more than 60 years ago. SEF is comprised of the ESSAU and the Lindoss Unit. The two units abut 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 units in the SEF. In addition, the two units 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 reservoir similarities, one MRV Plan is being prepared for the two units in the SEF and any important differences between the units will be noted in the MRV plan. CO_2 flooding was initiated in 2013 in both units. The field is well characterized and is suitable for secure geologic storage. CapturePoint uses a water alternating with gas (WAG) injection process and maintains an injection to withdrawal ratio (IWR) at or near 1.0.

3.1. Project Characteristics

The SEF was discovered in 1959 and started producing in the same year. The SEF consists of two units, the ESSAU and the Lindoss Unit. The ESSAU began to produce in May 1959 and waterflood was initiated in January 1983. CO_2 flooding was initiated in 2013, in both the Main Pay and Residual Oil Zone (ROZ). The ROZ is an oil-bearing zone that has been swept by water movement under hydrodynamic conditions over geologic time to a reduced oil saturation that is no longer mobile. The ROZs are attractive targets for EOR with CO_2 Capture and Sequestration. The Lindoss Unit began to produce in November 1979 and waterflood was initiated in July 1984. CO_2 flooding was initiated in October 2013, also in the Main Pay and ROZ.

A long-term CO_2 and hydrocarbon injection and production forecast for both ESSAU and Lindoss was developed using a performance dimensionless curve (DPC) approach. Using this approach, a total injection of approximately 9 million tonnes of 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 SEF.

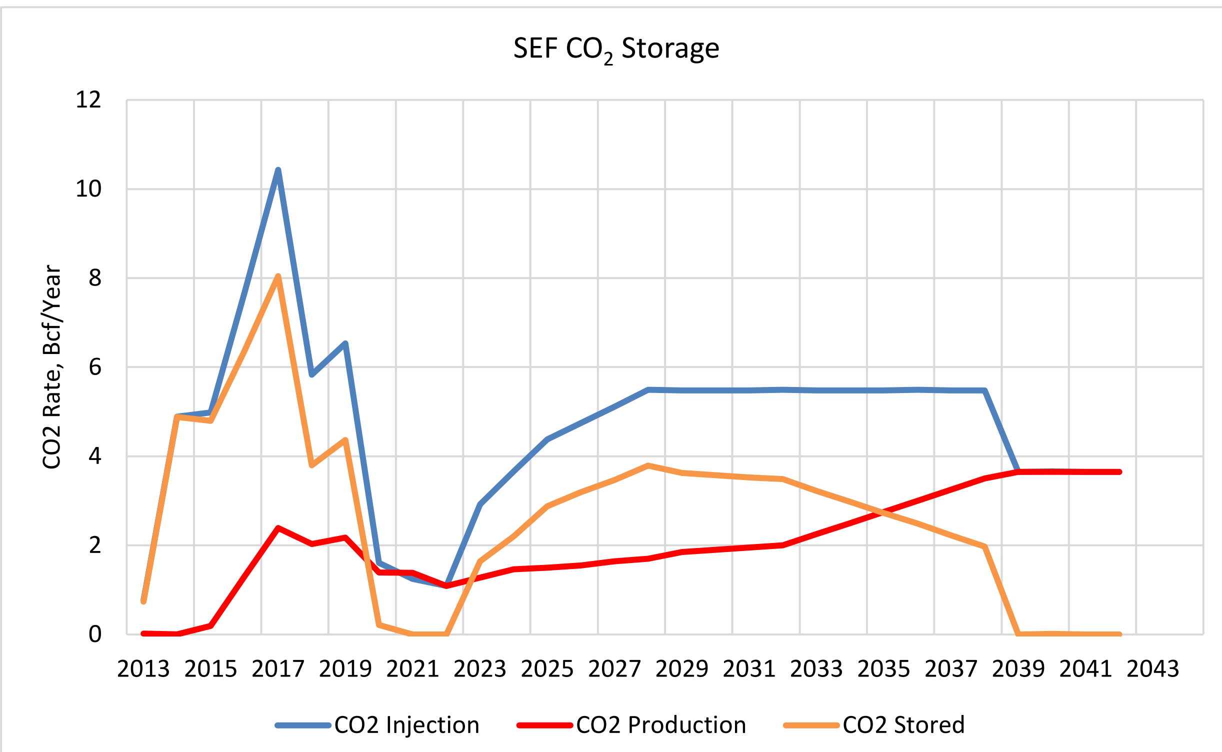

Figure 3-1 SEF Historic and Forecast CO_2 Injection, Production, and Storage

3.2. Environmental Setting

The SEF is located in the NE portion of the Central Basin Platform in West Texas (See Figure 3-2).

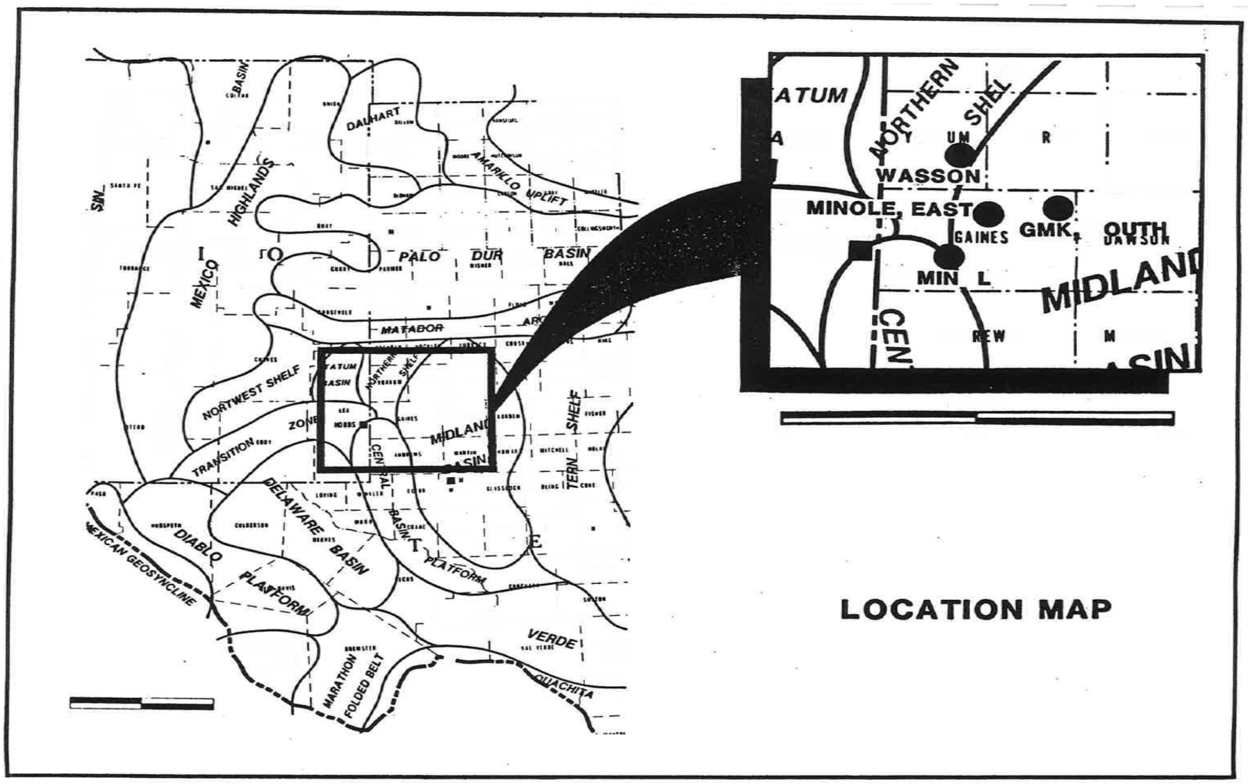

Figure 3-2 Location of SEF in West Texas

The productive formation is the Upper Permian San Andres and consists of anhydritic dolomite with vuggy, moldic, and intercrystalline porosity as seen in the Seminole East Generalized Stratigraphic Section Figure 3-3. The environment of deposition was shallow tidal water deposits with oolitic shoals ("carbonate sands") developed on tidal flats. Secondary porosity later developed from dolomitization.

The structure is an elliptical anticline oriented in a northwest to southeast direction (See Figure 3-4). The anticlinal structure is rimmed to the east and west by two arcuate shoals which merge toward the northwest and southeast to form an elliptical shaped structure with an intershoal "sag" in the center of the field. The east half of the field is the front, or "seaward," shoal and the west half is the back, or "landward" shoal.

The San Andres is a stratified reservoir. The stratification is due to tidal movements that occurred across the shoals. The tidal movements formed a stacked sequence of shoals with alternating thin intertidal deposits. The thin intertidal deposits are anhydritic carbonate mudstone layers and result in effective vertical permeability barriers (supported by core data). These barriers are continuous over the entire field and vary in thickness from two to ten feet with most averaging three to four feet in thickness. Detailed log analysis shows these barriers to be of very high-water saturation (+75%) with the adjacent zones of lower (+/- 24%) water saturation. The high-water saturation zones noted from log analysis are correlatable to very low permeability zones ("tight" and unproductive) in the available cores.

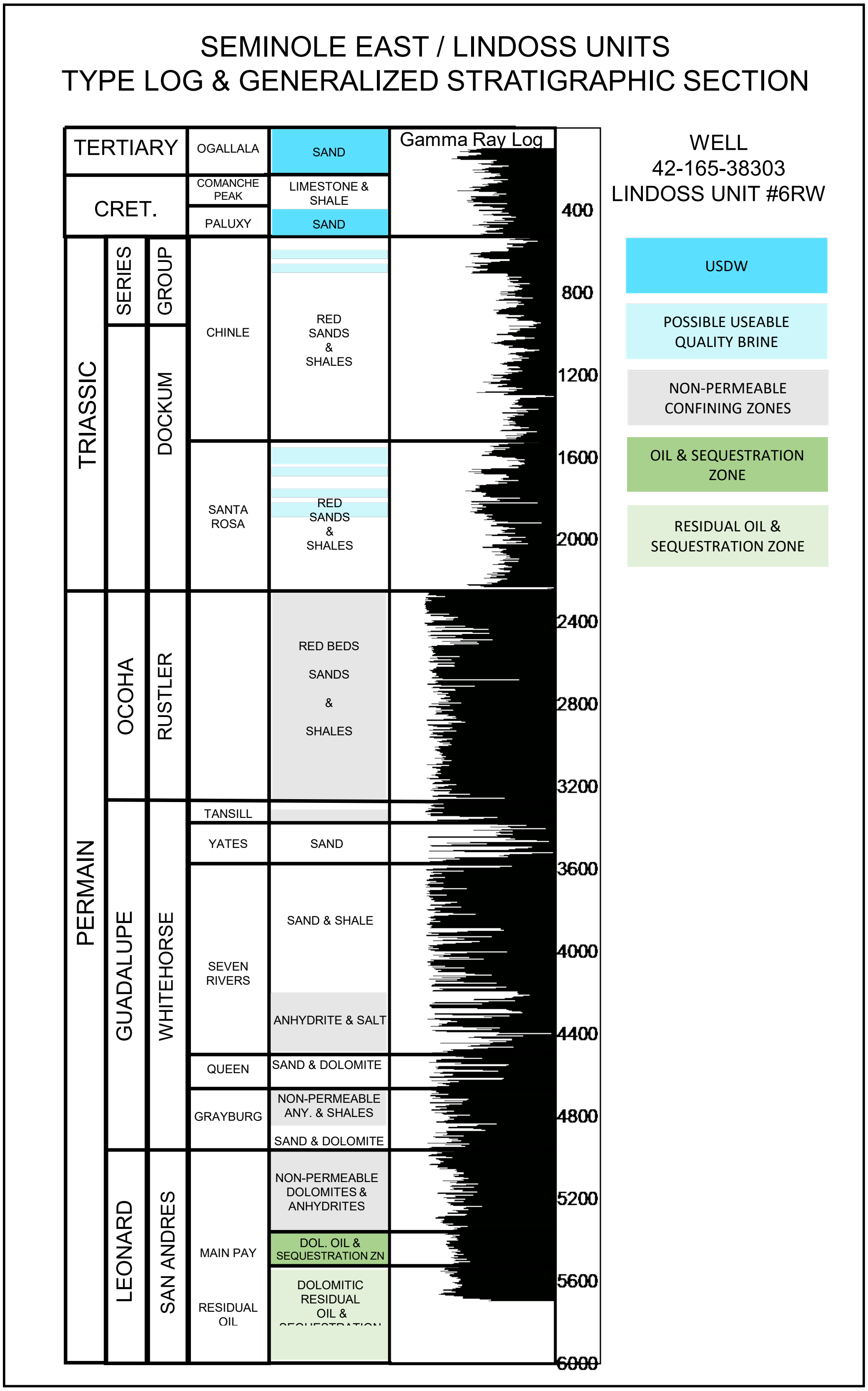

Figure 3-3 Local Area Structure on Top of San Andres

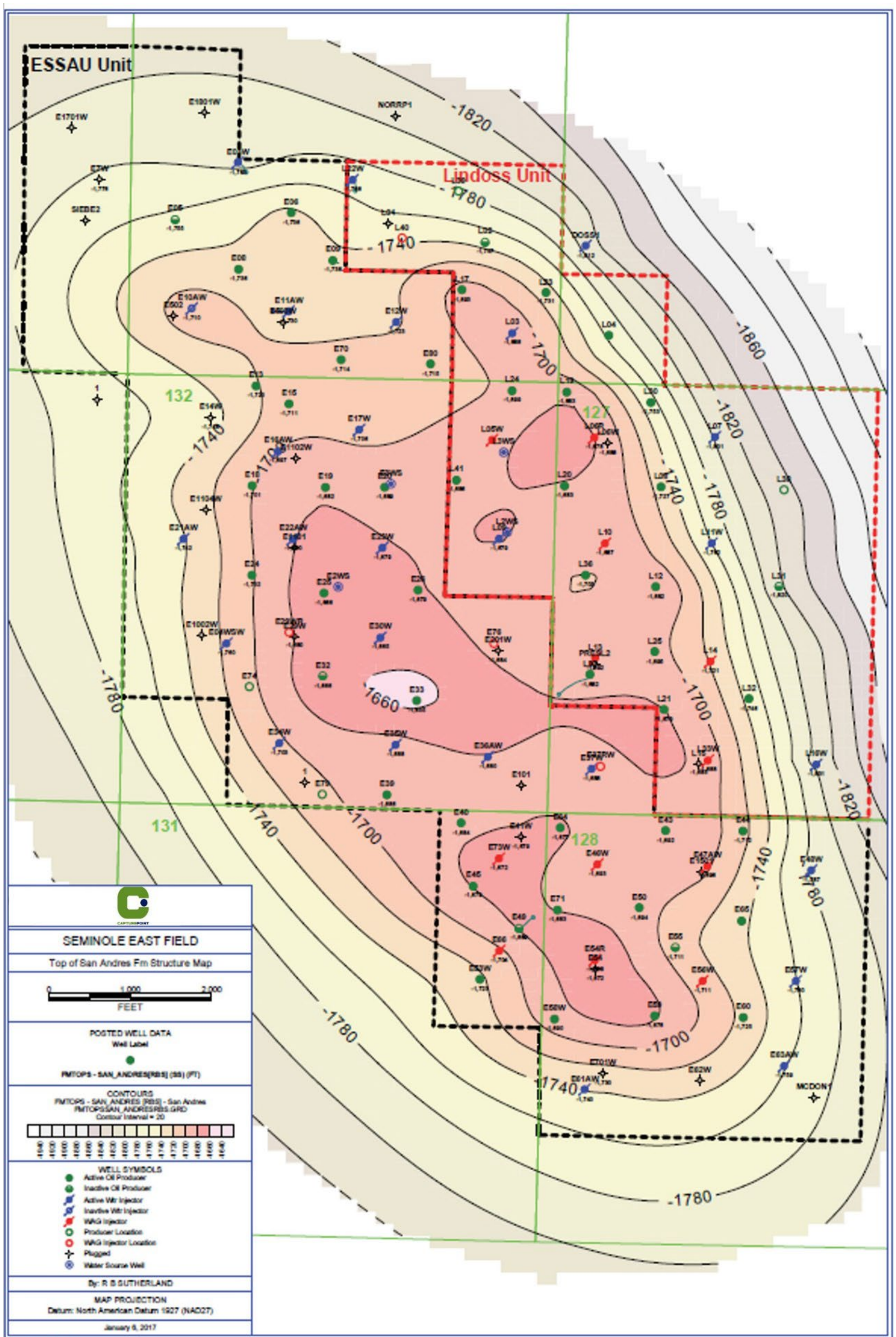

Figure 3-4 Local Area Structure on Top of San Andres

Log and core analyses identify seven major stratified zones in the SEF. The first porous zone or Main Pay is located nearly 400 feet into the San Andres Formation. Due to hydrodynamic flow in the San Andres aquifer, a thick residual oil zone 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 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 Central Basin Platform is negligible. The volume of CO_2 storage is based on the estimated total pore space within SEF. The total pore space within SEF, from the top of the reservoir down to the base of the residual oil zone, is calculated to be 104.2 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 158 Billion Cubic Feet (BCF) (9 million tonnes) of CO_2 storage in the reservoir. CO_2 will occupy only 50% of the total calculated storage capacity by the year 2042 based on the current project forecast.

