OCCIDENTAL OF ELK HILLS, INC.
10800 Stockdale Highway, Bakersfield, CA 93311
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DATE	JUN 06 2012
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June 6, 2012

Robert Worl, Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814-5512

**RE: HYDROGEN ENERGY CALIFORNIA PROJECT (08-AFC-8)
CALIFORNIA ENERGY COMMISSION DATA REQUEST,
AUGUST 5, 2011(#s 51-55)**

Dear Mr. Worl,

Attached is Occidental of Elk Hills, Inc.'s (OEHI) response to items 51-55 of the August 5, 2011, California Energy Commission (CEC) information request, regarding OEHI's proposed CO_2 EOR Project relating to the pending Application for Certification of the Hydrogen Energy California Project. Also enclosed is OEHI's proposed Measuring, Reporting and Verification Plan for quantifying volumes of CO_2 that become sequestered during OEHI's proposed CO_2 EOR operations.

We look forward to discussing the OEHI responses to CEC data and information requests, and the MRV Plan, with staff and stakeholders. In the meantime, please feel free to contact the applicant or OEHI should you need additional information or clarification.

Sincerely,

William Barrett (eh)

William H. Barrett
EOR Business Manager
Occidental of Elk Hills, Inc.

CEC questions (#51-#55) of the August 5, 2011 letter from A. Solomon (CEC) to A. Udobot (HECA) are in bold font below. OEHI responses are in standard font below. Note that many of the apparent issues are addressed in OEHI's Monitoring, Reporting and Verification Plan (MRV).

Sequestration/Enhanced Oil Recovery

Most of the questions still outstanding are related to the response of the Occidental Petroleum fields to injection and storage pressures that approach, or may exceed, overburden pressures considering the volumes to be injected and time scale of the injection.

51. A storage rate or trapping ratio for CO_2 per pass is needed to evaluate the amounts of CO_2 stored with time. The original application assumed a ratio of 1:3, which seems to be unrealistic given that there is no basis from field data, especially when compared with many other documented injection projects that report an average recirculation rate of 100 percent of purchased CO_2 and thus a trapping ratio of zero. Staff is aware of the results of the study conducted at the University of Wyoming that indicates a trapping ratio on the order of 1:3 per pass, but cannot verify this ratio from pilot studies or reports.

We believe that the University of Wyoming study does most accurately capture the average trapping ratio over time. However, there appears to be some confusion over how CO_2 injection projects are operated.

Generally, once injected into the reservoir subsurface, CO_2 exists in two states: 1) mobile CO_2 (including free CO_2, CO_2 dissolved in water, and CO_2 in-phase with oil) that is moving through the reservoir and will be produced through production wells; and 2) CO_2 that becomes trapped in the formation by the structural, stratigraphic, solubility and mineralization mechanisms discussed in the MRV Plan. In a closed-loop system, CO_2 produced to the surface is separated from the oil and water streams and is re-combined and compressed to higher pressure for re-injection into the reservoir along with additional CO_2 purchases and any associated hydrocarbon gas. At some point in the process, as an individual injection pattern matures, the quantity of CO_2 produced at the production well increases dramatically (called "breakthrough") and there is a corresponding increase in the CO_2 production to injection ratio. Regardless, CO_2 is still being trapped in the reservoir through the geologic trapping mechanisms for as long as CO_2 is cycled through the pattern.

Because of the cost of purchased CO_2 and recycle compression equipment, recycle rate is often the most important factor in CO_2 flood design. On a well-by-well basis, CO_2 purchases are high during flood initiation prior to CO_2 reaching production wells. CO_2 purchase rates will drop with time depending on CO_2 breakthrough. As CO_2 breakthrough occurs, more patterns are added to CO_2 injection until the recycle compression limit is reached. The migration to new patterns is adjusted to match the purchased volumes, trapping loss and compression limit as appropriate. Accordingly, the purchase rate of CO_2 to "make up" for volumes lost to geologic trapping over time is a better indicator of the sequestered volumes than is any estimate of trapping ratio "per pass." However, the most accurate measurement of sequestered volumes can be determined using the mass balance equation set forth in the MRV Plan.

Oxy estimates that the amount of CO_2 from the HECA project will fill a small percentage of the useable reservoir pore volume. Ultimately, all of the CO_2 injected through the Oxy CO_2 EOR Project (net of fugitive CO_2 emissions, de minimis sales in product streams, and operational losses) will become trapped in the formation and will be sequestered.

52. Data needed to characterize the formation where the CO_2 will be injected and stored are still lacking. Of particular importance are data pertaining to the following:

a- pore space characteristics and oil distribution, which are necessary to judge the availability and ease of pumping the carbon dioxide (CO_2);

Pore space characteristics and oil distribution are as follows:

1. Porosity range: Please refer to MRV section 3.1.2.1.
2. Average permeability: Please refer to MRV section 3.1.2.1 and 3.1.2.3.
3. Oil (post-waterflood) saturation varies between 25% to 35% of pore volume.

b- information needed to characterize the rock formations that will help determine the response of the rocks to available and additional stresses;

Please see information provided in the MRV Plan.

c- pore pressure, which is needed to assess the pressure required for the injection of the CO_2 into the formation; and

Pore Pressure currently ranges between 2600 psi to 3900 psi. With the initiation of the pattern waterflood and CO_2 flood, the target pore pressure will be in the ~3000-3300 psi range.

d- formation stresses, which are needed to assess the behavior of any faults that may be present.

Please see information provided in the MRV Plan.

53. Rock-mechanics data and reservoir data are needed to demonstrate the feasibility of the EOR and CCS project. Also, in-situ stress measurements at multiple locations as a function of depth are needed. In addition, estimates of the bulk rock moduli, Poisson's ratios, and/or Young's moduli for the Stevens sandstone and the confining Reef Ridge shale are needed in order to characterize the rock formation in terms of maximum stressed that can be sustained and the induced deformations.

Included below are Young's Moduli and Poisson's Ratios for the Stevens Sandstone and confining Reef Ridge shale.

Formation	Data Source	Well Name	Depth	Young's Modulus	Poisson's Ratio
Reef Ridge	Sonic Log	348X-33S	6050	0.37	0.31
Reef Ridge	Sonic Log	357A-33S	6100	0.22	0.29
Reef Ridge	Sonic Log	378X-34S	6200	0.22	0.29
Stevens Sand	Sonic Log	348X-33S	6700	0.34	0.21
Stevens Sand	Sonic Log	357A-33S	6800	0.28	0.27
Stevens Sand	Sonic Log	378X-34S	7250	0.27	0.28

54. There are hundreds of wells that penetrate the Reef Ridge (RR) shale, but no information is available as to their integrity and keeping their casing and cement components from being corroded/eroded away by the combination of CO_2 and carbonic acid. This information will be necessary for staff's analysis.

Details of construction of wellbores that penetrate the Reef Ridge, including cement tops behind casing, are discussed in sections 3.1.4 and 3.3.2 of the MRV Plan, and will be included in the UIC Class II permit application as required by the California Department of Oil, Gas and Geothermal Resources (DOGGR). All wellbores that penetrate the Reef Ridge formation will have a cement top which extends in to the base of the Reef Ridge or higher. Industry technical studies indicate that the phenomenon of dissolution of cement by carbonic acid is slow, so slow as to not pose a credible risk of failure of the cement seal, and in some conditions reaches chemical equilibrium.

The operating plan for managing corrosion both externally and internally on wellbore casing strings will include placing inert fluids in the tubing and casing annulus where possible, chemical inhibition where the annulus contains flowing fluids, and cathodic protection of external surfaces. (See MRV Section 4, Tier 3 for a detailed discussion).

55. The Oxy Hills field is characterized as a plunging anticline that forms a natural geologic trap for petroleum hydrocarbons. This anticline has formed as a result of faulting and folding of sedimentary rock in an active tectonic region of California. Staff is concerned that the faulting and folding remain active and that there is potential for future rupture of existing or new faults in or along the plunging anticline which would allow for leakage and failure of the short- and long-term CCS component of the project. There is a lack of information about the location of active and potentially active faults and time and magnitude of rupture along faults in the vicinity of the project site. Also, information is needed to analyze the potential for reactivating existing ruptures or creating new ones.

For a detailed discussion, please refer to Section 3.1.2.2 of the MRV plan. The Reef Ridge Shale is the main seal for the area and a natural lithologic barrier with no evidence of major reverse fault penetration. A detailed explanation of potential pathways for leakage to the surface due to faults, fractures and naturally and induced seismic activity is also included in Section 3.3 of the MRV Plan.

There is little possibility that pressure change due to injection can induce fractures or shear for leakage. Historical data and information also indicate that natural seismic events do not constitute a significant threat for leakage to the surface. With more than 58,000 deep production and injection wells in the Southern San Joaquin Valley, and decades of seismic activity, there has been no evidence of dangerous release of gas, oil, or water due to earthquakes. Major California earthquakes, with magnitude 6 and above, occur at depths of 6 miles or more in brittle basement rock far below the injections zones of soft sandstone less than 2 miles deep at the Elk Hills Unit.

Oxy Elk Hills CO_2 EOR Project

Monitoring, Reporting and Verification Plan

June 5, 2012

Occidental of Elk Hills, Inc.
A subsidiary of Occidental Petroleum Corporation

Table of Contents

Acronyms

A1/A2 – Reservoirs within the Stevens reservoirs within the NWS structure
AGA – American Gas Association
API – American Petroleum Institute
ASP – Alkaline Surfactant Polymer
bbo – billion barrels of oil
CAPUC – California Public Utilities Commission
CCF – Central Control Facility
CEC – California Energy Commission
CH_4 – Methane
CO_2 – Carbon Dioxide
CRP – CO_2 Removal Plant
CTB – Central Tank Battery
DOGGR – Division of Oil, Gas and Geothermal Resources
EHOF – Elk Hills Oil Field
EHU – Elk Hills Unit
EOR – Enhanced Oil Recovery
GEM – Geochemical Equation Compositional Model
GPA – Gas Processors Association
HC – Hydrocarbon
HECA – Hydrogen Energy California
LSE – Load Serving Entity
MBB – Main Body B
mmscfd – million standard cubic feet per day
MRV – Monitoring, Reporting, and Verification
NGL – Natural Gas Liquid
NWS – Northwest Stevens
OEHI – Occidental Elk Hills, Inc.
OOIP – Original Oil In Place
RCF – Reinjection Compression Facility
SOZ – Shallow Oil Zone
SS1 – First Sub-Scalez
SS2 – Second Sub-Scalez
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USEPA – U.S. Environmental Protection Agency
USDW – Underground Source of Drinking Water
USS2 – Upper Second Sub-Scalez
WAG – Water Alternating with Gas

1. Introduction[1]

Occidental of Elk Hills, Inc. (OEHI or Company), a subsidiary of Occidental Petroleum Corporation, plans to use carbon dioxide (CO_2) from the proposed Hydrogen Energy California power plant (HECA Project) to extend OEHI's existing enhanced oil recovery (EOR) in an area within the Elk Hills Unit (EHU). The EHU is part of a large, mature oil and gas field (Elk Hills Oil Field or EHOF) that OEHI operates near Bakersfield, California. The Company's planned CO_2 EOR project is hereinafter referred to as the Oxy CO_2 EOR Project or the Oxy Project. The Oxy CO_2 EOR Project is designed to meet a number of objectives, which are summarized below.

- Extend and enhance the useful and productive life of the EHU thereby increasing domestic oil and gas energy supplies and improving energy security.
- Provide an accounting of the CO_2 received onsite and used for EOR, which will: 1) demonstrate the safe and cost-effective sequestration of CO_2 through EOR, 2) help demonstrate that the HECA Project meets its greenhouse gas (GHG) requirements, 3) facilitate OEHI's compliance with applicable regulatory requirements.
- Minimize environmental impacts associated with the construction and operation of the Oxy Project through choice of technology, project design and implementation of feasible and appropriate mitigation measures. In addition, the Oxy CO_2 EOR

[1] The data reported in this MRV Plan were based on the HECA Project as proposed in HECA's Revised AFC dated May 28, 2009, which projected an average rate of CO_2 delivered to OEHI of 107 million standard cubic feet per day (mmscfd). HECA recently submitted to the California Energy Commission a revised Project Description for a project that could deliver an average of up to 135 mmscfd of CO_2. HECA and OEHI are in discussions regarding delivery of the increased volumes. If volumes of CO_2 are delivered in excess of an average of 107 mmscfd, certain analyses of this MRV Plan would be revised to reflect these increased volumes, including in particular certain analyses relating to Section 3 and Section 4. In addition, in conjunction with its on-going development of the resources at the Elk Hills Oil Field, OEHI is seeking approval from DOGGR for a miscible gas injection project using a methane/ethane/CO_2 mixture that would affect some of the same reservoirs that are proposed to be used for the CO_2 EOR Project. If approved, the miscible gas project also may prompt further analysis of certain provisions of this MRV Plan, including Section 3. OEHI does not believe that either or both of these potential revisions will materially affect the Summary of the Assessment of Risk of Release from Subsurface set forth in Section 3.4 herein. Finally, Certain data in this plan, such as the specific number of closed and operational wells, are accurate as of July 23, 2010 when the discussion draft of the Monitoring, Reporting, and Verification (MRV) report was submitted to the California Energy Commission (CEC). Although these data will not change significantly, they are subject to change due to ongoing operations of the Elk Hills facility and will be revised for the final submission of this MRV plan.

Project will provide significant net environmental and economic benefits in air emissions, habitat conservation, and the efficient use of existing infrastructure.

- Provide economic benefit to the local and California economies through jobs associated with construction and operations at the EHU where approximately 500 employees and 3,000 contractors currently work.
- Further demonstrate the commercial viability of the process wherein CO_2 used for EOR becomes sequestered.

Much like the existing EHU water-flood projects, the Oxy CO_2 EOR Project is a commercial operation to enhance the recovery of existing oil that would otherwise be left stranded, and OEHI is proposing the Oxy CO_2 EOR Project solely on its economic merits. Oxy's CO_2 EOR Project will simultaneously result in significant CO_2 sequestration and this monitoring, reporting, and verification (MRV) plan (MRV Plan) is designed to create a transparent methodology for quantifying the amount of sequestered CO_2 to enable HECA to demonstrate compliance with the requirements of the California Public Utilities Commission (CA PUC).

OEHI's MRV Plan rests on a thorough understanding of the subsurface environment into which the CO_2 will be injected and a full-field simulation of the planned injection that includes potential scenarios for subsurface migration of the injected CO_2 over time. This assessment indicates that the natural geologic seal that overlays the entire EHOF, known as the Reef Ridge Shale, will provide a physical trap that will prevent injected CO_2 from migrating to the surface. Conceptually, the Reef Ridge Shale is like the vertical and lateral sides of a "box" that has contained hydrocarbons for millions of years. Similarly, this same "box" will contain the CO_2 that will be injected to mobilize those hydrocarbons. The MRV Plan is tailored to the Oxy CO_2 EOR Project based on what is known and modeled regarding the subsurface as well as what is planned for the injection and production schedule.

1.1 Overview of the Monitoring, Reporting, and Verification Plan

Section 1 is an overview of the MRV Plan.

Section 2 of the MRV Plan describes the project location, main geologic features at the project site, and the major components of the Oxy CO_2 EOR Project. A representative flow diagram is used throughout much of the section to explain in detail how various fluids (i.e., crude oil, hydrocarbon gas, water and CO_2) will flow to, through, and from the Oxy CO_2 EOR Project.

Section 3 of the MRV Plan presents the assessment of the potential risk of leakage to the surface by reviewing site characterization, the reservoir simulation, and potential leakage pathways. There are three important conclusions stemming from this information:

- Excellent Site Characterization - Geologic sequestration authorities note that proper site selection is the most important measure to mitigate the risk of atmospheric loss of CO_2 from geologic sequestration. The EHOF is one of the largest oil fields in the

United States and has been studied and documented extensively during its 100+ year operating history. The EHOF has multiple injection zones and sealing formations that are well suited to CO_2 sequestration. Accordingly, much of this MRV Plan addresses the suitability of the EHOF for geologic sequestration.

- Full Containment of Injected CO_2 within the EHOF - OEHI has developed a full-field simulation model of the planned operations. This model predicts the movement of injected CO_2 in the subsurface over time. The model will be updated periodically based on actual monitoring data, which will enhance and refine its usefulness in predicting future movement of CO_2. It will be used to adjust the monitoring plans and operations as necessary, and over time it will be used as part of the demonstration that injected CO_2 will remain in the target injection zones.
- Insignificant Risk of Leakage to the Surface - The target injection zones are compartmentalized within a geologic structure that has contained oil and natural gas for millions of years. There is no history of surface seeps and there are no known natural features, such as transmissive faults or fractures, which penetrate the geologic seal (the Reef Ridge Shale) in the area of the Oxy CO_2 EOR Project. Furthermore, the operating history of the EHOF is well documented, which informs the conclusion that the potential for unplanned fluid migration through man-made pathways is minimal. And finally, the risk of unexpected leakage to the surface through wellbores will be mitigated through the use of proven engineering practices, regular monitoring for well integrity, and scheduled maintenance. Based on these characteristics, the potential risk of leakage to the surface resulting from future injection operations is extremely remote.

Section 4 of the MRV Plan outlines the monitoring program proposed by OEHI based an assessment of existing data and modeling. This program addresses monitoring during both the operational and closure periods. Potential leakage pathways and reasonable scenarios that could lead to leakage to the surface have been assessed using the full field reservoir simulation model in combination with OEHI's extensive operating experience in the EHU. OEHI has collected data on the field operations for decades and will use this plus any additional information necessary, to develop baselines for fluid pressures and compositions. The monitoring program has been designed to quickly detect changes in these parameters that might indicate unplanned CO_2 migration.

The majority of the Oxy CO_2 EOR Project will be conducted in a portion of the EHU in which there is an active production zone located above the Reef Ridge Shale seal. OEHI will be able to use monitoring data obtained from wells located in this overlying production zone to detect CO_2 if it migrates through the Reef Ridge Shale seal. The remainder of the Oxy CO_2 EOR Project will be conducted in a small geologic structure in which there is no active production zone above the Reef Ridge Shale seal. This area is hydrologically isolated from other production areas and OEHI will locate monitoring wells in a zone above the Reef Ridge Shale seal.

OEHI has a sophisticated central control system that continuously monitors pressures and fluid flow rates throughout the EHU. Monitoring related to the Oxy CO_2 EOR Project will be designed to confirm that the injected CO_2 behaves as the model predicts and will allow rapid detection of unplanned movement of injected CO_2. Unexpected behavior will be responded to appropriately. The monitoring data will be used to inform and update the full-field simulation model.

Section 5 of the MRV Plan describes the approach for determining the volume of CO_2 sequestered using mass balance equations. OEHI intends to use data from the existing control and monitoring systems and mass-balance equations to calculate the volumes of sequestered CO_2.

Section 6 of the MRV Plan describes OEHI's approach to data handling, recordkeeping, reporting, and adjustments to the monitoring plan.

2. Project Description

2.1 Background

The EHU is located 26 miles (42 kilometers) southwest of Bakersfield in western Kern County, California and includes land distributed across all or part of 81 sections as indicated in Figure 1.

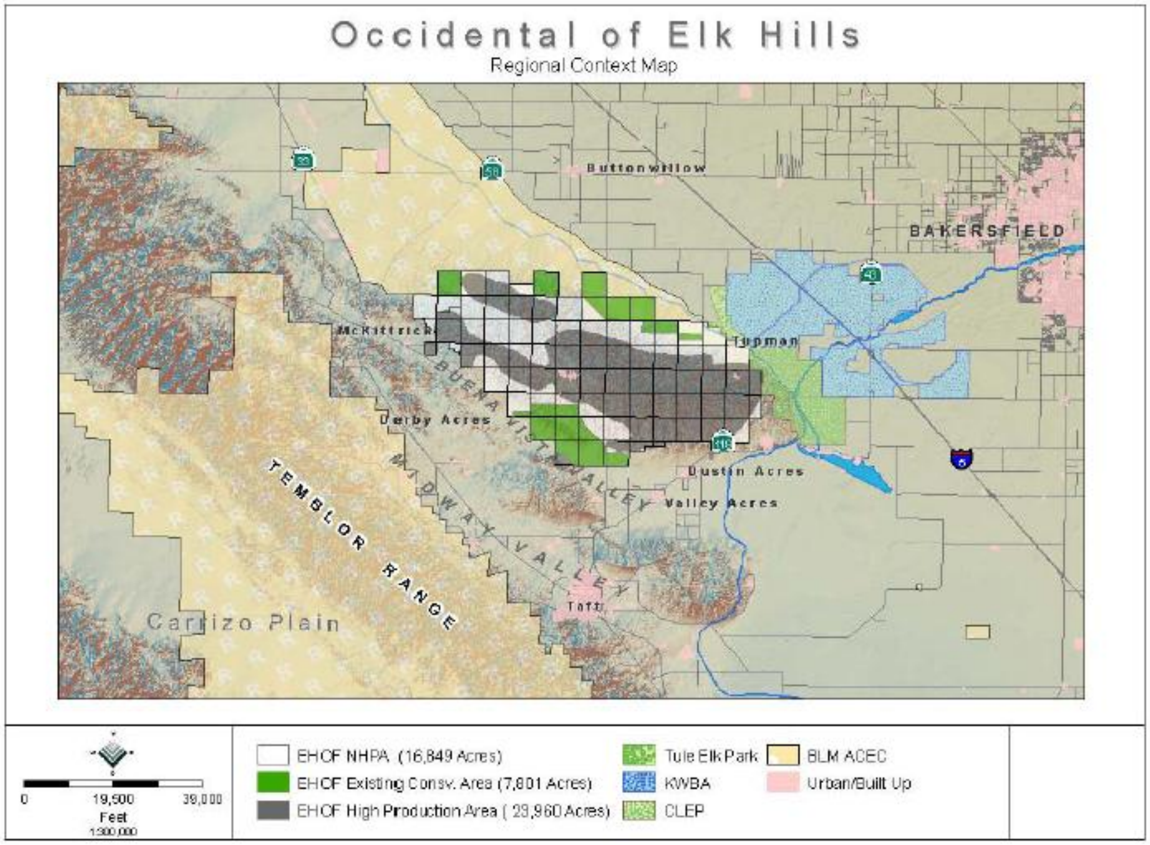


Figure 1 - Location of Elk Hills Oil Field

The EHOF was originally developed as part of the federal Naval Petroleum Reserves. Today OEHI is the majority owner (78 percent) of the EHU and Chevron owns the remaining 22 percent. OEHI operates the EHU on behalf of itself and Chevron.

