

Technical Review of Subpart RR MRV Plan for Northeast Purdy Springer Unit (NEPSU) / South East Bradley A Unit (SEBAU)

October 2025

Contents

1	Overview of Project	1
2	Evaluation of the Delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA)	2
3	Identification of Potential Surface Leakage Pathways	4
4	Strategy for Detecting and Quantifying Surface Leakage of CO ₂ and for Establishing Expected Baselines for Monitoring.....	8
5	Considerations Used to Calculate Site-Specific Variables for the Mass Balance Equation.....	15
6	Summary of Findings	19

Appendices

Appendix A:
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 by Daylight Petroleum, LLC (Daylight) for the Northeast Purdy Springer Unit (NEPSU) / South East Bradley A Unit (SEBAU) facility, collectively referred to as the Purdy-Bradley Springer Field (PBSF). PBSF is a carbon dioxide (CO₂)-enhanced oil recovery (EOR) project located in south-central Oklahoma. 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. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

1 Overview of Project

The MRV plan states that Daylight operates PBSF in south-central Oklahoma for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO₂) flooding. As a secondary purpose, PBSF intends to establish secure geological storage (sequestration) of a measurable quantity of CO₂ in subsurface geologic formations at the Purdy-Bradley Springer Field. PBSF intends to continue CO₂-EOR operations until the end of economic life of the field, with the subsequent goal of long-term storage of CO₂ in geologic formations.

Section 1.2 of the MRV plan states that the EOR wells covered by this MRV Plan are permitted and operated as Class II Underground Injection Control (UIC) wells under the jurisdiction of the Oklahoma Corporation Commission (OCC), which has primacy for administering Class II UIC regulations in the state. A list of all wells (including injection wells) in PBSF is provided as part of Appendix 1 of the MRV plan.

Section 2 of the MRV plan states that CO₂ has been injected at NEPSU since 1982 and at SEBAU since 1997. The cumulative CO₂ retention capacity of the subsurface formation is estimated to be 278 billion standard cubic feet (Bscf) or 14.7 million metric tons (MMT). This capacity is anticipated to be able to sequester the volume of gas from historical CO₂ injections of NEPSU and SEBAU, as well as the forecasted injections into these units through March 2054.

According to the MRV plan, the PBSF is located within the Golden Trend of South-Central Oklahoma, in the southeastern embayment of the Anadarko Basin. The Anadarko Basin contains up to 40,000 feet of sedimentary rock and is a prolific hydrocarbon producer. For NEPSU, the Lower Pennsylvanian Cunningham Sandstone, historically referred to as the Springer "A" sand, was deposited in shallow marine settings and consists of southwest-dipping, fine- to medium- grained siliceous sandstone. The geologic and reservoir properties of SEBAU are similar to those of NEPSU. In this unit, the Springer strata were deposited in shallow marine tidal bar and channel settings. Fine- and medium-grain sand with shale laminations and dominantly clay cements comprise the primary reservoir facies of the Cunningham Sandstone.

As stated in the MRV plan, the reservoirs of the Springer are sandstone bodies that have lateral porosity and permeability variations and are encased in shale. At PBSF, the Cunningham Sandstone is top sealed

by shales of the upper Springerean and Morrowan series that directly overlie the reservoir unit and by truncation against the base Atoka unconformity. The Cunningham Sandstone is tilted and eroded below the unconformity. Above the unconformity, the Cunningham is sealed by shales of the lower Atokan series. The MRV plan also states that the Goddard Shale is the bottom seal for the Cunningham Sandstone and varies in thickness from 1,550 feet to 2,000 feet within the units. It is homogenous and rich in ductile swelling clays (smectite). The Goddard Shale also serves as a top seal of large over pressured zones (Mississippian and Devonian reservoirs) in the deep Anadarko basin. The high ductility, thickness, and overpressuring of this shale package make it a highly effective bottom seal for the Cunningham Sandstone.

Figure 5 in the MRV plan shows a simplified flow diagram of the CO₂-EOR operations within the boundaries of the PBSF. PBSF explains in the MRV plan that historically, a fertilizer plant in Enid, Oklahoma has been the only source of CO₂, with CO₂ captured from the plant delivered via a Daylight-operated pipeline to the field for injection. No new CO₂ has been received since 2022, but PBSF is currently working with multiple emitters to source additional CO₂ for the EOR project. These potential sources include gas processing plants, landfills, fertilizer plants, refineries, and ethanol plants. The MRV plan states that purchased CO₂ (when applicable) is combined with recycled CO₂ obtained from the produced gas stream and sent through the main CO₂ distribution system to various water alternating gas (WAG) injectors.

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

2 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 CO₂ plume until the CO₂ 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 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.” See 40 CFR 98.449.

Section 2.4 of the MRV plan reiterates that NEPSU and SEBAU are operated collectively as the PBSF and have similar reservoir properties. A reservoir fluid model was developed based on the work of Fox et al. (1988), which documents fluid properties for NEPSU, and pressure, volume, and temperature (PVT) parameters, which were applied uniformly across the field. In this study, a modified Muskat model was

used to calculate the pore volume available for CO₂ sequestration. Based on the analysis, should EOR be conducted for another 30 years, the volume potentially sequestered will reach 278 Bscf by 2054, or 14.7 MMT, assuming pure CO₂ is injected. In delineating the monitoring areas, Section 3.1 of the MRV plan states that the estimated void space of 21 million standard cubic feet (MMscf) of CO₂ per acre of surface area, or a total of 278 Bscf CO₂, is assumed to be entirely contained within the Purdy-Bradley Springer Field (~13,200 acres).

The MRV plan defines the AMA as the combined boundaries of the PBSF plus a buffer zone of at least one-half mile (see Figure 22 of the MRV plan). The AMA is the area that PBSF will monitor over a specific time interval from the first year of the period (n) to the last year in the period (t). Consistent with the requirements in 40 CFR 98.449, the boundary is established by superimposing two areas:

1. The area projected to contain the free phase CO₂ plume for the duration of the project (year t), plus an all-around buffer zone of one-half mile.
2. The area projected to contain the free phase CO₂ plume for at least five years after injection ceases (year t+5).

According to the MRV plan, the unit boundaries were defined during unitization based on the geologic boundaries and truncational limits of the Springer reservoir. Successful containment of free-phase CO₂ within these boundaries has been demonstrated and confirmed during 43 years of CO₂ flooding in NEPSU and 28 years of CO₂ flooding in SEBAU. Furthermore, the estimated void space of 278 Bscf is entirely contained within the unit boundaries and will not be exceeded by CO₂ injection volumes. Therefore, PBSF expects the free-phase CO₂ to remain within these boundaries for the duration of the project (t = Year 2054) and at least 5 years thereafter, as required for the AMA by 40 CFR 98.449. PBSF states that no known leakage pathways extend laterally more than one-half mile.

Section 3.3 of the MRV plan states that the MMA is equal to or greater than the area expected to contain the free-phase CO₂ until the CO₂ has stabilized, plus an all-around buffer zone of at least one-half mile. The MMA is defined as equivalent to the AMA, and PBSF will continuously monitor the entire MMA for the purposes of this MRV. PBSF explains that this is reasonable because after 43 years of CO₂ flooding in NEPSU and 28 years of CO₂ flooding in SEBAU, the free-phase CO₂ plume extent has spread throughout both units and is successfully contained by the geologic limits of the reservoir, as demonstrated by PBSF's current monitoring practices. PBSF expects the extent of the free-phase CO₂ plume will continue to be contained by and stabilized within the geologic limits of the reservoir, since it has a proven impermeable seal and the amount of CO₂ injected will not exceed the reservoir's secure storage capacity of 278 Bscf. As such, there is no difference in the expected free-phase CO₂ plume extent between year t and year t + 5. Furthermore, the CO₂ plume extent is expected to remain stable once this facility discontinues injection operations based on historical monitoring trends.

The delineations of the MMA and AMA are acceptable per the requirements in 40 CFR 98.448(a)(1). The MMA and AMA described in the MRV plan are clearly 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 CO₂ in the MMA, and the likelihood, magnitude, and timing of surface leakage of CO₂ through these pathways pursuant to 40 CFR 98.448(a)(2). PBSF identified the following as potential leakage pathways in Section 4 of the MRV plan:

1. Surface Equipment
2. Wells
3. Faults, Fractures, and Bedding Plane Partings
4. Lateral Fluid Movement
5. Confining/Seal System
6. Natural and Induced Seismic Activity

A summary table of PBSF's characterization of the likelihood, magnitude, and timing of surface leakage through the potential leakage pathways can be found in Table 3 of the MRV plan and is copied below.

Potential Leakage Pathway	Likelihood	Magnitude ¹	Timing
Surface Equipment	Unlikely but possible	Variable – Small or easily detected failure could result in low- to medium-magnitude CO ₂ release, while a catastrophic failure could result in medium- to high- magnitude CO ₂ release	During injection period
Shallow Groundwater Wells	Unlikely	Low – Monitoring should minimize any release of CO ₂	During injection and post-injection periods
Other Wells	Unlikely but possible	Low – Monitoring / surveillance and well construction requirements should minimize any release of CO ₂	During injection and post-injection periods
Faults, Fractures, and Bedding Plane Partings	Unlikely	Low	During injection and post-injection periods
Lateral Fluid Movement	Unlikely	Low	During injection and post-injection periods

Potential Leakage Pathway	Likelihood	Magnitude ¹	Timing
Confining Seal / System	Unlikely	Low	During injection and post-injection periods
Natural and Induced Seismic Activity	Unlikely	Low	During injection and post-injection periods

¹Magnitude assessed as follows:

Low – minimal risk to safety, health and environment, or underground sources of drinking water (USDW)

Medium – moderate risk to safety, health and environment, or USDW, but easily remediated

High – extreme risk to safety, health and environment, or USDW, and difficult and/or costly to remediate.

3.1 Leakage from Surface Equipment

Section 4.1 of the MRV plan states that surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO₂-EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment is conducted by personnel instructed on how to detect surface leaks and other equipment failure, thereby minimizing the potential for and impact of any leakage. Surface equipment leaks have a low risk of occurring based on design standards. In addition, the MRV plan states that under OCC rules, operators must take prompt action to eliminate leakage hazards and to conduct inspections or repairs.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected from surface equipment.

3.2 Leakage through Wells

Sections 4.2 of the MRV plan states that as of January 2025, PBSF identified 23 active CO₂ injection wells and 36 active production wells in the SEBAU; 69 active CO₂ injection wells and 88 active production wells in the NEPSU; and approximately 886 total wellbore penetrations within the AMA. Regulations governing wells in the NEPSU and SEBAU require that wells be completed and operated so that fluids are contained in the strata in which they are encountered and that well operations do not pollute subsurface and surface waters. Figure 22 in the MRV plan shows all wells in the AMA/MMA. In addition, the MRV plan states that approximately 85 shallow groundwater wells are in the AMA/MMA, per the Oklahoma Water Resources Board General Viewer. The deepest well is 360 feet, ~8,000 feet above the reservoir. Therefore, the likelihood of leakage via shallow groundwater wells is low.

Abandoned Wells

Section 4.2.1 of the MRV plan states that based on past and future area of review (AoR) evaluations and a lack of historical leakage, PBSF concludes that leakage of CO₂ to the surface through abandoned wells is unlikely but cannot be ruled out.

Injection Wells

Section 4.2.2 of the MRV plan states that mechanical integrity testing (MIT) is an essential requirement of the UIC program in demonstrating that injection wells do not act as conduits for leakage into USDWs and to the surface environment. Under Oklahoma Administrative Code (OAC) Title 165 Chapter 10, a pressure or monitoring test must be performed on new and existing injection wells and disposal wells. Considering past and future expectations of adhering to these rules, PBSF concludes that leakage of CO₂ to the surface through active injection wells is unlikely.

Production Wells

Section 4.2.3 of the MRV plan states that as the project matures, production wells may be added and will be constructed according to the rules of the State of Oklahoma. Additionally, inactive wells may become active according to the rules of the State of Oklahoma.

The MRV plan also states that during production, fluids including oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by differential pressure, where the bottom hole wellbore pressure is less than the reservoir pressure. These lower-pressure fluids are contained by the casing, tubing, wellhead, and flowline all the way to the batteries and production/separation facilities. PBSF concludes that leakage of CO₂ to the surface through production wells is unlikely.

Inactive Wells

Section 4.2.4 of the MRV plan states that the inactive wells that have been temporarily abandoned typically have a cast iron bridge plug or other isolation mechanism set above the existing perforations to isolate the reservoir from the surface. The wellhead pressures are then checked by operation schedule for any change. Given the regular monitoring of and procedures for securing inactive wells, it is unlikely that any leakage event would result in a significant magnitude or duration of CO₂ loss.

New Wells

Section 4.2.5 states that as the project develops, new production wells and injection wells may be added to PBSF. All new wells will be constructed according to the relevant rules for the OCC which ensure protection of subsurface and surface resources and the environment. This will significantly limit any potential leakage from well pathways; however, leakage during drilling of a new well through the CO₂ flood interval cannot be ruled out.

The MRV plan also states that in the event a non-operated well is drilled within the AMA, the operator would be required to follow all OCC rules and procedures in drilling the well and the potential for leakage would be like that of any well PBSF drills within the AMA. In addition, PBSF's visual inspection process during routine field operation will identify any unapproved drilling activity in PBSF

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected from wells.

3.3 Leakage through Faults, Fractures, and Bedding Plane Partings

Section 4.3 of the MRV plan states that primary seals at PBSF have been demonstrated to be mechanically competent despite the presence of faults in and around the field. The following lines of analysis have been used to assess this risk in the area.

Presence of Hydrocarbons

Section 4.3.1 of the MRV plan states that the primary evidence that leakage does not occur along faults, fractures, and bedding plane partings is the ~330 million barrels (MMB) of oil estimated to be originally in place in PBSF. If significant escape pathways existed, PBSF states that oil would have drained from the reservoir prior to the present day.

Fracture Analysis

Section 4.3.2 of the MRV plan states that despite the presence of faulting in the area, conventional core samples taken from the Springer showed little evidence of fracturing. In the event CO₂ leakage occurs through faults and fractures, it is unlikely that the leak would result in surface leakage, as these features are not known to extend from the reservoir to the surface.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected from faults, fractures, and bedding plane partings.

3.4 Leakage through Lateral Fluid Movement

Section 4.4 of the MRV plan states that the Springerean strata in Oklahoma represent primarily a deltaic to coastal island set of depositional systems that prograded toward the southeast, resulting in deposition of shales and lenticular, discontinuous coarse sandstones separated by very fine sandstone, minor conglomerates, and shale. The likelihood of extensive migration of fluid outside of the MMA is considered low.

PBSF states that since CO₂ is lighter than the water and oil remaining in the reservoir, it will tend to migrate to the top of the reservoir. The producing wells create low pressure points in the field, draining water and oil while keeping some CO₂ within each discontinuous sandstone. It is estimated that the total

mass of stored CO₂ will be considerably less than the calculated storage capacity and once production operations cease, very small lateral movement will occur.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected through lateral fluid movement.

3.5 Leakage through the Confining/Seal System

Section 4.5 of the MRV plan states that the results of gas sampling analysis from wells producing from the Cunningham Sandstone and the shallower Hart Sandstone (i.e., the next overlying reservoir) show that CO₂ does not move vertically through the confining strata. Baseline testing of the Cunningham Sandstone prior to CO₂ injection showed a 0.6% molar concentration of CO₂. In October 2023, PBSF's testing of more than 50 wells producing from the Hart reservoir showed an average of 0.25% molar concentration of CO₂ in the gas stream. These results confirm that the sealing units above the Cunningham Sandstone prevent upward migration of CO₂ out of the reservoir.

In the unlikely event of CO₂ leakage through the confining seal, there is a very low risk of surface leakage, since the reservoir is at depths of ~8,200-10,900 feet and is overlain by >1,200 feet of impermeable shale net thickness.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected from leakage through confining/seal systems.

3.6 Leakage from Natural and Induced Seismicity

Section 4.6 of the MRV plan states that Figure 23 shows the locations of earthquakes with magnitudes of 2.5 or greater that have occurred within 2 miles of the MMA based on data obtained from the United States Geological Survey (USGS) Earthquakes Hazard Program catalog. PBSF is in a seismically active region, and all but one of the mapped earthquakes occurred since the initiation of CO₂ injection in 1982. However, there is no evidence that proximal or distal earthquakes have caused a disruption in injectivity, CO₂ leakage, or damage to any of the wellbores in PBSF.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected from natural and induced seismicity.

4 Strategy for Detecting and Quantifying Surface Leakage of CO₂ and for Establishing Expected Baselines for Monitoring

40 CFR 98.448(a)(3) requires that an MRV plan contains a strategy for detecting and quantifying any surface leakage of CO₂, and 40 CFR 98.448(a)(4) requires that an MRV plan includes a strategy for

establishing the expected baselines for monitoring CO₂ surface leakage. Section 4 of the MRV plan describes PBSF's strategy for detecting and quantifying CO₂ leakage.

PBSF intends to use the results of daily monitoring of field conditions, operational data (including automatic data systems), routine testing, and maintenance information to monitor for surface leakage and to identify and investigate deviations from expected performance that could indicate CO₂ leakage. A summary table of PBSF's strategies for monitoring and responding to any potential CO₂ leakage can be found in Table 4 of the MRV plan and is copied below.

Known Potential Leakage Risks	Monitoring Methods and Frequency	Anticipated Response Plan
Tubing leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days
Casing leak	Weekly field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days
Wellhead leak	Weekly field inspection	Workover crews respond within days
Loss of bottomhole pressure control	Blowout during well operations (weekly inspection but field personnel present daily)	Maintain well kill procedures
Unplanned wells drilled through the Cunningham Sandstone	Weekly field inspection to prevent unapproved drilling; compliance with OCC permitting for planned wells	Assure compliance with OCC regulations
Loss of seal in abandoned wells	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Re-enter and re-seal abandoned wells
Pumps, valves, etc.	Weekly field inspection	Workover crews respond within days
Leakage along faults	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near faults
Leakage laterally	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Fluid management along lease lines

Known Potential Leakage Risks	Monitoring Methods and Frequency	Anticipated Response Plan
Leakage through induced fractures	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near seismic event

4.1 Detection of Leakage from Surface Equipment

As stated in the MRV plan, the risk of surface leakage from pipelines and surface equipment is unlikely but possible. As described in Section 4.8.1 of the MRV plan, PBSF uses onsite management and a Supervisory Control and Data Acquisition (SCADA) system to conduct its CO₂-EOR operations. PBSF uses data from these efforts to identify and investigate variances from expected performance that could indicate CO₂ leakage. Some CO₂ meters are installed with SCADA systems that transmit data from the meters automatically into a data warehouse.

As described in Section 4.8.2 of the MRV plan, PBSF field personnel conduct routine weekly or daily inspections of the facilities, wells, and other equipment (such as vessels, piping, and valves). Any visual identification of CO₂ vapor emission or ice formation will be reported and documented, and a plan will be developed and executed to correct the issue. PBSF states that should leakage from surface equipment occur, it will be quantified according to procedures required by the GHGRP.

According to Section 4.8.5 of the MRV plan, PBSF currently operates the CO₂-related infrastructure used to operate the units, including the associated on-site CO₂ capture, compression, and dehydration facility. The facility includes a monitoring program that monitors the rates and pressures at the facility and on the pipeline on a continuous basis. High and low set points are established in the program, and operators at the plant, pipeline and/or the units are alerted if a parameter is outside the allowable window. If the flagged parameter is the delivery point on the pipeline, but no other parameter at the plant or pipeline is flagged, then the field personnel are alerted so that further investigation can be conducted in the field to determine if the issue poses a leak threat.

Table 4 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected from surface equipment. Thus, the MRV plan provides adequate characterization of PBSF's approach to detect potential leakage from surface equipment as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage through Wells

As stated in the MRV plan, the risk of surface leakage through wells is unlikely but possible. PBSF will monitor leakage through wells using the methodologies discussed in Sections 4.8.1, 4.8.2, 4.8.3, 4.8.4 and 4.8.6 of the MRV plan.

As described in Section 4.8.3 of the MRV plan, PBSF manages its CO₂-EOR operations by developing and implementing target injection rates and pressures for each CO₂ injection well. These target rates and pressures are developed based on various parameters such as historic and ongoing pattern development, WAG operations, CO₂ availability, field performance, and permit conditions. Generally, CO₂ injection rates for each CO₂ injection well are reported and compared to the target rates daily. Injection pressures and casing pressures are also monitored on each CO₂ injection well. Injection rates or pressures falling outside of the target rates or pressures to a statistically significant degree are screened to determine whether they could lead to CO₂ leakage to the surface.

Additionally, as described in Section 4.8.4 of the MRV plan, PBSF forecasts the volume of fluids (e.g. oil, water, CO₂) that are likely to be produced from each production well at the unit level in PBSF over various periods of time. Evaluation of these produced volumes, along with other data, informs operational decisions regarding management of the CO₂-EOR project and aids in identifying possible issues that may involve CO₂ leakage.

Furthermore, according to Section 4.8.6 of the MRV plan, injection wells are leak-tested via MIT as required by the EPA or OCC. This consists of regular monitoring of the tubing-casing annular pressure and conducting a test that pressures up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. Sometimes, in addition to or in lieu of MIT, PBSF is required to perform a radioactive tracer survey (RTS) to ensure that all injection fluids are going into the injection zone. PBSF personnel monitor the pressure and conduct the tests in accordance with regulations and permit requirements. In the event of a loss of mechanical integrity, the subject injection well is immediately shut in and an investigation is initiated to determine what caused the loss of mechanical integrity. If investigation of an event identifies that a CO₂ leak has occurred, it will be reported and documented, and a plan will be developed and executed to correct the issue.

Table 4 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected through wells. Thus, the MRV plan provides adequate characterization of PBSF's approach to detect potential leakage through wells as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage through Faults, Fractures, and Bedding Plane Partings

As stated in the MRV plan, the risk of surface leakage through faults, fractures, and bedding plane partings is unlikely. PBSF will monitor leakage through faults, fractures, and bedding plane partings using the methodologies discussed in Sections 4.8.1 and 4.8.3 of the MRV plan. If that screening or

investigation identifies any indication of a CO₂ leakage to the surface in this manner, it will be reported and documented, and a plan will be developed and executed to correct the issue.

Table 4 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected through faults, fractures, and bedding plane partings. Thus, the MRV plan provides adequate characterization of PBSF's approach to detect potential leakage through faults, fractures, and bedding plane partings as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage through Lateral Fluid Movement

As stated in the MRV plan, the risk of surface leakage through lateral fluid movement is unlikely. PBSF will monitor leakage through lateral movement using the methodologies discussed in Sections 4.8.1 and 4.8.3 of the MRV plan. If that screening or investigation identifies any indication of a CO₂ leakage to the surface in this manner, it will be reported and documented, and a plan will be developed and executed to correct the issue.

Table 4 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected through lateral fluid movement. Thus, the MRV plan provides adequate characterization of PBSF's approach to detect potential leakage through lateral fluid movement as required by 40 CFR 98.448(a)(3).

4.5 Detection of Leakage through the Confining/Seal System

As stated in the MRV plan, the risk of surface leakage through the confining/seal system is unlikely. PBSF will monitor leakage through the confining/seal system using the methodologies discussed in Sections 4.8.1 and 4.8.3 of the MRV plan. If that screening or investigation identifies any indication of a CO₂ leakage to the surface in this manner, it will be reported and documented, and a plan will be developed and executed to correct the issue.

Table 4 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected through the confining/seal system. Thus, the MRV plan provides adequate characterization of PBSF's approach to detect potential leakage through the confining/seal system as required by 40 CFR 98.448(a)(3).

4.6 Detection of Leakage from Natural and Induced Seismicity

As stated in the MRV plan, the risk of surface leakage from natural and induced seismicity is unlikely. PBSF will monitor leakage from natural and induced seismicity using the methodologies discussed in Sections 4.8.1 and 4.8.3 of the MRV plan. If that screening or investigation identifies any indication of a CO₂ leakage to the surface in this manner, it will be reported and documented, and a plan will be developed and executed to correct the issue.

Table 4 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected from natural and induced seismicity. Thus, the MRV plan provides adequate characterization of PBSF's approach to detect potential leakage from natural and induced seismicity as required by 40 CFR 98.448(a)(3).

4.7 Quantification of Potential CO₂ Leakage

Section 4.10 of the MRV plan states that leakage of CO₂ on the surface will be quantified once leakage has been detected and confirmed. Major CO₂ losses are typically event-driven and require a process to assess, address, track, and if applicable, quantify potential CO₂ leakage to the surface. PBSF states that subpart W techniques will be used to estimate leakages only on equipment and ensure those results are consistently represented in the annual subpart RR report. Any event-driven leakage quantification reported in subpart RR for surface leaks will use other techniques.

According to the MRV plan, PBSF will determine the most appropriate method for quantifying the leaked volume and will report the methodology used as required as part of the annual subpart RR submission. PBSF states that leakage estimating methods may potentially consist of modeling or engineering estimates based on operating conditions at the time of the leak, such as temperatures, pressures, volumes, and hole size. An example methodology would be to place a flux box or ring tent over the surface leak to measure the flow rate and gather gas samples for analysis. The volume of CO₂ in the soil can also be used with this technique. Any volume of CO₂ detected leaking to the surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 subpart W or engineering estimates of leak amounts based on measurements in the subsurface, PBSF's field experience, and other factors such as the frequency of inspection. Records of leakage events will be retained in PBSF's electronic documentation and reporting system, which consists of reports stored on servers, with certain details uploaded into third-party software.

4.8 Determination of Baselines

Section 5 of the MRV plan describes PBSF's strategy for establishing the expected baselines for monitoring CO₂ surface leakage. The MRV plan states that ongoing operational monitoring of well pressures and rates has provided data for establishing baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO₂ leakage. Additionally, the MRV plan states that 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.

Site Characterization and Monitoring

Section 5.1 of the MRV plan states that PBSF's testing of more than 50 wells producing from the Hart reservoir showed an average of 0.25% molar concentration of CO₂ in the gas stream. Additionally, the MRV plan states that a review of gas sample data published in Higley (2014) shows the range of natural CO₂ concentration in the Central Anadarko Basin is 0.00-10.9 mole percent (average, 1.73 mole percent).

PBSF states that these field- and basin-scale data will be considered in the determination of CO₂ baseline values should a potential leak be detected.

Additionally, no significant faults or fracture zones that compromise the sealing capacity of the confining shales have been identified in PBSF, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented.

Groundwater Monitoring

Section 5.2 of the MRV plan states that PBSF obtains and tests water samples from shallow groundwater wells during the preparation of permit applications for new Class II UIC EOR injection wells. PBSF has not monitored USDW wells for CO₂ or brine contamination, as characterization of the Springer suggests that risk of groundwater contamination from CO₂ leakage from the reservoir is minimal. While groundwater contamination is unlikely to happen, any change in groundwater that is brought to the attention of PBSF will be investigated to eliminate the potential leakage pathway.

Soil CO₂ Monitoring

Section 5.3 of the MRV plan states that PBSF does not intend to collect background soil gas data. Should a possible leakage event be detected, PBSF may elect to use vapor monitoring points installed into the shallow subsurface as part of the leakage verification and quantification process.

Visual Inspection

Section 5.4 of the MRV plan states that PBSF operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage. Visual inspection consists of finding evidence of stains, unusual accumulation of frost, washouts exposing buried pipe, dead rodents, birds or reptiles, and changes to vegetation. In addition to looking for evidence of leaks, PBSF field personnel will look for conditions that could lead to equipment failure such as public utility digging, ditching, settling of backfill, boring, and tunneling.

Well Surveillance

Section 5.5 of the MRV plan states that PBSF adheres to the requirements of OAC Title 165 Chapter 10 governing fluid injection into productive reservoirs, which includes requirements for monitoring, reporting, and testing of Class II UIC injection wells, including an initial MIT prior to injection operations and subsequent MIT at least once every year or every 5 years, depending on the permitted injection rate. PBSF states that it will report any mechanical failure of surface casing or cement to the appropriate regulatory authority in full compliance with all applicable legal and regulatory requirements.

Injection Well Rates, Pressures, and Volumes

Section 5.6 of the MRV plan states that target injection rates and pressures for each injector are developed within the permitted limits based on the results of ongoing pattern surveillance. The field

operations staff monitor equipment readings and investigate any departures from the permitted limits which could have resulted in a surface CO₂ leak.

Thus, PBSF provides an acceptable approach for detecting and quantifying leakage and for establishing expected baselines in accordance with 40 CFR 98.448(a)(3) and 40 CFR 98.448(a)(4).

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

Section 6 of the MRV plan provides the equations that PBSF will use to calculate the mass of CO₂ sequestered in subsurface geologic formations.

5.1 Calculation of Mass of CO₂ Received

According to Section 6.1 of the MRV plan, PBSF can receive CO₂ via its operated pipeline from Enid, Oklahoma. PBSF also recycles CO₂ from its production wells in NEPSU and SEBAU. PBSF calculates the annual mass of CO₂ received using Equation RR-2.

$$CO_{2T,r} = \sum_{p=1}^4 (Q_{r,p} - S_{r,p}) \times D \times C_{CO_{2,p,r}} \quad (\text{Equation RR-2})$$

where:

$CO_{2T,r}$ = Net annual mass of CO₂ 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 CO₂ at standard conditions (metric tons per standard cubic meter), 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO₂ concentration measurement in flow for flow meter r in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

5.2 Calculation of Mass of CO₂ Injected

According to Section 6.2 of the MRV plan, PBSF calculates the annual mass of CO₂ injected using Equation RR-5. PBSF injects CO₂ into the wells listed in Appendix 1 of the MRV plan.

$$CO_{2,u} = \sum_{p=1}^4 Q_{p,u} \times D \times C_{CO_2,p,u} \quad (\text{Equation RR-5})$$

where:

$CO_{2,u}$ = Annual CO₂ mass injected (metric tons) as measured by flow meter u.

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

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

p = Quarter of the year.

u = Flow meter.

The MRV plan states that to aggregate injection data, PBSF will sum the mass of all the CO₂ injected through each injection well in accordance with the procedure specified in Equation RR-6.

$$CO_{2I} = \sum_{u=1}^U CO_{2,u} \quad (\text{Equation RR-6})$$

where:

CO_{2I} = Total annual CO₂ mass injected (metric tons) through all injection wells.

$CO_{2,u}$ = Annual CO₂ mass injected (metric tons) as measured by flow meter u.

u = Flow meter.

PBSF provides an acceptable approach for calculating the mass of CO₂ injected under subpart RR.

5.3 Mass of CO₂ Produced

According to Section 6.3 of the MRV plan, PBSF also recycles CO₂ from its EOR production wells in the PBSF, and therefore, Equation RR-8 is used to calculate the annual mass of CO₂ produced.

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

where:

CO_{2,w} = Annual CO₂ mass produced (metric tons) through separator w.

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter), 0.0018682.

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

p = Quarter of the year.

w = Separator.

The MRV plan states that to aggregate production data, PBSF will sum the mass of all the CO₂ separated at each gas- liquid separator in accordance with the procedure specified in Equation RR-9.

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

where:

CO_{2P} = Total annual CO₂ mass produced (metric tons) through all separators in the reporting year.

CO_{2,w} = Annual CO₂ mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO₂ in produced oil or other fluid divided by the CO₂ separated through all separators in the reporting year (weight percent CO₂, expressed as a decimal fraction).

w = Separator.

PBSF provides an acceptable approach for calculating the mass of CO₂ produced under subpart RR.

5.4 Calculation of Mass of CO₂ Emitted by Surface Leakage

According to Section 6.4 of the MRV plan, PBSF will reference the potential quantification methods described in Section 4.10 of the MRV plan to determine the total mass of CO₂ emitted by all surface leakage pathways. PBSF will calculate the total annual mass of CO₂ emitted by surface leakage using Equation RR-10.

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

where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year.

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

PBSF provides an acceptable approach for calculating the mass of CO₂ emitted by surface leakage under subpart RR.

5.5 Calculation of Mass of CO₂ Sequestered

According to Section 6.5 of the MRV plan, Equation RR-11 will be used to calculate the annual mass of CO₂ sequestered in subsurface geologic formations.

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

where:

CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

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

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

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

PBSF provides an acceptable approach for calculating the mass of CO_2 sequestered under subpart RR.

6 Summary of Findings

The subpart RR MRV plan for Northeast Purdy Springer Unit (NEPSU) / South East Bradley A Unit (SEBAU) meets the requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448(a), which specify the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the PBSF MRV plan.

Subpart RR MRV Plan Requirement	Northeast Purdy Springer Unit (NEPSU) / South East Bradley A Unit (SEBAU) MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 3 of the MRV plan defines and delineates the MMA and AMA. PBSF states that the AMA is defined by the combined boundaries of NEPSU and SEBAU plus a buffer zone of at least one-half mile. PBSF also states that the MMA is defined as equivalent to the AMA.
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 4 of the MRV plan identifies and evaluates potential surface leakage pathways. PBSF identifies the following potential pathways: surface equipment; wells; faults, fractures, and bedding plane partings; lateral fluid movement; confining/seal system; and natural and induced seismic activity. The MRV plan

	analyzes the likelihood, magnitude, and timing of surface leakage through these pathways.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO ₂ .	Section 4 of the MRV plan describes the strategies that PBSF will use to detect and quantify any surface leakage of CO ₂ . Specifically, PBSF states in Section 4.10 of the MRV plan that leakage estimating methods may potentially consist of modeling, direct measurement, or engineering estimates based on operating conditions at the time of the leak, such as temperatures, pressures, volumes, and hole size.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO ₂ surface leakage.	Section 5 of the MRV plan describes PBSF's strategy for establishing the expected baselines for monitoring CO ₂ surface leakage. PBSF identifies the following baselines: site characterization and monitoring; groundwater monitoring; soil CO ₂ monitoring; visual inspections; well surveillance; and injection well rates, pressures, and volumes.
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 PBSF's approach to determining the amount of CO ₂ sequestered using the subpart RR mass balance equation. PBSF will calculate the annual mass of CO ₂ sequestered using Equation RR-11.
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.	Appendix 1 of the MRV plan provides the well identification numbers for all active wells in PBSF as of January 2025. The MRV plan specifies that all the injection wells in the PBSF are permitted by OCC 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 the proposed date on which PBSF will begin collecting data for calculating the total amount of CO ₂ sequestered according to Equation RR-11 is expected to begin in 2026 after the MRV Plan is approved and a supply of fresh CO ₂ is secured.

Appendix A: Submissions and Responses to Requests for Additional Information

**Purdy-Bradley Springer Field:
Northeast Purdy Springer Unit (NEPSU) /
South East Bradley A Unit (SEBAU)**

Monitoring, Reporting, and Verification (MRV) Plan

**Daylight Petroleum, LLC
August 2025**

Contents

Introduction	1
1.0. Facility	2
1.1. Reporter Number.....	2
1.2. UIC Permit Class.....	2
1.3. UIC Injection Well Numbers.....	2
2.0. Project Description	2
2.1. Project Characteristics	2
2.1.1. Estimated Years of CO ₂ Injection.....	2
2.1.2. Estimated Volume of CO ₂ Injected Over Lifetime of Project	2
2.2. Environmental Setting of MMA	2
2.2.1. Boundary of the MMA.....	2
2.2.2. Geology.....	2
2.2.3. Hydrogeology.....	9
2.3. Description of the CO₂ Injection Process.....	9
2.3.1. CO ₂ Collection and Distribution	12
2.3.2. Injection and Production Well Operations	12
2.3.3. Produced Fluids Handling and Gas Processing and Compression.....	12
2.3.4. Well Operations and Permitting	16
2.3.5. Number, Location, and Depth of Wells	17
2.4. Reservoir Description	17
2.4.1. Reservoir Characteristics	17
2.4.2. Reservoir Fluid Modeling.....	22
2.4.3. CO ₂ Analytical Sweeping Efficiency Calculation	22
2.4.4. CO ₂ -EOR Performance Projections.....	26
3.0. Delineation of Monitoring Area.....	30
3.1. Determination of CO₂ Storage Volumes.....	30
3.2. Active Monitoring Area (AMA)	30
3.2.1. Determination of Buffer Zone.....	30
3.3. Maximum Monitoring Area (MMA)	30
4.0. Identification and Evaluation of Leakage Pathways	31
4.1. Leakage from Surface Equipment	31
4.2. Leakage from Wells	31
4.2.1. Abandoned Wells	32
4.2.2. Injection Wells.....	32
4.2.3. Production Wells	32
4.2.4. Inactive Wells.....	34
4.2.5. New Wells	34
4.3. Leakage from Faults, Fractures, and Bedding Plane Partings	34
4.3.1. Presence of Hydrocarbons	34

4.3.2.	Fracture Analysis	34
4.4.	Lateral Fluid Movement.....	34
4.5.	Leakage through Confining/Seal System.....	35
4.6.	Natural and Induced Seismic Activity.....	35
4.7.	Likelihood, Timing, and Magnitude of Potential Surface Leakage.....	37
4.8.	Strategy for Detection of CO₂ Loss	38
4.8.1.	Data System	38
4.8.2.	Visual Inspections.....	38
4.8.3.	Injection Target Rates and Pressures	38
4.8.4.	Production Wells	38
4.8.5.	Continuous Plant and Pipeline Monitoring.....	39
4.8.6.	Well Testing	39
4.9.	Strategy for Response to CO₂ Loss	39
4.10.	Strategy for Quantifying CO₂ Loss	41
4.11.	Demonstration at End of Specified Period	41
5.0.	Strategy for Determining CO₂ Baselines for CO₂ Monitoring	42
5.1.	Site Characterization and Monitoring	42
5.2.	Groundwater Monitoring	42
5.3.	Soil CO ₂ Monitoring	42
5.4.	Visual Inspection.....	42
5.5.	Well Surveillance	43
5.6.	Injection Well Rates, Pressures, and Volumes	43
6.0.	Site-Specific Considerations for Determining the Mass of CO₂ Sequestered	43
6.1.	Determining Mass of CO ₂ Received.....	43
6.2.	Determining Mass of CO ₂ Injected	44
6.3.	Determining Mass of CO ₂ Produced from Oil Wells	44
6.4.	Determining Mass of CO ₂ Emitted by Surface Leakage	45
6.5.	Determining Mass of CO ₂ Sequestered	45
7.0.	Estimated Schedule for Implementation of MRV plan.....	46
8.0.	GHG Monitoring and Quality Assurance Program	46
8.1.	GHG Monitoring	46
8.1.1.	General	46
8.1.2.	CO ₂ Received.....	47
8.1.3.	CO ₂ Injected	47
8.1.4.	CO ₂ Produced	47
8.1.5.	CO ₂ Emissions from Equipment Leaks and Vented Emissions of CO ₂	47
8.1.6.	Measurement Devices.....	48
8.2.	QA/QC Procedures.....	48
8.3.	Estimating Missing Data	48
8.4.	Revisions to the MRV plan	48
9.0.	Records Retention	49

List of Figures	50
List of Tables	50
Appendix 1 – List of Wells	51
Appendix 2 – References.....	52
Appendix 3 – Abbreviations and Acronyms.....	54
Appendix 4 – Conversion Factors	56
Appendix 5 – Koval Factor Calculation	57
Appendix 6 – Muskat Model Description	58

Introduction

Daylight Petroleum, LLC (Daylight) operates the Northeast Purdy Springer Unit (NEPSU) / South East Bradley A Unit (SEBAU), collectively referred to as the Purdy-Bradley Springer Field, in south-central Oklahoma for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO₂) flooding on the behalf of PBMS Oil, LLC. As a secondary purpose, Daylight intends to establish secure geological storage (sequestration) of a measurable quantity of CO₂ in subsurface geologic formations at the Purdy-Bradley Springer Field. Daylight intends to continue CO₂-EOR operations until the end of economic life of the field, with the subsequent goal of long-term storage of CO₂ in geologic formations (sequestration).

Daylight has developed this Monitoring, Reporting, and Verification (MRV) Plan in accordance with 40 Code of Federal Regulations (CFR) 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in Section 45Q of the Internal Revenue Code. Daylight intends to implement this MRV plan for both NEPSU and SEBAU, and upon merging of the facilities in the United States Environmental Protection Agency (USEPA) system will begin reporting under a single identification number.

This MRV Plan contains nine sections:

Section 1 – General facility information.

Section 2 – Project description. Contains details of the injection operation, including duration and volume of CO₂ to be injected; a description of the geology and hydrogeology of the Purdy-Bradley Springer Field; and a description of the injection reservoir assessment techniques.

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

Section 4 – Evaluation of potential surface leakage pathways for CO₂ in the MMA as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP. A strategy is proposed for detecting, verifying, and quantifying any surface leakage of CO₂ as required by 40 CFR 98.448(a)(3), Subpart RR of the GHGRP. Other than wellbores and surface equipment, the risk of CO₂ leakage through identified pathways is demonstrated as minimal.

Section 5 – Strategy for monitoring to identify CO₂ surface leakage, including establishment of baselines to assess for potential leaks and the proposed monitoring process, as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP. Monitoring will focus primarily on identifying potential leaks through wellbores and surface equipment.

Section 6 – Summary of the mass balance calculations and site-specific variables used to determine the volume of CO₂ sequestered as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 7 – Estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 8 – Quality assurance and quality control procedures to ensure data integrity.

Section 9 – Program for records retention as required by 40 CFR 98.3(g), Subpart A of the GHGRP, and 40 CFR 98.447, Subpart RR of the GRGRP.

Appendices with supplemental data are provided at the end of this document (Appendix 1 includes an attachment).

1.0. Facility

1.1. Reporter Number

Historically, the facility identifiers were 545261 for NEPSU and 545263 for SEBAU. Both units are now merged into one facility identifier (545261) under the name Northeast Purdy Springer Unit (NEPSU) / South East Bradley A Unit (SEBAU).

1.2. UIC Permit Class

The EOR wells covered by this MRV Plan are permitted and operated as Class II Underground Injection Control (UIC) wells under the jurisdiction of the Oklahoma Corporation Commission (OCC), which has primacy for administering Class II UIC regulations in the state.

1.3. UIC Injection Well Numbers

A list of all wells (including injection wells) in the NEPSU and SEBAU is provided as part of **Appendix 1**. Wells are identified by name, unique well identifier (UWI, using a 14-digit American Petroleum Institute [API] number), status, and type. The list is current as of January 2025, around the time this MRV Plan was created.

2.0. Project Description

2.1. Project Characteristics

2.1.1. Estimated Years of CO₂ Injection

CO₂ has been injected at the NEPSU since 1982 and at the SEBAU since 1997. Daylight intends to continue injecting CO₂ for the foreseeable future.

2.1.2. Estimated Volume of CO₂ Injected Over Lifetime of Project

Historical and forecasted cumulative CO₂ retention capacity is up to approximately 278 billion standard cubic feet (Bscf), or 14.7 million metric tons (MMT), from the start of CO₂ injection through March 2054.

2.2. Environmental Setting of MMA

2.2.1. Boundary of the MMA

Daylight has defined the boundary of the MMA as equivalent to the boundaries of the NEPSU and SEBAU plus a minimum of a half-mile buffer. A discussion of the methods used in delineating the MMA and the AMA is presented in **Section 3**.

2.2.2. Geology

This geologic description of the Purdy-Bradley Springer Field incorporates regional literature, field development studies, core and well log data, and the interpretations of Daylight, legacy operators, laboratories, and service companies.

Tectonic and Structural Setting

The Purdy-Bradley Springer Field is located within the Golden Trend of South-Central Oklahoma, in the southeastern embayment of the Anadarko Basin (**Figure 1**). The Anadarko Basin contains up to 40,000 feet of sedimentary rock and is a prolific hydrocarbon producer (Ball, Henry, and Frezon, 1991). This asymmetrical foreland basin is structurally deepest along its southern margin and is separated to the south and southeast from Cambrian-age crystalline rocks exposed in the Wichita Mountains (Ham et al., 1964; Perry, 1989). In updip areas, particularly around structural features that define the basin margins, sedimentary units are commonly truncated by onlap or erosion.

Structural development of the Anadarko Basin was preceded by crustal extension in the Precambrian and formation of the southern Oklahoma aulacogen, or failed rift, during the Cambrian (Perry, 1989). At the end of rifting, the aulacogen cooled and subsided, creating a trough that was filled with Cambrian through lower Mississippian sediments. The Anadarko Basin developed on the northwestern flank of this trough during the late Mississippian through Pennsylvanian as a result of the Wichita Orogeny. During the orogeny, the Wichita and Arbuckle mountains were uplifted and thrust over the southern margin of the trough, causing renewed subsidence and creating the Anadarko Basin. Faulting and uplift associated with the Wichita-Arbuckle structural trend peaked in the early Pennsylvanian and had mostly ended by Permian time (Ball, Henry, and Frezon, 1991).

Producing structures in the Anadarko Basin range from complex combinations of folds and fault blocks to simpler, homoclinally dipping sediment wedges that form stratigraphic traps through erosion or facies change. The Golden Trend, which is bounded by the Nemaha-Pauls Valley uplifts on the east and by the Arbuckle Mountains to the south, produces hydrocarbons from Ordovician through Permian-age rocks (Swesnick, 1950). The NEPSU and SEBAU are two of numerous Pennsylvanian-age reservoirs formed by tilting and truncation. These units produce from the Cunningham Sandstone in the upper part of the Springer series, with shales of the upper Springer, Morrow, and Atoka series providing seal. Uplift of the Pauls Valley arch in late Springerean or early Morrowan time (Pennsylvanian) resulted in erosion of the southwest flank of the structure as Springer sands were tilted to the southwest, creating a stratigraphic trap below the unconformity.

Stratigraphy

A generalized basin stratigraphy applicable to the Purdy-Bradley Springer field area is shown in **Figure 2** and summarized below. Stratigraphic units are listed from oldest to youngest (adapted from Ball, Henry, and Frezon, 1991, except as noted):

- Granite wash and sandstone overlying igneous basement rocks
- Arbuckle Group (Cambrian to Ordovician) – Interior platform carbonates and tidal-flat mudstones; porous dolomite is common in the Western Anadarko basin, while tight facies are more common in the eastern basin.
- Simpson Group (Ordovician) – Erosionally truncated sandstones sealed by overlying Pennsylvanian shales
- Viola Limestone (Ordovician) – Dense limestone, locally dolomitized
- Hunton Group (Silurian-Devonian) – Fractured and dolomitized carbonates sealed and sourced by the overlying, organic-rich Woodford Shale

- Kinderhook, Osage, and Meramec Series (Mississippian) – Fractured limestones that shale out basinward; deposition followed by uplift and erosion resulting from the Wichita Orogeny
- Springer Group (Pennsylvanian – Springerean series) – Deltaic and shallow marine sands deposited during a marine regression, with potential reservoirs including feeder channels, upper-fan channels, middle-fan channels and sheet sands, and distal-fan sheet sands. The section reaches a maximum total thickness of 6,000 feet, though sands are on the order of tens to more than 100 feet thick, with dark shales comprising the remaining thickness. In the NEPSU and SEBAU, the Cunningham Sandstone in the upper Springer series is the historical and current production target.
- Dornick Hills Group (Pennsylvanian – Morrowan and Atokan series) – Mostly transgressive shales with sandstones (e.g., Primrose) deposited during brief regressions
- Deese Group (Pennsylvanian – Des Moinesian series) – Shales and sands (e.g., Osborne and Hart) derived from erosion of uplifted crystalline basement rocks, primarily forming stratigraphically trapped reservoirs
- Hoxbar Group (Pennsylvanian – Missourian series) – Shales and limestones (e.g., Hogshooter and Checkerboard)
- Pontotoc Group (Permian) – Conglomerates, sandstones, and mudstones
- Sumner Group (Permian) – Garber-Wellington interval consisting of sandstones, shales, and conglomerates
- Hennessey Formation (Permian) – Shale with red siltstones and very fine-grained sandstones; one of two bedrock units, along with the Duncan Sandstone of the El Reno Group, that are present at surface within the Purdy-Bradley Springer Field (Chang and Stanley, 2010)
- El Reno Group (Permian) – Duncan Sandstone and undifferentiated sandstone and shale, present at surface within the Purdy-Bradley Springer Field (Chang and Stanley, 2010)
- Alluvium (Holocene) – Clay, silt, sand, and gravel deposited in channels and on floodplains of modern streams (Chang and Stanley, 2010)

NEPSU Reservoir

The Lower Pennsylvanian Cunningham Sandstone, historically referred to as the Springer “A” sand, was deposited in shallow marine settings and consists of southwest-dipping, fine- to medium-grained siliceous sandstone (Cities Service Company, 1978; Fox et al., 1988). Within the reservoir are two lower zones deposited as bar sands on a shallow marine shelf and two upper zones consisting of channel sands.

The reservoir trends northwest-southeast and is approximately 9 miles long and 1-3 miles wide, comprising 15.6 square miles or ~10,000 acres (NEPSU, 1979). Reservoir and unit boundaries were established by erosional truncation of the Cunningham Sandstone and the original oil-water contact (Cities Service Company, 1978). The sands dip approximately 8 degrees to the southwest, and legacy core analysis showed the presence of “tight” layers within the clean sand reservoir (NEPSU, 1979). The reservoir is at a depth of about 8,000-9,000 feet, has an average porosity of 13% and permeability of 44 millidarcies (mD), and had an average initial water saturation of 18%.

Mineralogy is primarily quartz, with limited calcitic cements in shalier intervals and kaolinite, illite, and smectite within the clay fraction. These clay minerals are believed to remain stable under reservoir conditions.

SEBAU Reservoir

The geologic and reservoir properties of the SEBAU are similar to those of the NEPSU. In this unit the Springer strata were deposited in shallow marine tidal bar and channel settings (Oxy, 1998). Fine- and medium-grain sand with shale laminations and dominantly clay cements comprise the primary reservoir facies of the Cunningham Sandstone. A high degree of vertical and lateral facies heterogeneity is present as a result of shoreline deposition. Upper, middle, and lower flow units are recognized, truncated by faults to the south and west and stratigraphic pinch-outs and erosional surfaces to the northeast. The upper sand, usually the only productive flow unit, is 25-200 feet thick and 8,900-10,800 feet deep. Porosity averages 12.5% and permeability is 58 mD (Oxy, 1988). Permeability-porosity relationships are inconsistent in part because of reservoir heterogeneity.

Primary Seals

Reservoirs of the Springer are sandstone bodies that have lateral porosity and permeability variations and are encased in shale (Ball, Henry, and Frezon, 1991). At the Purdy-Bradley Springer Field, the Cunningham Sandstone is top-sealed by shales of the upper Springerean and Morrowan series that directly overlie the reservoir unit and by truncation against the base Atoka unconformity. The Cunningham is tilted and eroded below the unconformity. Above the unconformity, the Cunningham is sealed by shales of the lower Atokan series.

Bottom Seal

The Goddard Shale is the bottom seal for the Cunningham Sandstone and varies in thickness from 1,550 feet to 2,000 feet within the units. It is homogenous and rich in ductile swelling clays (smectite). The Goddard Shale also serves as a top seal of large overpressured zones (Mississippian and Devonian reservoirs) in the deep Anadarko basin. The high ductility, thickness, and overpressuring of this shale package make it a highly effective bottom seal for the Cunningham Sandstone.

Well Log Analysis

A reference petrophysical well log (SE Bradley A Unit O-19A) through the reservoir and overlying shales is shown in **Figure 3**. In this well, the Cunningham Sandstone is approximately 50 feet thick, with an approximate porosity range of 10-20% as estimated from the sonic (SPHI), neutron (NPHI), and density porosity (DPHI) logs. A permeability response in the sands is also observed in the deflection of the spontaneous potential (SP) log. These reservoir sands (yellow shade on the gamma ray [GR] log) are truncated just below the unconformity and are overlain by an estimated 170 feet of net shale (brown shade on GR log) within the Osborne section, providing separation and confinement from the Hart sandstones above. Within the Hart are another 110 feet of net shale, and as previously shown in **Figure 2** additional shales overlie the Hart section. Daylight's broader review of well logs in the field shows total net shale thickness above the Cunningham exceeds 1,200 feet, which is sufficient to prevent vertical migration of CO₂ and other fluids to the surface or into underground sources of drinking water (USDWs).

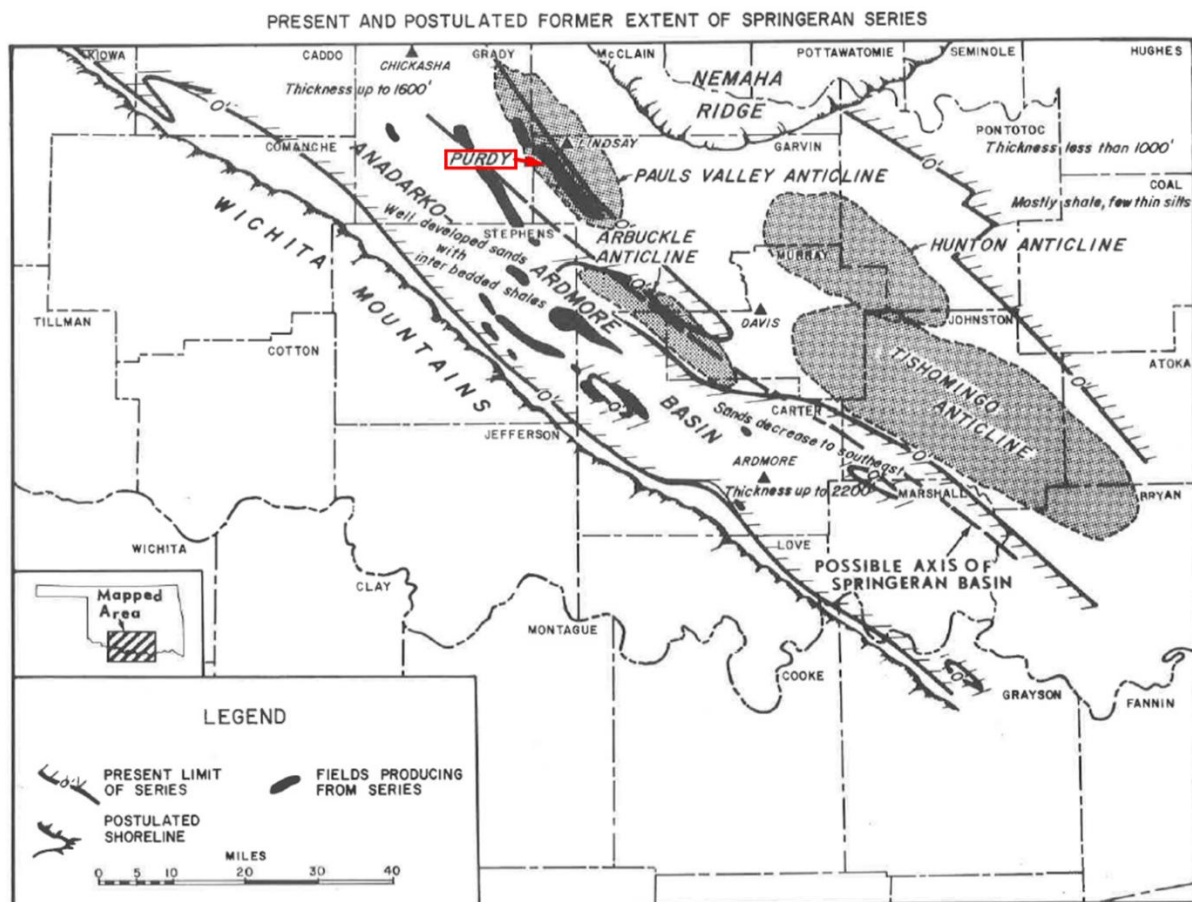
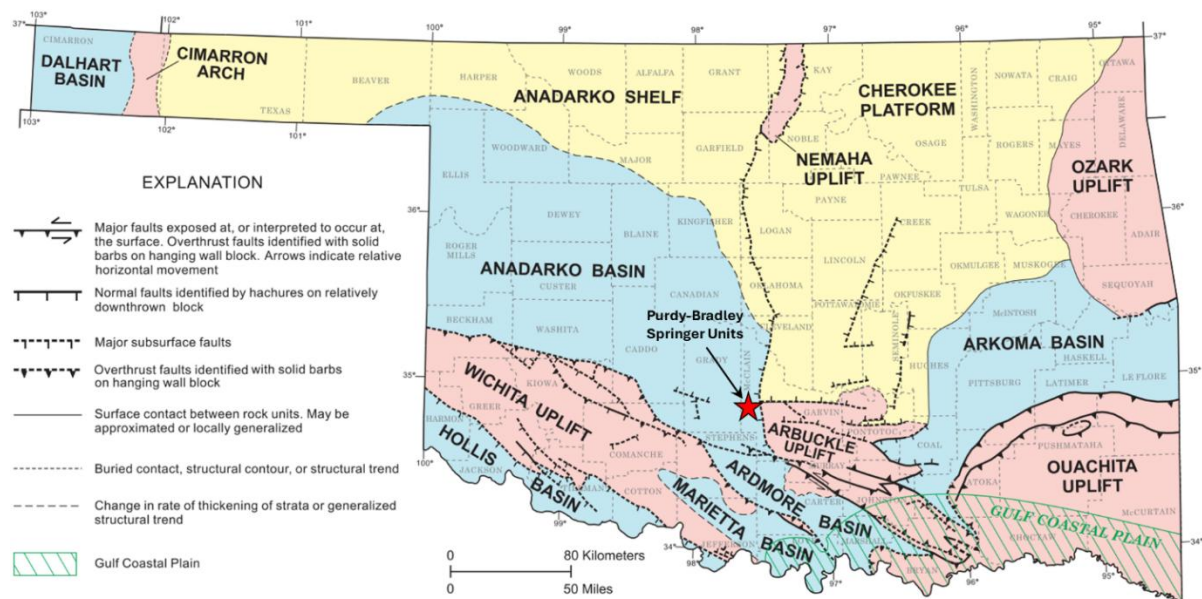


Figure 1: Top panel shows the location of the Purdy-Bradley Springer Field in the Anadarko Basin, South-Central Oklahoma, and proximity to major structural features (adapted from Johnson and Luza, 2008). Bottom panel shows the field location in relation to smaller-scale structures, the extent of the Springer series, and the locations of other Springer fields in the Anadarko-Ardmore basin trend (adapted from Cities Service Company, 1978).

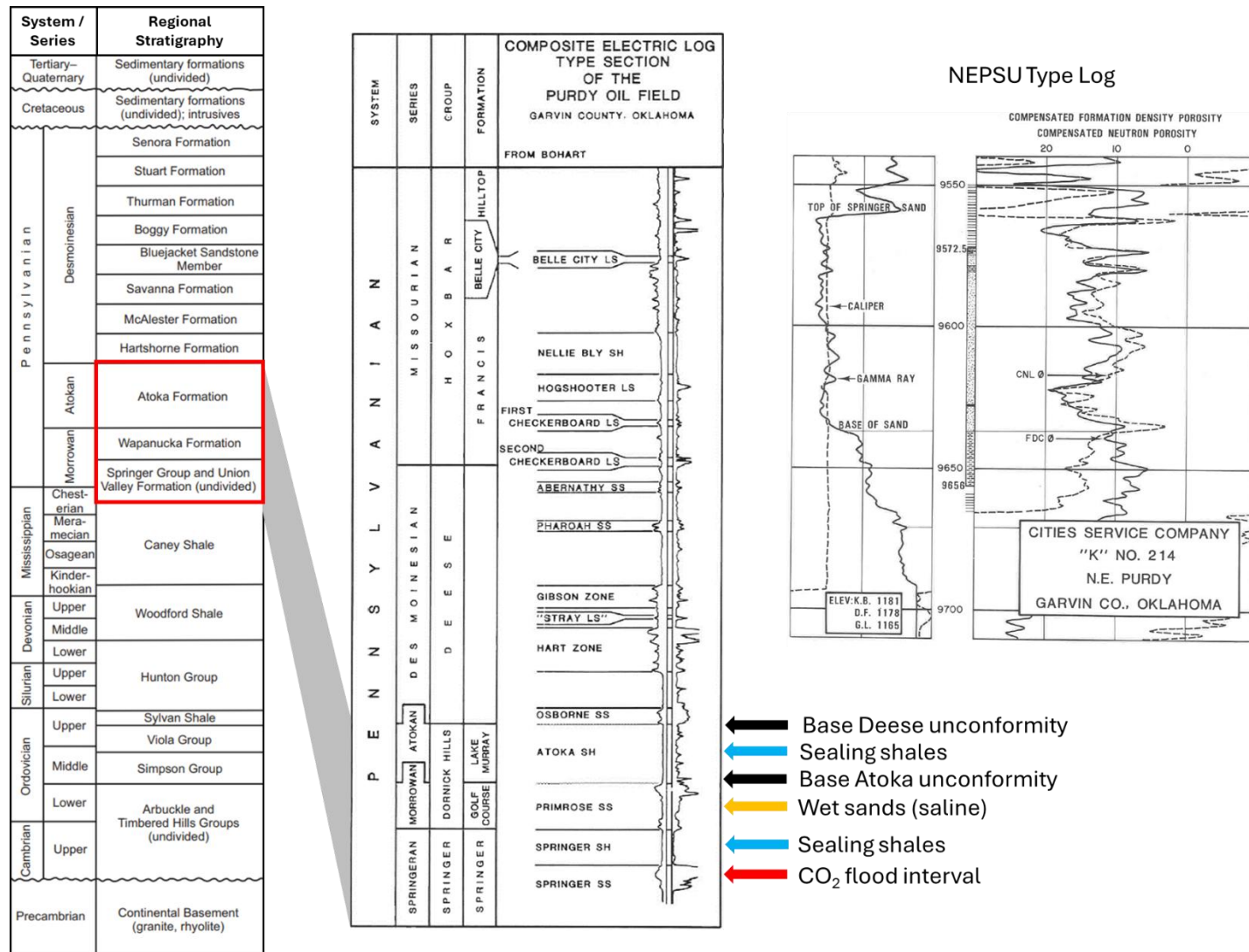


Figure 2: Regional stratigraphic column (left) shows the ages and names of sedimentary rock units in the Anadarko Basin from basement to surface. Center chart shows the type section for the Purdy-Bradley Springer Field and relation to the regional stratigraphy; colored arrows identify key units and surfaces in the Purdy-Bradley Springer Field. Note the multiple shale layers that serve as sealing units for the Springer (Cunningham Sandstone) reservoir. At right is the type log for the Northeast Purdy Springer Unit (NEPSU) reservoir, showing porosity (average ~12%) and gamma ray well log response in the Cunningham Sandstone.

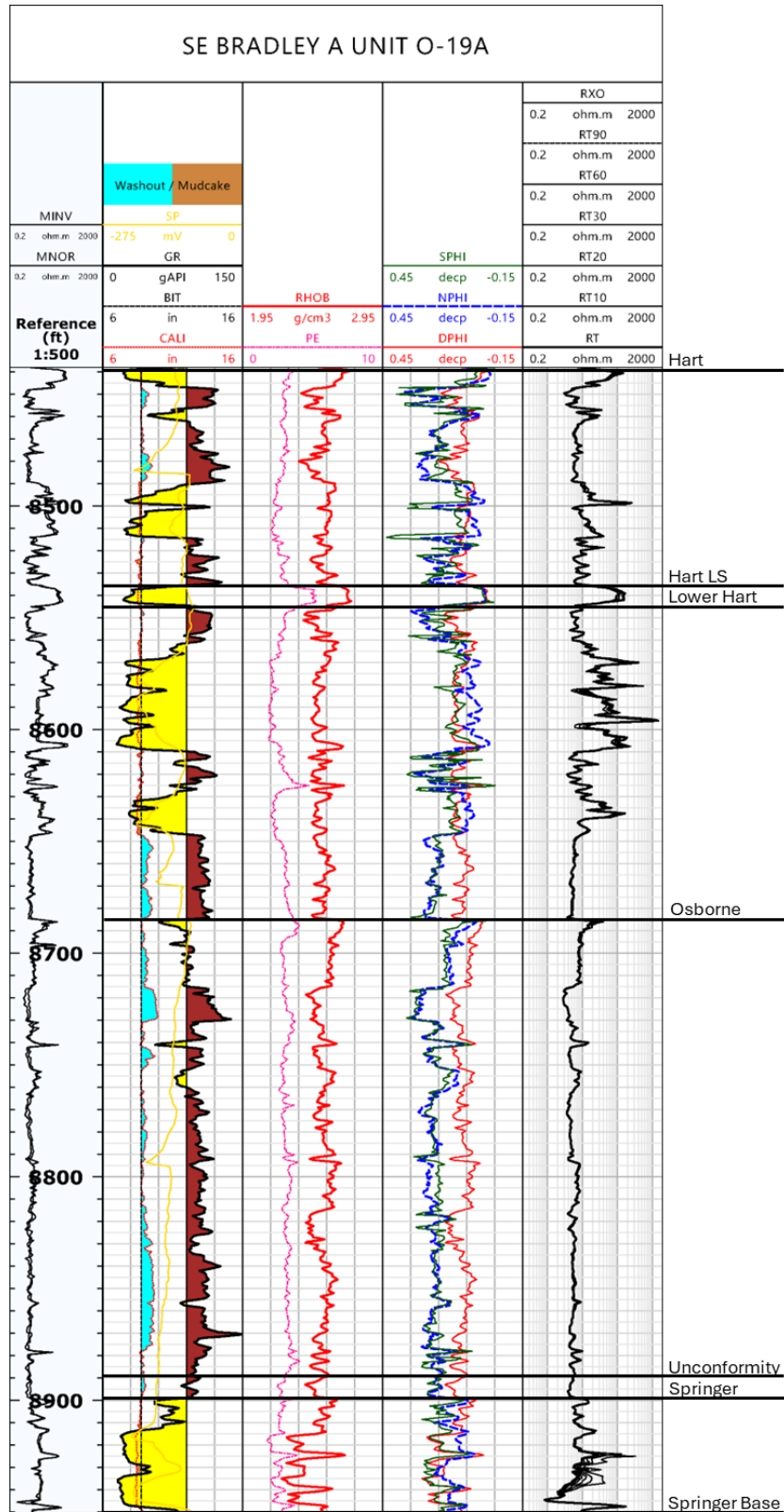


Figure 3: Type log showing the Cunningham Sandstone (at ~8,900-8,950 feet in the Springer reservoir) and overlying shales (seal). The well is located in the SE 1/4 of Section 7, T4N, R4W (API: 3504925047).

2.2.3. Hydrogeology

Groundwater flow rates in confined deep Anadarko layers are considered to be low-flow to no-flow, based on four lines of evidence presented by Nelson and Gianoutsos (2014). First, recharge of groundwater into Pennsylvanian and older strata is limited due to the presence of a low-permeability Permian cap. Second, stratigraphic pinch-outs establish a western limit of recharge. Third, highly saline formation water along the Nemaha uplift creates a west-to-east flow density barrier. Lastly, fluid movement is restricted by overpressured strata in the deep basin.

Further evidence of stratigraphic pinch-out that is more specific to the NEPSU and SEBAU is documented in internal studies developed by previous operators, including a geologic and reservoir description (Oxy, 1988) and a feasibility analysis of applying EOR methods (Cities Service Company, 1978). The SEBAU is isolated by faults to the south and west and pinched out or erosionally truncated to the northeast, while the NEPSU is bounded to the north by erosional truncation and to the southwest by a fault. Jorgensen (1993) suggested that, beginning during the Laramide Orogeny and continuing to present, the groundwater flow is west to east, driven by recharge at elevated units to the west. The NEPSU and SEBAU CO₂ injection and production operations therefore are considered unlikely to cause water to flow to the outcrops.

Groundwater is generally at shallow depths, with the base of treatable water approximately 100-300 feet deep (**Figure 4**). In Oklahoma, the base of treatable water is equivalent to the deepest USDW. The base of treatable water depth is relatively consistent throughout the MMA, deepening to the west and south of the MMA. The shallow base of treatable water provides upward of 8,000 feet minimum vertical separation from the Purdy-Bradley Springer Field injection interval.

2.3. Description of the CO₂ Injection Process

Figure 5 shows a simplified flow diagram of the CO₂-EOR operations within the boundaries of the NEPSU and SEBAU. Historically, a fertilizer plant in Enid, Oklahoma, has been the only source of CO₂, with CO₂ captured from the plant delivered via a Daylight-operated pipeline to the field for injection. No new CO₂ has been received since 2022, but Daylight is currently working with multiple emitters to source additional CO₂ for the EOR project. These potential sources include gas processing plants, landfills, fertilizer plants, refineries, and ethanol plants.

Currently, the CO₂-EOR operations involve three main processes. These processes are detailed in the subsections below and include:

1. **CO₂ distribution and injection.** Purchased CO₂ (when applicable) is combined with recycled CO₂ obtained from the produced gas stream and sent through the main CO₂ distribution system to various water alternating gas (WAG) injectors.
2. **Injection and production well operations.** As of January 2025, 23 injection and 36 production wells were active in the SEBAU, and 69 injection and 88 production wells were active in the NEPSU. Production is a mixture of oil, water, and CO₂ or other gases.
3. **Produced fluids handling and gas processing and compression.** Produced fluids and gases flow to satellite batteries and/or centralized tank batteries for separation. The gas phase is transported via a field gathering system to the Lindsay Gas Plant for further gas processing to dehydrate and remove natural gas liquids and hydrocarbon fuel gas. The separated CO₂ gas stream is returned to the field via a CO₂ gas distribution system for compression and injection to the producing reservoir.

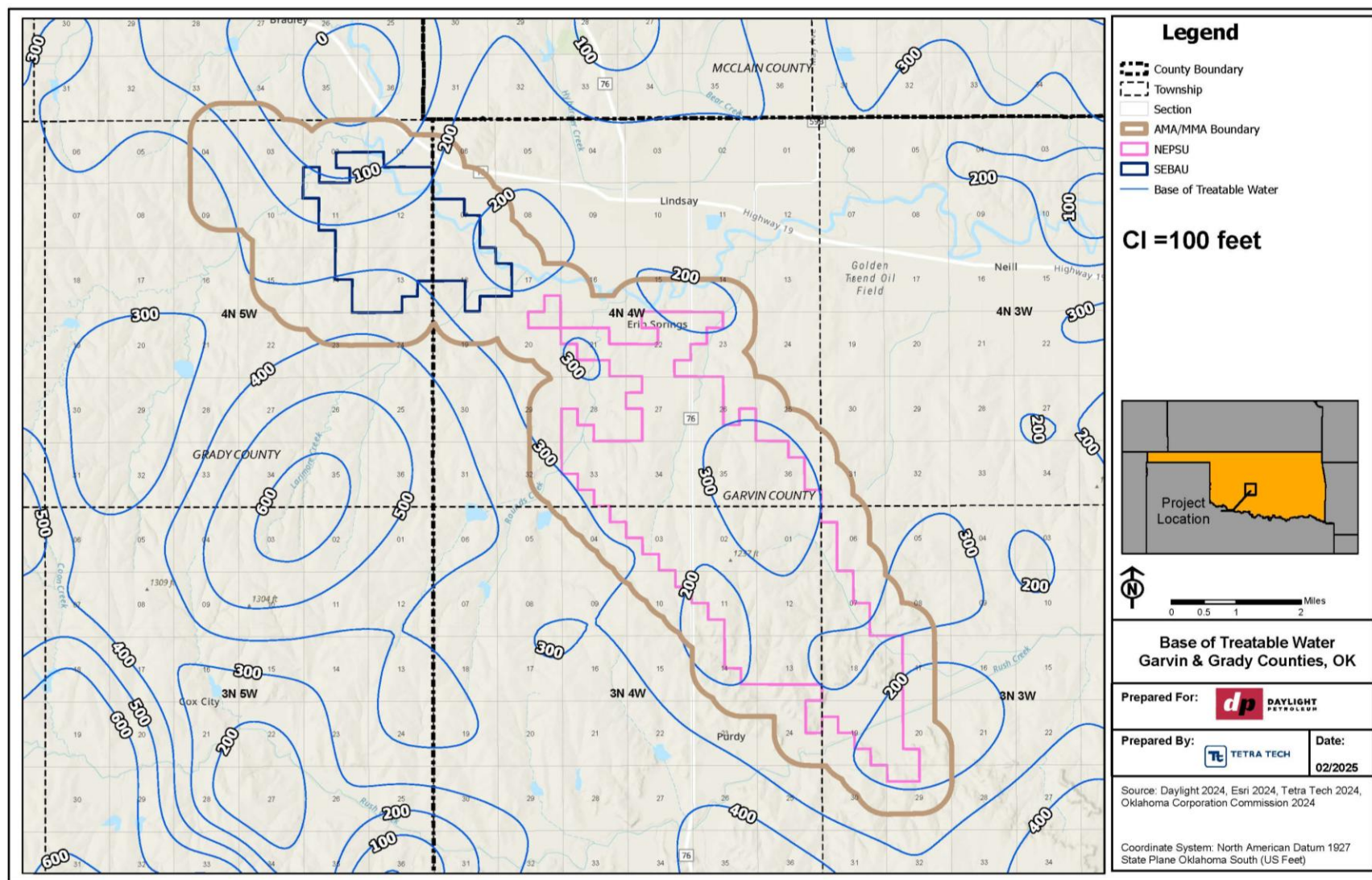


Figure 4: Depth (feet) to base of treatable water

Satellites provide 3 phase separation and testing for the producers, they also hold compression and H Pumps for reinjection of Processed Gas (from Plant) and Water (separated on site)

EOR Summary

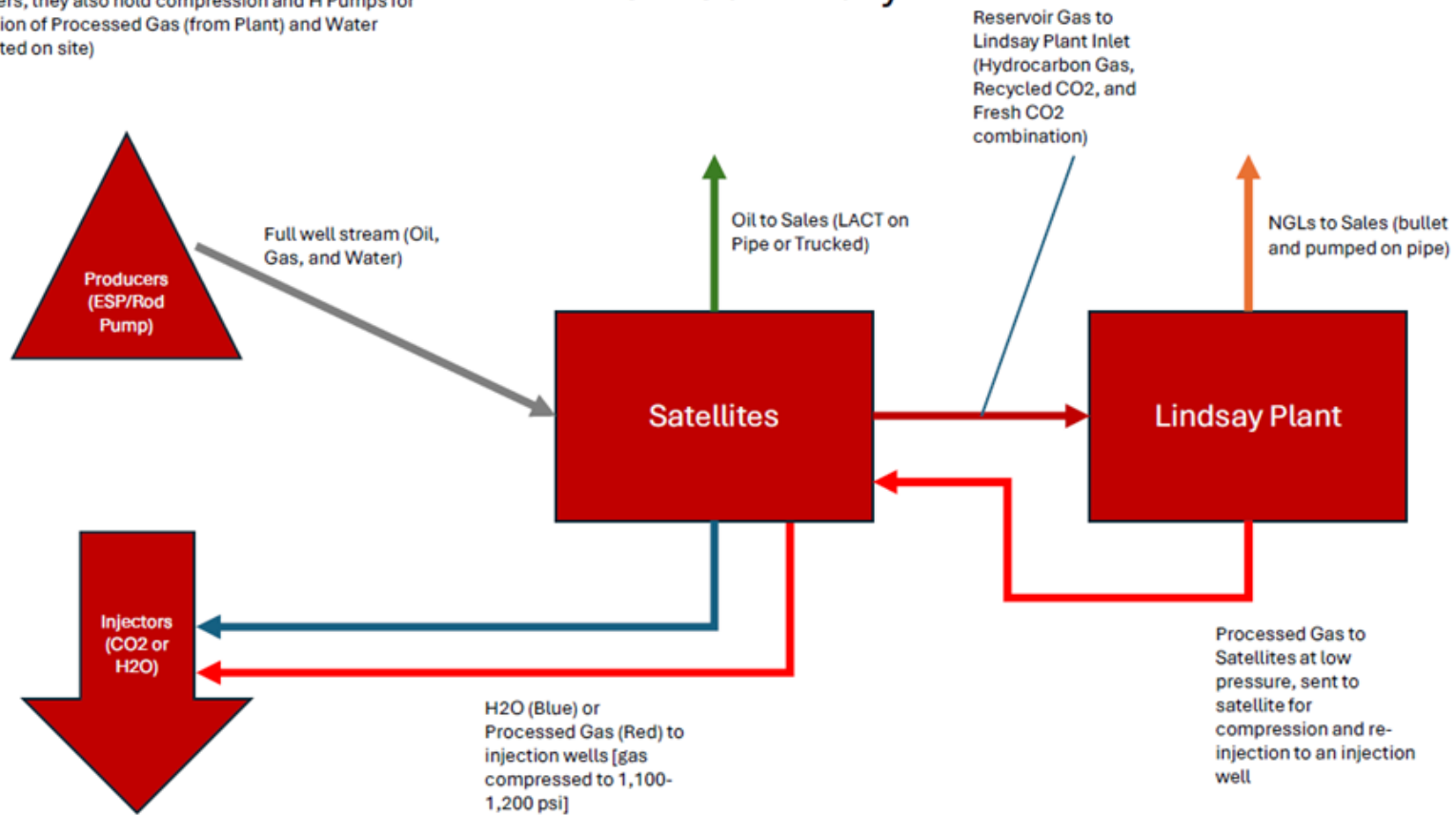


Figure 5: Simplified flow diagram of the CO₂-EOR operations within the Purdy-Bradley Springer Field

2.3.1. CO₂ Collection and Distribution

The CO₂ delivered to the NEPSU and SEBAU is supplied by one or more sources. Historically, new CO₂ delivered from the fertilizer plant was sent through an injection pipeline distribution system to CO₂ injection wells throughout the two units. Produced (recycled) CO₂ is received from Daylight's Lindsay Gas Plant, which extracts natural gas liquids (NGLs) from the produced gas stream (consisting of CO₂ and hydrocarbon gas). The produced gas stream is transported to the Lindsay plant via gathering lines. The gas compression process consists of gathering CO₂ and other produced gases, processing an NGL stream that is sold via pipeline at the plant, and sending CO₂ back out to satellites for compression and reinjection into the injection wells. The CO₂ collection and distribution process is illustrated in **Figure 6**.