Table 3-1 Calculation of Maximum Volume of CO_2 Storage Capacity at Seminole East Field (SEF)

Top of Main Pay to Bottom of Residual Oil Zone	
Variables	SEF Outline
Pore Volume (**RB**)	104,199,573
$\mathbf{B}_{CO2}$ (RB/MCF)	0.40
$\mathbf{S}_{wirr}$	0.24
$\mathbf{S}_{or\ CO2}$	0.15
Max CO_2 (MCF)	158,904,349
Max CO_2 (BCF)	158

$$\mathbf{M}\text{ax } CO_2 = \text{Pore Volume} * (1 - \mathbf{S}\text{wirr} - \mathbf{S}\text{or}_{CO2}) / \mathbf{B}_{CO2}$$

Where:

Max CO_2 = the maximum amount of storage capacity

Pore Volume = Total pore space in reservoir barrels (RB)

B_{CO2} = the formation volume factor for CO_2

S_{wirr} = the irreducible water saturation

Sor_{CO2} = 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 is being utilized in SEF 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 SEF unit boundary and do not move to adjacent areas.

Given that in SEF the confining zone has proved competent over both millions of years and in the current CO_2 flooding, and that the SEF 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 ESSAU. CO_2 is delivered to the ESSAU via the Kinder Morgan CO_2 pipeline network. The CO_2 is supplied by a number of different sources including both natural and anthropogenic CO_2 sources. Specified amounts are drawn from an outside source pipeline based on contractual arrangements among suppliers of CO_2, purchasers of CO_2, and the pipeline operator.

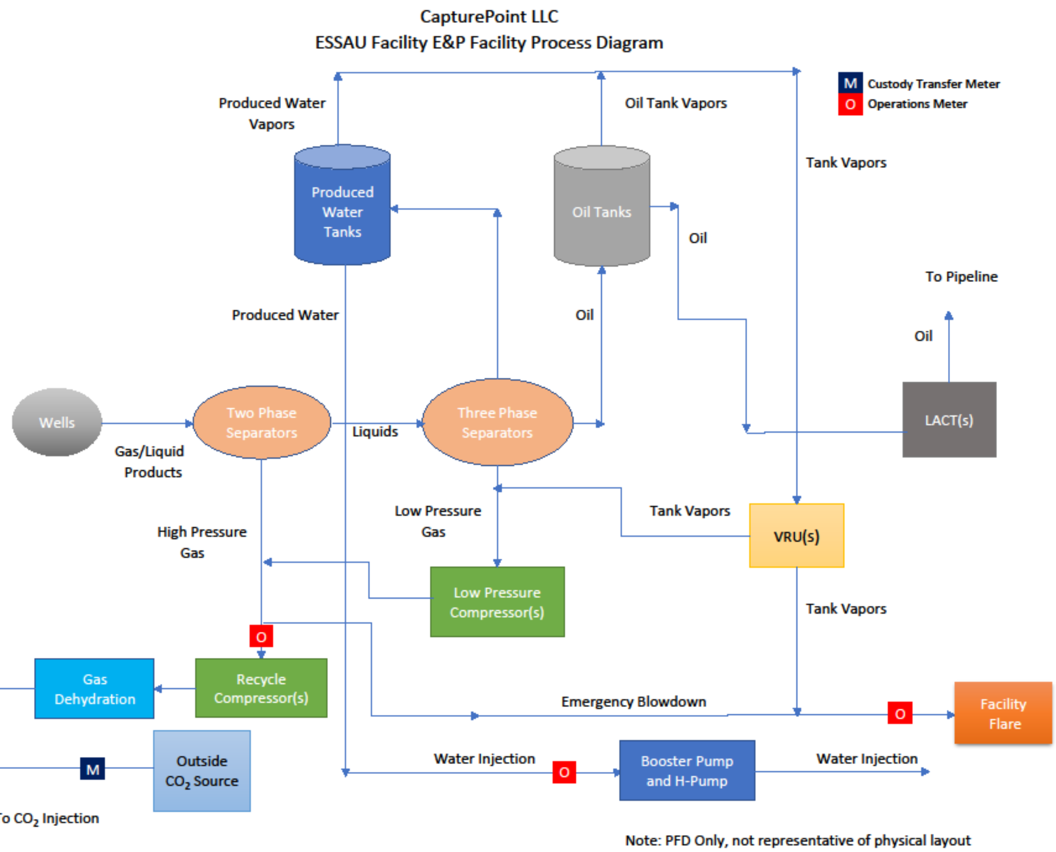

Figure 3-5 ESSAU Process Flow Diagram

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

i. CO_2 Distribution and Injection: The mass of CO_2 received at ESSAU 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 recycle compression facility 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 treatment and reinjection or disposal.

Figure 3-6 shows a simplified process flow diagram of the project facilities and equipment in the Lindoss Unit. CO_2 is delivered to the Lindoss Unit via the Kinder Morgan CO_2 pipeline network. The CO_2 is supplied by a number of different sources including both natural and anthropogenic CO_2 sources. Specified amounts are drawn from an outside source pipeline based on contractual arrangements among suppliers of CO_2, purchasers of CO_2, and the pipeline operator.

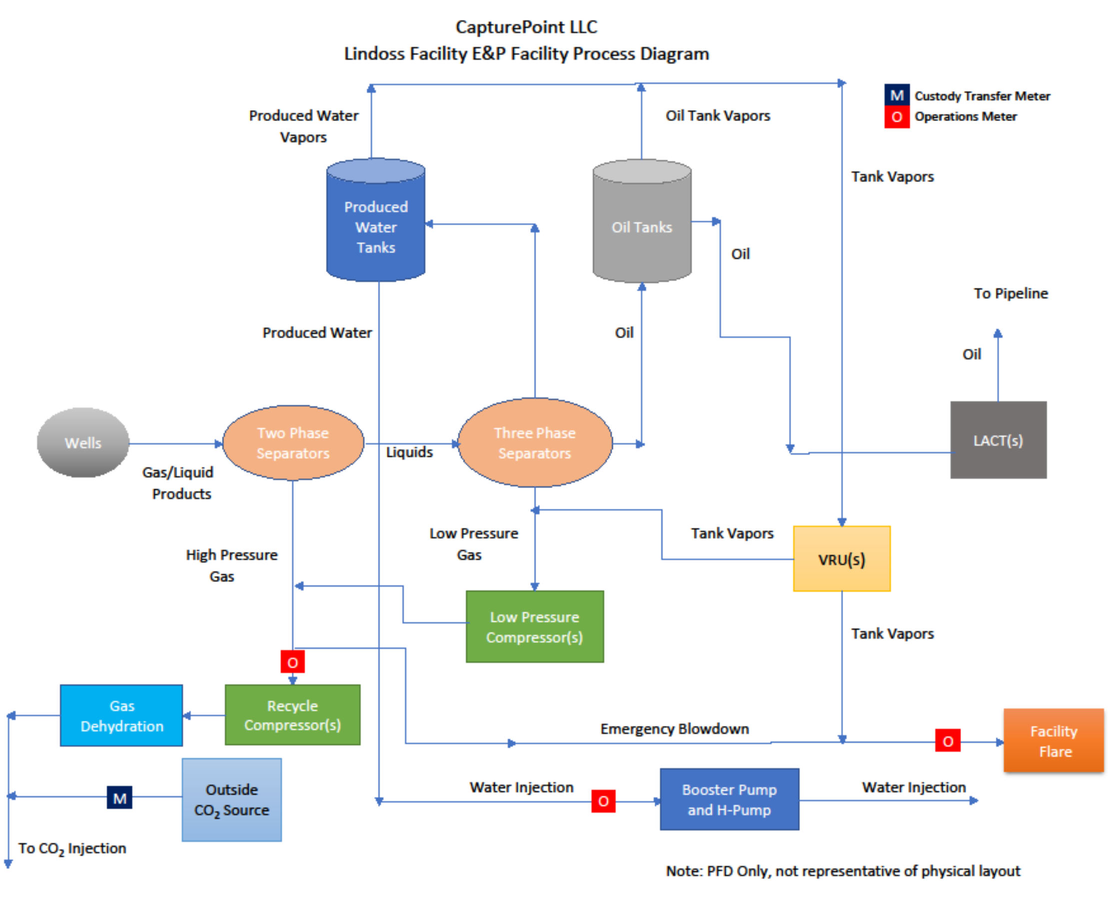

Figure 3-6 Lindoss Process Flow Diagram

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

i. CO_2 Distribution and Injection: The mass of CO_2 received at Lindoss 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 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.

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 H_2S as discussed in Section 7. They are gathered and sent to SATs 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 recycle compression facility 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 treatment and reinjection or disposal.

There are no physical differences between the ESSAU and Lindoss facilities.

3.3.1 Wells in the Seminole East Field

The TRRC has broad authority over oil and gas operations including primacy to implement UIC Class II wells. The rules are found in Texas Administrative Code 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 they 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 3.1 provides a well count by type and status. All these wells are in material compliance with TRRC rules.

Table 3.1 SEF Well Penetrations by Type and Status

TYPE	ACTIVE	INACTIVE	P & A	Total
PROD_OIL	32	16	0	**48**
INJ_WTR	16	4	0	**20**
INJ_WAG	18	0	0	**18**
INJ_SWD*	1	0	0	**1**
WSW**	1	4	0	**5**
P&A***	0	0	28	**28**
TOTAL	**68**	**24**	**28**	**120**

*INJ_SWD = Saltwater disposal wells
**WSW= Water source wells
***P&A = Plugged and Abandoned wells

As indicated in Figure 3-7, wells are distributed across the SEF. The well patterns currently undergoing CO_2 flooding are identified by black 5-spot pattern outlines and red symbols. CO_2 will be injected across the entire unit over the project life.

SEF CO_2-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Reservoir pressure in the SEF 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.

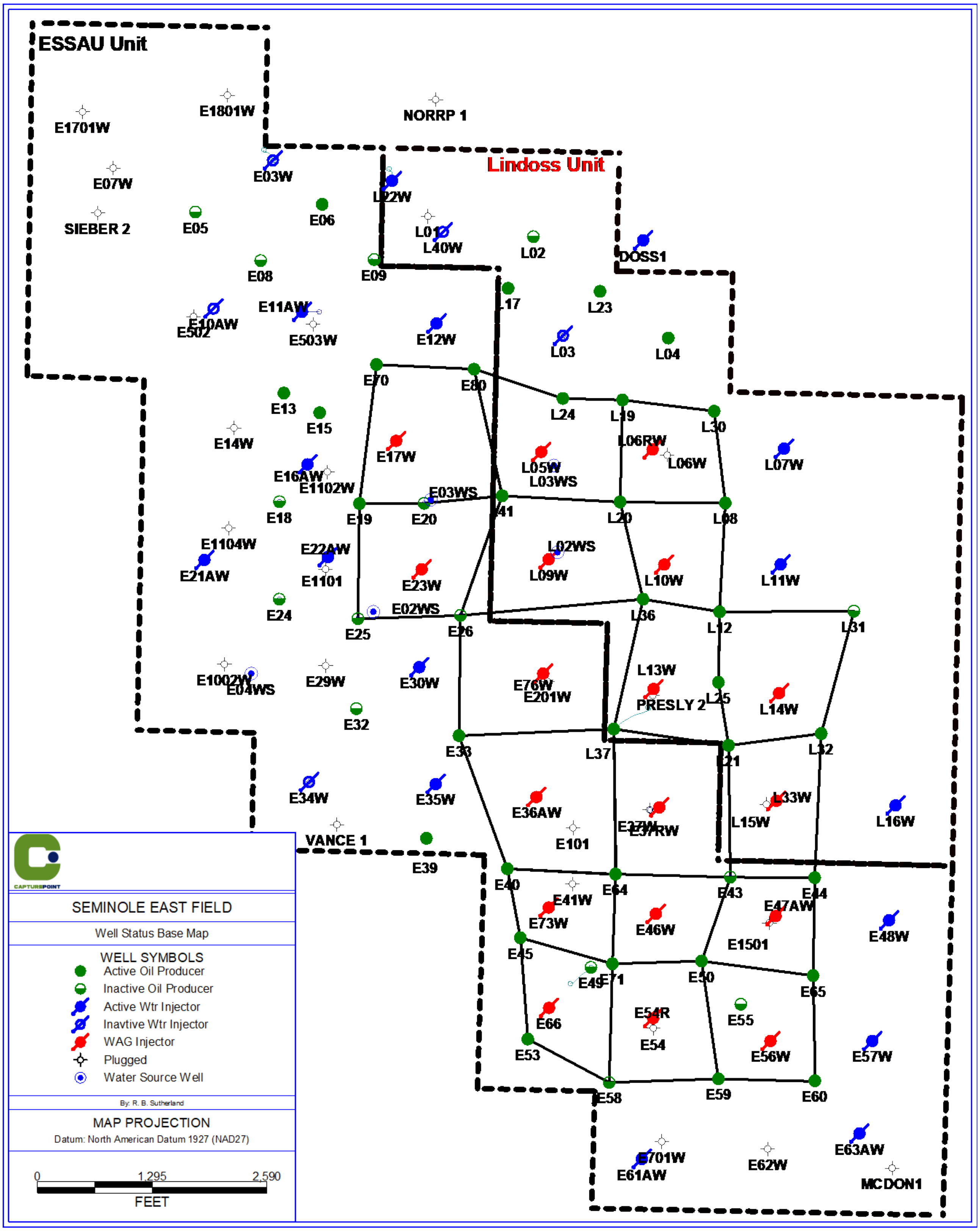

Figure 3-7 SEF Wells and Injection Patterns

3.4 Reservoir Forecasting

DPCs derived from analogous fields were used to project carbon dioxide enhanced oil recovery in the Seminole East Field. Most DPCs are derived from geologic and reservoir models. In the SEF case the DPC was derived from actual field performance from an analogous field.

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 3-8. The dimensioned projections of oil, CO_2 and water production, and CO_2 and water injection are made from DPCs using the original oil in place of an area of interest.