The EHOF has been well studied and provides a uniquely suited setting for large-scale geologic sequestration of CO_2. During its 100+ year history, more than 6,000 wells have been drilled in the EHOF and geophysical surveys have been conducted. The well and geophysical data are contained in an extensive database developed by the federal government prior to 1998, which has been expanded since OEHI acquired ownership and is now maintained by OEHI. This database is the foundation for modeling the Oxy CO_2 EOR Project.

2.1.1 OEHI's Approach to Field Management

Occidental is one of the largest and most respected CO_2 EOR operators in the world, operating 28 CO_2 EOR projects that include thousands of wells. OEHI's standard practices for field management will be utilized in planning and executing the Oxy CO_2 EOR Project. OEHI managers employ a strategy that is based upon cascading accountability for performance among staff with operations expertise, who are responsible for geographic areas of the field; and, staff with technical expertise, who are responsible for specific reservoirs, equipment, or functions. Field technicians, who are trained in operating procedures, well surveillance, safety and environmental protection, and other functions, are an integral part of the effective management of the EHOF and work closely with contractors that perform specialized field services. This organizational model provides multiple perspectives on performance of the EHOF and stimulates identification of enhancement opportunities as information is shared among staff having different specializations and depth of knowledge.

2.1.2 Expansion of EOR Operations in the EHU Using CO_2

The Elk Hills Oil Field occupies about 48,000 acres (75 square miles) as indicated in Figure 2. There are multiple compartmentalized oil reservoirs at various intervals within the EHOF, as well as multiple layers of stratigraphic seals overlying the oil reservoirs. Current and historic EOR operations include injection of produced brine water, nitrogen gas, methane, and Alkaline Surfactant Polymer (ASP). In addition, a successful CO_2-injection pilot project was performed in 2005. All of the existing wells at the EHOF have been permitted through the California Division and Oil, Gas, and Geothermal Resources (DOGGR) under rules that require OEHI to provide extensive and detailed information about the character of the geologic setting, the construction and operation of the wells, and other information used to assess the suitability of the site. DOGGR maintains a public database that contains the location, construction details and injection/production history of each well.

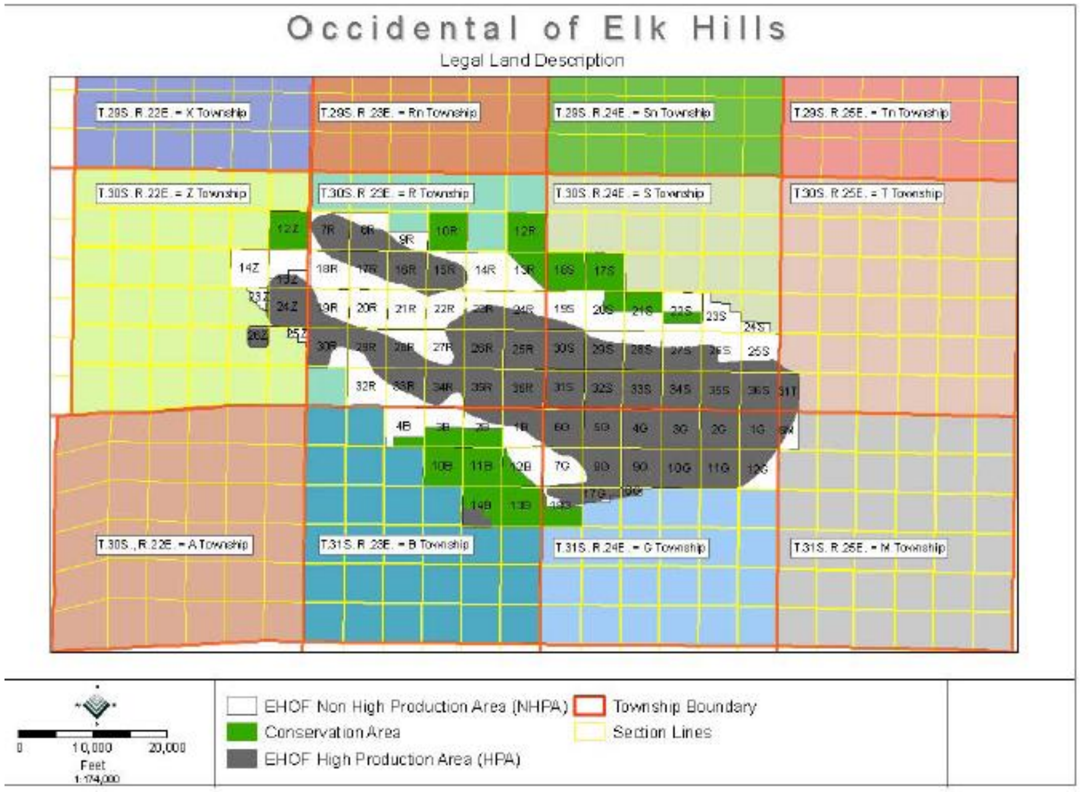


Figure 2 - EHOF Sections and Naming Convention

OEHI plans to use CO_2 from the HECA Project to enhance the production of oil in the EHU. Although several oil-producing reservoirs in the EHU are attractive targets for CO_2 EOR, the Stevens reservoirs have been identified as being particularly well suited for such operations because of their good injectivity. In addition, since the Stevens reservoirs have more than sufficient available pore space to accept the total volume of CO_2 planned to be purchased from the HECA Project, the Stevens reservoirs are the target CO_2 injection zones for the Oxy CO_2 EOR Project.

2.1.3 Major Geologic Features Involved in the Oxy CO_2 EOR Project

There are three major types of geologic features involved in the Oxy CO_2 EOR Project, as indicated in Figure 3:

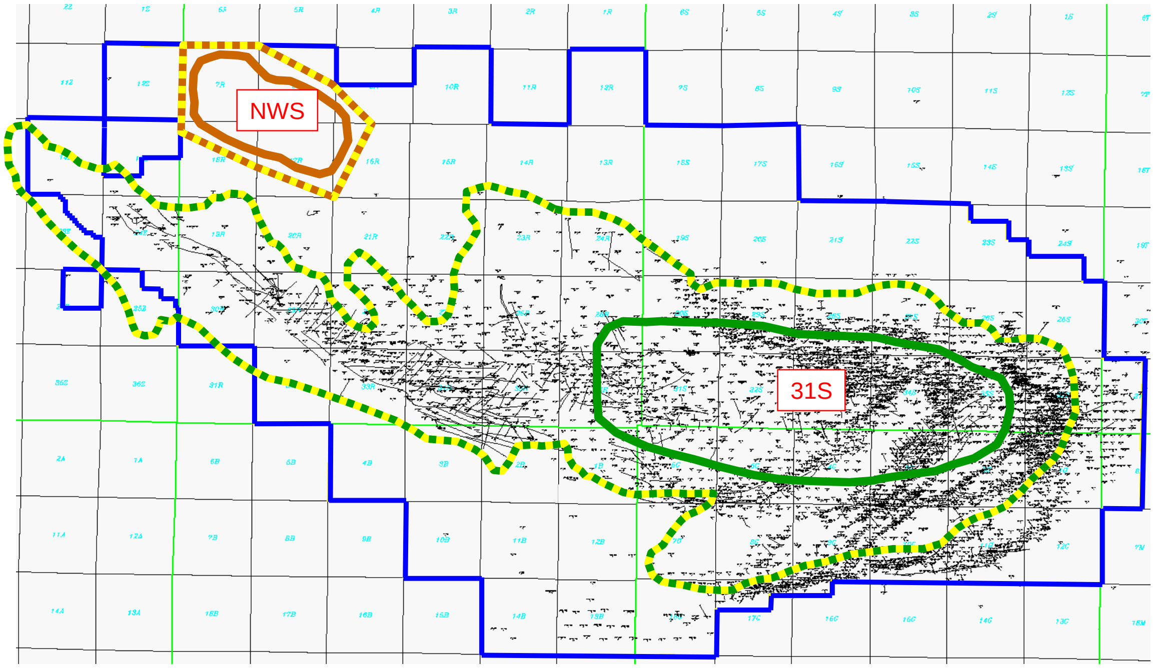


Figure 3 Major Geologic Features Involved in the Oxy CO_2 EOR Project
Location of the 31S structure (solid green) and Northwest Stevens (NWS) structure (solid brown), Shallow Oil Zone (SOZ) (dashed yellow/green line) and formation above the Reef Ridge Shale (not marked, but which extends well beyond the limits of this figure) over the Stevens injection reservoirs and the NWS structure (dashed yellow/brown line). Note, the EHOF boundary is drawn in blue.

- Injection reservoirs –The Stevens reservoirs are located approximately 5,000 feet below ground surface. The Oxy CO_2 EOR Project will take place within portions of the Stevens reservoirs located on two geologic structures that are known as 31S and the Northwest Stevens (NWS) structures. In Figure 3 the general locations of the planned injection operations are indicated by the solid brown and solid green lines.
- A sealing formation – The Reef Ridge Shale is an extensive geologic formation that covers an area much larger than the entire EHOF (as noted in Figure 15). The Reef Ridge Shale is a natural lithologic barrier with a minimum thickness of approximately 750 feet over the target injection zones in the 31S and NWS structures. As discussed below, the Reef Ridge Shale is a proven physical seal that will prevent upward migration of CO_2 out of the Stevens reservoirs.
- Formations located above the sealing formation – There are two distinct areas immediately above the Reef Ridge Shale over the injection zones. There is ongoing oil and gas production from the Shallow Oil Zone (SOZ) over the 31S structure; this is indicated by a dashed yellow/green line in Figure 3. There is no production from the formation above the Reef Ridge Shale over the Stevens injection reservoirs in the NWS structure; this area is generally outlined by the dashed yellow/brown line in Figure 3. In both cases, the overlying formations are isolated from each other and are at different pressures than the Stevens reservoirs. Therefore, monitoring in these formations will provide an early indication in the unlikely event of CO_2 migration out of the target injection zones.

2.1.4 CO_2 EOR Is a Proven Technology

Primary oil and gas recovery is driven mostly by native pressure. Once that pressure drops, various methods are used to enhance recovery of existing oil and gas in place. Advances in these EOR methods are the result of new technology, new injectants , and the generally increasing value of oil and gas.

CO_2 EOR is a well-established EOR technique used in mature oil fields. It is often known as "tertiary recovery" because it is typically applied after gas injection or water flooding has been employed, to further enhance the recovery of oil. Currently more than 40 million metric tons of CO_2 are injected annually in oil fields throughout the United States. Today, as CO_2 becomes increasingly available and technological advances provide better ways to use CO_2 in EOR, more CO_2 EOR projects are under development.

Miscible CO_2 EOR processes, still the most common type of CO_2 EOR, are designed to inject CO_2 into reservoirs at high enough pressures to cause the CO_2 and oil to become a homogenous mixture (this pressure level is known as the minimum miscibility pressure or "MMP"), but below pressures that would fracture and compromise the confining geologic seal. Above the MMP, CO_2 and crude oil are miscible, meaning they are capable of mixing in any ratio and becoming a single homogeneous solution. Due to the pressure gradient caused by the injection of the CO_2, the CO_2 will flow away from the injection well and become miscible with the reservoir oil. The resulting fluid has lower viscosity, enhanced mobility, and lower interfacial tension as compared to reservoir oil without dissolved CO_2. In effect, this process mobilizes and recovers oil that would otherwise be unrecoverable. Water injection is often alternated with CO_2 injection in a process known as Water Alternating Gas (WAG) to sweep the miscible CO_2/oil mixture to production wells and to help optimize the movement of CO_2 through the reservoir.

In addition to the WAG process, other forms of CO_2 EOR can be used in low reservoir pressure situations – those where it is not economically feasible or geochemically not possible to achieve MMP. These displacement or drainage processes are generally characterized as immiscible CO_2 flooding. Upon injection of CO_2 the main mechanisms involved in immiscible CO_2 flooding are: (1) oil phase swelling, as the oil becomes saturated with CO_2; (2) viscosity reduction of the swollen oil and CO_2 mixture; (3) extraction of lighter hydrocarbon into the CO_2 phase; and, (4) fluid drive and/or pressure which forces the oil to gravity recovery wells. This combination of mechanisms enables a portion of the reservoir's remaining oil to be mobilized and produced.

OEHI intends to use both miscible and immiscible CO_2 EOR techniques in the EHOF.

2.1.5 Regulation of the Oxy CO_2 EOR Project

On May 28, 2009, HECA submitted a Revised Application for Certification to the California Energy Commission (CEC) to authorize siting and licensing of the HECA Project pursuant to the Warren-Alquist Act. The CEC energy facility siting process has been determined to be a certified regulatory program under the California Environmental Quality Act (CEQA) and the functional equivalent of preparing environmental impact reports under CEQA. As such, the CEC is required to consider all potential significant impacts of the "whole of the project," which includes potential significant impacts from the Oxy CO_2 EOR Project. To the extent that the CEC identifies potential significant impacts relating to the Oxy CO_2 EOR Project, as it relates to the HECA Project, the CEC can specify additional project design features or mitigation measures to be implemented by other agencies responsible for permitting the Oxy CO_2 EOR Project. Such additional requirements may include, for example, monitoring, reporting and verification. This proposed MRV Plan seeks to inform the CEC's consideration of necessary and appropriate monitoring, verification and reporting mitigation measures to address potential significant impacts relating to the Oxy CO_2 EOR Project as it relates to the HECA Project.

The Oxy CO_2 EOR Project is an extension of the ongoing OEHI operations in the EHU. The California Public Resources Code ("PRC") fully authorizes DOGGR to permit injection and extraction wells and associated well facilities for the purpose of injecting fluids and gases, including CO_2, for EOR. The underground injection of fluid for EOR also is regulated under the federal Safe Drinking Water Act's Underground Injection Control (UIC) Class II permit program. The U.S. EPA has granted DOGGR primacy over the federal Class II UIC program in California. DOGGR has issued permits for a variety of oil and gas production operations at the EHU in the past, including Class II UIC permits for injection wells used for gas pressurization, water flooding, ASP flooding, and a CO_2 EOR project.

OEHI will apply for Class II UIC permits to inject CO_2 as part of the Oxy CO_2 EOR Project. OEHI's application will provide information regarding its planned operations, well design features, capacity calculations, operational injection volumes and pressures. In addition, all other necessary and appropriate permits and approvals for the Oxy CO_2 EOR Project (e.g., the Kern County Engineering, Survey and Permit Services Department, the San Joaquin Valley Unified Air Pollution Control District, and the California Department of Fish and Game) will be applied for and obtained in a timely manner. Mitigation measures identified in a final CEC certification of the HECA Project to address potential significant impacts of the Oxy CO_2 EOR Project will be included as conditions to appropriate permits and approvals for the Oxy CO_2 EOR Project.

2.1.6 The Oxy CO_2 EOR Project Will Result in CO_2 Sequestration

In the Oxy CO_2 EOR Project, where WAG will be the primary process employed, CO_2 will be injected through underground injection wells and hydrocarbon gas (including some volume of the injected CO_2), produced water and oil will be pumped to the surface through production wells. The hydrocarbon gas will be separated from the produced oil and water at the surface in a closed-loop system and the separated CO_2 will be re-injected into the target CO_2 injection zones. Because of the closed-loop operating system, recovered CO_2 is not released to the atmosphere other than fugitive losses (discussed more fully herein). With each pass of the CO_2 stream through the oil reservoir, a significant portion of the injected CO_2 will become trapped and stranded in the reservoir. As a result, additional purchased CO_2 must be added to continue the EOR operations.

Oxy estimates that the amount of CO_2 from the HECA project will fill less than 5% of the useable reservoir pore volume. Ultimately, all of the CO_2 injected through the Oxy CO_2 EOR Project (net of fugitive CO_2 emissions, de minimis sales in product streams, and operational losses) will become trapped in the formation by structural, stratigraphic, solubility and mineralization mechanisms, and will be sequestered. Sequestration is an inevitable consequence of EOR, and, for the purposes of this document, the term “sequestration” will be used interchangeably with the term “trapping.”

2.2 Project Facilities and Equipment

The Oxy CO_2 EOR Project will be conducted in phases in the Stevens reservoirs with the requested permit area expanding over time to accommodate 20 years of CO_2 delivery. The first phase of operations will start in the eastern portion of the Stevens reservoirs (those at or near the MMP) within the 31S structure (see Figure 4). Over time, the Oxy CO_2 EOR Project will expand westerly through the reservoirs that are at or near the MMP on this structure. Additionally, there are low pressure reservoirs within the NWS and 31S structures that also can be used for CO_2 injection during the initial phase of the Oxy CO_2 EOR Project. These reservoirs can accept CO_2 directly from HECA without additional compression. Including these low pressure reservoirs in the plan ensures that the Oxy CO_2 EOR Project can continue to accept CO_2 from HECA in the unlikely event of a temporary power failure or operational upset at the EHU which could affect injection into the higher pressured reservoirs.

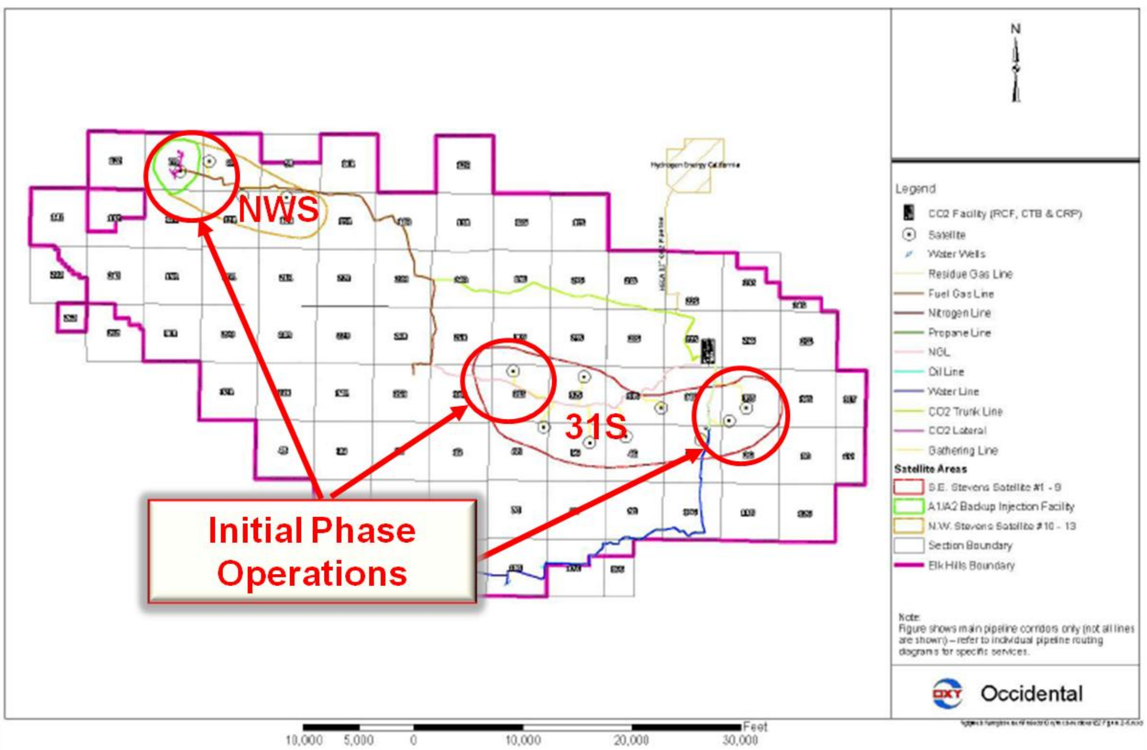


Figure 4 - Conceptual Plot Plan of Oxy CO_2 EOR Project

The Oxy CO_2 EOR Project is expected to receive an annual average rate of 107 million standard cubic feet per day (mmscfd) of CO_2 (approximately 2.1 million metric tons per year) from the proposed HECA Project. Figure 5 shows the conceptual process flow for the Oxy CO_2 EOR Project. OEHI will construct and phase in process components and interconnecting systems to match the development of the Oxy CO_2 EOR Project over its life. Given the complexity of the system, this section provides a description of each of the component steps using Figure 5 as the base diagram.

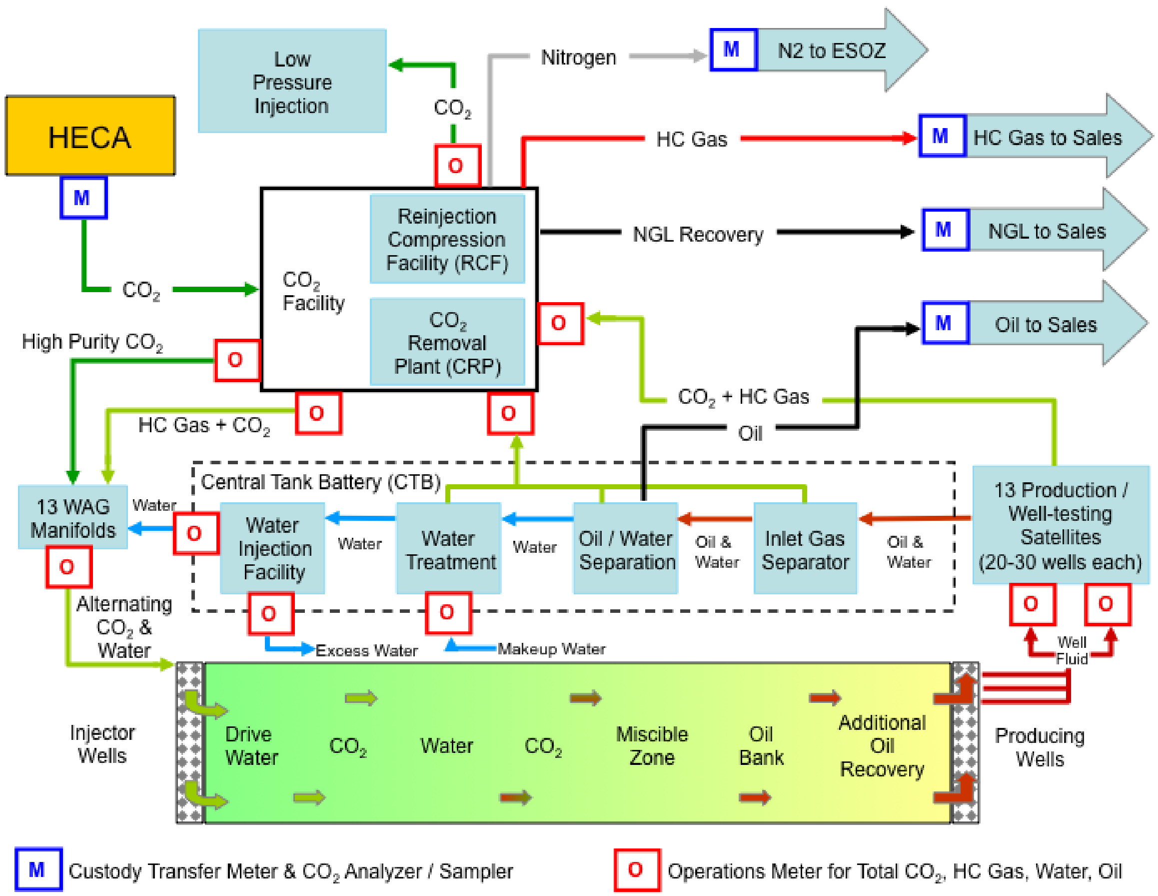


Figure 5 - Process Flow for Planned Oxy CO_2 EOR Project

1. Receiving CO_2 from HECA

The CO_2 will be compressed into a supercritical (fluid) state and be delivered via pipeline to OEHI as depicted in the upper left of Figure 6. A custody transfer meter will be installed at the delivery point to continuously monitor flow and CO_2 composition.