Currently, CO₂ delivered to the floods for injection is received through many meters, including at the Purdy Tee delivery point, the source receipt point, the plant outlet, the recycle CO₂ source point, and at each injection well. All CO₂ that flows through the meters is sent through CO₂ injection lines to individual injection wells in the floods, in many instances through manifolds and distribution lines prior to arriving at an injection well. A flow meter at each injection well measures the injection rate of the CO₂ or water. Currently, for any given CO₂ injection well, the CO₂ injected may be sourced from the CO₂ pipeline, the Lindsay plant, or a combination of both. The ratio of CO₂ sources is expected to fluctuate over the course of time.

2.3.2. Injection and Production Well Operations

As of January 2025, 23 injection and 36 production wells were active in the SEBAU, and 69 injection and 88 production wells were active in the NEPSU. Currently, each injection well can inject CO₂, water, or both, at various rates and injection pressures, as determined by Daylight. Upon injection of CO₂ or water into the reservoir, a mixture of oil, water, CO₂ and/or other gases (collectively, produced fluids) is mobilized toward and produced at one or more production wells.

2.3.3. Produced Fluids Handling and Gas Processing and Compression

The produced fluids handling system gathers fluids from the production wells throughout various satellite batteries in the units, via gathering lines that combine, collect, and commingle the produced fluids. The mixture of produced fluids (oil, water, and gas including CO₂) flows to one of 10 satellite separation facilities or batteries and then to a centralized tank battery. Each satellite is equipped with well test equipment to measure production rates of oil, gas, and water from individual production wells.

The fluids stream is further separated into oil and water, which is recovered for reuse, re-injection, or disposal. The produced fluids handling process is illustrated in **Figure 7**. Produced oil is sold via truck or through one or more lease automatic custody transfer (LACT) units located at centralized tank batteries. The gas stream, consisting of CO₂ and other gases, is transported to the Lindsay plant via gas gathering lines throughout the fields.

The produced gas compression process (**Figure 8**) consists of gathering CO₂ and other gases produced from the floods, processing an NGL stream that is sold via pipeline at the plant, and sending CO₂ back to satellite compression for reinjection into the injection wells. The average gas mixture composition is ~82-90% CO₂, with the remaining portion comprising hydrocarbons and trace nitrogen (N₂). Future plant modifications would be intended to produce a higher-quality fuel gas stream for use on-site that would also result in a higher-quality CO₂ stream for sequestration. The CO₂ concentration is likely to change over time as CO₂-EOR operations continue and expand.

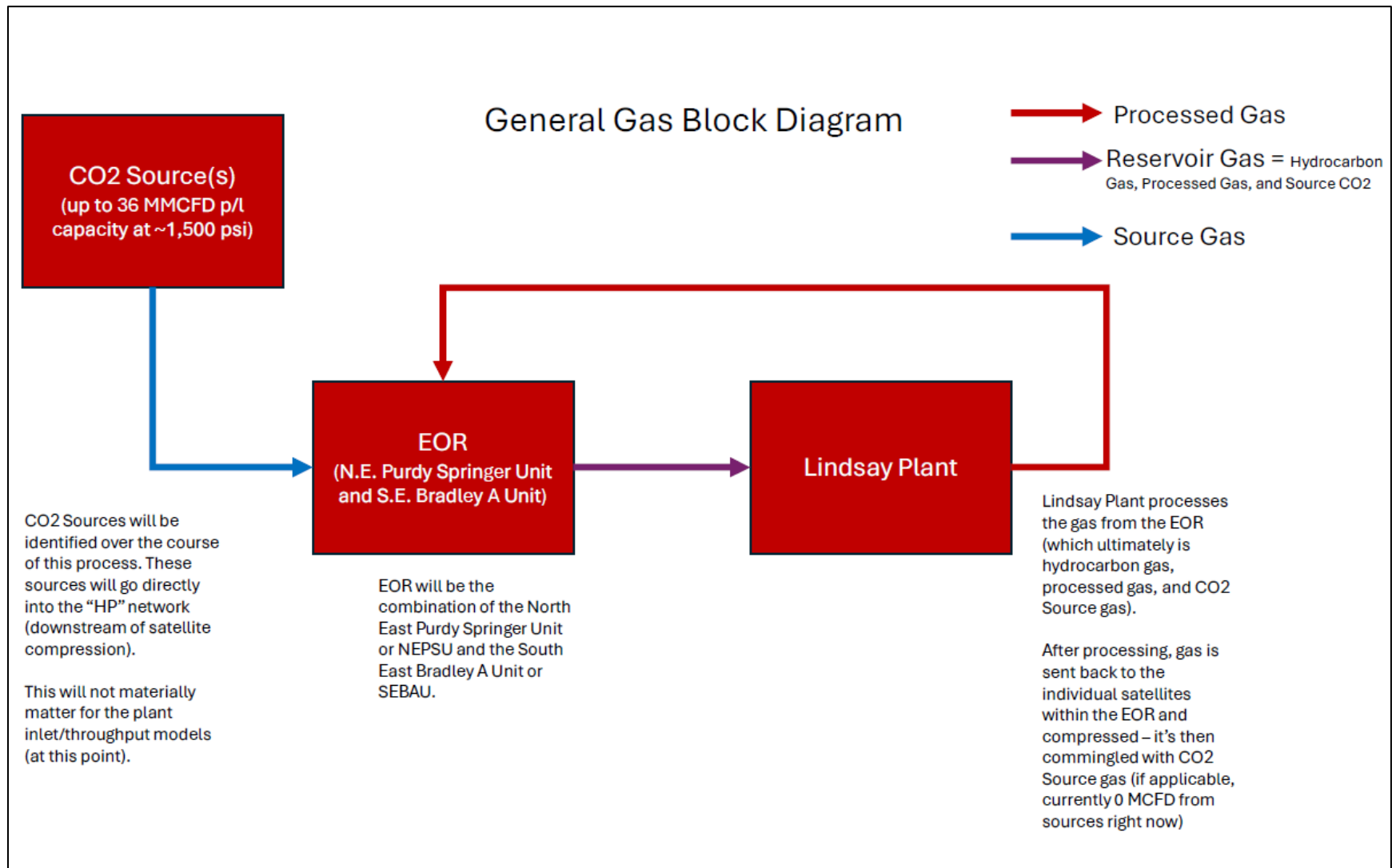


Figure 6: CO₂ collection and distribution process

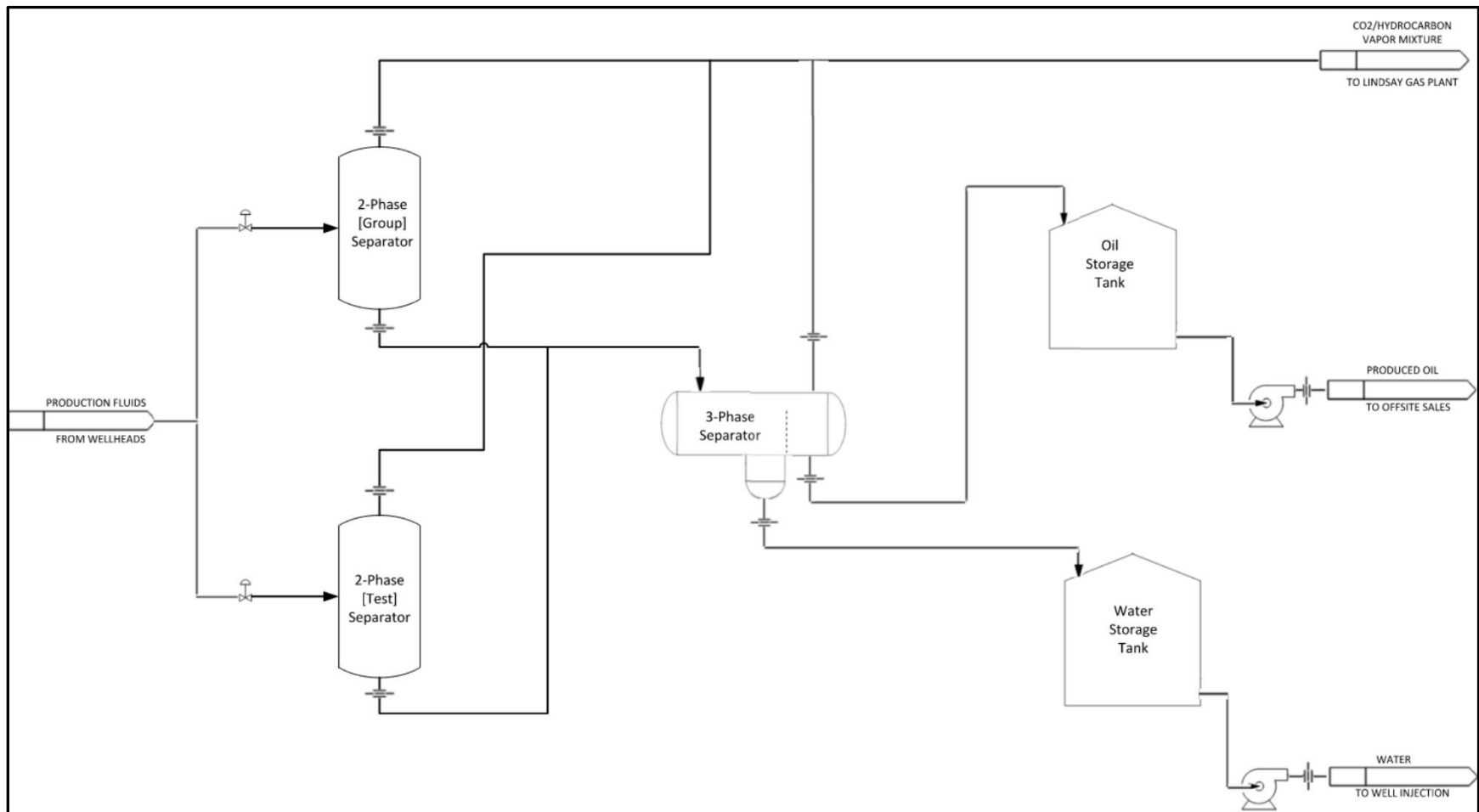


Figure 7: Simplified fluids flow diagram for a typical NEPSU satellite

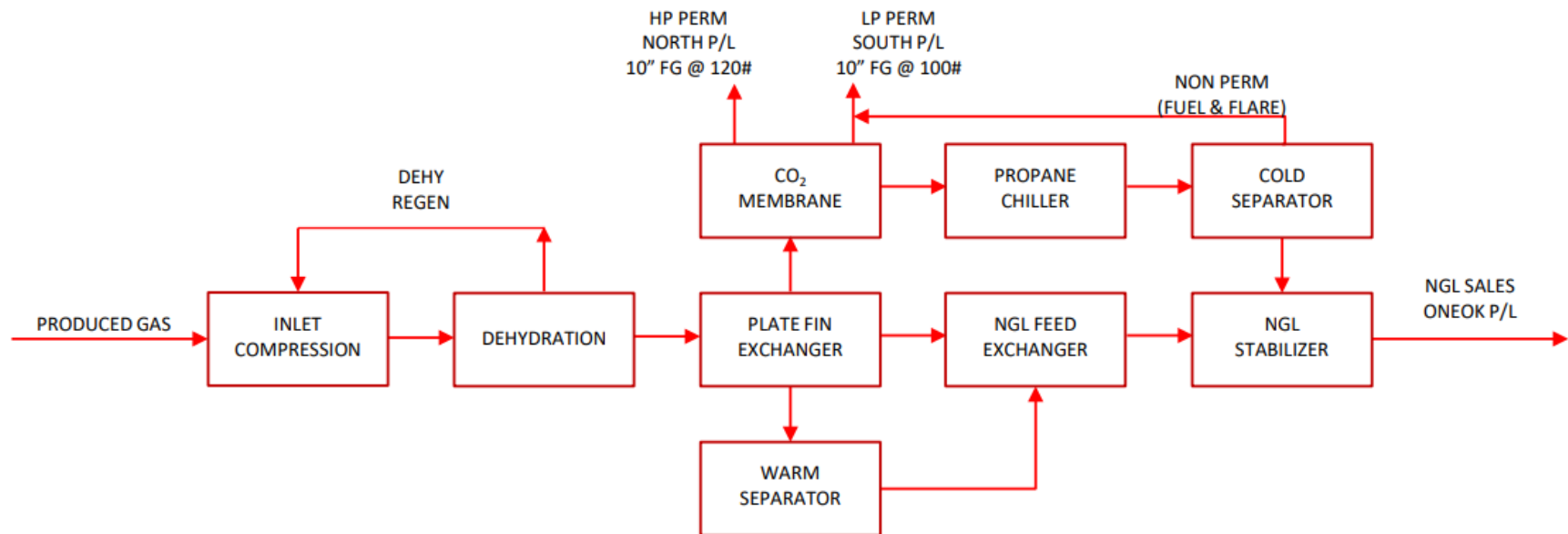


Figure 8: Process diagram for the Lindsay Gas Plant

2.3.4. Well Operations and Permitting

OCC regulations require that injection wells be completed and operated so that fluids are contained in the injection zone and that well operations do not pollute subsurface or surface waters (Oklahoma Administrative Code [OAC] §165:10-5-5 b4). Depending on the purpose of the well, regulatory requirements can impose additional standards.

CO₂ injection well permits are authorized only after approval of an application, public notice, and opportunity for a hearing. As part of the application process, Daylight establishes an Area of Review (AoR) that includes wells within the floods plus a one-quarter mile buffer. Pursuant to applicable regulations, all wells within the AoR that penetrate the injection interval are located and evaluated.

All active injection wells must undergo a periodic mechanical integrity test (MIT) per regulatory guidelines (per OAC §165:10-5-6), depending on various dates and activities associated with the well. MIT includes the use of a pressure recorder, pressure gauge, and testing of the casing-tubing annulus for a minimum amount of time at a minimum pressure, as specified in the approved well injection permit. In some instances, a radioactive tracer survey (RTS) is conducted, sometimes in combination with a pressure test, to ensure all fluids are being injected into the permitted zone.

Daylight has developed operating procedures based on its experience as a CO₂-EOR operator. Operations include developing detailed modeling at the EOR pattern level to guide injection pressures and performance expectations, leveraging Daylight's expertise in diverse disciplines to operate EOR projects based on specific site characteristics. Field personnel are trained to look for and address issues promptly and to implement corrosion prevention techniques, or to engage contracted parties for such services, to protect wellbores as needed.

Daylight's operations are designed to comply with the applicable regulations and to ensure that all fluids (including oil, water, and CO₂) remain in the units until they are produced through a Daylight-operated well. Well pressure in injection wells is monitored on a continual basis. Individual well injection is guided by a pattern-level WAG program to govern the rate, pressure, and duration of water or CO₂ injection in accordance with regulatory requirements. Pressure monitoring of the injection wells flags pressures that significantly deviate from the plan. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such excursions occur, they are investigated and addressed. It is the company's experience that few excursions result in fluid migration out of the intended zone and that leakage to the surface is very rare.

In addition to monitoring well pressure and injection performance, Daylight uses the experience gained over time to strategically approach well maintenance and updating. Operations staff is in the field daily monitoring the performance of the units and plant, and a call-out system exists for any disruptions when staff is away from the field. Daylight uses all the information at hand, including pattern performance and well characteristics, to determine well maintenance schedules. Production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to a satellite battery. There is a routine cycle for each satellite battery, with each well being tested approximately once every 1-2 months. During this cycle, each production well is diverted to the well test equipment for a period of time sufficient to measure and sample produced fluids (generally 24 hours). This test allows Daylight to allocate a portion of the produced fluids measured at the satellite battery to each production well, assess the composition of produced fluids by location, and assess the performance of each well.

Performance data are reviewed on a routine basis to ensure that CO₂ flooding is optimized. If production is off plan, it is investigated and any identified issues addressed.

Leakage to the outside of production wells is not considered a major risk because of the reduced pressure in the casing. Field inspections are conducted on a routine basis by field personnel. Currently, Daylight has approximately 20 personnel in the field throughout the two units. Leaking CO₂ is very cold and leads to the formation of bright white clouds or dry ice, either of which is easily spotted. All field personnel are trained to identify leaking CO₂ and other potential problems at wellbores and in the field. Any CO₂ leakage detected will be documented and reported, quantified, and addressed as described in **Section 4** and **Section 6**. Continual and routine monitoring of wellbores and site operations will be used to detect leaks. Based on these activities, Daylight will mitigate the risk of CO₂ leakage through existing wellbores by detecting problems as they arise and quantifying any leakage that does occur.

2.3.5. Number, Location, and Depth of Wells

As of January 2025, Daylight operated 23 active CO₂ injection wells and 36 active production wells in the SEBAU, and 69 active CO₂ injection wells and 88 active production wells in the NEPSU. The depth of these wells is approximately 8,200-10,800 feet (Cunningham Sandstone). These wells are listed in **Appendix 1**.

2.4. Reservoir Description

2.4.1. Reservoir Characteristics

Generalized reservoir parameters are provided in **Table 1**. These were determined from data collection, interpretation, and studies performed by historical field operators and, more recently, Daylight in support of primary, secondary, and tertiary recovery operations.

Core, well log, and operational data suggest that reservoir properties for the NEPSU and SEBAU are largely similar. Routine core analysis and flow studies conducted in the Northeast Purdy K-214 well (Ekstrand, 1979) showed an average porosity of 10% and permeability of 14.8 mD. The effect of overburden was determined to reduce porosity by 3-10% (or less than 1 porosity percent) at typical net overburden pressures (approximately 7,000 psig). Additional legacy conventional core samples have been studied from nearly 30 NEPSU wells and approximately 23 SEBAU wells. Currently accepted permeability and porosity values are generally more optimistic than those seen in the K-214 core, at 13% porosity and 44 mD permeability in the NEPSU and 12.5-14% porosity and 50-58 mD permeability in the SEBAU.

As discussed earlier, the NEPSU and SEBAU are fault-bounded stratigraphic traps, with the Cunningham Sandstone having been tilted, eroded, and covered by subsequent deposition of shales above the base Atoka unconformity. The top structure of the Springer is mapped in **Figure 9**, the net pay thickness of Springer reservoir sands is mapped in **Figure 10**, and the trapping configuration is illustrated in **Figure 11**. The Cunningham Sandstone comprises primarily quartz framework grains and cements, with calcite cements in shaly intervals and tight streaks, significant kaolinite, and some smectite and illite (Cities Service Company, 1978). The clays are stable under reservoir conditions. Limited chemical reaction is expected from CO₂ injection given the native pH range of 5.1 to 5.4, so long as pH is maintained at 4.5-5.0 or higher. Plugging from fines migration is the primary risk to permeability and reservoir quality during flooding and production.

Initial pressure of the NEPSU reservoir was 3,050 psig at 8,200 feet, and original oil in place was approximately 225 million stock tank barrels (MMSTB) (Simlote and Withjack, 1981). Primary production began in 1951, and waterflooding for secondary recovery commenced in 1960. Cumulative production through 1977 was 79.5 million MMSTB, prompting efforts to develop a tertiary recovery program. Extensive reservoir study led to the establishment of CO₂ injection in 1982 as the most feasible tertiary method to maximize recovery (Cities Service Company, 1978).

In the SEBAU, which had ~105 MMSTB oil originally in place, primary and secondary recovery occurred from the 1950s into the 1990s. Tertiary recovery in the SEBAU began in 1997.

Operations and development throughout the history of the units have been very similar, owing in part to their immediate proximity and similar reservoir and production parameters.

Table 1: Reservoir Summary Characteristics

Parameter	Parameter by Unit	
	NEPSU	SEBAU
Unitized Area	~10,160 acres	~3,100 acres
Injection Reservoir	Cunningham Sand	Cunningham Sand
Flood Type	CO ₂ and Water Alternating Gas	CO ₂ and Water Alternating Gas
Depth	8,200-10,200 feet	8,900-10,800 feet
Porosity ¹	13%	12.5-14%
Permeability ²	44 mD	50-58 mD
Temperature	148 degrees F	150 degrees F
Initial Water Saturation	18%	NA
Irreducible Water Saturation	14%	NA
Average Net Pay	40 feet	40 feet
Initial Reservoir Pressure	3,050 psi @ 8,200 feet subsea	NA
Original Oil in Place	225 MMSTB	105 MMSTB
Oil Gravity	38 degrees API	38 degrees API
Oil Viscosity	1.2 cp	1.0 cp
Minimum Miscibility Pressure	1,700-2,300 psi	1,820-2,350 psi
Water Salinity	200,000 ppm TDS	NA

¹ Range across both units = 10-22%; ² Range across both units = 5-500 mD

Sources: Daylight internal data; Advanced Resources International, 2024; Birk, 1986; Brinlee and Brandt, 1982; Cities Service Company, 1978; Fox et al., 1988.

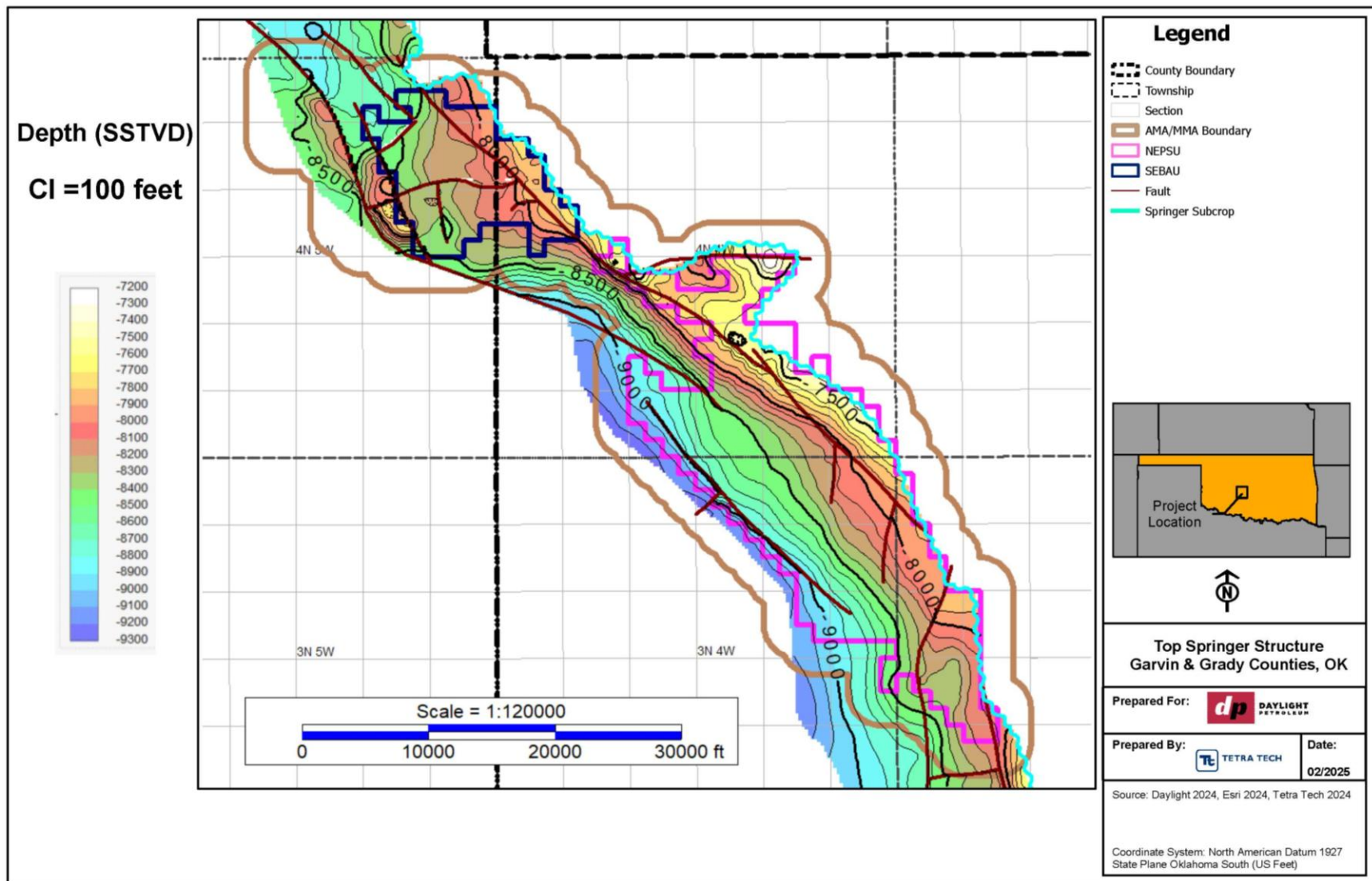


Figure 9: Top Springer structure

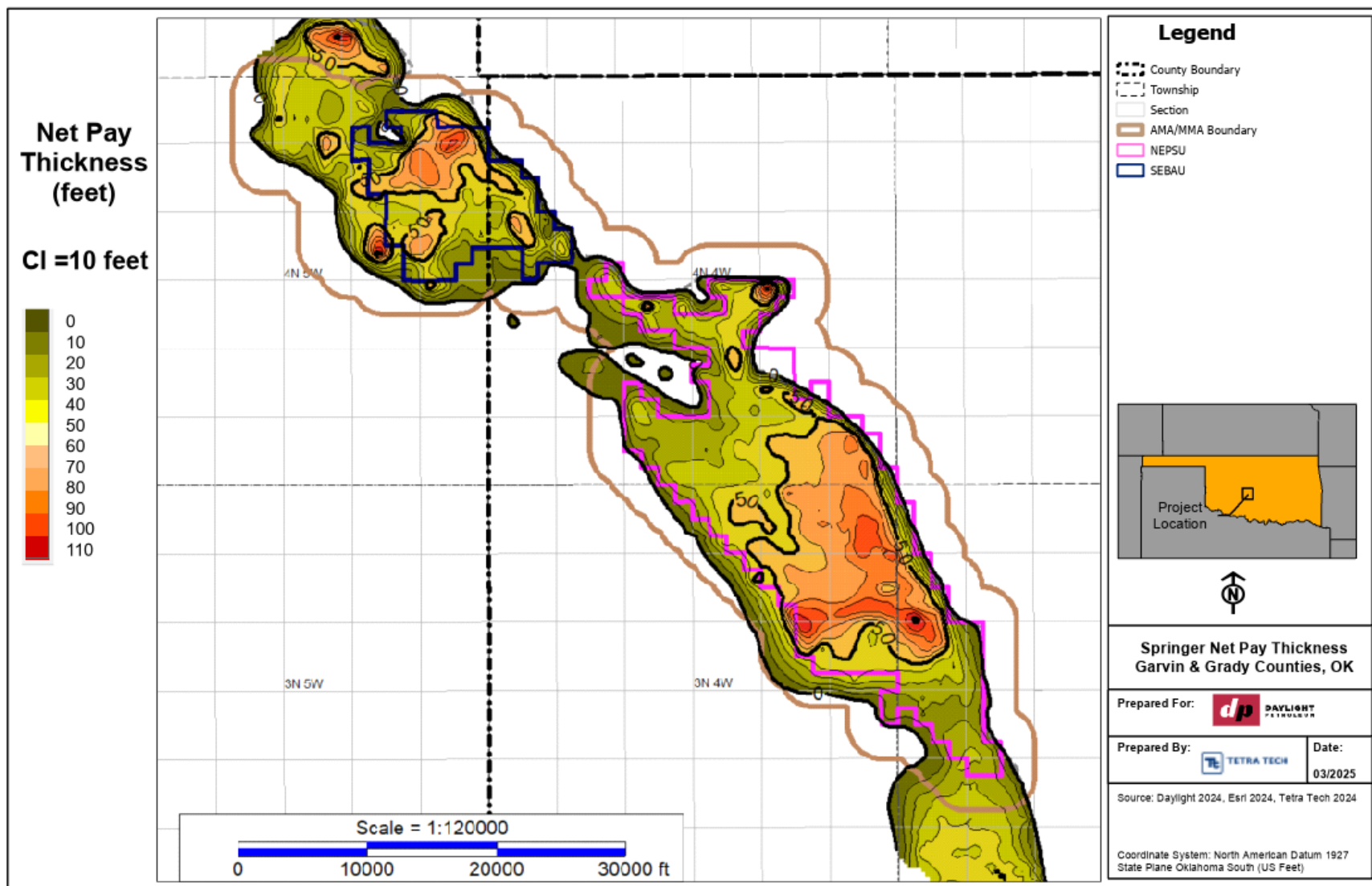


Figure 10: Net pay thickness for the Springer reservoir sands

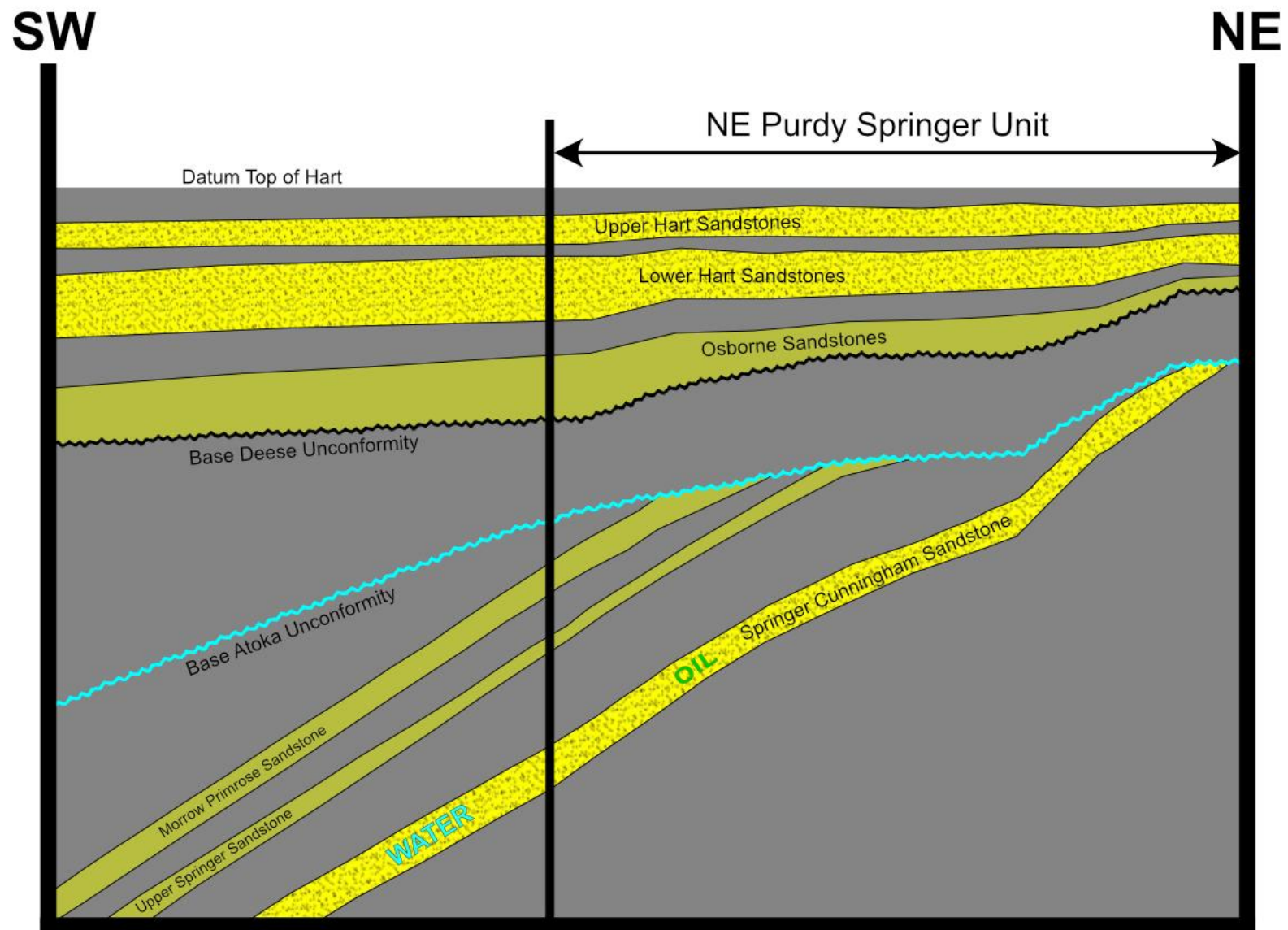


Figure 11: Schematic of the reservoir-seal stratigraphic trapping configuration

2.4.2. Reservoir Fluid Modeling

As discussed previously, NEPSU and SEBAU are operated collectively as the Purdy-Bradley Springer Field and have similar reservoir properties. Nearly all the historical reservoir data is from NEPSU, and available production data are generally combined for the two units. Therefore, the work presented in the following sections is considered to apply to the field as a whole.

A reservoir fluid model was developed based on the work of Fox et al. (1988). This article documents fluid properties for the NEPSU, and pressure, volume, and temperature (PVT) parameters were applied uniformly across the field. The minimum miscibility pressure (MMP) is calculated to be 1,750 psi. It is important to note that MMP measurements from 1979 show location dependency, with some values ranging between 2,100 psig and 2,300 psig. The tertiary flood was initiated by injection of CO₂ in September 1982, and because pressure measurements since 1982 are reported to be above 2,400 psi, flooding is expected to be miscible in most of the reservoir. Since the project involved continuous injection, a decline in pressures was not expected.

The reservoir temperature, used to create the oil PVT plots, was assumed to be 148 degrees F (Fox et al., 1988). The predicted plots and the data points from Fox et al. (1988) are compared in **Figure 12** and **Figure 13**. The gas viscosity is estimated based on a specific gravity of 8.42, calculated from the gas composition of the pre-CO₂ injection gas provided in Fox et al. (1988).

2.4.3. CO₂ Analytical Sweeping Efficiency Calculation

Accepted conventional reservoir engineering practice relies on dimensionless equations to predict the amount of oil that can be recovered through CO₂ flooding in oil reservoirs (Lee et al., 2019; Stell, 2010). The amount of oil recovered is plotted as a decimal fraction of the original oil in place, compared to the decimal fraction of the hydrocarbon pore volume (HCPV) of CO₂ injected into the reservoir, measured in reservoir barrels (rb).

To assess the enhanced oil recovery (EOR) performance, the commonly used Koval factor is applied. The Koval theory was meant to interpret the core-scale production of oil by a miscible displacement by CO₂ injection. It is calculated by multiplying the viscosity contrast effect by the heterogeneity effect. Based on core data from Daylight, the Lorenz coefficient is calculated to be 0.911, indicating a high level of heterogeneity in the reservoir (**Figure 14**).

The Lorenz coefficient and Dykstra-Parsons are common parameters used for evaluating heterogeneity. In this study, since the Koval factor is primarily calculated using Lorenz, it was employed for the heterogeneity assessment. The Lorenz coefficient ranges from 0 for a completely homogeneous system to 1 for a completely heterogeneous system. To calculate it, the normalized cumulative permeability capacity is first plotted against the normalized cumulative volume capacity (**Figure 14**). The Lorenz coefficient is then determined by dividing the area above the straight line (Area A) by the area below the straight line (Area B).

To convert the Lorenz factor into the Koval Factor, a chart provided by Salazar and Lake (2020) was used. According to this chart, the Koval Factor is estimated to be 140 (see **Appendix 5** for additional information). With this value, the volumetric sweep efficiency can be calculated using Koval's Theory (Koval, 1963), based on the CO₂ pore volume injected. The hydrocarbon pore volume (HCPV) filled by CO₂ injected into the oil reservoir over time is shown in **Figure 15**.

By assuming 25% of the HCPV for CO₂ injection, the estimated recovery is approximately 8% (**Figure 16**). The expected sweep efficiency is relatively low due to the reservoir's heterogeneity.

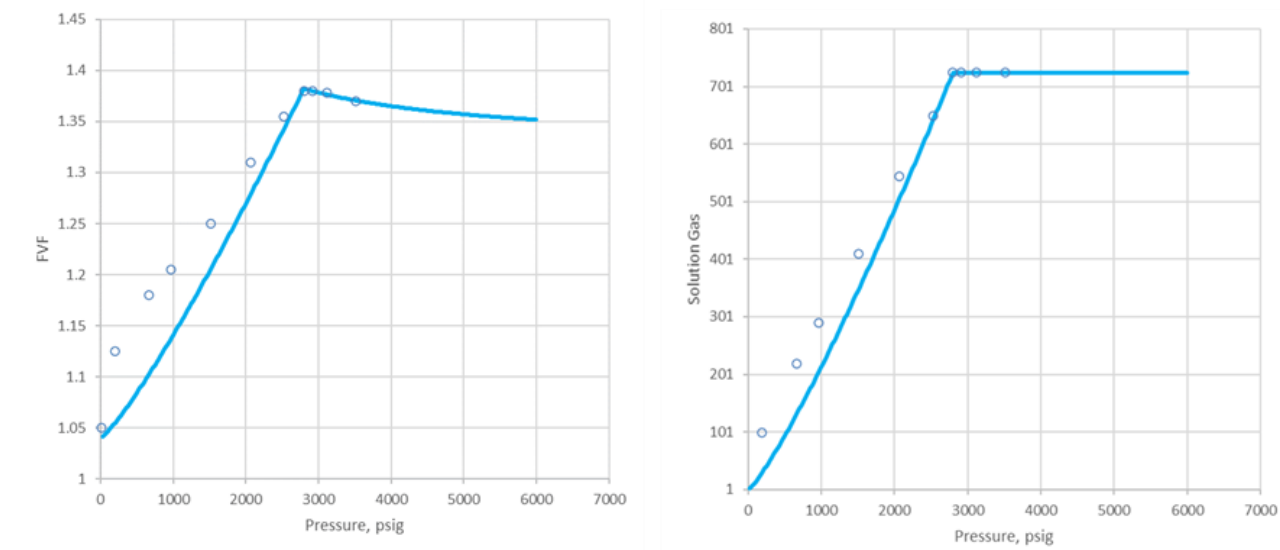


Figure 12: Oil PVT plots constructed for this modeling

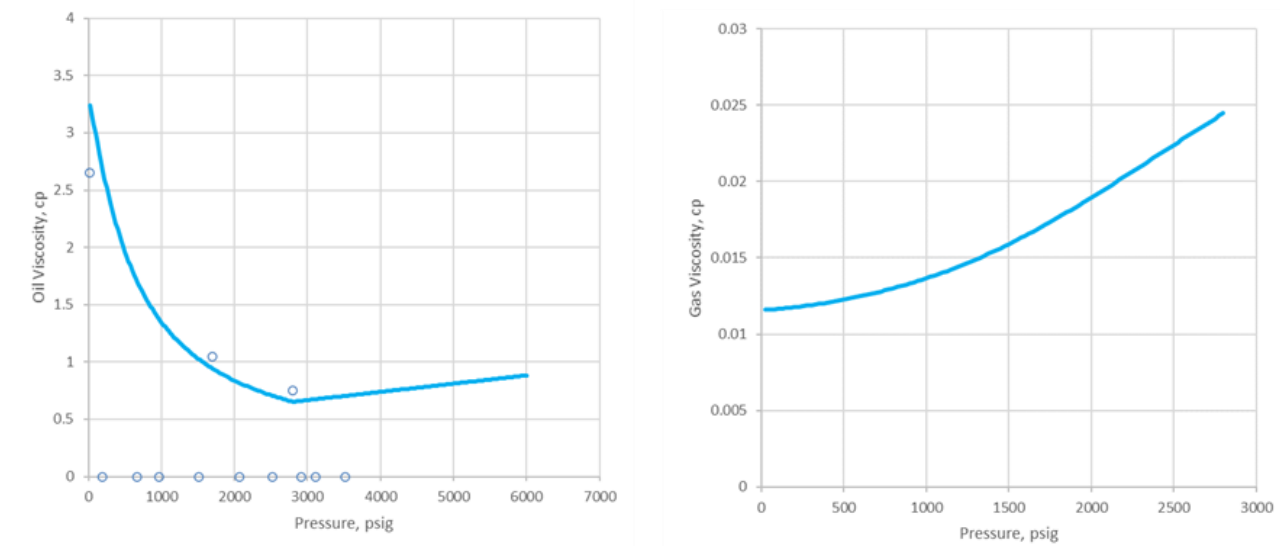


Figure 13: Oil and gas viscosity used in this modeling

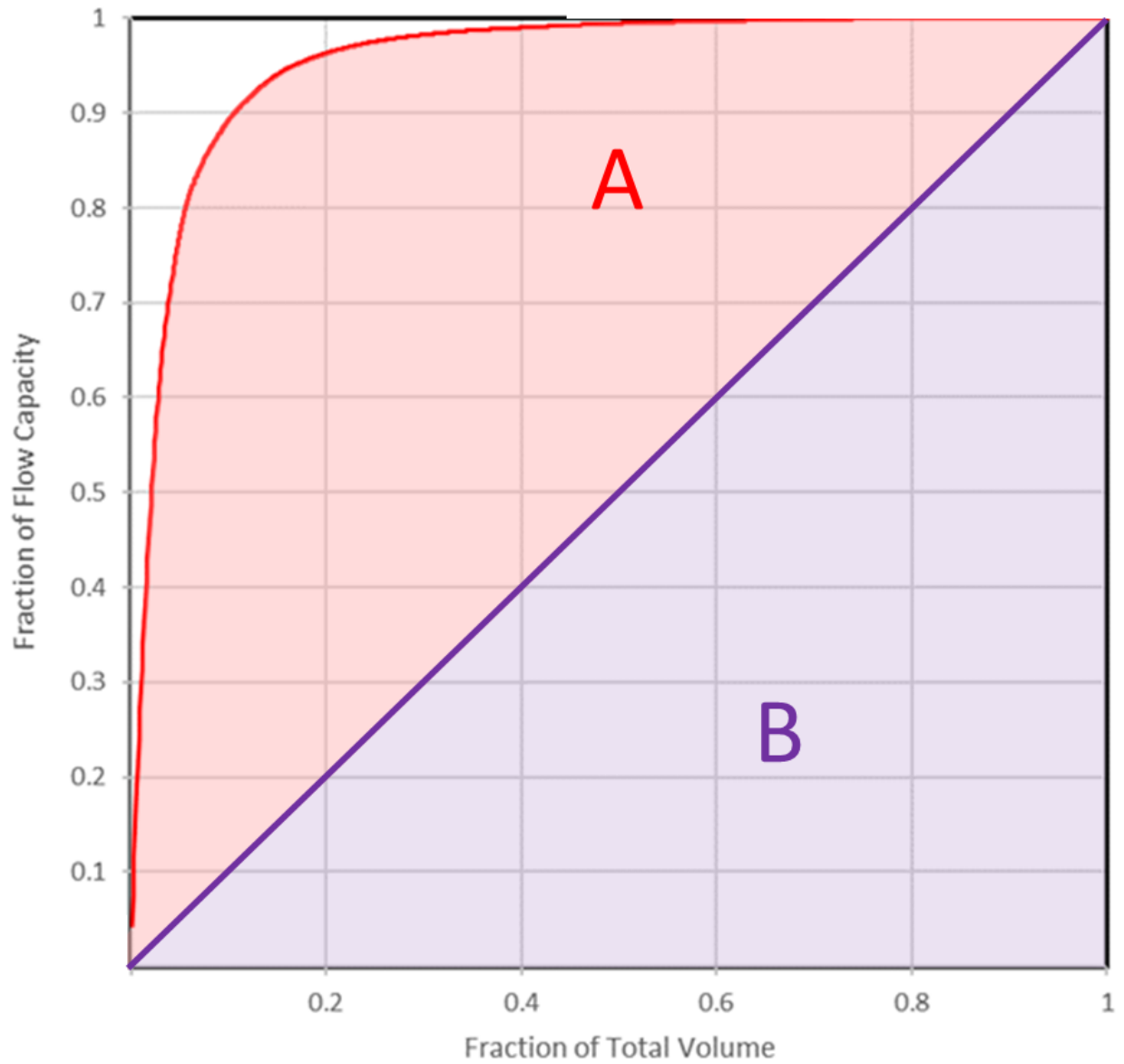


Figure 14: A Lorenz plot shows the high heterogeneity in this reservoir. The Lorenz coefficient is calculated by dividing the area above the straight line (area A) by the area under the straight line (area B).

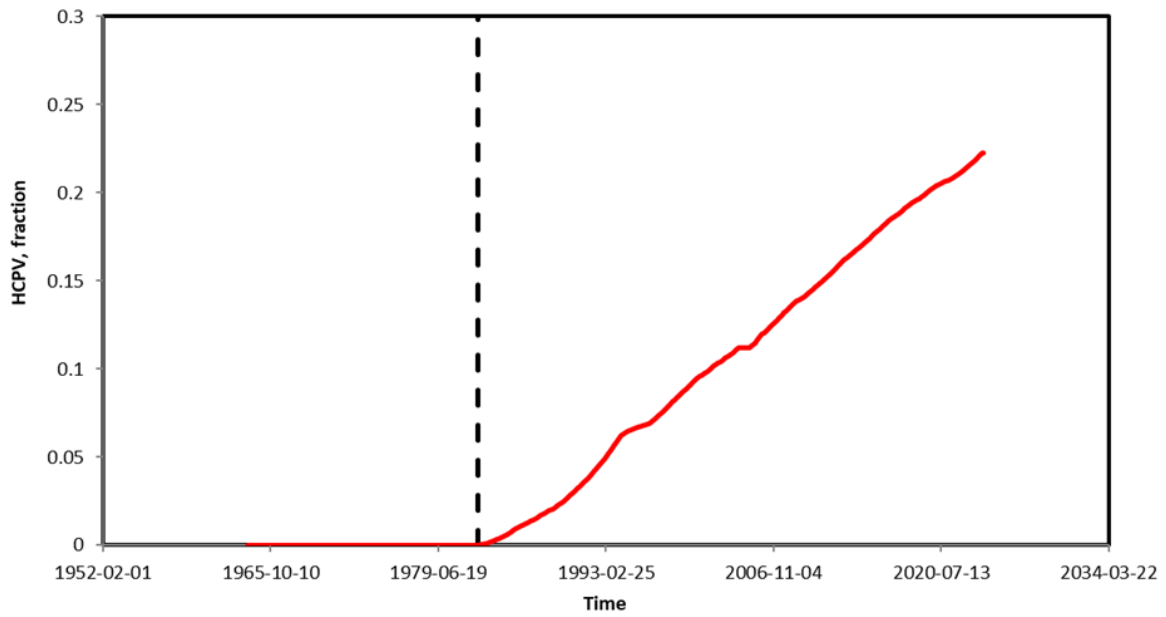


Figure 15: Hydrocarbon pore volume filled by CO₂ injection vs. time

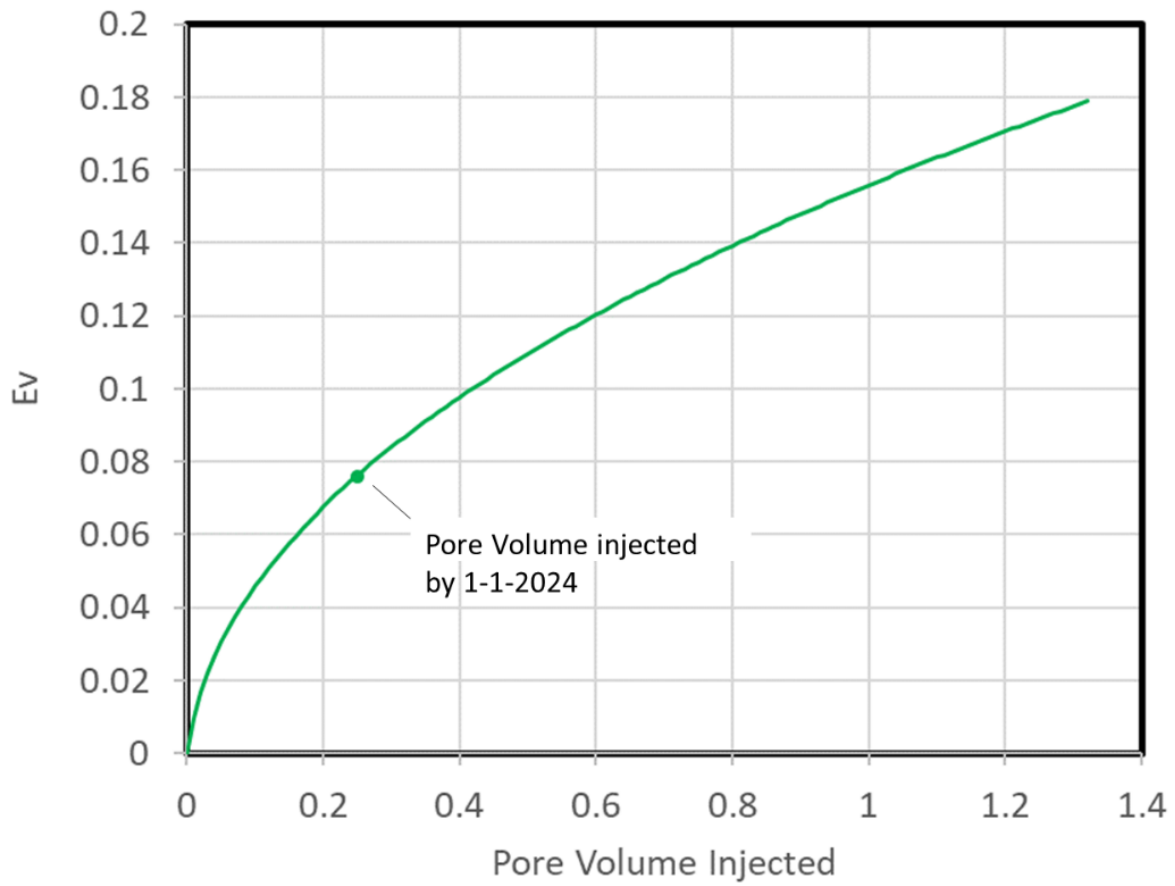


Figure 16: Recovery factor vs. CO₂ pore volume injected

2.4.4. CO₂-EOR Performance Projections

In this study, a modified Muskat model was used to calculate the pore volume available for CO₂ sequestration. This model accounts for the oil and gas PVT properties, as well as the relative permeability of the rock. A key uncertainty lies in the reservoir pressure. Actual reservoir pressure was not available and therefore was estimated using a pressure vs. time profile that offers a reasonable estimate of oil and gas production. The estimated gas saturation from the model is a critical factor, indicating the volume expected to be injectable into the reservoir. A linear pressure reduction is suggested during primary production, followed by an increase in pressure after waterflooding. Over the long term, the pressure begins to decline at a slow rate. The estimated rate is compared with actual production rates in **Figure 17**.

The primary aim of this analysis is to estimate oil production rates since September 1982, when the tertiary flood began through CO₂ injection. To determine the available volume for CO₂ storage, cumulative production rates were utilized. **Figure 18** presents a comparison of the predicted cumulative oil production with the actual cumulative oil production. As illustrated in **Figure 17** and **Figure 18**, the model demonstrates a reasonable accuracy in its predictions.

As the reservoir pressure fluctuates, both the formation volume factor (FVF) of the oil and the density of CO₂ change over time. Assuming a long-term reservoir temperature of 148 degrees F (the initial temperature of the field prior to CO₂ injection) and the current estimated pressure of 2,100 psia, the density of CO₂ is estimated to be 34.1 lbs/ft³ (**Figure 19**). It is essential to recognize that CO₂ density is highly sensitive to pressure; for instance, a reduction in pressure to 1,800 psi would result in an approximate 20% decrease in density. Although a decline in pressure over the long term is anticipated, the last pressure measurement was used for estimating these parameters due to a lack of recent pressure measurements.

In this analysis, the dissolution of CO₂ into the oil is not considered. It is important to note that as CO₂ primarily dissolves in the oil, the capacity for this volume will diminish over time as the oil volume decreases, unless there is a subsequent increase in reservoir pressure.

Given that the oil FVF is 1.31 rb/STB at a pressure of 2,100 psi, the available volume over time is plotted in **Figure 20**. The pressure of 2,100 psi is assumed from the expectation that it has declined by a few hundred psi from the last reported value of 2,400 psi (Fox et al., 1988), and it is further assumed that the pressure will be maintained through additional CO₂ injection in the coming years. Based on the analysis, should EOR be conducted for another 30 years, the volume potentially sequestered will reach 278 Bscf by 2054. To determine the injected CO₂ volume, the CO₂ density at standard conditions is 0.117 lbs/ft³, resulting in a gas FVF of 0.00342 rcf/scf.

It should be noted that the reported cumulative oil production at the end of 1985 was approximately 84.5 million STB (Fox et al., 1988). To account for this discrepancy, the oil production volumes have been adjusted. The gap arises due to the lack of historical data prior to the acquisition of these wells by Daylight. In **Figure 20**, this gap is referred to as the “mismatch.”

Knowing the CO₂ density (34.1 lbs/ft³), the mass of CO₂ to be stored can be calculated. It is important to note that the key assumption is that the CO₂ will only replace the oil recovered, with no additional volume considered for CO₂ dissolution. Based on this calculation, if EOR is conducted for another 30 years, the potential mass of CO₂ to be sequestered by 2054 is estimated to be approximately 278 billion Bscf, or 14.7 MMT, assuming pure CO₂ is injected (**Figure 21**).

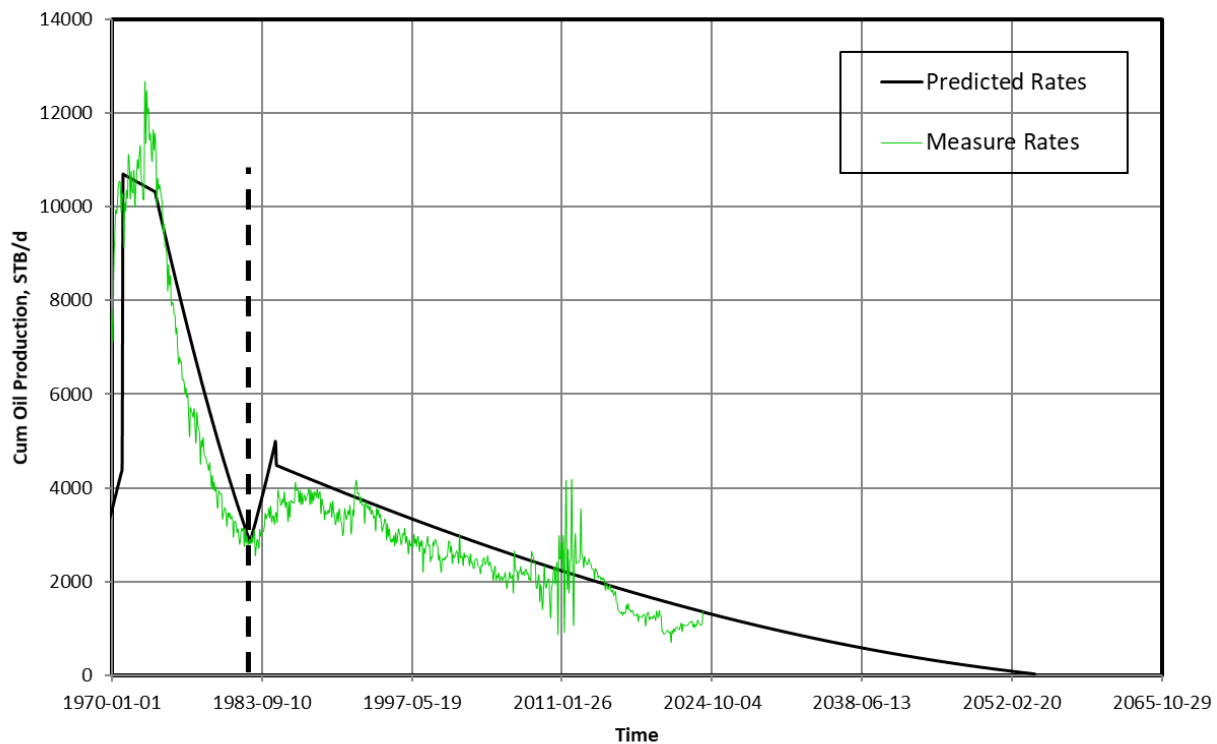


Figure 17: Oil rate-time curve comparison with actual estimations

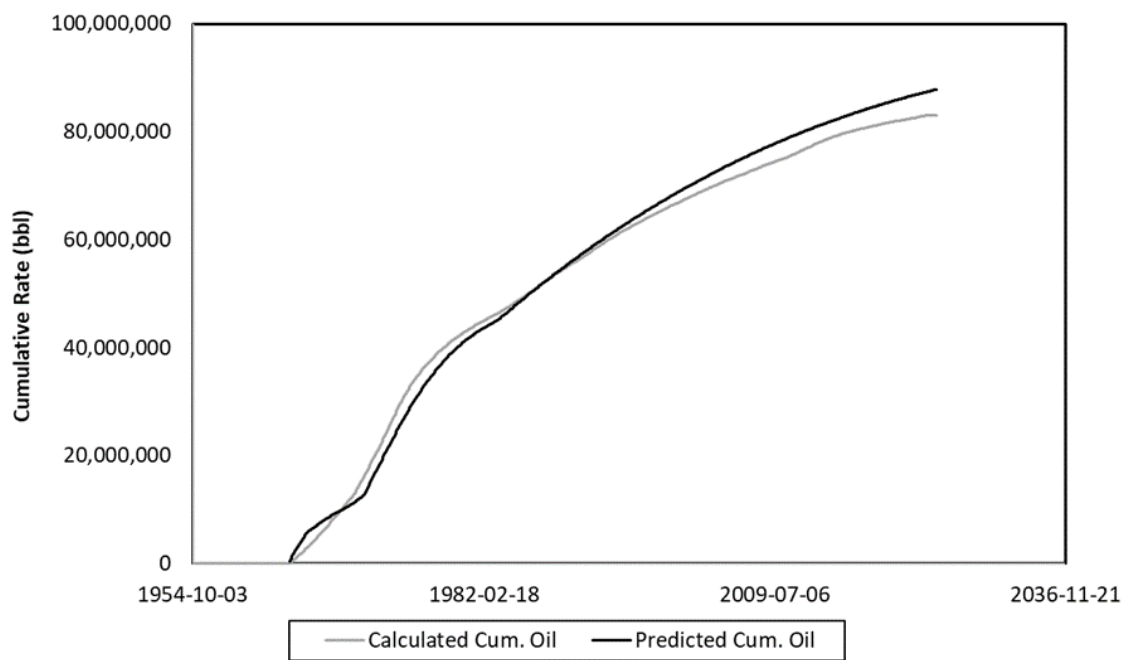


Figure 18: Comparison of the cumulative oil rates

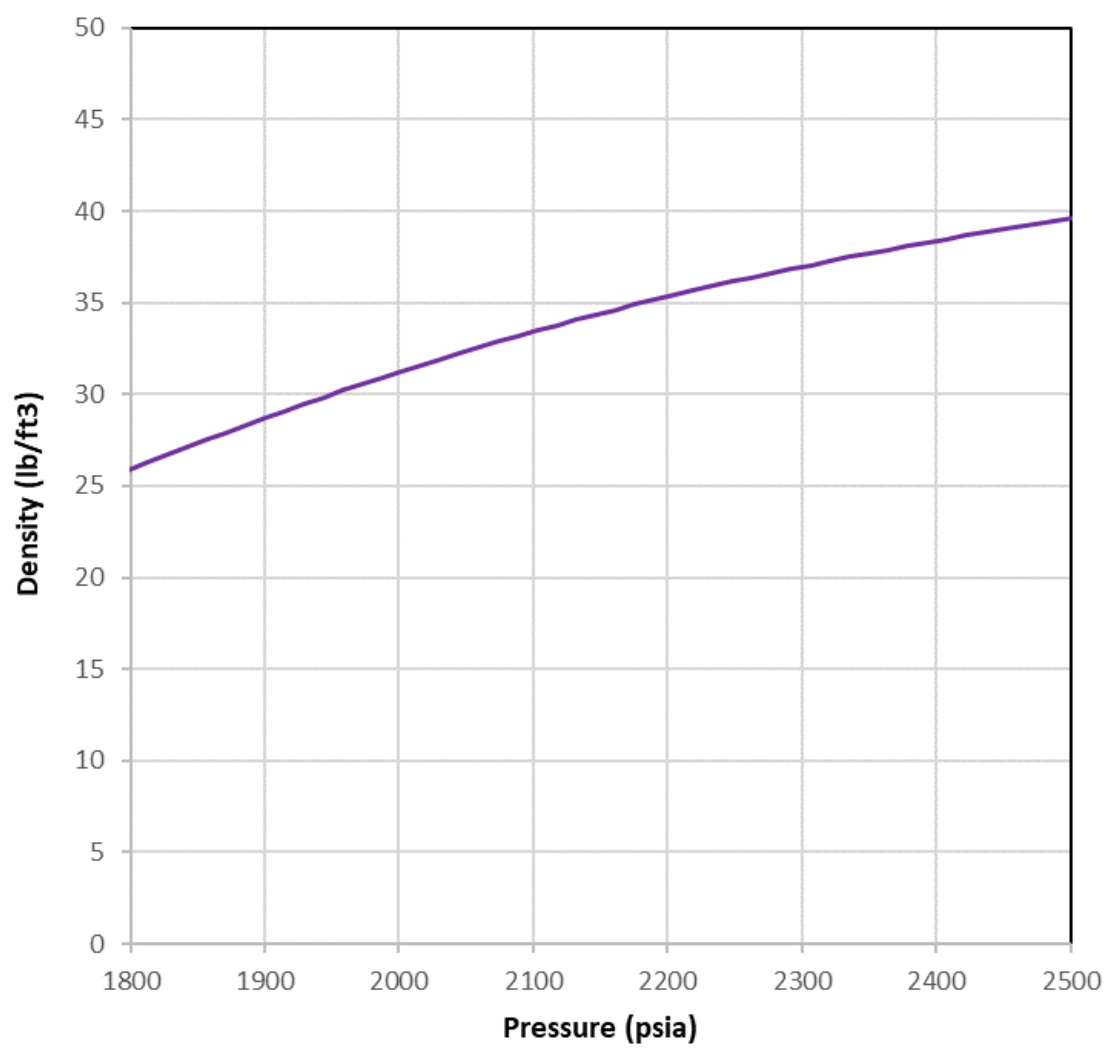


Figure 19: Variation of CO₂ density at 148 degrees F

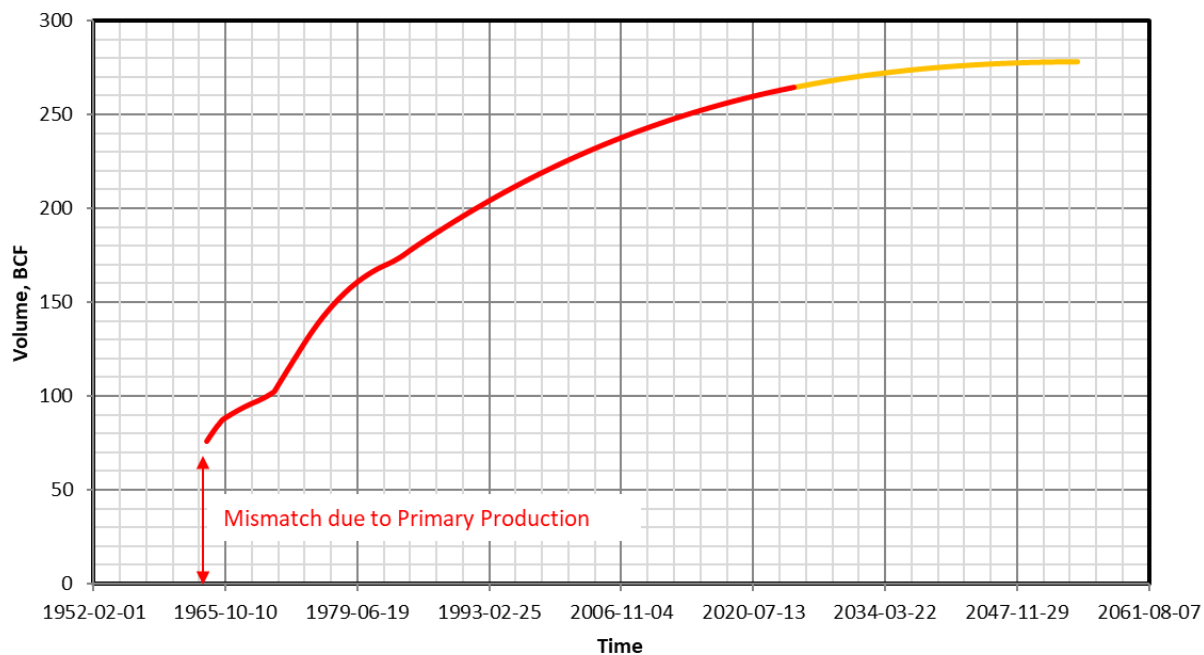


Figure 20: Predicted volume available for CO₂ injection

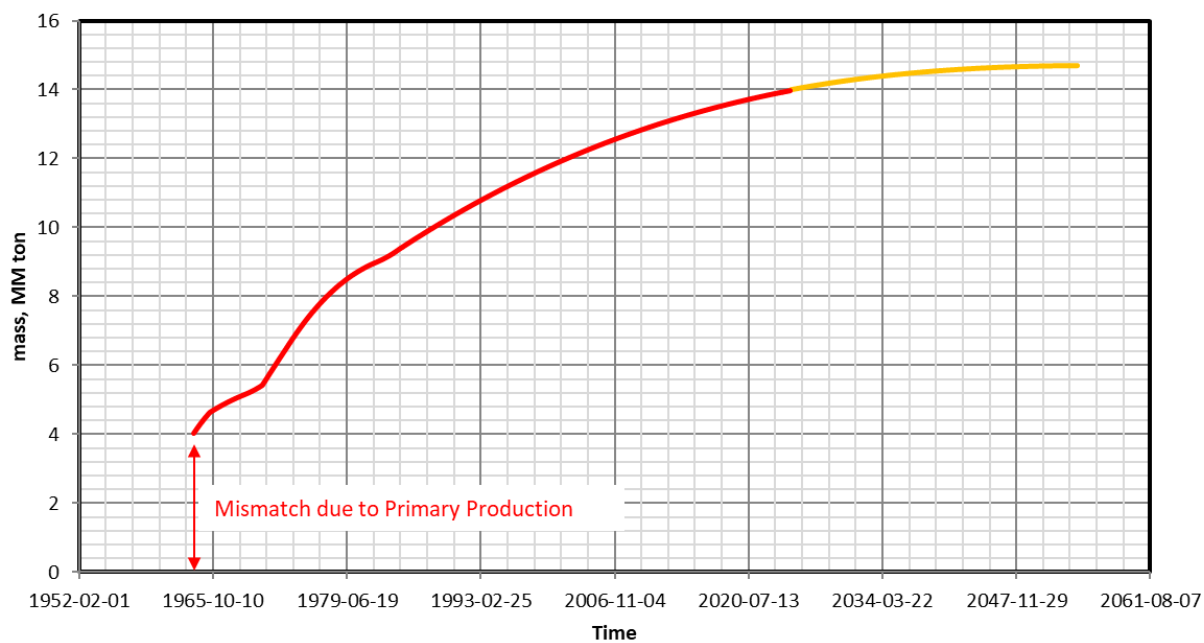


Figure 21: Predicted CO₂ storage in terms of mass

3.0. Delineation of Monitoring Area

3.1. Determination of CO₂ Storage Volumes

The estimated voidage space of 21 MMscf of CO₂ per acre of surface area, or a total of 278 Bscf CO₂, is assumed to be entirely contained within the Purdy-Bradley Springer Field (~13,200 acres).

3.2. Active Monitoring Area (AMA)

The AMA is defined by the combined boundaries of the NEPSU and SEBAU plus a buffer zone of at least one-half mile (**Figure 22**). The AMA is the area that Daylight will monitor over a specific time interval from the first year of the period (n) to the last year in the period (t). Consistent with the requirements in 40 CFR 98.449, the boundary is established by superimposing two areas:

1. The area projected to contain the free-phase CO₂ plume for the duration of the project (year t), plus an all-around buffer zone of one-half mile; and
2. The area projected to contain the free-phase CO₂ plume for at least 5 years after injection ceases (year t + 5).

Currently, Daylight's operations cover NEPSU and SEBAU in their entirety. The unit boundaries were defined during unitization based on the geologic boundaries and truncational limits of the Springer reservoir. Successful containment of free-phase CO₂ within these boundaries has been demonstrated and confirmed during 43 years of CO₂ flooding in NEPSU and 28 years of CO₂ flooding in SEBAU. Furthermore, the estimated voidage space of 278 Bscf is entirely contained within the unit boundaries and will not be exceeded by CO₂ injection volumes. Therefore, Daylight expects the free-phase CO₂ to remain within these boundaries for the duration of the project (t = Year 2054) and at least 5 years thereafter, as required for the AMA by 40 CFR 98.449.

Any additional CO₂ injection wells will be permitted under the UIC program and will be included in the annual submittal per 40 CFR 98.446(f)(13).

3.2.1. Determination of Buffer Zone

The buffer zone of a minimum of one-half mile is required by Subpart RR. No known leakage pathways extend laterally more than one-half mile.

3.3. Maximum Monitoring Area (MMA)

As defined in Subpart RR, the MMA is equal to or greater than the area expected to contain the free-phase CO₂ until the CO₂ has stabilized, plus an all-around buffer zone of at least one-half mile. The MMA is defined as equivalent to the AMA, and Daylight will continuously monitor the entire MMA for the purposes of this MRV.

The free-phase CO₂ is currently contained and will continue to be contained by the geologic limits of the Springer reservoir, which are the truncation limits of the reservoir as defined by well control obtained through the full field delineation and development of NEPSU and SEBAU since their discovery in 1951. These geologic boundaries serve as an impermeable seal as demonstrated by the initial trapping and accumulation of hydrocarbons (oil and gas cap) resulting in the formation of the field and confirmed by active monitoring of the ongoing CO₂ flood as described in **Section 4**.

After 43 years of CO₂ flooding in NEPSU and 28 years of CO₂ flooding in SEBAU, the free-phase CO₂

plume extent has spread throughout most of both units and is successfully contained by the geologic limits of the reservoir, as demonstrated by Daylight's current monitoring practices, which include production, injection, and pressure monitoring. Therefore, Daylight expects the extent of the free-phase CO₂ plume will continue to be contained by and stabilized within the geologic limits of the reservoir, since it has a proven impermeable seal and the amount of CO₂ injected will not exceed the reservoir's secure storage capacity of 278 Bscf. As such, there is no difference in the expected free-phase CO₂ plume extent between year t and year t + 5. Furthermore, the CO₂ plume extent is expected to remain stable once this facility discontinues injection operations based on historical monitoring trends.

Stabilization of the CO₂ plume will continue to be monitored and reported until the criteria outlined in **Section 4.11** have been met.

4.0. Identification and Evaluation of Leakage Pathways

Since its discovery in 1951, the unitization of the NEPSU (1959) and SEBAU (1956), and the initiation of CO₂-EOR in 1982 (NEPSU) and 1997 (SEBAU), the Purdy-Bradley Springer Field has been extensively investigated and documented. Based on this history, Daylight has identified the following potential pathways of CO₂ leakage to the surface. This section also addresses detection, verification, and quantification of leakage from each pathway.

4.1. Leakage from Surface Equipment

The surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO₂-EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment is conducted by personnel instructed on how to detect surface leaks and other equipment failure, thereby minimizing the potential for and impact of any leakage. Surface equipment leaks have a low risk of occurring based on design standards. In addition, under OCC rules, operators must take prompt action to eliminate leakage hazards and to conduct inspections or repairs. Operating and maintenance practices currently follow and will continue to follow industry standards. As described in **Section 6.4**, should leakage from surface equipment occur, it will be quantified according to procedures required by the GHGRP.

4.2. Leakage from Wells

As of January 2025, Daylight identified 23 active CO₂ injection wells and 36 active production wells in the SEBAU; 69 active CO₂ injection wells and 88 active production wells in the NEPSU; and approximately 886 total wellbore penetrations within the AMA. These are listed in **Appendix 1**.

Regulations governing wells in the NEPSU and SEBAU require that wells be completed and operated so that fluids are contained in the strata in which they are encountered and that well operations do not pollute subsurface and surface waters. The regulations establish the requirements with which all wells must comply, whether they are injection, production, or disposal wells. Depending on the purpose of the well, regulatory requirements can impose additional standards for evaluation of an AoR. CO₂ injection well permits are authorized only after an application, notice, and opportunity for a hearing. As part of the permit application process, Daylight evaluates an AoR that includes wells within the unit and one-quarter mile from the set of

wells considered in that AoR. Pursuant to USEPA and OCC regulations, all wells within the AoR that have penetrated the injection interval are located and evaluated.

Figure 22 shows all wells in the AMA/MMA. The OCC utilizes a risk-based data management system and can only guarantee well data since 1980. The wells listed in **Appendix 1** and shown in **Figure 22** were compiled from S&P Global in an effort to provide a more complete well list.

In addition, approximately 85 shallow groundwater wells are in the AMA/MMA, per the [Oklahoma Water Resources Board General Viewer](#). The deepest well is 360 feet, ~8,000 feet above the reservoir. Therefore, the likelihood of leakage via shallow groundwater wells is low. Daylight will test a groundwater well within the AMA on an annual basis to provide additional monitoring for potential leakage. Shallow groundwater wells are not included in **Figure 22** and **Appendix 1**.

4.2.1. Abandoned Wells

Figure 22 shows abandoned wells in the AMA/MMA. Owing to past and future AoR evaluations and a lack of historical leakage, Daylight concludes that leakage of CO₂ to the surface through abandoned wells is unlikely but cannot be ruled out. Strategies for leak detection are in place as discussed in **Section 4.8**, and the strategy to quantify any leaks is discussed in **Section 4.10**.

4.2.2. Injection Wells

Figure 22 shows the injection wells in the AMA/MMA. MIT is an essential requirement of the UIC program in demonstrating that injection wells do not act as conduits for leakage into USDWs and to the surface environment. Under OAC Title 165 Chapter 10, a pressure or monitoring test must be performed on new and existing injection wells and disposal wells. Information must be submitted on Form 1075 and witnessed by a field inspector when required. MIT and other rules documented in OAC Title 165 Chapter 10 ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Owing to past and future expectations of adhering to these rules, Daylight concludes that leakage of CO₂ to the surface through active injection wells is unlikely.

4.2.3. Production Wells

Figure 22 shows the active production wells in the AMA/MMA. As the project matures, production wells may be added and will be constructed according to the rules of the State of Oklahoma. Additionally, inactive wells may become active according to the rules of the State of Oklahoma.

During production, fluids including oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by a differential pressure, where the bottom hole wellbore pressure is less than the reservoir pressure. These lower-pressure fluids are contained by the casing, tubing, wellhead, and flowline all the way to the batteries and production/separation facilities. Daylight concludes that leakage of CO₂ to the surface through production wells is unlikely.

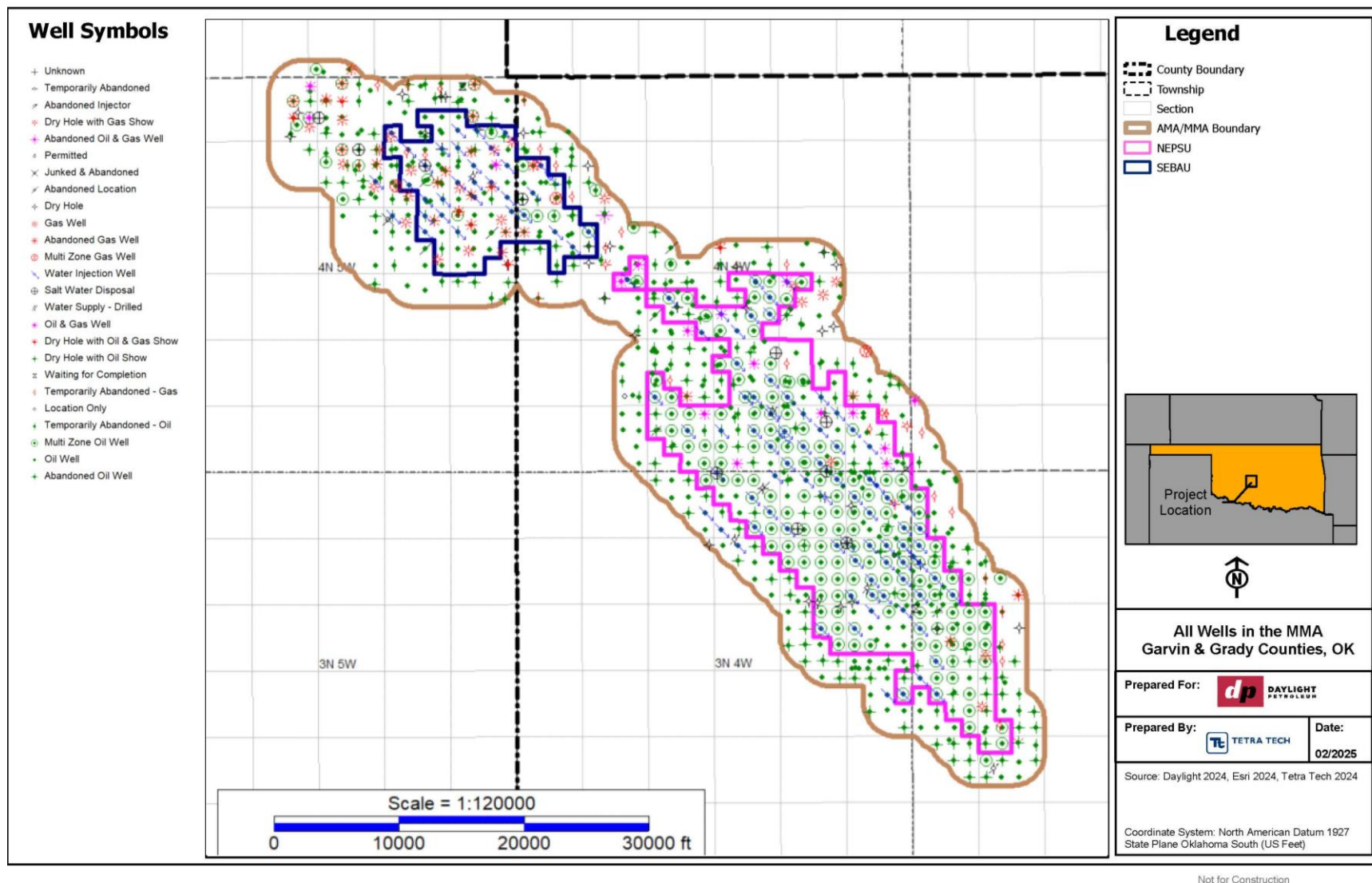


Figure 22: Location and type of all wells within the Active Monitoring Area (AMA). The Maximum Monitoring Area (MMA) is equivalent to the AMA.