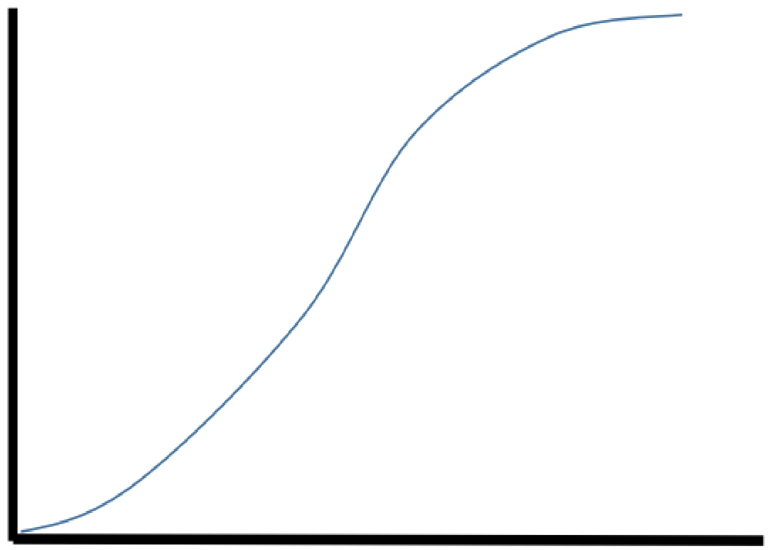

Figure 3-8 Dimensionless performance curve plot

The SEF DPC was calculated from the cumulative production and injection from an analogous field. The SEF DPC was used on each pattern in the SEF 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 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 laterally or vertically 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 ESSAU and Lindoss Unit boundaries plus the required ½ mile buffer.

Figure 3-7 displays wells that have CO2 retention on the 680 acres that have been under CO_2 injection since project initialization. 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 (158 BCF) is limited to the amount of space available by the removal of the produced hydrocarbon. The projection indicates that there is pore space available to store approximately .51 decimal fraction of HCPV amounting to 32 MMRB (80.2 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 80.2 BCF plus an all-around buffer zone of one-half mile. Figure 4-1 shows the map of the storage area outline (dashed red line). This calculation showed 1000 acres would be needed to store the 80.2 BCF. This is a lot less than the 2045 acres in the SEF outline.

4.2. Maximum Monitoring Area

The Maximum Monitoring Area (MMA) is defined by the ESSAU and Lindoss Unit boundaries plus the required ½ mile buffer as required by 40 CFR §98.440-449 (Subpart RR). The MMA would be the same as the AMA since the plume location is less than the Unit area.

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 SEF. The Specified Period will be shorter than the period of production from the SEF.

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 SEF is collected for use in operations management. Reservoir pressure is not forecasted to change appreciably since the IWR will be maintained at approximately 1.0. 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).

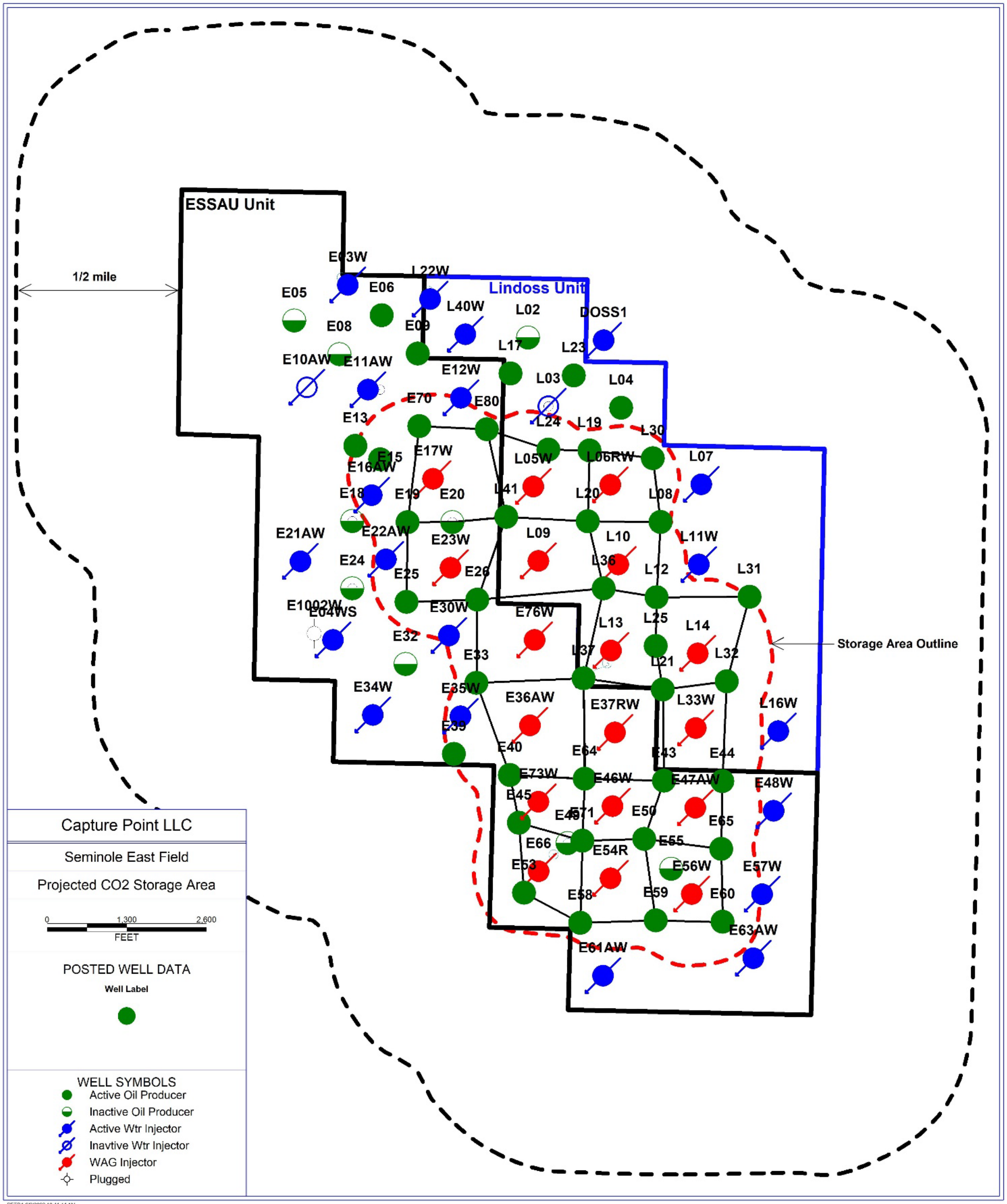

Figure 4-1 Estimated potential CO_2 storage area for SEF

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

In the roughly 60 years since the SEF 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 Well Bores
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the SEF
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 Wellbores

As part of the TRRC requirement to initiate CO_2 flooding, an extensive review of all SEF 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 SEF 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 beam pumped producing wells,
- CO_2 flood electrical submersible pump (ESP) producing wells, and
- CO_2 WAG 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 SEF 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 SEF 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 are investigated and addressed. CapturePoint's experience, from over 10 years of operating CO_2-EOR projects, is that such leakage is very rare.

- 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 the 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 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 and reported and quantified.

Based on ongoing monitoring activities and review of the potential leakage risks posed by well bores, it is concluded that the risk of CO_2 leakage through well bores is being mitigated by detecting problems as they arise and quantifying any leakage that does occur.

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 little to no risk 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 1.0 is also maintained. Both measures mitigate the potential for inducing faults or fractures. As a safeguard, WAG skids are continuously monitored.

5.3. Natural or 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 SEF.

To evaluate this potential risk at SEF, CapturePoint has reviewed the nature and location of seismic events in West Texas. Some of the recorded earthquakes in West Texas are far removed from any injection operation. These 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 M0.5 or greater in the Permian Basin since 1966 indicates that none have occurred in the SEF; the closest took place in 1992 approximately 30 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 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 SEF. 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 (GIS) site[3] for seismic signals that could indicate the creation of potential leakage pathways in the SEF.

[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/

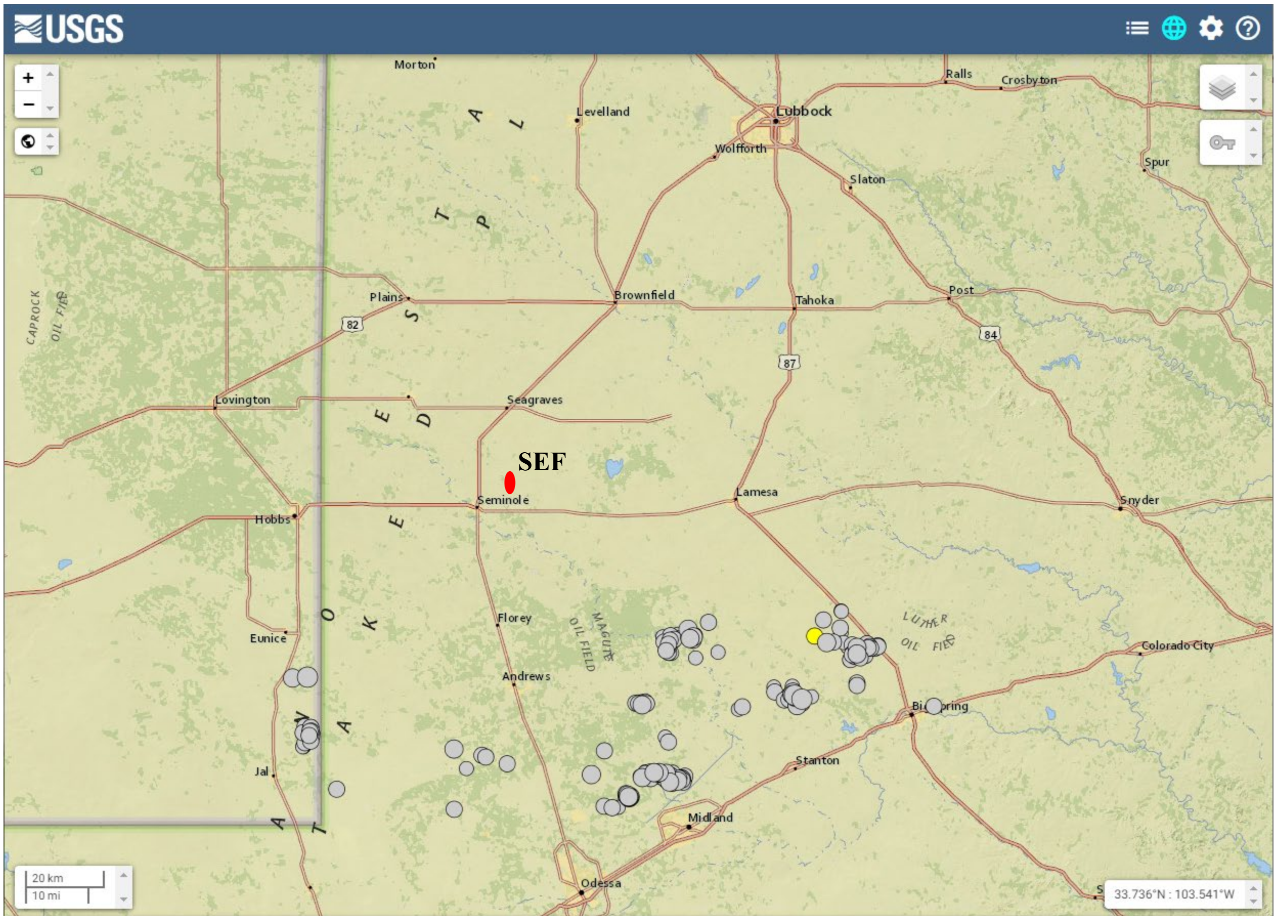

Figure 5-1 USGS earthquakes (+1.0 magnitude) for last 56 years)

5.4. Previous Operations

CO_2 flooding was initiated in SEF in 2013. 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 SEF. These practices ensure that that there are no unknown wells within SEF and that the risk of migration from older wells has been sufficiently mitigated. The successful experience with CO_2 flooding in SEF demonstrates that the confining zone has not been impaired by previous operations.

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 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. 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).

5.6. Lateral Migration Outside the Seminole East Field

It is highly unlikely that injected CO_2 will migrate downdip and laterally outside the SEF because of the nature of the geology and the approach used for injection. Over long periods of time, injected CO_2 will tend to rise vertically towards the Upper San Andres and continue towards the point in the SEF 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. Water Curtain Injection (WCI) methods are employed during CO_2-EOR operations to prevent CO_2 lateral migration out of the unit boundary. Continuous WCI operations are conducted at the SEF unit boundaries to create a pressure barrier to contain injected fluids within the SEF. Finally, the total volume of fluids contained in the SEF will stay relatively constant. Based on site characterization and planned and projected operations it is estimated that the total volume of stored CO_2 will be considerably less than calculated capacity.

5.7. Drilling in the Seminole East 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 SEF is conducted in accordance with TRRC rules. CapturePoint's visual inspection process, including routine site visits, will identify unapproved drilling activity in the SEF.

In addition, CapturePoint intends to operate SEF 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 SEF 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 into the formations beneath them. As mentioned in Section 3.2 "The San Andres is a stratified reservoir. The stratification is due to tidal movements that occurred across the shoals. The tidal movements formed a stacked sequence of shoals with alternating thin intertidal

deposits. The thin intertidal deposits are anhydritic carbonate mudstone layers and result in effective vertical permeability barriers (supported by core data). These barriers are continuous over the entire field and vary in thickness from two to ten feet with most averaging three to four feet in thickness."

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.

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 (well bores), 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.

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 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 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
Diffuse leakage through the seal	Injection pressure is continuously monitored and unexplained changes in injection pressure that might indicate leakage would trigger investigation as to the cause.	Conduct an injection radioactive tracer survey. If verified, well is shut in and workover crews respond within days.
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

5.10. Summary

The structure and stratigraphy of the San Andres reservoir in the SEF 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 SEF 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 SEF 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 SEF follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), 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 & 3-6, 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 SEF. 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 inlet to the RCF.
- CO_2 that is entrained in produced oil, as indicated in Figure 3-5 & 3-6, is calculated using volumetric flow through the custody transfer 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 SEF. 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. The Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.

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, 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 SEF. 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

SEF 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 SEF. 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 SEF. 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 Greenhouse 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 SEF 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 worn by all field personnel at all times and are permanent throughout the field at ground level, is used as a last method to detect leakage from wellbores. The H_2S monitor 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. Currently the concentration of H_2S in the recycled or produced gas is in excess of 18,000 ppm making leak detection viable. Thus, detected H_2S leaks will be investigated in order 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, 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 equipment, the CO_2 content of produced oil, and 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 equipment, the CO_2 content of produced oil, and vented CO_2, as required under 40 CFR Part 98 Subpart W.

6.2. To Demonstrate that Injected CO2 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 SEF 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 reservoir pressure that 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 and as such 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 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 H_2S monitors throughout the field at ground level to detect H_2S 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 and 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

To account for the potential propagation of error that would result if volume data from flow meters at each injection and production well were utilized, it is proposed to use the data from custody and operations meters on the main system pipelines to determine injection and production volumes used in the mass balance. 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 of the well head meters within the SEF.

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 Kinder Morgan 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.

$$CO_2T,r = \sum_{p=1}^{4} (Q_{p,r} - S_{r,p})*D*C_{CO2,r,p} \qquad \text{(Eq. RR-2)}$$

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 a site well in quarter p (standard cubic meters).

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

$C_{CO2,r,r}$ = 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 SEF's method of receiving CO_2 and requirements at Subpart RR §98.444(a):

- All delivery to the SEF is used within the unit so no quarterly flow redelivered, and Sr,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 SEF 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 output of the RCF (see Figure 3-5). 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:

$$CO_2u = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO2,p,u} \qquad \text{(Eq. RR-5)}$$

where:

CO_2u = Annual CO_2 mass recycled (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.