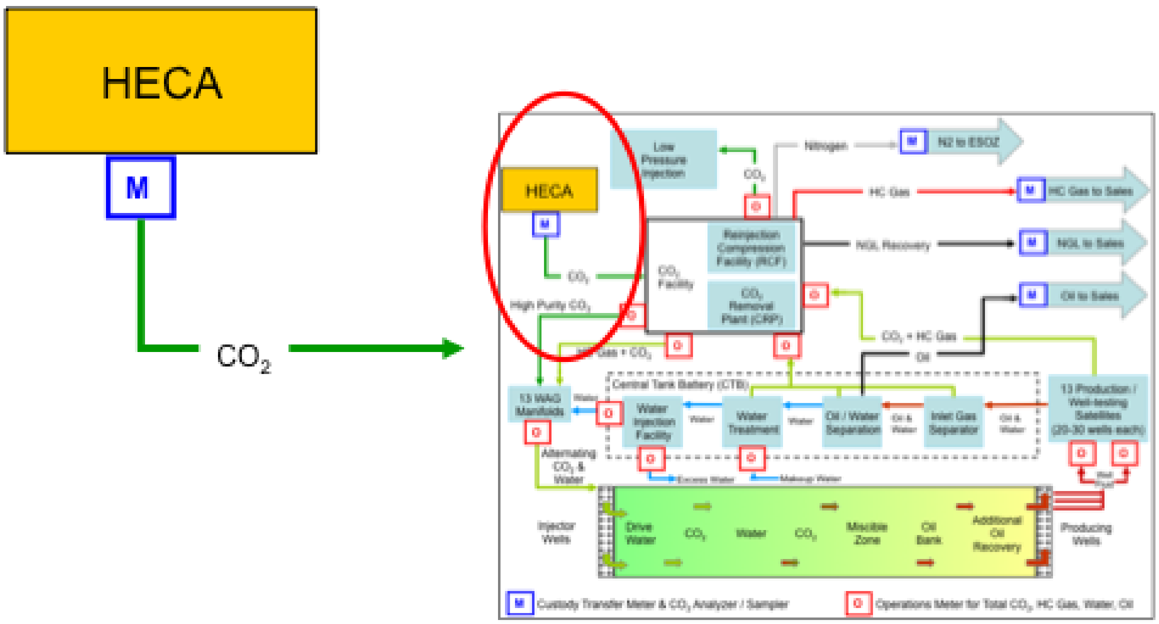


Figure 6 - CO_2 Pipeline from HECA

2. Moving CO_2 from the CO_2 Facility to the Injection Well

The CO_2 Facility, which will be at the terminus of the CO_2 pipeline from the HECA plant, is depicted in the upper center of Figure 7. Under normal operating conditions, CO_2 from the HECA plant is expected to meet typical specifications for common carrier CO_2 pipelines and will only need to be distributed from the CO_2 Facility to the injection wells.

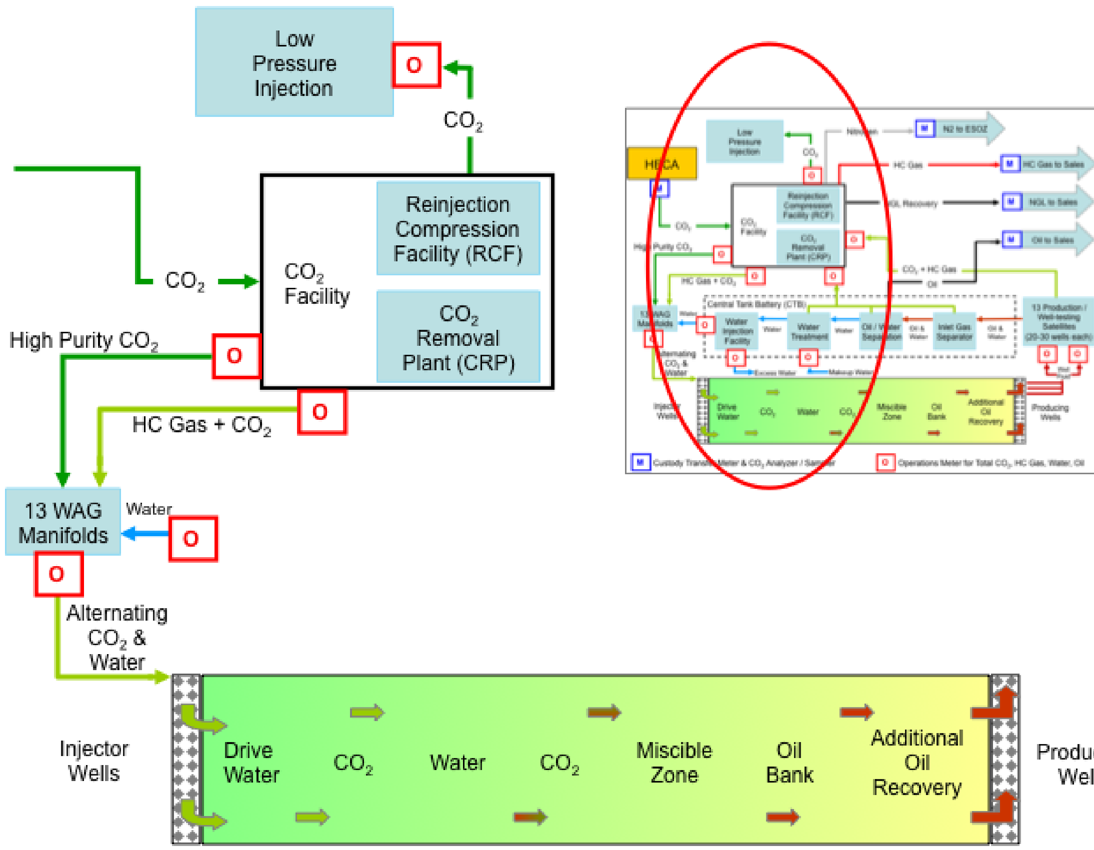


Figure 7 - CO_2 Transport from CO_2 Facility to Injection Wells

CO_2 that is recovered from the production wells will also be brought to the CO_2 Facility. (This is described in further detail after the following discussion about the production wells.)

CO_2 will be transported via pipeline either to the WAG manifolds located in the center left of Figure 7, or to the Low-Pressure Injection facilities (depicted in the very upper left of Figure 7). All CO_2 leaving the CO_2 Facility will be tracked using operations flow meters to measure flow and either a continuous gas composition monitor or periodic gas sampling to determine CO_2 concentration.

The injection wells will be placed in a pattern designed to optimize the recovery of oil. A typical well pattern will consist of an injection well in the center and production wells located in a geometric pattern on the perimeter. For example, in a five-spot pattern, there would be four production wells spaced around a center injector, as if on the four corners of a square. OEHI will determine the exact number of injection wells needed for the Oxy CO_2 EOR Project based on the actual rates of injection and production. The draft project description called for roughly 250 injection wells, but based on additional analysis of the geology, OEHI has revised that projection downward to roughly 150 injection wells. OEHI intends to optimize the final number of wells as actual injection and production data are obtained. These injection wells are represented by the text and the image at the bottom of Figure 7.

An operations flow meter at the WAG manifold for each injector will be used to measure the volume of the injection fluid. OEHI will use the flow meter data from the CO_2 Facility and water injection facility to determine the total volume of injected CO_2 and water and will use the individual well data to allocate the total volumes to each well. OEHI will also use this combination of data to monitor the performance of the EHOF and optimize operations. The methodology described above is similar to the procedure OEHI currently uses to report waterflood data to DOGGR.

All injection equipment and controls will conform to the requirements of the American Petroleum Institute (API) recommended practices for petroleum equipment and operations as well as applicable California regulations. In addition, OEHI will have controls that allow it to adjust injection rates and perform automatic shutdowns. For instance, each injection well is equipped with pressure indicators on the casing and tubing and a flow rate meter to monitor injection volume. The outputs from most meters and pressure indicators are monitored continuously and a small percentage located remotely are monitored manually on a routine basis, and alarms are set to notify control-center personnel if a certain threshold is reached.

3. Processing Produced Fluids – Part 1 Gas Streams

Fluids recovered from the production wells will flow to one of 13 production / well-testing satellites (referred to as the satellite gathering stations) shown in the center right of Figure 8. Each satellite gathering station will be dedicated to the Oxy CO_2 EOR Project and service 20-30 production wells.

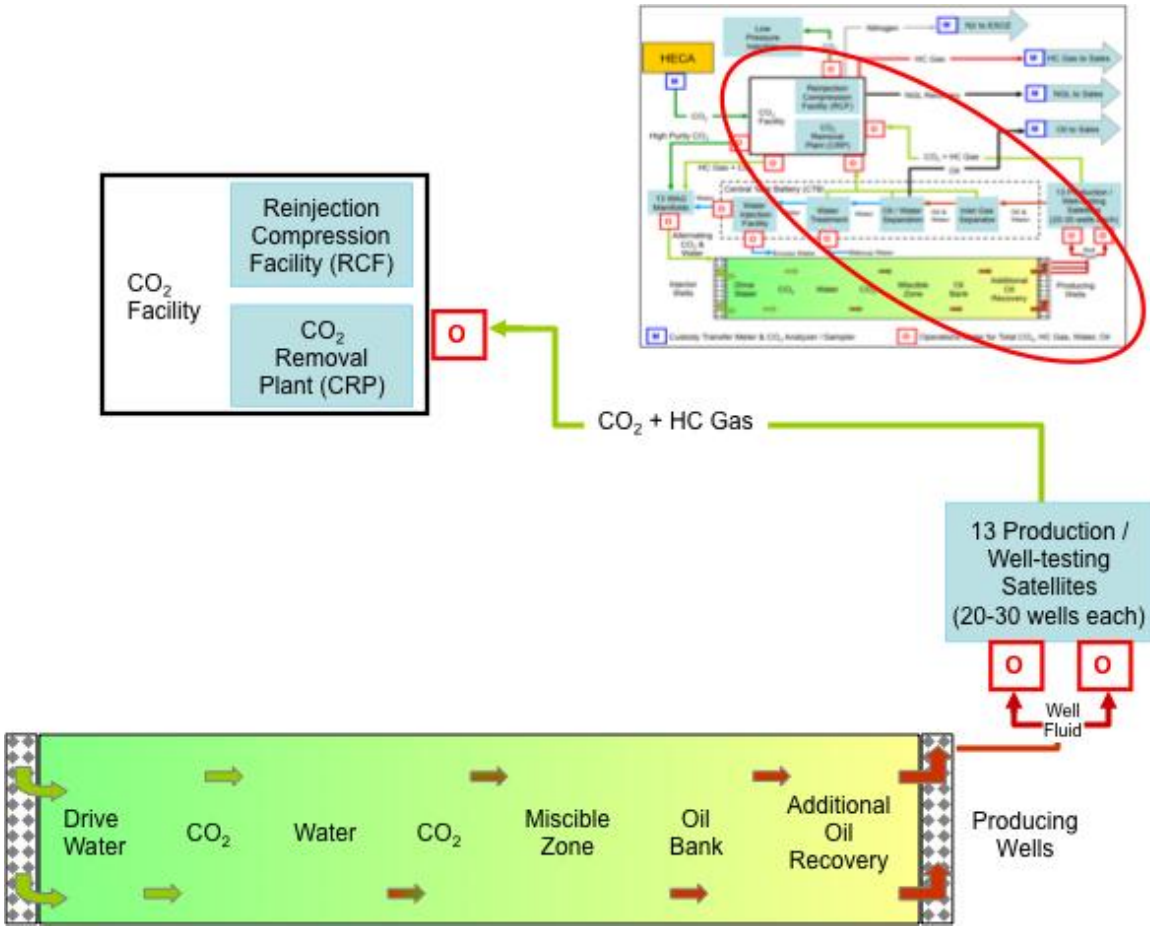


Figure 8 - Fluids Processing - Part 1

There will be two operations flow meters at each satellite gathering station used to determine flow rates. One will be used to measure the aggregate volume of the produced fluid from all wells. A second meter will be used to measure the oil/water/gas rate of each production well on a rotating basis at least once a month. OEHI will use the total volume data from each satellite gathering station and the results from each individual test of a production well to determine total produced volumes from each production well. OEHI will also use this combination of data to monitor the performance of the Oxy CO_2 EOR Project and optimize operations.

At the satellite gathering stations, the produced fluid will be separated into two streams: CO_2 mixed with hydrocarbon (HC) gas and CO_2 mixed with oil and water. From the satellite gathering station, a mixture of CO_2 and HC gas will flow to the CO_2 Facility (as seen in the upper center of Figure 8). The concentration of CO_2 in the mixed flow stream will be measured at this point. The CO_2-rich gas will then flow through the Reinjection Compression Facility (RCF) to be dehydrated, compressed, blended with CO_2 purchased from the HECA Project, and sent back out for injection, as depicted in Figure 7.

As the volumes of recycled CO_2 increase over time, a CO_2 Removal Plant (CRP) may be constructed at the OEHI CO_2 Facility to separate CO_2 from the HC gas. The CO_2 from the CRP will be pumped and combined with the compressed CO_2-rich gas from the RCF and then combined with purchased CO_2 from the HECA Project before being sent back out for injection as depicted in Figure 7. When the CRP is in operation, HC gas will be sent to the sales pipeline.

4. Processing Produced Fluids – Part 2 Liquid Streams

As described above, all fluids recovered from the production wells will flow to one of 13 production / well testing satellites (center right of Figure 9).

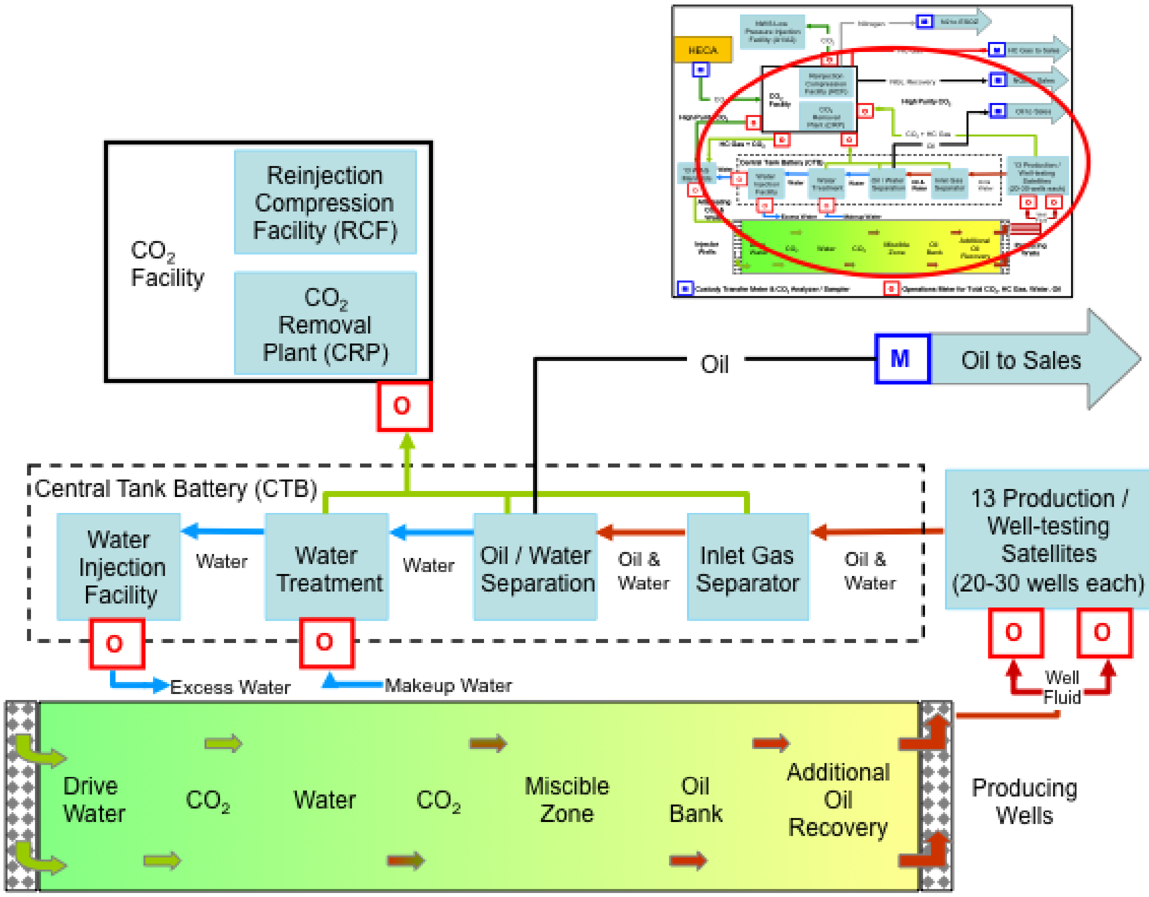


Figure 9 - Fluids Processing - Part 2

From the satellite gathering station, a mixture of oil and water with CO_2 will flow to the Central Tank Battery (CTB) as seen in the center of Figure 9. In the CTB, the liquid will flow through a gas separator to remove CO_2-rich HC gas.

The remaining mixture will pass through an oil/water separation unit which will separate additional CO_2-rich HC gas, oil and water. The oil will be pumped to a commercial transfer point where the flow rate will be measured by a custody-transfer meter and where the stream will be sampled periodically to ensure that the oil meets pipeline quality specifications, including dissolved CO_2 concentration.

The separated water will flow to a water-treatment unit where remaining CO_2-rich HC gas is separated. All of the CO_2-rich gas is collected and piped to the CO_2 Facility. An operations meter will track the flow of the CO_2-rich gas entering the CO_2 Facility.

Excluding fugitive and vented emissions, all CO_2 leaving the CO_2 Facility will be recycled for reinjection.

At the water treatment unit, additional water may be added from the make-up supply. An operations meter leading into the unit will track water flow. Water will then flow to the water-injection facility. If there is excess water, the surplus will be sent to existing water-injection or disposal wells, the remainder will be sent to the WAG manifold as discussed in Figure 7. Operations flow meters at both of the outlets from the water-injection facility will track flow. No produced water will be discharged to the surface.

5. Commercial Transfer of Certain Fluids

As discussed above (in reference to Figures 8 and 9), oil will be pumped to an oil-shipment facility before custody is transferred to a commercial pipeline. Certain other fluids will be similarly transferred as depicted in the upper right of Figure 10.

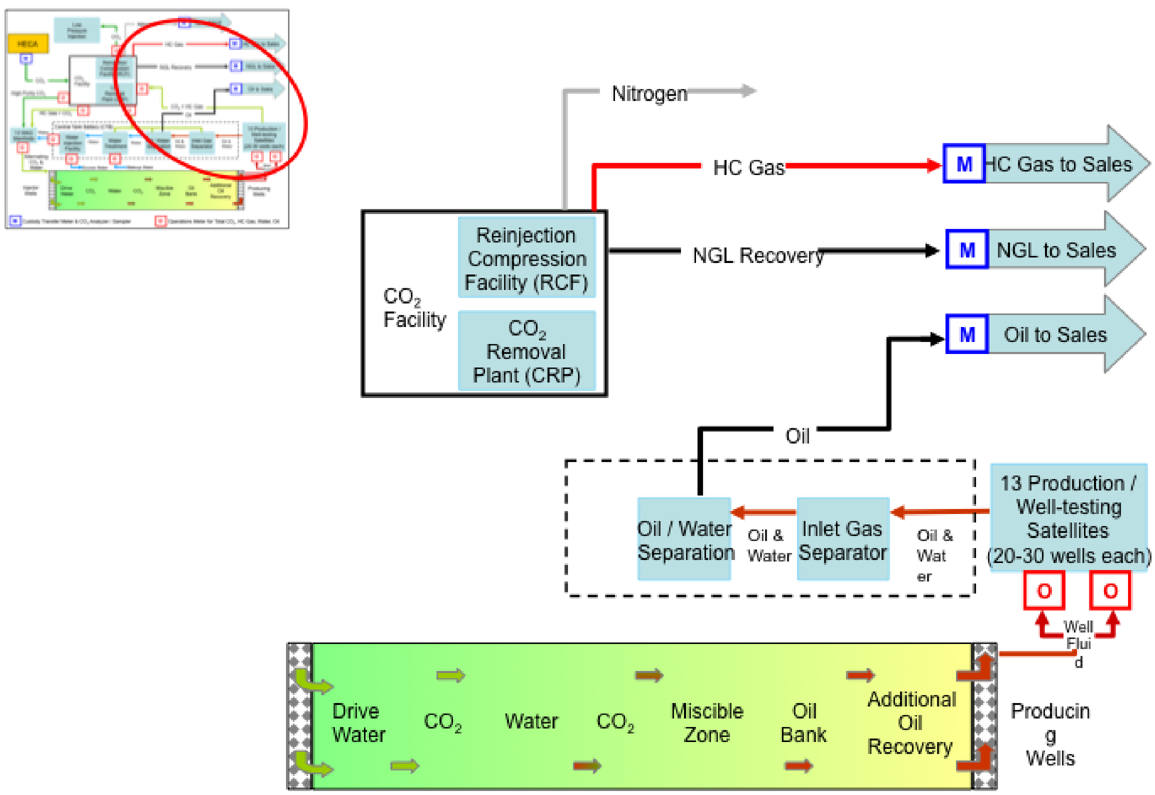


Figure 10 - Custody Transfer of Certain Fluids

Nitrogen gas, HC gas, and liquid natural gas will flow directly from the CO_2 Facility to pipelines for off-site transfers, where volumes and composition will be determined at custody transfer meters to confirm compliance with sales contracts and for financial accounting purposes.

3. Assessment of Risk of Leakage to the Surface

This section describes the site characteristics that make the Stevens reservoirs on the 31S and NWS structures good sequestration candidates and discusses the assessment of potential pathways for leakage to the surface.