4.2.4. *Inactive Wells*

Inactive wells that have been temporarily abandoned typically have a cast iron bridge plug or other isolation mechanism set above the existing perforations to isolate the reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change. Given the regular monitoring of and procedures for securing inactive wells, it is unlikely that any leakage event would result in a significant magnitude or duration of CO₂ loss.

4.2.5. *New Wells*

As the project develops, new production wells and injection wells may be added to the NEPSU and SEBAU. All wells in Oklahoma oilfields, including injection and production wells, are regulated by the OCC, which has primacy to implement the Class II UIC programs. Rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. All new wells will be constructed according to the relevant rules for the OCC which ensure protection of subsurface and surface resources and the environment. This will significantly limit any potential leakage from well pathways; however, leakage during drilling of a new well through the CO₂ flood interval cannot be ruled out.

In the event a non-operated well is drilled within the AMA, the operator would be required to follow all OCC rules and procedures in drilling the well and the potential for leakage would be similar to that of any well Daylight drills within the AMA. In addition, Daylight's visual inspection process during routine field operation will identify any unapproved drilling activity in the NEPSU and SEBAU.

4.3. Leakage from Faults, Fractures, and Bedding Plane Partings

Primary seals at the NEPSU and SEBAU have been demonstrated to be mechanically competent despite the presence of faults in and around the field (see also **Section 2.2.2**). The following lines of analysis have been used to assess this risk in the area.

4.3.1. *Presence of Hydrocarbons*

The primary evidence that leakage does not occur along faults, fractures, and bedding plane partings is the ~330 MMB of oil estimated to be originally in place in the NEPSU and SEBAU. If significant escape pathways existed, oil would have drained from the reservoir prior to the present day.

4.3.2. *Fracture Analysis*

Despite the presence of faulting in the area, conventional core samples taken from the Springer showed little evidence of fracturing (Oxy, 1988). In the event CO₂ leakage occurs through faults and fractures, it is unlikely that the leak would result in surface leakage, as these features are not known to extend from the reservoir to the surface. Daylight has strategies for leak detection in place that are discussed in **Section 4.8**, and the strategy to quantify leaks is discussed in **Section 4.10**.

4.4. Lateral Fluid Movement

The Springerean strata in Oklahoma represent primarily a deltaic to coastal island set of depositional systems that prograded toward the southeast, resulting in deposition of shales and lenticular, discontinuous coarse sandstones separated by very fine sandstone, minor

conglomerates, and shale. The likelihood of extensive migration of fluid outside of the MMA is considered low.

Since CO₂ is lighter than the water and oil remaining in the reservoir, it will tend to migrate to the top of the reservoir. The producing wells create low pressure points in the field, draining water and oil while keeping some CO₂ within each discontinuous sandstone. It is estimated that the total mass of stored CO₂ will be considerably less than the calculated storage capacity and once production operations cease, very small lateral movement will occur.

4.5. Leakage through Confining/Seal System

The results of gas sampling analysis from wells producing from the Cunningham Sandstone and the shallower Hart Sandstone (i.e., the next overlying reservoir) show that CO₂ does not move vertically through the confining strata. Baseline testing of the Cunningham prior to CO₂ injection showed a 0.6% molar concentration of CO₂ (Fox et al., 1988). In October 2023, Daylight's testing of more than 50 wells producing from the Hart reservoir showed an average of 0.25% molar concentration of CO₂ in the gas stream. These results confirm that the sealing units above the Cunningham prevent upward migration of CO₂ out of the reservoir.

In the unlikely event of CO₂ leakage through the confining seal, there is a very low risk of surface leakage, since the reservoir is at depths of ~8,200-10,900 feet and is overlain by >1,200 feet of impermeable shale net thickness. As with any CO₂ leakage, Daylight has strategies for leak detection in place that are discussed in **Section 4.8** and the strategy to quantify the leak is discussed in **Section 4.10**.

4.6. Natural and Induced Seismic Activity

Figure 23 shows the locations of earthquakes with magnitudes of 2.5 or greater that have occurred within 2 miles of the MMA (data obtained from the United States Geological Survey [USGS] Earthquakes Hazard Program catalog [<https://earthquake.usgs.gov/earthquakes/search/>], accessed 1/30/2025). Details of these earthquakes are provided in **Table 2**. The Purdy-Bradley Springer Field is located in a seismically active region, and all but one of the mapped earthquakes occurred since the initiation of CO₂ injection in 1982. However, there is no evidence that proximal or distal earthquakes have caused a disruption in injectivity, CO₂ leakage, or damage to any of the wellbores in the Purdy-Bradley Springer Field.

In the unlikely event that induced or natural seismicity results in a pathway for material amounts of CO₂ to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would lead to further investigation.

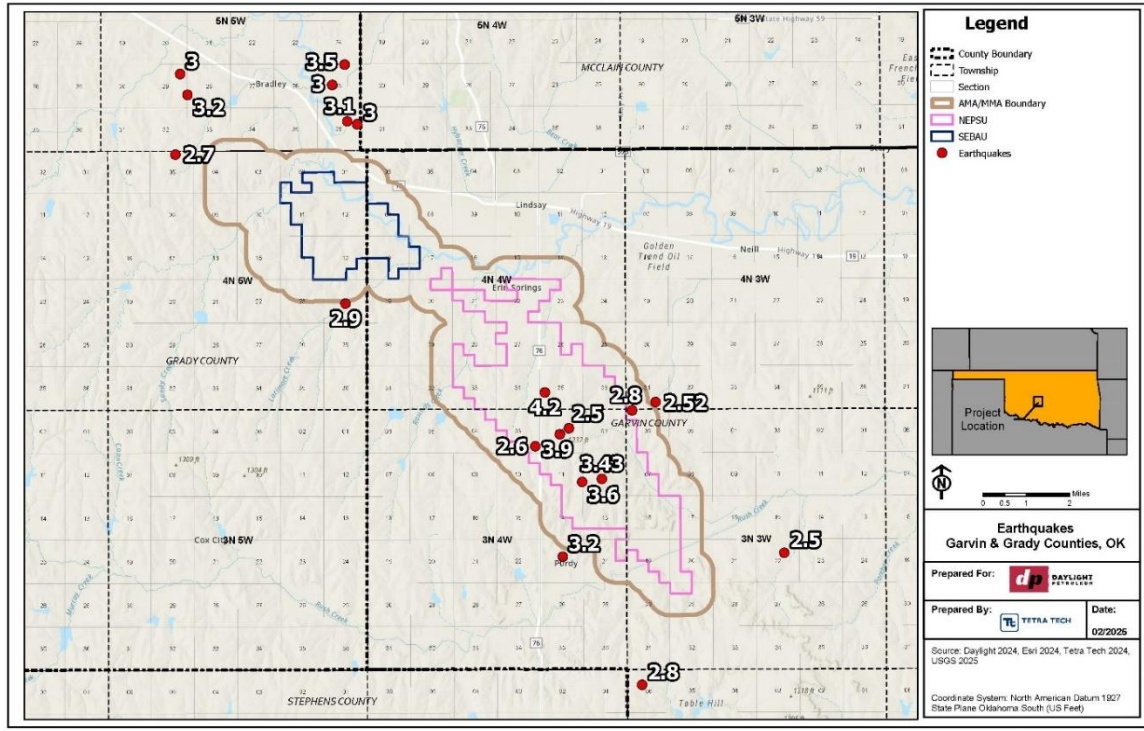


Figure 23: Earthquakes (2.5 magnitude or greater) within 2 miles of the MMA

Table 2: Details of earthquakes within the MMA

Earthquake Date	Magnitude	Location and Depth
1981-07-11	3.5	34.884°N 97.677°W – 5.0 km
1990-11-15	3.9	34.760°N 97.590°W – 5.0 km
1992-12-16	2.6	34.756°N 97.600°W – 5.0 km
1992-12-17	3.6	34.744°N 97.581°W – 5.0 km
1994-07-04	2.8	34.676°N 97.557°W – 5.0 km
1995-01-18	4.2	34.774°N 97.596°W – 5.0 km
1997-03-11	2.5	34.720°N 97.499°W – 5.0 km
1998-07-07	3.2	34.719°N 97.589°W – 5.0 km
2004-04-22	2.9	34.804°N 97.677°W – 5.0 km
2004-11-22	3.0	34.864°N 97.672°W – 5.0 km
2010-06-14	3.1	34.865°N 97.676°W – 5.0 km
2010-10-25	3.2	34.874°N 97.741°W – 5.0 km
2011-03-16	2.7	34.854°N 97.746°W – 5.0 km
2011-08-18	3.0	34.881°N 97.744°W – 5.0 km
2017-11-21	3.0	34.877°N 97.682°W – 2.4 km
2019-05-11	2.8	34.768°N 97.561°W – 5.0 km
2019-05-11	2.5	34.762°N 97.586°W – 5.0 km
2020-09-06	3.4	34.745°N 97.573°W – 7.0 km
2021-12-20	2.5	34.771°N 97.551°W – 6.5 km

4.7. Likelihood, Timing, and Magnitude of Potential Surface Leakage

Table 3 summarizes Daylight’s assessment of the likelihood, timing, and magnitude of surface leakage through the potential leakage pathways identified in this section.

Table 3: Assessment of Likelihood, Magnitude, and Timing of Potential Leakage Pathways

Potential Leakage Pathway	Likelihood	Magnitude ¹	Timing
Surface Equipment	Unlikely but possible	Variable – Small or easily detected failure could result in low- to medium-magnitude CO ₂ release, while a catastrophic failure could result in medium- to high-magnitude CO ₂ release	During injection period
Shallow Groundwater Wells	Unlikely	Low – Monitoring should minimize any release of CO ₂	During injection and post-injection periods
Other Wells	Unlikely but possible	Low – Monitoring / surveillance and well construction requirements should minimize any release of CO ₂	During injection and post-injection periods
Faults, Fractures, and Bedding Plane Partings	Unlikely	Low	During injection and post-injection periods
Lateral Fluid Movement	Unlikely	Low	During injection and post-injection periods
Confining Seal / System	Unlikely	Low	During injection and post-injection periods
Natural and Induced Seismic Activity	Unlikely	Low	During injection and post-injection periods

¹ Magnitude assessed as follows:

Low – minimal risk to safety, health and environment, or USDW

Medium – moderate risk to safety, health and environment, or USDW, but easily remediated

High – extreme risk to safety, health and environment, or USDW, and difficult and/or costly to remediate.

4.8. Strategy for Detection of CO₂ Loss

Daylight intends to use the results of daily monitoring of field conditions, operational data (including automatic data systems), routine testing, and maintenance information to monitor for surface leakage and to identify and investigate deviations from expected performance that could indicate CO₂ leakage. In the event any of those results indicate a CO₂ leak may have occurred, the event will be documented and an estimate will be made of the amount of CO₂ leaked. The event and estimate will be included in the annual Subpart RR reporting. Records of each event will be kept on file for a minimum of 3 years. The methods that Daylight intends to use in this strategy include the following:

4.8.1. *Data System*

Daylight uses onsite management and a Supervisory Control and Data Acquisition (SCADA) system to conduct its CO₂-EOR operations. Daylight uses data from these efforts to identify and investigate variances from expected performance that could indicate CO₂ leakage. Some CO₂ meters are installed with SCADA systems that transmit data from the meters automatically into a data warehouse. Those data, as well as other operational data collected manually, are also used for operational management and controls.

4.8.2. *Visual Inspections*

Daylight's field personnel conduct routine weekly or daily inspections of the facilities, wells, and other equipment (such as vessels, piping, and valves). These visual inspections provide an opportunity to identify issues early and to address them proactively, which may preclude leaks from happening and/or minimize any CO₂ leakage. Any visual identification of CO₂ vapor emission or ice formation will be reported and documented, and a plan will be developed and executed to correct the issue.

4.8.3. *Injection Target Rates and Pressures*

Daylight manages its CO₂-EOR operations by developing and implementing target injection rates and pressures for each CO₂ injection well. These target rates and pressures are developed based on various parameters such as historic and ongoing pattern development, WAG operations, CO₂ availability, field performance, and permit conditions. Field personnel implement the WAG schedule by manually making choke adjustments at each injection well, allowing for a physical inspection of the injection well during each adjustment. Generally on a daily basis, injection rates for each CO₂ injection well are reported and compared to the target rates. Injection pressures and casing pressures are monitored on each CO₂ injection well. Injection rates or pressures falling outside of the target rates or pressures to a statistically significant degree are screened to determine whether they could lead to CO₂ leakage to the surface. If that screening or investigation identifies any indication of a CO₂ leakage to the surface in this manner, it will be reported and documented, and a plan will be developed and executed to correct the issue.

4.8.4. *Production Wells*

Daylight forecasts the amount of fluids (e.g. oil, water, CO₂) that is likely to be produced from each production well at the unit level in the NEPSU and SEBAU over various periods of time. Evaluation of these produced volumes, along with other data, informs operational decisions regarding management of the CO₂-EOR project and aid in identifying possible issues that may involve CO₂ leakage. These evaluations can direct engineering and/or operational personnel to investigate

further. If an investigation identifies that a CO₂ leak has occurred, it will be reported and documented, and a plan will be developed and executed to correct the issue.

4.8.5. Plant and Pipeline Monitoring

Daylight currently operates the CO₂-related infrastructure used to operate the units, including the associated on-site CO₂ capture, compression, and dehydration facility. The facility includes a monitoring program that monitors the rates and pressures at the facility and on the pipeline on a continuous basis. High and low set points are established in the program, and operators at the plant, pipeline and/or the units are alerted if a parameter is outside the allowable window. If the flagged parameter is the delivery point on the pipeline, but no other parameter at the plant or pipeline is flagged, then the field personnel are alerted so that further investigation can be conducted in the field to determine if the issue poses a leak threat.

4.8.6. Well Testing

Injection wells are leak-tested via MIT as required by the USEPA or OCC. This consists of regular monitoring of the tubing-casing annular pressure and conducting a test that pressures up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. Sometimes, in addition to or in lieu of MIT, Daylight is required to perform a RTS to ensure that all injection fluids are going into the injection zone. Daylight personnel monitor the pressure and conduct the tests in accordance with regulations and permit requirements. In the event of a loss of mechanical integrity, the subject injection well is immediately shut in and an investigation is initiated to determine what caused the loss of mechanical integrity. If investigation of an event identifies that a CO₂ leak has occurred, it will be reported and documented, and a plan will be developed and executed to correct the issue.

4.9. Strategy for Response to CO₂ Loss

As discussed above, the potential sources of leakage include routine issues, such as problems with surface equipment (e.g., pumps, valves), wellbores or subsurface equipment, and unique and unlikely events such as induced fractures. **Table 4** summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, Daylight's standard response, and other applicable regulatory programs requiring similar reporting.

The potential CO₂ losses discussed in the table are identified by type. If there is a report or indication of a CO₂ leak, such as from a visual inspection, monitor, or pressure drop, a Daylight employee or supervisor will be dispatched to investigate. Emergency shutdown systems will be utilized as necessary to isolate the leak. If the leak cannot be located without movement of equipment or other substantial work, further involvement of Daylight personnel or management will be involved to determine how the leak will be located. Once the leak is located and isolated, pressure from the system will be relieved so that further investigation of the leak area can be performed and repair work can be estimated and ultimately performed.

Table 4: Response Plan for CO₂ Loss

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

4.10. Strategy for Quantifying CO₂ Loss

Leakage of CO₂ on the surface will be quantified once leakage has been detected and confirmed. Major CO₂ losses are typically event-driven and require a process to assess, address, track, and if applicable, quantify potential CO₂ leakage to the surface. Daylight will use Subpart W techniques to estimate leakages only on equipment and ensure those results are consistently represented in the Subpart RR report. Any event-driven leakage quantification reported in Subpart RR for surface leaks will use other techniques.

In the event leakage occurs, Daylight will determine the most appropriate method for quantifying the volume leaked and will report the methodology used as required as part of the annual Subpart RR submission. Leakage estimating methods may potentially consist of modeling or engineering estimates based on operating conditions at the time of the leak, such as temperatures, pressures, volumes, and hole size. An example methodology would be to place a flux box or ring tent over the surface leak to measure the flow rate and gather gas samples for analysis. The volume of CO₂ in the soil can also be used with this technique. Any volume of CO₂ detected leaking to the surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 Subpart W or engineering estimates of leak amounts based on measurements in the subsurface, Daylight's field experience, and other factors such as the frequency of inspection. Records of leakage events will be retained in Daylight's electronic documentation and reporting system, which consists of reports stored on servers, with certain details uploaded into third-party software.

4.11. Demonstration at End of Specified Period

At the end of EOR injection operations, Daylight intends to cease injecting CO₂ for the purpose of establishing long-term storage of CO₂ in the units. At that time, Daylight anticipates submitting a request to discontinue monitoring and reporting, including a demonstration that the amount of CO₂ reported under Subpart RR is not expected to migrate in the future in a manner likely to result in surface leakage. Daylight will support its request with data collected during operations as well as 1-3 years of data (or more, if needed) collected after the end of operations. Daylight expects this demonstration will provide the information necessary for the USEPA to approve the request to discontinue monitoring and reporting. This demonstration may include but is not limited to:

- An assessment of CO₂ injection data for the units, including the total volume of CO₂ injected and stored as well as actual surface injection pressures;
- An assessment of any CO₂ leakage detected, including discussion of the estimated amount of CO₂ leaked and the distribution of emissions by leakage pathway; and
- An assessment of reservoir pressure in the units that demonstrates that the reservoir pressure is stable enough to demonstrate that the injected CO₂ is not expected to migrate in a manner to create a potential leakage pathway.

5.0. Strategy for Determining CO₂ Baselines for CO₂ Monitoring

Daylight may elect to collect additional atmospheric test data using ambient air detectors or other methodologies to characterize baseline values in the units. Ongoing operational monitoring of well pressures and rates has provided data for establishing baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO₂ 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. Each of these is discussed in more detail below.

5.1. Site Characterization and Monitoring

As described in **Section 2.2.2** and **Section 2.4**, the Cunningham Sandstone is isolated by impermeable shale units of the upper Springer, Morrow, and/or Atoka reaching thicknesses of 150-200 feet. These units provide a suitable primary seal to prevent the migration of CO₂ out of the injection reservoir, and additional shale layers above the primary seal provide secondary confinement with a total net shale thickness >1,200 feet. As discussed in **Section 4.5**, testing of the Springer prior to CO₂ injection showed a 0.6% molar concentration of CO₂ (Fox et al., 1988). In October 2023, Daylight's testing of more than 50 wells producing from the Hart reservoir showed an average of 0.25% molar concentration of CO₂ in the gas stream. Furthermore, a review of gas sample data published in Higley (2014) shows the range of natural CO₂ concentration in the Central Anadarko Basin is 0.00-10.9 mole percent (average, 1.73 mole percent). These field- and basin-scale data will be considered in the determination of CO₂ baseline values should a potential leak be detected.

Additionally, no significant faults or fracture zones that compromise the sealing capacity of the confining shales have been identified in the Purdy-Bradley Springer Field, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented. After ~42 years of tertiary oil recovery operations, no significant wellbore leaks are known to have occurred, and therefore Daylight concludes that wellbore leaks are unlikely to happen.

5.2. Groundwater Monitoring

Daylight obtains and tests water samples from shallow groundwater wells during the preparation of permit applications for new Class II UIC EOR injection wells. Daylight has not monitored USDW wells for CO₂ or brine contamination, as characterization of the Springer suggests that risk of groundwater contamination from CO₂ leakage from the reservoir is minimal. While groundwater contamination is unlikely to happen, any change in groundwater that is brought to the attention of Daylight will be investigated to eliminate the potential leakage pathway.

5.3. Soil CO₂ Monitoring

Daylight does not intend to collect background soil gas data. Should a possible leakage event be detected, Daylight may elect to use vapor monitoring points installed into the shallow subsurface as part of the leakage verification and quantification process.

5.4. Visual Inspection

Daylight operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage. Visual inspection consists of finding evidence of stains, unusual

accumulation of frost, washouts exposing buried pipe, dead rodents, birds or reptiles, and changes to vegetation. In addition to looking for evidence of leaks, field personnel will look for conditions that could lead to equipment failure such as public utility digging, ditching, settling of backfill, boring, and tunneling.

5.5. Well Surveillance

Daylight adheres to the requirements of OAC Title 165 Chapter 10 governing fluid injection into productive reservoirs. Title 165 includes requirements for monitoring, reporting, and testing of Class II UIC injection wells, including an initial MIT prior to injection operations and subsequent MIT at least once every year or every 5 years, depending on the permitted injection rate. Daylight will report any mechanical failure of the surface casing or cement to the appropriate regulatory authority in full compliance with all applicable legal and regulatory requirements.

5.6. Injection Well Rates, Pressures, and Volumes

Target injection rates and pressures for each injector are developed within the permitted limits based on the results of ongoing pattern surveillance. The field operations staff monitor equipment readings and investigate any departures from the permitted limits which could have resulted in a surface CO₂ leak.

6.0. Site-Specific Considerations for Determining the Mass of CO₂ Sequestered

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

6.1. Determining Mass of CO₂ Received

Daylight has the ability to receive CO₂ at its NEPSU and SEBAU facilities via its operated pipeline from Enid, Oklahoma. Daylight also recycles CO₂ from its production wells in NEPSU and SEBAU.

$$CO_{2T,r} = \sum_{p=1}^4 (Q_{r,p} - S_{r,p}) \times D \times C_{CO_2,p,r} \quad (\text{Equation RR-2})$$

where:

CO_{2T,r} = Net annual mass of CO₂ received through flow meter r (metric tons)

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

C_{CO₂,p,r} = Quarterly CO₂ concentration measurement in flow for flow meter r in quarter p (volume percent CO₂, expressed as a decimal fraction)

p = Quarter of the year

r = Receiving flow meter

6.2. Determining Mass of CO₂ Injected

Daylight injects CO₂ into the injection wells listed in **Appendix 1**.

$$CO_{2,u} = \sum_{p=1}^4 Q_{p,u} \times D \times C_{CO_2,p,u} \quad (\text{Equation RR-5})$$

where:

CO_{2,u} = Annual CO₂ mass injected (metric tons) as measured by flow meter u

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

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

p = Quarter of the year

u = Flow meter

To aggregate injection data, Daylight will sum the mass of all the CO₂ injected through each injection well listed in **Appendix 1** in accordance with the procedure specified in Equation RR-6:

$$CO_{2I} = \sum_{u=1}^U CO_{2,u} \quad (\text{Equation RR-6})$$

where:

CO_{2I} = Total annual CO₂ mass injected (metric tons) through all injection wells

CO_{2,u} = Annual CO₂ mass injected (metric tons) as measured by flow meter u

u = Flow meter

6.3. Determining Mass of CO₂ Produced from Oil Wells

Daylight also recycles CO₂ from its EOR production wells in the NEPSU and SEBAU. Therefore, the following equation is relevant to its operations.

$$CO_{2,w} = \sum_{p=1}^4 Q_{p,w} \times D \times C_{CO_2,p,w} \quad (\text{Equation RR-8})$$

where:

CO_{2,w} = Annual CO₂ mass produced (metric tons) through separator w

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

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

p = Quarter of the year

w = Separator

To aggregate production data, Daylight will sum the mass of all the CO₂ separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9:

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

where:

CO_{2P} = Total annual CO₂ mass produced (metric tons) through all separators in the reporting year

CO_{2,w} = Annual CO₂ mass produced (metric tons) through separator w in the reporting year

X = Entrained CO₂ in produced oil or other fluid divided by the CO₂ separated through all separators in the reporting year (weight percent CO₂, expressed as a decimal fraction).

w = Separator

6.4. Determining Mass of CO₂ Emitted by Surface Leakage

If needed, Daylight will reference the potential quantification methods described in **Section 4.10** to determine the total mass of CO₂ emitted by all surface leakage pathways. Daylight will calculate the total annual mass of CO₂ emitted by surface leakage using Equation RR-10:

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

where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year

x = Leakage pathway

6.5. Determining Mass of CO₂ Sequestered

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

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

where:

CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

CO_{2P} = Total annual CO₂ mass produced (metric tons) in the reporting year

CO_{2E} = Total annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year

CO_{2FI} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ 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

CO_{2FP} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ 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

7.0. Estimated Schedule for Implementation of MRV Plan

Daylight expects to begin implementing this MRV Plan after approval, or tentatively in 2026. Data collection for Subpart RR reporting (calculating total amount sequestered according to Equation RR-11 of this subpart) is expected to begin in 2026 after the MRV Plan is approved and a supply of fresh CO₂ is secured. As such, this data collection would begin no later than 12/31/2026 for 2027 reporting.

8.0. GHG Monitoring and Quality Assurance Program

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

8.1. GHG Monitoring

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

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

8.1.1. General

Daylight follows industry-standard metering protocols for custody transfers, such as those standards for accuracy and calibration issued by the API, the American Gas Association (AGA), and the Gas Producers Association (GPA), as appropriate. This approach is consistent with 98.444(e)(3). Meters are maintained routinely, operated continually, and will feed data directly to the centralized data collection systems. CO₂ composition is governed by contract, and the CO₂ is routinely and periodically sampled to determine average composition. These custody meters provide an accurate method of measuring mass flow.

In addition to custody transfer meters, various process control meters are used in NEPSU and SEBAU to monitor and manage in-field activities, often on a real-time basis. These operations meters provide information used to make operational decisions but are not intended to provide the same level of accuracy as the custody-transfer meters. The level of precision and accuracy for operational meters currently satisfies the requirements for reporting in existing UIC permits. Although the process control meters are accurate for operational purposes, there is some variance between most commercial meters (on the order of 1-5%), which is additive across meters. This

variance is due to differences in factory settings and meter calibration, as well as the operating conditions within the field. Meter elevation, changes in temperature, fluid composition (especially in multi-component or multi-phase streams), and pressure can affect readings of these operational meters.

Measurement of CO₂ Concentration – All measurements of CO₂ concentrations of any CO₂ quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as those established by the GPA.

Measurement of CO₂ Volume – All measurements of CO₂ volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees F and at an absolute pressure of 1 atmosphere. Measurement devices will be compliant with AGA and API standards and can produce and export .cfx industry-standard files for either gas or liquid meter runs.

8.1.2. CO₂ Received

Fresh CO₂ (non-recycled) is received via a pipeline running from Enid, Oklahoma, and is measured with an orifice meter (recorded with a digital transducer). Information is sent to a flow computer (Fisher/Emerson ROC800) and is configured to calculate volumes. Data is stored temporarily to be pulled by the SCADA system. Daylight will bring in new sources of CO₂ in the future according to field development and operational needs.

8.1.3. CO₂ Injected

Daily CO₂ injection is recorded by combining the totals for the recycle compressor meter and the received CO₂ meter based on what is delivered on a 24-hour basis. These data are taken from the meter daily and stored according to Daylight's data management protocols.

8.1.4. CO₂ Produced

The point of produced gas measurement is from a meter downstream of the compressors prior to being combined with purchase CO₂. The produced gas is sampled and analyzed quarterly at the plant inlet, plant tailgate (north and south) and as needed at each satellite.

8.1.5. CO₂ Emissions from Equipment Leaks and Vented Emissions of CO₂

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

As required by 98.444 (d) of Subpart RR, Daylight will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO₂ stream, for facilities that conduct CO₂-EOR operations. The default emission factors for production equipment are applied to the carbon capture utilization and storage (CCUS) injection operations reporting under Subpart RR.

8.1.6. *Measurement Devices*

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

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

8.2. QA/QC Procedures

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

8.3. Estimating Missing Data

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

A quarterly flow rate of CO₂ received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.

A quarterly CO₂ concentration of a CO₂ 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 CO₂ injected that is missing would be estimated using a representative quantity of CO₂ injected from the nearest previous period of time at a similar injection pressure.

For any values associated with CO₂ emissions from equipment leaks and vented emissions of CO₂ 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.

A quarterly quantity of CO₂ produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO₂ produced from the nearest previous period of time.

8.4. Revisions to the MRV plan

Daylight will revise the MRV Plan as necessary per 40 CFR 98.448(d).

9.0. Records Retention

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

- (1) A list of all units, operations, processes, and activities for which GHG emissions were calculated. The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:
 - (i) The GHG emissions calculations and methods used.
 - (ii) Analytical results for the development of site-specific emissions factors, if applicable.
 - (iii) The results of all required analyses.
 - (iv) Any facility operating data or process information used for the GHG emission calculations.
- (2) The annual GHG reports.
- (3) Missing data computations. For each missing data event, Daylight will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
- (4) A copy of the most recent revision of this MRV Plan.
- (5) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
- (6) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
- (7) Quarterly records of CO₂ received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- (8) Quarterly records of produced CO₂, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- (9) Quarterly records of injected CO₂ including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- (10) Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- (11) Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
- (12) Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.
- (13) Any other records as specified for retention in this USEPA-approved MRV plan.

List of Figures

Figure 1: Location of the Purdy-Bradley Springer field in the Arkoma Basin	6
Figure 2: Regional stratigraphic column	7
Figure 3: Type log	8
Figure 4: Depth to base of treatable water	10
Figure 5: Simplified flow diagram of the CO ₂ -EOR operations	11
Figure 6: CO ₂ collection and distribution process	13
Figure 7: Simplified fluids flow diagram for a typical NEPSU satellite.....	14
Figure 8: Process diagram for the Lindsay Gas Plant.....	15
Figure 9: Top Springer structure	19
Figure 10: Net pay thickness for the Springer reservoir sands	20
Figure 11: Schematic of the reservoir-seal stratigraphic trapping configuration	21
Figure 12: Oil PVT plots.....	23
Figure 13: Oil and gas viscosity	23
Figure 14: Lorenz plot.....	24
Figure 15: Hydrocarbon pore volume filled by CO ₂ injection vs. time.	25
Figure 16: Recovery factor vs. CO ₂ pore volume injected	25
Figure 17: Oil rate-time curve comparison with actual estimations	27
Figure 18: Comparison of the cumulative oil rates	27
Figure 19: Variation of CO ₂ density at 148 degrees F.....	28
Figure 20: Predicted volume available for CO ₂ injection	29
Figure 21: Predicted CO ₂ storage in terms of mass.....	29
Figure 22: Location and type of all wells within the Active / Maximum Monitoring Area.....	33
Figure 23: Earthquakes (+2.5 magnitude) within 2 miles of the MMA.....	36

List of Tables

Table 1: Reservoir Summary Characteristics	18
Table 2: Details of earthquakes within the MMA	36
Table 3: Assessment of Likelihood, Magnitude, and Timing of Potential Leakage Pathways	37
Table 4: Response Plan for CO ₂ Loss	40

Appendix 1 – List of Wells

A list of all known wells in the MMA is provided in the attached PDF spreadsheet. Information was compiled from available S&P Global (formerly IHS) data. This information may differ from records available from the online OCC Well Data Finder as well as the archived documents database for well data, which may not include certain legacy well records. To ensure all wells within the MMA are accounted for, Daylight is providing the more extensive well record data provided by S&P Global that contains 886 unique wellbores within the MMA.

Appendix 2 – References

Regulatory Citations

Oklahoma Administrative Code Title 165 Chapter 10 (<https://rules.ok.gov/code>)

26 CFR 1.45Q (for table of contents, see <https://www.ecfr.gov/current/title-26/section-1.45Q-0>)

40 CFR Part 98 Subpart A (<https://www.ecfr.gov/current/title-40/part-98/subpart-A>)

40 CFR Part 98 Subpart W (<https://www.ecfr.gov/current/title-40/part-98/subpart-W>)

40 CFR Part 98 Subpart RR (<https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-RR>)

40 CFR Part 98 Subpart UU (<https://www.ecfr.gov/current/title-40/part-98/subpart-UU>)

Other Publications

Advanced Resources International (2024). The U.S. CO₂ enhanced oil recovery survey. <https://adv-res.com/pdf/ARI-2021-EOY-2020-CO2-EOR-Survey-OCT-21-2021.pdf>

Ball, M. M., Henry, M. E., and Frezon, S. E. (1991). Petroleum geology of the Anadarko Basin region, Province (115), Kansas, Oklahoma, and Texas. Open-File Report 88-450W, U.S. Geological Survey.

Birk, S.C. (1986). Letter to Cuscaden, J.A., S.E. Bradley – minimum miscibility pressure. Project 208-5480. Mobil Research and Development Corporation, Dallas Research Laboratory.

Brinlee, L. D., and Brandt, J. A. (1982). Planning and development of the Northeast Purdy Springer CO₂ miscible project. Paper presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, September 1982. SPE-11163-MS, 13 pp. doi: <https://doi.org/10.2118/11163-MS>

Chang, J.M., and Stanley, T.M. (2010). Geologic map of the Pauls Valley 30' X 60' quadrangle (Preliminary), Carter, Cleveland, Garvin, Grady, McClain, Murray, Pottawatomie, and Stephens Counties, Oklahoma. Oklahoma Geological Survey OGQ-81 Color.

Cities Service Company (1978). Feasibility analysis of applying enhanced recovery methods, Northeast Purdy Spring Sand Unit “A”, Garvin County, Oklahoma. Unpublished manuscript, Cities Service Company Task Force for Purdy Unit.

Ekstrand, J.D. (1979). Routine core analysis and special flow studies, N.E. Purdy K-214, Garvin County, Oklahoma. Cities Service Company Energy Resources Group Research Laboratory, PR 79-02.

Fox, M.J., Simlote, V.N., Stark, K.L., and Brinlee, L.D. (1988). Review of CO₂ flood, Springer “A” Sand, Northeast Purdy Unit, Garvin County, Oklahoma. SPE Res Eng 3: 1161–1167. doi: <https://doi.org/10.2118/14938-PA>

Koval, E.J. (1963). A method for predicting the performance of unstable miscible displacement in heterogeneous media. SPE J. 3: 145–154. doi: <https://doi.org/10.2118/450-PA>

Ham, W.E., Denison, R.E., and Merritt, C.A. (1964). Basement Rocks and Structural Evolution of Southern Oklahoma: Oklahoma Geological Survey Bulletin 95, 302 p.

Higley, D.K., compiler. (2014). Petroleum systems and assessment of undiscovered oil and gas in the Anadarko Basin Province, Colorado, Kansas, Oklahoma, and Texas—USGS Province 58: U.S. Geological Survey Digital Data Series DDS–69–EE, 409 p. <http://dx.doi.org/10.3133/ds69EE>

Irani, M., Bashtani, F., and Kantzas, A. (2021). Control of gas cresting/coning in horizontal wells with tubing-deployed inflow control devices. *Fuel* 293, 120328. doi:10.1016/j.fuel.2021.120328

Johnson, K.S., and Luza, K.V., eds. (2008). *Earth Sciences and Mineral Resources of Oklahoma*. Oklahoma Geological Survey, University of Oklahoma.

Jorgensen, D.G. (1993). Paleohydrology of the Central United States, Chap. D, in: *Strategic and critical minerals of the Midcontinent region, United States* – U.S. Geological Survey Bulletin 1989.

Lee, E., Hornafius, J. S., Dean, E. Kazemi, H., (2019). Potential of Denver Basin oil fields to store CO₂ and produce Bio-CO₂-EOR oil. *International Journal of Greenhouse Gas Control* (81): 137-156. <https://doi.org/10.1016/j.ijggc.2018.11.013>

Nelson, P.H., and Gianoutsos, N.J. (2014). Potentiometric surfaces for seven stratigraphic units and an explanation for underpressure in the Greater Anadarko Basin, Oklahoma, Texas, Kansas, and Colorado, Chap. 9, in: Higley, D.K., compiler, *Petroleum systems and assessment of undiscovered oil and gas in the Anadarko Basin Province, Colorado, Kansas, Oklahoma, and Texas* – USGS Province 58: U.S. Geological Survey Digital Data Series DDS–69–EE, 24 p. doi: <http://dx.doi.org/10.3133/ds69EE>.

NEPSU (1979). Enhanced recovery reservoir geology – Northeast Purdy Field, Garvin County, Oklahoma. Unpublished manuscript.

OWRB (n.d.). Oklahoma groundwater resources – major and minor aquifers of Oklahoma (map). Accessed January 2025 at: https://www.owrb.ok.gov/maps/pdf_map/GW%20Aquifers.pdf

Oxy (1988). Geologic and reservoir description. Unpublished manuscript.

Perry Jr., W. J. (1989). Tectonic evolution of the Anadarko Basin region, Oklahoma. Chapter A, in: *Evolution of Sedimentary Basins*, U.S. Geological Survey Bulletin 1866.

Salazar, J., and Lake, L. (2020). The physical meaning of the Koval factor. *Mathematical Geosciences*. 52. doi: 10.1007/s11004-020-09883-0.

Simlote, V., and Withjack, E. M. (1981). Estimation of tertiary recovery by CO₂ injection – Springer A Sand, Northeast Purdy Unit. *J Pet Technol* 33: 808–818. doi: <https://doi.org/10.2118/9431-PA>

Stell, M. (2010). An auditor's view of booking reserves in CO₂ EOR projects and the ROZ. Presented at the 16th Annual CO₂ Flooding Conference, Midland, Texas.

Appendix 3 – Abbreviations and Acronyms

AGA – American Gas Association

AMA – Active Monitoring Area

ANSI – American National Standards Institute

AoR – Area of Review

API – American Petroleum Institute

ASTM – American Society for Testing and Materials

Bscf – Billion Standard Cubic Feet

CCUS – Carbon Capture, Utilization, and Storage

CFR – Code of Federal Regulations

CO₂ – Carbon Dioxide

CO₂-EOR – Carbon Dioxide Enhanced Oil Recovery

cp – Centipoise

DPHI – Density Porosity

EOR – Enhanced Oil Recovery

EOS – Equation of State

F – Fahrenheit

ft³ – Cubic Foot

FVF – Formation Volume Factor

GERG – European Gas Research Group

GHG – Greenhouse Gas

GHGRP – Greenhouse Gas Reporting Program

GPA – Gas Producers Association

GR – Gamma Ray

HCPV – Hydrocarbon Pore Volume

lbs – Pounds

m³ – Cubic Meter

Mcf – Thousand cubic feet

mD – Millidarcies

MIT – Mechanical Integrity Test (or Testing)

MMA – Maximum Monitoring Area

MMB – Million Barrels

MMP – Minimum Miscibility Pressure

MMscf – Million Standard Cubic Feet

MMSTB – Million Stock Tank Barrels

MMT – Million Metric Tons

MRV – Monitoring, Reporting, and Verification

MT – Metric Ton

NAESB – North American Energy Standards Board

NGL – Natural Gas Liquids

NIST – National Institute of Standards and Technology

NPHI – Neutron Porosity

OAC – Oklahoma Administrative Code

OCC – Oklahoma Corporation Commission

ppm – Parts Per Million

psi – Pounds per Square Inch

psia – Pounds per Square Inch Absolute

psig – Pounds per Square Inch Gauge

PVT – Pressure, Volume, Temperature

QA/QC – quality assurance/quality control

rb – Reservoir Barrels

RTS – Radioactive tracer survey

SPHI – Sonic Porosity

UIC – Underground Injection Control

USDW – Underground Source of Drinking Water

USEPA – United States Environmental Protection Agency

USGS – United States Geological Survey

WAG – Water Alternating Gas

Appendix 4 – Conversion Factors

Daylight reports CO₂ at standard conditions of temperature and pressure as defined in the Oklahoma Administrative Code (OAC) for Oil and Gas Conservation, Title 165 Chapter 10 as follows:

“Cubic foot of gas” means the volume of gas contained in one cubic foot (ft³) of space at an absolute pressure of 14.65 pounds per square inch (psi) and at a temperature 60 degrees F. Conversion of volumes to conform to standard conditions shall be made in accordance with Ideal Gas Laws corrected for deviation from Boyle’s Law when the pressure at point of measurement is in excess of 200 pounds per square inch gauge (psig).

To calculate CO₂ mass from CO₂ volume, USEPA recommends using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST). This online database is available at <https://webbook.nist.gov/chemistry/fluid/>. It provides the density of CO₂ using the Span and Wagner equation of state (EOS) at a wide range of temperature and pressures.

At the standard conditions prescribed in the OAC, the Span and Wagner EOS gives a density of 0.0026417 lb-moles per cubic foot. Using a molecular weight for CO₂ of 44.0095, 2,204.62 lbs/MT and 35.314667 ft³/m³, gives a CO₂ density of 5.27346×10^{-2} MT/Mcf or 0.0018623 MT/m³.

Note that the USEPA standard conditions of 60 degrees F and one atmosphere produce a slightly different value. The Span and Wagner EOS gives a density of 0.0026500 lb-moles per cubic foot. Using a molecular weight for CO₂ of 44.0095, 2,204.62 lbs/MT and 35.314667 ft³/m³, gives a CO₂ density of 5.29003×10^{-2} MT/Mcf or 0.0018682 MT/m³.

The conversion factor 5.27346×10^{-2} MT/Mcf is used to convert CO₂ volumes to metric tons.

Appendix 5 – Koval Factor Calculation

Based on theoretical considerations, laboratory experiments, and pilot tests, Koval (1963) suggests that in miscible flooding, viscous fingering affects the volumetric sweeping efficiency. Immiscible viscous fingering in porous media occurs when a high-viscosity fluid is displaced by an immiscible low-viscosity fluid. In such cases, the Buckley-Leverett model cannot be applied directly and requires modification. According to Koval's theory (Koval, 1963), the fraction of pore volume swept by the displacing agent, denoted as E_v , can be expressed as a function of K_v , the Koval heterogeneity factor.

$$\text{If } t_D \leq 1/K_v \text{ then } E_v = t_D \quad \text{Equation 5-1}$$

$$\text{If } 1/K_v < t_D < K_v \text{ then } E_v = \frac{2\sqrt{K_v t_D} - t_D - 1}{K_v - 1} \quad \text{Equation 5-2}$$

$$\text{If } t_D \geq K_v \text{ then } E_v = 1.0 \quad \text{Equation 5-3}$$

where t_D is injected pore volume.

The Koval factor combines both the viscosity contrast effect and the heterogeneity effect. In practical applications, calculating the Koval factor is a complex task. A comparison is made with the Lorenz coefficient (Salazar and Lake, 2020). In this model, **Figure A5** is used, and based on the given Lorenz coefficient, the Koval factor is calculated.

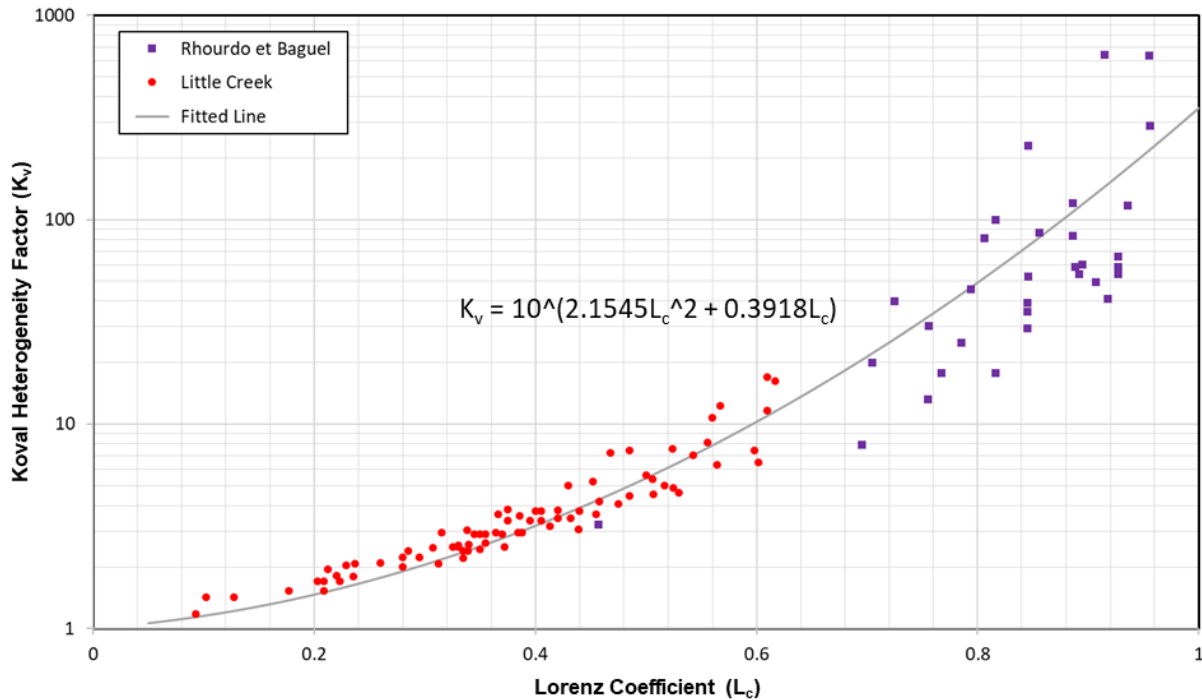


Figure A5: Comparison of the Koval factor and Lorenz coefficient.

Appendix 6 – Muskat Model Description

This appendix explains the formulation behind the Muskat Model, based on the work of Irani et al. (2021). Generally, when an analytical solution is not available, the depletion performance equations can be divided into blocks, with each block assuming constant properties. Muskat's method offers a solution that accounts for the expansion behavior of each pressure/saturation block, along with the corresponding flow equations. It also considers the expansion and liberation of gas due to pressure reduction, allowing for calculations of these effects. This method was chosen for its widespread application, simplicity, and compatibility with the available data size.

The first step involves calculating B_o , B_g , R_s , μ_o , and μ_g at pressures equal to or below the bubble point pressure.

Second, we calculate parameters α , β , and γ .

$$\alpha = (B_g^i)/(B_o^i) \times (R_s^{(i-1)} - R_s^i)/(P_i - P_{(i-1)}) \quad \text{Equation 6-1a}$$

$$\beta = 1/(B_o^i) \times (B_o^i - B_o^{(i-1)})/(P_i - P_{(i-1)}) \times (\mu_o^i)/(\mu_g^i) \quad \text{Equation 6-1b}$$

$$\gamma = 1/(B_g^i) \times (B_g^i - B_g^{(i-1)})/(P_i - P_{(i-1)}) \quad \text{Equation 6-1c}$$

At the first iteration, oil saturation can be obtained utilizing the water saturation derived from the resistivity log.

$$S_o = 1 - S_w \quad \text{Equation 6-2}$$

With both oil and water saturations available, the relative permeability of oil and gas can be determined. Using these relative permeability values, oil and water saturations can then be back calculated. In the next iteration, with the updated water and oil saturations, the gas saturation can be calculated, assuming a three-phase system.

$$S_g = 1 - S_w - S_o \quad \text{Equation 6-3}$$

Now, having the saturations at previous iterations, new oil saturation can be calculated as follows:

$$S_o^i = S_o^{(i-1)} - \left(\alpha S_o^i + \beta S_o^i (k_{rg}^i)/(k_{ro}^i) - \gamma (1 - S_w - S_o^i) \right) / \left(1 + (\mu_o^i)/(\mu_g^i) (k_{rg}^i)/(k_{ro}^i) \right) (P_{(i-1)} - P_i) \quad \text{Equation 6-4}$$

New relative permeability values can be determined using the updated oil saturation. This process is repeated iteratively until the difference between the old and new oil saturation becomes negligible. Next, we define a given rate at day 1, where the rate on any subsequent day is calculated by multiplying the initial rate by the new mobility factor. The mobility factor is the ratio of the new oil relative permeability to the oil viscosity at the given pressure. Finally, we define the pressure change over time to match both oil production and gas production (or the produced GOR).

UWI	Well Name	Well Type	Well Status
35049000610000	CANTRELL	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049000890000	ARTHUR W JONES	Temporarily Abandoned - Oil	
35049001770000	MCDANIEL	Dry Hole with Oil & Gas Show	DRY & ABANDONED-OIL & GAS SHOWS
35049002040000	SLAY	Oil Well	OIL PRODUCER
35049002050000	DUNCAN-ALCORN UNIT	Oil Well	OIL PRODUCER
35049003380000	REEVES	Oil Well	OIL PRODUCER
35049003410000	VIRGIL SMITH `A`	Oil & Gas Well	1 OIL & 1 GAS WELL
35049004080000	R L FREEMAN	Dry Hole with Gas Show	DRY & ABANDONED-GAS SHOWS
35049004190000	LESTER	Dry Hole with Gas Show	DRY & ABANDONED-GAS SHOWS
35049004470000	DENSON	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049004500000	ARNESSEN	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049004560000	JOHNSON-HOGUE UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049004600000	SWEENEY	Temporarily Abandoned - Gas	
35049005260000	HUGHES B	Oil Well	OIL PRODUCER
35049005640000	MORRIS UN B	Abandoned Oil & Gas Well	ABANDONED COMBINATION OIL & GAS PRODUCER
35049007190000	DENISON	Dry Hole	DRY & ABANDONED
35049008540000	MILLER B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049008660000	RODGERS B	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049009710000	MCKINNON	Dry Hole	DRY & ABANDONED
35049009740000	MAGEE	Dry Hole with Oil Show	DRY & ABANDONED-OIL SHOWS
35049009860000	NE PURDY SPRINGER A	Oil Well	OIL PRODUCER
35049012340000	CRAWFORD	Oil Well	OIL PRODUCER
35049012510000	NORTHEAST PURDY UNIT	Water Supply - Drilled	WATER SUPPLY WELL
35049012530000	N E PURDY UNIT	Water Supply - Drilled	WATER SUPPLY WELL
35049012540000	N E PURDYUNIT	Water Supply - Drilled	WATER SUPPLY WELL
35049012550000	N E PURDY UNIT	Water Supply - Drilled	WATER SUPPLY WELL
35049012620000	N E PURDY UNIT	Oil Well	OIL PRODUCER
35049012690000	N E PURDY UNIT	Water Supply - Drilled	WATER SUPPLY WELL
35049012720000	N E PURDY UNIT	Salt Water Disposal	SALT WATER DISPOSAL O&G OPERATOR
35049013030000	EASON	Oil Well	OIL PRODUCER
35049013040000	NORTHEAST PURDY UNIT	Oil Well	OIL PRODUCER
35049013060000	EWERT UNIT	Temporarily Abandoned - Oil	
35049013080000	PURDY NORTHEAST UNIT	Water Supply - Drilled	WATER SUPPLY WELL
35049013090000	PURDY N E UNIT	Salt Water Disposal	SALT WATER DISPOSAL O&G OPERATOR
35049013430000	V A CRWFORD-B NCT-2	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013440000	HUNTER WINNIE I	Temporarily Abandoned - Oil	
35049013450000	WINNIE I HUNTER	Oil Well	OIL PRODUCER
35049013460000	WINNIE I HUNTER	Oil Well	OIL PRODUCER
35049013470000	WINNIE I HUNTER	Oil Well	OIL PRODUCER
35049013480000	HUNTER-MOSLEY	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049013490000	MOSELY-A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013500000	MOSELY-B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013510000	MOSELY-B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER

35049013520000	DENSON-PARR UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013530000	DENSON-PARR UNIT	Oil Well	OIL PRODUCER
35049013540000	MARY E MOSELEY	Temporarily Abandoned - Oil	
35049013550000	MARY E MOSELEY	Oil Well	OIL PRODUCER
35049013560000	PARR B B	Oil Well	OIL PRODUCER
35049013570000	B B PARR /A/	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013580000	B B PARR-A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013590000	B B PARR-A	Oil Well	OIL PRODUCER
35049013600000	DENSON `A`	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013610000	DENSON UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013620000	DENSON ESTATE	Temporarily Abandoned - Oil	
35049013630000	DENSON ESTATE	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049013640000	DENSON	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013650000	DENSON-SCRIVN R UNI	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013660000	BARB	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013670000	CHARLIE-A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013680000	DENSON-C	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013690000	DENSON	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013700000	DENSON/A/	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013710000	DENSON-A	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049013720000	NORMA	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013730000	SPRINGER-A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013740000	VALERIE-A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013760000	BROWN-C	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013790000	MADGE-A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013810000	ROBERTA-F	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049013830000	DENSON	Dry Hole	DRY & ABANDONED
35049013840000	DENSON-REID UNIT	Temporarily Abandoned - Gas	
35049013850000	OKLA DENSON	Temporarily Abandoned - Gas	
35049013860000	DENSON-DENSON UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049014990000	C DENSON	Temporarily Abandoned - Oil	
35049015000000	DENSON	Oil Well	OIL PRODUCER
35049015010000	ROBERTA-G	Temporarily Abandoned - Oil	
35049015030000	DUNCAN	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049015040000	DUNCAN-B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049015050000	DUNCAN-BARKER UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049015050100	NE PURDY SPRINGER A	Oil Well	OIL PRODUCER-OLD WELL WORKED OVER
35049015060000	DUNCAN-LAWS UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049015070000	DUNCAN-MAYS UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049015080000	DUNCAN-NEILL UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049015090000	IMMOHO-TECHEY	Oil Well	OIL PRODUCER
35049015100000	MAYES A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049015110000	MCCOY	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049015120000	NEILL-A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER

35049015130000	ROBERTA-C	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049015140000	SADDLER	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049015150000	IRIS ARNER	Oil Well	OIL PRODUCER
35049015160000	ARNER	Oil Well	OIL PRODUCER
35049015170000	ARNER	Oil Well	OIL PRODUCER
35049015180000	FINES-REID	Temporarily Abandoned - Oil	
35049015200000	DUNCAN UNIT	Oil Well	OIL PRODUCER
35049015210000	DUNCAN-WILLIAMS UNI	Temporarily Abandoned - Gas	
35049015230000	VICTORIA UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049015240000	JONES G	Oil Well	OIL PRODUCER
35049015250000	JONES G	Temporarily Abandoned - Gas	
35049015260000	ALLIANCE-DUNCAN	Oil Well	OIL PRODUCER
35049015270000	ALLIANCE-TRUST	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049015280000	ALLIANCE-TRUST-SIMMONS	Temporarily Abandoned - Oil	
35049018970000	CLAUDILL	Oil Well	OIL PRODUCER
35049019510000	LANE UNIT	Oil Well	OIL PRODUCER
35049095260000	CRAWFORD-WERTZ	Oil & Gas Well	1 OIL & 1 GAS WELL
35049200260000	R L FREEMAN	Dry Hole	DRY & ABANDONED
35049210960000	NE PURDY SPR	Dry Hole	DRY & ABANDONED
35049213320000	MF DESPAIN GAS UN	Dry Hole	DRY & ABANDONED
35049213720000	MILLER	Temporarily Abandoned - Gas	
35049215510000	NE PURDY SPRINGER A	Oil Well	OIL PRODUCER
35049217470000	LEESE	Temporarily Abandoned - Oil	
35049218720000	SHUMATE	Dry Hole with Oil Show	DRY & ABANDONED-OIL SHOWS
35049221370000	BRADLEY `A` SOUTHEAST UNIT	Oil Well	OIL PRODUCER
35049223260000	NEPU SPRINGER	Oil Well	OIL PRODUCER
35049223550000	NEPU SPRINGER	Oil Well	OIL PRODUCER
35049224960000	CASTLEBURY	Oil Well	OIL PRODUCER
35049225210000	NEPU SPRINGER	Oil Well	OIL PRODUCER
35049225210100	NEPU SPRINGER A	Oil Well	OIL PRODUCER-OLD WELL WORKED OVER
35049226130000	BELL	Dry Hole	DRY & ABANDONED
35049228400000	NE PURDY SPRINGER SD UNIT `A`	Oil Well	OIL PRODUCER
35049230640000	SCHWARTZ	Oil Well	OIL PRODUCER
35049231800000	SOUTHEAST BRADLEY `A` UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049231950000	POWERS	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049232300000	DENSON	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049232670000	POWERS W L	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049233040000	LINDSAY	Temporarily Abandoned - Oil	
35049233230000	BRIDWELL `B`	Oil Well	OIL PRODUCER
35049233240000	PARK	Temporarily Abandoned - Oil	
35049233280000	MCDONALD `A`	Gas Well	GAS PRODUCER
35049233310000	LEWIS	Temporarily Abandoned - Oil	
35049233370000	NELSON	Oil Well	OIL PRODUCER
35049233480000	FARMS L S `A`	Oil Well	OIL PRODUCER

35049233640000	BRANCH	Oil Well	OIL PRODUCER
35049233670000	NOMOC `A`	Temporarily Abandoned - Oil	
35049233730000	FINES ARRIE	Temporarily Abandoned - Oil	
35049233860000	PARK `A`	Oil Well	OIL PRODUCER
35049233870000	MILLER `C`	Oil Well	OIL PRODUCER
35049234010000	JONES	Oil Well	OIL PRODUCER
35049234050000	SEIDEL `A`	Gas Well	GAS PRODUCER
35049234070000	BEACH `A`	Multi Zone Gas Well	2 GAS MULTIPLE PRODUCER
35049234210000	BURFORD `A`	Oil Well	OIL PRODUCER
35049234500000	JOHNSON I	Gas Well	GAS PRODUCER
35049234530000	HARMS	Oil Well	OIL PRODUCER
35049234570000	EMERSON	Oil Well	OIL PRODUCER
35049234650000	BRAY	Temporarily Abandoned - Oil	
35049234840000	FRYE	Oil Well	OIL PRODUCER
35049234860000	HILDERBRANDT `A`	Oil & Gas Well	1 OIL & 1 GAS WELL
35049234880000	HILDEBRANDT	Oil Well	OIL PRODUCER
35049234920000	MCDERMOTT	Oil Well	OIL PRODUCER
35049234930000	JIMMIE	Gas Well	GAS PRODUCER
35049234940000	BOWMAN	Oil Well	OIL PRODUCER
35049234950000	LACKEY	Temporarily Abandoned - Oil	
35049235040000	SINCLAIR	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049235070000	DAVIS	Temporarily Abandoned - Oil	
35049235250000	MILLER	Oil Well	OIL PRODUCER
35049235260000	HERZIG	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049235350000	LACKEY	Temporarily Abandoned - Oil	
35049235450000	BELL	Temporarily Abandoned - Oil	
35049235590000	CLEMENTS	Temporarily Abandoned - Oil	
35049235640000	LAWSON	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049235750000	FARROW	Oil Well	OIL PRODUCER
35049235770000	ELKINS	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049235800000	BRIDWELL	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049235820000	EVANS	Oil Well	OIL PRODUCER
35049235860000	MILLER E	Oil Well	OIL PRODUCER
35049236070000	PARR	Oil Well	OIL PRODUCER
35049236220000	TRAMMELL	Temporarily Abandoned - Oil	
35049236290000	BOBBY	Oil Well	OIL PRODUCER
35049236330000	VIRGIL	Oil Well	OIL PRODUCER
35049236420000	MAYS	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049236650000	MOBIL	Oil Well	OIL PRODUCER
35049236950000	STAPP	Oil Well	OIL PRODUCER
35049237090000	ERIN SPRINGS	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049237100000	BRIDWELL	Temporarily Abandoned - Oil	
35049237160000	GOSNELL	Temporarily Abandoned - Oil	
35049237200000	PURDY SPRINGER NE	Dry Hole	DRY & ABANDONED

35049237210000	BROWN	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049237280000	ALCORN	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049237290000	WILLIAMSON `B`	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049237340000	DENSON	Oil Well	OIL PRODUCER
35049237360000	YARBOROUGH	Oil Well	OIL PRODUCER
35049237390000	JOHNSON `I`	Oil Well	OIL PRODUCER
35049237580000	HILDERBRANDT	Oil Well	OIL PRODUCER
35049237590000	MURRAY	Oil Well	OIL PRODUCER
35049237600000	KELLY	Oil Well	OIL PRODUCER
35049237690000	OLEDA	Oil Well	OIL PRODUCER
35049237860000	REID `A`	Temporarily Abandoned - Oil	
35049237870000	PARR	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049237910000	LINDSAY L M	Oil Well	OIL PRODUCER
35049238180000	REID `C`	Temporarily Abandoned - Oil	
35049238210000	WELLS	Oil Well	OIL PRODUCER
35049238270000	REID `B`	Oil Well	OIL PRODUCER
35049238370000	PARK `A`	Gas Well	GAS PRODUCER
35049238430000	PURDY SPRINGER A NE	Dry Hole with Oil Show	DRY & ABANDONED-OIL SHOWS
35049238440000	PURDY SPRINGER A NE	Oil Well	OIL PRODUCER
35049238470000	MOSLEY `A`	Oil Well	OIL PRODUCER
35049238520000	CRAWFORD `A`	Oil Well	OIL PRODUCER
35049238550000	MARTIN `A`	Temporarily Abandoned - Oil	
35049238560000	NEPSU	Oil Well	OIL PRODUCER
35049238780000	MCCLURE	Oil Well	OIL PRODUCER
35049238890000	GAMBLE A	Multi Zone Oil Well	3 OIL MULTIPLE PRODUCER
35049238910000	CARTER	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049239230000	NEPSSUA	Oil Well	OIL PRODUCER
35049239270000	NEPSSUA	Oil Well	OIL PRODUCER
35049239560000	BURFORD `A`	Gas Well	GAS PRODUCER
35049239870000	NEPSSU A	Dry Hole	DRY & ABANDONED
35049239900000	LEO	Oil Well	OIL PRODUCER
35049239910000	NEPSSUA	Dry Hole	DRY & ABANDONED
35049240200000	MARY SUE	Temporarily Abandoned - Oil	
35049240220000	STANSBURY	Oil Well	OIL PRODUCER
35049240470000	BECK	Temporarily Abandoned - Oil	
35049240470100	BECK	Oil Well	OIL PRODUCER-OLD WELL WORKED OVER
35049240470101	BECK	Oil Well	OIL PRODUCER-OLD WELL WORKED OVER
35049240560000	PARK	Oil Well	OIL PRODUCER
35049240630000	CRAWFORD	Temporarily Abandoned - Gas	
35049240660000	MILLER `C`	Oil Well	OIL PRODUCER
35049240720000	REID `C`	Gas Well	GAS PRODUCER
35049240750000	REID	Oil Well	OIL PRODUCER
35049240800000	JOHN RAY	Temporarily Abandoned - Oil	
35049240840000	PARR	Oil Well	OIL PRODUCER

35049240840100	PARR	Gas Well	GAS PRODUCER-OLD WELL WORKED OVER
35049240850000	JOWANDA	Oil Well	OIL PRODUCER
35049241380000	NEPSU	Oil Well	OIL PRODUCER
35049241630000	RUTHIE	Oil Well	OIL PRODUCER
35049241740000	PURDY NORTHEAST SPRINGER UNIT	Oil Well	OIL PRODUCER
35049241760000	NEPHU	Oil Well	OIL PRODUCER
35049242060000	JONES	Oil Well	OIL PRODUCER
35049242150000	PURDY NORTHEAST SPRINGER SAND UNIT	Oil Well	OIL PRODUCER
35049242220000	PURDY NORTHEAST SPRINGER UNIT	Oil Well	OIL PRODUCER
35049242230000	PURDY NORTHEAST SPRINGER UNIT	Oil Well	OIL PRODUCER
35049242240000	PURDY NORTHEAST SPRINGER UNIT	Oil Well	OIL PRODUCER
35049242250000	PURDY NORTHEAST SPRINGER UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049242260000	PURDY NORTHEAST SPRINGER UNIT	Oil Well	OIL PRODUCER
35049242290000	NOMOC	Temporarily Abandoned - Oil	
35049242400000	PURDY NE SPRINGER SAND UNIT	Oil Well	OIL PRODUCER
35049242440000	NEPSU	Oil Well	OIL PRODUCER
35049242460000	PURDY NE SPRINGER UNIT	Oil Well	OIL PRODUCER
35049242500000	PURDY NE SPRINGER SD UNIT	Oil Well	OIL PRODUCER
35049242510000	PURDY NE SPRINGER SD UNIT	Oil Well	OIL PRODUCER
35049242560000	PURDY NE SPRINGER UNIT	Oil Well	OIL PRODUCER
35049242760000	NEPSU	Oil Well	OIL PRODUCER
35049242770000	NEPSU	Oil Well	OIL PRODUCER
35049242860000	WOODS	Oil Well	OIL PRODUCER
35049242890000	PARK	Temporarily Abandoned - Oil	
35049242900000	NEPSU	Oil Well	OIL PRODUCER
35049242960000	BRIDWELL	Dry Hole	DRY & ABANDONED
35049243020000	NEPSU	Oil Well	OIL PRODUCER
35049243130000	NEPSU	Oil Well	OIL PRODUCER
35049243150000	NEPSU	Dry Hole with Gas Show	DRY & ABANDONED-GAS SHOWS
35049244020000	RAY	Temporarily Abandoned - Gas	
35049244230000	PARK `A`	Oil Well	OIL PRODUCER
35049244280000	BURFORD `A`	Gas Well	GAS PRODUCER
35049244380000	MCDONALD A	Gas Well	GAS PRODUCER
35049245050000	GAMBLE A	Oil Well	OIL PRODUCER
35049245550000	TAYLOR	Oil Well	OIL PRODUCER
35049246830000	SEIDEL A	Gas Well	GAS PRODUCER
35049249370000	LINDSAY SOUTH	Salt Water Disposal	SALT WATER DISPOSAL COMMERCIAL
35049250460000	BRADLEY `A` SE UNIT	Oil Well	OIL PRODUCER
35049250470000	BRADLEY `A` SE UNIT	Water Injection Well	WATER INJECTION - ENHANCED OIL RECOVERY
35049250580000	WERTZ TRUST	Oil Well	OIL PRODUCER
35049250840000	NEPSU	Oil Well	OIL PRODUCER
35049251160000	GANNETT	Oil Well	OIL PRODUCER
35049251190000	RALPH 0304	Oil Well	OIL PRODUCER
35049251350000	ANTERO	Oil Well	OIL PRODUCER

35049251360000	TORERO	Oil Well	OIL PRODUCER
35049251530000	BALUCHI	Oil Well	OIL PRODUCER
35049251550000	WHITNEY	Oil Well	OIL PRODUCER
35049251840000	BALUCHI	Oil Well	OIL PRODUCER
35049251970000	BUD	Oil Well	OIL PRODUCER
35049251977000	BUD	Dry Hole	DRY & ABANDONED
35049251977100	BUD	Dry Hole	DRY & ABANDONED
35049251980000	ERIN SPRINGS SWD	Salt Water Disposal	SALT WATER DISPOSAL COMMERCIAL
35049252130000	MUSTANG	Oil Well	OIL PRODUCER
35049252240000	CORONA	Junked & Abandoned	JUNKED & ABANDONED
35049252270000	PRAIRIE	Oil Well	OIL PRODUCER
35049252330000	DILLY	Oil Well	OIL PRODUCER
35049252340000	DILLY	Oil Well	OIL PRODUCER
35049252350000	DILLY	Oil Well	OIL PRODUCER
35049252360000	BUD	Oil Well	OIL PRODUCER
35049252370000	BUD	Oil Well	OIL PRODUCER
35049252380000	BUD	Oil Well	OIL PRODUCER
35049252390000	BUD	Oil Well	OIL PRODUCER
35049252400000	BUD	Oil Well	OIL PRODUCER
35049252757000	PAPPY	Dry Hole	DRY & ABANDONED
35049252860000	ACTION JACKSON 0404	Oil Well	OIL PRODUCER
35049252870000	ROLLINS 0404	Oil Well	OIL PRODUCER
35049252890000	JIMMIE DELL 0404	Oil Well	OIL PRODUCER
35049252900000	HOLLYLUJAH 0404	Oil Well	OIL PRODUCER
35049253080000	JURGENS 0304	Dry Hole	DRY & ABANDONED
35049253080100	JURGENS 0304	Oil Well	OIL PRODUCER-OLD WELL WORKED OVER
35049253090000	RALPH 0304	Oil Well	OIL PRODUCER
35049253100000	KATHY A 0304	Oil Well	OIL PRODUCER
35049253110000	RALPH 0304	Oil Well	OIL PRODUCER
35049253120000	RALPH 0304	Dry Hole	DRY & ABANDONED
35049253550000	JEWELL BIA 0304	Dry Hole	DRY & ABANDONED
35049253550100	JEWELL BIA 0304	Oil Well	OIL PRODUCER-OLD WELL WORKED OVER
35049253570000	HARD KNOX	Oil Well	OIL PRODUCER
35049253600000	PRAIRIE	Oil Well	OIL PRODUCER
35049253610000	PRAIRIE	Oil Well	OIL PRODUCER
35049253630000	PRAIRIE	Oil Well	OIL PRODUCER
35049253640000	PRAIRIE	Oil Well	OIL PRODUCER
35049253700000	TORERO 0303	Oil Well	OIL PRODUCER
35049253710000	TORERO 0303	Oil Well	OIL PRODUCER
35049253720000	TORERO 0303	Oil Well	OIL PRODUCER
35049253730000	TORERO 0303	Oil Well	OIL PRODUCER
35049253770000	BALUCHI 0304-13	Oil Well	OIL PRODUCER
35049253780000	BALUCHI 0304-13	Oil Well	OIL PRODUCER
35049253790000	BALUCHI 0304-13	Oil Well	OIL PRODUCER

35049253800000	BALUCHI 0304-13	Oil Well	OIL PRODUCER
35049253810000	BALUCHI 0304-13	Oil Well	OIL PRODUCER
35049253830000	MUSTANG 0304-13	Oil Well	OIL PRODUCER
35049253840000	MUSTANG 0304-13	Oil Well	OIL PRODUCER
35049253890000	ANTERO	Oil Well	OIL PRODUCER
35049253900000	ANTERO FED	Oil Well	OIL PRODUCER
35049253920000	ANTERO	Oil Well	OIL PRODUCER
35049253940000	BUDWEISER	Waiting for Completion	AT TOTAL DEPTH
35049254150000	WERTZ TRUST	Oil Well	OIL PRODUCER
35049254200000	LILY	Location Only	WELL START
35049254290000	PRAIRIE	Oil Well	OIL PRODUCER
35049254300000	PRAIRIE	Oil Well	OIL PRODUCER
35049254360000	WERTZ TRUST	Oil Well	OIL PRODUCER
35049254430000	GANNET	Oil Well	OIL PRODUCER
35049304890000	LEO	Oil & Gas Well	1 OIL & 1 GAS WELL
35049379600000	BURFORD-MILLER UNIT	Dry Hole with Oil Show	DRY & ABANDONED-OIL SHOWS
35049379620000	MILLER C	Dry Hole	DRY & ABANDONED
35049379640000	J W BURFORD	Oil Well	OIL PRODUCER
35049379650000	BURFORD ESTATE	Temporarily Abandoned - Gas	
35049379660000	J W BURFORD	Temporarily Abandoned - Gas	
35049379670000	BURFORD ESTATE	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049379680000	T F GROSS	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049379690000	C A MILLER	Temporarily Abandoned - Oil	
35049379700000	HUGHES A	Temporarily Abandoned - Oil	
35049379710000	HUGHES B	Oil Well	OIL PRODUCER
35049379720000	BRADLEY A UNIT S E	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049379730000	ROSS B	Temporarily Abandoned - Oil	
35049379740000	ROSS C	Oil Well	OIL PRODUCER
35049379750000	SWEENEY UNIT	Oil Well	OIL PRODUCER
35049379760000	SWEENEY	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049379790000	MORRIS-MILLER	Gas Well	GAS PRODUCER
35049379810000	BURFORD	Dry Hole	DRY & ABANDONED
35049379820000	MILLER D	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049380200000	COCHRAN-BRAY	Dry Hole	DRY & ABANDONED
35049380240000	L M LINDSAY	Temporarily Abandoned - Gas	
35049380270000	PARTRIDGE UNIT	Oil Well	OIL PRODUCER
35049380280000	TUCKER UNIT	Temporarily Abandoned - Oil	
35049380330000	WOODS	Temporarily Abandoned - Oil	
35049380340000	MILLER E	Oil & Gas Well	1 OIL & 1 GAS WELL
35049380350000	MILLER E	Oil Well	OIL PRODUCER
35049380360000	MORRIS-KIRK UNIT	Temporarily Abandoned - Oil	
35049380370000	MORRIS-MCCOY UNIT	Temporarily Abandoned - Gas	
35049380380000	BRADLEY-MORRIS UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380390000	FREEMAN-BRADLEY UNT	Oil Well	OIL PRODUCER

35049380400000	FREEMAN	Temporarily Abandoned - Gas	
35049380410000	BRADLEY	Oil Well	OIL PRODUCER
35049380420000	BRADLEY UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049380430000	BRADLEY-GARR UNIT	Temporarily Abandoned - Oil	
35049380440000	BRADLEY UNIV UNIT	Oil Well	OIL PRODUCER
35049380450000	R L FREEMAN	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049380460000	GARR-UNIVERSITY UNIT	Oil Well	OIL PRODUCER
35049380470000	D HALL	Oil Well	OIL PRODUCER
35049380490000	HOGUE-FREEMAN UNIT	Oil Well	OIL PRODUCER
35049380500000	LYDIA JOHNSON	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049380510000	REALGAR	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380520000	TAYLOR B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380530000	TAYLOR C	Temporarily Abandoned - Oil	
35049380540000	GOSNELL-FREEMAN	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049380570000	BRIDWELL C	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380580000	BIRDWELL E	Oil Well	OIL PRODUCER
35049380590000	BRIDWELL F	Oil & Gas Well	1 OIL & 1 GAS WELL
35049380600000	EVANS	Temporarily Abandoned - Oil	
35049380620000	TRAMMELL	Oil Well	OIL PRODUCER
35049380650000	BALL B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380660000	BRAY	Oil Well	OIL PRODUCER
35049380670000	BRAY B	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049380680000	BRIDWELL-B	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049380690000	ELKINS	Oil Well	OIL PRODUCER
35049380700000	ARMON	Oil Well	OIL PRODUCER
35049380710000	DINK-A	Oil Well	OIL PRODUCER
35049380720000	GOSNELL	Oil Well	OIL PRODUCER
35049380730000	CULLY	Oil Well	OIL PRODUCER
35049380740000	CULLY-CONN	Oil Well	OIL PRODUCER
35049380750000	CULLY-REEVES	Oil Well	OIL PRODUCER
35049380760000	REEVES	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049380770000	REEVES-BRAY	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380780000	DOROTHY HALL	Oil Well	OIL PRODUCER
35049380790000	HARRIS B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380800000	PARR	Oil Well	OIL PRODUCER
35049380810000	PARR B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380820000	PARR B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380830000	PARR ` B`	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380840000	PARR-MCCLURE	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380850000	BELL UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049380860000	CONN	Dry Hole with Oil Show	DRY & ABANDONED-OIL SHOWS
35049380870000	JORDEN UNIT	Oil Well	OIL PRODUCER
35049380880000	MCCLURE UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380890000	WOOD-PAR	Temporarily Abandoned - Oil	

35049380900000	WOOD	Oil & Gas Well	1 OIL & 1 GAS WELL
35049380910000	WOODS	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380920000	WARD B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380930000	WARD-C	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049380940000	WARD-B	Oil & Gas Well	1 OIL & 1 GAS WELL
35049380950000	BARNES	Dry Hole	DRY & ABANDONED
35049380960000	MCNUTT UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049381030000	ROGERS-B	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049381040000	ROGERS C	Temporarily Abandoned - Oil	
35049381060000	BRIDWELL-PASCHALL	Temporarily Abandoned - Oil	
35049381090000	LANE-BRIDWELL	Temporarily Abandoned - Oil	
35049381100000	SPRINGER C	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381110000	WERTZ	Temporarily Abandoned - Oil	
35049381120000	GAMBLE	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381130000	JOHNSON C 3	Temporarily Abandoned - Gas	
35049381140000	PRICE B	Temporarily Abandoned - Oil	
35049381150000	PRICE D	Temporarily Abandoned - Oil	
35049381160000	SIMS B	Oil Well	OIL PRODUCER
35049381170000	SIMS B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381180000	BALL	Oil Well	OIL PRODUCER
35049381190000	BURKLEO-B	Oil & Gas Well	1 OIL & 1 GAS WELL
35049381200000	BURKLEO B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381210000	CUNNINGHAM	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381220000	CUNNINGHAM C	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381230000	CUNNINGHAM-MYERS	Temporarily Abandoned - Oil	
35049381240000	HUGHES-C	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381250000	MYERS C	Temporarily Abandoned - Oil	
35049381260000	SLAY B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381270000	STANSBURY	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381280000	STANSBURY B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381290000	HUGHES-SLAY	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381300000	SLAY	Temporarily Abandoned - Oil	
35049381310000	FORD	Temporarily Abandoned - Oil	
35049381320000	FOLEY-SLAY	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049381330000	LANE ROWE UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049381340000	SLAY C	Temporarily Abandoned - Oil	
35049381350000	FOLEY F W	Oil Well	OIL PRODUCER
35049381360000	SUSSIE	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381370000	CONN UNIT	Temporarily Abandoned - Oil	
35049381380000	BAGWELL	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381390000	FOLEY A	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049381400000	FOLEY-C	Temporarily Abandoned - Gas	
35049381410000	NOD A	Temporarily Abandoned - Oil	
35049381420000	WASHITA `A`	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER

35049381430000	LANE	Oil Well	OIL PRODUCER
35049381450000	EWERT UNIT	Oil Well	OIL PRODUCER
35049381460000	LANE UNIT	Oil Well	OIL PRODUCER
35049381470000	BRIDWELL D	Oil Well	OIL PRODUCER
35049381490000	J P BRIDWELL	Temporarily Abandoned - Oil	
35049381510000	KIND	Oil Well	OIL PRODUCER
35049381530000	WOODS B	Oil Well	OIL PRODUCER
35049381540000	R H BRIDWELL	Oil Well	OIL PRODUCER
35049381560000	WOODS-AINSWORTH B	Oil Well	OIL PRODUCER
35049381570000	R H BRIDWELL	Oil Well	OIL PRODUCER
35049381580000	BRIDWELL UNIT	Oil Well	OIL PRODUCER
35049381590000	DAVIS-SMITH	Temporarily Abandoned - Oil	
35049381600000	SHADE-B	Oil & Gas Well	1 OIL & 1 GAS WELL
35049381610000	DENNIS	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381620000	WOODS-BRIDWELL UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049381630000	BRIDWELL	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049381640000	WOODS AINSWORTH UNT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049381650000	JOEL DENNIS	Oil Well	OIL PRODUCER
35049381660000	JOEL DENNIS	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381670000	DENNIS-GOWDY UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381680000	DENNIS-MOODY UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049381690000	JOHN BRIDWELL	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381700000	VIRGIL SMITH B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381710000	VIRGIL SMITH TRCT B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381720000	SMITH-B	Oil Well	OIL PRODUCER
35049381730000	CUNNINGHAM B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381740000	CUNNINGHAM B	Oil Well	OIL PRODUCER
35049381750000	CUNNINGHAM B	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049381760000	CUNNINGHAM B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381770000	DOE	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381780000	DOE	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381790000	DOE	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381790100	NEPSSUA	Oil Well	OIL PRODUCER-OLD WELL WORKED OVER
35049381800000	DOE	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381810000	SHAD	Temporarily Abandoned - Oil	
35049381820000	V SMITH-A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381830000	SHADE	Temporarily Abandoned - Oil	
35049381840000	SHADE	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381850000	PRICE	Temporarily Abandoned - Oil	
35049381860000	REID	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049381870000	REID	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381880000	HERZIG	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381890000	SIMMS	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381900000	SHOWALTER	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER

35049381910000	SHOWALTER-B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381920000	SHOWALTER-C	Oil Well	OIL PRODUCER
35049381930000	SHOWALTER-C	Oil Well	OIL PRODUCER
35049381940000	WAYLAND	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381950000	WAYLAND	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381960000	D W FARROW	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381970000	FARROW D W	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381980000	FARROW D W UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049381990000	ZID-A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049382010000	RACHEL ELMORE	Temporarily Abandoned - Oil	
35049382020000	ELMORE-HERZIG	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049382030000	WERTZ UNIT	Temporarily Abandoned - Oil	
35049382040000	ANNA LESTER B	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049382050000	LESTER ALLINC TRUST	Temporarily Abandoned - Oil	
35049382060000	JOHNSON D	Temporarily Abandoned - Gas	
35049382070000	PRICE C	Oil & Gas Well	1 OIL & 1 GAS WELL
35049382080000	SCOGGINS	Temporarily Abandoned - Oil	
35049382090000	SCOGGINS	Oil Well	OIL PRODUCER
35049382100000	SCOGGINS	Temporarily Abandoned - Oil	
35049382110000	SCOGGINS-FARROW	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049382120000	SCOGGINS-FARROW	Oil Well	OIL PRODUCER
35049382130000	SCOGGINS-FRROW-BROWN	Temporarily Abandoned - Oil	
35049382140000	JOHNSON	Temporarily Abandoned - Gas	
35049382150000	DONATO-A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049385430000	C A MILLER	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049388450000	ENGLISH	Temporarily Abandoned - Oil	
35049395610000	ETHEL PARR	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049395620000	RAGNA	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049395630000	RAGNA	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049395640000	AUDY /A/	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049395650000	AUDY /B/	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049395660000	AUDY /C/	Oil Well	OIL PRODUCER
35049395670000	AUDY D	Oil Well	OIL PRODUCER
35049395680000	AUDY E	Oil Well	OIL PRODUCER
35049395690000	AUDY E	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049395700000	HENDERSON	Oil Well	OIL PRODUCER
35049395710000	HENDERSON B	Oil Well	OIL PRODUCER
35049395770000	REYNOLDS UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049395780000	REPLOGLE UNIT C	Oil Well	OIL PRODUCER
35049395820000	ERIN SPRINGS UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049395920000	WOODS	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396090000	AUDY JONES	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396100000	AUDY JONES	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396110000	AUDY JONES	Abandoned Oil Well	ABANDONED OIL PRODUCER

35049396120000	AUDY JONES	Oil Well	OIL PRODUCER
35049396140000	G CANTRELL	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049396150000	CANTRELL	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049396160000	MARION	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049396170000	PASCHALL	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396180000	PASCHALL UNIT	Oil Well	OIL PRODUCER
35049396190000	PASCHALL	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396200000	PASCHALL	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049396210000	PASCHALL	Oil Well	OIL PRODUCER
35049396220000	JONES UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396230000	SHELTON UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049396240000	HENDERSON RAGNA	Oil Well	OIL PRODUCER
35049396250000	RAGNA HENDERSON	Oil Well	OIL PRODUCER
35049396260000	RAGNA-HENDERSON	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396270000	RAGNA HENDERSON	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396280000	HENDERSON	Oil Well	OIL PRODUCER
35049396290000	HENDERSON C	Oil Well	OIL PRODUCER
35049396300000	HENDERSON	Oil Well	OIL PRODUCER
35049396310000	HENDERSON C	Oil Well	OIL PRODUCER
35049396320000	HENDERSON	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049396330000	HENDERSON C	Oil Well	OIL PRODUCER
35049396340000	HENDERSON	Oil Well	OIL PRODUCER
35049396350000	HENDERSON C	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396360000	HENDERSON	Oil Well	OIL PRODUCER
35049396370000	HENDERSON	Oil Well	OIL PRODUCER
35049396380000	HENDERSON	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396390000	HENDERSON B	Oil Well	OIL PRODUCER
35049396400000	B DAUGHERTY	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396410000	B DAUGHERTY UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396420000	B DAUGHERTY	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396430000	DAUGHERTY UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396440000	SINCLAIR	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396450000	FOCH DAVIS	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396460000	J H KING	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396470000	WINNIE WILLIAMS	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396480000	BRAY A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396490000	JULIUS A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396500000	JULIUS A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396510000	JULIUS A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396520000	JULIUS /A/	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396530000	YARBROUGH	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396540000	T B SINCLAIR	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396550000	SINCLAIR T B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396560000	BURCH	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER

35049396570000	BURCH B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396580000	BURCH	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396590000	BURCH	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396600000	CARLIN	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396610000	CARLIN	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396620000	CARLIN	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396630000	CARLIN	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396640000	BURCH ELLIE	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396650000	BURCH UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049396660000	BURCH UNIT B	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049396670000	BURCH ELLIE	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396680000	BURCH	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396690000	E BURCH	Oil Well	OIL PRODUCER
35049396700000	ELLIE BURCH	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396710000	BURCH ELLIE	Oil Well	OIL PRODUCER
35049396720000	BURKLEO	Oil Well	OIL PRODUCER
35049396730000	BURKLEO UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049396740000	B DAUGHERTY A	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049396770000	KING-SCHONWALD	Oil Well	OIL PRODUCER
35049396790000	BURKLEO C	Oil Well	OIL PRODUCER
35049396830000	JOSEPH A	Oil Well	OIL PRODUCER
35049396840000	JOSEPH B	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049396850000	CLINGMAN	Oil Well	OIL PRODUCER
35049396860000	PRICE	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049396870000	BRIBACK UNIT	Oil Well	OIL PRODUCER
35049397240000	MAMIE AINSWORTH	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049397280000	MAMIE AINSWORTH	Oil Well	OIL PRODUCER
35049397300000	H Q HINKLE	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049397310000	HINKLE-HARRIS UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049397320000	HINKLE-HEFNER UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397330000	HARRIS A	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049397340000	HARRIS UNIT B	Oil Well	OIL PRODUCER
35049397360000	HARRIS A	Oil Well	OIL PRODUCER
35049397370000	BURKLEO	Oil Well	OIL PRODUCER
35049397380000	BURKLEO	Oil Well	OIL PRODUCER
35049397410000	W O BRAY ETAL	Oil Well	OIL PRODUCER
35049397420000	BRAY-TYLER UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049397430000	PASCHALL-BRAY UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397440000	PASCHALL-DESPAIN UN	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397450000	BURKLEO	Temporarily Abandoned - Oil	
35049397460000	BURKLEO	Oil Well	OIL PRODUCER
35049397470000	KOENIG A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397480000	M F DESPAIN	Oil Well	OIL PRODUCER
35049397490000	BRAY	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER

3504939750000	BRAY UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397510000	BRAY	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049397520000	BRAY	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397530000	DAUGHERTY	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397540000	DAUGHERTY	Oil Well	OIL PRODUCER
35049397550000	DAUGHERTY	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397560000	DAUGHERTY	Oil Well	OIL PRODUCER
35049397570000	BRIDWELL	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397580000	EVERETT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049397590000	EVERETT	Oil Well	OIL PRODUCER
35049397600000	SWEET R A	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049397610000	R A SWEET	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397620000	R A SWEET	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397630000	SWEET R A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397640000	ARNESON	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397650000	ARNESON	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397660000	ARNESON	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397670000	ADA S COOK	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049397680000	ADA S COOK	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397690000	COOK	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397700000	D W FARROW	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397710000	BRIDWELL-NORTHCUTT	Oil Well	OIL PRODUCER
35049397720000	ALCORN	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397730000	ALCORN B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397740000	ALCORN C	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397750000	NORTHCUTT-FARROW	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397760000	NORTHCUTT-MUSTAIN	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397770000	ALLNC-ALCRN-DUNCN U	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397780000	DUNCAN L P	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397790000	DUNCAN-ALLIANCE UNT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397800000	EMERSON A	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397810000	EMERSON-COMSTOCK UN	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397820000	FRANKLIN	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397830000	FRNKLIN-COMSTOCK UN	Oil Well	OIL PRODUCER
35049397840000	FRNKLIN-NORTHCUTT U	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397850000	NORTHCUTT-FRNKLIN U	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049397860000	ALLIANCE TRST UNT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049398640000	SPIKER-WHITT UNIT	Temporarily Abandoned - Oil	
35049398680000	VERA CRAWFORD	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049398700000	WHITT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049398710000	WHITT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049398730000	WHITT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049398740000	WHITT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049398780000	CRAWFORD-B	Temporarily Abandoned - Oil	

35049398790000	CRAWFORD-E	Oil Well	OIL PRODUCER
35049398800000	CRAWFORD-B	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049398810000	CRAWFORD-B	Dry Hole with Oil & Gas Show	DRY & ABANDONED-OIL & GAS SHOWS
35049398820000	VERA CRAWFORD	Oil Well	OIL PRODUCER
35049398830000	VERA CRAWFORD	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049398850000	DAY	Oil Well	OIL PRODUCER
35049398870000	V A CRAWFORD UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049398880000	V A CRAWFORD	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049398890000	V A CRAWFORD	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35049398900000	CRWFORD-SPIKER UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049399880000	CRAWFORD	Temporarily Abandoned - Oil	
35049399890000	VERA A CRAWFORD	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049399900000	C E DENSON	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049399910000	DENSON-CRWFORD UNIT	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049399930000	SIMMONS-B	Temporarily Abandoned - Oil	
35049399940000	SIMMONS-B	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049399950000	CRAWFORD	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049399960000	CRAWFORD	Oil Well	OIL PRODUCER
35049399970000	CRAWFORD	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049399980000	CRAWFORD	Oil Well	OIL PRODUCER
35049399990000	CRAWFORD-B	Abandoned Oil Well	ABANDONED OIL PRODUCER
35049505000000	J W MORRIS	Dry Hole	DRY & ABANDONED
35051000220000	BILLY	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051000640000	BRISCOE UNIT	Oil Well	OIL PRODUCER
35051000760000	WOODRUFF M C	Oil Well	OIL PRODUCER
35051001150000	HOWELL-CRAGG	Oil Well	OIL PRODUCER
35051001880000	TODD	Dry Hole	DRY & ABANDONED
35051002820000	R A THOMAS	Junked & Abandoned	JUNKED & ABANDONED-OIL SHOWS
35051003980000	DOWNING-ORDOVICIAN	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35051004830000	WELCH	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051006280000	BRADLEY SOUTHEASTS `A` UNIT	Water Supply - Drilled	WATER SUPPLY WELL
35051200050000	BRISCOE	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051200630000	BRADLEY SE `D`	Salt Water Disposal	SALT WATER DISPOSAL O&G OPERATOR
35051209390000	KENNEMAN	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051210000000	BARRY	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051211050000	BARRINGTON	Gas Well	GAS PRODUCER
35051211220000	HOWELL	Oil Well	OIL PRODUCER
35051211600000	SE BRADLEY /A/ UNIT	Oil Well	OIL PRODUCER
35051211990000	HUGHES	Dry Hole	DRY & ABANDONED
35051212160000	BURKES RANCH	Oil Well	OIL PRODUCER
35051212350000	KAY	Dry Hole	DRY & ABANDONED
35051214560000	JANSSON	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35051216490000	DUPIRE	Multi Zone Oil Well	3 OIL MULTIPLE PRODUCER
35051216670000	BRISCOE ESTATES	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER

35051216870000	BRISCOE ESTATES	Temporarily Abandoned - Oil	
35051216940000	BRISCOE ESTATES	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051217090000	AMBER	Oil Well	OIL PRODUCER
35051217380000	JANSSON	Oil Well	OIL PRODUCER
35051217480000	SE BRADLEY `D` UNIT	Temporarily Abandoned - Oil	
35051217600000	SOUTHEAST BRADLEY `D` UNIT	Temporarily Abandoned - Oil	
35051219030000	SOUTHEAST BRADLEY `A` UNIT	Gas Well	GAS PRODUCER
35051221440000	BRISCOE	Dry Hole	DRY & ABANDONED
35051223210000	NEWBY	Oil Well	OIL PRODUCER
35051223610000	LACK `A`	Temporarily Abandoned - Oil	
35051223800000	SANDY CREEK	Oil Well	OIL PRODUCER
35051223880000	SIMMS `A`	Oil Well	OIL PRODUCER
35051223990000	CARNAHAN	Oil Well	OIL PRODUCER
35051224180000	SIMMS `B`	Oil Well	OIL PRODUCER
35051224250000	BRISCOE	Oil Well	OIL PRODUCER
35051224330000	KEELER	Oil Well	OIL PRODUCER
35051224470000	COOPER	Oil Well	OIL PRODUCER
35051224550000	PRATHER	Temporarily Abandoned - Oil	
35051224620000	BRITTANY	Oil Well	OIL PRODUCER
35051224680000	LEDA KAY	Oil Well	OIL PRODUCER
35051224800000	SLAVENS	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051224830000	POLK MARGIE	Temporarily Abandoned - Gas	
35051224890000	SAMSON	Oil Well	OIL PRODUCER
35051225040000	CROAN A	Temporarily Abandoned - Oil	
35051225080000	AGNES	Temporarily Abandoned - Oil	
35051225120000	THOMAS UNIT	Oil Well	OIL PRODUCER
35051225340000	BRISCOE	Gas Well	GAS PRODUCER
35051227520000	ROY LEE	Gas Well	GAS PRODUCER
35051227790000	SOUTHEAST BRADLEY UNIT	Oil Well	OIL PRODUCER
35051228310000	BRAD	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051228360000	BULLWINKLE `A`	Temporarily Abandoned - Oil	
35051228410000	DOWNING	Temporarily Abandoned - Oil	
35051228560000	SEBAU	Oil Well	OIL PRODUCER
35051228580000	BURKES	Temporarily Abandoned - Oil	
35051228710000	BOYD	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051228890000	SCHOCK	Dry Hole	DRY & ABANDONED
35051229090000	JONES	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051229770000	BRAD	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051229890000	DOWNING	Oil Well	OIL PRODUCER
35051230150000	RUSSELL	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051230200000	CROAN	Oil Well	OIL PRODUCER
35051230250000	RUSSELL	Temporarily Abandoned - Oil	
35051230890000	SEBSU `M`	Oil Well	OIL PRODUCER
35051231240000	SUE	Temporarily Abandoned - Gas	

35051231410000	BURKES	Gas Well	GAS PRODUCER
35051231490000	VIETA	Temporarily Abandoned - Gas	
35051231500000	SARAH	Gas Well	GAS PRODUCER
35051231560000	SHONDA	Gas Well	GAS PRODUCER
35051231600000	FREDA	Temporarily Abandoned - Gas	
35051231720000	LAVETA	Gas Well	GAS PRODUCER
35051231730000	SPEARS	Gas Well	GAS PRODUCER
35051231900000	BULLWINKLE A	Temporarily Abandoned - Oil	
35051232040000	LACK `A`	Temporarily Abandoned - Gas	
35051233840000	ENGLISH	Temporarily Abandoned - Oil	
35051234380000	BRISCOE C	Gas Well	GAS PRODUCER
35051234410000	BURKES	Gas Well	GAS PRODUCER
35051234450000	LODGE UNIT	Gas Well	GAS PRODUCER
35051234680000	ENGLISH	Gas Well	GAS PRODUCER
35051234760000	DOUGHERTY-WELCH	Oil Well	OIL PRODUCER
35051234860000	BURKES	Gas Well	GAS PRODUCER
35051235000000	SANDY CREEK FARM	Oil Well	OIL PRODUCER
35051235160000	SPIES	Oil Well	OIL PRODUCER
35051235270000	JOHNNA	Oil Well	OIL PRODUCER
35051235590000	DENNIS	Oil Well	OIL PRODUCER
35051235760000	DENNIS	Gas Well	GAS PRODUCER
35051235930000	DENNIS	Temporarily Abandoned - Oil	
35051235990000	WELCH DOUGHERTY	Oil Well	OIL PRODUCER
35051236560000	DENNIS	Temporarily Abandoned - Oil	
35051236800000	DOUGHERTY WELCH	Oil Well	OIL PRODUCER
35051237280000	DOUGHERTY VIRGIL	Temporarily Abandoned	TEMPORARILY ABANDONED
35051240930000	MCDANIEL	Gas Well	GAS PRODUCER
35051240960000	CUADRILLA	Gas Well	GAS PRODUCER
35051242180000	SPIES	Gas Well	GAS PRODUCER
35051300020000	WILLIAMS-ORDOVICIAN	Temporarily Abandoned - Oil	
35051300150000	VIRGIL DOUGHERTY	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35051300240000	RILEY	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35051300310000	ROE	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051354730000	W M BONNER	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35051354770000	BONNER	Oil Well	OIL PRODUCER
35051355260000	DOUGHERTY-SIMS UNIT	Oil Well	OIL PRODUCER
35051355270000	DOUGHERTY & WELCH	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35051355280000	DOUGHERTY-SIMS UNIT	Oil Well	OIL PRODUCER
35051355290000	VIRGIL DOUGHERTY	Temporarily Abandoned - Oil	
35051355300000	WELCH	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35051355310000	WELCH	Oil Well	OIL PRODUCER
35051355320000	VIRGIL DOUGHERTY	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051355330000	BARRY	Dry Hole	DRY & ABANDONED
35051355340000	SIMMS-G	Dry Hole	DRY & ABANDONED

35051355350000	BARRY	Oil Well	OIL PRODUCER
35051355360000	BOB-B	Temporarily Abandoned - Oil	
35051355370000	SIMMS-F	Oil Well	OIL PRODUCER
35051355390000	ONYX	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051355400000	BOB-B	Temporarily Abandoned - Oil	
35051355410000	ETHEL BAUGHMAN	Oil Well	OIL PRODUCER
35051355420000	MATSYE	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051355430000	PEARL BRISCOE B	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051355440000	PEARL BRISCOE A	Oil Well	OIL PRODUCER
35051355450000	GAYLE MCCORD	Temporarily Abandoned - Gas	
35051355460000	ENGLISH	Temporarily Abandoned - Oil	
35051355470000	ENGLISH	Temporarily Abandoned - Oil	
35051355480000	BILLY	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051355500000	W J HANING	Oil Well	OIL PRODUCER
35051355510000	MCCORD UNT A	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051355520000	MID-CONTINNT ENGLIS	Dry Hole with Oil & Gas Show	DRY & ABANDONED-OIL & GAS SHOWS
35051355530000	MID-CNT BILY-ENGLISH	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051355540000	HANING UNIT	Oil Well	OIL PRODUCER
35051355550000	HANING UNIT	Oil Well	OIL PRODUCER
35051355560000	BILLY	Oil & Gas Well	1 OIL & 1 GAS WELL
35051355570000	LODGE UNIT	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35051355600000	GODFREY-B	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35051355620000	BRISCOE C	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER
35051355630000	B W ENGLISH	Oil Well	OIL PRODUCER
35051355640000	B W ENGLISH	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051355650000	CROAN	Oil Well	OIL PRODUCER
35051355660000	R B CROAN	Oil Well	OIL PRODUCER
35051355670000	B W ENGLISH	Oil Well	OIL PRODUCER
35051355680000	BRISCOE D	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051355690000	DOWNING-WOODRUFF	Oil Well	OIL PRODUCER
35051355700000	DOWNING-HANCOCK	Oil Well	OIL PRODUCER
35051355710000	DOWNING HANCOCK	Oil Well	OIL PRODUCER
35051355720000	GRIFFIN	Temporarily Abandoned - Oil	
35051355730000	WILLIAMS WHITE UNIT	Oil Well	OIL PRODUCER
35051355740000	BAUGHMAN	Oil Well	OIL PRODUCER
35051355750000	WILBURN BAUGHMAN	Oil Well	OIL PRODUCER
35051355760000	ETHEL BAUGHMAN	Oil Well	OIL PRODUCER
35051355770000	KIRK	Oil Well	OIL PRODUCER
35051355780000	ADAMS-C	Oil Well	OIL PRODUCER
35051355790000	WILLIAMS HEIRS	Oil Well	OIL PRODUCER
35051355800000	ADDIE-A	Oil Well	OIL PRODUCER
35051355810000	H L GRIFFIN	Temporarily Abandoned - Oil	
35051355820000	THOMAS-WILLIAMS UNT	Oil Well	OIL PRODUCER
35051355830000	CROAN	Temporarily Abandoned - Oil	

35051355840000	WILLIAMS HEIRS	Oil Well	OIL PRODUCER
35051355850000	BURKES	Oil Well	OIL PRODUCER
35051355860000	BURKES-MORRIS UNIT	Oil Well	OIL PRODUCER
35051355870000	BURKES	Oil Well	OIL PRODUCER
35051355880000	BURKES-WELCH UNIT	Oil Well	OIL PRODUCER
35051355890000	E F WELCH	Oil Well	OIL PRODUCER
35051355900000	WILBURN BAUGHMAN	Oil Well	OIL PRODUCER
35051355910000	E F WELCH	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051355920000	BURKES	Oil Well	OIL PRODUCER
35051355930000	BOYD-BURKES	Oil Well	OIL PRODUCER
35051355940000	C & M BURKES	Oil Well	OIL PRODUCER
35051355950000	BURKES C & M	Oil Well	OIL PRODUCER
35051355960000	MARIE BURKES	Oil Well	OIL PRODUCER
35051355970000	MARIE BURKES	Oil Well	OIL PRODUCER
35051355980000	E F WELCH	Oil Well	OIL PRODUCER
35051355990000	WELCH-BAUGHMAN	Temporarily Abandoned - Oil	
35051356000000	C BURKES	Temporarily Abandoned - Oil	
35051356010000	SINCLAIR-BRICKEN	Dry Hole with Oil & Gas Show	DRY & ABANDONED-OIL & GAS SHOWS
35051356020000	SINCLAIR-HUGHES UNT	Oil Well	OIL PRODUCER
35051356030000	SARA BURKES	Oil Well	OIL PRODUCER
35051356040000	SARAH BURKES	Oil Well	OIL PRODUCER
35051356050000	S S HUGHES	Oil Well	OIL PRODUCER
35051356060000	HUGHES	Oil Well	OIL PRODUCER
35051356070000	C BURKES	Oil Well	OIL PRODUCER
35051356080000	CHARLIE-BURKES	Oil Well	OIL PRODUCER
35051356090000	ADDISON-BURKES	Oil Well	OIL PRODUCER
35051356100000	BURKES UNIT	Oil Well	OIL PRODUCER
35051356110000	SARAH BURKES	Oil Well	OIL PRODUCER
35051356120000	BURKES	Oil Well	OIL PRODUCER
35051356130000	SARAH ADDISON	Oil Well	OIL PRODUCER
35051356140000	THOMAS ESTATE	Oil Well	OIL PRODUCER
35051356150000	IDA THOMAS	Temporarily Abandoned - Oil	
35051356160000	IDA THOMAS	Temporarily Abandoned - Oil	
35051356170000	THOMAS ESTATE	Oil Well	OIL PRODUCER
35051356180000	THOMAS ESTATE	Oil Well	OIL PRODUCER
35051356190000	R A THOMAS	Oil Well	OIL PRODUCER
35051356200000	MORRIS-SCHOCK UNIT	Oil Well	OIL PRODUCER
35051356210000	CHARLES-THOMAS UNIT	Oil Well	OIL PRODUCER
35051356220000	R A THOMAS	Oil Well	OIL PRODUCER
35051356230000	HOWELL-GRAGG	Oil Well	OIL PRODUCER
35051356240000	SCHOOL LAND	Oil Well	OIL PRODUCER
35051356250000	J W MORRIS	Oil Well	OIL PRODUCER
35051356260000	GILLA	Oil Well	OIL PRODUCER
35051356270000	HAMILTON	Oil Well	OIL PRODUCER

35051356280000	BESS MCCANN	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051356300000	TOLSTON & THORNTON	Temporarily Abandoned - Oil	
35051356310000	BYERS	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051356320000	BYARS	Abandoned Oil Well	ABANDONED OIL PRODUCER
35051356330000	QUIDA	Dry Hole with Oil Show	DRY & ABANDONED-OIL SHOWS
35051367380000	BARRY	Oil Well	OIL PRODUCER
35051368600000	LOUIS BILLY	Multi Zone Oil Well	2 OIL MULTIPLE PRODUCER

API#	Operator	Op. No.	Well Typ	WellName	WellNumber	Order/Permit	Approval Date	County	Sec	Twp	Rng	Q4	Q3	Q2	Q1	BOTTOM HOLE	LAT	LONG	PSI	BBLs	GAS	MCF	ZONE
3504900205	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	P15	257169	4/10/1984	GARVIN	1	03N	04W		NE	NE	SE	VERTICAL	34.75986	-97.5646	1,300	5,000			SPRINGER
3504900986	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	B2	305559	11/18/1986	GARVIN	21	04N	04W		SW	SE	NW	VERTICAL	34.806	-97.6272	1,500	2,000	CO2	NA	SPRINGER
3504901254	DAYLIGHT	24225	2D	NE PURDY SPRINGER SAND UNIT A	M-17D	435231	9/15/1999	GARVIN	12	03N	04W		NW	NW	NW	VERTICAL	34.75261	-97.58	2,000	6,000			PERMIAN
3504901272	DAYLIGHT	24225	2D	NE PURDY SPRINGER SAND UNIT A	E-13S	562112	11/12/2008	GARVIN	3	03N	04W	NW	NW	NW	NW	VERTICAL	34.76705	-97.6151	1,000	6,000			PERMIAN
3504901308	DAYLIGHT	24225	2D	NE PURDY SPRINGER SAND UNIT A	H-9D	432611	5/28/1999	GARVIN	34	04N	04W		NE	NE	NE	VERTICAL	34.78156	-97.5997	1,000	6,000			PERMIAN
3504901309	DAYLIGHT	24225	2D	NE PURDY SPRINGER SAND UNIT A	K-9D	211359	3/18/1982	GARVIN	35	04N	04W	SE	SE	NW	NE	VERTICAL	34.77978	-97.5865	2,000	6,000			PERMIAN
3504901358	DAYLIGHT	24225	2R	NE PURDY HART SAND UNIT	R26	40625	10/2/1959	GARVIN	19	03N	03W		C	SE	NW	VERTICAL	34.71928	-97.5565	NA	NA			HART, SPRINGER
3504901364	DAYLIGHT	24225	2R	NE PURDY HART SAND UNIT	R24W	40625	10/2/1959	GARVIN	18	03N	03W		NW	SE	SW	VERTICAL	34.7265	-97.5565	NA	NA			HART, SPRINGER
3504901368	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	Q-22	432255	5/14/1999	GARVIN	18	03N	03W		C	SW	NW	VERTICAL	34.7336	-97.5613	2,000	6,000	CO2	NA	SPRINGER
3504901510	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	Q-17	445604	10/11/2000	GARVIN	7	03N	03W	E2	W2	NW	NW	VERTICAL	34.75173	-97.5613	2,000	6,000	CO2	NA	SPRINGER
3504921096	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	K214	348513	7/10/1990	GARVIN	2	03N	04W	W2	E2	SW	NE	VERTICAL	34.76255	-97.5876	1,500	5,000			SPRINGER
3504922137	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	P17A	310651	4/3/1987	GARVIN	7	04N	04W		NW	SE	SW	VERTICAL	34.82858	-97.6634	2,700	2,000			SPRINGER
3504923720	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	Q18-BW	374230	5/28/1993	GARVIN	7	03N	03W	N2	S2	SW	NW	VERTICAL	34.75173	-97.5613	1,500	3,500			SPRINGER
3504923923	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	YY1BW	395948	10/2/1995	GARVIN	20	04N	04W	SE	NE	NW	NE	VERTICAL	34.81004	-97.6387	2,500	5,000	CO2	NA	SPRINGER
3504924174	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT	1-1B	1105900160	6/2/2011	GARVIN	23	04N	04W	NW	SE	NW	NW	VERTICAL	34.80924	-97.5959	2,500	2,500	CO2	1200	SPRINGER
3504924250	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	N-13-1	1305420003	5/6/2013	GARVIN	1	03N	04W	SE	SE	NE	NW	VERTICAL	34.76461	-97.5759	3,500	3,500	CO2	3500	SPRINGER
3504924290	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT	I-10-1	1301650038	10/15/2012	GARVIN	35	04N	04W	SW	SW	SW	NW	34-4N-4W NE SE SE NE	34.7757	-97.5981	3,500	3,500			SPRINGER
3504924313	DAYLIGHT	24225	2D	N.E. PURDY HART UNIT	K-12-2	1403280259	1/21/2014	GARVIN	35	04N	04W	SE	SE	SW	SE	VERTICAL	34.76844	-97.586	1,500	6,000	CO2	500	PERMIAN
3504925047	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	O-19A	1601360045	9/17/2015	GARVIN	7	04N	04W	SE	NW	NW	SE	VERTICAL	34.83286	-97.6588	4,500	4,950	CO2	4500	SPRINGER
3504937964	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	N-18	1206040038	6/8/2012	GARVIN	7	04N	04W		C	SE	NW	VERTICAL	34.83545	-97.6615	3,500	3,500	CO2	3500	SPRINGER
3504938038	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	R21	36583	2/26/1958	GARVIN	17	04N	04W		C	SW	NW	VERTICAL	34.82047	-97.6491	NA	NA	GAS	NA	HART, SPRINGER
3504938044	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	S-20	1107250003	7/11/2011	GARVIN	18	04N	04W		N2	NE	SE	VERTICAL	34.81771	-97.6535	3,500	3,500	CO2	3500	SPRINGER
3504938046	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	R-19	36583	2/26/1958	GARVIN	18	04N	04W		C	SW	NE	VERTICAL	34.7448	-97.5568	NA	NA	CO2	NA	HART
3504938051	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	Q-17	2100201902	4/12/2021	GARVIN	18	04N	04W		C	NW	NW	VERTICAL	34.75189	-97.5609	1,800	2,000			SPRINGER
3504938069	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	D-4	1101580037	2/3/2011	GARVIN	21	04N	04W		C	SE	SE	VERTICAL	34.79875	-97.6184	2,500	2,500	CO2	1200	SPRINGER
3504938080	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT	F-4	437527	12/23/1999	GARVIN	22	04N	04W		C	SE	SW	VERTICAL	34.79878	-97.6096	2,000	3,500	CO2	NA	SPRINGER
3504938081	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	G-3	161061	12/6/1979	GARVIN	22	04N	04W		C	NW	SE	VERTICAL	34.80241	-97.6052	NA	NA	CO2	NA	SPRINGER
3504938083	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	H-3	518527	1/23/2006	GARVIN	22	04N	04W	E2	W2	NE	SE	VERTICAL	34.80966	-97.6096	2,500	2,500	CO2	1200	SPRINGER
3504938084	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	H-2	437526	12/23/1999	GARVIN	22	04N	04W	C	S2	SE	NE	VERTICAL	34.80513	-97.6019	2,000	3,500	CO2	NA	SPRINGER
3504938090	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	E-3	161061	12/6/1979	GARVIN	22	04N	04W		C	NW	SW	VERTICAL	34.80241	-97.614	NA	NA	CO2	NA	SPRINGER
3504938110	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	I-8	161061	12/6/1979	GARVIN	26	04N	04W		C	SW	SW	VERTICAL	34.78431	-97.5964	NA	NA	CO2	NA	HART, SPRINGER
3504938121	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	F-6W	542644	8/2/2007	GARVIN	27	04N	04W		C	SE	NW	VERTICAL	34.79153	-97.6096	2,500	2,500	CO2	1200	SPRINGER
3504938124	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	G-8W	161061	12/6/1979	GARVIN	27	04N	04W		C	SW	SE	VERTICAL	34.78428	-97.6052	NA	NA	CO2	NA	SPRINGER, HART
3504938126	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	F-8	1400480035	8/30/2013	GARVIN	27	04N	04W	E2	E2	SE	SW	VERTICAL	34.78428	-97.6096	3,500	3,500	CO2	3500	SPRINGER
3504938128	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	H-7	161061	12/6/1979	GARVIN	27	04N	04W		C	NE	SE	VERTICAL	34.7879	-97.6008	NA	NA	CO2	NA	HART, SPRINGER
3504938142	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	A8W	40625	10/2/1959	GARVIN	28	04N	04W		C	SW	SW	VERTICAL	34.78424	-97.6316	NA	NA	CO2	NA	HART, SPRINGER
3504938177	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	H9W	378323	12/1/1993	GARVIN	34	04N	04W		C	NE	NE	VERTICAL	34.78065	-97.6008	2,000	3,000	CO2	NA	HART, SPRINGER
3504938180	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	G-10	40633	9/10/1959	GARVIN	34	04N	04W		C	SW	NE	VERTICAL	34.77702	-97.6052	NA	NA	CO2	NA	HART, SPRINGER
3504938188	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	I-10W	161061	12/6/1979	GARVIN	35	04N	04W		C	SW	NW	VERTICAL	34.77706	-97.5964	420	1,500	CO2	NA	SPRINGER
3504938191	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	L11W	361125	10/31/1991	GARVIN	35	04N	04W		C	NE	SE	VERTICAL	34.77343	-97.5833	1,500	5,000			SPRINGER
3504938192	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	K-10	536594	3/12/2007	GARVIN	35	04N	04W		C	SW	NE	VERTICAL	34.77744	-97.5872	2,500	2,500	CO2	1200	SPRINGER
3504938195	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	I-12	161061	12/6/1979	GARVIN	35	04N	04W		C	SW	SW	VERTICAL	34.77018	-97.596	NA	NA	CO2	NA	SPRINGER
3504938197	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	J-11	364992	4/28/1992	GARVIN	35	04N	04W			NE	SW	VERTICAL	34.77343	-97.592	1,500	2,500			SPRINGER
3504938198	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	K-12	161061	12/6/1979	GARVIN	35	04N	04W		C	SW	SE	VERTICAL	34.7698	-97.5876	NA	NA	CO2	NA	SPRINGER
3504938201	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	J-9	361126	3/24/1982	GARVIN	35	04N	04W		C	NE	NW	VERTICAL	34.78101	-97.5917	1,500	3,000			SPRINGER
3504938203	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	L-9W	1103670153	4/5/2011	GARVIN	35	04N	04W		C	NE	NE	VERTICAL	34.78099	-97.5828	2,500	2,500	CO2	1200	SPRINGER
3504938209	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	N-11W	1305420004	4/23/2013	GARVIN	36	04N	04W		C	NE	SW	VERTICAL	34.77366	-97.5737	3,500	3,500	CO2	3500	SPRINGER
3504938213	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	O-12	1103670152	1/18/2011	GARVIN	36	04N	04W		C	SW	SE	VERTICAL	34.76984	-97.5701	2,500	2,500	CO2	1200	SPRINGER
3504938215	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	M-10	161061	12/6/1979	GARVIN	36	04N	04W	N2	S2	SW	NW	VERTICAL	34.77709	-97.5789	NA	NA	CO2	NA	SPRINGER
3504939565	DAYLIGHT	24225	2R	NE PURDY HART SAND UNIT	P26	40625	10/2/1959	GARVIN	24	03N	04W		W2	SE	NE	VERTICAL	34.71906	-97.5657	NA	NA			HART, SPRINGER
3504939570	DAYLIGHT	24225	2R	NE PURDY HART SAND UNIT	O26	40625	10/2/1959	GARVIN	24	03N	04W		C	SW	NE	VERTICAL	34.71918	-97.5695	NA	NA			HART
3504939582	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	G-1	161061	12/6/1979	GARVIN	22	04N	04W		C	NW	NE	VERTICAL	34.80966	-97.6052	NA	NA	CO2	NA	SPRINGER
3504939589	DAYLIGHT	24225	2R	NE PURDY HART SAND UNIT	D21	40625	10/2/1959	GARVIN	16	03N	04W		C	NE	NE	VERTICAL	34.73758	-97.6179	NA	NA			HART
3504939604	DAYLIGHT	24225	2R	NE PURDY HART SAND UNIT	E22	40625	10/2/1959	GARVIN	15	03N	04W		C	SW	NW	VERTICAL	34.73393	-97.6135	NA	NA			HART
3504939619	DAYLIGHT	24225	2R	NE PURDY HART SAND UNIT	K22	40625	10/2/1959	GARVIN	14	03N	04W		C	SW	NE	VERTICAL	34.73354	-97.5876	NA	NA			HART, SPRINGER
3504939629	DAYLIGHT	24225	2R	NE PURDY HART SAND UNIT	N-21	1302170001	12/4/2012	GARVIN	13	03N	04W			NE	NW	VERTICAL	34.73753	-97.5736	3,500	3,500			SPRINGER
3504939635	DAYLIGHT	24225	2R	NE PURDY HART SAND UNIT	M22	40625	10/2/1959	GARVIN	13	03N	04W		C	SW	NW	VERTICAL	34.7339	-97.5786	NA	NA			HART, SPRINGER
3504939637	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	P-21W	357309	5/29/1991	GARVIN	13	03N	04W	N2	E2	NE	NE	VERTICAL	34.73768	-97.5649					

3504939750	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	G14	567450	5/5/2009	GARVIN	3	03N	04W		C	SW	NE	VERTICAL	34.76252	-97.6052	2,500	2,500	CO2	1200	SPRINGER
3504939752	DAYLIGHT	24225	2R	NE PURDY HART SAND UNIT	G16	40625	10/2/1959	GARVIN	3	03N	04W			SW	SE	VERTICAL	34.75606	-97.6048	NA	NA			HART
3504939763	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	I-16	1102530088	1/5/2011	GARVIN	2	03N	04W	W2	E2	SW	SW	VERTICAL	34.75566	-97.5957	2,500	2,500	CO2	1200	SPRINGER
3504939769	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	L-13W	213160	4/13/1982	GARVIN	2	03N	04W		C	NE	NE	VERTICAL	34.76618	-97.5833	1,300	5,500			SPRINGER
3504939771	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	J-13W	213157	4/13/1982	GARVIN	2	03N	04W		C	NE	NW	VERTICAL	34.76618	-97.592	1,300	3,000			SPRINGER
3504939773	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	O-14W	161061	12/6/1979	GARVIN	1	03N	04W	NW	SE	SW	NE	VERTICAL	34.76213	-97.5695	NA	NA	CO2	NA	HART, SPRINGER
3504939775	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	N-13W	306046	12/2/1986	GARVIN	1	03N	04W		C	NE	NW	VERTICAL	34.76639	-97.574	1,500	5,000	CO2	NA	SPRINGER
3504939778	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	P-16	445603	10/11/2000	GARVIN	1	03N	04W	SW	NE	SE	SE	VERTICAL	34.75574	-97.565	2,000	6,000	CO2	NA	SPRINGER
3504939782	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	N-15	439832	3/23/2000	GARVIN	1	03N	04W		C	NE	SW	VERTICAL	34.75896	-97.5745	2,000	6,000	CO2	NA	HART, SPRINGER
3504939785	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	M-14	161061	12/6/1979	GARVIN	1	03N	04W	NW	SE	SW	NW	VERTICAL	34.76254	-97.5781	NA	NA	CO2	NA	SPRINGER
3504940166	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	S-20W	40633	9/10/1959	GARVIN	7	03N	03W		C	SW	SE	VERTICAL	34.74085	-97.5525	NA	NA	CO2	NA	SPRINGER
3504940171	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	R-19W	380018	2/8/1994	GARVIN	7	03N	03W		NW	NE	SW	VERTICAL	34.74538	-97.558	2,500	5,000			SPRINGER
3504940175	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	Q-20	40633	9/10/1959	GARVIN	7	03N	03W	E2	W2	SW	SW	VERTICAL	34.74085	-97.5613	NA	NA	CO2	NA	SPRINGER
3504940190	DAYLIGHT	24225	2R	NE PURDY SPRINGER SAND UNIT A	Q-16	161061	12/6/1979	GARVIN	6	03N	03W		NE	SW	SW	VERTICAL	34.75626	-97.5602	NA	NA	CO2	NA	SPRINGER
3505135529	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	L-14W	433876	7/23/1999	GRADY	1	04N	05W		NE	SE	SW	VERTICAL	34.84311	-97.6788	2,000	2,500	CO2	NA	SPRINGER
3505135531	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	L-16	36583	2/26/1958	GRADY	1	04N	05W	NE	SW	SE	SE	VERTICAL	34.84266	-97.6705	NA	NA	GAS	NA	SPRINGER
3505135535	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	L9W	36583	2/26/1958	GRADY	2	04N	05W		SW	SW	SW	VERTICAL	34.84224	-97.7019	NA	NA	GAS	NA	HART, SPRINGER
3505135566	DAYLIGHT	24225	2R	SE BRADLEY B UNIT	O8W	36996	4/24/1958	GRADY	10	04N	05W		C	NE	SE	VERTICAL	34.83229	-97.7052	NA	NA			SPRINGER
3505135569	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	P-12	1409240047	7/23/2014	GRADY	11	04N	05W	W2	E2	SE	SE	VERTICAL	34.82822	-97.6873	4,735	4,950	CO2	500	SPRINGER
3505135573	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	O-10W	541092	6/28/2007	GRADY	11	04N	05W		S2	NE	SW	VERTICAL	34.83136	-97.6964	2,500	2,500	CO2	1200	SPRINGER
3505135576	DAYLIGHT	24225	2D	SE BRADLEY A UNIT	M-12S	1201240111	9/16/2011	GRADY	11	04N	05W		C	NE	NE	VERTICAL	34.83952	-97.6876	1,000	6,000			PERMIAN
3505135577	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	N-11D	1408640011	7/29/2014	GRADY	11	04N	05W		C	SW	NE	VERTICAL	34.83589	-97.692	2,000	4,900			PERMIAN
3505135585	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	O-15	433420	7/1/1999	GRADY	12	04N	05W		C	NW	SE	VERTICAL	34.83223	-97.6744	2,500	6,000	CO2	NA	SPRINGER
3505135586	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	N-16	507077	6/17/2005	GRADY	12	04N	05W		C	SE	NE	VERTICAL	34.83586	-97.67	2,500	2,500	CO2	1200	SPRINGER
3505135588	DAYLIGHT	24225	2R	SE BRADLEY B UNIT	N-14W	397118	11/14/1995	GRADY	12	04N	05W		C	SE	NW	VERTICAL	34.83586	-97.6788	2,500	6,000	CO2	NA	SPRINGER
3505135589	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	M-15	397119	11/14/1995	GRADY	12	04N	05W	S2	N2	NW	NE	VERTICAL	34.83949	-97.6744	2,500	6,000	CO2	NA	SPRINGER
3505135593	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	P-16	416513	10/3/1997	GRADY	12	04N	05W		C	SE	SE	VERTICAL	34.82861	-97.67	2,500	5,000	CO2	NA	SPRINGER
3505135594	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	P-14W	397116	11/14/1995	GRADY	12	04N	05W		C	SE	SW	VERTICAL	34.82861	-97.6788	2,500	6,000	CO2	NA	SPRINGER
3505135597	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	O13W	397122	4/21/1978	GRADY	12	04N	05W		C	NW	SW	VERTICAL	34.83223	-97.6832	2,500	6,000	CO2	NA	SPRINGER
3505135599	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	M-13	1608760006	7/6/2016	GRADY	12	04N	05W		C	NW	NW	VERTICAL	34.83949	-97.6832	3,500	3,500	CO2	3500	SPRINGER
3505135607	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	Q16W	36583	2/26/1958	GRADY	13	04N	05W		C	NE	NE	VERTICAL	34.82498	-97.67	NA	NA	GAS	NA	SPRINGER
3505135613	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	R-13	1409240046	7/31/2014	GRADY	13	04N	05W		C	SW	NW	VERTICAL	34.82096	-97.6832	4,782	4,950	CO2	500	SPRINGER
3505135615	DAYLIGHT	24225	2R	SE BRADLEY B UNIT	Q-9W	292937	2/11/1986	GRADY	14	04N	05W		C	NW	NW	VERTICAL	34.82501	-97.7008	3,500	1,000			SPRINGER
3505135618	DAYLIGHT	24225	2R	SE BRADLEY UNIT	Q-11	1409090008	7/23/2014	GRADY	14	04N	05W	N2	S2	NW	NE	VERTICAL	34.82456	-97.692	4,653	4,950	CO2	500	SPRINGER
3505135620	DAYLIGHT	24225	2R	SE BRADLEY A UNIT	R-11	1409190012	7/31/2014	GRADY	14	04N	05W		C	SE	NE	VERTICAL	34.82098	-97.692	4,670	4,950	CO2	500	SPRINGER

Request for Additional Information: Northeast Purdy Springer Unit (NEPSU) South East Bradley A Unit (SEBAU)
July 24, 2025

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.	2.2	5	While the MRV plan discusses the primary seals that overlie the reservoirs, it does not discuss bottom sealing formations. Please clarify whether there are bottom sealing formations and discuss them if so.	The Goddard shale is the bottom seal for the Cunningham Sandstone. To address this in the MRV, we have incorporated the following description of the bottom seal into Section 2.2 on page 5 just below the Primary Seal section and above the Well Log Analysis section. Bottom Seals The Goddard Shale is the bottom seal for the Cunningham Sandstone and varies in thickness from 1,550 feet to 2,000 feet within the unit. It is homogenous and rich in ductile swelling clays (smectite). The Goddard Shale also serves as a top seal of large overpressured zones (Mississippian and Devonian reservoirs) in the deep Anadarko basin. The high ductility, thickness, and overpressuring of this shale package make it a highly effective bottom seal for the Cunningham Sandstone.

2.	3.0	30	“The free-phase CO₂ will be contained by the geologic limits of the reservoir and therefore will stabilize within the MMA following year t and prior to year t + 5.” Please clarify how it was determined that the free-phase CO₂ plume will stabilize at this time. Furthermore, please clarify whether there is any difference in expected plumes between year t and year t+5. Furthermore, please clarify whether the CO₂ plume is expected to remain stable once this facility discontinues injection operations, etc.	We replaced the 2nd paragraph in Section 3.3 (page 30) of the MRV with the following paragraphs to address both question #2 and question #3. The free-phase CO₂ is currently contained and will continue to be contained by the geologic limits of the Springer reservoir, which are the truncation limits of the reservoir as defined by well control obtained through the full field delineation and development of NEPSU and SEBAU since their discovery in 1951. These geologic boundaries serve as an impermeable seal as demonstrated by the initial trapping and accumulation of hydrocarbons (oil and gas cap) resulting in the formation of the field and confirmed by active monitoring of the ongoing CO₂ flood as described in Section 4. After 43 years of CO₂ flooding in NEPSU and 28 years of CO₂ flooding in SEBAU, the free-phase CO₂ plume extent has spread throughout most of both units and is successfully contained by the geologic limits of the reservoir, as demonstrated by Daylight’s current monitoring practices, which include production, injection, and pressure monitoring. Therefore, Daylight expects the extent of the free-phase CO₂ plume will continue to be contained by and stabilized within the geologic limits of the reservoir, since it has a proven impermeable seal and the amount of CO₂ injected will not exceed the reservoir’s secure storage capacity of 278 Bscf. As such, there is no difference in the expected free-phase CO₂ plume extent between year t and year t + 5. Furthermore, the CO₂ plume extent is expected to remain stable once this
----	-----	----	---	---

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
				facility discontinues injection operations based on historical monitoring trends. Stabilization of the CO₂ plume will continue to be monitored and reported until the criteria outlined in Section 4.11 have been met.
3.	3.0	30	“Stabilization will be measured and demonstrated with pressure monitoring until at least the end of year t + 5.” We recommend reviewing the regulations at 40 CFR 98.441(b) about discontinuing reporting under subpart RR and ensuring none of the statements in the MRV plan conflict with these requirements.	We have revised this statement as shown in the last paragraph of our response to question 2 above to reference the criteria for discontinuing reporting outline in Section 4.11 to ensure that the MRV is consistent with the regulations at 40 CFR 98.441(b).

4.	6.4	45	“As required by 98.448 (d) of Subpart RR, Daylight will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO₂ stream, for facilities that conduct CO₂-EOR operations...” Based on the wording in Section 6.4, it is not clear that the distinction between CO_{2E} and CO_{2FI}/CO_{2FP} is correctly described. This section references Equation RR-10 but mentions only “surface equipment” and subpart W calculation methodologies. According to the regulations at 40 CFR 98.443, CO_{2E}, the “Total annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year”, is not limited to surface equipment and would include the other potential surface leakage pathways identified in Section 4 of the MRV plan. This calculation could incorporate the other quantification methods outlined in Section 4.10 of the MRV plan. CO_{2FI} is the “Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ 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 <u>subpart W of this part</u>.” CO_{2FP} is the “Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ 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 <u>subpart W of this part</u>.” We recommend adding to or revising this section to make it clear that CO_{2E} includes all potential surface leakage pathways, and if needed the facility would reference the potential quantification methods described in Section 4.10.	We have streamlined Section 6.4 to address the comment.
----	-----	----	--	--

**Purdy-Bradley Springer Field:
Northeast Purdy Springer Unit (NEPSU) /
South East Bradley A Unit (SEBAU)**

Monitoring, Reporting, and Verification (MRV) Plan

**Daylight Petroleum, LLC
June 2025**

Contents

Introduction.....	1
1.0. Facility	2
1.1. Reporter Number	2
1.2. UIC Permit Class	2
1.3. UIC Injection Well Numbers	2
2.0. Project Description	2
2.1. Project Characteristics	2
2.1.1. Estimated Years of CO ₂ Injection	2
2.1.2. Estimated Volume of CO ₂ Injected Over Lifetime of Project	2
2.2. Environmental Setting of MMA.....	2
2.2.1. Boundary of the MMA.....	2
2.2.2. Geology.....	2
2.2.3. Hydrogeology	9
2.3. Description of the CO₂ Injection Process	9
2.3.1. CO ₂ Collection and Distribution	12
2.3.2. Injection and Production Well Operations	12
2.3.3. Produced Fluids Handling and Gas Processing and Compression	12
2.3.4. Well Operations and Permitting	16
2.3.5. Number, Location, and Depth of Wells	17
2.4. Reservoir Description	17
2.4.1. Reservoir Characteristics	17
2.4.2. Reservoir Fluid Modeling	22
2.4.3. CO ₂ Analytical Sweeping Efficiency Calculation	22
2.4.4. CO ₂ -EOR Performance Projections	26
3.0. Delineation of Monitoring Area.....	30
3.1. Determination of CO₂ Storage Volumes.....	30
3.2. Active Monitoring Area (AMA).....	30
3.2.1. Determination of Buffer Zone	30
3.3. Maximum Monitoring Area (MMA).....	30
4.0. Identification and Evaluation of Leakage Pathways.....	31
4.1. Leakage from Surface Equipment.....	31
4.2. Leakage from Wells	31
4.2.1. Abandoned Wells.....	31
4.2.2. Injection Wells	32
4.2.3. Production Wells.....	32
4.2.4. Inactive Wells	32
4.2.5. New Wells	32
4.3. Leakage from Faults, Fractures, and Bedding Plane Partings	34
4.3.1. Presence of Hydrocarbons	34

4.3.2.	Fracture Analysis.....	34
4.4.	Lateral Fluid Movement.....	34
4.5.	Leakage through Confining/Seal System.....	34
4.6.	Natural and Induced Seismic Activity	35
4.7.	Likelihood, Timing, and Magnitude of Potential Surface Leakage	37
4.8.	Strategy for Detection of CO₂ Loss.....	38
4.8.1.	Data System	38
4.8.2.	Visual Inspections	38
4.8.3.	Injection Target Rates and Pressures	38
4.8.4.	Production Wells.....	38
4.8.5.	Continuous Plant and Pipeline Monitoring	39
4.8.6.	Well Testing.....	39
4.9.	Strategy for Response to CO₂ Loss.....	39
4.10.	Strategy for Quantifying CO₂ Loss.....	41
4.11.	Demonstration at End of Specified Period	41
5.0.	Strategy for Determining CO₂ Baselines for CO₂ Monitoring	42
5.1.	Site Characterization and Monitoring.....	42
5.2.	Groundwater Monitoring.....	42
5.3.	Soil CO ₂ Monitoring	42
5.4.	Visual Inspection	42
5.5.	Well Surveillance	43
5.6.	Injection Well Rates, Pressures, and Volumes.....	43
6.0.	Site-Specific Considerations for Determining the Mass of CO₂ Sequestered	43
6.1.	Determining Mass of CO ₂ Received	43
6.2.	Determining Mass of CO ₂ Injected.....	44
6.3.	Determining Mass of CO ₂ Produced from Oil Wells	44
6.4.	Determining Mass of CO ₂ Emitted by Surface Leakage	45
6.5.	Determining Mass of CO ₂ Sequestered	45
7.0.	Estimated Schedule for Implementation of MRV plan	46
8.0.	GHG Monitoring and Quality Assurance Program	46
8.1.	GHG Monitoring	46
8.1.1.	General	46
8.1.2.	CO ₂ Received	47
8.1.3.	CO ₂ Injected.....	47
8.1.4.	CO ₂ Produced	47
8.1.5.	CO ₂ Emissions from Equipment Leaks and Vented Emissions of CO ₂	47
8.1.6.	Measurement Devices	47
8.2.	QA/QC Procedures	48
8.3.	Estimating Missing Data	48
8.4.	Revisions to the MRV plan	48
9.0.	Records Retention	49

List of Figures	50
List of Tables	50
Appendix 1 – List of Wells	51
Appendix 2 – References	52
Appendix 3 – Abbreviations and Acronyms	54
Appendix 4 – Conversion Factors	56
Appendix 5 – Koval Factor Calculation	57
Appendix 6 – Muskat Model Description	58

Introduction

Daylight Petroleum, LLC (Daylight) operates the Northeast Purdy Springer Unit (NEPSU) / South East Bradley A Unit (SEBAU), collectively referred to as the Purdy-Bradley Springer Field, in south-central Oklahoma for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO₂) flooding on the behalf of PBMS Oil, LLC. As a secondary purpose, Daylight intends to establish secure geological storage (sequestration) of a measurable quantity of CO₂ in subsurface geologic formations at the Purdy-Bradley Springer Field. Daylight intends to continue CO₂-EOR operations until the end of economic life of the field, with the subsequent goal of long-term storage of CO₂ in geologic formations (sequestration).

Daylight has developed this Monitoring, Reporting, and Verification (MRV) Plan in accordance with 40 Code of Federal Regulations (CFR) 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in Section 45Q of the Internal Revenue Code. Daylight intends to implement this MRV plan for both NEPSU and SEBAU, and upon merging of the facilities in the United States Environmental Protection Agency (USEPA) system will begin reporting under a single identification number.

This MRV Plan contains nine sections:

Section 1 – General facility information.

Section 2 – Project description. Contains details of the injection operation, including duration and volume of CO₂ to be injected; a description of the geology and hydrogeology of the Purdy-Bradley Springer Field; and a description of the injection reservoir assessment techniques.

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

Section 4 – Evaluation of potential surface leakage pathways for CO₂ in the MMA as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP. A strategy is proposed for detecting, verifying, and quantifying any surface leakage of CO₂ as required by 40 CFR 98.448(a)(3), Subpart RR of the GHGRP. Other than wellbores and surface equipment, the risk of CO₂ leakage through identified pathways is demonstrated as minimal.

Section 5 – Strategy for monitoring to identify CO₂ surface leakage, including establishment of baselines to assess for potential leaks and the proposed monitoring process, as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP. Monitoring will focus primarily on identifying potential leaks through wellbores and surface equipment.

Section 6 – Summary of the mass balance calculations and site-specific variables used to determine the volume of CO₂ sequestered as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 7 – Estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 8 – Quality assurance and quality control procedures to ensure data integrity.

Section 9 – Program for records retention as required by 40 CFR 98.3(g), Subpart A of the GHGRP, and 40 CFR 98.447, Subpart RR of the GRGRP.

Appendices with supplemental data are provided at the end of this document (Appendix 1 includes an attachment).

1.0. Facility

1.1. Reporter Number

Historically, the facility identifiers were 545261 for NEPSU and 545263 for SEBAU. Both units are now merged into one facility identifier (545261) under the name Northeast Purdy Springer Unit (NEPSU) / South East Bradley A Unit (SEBAU).

1.2. UIC Permit Class

The EOR wells covered by this MRV Plan are permitted and operated as Class II Underground Injection Control (UIC) wells under the jurisdiction of the Oklahoma Corporation Commission (OCC), which has primacy for administering Class II UIC regulations in the state.

1.3. UIC Injection Well Numbers

A list of all wells (including injection wells) in the NEPSU and SEBAU is provided as part of **Appendix 1**. Wells are identified by name, unique well identifier (UWI, using a 14-digit American Petroleum Institute [API] number), status, and type. The list is current as of January 2025, around the time this MRV Plan was created.

2.0. Project Description

2.1. Project Characteristics

2.1.1. Estimated Years of CO₂ Injection

CO₂ has been injected at the NEPSU since 1982 and at the SEBAU since 1997. Daylight intends to continue injecting CO₂ for the foreseeable future.

2.1.2. Estimated Volume of CO₂ Injected Over Lifetime of Project

Historical and forecasted cumulative CO₂ retention capacity is up to approximately 278 billion standard cubic feet (Bscf), or 14.7 million metric tons (MMT), from the start of CO₂ injection through March 2054.

2.2. Environmental Setting of MMA

2.2.1. Boundary of the MMA

Daylight has defined the boundary of the MMA as equivalent to the boundaries of the NEPSU and SEBAU plus a minimum of a half-mile buffer. A discussion of the methods used in delineating the MMA and the AMA is presented in **Section 3**.

2.2.2. Geology

This geologic description of the Purdy-Bradley Springer Field incorporates regional literature, field development studies, core and well log data, and the interpretations of Daylight, legacy operators, laboratories, and service companies.

Tectonic and Structural Setting

The Purdy-Bradley Springer Field is located within the Golden Trend of South-Central Oklahoma, in the southeastern embayment of the Anadarko Basin (**Figure 1**). The Anadarko Basin contains up to 40,000 feet of sedimentary rock and is a prolific hydrocarbon producer (Ball, Henry, and Frezon, 1991). This asymmetrical foreland basin is structurally deepest along its southern margin and is separated to the south and southeast from Cambrian-age crystalline rocks exposed in the Wichita Mountains (Ham et al., 1964; Perry, 1989). In updip areas, particularly around structural features that define the basin margins, sedimentary units are commonly truncated by onlap or erosion.

Structural development of the Anadarko Basin was preceded by crustal extension in the Precambrian and formation of the southern Oklahoma aulacogen, or failed rift, during the Cambrian (Perry, 1989). At the end of rifting, the aulacogen cooled and subsided, creating a trough that was filled with Cambrian through lower Mississippian sediments. The Anadarko Basin developed on the northwestern flank of this trough during the late Mississippian through Pennsylvanian as a result of the Wichita Orogeny. During the orogeny, the Wichita and Arbuckle mountains were uplifted and thrust over the southern margin of the trough, causing renewed subsidence and creating the Anadarko Basin. Faulting and uplift associated with the Wichita-Arbuckle structural trend peaked in the early Pennsylvanian and had mostly ended by Permian time (Ball, Henry, and Frezon, 1991).

Producing structures in the Anadarko Basin range from complex combinations of folds and fault blocks to simpler, homoclinally dipping sediment wedges that form stratigraphic traps through erosion or facies change. The Golden Trend, which is bounded by the Nemaha-Pauls Valley uplifts on the east and by the Arbuckle Mountains to the south, produces hydrocarbons from Ordovician through Permian-age rocks (Swesnick, 1950). The NEPSU and SEBAU are two of numerous Pennsylvanian-age reservoirs formed by tilting and truncation. These units produce from the Cunningham Sandstone in the upper part of the Springer series, with shales of the upper Springer, Morrow, and Atoka series providing seal. Uplift of the Pauls Valley arch in late Springerean or early Morrowan time (Pennsylvanian) resulted in erosion of the southwest flank of the structure as Springer sands were tilted to the southwest, creating a stratigraphic trap below the unconformity.

Stratigraphy

A generalized basin stratigraphy applicable to the Purdy-Bradley Springer field area is shown in **Figure 2** and summarized below. Stratigraphic units are listed from oldest to youngest (adapted from Ball, Henry, and Frezon, 1991, except as noted):

- Granite wash and sandstone overlying igneous basement rocks
- Arbuckle Group (Cambrian to Ordovician) – Interior platform carbonates and tidal-flat mudstones; porous dolomite is common in the Western Anadarko basin, while tight facies are more common in the eastern basin.
- Simpson Group (Ordovician) – Erosionally truncated sandstones sealed by overlying Pennsylvanian shales
- Viola Limestone (Ordovician) – Dense limestone, locally dolomitized
- Hunton Group (Silurian-Devonian) – Fractured and dolomitized carbonates sealed and sourced by the overlying, organic-rich Woodford Shale

- Kinderhook, Osage, and Meramec Series (Mississippian) – Fractured limestones that shale out basinward; deposition followed by uplift and erosion resulting from the Wichita Orogeny
- Springer Group (Pennsylvanian – Springerean series) – Deltaic and shallow marine sands deposited during a marine regression, with potential reservoirs including feeder channels, upper-fan channels, middle-fan channels and sheet sands, and distal-fan sheet sands. The section reaches a maximum total thickness of 6,000 feet, though sands are on the order of tens to more than 100 feet thick, with dark shales comprising the remaining thickness. In the NEPSU and SEBAU, the Cunningham Sandstone in the upper Springer series is the historical and current production target.
- Dornick Hills Group (Pennsylvanian – Morrowan and Atokan series) – Mostly transgressive shales with sandstones (e.g., Primrose) deposited during brief regressions
- Deese Group (Pennsylvanian – Des Moinesian series) – Shales and sands (e.g., Osborne and Hart) derived from erosion of uplifted crystalline basement rocks, primarily forming stratigraphically trapped reservoirs
- Hoxbar Group (Pennsylvanian – Missourian series) – Shales and limestones (e.g., Hogshooter and Checkerboard)
- Pontotoc Group (Permian) – Conglomerates, sandstones, and mudstones
- Sumner Group (Permian) – Garber-Wellington interval consisting of sandstones, shales, and conglomerates
- Hennessey Formation (Permian) – Shale with red siltstones and very fine-grained sandstones; one of two bedrock units, along with the Duncan Sandstone of the El Reno Group, that are present at surface within the Purdy-Bradley Springer Field (Chang and Stanley, 2010)
- El Reno Group (Permian) – Duncan Sandstone and undifferentiated sandstone and shale, present at surface within the Purdy-Bradley Springer Field (Chang and Stanley, 2010)
- Alluvium (Holocene) – Clay, silt, sand, and gravel deposited in channels and on floodplains of modern streams (Chang and Stanley, 2010)

NEPSU Reservoir

The Lower Pennsylvanian Cunningham Sandstone, historically referred to as the Springer “A” sand, was deposited in shallow marine settings and consists of southwest-dipping, fine- to medium-grained siliceous sandstone (Cities Service Company, 1978; Fox et al., 1988). Within the reservoir are two lower zones deposited as bar sands on a shallow marine shelf and two upper zones consisting of channel sands.

The reservoir trends northwest-southeast and is approximately 9 miles long and 1-3 miles wide, comprising 15.6 square miles or ~10,000 acres (NEPSU, 1979). Reservoir and unit boundaries were established by erosional truncation of the Cunningham Sandstone and the original oil-water contact (Cities Service Company, 1978). The sands dip approximately 8 degrees to the southwest, and legacy core analysis showed the presence of “tight” layers within the clean sand reservoir (NEPSU, 1979). The reservoir is at a depth of about 8,000-9,000 feet, has an average porosity of 13% and permeability of 44 millidarcies (mD), and had an average initial water saturation of 18%.

Mineralogy is primarily quartz, with limited calcitic cements in shalier intervals and kaolinite, illite, and smectite within the clay fraction. These clay minerals are believed to remain stable under reservoir conditions.

SEBAU Reservoir

The geologic and reservoir properties of the SEBAU are similar to those of the NEPSU. In this unit the Springer strata were deposited in shallow marine tidal bar and channel settings (Oxy, 1998). Fine- and medium-grain sand with shale laminations and dominantly clay cements comprise the primary reservoir facies of the Cunningham Sandstone. A high degree of vertical and lateral facies heterogeneity is present as a result of shoreline deposition. Upper, middle, and lower flow units are recognized, truncated by faults to the south and west and stratigraphic pinch-outs and erosional surfaces to the northeast. The upper sand, usually the only productive flow unit, is 25-200 feet thick and 8,900-10,800 feet deep. Porosity averages 12.5% and permeability is 58 mD (Oxy, 1988). Permeability-porosity relationships are inconsistent in part because of reservoir heterogeneity.

Primary Seals

Reservoirs of the Springer are sandstone bodies that have lateral porosity and permeability variations and are encased in shale (Ball, Henry, and Frezon, 1991). At the Purdy-Bradley Springer Field, the Cunningham Sandstone is sealed by shales of the upper Springerean and Morrowan series that directly overlie the reservoir unit and by truncation against the base Atoka unconformity. The Cunningham is tilted and eroded below the unconformity. Above the unconformity, the Cunningham is sealed by shales of the lower Atokan series.

Well Log Analysis

A reference petrophysical well log (SE Bradley A Unit O-19A) through the reservoir and overlying shales is shown in **Figure 3**. In this well, the Cunningham Sandstone is approximately 50 feet thick, with an approximate porosity range of 10-20% as estimated from the sonic (SPHI), neutron (NPHI), and density porosity (DPHI) logs. A permeability response in the sands is also observed in the deflection of the spontaneous potential (SP) log. These reservoir sands (yellow shade on the gamma ray [GR] log) are truncated just below the unconformity and are overlain by an estimated 170 feet of net shale (brown shade on GR log) within the Osborne section, providing separation and confinement from the Hart sandstones above. Within the Hart are another 110 feet of net shale, and as previously shown in **Figure 2** additional shales overlie the Hart section. Daylight's broader review of well logs in the field shows total net shale thickness above the Cunningham exceeds 1,200 feet, which is sufficient to prevent vertical migration of CO₂ and other fluids to the surface or into underground sources of drinking water (USDWs).

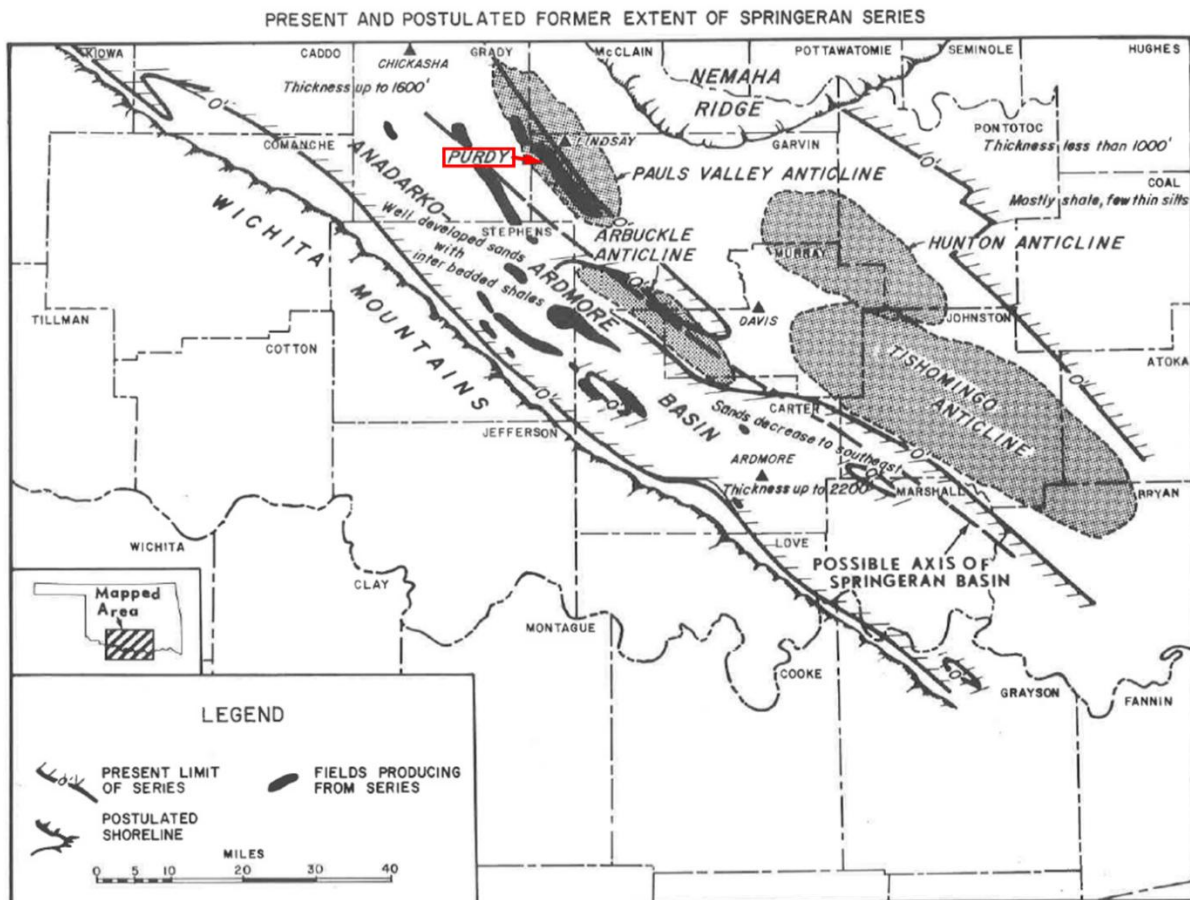
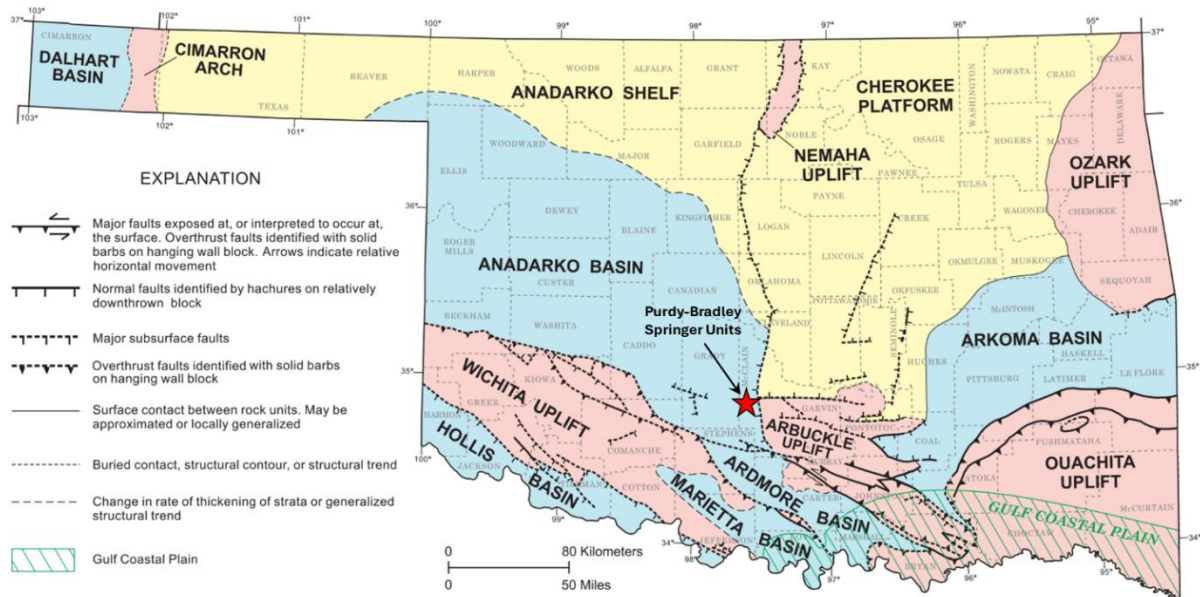


Figure 1: Top panel shows the location of the Purdy-Bradley Springer Field in the Anadarko Basin, South-Central Oklahoma, and proximity to major structural features (adapted from Johnson and Luza, 2008). Bottom panel shows the field location in relation to smaller-scale structures, the extent of the Springer series, and the locations of other Springer fields in the Anadarko-Ardmore basin trend (adapted from Cities Service Company, 1978).

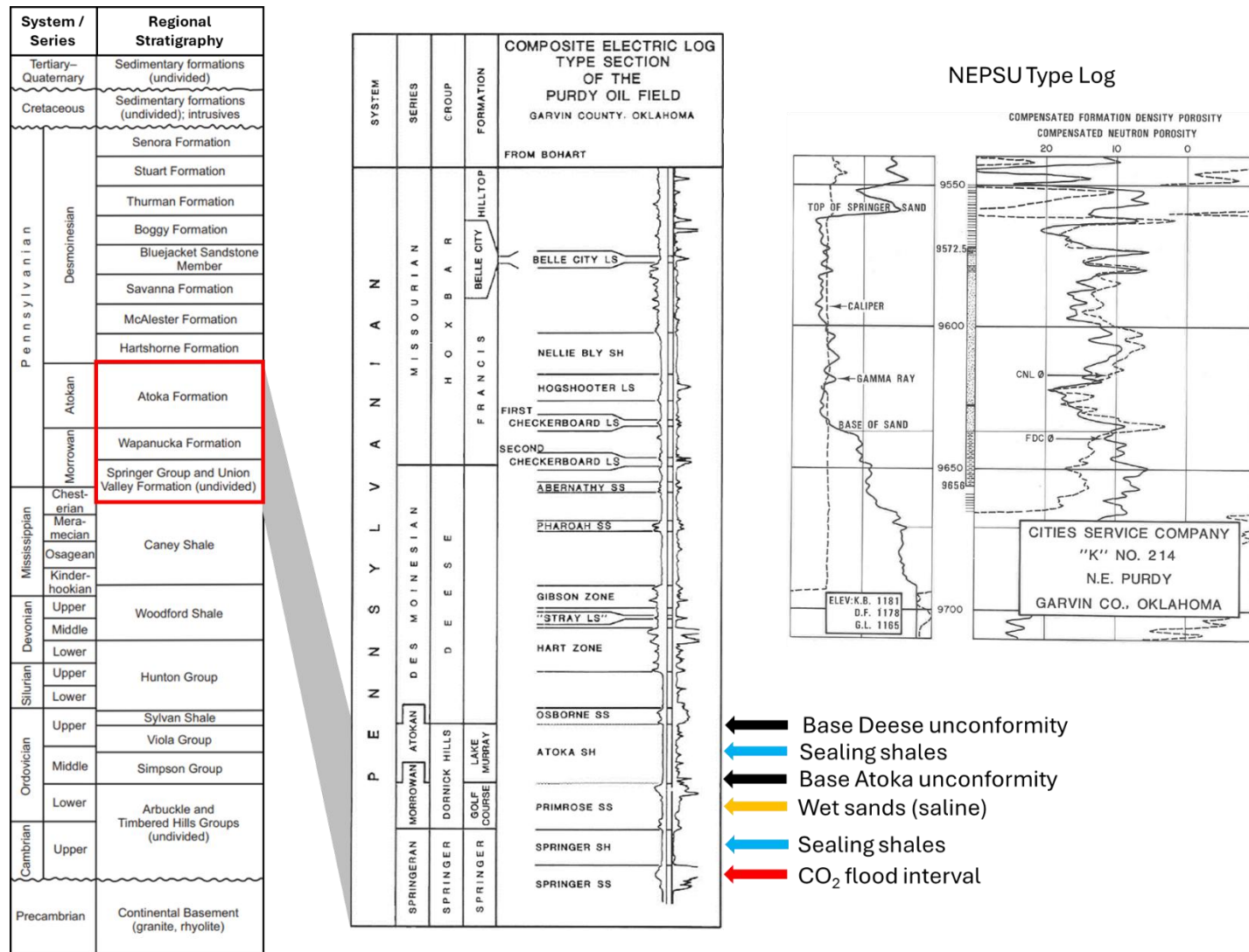


Figure 2: Regional stratigraphic column (left) shows the ages and names of sedimentary rock units in the Anadarko Basin from basement to surface. Center chart shows the type section for the Purdy-Bradley Springer Field and relation to the regional stratigraphy; colored arrows identify key units and surfaces in the Purdy-Bradley Springer Field. Note the multiple shale layers that serve as sealing units for the Springer (Cunningham Sandstone) reservoir. At right is the type log for the Northeast Purdy Springer Unit (NEPSU) reservoir, showing porosity (average ~12%) and gamma ray well log response in the Cunningham Sandstone.