$C_{CO2,p,u}$ = 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-3) and Mass of CO_2 Recycled (modified RR-5).

$$CO_{2I} = CO_2 + CO_2u$$

8.3. Mass of CO_2 Produced

The Mass of CO_2 Produced at the SEF 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:

$$CO_{2w} = \sum_{p=1}^{4} Qp,w * D * C_{CO2,p,w} \qquad \text{(Eq. RR-8)}$$

where:

CO_{2W} = Annual CO_2 mass produced (metric tons).

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

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

$C_{CO2,pw}$ = CO_2 concentration measurement in flow for meter w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Inlet meters to RCF

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

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

where:

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

CO_2w = Annual CO_2 mass produced (metric tons) through all separators in the reporting year.

Xoil = 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).

8.4. Mass of CO_2 Emitted by Surface Leakage

The total annual Mass of CO_2 emitted by Surface Leakage will be calculated and reported using an approach that is tailored to specific leakage events and relies on 40 CFR Part 98 Subpart W reports of equipment leakage. 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 a number of 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 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. Further, the Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.

Equation RR-10 in §98.433 will be used to calculate and report the Mass of CO_2 emitted by Surface Leakage:

$$CO_{2E} = \sum_{x=1}^{x} CO_{2}x \qquad \text{(Eq. RR-10)}$$

where:

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

CO_2x = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

8.5. Mass of CO_2 Sequestered in Subsurface Geologic Formation

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

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \qquad \text{(Eq. RR-11)}$$

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) net of CO_2 entrained in oil 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 this part.

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 this part.

8.6. Cumulative Mass of CO_2 Reported as Sequestered in Subsurface Geologic Formation

The total annual volumes obtained using equation RR-11 in §98.443 will be summed to arrive at the Cumulative Mass of CO_2 Sequestered in Subsurface Geologic Formations.

9. MRV Plan Implementation Schedule

This MRV plan will be implemented starting January 2023 or within 90 days of EPA approval, whichever occurs later. Other GHG 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 program will be in effect during the Specified Period, during which time the SEF 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 SEF. 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 Program

10.1. Monitoring QA/QC

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.
- The quarterly flow rate of the produced gas is measured at the flow meters located at the RCF inlet.

CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2

These volumes are measured in conformance with the monitoring and QA/QC 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 nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.
- The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

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 SEF 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 and number, API number, type, and status for active wells in the SEF as of August 2021. 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_WTR refers to wells that inject water
  - INJ_WAG refers to wells that inject water and CO_2 Gas
  - INJ_SWD refers to wells that inject water for disposal
  - SWS refers to wells that supply water
  - 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

Well Name	API Number	Well Type	Status
DCB Doss 1 (INJ)	4216534180	INJ_WTR	ACTIVE
ESSAU 02WS	4216530590	WSW	SHUT_IN
ESSAU 03W (INJ)	4216534370	INJ_WTR	SHUT_IN
ESSAU 03WS	4216534343	WSW	ACTIVE
ESSAU 04WS	4216532191	WSW	SHUT_IN
ESSAU 05	4216581203	PROD_OIL	SHUT_IN
ESSAU 06	4216533021	PROD_OIL	ACTIVE
ESSAU 07W (INJ)	4216530591	P&A	INACTIVE
ESSAU 08	4216533913	PROD_OIL	SHUT_IN
ESSAU 09	4216534600	PROD_OIL	SHUT_IN
ESSAU 1002W	4216510149	P&A	INACTIVE
ESSAU 101	4216501006	P&A	INACTIVE
ESSAU 10AW (INJ)	4216533614	INJ_WTR	SHUT_IN
ESSAU 1101	4216510058	P&A	INACTIVE
ESSAU 1102W (INJ)	4216510079	P&A	INACTIVE
ESSAU 1104W (INJ)	4216510241	P&A	INACTIVE
ESSAU 11AW (INJ)	4216533615	INJ_WTR	ACTIVE
ESSAU 12W (INJ)	4216533403	INJ_WTR	ACTIVE

Well Name	API Number	Well Type	Status
ESSAU 13	4216534028	PROD_OIL	ACTIVE
ESSAU 14W (INJ)	4216510072	P&A	INACTIVE
ESSAU 15	4216534110	PROD_OIL	ACTIVE
ESSAU 1501	4216510413	P&A	INACTIVE
ESSAU 16AW (INJ)	4216534371	INJ_WTR	ACTIVE
ESSAU 1701W (INJ)	4216510246	P&A	INACTIVE
ESSAU 17W (INJ)	4216534108	INJ_WAG	ACTIVE
ESSAU 18	4216533910	PROD_OIL	SHUT_IN
ESSAU 1801W (INJ)	4216510250	P&A	INACTIVE
ESSAU 19	4216533912	PROD_OIL	ACTIVE
ESSAU 20	4216534111	PROD_OIL	SHUT_IN
ESSAU 201W (INJ)	4216500168	P&A	INACTIVE
ESSAU 21AW (INJ)	4216533819	INJ_WTR	ACTIVE
ESSAU 22AW (INJ)	4216533908	INJ_WTR	ACTIVE
ESSAU 23W (INJ)	4216501005	INJ_WAG	ACTIVE
ESSAU 24	4216533906	PROD_OIL	SHUT_IN
ESSAU 25	4216533914	PROD_OIL	SHUT_IN
ESSAU 26	4216534112	PROD_OIL	SHUT_IN
ESSAU 29W (INJ)	4216501019	P&A	INACTIVE
ESSAU 30W (INJ)	4216501007	INJ_WTR	ACTIVE
ESSAU 32	4216533909	PROD_OIL	SHUT_IN
ESSAU 33	4216534031	PROD_OIL	ACTIVE
ESSAU 34W (INJ)	4216534109	INJ_WTR	SHUT_IN
ESSAU 35W (INJ)	4216501008	INJ_WTR	ACTIVE
ESSAU 36AW (INJ)	4216530147	INJ_WAG	ACTIVE
ESSAU 37RW (INJ)	4216538478	INJ_WAG	ACTIVE
ESSAU 37W (INJ)	4216502594	P&A	INACTIVE
ESSAU 39	4216534106	PROD_OIL	ACTIVE
ESSAU 40	4216534104	PROD_OIL	ACTIVE
ESSAU 41W (INJ)	4216501012	P&A	INACTIVE
ESSAU 43	4216534601	PROD_OIL	SHUT_IN
ESSAU 44	4216534652	PROD_OIL	ACTIVE
ESSAU 45	4216534107	PROD_OIL	ACTIVE
ESSAU 46W (INJ)	4216500002	INJ_WAG	ACTIVE
ESSAU 47AW (INJ)	4216533014	INJ_WAG	ACTIVE
ESSAU 48W (INJ)	4216533015	INJ_WTR	ACTIVE
ESSAU 49	4216534049	PROD_OIL	SHUT_IN
ESSAU 50	4216533907	PROD_OIL	ACTIVE
ESSAU 502	4216510251	P&A	INACTIVE
ESSAU 503W (INJ)	4216530452	P&A	INACTIVE
ESSAU 53	4216533911	PROD_OIL	SHUT_IN
ESSAU 54	4216502901	P&A	INACTIVE
ESSAU 54R (INJ)	4216538339	INJ_WAG	ACTIVE

Well Name	API Number	Well Type	Status
ESSAU 55	4216501046	PROD_OIL	SHUT_IN
ESSAU 56W (INJ)	4216534030	INJ_WAG	ACTIVE
ESSAU 57W (INJ)	4216510252	INJ_WTR	ACTIVE
ESSAU 58	4216534105	PROD_OIL	SHUT_IN
ESSAU 59	4216533905	PROD_OIL	ACTIVE
ESSAU 60	4216534048	PROD_OIL	ACTIVE
ESSAU 61AW (INJ)	4216533820	INJ_WTR	ACTIVE
ESSAU 62W (INJ)	4216502902	P&A	INACTIVE
ESSAU 63AW (INJ)	4216534029	INJ_WTR	ACTIVE
ESSAU 64	4216534027	PROD_OIL	ACTIVE
ESSAU 65	4216534026	PROD_OIL	ACTIVE
ESSAU 66W (INJ)	4216501003	INJ_WAG	ACTIVE
ESSAU 70	4216537356	PROD_OIL	ACTIVE
ESSAU 701W (INJ)	4216501011	P&A	INACTIVE
ESSAU 71	4216537747	PROD_OIL	ACTIVE
ESSAU 73W (INJ)	4216537748	INJ_WAG	ACTIVE
ESSAU 76W (INJ)	4216538479	INJ_WAG	ACTIVE
ESSAU 80	4216538294	PROD_OIL	ACTIVE
Lindoss 01	4216533392	P&A	INACTIVE
Lindoss 02	4216533467	PROD_OIL	SHUT_IN
Lindoss 02WS	4216534452	WSW	SHUT_IN
Lindoss 03 (INJ)	4216533284	INJ_WTR	SHUT_IN
Lindoss 03WS	4216534453	WSW	SHUT_IN
Lindoss 04	4216533041	PROD_OIL	ACTIVE
Lindoss 05W (INJ)	4216532364	INJ_WAG	ACTIVE
Lindoss 06RW (INJ)	4216538303	INJ_WAG	ACTIVE
Lindoss 06W (INJ)	4216532733	P&A	INACTIVE
Lindoss 07W (INJ)	4216532883	INJ_WTR	ACTIVE
Lindoss 08	4216533452	PROD_OIL	ACTIVE
Lindoss 09W (INJ)	4216532200	INJ_WAG	ACTIVE
Lindoss 10W (INJ)	4216532606	INJ_WAG	ACTIVE
Lindoss 11W (INJ)	4216532757	INJ_WTR	ACTIVE
Lindoss 12	4216533453	PROD_OIL	ACTIVE
Lindoss 13W (INJ)	4216533422	INJ_WAG	ACTIVE
Lindoss 14W (INJ)	4216531826	INJ_WAG	ACTIVE
Lindoss 15 (INJ)	4216531527	P&A	INACTIVE
Lindoss 16W (INJ)	4216532025	INJ_WTR	ACTIVE
Lindoss 17	4216534440	PROD_OIL	ACTIVE
Lindoss 19	4216534442	PROD_OIL	ACTIVE
Lindoss 20	4216534441	PROD_OIL	ACTIVE
Lindoss 21	4216534602	PROD_OIL	ACTIVE
Lindoss 22W (INJ)	4216534604	INJ_WTR	ACTIVE
Lindoss 23	4216536582	PROD_OIL	ACTIVE

Well Name	API Number	Well Type	Status
Lindoss 24	4216536583	PROD_OIL	ACTIVE
Lindoss 25	4216536581	PROD_OIL	ACTIVE
Lindoss 30	4216537352	PROD_OIL	ACTIVE
Lindoss 31	4216537345	PROD_OIL	SHUT_IN
Lindoss 32	4216537341	PROD_OIL	ACTIVE
Lindoss 33W (INJ)	4216537346	INJ_WAG	ACTIVE
Lindoss 36	4216537772	PROD_OIL	ACTIVE
Lindoss 37	4216538297	PROD_OIL	ACTIVE
Lindoss 40W (SWD)	4216538466	INJ_SWD	SHUT_IN
Lindoss 41	4216538296	PROD_OIL	ACTIVE
McDonald 1	4216502903	P&A	INACTIVE
Norrp 1	4216533505	P&A	INACTIVE
Presely 2	4216531620	P&A	INACTIVE
Sieber 2	4216510247	P&A	INACTIVE
Vance 1	4216501018	P&A	INACTIVE

12.2 Regulatory References

Regulations cited in this plan:

- Texas Administrative Code 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

AGA - American Gas Association

AMA - Active Monitoring Area

API - American Petroleum Institute

AoR - Area of Review

Bcf – 1 Billion Cubic Feet of Gas

CO_2 - Carbon Dioxide

DPC - Dimensionless Performance Curve

EPA - Environmental Protection Agency

EOR - Enhanced Oil Recovery

ESP - Electrical Submersible Pump

ESSAU - East Seminole San Andres Unit

FPP - Formation Parting Pressure (psi)