3.1 Site Characteristics

The Stevens reservoirs on the 31S and NWS structures are ideally suited for CO_2 EOR, and their characteristics have been carefully studied and documented. Exhibit 2 contains a list of significant studies. The results of the prior work on site characterization, including: property ownership and land use, structure and geology, storage volumes, and well penetrations, are discussed below.

3.1.1 Property Ownership and Land Use

The EHU is located along the southwest edge of the San Joaquin Valley as indicated in Figure 1 above. The EHOF has been operated for more than 100 years as an oil and gas production facility. The majority of land and associated mineral rights are owned by OEHI, and Chevron owns the remaining minority interest. The target injection zones are contained within the boundaries of the EHU, and OEHI does not need to acquire any additional surface or subsurface property rights in order to operate the Oxy CO_2 EOR Project.

3.1.2 EHOF Structure and Geology

The EHOF produces oil and gas from several reservoirs that are vertically stacked and were formed in the Tertiary age (65 million to 2 million years ago). Individual layers within these reservoirs are primarily interbedded sandstone and shale. These layers have been folded and faulted, resulting in anticlinal structures containing hydrocarbons formed from the deposition of organic material approximately 33 million to 5 million years ago (likely during the Oligocene and Miocene age). The combination of multiple porous and permeable sandstone reservoirs interbedded with impermeable shale seals within the three large Stevens anticlines make the EHOF one of the most suitable locations in North America for the extraction of hydrocarbons and the trapping of CO_2.

OEHI conducted a three-dimensional (3-D) seismic survey over approximately 400 square kilometers within the EHU from 1999-2000. These 3-D data were computer processed to allow for an accurate interpretation of the EHU's complex structure. Information gleaned from this 3-D seismic program has been integrated with data acquired from drilling and well workover operations. This wealth of data has been used to complete a detailed structural and stratigraphic characterization of the reservoirs within the EHU. OEHI has used this information for years to develop and implement drilling, completion, and pumping innovations to manage the reservoir and maximize production throughout the field. This same information will enable OEHI to successfully meet the goals of the Oxy CO_2 EOR project.

At the surface, the EHOF presents as a large WNW-ESE trending anticlinal structure, approximately 17 miles long and over 7 miles wide. With increasing depth, the structure sub-divides into three distinct anticlines, separated at depth by high-angle reverse faults. The anticlines are believed to have formed in a transpressional regime associated with formation of the San Andreas Fault, beginning in the Middle Miocene, which began approximately 16 million years ago (Callaway and Rennie Jr., 1991).

A study of regional geology by Fiore et al includes the illustration in Fig. 11 (Note the figure has been amended to include red arrows used to indicate named faults and areas that are part of the Oxy CO_2 EOR Project). Figure 11 shows two anticline structures (31S and NWS) that are part of the Oxy CO_2 EOR Project and a third anticline structure (29R). The structures shown in Fig. 11 formed bathymetric highpoints on the deep inland marine surface (seafloor), affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds generated as subaqueous turbidite flows. It is important to note that the illustration in Figure 11 only roughly approximates the location and extent of four faults that helped to form these anticlines. The illustration in the right side of Figure 11 suggests that all four faults penetrate the Reef Ridge Shale and that one of them, labeled 5R (which is outside the Oxy CO_2 EOR Project area), fully transects this formation. Based on site-specific studies, OEHI has concluded that the vertical extent of faults 1R, 2R and 3R in this image are exaggerated and that any penetration of the confining zone of the Reef Ridge Shale is minimal and does not present a likely pathway for leakage to the surface. Further discussion of this analysis is presented in Section 3.1.2.2 which discusses the Reef Ridge Shale characterization studies conducted by OEHI.

Analysis of OEHI's 3-D seismic data provides further evidence of the sealing characteristics of the Reef Ridge Shale. A 3-D seismic survey was performed from 1999 – 2000, and covered nearly 70 square miles in the EHU. The data were processed using pre-stack depth migration which produces superior imaging in steeply dipping beds, such as on the flanks of the Stevens structures. Analysis of these data indicates that faults above and below the Reef Ridge Shale terminate before penetrating the seal as discussed later in section 3.1.2.2.

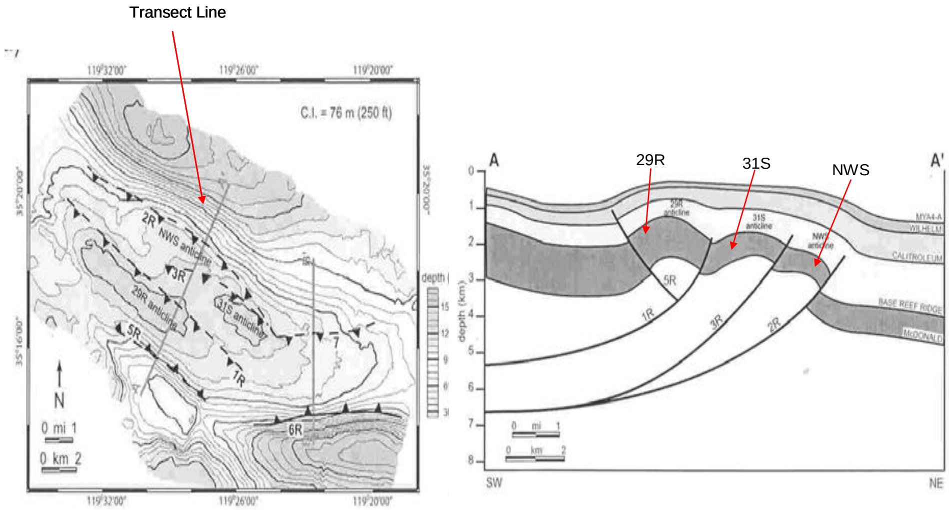


Figure 11 - (Left) EHOF Structure Contour Map Of Upper Pliocene Rocks Showing Faults And Location Of Cross Section A-A'; (Right) Cross Section A-A' Showing Structure Of EHOF Anticlines. [Note: the faults indicated by lines 5R and 6R in the image on the left are the two faults that have some penetration into the Reef Ridge Shale, but these are located beyond the boundaries of the Oxy CO_2 EOR Project]

To date, more than 6,000 wells have been drilled to various depths within the EHOF, creating an extensive library of information compiled within a comprehensive database. The deepest well in the field is the 934-29R, drilled down to Mesozoic, Upper Cretaceous age (93 million to 65 million years ago) sediments at a total depth of 24,426 feet. A schematic diagram of the EHOF area stratigraphy based on well 934-29R is presented in Figure 12.

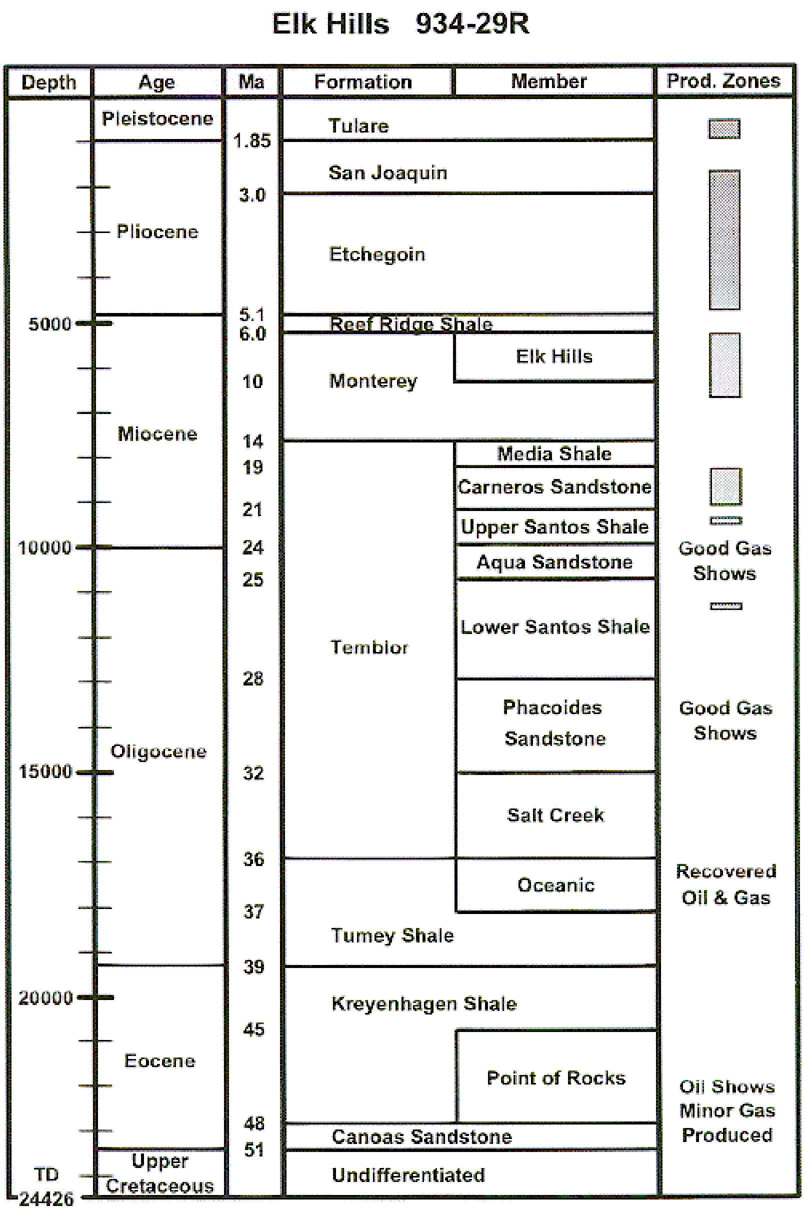


Figure 12 - EHOF Stratigraphy based on 934-29R Well

The oldest rocks observed in the field are Upper Cretaceous in age, but they are not productive. The Miocene-aged Carneros sandstone member of the Temblor Formation is the lower-most hydrocarbon producing interval in the field, although oil and gas shows have been recorded in deeper, older sediments. Above the Temblor is the Miocene-aged Monterey Formation. The Monterey is approximately 4,500 to 10,000 feet deep and includes the targeted portions of the Stevens reservoirs that produce from stratigraphic-structural traps on the three deep anticlines indicated in Figure 11. Within the upper Miocene is the Reef Ridge Shale, which is siliceous (Nicholson, 1990) and acts as a stratigraphic trap keeping hydrocarbons sealed below.

3.1.2.1 Injection Zones

OEHI will be injecting CO_2 into the Stevens reservoirs on the 31S and NWS structures (See Figure 3).

1. 31S Structure

The Stevens reservoirs of the Monterey Formation are considered the best CO_2 EOR targets within the EHOF. They have been developed on 10 - 20 acre pattern spacing and have produced over 500 million barrels of oil to date.

Data collected from these operations have refined OEHI's understanding of the subsurface geology in the Stevens reservoirs. As indicated in Figure 13, the Stevens reservoirs are actually comprised of both sandstone (blue, MBB) and shale (green/yellow, "N and A Shales"; and purple/pink/red, "C and D Shales") lithologies.

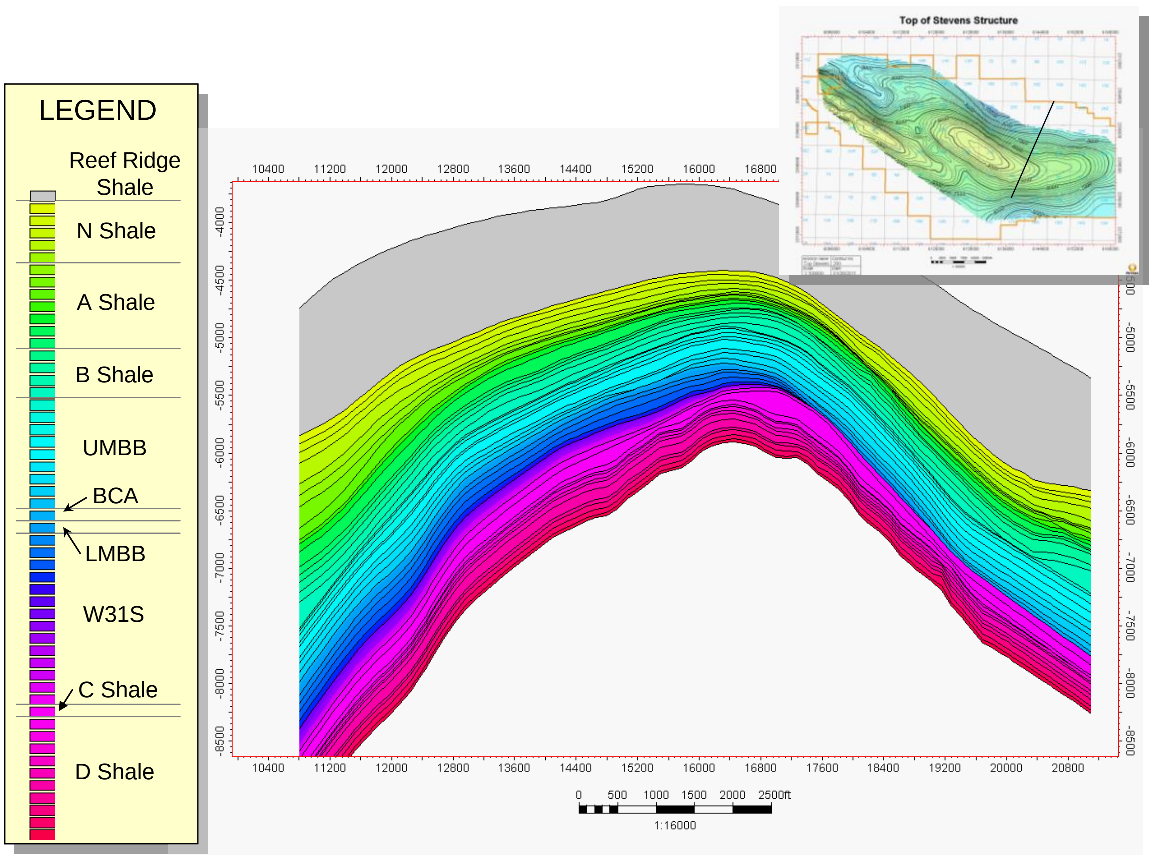


Figure 13 Typical cross-section of Stevens reservoirs along transect line shown on locator map. Reef Ridge Shale shown in gray.

Within the MBB, fining-upward turbidite deposits known as Bouma Sequences stack to form lenticular sheet sands, channels, and levee deposits within a submarine fan complex (Reid, 1990) as indicated in Figure 14. The sands have porosities between 20 and 25 percent, permeabilities that average 150 millidarcy, and net reservoir thickness that can exceed 1,000 feet. Pressure in the MBB is already near the MMP, indicating that it is an ideal initial candidate for CO_2 EOR.

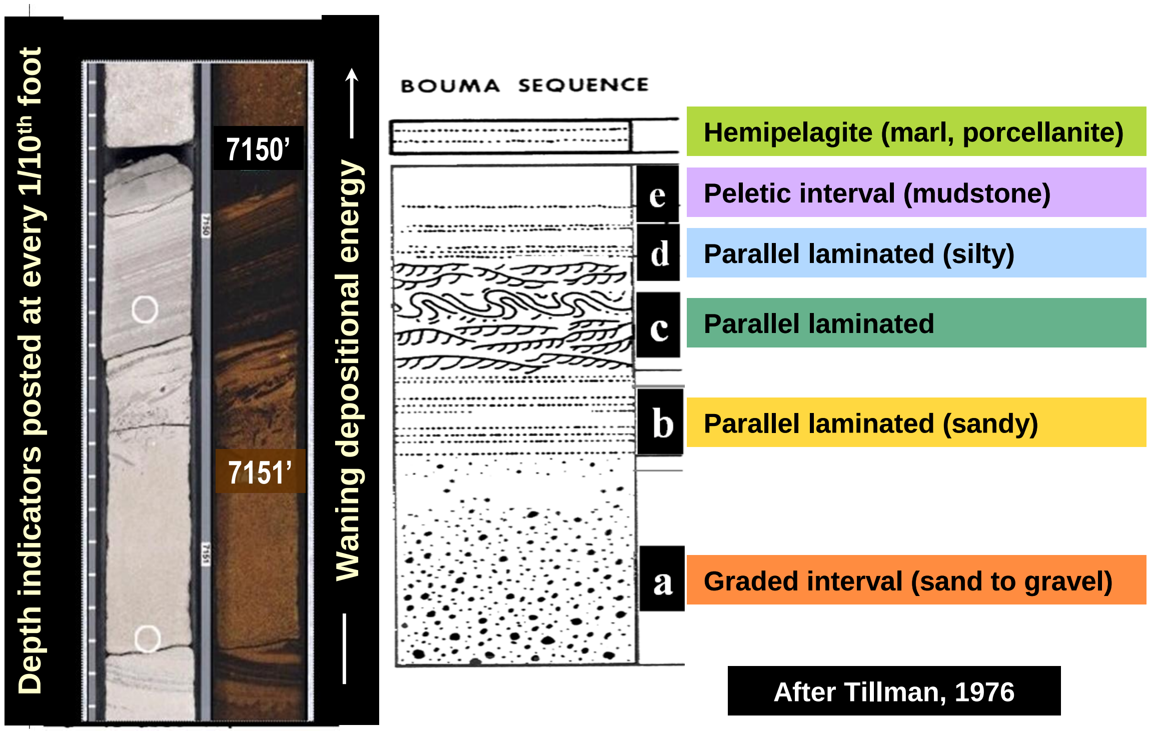


Figure 14 - Geologic Layers within the Main Body B (MBB), Well 358X-33S

As noted earlier, overlying the Reef Ridge Shale above the 31S structure is the oil-producing SOZ. The SOZ is extensively layered with hydrocarbon containing sands and impermeable clay, forming many local traps. The SOZ itself is topped by a cap rock known as the San Joaquin Formation which is mainly comprised of continuous clay and shales interbeded with the lenticular Mya sands. Evidence supporting the vertical isolation between the Stevens reservoirs, and the SOZ and that the Oxy CO_2 EOR Project will not breach that isolation, includes:

1. Unique oil-water contacts, pressures, and temperatures of the Stevens and the overlying SOZ reservoirs (note, the SOZ is not included in Figure 13) indicate that there are no transmissive faults across the Reef Ridge Shale (indicated in gray in Figure 13) in the area of the Oxy CO_2 EOR Project.
2. Concurrent hydrocarbon development programs, including programs resulting in significant pressure changes, have been employed without causing interference in either the SOZ or Stevens reservoirs.
3. Reservoir simulation (discussed further in section 3.2), which computed the volumes and pressures that would compromise the Reef Ridge Shale, shows that it would be nearly impossible to operate the Oxy CO_2 EOR Project in a way that

would compromise the seal. The capacity of the Stevens reservoirs is vast compared to the planned injection volumes, and the equipment that will be used to deliver HECA CO_2 physically limits the rate of injection below the injectivity of the Steven reservoirs. The result is that the integrity of the seal will remain secure.

Data from a four-month pilot conducted by OEHI in 2005 provided additional confidence that the 31S structure is an attractive target for CO_2 EOR. This project was designed to assess how much oil could be mobilized from the Stevens reservoirs, how much CO_2 would be required to mobilize that oil, and how quickly the oil would be mobilized. Information showed that the Stevens reservoirs selected for the Oxy CO_2 EOR Project are ideal for EOR.

2. NWS Structure

Beneath the Reef Ridge Shale, the NWS structure is comprised of stacked upper Miocene Stevens sands, which are the product of two coalescing turbidite channels. One channel contains the "T" turbidite sands (thickness ~500 to 1000 feet), which form offlapping geometries and structural/stratigraphic traps due to deposition across the rising northwest-plunging nose of the NWS anticline. They are medium to coarse-grained with abundant mudstone interbeds and are interpreted to represent a depositional channel fill which grades laterally to less permeable finer grained overbank deposits along the east side of NWS. The second channel forms a 1700-foot sequence of 80 to 500-foot thick sandstone intervals having high net-to-gross ratios with abundant conglomeratic interbeds. These intervals have lenticular geometries at the top of the sequence and offlapping geometries at the base. The A1/A2 reservoirs on the NWS structure are currently at a very low reservoir pressure (<90 psig), having been pressure depleted during earlier operations. They will need to be re-pressurized to MMP before miscible EOR can begin and are able to accept CO_2 at lower pressure than will be required to inject CO_2 into the reservoirs in the 31S structure. The A1/A2 reservoirs within the NWS will be both an EOR target as well as an excellent source of “backup” storage capacity in the event of power outages, scheduled maintenance periods, or emergency shutdowns, or when injection into the MBB is not possible.

3.1.2.2 Sealing Formation

As indicated in the discussion of Figure 11 above, the Stevens reservoirs are contained within three geologic structures that are completely overlaid by the Reef Ridge Shale which serves as the primary seal. There is substantial evidence that confirms the sealing characteristics of the Reef Ridge Shale, including:

1. Physical rock characteristics of the Reef Ridge Shale,
2. Fluid contacts and reservoir pressure depletion,
3. Core analysis of the Reef Ridge Shale,
4. Seismic control,
5. Geochemical analysis, and
6. Geomechanical analysis.

1. Physical Rock Characteristics of the Reef Ridge Shale

The significant areal extent and vertical thickness of the Reef Ridge Shale are the two main factors in its effectiveness as a seal for containing injected CO_2. The areal extent of the Reef Ridge Shale is enormous. The formation is continuous across a large portion of the San Joaquin Valley (see Figure 15 – blue dots show key wells where the Reef Ridge Shale was penetrated). These data show that the Reef Ridge Shale covers an area that is many times larger than the planned areal extent of the Oxy CO_2 EOR Project as indicated in Figure 16.