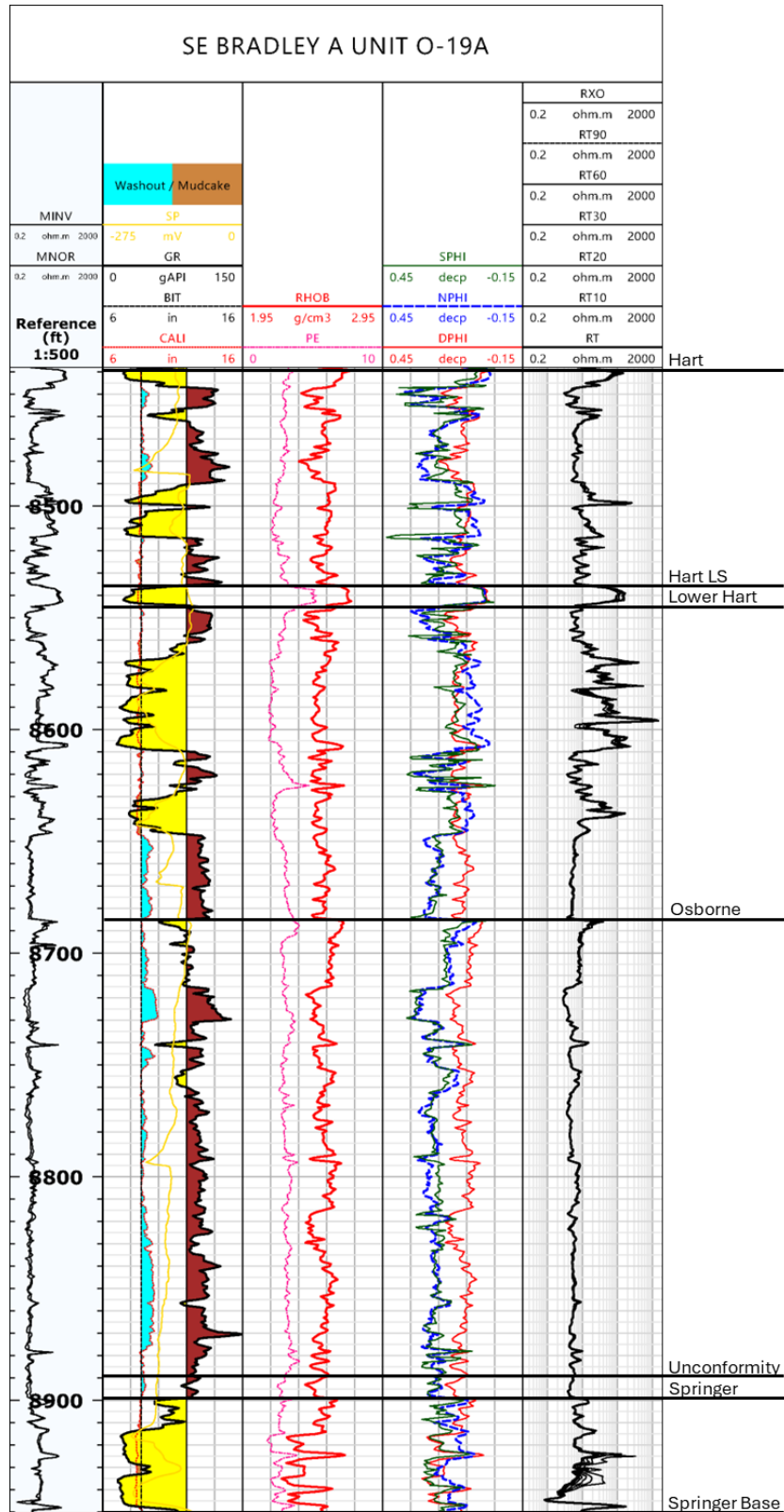


Figure 3: Type log showing the Cunningham Sandstone (at ~8,900-8,950 feet in the Springer reservoir) and overlying shales (seal). The well is located in the SE 1/4 of Section 7, T4N, R4W (API: 3504925047).

2.2.3. Hydrogeology

Groundwater flow rates in confined deep Anadarko layers are considered to be low-flow to no-flow, based on four lines of evidence presented by Nelson and Gianoutsos (2014). First, recharge of groundwater into Pennsylvanian and older strata is limited due to the presence of a low-permeability Permian cap. Second, stratigraphic pinch-outs establish a western limit of recharge. Third, highly saline formation water along the Nemaha uplift creates a west-to-east flow density barrier. Lastly, fluid movement is restricted by overpressured strata in the deep basin.

Further evidence of stratigraphic pinch-out that is more specific to the NEPSU and SEBAU is documented in internal studies developed by previous operators, including a geologic and reservoir description (Oxy, 1988) and a feasibility analysis of applying EOR methods (Cities Service Company, 1978). The SEBAU is isolated by faults to the south and west and pinched out or erosional truncated to the northeast, while the NEPSU is bounded to the north by erosional truncation and to the southwest by a fault. Jorgensen (1993) suggested that, beginning during the Laramide Orogeny and continuing to present, the groundwater flow is west to east, driven by recharge at elevated units to the west. The NEPSU and SEBAU CO₂ injection and production operations therefore are considered unlikely to cause water to flow to the outcrops.

Groundwater is generally at shallow depths, with the base of treatable water approximately 100-300 feet deep (**Figure 4**). In Oklahoma, the base of treatable water is equivalent to the deepest USDW. The base of treatable water depth is relatively consistent throughout the MMA, deepening to the west and south of the MMA. The shallow base of treatable water provides upward of 8,000 feet minimum vertical separation from the Purdy-Bradley Springer Field injection interval.

2.3. Description of the CO₂ Injection Process

Figure 5 shows a simplified flow diagram of the CO₂-EOR operations within the boundaries of the NEPSU and SEBAU. Historically, a fertilizer plant in Enid, Oklahoma, has been the only source of CO₂, with CO₂ captured from the plant delivered via a Daylight-operated pipeline to the field for injection. No new CO₂ has been received since 2022, but Daylight is currently working with multiple emitters to source additional CO₂ for the EOR project. These potential sources include gas processing plants, landfills, fertilizer plants, refineries, and ethanol plants.

Currently, the CO₂-EOR operations involve three main processes. These processes are detailed in the subsections below and include:

1. **CO₂ distribution and injection.** Purchased CO₂ (when applicable) is combined with recycled CO₂ obtained from the produced gas stream and sent through the main CO₂ distribution system to various water alternating gas (WAG) injectors.
2. **Injection and production well operations.** As of January 2025, 23 injection and 36 production wells were active in the SEBAU, and 69 injection and 88 production wells were active in the NEPSU. Production is a mixture of oil, water, and CO₂ or other gases.
3. **Produced fluids handling and gas processing and compression.** Produced fluids and gases flow to satellite batteries and/or centralized tank batteries for separation. The gas phase is transported via a field gathering system to the Lindsay Gas Plant for further gas processing to dehydrate and remove natural gas liquids and hydrocarbon fuel gas. The separated CO₂ gas stream is returned to the field via a CO₂ gas distribution system for compression and injection to the producing reservoir.

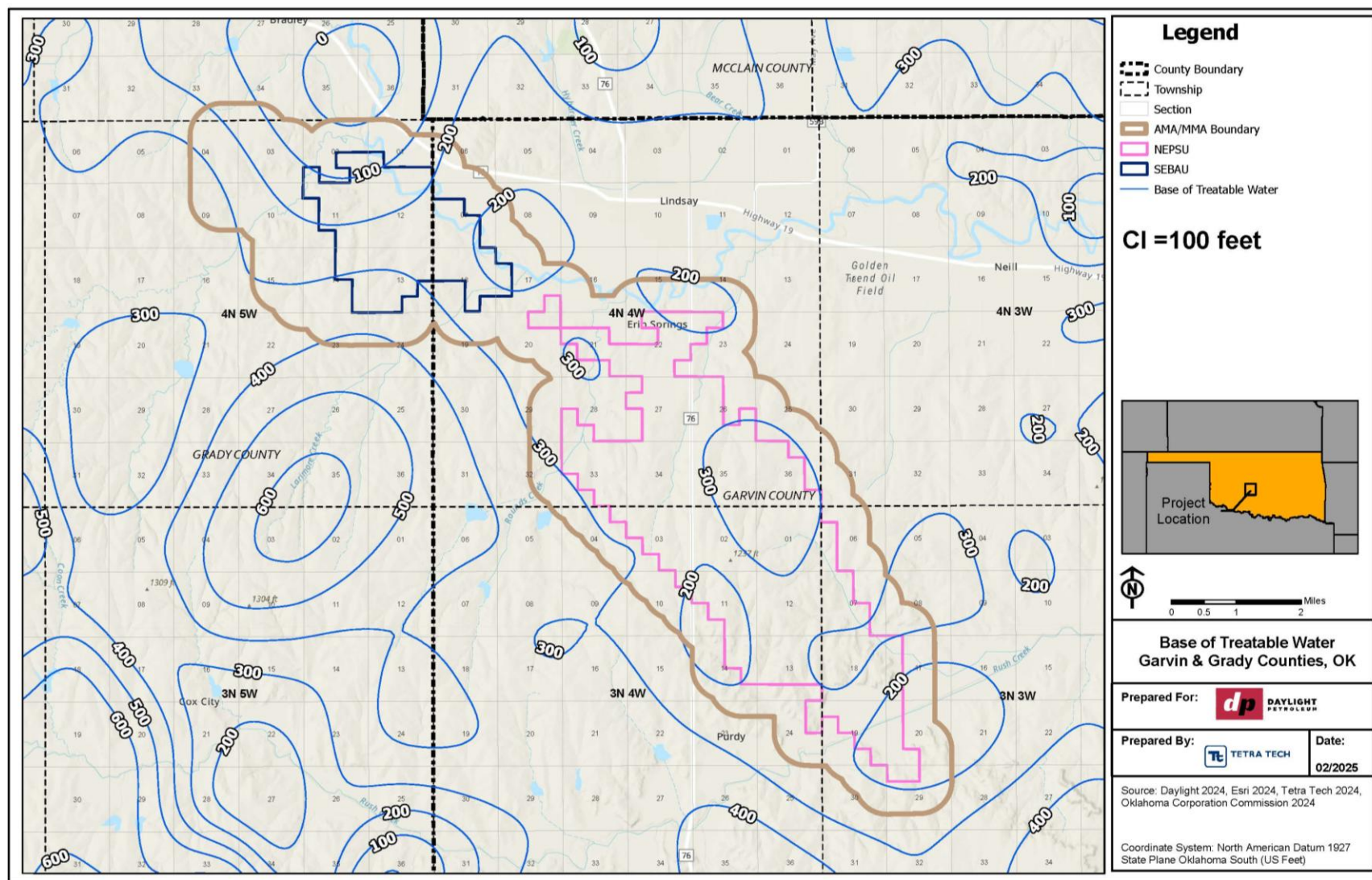


Figure 4: Depth (feet) to base of treatable water

Satellites provide 3 phase separation and testing for the producers, they also hold compression and H Pumps for reinjection of Processed Gas (from Plant) and Water (separated on site)

EOR Summary

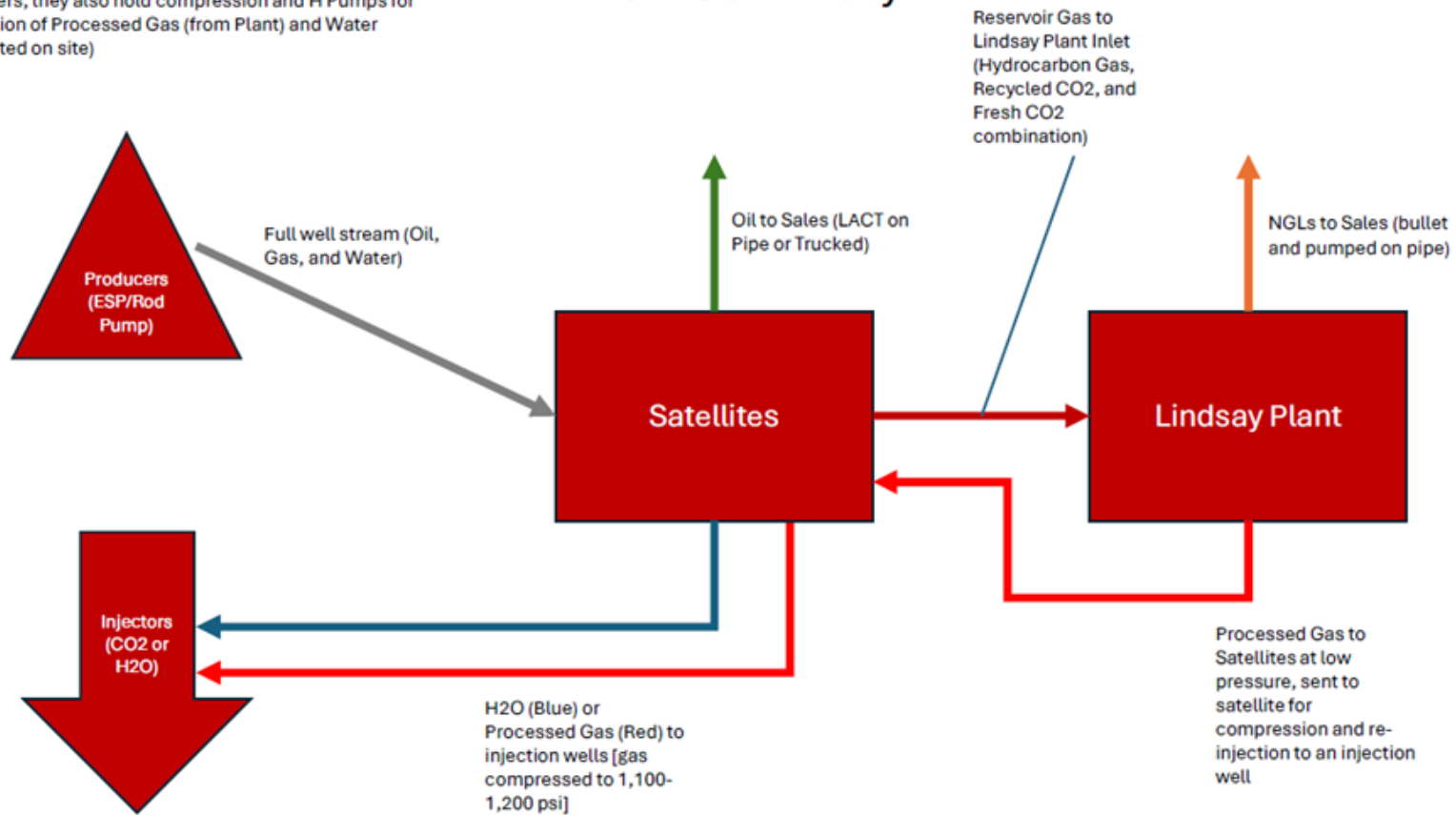


Figure 5: Simplified flow diagram of the CO₂-EOR operations within the Purdy-Bradley Springer Field

2.3.1. CO₂ Collection and Distribution

The CO₂ delivered to the NEPSU and SEBAU is supplied by one or more sources. Historically, new CO₂ delivered from the fertilizer plant was sent through an injection pipeline distribution system to CO₂ injection wells throughout the two units. Produced (recycled) CO₂ is received from Daylight's Lindsay Gas Plant, which extracts natural gas liquids (NGLs) from the produced gas stream (consisting of CO₂ and hydrocarbon gas). The produced gas stream is transported to the Lindsay plant via gathering lines. The gas compression process consists of gathering CO₂ and other produced gases, processing an NGL stream that is sold via pipeline at the plant, and sending CO₂ back out to satellites for compression and reinjection into the injection wells. The CO₂ collection and distribution process is illustrated in **Figure 6**.

Currently, CO₂ delivered to the floods for injection is received through many meters, including at the Purdy Tee delivery point, the source receipt point, the plant outlet, the recycle CO₂ source point, and at each injection well. All CO₂ that flows through the meters is sent through CO₂ injection lines to individual injection wells in the floods, in many instances through manifolds and distribution lines prior to arriving at an injection well. A flow meter at each injection well measures the injection rate of the CO₂ or water. Currently, for any given CO₂ injection well, the CO₂ injected may be sourced from the CO₂ pipeline, the Lindsay plant, or a combination of both. The ratio of CO₂ sources is expected to fluctuate over the course of time.

2.3.2. Injection and Production Well Operations

As of January 2025, 23 injection and 36 production wells were active in the SEBAU, and 69 injection and 88 production wells were active in the NEPSU. Currently, each injection well can inject CO₂, water, or both, at various rates and injection pressures, as determined by Daylight. Upon injection of CO₂ or water into the reservoir, a mixture of oil, water, CO₂ and/or other gases (collectively, produced fluids) is mobilized toward and produced at one or more production wells.

2.3.3. Produced Fluids Handling and Gas Processing and Compression

The produced fluids handling system gathers fluids from the production wells throughout various satellite batteries in the units, via gathering lines that combine, collect, and commingle the produced fluids. The mixture of produced fluids (oil, water, and gas including CO₂) flows to one of 10 satellite separation facilities or batteries and then to a centralized tank battery. Each satellite is equipped with well test equipment to measure production rates of oil, gas, and water from individual production wells.

The fluids stream is further separated into oil and water, which is recovered for reuse, re-injection, or disposal. The produced fluids handling process is illustrated in **Figure 7**. Produced oil is sold via truck or through one or more lease automatic custody transfer (LACT) units located at centralized tank batteries. The gas stream, consisting of CO₂ and other gases, is transported to the Lindsay plant via gas gathering lines throughout the fields.

The produced gas compression process (**Figure 8**) consists of gathering CO₂ and other gases produced from the floods, processing an NGL stream that is sold via pipeline at the plant, and sending CO₂ back to satellite compression for reinjection into the injection wells. The average gas mixture composition is ~82-90% CO₂, with the remaining portion comprising hydrocarbons and trace nitrogen (N₂). Future plant modifications would be intended to produce a higher-quality fuel gas stream for use on-site that would also result in a higher-quality CO₂ stream for sequestration. The CO₂ concentration is likely to change over time as CO₂-EOR operations continue and expand.

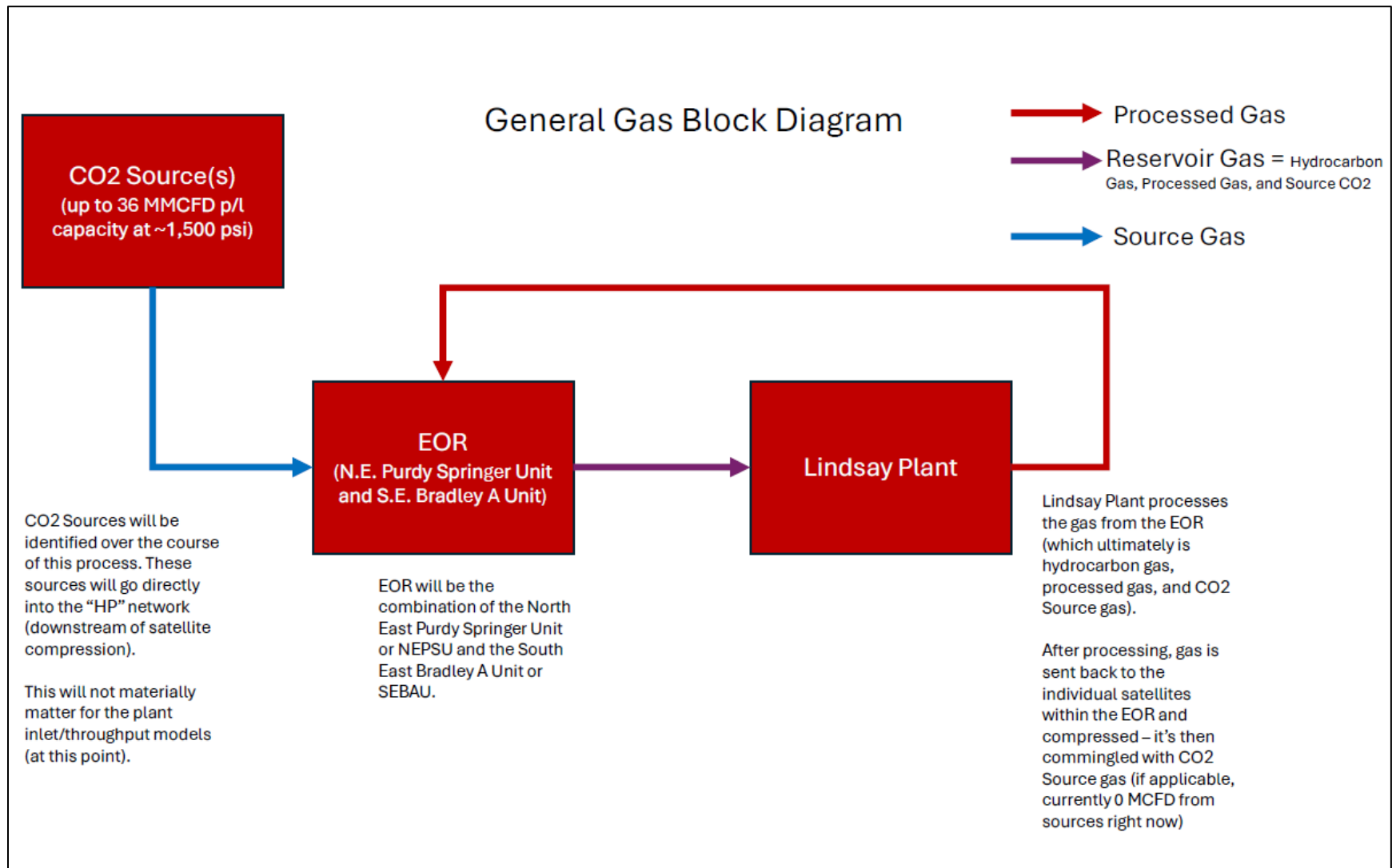


Figure 6: CO₂ collection and distribution process

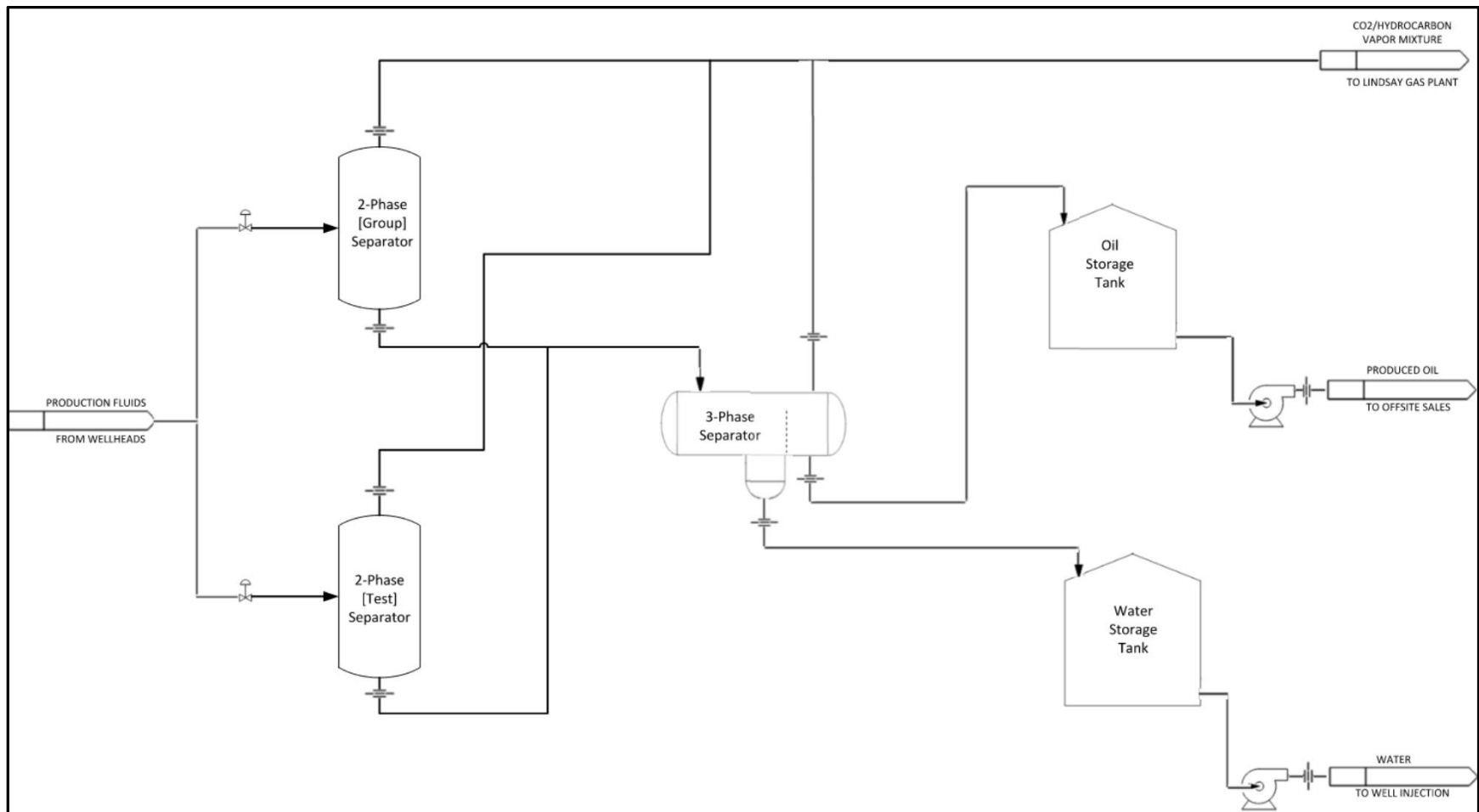


Figure 7: Simplified fluids flow diagram for a typical NEPSU satellite

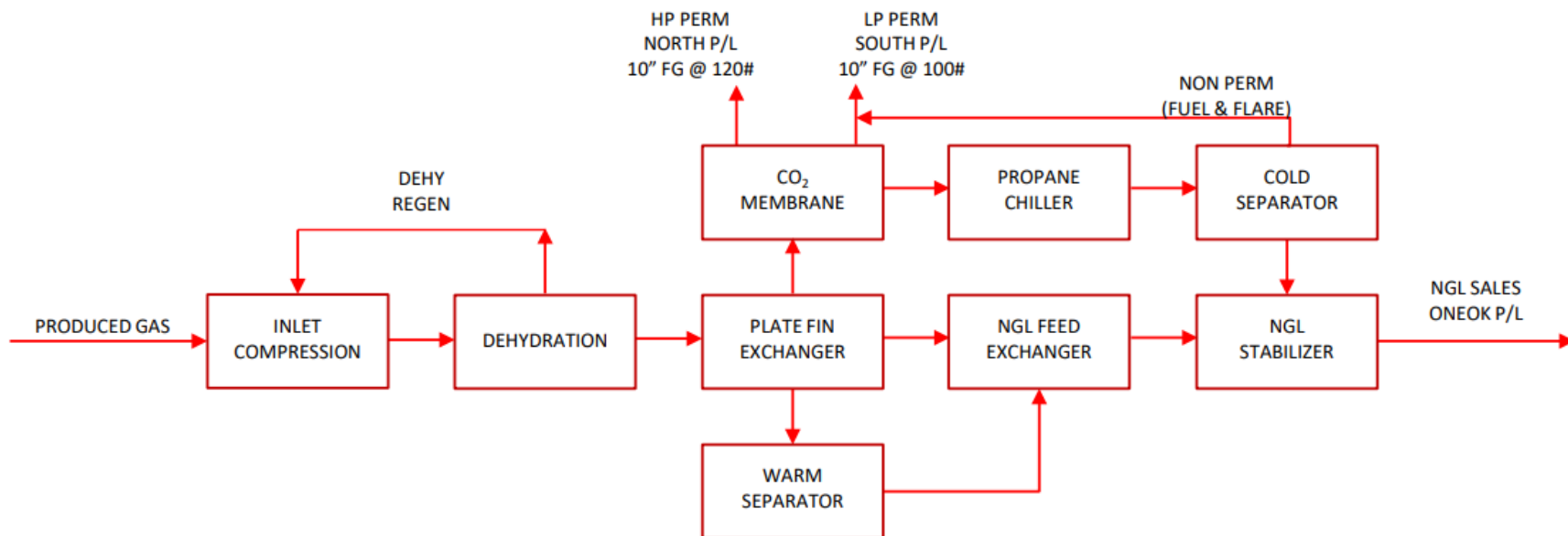


Figure 8: Process diagram for the Lindsay Gas Plant

2.3.4. Well Operations and Permitting

OCC regulations require that injection wells be completed and operated so that fluids are contained in the injection zone and that well operations do not pollute subsurface or surface waters (Oklahoma Administrative Code [OAC] §165:10-5-5 b4). Depending on the purpose of the well, regulatory requirements can impose additional standards.

CO₂ injection well permits are authorized only after approval of an application, public notice, and opportunity for a hearing. As part of the application process, Daylight establishes an Area of Review (AoR) that includes wells within the floods plus a one-quarter mile buffer. Pursuant to applicable regulations, all wells within the AoR that penetrate the injection interval are located and evaluated.

All active injection wells must undergo a periodic mechanical integrity test (MIT) per regulatory guidelines (per OAC §165:10-5-6), depending on various dates and activities associated with the well. MIT includes the use of a pressure recorder, pressure gauge, and testing of the casing-tubing annulus for a minimum amount of time at a minimum pressure, as specified in the approved well injection permit. In some instances, a radioactive tracer survey (RTS) is conducted, sometimes in combination with a pressure test, to ensure all fluids are being injected into the permitted zone.

Daylight has developed operating procedures based on its experience as a CO₂-EOR operator. Operations include developing detailed modeling at the EOR pattern level to guide injection pressures and performance expectations, leveraging Daylight's expertise in diverse disciplines to operate EOR projects based on specific site characteristics. Field personnel are trained to look for and address issues promptly and to implement corrosion prevention techniques, or to engage contracted parties for such services, to protect wellbores as needed.

Daylight's operations are designed to comply with the applicable regulations and to ensure that all fluids (including oil, water, and CO₂) remain in the units until they are produced through a Daylight-operated well. Well pressure in injection wells is monitored on a continual basis.

Individual well injection is guided by a pattern-level WAG program to govern the rate, pressure, and duration of water or CO₂ injection in accordance with regulatory requirements. Pressure monitoring of the injection wells flags pressures that significantly deviate from the plan. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such excursions occur, they are investigated and addressed. It is the company's experience that few excursions result in fluid migration out of the intended zone and that leakage to the surface is very rare.

In addition to monitoring well pressure and injection performance, Daylight uses the experience gained over time to strategically approach well maintenance and updating. Operations staff is in the field daily monitoring the performance of the units and plant, and a call-out system exists for any disruptions when staff is away from the field. Daylight uses all the information at hand, including pattern performance and well characteristics, to determine well maintenance schedules. Production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to a satellite battery. There is a routine cycle for each satellite battery, with each well being tested approximately once every 1-2 months. During this cycle, each production well is diverted to the well test equipment for a period of time sufficient to measure and sample produced fluids (generally 24 hours). This test allows Daylight to allocate a portion of the produced fluids measured at the satellite battery to each production well, assess the composition of produced fluids by location, and assess the performance of each well.

Performance data are reviewed on a routine basis to ensure that CO₂ flooding is optimized. If production is off plan, it is investigated and any identified issues addressed.

Leakage to the outside of production wells is not considered a major risk because of the reduced pressure in the casing. Field inspections are conducted on a routine basis by field personnel. Currently, Daylight has approximately 20 personnel in the field throughout the two units. Leaking CO₂ is very cold and leads to the formation of bright white clouds or dry ice, either of which is easily spotted. All field personnel are trained to identify leaking CO₂ and other potential problems at wellbores and in the field. Any CO₂ leakage detected will be documented and reported, quantified, and addressed as described in **Section 4** and **Section 6**. Continual and routine monitoring of wellbores and site operations will be used to detect leaks. Based on these activities, Daylight will mitigate the risk of CO₂ leakage through existing wellbores by detecting problems as they arise and quantifying any leakage that does occur.

2.3.5. Number, Location, and Depth of Wells

As of January 2025, Daylight operated 23 active CO₂ injection wells and 36 active production wells in the SEBAU, and 69 active CO₂ injection wells and 88 active production wells in the NEPSU. The depth of these wells is approximately 8,200-10,800 feet (Cunningham Sandstone). These wells are listed in **Appendix 1**.

2.4. Reservoir Description

2.4.1. Reservoir Characteristics

Generalized reservoir parameters are provided in **Table 1**. These were determined from data collection, interpretation, and studies performed by historical field operators and, more recently, Daylight in support of primary, secondary, and tertiary recovery operations.

Core, well log, and operational data suggest that reservoir properties for the NEPSU and SEBAU are largely similar. Routine core analysis and flow studies conducted in the Northeast Purdy K-214 well (Ekstrand, 1979) showed an average porosity of 10% and permeability of 14.8 mD. The effect of overburden was determined to reduce porosity by 3-10% (or less than 1 porosity percent) at typical net overburden pressures (approximately 7,000 psig). Additional legacy conventional core samples have been studied from nearly 30 NEPSU wells and approximately 23 SEBAU wells. Currently accepted permeability and porosity values are generally more optimistic than those seen in the K-214 core, at 13% porosity and 44 mD permeability in the NEPSU and 12.5-14% porosity and 50-58 mD permeability in the SEBAU.

As discussed earlier, the NEPSU and SEBAU are fault-bounded stratigraphic traps, with the Cunningham Sandstone having been tilted, eroded, and covered by subsequent deposition of shales above the base Atoka unconformity. The top structure of the Springer is mapped in **Figure 9**, the net pay thickness of Springer reservoir sands is mapped in **Figure 10**, and the trapping configuration is illustrated in **Figure 11**. The Cunningham Sandstone comprises primarily quartz framework grains and cements, with calcite cements in shaly intervals and tight streaks, significant kaolinite, and some smectite and illite (Cities Service Company, 1978). The clays are stable under reservoir conditions. Limited chemical reaction is expected from CO₂ injection given the native pH range of 5.1 to 5.4, so long as pH is maintained at 4.5-5.0 or higher. Plugging from fines migration is the primary risk to permeability and reservoir quality during flooding and production.

Initial pressure of the NEPSU reservoir was 3,050 psig at 8,200 feet, and original oil in place was approximately 225 million stock tank barrels (MMSTB) (Simlote and Withjack, 1981). Primary production began in 1951, and waterflooding for secondary recovery commenced in 1960. Cumulative production through 1977 was 79.5 million MMSTB, prompting efforts to develop a tertiary recovery program. Extensive reservoir study led to the establishment of CO₂ injection in 1982 as the most feasible tertiary method to maximize recovery (Cities Service Company, 1978).

In the SEBAU, which had ~105 MMSTB oil originally in place, primary and secondary recovery occurred from the 1950s into the 1990s. Tertiary recovery in the SEBAU began in 1997.

Operations and development throughout the history of the units have been very similar, owing in part to their immediate proximity and similar reservoir and production parameters.

Table 1: Reservoir Summary Characteristics

Parameter	Parameter by Unit	
	NEPSU	SEBAU
Unitized Area	~10,160 acres	~3,100 acres
Injection Reservoir	Cunningham Sand	Cunningham Sand
Flood Type	CO ₂ and Water Alternating Gas	CO ₂ and Water Alternating Gas
Depth	8,200-10,200 feet	8,900-10,800 feet
Porosity ¹	13%	12.5-14%
Permeability ²	44 mD	50-58 mD
Temperature	148 degrees F	150 degrees F
Initial Water Saturation	18%	NA
Irreducible Water Saturation	14%	NA
Average Net Pay	40 feet	40 feet
Initial Reservoir Pressure	3,050 psi @ 8,200 feet subsea	NA
Original Oil in Place	225 MMSTB	105 MMSTB
Oil Gravity	38 degrees API	38 degrees API
Oil Viscosity	1.2 cp	1.0 cp
Minimum Miscibility Pressure	1,700-2,300 psi	1,820-2,350 psi
Water Salinity	200,000 ppm TDS	NA

¹ Range across both units = 10-22%; ² Range across both units = 5-500 mD

Sources: Daylight internal data; Advanced Resources International, 2024; Birk, 1986; Brinlee and Brandt, 1982; Cities Service Company, 1978; Fox et al., 1988.

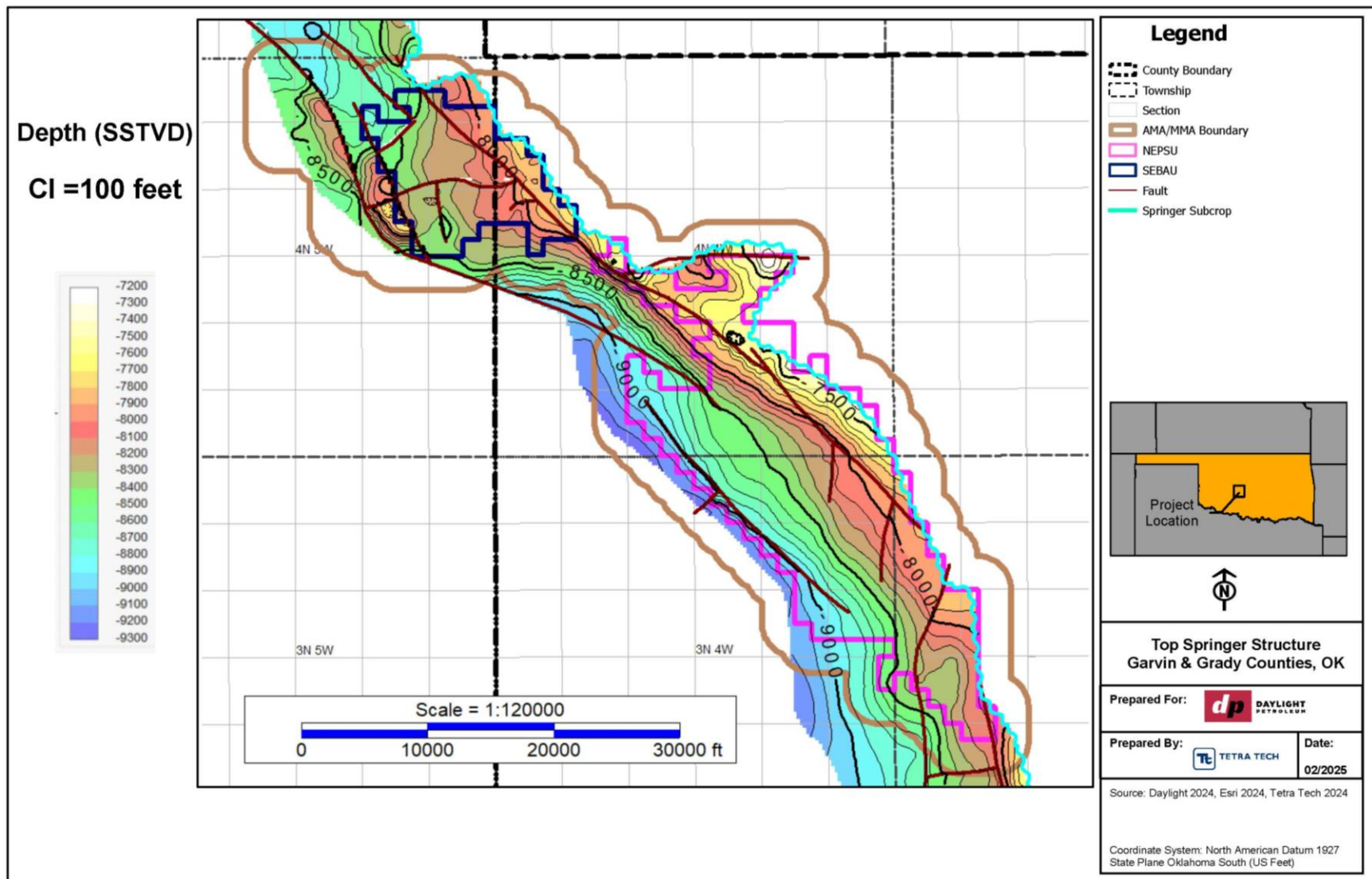


Figure 9: Top Springer structure

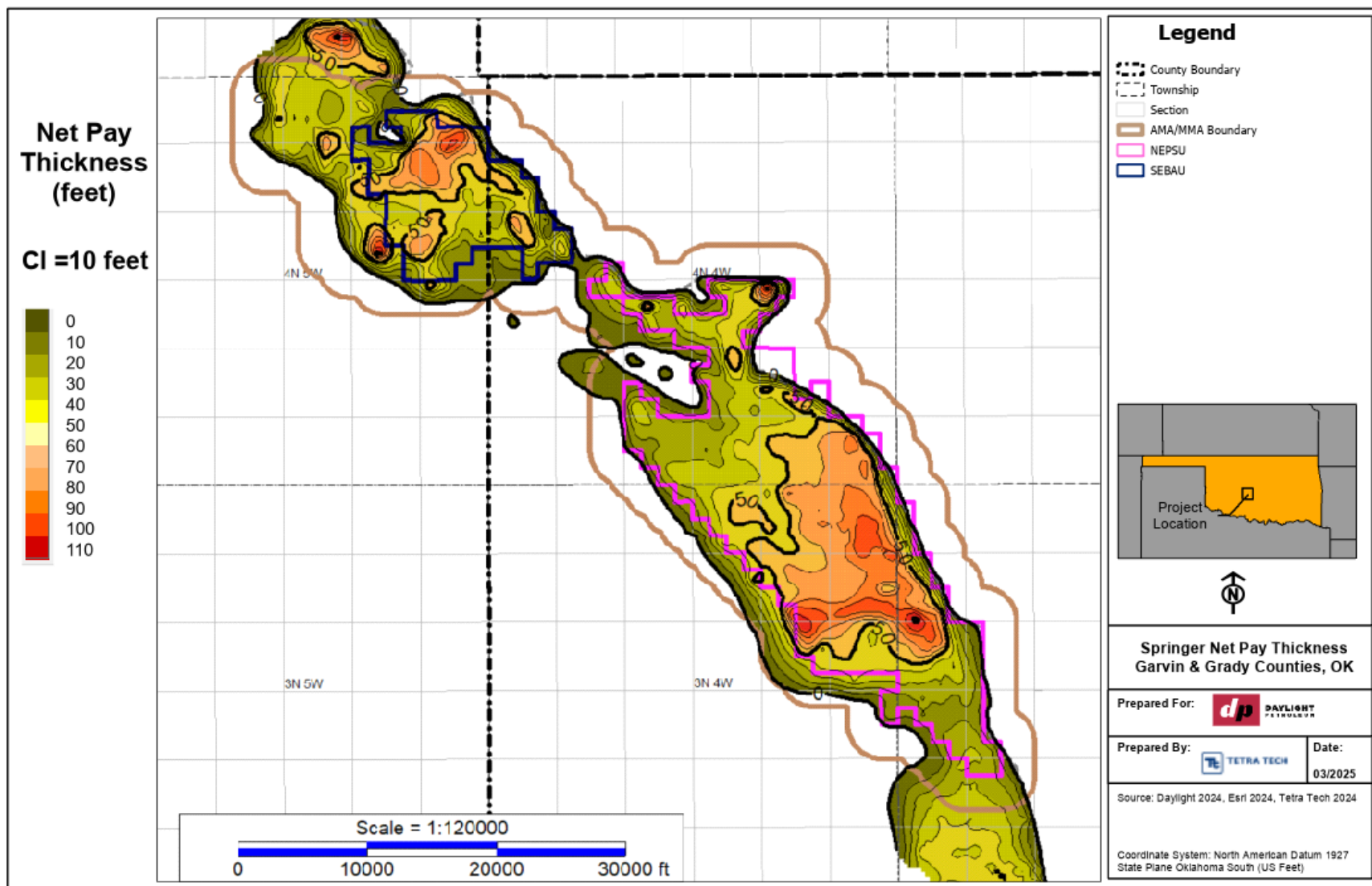


Figure 10: Net pay thickness for the Springer reservoir sands

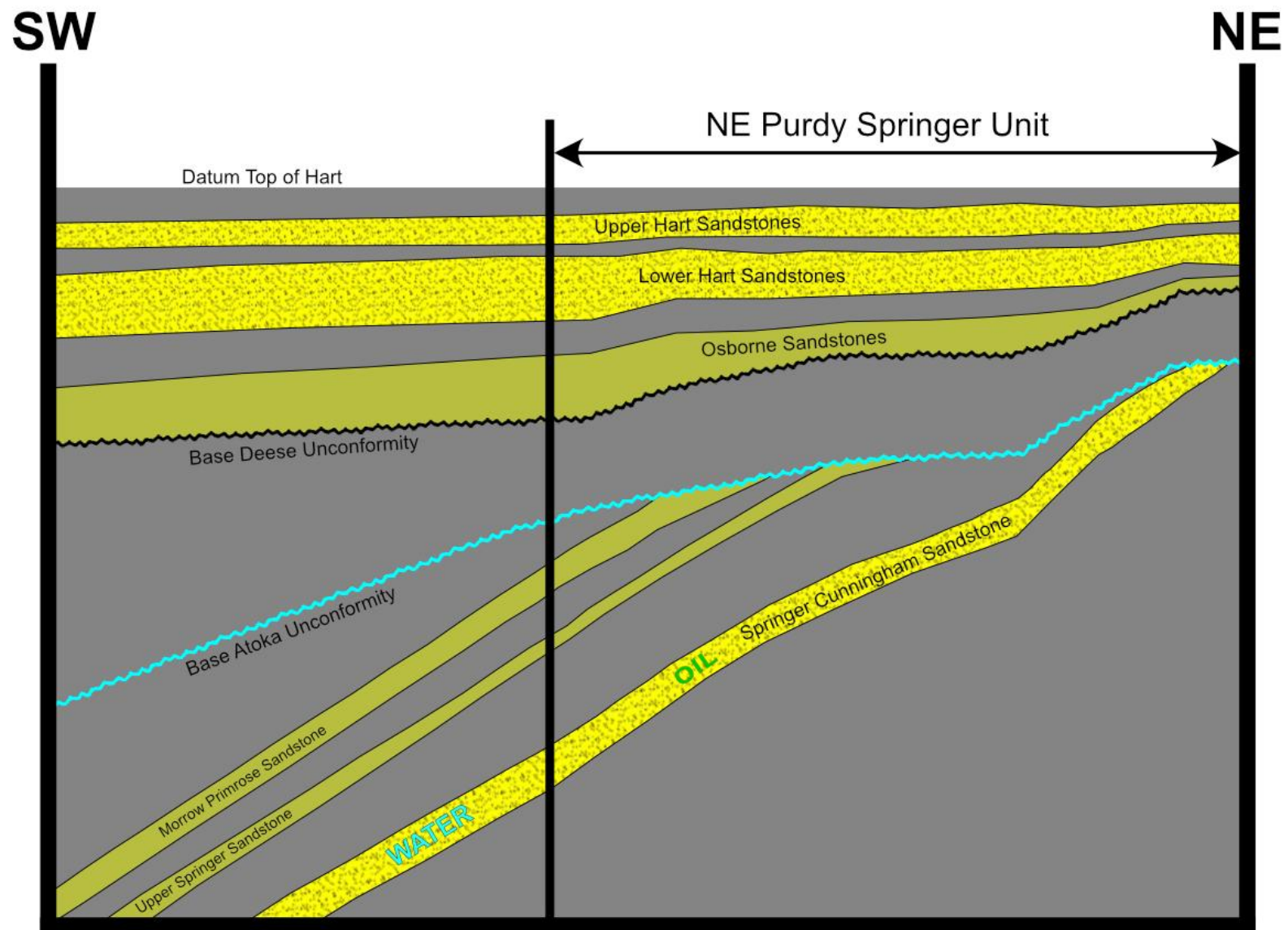


Figure 11: Schematic of the reservoir-seal stratigraphic trapping configuration

2.4.2. Reservoir Fluid Modeling

As discussed previously, NEPSU and SEBAU are operated collectively as the Purdy-Bradley Springer Field and have similar reservoir properties. Nearly all the historical reservoir data is from NEPSU, and available production data are generally combined for the two units. Therefore, the work presented in the following sections is considered to apply to the field as a whole.

A reservoir fluid model was developed based on the work of Fox et al. (1988). This article documents fluid properties for the NEPSU, and pressure, volume, and temperature (PVT) parameters were applied uniformly across the field. The minimum miscibility pressure (MMP) is calculated to be 1,750 psi. It is important to note that MMP measurements from 1979 show location dependency, with some values ranging between 2,100 psig and 2,300 psig. The tertiary flood was initiated by injection of CO₂ in September 1982, and because pressure measurements since 1982 are reported to be above 2,400 psi, flooding is expected to be miscible in most of the reservoir. Since the project involved continuous injection, a decline in pressures was not expected.

The reservoir temperature, used to create the oil PVT plots, was assumed to be 148 degrees F (Fox et al., 1988). The predicted plots and the data points from Fox et al. (1988) are compared in **Figure 12** and **Figure 13**. The gas viscosity is estimated based on a specific gravity of 8.42, calculated from the gas composition of the pre-CO₂ injection gas provided in Fox et al. (1988).

2.4.3. CO₂ Analytical Sweeping Efficiency Calculation

Accepted conventional reservoir engineering practice relies on dimensionless equations to predict the amount of oil that can be recovered through CO₂ flooding in oil reservoirs (Lee et al., 2019; Stell, 2010). The amount of oil recovered is plotted as a decimal fraction of the original oil in place, compared to the decimal fraction of the hydrocarbon pore volume (HCPV) of CO₂ injected into the reservoir, measured in reservoir barrels (rb).

To assess the enhanced oil recovery (EOR) performance, the commonly used Koval factor is applied. The Koval theory was meant to interpret the core-scale production of oil by a miscible displacement by CO₂ injection. It is calculated by multiplying the viscosity contrast effect by the heterogeneity effect. Based on core data from Daylight, the Lorenz coefficient is calculated to be 0.911, indicating a high level of heterogeneity in the reservoir (**Figure 14**).

The Lorenz coefficient and Dykstra-Parsons are common parameters used for evaluating heterogeneity. In this study, since the Koval factor is primarily calculated using Lorenz, it was employed for the heterogeneity assessment. The Lorenz coefficient ranges from 0 for a completely homogeneous system to 1 for a completely heterogeneous system. To calculate it, the normalized cumulative permeability capacity is first plotted against the normalized cumulative volume capacity (**Figure 14**). The Lorenz coefficient is then determined by dividing the area above the straight line (Area A) by the area below the straight line (Area B).

To convert the Lorenz factor into the Koval Factor, a chart provided by Salazar and Lake (2020) was used. According to this chart, the Koval Factor is estimated to be 140 (see **Appendix 5** for additional information). With this value, the volumetric sweep efficiency can be calculated using Koval's Theory (Koval, 1963), based on the CO₂ pore volume injected. The hydrocarbon pore volume (HCPV) filled by CO₂ injected into the oil reservoir over time is shown in **Figure 15**.

By assuming 25% of the HCPV for CO₂ injection, the estimated recovery is approximately 8% (**Figure 16**). The expected sweep efficiency is relatively low due to the reservoir's heterogeneity.

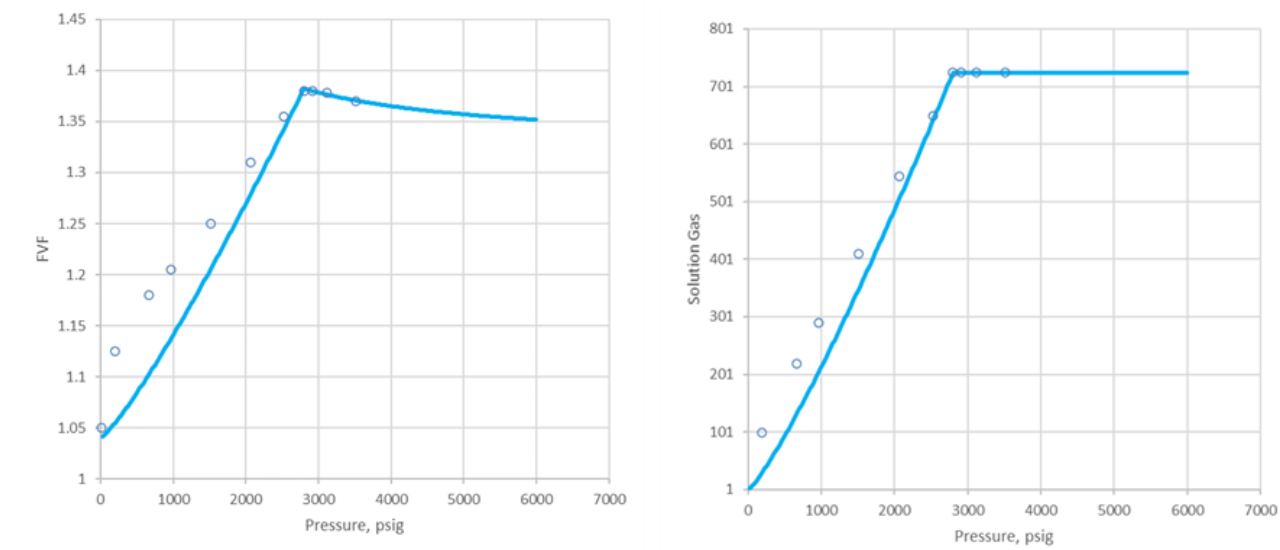


Figure 12: Oil PVT plots constructed for this modeling

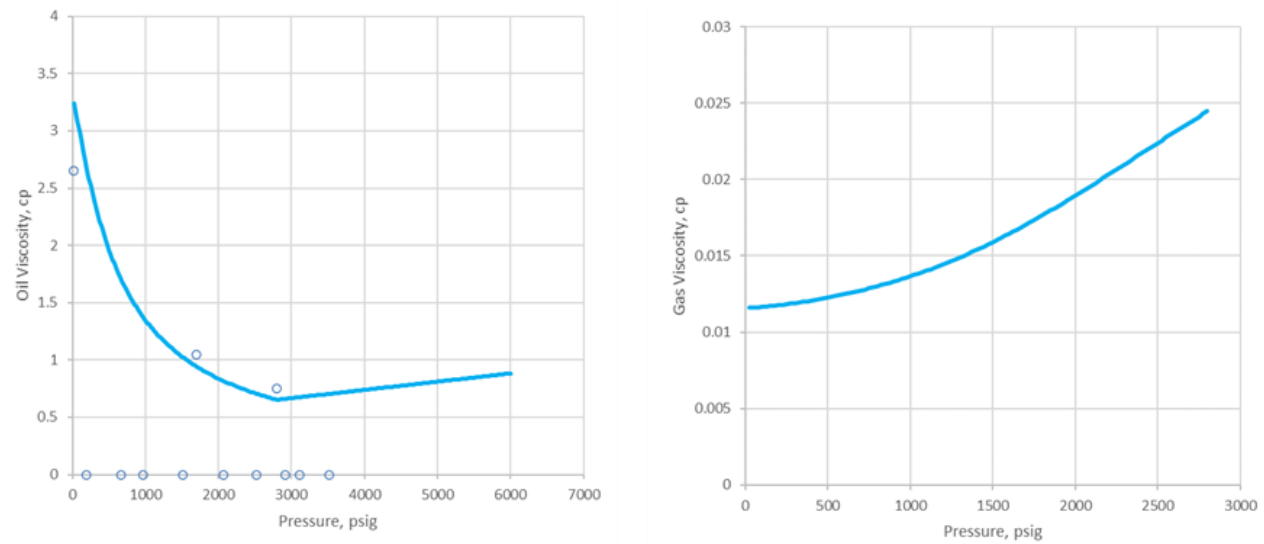


Figure 13: Oil and gas viscosity used in this modeling

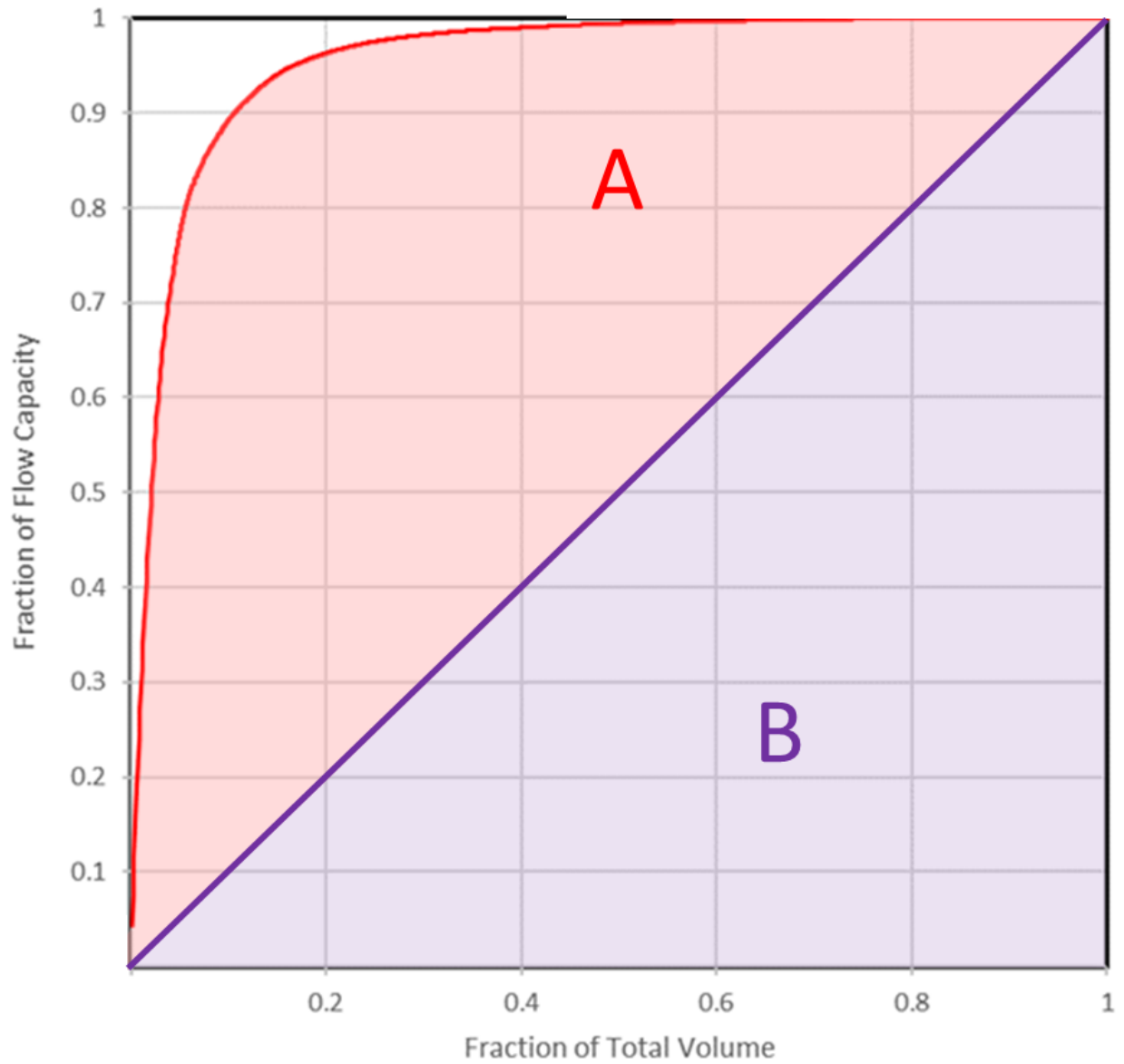


Figure 14: A Lorenz plot shows the high heterogeneity in this reservoir. The Lorenz coefficient is calculated by dividing the area above the straight line (area A) by the area under the straight line (area B).

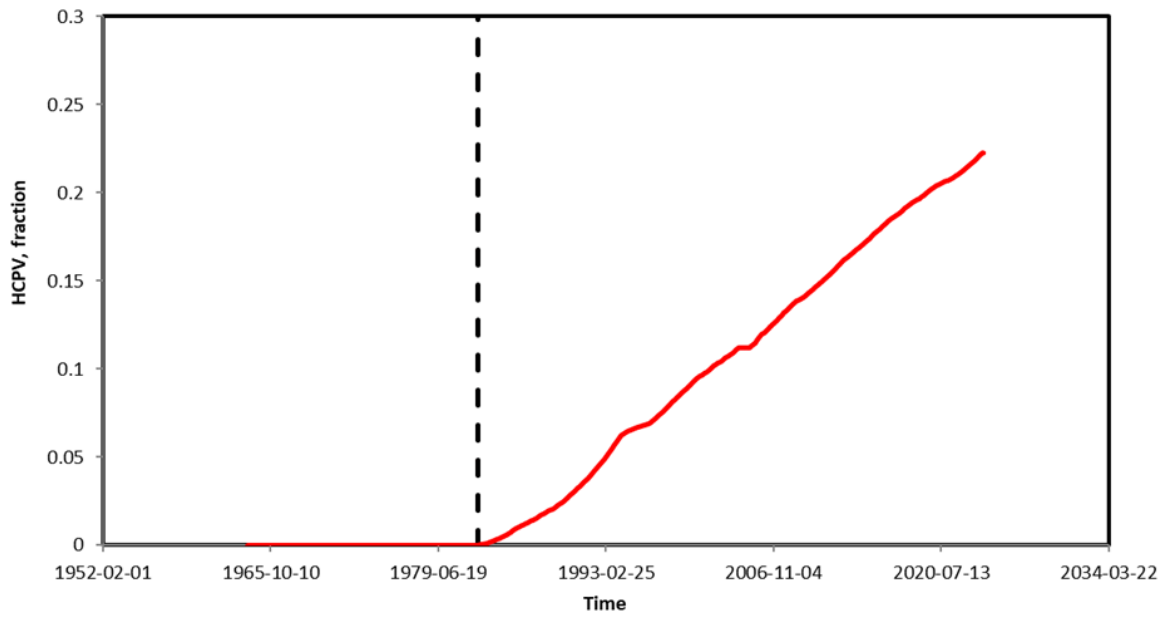


Figure 15: Hydrocarbon pore volume filled by CO₂ injection vs. time

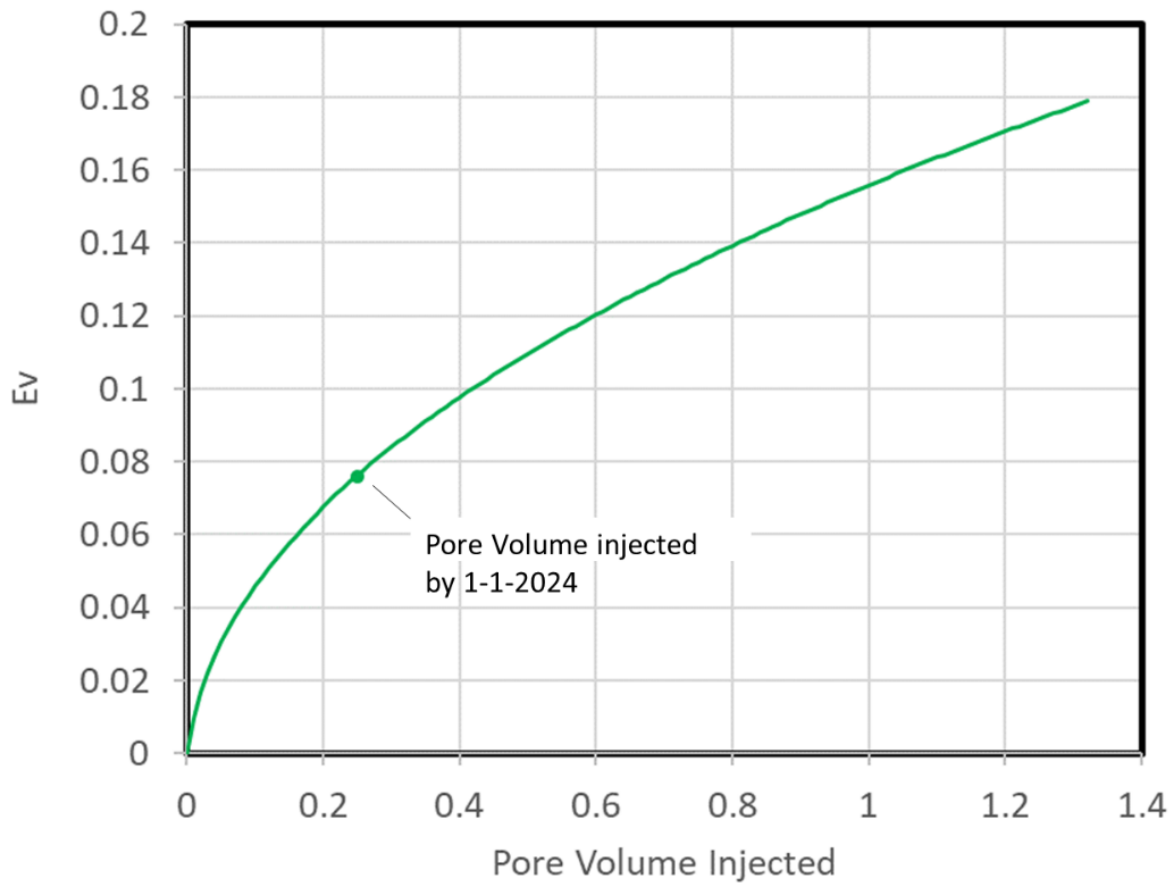


Figure 16: Recovery factor vs. CO₂ pore volume injected

2.4.4. CO₂-EOR Performance Projections

In this study, a modified Muskat model was used to calculate the pore volume available for CO₂ sequestration. This model accounts for the oil and gas PVT properties, as well as the relative permeability of the rock. A key uncertainty lies in the reservoir pressure. Actual reservoir pressure was not available and therefore was estimated using a pressure vs. time profile that offers a reasonable estimate of oil and gas production. The estimated gas saturation from the model is a critical factor, indicating the volume expected to be injectable into the reservoir. A linear pressure reduction is suggested during primary production, followed by an increase in pressure after waterflooding. Over the long term, the pressure begins to decline at a slow rate. The estimated rate is compared with actual production rates in **Figure 17**.

The primary aim of this analysis is to estimate oil production rates since September 1982, when the tertiary flood began through CO₂ injection. To determine the available volume for CO₂ storage, cumulative production rates were utilized. **Figure 18** presents a comparison of the predicted cumulative oil production with the actual cumulative oil production. As illustrated in **Figure 17** and **Figure 18**, the model demonstrates a reasonable accuracy in its predictions.

As the reservoir pressure fluctuates, both the formation volume factor (FVF) of the oil and the density of CO₂ change over time. Assuming a long-term reservoir temperature of 148 degrees F (the initial temperature of the field prior to CO₂ injection) and the current estimated pressure of 2,100 psia, the density of CO₂ is estimated to be 34.1 lbs/ft³ (**Figure 19**). It is essential to recognize that CO₂ density is highly sensitive to pressure; for instance, a reduction in pressure to 1,800 psi would result in an approximate 20% decrease in density. Although a decline in pressure over the long term is anticipated, the last pressure measurement was used for estimating these parameters due to a lack of recent pressure measurements.

In this analysis, the dissolution of CO₂ into the oil is not considered. It is important to note that as CO₂ primarily dissolves in the oil, the capacity for this volume will diminish over time as the oil volume decreases, unless there is a subsequent increase in reservoir pressure.

Given that the oil FVF is 1.31 rb/STB at a pressure of 2,100 psi, the available volume over time is plotted in **Figure 20**. The pressure of 2,100 psi is assumed from the expectation that it has declined by a few hundred psi from the last reported value of 2,400 psi (Fox et al., 1988), and it is further assumed that the pressure will be maintained through additional CO₂ injection in the coming years. Based on the analysis, should EOR be conducted for another 30 years, the volume potentially sequestered will reach 278 Bscf by 2054. To determine the injected CO₂ volume, the CO₂ density at standard conditions is 0.117 lbs/ft³, resulting in a gas FVF of 0.00342 rcf/scf.

It should be noted that the reported cumulative oil production at the end of 1985 was approximately 84.5 million STB (Fox et al., 1988). To account for this discrepancy, the oil production volumes have been adjusted. The gap arises due to the lack of historical data prior to the acquisition of these wells by Daylight. In **Figure 20**, this gap is referred to as the “mismatch.”

Knowing the CO₂ density (34.1 lbs/ft³), the mass of CO₂ to be stored can be calculated. It is important to note that the key assumption is that the CO₂ will only replace the oil recovered, with no additional volume considered for CO₂ dissolution. Based on this calculation, if EOR is conducted for another 30 years, the potential mass of CO₂ to be sequestered by 2054 is estimated to be approximately 278 billion Bscf, or 14.7 MMT, assuming pure CO₂ is injected (**Figure 21**).

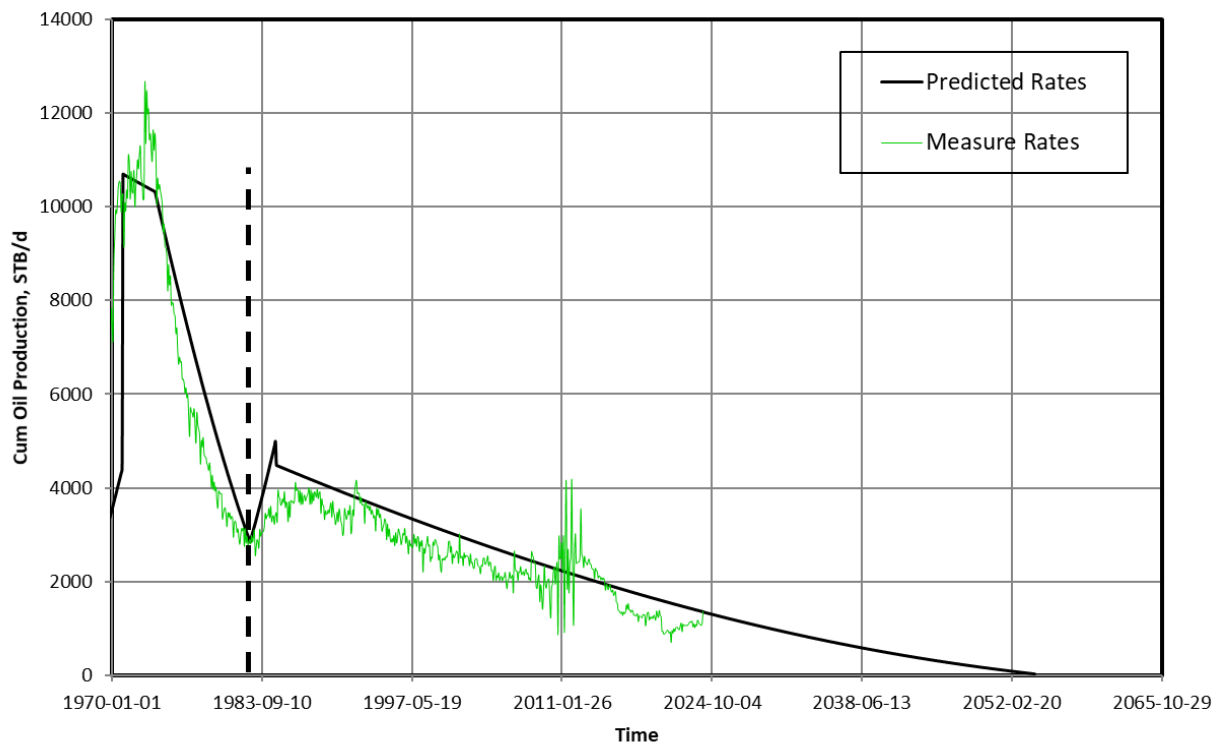


Figure 17: Oil rate-time curve comparison with actual estimations

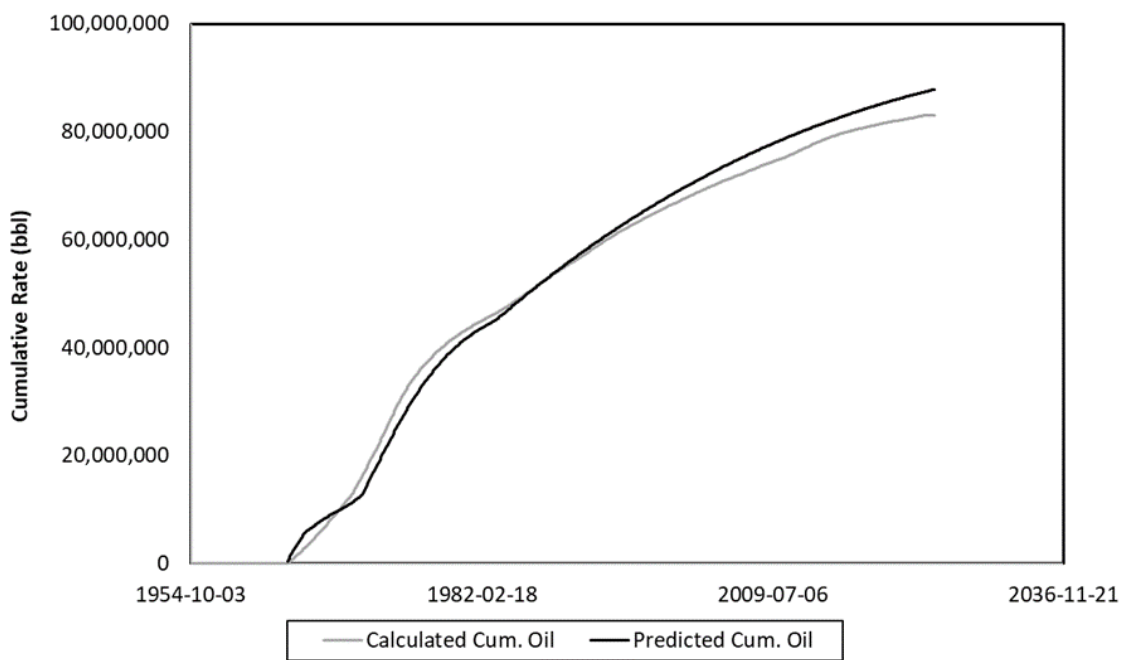


Figure 18: Comparison of the cumulative oil rates

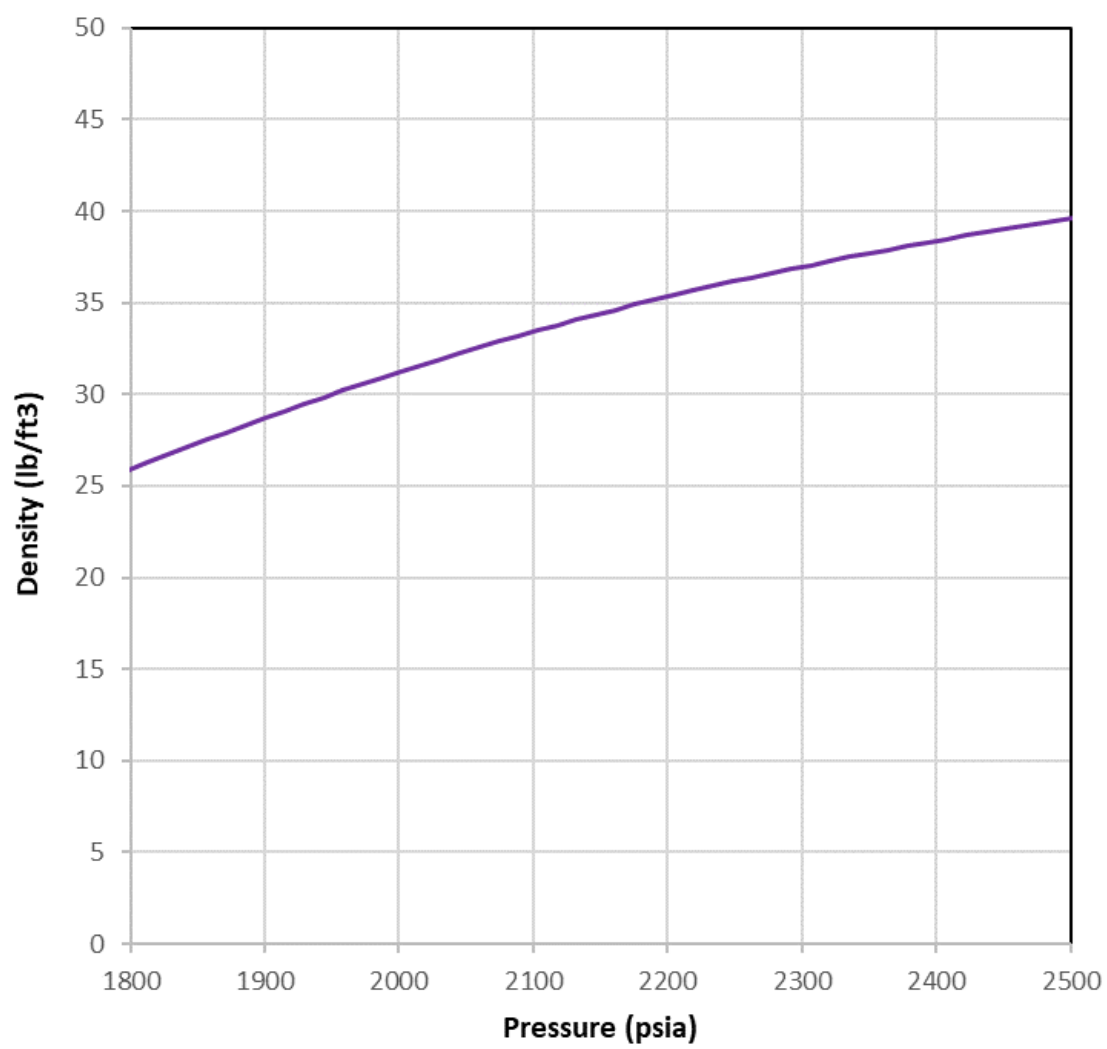


Figure 19: Variation of CO₂ density at 148 degrees F

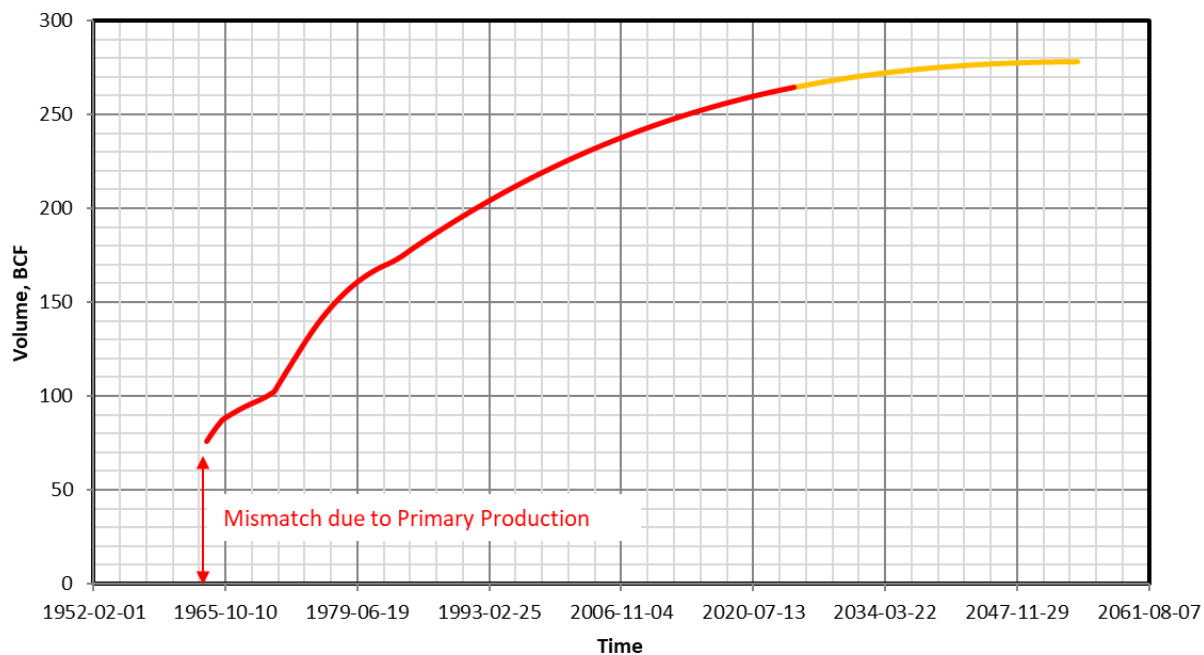


Figure 20: Predicted volume available for CO₂ injection

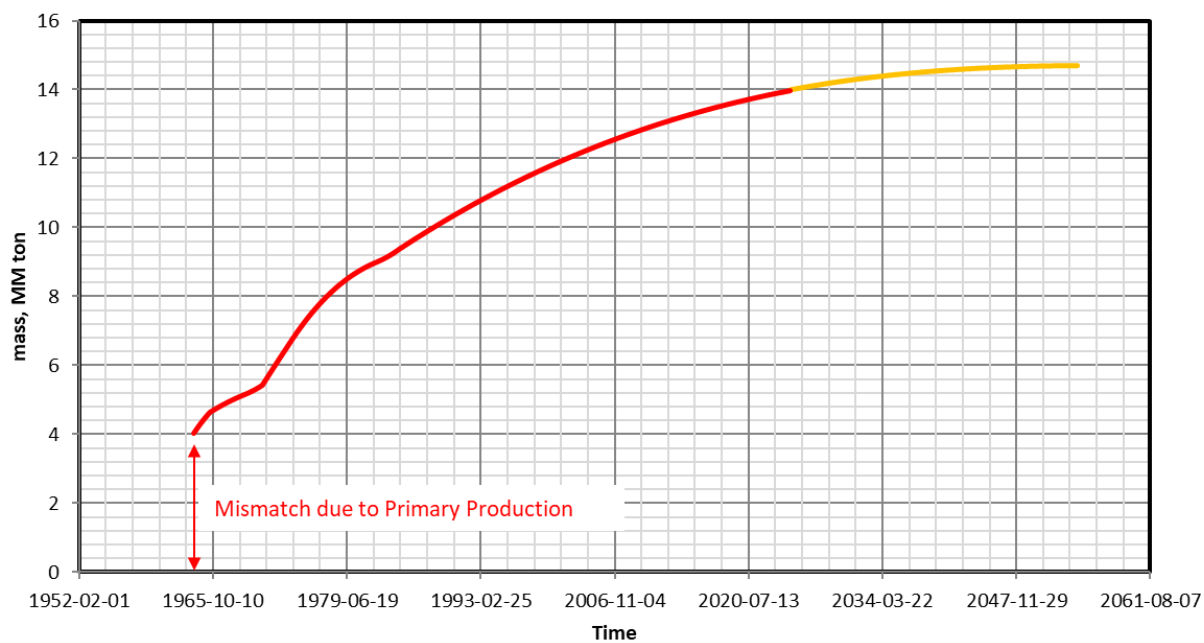


Figure 21: Predicted CO₂ storage in terms of mass

3.0. Delineation of Monitoring Area

3.1. Determination of CO₂ Storage Volumes

The estimated voidage space of 21 MMscf of CO₂ per acre of surface area, or a total of 278 Bscf CO₂, is assumed to be entirely contained within the Purdy-Bradley Springer Field (~13,200 acres).