GHG - Greenhouse Gas

GHGRP - Greenhouse Gas Reporting Program

GIS - Geographical Information System

GPA - Gas Processors Association

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 – 1,000 Cubic Feet of Gas

NIST - National Institute of Standards and Technology

RB - Reservoir Barrels

RCF - Recycle Compression Facility

ROZ - Residual Oil Zone

SAT - Satellite Test Stations

SEF - Seminole East Field

TAC - Texas Administrative Code

TRRC - Texas Railroad Commission - Oil and Gas Division

UIC - Underground Injection Control

USGS - United States Geological Survey

WAG - Water Alternating with Gas

WCI - Water Curtain Injection

Request for Additional Information: Seminole East Field
May 12, 2022

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	Throughout the MRV plan, acronyms which have already been defined are defined again. We suggest removing repeated definitions for conciseness.	Repeated definitions were removed for conciseness.
2.	N/A	N/A	Both "feet" and apostrophes are used in the document in describing measurements. It is suggested one of these be used for consistency.	The document was changed to "feet" for consistency.
3.	TOC	2	"April 1st, 2022" is listed as a section in the Table of Contents. Please remove or clarify its meaning.	This section was removed.
4.	1	4	"CapturePoint LLC operates a CO_2-EOR project…" Both 'CO_2' and 'EOR' are used in the phrase above before they are defined. Please define these terms when they are first used.	The terms are now defined in the phrase first used.
5.	1	4	"…with a subsidiary or ancillary purpose…" Is the sequestration of CO_2 subsidiary or ancillary to the EOR operations in the East Seminole Field? These terms have distinctly different meanings, specifically, ancillary suggests that sequestration is necessary for normal operations.	Took out ancillary.
6.	3.1	5	"…East Seminole San Andres Unit (ESSAU)…" This term is already defined in the preceding section. It is only necessary to define an acronym the first time it is used.	Took out definitions. Used ESSAU.
7.	3.1	5	It would be useful to define "Residual Oil Zone (ROZ). Not all potential readers of this plan will know what this is.	Residual Oil Zone (ROZ) is now defined in the paragraph.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
8.	3.2	9	"There is more than enough pore space to sequester the planned CO_2 injection." We suggest changing the above phrase to '…to sequester the volume of CO_2 planned for injection' to improve clarity.	Done. The phrase was changed to '..sequester the volume of CO2 planned for injection'
9.	3.2	9	"Max CO_2 = Volume (RB) * $(1 - S_{wirr} - S_{orCO2}) / B_{CO2}$" In the equation above, it is unclear whether 'Volume (RB)' is one variable or two. We suggest choosing one symbol for the equation and defining it below as with the other variables.	Done. Volume was changed to "Pore Volume" and then defined below with the other variables.
10.	3.2	9	"CO_2 (max) = the maximum amount of storage capacity" In the equation this variable is referred to as 'Max CO_2'. Please edit one of the instances to maintain uniformity.	Done. CO2 (max) was changed to Max CO2.
11.	3.3	10	Figure 3-5 contains several labels, such as 'liquids' and 'produced water' that are located close to multiple flow lines. Please edit these labels to make it more clear which line they are associated with.	Labels edited correctly.
12.	3.3	11	"The CO_2 is supplied by a number of different sources, including both natural and anthropogenic CO_2 sources Specified amounts are drawn from an outside source pipeline based on contractual arrangements among suppliers of CO_2, purchasers of CO_2, and the pipeline operator." The sentences above are missing a comma or a period to separate them. Please correct this error.	Done. Placed a period between sources and Specified.
13.	3.3	10-11	Figures 3-5 and 3-6 appear to be identical. Similarly, the discussions in the subsections titled 'CO_2 Distribution and Injection', 'Produced Fluids Handling', and 'Water Treatment also appear to be identical. Are there any differences between the project facilities/injection processes for these two units?	There are no physical differences between these facilities. Each unit will have its own facility.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
14.	3.3	10-12	Additionally, the content under bullet 'ii.' that is repeated on these pages is a different font size than the rest of the body of the draft MRV plan. Please correct this to maintain uniformity.	Fixed the font size to match the rest of the body.
15.	3.3	10-12	"…recycle compression facility (RCF)…" "…recompression facility (RCF)…" From page 10 to 12 of the draft MRV plan the acronym 'RCF' is defined four times using two differing definitions. Please clarify.	RCF was changed to include one definition. The definition is recycle compression facility (RCF).
16.	3.3.1	13	"The Texas Railroad Commission (TRRC)…" TRRC was already defined in a preceding section.	Texas Railroad Commission was taken out.
17.	3.3.1	13	The 'Total' row and column in Table 3.1 contains incorrect values. Please correct them. Additionally, it is unclear as to why plugged and abandoned wells are given both a row and column in this table. Please explain.	The values were corrected. P&A wells are given both a row and column because they are neither active or inactive wells. They are wells that have been permanently plugged and abandoned.
18.	3.4	15	The role of the dimensionless performance curves in the MRV plan is not specified. Is it to provide a baseline against which perturbations/deviations can be assessed? Please clarify how the DPCs are used in MRV activities.	The section was updated to specify role of the dimensionless performance curves and clarify how the DPC's are used in the MRV activities.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
19.	3.4	15	"Most **dimensionless curves** are derived from geologic and reservoir models." "A **dimensionless curve** is a plot where everything is normalized by dividing by Hydrocarbon Pore Volume (HCPV)." "The SEF **dimensionless curve** was calculated from the cumulative production and injection from an analogous field. The SEF **dimensionless curve**…" It appears that dimensionless performance curves (defined as DPC in a preceding sentence) are being referred to here under a different name. We suggest editing these references to maintain uniformity.	These references were changed from "dimensionless curve" to "dimensionless performance curve" to maintain uniformity.
20.	4	15	"The Active Monitoring Area (AMA) is defined by the ESSAU and Lindoss Unit boundaries plus the required ½ mile buffer." Active monitoring area is defined at 40 CFR 98.449 as "the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase CO2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile. (2) The area projected to contain the free phase CO2 plume at the end of year t + 5". Please elaborate as to how you determined the expected extent of the CO_2 plume and the proposed AMA. Additionally, provide analogous information for the MMA.	Revised to include that the plume area at the end of injection was determined by volumetric calculation plus a buffer zone one-half mile. MMA would be the same as the AMA since the plume location is less than the Unit Area.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
21.	5.2	18	"…there are no known faults or fractures that transect the San Andres reservoir in the project area. As a result, there is **no risk of leakage** due to fractures or faults." Likelihood of leakage through faults and fractures may be very low, but is not impossible (given the discussion of measures to not exceed FPP). We recommend revising this characterization.	Revised wording to read "As a result, there is little to no risk of leakage due to fractures or faults."
22.	5.7	20	"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." It is unclear whether the above sentence is sourced from TRRC regulations or is the opinion of the author of the MRV plan. Please clarify.	Added source. 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).
23.	5.9	20-21	Diffuse leakage through the seal is listed as a potential leakage pathway, but it does not have a corresponding monitoring strategy in section 5.9. Please ensure that all leakage pathways identified have a corresponding monitoring strategy.	Strategy incorporated into Table 5.1.
24.	6.1.5	25	"The H2S **monitors** detection limit is 10 ppm…" The plan mentions H_2S detection as a proxy for CO_2 leakage detection. We recommend adding information about the H_2S concentration in the fluids. Additionally, please either remove the 's' from the end of the word 'monitors' in the phrase above or add an apostrophe to indicate possession.	The 's' was removed from monitor. Information was added about the H_2S concentration. Currently the concentration of H_2S in the recycled or produced gas is over 18,000 ppm.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
25.	7	27	"Ongoing operational monitoring **have** provided data for establishing baselines and **will utilized** to…" It appears that there are two typos in the above phrase, specifically regarding the word 'have' and the phrase 'will utilized'. If you determine that these are errors, then please correct them.	Corrected the typos to read "Ongoing operational monitoring has provided data for establishing baselines and will be utilized to…"
26.	7	27	"The Annual Subpart RR Report will provide an **estimate the** amount…" It appears that the word 'of' is missing from the above phrase, please add it if you determine this is an error.	Corrected the phrase to include the word "of".
27.	8.3	30	"Xoil = Mass of entrained CO_2 in oil in the reporting year measured utilizing commercial meters and electronic flow-measurement devices at each point of custody transfer. The mass of CO_2 will be calculated by multiplying the total volumetric rate by the CO_2 concentration." Under Subpart RR, X is "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)." Equation RR-9 in the MRV plan (and the definition for X) appears to be inconsistent with 40 CFR 98.443(d)(3). Please note that no modification of equations is allowed under Subpart RR, so please revise your MRV plan to reflect this. Additionally, please include information about how your facility would calculate X. For example, how would the concentration/percentage of entrained CO_2 be measured/calculated?	MRV plan revised with no modification to equations. Information added on how facility would calculate X.

CapturePoint LLC Seminole East Field Subpart RR Monitoring, Reporting and Verification (MRV) Plan

April 6th, 2022

Table of Contents

1. Introduction

CapturePoint LLC operates a CO_2-EOR project in the Seminole East Field (SEF) located in Gaines County, Texas, approximately one and one-half miles northeast of the town of Seminole 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 SEF is comprised of the East Seminole San Andres Unit (ESSAU) and the Lindoss Unit. Production is from the San Andres formation at an average depth of 5500'. 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 Seminole East Field during a specified period of injection.

2. Facility Information

2.1. Reporter Number

562518 – Seminole East Field

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 SEF (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 SEF are currently classified as UIC Class II wells.

2.3. Existing Wells

Wells in the Seminole East Field are identified by name and number, API number, type, and status. The list of wells as of February 2022 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 Seminole East Field an oil field located in West Texas that was first produced more than 60 years ago. SEF is comprised of the East Seminole San Andres Unit (ESSAU) and the Lindoss Unit. The two units abut 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 units in the Seminole East Field. In addition, the two units 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 reservoir similarities, one MRV Plan is being prepared for the two units in the SEF and any important differences between the units will be noted in the MRV plan. CO_2 flooding was initiated in 2013 in both units. The field is well characterized and is suitable for secure geologic storage. CapturePoint uses a water alternating with gas (WAG) injection process and maintains an injection to withdrawal ratio (IWR) at or near 1.0.

3.1. Project Characteristics

The Seminole East Field was discovered in 1959 and started producing in the same year. The SEF consists of two units, the East Seminole San Andres Unit (ESSAU) and the Lindoss Unit. The ESSAU began to produce in May 1959 and waterflood was initiated in January 1983. CO_2 flooding was initiated in 2013, in both the Main Pay and Residual Oil Zone (ROZ). The Lindoss Unit began to produce in November 1979 and waterflood was initiated in July 1984. CO_2 flooding was initiated in October 2013, also in the Main Pay and ROZ.

A long-term forecast for both ESSAU and Lindoss was developed using a dimensionless curve approach. Using this approach, a total injection of approximately 9 million tonnes of 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 SEF.

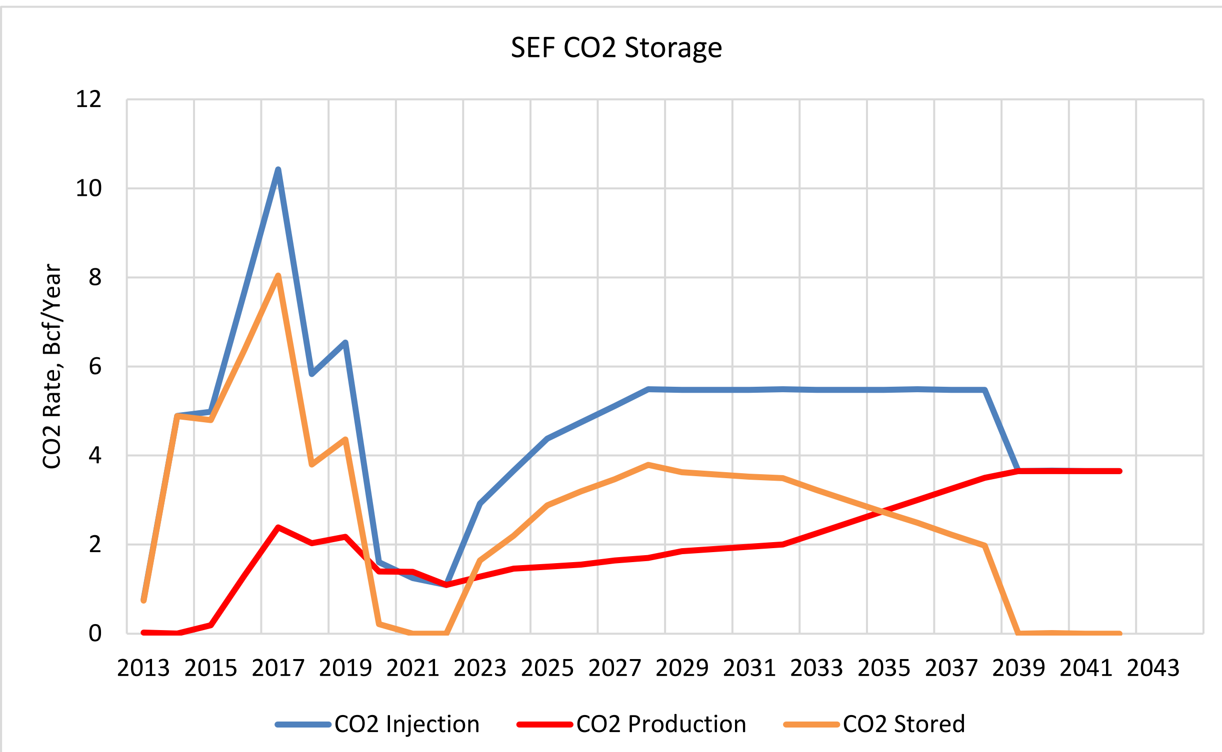

Figure 3-1 SEF Historic and Forecast CO_2 Injection, Production, and Storage

3.2. Environmental Setting

The SEF is located in the NE portion of the Central Basin Platform in West Texas (See Figure 3-2).

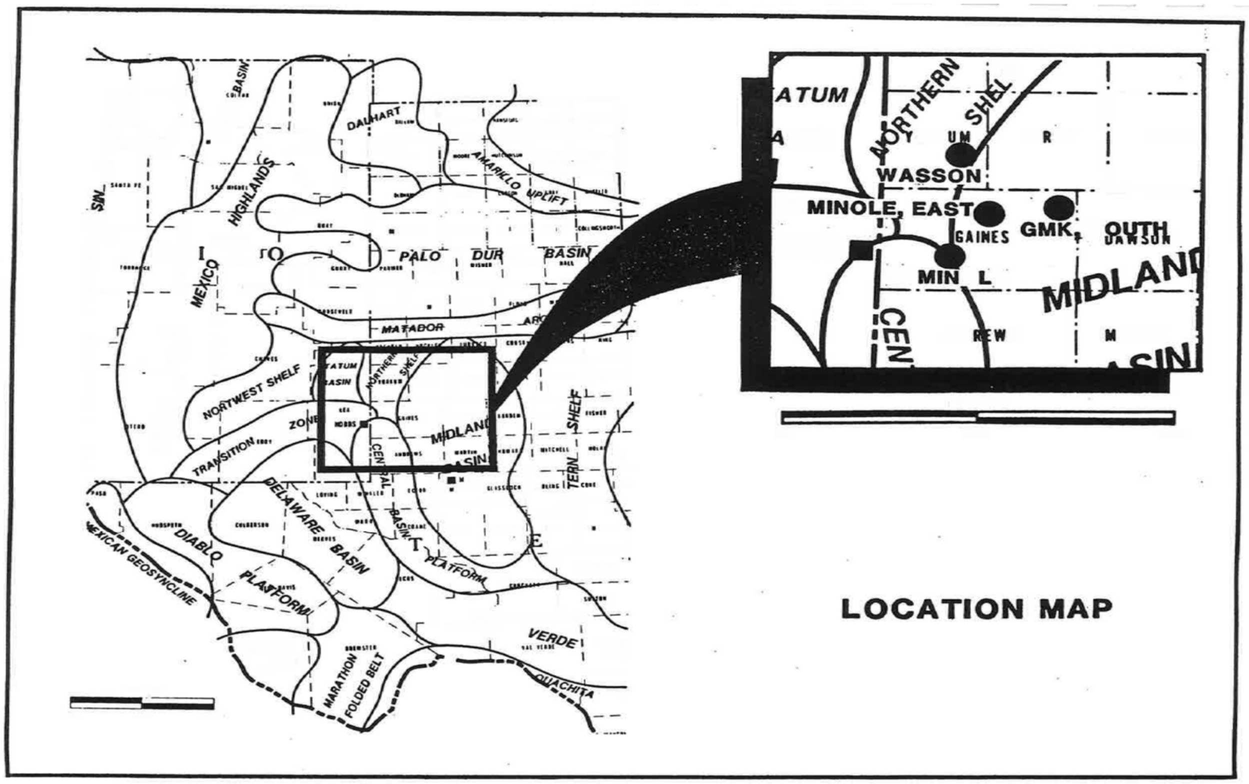

Figure 3-2 Location of SEF in West Texas

The productive formation is the Upper Permian San Andres and consists of anhydritic dolomite with vuggy, moldic, and intercrystalline porosity as seen in the Seminole East Generalized Stratigraphic Section Figure 3-3. The environment of deposition was shallow tidal water deposits with oolitic shoals ("carbonate sands") developed on tidal flats. Secondary porosity later developed from dolomitization.

The structure is an elliptical anticline oriented in a northwest to southeast direction (See Figure 3-4). The anticlinal structure is rimmed to the east and west by two arcuate shoals which merge toward the northwest and southeast to form an elliptical shaped structure with an intershoal "sag" in the center of the field. The east half of the field is the front, or "seaward," shoal and the west half is the back, or "landward" shoal.

The San Andres is a stratified reservoir. The stratification is due to tidal movements that occurred across the shoals. The tidal movements formed a stacked sequence of shoals with alternating thin intertidal deposits. The thin intertidal deposits are anhydritic carbonate mudstone layers and result in effective vertical permeability barriers (supported by core data). These barriers are continuous over the entire field and vary in thickness from two to ten feet with most averaging three to four feet in thickness. Detailed log analysis shows these barriers to be of very high-water saturation (+75%) with the adjacent zones of lower (+/- 24%) water saturation. The high-water saturation zones noted from log analysis are correlatable to very low permeability zones ("tight" and unproductive) in the available cores.