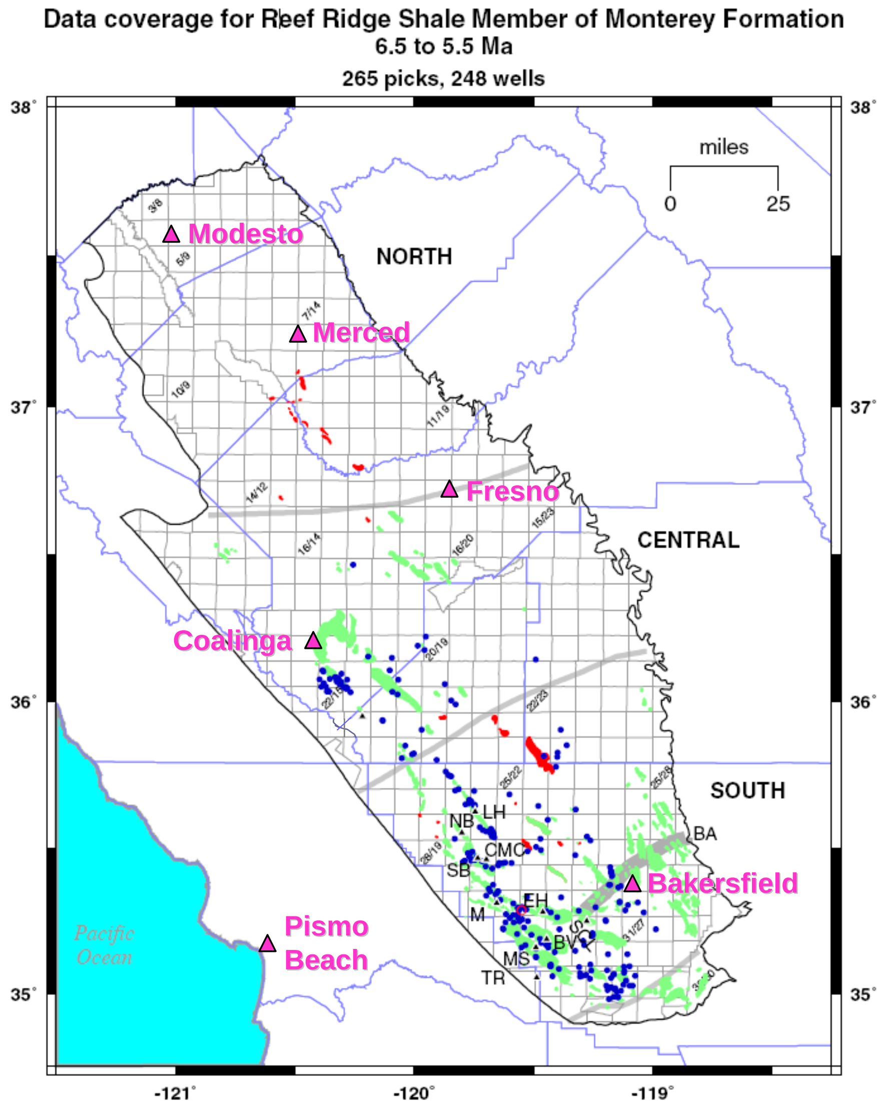


Figure 15 - Map of Reef Ridge Shale in Southern San Joaquin Valley
From Hosford Scheirer, Allegra, ed., 2007, Petroleum systems and geologic assessment of oil and gas in the San Joaquin Basin Province, California: U.S. Geological Survey Professional Paper 1713 [http://pubs.usgs.gov/pp/pp1713/]. (EH = Elk Hills oil field).

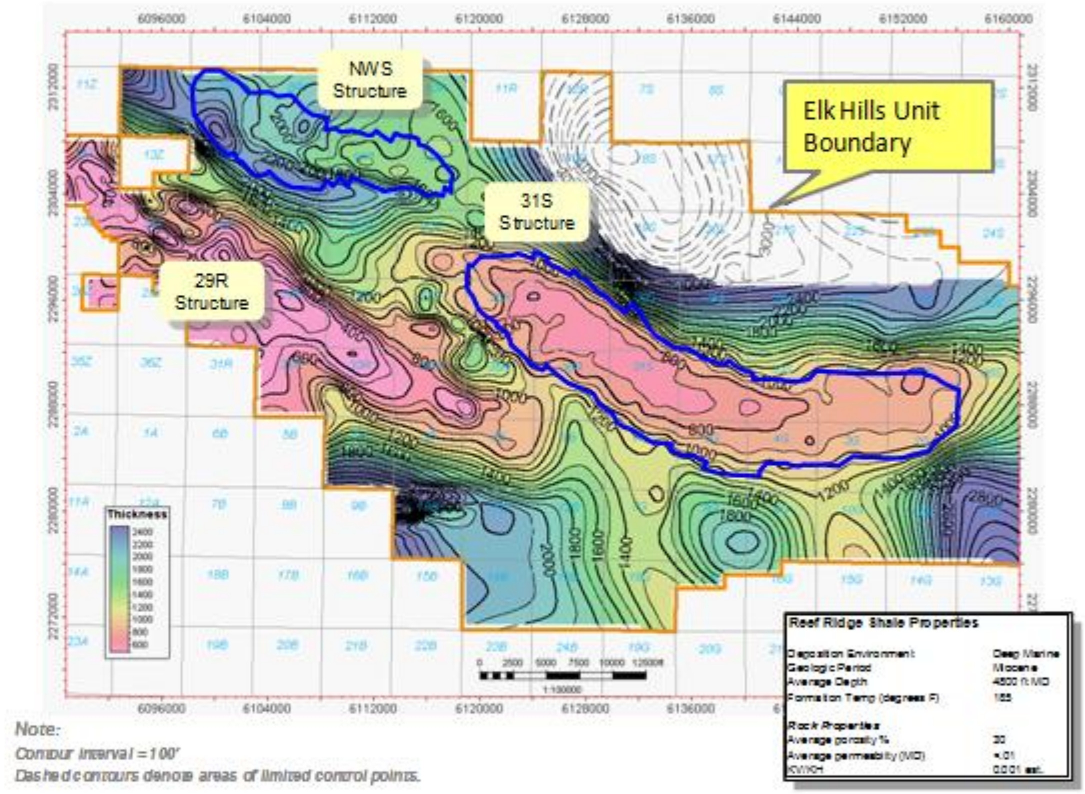


Figure 16 – Reef Ridge Shale Isochore Map in the Vicinity of the

The second important characteristic is the thickness of the reef Ridge Shale. Throughout the area planned for the entire 20+ year injection period, the Reef Ridge Shale is very thick, ranging from 750+ to 1,400 feet thick over the injection zones in the NWS and 31S structures (refer to Figure 16).

The continuity of the Reef Ridge is shown by the cross section in Figure 17 across all three structures (31S, NWS and 29R).

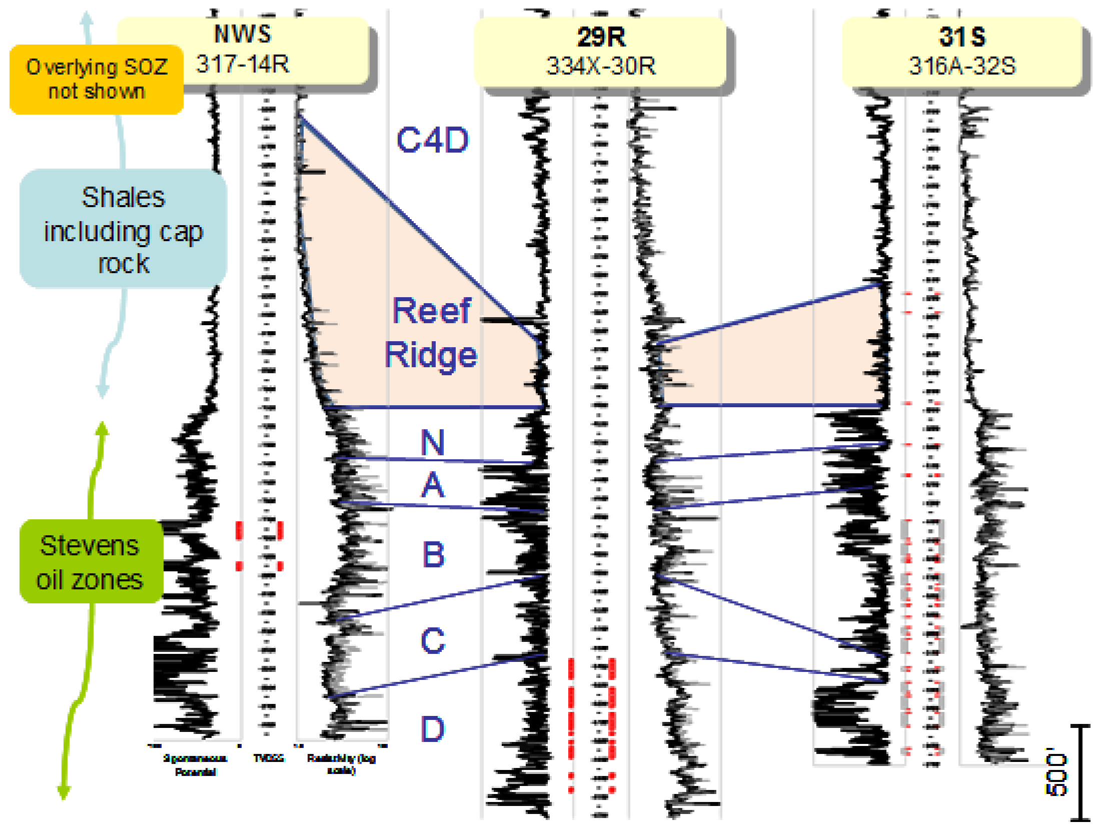


Figure 17 - Continuity of Reef Ridge Shale Anticlinal Structures

2. Waterflooding and Fluid Contacts Analysis

Waterflood development in the Stevens reservoirs started in 1980. Waterflooding is conducted under a set of Class II UIC permits issued by DOGGR. To date, more than 830 million barrels of water have been injected and there are currently about 150 active water-injection wells and 580 active oil and gas production wells in the Stevens reservoirs. This waterflooding process has yielded approximately 320 million barrels of oil. As is planned for the CO_2 flood, OEHI monitors the pressures and fluid composition in the wellbores producing from reservoirs adjacent to the waterflooded intervals (including the SOZ) and in areas adjacent to those that have undergone water flooding. Since OEHI actively produces hydrocarbons in the Stevens and the zones above it, OEHI would see evidence of any communication between zones (e.g., changes in the pressures and composition of formation fluids). To date OEHI has not seen any such evidence of communication between zones. This lack of communication between the zones, which indicates that they are separated from each other even when both reservoirs are pressured for production, is confirmed by publicly-available production and pressure records reported to DOGGR. The waterflood results provide meaningful evidence that the planned CO_2 EOR injection zone is confined. Furthermore, OEHI's established surveillance practices for monitoring and optimizing the waterflood have refined the degree of reservoir characterization, allowing for detailed EOR planning.

OEHI also conducted an analysis of the potential fluid contacts between zones in the Stevens reservoirs and overlying SOZ reservoirs. The results indicate that the original oil/water contacts for the two reservoirs varied by over 3,000 feet. In addition, past development of each reservoir has created a large pressure differential across the Reef Ridge Shale, further demonstrating the lack of communication between the reservoirs. Considering the history of oil and gas production in the EHOF, the lack of fluid movement from areas of high pressure to areas of low pressure confirms the integrity and long-term stability of the seal.

3. Core Analysis

In 2000, Reef Ridge Shale core samples were collected from the 31S structure. These core samples demonstrated two important features. First, X-ray diffraction of the core indicated that the predominant secondary mineral is clay, which inhibits the Reef Ridge Shale's ability to fracture. Second, low permeability was verified by the absence of oil saturation. This indicates that as zones below the Reef Ridge Shale were being charged with hydrocarbons, the permeability of the Reef Ridge Shale was sufficiently low to prevent hydrocarbon migration through the shale. The presence of the EHOF today indicates that this very thick, low-permeability interval has been an effective seal to hydrocarbons for millions of years. This conclusion is further evidenced by the results of geochemical analysis.

4. Seismic Control

Analysis of OEHI's 3-D seismic data provides further evidence of the sealing characteristics of the Reef Ridge Shale. A 3-D seismic survey was performed from 1999 – 2000, and covered nearly 70 square miles in the EHU. The data were processed using pre-stack depth migration which produces superior imaging in steeply dipping beds, such as on the flanks of the Stevens structures. Analysis of these data indicates that faults above and below the Reef Ridge Shale terminate before penetrating the seal.

OEHI has also reviewed the potential for naturally occurring seismic activity to propagate these faults and finds no evidence this has occurred. From a longer-term perspective, the anticline structures in the EHOF developed over millions of years (since the middle Miocene) in response to regional shortening. The Miocene Monterey Formation is the source rock for the oil reservoirs in the EHOF, and it is thought that oil began moving into the reservoir early in the Pliocene. Although the area has undergone deformation since at least the early Pliocene (5 million years ago), the migrated oil has remained in place. Since 1990, 129 naturally occurring earthquakes have been recorded with a magnitude greater than 3.0 within a 60-mile (100-km) radius of the EHOF. The vast majority of these have occurred along the White Wolf fault, approximately 30 miles southeast of the EHOF (Southern California Earthquake Data Center web site). The historical data (long-term and short-term) indicate that naturally occurring seismic activity throughout history has not compromised the sealing integrity of the Reef Ridge Shale. This is due, in part, to the high level of clay in the rock composition.

5. Geochemical Analysis

Geochemical data provides additional evidence that there is vertical isolation between the Stevens and SOZ reservoirs which lie above the Reef Ridge Shale. Zumberge, Russell and Reid documented (Appendix J) geochemical data along with their analysis of 66 oil samples from the EHOF. This analysis revealed five distinct oil families sourced from the Miocene Monterey Formation and tied to stratigraphic intervals. The differences between the distinct geochemical compositions of the Stevens and SOZ oils among the other oil "families" identified corresponds to separate reservoir horizons and suggests "minimal upsection, [and] cross stratigraphic migration,"(Appendix J, page 1370) and the authors conclude that the hydrocarbons present in the SOZ reservoirs are from "another Monterey source facies (perhaps the youngest) with charging of Pliocene reservoirs" and not the result of upward movement from the older Miocene reservoirs.

6. Geomechanical Analysis

Extensive geomechanical data about rock stress, rock strength, and fault stability that have been collected throughout the 100 year operating history of the EHOF have been incorporated into the full-field simulation model (see discussion in Section 3.2 below). This model has allowed OEHI to assess the integrity of the Reef Ridge Shale under various injection-volume and pressure scenarios over extended periods of time.

3.1.2.3 Areas Above the Reef Ridge Shale Sealing Formation

Deep beneath the surface, but positioned above the Reef Ridge Shale are the SOZ and the non-productive area above the Stevens reservoirs in the NWS. Both of these areas will be used for monitoring as discussed in Section 3.3 below.

1. The SOZ

The SOZ has a near shore shallow marine / tide dominated estuarine depositional environment. The formation structure is a plunging anticline that dips toward the southeast and is flat at the crest. The reservoir is highly faulted and compartmentalized, making it a very productive hydrocarbon zone.

The SOZ sands are generally coarse-to medium-grained with good porosity, permeability, and initial oil saturation. They can be categorized in six major sand units:

1. Above Scalez; discontinuous pods

2. First Sub-Scalez (SS1); contains 50% of original oil in place (OOIP); pinches out to the west
3. Upper Second Sub-Scalez (USS2); water influx on east; pinches out to the west
4. Second Sub-Scalez (SS2); continuous but not productive across the field
5. Mulinia; continuous but not productive across the field
6. Sub-Mulinia; exists and is productive across both SOZ reservoirs

The major sands are subdivided into many sublayers by thin shales. Pressure and production testing indicate these shales are continuous and often act to isolate the sublayers. The stratigraphic column of the SOZ and the overlying dry gas zone shown in Figure 18 illustrates this layering and compartmentalization.

The SS1 is the largest oil reservoir in the SOZ. This unit consists of a series of tidally dominated sands with excellent porosity and permeability, which tend to act as separate reservoirs. This near shore deposit represents the end of clearly defined marine sands in the geologic column.

The production history of the SOZ dates back to its discovery in 1918. It is estimated that the SOZ reservoirs originally contained more the 1.25 billion barrels of oil. While production in the SOZ began in 1918, it was controlled in response to the needs of the U.S. Government (e.g. for use in World War II and the Korean War). In 1976, the levels of oil and gas production increased significantly. After acquiring the EHOF, OEHI commenced infill drilling in the SOZ in 1998 to reduce well spacing. Since that time, OEHI has initiated waterflood and EOR development with crestal waterflood and ASP piloting. The long production history of the SOZ has generated extensive data on reservoir pressures and compositional information for produced oil and gas streams.

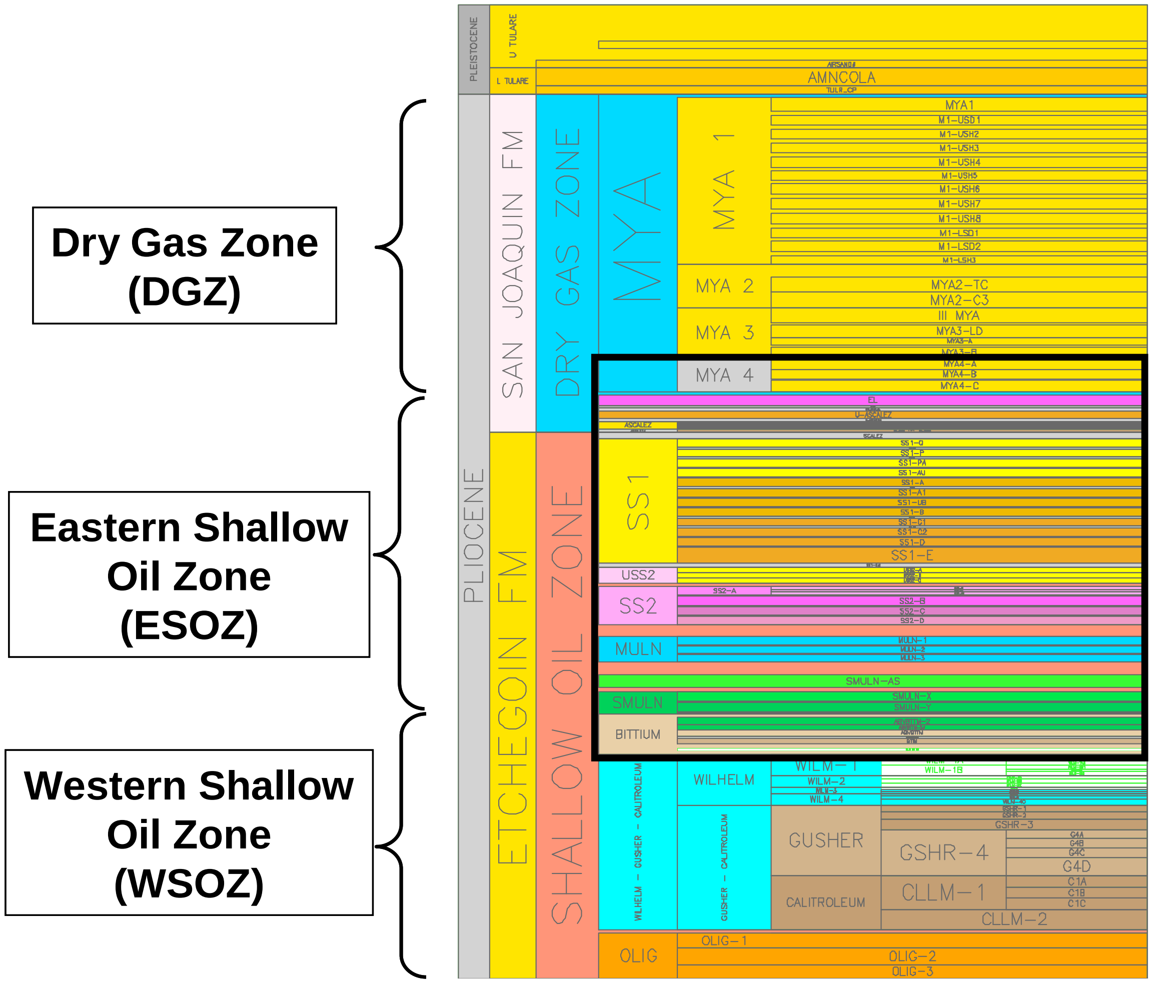


Figure 18 Shallow Oil Zone and Dry Gas Zone Stratigraphic Column

2. Area Above the Reef Ridge Shale on the NWS Structure

The area above the Stevens reservoirs in the NWS structure is not a productive zone. OEHI has drilled some test wells into this zone in the past, and evidence from those wells indicates that this area is geologically (both stratigraphically and structurally) isolated laterally from the SOZ and vertically from zones below the Reef Ridge Shale. Stratigraphically, the main interval in this area is thick and relatively continuous. There are shaly zones around the two nearest producing structures (the 29R and 31S) that have proven to be a seal. Structurally, it appears that there is no hydraulic connection within the pools on those structures; SOZ faulting trends in the opposite direction and does not appear to provide hydraulic connectivity.

3.1.3 Estimated Storage Volumes

Based on physical site characterization and analysis of historic operating records from the Stevens reservoirs, OEHI has calculated that there is sufficient reservoir capacity to store the entire volume of CO_2 that will be purchased from HECA during the lifetime of the Oxy CO_2 EOR Project. As illustrated below, the cumulative net fluid volume produced is already larger than the total volume of the planned CO_2 injection. During the CO_2 EOR process, which relies on injecting CO_2 and producing more oil, significant storage takes place as injected CO_2 replaces oil that would otherwise remain in the reservoir.

OEHI's experience in the EHU is that more fluid is produced than is injected. Table 1 illustrates this concept by showing the estimate for "Cumulative Net Fluid Volume Produced" based on operations that have occurred to date, including gas pressurization and water flooding.

Table 1: Calculation of Cumulative Net Fluid Volume Produced

	Volume in billions of reservoir barrels of oil (Brbbls)
Cumulative Fluid Produced	>3.4 Brbbls
Cumulative Fluid Injected	<2.1 Brbbls
Cumulative Net Fluid Volume Produced	>1.3 Brbbls
Estimated volume of 44 million metric tons CO_2	<1 Brbbls

3.1.4 Existing Wells / UIC Class II Existing Area Of Review

3.1.4.1 Known Wells[2]

More than 6,000 wells have been drilled in the EHOF throughout its history. As described in section 2.1.5, DOGGR has promulgated requirements relating to the permitting of Class II injection wells. Detailed records describing the location and status of wells in the EHOF have been submitted to DOGGR as part of the existing Class II UIC permit applications and these data will be updated as necessary and included in the application for the CO_2 flooding injection permits. The previously submitted information includes: (1) a completion and status map of all wells that have penetrated the Reef Ridge Shale indicating active or inactive producers and injectors, and abandoned wellbores; (2) wellbore and casing diagrams for wells penetrating the Reef Ridge Shale located within a ¼ mile radius of proposed project boundaries of all wells penetrating the Reef Ridge Shale; and (3) a list of wells within a ¼ mile radius of

[2] Data in this section regarding known well counts, depths, and status were current as of July 23, 2010 when the discussion draft of the MRV plan was submitted to the CEC. There may be some change in these data due to routine operations in the EHOF that have occurred since that date. A revised description of known wells will be updated for the final plan, but it is unlikely that there will be significant revisions.

the proposed permit area for the Oxy CO_2 EOR Project that do not penetrate the Reef Ridge Shale. Included in the Class II UIC permit for the Oxy CO_2 EOR Project application will be API number, year of completion, status, and depth for all wells within a ¼ mile radius of the proposed permit area.