3.2. Active Monitoring Area (AMA)

The AMA is defined by the combined boundaries of the NEPSU and SEBAU plus a buffer zone of at least one-half mile (**Figure 22**). The AMA is the area that Daylight will monitor over a specific time interval from the first year of the period (n) to the last year in the period (t). Consistent with the requirements in 40 CFR 98.449, the boundary is established by superimposing two areas:

1. The area projected to contain the free-phase CO₂ plume for the duration of the project (year t), plus an all-around buffer zone of one-half mile; and
2. The area projected to contain the free-phase CO₂ plume for at least 5 years after injection ceases (year t + 5).

Currently, Daylight's operations cover NEPSU and SEBAU in their entirety. The unit boundaries were defined during unitization based on the geologic boundaries and truncational limits of the Springer reservoir. Successful containment of free-phase CO₂ within these boundaries has been demonstrated and confirmed during 43 years of CO₂ flooding in NEPSU and 28 years of CO₂ flooding in SEBAU. Furthermore, the estimated voidage space of 278 Bscf is entirely contained within the unit boundaries and will not be exceeded by CO₂ injection volumes. Therefore, Daylight expects the free-phase CO₂ to remain within these boundaries for the duration of the project (t = Year 2054) and at least 5 years thereafter, as required for the AMA by 40 CFR 98.449.

Any additional CO₂ injection wells will be permitted under the UIC program and will be included in the annual submittal per 40 CFR 98.446(f)(13).

3.2.1. Determination of Buffer Zone

The buffer zone of a minimum of one-half mile is required by Subpart RR. No known leakage pathways extend laterally more than one-half mile.

3.3. Maximum Monitoring Area (MMA)

As defined in Subpart RR, the MMA is equal to or greater than the area expected to contain the free-phase CO₂ until the CO₂ has stabilized, plus an all-around buffer zone of at least one-half mile. The MMA is defined as equivalent to the AMA, and Daylight will continuously monitor the entire MMA for the purposes of this MRV.

The free-phase CO₂ will be contained by the geologic limits of the reservoir and therefore will stabilize within the MMA following year t and prior to year t + 5. Stabilization will be measured and demonstrated with pressure monitoring until at least the end of year t + 5.

4.0. Identification and Evaluation of Leakage Pathways

Since its discovery in 1951, the unitization of the NEPSU (1959) and SEBAU (1956), and the initiation of CO₂-EOR in 1982 (NEPSU) and 1997 (SEBAU), the Purdy-Bradley Springer Field has been extensively investigated and documented. Based on this history, Daylight has identified the following potential pathways of CO₂ leakage to the surface. This section also addresses detection, verification, and quantification of leakage from each pathway.

4.1. Leakage from Surface Equipment

The surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO₂-EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment is conducted by personnel instructed on how to detect surface leaks and other equipment failure, thereby minimizing the potential for and impact of any leakage. Surface equipment leaks have a low risk of occurring based on design standards. In addition, under OCC rules, operators must take prompt action to eliminate leakage hazards and to conduct inspections or repairs. Operating and maintenance practices currently follow and will continue to follow industry standards. As described in **Section 6.4**, should leakage from surface equipment occur, it will be quantified according to procedures required by the GHGRP.

4.2. Leakage from Wells

As of January 2025, Daylight identified 23 active CO₂ injection wells and 36 active production wells in the SEBAU; 69 active CO₂ injection wells and 88 active production wells in the NEPSU; and approximately 886 total wellbore penetrations within the AMA. These are listed in **Appendix 1**.

Regulations governing wells in the NEPSU and SEBAU require that wells be completed and operated so that fluids are contained in the strata in which they are encountered and that well operations do not pollute subsurface and surface waters. The regulations establish the requirements with which all wells must comply, whether they are injection, production, or disposal wells. Depending on the purpose of the well, regulatory requirements can impose additional standards for evaluation of an AoR. CO₂ injection well permits are authorized only after an application, notice, and opportunity for a hearing. As part of the permit application process, Daylight evaluates an AoR that includes wells within the unit and one-quarter mile from the set of wells considered in that AoR. Pursuant to USEPA and OCC regulations, all wells within the AoR that have penetrated the injection interval are located and evaluated.

Figure 22 shows all wells in the AMA/MMA. The OCC utilizes a risk-based data management system and can only guarantee well data since 1980. The wells listed in **Appendix 1** and shown in **Figure 22** were compiled from S&P Global in an effort to provide a more complete well list.

In addition, approximately 85 shallow groundwater wells are in the AMA/MMA, per the [Oklahoma Water Resources Board General Viewer](#). The deepest well is 360 feet, ~8,000 feet above the reservoir. Therefore, the likelihood of leakage via shallow groundwater wells is low. Daylight will test a groundwater well within the AMA on an annual basis to provide additional monitoring for potential leakage. Shallow groundwater wells are not included in **Figure 22** and **Appendix 1**.

4.2.1. Abandoned Wells

Figure 22 shows abandoned wells in the AMA/MMA. Owing to past and future AoR evaluations

and a lack of historical leakage, Daylight concludes that leakage of CO₂ to the surface through abandoned wells is unlikely but cannot be ruled out. Strategies for leak detection are in place as discussed in **Section 4.8**, and the strategy to quantify any leaks is discussed in **Section 4.10**.

4.2.2. Injection Wells

Figure 22 shows the injection wells in the AMA/MMA. MIT is an essential requirement of the UIC program in demonstrating that injection wells do not act as conduits for leakage into USDWs and to the surface environment. Under OAC Title 165 Chapter 10, a pressure or monitoring test must be performed on new and existing injection wells and disposal wells. Information must be submitted on Form 1075 and witnessed by a field inspector when required. MIT and other rules documented in OAC Title 165 Chapter 10 ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Owing to past and future expectations of adhering to these rules, Daylight concludes that leakage of CO₂ to the surface through active injection wells is unlikely.

4.2.3. Production Wells

Figure 22 shows the active production wells in the AMA/MMA. As the project matures, production wells may be added and will be constructed according to the rules of the State of Oklahoma. Additionally, inactive wells may become active according to the rules of the State of Oklahoma.

During production, fluids including oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by a differential pressure, where the bottom hole wellbore pressure is less than the reservoir pressure. These lower-pressure fluids are contained by the casing, tubing, wellhead, and flowline all the way to the batteries and production/separation facilities. Daylight concludes that leakage of CO₂ to the surface through production wells is unlikely.

4.2.4. Inactive Wells

Inactive wells that have been temporarily abandoned typically have a cast iron bridge plug or other isolation mechanism set above the existing perforations to isolate the reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change. Given the regular monitoring of and procedures for securing inactive wells, it is unlikely that any leakage event would result in a significant magnitude or duration of CO₂ loss.

4.2.5. New Wells

As the project develops, new production wells and injection wells may be added to the NEPSU and SEBAU. All wells in Oklahoma oilfields, including injection and production wells, are regulated by the OCC, which has primacy to implement the Class II UIC programs. Rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. All new wells will be constructed according to the relevant rules for the OCC which ensure protection of subsurface and surface resources and the environment. This will significantly limit any potential leakage from well pathways; however, leakage during drilling of a new well through the CO₂ flood interval cannot be ruled out.

In the event a non-operated well is drilled within the AMA, the operator would be required to follow all OCC rules and procedures in drilling the well and the potential for leakage would be similar to that of any well Daylight drills within the AMA. In addition, Daylight's visual inspection process during routine field operation will identify any unapproved drilling activity in the NEPSU and SEBAU.

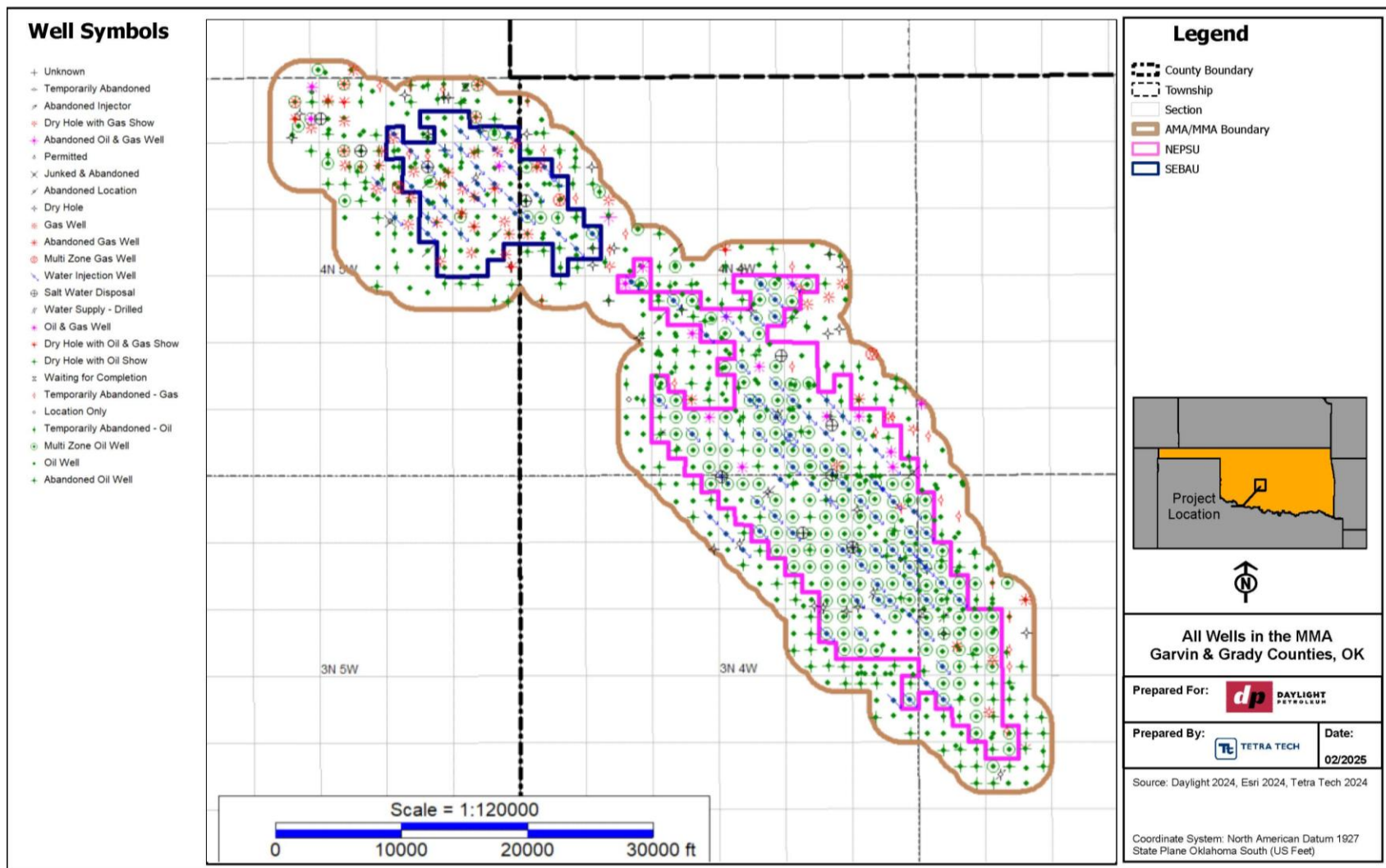


Figure 22: Location and type of all wells within the Active Monitoring Area (AMA). The Maximum Monitoring Area (MMA) is equivalent to the AMA.

4.3. Leakage from Faults, Fractures, and Bedding Plane Partings

Primary seals at the NEPSU and SEBAU have been demonstrated to be mechanically competent despite the presence of faults in and around the field (see also **Section 2.2.2**). The following lines of analysis have been used to assess this risk in the area.

4.3.1. *Presence of Hydrocarbons*

The primary evidence that leakage does not occur along faults, fractures, and bedding plane partings is the ~330 MMB of oil estimated to be originally in place in the NEPSU and SEBAU. If significant escape pathways existed, oil would have drained from the reservoir prior to the present day.

4.3.2. *Fracture Analysis*

Despite the presence of faulting in the area, conventional core samples taken from the Springer showed little evidence of fracturing (Oxy, 1988). In the event CO₂ leakage occurs through faults and fractures, it is unlikely that the leak would result in surface leakage, as these features are not known to extend from the reservoir to the surface. Daylight has strategies for leak detection in place that are discussed in **Section 4.8**, and the strategy to quantify leaks is discussed in **Section 4.10**.

4.4. Lateral Fluid Movement

The Springerean strata in Oklahoma represent primarily a deltaic to coastal island set of depositional systems that prograded toward the southeast, resulting in deposition of shales and lenticular, discontinuous coarse sandstones separated by very fine sandstone, minor conglomerates, and shale. The likelihood of extensive migration of fluid outside of the MMA is considered low.

Since CO₂ is lighter than the water and oil remaining in the reservoir, it will tend to migrate to the top of the reservoir. The producing wells create low pressure points in the field, draining water and oil while keeping some CO₂ within each discontinuous sandstone. It is estimated that the total mass of stored CO₂ will be considerably less than the calculated storage capacity and once production operations cease, very small lateral movement will occur.

4.5. Leakage through Confining/Seal System

The results of gas sampling analysis from wells producing from the Cunningham Sandstone and the shallower Hart Sandstone (i.e., the next overlying reservoir) show that CO₂ does not move vertically through the confining strata. Baseline testing of the Cunningham prior to CO₂ injection showed a 0.6% molar concentration of CO₂ (Fox et al., 1988). In October 2023, Daylight's testing of more than 50 wells producing from the Hart reservoir showed an average of 0.25% molar concentration of CO₂ in the gas stream. These results confirm that the sealing units above the Cunningham prevent upward migration of CO₂ out of the reservoir.

In the unlikely event of CO₂ leakage through the confining seal, there is a very low risk of surface leakage, since the reservoir is at depths of ~8,200-10,900 feet and is overlain by >1,200 feet of impermeable shale net thickness. As with any CO₂ leakage, Daylight has strategies for leak detection in place that are discussed in **Section 4.8** and the strategy to quantify the leak is discussed in **Section 4.10**.

4.6. Natural and Induced Seismic Activity

Figure 23 shows the locations of earthquakes with magnitudes of 2.5 or greater that have occurred within 2 miles of the MMA (data obtained from the United States Geological Survey [USGS] Earthquakes Hazard Program catalog [<https://earthquake.usgs.gov/earthquakes/search/>], accessed 1/30/2025). Details of these earthquakes are provided in **Table 2**. The Purdy-Bradley Springer Field is located in a seismically active region, and all but one of the mapped earthquakes occurred since the initiation of CO₂ injection in 1982. However, there is no evidence that proximal or distal earthquakes have caused a disruption in injectivity, CO₂ leakage, or damage to any of the wellbores in the Purdy-Bradley Springer Field.

In the unlikely event that induced or natural seismicity results in a pathway for material amounts of CO₂ to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would lead to further investigation.

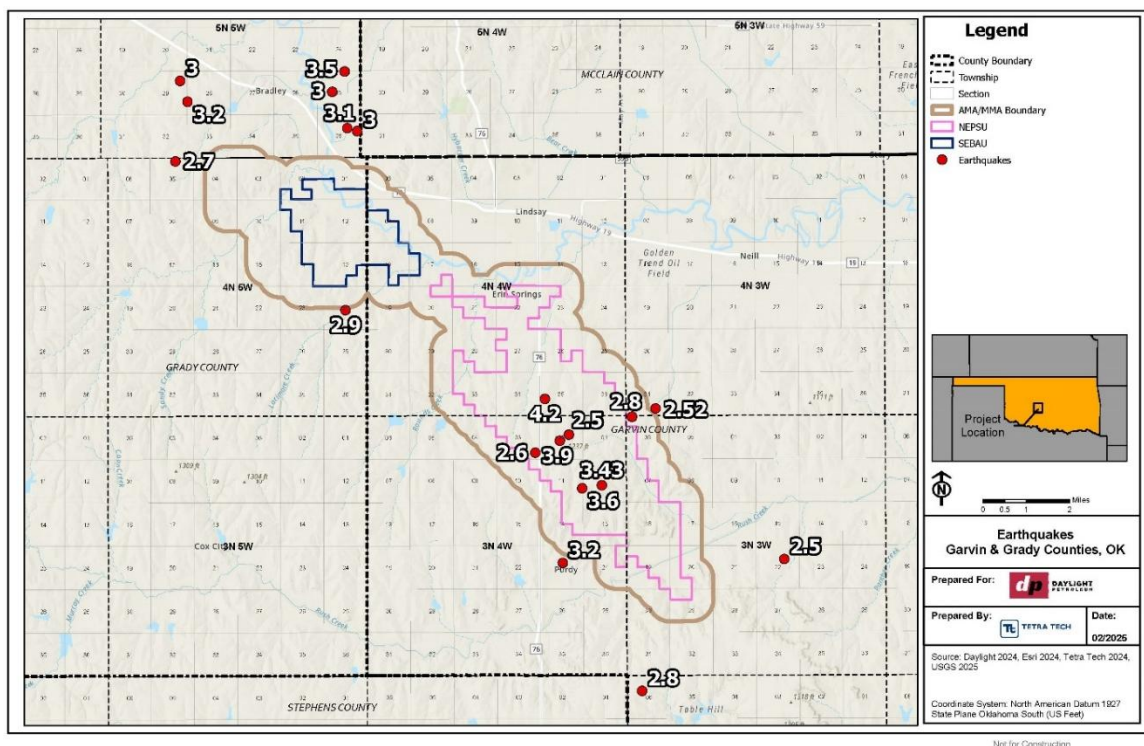


Figure 23: Earthquakes (2.5 magnitude or greater) within 2 miles of the MMA

Table 2: Details of earthquakes within the MMA

Earthquake Date	Magnitude	Location and Depth
1981-07-11	3.5	34.884°N 97.677°W – 5.0 km
1990-11-15	3.9	34.760°N 97.590°W – 5.0 km
1992-12-16	2.6	34.756°N 97.600°W – 5.0 km
1992-12-17	3.6	34.744°N 97.581°W – 5.0 km
1994-07-04	2.8	34.676°N 97.557°W – 5.0 km
1995-01-18	4.2	34.774°N 97.596°W – 5.0 km
1997-03-11	2.5	34.720°N 97.499°W – 5.0 km
1998-07-07	3.2	34.719°N 97.589°W – 5.0 km
2004-04-22	2.9	34.804°N 97.677°W – 5.0 km
2004-11-22	3.0	34.864°N 97.672°W – 5.0 km
2010-06-14	3.1	34.865°N 97.676°W – 5.0 km
2010-10-25	3.2	34.874°N 97.741°W – 5.0 km
2011-03-16	2.7	34.854°N 97.746°W – 5.0 km
2011-08-18	3.0	34.881°N 97.744°W – 5.0 km
2017-11-21	3.0	34.877°N 97.682°W – 2.4 km
2019-05-11	2.8	34.768°N 97.561°W – 5.0 km
2019-05-11	2.5	34.762°N 97.586°W – 5.0 km
2020-09-06	3.4	34.745°N 97.573°W – 7.0 km
2021-12-20	2.5	34.771°N 97.551°W – 6.5 km

4.7. Likelihood, Timing, and Magnitude of Potential Surface Leakage

Table 3 summarizes Daylight’s assessment of the likelihood, timing, and magnitude of surface leakage through the potential leakage pathways identified in this section.

Table 3: Assessment of Likelihood, Magnitude, and Timing of Potential Leakage Pathways

Potential Leakage Pathway	Likelihood	Magnitude ¹	Timing
Surface Equipment	Unlikely but possible	Variable – Small or easily detected failure could result in low- to medium-magnitude CO ₂ release, while a catastrophic failure could result in medium- to high-magnitude CO ₂ release	During injection period
Shallow Groundwater Wells	Unlikely	Low – Monitoring should minimize any release of CO ₂	During injection and post-injection periods
Other Wells	Unlikely but possible	Low – Monitoring / surveillance and well construction requirements should minimize any release of CO ₂	During injection and post-injection periods
Faults, Fractures, and Bedding Plane Partings	Unlikely	Low	During injection and post-injection periods
Lateral Fluid Movement	Unlikely	Low	During injection and post-injection periods
Confining Seal / System	Unlikely	Low	During injection and post-injection periods
Natural and Induced Seismic Activity	Unlikely	Low	During injection and post-injection periods

¹ Magnitude assessed as follows:

Low – minimal risk to safety, health and environment, or USDW

Medium – moderate risk to safety, health and environment, or USDW, but easily remediated

High – extreme risk to safety, health and environment, or USDW, and difficult and/or costly to remediate.

4.8. Strategy for Detection of CO₂ Loss

Daylight intends to use the results of daily monitoring of field conditions, operational data (including automatic data systems), routine testing, and maintenance information to monitor for surface leakage and to identify and investigate deviations from expected performance that could indicate CO₂ leakage. In the event any of those results indicate a CO₂ leak may have occurred, the event will be documented and an estimate will be made of the amount of CO₂ leaked. The event and estimate will be included in the annual Subpart RR reporting. Records of each event will be kept on file for a minimum of 3 years. The methods that Daylight intends to use in this strategy include the following:

4.8.1. *Data System*

Daylight uses onsite management and a Supervisory Control and Data Acquisition (SCADA) system to conduct its CO₂-EOR operations. Daylight uses data from these efforts to identify and investigate variances from expected performance that could indicate CO₂ leakage. Some CO₂ meters are installed with SCADA systems that transmit data from the meters automatically into a data warehouse. Those data, as well as other operational data collected manually, are also used for operational management and controls.

4.8.2. *Visual Inspections*

Daylight's field personnel conduct routine weekly or daily inspections of the facilities, wells, and other equipment (such as vessels, piping, and valves). These visual inspections provide an opportunity to identify issues early and to address them proactively, which may preclude leaks from happening and/or minimize any CO₂ leakage. Any visual identification of CO₂ vapor emission or ice formation will be reported and documented, and a plan will be developed and executed to correct the issue.

4.8.3. *Injection Target Rates and Pressures*

Daylight manages its CO₂-EOR operations by developing and implementing target injection rates and pressures for each CO₂ injection well. These target rates and pressures are developed based on various parameters such as historic and ongoing pattern development, WAG operations, CO₂ availability, field performance, and permit conditions. Field personnel implement the WAG schedule by manually making choke adjustments at each injection well, allowing for a physical inspection of the injection well during each adjustment. Generally on a daily basis, injection rates for each CO₂ injection well are reported and compared to the target rates. Injection pressures and casing pressures are monitored on each CO₂ injection well. Injection rates or pressures falling outside of the target rates or pressures to a statistically significant degree are screened to determine whether they could lead to CO₂ leakage to the surface. If that screening or investigation identifies any indication of a CO₂ leakage to the surface in this manner, it will be reported and documented, and a plan will be developed and executed to correct the issue.

4.8.4. *Production Wells*

Daylight forecasts the amount of fluids (e.g. oil, water, CO₂) that is likely to be produced from each production well at the unit level in the NEPSU and SEBAU over various periods of time. Evaluation of these produced volumes, along with other data, informs operational decisions regarding management of the CO₂-EOR project and aid in identifying possible issues that may involve CO₂ leakage. These evaluations can direct engineering and/or operational personnel to investigate

further. If an investigation identifies that a CO₂ leak has occurred, it will be reported and documented, and a plan will be developed and executed to correct the issue.

4.8.5. Plant and Pipeline Monitoring

Daylight currently operates the CO₂-related infrastructure used to operate the units, including the associated on-site CO₂ capture, compression, and dehydration facility. The facility includes a monitoring program that monitors the rates and pressures at the facility and on the pipeline on a continuous basis. High and low set points are established in the program, and operators at the plant, pipeline and/or the units are alerted if a parameter is outside the allowable window. If the flagged parameter is the delivery point on the pipeline, but no other parameter at the plant or pipeline is flagged, then the field personnel are alerted so that further investigation can be conducted in the field to determine if the issue poses a leak threat.

4.8.6. Well Testing

Injection wells are leak-tested via MIT as required by the USEPA or OCC. This consists of regular monitoring of the tubing-casing annular pressure and conducting a test that pressures up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. Sometimes, in addition to or in lieu of MIT, Daylight is required to perform a RTS to ensure that all injection fluids are going into the injection zone. Daylight personnel monitor the pressure and conduct the tests in accordance with regulations and permit requirements. In the event of a loss of mechanical integrity, the subject injection well is immediately shut in and an investigation is initiated to determine what caused the loss of mechanical integrity. If investigation of an event identifies that a CO₂ leak has occurred, it will be reported and documented, and a plan will be developed and executed to correct the issue.

4.9. Strategy for Response to CO₂ Loss

As discussed above, the potential sources of leakage include routine issues, such as problems with surface equipment (e.g., pumps, valves), wellbores or subsurface equipment, and unique and unlikely events such as induced fractures. **Table 4** summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, Daylight's standard response, and other applicable regulatory programs requiring similar reporting.

The potential CO₂ losses discussed in the table are identified by type. If there is a report or indication of a CO₂ leak, such as from a visual inspection, monitor, or pressure drop, a Daylight employee or supervisor will be dispatched to investigate. Emergency shutdown systems will be utilized as necessary to isolate the leak. If the leak cannot be located without movement of equipment or other substantial work, further involvement of Daylight personnel or management will be involved to determine how the leak will be located. Once the leak is located and isolated, pressure from the system will be relieved so that further investigation of the leak area can be performed and repair work can be estimated and ultimately performed.

Table 4: Response Plan for CO₂ Loss

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

4.10. Strategy for Quantifying CO₂ Loss

Leakage of CO₂ on the surface will be quantified once leakage has been detected and confirmed. Major CO₂ losses are typically event-driven and require a process to assess, address, track, and if applicable, quantify potential CO₂ leakage to the surface. Daylight will use Subpart W techniques to estimate leakages only on equipment and ensure those results are consistently represented in the Subpart RR report. Any event-driven leakage quantification reported in Subpart RR for surface leaks will use other techniques.

In the event leakage occurs, Daylight will determine the most appropriate method for quantifying the volume leaked and will report the methodology used as required as part of the annual Subpart RR submission. Leakage estimating methods may potentially consist of modeling or engineering estimates based on operating conditions at the time of the leak, such as temperatures, pressures, volumes, and hole size. An example methodology would be to place a flux box or ring tent over the surface leak to measure the flow rate and gather gas samples for analysis. The volume of CO₂ in the soil can also be used with this technique. Any volume of CO₂ detected leaking to the surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 Subpart W or engineering estimates of leak amounts based on measurements in the subsurface, Daylight's field experience, and other factors such as the frequency of inspection. Records of leakage events will be retained in Daylight's electronic documentation and reporting system, which consists of reports stored on servers, with certain details uploaded into third-party software.

4.11. Demonstration at End of Specified Period

At the end of EOR injection operations, Daylight intends to cease injecting CO₂ for the purpose of establishing long-term storage of CO₂ in the units. At that time, Daylight anticipates submitting a request to discontinue monitoring and reporting, including a demonstration that the amount of CO₂ reported under Subpart RR is not expected to migrate in the future in a manner likely to result in surface leakage. Daylight will support its request with data collected during operations as well as 1-3 years of data (or more, if needed) collected after the end of operations. Daylight expects this demonstration will provide the information necessary for the USEPA to approve the request to discontinue monitoring and reporting. This demonstration may include but is not limited to:

- An assessment of CO₂ injection data for the units, including the total volume of CO₂ injected and stored as well as actual surface injection pressures;
- An assessment of any CO₂ leakage detected, including discussion of the estimated amount of CO₂ leaked and the distribution of emissions by leakage pathway; and
- An assessment of reservoir pressure in the units that demonstrates that the reservoir pressure is stable enough to demonstrate that the injected CO₂ is not expected to migrate in a manner to create a potential leakage pathway.

5.0. Strategy for Determining CO₂ Baselines for CO₂ Monitoring

Daylight may elect to collect additional atmospheric test data using ambient air detectors or other methodologies to characterize baseline values in the units. Ongoing operational monitoring of well pressures and rates has provided data for establishing baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO₂ 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. Each of these is discussed in more detail below.

5.1. Site Characterization and Monitoring

As described in **Section 2.2.2** and **Section 2.4**, the Cunningham Sandstone is isolated by impermeable shale units of the upper Springer, Morrow, and/or Atoka reaching thicknesses of 150-200 feet. These units provide a suitable primary seal to prevent the migration of CO₂ out of the injection reservoir, and additional shale layers above the primary seal provide secondary confinement with a total net shale thickness >1,200 feet. As discussed in **Section 4.5**, testing of the Springer prior to CO₂ injection showed a 0.6% molar concentration of CO₂ (Fox et al., 1988). In October 2023, Daylight's testing of more than 50 wells producing from the Hart reservoir showed an average of 0.25% molar concentration of CO₂ in the gas stream. Furthermore, a review of gas sample data published in Higley (2014) shows the range of natural CO₂ concentration in the Central Anadarko Basin is 0.00-10.9 mole percent (average, 1.73 mole percent). These field- and basin-scale data will be considered in the determination of CO₂ baseline values should a potential leak be detected.

Additionally, no significant faults or fracture zones that compromise the sealing capacity of the confining shales have been identified in the Purdy-Bradley Springer Field, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented. After ~42 years of tertiary oil recovery operations, no significant wellbore leaks are known to have occurred, and therefore Daylight concludes that wellbore leaks are unlikely to happen.

5.2. Groundwater Monitoring

Daylight obtains and tests water samples from shallow groundwater wells during the preparation of permit applications for new Class II UIC EOR injection wells. Daylight has not monitored USDW wells for CO₂ or brine contamination, as characterization of the Springer suggests that risk of groundwater contamination from CO₂ leakage from the reservoir is minimal. While groundwater contamination is unlikely to happen, any change in groundwater that is brought to the attention of Daylight will be investigated to eliminate the potential leakage pathway.

5.3. Soil CO₂ Monitoring

Daylight does not intend to collect background soil gas data. Should a possible leakage event be detected, Daylight may elect to use vapor monitoring points installed into the shallow subsurface as part of the leakage verification and quantification process.

5.4. Visual Inspection

Daylight operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage. Visual inspection consists of finding evidence of stains, unusual

accumulation of frost, washouts exposing buried pipe, dead rodents, birds or reptiles, and changes to vegetation. In addition to looking for evidence of leaks, field personnel will look for conditions that could lead to equipment failure such as public utility digging, ditching, settling of backfill, boring, and tunneling.

5.5. Well Surveillance

Daylight adheres to the requirements of OAC Title 165 Chapter 10 governing fluid injection into productive reservoirs. Title 165 includes requirements for monitoring, reporting, and testing of Class II UIC injection wells, including an initial MIT prior to injection operations and subsequent MIT at least once every year or every 5 years, depending on the permitted injection rate. Daylight will report any mechanical failure of the surface casing or cement to the appropriate regulatory authority in full compliance with all applicable legal and regulatory requirements.

5.6. Injection Well Rates, Pressures, and Volumes

Target injection rates and pressures for each injector are developed within the permitted limits based on the results of ongoing pattern surveillance. The field operations staff monitor equipment readings and investigate any departures from the permitted limits which could have resulted in a surface CO₂ leak.

6.0. Site-Specific Considerations for Determining the Mass of CO₂ Sequestered

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

6.1. Determining Mass of CO₂ Received

Daylight has the ability to receive CO₂ at its NEPSU and SEBAU facilities via its operated pipeline from Enid, Oklahoma. Daylight also recycles CO₂ from its production wells in NEPSU and SEBAU.

$$CO_{2T,r} = \sum_{p=1}^4 (Q_{r,p} - S_{r,p}) \times D \times C_{CO_{2,p,r}} \quad (\text{Equation RR-2})$$

where:

CO_{2T,r} = Net annual mass of CO₂ received through flow meter r (metric tons)

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

C_{CO₂,p,r} = Quarterly CO₂ concentration measurement in flow for flow meter r in quarter p (volume percent CO₂, expressed as a decimal fraction)

p = Quarter of the year

r = Receiving flow meter

6.2. Determining Mass of CO₂ Injected

Daylight injects CO₂ into the injection wells listed in **Appendix 1**.

$$CO_{2,u} = \sum_{p=1}^4 Q_{p,u} \times D \times C_{CO_2,p,u} \quad (\text{Equation RR-5})$$

where:

CO_{2,u} = Annual CO₂ mass injected (metric tons) as measured by flow meter u

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

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

p = Quarter of the year

u = Flow meter

6.3. Determining Mass of CO₂ Produced from Oil Wells

Daylight also recycles CO₂ from its EOR production wells in the NEPSU and SEBAU. Therefore, the following equation is relevant to its operations.

$$CO_{2,w} = \sum_{p=1}^4 Q_{p,w} \times D \times C_{CO_2,p,w} \quad (\text{Equation RR-8})$$

where:

CO_{2,w} = Annual CO₂ mass produced (metric tons) through separator w

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

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

p = Quarter of the year

w = Separator

To aggregate production data, Daylight will sum the mass of all the CO₂ separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 below:

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

where:

CO_{2P} = Total annual CO₂ mass produced (metric tons) through all separators in the reporting year

CO_{2,w} = Annual CO₂ mass produced (metric tons) through separator w in the reporting year

X = Entrained CO₂ in produced oil or other fluid divided by the CO₂ separated through all separators in the reporting year (weight percent CO₂, expressed as a decimal fraction).

w = Separator

6.4. Determining Mass of CO₂ Emitted by Surface Leakage

As required by 98.448 (d) of Subpart RR, Daylight will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO₂ stream, for facilities that conduct CO₂-EOR operations.

Daylight will calculate the total annual mass of CO₂ emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 below:

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

where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year

x = Leakage pathway

Note: CO_{2E} is separate from and calculated differently than the terms CO_{2FI} and CO_{2FP} (leakage from equipment leaks and vented emissions) used in Equation RR-11 below.

6.5. Determining Mass of CO₂ Sequestered

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

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

where:

CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

CO_{2P} = Total annual CO₂ mass produced (metric tons) in the reporting year

CO_{2E} = Total annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year

CO_{2FI} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ 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

CO_{2FP} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ 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

7.0. Estimated Schedule for Implementation of MRV Plan

Daylight expects to begin implementing this MRV Plan after approval, or tentatively in 2026. Data collection for Subpart RR reporting (calculating total amount sequestered according to Equation RR-11 of this subpart) is expected to begin in 2026 after the MRV Plan is approved and a supply of fresh CO₂ is secured. As such, this data collection would begin no later than 12/31/2026 for 2027 reporting.

8.0. GHG Monitoring and Quality Assurance Program

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

8.1. GHG Monitoring

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

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

8.1.1. General

Daylight follows industry-standard metering protocols for custody transfers, such as those standards for accuracy and calibration issued by the API, the American Gas Association (AGA), and the Gas Producers Association (GPA), as appropriate. This approach is consistent with 98.444(e)(3). Meters are maintained routinely, operated continually, and will feed data directly to the centralized data collection systems. CO₂ composition is governed by contract, and the CO₂ is routinely and periodically sampled to determine average composition. These custody meters provide an accurate method of measuring mass flow.

In addition to custody transfer meters, various process control meters are used in NEPSU and SEBAU to monitor and manage in-field activities, often on a real-time basis. These operations meters provide information used to make operational decisions but are not intended to provide the same level of accuracy as the custody-transfer meters. The level of precision and accuracy for operational meters currently satisfies the requirements for reporting in existing UIC permits. Although the process control meters are accurate for operational purposes, there is some variance between most commercial meters (on the order of 1-5%), which is additive across meters. This variance is due to differences in factory settings and meter calibration, as well as the operating conditions within the field. Meter elevation, changes in temperature, fluid composition (especially in multi-component or multi-phase streams), and pressure can affect readings of these operational meters.

Measurement of CO₂ Concentration – All measurements of CO₂ concentrations of any CO₂ quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as those established by the GPA.

Measurement of CO₂ Volume – All measurements of CO₂ volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees F and at an absolute pressure of 1 atmosphere. Measurement devices will be compliant with AGA and API standards and can produce and export .cfx industry-standard files for either gas or liquid meter runs.

8.1.2. CO₂ Received

Fresh CO₂ (non-recycled) is received via a pipeline running from Enid, Oklahoma, and is measured with an orifice meter (recorded with a digital transducer). Information is sent to a flow computer (Fisher/Emerson ROC800) and is configured to calculate volumes. Data is stored temporarily to be pulled by the SCADA system. Daylight will bring in new sources of CO₂ in the future according to field development and operational needs.

8.1.3. CO₂ Injected

Daily CO₂ injection is recorded by combining the totals for the recycle compressor meter and the received CO₂ meter based on what is delivered on a 24-hour basis. These data are taken from the meter daily and stored according to Daylight's data management protocols.

8.1.4. CO₂ Produced

The point of produced gas measurement is from a meter downstream of the compressors prior to being combined with purchase CO₂. The produced gas is sampled and analyzed quarterly at the plant inlet, plant tailgate (north and south) and as needed at each satellite.

8.1.5. CO₂ Emissions from Equipment Leaks and Vented Emissions of CO₂

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

As required by 98.444 (d) of Subpart RR, Daylight will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO₂ stream, for facilities that conduct CO₂-EOR operations. The default emission factors for production equipment are applied to the carbon capture utilization and storage (CCUS) injection operations reporting under Subpart RR.

8.1.6. Measurement Devices

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

- All flow meters are operated continuously except as necessary for maintenance and calibration.

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

8.2. QA/QC Procedures

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

8.3. Estimating Missing Data

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

A quarterly flow rate of CO₂ received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.

A quarterly CO₂ concentration of a CO₂ 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 CO₂ injected that is missing would be estimated using a representative quantity of CO₂ injected from the nearest previous period of time at a similar injection pressure.

For any values associated with CO₂ emissions from equipment leaks and vented emissions of CO₂ 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.

A quarterly quantity of CO₂ produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO₂ produced from the nearest previous period of time.

8.4. Revisions to the MRV plan

Daylight will revise the MRV Plan as necessary per 40 CFR 98.448(d).

9.0. Records Retention

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

- (1) A list of all units, operations, processes, and activities for which GHG emissions were calculated. The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:
 - (i) The GHG emissions calculations and methods used.
 - (ii) Analytical results for the development of site-specific emissions factors, if applicable.
 - (iii) The results of all required analyses.
 - (iv) Any facility operating data or process information used for the GHG emission calculations.
- (2) The annual GHG reports.
- (3) Missing data computations. For each missing data event, Daylight will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
- (4) A copy of the most recent revision of this MRV Plan.
- (5) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
- (6) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
- (7) Quarterly records of CO₂ received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- (8) Quarterly records of produced CO₂, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- (9) Quarterly records of injected CO₂ including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- (10) Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- (11) Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
- (12) Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.
- (13) Any other records as specified for retention in this USEPA-approved MRV plan.

List of Figures

Figure 1: Location of the Purdy-Bradley Springer field in the Arkoma Basin	6
Figure 2: Regional stratigraphic column	7
Figure 3: Type log	8
Figure 4: Depth to base of treatable water	10
Figure 5: Simplified flow diagram of the CO ₂ -EOR operations	11
Figure 6: CO ₂ collection and distribution process	13
Figure 7: Simplified fluids flow diagram for a typical NEPSU satellite	14
Figure 8: Process diagram for the Lindsay Gas Plant	15
Figure 9: Top Springer structure	19
Figure 10: Net pay thickness for the Springer reservoir sands	20
Figure 11: Schematic of the reservoir-seal stratigraphic trapping configuration	21
Figure 12: Oil PVT plots	23
Figure 13: Oil and gas viscosity	23
Figure 14: Lorenz plot	24
Figure 15: Hydrocarbon pore volume filled by CO ₂ injection vs. time	25
Figure 16: Recovery factor vs. CO ₂ pore volume injected	25
Figure 17: Oil rate-time curve comparison with actual estimations	27
Figure 18: Comparison of the cumulative oil rates	27
Figure 19: Variation of CO ₂ density at 148 degrees F	28
Figure 20: Predicted volume available for CO ₂ injection	29
Figure 21: Predicted CO ₂ storage in terms of mass	29
Figure 22: Location and type of all wells within the Active / Maximum Monitoring Area	33
Figure 23: Earthquakes (+2.5 magnitude) within 2 miles of the MMA	35

List of Tables

Table 1: Reservoir Summary Characteristics	18
Table 2: Details of earthquakes within the MMA	36
Table 3: Assessment of Likelihood, Magnitude, and Timing of Potential Leakage Pathways	37
Table 4: Response Plan for CO ₂ Loss	40

Appendix 1 – List of Wells

A list of all known wells in the MMA is provided in the attached PDF spreadsheet. Information was compiled from available S&P Global (formerly IHS) data. This information may differ from records available from the online OCC Well Data Finder as well as the archived documents database for well data, which may not include certain legacy well records. To ensure all wells within the MMA are accounted for, Daylight is providing the more extensive well record data provided by S&P Global that contains 886 unique wellbores within the MMA.

Appendix 2 – References

Regulatory Citations

Oklahoma Administrative Code Title 165 Chapter 10 (<https://rules.ok.gov/code>)

26 CFR 1.45Q (for table of contents, see <https://www.ecfr.gov/current/title-26/section-1.45Q-0>)

40 CFR Part 98 Subpart A (<https://www.ecfr.gov/current/title-40/part-98/subpart-A>)

40 CFR Part 98 Subpart W (<https://www.ecfr.gov/current/title-40/part-98/subpart-W>)

40 CFR Part 98 Subpart RR (<https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-RR>)

40 CFR Part 98 Subpart UU (<https://www.ecfr.gov/current/title-40/part-98/subpart-UU>)

Other Publications

Advanced Resources International (2024). The U.S. CO₂ enhanced oil recovery survey. <https://adv-res.com/pdf/ARI-2021-EOY-2020-CO2-EOR-Survey-OCT-21-2021.pdf>

Ball, M. M., Henry, M. E., and Frezon, S. E. (1991). Petroleum geology of the Anadarko Basin region, Province (115), Kansas, Oklahoma, and Texas. Open-File Report 88-450W, U.S. Geological Survey.

Birk, S.C. (1986). Letter to Cuscaden, J.A., S.E. Bradley – minimum miscibility pressure. Project 208-5480. Mobil Research and Development Corporation, Dallas Research Laboratory.

Brinlee, L. D., and Brandt, J. A. (1982). Planning and development of the Northeast Purdy Springer CO₂ miscible project. Paper presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, September 1982. SPE-11163-MS, 13 pp. doi: <https://doi.org/10.2118/11163-MS>

Chang, J.M., and Stanley, T.M. (2010). Geologic map of the Pauls Valley 30' X 60' quadrangle (Preliminary), Carter, Cleveland, Garvin, Grady, McClain, Murray, Pottawatomie, and Stephens Counties, Oklahoma. Oklahoma Geological Survey OGQ-81 Color.

Cities Service Company (1978). Feasibility analysis of applying enhanced recovery methods, Northeast Purdy Spring Sand Unit “A”, Garvin County, Oklahoma. Unpublished manuscript, Cities Service Company Task Force for Purdy Unit.

Ekstrand, J.D. (1979). Routine core analysis and special flow studies, N.E. Purdy K-214, Garvin County, Oklahoma. Cities Service Company Energy Resources Group Research Laboratory, PR 79-02.

Fox, M.J., Simlote, V.N., Stark, K.L., and Brinlee, L.D. (1988). Review of CO₂ flood, Springer “A” Sand, Northeast Purdy Unit, Garvin County, Oklahoma. SPE Res Eng 3: 1161–1167. doi: <https://doi.org/10.2118/14938-PA>

Koval, E.J. (1963). A method for predicting the performance of unstable miscible displacement in heterogeneous media. SPE J. 3: 145–154. doi: <https://doi.org/10.2118/450-PA>

Ham, W.E., Denison, R.E., and Merritt, C.A. (1964). Basement Rocks and Structural Evolution of Southern Oklahoma: Oklahoma Geological Survey Bulletin 95, 302 p.

- Higley, D.K., compiler. (2014). Petroleum systems and assessment of undiscovered oil and gas in the Anadarko Basin Province, Colorado, Kansas, Oklahoma, and Texas—USGS Province 58: U.S. Geological Survey Digital Data Series DDS-69-EE, 409 p. <http://dx.doi.org/10.3133/ds69EE>
- Irani, M., Bashtani, F., and Kantzas, A. (2021). Control of gas cresting/coning in horizontal wells with tubing-deployed inflow control devices. *Fuel* 293, 120328. doi:10.1016/j.fuel.2021.120328
- Johnson, K.S., and Luza, K.V., eds. (2008). *Earth Sciences and Mineral Resources of Oklahoma*. Oklahoma Geological Survey, University of Oklahoma.
- Jorgensen, D.G. (1993). Paleohydrology of the Central United States, Chap. D, in: *Strategic and critical minerals of the Midcontinent region, United States* – U.S. Geological Survey Bulletin 1989.
- Lee, E., Hornafius, J. S., Dean, E. Kazemi, H., (2019). Potential of Denver Basin oil fields to store CO₂ and produce Bio-CO₂-EOR oil. *International Journal of Greenhouse Gas Control* (81): 137-156. <https://doi.org/10.1016/j.ijggc.2018.11.013>
- Nelson, P.H., and Gianoutsos, N.J. (2014). Potentiometric surfaces for seven stratigraphic units and an explanation for underpressure in the Greater Anadarko Basin, Oklahoma, Texas, Kansas, and Colorado, Chap. 9, in: Higley, D.K., compiler, *Petroleum systems and assessment of undiscovered oil and gas in the Anadarko Basin Province, Colorado, Kansas, Oklahoma, and Texas* – USGS Province 58: U.S. Geological Survey Digital Data Series DDS-69-EE, 24 p. doi: <http://dx.doi.org/10.3133/ds69EE>.
- NEPSU (1979). Enhanced recovery reservoir geology – Northeast Purdy Field, Garvin County, Oklahoma. Unpublished manuscript.
- OWRB (n.d.). Oklahoma groundwater resources – major and minor aquifers of Oklahoma (map). Accessed January 2025 at: https://www.owrb.ok.gov/maps/pdf_map/GW%20Aquifers.pdf
- Oxy (1988). Geologic and reservoir description. Unpublished manuscript.
- Perry Jr., W. J. (1989). Tectonic evolution of the Anadarko Basin region, Oklahoma. Chapter A, in: *Evolution of Sedimentary Basins*, U.S. Geological Survey Bulletin 1866.
- Salazar, J., and Lake, L. (2020). The physical meaning of the Koval factor. *Mathematical Geosciences*. 52. doi: 10.1007/s11004-020-09883-0.
- Simlote, V., and Withjack, E. M. (1981). Estimation of tertiary recovery by CO₂ injection – Springer A Sand, Northeast Purdy Unit. *J Pet Technol* 33: 808–818. doi: <https://doi.org/10.2118/9431-PA>
- Stell, M. (2010). An auditor's view of booking reserves in CO₂ EOR projects and the ROZ. Presented at the 16th Annual CO₂ Flooding Conference, Midland, Texas.

Appendix 3 – Abbreviations and Acronyms

AGA – American Gas Association

AMA – Active Monitoring Area

ANSI – American National Standards Institute

AoR – Area of Review

API – American Petroleum Institute

ASTM – American Society for Testing and Materials

Bscf – Billion Standard Cubic Feet

CCUS – Carbon Capture, Utilization, and Storage

CFR – Code of Federal Regulations

CO₂ – Carbon Dioxide

CO₂-EOR – Carbon Dioxide Enhanced Oil Recovery

cp – Centipoise

DPHI – Density Porosity

EOR – Enhanced Oil Recovery

EOS – Equation of State

F – Fahrenheit

ft³ – Cubic Foot

FVF – Formation Volume Factor

GERG – European Gas Research Group

GHG – Greenhouse Gas

GHGRP – Greenhouse Gas Reporting Program

GPA – Gas Producers Association

GR – Gamma Ray

HCPV – Hydrocarbon Pore Volume

lbs – Pounds

m³ – Cubic Meter

Mcf – Million cubic feet

mD – Millidarcies

MIT – Mechanical Integrity Test (or Testing)

MMA – Maximum Monitoring Area

MMB – Million Barrels

MMP – Minimum Miscibility Pressure

MMscf – Million Standard Cubic Feet

MMSTB – Million Stock Tank Barrels

MMT – Million Metric Tons

MRV – Monitoring, Reporting, and Verification

MT – Metric Ton

NAESB – North American Energy Standards Board

NGL – Natural Gas Liquids

NIST – National Institute of Standards and Technology

NPHI – Neutron Porosity

OAC – Oklahoma Administrative Code

OCC – Oklahoma Corporation Commission

ppm – Parts Per Million

psi – Pounds per Square Inch

psia – Pounds per Square Inch Absolute

psig – Pounds per Square Inch Gauge

PVT – Pressure, Volume, Temperature

QA/QC – quality assurance/quality control

rb – Reservoir Barrels

RTS – Radioactive tracer survey

SPHI – Sonic Porosity

UIC – Underground Injection Control

USDW – Underground Source of Drinking Water

USEPA – United States Environmental Protection Agency

USGS – United States Geological Survey

WAG – Water Alternating Gas

Appendix 4 – Conversion Factors

Daylight reports CO₂ at standard conditions of temperature and pressure as defined in the Oklahoma Administrative Code (OAC) for Oil and Gas Conservation, Title 165 Chapter 10 as follows:

“Cubic foot of gas” means the volume of gas contained in one cubic foot (ft₃) of space at an absolute pressure of 14.65 pounds per square inch (psi) and at a temperature 60 degrees F. Conversion of volumes to conform to standard conditions shall be made in accordance with Ideal Gas Laws corrected for deviation from Boyle’s Law when the pressure at point of measurement is in excess of 200 pounds per square inch gauge (psig).

To calculate CO₂ mass from CO₂ volume, USEPA recommends using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST). This online database is available at <https://webbook.nist.gov/chemistry/fluid/>. It provides the density of CO₂ using the Span and Wagner equation of state (EOS) at a wide range of temperature and pressures.

At the standard conditions prescribed in the OAC, the Span and Wagner EOS gives a density of 0.0026417 lb-moles per cubic foot. Using a molecular weight for CO₂ of 44.0095, 2,204.62 lbs/MT and 35.314667 ft³/m³, gives a CO₂ density of 5.27346×10^{-2} MT/Mcf or 0.0018623 MT/m³.

Note that the USEPA standard conditions of 60 degrees F and one atmosphere produce a slightly different value. The Span and Wagner EOS gives a density of 0.0026500 lb-moles per cubic foot. Using a molecular weight for CO₂ of 44.0095, 2,204.62 lbs/MT and 35.314667 ft³/m³, gives a CO₂ density of 5.29003×10^{-2} MT/Mcf or 0.0018682 MT/m³.

The conversion factor 5.27346×10^{-2} MT/Mcf is used to convert CO₂ volumes to metric tons.

Appendix 5 – Koval Factor Calculation

Based on theoretical considerations, laboratory experiments, and pilot tests, Koval (1963) suggests that in miscible flooding, viscous fingering affects the volumetric sweeping efficiency. Immiscible viscous fingering in porous media occurs when a high-viscosity fluid is displaced by an immiscible low-viscosity fluid. In such cases, the Buckley-Leverett model cannot be applied directly and requires modification. According to Koval's theory (Koval, 1963), the fraction of pore volume swept by the displacing agent, denoted as E_v , can be expressed as a function of K_v , the Koval heterogeneity factor.

$$\text{If } t_D \leq 1/K_v \text{ then } E_v = t_D \quad \text{Equation 5-1}$$

$$\text{If } 1/K_v < t_D < K_v \text{ then } E_v = \frac{2\sqrt{K_v t_D} - t_D - t_D}{K_v - 1} \quad \text{Equation 5-2}$$

$$\text{If } t_D \geq K_v \text{ then } E_v = 1.0 \quad \text{Equation 5-3}$$

where t_D is injected pore volume.

The Koval factor combines both the viscosity contrast effect and the heterogeneity effect. In practical applications, calculating the Koval factor is a complex task. A comparison is made with the Lorenz coefficient (Salazar and Lake, 2020). In this model, **Figure A5** is used, and based on the given Lorenz coefficient, the Koval factor is calculated.

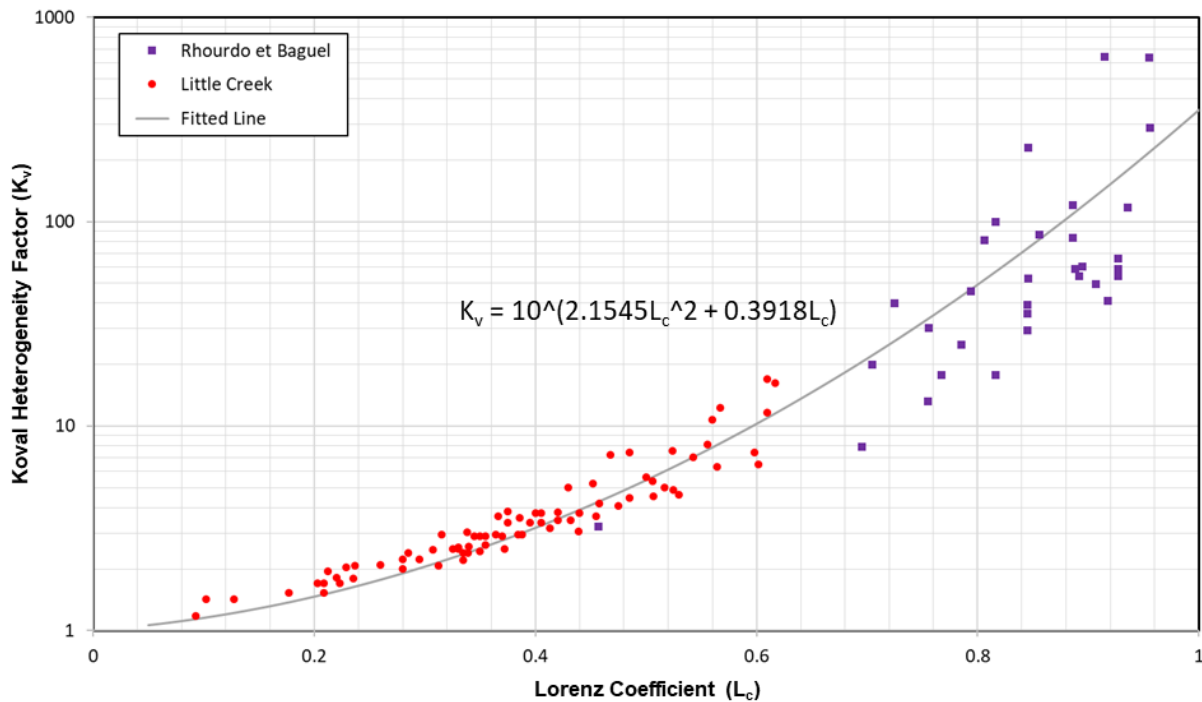


Figure A5: Comparison of the Koval factor and Lorenz coefficient.

Appendix 6 – Muskat Model Description

This appendix explains the formulation behind the Muskat Model, based on the work of Irani et al. (2021). Generally, when an analytical solution is not available, the depletion performance equations can be divided into blocks, with each block assuming constant properties. Muskat's method offers a solution that accounts for the expansion behavior of each pressure/saturation block, along with the corresponding flow equations. It also considers the expansion and liberation of gas due to pressure reduction, allowing for calculations of these effects. This method was chosen for its widespread application, simplicity, and compatibility with the available data size.

The first step involves calculating B_o , B_g , R_s , μ_o , and μ_g at pressures equal to or below the bubble point pressure.

Second, we calculate parameters α , β , and γ .

$$\alpha = (B_g^i)/(B_o^i) \times (R_s^{(i-1)} - R_s^i)/(P_i - P_{(i-1)}) \quad \text{Equation 6-1a}$$

$$\beta = 1/(B_o^i) \times (B_o^i - B_o^{(i-1)})/(P_i - P_{(i-1)}) \times (\mu_o^i)/(\mu_g^i) \quad \text{Equation 6-1b}$$

$$\gamma = 1/(B_g^i) \times (B_g^i - B_g^{(i-1)})/(P_i - P_{(i-1)}) \quad \text{Equation 6-1c}$$

At the first iteration, oil saturation can be obtained utilizing the water saturation derived from the resistivity log.

$$S_o = 1 - S_w \quad \text{Equation 6-2}$$

With both oil and water saturations available, the relative permeability of oil and gas can be determined. Using these relative permeability values, oil and water saturations can then be back calculated. In the next iteration, with the updated water and oil saturations, the gas saturation can be calculated, assuming a three-phase system.

$$S_g = 1 - S_w - S_o \quad \text{Equation 6-3}$$

$$S_o^i = S_o^{(i-1)} - \left(\alpha S_o^i + \beta S_o^i (k_{rg}^i)/(k_{ro}^i) - \gamma (1 - S_w - S_o^i) \right) / \left(1 + (\mu_o^i)/(\mu_g^i) (k_{rg}^i)/(k_{ro}^i) \right) (P_{(i-1)} - P_i) \quad \text{Equation 6-4}$$

New relative permeability values can be determined using the updated oil saturation. This process is repeated iteratively until the difference between the old and new oil saturation becomes negligible. Next, we define a given rate at day 1, where the rate on any subsequent day is calculated by multiplying the initial rate by the new mobility factor. The mobility factor is the ratio of the new oil relative permeability to the oil viscosity at the given pressure. Finally, we define the pressure change over time to match both oil production and gas production (or the produced GOR).

Request for Additional Information: Northeast Purdy Springer Unit (NEPSU) / South East Bradley A Unit (SEBAU)
May 29, 2025

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	The facility representatives have notified EPA that NEPSU and SEBAU were merged under facility ID. Please update the facility name and ID numbers as necessary in the MRV plan.	Both units are now merged into one facility ID (545261) under the name Northeast Purdy Springer Unit (NEPSU) / South East Bradley A Unit (SEBAU). The MRV plan has been updated to reflect the single facility ID and name (Page 1, first paragraph, and Section 1.1, Page 2).
2.	2.3	9	“Historically, a fertilizer plant in Enid, Oklahoma, has been the only source of CO₂, with CO₂ captured from the plant delivered via a Daylight-operated pipeline to the field for injection. No new CO₂ has been received since 2022, but Daylight anticipates securing additional sources of new CO₂ in future years.” 40 CFR 98.446(d) requires that the annual subpart RR report identify the source of the CO₂ received according to one of the categories listed. We recommend clarifying in the MRV plan what types of sources may supply CO₂ to the facility in the future.	Daylight is currently working with multiple emitters to source additional CO ₂ for the EOR project. These potential sources include gas processing plants, landfills, fertilizer plants, refineries, and ethanol plants. Edits have been made in the MRV plan (page 9) to clarify what types of sources may supply CO ₂ to the facility in the future.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	3.0	30	Please clarify how the anticipated CO₂ plume was projected and/or modeled. E.g., on what basis does the facility anticipate the CO₂ plume to remain within the unit boundaries?	The unit boundaries were defined during unitization based on the geologic boundaries and truncational limits of the Springer reservoir, and the successful containment of CO₂ within these boundaries has been demonstrated by field EOR operations. The estimated voidage space of 278 Bscf is entirely contained within the unit boundaries and will not be exceeded by CO₂ injection volumes. Therefore, Daylight expects the free-phase CO₂ to remain within these boundaries for the duration of the project and at least 5 years thereafter, as required for the AMA by 40 CFR 98.449. Clarifying edits have been made to Section 3.2 (Page 30).
4.	3.2	30	Per 40 CFR 98.449, active monitoring area is defined 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. While the MRV plan defines the AMA, please provide further explanation of whether the AMA meets the definitions in 40 CFR 98.449. For example, please define year t in the MRV plan. The length of each monitoring period can be any time interval chosen by you that is greater than one year, per 40 CFR 98.448(a)(1).	Year t is defined as 2054. This has been added to the MRV plan on Page 30.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	3.3	30	Per 40 CFR 98.449, maximum monitoring area 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. While the MRV plan defines the MMA, please provide further explanation of whether the MMA meets the definitions in 40 CFR 98.449. For example, please specify whether the area is expected to contain the free phase CO₂ plume once it has stabilized as required in the above definitions. Furthermore, please state in the MRV plan when the CO₂ plume is expected to stabilize.	The free-phase CO ₂ will be contained by the geologic limits of the reservoir and therefore will stabilize within the MMA following year t and prior to year t + 5. Stabilization will be measured and demonstrated with pressure monitoring until at least the end of year t + 5. Explanatory edits have been made to Section 3.3 (Page 30).
6.	5.2	42	“While groundwater contamination is unlikely to happen, any change in groundwater that is brought to the attention of Daylight will be investigated to eliminate the potential leakage pathway.” Please clarify whether there are groundwater wells in the monitoring area and characterize the likelihood, magnitude, and timing of potential leakage through groundwater wells in section 4.0 as necessary.	Approximately 85 shallow groundwater wells are in the AMA, per the Oklahoma Water Resources Board General Viewer . The deepest well is 360 feet, ~8,000 feet above the reservoir. Therefore, the likelihood of leakage via shallow groundwater wells is low. Daylight will test a groundwater well within the AMA on an annual basis to provide additional monitoring for potential leakage. To clarify, a paragraph has been added to Page 31, and Table 3 on Page 37 has been amended.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
7.	6.4	45	“As required by 98.448 (d) of Subpart RR, Daylight will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO₂ stream, for facilities that conduct CO₂-EOR operations.” This discussion of surface equipment occurs in conjunction with mention of Equation RR-10, which is specific to surface leakage. We recommend revising this section to clarify that surface leakage (CO_{2E}) and leakage from equipment and vented emissions (CO_{2FI} and CO_{2FP}) are separate terms in equation RR-11 and are calculated differently.	Clarification note added to Section 6.4 (Page 45).
8.	7.0	46	“Daylight expects to begin implementing this MRV plan after approval, or tentatively in 2026.” Please clarify whether the plan includes a “Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart” as required per 40 CFR 448(a)(7).	Daylight anticipates beginning data collection for Subpart RR reporting (calculating total amount sequestered according to Equation RR-11 of this subpart) in 2026 after the MRV plan is approved and a supply of fresh CO ₂ is secured. As such, this data collection would begin no later than 12/31/2026 for 2027 reporting. Clarification added to 7.0 (Page 46).

**Purdy-Bradley Springer Field:
Northeast Purdy Springer Unit (NEPSU) and
Southeast Bradley A Unit (SEBAU)**

Monitoring, Reporting, and Verification (MRV) Plan

**Daylight Petroleum, LLC
April 2025**

Contents

Introduction	1
1.0. Facility	2
1.1. Reporter Number	2
1.2. UIC Permit Class	2
1.3. UIC Injection Well Numbers	2
2.0. Project Description	2
2.1. Project Characteristics	2
2.1.1. Estimated Years of CO ₂ Injection	2
2.1.2. Estimated Volume of CO ₂ Injected Over Lifetime of Project	2
2.2. Environmental Setting of MMA	2
2.2.1. Boundary of the MMA	2
2.2.2. Geology	2
2.2.3. Hydrogeology	9
2.3. Description of the CO ₂ Injection Process	9
2.3.1. CO ₂ Collection and Distribution	12
2.3.2. Injection and Production Well Operations	12
2.3.3. Produced Fluids Handling and Gas Processing and Compression	12
2.3.4. Well Operations and Permitting	16
2.3.5. Number, Location, and Depth of Wells	17
2.4. Reservoir Description	17
2.4.1. Reservoir Characteristics	17
2.4.2. Reservoir Fluid Modeling	22
2.4.3. CO ₂ Analytical Sweeping Efficiency Calculation	22
2.4.4. CO ₂ -EOR Performance Projections	26
3.0. Delineation of Monitoring Area	30
3.1. Determination of CO ₂ Storage Volumes	30
3.2. Active Monitoring Area (AMA)	30
3.2.1. Determination of Buffer Zone	30
3.3. Maximum Monitoring Area (MMA)	30
4.0. Identification and Evaluation of Leakage Pathways	31
4.1. Leakage from Surface Equipment	31
4.2. Leakage from Wells	31
4.2.1. Abandoned Wells	31
4.2.2. Injection Wells	32
4.2.3. Production Wells	32
4.2.4. Inactive Wells	32
4.2.5. New Wells	32
4.3. Leakage from Faults, Fractures, and Bedding Plane Partings	34
4.3.1. Presence of Hydrocarbons	34

4.3.2.	Fracture Analysis.....	34
4.4.	Lateral Fluid Movement.....	34
4.5.	Leakage through Confining/Seal System.....	34
4.6.	Natural and Induced Seismic Activity	35
4.7.	Likelihood, Timing, and Magnitude of Potential Surface Leakage	37
4.8.	Strategy for Detection of CO₂ Loss.....	38
4.8.1.	Data System	38
4.8.2.	Visual Inspections	38
4.8.3.	Injection Target Rates and Pressures	38
4.8.4.	Production Wells.....	38
4.8.5.	Continuous Plant and Pipeline Monitoring	39
4.8.6.	Well Testing.....	39
4.9.	Strategy for Response to CO₂ Loss.....	39
4.10.	Strategy for Quantifying CO₂ Loss.....	41
4.11.	Demonstration at End of Specified Period	41
5.0.	Strategy for Determining CO₂ Baselines for CO₂ Monitoring	42
5.1.	Site Characterization and Monitoring.....	42
5.2.	Groundwater Monitoring.....	42
5.3.	Soil CO ₂ Monitoring	42
5.4.	Visual Inspection	42
5.5.	Well Surveillance	43
5.6.	Injection Well Rates, Pressures, and Volumes.....	43
6.0.	Site-Specific Considerations for Determining the Mass of CO₂ Sequestered	43
6.1.	Determining Mass of CO ₂ Received	43
6.2.	Determining Mass of CO ₂ Injected.....	44
6.3.	Determining Mass of CO ₂ Produced from Oil Wells	44
6.4.	Determining Mass of CO ₂ Emitted by Surface Leakage	45
6.5.	Determining Mass of CO ₂ Sequestered	45
7.0.	Estimated Schedule for Implementation of MRV plan	46
8.0.	GHG Monitoring and Quality Assurance Program	46
8.1.	GHG Monitoring	46
8.1.1.	General	46
8.1.2.	CO ₂ Received	47
8.1.3.	CO ₂ Injected.....	47
8.1.4.	CO ₂ Produced	47
8.1.5.	CO ₂ Emissions from Equipment Leaks and Vented Emissions of CO ₂	47
8.1.6.	Measurement Devices	47
8.2.	QA/QC Procedures	48
8.3.	Estimating Missing Data	48
8.4.	Revisions to the MRV plan	48
9.0.	Records Retention	49

List of Figures	50
List of Tables	50
Appendix 1 – List of Wells	51
Appendix 2 – References	52
Appendix 3 – Abbreviations and Acronyms	54
Appendix 4 – Conversion Factors	56
Appendix 5 – Koval Factor Calculation	57
Appendix 6 – Muskat Model Description	58

Introduction

Daylight Petroleum, LLC (Daylight) operates the Northeast Purdy Springer Unit (NEPSU) and Southeast Bradley A Unit (SEBAU), collectively referred to as the Purdy-Bradley Springer Field, in south-central Oklahoma for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO₂) flooding on the behalf of PBMS Oil, LLC. As a secondary purpose, Daylight intends to establish secure geological storage (sequestration) of a measurable quantity of CO₂ in subsurface geologic formations at the Purdy-Bradley Springer Field. Daylight intends to continue CO₂-EOR operations until the end of economic life of the field, with the subsequent goal of long-term storage of CO₂ in geologic formations (sequestration).

Daylight has developed this Monitoring, Reporting, and Verification (MRV) Plan in accordance with 40 Code of Federal Regulations (CFR) 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in Section 45Q of the Internal Revenue Code. Daylight intends to implement this MRV plan for both NEPSU and SEBAU, and upon merging of the facilities in the United States Environmental Protection Agency (USEPA) system will begin reporting under a single identification number.

This MRV Plan contains nine sections:

Section 1 – General facility information.

Section 2 – Project description. Contains details of the injection operation, including duration and volume of CO₂ to be injected; a description of the geology and hydrogeology of the Purdy-Bradley Springer Field; and a description of the injection reservoir assessment techniques.

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

Section 4 – Evaluation of potential surface leakage pathways for CO₂ in the MMA as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP. A strategy is proposed for detecting, verifying, and quantifying any surface leakage of CO₂ as required by 40 CFR 98.448(a)(3), Subpart RR of the GHGRP. Other than wellbores and surface equipment, the risk of CO₂ leakage through identified pathways is demonstrated as minimal.

Section 5 – Strategy for monitoring to identify CO₂ surface leakage, including establishment of baselines to assess for potential leaks and the proposed monitoring process, as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP. Monitoring will focus primarily on identifying potential leaks through wellbores and surface equipment.

Section 6 – Summary of the mass balance calculations and site-specific variables used to determine the volume of CO₂ sequestered as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 7 – Estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 8 – Quality assurance and quality control procedures to ensure data integrity.

Section 9 – Program for records retention as required by 40 CFR 98.3(g), Subpart A of the GHGRP, and 40 CFR 98.447, Subpart RR of the GRGRP.

Appendices with supplemental data are provided at the end of this document (Appendix 1 includes an attachment).

1.0. Facility

1.1. Reporter Number

The facility identifiers are 545261 for NEPSU and 545263 for SEBAU.

1.2. UIC Permit Class

The EOR wells covered by this MRV Plan are permitted and operated as Class II Underground Injection Control (UIC) wells under the jurisdiction of the Oklahoma Corporation Commission (OCC), which has primacy for administering Class II UIC regulations in the state.

1.3. UIC Injection Well Numbers

A list of all wells (including injection wells) in the NEPSU and SEBAU is provided as part of **Appendix 1**. Wells are identified by name, unique well identifier (UWI, using a 14-digit American Petroleum Institute [API] number), status, and type. The list is current as of January 2025, around the time this MRV Plan was created.

2.0. Project Description

2.1. Project Characteristics

2.1.1. Estimated Years of CO₂ Injection

CO₂ has been injected at the NEPSU since 1982 and at the SEBAU since 1997. Daylight intends to continue injecting CO₂ for the foreseeable future.

2.1.2. Estimated Volume of CO₂ Injected Over Lifetime of Project

Historical and forecasted cumulative CO₂ retention capacity is up to approximately 278 billion standard cubic feet (Bscf), or 14.7 million metric tons (MMT), from the start of CO₂ injection through March 2054.

2.2. Environmental Setting of MMA

2.2.1. Boundary of the MMA

Daylight has defined the boundary of the MMA as equivalent to the boundaries of the NEPSU and SEBAU plus a minimum of a half-mile buffer. A discussion of the methods used in delineating the MMA and the AMA is presented in **Section 3**.

2.2.2. Geology

This geologic description of the Purdy-Bradley Springer Field incorporates regional literature, field development studies, core and well log data, and the interpretations of Daylight, legacy operators, laboratories, and service companies.

Tectonic and Structural Setting

The Purdy-Bradley Springer Field is located within the Golden Trend of South-Central Oklahoma, in

the southeastern embayment of the Anadarko Basin (**Figure 1**). The Anadarko Basin contains up to 40,000 feet of sedimentary rock and is a prolific hydrocarbon producer (Ball, Henry, and Frezon, 1991). This asymmetrical foreland basin is structurally deepest along its southern margin and is separated to the south and southeast from Cambrian-age crystalline rocks exposed in the Wichita Mountains (Ham et al., 1964; Perry, 1989). In updip areas, particularly around structural features that define the basin margins, sedimentary units are commonly truncated by onlap or erosion.

Structural development of the Anadarko Basin was preceded by crustal extension in the Precambrian and formation of the southern Oklahoma aulacogen, or failed rift, during the Cambrian (Perry, 1989). At the end of rifting, the aulacogen cooled and subsided, creating a trough that was filled with Cambrian through lower Mississippian sediments. The Anadarko Basin developed on the northwestern flank of this trough during the late Mississippian through Pennsylvanian as a result of the Wichita Orogeny. During the orogeny, the Wichita and Arbuckle mountains were uplifted and thrust over the southern margin of the trough, causing renewed subsidence and creating the Anadarko Basin. Faulting and uplift associated with the Wichita-Arbuckle structural trend peaked in the early Pennsylvanian and had mostly ended by Permian time (Ball, Henry, and Frezon, 1991).