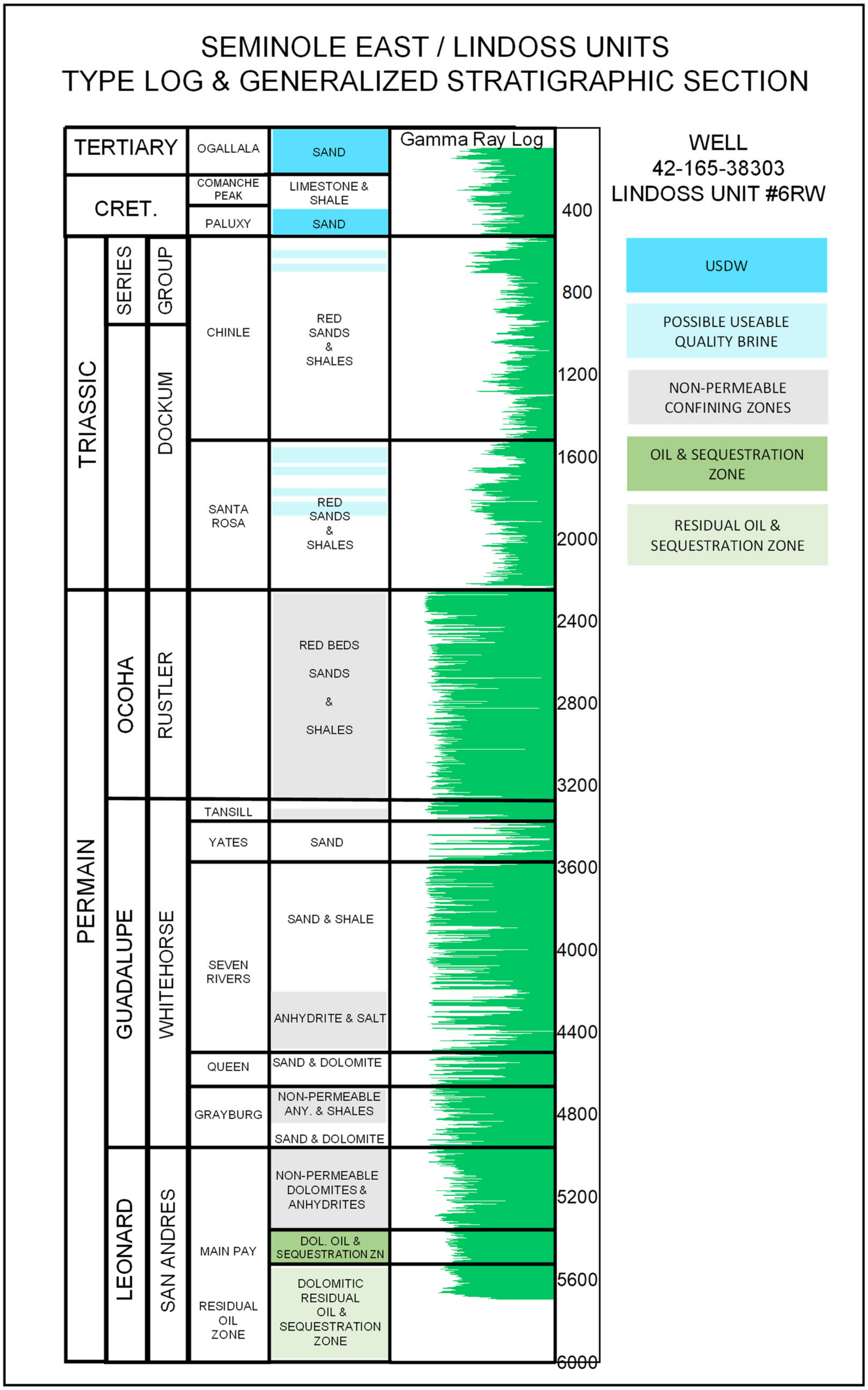

Figure 3-3 Local Area Structure on Top of San Andres

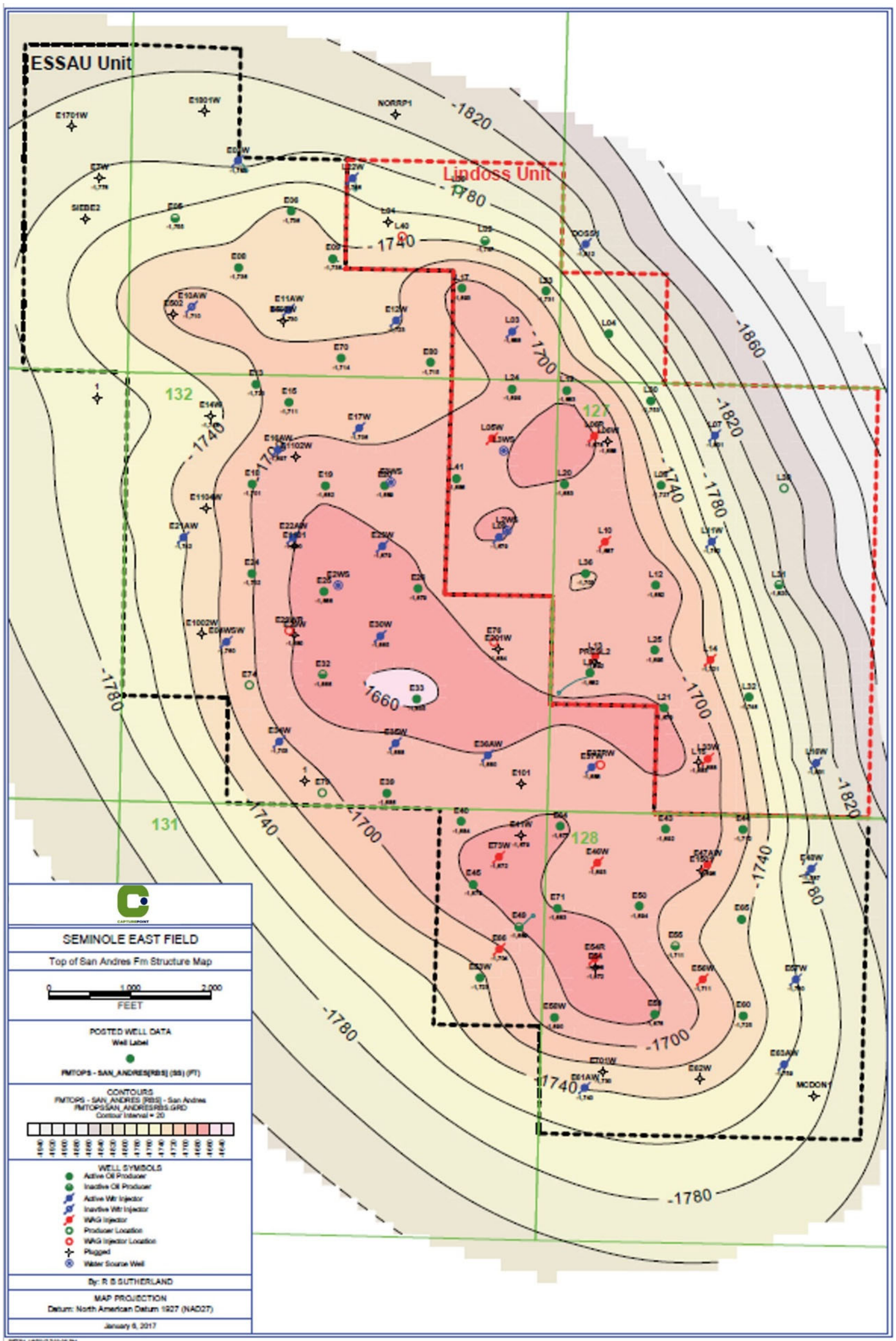

Figure 3-4 Local Area Structure on Top of San Andres

Log and core analyses identify seven major stratified zones in the Seminole East Field. The first porous zone or Main Pay is located nearly 400 feet into the San Andres Formation. Due to hydrodynamic flow in the San Andres aquifer, a thick residual oil zone (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 to sequester the planned CO_2 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 Central Basin Platform is negligible. The volume of CO_2 storage is based on the estimated total pore space within SEF. The total pore space within SEF, from the top of the reservoir down to the base of the residual oil zone, is calculated to be 104.2 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 158 Bcf (9 million tonnes) of CO_2 storage in the reservoir. CO_2 will occupy only 50% of the total calculated storage capacity by the year 2042 based on the current project forecast.

Table 3-1 Calculation of Maximum Volume of CO_2 Storage Capacity at Seminole East Field (SEF)

Top of Main Pay to Bottom of Residual Oil Zone (ROZ)	
Variables	SEF Outline
Pore Volume (**RB**)	104,199,573
B$_{CO2}$ (RB/Mscf)	0.40
S$_{wirr}$	0.24
S$_{or\ CO2}$	0.15
Max CO_2 (MCF)	158,904,349
Max CO_2 (BCF)	158

Max CO_2 = Volume (**RB**) * (1 – **S**wirr – **S**or $_{CO2}$) / **B**$_{CO2}$

Where:
CO_2 (max) = the maximum amount of storage capacity
B_{CO2} = the formation volume factor for CO_2
S_{wirr} = the irreducible water saturation
Sor $_{CO2}$ = 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 is being utilized in SEF 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 SEF unit boundary and do not move to adjacent areas.

Given that in SEF the confining zone has proved competent over both millions of years and in the current CO_2 flooding, and that the SEF 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 ESSAU. CO_2 is delivered to the ESSAU via the Kinder Morgan CO_2 pipeline network. The CO_2 is supplied by a number of different sources including both natural and anthropogenic CO_2 sources. Specified amounts are drawn from an outside source pipeline based on contractual arrangements among suppliers of CO_2, purchasers of CO_2, and the pipeline operator.

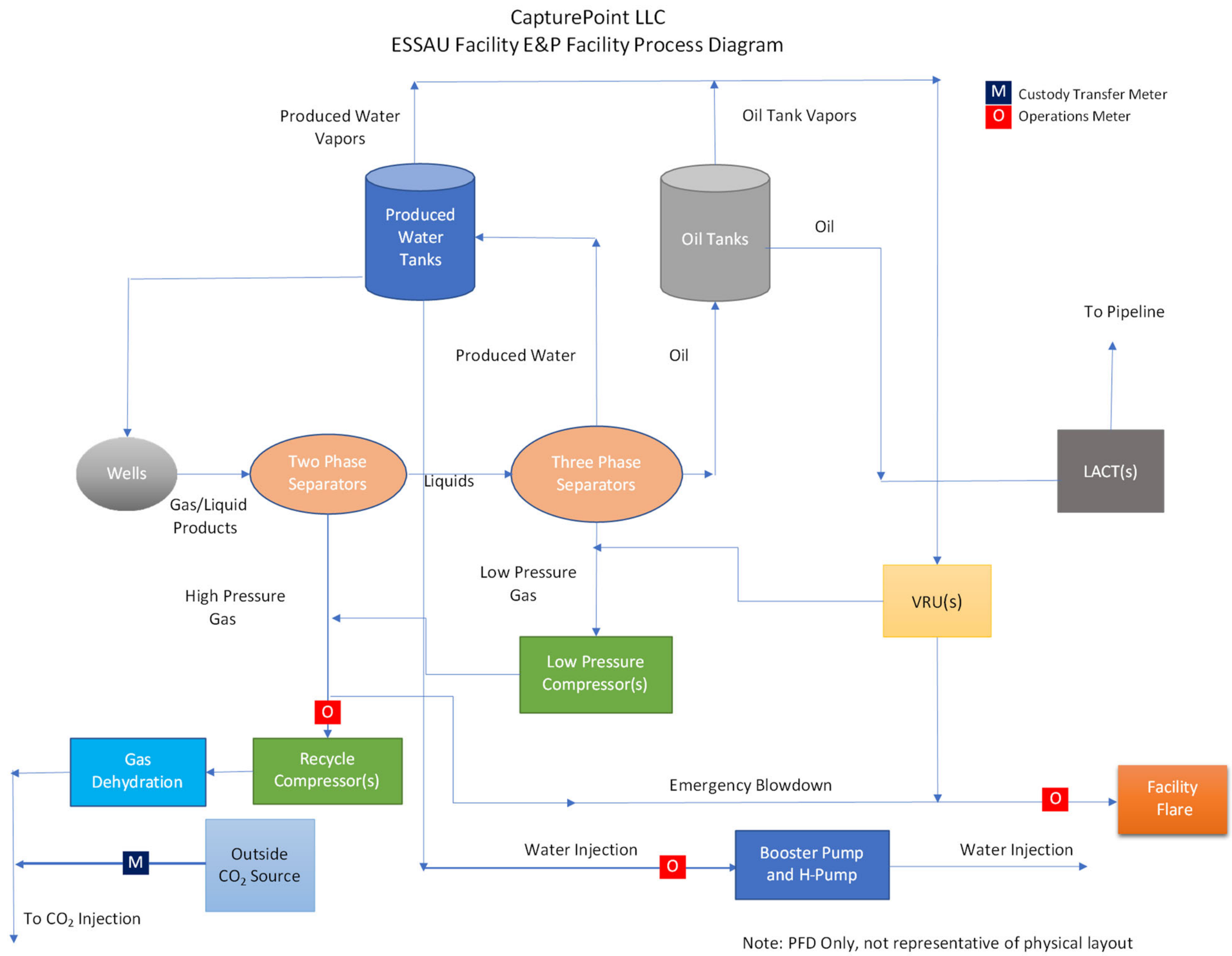

Figure 3-5 ESSAU Process Flow Diagram

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

i. CO_2 Distribution and Injection: The mass of CO_2 received at ESSAU 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 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 recompression facility (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 treatment and reinjection or disposal.

Figure 3-6 shows a simplified process flow diagram of the project facilities and equipment in the Lindoss Unit. CO_2 is delivered to the Lindoss Unit via the Kinder Morgan CO_2 pipeline network. The CO_2 is supplied by a number of different sources including both natural and anthropogenic CO_2 sources Specified amounts are drawn from an outside source pipeline based on contractual arrangements among suppliers of CO_2, purchasers of CO_2, and the pipeline operator.

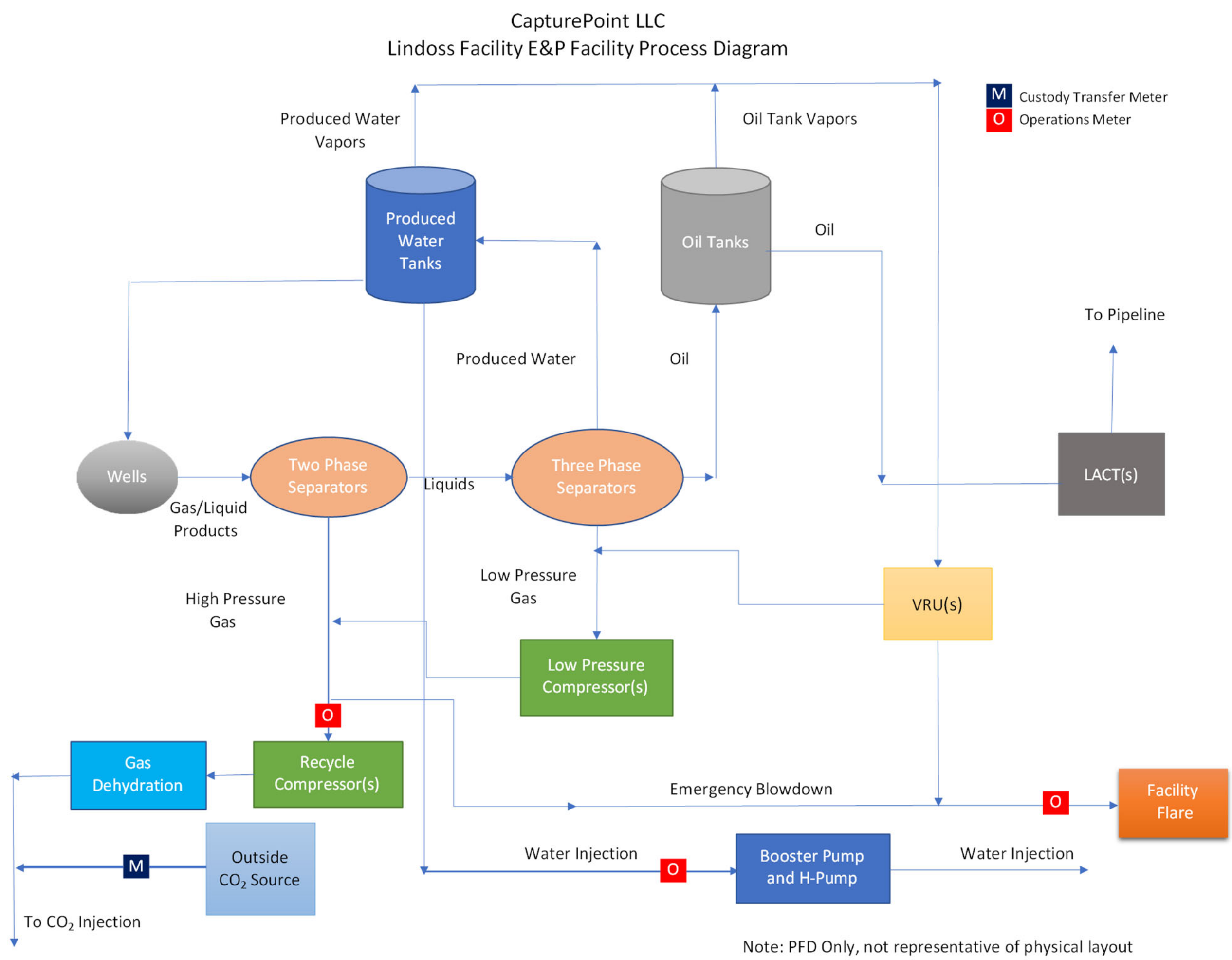

Figure 3-6 Lindoss Process Flow Diagram

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

i. CO_2 Distribution and Injection: The mass of CO_2 received at Lindoss 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 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 recompression facility (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 treatment and reinjection or disposal

3.3.1. Wells in the Seminole East Field

The Texas Railroad Commission (TRRC) has broad authority over oil and gas operations including primacy to implement UIC Class II wells. The rules are found in Texas Administrative Code 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 they 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 3.1 provides a well count by type and status. All these wells are in material compliance with TRRC rules.