1. Wells in the 31S Structure of Stevens Reservoirs

Currently 1,021 active wells penetrate the Reef Ridge Shale in the 31S structure; 128 wells are permitted by DOGGR as UIC Class II injection wells and 749 wells are permitted by DOGGR as production wells. An additional 144 active wells in the 31S structure can be utilized as producers or injectors. There are 178 inactive injection and production wells, 22 injection and production wells that have been plugged and abandoned according to regulatory requirements, and 10 wells that are shut in. The following two tables indicate depth and completion dates for these wells.

Table 3: Depths of Stevens Wells

Number of Wells	True Vertical Depth Subsea (TVDSS)
174	1,500 – 4,999 feet
321	5,000 – 5,999 feet
352	6,000 - 6,999 feet
144	7,000 – 7,999 feet
143	8,000 – 8,999 feet
97	9,000 feet or greater

The majority of the Stevens wells were completed since 1980 as indicated in the following table.

Table 4: Completion Dates for Stevens Wells

Number of Wells	Completion Date
718	After 1980
284	1960 - 1979
229	Before 1960

As part of the permit process for the existing Stevens injection wells, OEHI documented the status of all other wells penetrating the Reef Ridge Shale and demonstrated that those wells were properly maintained and closed as appropriate. OEHI will make the same kind of demonstration in applying for necessary permits for the Oxy CO_2 EOR Project.

2. Wells in the SOZ

Approximately 1,140 wells which do not penetrate the Reef Ridge Shale are located within the ¼-mile radius of the Oxy CO_2 EOR Project area. As with the wells in

Stevens, OEHI has data documenting the status of these wells that will be used in the permit application for the Oxy CO_2 EOR Project to demonstrate that they will not create a pathway for leakage to the surface.

3. Wells in the NWS Structure of Stevens Reservoirs

Currently, 137 active wells penetrate the Reef Ridge Shale in the NWS structure; 49 wells are permitted by DOGGR as UIC Class II injection wells and 88 wells are permitted by DOGGR as production wells. In addition, there are 43 inactive injectors and 7 production wells that have been plugged and abandoned according to regulatory requirements. There are 7 wells that do not penetrate the Reef Ridge Shale: 2 of which are inactive injectors and 5 that are plugged and abandoned. (Note that the SOZ does not extend above the NWS structure.) The following two tables indicate depth and completion dates for these wells.

Table 5: Depth of NWS Wells

Number of Wells	True Vertical Depth Subsea (TVDSS)
7	1,000-5999 feet
1	6,000-6,999 feet
110	7,000-7,999 feet
68	8,000-8,999 feet
5	9,000-9,999 feet
3	10,000 or greater

Table 6: Completion Dates for NWS Wells

Number of Wells	Completion Date
119	After 1980
70	1960-1979
5	Before 1960

3.1.4.2 Unknown Wells

In a field like the EHOF which is highly productive and has been in operation for more than 100 years, there is a very low possibility that some older wells exist but are unknown to OEHI. It is OEHI's standard practice when drilling new wells or planning workovers of existing wells to conduct anti-collision reviews in order to ensure that a new or reworked well will not interfere with other ongoing operations. This review includes a review of satellite imagery and can include a new review of survey data of old wells. Since 1998, when it acquired and became operator of the EHU, and after drilling more than 300 wells through the Reef Ridge Shale in the 31S and NWS areas, OEHI has never found an "unknown" well. The history of not finding unknown wells coupled with the protocols for locating new wells or reworking existing wells, gives OEHI high confidence that there are not any unknown wells in the Oxy CO_2 EOR Project area.

3.2 Reservoir Simulation

3.2.1 Introduction

Reservoir simulation is used for many purposes including optimizing reservoir management, forecasting hydrocarbon production, and predicting the behavior of injected fluids such as CO_2. Such models are developed at different resolutions to suit the purpose for which they are being developed; the size of the model (horizontally and vertically) and the available computing capacity dictate the model's grid resolution. OEHI primarily uses high resolution, or fine grid models, to evaluate defined portions of the EHOF with active operations and to monitor production output. These fine grid models, which consider factors such as reservoir heterogeneity and compartmentalization, are used and updated on a real-time basis based on actual injection and production volumes. OEHI has embedded proprietary data and workflows into these models so that they can be used to inform development plans. The key parameters of the fine grid model are used to build and update the coarse grid / lower resolution model that is used to assess the entire EHOF, as discussed in the following paragraph.

Lower resolution models are used to evaluate larger areas of geology, such as a full oil field. These models use a coarser, or larger, grid than fine grid models. The primary factor controlling grid size is computing capacity; the required processing time and file space increases exponentially with the resolution of the simulation grids. Coarse grid models are built on the same raw data as used in a fine grid model, but coarse grid models interpret the data over a larger area. A fine grid model of a large area such as the Stevens reservoirs would not only be prohibitively time consuming to run, but would exceed the ability of simulation applications to initialize the model.

Excellent results can be obtained from a full-field coarse grid model, especially one that is built on extensive and highly accurate data used in the fine grid models. OEHI commissioned the development of such full-field models of the 31S and NWS structures. These models were built by Computer Modeling Group (CMG), a third-party modeling expert to evaluate the injected CO_2 containment using a dynamic reservoir simulation known as the Geochemical Equation-of-State Compositional Simulator (GEM). The reservoir models were used to evaluate the following questions:

a. Given the planned volume of CO_2 to be supplied by HECA and the expected recycling of CO_2, what portion of the injected CO_2 will remain in the MBB over time? This is the base case.

b. If some percentage of injected CO_2 migrates vertically through the overlying NA Shales of the Stevens reservoirs – which are included within the injection zone – how long will it take for the injected CO_2 to reach the Reef Ridge Shale? This scenario tested different rates of migration from the MBB.

c. Will the Reef Ridge Shale contain any CO_2 that migrates from the MBB? This scenario tested cap rock integrity as a function of geomechanical properties of the Reef Ridge Shale and modeled reservoir pressure immediately below this layer.

d. If CO_2 first migrates horizontally from the MBB will it still be contained by the Reef Ridge Shale as it subsequently begins to migrate vertically within the Stevens reservoirs? This scenario tested potential migration through lateral spill points.

e. Will the NWS structure contain the CO_2 injected into it during the course of the Oxy CO_2 EOR Project?

The full-field simulation models of the Oxy CO_2 EOR Project have been used to confirm the original calculations of storage capacity of the 31S and NWS structures as well as volumes and pressures that could cause a breach of the Reef Ridge Shale or lateral spillover. The results of the full-field modeling are discussed in greater detail below.

The models will also be used to finalize the selection of monitoring wells in the SOZ and areas above the NWS, and to predict CO_2 behavior in the subsurface. A summary description of the design of the coarse grid model is included in Exhibit 3.

3.2.2 Design of the OEHI Full-Field Simulation

The design of the full field simulation included three studies:

First, a dynamic reservoir simulation model of the portion of the Stevens reservoirs in the 31S structure was used to evaluate the impact of a CO_2 EOR project with inevitable CO_2 storage in the MBB reservoir within the Stevens. Three scenarios were included.

a. A base case model assumed all injected CO_2 remained in the MBB reservoir or was recycled from produced gas and re-injected back into this reservoir.

b. A second scenario modeled potential CO_2 migration from the MBB into the overlying NA Shale reservoir. This migration was modeled to occur through faults which intersect both reservoir layers within the Stevens but below the Reef Ridge Shale. Three rates of migration were evaluated by setting different vertical transmissibilities through columns of grids representing the faults. It is important to recognize that since the NA Shales are beneath the Reef Ridge Shale, this scenario investigated the potential movement of CO_2 wholly within the Stevens reservoirs within the 31S structure. Such movement does not indicate, in any way, migration through the Reef Ridge Shale.

c. A third scenario modeled potential migration of CO_2 through a potential spill point located at the extreme eastern, down-dip, extent of the MBB.

Second, a simpler GEM-based model was coupled with a finite element geomechanical module, GEOMECH, to model cap rock failure in the Reef Ridge Shale as a function of cap rock mechanical properties and reservoir pressure immediately below the cap rock.

Third, a dynamic model was built for the NWS structure to evaluate a combined CO_2 storage and CO_2 EOR project.

3.2.3 Summary of Results of the OEHI Full Field Simulation

The most fundamental question related to the Project is whether the confining system comprised of the Reef Ridge Shale will trap the total volume of CO_2 to be injected during the Oxy CO_2 EOR Project. Results from the full-field simulation model predict that the Reef Ridge Shale can permanently trap all HECA CO_2 injected into the Stevens reservoir during the life of the Oxy CO_2 EOR Project. Further, the simulation provides useful insights about the migration of CO_2 within the Stevens reservoirs over time.

- The modeling results from the full-field simulation show that after 250 years, 100 percent of the CO_2 remains physically trapped by the structure and stratigraphy of the MBB and the shale reservoirs immediately above it but still considered part of the Stevens reservoirs, as indicated in Figure 13.
- The modeling results show that the Reef Ridge Shale can tolerate a pressure at the top of the NA shale of 7,500 psi or more without failure. This provides a safety margin of 4,500 psi, which is well over the MMP. This modeling also indicates that the Reef Ridge Shale will provide an effective seal for any CO_2 that first migrates laterally before migrating vertically.
- The modeling results show that the even with conservative assumptions regarding injection rates (2.5x the design basis) and significantly constrained production rates, the reservoirs in the 31S structure can easily hold the full volume purchased from HECA.

On at least an annual basis, OEHI will compare the actual rates of injection and production achieved in the Oxy CO_2 EOR Project to those predicted in the full-field simulation and determine whether the full-field model needs to be updated to reflect differences. As indicated above, variances in the predicted and actual injectivity will likely impact the number of well patterns necessary to fully implement the project. These types of changes will be reflected in updates to the full-field simulation.

3.3 Identification of Potential Pathways for Leakage to the Surface

3.3.1 Introduction

The analysis of potential pathways for leakage to the surface at the EHOF rests on a strong base of information. During its more than 100-year history, the EHOF has been studied and documented extensively. Due to its numerous and prolific producing zones, it is one of the most fully characterized oil fields in the United States.

The following detailed discussion of potential pathways for leakage to the surface from the Stevens reservoirs includes:

- Existing Well Bores
- Faults and Fractures

- Natural and Induced Seismic Activity
- Previous Operations
- Pipeline/Surface Equipment
- Overfill through Lateral Spill points
- Dissolution of CO_2 into Formation Fluid and Subsequent Migration
- Drilling through the CO_2 Area

3.3.2 Existing Well Bores

Due to its limited number of operators – OEHI is the second operator – the EHOF has an unparalleled historical record of wellbores. As indicated in Tables 3 and 4 of Section 3.1.1, there are roughly 1,231 existing well bores that penetrate the Stevens reservoir in the project area, which includes approximately 20 wells that have been abandoned. From these extensive operating records, OEHI has the ability to establish with great confidence that active and abandoned well bores within the project area are not, and will not become, pathways for leakage to the surface.

The Stevens reservoirs have been productively operated for decades and have been waterflooded since 1983. Current evidence indicates that the Stevens has successfully contained all injected fluids, suggesting that there is no unknown pathway from existing wellbores. This is true even after more than 25 years of waterflood operations in which water was injected into the Stevens reservoirs under pressure as an enhanced recovery method (see Exhibit 4 for more detailed information on the waterflood).

As a matter of practice, OEHI systematically implements rigorous operational protocols to protect the environment and worker safety. This extends to protocols for well construction, operation, and scheduled maintenance. In developing the current waterflood operation in the Stevens reservoirs, OEHI conducted an analysis to ensure that it had accurate well bore schematics for each well used in the flood. This includes an evaluation for internal and external well integrity for all wells in the area of review for the waterflood.

It is expected that all of the injection and production wells that would be involved in the Oxy CO_2 EOR Project operations will be permitted by DOGGR according to the appropriate provisions in the UIC Class II rules and other California regulatory requirements. As part of this permitting process, OEHI will again be required to demonstrate to DOGGR that existing well bores do not pose a threat of leakage to the surface from existing oil production operations. OEHI plans to conduct a similar well-by-well assessment for the Oxy CO_2 EOR Project permitting process and will undertake detailed tests as needed to demonstrate internal and external well integrity on all wells in the area of review for the Oxy CO_2 EOR Project. This area includes the entire footprint of injected CO_2 as determined by the reservoir simulation.

Lastly, per the DOGGR requirements noted above, OEHI is and will continue to be required to annually test injection wells for mechanical integrity, demonstrate proper construction of production wells, and provide a demonstration of well integrity for both injection and production wells at closure.

3.3.3 Faults and Fractures

Analysis of OEHI's 3-D seismic data provides further evidence of the sealing characteristics of the Reef Ridge Shale. A 3-D seismic survey was performed from 1999 – 2000, and covered nearly 70 square miles in the EHU. The data were processed using pre-stack depth migration which produces superior imaging in steeply dipping beds, such as on the flanks of the Stevens structures. Analysis of these data indicates that faults above and below the Reef Ridge Shale terminate before penetrating the seal.

After reviewing geologic, geomechanical, geochemical, seismic, operating, and other evidence, OEHI has concluded that there are no known transmissive faults or fractures that transect the Reef Ridge Shale interval in the project area. There are two faults (5R and 6R, as shown on Fig. 11) located in the southwest flanks of the EHOF in an area currently being used to produce natural gas. These faults are not located in the area where the injected CO_2 will be contained and are not expected to become potential leakage pathways to the surface.

There is little possibility that injection pressures could induce fractures or shear. As previously discussed, there is a large difference (a minimum of 4,500 psi based on model results) between MMP and fracture pressure of the overlying shale. This pressure difference is significant and ensures that OEHI can safely achieve miscibility pressure without reaching a pressure and rate of injection in the reservoir that would compromise the Reef Ridge Shale. The pressure difference, sometimes referred to as "headroom" varies in portions of the Stevens but remains large throughout. Consequently, OEHI will be able to mitigate the potential risk of leakage to the surface by managing injection pressure.

Managing injection pressure is a standard requirement of any Class II UIC permit, which specifically prohibits operating at pressures that could compromise the overlying seal. This approach is currently employed in the existing waterflood operations, where permits specify a maximum injection pressure (0.8 psi per foot of depth measured from the top perforation) and require the operator to conduct a rate/pressure test to justify any sustained injection pressures greater than the specified maximum. The Oxy CO_2 EOR Project is expected to be permitted at pressures consistent with the foregoing waterflood permit provisions.

3.3.4 Natural and Induced Seismic Activity

Natural seismicity is not likely to impact field operations and is highly unlikely to lead to leakage to the surface of any injected CO_2 from the EHOF. This assessment is based on decades of historical data for earthquake effects on wells in oil and gas operations in Southern California. It is also based on the geological setting of the EHOF, which is in relatively soft and shallow sediments.

With respect to natural seismic events, abundant historical data and information indicate that such events do not constitute a significant threat of leakage to the surface. The southern San Joaquin Valley area has a 100-year history of being a prolific oil and gas producing region with about 70 medium-to-very-large-scale oil and gas fields. There are more than 58,000 deep production and injection wells in Kern and Inyo counties. These existing wells have experienced decades of seismic activity with no significant release of gas, oil or water to the surface during earthquakes.

It is notable that the nearby Los Angeles Basin contains more than 24,000 production and injection wells and is even more seismically active than the Southern San Joaquin Basin. From 1998 to 2008, over 400 earthquakes greater than magnitude 3.0 were recorded within 100 miles of Los Angeles, whereas less than 200 earthquakes greater than magnitude 3.0 were recorded within 100 miles of the EHOF (Southern California Earthquake Data Center).

With respect to major earthquakes, most earthquakes with a magnitude 6 and above in California occur at depths of 6 miles or more in brittle basement rock. In contrast, the proposed injection zones at EHU are less than 2 miles deep in relatively soft sandstone. The strength of seismic waves decreases with distance; therefore, the large separation between any major earthquake source and the injection reservoirs would help prevent well damage. The Los Angeles Basin contains more than 80 oil and gas fields and several natural gas storage fields. During the operational life of these wells, the Los Angeles Basin has experienced more than 20 major earthquakes (greater than magnitude 6), some directly adjacent to major gas fields and natural gas storage fields, with no damaging release of gas to the surface.

The risk of induced seismicity from CO_2 EOR has been assessed to be very low. Injection operations have been implicated in low level seismic occurrences at a limited number of oil and gas fields around the world, including some in California (most notably the Geysers geothermal operations).

Generally, the low risk of induced seismicity is supported by the results of a comprehensive study that reviewed data on low-level seismic effects related to underground injection operations designed to hydraulically fracture shale formations. (See: Warpinski, N.R., Du, J. and Zimmer, U. Measurements of Hydraulic-Fracture Induced Seismicity in Gas Shales. Paper SPE 151597, SPE Hydraulic Fracture Technology Conference, February 2012). The study covered several thousand shale fracture treatments in various North American shale basins and the largest microseism (earth tremor) recorded had a measured magnitude of about 0.8. A deep earthquake of this magnitude would not be felt at the surface of the earth, and would not cause surface damage.

While there is no history of induced seismicity at Elk Hills, the possibility cannot be ruled out completely. Any such induced seismicity events would likely be less than magnitude 4, considering the geologic setting, areal extent and depth of proposed operations, and anticipated pressure and stress changes. Seismic events on the order of magnitude 3 to 4 would be felt in the local area but should not cause structural damage to facilities and buildings. Peak ground acceleration from such events should be on the order of 0.01g, well within seismic building code standards for the area. This is also at least an order of magnitude smaller than anticipated natural seismicity hazards for the area. Since induced seismic events should not cause structural damage, OEHI has reasonably concluded that a release of CO_2 from the subsurface due to induced seismicity is unlikely.

3.3.5 Previous Operations

OEHI has measured the pressure differential between the SOZ and the Stevens reservoirs. This differential is significant: approximately ten times greater in the Stevens versus the SOZ. For example, in one set of measurements, the pressure gradient in the SOZ ranges between 0.03-0.05 psi/ft-TVD and the pressure gradient in the Stevens ranges from 0.43-0.55 psi/ft-TVD. These two reservoirs are separated by a vertical depth of approximately 1,400 feet. The pressure gradient differential between the two zones, coupled with an operating history showing no fluid communication between the zones, indicates that previous operations have not compromised the Reef Ridge Shale's ability to serve as an effective seal.

3.3.6 Pipeline / Surface Equipment

Damage to or failure of pipelines and surface equipment can result in losses of CO_2. OEHI anticipates that the use of prevailing design and construction practices and compliance with applicable regulatory requirements will reduce to the maximum extent practicable the risk of leakage from surface facilities. The facilities and pipelines of the Oxy CO_2 EOR Project will utilize materials of construction and control processes that are common to new CO_2 EOR projects in the oil and gas industry. Operating and maintenance will follow industry practices and requirements demonstrated to be effective. Facilities will be designed to follow the elements of process safety management specified in OSHA's Occupational Safety and Health Standard 29 CFR 1910.119. Other field pipelines will comply with California Code of Regulations, Title 8. The unique and centralized automation and control system currently in use at the EHOF will facilitate excellent operational control over the Oxy CO_2 EOR Project and ensure the safety and reliability of the facilities.

In addition, there is a possibility that there will be small amounts of leakage (fugitive emissions) from surface equipment or the CO_2 will need to be vented from surface equipment. OEHI is monitoring and reporting this CO_2 as part of its facility-wide reporting requirements under 40 CFR Part 98 Subpart W and the analogous state provisions at Division 3, Chapter 1, Subchapter 10 of Title 17 of the California Code of Regulations. The amount of CO_2 emissions attributed to the surface equipment associated with the Oxy CO_2 EOR Project will be subtracted from this report and included in the mass balance equation as described in sections 4.1.1 (Monitoring for Mass Balance Calculations) and section 5 (Determining Sequestration Volumes).

3.3.7 Overfill at Lateral Spill Points

Injected CO_2 is more buoyant than formation fluids and tends to rise in the target formation until it reaches the ceiling of the structural or stratigraphic trap that has held hydrocarbons for millions of years. Hypothetically, more CO_2 could be injected into a structural or stratigraphic trap than that trap could hold, filling the space from the top downward until the CO_2 flows out of the trap through the lowermost "spill point." This concept is sometimes referred to as "overfill" at "lateral spill points."

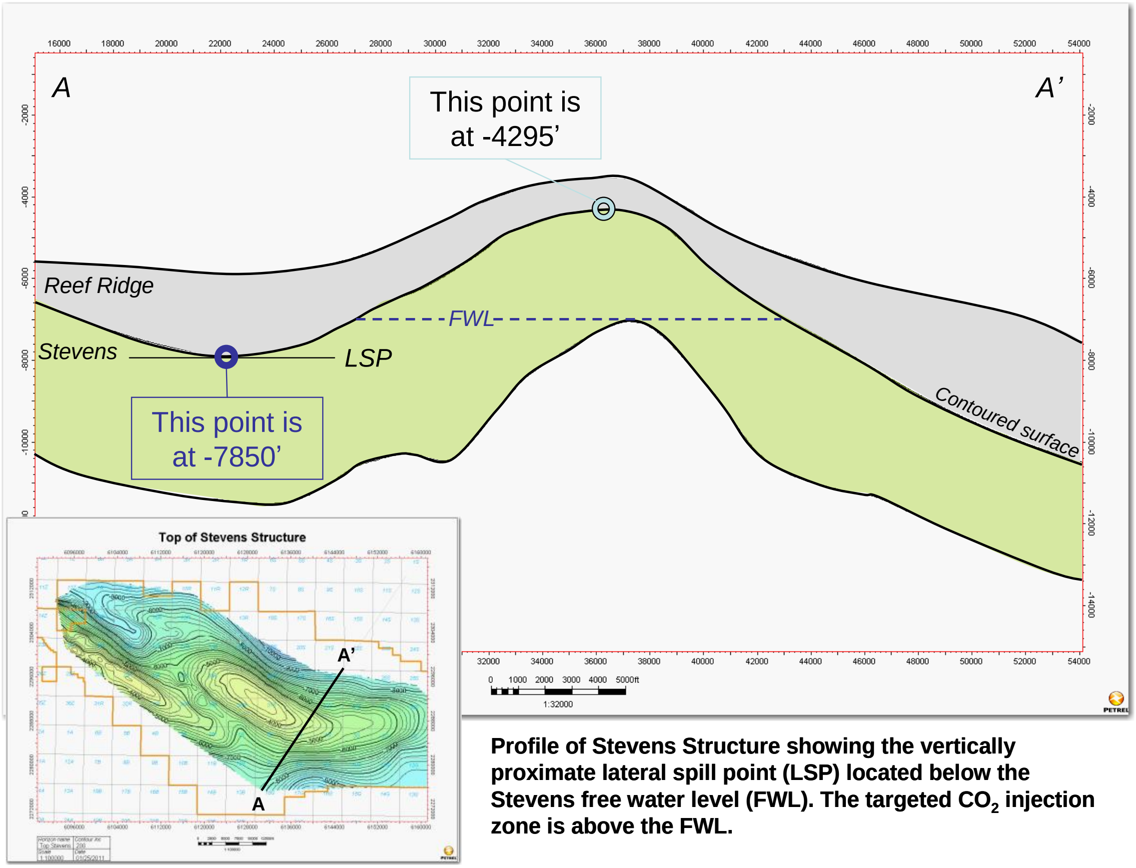
However, there are no reasonable injection scenarios that would lead to overfilling the Stevens reservoir with CO_2 to result in leakage at lateral spill points. This conclusion is based on several factors, including the physical characteristics of the 31S and NWS structures and the relatively small volume of CO_2 to be injected compared to the capacity of the Stevens reservoirs on the 31S and NWS structures (as noted in Table 1):

Figure 19 depicts the Reef Ridge Shale seal overlying the 31S structure. The oil bearing layers within the Stevens reservoirs in the 31S structure are above the free water levels. Beneath the free water level there is no residual oil saturation (i.e. no oil to be recovered through CO_2 EOR). The lateral spill point (LSP) can be seen on the left flank of the 31S structure (the right flank is so distant from the injection point that it cannot be shown in Figure 19). On both flanks, the LSPs lie below the free-water level and far away from the injection point.