Producing structures in the Anadarko Basin range from complex combinations of folds and fault blocks to simpler, homoclinally dipping sediment wedges that form stratigraphic traps through erosion or facies change. The Golden Trend, which is bounded by the Nemaha-Pauls Valley uplifts on the east and by the Arbuckle Mountains to the south, produces hydrocarbons from Ordovician through Permian-age rocks (Swesnick, 1950). The NEPSU and SEBAU are two of numerous Pennsylvanian-age reservoirs formed by tilting and truncation. These units produce from the Cunningham Sandstone in the upper part of the Springer series, with shales of the upper Springer, Morrow, and Atoka series providing seal. Uplift of the Pauls Valley arch in late Springerean or early Morrowan time (Pennsylvanian) resulted in erosion of the southwest flank of the structure as Springer sands were tilted to the southwest, creating a stratigraphic trap below the unconformity.

Stratigraphy

A generalized basin stratigraphy applicable to the Purdy-Bradley Springer field area is shown in **Figure 2** and summarized below. Stratigraphic units are listed from oldest to youngest (adapted from Ball, Henry, and Frezon, 1991, except as noted):

- Granite wash and sandstone overlying igneous basement rocks
- Arbuckle Group (Cambrian to Ordovician) – Interior platform carbonates and tidal-flat mudstones; porous dolomite is common in the Western Anadarko basin, while tight facies are more common in the eastern basin.
- Simpson Group (Ordovician) – Erosionally truncated sandstones sealed by overlying Pennsylvanian shales
- Viola Limestone (Ordovician) – Dense limestone, locally dolomitized
- Hunton Group (Silurian-Devonian) – Fractured and dolomitized carbonates sealed and sourced by the overlying, organic-rich Woodford Shale
- Kinderhook, Osage, and Meramec Series (Mississippian) – Fractured limestones that shale out basinward; deposition followed by uplift and erosion resulting from the Wichita Orogeny

- Springer Group (Pennsylvanian – Springerean series) – Deltaic and shallow marine sands deposited during a marine regression, with potential reservoirs including feeder channels, upper-fan channels, middle-fan channels and sheet sands, and distal-fan sheet sands. The section reaches a maximum total thickness of 6,000 feet, though sands are on the order of tens to more than 100 feet thick, with dark shales comprising the remaining thickness. In the NEPSU and SEBAU, the Cunningham Sandstone in the upper Springer series is the historical and current production target.
- Dornick Hills Group (Pennsylvanian – Morrowan and Atokan series) – Mostly transgressive shales with sandstones (e.g., Primrose) deposited during brief regressions
- Deese Group (Pennsylvanian – Des Moinesian series) – Shales and sands (e.g., Osborne and Hart) derived from erosion of uplifted crystalline basement rocks, primarily forming stratigraphically trapped reservoirs
- Hoxbar Group (Pennsylvanian – Missourian series) – Shales and limestones (e.g., Hogshooter and Checkerboard)
- Pontotoc Group (Permian) – Conglomerates, sandstones, and mudstones
- Sumner Group (Permian) – Garber-Wellington interval consisting of sandstones, shales, and conglomerates
- Hennessey Formation (Permian) – Shale with red siltstones and very fine-grained sandstones; one of two bedrock units, along with the Duncan Sandstone of the El Reno Group, that are present at surface within the Purdy-Bradley Springer Field (Chang and Stanley, 2010)
- El Reno Group (Permian) – Duncan Sandstone and undifferentiated sandstone and shale, present at surface within the Purdy-Bradley Springer Field (Chang and Stanley, 2010)
- Alluvium (Holocene) – Clay, silt, sand, and gravel deposited in channels and on floodplains of modern streams (Chang and Stanley, 2010)

NEPSU Reservoir

The Lower Pennsylvanian Cunningham Sandstone, historically referred to as the Springer “A” sand, was deposited in shallow marine settings and consists of southwest-dipping, fine- to medium-grained siliceous sandstone (Cities Service Company, 1978; Fox et al., 1988). Within the reservoir are two lower zones deposited as bar sands on a shallow marine shelf and two upper zones consisting of channel sands.

The reservoir trends northwest-southeast and is approximately 9 miles long and 1-3 miles wide, comprising 15.6 square miles or ~10,000 acres (NEPSU, 1979). Reservoir and unit boundaries were established by erosional truncation of the Cunningham Sandstone and the original oil-water contact (Cities Service Company, 1978). The sands dip approximately 8 degrees to the southwest, and legacy core analysis showed the presence of “tight” layers within the clean sand reservoir (NEPSU, 1979). The reservoir is at a depth of about 8,000-9,000 feet, has an average porosity of 13% and permeability of 44 millidarcies (mD), and had an average initial water saturation of 18%.

Mineralogy is primarily quartz, with limited calcitic cements in shalier intervals and kaolinite, illite, and smectite within the clay fraction. These clay minerals are believed to remain stable under

reservoir conditions.

SEBAU Reservoir

The geologic and reservoir properties of the SEBAU are similar to those of the NEPSU. In this unit the Springer strata were deposited in shallow marine tidal bar and channel settings (Oxy, 1998). Fine- and medium-grain sand with shale laminations and dominantly clay cements comprise the primary reservoir facies of the Cunningham Sandstone. A high degree of vertical and lateral facies heterogeneity is present as a result of shoreline deposition. Upper, middle, and lower flow units are recognized, truncated by faults to the south and west and stratigraphic pinch-outs and erosional surfaces to the northeast. The upper sand, usually the only productive flow unit, is 25-200 feet thick and 8,900-10,800 feet deep. Porosity averages 12.5% and permeability is 58 mD (Oxy, 1988). Permeability-porosity relationships are inconsistent in part because of reservoir heterogeneity.

Primary Seals

Reservoirs of the Springer are sandstone bodies that have lateral porosity and permeability variations and are encased in shale (Ball, Henry, and Frezon, 1991). At the Purdy-Bradley Springer Field, the Cunningham Sandstone is sealed by shales of the upper Springerean and Morrowan series that directly overlie the reservoir unit and by truncation against the base Atoka unconformity. The Cunningham is tilted and eroded below the unconformity. Above the unconformity, the Cunningham is sealed by shales of the lower Atokan series.

Well Log Analysis

A reference petrophysical well log (SE Bradley A Unit O-19A) through the reservoir and overlying shales is shown in **Figure 3**. In this well, the Cunningham Sandstone is approximately 50 feet thick, with an approximate porosity range of 10-20% as estimated from the sonic (SPHI), neutron (NPHI), and density porosity (DPHI) logs. A permeability response in the sands is also observed in the deflection of the spontaneous potential (SP) log. These reservoir sands (yellow shade on the gamma ray [GR] log) are truncated just below the unconformity and are overlain by an estimated 170 feet of net shale (brown shade on GR log) within the Osborne section, providing separation and confinement from the Hart sandstones above. Within the Hart are another 110 feet of net shale, and as previously shown in **Figure 2** additional shales overlie the Hart section. Daylight's broader review of well logs in the field shows total net shale thickness above the Cunningham exceeds 1,200 feet, which is sufficient to prevent vertical migration of CO₂ and other fluids to the surface or into underground sources of drinking water (USDWs).

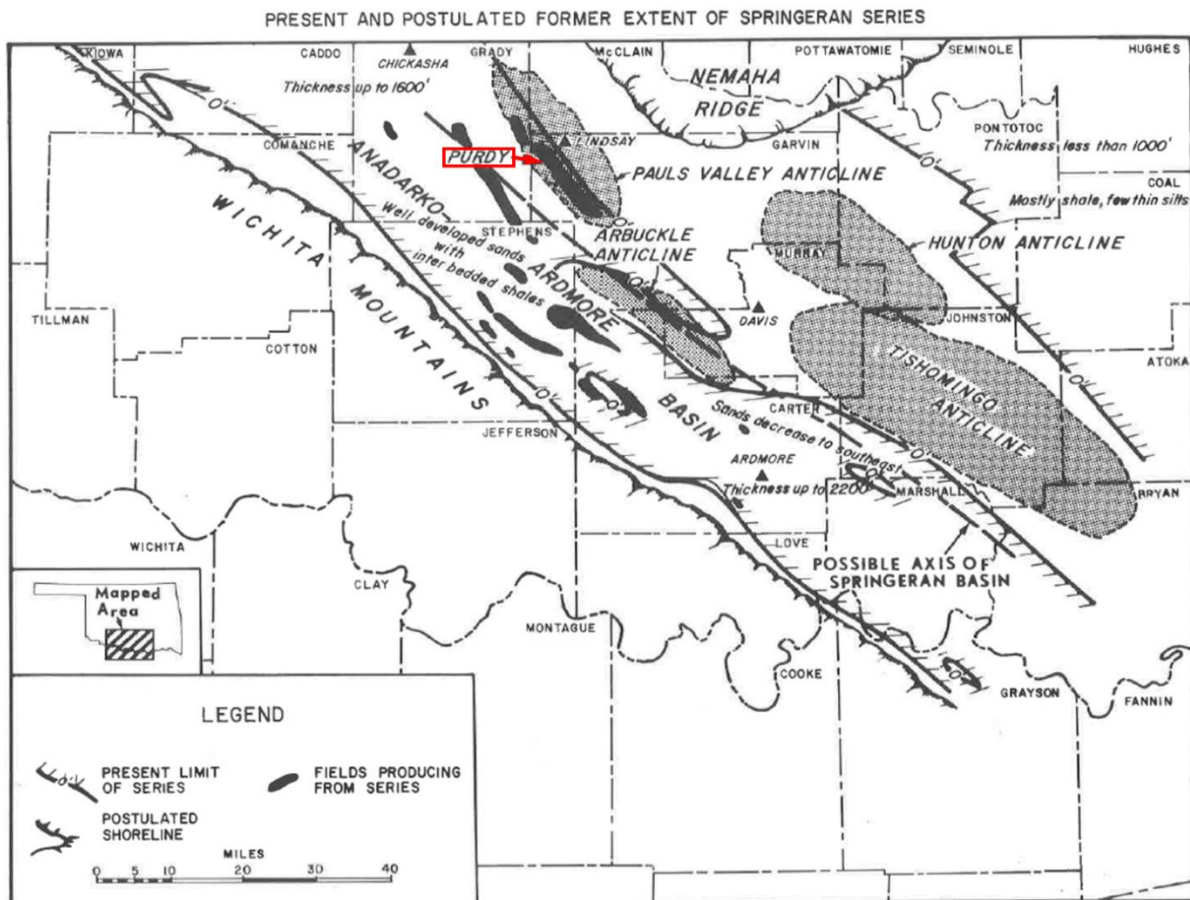
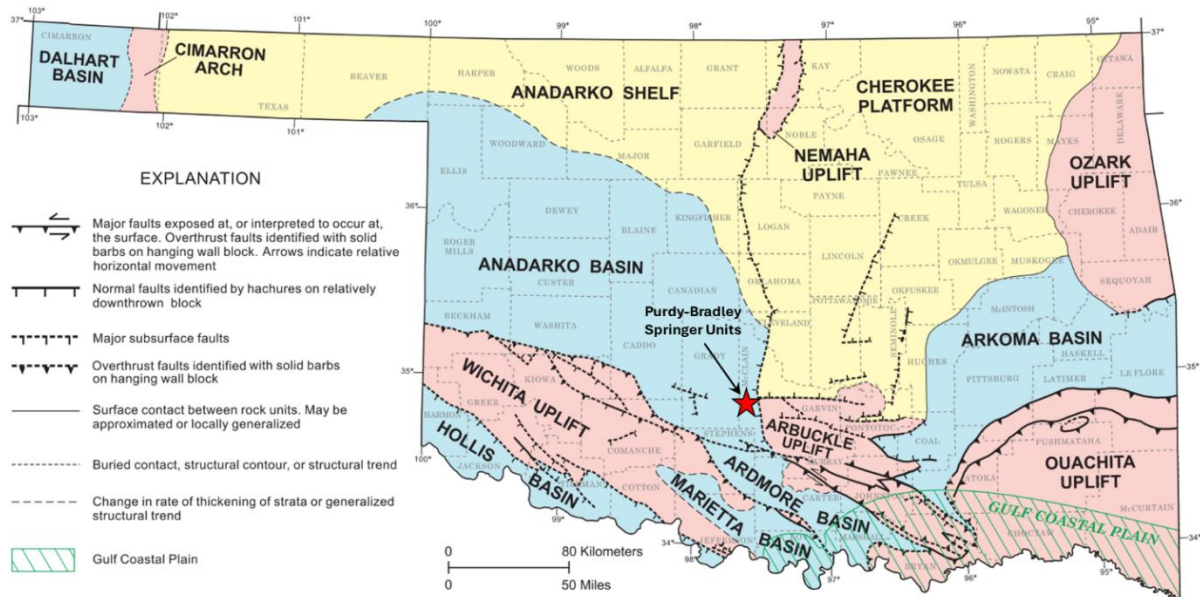


Figure 1: Top panel shows the location of the Purdy-Bradley Springer Field in the Anadarko Basin, South-Central Oklahoma, and proximity to major structural features (adapted from Johnson and Luza, 2008). Bottom panel shows the field location in relation to smaller-scale structures, the extent of the Springer series, and the locations of other Springer fields in the Anadarko-Ardmore basin trend (adapted from Cities Service Company, 1978).

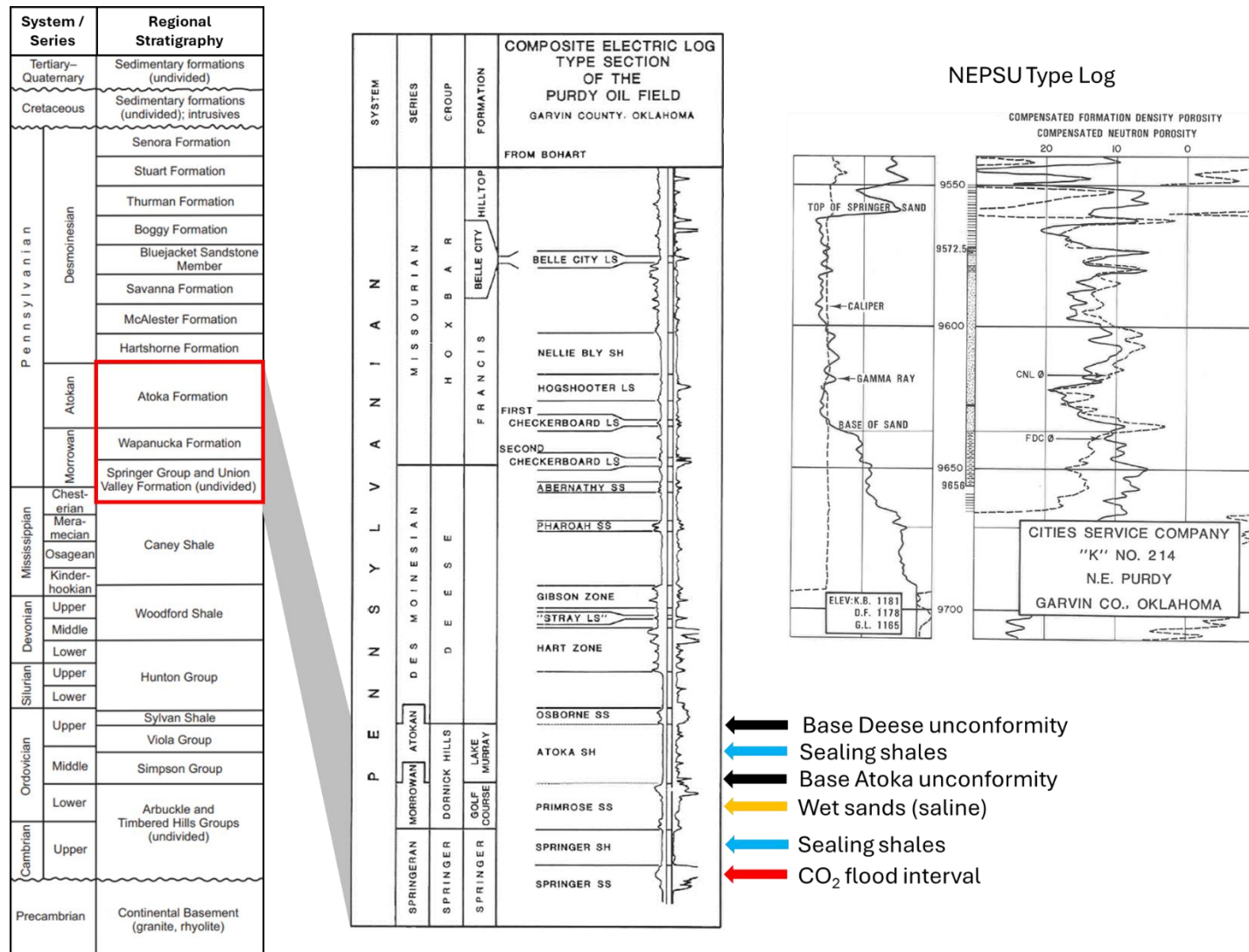


Figure 2: Regional stratigraphic column (left) shows the ages and names of sedimentary rock units in the Anadarko Basin from basement to surface. Center chart shows the type section for the Purdy-Bradley Springer Field and relation to the regional stratigraphy; colored arrows identify key units and surfaces in the Purdy-Bradley Springer Field. Note the multiple shale layers that serve as sealing units for the Springer (Cunningham Sandstone) reservoir. At right is the type log for the Northeast Purdy Springer Unit (NEPSU) reservoir, showing porosity (average ~12%) and gamma ray well log response in the Cunningham Sandstone.

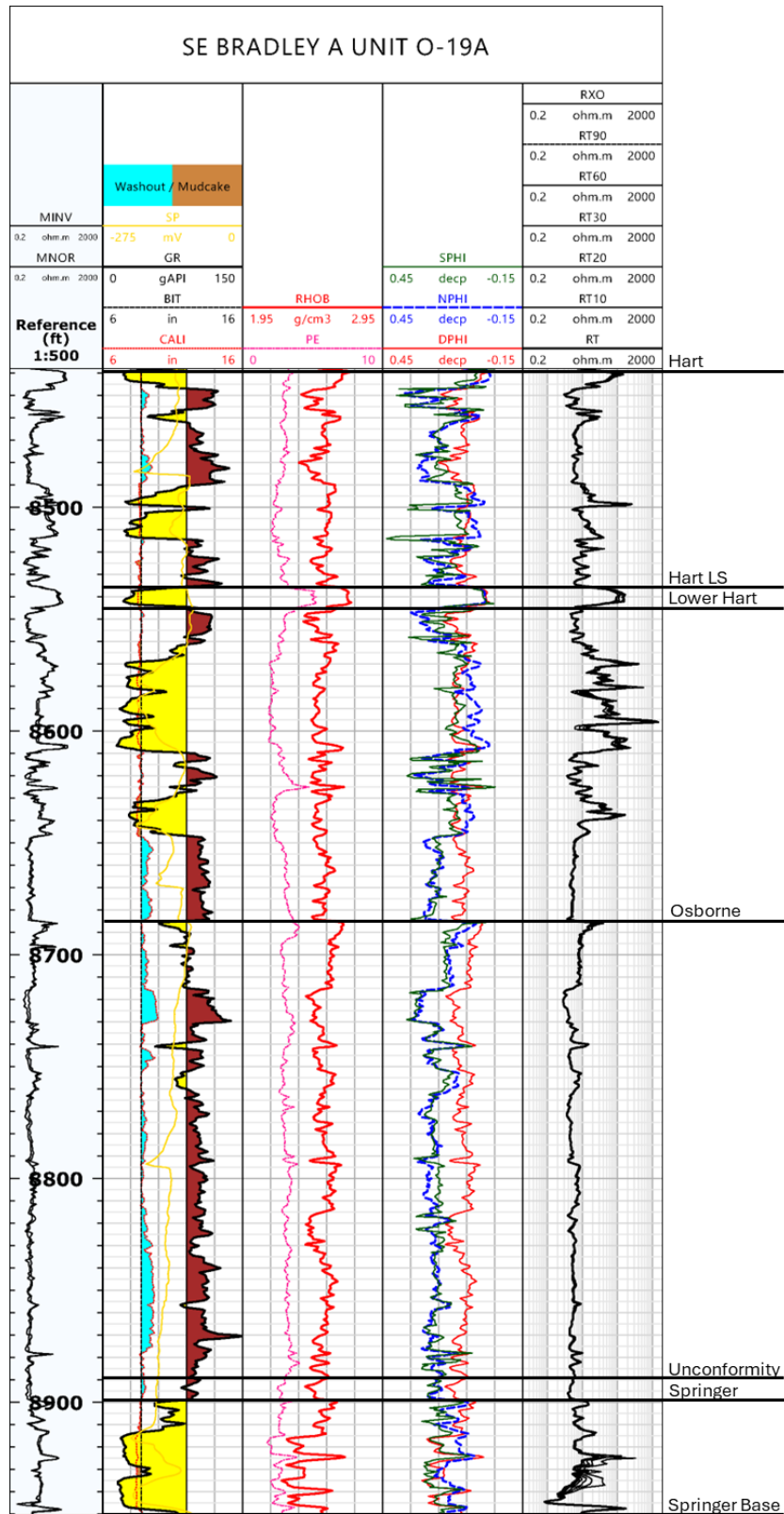


Figure 3: Type log showing the Cunningham Sandstone (at ~8,900-8,950 feet in the Springer reservoir) and overlying shales (seal). The well is located in the SE 1/4 of Section 7, T4N, R4W (API: 3504925047).

2.2.3. Hydrogeology

Groundwater flow rates in confined deep Anadarko layers are considered to be low-flow to no-flow, based on four lines of evidence presented by Nelson and Gianoutsos (2014). First, recharge of groundwater into Pennsylvanian and older strata is limited due to the presence of a low-permeability Permian cap. Second, stratigraphic pinch-outs establish a western limit of recharge. Third, highly saline formation water along the Nemaha uplift creates a west-to-east flow density barrier. Lastly, fluid movement is restricted by overpressured strata in the deep basin.

Further evidence of stratigraphic pinch-out that is more specific to the NEPSU and SEBAU is documented in internal studies developed by previous operators, including a geologic and reservoir description (Oxy, 1988) and a feasibility analysis of applying EOR methods (Cities Service Company, 1978). The SEBAU is isolated by faults to the south and west and pinched out or erosionally truncated to the northeast, while the NEPSU is bounded to the north by erosional truncation and to the southwest by a fault. Jorgensen (1993) suggested that, beginning during the Laramide Orogeny and continuing to present, the groundwater flow is west to east, driven by recharge at elevated units to the west. The NEPSU and SEBAU CO₂ injection and production operations therefore are considered unlikely to cause water to flow to the outcrops.

Groundwater is generally at shallow depths, with the base of treatable water approximately 100-300 feet deep (**Figure 4**). In Oklahoma, the base of treatable water is equivalent to the deepest USDW. The base of treatable water depth is relatively consistent throughout the MMA, deepening to the west and south of the MMA. The shallow base of treatable water provides upward of 8,000 feet minimum vertical separation from the Purdy-Bradley Springer Field injection interval.

2.3. Description of the CO₂ Injection Process

Figure 5 shows a simplified flow diagram of the CO₂-EOR operations within the boundaries of the NEPSU and SEBAU. Historically, a fertilizer plant in Enid, Oklahoma, has been the only source of CO₂, with CO₂ captured from the plant delivered via a Daylight-operated pipeline to the field for injection. No new CO₂ has been received since 2022, but Daylight anticipates securing additional sources of new CO₂ in future years.

Currently, the CO₂-EOR operations involve three main processes. These processes are detailed in the subsections below and include:

1. **CO₂ distribution and injection.** Purchased CO₂ (when applicable) is combined with recycled CO₂ obtained from the produced gas stream and sent through the main CO₂ distribution system to various water alternating gas (WAG) injectors.
2. **Injection and production well operations.** As of January 2025, 23 injection and 36 production wells were active in the SEBAU, and 69 injection and 88 production wells were active in the NEPSU. Production is a mixture of oil, water, and CO₂ or other gases.
3. **Produced fluids handling and gas processing and compression.** Produced fluids and gases flow to satellite batteries and/or centralized tank batteries for separation. The gas phase is transported via a field gathering system to the Lindsay Gas Plant for further gas processing to dehydrate and remove natural gas liquids and hydrocarbon fuel gas. The separated CO₂ gas stream is returned to the field via a CO₂ gas distribution system for compression and injection to the producing reservoir.

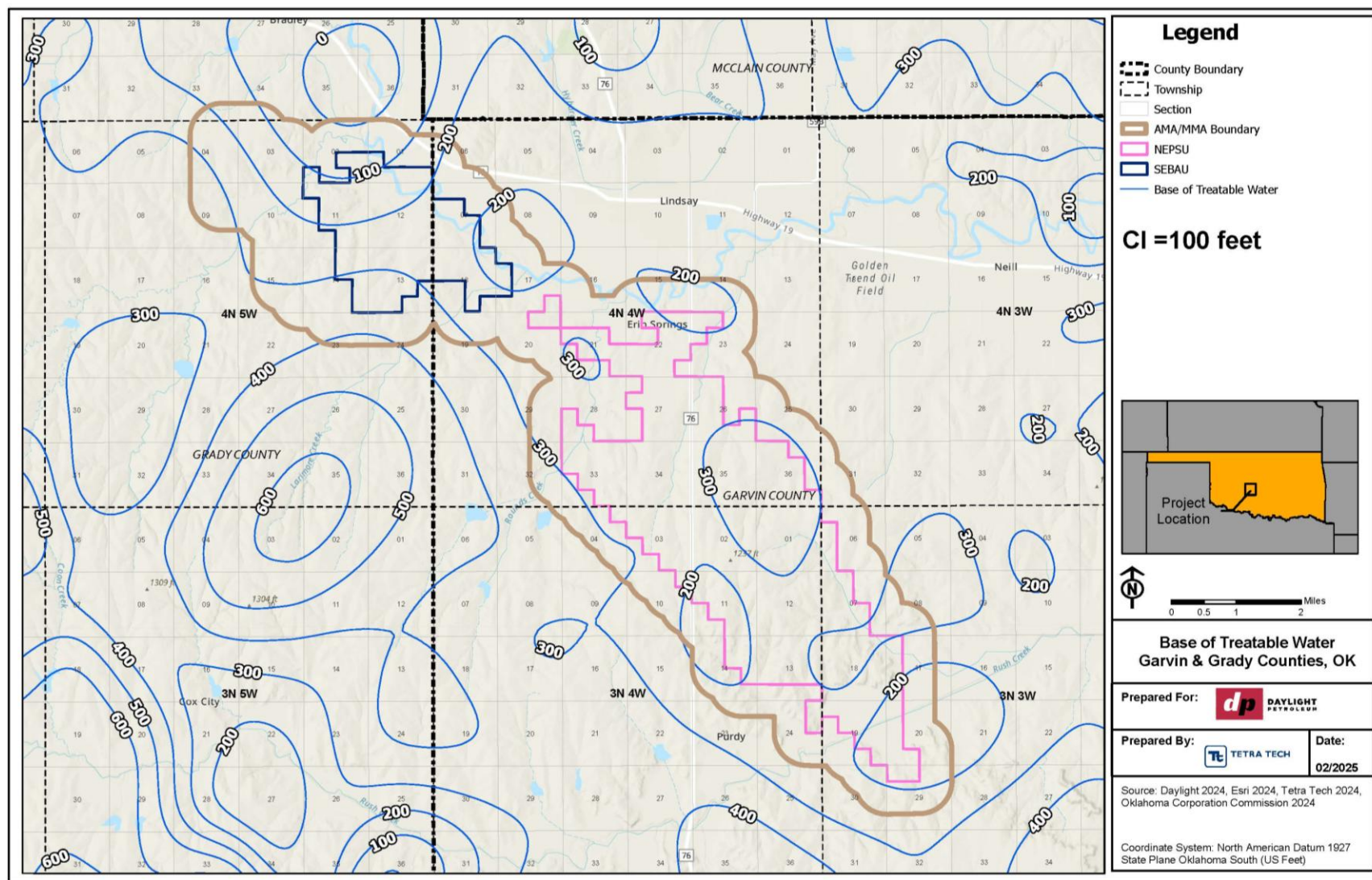


Figure 4: Depth (feet) to base of treatable water

Satellites provide 3 phase separation and testing for the producers, they also hold compression and H Pumps for reinjection of Processed Gas (from Plant) and Water (separated on site)

EOR Summary

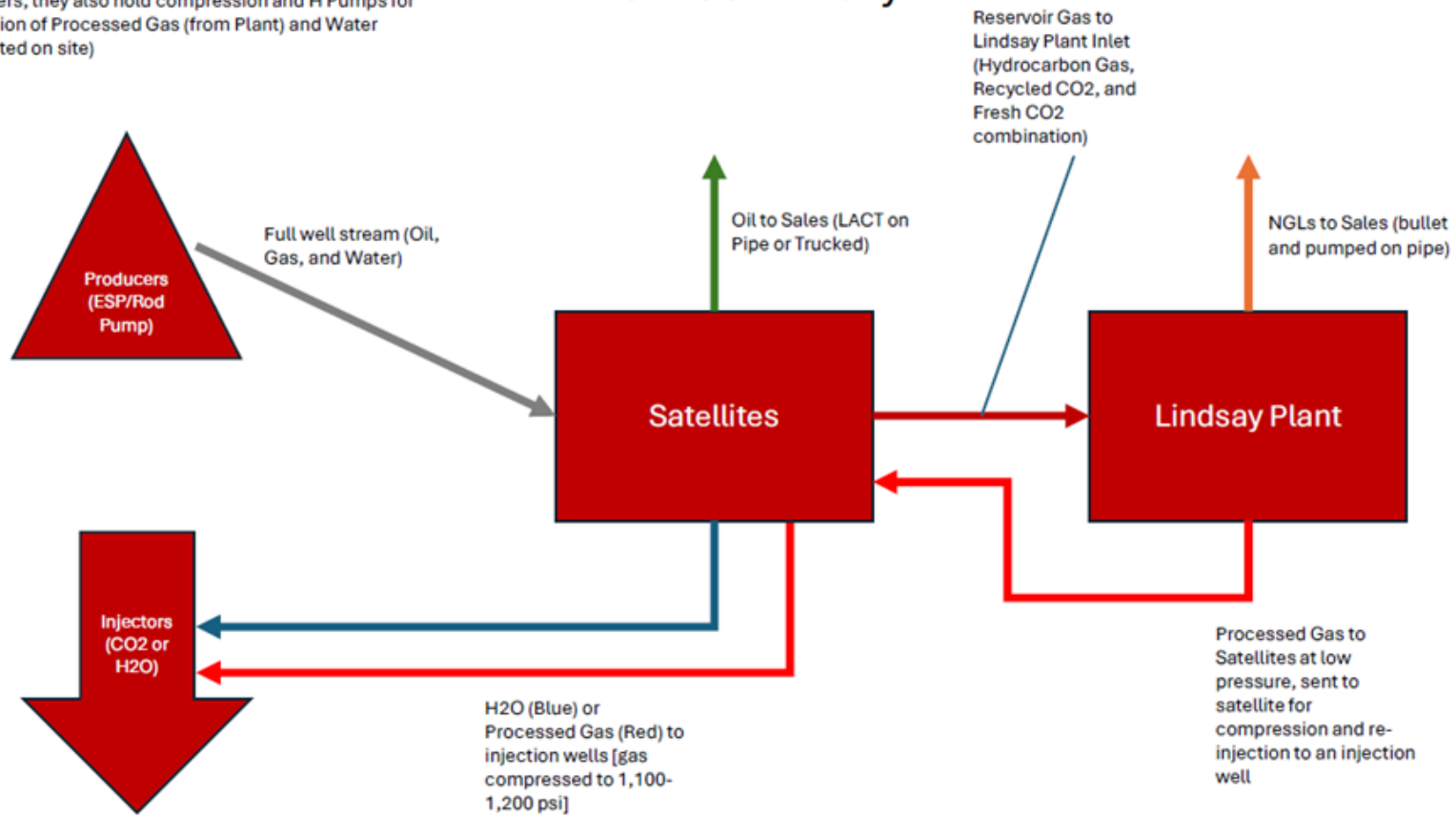


Figure 5: Simplified flow diagram of the CO₂-EOR operations within the Purdy-Bradley Springer Field

2.3.1. CO₂ Collection and Distribution

The CO₂ delivered to the NEPSU and SEBAU is supplied by one or more sources. Historically, new CO₂ delivered from the fertilizer plant was sent through an injection pipeline distribution system to CO₂ injection wells throughout the two units. Produced (recycled) CO₂ is received from Daylight's Lindsay Gas Plant, which extracts natural gas liquids (NGLs) from the produced gas stream (consisting of CO₂ and hydrocarbon gas). The produced gas stream is transported to the Lindsay plant via gathering lines. The gas compression process consists of gathering CO₂ and other produced gases, processing an NGL stream that is sold via pipeline at the plant, and sending CO₂ back out to satellites for compression and reinjection into the injection wells. The CO₂ collection and distribution process is illustrated in **Figure 6**.

Currently, CO₂ delivered to the floods for injection is received through many meters, including at the Purdy Tee delivery point, the source receipt point, the plant outlet, the recycle CO₂ source point, and at each injection well. All CO₂ that flows through the meters is sent through CO₂ injection lines to individual injection wells in the floods, in many instances through manifolds and distribution lines prior to arriving at an injection well. A flow meter at each injection well measures the injection rate of the CO₂ or water. Currently, for any given CO₂ injection well, the CO₂ injected may be sourced from the CO₂ pipeline, the Lindsay plant, or a combination of both. The ratio of CO₂ sources is expected to fluctuate over the course of time.

2.3.2. Injection and Production Well Operations

As of January 2025, 23 injection and 36 production wells were active in the SEBAU, and 69 injection and 88 production wells were active in the NEPSU. Currently, each injection well can inject CO₂, water, or both, at various rates and injection pressures, as determined by Daylight. Upon injection of CO₂ or water into the reservoir, a mixture of oil, water, CO₂ and/or other gases (collectively, produced fluids) is mobilized toward and produced at one or more production wells.

2.3.3. Produced Fluids Handling and Gas Processing and Compression

The produced fluids handling system gathers fluids from the production wells throughout various satellite batteries in the units, via gathering lines that combine, collect, and commingle the produced fluids. The mixture of produced fluids (oil, water, and gas including CO₂) flows to one of 10 satellite separation facilities or batteries and then to a centralized tank battery. Each satellite is equipped with well test equipment to measure production rates of oil, gas, and water from individual production wells.

The fluids stream is further separated into oil and water, which is recovered for reuse, re-injection, or disposal. The produced fluids handling process is illustrated in **Figure 7**. Produced oil is sold via truck or through one or more lease automatic custody transfer (LACT) units located at centralized tank batteries. The gas stream, consisting of CO₂ and other gases, is transported to the Lindsay plant via gas gathering lines throughout the fields.

The produced gas compression process (**Figure 8**) consists of gathering CO₂ and other gases produced from the floods, processing an NGL stream that is sold via pipeline at the plant, and sending CO₂ back to satellite compression for reinjection into the injection wells. The average gas mixture composition is ~82-90% CO₂, with the remaining portion comprising hydrocarbons and trace nitrogen (N₂). Future plant modifications would be intended to produce a higher-quality fuel gas stream for use on-site that would also result in a higher-quality CO₂ stream for sequestration. The CO₂ concentration is likely to change over time as CO₂-EOR operations continue and expand.

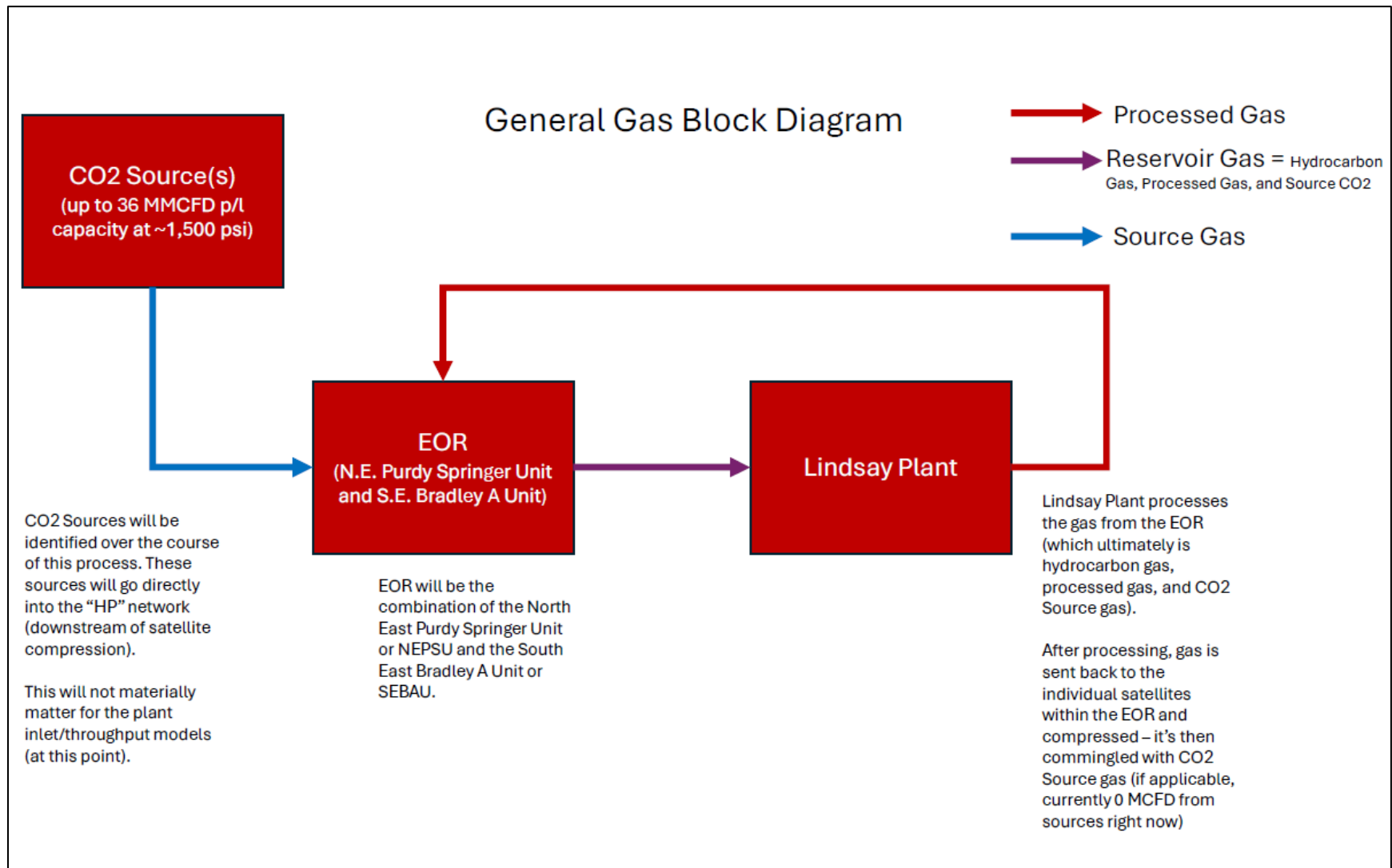


Figure 6: CO₂ collection and distribution process

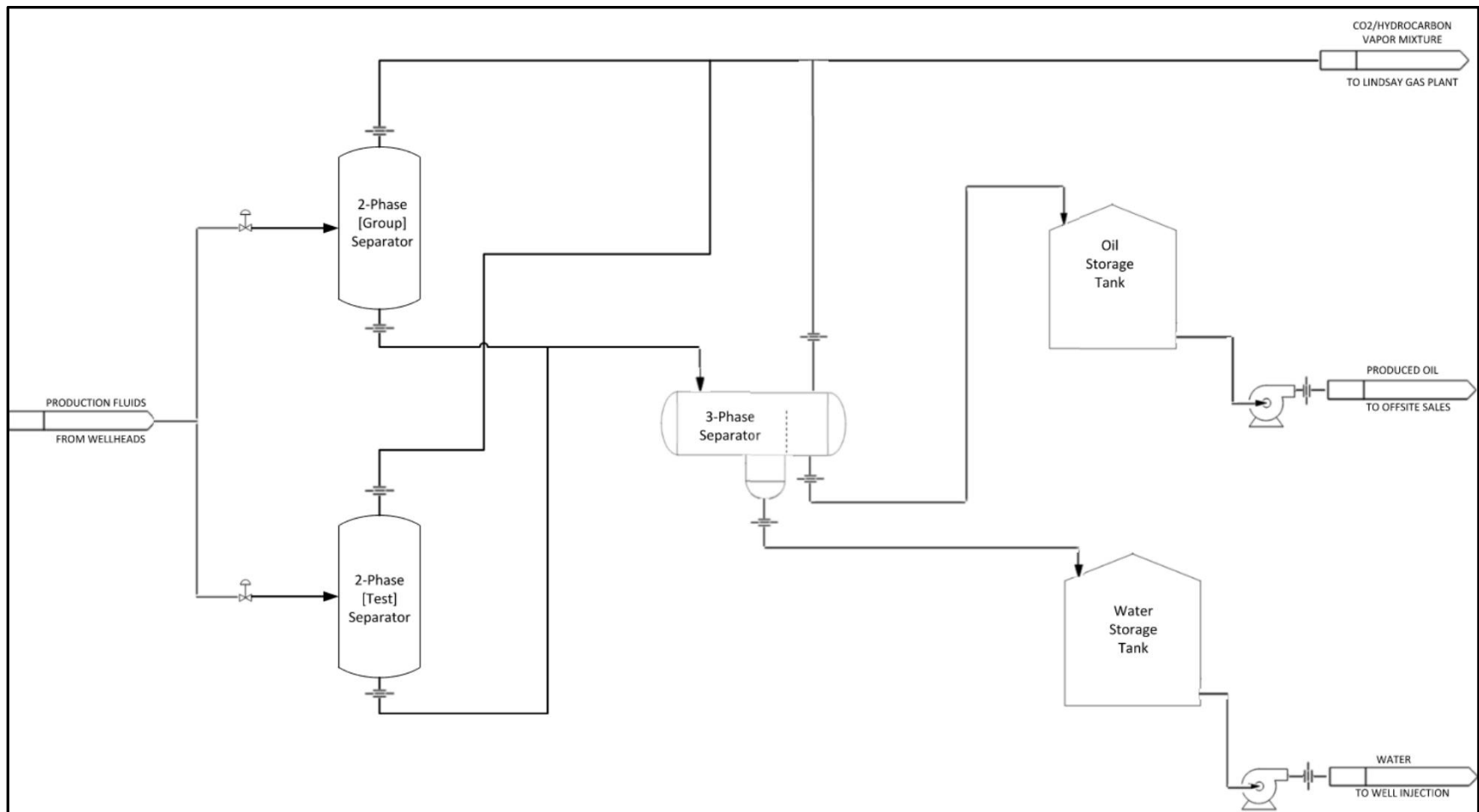


Figure 7: Simplified fluids flow diagram for a typical NEPSU satellite

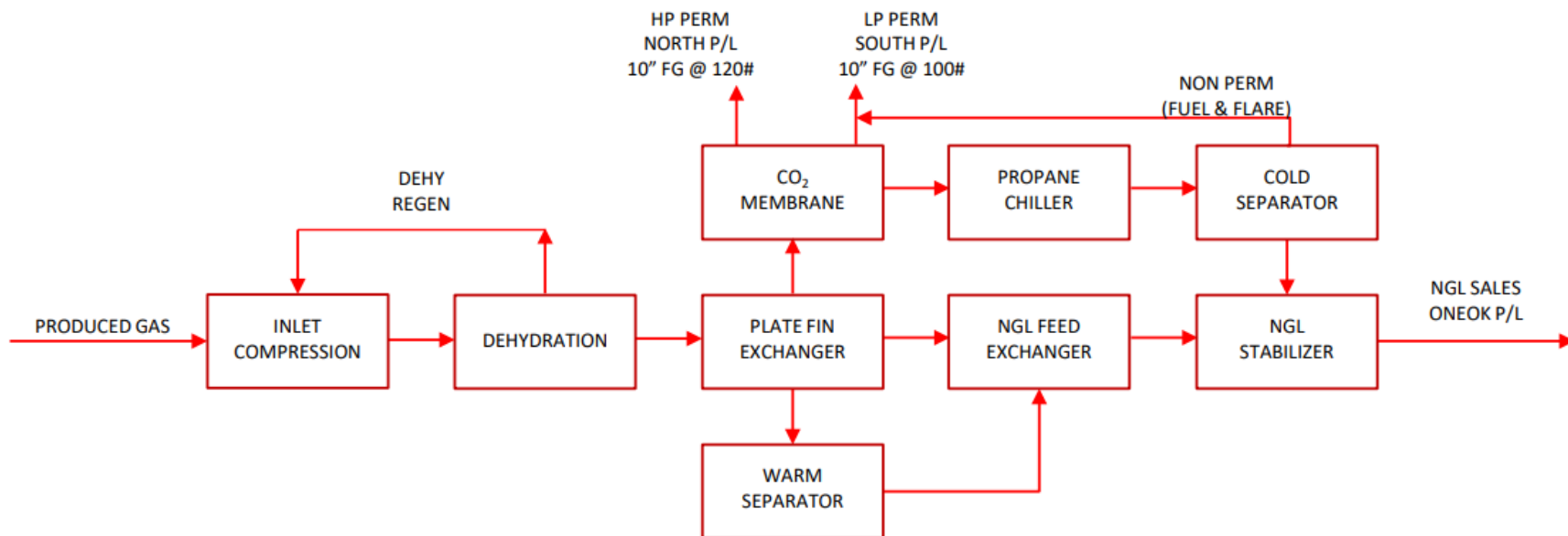


Figure 8: Process diagram for the Lindsay Gas Plant

2.3.4. Well Operations and Permitting

OCC regulations require that injection wells be completed and operated so that fluids are contained in the injection zone and that well operations do not pollute subsurface or surface waters (Oklahoma Administrative Code [OAC] §165:10-5-5 b4). Depending on the purpose of the well, regulatory requirements can impose additional standards.

CO₂ injection well permits are authorized only after approval of an application, public notice, and opportunity for a hearing. As part of the application process, Daylight establishes an Area of Review (AoR) that includes wells within the floods plus a one-quarter mile buffer. Pursuant to applicable regulations, all wells within the AoR that penetrate the injection interval are located and evaluated.

All active injection wells must undergo a periodic mechanical integrity test (MIT) per regulatory guidelines (per OAC §165:10-5-6), depending on various dates and activities associated with the well. MIT includes the use of a pressure recorder, pressure gauge, and testing of the casing-tubing annulus for a minimum amount of time at a minimum pressure, as specified in the approved well injection permit. In some instances, a radioactive tracer survey (RTS) is conducted, sometimes in combination with a pressure test, to ensure all fluids are being injected into the permitted zone.

Daylight has developed operating procedures based on its experience as a CO₂-EOR operator. Operations include developing detailed modeling at the EOR pattern level to guide injection pressures and performance expectations, leveraging Daylight's expertise in diverse disciplines to operate EOR projects based on specific site characteristics. Field personnel are trained to look for and address issues promptly and to implement corrosion prevention techniques, or to engage contracted parties for such services, to protect wellbores as needed.

Daylight's operations are designed to comply with the applicable regulations and to ensure that all fluids (including oil, water, and CO₂) remain in the units until they are produced through a Daylight-operated well. Well pressure in injection wells is monitored on a continual basis.

Individual well injection is guided by a pattern-level WAG program to govern the rate, pressure, and duration of water or CO₂ injection in accordance with regulatory requirements. Pressure monitoring of the injection wells flags pressures that significantly deviate from the plan. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such excursions occur, they are investigated and addressed. It is the company's experience that few excursions result in fluid migration out of the intended zone and that leakage to the surface is very rare.

In addition to monitoring well pressure and injection performance, Daylight uses the experience gained over time to strategically approach well maintenance and updating. Operations staff is in the field daily monitoring the performance of the units and plant, and a call-out system exists for any disruptions when staff is away from the field. Daylight uses all the information at hand, including pattern performance and well characteristics, to determine well maintenance schedules. Production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to a satellite battery. There is a routine cycle for each satellite battery, with each well being tested approximately once every 1-2 months. During this cycle, each production well is diverted to the well test equipment for a period of time sufficient to measure and sample produced fluids (generally 24 hours). This test allows Daylight to allocate a portion of the produced fluids measured at the satellite battery to each production well, assess the composition of produced fluids by location, and assess the performance of each well.

Performance data are reviewed on a routine basis to ensure that CO₂ flooding is optimized. If production is off plan, it is investigated and any identified issues addressed.

Leakage to the outside of production wells is not considered a major risk because of the reduced pressure in the casing. Field inspections are conducted on a routine basis by field personnel. Currently, Daylight has approximately 20 personnel in the field throughout the two units. Leaking CO₂ is very cold and leads to the formation of bright white clouds or dry ice, either of which is easily spotted. All field personnel are trained to identify leaking CO₂ and other potential problems at wellbores and in the field. Any CO₂ leakage detected will be documented and reported, quantified, and addressed as described in **Section 4** and **Section 6**. Continual and routine monitoring of wellbores and site operations will be used to detect leaks. Based on these activities, Daylight will mitigate the risk of CO₂ leakage through existing wellbores by detecting problems as they arise and quantifying any leakage that does occur.

2.3.5. Number, Location, and Depth of Wells

As of January 2025, Daylight operated 23 active CO₂ injection wells and 36 active production wells in the SEBAU, and 69 active CO₂ injection wells and 88 active production wells in the NEPSU. The depth of these wells is approximately 8,200-10,800 feet (Cunningham Sandstone). These wells are listed in **Appendix 1**.

2.4. Reservoir Description

2.4.1. Reservoir Characteristics

Generalized reservoir parameters are provided in **Table 1**. These were determined from data collection, interpretation, and studies performed by historical field operators and, more recently, Daylight in support of primary, secondary, and tertiary recovery operations.

Core, well log, and operational data suggest that reservoir properties for the NEPSU and SEBAU are largely similar. Routine core analysis and flow studies conducted in the Northeast Purdy K-214 well (Ekstrand, 1979) showed an average porosity of 10% and permeability of 14.8 mD. The effect of overburden was determined to reduce porosity by 3-10% (or less than 1 porosity percent) at typical net overburden pressures (approximately 7,000 psig). Additional legacy conventional core samples have been studied from nearly 30 NEPSU wells and approximately 23 SEBAU wells. Currently accepted permeability and porosity values are generally more optimistic than those seen in the K-214 core, at 13% porosity and 44 mD permeability in the NEPSU and 12.5-14% porosity and 50-58 mD permeability in the SEBAU.

As discussed earlier, the NEPSU and SEBAU are fault-bounded stratigraphic traps, with the Cunningham Sandstone having been tilted, eroded, and covered by subsequent deposition of shales above the base Atoka unconformity. The top structure of the Springer is mapped in **Figure 9**, the net pay thickness of Springer reservoir sands is mapped in **Figure 10**, and the trapping configuration is illustrated in **Figure 11**. The Cunningham Sandstone comprises primarily quartz framework grains and cements, with calcite cements in shaly intervals and tight streaks, significant kaolinite, and some smectite and illite (Cities Service Company, 1978). The clays are stable under reservoir conditions. Limited chemical reaction is expected from CO₂ injection given the native pH range of 5.1 to 5.4, so long as pH is maintained at 4.5-5.0 or higher. Plugging from fines migration is the primary risk to permeability and reservoir quality during flooding and production.

Initial pressure of the NEPSU reservoir was 3,050 psig at 8,200 feet, and original oil in place was approximately 225 million stock tank barrels (MMSTB) (Simlote and Withjack, 1981). Primary production began in 1951, and waterflooding for secondary recovery commenced in 1960. Cumulative production through 1977 was 79.5 million MMSTB, prompting efforts to develop a tertiary recovery program. Extensive reservoir study led to the establishment of CO₂ injection in 1982 as the most feasible tertiary method to maximize recovery (Cities Service Company, 1978).

In the SEBAU, which had ~105 MMSTB oil originally in place, primary and secondary recovery occurred from the 1950s into the 1990s. Tertiary recovery in the SEBAU began in 1997.

Operations and development throughout the history of the units have been very similar, owing in part to their immediate proximity and similar reservoir and production parameters.

Table 1: Reservoir Summary Characteristics

Parameter	Parameter by Unit	
	NEPSU	SEBAU
Unitized Area	~10,160 acres	~3,100 acres
Injection Reservoir	Cunningham Sand	Cunningham Sand
Flood Type	CO ₂ and Water Alternating Gas	CO ₂ and Water Alternating Gas
Depth	8,200-10,200 feet	8,900-10,800 feet
Porosity ¹	13%	12.5-14%
Permeability ²	44 mD	50-58 mD
Temperature	148 degrees F	150 degrees F
Initial Water Saturation	18%	NA
Irreducible Water Saturation	14%	NA
Average Net Pay	40 feet	40 feet
Initial Reservoir Pressure	3,050 psi @ 8,200 feet subsea	NA
Original Oil in Place	225 MMSTB	105 MMSTB
Oil Gravity	38 degrees API	38 degrees API
Oil Viscosity	1.2 cp	1.0 cp
Minimum Miscibility Pressure	1,700-2,300 psi	1,820-2,350 psi
Water Salinity	200,000 ppm TDS	NA

¹ Range across both units = 10-22%; ² Range across both units = 5-500 mD

Sources: Daylight internal data; Advanced Resources International, 2024; Birk, 1986; Brinlee and Brandt, 1982; Cities Service Company, 1978; Fox et al., 1988.

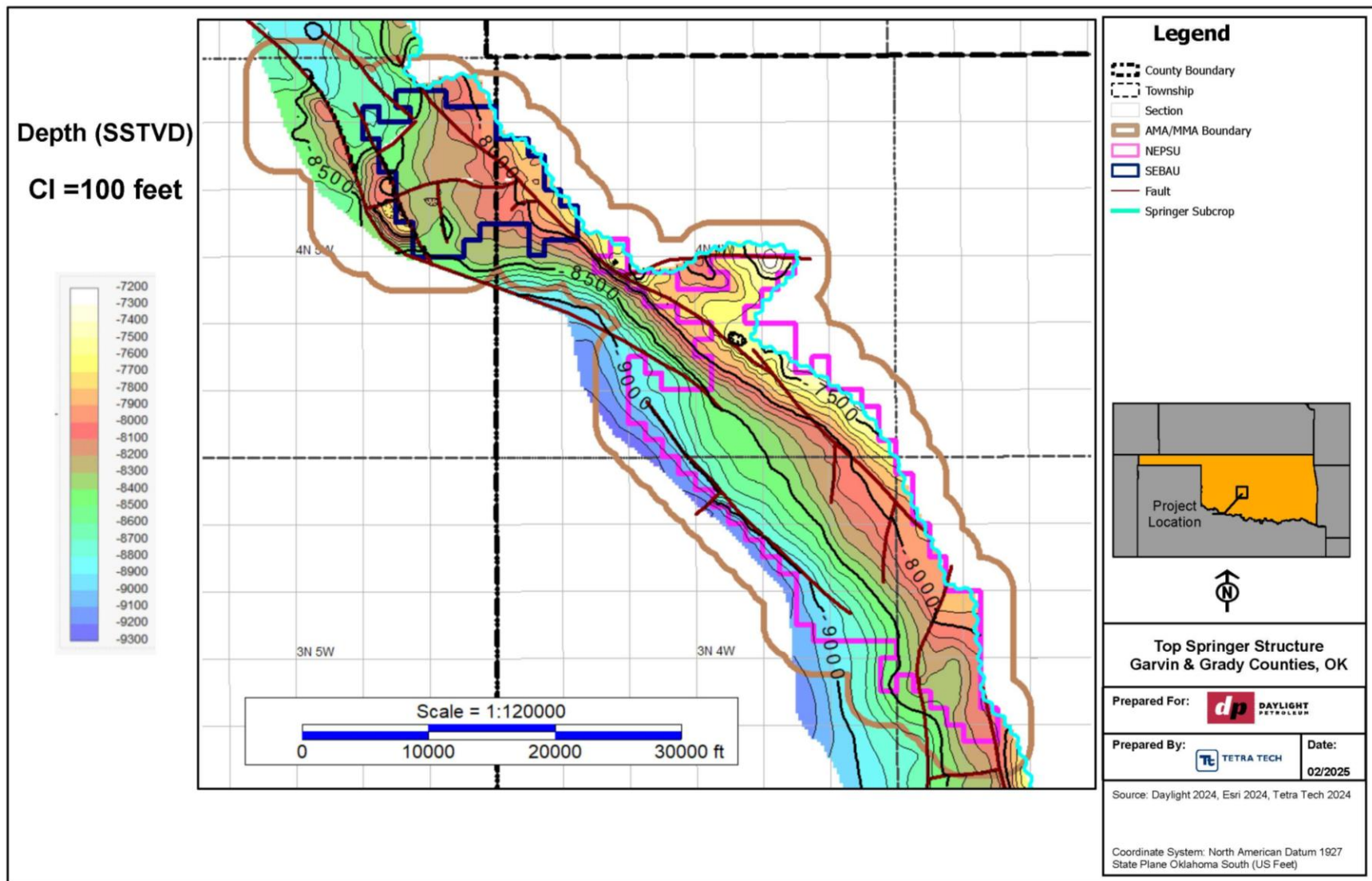
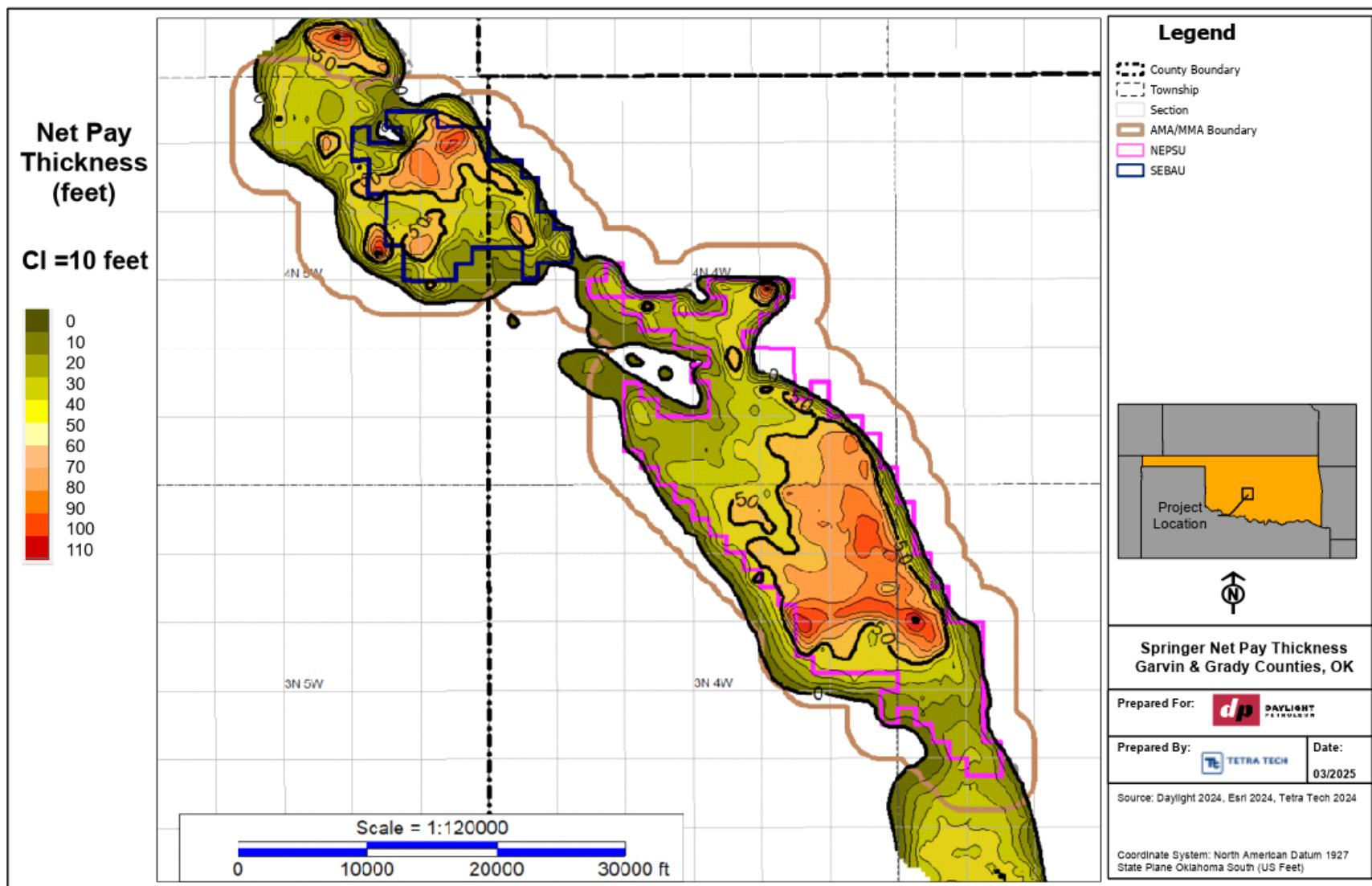


Figure 9: Top Springer structure



Not for Construction

Figure 10: Net pay thickness for the Springer reservoir sands

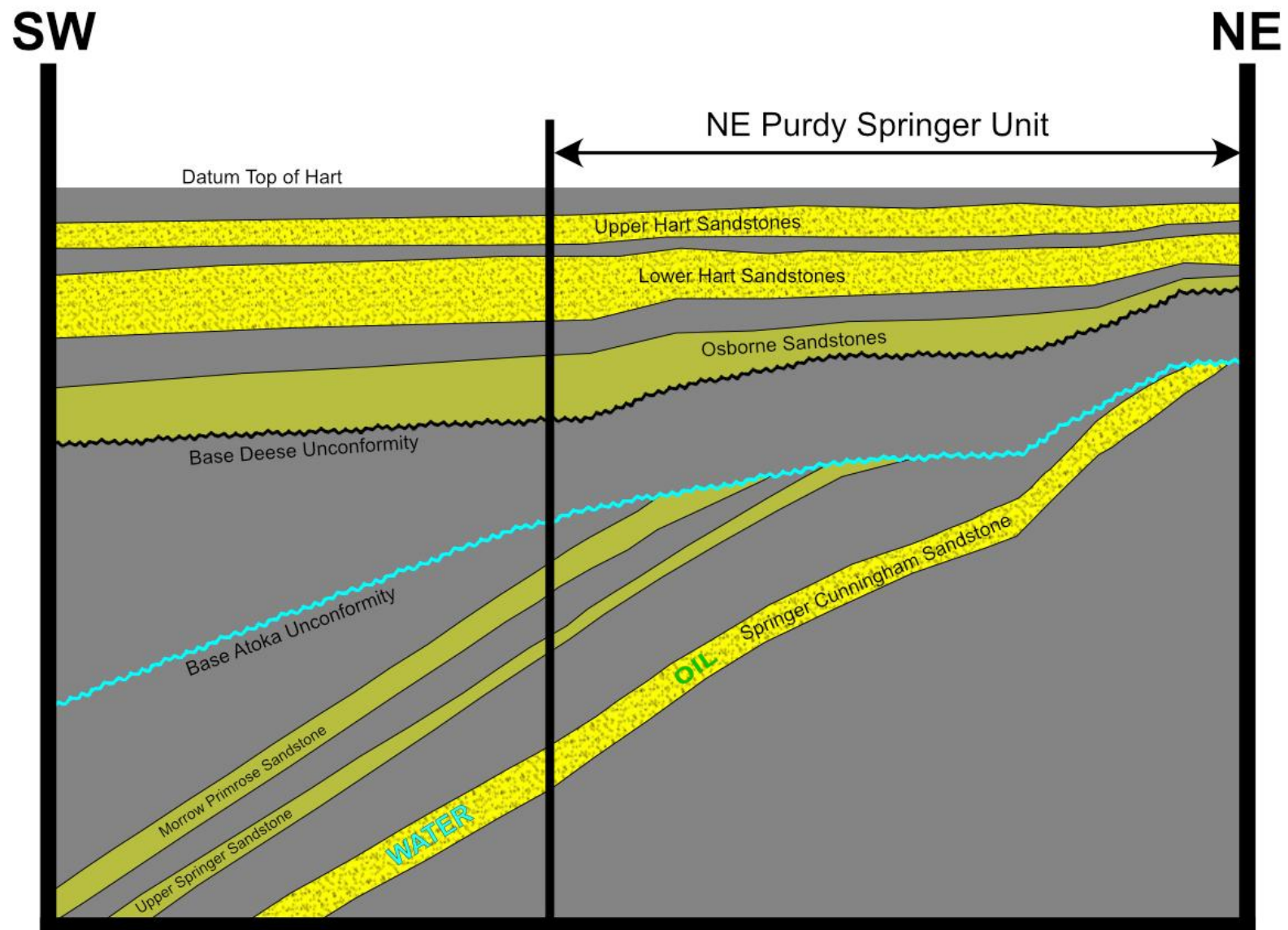


Figure 11: Schematic of the reservoir-seal stratigraphic trapping configuration

2.4.2. Reservoir Fluid Modeling

As discussed previously, NEPSU and SEBAU are operated collectively as the Purdy-Bradley Springer Field and have similar reservoir properties. Nearly all the historical reservoir data is from NEPSU, and available production data are generally combined for the two units. Therefore, the work presented in the following sections is considered to apply to the field as a whole.

A reservoir fluid model was developed based on the work of Fox et al. (1988). This article documents fluid properties for the NEPSU, and pressure, volume, and temperature (PVT) parameters were applied uniformly across the field. The minimum miscibility pressure (MMP) is calculated to be 1,750 psi. It is important to note that MMP measurements from 1979 show location dependency, with some values ranging between 2,100 psig and 2,300 psig. The tertiary flood was initiated by injection of CO₂ in September 1982, and because pressure measurements since 1982 are reported to be above 2,400 psi, flooding is expected to be miscible in most of the reservoir. Since the project involved continuous injection, a decline in pressures was not expected.

The reservoir temperature, used to create the oil PVT plots, was assumed to be 148 degrees F (Fox et al., 1988). The predicted plots and the data points from Fox et al. (1988) are compared in **Figure 12** and **Figure 13**. The gas viscosity is estimated based on a specific gravity of 8.42, calculated from the gas composition of the pre-CO₂ injection gas provided in Fox et al. (1988).

2.4.3. CO₂ Analytical Sweeping Efficiency Calculation

Accepted conventional reservoir engineering practice relies on dimensionless equations to predict the amount of oil that can be recovered through CO₂ flooding in oil reservoirs (Lee et al., 2019; Stell, 2010). The amount of oil recovered is plotted as a decimal fraction of the original oil in place, compared to the decimal fraction of the hydrocarbon pore volume (HCPV) of CO₂ injected into the reservoir, measured in reservoir barrels (rb).

To assess the enhanced oil recovery (EOR) performance, the commonly used Koval factor is applied. The Koval theory was meant to interpret the core-scale production of oil by a miscible displacement by CO₂ injection. It is calculated by multiplying the viscosity contrast effect by the heterogeneity effect. Based on core data from Daylight, the Lorenz coefficient is calculated to be 0.911, indicating a high level of heterogeneity in the reservoir (**Figure 14**).

The Lorenz coefficient and Dykstra-Parsons are common parameters used for evaluating heterogeneity. In this study, since the Koval factor is primarily calculated using Lorenz, it was employed for the heterogeneity assessment. The Lorenz coefficient ranges from 0 for a completely homogeneous system to 1 for a completely heterogeneous system. To calculate it, the normalized cumulative permeability capacity is first plotted against the normalized cumulative volume capacity (**Figure 14**). The Lorenz coefficient is then determined by dividing the area above the straight line (Area A) by the area below the straight line (Area B).

To convert the Lorenz factor into the Koval Factor, a chart provided by Salazar and Lake (2020) was used. According to this chart, the Koval Factor is estimated to be 140 (see **Appendix 5** for additional information). With this value, the volumetric sweep efficiency can be calculated using Koval's Theory (Koval, 1963), based on the CO₂ pore volume injected. The hydrocarbon pore volume (HCPV) filled by CO₂ injected into the oil reservoir over time is shown in **Figure 15**.

By assuming 25% of the HCPV for CO₂ injection, the estimated recovery is approximately 8% (**Figure 16**). The expected sweep efficiency is relatively low due to the reservoir's heterogeneity.

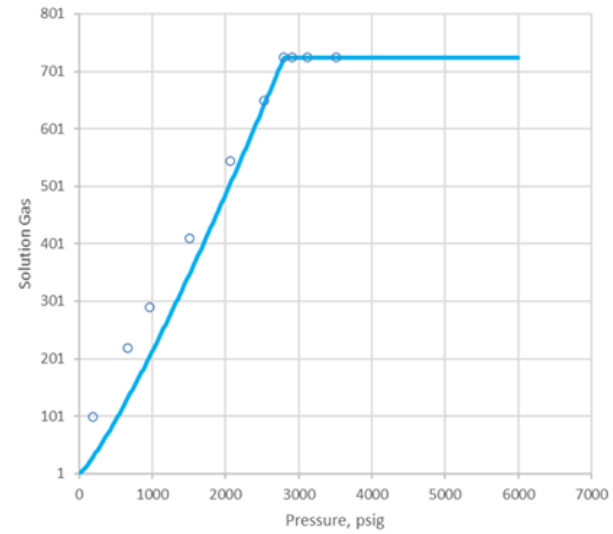
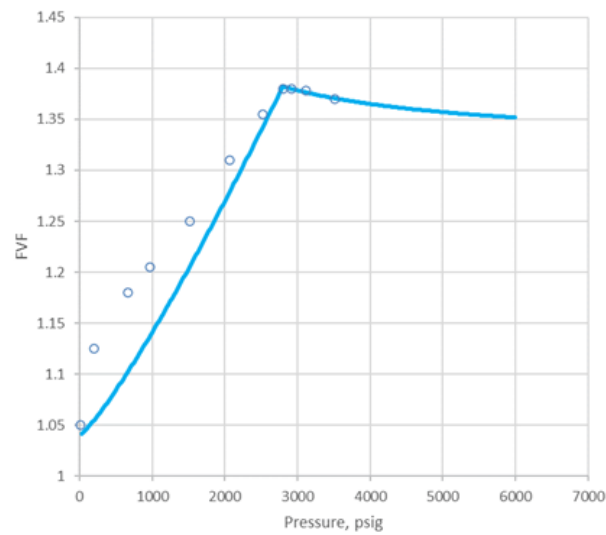


Figure 12: Oil PVT plots constructed for this modeling

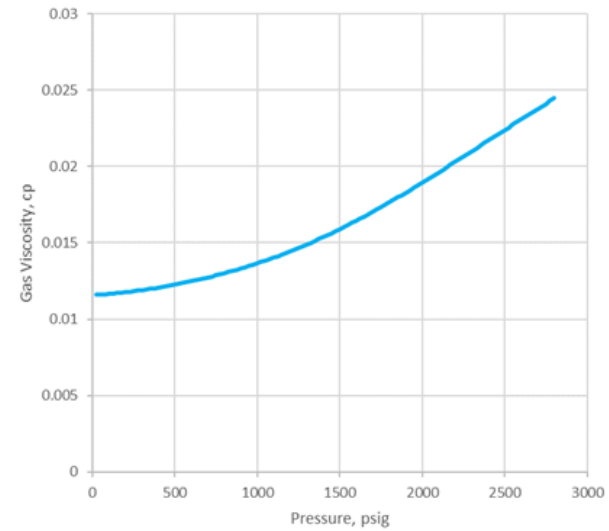
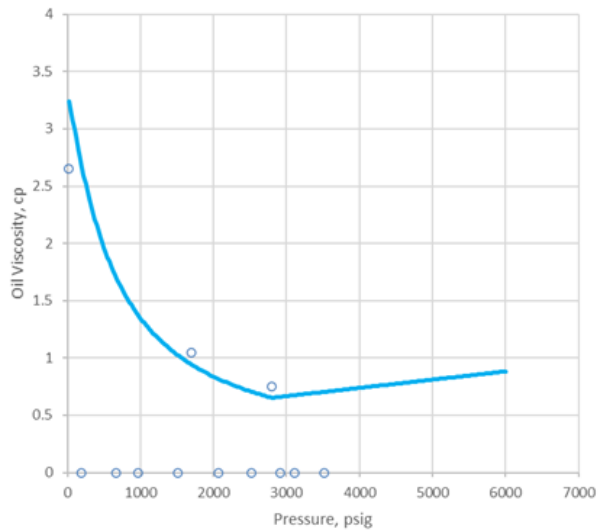


Figure 13: Oil and gas viscosity used in this modeling

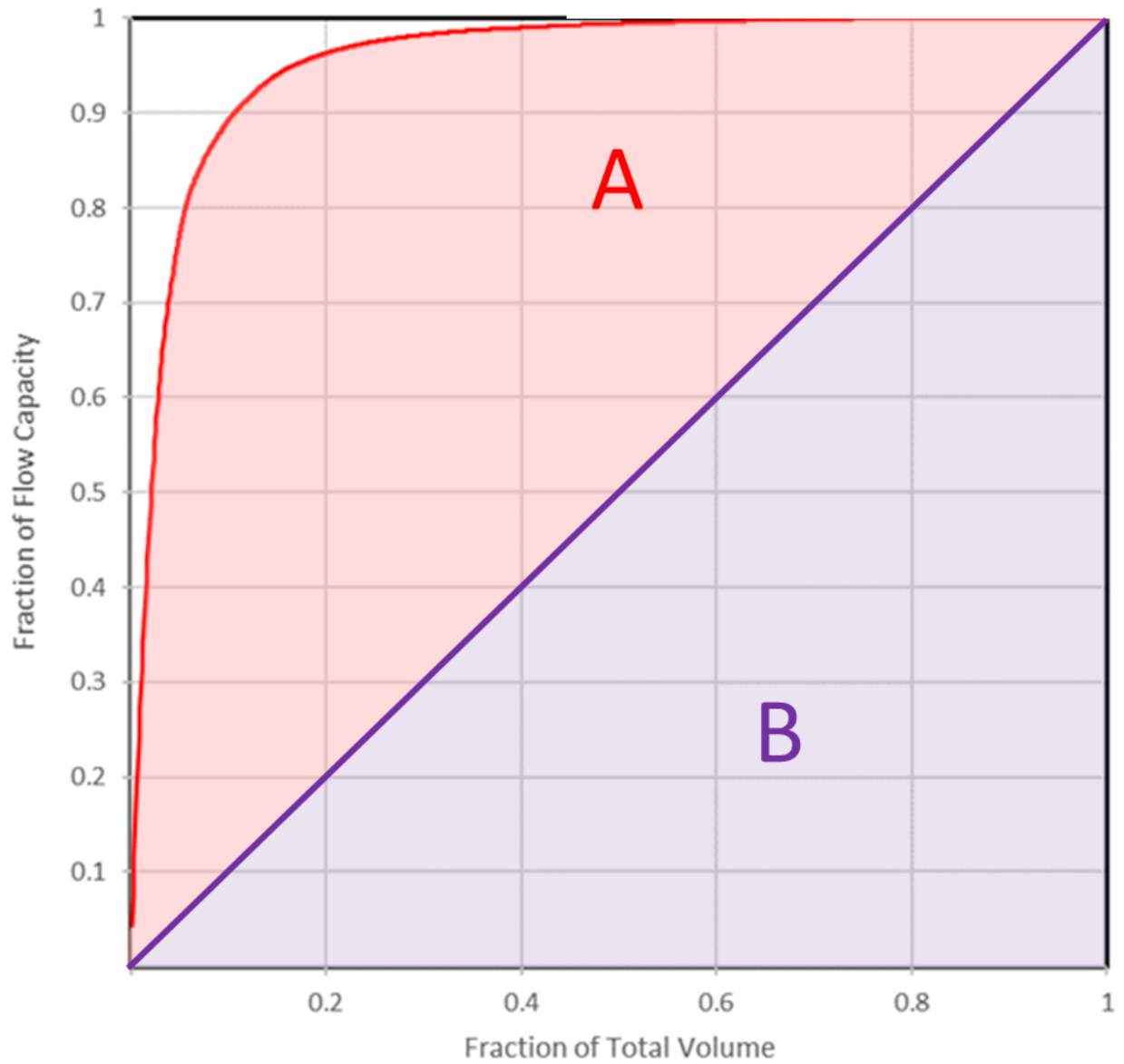


Figure 14: A Lorenz plot shows the high heterogeneity in this reservoir. The Lorenz coefficient is calculated by dividing the area above the straight line (area A) by the area under the straight line (area B).