Table 3.1 SEF Well Penetrations by Type and Status

TYPE	ACTIVE	INACTIVE	P & A	Total
PROD_OIL	32	16		**48**
INJ_WTR	16	4		**20**
INJ_WAG	18	0		**18**
INJ_SWD*	1	0		**1**
WSW**	1	4		**5**
P&A***			28	**27**
TOTAL	**71**	**20**	**28**	**119**

*INJ_SWD = Saltwater disposal wells
**WSW= Water source wells
***P&A = Plugged and Abandoned wells

As indicated in Figure 3-7, wells are distributed across the SEF. 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.

SEF CO_2-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Reservoir pressure in the SEF is managed by maintaining an injection to withdrawal ratio (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.

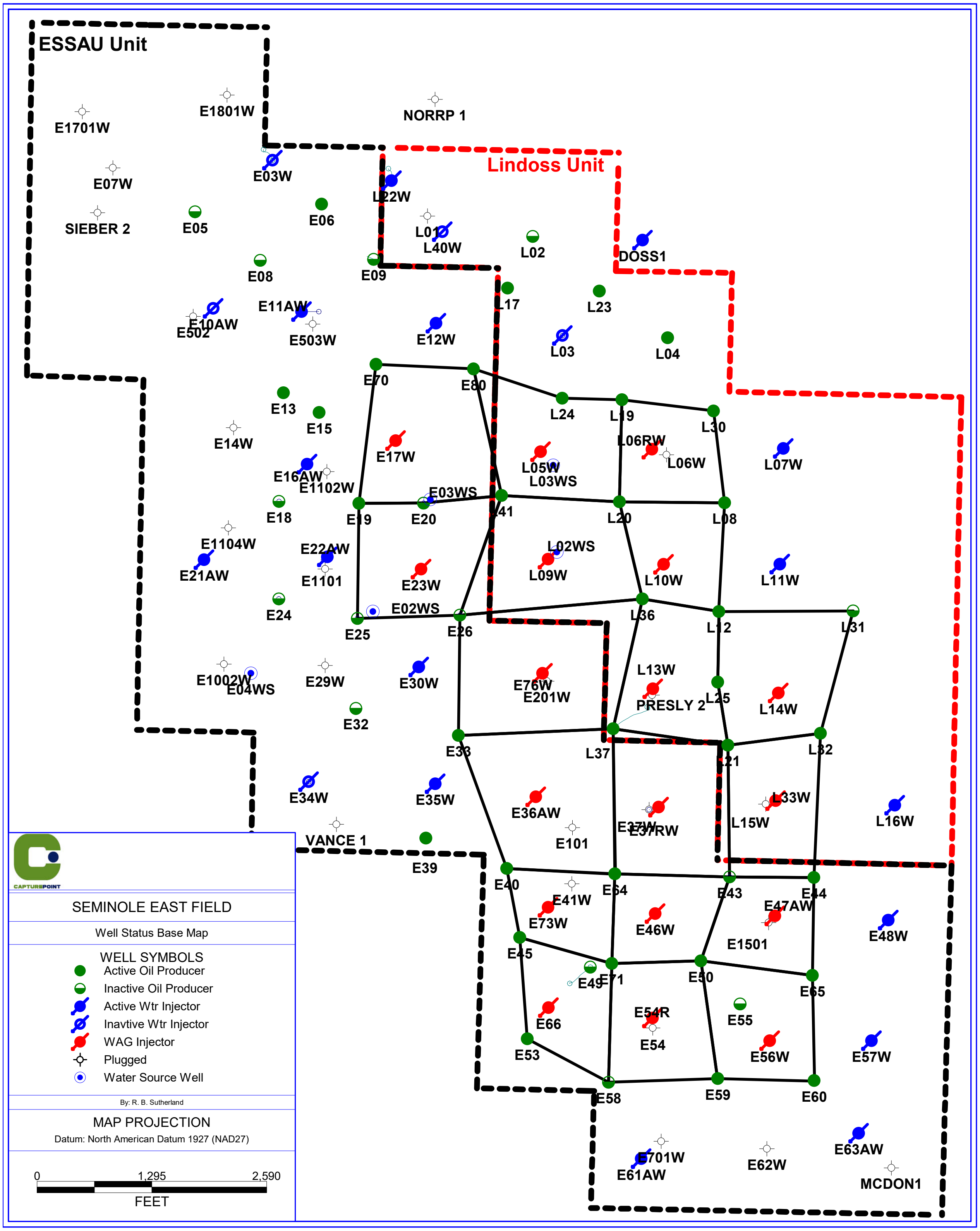

Figure 3-7 SEF Wells and Injection Patterns

3.4. Reservoir Forecasting

Dimensionless performance curves (DPCs) derived from analogous fields were used to project carbon dioxide (CO_2) enhanced oil recovery (EOR) in the Seminole East Field. Most dimensionless curves are derived from geologic and reservoir models. In the SEF case the DPC was derived from actual field performance from an analogous field.

A dimensionless curve is a plot where everything is normalized by dividing by Hydrocarbon Pore Volume (HCPV). See figure 3-8. The dimensioned projections of oil, CO_2 and water production, and CO_2 and water injection are made from DPCs using the original oil in place of an area of interest.

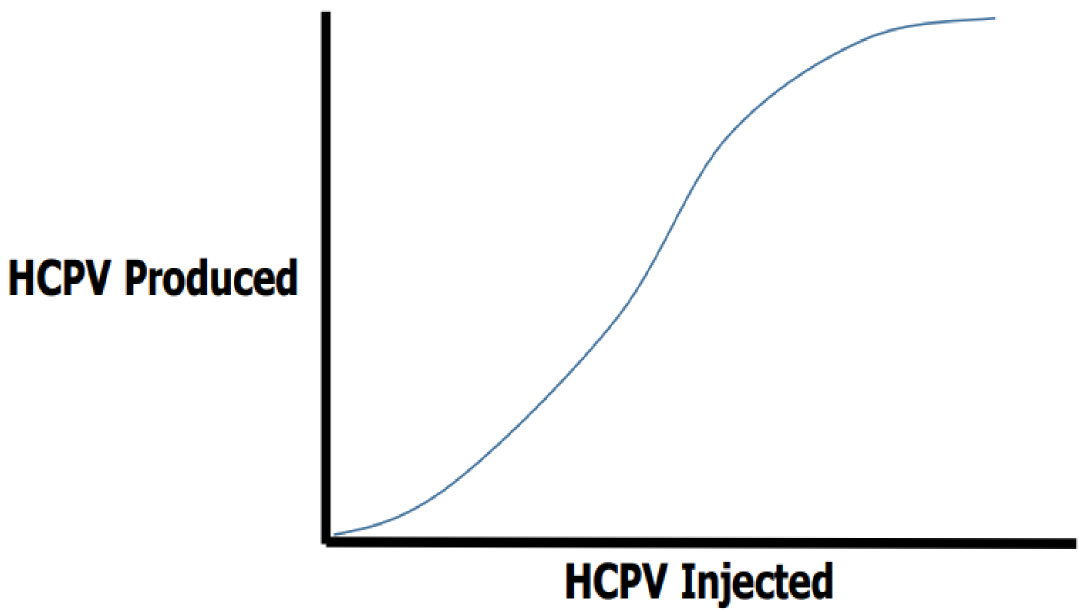

Figure 3-8 Dimensionless curve plot

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

4. Delineation of Monitoring Area and Timeframes

4.1. Active Monitoring Area

The Active Monitoring Area (AMA) is defined by the ESSAU and Lindoss Unit boundaries plus the required ½ mile buffer.

4.2. Maximum Monitoring Area

The Maximum Monitoring Area (MMA) is defined by the ESSAU and Lindoss Unit boundaries plus the required ½ mile buffer as required by 40 CFR §98.440-449 (Subpart RR).

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 SEF. The Specified Period will be shorter than the period of production from the SEF.

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 SEF is collected for use in operations management. Reservoir pressure is not forecasted to change appreciably since the IWR will be maintained at approximately 1.0. Once injection ceases, reservoir pressure is predicted to stabilize within one year.

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

In the roughly 60 years since the Seminole East Field (SEF) 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 Well Bores
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the SEF
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.

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

5.1. Existing Wellbores

As part of the TRRC requirement to initiate CO_2 flooding, an extensive review of all SEF 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 SEF 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 beam pumped producing wells,
- CO_2 flood electrical submersible pump (ESP) producing wells, and
- CO_2 WAG 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 SEF 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 SEF 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 are investigated and addressed. CapturePoint's experience, from over 10 years of operating CO_2-EOR projects, is that such leakage is very rare.

- 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 the 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 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 and reported and quantified.

Based on ongoing monitoring activities and review of the potential leakage risks posed by well bores, it is concluded that the risk of CO_2 leakage through well bores is being mitigated by detecting problems as they arise and quantifying any leakage that does occur.

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 no risk 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. Both measures mitigate the potential for inducing faults or fractures. As a safeguard, WAG skids are continuously monitored.

5.3. Natural or 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 SEF.

To evaluate this potential risk at SEF, CapturePoint has reviewed the nature and location of seismic events in West Texas. Some of the recorded earthquakes in West Texas are far removed from any injection operation. These 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 USGS database of recorded earthquakes at M0.5 or greater in the Permian Basin since 1966 indicates that none have occurred in the Seminole East Field; the closest took place in 1992 approximately 30 miles away. See Figure 5.1.

[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.

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 SEF. 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 GIS site[3] for seismic signals that could indicate the creation of potential leakage pathways in the SEF.

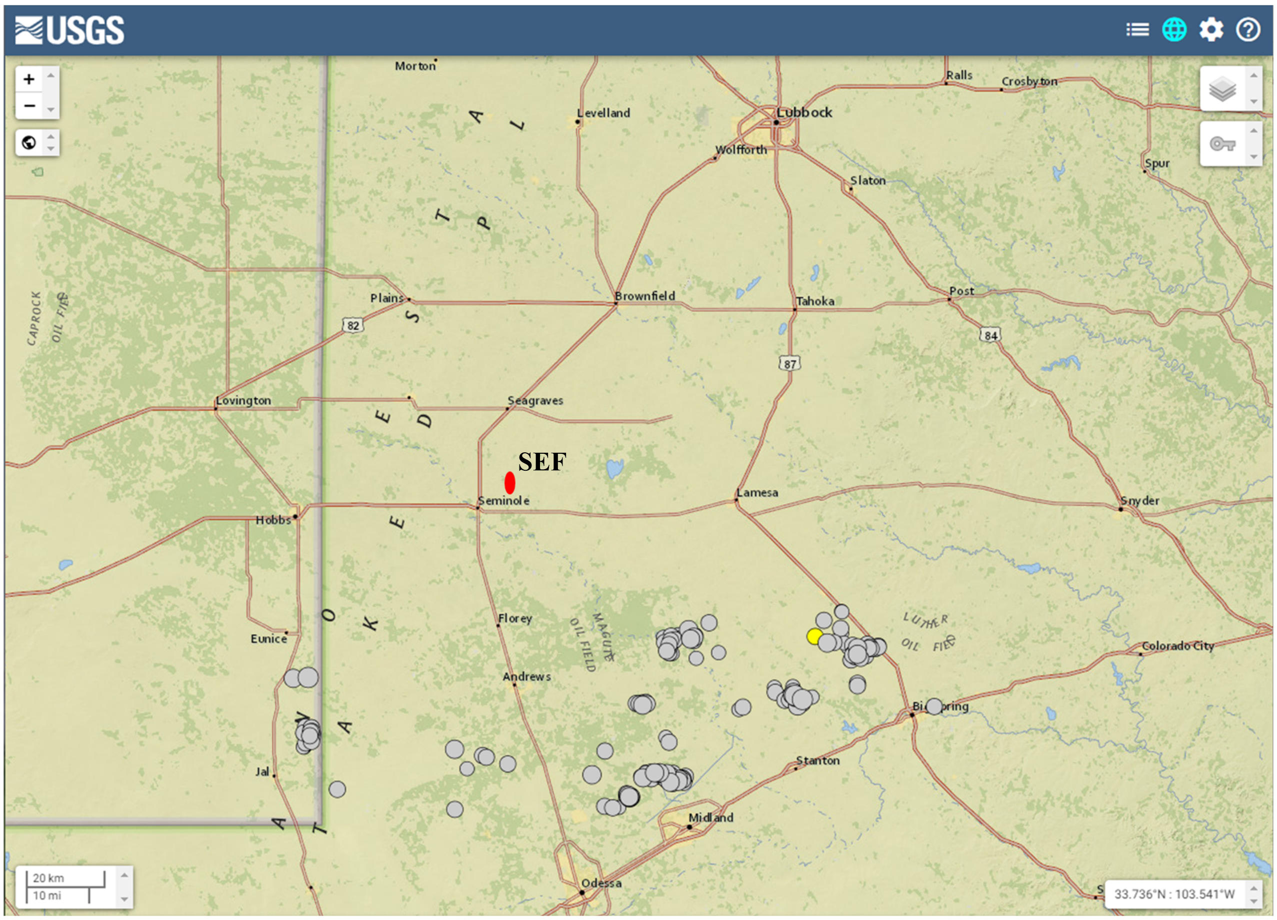

Figure 5-1 USGS earthquakes (+1.0 magnitude) for last 56 years)

5.4. Previous Operations

CO_2 flooding was initiated in SEF in 2013. 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

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

SEF. These practices ensure that that there are no unknown wells within SEF and that the risk of migration from older wells has been sufficiently mitigated. The successful experience with CO_2 flooding in SEF demonstrates that the confining zone has not been impaired by previous operations.

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 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. 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 EPA's GHGRP.

5.6. Lateral Migration Outside the Seminole East Field

It is highly unlikely that injected CO_2 will migrate downdip and laterally outside the SEF because of the nature of the geology and the approach used for injection. Over long periods of time, injected CO_2 will tend to rise vertically towards the Upper San Andres and continue towards the point in the SEF 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. Water curtain injection (WCI) methods are employed during CO_2-EOR operations to prevent CO_2 lateral migration out of the unit boundary. Continuous WCI operations are conducted at the SEF unit boundaries to create a pressure barrier to contain injected fluids within the SEF. Finally, the total volume of fluids contained in the SEF will stay relatively constant. Based on site characterization and planned and projected operations it is estimated that the total volume of stored CO_2 will be considerably less than calculated capacity.