Volumetrically, the Oxy CO_2 EOR Project will produce roughly the same quantity of fluids as are injected. This operating practice precludes overfilling the reservoir to the spill point with CO_2. Moreover, the quantity of CO_2 to be injected over the 20-year life of the Oxy CO_2 EOR Project is equivalent to less than 5 percent (approximately) of the useable reservoir pore volume, (i.e., the pore volume located above the free-water levels). As the full field simulation indicates, it is predicted that a majority of the injected CO_2 will be contained in the MBB portion of the Stevens reservoirs.

And finally, the Reef Ridge Shale extends hundreds of miles beyond the EHOF. If CO_2 were to migrate beyond the LSP's, it would be sequestered because of the influence of other natural trapping mechanisms including mineralization and residual trapping.

Consequently, the small injection volume relative to the available storage capacity, the production of fluids during projected EOR operations, the physical dimensions of the injection reservoir, and the size of the Reef Ridge Shale, render the risk of overfill through lateral spill points insignificant.



Profile of Stevens Structure showing the vertically proximate lateral spill point (LSP) located below the Stevens free water level (FWL). The targeted CO_2 injection zone is above the FWL.

Figure 19 - View of Stevens Cross Section Showing Spill Point and Free Water Level

3.3.8 Dissolution of CO_2 into Formation Fluid and Subsequent Migration

The reservoir simulation indicates that only a small percentage of injected CO_2 will dissolve into the formation fluids over time. Still, some academic studies suggest that this dissolution could lead to potential leakage. Under this theory, brine saturated with CO_2 may be heavier than brine which is not saturated with CO_2. Over time, CO_2 saturated brine could sink down the anticline and be carried in to a location with different pressures. From there, the release of pressure would allow the dissolved CO_2 to come out of dissolution and be released out of the formation fluid in an area where there is not an overlying physical barrier.

Based on a review of existing data and the preliminary results from the full-field simulation model showing that only a small fraction of injected CO_2 is dissolved in formation fluids, OEHI calculates that risk of migration of formation fluids containing dissolved CO_2 is insignificant and that this is a very unlikely pathway for leakage to the surface from the Stevens reservoirs. As previously discussed, overfill through lateral spill points is highly unlikely. Furthermore, evidence suggests that the formation fluid in the anticlinal structures is isolated either by the compression faults that formed them or by diagenetic differences in the water leg beneath the free water level. No influx of formation fluid has been observed to date and the injection volume is not expected to be sufficient enough to induce an outward flow of formation fluids past these spill points.

3.3.9 Drilling Through the CO_2 Area

There exists the possibility that drilling a new well into or through a CO_2 injection zone could create a leakage pathway. Existing state and federal regulations are intended to mitigate this risk. Several regulations and guidelines specifically address zonal isolation during well construction. These regulations and guidelines are designed to ensure that wellbores pose no significant risk of leakage of fluids, including CO_2, to the surface. They include the following requirements:

- Surface casing strings require a sufficient volume of cement to be pumped into the casing well-bore annulus so that the entire annulus is filled to surface.
- A minimum of 500 lineal feet of cement is required above oil and gas zones in an intermediate or production casing string, which further provides zonal isolation.

All OEHI well designs are approved by DOGGR, and a drilling permit is issued prior to commencement of any drilling operations. All permits are publicly available through DOGGR.

3.4 Summary of Assessment of Risk of Release from Subsurface

After assessing potential risk of release from the subsurface, OEHI has concluded that release of injected CO_2 from the subsurface is improbable.

- The structure and stratigraphy of the EHOF is ideally suited for the injection and trapping of CO_2. The stratigraphy within the CO_2 injection zones is porous and permeable and can be very thick, providing an excellent EOR target and ample capacity for long-term CO_2 sequestration. Between the surface and the Stevens reservoirs, naturally occurring dense and thick overlying shales exist – including the Reef Ridge Shale – which serve as excellent seals that have proven capable of containing fluids and gases for millions of years.
- While boreholes that penetrate the Reef Ridge Shale could be a potential pathway for release of CO_2 to the surface, OEHI has concluded that existing and future boreholes present little risk of release to the surface for the following reasons: 1) the operating history is well documented and does not indicate leakage from man-made pathways due to past production activities; and 2) adequate regulatory and operations procedures exist to ensure that new boreholes will not create pathways for release of CO_2 from the subsurface.
- Faults are present within the EHOF. However, these faults are non-transmissive through the Reef Ridge Shale within the area encompassed by the modeled project boundaries.

- The other potential leakage pathways are not considered significant in the case of the Oxy CO_2 EOR Project because of the formation geology and the small volume of planned injection relative to available pore volume.

In summary, based on a careful assessment of the potential risk of release of CO_2 from the subsurface, OEHI has determined that there are no reasonably expected pathways that are likely to result in significant loss of CO_2 to the atmosphere. Further, given the detailed knowledge of the field and the operating protocols, OEHI believes that it would be able to mitigate any leakage to the surface that could arise from currently unknown pathways. Finally, as discussed further below (see Section 4), OEHI will employ adequate monitoring protocols to detect any unexpected releases of CO_2 from the subsurface.

4. Monitoring Program

OEHI proposes a monitoring program that includes simultaneous monitoring of:

- CO_2 injection and fluid production during operations of the Oxy CO_2 EOR Project;
- A tiered approach to monitoring in the subsurface and at the surface to detect migration, if any, of injected CO_2; and,
- An approach to monitoring after CO_2 injection operations cease.

4.1 Monitoring During Operations

4.1.1 Monitoring for Mass Balance Calculations

As previously noted, existing OEHI operations are centrally monitored and controlled by an extensive and sophisticated system referred to as the Central Control Facility (CCF). The CCF is used to make operational control decisions on a real-time basis throughout the EHOF to assure the safety of field operations and to comply with monitoring and reporting requirements in current permits.

As part of its ongoing operations, OEHI collects flow, pressure, and gas composition data in a centralized data management system. These data are monitored 24 hours a day by qualified technicians who follow OEHI response and reporting protocols when the system delivers notifications if data exceed pre-determined statistically acceptable boundaries. The data can be accessed for immediate analysis.

The CCF also will be used to collect and analyze data from the Oxy CO_2 EOR Project. Figure 5 (repeated here again as Figure 20 for convenience) identifies the meters that will be used to evaluate, monitor, and report on the CO_2 flood as described earlier in Section 2.2. A similar metering system is already installed throughout the EHOF.

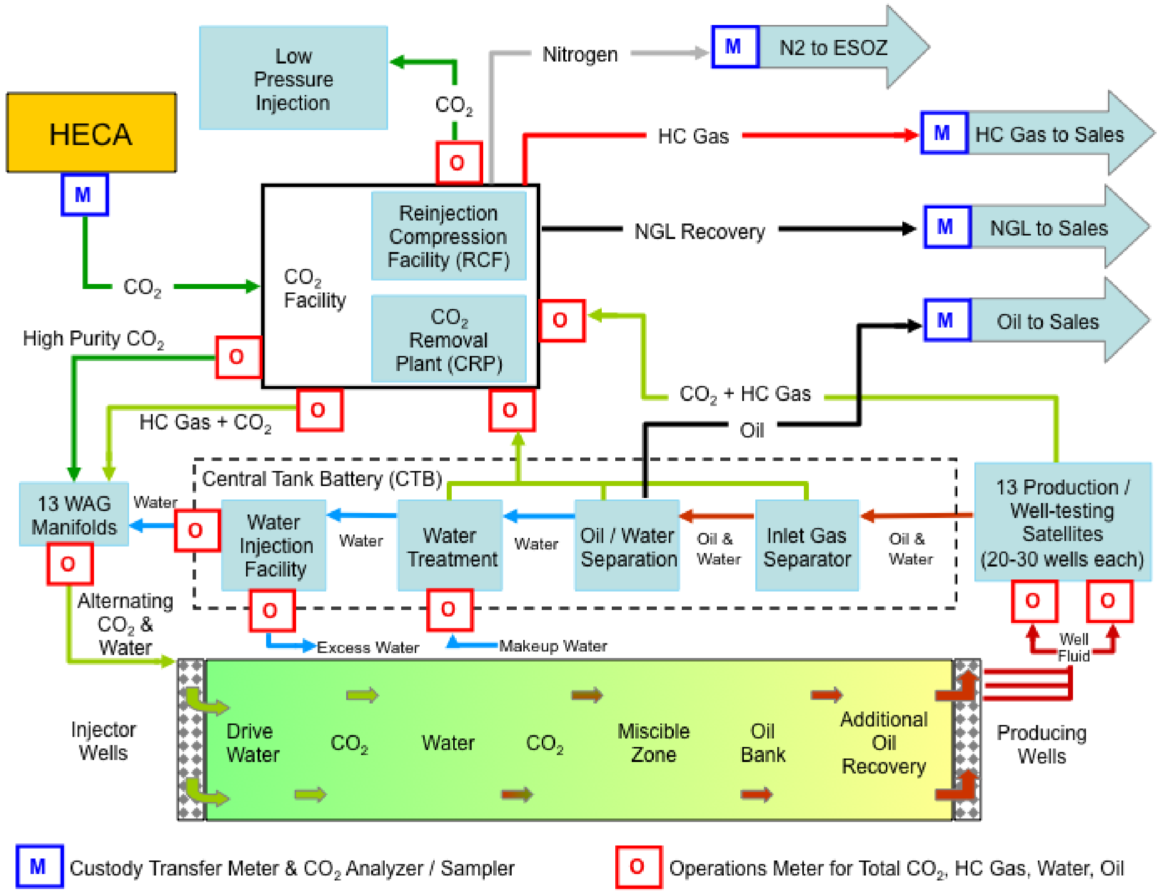


Figure 20 - Process Flow of Oxy CO_2 EOR Project, Indicating Meters

OEHI uses different meters for specific purposes. These meters fall into two primary categories: custody-transfer meters and operations meters.

As indicated in Figure 20, OEHI intends to operate a custody-transfer meter at the point at which custody of the CO_2 from HECA is transferred to OEHI and also at the points at which custody of oil, liquid natural gas, HC gas and nitrogen gas is transferred from OEHI to another party. The custody-transfer meters will measure flow rate continuously. Fluid composition will be determined on either a continuous basis or by periodic sampling depending on the specific meter; both options are considered to be accurate for purposes of commercial transactions. All meter and composition data will be recorded.

OEHI's metering protocols follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate. These meters will be maintained routinely, operated continuously and will feed data directly to the CCF. In the oil and gas industry, the generally accepted level of custody transfer meter accuracy is 0.25% or better and the meters are calibrated every 60-90 days. A third party is frequently used to calibrate these meters and both parties to any transaction have rights to witness meter calibration. These custody meters provide the most accurate way to measure mass flows.

Most process streams are multi-component or multi-phase, with varying CO_2 compositions. For these streams, flow rate is the most important control parameter. OEHI uses operations flow meters to determine the volumetric flow rates of these process streams, which allows for the monitoring of trends to identify deviations and determine if any intervention is needed. OEHI also uses operations flow meters – comparing aggregate data to individual meter data – to provide a cross-check on actual operational performance.

As noted earlier in Section 2, in-field flow rate monitoring presents a formidable technical and maintenance challenge. Some variance is due simply to differences in factory settings and meter calibration. Additional variance is due to the operating conditions within a field. Meter elevation, changes in temperature (over the course of the day), fluid composition (especially in multi-component or multi-phase streams), or pressure will each have an effect on any in-field meter reading. Many meters have some form of automatic adjustment for some of these factors, others utilize a conversion factor that is programmed into the meter, and still others need to be adjusted manually in the calculation process. Use of a smaller number of centrally located meters reduces the potential error that is inherent in employing multiple meters in various locations to measure the same volume of flow and gas composition. Consequently, developing a CO_2 mass balance on multi-phase, multi-component process streams is better accomplished using custody-transfer meters instead of operations meters.

1. CO_2 Received from HECA

A custody transfer meter will be used at the delivery point to continuously measure the volume and composition of CO_2 received at the CO_2 Facility from HECA. The metering protocols will follow the prevailing industry standard(s) for custody transfer (as promulgated by the API and the AGA).

2. Injection

Under Class II UIC permits, OEHI is required to report volumes of fluids injected. Following the manner in which injection volumes are reported under existing Class II UIC permits at the EHOF, OEHI will allocate aggregate injected volume from data collected at the meters going into the CO_2 Facility (the custody-transfer meter and the two flow meters measuring recycled CO_2 from the production wells) to individual wells based on a ratio established by reviewing individual injection volume data as measured by in-field operations flow meters.

3. Production

DOGGR requires OEHI to report volumes of produced fluids (oil, water, and produced gas). There will be two operations meters at each satellite gathering station used to determine flow rates. One will be used to measure the aggregate volume of the produced fluid from all wells. A second meter will be used to measure the oil/water/gas rate of each production well on a rotating basis at least once a month. OEHI will use the total volume data gathered at each satellite gathering station and the results from each individual test of a production well to calculate total produced volumes from each production well. This is the same approach OEHI uses in reporting produced volumes under existing DOGGR requirements.

4. CO_2 from Surface Equipment Leakage and Venting

The federal EPA and California recently adopted rules for GHG reporting at petroleum and natural-gas systems and CO_2-injection facilities. OEHI anticipates reporting on surface equipment leakage and venting of CO_2 emissions under 40 CFR Part 98, Mandatory Reporting Rule for GHGs, and the analogous state provisions at Division 3, Chapter 1, Subchapter 10 of Title 17 of the California Code of Regulations, as applicable. Under the rules, OEHI will be required to report the total CO_2 and methane (CH_4) emissions from the many source types, including those listed below, as they apply to the Oxy CO_2 EOR Project:

- For onshore petroleum and natural-gas production: fugitive emissions from valves, connectors, open-ended lines, pressure-relief valves, compressor-starter gas vents, pumps, flanges, well work, and other fugitive sources (such as instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and breather caps for crude services);
- For onshore natural-gas processing: fugitive emissions from valves, connectors, open-ended lines, pressure-relief valves, meters, and centrifugal compressor dry seals; and
- For onshore natural-gas transmission: fugitive emissions from connectors, block valves, control valves, compressor blowdown valves, pressure-relief valves, orifice meters, other meters, regulators, and open-ended lines.

4.1.2 Monitoring to Detect Surface Leakage of CO_2

As discussed above, OEHI has identified the following potential pathways for leakage of injected CO_2 to the surface: existing well bores, faults and fractures, seismic activity, previous operations, pipeline/surface equipment, overfill through lateral spill points, migration of dissolved CO_2 into formation fluid, and potential future drilling operations. After assessing the background conditions and standard operating procedures in place at the EHOF, OEHI has determined (see section 3.3) that while there will be some level of fugitive emissions from pipeline and surface equipment, the other potential pathways will not likely result in leakage of CO_2 to the atmosphere. Nonetheless, OEHI has designed a monitoring program that will focus first on detecting unanticipated migration of the CO_2 out of the injection zone in the subsurface and, second, if such migration is detected, determining if leakage of CO_2 to the surface is occurring.

It is important to recognize that the Oxy CO_2 EOR Project, which is very similar to the existing waterflood project, will be conducted in an active and very productive oil field and is much like the existing waterflood project. Both the CO_2 injection and the water flooding are designed to enhance the recovery of existing oil that would otherwise be left stranded. Although not currently a regulatory requirement, it is OEHI's current practice to monitor on a real-time basis the performance of producing oil reservoirs for differences between expected and observed performance and movement of fluids (and this practice will continue for the Oxy CO_2 EOR Project). Any such difference tends to indicate inefficiencies in oil-production operations, and addressing them quickly leads to improved performance. Typically, OEHI initially investigates wells or surface equipment to address such differences and it is standard practice to conduct further investigation of the subsurface if warranted. For the same reasons and to ensure the optimal use of purchased CO_2 during the Oxy CO_2 EOR Project, OEHI would assess injection and production performance to identify and address anomalies that could identify opportunities to improve performance of the Oxy CO_2 EOR Project or the possibility of leakage to the surface, even if not required to do so. OEHI will ensure that these procedures also meet all regulatory requirements and make any necessary modifications.

There are a number of CO_2 monitoring techniques available and successfully in use. Many of these techniques have unique attributes that make their application more or less practical in specific geologic settings. The monitoring plan set forth below outlines the techniques selected for monitoring at the EHOF based on OEHI's assessment of the effectiveness of an array of monitoring technologies given the conditions at the EHOF. A common principle among these measures is the use of an iterative approach to both the monitoring and the resulting follow-up actions, if warranted.

This monitoring plan includes four tiers. Tier 1 is monitoring in the injection zone to ensure operations are proceeding as expected. Tier 2 is the monitoring of the subsurface above the Reef Ridge Shale to ensure early detection in the unlikely event that injected CO_2 migrates through the Reef Ridge Shale. Tier 3 is the monitoring of well bores to ensure their integrity. Tier 4 is the monitoring of surface equipment and the areal surface over the injection zones to detect leakage at the surface. Before injection begins, OEHI will develop statistically reliable baselines for key parameters used in Tier 1 and Tier 2.

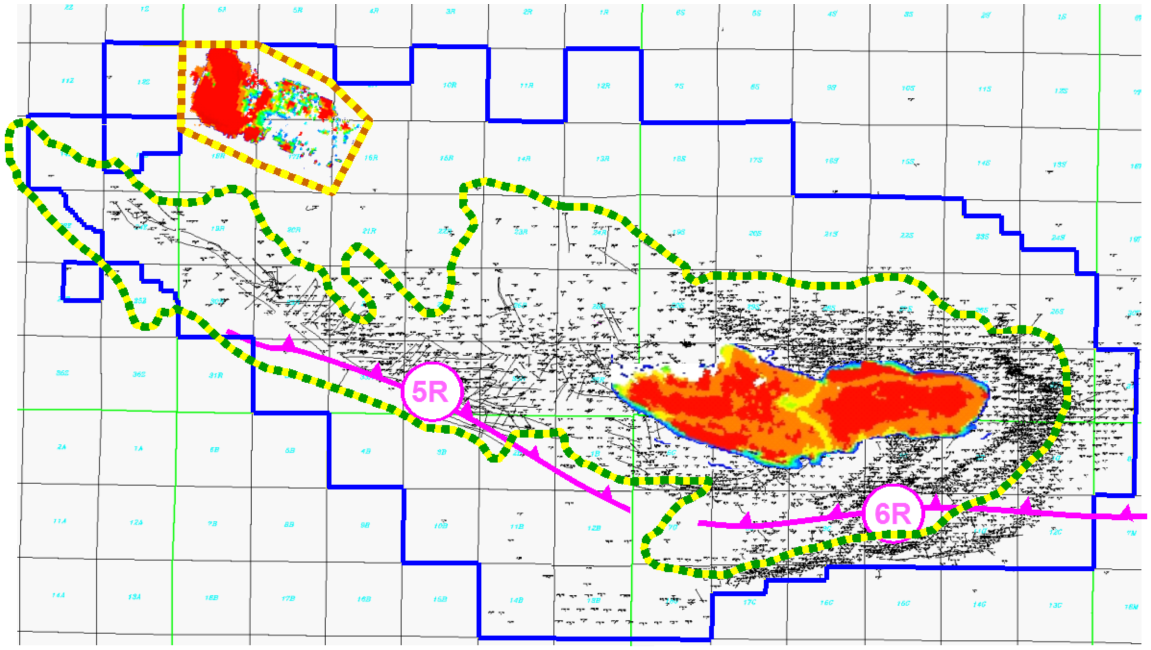


Figure 21 Modeled Extent of CO_2Footprint After 251 Years (represented by the red-orange-yellow colored areas)

Figure 21 provides the backdrop to illustrate this monitoring plan. The red/orange/yellow colored areas in Figure 21 indicate the maximum expected lateral extent of the injected CO_2 based on the reservoir simulation. The dotted lines indicate the SOZ over the 31S structure and the inactive, isolated geology above the NWS.

Tier 1. Monitoring in the CO_2 Injection Zone(s)

Tier 1 monitoring is designed to detect if CO_2 is moving laterally outside the modeled extent of the injected CO_2 below the Reef Ridge Shale. This monitoring will assist OEHI in managing its injection operations and serve as an early indicator of potential unanticipated CO_2 migration. It is important to note that unanticipated CO_2 migration is not indicative of a release from the subsurface to the atmosphere because such migration is occurring beneath layers of confining zones, including the Reef Ridge Shale.

OEHI will develop an injection and production performance plan for the Oxy CO_2 EOR Project. This plan will provide a projection of the rate and volume of CO_2 injection, the rate and volume of fluid production, and expected CO_2 movement. By design, this plan relies on close integration of the fine grid and full field models to optimize reservoir productivity and effectively manage the CO_2 injection. OEHI will also develop a pre-determined control chart filter that will automatically notify technicians in the CCF of any material variances between the projected and monitored results in the Oxy CO_2 EOR Project. If such a variance is noted, OEHI's response will be to first ensure that the data are accurate; and then conduct additional testing and inspection to determine the cause of the variance. OEHI will address such variance and remedy it as appropriate. Representative control parameters, baselines, set points and responses are commercially sensitive and will be used for only internal monitoring.