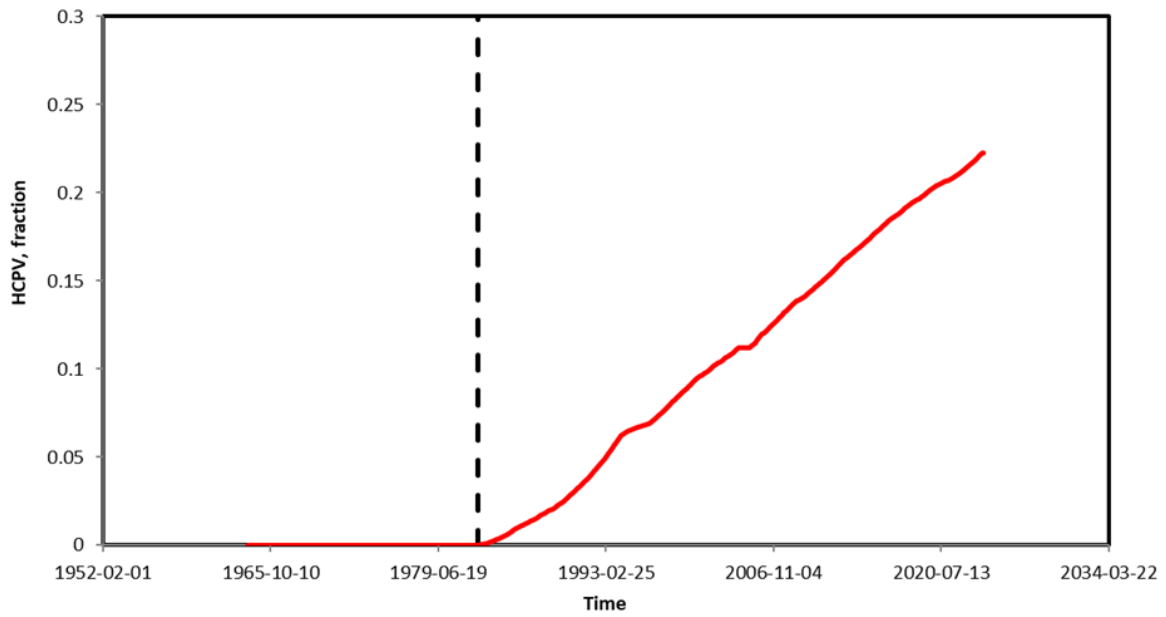


Figure 15: Hydrocarbon pore volume filled by CO₂ injection vs. time

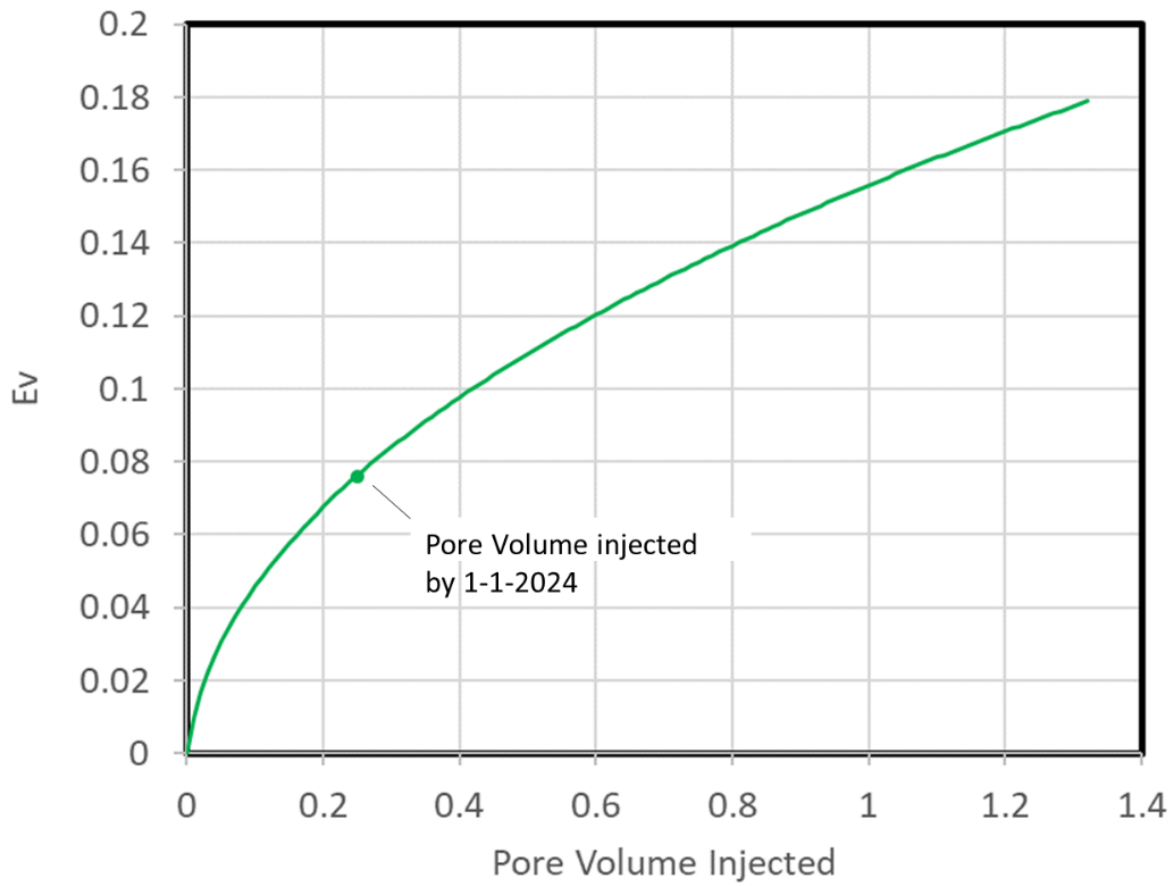


Figure 16: Recovery factor vs. CO₂ pore volume injected

2.4.4. CO₂-EOR Performance Projections

In this study, a modified Muskat model was used to calculate the pore volume available for CO₂ sequestration. This model accounts for the oil and gas PVT properties, as well as the relative permeability of the rock. A key uncertainty lies in the reservoir pressure. Actual reservoir pressure was not available and therefore was estimated using a pressure vs. time profile that offers a reasonable estimate of oil and gas production. The estimated gas saturation from the model is a critical factor, indicating the volume expected to be injectable into the reservoir. A linear pressure reduction is suggested during primary production, followed by an increase in pressure after waterflooding. Over the long term, the pressure begins to decline at a slow rate. The estimated rate is compared with actual production rates in **Figure 17**.

The primary aim of this analysis is to estimate oil production rates since September 1982, when the tertiary flood began through CO₂ injection. To determine the available volume for CO₂ storage, cumulative production rates were utilized. **Figure 18** presents a comparison of the predicted cumulative oil production with the actual cumulative oil production. As illustrated in **Figure 17** and **Figure 18**, the model demonstrates a reasonable accuracy in its predictions.

As the reservoir pressure fluctuates, both the formation volume factor (FVF) of the oil and the density of CO₂ change over time. Assuming a long-term reservoir temperature of 148 degrees F (the initial temperature of the field prior to CO₂ injection) and the current estimated pressure of 2,100 psia, the density of CO₂ is estimated to be 34.1 lbs/ft³ (**Figure 19**). It is essential to recognize that CO₂ density is highly sensitive to pressure; for instance, a reduction in pressure to 1,800 psi would result in an approximate 20% decrease in density. Although a decline in pressure over the long term is anticipated, the last pressure measurement was used for estimating these parameters due to a lack of recent pressure measurements.

In this analysis, the dissolution of CO₂ into the oil is not considered. It is important to note that as CO₂ primarily dissolves in the oil, the capacity for this volume will diminish over time as the oil volume decreases, unless there is a subsequent increase in reservoir pressure.

Given that the oil FVF is 1.31 rb/STB at a pressure of 2,100 psi, the available volume over time is plotted in **Figure 20**. The pressure of 2,100 psi is assumed from the expectation that it has declined by a few hundred psi from the last reported value of 2,400 psi (Fox et al., 1988), and it is further assumed that the pressure will be maintained through additional CO₂ injection in the coming years. Based on the analysis, should EOR be conducted for another 30 years, the volume potentially sequestered will reach 278 Bscf by 2054. To determine the injected CO₂ volume, the CO₂ density at standard conditions is 0.117 lbs/ft³, resulting in a gas FVF of 0.00342 rcf/scf.

It should be noted that the reported cumulative oil production at the end of 1985 was approximately 84.5 million STB (Fox et al., 1988). To account for this discrepancy, the oil production volumes have been adjusted. The gap arises due to the lack of historical data prior to the acquisition of these wells by Daylight. In **Figure 20**, this gap is referred to as the “mismatch.”

Knowing the CO₂ density (34.1 lbs/ft³), the mass of CO₂ to be stored can be calculated. It is important to note that the key assumption is that the CO₂ will only replace the oil recovered, with no additional volume considered for CO₂ dissolution. Based on this calculation, if EOR is conducted for another 30 years, the potential mass of CO₂ to be sequestered by 2054 is estimated to be approximately 278 billion Bscf, or 14.7 MMT, assuming pure CO₂ is injected (**Figure 21**).

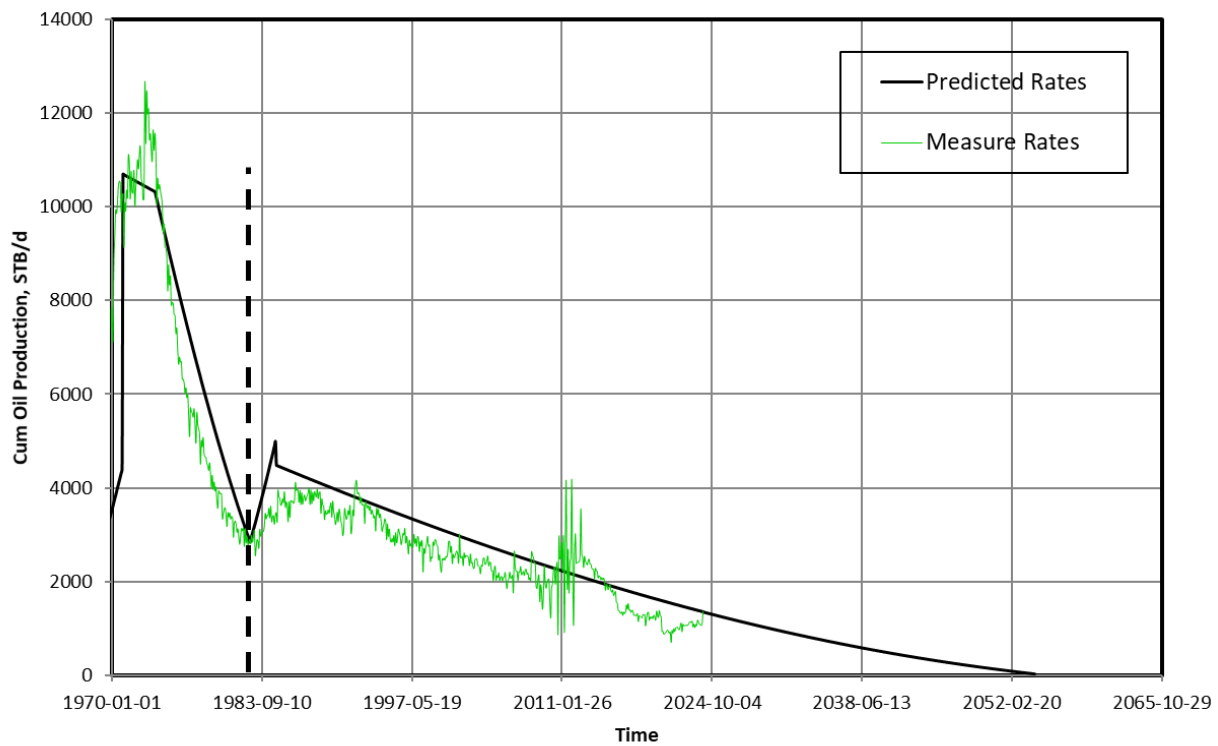


Figure 17: Oil rate-time curve comparison with actual estimations

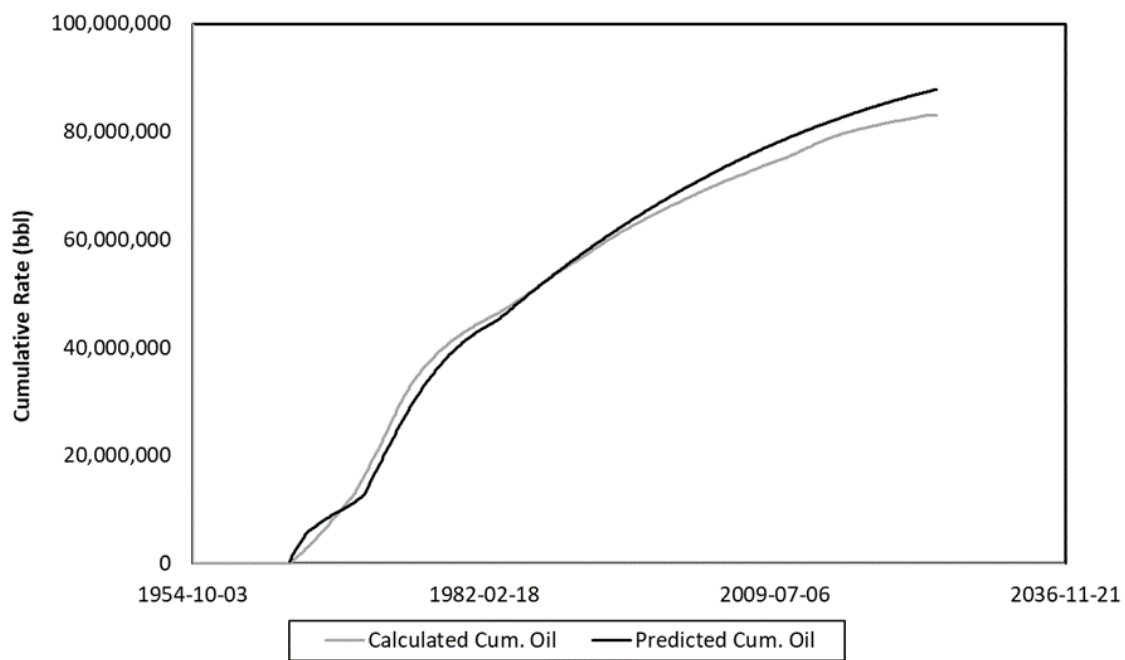


Figure 18: Comparison of the cumulative oil rates

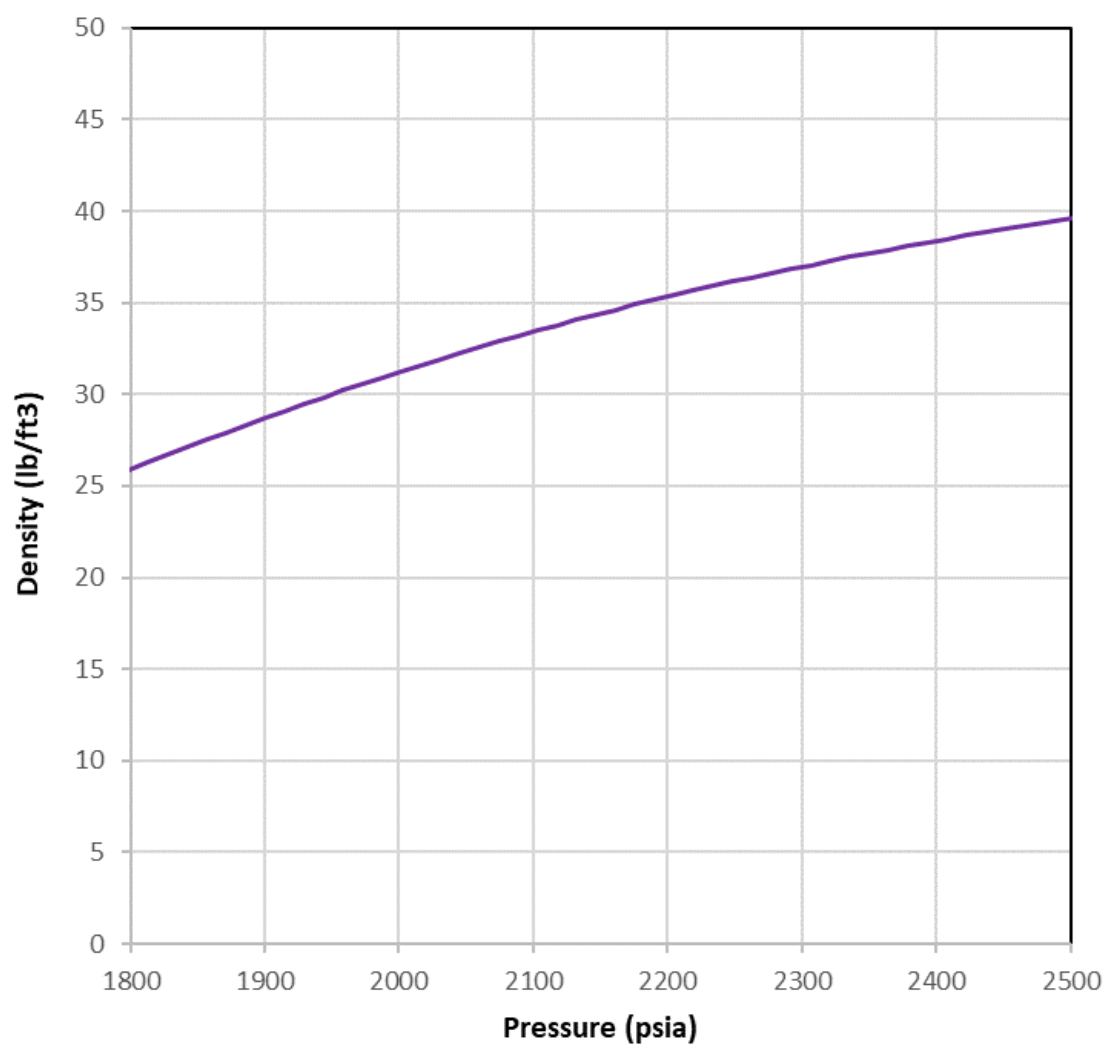


Figure 19: Variation of CO₂ density at 148 degrees F

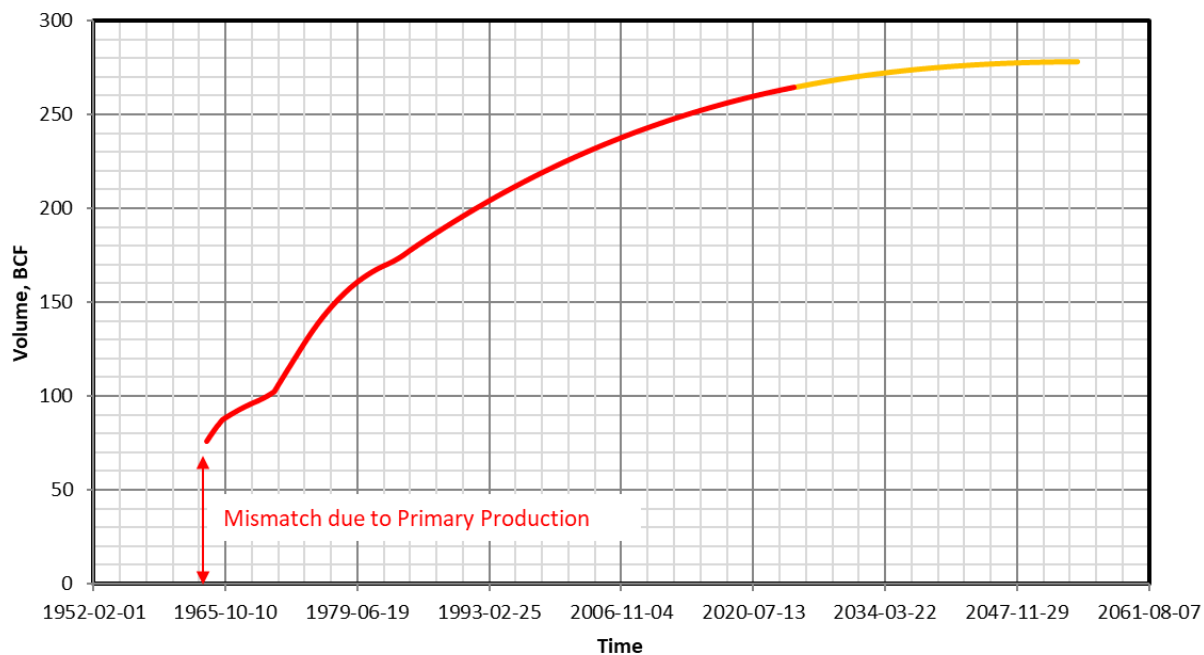


Figure 20: Predicted volume available for CO₂ injection

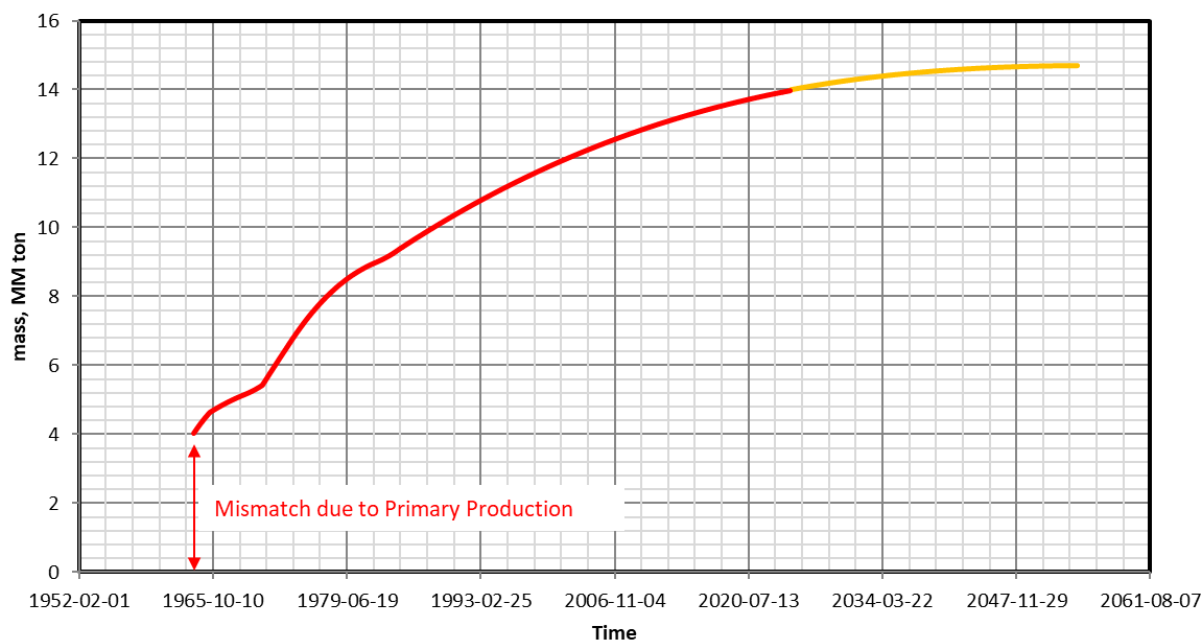


Figure 21: Predicted CO₂ storage in terms of mass

3.0. Delineation of Monitoring Area

3.1. Determination of CO₂ Storage Volumes

The estimated voidage space of 21 MMscf of CO₂ per acre of surface area, or a total of 278 Bscf CO₂, is assumed to be entirely contained within the Purdy-Bradley Springer Field (~13,200 acres).

3.2. Active Monitoring Area (AMA)

The AMA is defined by the combined boundaries of the NEPSU and SEBAU plus a buffer zone of at least one-half mile (**Figure 22**). The AMA is the area that Daylight will monitor over a specific time interval from the first year of the period (n) to the last year in the period (t). Consistent with the requirements in 40 CFR 98.449, the boundary is established by superimposing two areas:

1. The area projected to contain the free-phase CO₂ plume for the duration of the project (year t), plus an all-around buffer zone of one-half mile; and
2. The area projected to contain the free-phase CO₂ plume for at least 5 years after injection ceases (year t + 5).

3.2.1. Determination of Buffer Zone

The buffer zone of a minimum of one-half mile is required by Subpart RR. No known leakage pathways extend laterally more than one-half mile. Currently, Daylight's operations cover NEPSU and SEBAU in their entirety, and Daylight expects the free-phase CO₂ to remain within the unitized lands for the duration of the project and at least 5 years thereafter, as required for the AMA by 40 CFR 98.449. Any additional CO₂ injection wells will be permitted under the UIC program and will be included in the annual submittal per 40 CFR 98.446(f)(13).

3.3. Maximum Monitoring Area (MMA)

As defined in Subpart RR, the MMA is equal to or greater than the area expected to contain the free-phase CO₂ until the CO₂ has stabilized, plus an all-around buffer zone of at least one-half mile. The MMA is defined as equivalent to the AMA, and Daylight will continuously monitor the entire MMA for the purposes of this MRV.

4.0. Identification and Evaluation of Leakage Pathways

Since its discovery in 1951, the unitization of the NEPSU (1959) and SEBAU (1956), and the initiation of CO₂-EOR in 1982 (NEPSU) and 1997 (SEBAU), the Purdy-Bradley Springer Field has been extensively investigated and documented. Based on this history, Daylight has identified the following potential pathways of CO₂ leakage to the surface. This section also addresses detection, verification, and quantification of leakage from each pathway.

4.1. Leakage from Surface Equipment

The surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO₂-EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment is conducted by personnel instructed on how to detect surface leaks and other equipment failure, thereby minimizing the potential for and impact of any leakage. Surface equipment leaks have a low risk of occurring based on design standards. In addition, under OCC rules, operators must take prompt action to eliminate leakage hazards and to conduct inspections or repairs. Operating and maintenance practices currently follow and will continue to follow industry standards. As described in **Section 6.4**, should leakage from surface equipment occur, it will be quantified according to procedures required by the GHGRP.

4.2. Leakage from Wells

As of January 2025, Daylight identified 23 active CO₂ injection wells and 36 active production wells in the SEBAU; 69 active CO₂ injection wells and 88 active production wells in the NEPSU; and approximately 886 total wellbore penetrations within the AMA. These are listed in **Appendix 1**.

Regulations governing wells in the NEPSU and SEBAU require that wells be completed and operated so that fluids are contained in the strata in which they are encountered and that well operations do not pollute subsurface and surface waters. The regulations establish the requirements with which all wells must comply, whether they are injection, production, or disposal wells. Depending on the purpose of the well, regulatory requirements can impose additional standards for evaluation of an AoR. CO₂ injection well permits are authorized only after an application, notice, and opportunity for a hearing. As part of the permit application process, Daylight evaluates an AoR that includes wells within the unit and one-quarter mile from the set of wells considered in that AoR. Pursuant to USEPA and OCC regulations, all wells within the AoR that have penetrated the injection interval are located and evaluated.

4.2.1. Abandoned Wells

Figure 22 shows all wells in the AMA/MMA. The OCC utilizes a risk-based data management system and can only guarantee well data since 1980. The wells listed in **Appendix 1** and shown in **Figure 22** were compiled from S&P Global in an effort to provide a more complete well list.

Owing to past and future AoR evaluations and a lack of historical leakage events, Daylight concludes that leakage of CO₂ to the surface through abandoned wells is unlikely but cannot be ruled out. Strategies for leak detection are in place as discussed in **Section 4.8**, and the strategy to quantify any leaks is discussed in **Section 4.10**.

4.2.2. Injection Wells

Figure 22 shows the injection wells in the AMA/MMA. MIT is an essential requirement of the UIC program in demonstrating that injection wells do not act as conduits for leakage into USDWs and to the surface environment. Under OAC Title 165 Chapter 10, a pressure or monitoring test must be performed on new and existing injection wells and disposal wells. Information must be submitted on Form 1075 and witnessed by a field inspector when required. MIT and other rules documented in OAC Title 165 Chapter 10 ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Owing to past and future expectations of adhering to these rules, Daylight concludes that leakage of CO₂ to the surface through active injection wells is unlikely.

4.2.3. Production Wells

Figure 22 shows the active production wells in the AMA/MMA. As the project matures, production wells may be added and will be constructed according to the rules of the State of Oklahoma. Additionally, inactive wells may become active according to the rules of the State of Oklahoma.

During production, fluids including oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by a differential pressure, where the bottom hole wellbore pressure is less than the reservoir pressure. These lower-pressure fluids are contained by the casing, tubing, wellhead, and flowline all the way to the batteries and production/separation facilities. Daylight concludes that leakage of CO₂ to the surface through production wells is unlikely.

4.2.4. Inactive Wells

Inactive wells that have been temporarily abandoned typically have a cast iron bridge plug or other isolation mechanism set above the existing perforations to isolate the reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change. Given the regular monitoring of and procedures for securing inactive wells, it is unlikely that any leakage event would result in a significant magnitude or duration of CO₂ loss.

4.2.5. New Wells

As the project develops, new production wells and injection wells may be added to the NEPSU and SEBAU. All wells in Oklahoma oilfields, including injection and production wells, are regulated by the OCC, which has primacy to implement the Class II UIC programs. Rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. All new wells will be constructed according to the relevant rules for the OCC which ensure protection of subsurface and surface resources and the environment. This will significantly limit any potential leakage from well pathways; however, leakage during drilling of a new well through the CO₂ flood interval cannot be ruled out.

In the event a non-operated well is drilled within the AMA, the operator would be required to follow all OCC rules and procedures in drilling the well and the potential for leakage would be similar to that of any well Daylight drills within the AMA. In addition, Daylight's visual inspection process during routine field operation will identify any unapproved drilling activity in the NEPSU and SEBAU.

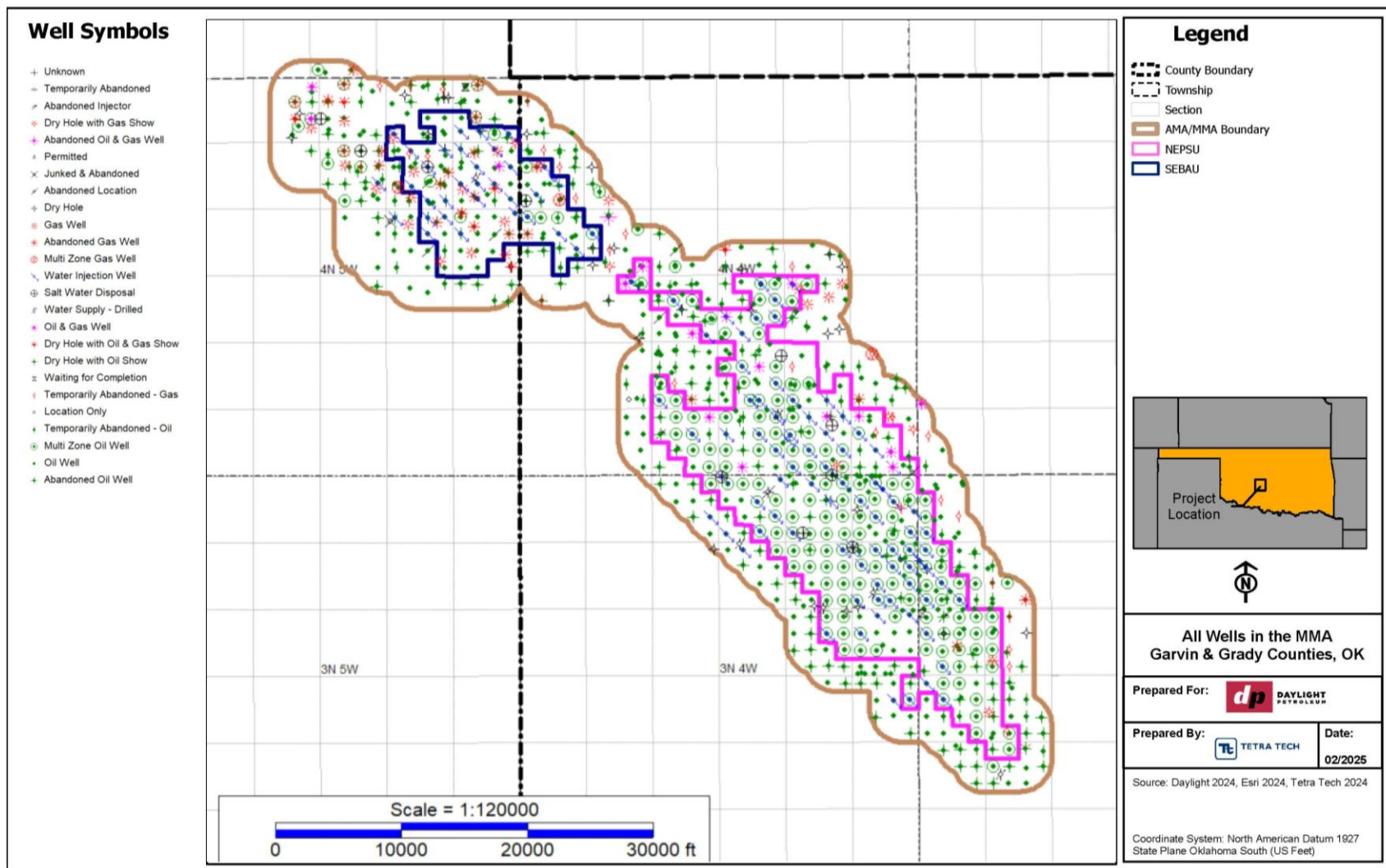


Figure 22: Location and type of all wells within the Active Monitoring Area (AMA). The Maximum Monitoring Area (MMA) is equivalent to the AMA.

4.3. Leakage from Faults, Fractures, and Bedding Plane Partings

Primary seals at the NEPSU and SEBAU have been demonstrated to be mechanically competent despite the presence of faults in and around the field (see also **Section 2.2.2**). The following lines of analysis have been used to assess this risk in the area.

4.3.1. *Presence of Hydrocarbons*

The primary evidence that leakage does not occur along faults, fractures, and bedding plane partings is the ~330 MMB of oil estimated to be originally in place in the NEPSU and SEBAU. If significant escape pathways existed, oil would have drained from the reservoir prior to the present day.

4.3.2. *Fracture Analysis*

Despite the presence of faulting in the area, conventional core samples taken from the Springer showed little evidence of fracturing (Oxy, 1988). In the event CO₂ leakage occurs through faults and fractures, it is unlikely that the leak would result in surface leakage, as these features are not known to extend from the reservoir to the surface. Daylight has strategies for leak detection in place that are discussed in **Section 4.8**, and the strategy to quantify leaks is discussed in **Section 4.10**.

4.4. Lateral Fluid Movement

The Springerean strata in Oklahoma represent primarily a deltaic to coastal island set of depositional systems that prograded toward the southeast, resulting in deposition of shales and lenticular, discontinuous coarse sandstones separated by very fine sandstone, minor conglomerates, and shale. The likelihood of extensive migration of fluid outside of the MMA is considered low.

Since CO₂ is lighter than the water and oil remaining in the reservoir, it will tend to migrate to the top of the reservoir. The producing wells create low pressure points in the field, draining water and oil while keeping some CO₂ within each discontinuous sandstone. It is estimated that the total mass of stored CO₂ will be considerably less than the calculated storage capacity and once production operations cease, very small lateral movement will occur.

4.5. Leakage through Confining/Seal System

The results of gas sampling analysis from wells producing from the Cunningham Sandstone and the shallower Hart Sandstone (i.e., the next overlying reservoir) show that CO₂ does not move vertically through the confining strata. Baseline testing of the Cunningham prior to CO₂ injection showed a 0.6% molar concentration of CO₂ (Fox et al., 1988). In October 2023, Daylight's testing of more than 50 wells producing from the Hart reservoir showed an average of 0.25% molar concentration of CO₂ in the gas stream. These results confirm that the sealing units above the Cunningham prevent upward migration of CO₂ out of the reservoir.

In the unlikely event of CO₂ leakage through the confining seal, there is a very low risk of surface leakage, since the reservoir is at depths of ~8,200-10,900 feet and is overlain by >1,200 feet of impermeable shale net thickness. As with any CO₂ leakage, Daylight has strategies for leak detection in place that are discussed in **Section 4.8** and the strategy to quantify the leak is discussed in **Section 4.10**.

4.6. Natural and Induced Seismic Activity

Figure 23 shows the locations of earthquakes with magnitudes of 2.5 or greater that have occurred within 2 miles of the MMA (data obtained from the United States Geological Survey [USGS] Earthquakes Hazard Program catalog [<https://earthquake.usgs.gov/earthquakes/search/>], accessed 1/30/2025). Details of these earthquakes are provided in **Table 2**. The Purdy-Bradley Springer Field is located in a seismically active region, and all but one of the mapped earthquakes occurred since the initiation of CO₂ injection in 1982. However, there is no evidence that proximal or distal earthquakes have caused a disruption in injectivity, CO₂ leakage, or damage to any of the wellbores in the Purdy-Bradley Springer Field.

In the unlikely event that induced or natural seismicity results in a pathway for material amounts of CO₂ to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would lead to further investigation.

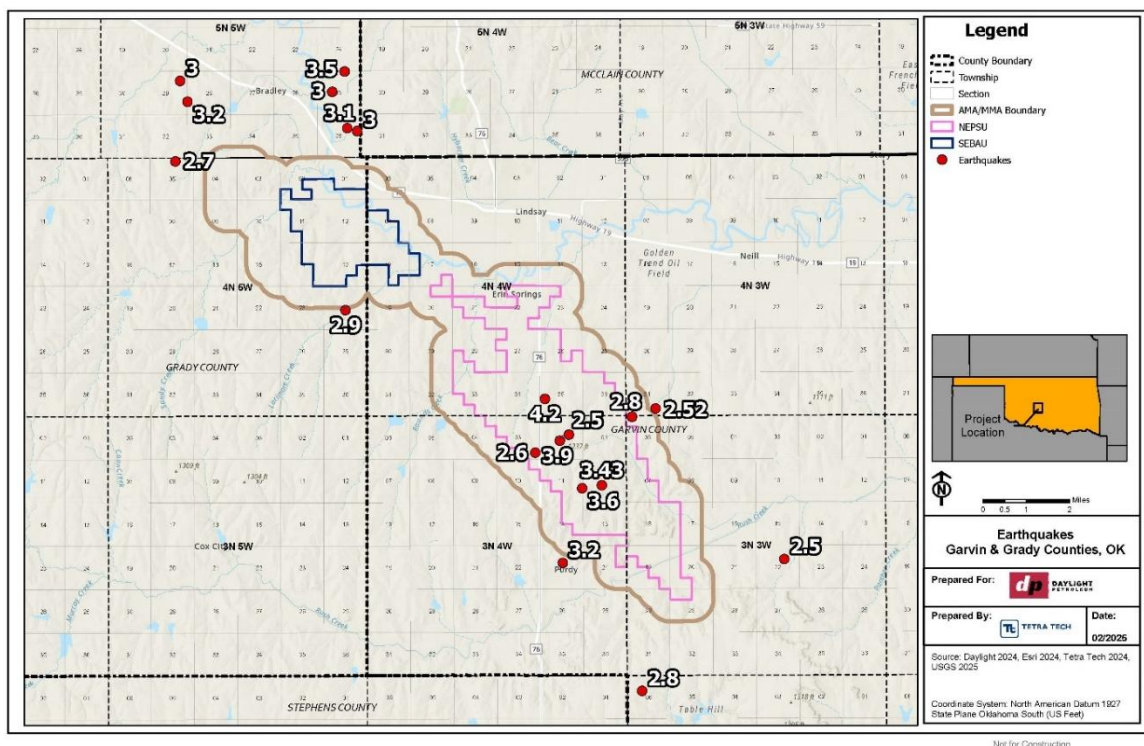


Figure 23: Earthquakes (2.5 magnitude or greater) within 2 miles of the MMA

Table 2: Details of earthquakes within the MMA

Earthquake Date	Magnitude	Location and Depth
1981-07-11	3.5	34.884°N 97.677°W – 5.0 km
1990-11-15	3.9	34.760°N 97.590°W – 5.0 km
1992-12-16	2.6	34.756°N 97.600°W – 5.0 km
1992-12-17	3.6	34.744°N 97.581°W – 5.0 km
1994-07-04	2.8	34.676°N 97.557°W – 5.0 km
1995-01-18	4.2	34.774°N 97.596°W – 5.0 km
1997-03-11	2.5	34.720°N 97.499°W – 5.0 km
1998-07-07	3.2	34.719°N 97.589°W – 5.0 km
2004-04-22	2.9	34.804°N 97.677°W – 5.0 km
2004-11-22	3.0	34.864°N 97.672°W – 5.0 km
2010-06-14	3.1	34.865°N 97.676°W – 5.0 km
2010-10-25	3.2	34.874°N 97.741°W – 5.0 km
2011-03-16	2.7	34.854°N 97.746°W – 5.0 km
2011-08-18	3.0	34.881°N 97.744°W – 5.0 km
2017-11-21	3.0	34.877°N 97.682°W – 2.4 km
2019-05-11	2.8	34.768°N 97.561°W – 5.0 km
2019-05-11	2.5	34.762°N 97.586°W – 5.0 km
2020-09-06	3.4	34.745°N 97.573°W – 7.0 km
2021-12-20	2.5	34.771°N 97.551°W – 6.5 km

4.7. Likelihood, Timing, and Magnitude of Potential Surface Leakage

Table 3 summarizes Daylight’s assessment of the likelihood, timing, and magnitude of surface leakage through the potential leakage pathways identified in this section.

Table 3: Assessment of Likelihood, Magnitude, and Timing of Potential Leakage Pathways

Potential Leakage Pathway	Likelihood	Magnitude ¹	Timing
Surface Equipment	Unlikely but possible	Variable – Small or easily detected failure could result in low- to medium-magnitude CO ₂ release, while a catastrophic failure could result in medium- to high-magnitude CO ₂ release	During injection period
Wells	Unlikely but possible	Low – Monitoring / surveillance and well construction requirements should minimize any release of CO ₂	During injection and post-injection periods
Faults, Fractures, and Bedding Plane Partings	Unlikely	Low	During injection and post-injection periods
Lateral Fluid Movement	Unlikely	Low	During injection and post-injection periods
Confining Seal / System	Unlikely	Low	During injection and post-injection periods
Natural and Induced Seismic Activity	Unlikely	Low	During injection and post-injection periods

¹ Magnitude assessed as follows:

Low – minimal risk to safety, health and environment, or USDW

Medium – moderate risk to safety, health and environment, or USDW, but easily remediated

High – extreme risk to safety, health and environment, or USDW, and difficult and/or costly to remediate.

4.8. Strategy for Detection of CO₂ Loss

Daylight intends to use the results of daily monitoring of field conditions, operational data (including automatic data systems), routine testing, and maintenance information to monitor for surface leakage and to identify and investigate deviations from expected performance that could indicate CO₂ leakage. In the event any of those results indicate a CO₂ leak may have occurred, the event will be documented and an estimate will be made of the amount of CO₂ leaked. The event and estimate will be included in the annual Subpart RR reporting. Records of each event will be kept on file for a minimum of 3 years. The methods that Daylight intends to use in this strategy include the following:

4.8.1. *Data System*

Daylight uses onsite management and a Supervisory Control and Data Acquisition (SCADA) system to conduct its CO₂-EOR operations. Daylight uses data from these efforts to identify and investigate variances from expected performance that could indicate CO₂ leakage. Some CO₂ meters are installed with SCADA systems that transmit data from the meters automatically into a data warehouse. Those data, as well as other operational data collected manually, are also used for operational management and controls.

4.8.2. *Visual Inspections*

Daylight's field personnel conduct routine weekly or daily inspections of the facilities, wells, and other equipment (such as vessels, piping, and valves). These visual inspections provide an opportunity to identify issues early and to address them proactively, which may preclude leaks from happening and/or minimize any CO₂ leakage. Any visual identification of CO₂ vapor emission or ice formation will be reported and documented, and a plan will be developed and executed to correct the issue.

4.8.3. *Injection Target Rates and Pressures*

Daylight manages its CO₂-EOR operations by developing and implementing target injection rates and pressures for each CO₂ injection well. These target rates and pressures are developed based on various parameters such as historic and ongoing pattern development, WAG operations, CO₂ availability, field performance, and permit conditions. Field personnel implement the WAG schedule by manually making choke adjustments at each injection well, allowing for a physical inspection of the injection well during each adjustment. Generally on a daily basis, injection rates for each CO₂ injection well are reported and compared to the target rates. Injection pressures and casing pressures are monitored on each CO₂ injection well. Injection rates or pressures falling outside of the target rates or pressures to a statistically significant degree are screened to determine whether they could lead to CO₂ leakage to the surface. If that screening or investigation identifies any indication of a CO₂ leakage to the surface in this manner, it will be reported and documented, and a plan will be developed and executed to correct the issue.

4.8.4. *Production Wells*

Daylight forecasts the amount of fluids (e.g. oil, water, CO₂) that is likely to be produced from each production well at the unit level in the NEPSU and SEBAU over various periods of time. Evaluation of these produced volumes, along with other data, informs operational decisions regarding management of the CO₂-EOR project and aid in identifying possible issues that may involve CO₂ leakage. These evaluations can direct engineering and/or operational personnel to investigate

further. If an investigation identifies that a CO₂ leak has occurred, it will be reported and documented, and a plan will be developed and executed to correct the issue.

4.8.5. Plant and Pipeline Monitoring

Daylight currently operates the CO₂-related infrastructure used to operate the units, including the associated on-site CO₂ capture, compression, and dehydration facility. The facility includes a monitoring program that monitors the rates and pressures at the facility and on the pipeline on a continuous basis. High and low set points are established in the program, and operators at the plant, pipeline and/or the units are alerted if a parameter is outside the allowable window. If the flagged parameter is the delivery point on the pipeline, but no other parameter at the plant or pipeline is flagged, then the field personnel are alerted so that further investigation can be conducted in the field to determine if the issue poses a leak threat.

4.8.6. Well Testing

Injection wells are leak-tested via MIT as required by the USEPA or OCC. This consists of regular monitoring of the tubing-casing annular pressure and conducting a test that pressures up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. Sometimes, in addition to or in lieu of MIT, Daylight is required to perform a RTS to ensure that all injection fluids are going into the injection zone. Daylight personnel monitor the pressure and conduct the tests in accordance with regulations and permit requirements. In the event of a loss of mechanical integrity, the subject injection well is immediately shut in and an investigation is initiated to determine what caused the loss of mechanical integrity. If investigation of an event identifies that a CO₂ leak has occurred, it will be reported and documented, and a plan will be developed and executed to correct the issue.

4.9. Strategy for Response to CO₂ Loss

As discussed above, the potential sources of leakage include routine issues, such as problems with surface equipment (e.g., pumps, valves), wellbores or subsurface equipment, and unique and unlikely events such as induced fractures. **Table 4** summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, Daylight's standard response, and other applicable regulatory programs requiring similar reporting.

The potential CO₂ losses discussed in the table are identified by type. If there is a report or indication of a CO₂ leak, such as from a visual inspection, monitor, or pressure drop, a Daylight employee or supervisor will be dispatched to investigate. Emergency shutdown systems will be utilized as necessary to isolate the leak. If the leak cannot be located without movement of equipment or other substantial work, further involvement of Daylight personnel or management will be involved to determine how the leak will be located. Once the leak is located and isolated, pressure from the system will be relieved so that further investigation of the leak area can be performed and repair work can be estimated and ultimately performed.

Table 4: Response Plan for CO₂ Loss

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

4.10. Strategy for Quantifying CO₂ Loss

Leakage of CO₂ on the surface will be quantified once leakage has been detected and confirmed. Major CO₂ losses are typically event-driven and require a process to assess, address, track, and if applicable, quantify potential CO₂ leakage to the surface. Daylight will use Subpart W techniques to estimate leakages only on equipment and ensure those results are consistently represented in the Subpart RR report. Any event-driven leakage quantification reported in Subpart RR for surface leaks will use other techniques.

In the event leakage occurs, Daylight will determine the most appropriate method for quantifying the volume leaked and will report the methodology used as required as part of the annual Subpart RR submission. Leakage estimating methods may potentially consist of modeling or engineering estimates based on operating conditions at the time of the leak, such as temperatures, pressures, volumes, and hole size. An example methodology would be to place a flux box or ring tent over the surface leak to measure the flow rate and gather gas samples for analysis. The volume of CO₂ in the soil can also be used with this technique. Any volume of CO₂ detected leaking to the surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 Subpart W or engineering estimates of leak amounts based on measurements in the subsurface, Daylight's field experience, and other factors such as the frequency of inspection. Records of leakage events will be retained in Daylight's electronic documentation and reporting system, which consists of reports stored on servers, with certain details uploaded into third-party software.

4.11. Demonstration at End of Specified Period

At the end of EOR injection operations, Daylight intends to cease injecting CO₂ for the purpose of establishing long-term storage of CO₂ in the units. At that time, Daylight anticipates submitting a request to discontinue monitoring and reporting, including a demonstration that the amount of CO₂ reported under Subpart RR is not expected to migrate in the future in a manner likely to result in surface leakage. Daylight will support its request with data collected during operations as well as 1-3 years of data (or more, if needed) collected after the end of operations. Daylight expects this demonstration will provide the information necessary for the USEPA to approve the request to discontinue monitoring and reporting. This demonstration may include but is not limited to:

- An assessment of CO₂ injection data for the units, including the total volume of CO₂ injected and stored as well as actual surface injection pressures;
- An assessment of any CO₂ leakage detected, including discussion of the estimated amount of CO₂ leaked and the distribution of emissions by leakage pathway; and
- An assessment of reservoir pressure in the units that demonstrates that the reservoir pressure is stable enough to demonstrate that the injected CO₂ is not expected to migrate in a manner to create a potential leakage pathway.

5.0. Strategy for Determining CO₂ Baselines for CO₂ Monitoring

Daylight may elect to collect additional atmospheric test data using ambient air detectors or other methodologies to characterize baseline values in the units. Ongoing operational monitoring of well pressures and rates has provided data for establishing baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO₂ 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. Each of these is discussed in more detail below.

5.1. Site Characterization and Monitoring

As described in **Section 2.2.2** and **Section 2.4**, the Cunningham Sandstone is isolated by impermeable shale units of the upper Springer, Morrow, and/or Atoka reaching thicknesses of 150-200 feet. These units provide a suitable primary seal to prevent the migration of CO₂ out of the injection reservoir, and additional shale layers above the primary seal provide secondary confinement with a total net shale thickness >1,200 feet. As discussed in **Section 4.5**, testing of the Springer prior to CO₂ injection showed a 0.6% molar concentration of CO₂ (Fox et al., 1988). In October 2023, Daylight's testing of more than 50 wells producing from the Hart reservoir showed an average of 0.25% molar concentration of CO₂ in the gas stream. Furthermore, a review of gas sample data published in Higley (2014) shows the range of natural CO₂ concentration in the Central Anadarko Basin is 0.00-10.9 mole percent (average, 1.73 mole percent). These field- and basin-scale data will be considered in the determination of CO₂ baseline values should a potential leak be detected.

Additionally, no significant faults or fracture zones that compromise the sealing capacity of the confining shales have been identified in the Purdy-Bradley Springer Field, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented. After ~42 years of tertiary oil recovery operations, no significant wellbore leaks are known to have occurred, and therefore Daylight concludes that wellbore leaks are unlikely to happen.

5.2. Groundwater Monitoring

Daylight obtains and tests water samples from shallow groundwater wells during the preparation of permit applications for new Class II UIC EOR injection wells. Daylight has not monitored USDW wells for CO₂ or brine contamination, as characterization of the Springer suggests that risk of groundwater contamination from CO₂ leakage from the reservoir is minimal. While groundwater contamination is unlikely to happen, any change in groundwater that is brought to the attention of Daylight will be investigated to eliminate the potential leakage pathway.

5.3. Soil CO₂ Monitoring

Daylight does not intend to collect background soil gas data. Should a possible leakage event be detected, Daylight may elect to use vapor monitoring points installed into the shallow subsurface as part of the leakage verification and quantification process.

5.4. Visual Inspection

Daylight operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage. Visual inspection consists of finding evidence of stains, unusual

accumulation of frost, washouts exposing buried pipe, dead rodents, birds or reptiles, and changes to vegetation. In addition to looking for evidence of leaks, field personnel will look for conditions that could lead to equipment failure such as public utility digging, ditching, settling of backfill, boring, and tunneling.

5.5. Well Surveillance

Daylight adheres to the requirements of OAC Title 165 Chapter 10 governing fluid injection into productive reservoirs. Title 165 includes requirements for monitoring, reporting, and testing of Class II UIC injection wells, including an initial MIT prior to injection operations and subsequent MIT at least once every year or every 5 years, depending on the permitted injection rate. Daylight will report any mechanical failure of the surface casing or cement to the appropriate regulatory authority in full compliance with all applicable legal and regulatory requirements.

5.6. Injection Well Rates, Pressures, and Volumes

Target injection rates and pressures for each injector are developed within the permitted limits based on the results of ongoing pattern surveillance. The field operations staff monitor equipment readings and investigate any departures from the permitted limits which could have resulted in a surface CO₂ leak.

6.0. Site-Specific Considerations for Determining the Mass of CO₂ Sequestered

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

6.1. Determining Mass of CO₂ Received

Daylight has the ability to receive CO₂ at its NEPSU and SEBAU facilities via its operated pipeline from Enid, Oklahoma. Daylight also recycles CO₂ from its production wells in NEPSU and SEBAU.

$$CO_{2T,r} = \sum_{p=1}^4 (Q_{r,p} - S_{r,p}) \times D \times C_{CO_{2,p,r}} \quad (\text{Equation RR-2})$$

where:

CO_{2T,r} = Net annual mass of CO₂ received through flow meter r (metric tons)

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

C_{CO₂,p,r} = Quarterly CO₂ concentration measurement in flow for flow meter r in quarter p (volume percent CO₂, expressed as a decimal fraction)

p = Quarter of the year

r = Receiving flow meter

6.2. Determining Mass of CO₂ Injected

Daylight injects CO₂ into the injection wells listed in **Appendix 1**.

$$CO_{2,u} = \sum_{p=1}^4 Q_{p,u} \times D \times C_{CO_2,p,u} \quad (\text{Equation RR-5})$$

where:

CO_{2,u} = Annual CO₂ mass injected (metric tons) as measured by flow meter u

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

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

p = Quarter of the year

u = Flow meter

6.3. Determining Mass of CO₂ Produced from Oil Wells

Daylight also recycles CO₂ from its EOR production wells in the NEPSU and SEBAU. Therefore, the following equation is relevant to its operations.

$$CO_{2,w} = \sum_{p=1}^4 Q_{p,w} \times D \times C_{CO_2,p,w} \quad (\text{Equation RR-8})$$

where:

CO_{2,w} = Annual CO₂ mass produced (metric tons) through separator w

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682

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

p = Quarter of the year

w = Separator

To aggregate production data, Daylight will sum the mass of all the CO₂ separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 below:

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

where:

CO_{2P} = Total annual CO₂ mass produced (metric tons) through all separators in the reporting year

CO_{2,w} = Annual CO₂ mass produced (metric tons) through separator w in the reporting year

X = Entrained CO₂ in produced oil or other fluid divided by the CO₂ separated through all separators in the reporting year (weight percent CO₂, expressed as a decimal fraction).

w = Separator

6.4. Determining Mass of CO₂ Emitted by Surface Leakage

As required by 98.448 (d) of Subpart RR, Daylight will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO₂ stream, for facilities that conduct CO₂-EOR operations.

Daylight will calculate the total annual mass of CO₂ emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 below:

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

where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year

x = Leakage pathway

6.5. Determining Mass of CO₂ Sequestered

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

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

where:

CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

CO_{2P} = Total annual CO₂ mass produced (metric tons) in the reporting year

CO_{2E} = Total annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year

CO_{2FI} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ 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

CO_{2FP} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ 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

7.0. Estimated Schedule for Implementation of MRV Plan

Daylight expects to begin implementing this MRV plan after approval, or tentatively in 2026.

8.0. GHG Monitoring and Quality Assurance Program

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

8.1. GHG Monitoring

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

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

8.1.1. General

Daylight follows industry-standard metering protocols for custody transfers, such as those standards for accuracy and calibration issued by the API, the American Gas Association (AGA), and the Gas Producers Association (GPA), as appropriate. This approach is consistent with 98.444(e)(3). Meters are maintained routinely, operated continually, and will feed data directly to the centralized data collection systems. CO₂ composition is governed by contract, and the CO₂ is routinely and periodically sampled to determine average composition. These custody meters provide an accurate method of measuring mass flow.

In addition to custody transfer meters, various process control meters are used in NEPSU and SEBAU to monitor and manage in-field activities, often on a real-time basis. These operations meters provide information used to make operational decisions but are not intended to provide the same level of accuracy as the custody-transfer meters. The level of precision and accuracy for operational meters currently satisfies the requirements for reporting in existing UIC permits. Although the process control meters are accurate for operational purposes, there is some variance between most commercial meters (on the order of 1-5%), which is additive across meters. This variance is due to differences in factory settings and meter calibration, as well as the operating conditions within the field. Meter elevation, changes in temperature, fluid composition (especially in multi-component or multi-phase streams), and pressure can affect readings of these operational meters.

Measurement of CO₂ Concentration – All measurements of CO₂ concentrations of any CO₂ quantity will be conducted according to an appropriate standard method published by a

consensus-based standards organization or an industry standard practice such as those established by the GPA.

Measurement of CO₂ Volume – All measurements of CO₂ volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees F and at an absolute pressure of 1 atmosphere. Measurement devices will be compliant with AGA and API standards and can produce and export .cfx industry-standard files for either gas or liquid meter runs.

8.1.2. CO₂ Received

Fresh CO₂ (non-recycled) is received via a pipeline running from Enid, Oklahoma, and is measured with an orifice meter (recorded with a digital transducer). Information is sent to a flow computer (Fisher/Emerson ROC800) and is configured to calculate volumes. Data is stored temporarily to be pulled by the SCADA system. Daylight will bring in new sources of CO₂ in the future according to field development and operational needs.

8.1.3. CO₂ Injected

Daily CO₂ injection is recorded by combining the totals for the recycle compressor meter and the received CO₂ meter based on what is delivered on a 24-hour basis. These data are taken from the meter daily and stored according to Daylight's data management protocols.

8.1.4. CO₂ Produced

The point of produced gas measurement is from a meter downstream of the compressors prior to being combined with purchase CO₂. The produced gas is sampled and analyzed quarterly at the plant inlet, plant tailgate (north and south) and as needed at each satellite.

8.1.5. CO₂ Emissions from Equipment Leaks and Vented Emissions of CO₂

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

As required by 98.444 (d) of Subpart RR, Daylight will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO₂ stream, for facilities that conduct CO₂-EOR operations. The default emission factors for production equipment are applied to the carbon capture utilization and storage (CCUS) injection operations reporting under Subpart RR.

8.1.6. Measurement Devices

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

- All flow meters are operated continuously except as necessary for maintenance and calibration.
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i) of Subpart A of the GHGRP.

- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: American Society for Testing and Materials (ASTM) International, the American National Standards Institute (ANSI), the AGA, the GPA, the American Society of Mechanical Engineers (ASME), the API, and the North American Energy Standards Board (NAESB).
- All flow meters are National Institute of Standards and Technology (NIST) and European Gas Research Group (GERG) traceable.

8.2. QA/QC Procedures

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

8.3. Estimating Missing Data

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

A quarterly flow rate of CO₂ received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.

A quarterly CO₂ concentration of a CO₂ 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 CO₂ injected that is missing would be estimated using a representative quantity of CO₂ injected from the nearest previous period of time at a similar injection pressure.

For any values associated with CO₂ emissions from equipment leaks and vented emissions of CO₂ 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.

A quarterly quantity of CO₂ produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO₂ produced from the nearest previous period of time.

8.4. Revisions to the MRV plan

Daylight will revise the MRV Plan as necessary per 40 CFR 98.448(d).

9.0. Records Retention

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

- (1) A list of all units, operations, processes, and activities for which GHG emissions were calculated. The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:
 - (i) The GHG emissions calculations and methods used.
 - (ii) Analytical results for the development of site-specific emissions factors, if applicable.
 - (iii) The results of all required analyses.
 - (iv) Any facility operating data or process information used for the GHG emission calculations.
- (2) The annual GHG reports.
- (3) Missing data computations. For each missing data event, Daylight will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
- (4) A copy of the most recent revision of this MRV Plan.
- (5) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
- (6) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
- (7) Quarterly records of CO₂ received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- (8) Quarterly records of produced CO₂, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- (9) Quarterly records of injected CO₂ including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- (10) Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- (11) Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
- (12) Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.
- (13) Any other records as specified for retention in this USEPA-approved MRV plan.

List of Figures

Figure 1: Location of the Purdy-Bradley Springer field in the Arkoma Basin	6
Figure 2: Regional stratigraphic column	7
Figure 3: Type log	8
Figure 4: Depth to base of treatable water	10
Figure 5: Simplified flow diagram of the CO ₂ -EOR operations	11
Figure 6: CO ₂ collection and distribution process	13
Figure 7: Simplified fluids flow diagram for a typical NEPSU satellite	14
Figure 8: Process diagram for the Lindsay Gas Plant	15
Figure 9: Top Springer structure	19
Figure 10: Net pay thickness for the Springer reservoir sands	20
Figure 11: Schematic of the reservoir-seal stratigraphic trapping configuration	21
Figure 12: Oil PVT plots	23
Figure 13: Oil and gas viscosity	23
Figure 14: Lorenz plot	24
Figure 15: Hydrocarbon pore volume filled by CO ₂ injection vs. time	25
Figure 16: Recovery factor vs. CO ₂ pore volume injected	25
Figure 17: Oil rate-time curve comparison with actual estimations	27
Figure 18: Comparison of the cumulative oil rates	27
Figure 19: Variation of CO ₂ density at 148 degrees F	28
Figure 20: Predicted volume available for CO ₂ injection	29
Figure 21: Predicted CO ₂ storage in terms of mass	29
Figure 22: Location and type of all wells within the Active / Maximum Monitoring Area	33
Figure 23: Earthquakes (+2.5 magnitude) within 2 miles of the MMA	35

List of Tables

Table 1: Reservoir Summary Characteristics	18
Table 2: Details of earthquakes within the MMA	36
Table 3: Assessment of Likelihood, Magnitude, and Timing of Potential Leakage Pathways	37
Table 4: Response Plan for CO ₂ Loss	40

Appendix 1 – List of Wells

A list of all known wells in the MMA is provided in the attached PDF spreadsheet. Information was compiled from available S&P Global (formerly IHS) data. This information may differ from records available from the online OCC Well Data Finder as well as the archived documents database for well data, which may not include certain legacy well records. To ensure all wells within the MMA are accounted for, Daylight is providing the more extensive well record data provided by S&P Global that contains 886 unique wellbores within the MMA.

Appendix 2 – References

Regulatory Citations

Oklahoma Administrative Code Title 165 Chapter 10 (<https://rules.ok.gov/code>)

26 CFR 1.45Q (for table of contents, see <https://www.ecfr.gov/current/title-26/section-1.45Q-0>)

40 CFR Part 98 Subpart A (<https://www.ecfr.gov/current/title-40/part-98/subpart-A>)

40 CFR Part 98 Subpart W (<https://www.ecfr.gov/current/title-40/part-98/subpart-W>)

40 CFR Part 98 Subpart RR (<https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-RR>)

40 CFR Part 98 Subpart UU (<https://www.ecfr.gov/current/title-40/part-98/subpart-UU>)

Other Publications

Advanced Resources International (2024). The U.S. CO₂ enhanced oil recovery survey. <https://adv-res.com/pdf/ARI-2021-EOY-2020-CO2-EOR-Survey-OCT-21-2021.pdf>

Ball, M. M., Henry, M. E., and Frezon, S. E. (1991). Petroleum geology of the Anadarko Basin region, Province (115), Kansas, Oklahoma, and Texas. Open-File Report 88-450W, U.S. Geological Survey.

Birk, S.C. (1986). Letter to Cuscaden, J.A., S.E. Bradley – minimum miscibility pressure. Project 208-5480. Mobil Research and Development Corporation, Dallas Research Laboratory.

Brinlee, L. D., and Brandt, J. A. (1982). Planning and development of the Northeast Purdy Springer CO₂ miscible project. Paper presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, September 1982. SPE-11163-MS, 13 pp. doi: <https://doi.org/10.2118/11163-MS>

Chang, J.M., and Stanley, T.M. (2010). Geologic map of the Pauls Valley 30' X 60' quadrangle (Preliminary), Carter, Cleveland, Garvin, Grady, McClain, Murray, Pottawatomie, and Stephens Counties, Oklahoma. Oklahoma Geological Survey OGQ-81 Color.

Cities Service Company (1978). Feasibility analysis of applying enhanced recovery methods, Northeast Purdy Spring Sand Unit “A”, Garvin County, Oklahoma. Unpublished manuscript, Cities Service Company Task Force for Purdy Unit.

Ekstrand, J.D. (1979). Routine core analysis and special flow studies, N.E. Purdy K-214, Garvin County, Oklahoma. Cities Service Company Energy Resources Group Research Laboratory, PR 79-02.

Fox, M.J., Simlote, V.N., Stark, K.L., and Brinlee, L.D. (1988). Review of CO₂ flood, Springer “A” Sand, Northeast Purdy Unit, Garvin County, Oklahoma. SPE Res Eng 3: 1161–1167. doi: <https://doi.org/10.2118/14938-PA>

Koval, E.J. (1963). A method for predicting the performance of unstable miscible displacement in heterogeneous media. SPE J. 3: 145–154. doi: <https://doi.org/10.2118/450-PA>

Ham, W.E., Denison, R.E., and Merritt, C.A. (1964). Basement Rocks and Structural Evolution of Southern Oklahoma: Oklahoma Geological Survey Bulletin 95, 302 p.

- Higley, D.K., compiler. (2014). Petroleum systems and assessment of undiscovered oil and gas in the Anadarko Basin Province, Colorado, Kansas, Oklahoma, and Texas—USGS Province 58: U.S. Geological Survey Digital Data Series DDS–69–EE, 409 p. <http://dx.doi.org/10.3133/ds69EE>
- Irani, M., Bashtani, F., and Kantzas, A. (2021). Control of gas cresting/coning in horizontal wells with tubing-deployed inflow control devices. *Fuel* 293, 120328. doi:10.1016/j.fuel.2021.120328
- Johnson, K.S., and Luza, K.V., eds. (2008). *Earth Sciences and Mineral Resources of Oklahoma*. Oklahoma Geological Survey, University of Oklahoma.
- Jorgensen, D.G. (1993). Paleohydrology of the Central United States, Chap. D, in: *Strategic and critical minerals of the Midcontinent region, United States* – U.S. Geological Survey Bulletin 1989.
- Lee, E., Hornafius, J. S., Dean, E. Kazemi, H., (2019). Potential of Denver Basin oil fields to store CO₂ and produce Bio-CO₂-EOR oil. *International Journal of Greenhouse Gas Control* (81): 137-156. <https://doi.org/10.1016/j.ijggc.2018.11.013>
- Nelson, P.H., and Gianoutsos, N.J. (2014). Potentiometric surfaces for seven stratigraphic units and an explanation for underpressure in the Greater Anadarko Basin, Oklahoma, Texas, Kansas, and Colorado, Chap. 9, in: Higley, D.K., compiler, *Petroleum systems and assessment of undiscovered oil and gas in the Anadarko Basin Province, Colorado, Kansas, Oklahoma, and Texas* – USGS Province 58: U.S. Geological Survey Digital Data Series DDS–69–EE, 24 p. doi: <http://dx.doi.org/10.3133/ds69EE>.
- NEPSU (1979). Enhanced recovery reservoir geology – Northeast Purdy Field, Garvin County, Oklahoma. Unpublished manuscript.
- OWRB (n.d.). Oklahoma groundwater resources – major and minor aquifers of Oklahoma (map). Accessed January 2025 at: https://www.owrb.ok.gov/maps/pdf_map/GW%20Aquifers.pdf
- Oxy (1988). Geologic and reservoir description. Unpublished manuscript.
- Perry Jr., W. J. (1989). Tectonic evolution of the Anadarko Basin region, Oklahoma. Chapter A, in: *Evolution of Sedimentary Basins*, U.S. Geological Survey Bulletin 1866.
- Salazar, J., and Lake, L. (2020). The physical meaning of the Koval factor. *Mathematical Geosciences*. 52. doi: 10.1007/s11004-020-09883-0.
- Simlote, V., and Withjack, E. M. (1981). Estimation of tertiary recovery by CO₂ injection – Springer A Sand, Northeast Purdy Unit. *J Pet Technol* 33: 808–818. doi: <https://doi.org/10.2118/9431-PA>
- Stell, M. (2010). An auditor's view of booking reserves in CO₂ EOR projects and the ROZ. Presented at the 16th Annual CO₂ Flooding Conference, Midland, Texas.

Appendix 3 – Abbreviations and Acronyms

AGA – American Gas Association

AMA – Active Monitoring Area

ANSI – American National Standards Institute

AoR – Area of Review

API – American Petroleum Institute

ASTM – American Society for Testing and Materials

CCUS – Carbon Capture, Utilization, and Storage

CFR – Code of Federal Regulations

CO₂ – Carbon Dioxide

CO₂-EOR – Carbon Dioxide Enhanced Oil Recovery

cp – Centipoise

DPHI – Density Porosity

EOR – Enhanced Oil Recovery

EOS – Equation of State

F – Fahrenheit

ft³ – Cubic Foot

FVF – Formation Volume Factor

GERG – European Gas Research Group

GHG – Greenhouse Gas

GHGRP – Greenhouse Gas Reporting Program

GPA – Gas Producers Association

GR – Gamma Ray

HCPV – Hydrocarbon Pore Volume

lbs – Pounds

m³ – Cubic Meter

mD – Millidarcies

MIT – Mechanical Integrity Test (or Testing)

MMA – Maximum Monitoring Area

MMB – Million Barrels

MMP – Minimum Miscibility Pressure

MMscf – Million Standard Cubic Feet

MMSTB – Million Stock Tank Barrels

MRV – Monitoring, Reporting, and Verification

MMT – Million Metric Tons

Mcf – Million cubic feet

MT – Metric Ton

NAESB – North American Energy Standards Board

NGL – Natural Gas Liquids

NIST – National Institute of Standards and Technology

NPHI – Neutron Porosity

OAC – Oklahoma Administrative Code

OCC – Oklahoma Corporation Commission

ppm – Parts Per Million

psi – Pounds per Square Inch

psia – Pounds per Square Inch Absolute

psig – Pounds per Square Inch Gauge

PVT – Pressure, Volume, Temperature

QA/QC – quality assurance/quality control

rb – Reservoir Barrels

RTS – Radioactive tracer survey

SPHI – Sonic Porosity

UIC – Underground Injection Control

USDW – Underground Source of Drinking Water

USEPA – United States Environmental Protection Agency

USGS – United States Geological Survey

WAG – Water Alternating Gas

Appendix 4 – Conversion Factors

Daylight reports CO₂ at standard conditions of temperature and pressure as defined in the Oklahoma Administrative Code (OAC) for Oil and Gas Conservation, Title 165 Chapter 10 as follows:

“Cubic foot of gas” means the volume of gas contained in one cubic foot (ft₃) of space at an absolute pressure of 14.65 pounds per square inch (psi) and at a temperature 60 degrees F. Conversion of volumes to conform to standard conditions shall be made in accordance with Ideal Gas Laws corrected for deviation from Boyle’s Law when the pressure at point of measurement is in excess of 200 pounds per square inch gauge (psig).

To calculate CO₂ mass from CO₂ volume, USEPA recommends using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST). This online database is available at <https://webbook.nist.gov/chemistry/fluid/>. It provides the density of CO₂ using the Span and Wagner equation of state (EOS) at a wide range of temperature and pressures.

At the standard conditions prescribed in the OAC, the Span and Wagner EOS gives a density of 0.0026417 lb-moles per cubic foot. Using a molecular weight for CO₂ of 44.0095, 2,204.62 lbs/MT and 35.314667 ft³/m³, gives a CO₂ density of 5.27346×10^{-2} MT/Mcf or 0.0018623 MT/m³.

Note that the USEPA standard conditions of 60 degrees F and one atmosphere produce a slightly different value. The Span and Wagner EOS gives a density of 0.0026500 lb-moles per cubic foot. Using a molecular weight for CO₂ of 44.0095, 2,204.62 lbs/MT and 35.314667 ft³/m³, gives a CO₂ density of 5.29003×10^{-2} MT/Mcf or 0.0018682 MT/m³.

The conversion factor 5.27346×10^{-2} MT/Mcf is used to convert CO₂ volumes to metric tons.

Appendix 5 – Koval Factor Calculation

Based on theoretical considerations, laboratory experiments, and pilot tests, Koval (1963) suggests that in miscible flooding, viscous fingering affects the volumetric sweeping efficiency. Immiscible viscous fingering in porous media occurs when a high-viscosity fluid is displaced by an immiscible low-viscosity fluid. In such cases, the Buckley-Leverett model cannot be applied directly and requires modification. According to Koval's theory (Koval, 1963), the fraction of pore volume swept by the displacing agent, denoted as E_v , can be expressed as a function of K_v , the Koval heterogeneity factor.

$$\text{If } t_D \leq 1/K_v \text{ then } E_v = t_D \quad \text{Equation 5-1}$$

$$\text{If } 1/K_v < t_D < K_v \text{ then } E_v = \frac{2\sqrt{K_v t_D} - t_D - t_D}{K_v - 1} \quad \text{Equation 5-2}$$

$$\text{If } t_D \geq K_v \text{ then } E_v = 1.0 \quad \text{Equation 5-3}$$

where t_D is injected pore volume.

The Koval factor combines both the viscosity contrast effect and the heterogeneity effect. In practical applications, calculating the Koval factor is a complex task. A comparison is made with the Lorenz coefficient (Salazar and Lake, 2020). In this model, **Figure A5** is used, and based on the given Lorenz coefficient, the Koval factor is calculated.

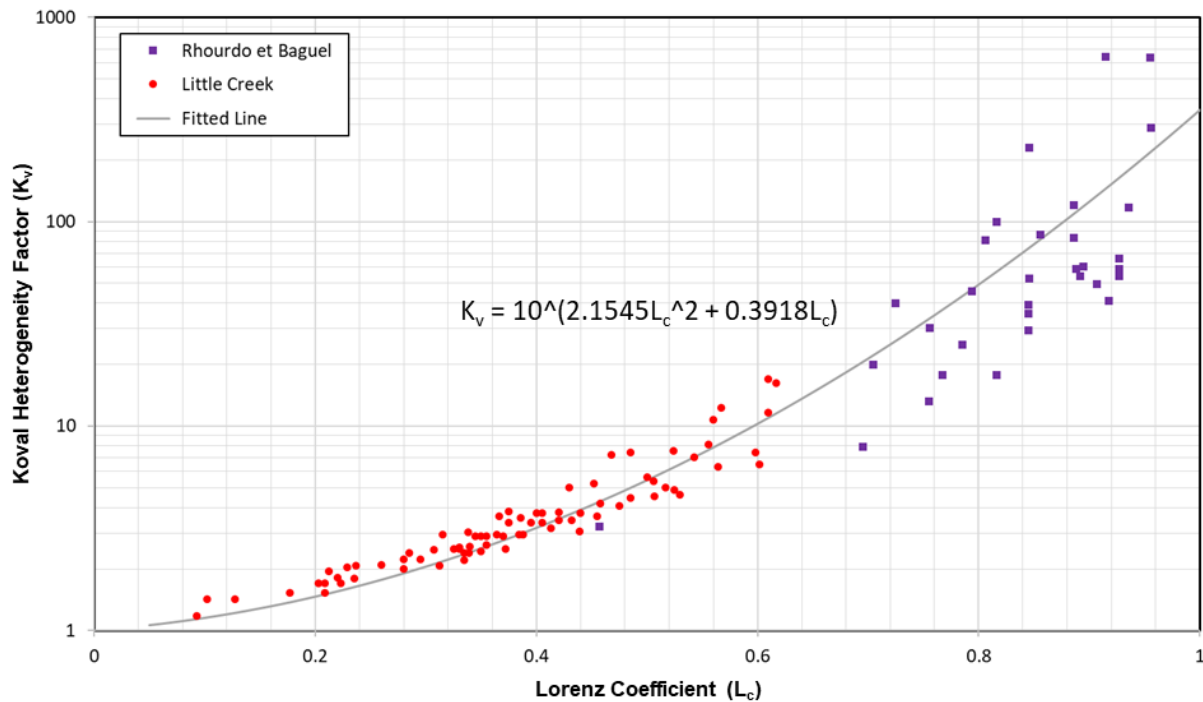


Figure A5: Comparison of the Koval factor and Lorenz coefficient.

Appendix 6 – Muskat Model Description

This appendix explains the formulation behind the Muskat Model, based on the work of Irani et al. (2021). Generally, when an analytical solution is not available, the depletion performance equations can be divided into blocks, with each block assuming constant properties. Muskat's method offers a solution that accounts for the expansion behavior of each pressure/saturation block, along with the corresponding flow equations. It also considers the expansion and liberation of gas due to pressure reduction, allowing for calculations of these effects. This method was chosen for its widespread application, simplicity, and compatibility with the available data size.

The first step involves calculating B_o , B_g , R_s , μ_o , and μ_g at pressures equal to or below the bubble point pressure.

Second, we calculate parameters α , β , and γ .

$$\alpha = (B_g^i)/(B_o^i) \times (R_s^{(i-1)} - R_s^i)/(P_i - P_{(i-1)}) \quad \text{Equation 6-1a}$$

$$\beta = 1/(B_o^i) \times (B_o^i - B_o^{(i-1)})/(P_i - P_{(i-1)}) \times (\mu_o^i)/(\mu_g^i) \quad \text{Equation 6-1b}$$

$$\gamma = 1/(B_g^i) \times (B_g^i - B_g^{(i-1)})/(P_i - P_{(i-1)}) \quad \text{Equation 6-1c}$$

At the first iteration, oil saturation can be obtained utilizing the water saturation derived from the resistivity log.

$$S_o = 1 - S_w \quad \text{Equation 6-2}$$

With both oil and water saturations available, the relative permeability of oil and gas can be determined. Using these relative permeability values, oil and water saturations can then be back calculated. In the next iteration, with the updated water and oil saturations, the gas saturation can be calculated, assuming a three-phase system.

$$S_g = 1 - S_w - S_o \quad \text{Equation 6-3}$$

Now, having the saturations at previous iterations, new oil saturation can be calculated as follows:

$$S_o^i = S_o^{(i-1)} - \left(\alpha S_o^i + \beta S_o^i (k_{rg}^i)/(k_{ro}^i) - \gamma (1 - S_w - S_o^i) \right) / \left(1 + (\mu_o^i)/(\mu_g^i) (k_{rg}^i)/(k_{ro}^i) \right) (P_{(i-1)} - P_i) \quad \text{Equation 6-4}$$

New relative permeability values can be determined using the updated oil saturation. This process is repeated iteratively until the difference between the old and new oil saturation becomes negligible. Next, we define a given rate at day 1, where the rate on any subsequent day is calculated by multiplying the initial rate by the new mobility factor. The mobility factor is the ratio of the new oil relative permeability to the oil viscosity at the given pressure. Finally, we define the pressure change over time to match both oil production and gas production (or the produced GOR).