5.7. Drilling in the Seminole East 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. The TRRC requires applications and approvals before a well is drilled, recompleted, or reentered. Well drilling activity at SEF is conducted in accordance with TRRC rules. CapturePoint's visual inspection process, including routine site visits, will identify unapproved drilling activity in the SEF.

In addition, CapturePoint intends to operate SEF 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 SEF 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 into the formations beneath them. As mentioned in Section 3.2 "The San Andres is a stratified reservoir. The stratification is due to tidal movements that occurred across the shoals. The tidal movements formed a stacked sequence of shoals with alternating thin intertidal deposits. The thin intertidal deposits are anhydritic carbonate mudstone layers and result in effective vertical permeability barriers (supported by core data). These barriers are continuous over the entire field and vary in thickness from two to ten feet with most averaging three to four feet in thickness."

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.

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 (well bores), 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.

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 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 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

5.10. Summary

The structure and stratigraphy of the San Andres reservoir in the SEF 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 SEF 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 SEF 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 SEF follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), 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 & 3-6, 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 SEF. 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 inlet to the RCF.
- CO_2 that is entrained in produced oil, as indicated in Figure 3-5 & 3-6, is calculated using volumetric flow through the custody transfer 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 SEF. 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. The Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.

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, 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 SEF. 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

SEF 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 SEF. 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 SEF. 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 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 SEF 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 worn by all field personnel at all times and are permanent throughout the field at ground level, is used as a last method to detect leakage from wellbores. The H_2S monitors 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 equipment, the CO_2 content of produced oil, and 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 equipment, the CO_2 content of produced oil, and 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 SEF 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 reservoir pressure that 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 have provided data for establishing baselines and will 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 and as such 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 include an estimate of the amount of CO_2 leaked. 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 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 H_2S monitors throughout the field at ground level to detect H_2S 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 and 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

To account for the potential propagation of error that would result if volume data from flow meters at each injection and production well were utilized, it is proposed to use the data from custody and operations meters on the main system pipelines to determine injection and production volumes used in the mass balance. 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 of the well head meters within the SEF.

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 Kinder Morgan 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.

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{p,r} - S_{r,p}) * D * C_{CO2,r,p} \qquad \text{(Eq. RR-2)}$$

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 a site well in quarter p (standard cubic meters).

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

$C_{CO2,r,r}$ = 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 SEF's method of receiving CO_2 and requirements at Subpart RR §98.444(a):

- All delivery to the SEF is used within the unit so no quarterly flow redelivered, and Sr,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 SEF 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 output of the RCF (see Figure 3-5). 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:

$$CO_2u = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO2,p,u} \qquad \text{(Eq. RR-5)}$$

where:

CO_2u = Annual CO_2 mass recycled (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.

$C_{CO2,p,u}$ = 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-3) and Mass of CO_2 Recycled (modified RR-5).

$CO_{2I} = CO_2 + CO_{2}u$

8.3. Mass of CO_2 Produced

The Mass of CO_2 Produced at the SEF 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:

$$CO_{2w} = \sum_{p=1}^{4} Q_{p,w} * D * C_{CO2,p,w} \qquad \text{(Eq. RR-8)}$$

where:

CO_{2W} = Annual CO_2 mass produced (metric tons).

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

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

$C_{CO2,pw}$ = CO_2 concentration measurement in flow for meter w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Inlet meter to RCF.

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

$$CO_{2}p = \sum_{w=1}^{W} CO_{2}w + X_{oil} \qquad \text{(Eq. RR-9)}$$

where:

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

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

Xoil = Mass of entrained CO_2 in oil in the reporting year measured utilizing commercial meters and electronic flow-measurement devices at each point of custody transfer. The mass of CO_2 will be calculated by multiplying the total volumetric rate by the CO_2 concentration.

8.4. Mass of CO_2 Emitted by Surface Leakage

The total annual Mass of CO_2 emitted by Surface Leakage will be calculated and reported using an approach that is tailored to specific leakage events and relies on 40 CFR Part 98 Subpart W reports of equipment leakage. 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 a number of 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 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. Further, the Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.

Equation RR-10 in §98.433 will be used to calculate and report the Mass of CO_2 emitted by Surface Leakage:

$$CO_{2E} = \sum_{x=1}^{x} CO_{2x} \qquad \text{(Eq. RR-10)}$$

where:

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

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

x = Leakage pathway.

8.5. Mass of CO_2 Sequestered in Subsurface Geologic Formation

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

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \qquad \text{(Eq. RR-11)}$$

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) net of CO_2 entrained in oil 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 this part.

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 this part.

8.6. Cumulative Mass of CO_2 Reported as Sequestered in Subsurface Geologic Formation

The total annual volumes obtained using equation RR-11 in §98.443 will be summed to arrive at the Cumulative Mass of CO_2 Sequestered in Subsurface Geologic Formations.

9. MRV Plan Implementation Schedule

This MRV plan will be implemented starting January 2023 or within 90 days of EPA approval, whichever occurs later. Other GHG 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 program will be in effect during the Specified Period, during which time the SEF 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 SEF. 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 Program

10.1. Monitoring QA/QC

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.
- The quarterly flow rate of the produced gas is measured at the flow meters located at the RCF inlet.

CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2

These volumes are measured in conformance with the monitoring and QA/QC 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 American Petroleum Institute (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 nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.
- The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

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 SEF 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 and number, API number, type, and status for active wells in the SEF as of August 2021. 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_WTR refers to wells that inject water
    - INJ_WAG refers to wells that inject water and CO_2 Gas
    - INJ_SWD refers to wells that inject water for disposal
    - SWS refers to wells that supply water
    - 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

Well Name	API Number	Well Type	Status
DCB Doss 1 (INJ)	4216534180	INJ_WTR	ACTIVE
ESSAU 02WS	4216530590	WSW	SHUT_IN
ESSAU 03W (INJ)	4216534370	INJ_WTR	SHUT_IN
ESSAU 03WS	4216534343	WSW	ACTIVE
ESSAU 04WS	4216532191	WSW	SHUT_IN
ESSAU 05	4216581203	PROD_OIL	SHUT_IN
ESSAU 06	4216533021	PROD_OIL	ACTIVE
ESSAU 07W (INJ)	4216530591	P&A	INACTIVE
ESSAU 08	4216533913	PROD_OIL	SHUT_IN
ESSAU 09	4216534600	PROD_OIL	SHUT_IN
ESSAU 1002W	4216510149	P&A	INACTIVE
ESSAU 101	4216501006	P&A	INACTIVE
ESSAU 10AW (INJ)	4216533614	INJ_WTR	SHUT_IN
ESSAU 1101	4216510058	P&A	INACTIVE
ESSAU 1102W (INJ)	4216510079	P&A	INACTIVE
ESSAU 1104W (INJ)	4216510241	P&A	INACTIVE
ESSAU 11AW (INJ)	4216533615	INJ_WTR	ACTIVE
ESSAU 12W (INJ)	4216533403	INJ_WTR	ACTIVE
ESSAU 13	4216534028	PROD_OIL	ACTIVE
ESSAU 14W (INJ)	4216510072	P&A	INACTIVE

Well Name	API Number	Well Type	Status
ESSAU 15	4216534110	PROD_OIL	ACTIVE
ESSAU 1501	4216510413	P&A	INACTIVE
ESSAU 16AW (INJ)	4216534371	INJ_WTR	ACTIVE
ESSAU 1701W (INJ)	4216510246	P&A	INACTIVE
ESSAU 17W (INJ)	4216534108	INJ_WAG	ACTIVE
ESSAU 18	4216533910	PROD_OIL	SHUT_IN
ESSAU 1801W (INJ)	4216510250	P&A	INACTIVE
ESSAU 19	4216533912	PROD_OIL	ACTIVE
ESSAU 20	4216534111	PROD_OIL	SHUT_IN
ESSAU 201W (INJ)	4216500168	P&A	INACTIVE
ESSAU 21AW (INJ)	4216533819	INJ_WTR	ACTIVE
ESSAU 22AW (INJ)	4216533908	INJ_WTR	ACTIVE
ESSAU 23W (INJ)	4216501005	INJ_WAG	ACTIVE
ESSAU 24	4216533906	PROD_OIL	SHUT_IN
ESSAU 25	4216533914	PROD_OIL	SHUT_IN
ESSAU 26	4216534112	PROD_OIL	SHUT_IN
ESSAU 29W (INJ)	4216501019	P&A	INACTIVE
ESSAU 30W (INJ)	4216501007	INJ_WTR	ACTIVE
ESSAU 32	4216533909	PROD_OIL	SHUT_IN
ESSAU 33	4216534031	PROD_OIL	ACTIVE
ESSAU 34W (INJ)	4216534109	INJ_WTR	SHUT_IN
ESSAU 35W (INJ)	4216501008	INJ_WTR	ACTIVE
ESSAU 36AW (INJ)	4216530147	INJ_WAG	ACTIVE
ESSAU 37RW (INJ)	4216538478	INJ_WAG	ACTIVE
ESSAU 37W (INJ)	4216502594	P&A	INACTIVE
ESSAU 39	4216534106	PROD_OIL	ACTIVE
ESSAU 40	4216534104	PROD_OIL	ACTIVE
ESSAU 41W (INJ)	4216501012	P&A	INACTIVE
ESSAU 43	4216534601	PROD_OIL	SHUT_IN
ESSAU 44	4216534652	PROD_OIL	ACTIVE
ESSAU 45	4216534107	PROD_OIL	ACTIVE
ESSAU 46W (INJ)	4216500002	INJ_WAG	ACTIVE
ESSAU 47AW (INJ)	4216533014	INJ_WAG	ACTIVE
ESSAU 48W (INJ)	4216533015	INJ_WTR	ACTIVE
ESSAU 49	4216534049	PROD_OIL	SHUT_IN
ESSAU 50	4216533907	PROD_OIL	ACTIVE
ESSAU 502	4216510251	P&A	INACTIVE
ESSAU 503W (INJ)	4216530452	P&A	INACTIVE
ESSAU 53	4216533911	PROD_OIL	SHUT_IN
ESSAU 54	4216502901	P&A	INACTIVE
ESSAU 54R (INJ)	4216538339	INJ_WAG	ACTIVE
ESSAU 55	4216501046	PROD_OIL	SHUT_IN
ESSAU 56W (INJ)	4216534030	INJ_WAG	ACTIVE
ESSAU 57W (INJ)	4216510252	INJ_WTR	ACTIVE
ESSAU 58	4216534105	PROD_OIL	SHUT_IN
ESSAU 59	4216533905	PROD_OIL	ACTIVE
ESSAU 60	4216534048	PROD_OIL	ACTIVE
ESSAU 61AW (INJ)	4216533820	INJ_WTR	ACTIVE

Well Name	API Number	Well Type	Status
ESSAU 62W (INJ)	4216502902	P&A	INACTIVE
ESSAU 63AW (INJ)	4216534029	INJ_WTR	ACTIVE
ESSAU 64	4216534027	PROD_OIL	ACTIVE
ESSAU 65	4216534026	PROD_OIL	ACTIVE
ESSAU 66W (INJ)	4216501003	INJ_WAG	ACTIVE
ESSAU 70	4216537356	PROD_OIL	ACTIVE
ESSAU 701W (INJ)	4216501011	P&A	INACTIVE
ESSAU 71	4216537747	PROD_OIL	ACTIVE
ESSAU 73W (INJ)	4216537748	INJ_WAG	ACTIVE
ESSAU 76W (INJ)	4216538479	INJ_WAG	ACTIVE
ESSAU 80	4216538294	PROD_OIL	ACTIVE
Lindoss 01	4216533392	P&A	INACTIVE
Lindoss 02	4216533467	PROD_OIL	SHUT_IN
Lindoss 02WS	4216534452	WSW	SHUT_IN
Lindoss 03 (INJ)	4216533284	INJ_WTR	SHUT_IN
Lindoss 03WS	4216534453	WSW	SHUT_IN
Lindoss 04	4216533041	PROD_OIL	ACTIVE
Lindoss 05W (INJ)	4216532364	INJ_WAG	ACTIVE
Lindoss 06RW (INJ)	4216538303	INJ_WAG	ACTIVE
Lindoss 06W (INJ)	4216532733	P&A	INACTIVE
Lindoss 07W (INJ)	4216532883	INJ_WTR	ACTIVE
Lindoss 08	4216533452	PROD_OIL	ACTIVE
Lindoss 09W (INJ)	4216532200	INJ_WAG	ACTIVE
Lindoss 10W (INJ)	4216532606	INJ_WAG	ACTIVE
Lindoss 11W (INJ)	4216532757	INJ_WTR	ACTIVE
Lindoss 12	4216533453	PROD_OIL	ACTIVE
Lindoss 13W (INJ)	4216533422	INJ_WAG	ACTIVE
Lindoss 14W (INJ)	4216531826	INJ_WAG	ACTIVE
Lindoss 15 (INJ)	4216531527	P&A	INACTIVE
Lindoss 16W (INJ)	4216532025	INJ_WTR	ACTIVE
Lindoss 17	4216534440	PROD_OIL	ACTIVE
Lindoss 19	4216534442	PROD_OIL	ACTIVE
Lindoss 20	4216534441	PROD_OIL	ACTIVE
Lindoss 21	4216534602	PROD_OIL	ACTIVE
Lindoss 22W (INJ)	4216534604	INJ_WTR	ACTIVE
Lindoss 23	4216536582	PROD_OIL	ACTIVE
Lindoss 24	4216536583	PROD_OIL	ACTIVE
Lindoss 25	4216536581	PROD_OIL	ACTIVE
Lindoss 30	4216537352	PROD_OIL	ACTIVE
Lindoss 31	4216537345	PROD_OIL	SHUT_IN
Lindoss 32	4216537341	PROD_OIL	ACTIVE
Lindoss 33W (INJ)	4216537346	INJ_WAG	ACTIVE
Lindoss 36	4216537772	PROD_OIL	ACTIVE
Lindoss 37	4216538297	PROD_OIL	ACTIVE
Lindoss 40W (SWD)	4216538466	INJ_SWD	SHUT_IN
Lindoss 41	4216538296	PROD_OIL	ACTIVE
McDonald 1	4216502903	P&A	INACTIVE
Norrp 1	4216533505	P&A	INACTIVE

Well Name	API Number	Well Type	Status
Presely 2	4216531620	P&A	INACTIVE
Sieber 2	4216510247	P&A	INACTIVE
Vance 1	4216501018	P&A	INACTIVE

12.2 Regulatory References

Regulations cited in this plan:

- Texas Administrative Code 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

AGA - American Gas Association

AMA - Active Monitoring Area

API - American Petroleum Institute

AoR - Area of Review

Bcf – 1 Billion Standard Cubic Feet of Gas

CO_2 - Carbon Dioxide

DPCs - Dimensionless Performance Curves

EPA - Environmental Protection Agency

EOR - Enhanced Oil Recovery

ESP - Electrical Submersible Pump

ESSAU - East Seminole San Andres Unit

FPP - Formation Parting Pressure

GHG - Greenhouse Gas

GHGRP - Greenhouse Gas Reporting Program

GIS - Geographical Information System

GPA - Gas Processors Association

H_2S – Hydrogen Sulfide

HCPV - Hydrocarbon Pore Volume

IWR - Injection to withdrawal Ratio

MMA - Maximum Monitoring Area

MRV Plan - Monitoring, Reporting and Verification Plan

Mscf – 1,000 Standard Cubic Feet of Gas

NIST - National Institute of Standards and Technology

RB - Reservoir Barrels

RCF - Recycle Compression Facility

ROZ - Residual Oil Zone

SAT - Satellite Test Stations

SEF - Seminole East Field

TAC - Texas Administrative Code

TRRC - Texas Railroad Commission - Oil and Gas Division

UIC - Underground Injection Control

USGS - United States Geological Survey

WAG - Water Alternating Gas

WCI - Water Curtain Injection