For purposes of reporting, OEHI will use static monitors in wells completed in the injection zone and located at the periphery of the modeled extent of the injected CO_2 (see Figure 21). OEHI will establish baselines, derived from historic data, for these wells for use in determining variances from expected performance. Trend analysis will be used to detect changes over time against the baseline due to the Oxy CO_2 EOR Project operations. If data collected from these wells indicate that the extent or rate of CO_2 movement varies significantly from the full field model predictions, OEHI will investigate and respond accordingly. If a variance indicates CO_2 migration from the Stevens reservoirs, OEHI will report the condition and the response action to DOGGR as quickly as practicable. OEHI will describe any such variances and the response in the annual MRV Report, including any necessary changes to the full field model.

Tier 2. Monitoring in the Areas Above the Reef Ridge Shale

Information from the full-field simulation model and detailed knowledge of EHOF geology indicate that the SOZ and the area above the NWS are the most likely locations where injected CO_2 would be found if the integrity of the Reef Ridge Shale were compromised. Both of these areas are well-suited for monitoring and OEHI has developed the following plans for each area.

The SOZ Above the 31S Structure

OEHI is actively producing hydrocarbons from the SOZ and monitors oil and gas production on a continuous basis and periodically measures fluid and gas compositions.

OEHI will establish a baseline, derived from historic data, for CO_2 concentrations in the fluids produced from the SOZ. Trend analysis will be used to detect changes over time against the baseline due to the Oxy CO_2 EOR Project operations. Much like the system outlined in Figure 20, the hydrocarbon collection system in the SOZ consists of multiple individual wells tied to one of several gathering stations. If data collected from the SOZ show increased CO_2 levels, OEHI will isolate each system in order to find the source of the increased levels and then investigate and respond accordingly. If a variance indicates CO_2 migration from the Stevens reservoirs, OEHI will report the condition and the response action to DOGGR as quickly as practicable. OEHI will describe any such variances and the response in the annual MRV Report, including any necessary changes to the full field model.

Above the Stevens reservoirs in the NWS Structure

Based on the reservoir simulation and the planned injection in the Stevens reservoirs in the NWS structure, OEHI will establish a representative number of monitoring wells in the nonproducing zone above the Reef Ridge Shale overlying the NWS. OEHI will sample these wells to develop a baseline for background CO_2 concentrations and formation fluid pressure. If data collected from the monitoring wells show increased CO_2 levels or formation pressures, OEHI will investigate to find the source of the increased levels and respond accordingly. If monitoring indicates CO_2 migration into the area above the NWS, OEHI will report the condition and the response action to DOGGR as quickly as practicable. OEHI will describe any such variances and the response in the annual MRV Report, including any necessary changes to the full field model.

Tier 3. Monitoring of Wellbores

Preventing leakage from wellbores begins with proper design and construction. It is expected that all of the injection and production wells involved in the Oxy CO_2 EOR Project operations will be permitted pursuant to the UIC Class II rules, which include specific design and construction requirements. As an additional part of this permitting process, OEHI is required to demonstrate that existing well bores within the area of review do not pose a threat of leakage to the surface. OEHI plans to conduct a well by well assessment for this permitting process and will undertake detailed tests as needed to demonstrate well integrity on all wells in the area of review for the Oxy CO_2 EOR Project.

Wellbores permitted as part of the Oxy CO_2 EOR Project will require ongoing management and planned maintenance, including mechanical integrity testing of injection wells and OEHI will meet or exceed API standards and California regulatory requirements for well maintenance and monitoring. In addition, OEHI will apply a corrosion protection program to establish and maintain the barrier between the steel used in wells and any CO_2 enriched fluids. The extensive experience developed by OEHI from EHOF waterflooding is directly applicable since the injected produced water, similar to CO_2, is corrosive.

Methods are currently employed or planned to mitigate both internal and external corrosion of casing in wells that will be part of Oxy CO_2 Project. To prevent/mitigate external corrosion, OEHI plans to place a column of cement between the formation and casing from total depth of the well bore to 500 feet above the shallowest open perforation in newly drilled wells. Cement is an effective and proven barrier to protect casing from external corrosion. Cement tops on existing wells will be evaluated as part of the DOGGR UIC permit process. Also, a cathodic protection system, which is already in place, will continue to be applied to wells in the project area.

To prevent/mitigate internal corrosion in the injection well casing/tubing annulus, OEHI plans to place an inhibited fluid inside the casing above the packer to protect the steel. The tubing and packer will be internally coated with corrosion resistant materials to prevent internal corrosion. The annulus will be monitored for pressure fluctuations that may indicate contamination due to leaks in the tubing or packer. Periodic pressure tests will also be performed in accordance with UIC permit conditions.

An internal barrier for production well casing will be established by exposing the steel to an inhibitor fluid, thereby placing a film of corrosion inhibitor directly on the steel surface. By design, this inhibitor film depletes over time and will be re-established as needed according to a monitoring program. An accepted method to monitor the effectiveness of this film is to place a strip of steel similar in composition to the casing into the fluid stream and measuring the steel strip for any weight loss through time, which is an indicator of the corrosion rate.

As a result of design requirements, corrosion protection activities, field surveillance (see Tier 4, below), and regulatory standards, OEHI believes existing well bores pose an unlikely risk of significant leakage to the surface. This can be validated through use of the fine-grid model to confirm that actual performance matches model predictions. If surveillance, testing or modeling indicate CO_2 migration from the Stevens reservoirs through wellbores, OEHI will report the condition and the response action to DOGGR. OEHI will describe any material variances and how they were addressed in the annual MRV Report. If warranted, OEHI will update its reservoir simulation to address these variances.

Tier 4. Surface Inspection and Monitoring

OEHI will monitor fugitive and vented CO_2 emissions under the EPA GHG reporting rules. In addition, OEHI will employ two methods to detect leaks at the surface. First, along with daily computer surveillance, OEHI will perform daily facility inspections and weekly well-site inspections. This surveillance, by trained and experienced oilfield operators, is designed to identify and address safety, environmental compliance, efficiency or operability conditions. For any situation where compressed CO_2 leaks or is inadvertently vented at the surface, it decompresses, rapidly cooling and forming vapor and ice, a process which is both audible and easily observed. Second, OEHI will also focus on the low-rate leakage scenario. The Tier 4 monitoring will be informed by the results of the routine monitoring that will occur within the injection zones, in the SOZ and above the Stevens reservoirs on the NWS structure, and the monitoring activities under Tier 3. Where such monitoring identifies a well or wells of potential concern, further investigation such as ambient CO_2 detectors or hand-operated CO_2 monitors may be employed. Regardless of the method used, if a leak to the surface is detected, the leaking system will be immediately isolated, depressurized, and repaired. Any maintenance requirements will be logged, planned, and scheduled. OEHI will describe in its annual MRV Report any leaks found in the surface equipment and how they were addressed, and will include an estimate of the CO_2 loss. Records of visual inspection logs will be made available for review by DOGGR representatives upon request.

4.2 Expected Duration of MRV Program

OEHI anticipates conducting the MRV program until it obtains regulatory approval to discontinue it. Once active CO_2 injection ceases, OEHI will revise the MRV plan as warranted to continue its demonstration that CO_2 remains in the target reservoirs even if all wells have not been closed and plugged. It is expected that during this phase, less intensive monitoring will be sufficient to demonstrate that the injected CO_2 has not migrated outside the injection zone.

The goal of the Oxy CO_2 EOR Project is to optimize the effectiveness of the injected CO_2 in enhancing the recovery of hydrocarbons. At some point, the efficiency of the sweep would no longer be considered optimal and the recovered CO_2 would be directed to the next pattern of wells being used in the project. OEHI will determine when to implement new wells and patterns and phase out existing wells and patterns based on performance compared to behavior predicted by reservoir modeling. As a well or pattern is phased out of operation, it will either be shut-in (temporarily closed) or plugged (permanently closed). It is rare to permanently close wells in a productive oil field – like the EHOF – unless there is a concern about the mechanical integrity of the well or it is determined that there is absolutely no chance of recovering additional hydrocarbons. Whether shut-in or plugged, any well will continue to be subject to DOGGR regulations and oversight with respect to mechanical integrity.

It is quite possible that as the Oxy CO_2 EOR Project nears the end of its design life, other processes for economically recovering remaining oil – either from the Stevens reservoirs or from reservoirs above or below – will emerge. In such cases, wells that are drilled into the Stevens reservoirs, but which are temporarily closed, could be re-purposed for recovery operations. As such, the majority of wells associated with the Oxy CO_2 EOR Project will be temporarily closed until such time as it is determined that the further production from other vertically proximate reservoirs is no longer possible, or that the entire EHOF has reached the end of its economic life. Upon determining that temporarily closed wells cannot be used for commercial purposes in other intervals, such wells will be inspected and/or tested to assure their mechanical integrity and then permanently closed.

In the way that wells progress through temporary closure to permanent closure, so too will surface facilities. OEHI will treat the surface equipment associated with the Oxy EOR CO_2 project accordingly. As production in any portion of the field reaches an economic endpoint, surface piping, tanks and other equipment will be taken out of service, de-inventoried of fluids, and blinded or locked to prevent inadvertent use. In this state the equipment will no longer be part of the Oxy CO_2 EOR Project, routine monitoring will cease, and it will be considered closed. However, if production operations resume such that CO_2 containing fluids are reintroduced into the equipment, then routine monitoring will resume. Ultimately, the separators, tanks, water treatment and gas compression facilities will be disassembled and removed.

OEHI expects that by the time the EHOF has reached the end of its economic life, the record of monitoring during the Oxy CO_2 EOR Project will: a) establish the location of the injected CO_2 and its pressure profile, b) verify the integrity of the Reef Ridge Shale, c) demonstrate that there is no threat of leakage to the surface from well bores, and d) demonstrate that there is no threat of leakage to the surface from the Steven reservoir. Also, by that point in time, OEHI will have plugged all open wells according to permit conditions and other regulatory requirements and will have demonstrated that the wells will not pose pathways for future leakage to the surface. OEHI believes these showings will be sufficient to demonstrate that the injected CO_2 is not expected to migrate in the future in a manner likely to result in surface leakage. Specifically, OEHI intends to perform the steps outlined in the following subsections before submitting a request for permission to discontinue its MRV plan.

4.2.1 Magnitude and Extent of CO_2 Footprint

OEHI will use a combination of modeling and the best available data to demonstrate the magnitude and extent of the injected CO_2 within the Stevens reservoir. This will validate that the injected CO_2 is contained by the Reef Ridge Shale. Monitoring and full-field modeling conducted throughout the operational life of the project will be used to demonstrate that there continues to be no communication between the Stevens reservoirs and the areas above the Reef Ridge Shale and that the full volume of injected CO_2 is contained below the Reef Ridge Shale. Further, OEHI will use information regarding CO_2 in produced fluids from the 31S and NWS structures to demonstrate the reliability of the full-field simulation model in predicting movement of CO_2.

4.2.2 Location of Injected CO_2

OEHI will use a combination of modeling and the best available data to demonstrate the location of the injected CO_2. During the operational life of the project, OEHI will use measured data at the production wells to validate OEHI's full-field simulation model (see discussion of this model in Section 3.2). When all injection and production operations in the Stevens reservoirs cease, there will be no new man-made changes in reservoir pressure, either from injection or de-pressurization (through production). Movement of the injected fluids, including CO_2 will be driven by natural forces and will be countered by structural trapping (vertical movement mitigated by intervening shale layers and ultimately stopped at the physical boundary of the Reef Ridge Shale), capillary trapping and long-term mineralization processes.

The expected location and predicted movement of CO_2 has been forecast using a full-field simulation model. Figures 21 and 22 show the areal extent of the CO_2 in the Stevens reservoirs in the 31S structure at 20 years (the end of CO_2 purchase from HECA) and 138 years (a point far beyond the cessation of CO_2 EOR Project operations). In these and the following figures (Figures 23 and 24), the area in the 31S where injected CO_2 would likely move is highlighted by the colored area. The coloring indicates the predicted mole fraction of injected CO_2 as indicated on the scales. Note that the royal blue color signifies a predicted CO_2 mole fraction of zero percent (0%), red signifies 100% CO_2. This approach to color coding is commonly used. Inclusion of the blue zones indicates that the entire boundary of the modeled CO_2 movement is mapped in the model.

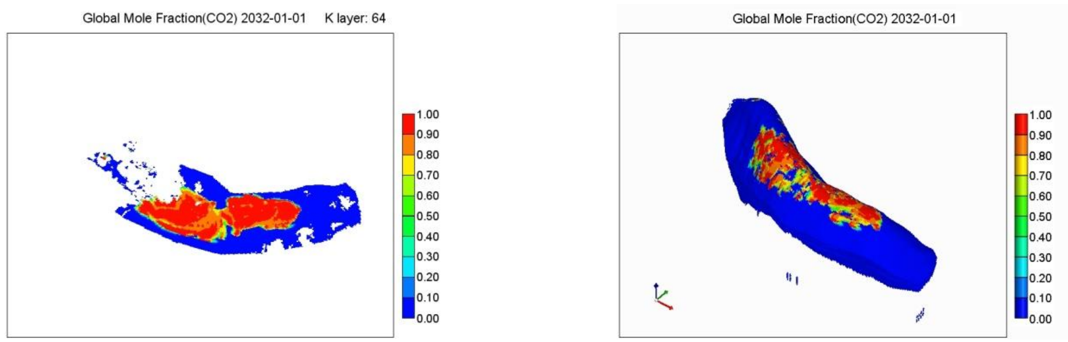


Figure 21: CO_2 at mid-depth (left) and top (right) of MBB after 20 Years

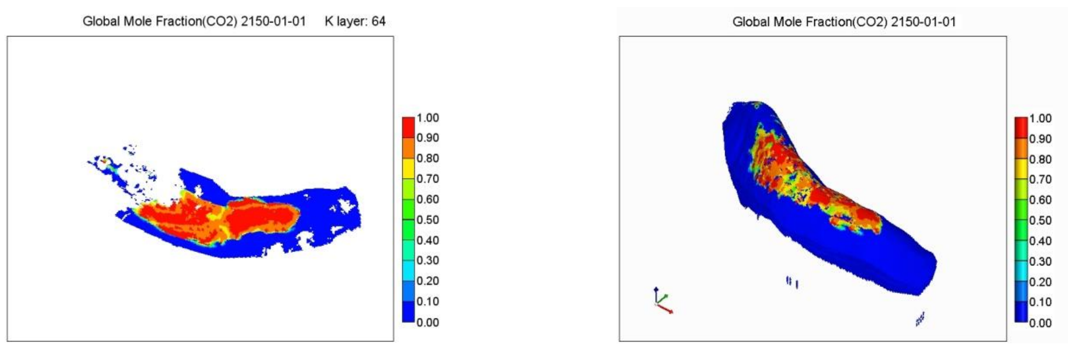


Figure 22: CO2 at mid-depth (left) and top (right) of MBB after 138 Years

Figures 21 and 22 present a "bird's eye" view of the location of CO_2 predicted by the full-field simulation model at the mid-depth and the top of the MBB. Note that the MBB is a layer within the Stevens reservoirs. The NA Shale lies above the MBB between it and the Reef Ridge Shale. In Figure 21, the large extent of bright orange at mid-depth and smaller extent at top depth is indicative of higher concentrations of CO_2 at mid-depth where injection will take place. Some of the injected CO_2 is projected to migrate to the top of the MBB within 20 years before it encounters the interbedded NA Shale within the Stevens reservoirs. In Figure 22, 100+ years after injection has stopped, the concentration of CO_2 at mid-depth is lower than it was after 20 years, showing some movement away from the injection point. The image at the top of the MBB shows more infilling of CO_2, as the area with measurable CO_2 concentrations has grown in size and there are more areas with a higher concentration of CO_2 than is predicted after 20 years. This is indicative of CO_2 moving vertically and being slowed or trapped by the interbedded NA Shale.

Reservoir cross-sections shown in Figures 23 and 24 indicate the vertical extent of injected CO_2 predicted by the full-field simulation model at the same points in time used in the prior figures.

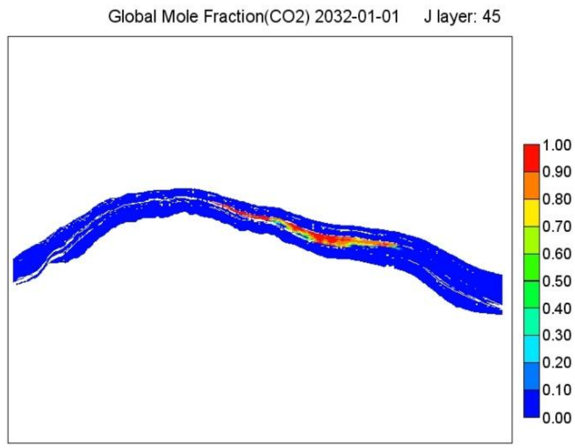


Figure 23: CO_2 at mid-depth of MBB after 20 Years

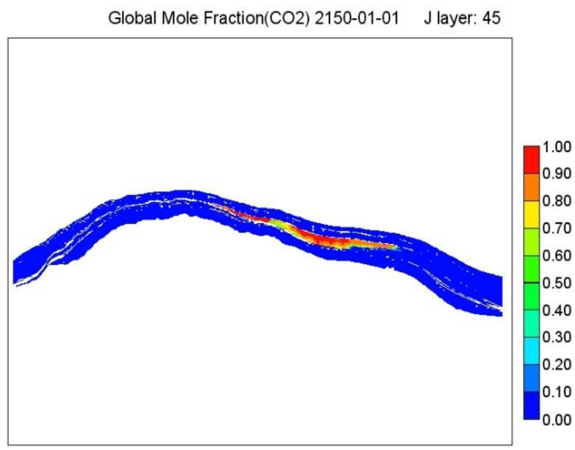


Figure 24: CO_2 at mid-depth of MBB after 138 Years

Figure 23 shows some CO_2 in the Stevens reservoirs still concentrated around the injection wells after 20 years. The royal blue area shows the very top of the MBB, where only a small amount of CO_2 is predicted to migrate in that timeframe. Figure 24 shows the vertical extent of CO_2 predicted after 138 years. This image shows that over the approximately 120 year period (from the time depicted in Figure 23), injected CO_2 has spread out into the formation and begun to move "up dip" towards the highest point in the MBB but remains contained by the Reef Ridge Shale. These model predictions will be tested and refined as necessary during production operations by comparison with OEHI's proprietary history matched full-field simulation model.

4.2.3 Demonstration of No-Leakage to the Surface

OEHI will use data from monitoring reports to demonstrate that there is no significant leakage of CO_2 to the surface from the Oxy CO_2 EOR Project. Information from these reports will include:

1. Use of monitoring wells located in the zone above the Reef Ridge Shale to determine if there are pressure changes or increasing CO_2 levels, which could indicate movement through the Reef Ridge Shale.
2. Visual inspections of the project area to identify leaks to the atmosphere at the surface.
3. Conversion of some wells within the injection zone to serve as monitoring wells during the phased closure period. These wells will be used to monitor reservoir pressure.
4. Testing of representative producers and injectors (as noted in 3.3.1.2), whether operational or temporarily shut-in, to confirm that mechanical integrity is being maintained and that there are no unanticipated routes of CO_2 migration around the well bore.

As individual wells in the Stevens reservoirs are temporarily shut-in, OEHI will comply with permit requirements for each such well. DOGGR regulations assure that wells are properly shut-in and present no risk of leakage to the surface. OEHI will employ additional measures if OEHI's CO_2 EOR experience indicates that such measures are needed, but prior practice has not shown this to be the case for wells used in current operations, including waterflooding.

4.2.4 Future Migration of Injected CO_2

OEHI will use a combination of modeling and the best available data to demonstrate that the injected CO_2 will remain confined in the Stevens after the project is closed. As noted in the preceding discussion the full-field simulation models of the Oxy CO_2 EOR Project show that all injected CO_2 will remain within the Stevens reservoirs and not cause a breach of the Reef Ridge Shale or lateral spillover. OEHI will update the full-field model to reflect actual monitoring results and calibrate it using OEHI's proprietary history matched reservoir simulation model. At least once a year, OEHI will confirm: (i) that the full-field model predictions remain accurate and conservative, and (ii) determine if there is a material change in the full-field simulation model that would warrant a modification to the MRV Plan.

4.2.5 Integrity of Well Closures

As individual wells in the Stevens reservoirs are closed, OEHI will comply with permit conditions and other regulatory requirements that will specify notice, construction, testing, and reporting/review of each closure. In particular, it is anticipated that DOGGR will develop specific field rules that are applicable to the Oxy CO_2 EOR Project and that these will include among other elements, closure requirements, standards for cement integrity, and the use of non-corrosive agents. OEHI's experience with other CO_2 EOR projects suggests that properly closed wells will not require significant maintenance or workovers in the period after operations cease and the well has been plugged. Nevertheless, OEHI will continue to monitor these wells with visual inspections on an annual basis during active operations of the EHOF and will modify any wells where conditions warrant.

As the Stevens reservoirs reach the end of their economic lives, OEHI will transition to a post-injection monitoring stage. The majority of wells will be permanently closed and OEHI will demonstrate that any wells that penetrate through the Stevens reservoirs have mechanical integrity. A small number of wells will be converted to monitoring wells. Their primary function will be to demonstrate pressure decline in the injection zone and show the long-term stability of the pressure regime within the Stevens reservoirs.

4.2.6 Maintenance of Any Open Wells

While it is impossible to know what technological advances will be made over the 40+ year project life, such advances are certain to occur. As has been the practice of OEHI, new technology and techniques are reviewed and adopted to maintain and enhance operations and efficiency. Also, OEHI is committed to appropriately managing the risk of potential leakage of CO_2 to the atmosphere, and will adopt new wellbore maintenance techniques to fulfill that commitment. Further, any wells that remain open after closure will be subject to the then applicable rules administered by DOGGR for well monitoring and scheduled maintenance.

5. Determining Sequestration Volumes

5.1 Mass Balance Methodology

OEHI proposes to calculate the total mass of sequestered CO_2 on an annual and cumulative basis using the following mass-balance equation (all terms are in mass). Mass calculations will be determined as set forth in the subsections below.

Annual Mass Balance of Sequestered CO_2

OEHI will calculate CO_2 sequestered (C_s) equals CO_2 transferred to OEHI (C_t) minus CO_2 measured at the custody-transfer points in products (C_p) sold offsite minus fugitive and vented CO_2 (C_{fv}) associated with injection and production minus CO_2 emitted through leakage (C_l) as described in the following equation:

$$C_s = C_t - C_p - C_l - C_{fv}$$

Cumulative Mass Balance of Sequestered CO_2

OEHI will calculate the cumulative mass balance of sequestered CO_2 by summing the annual total mass balance reported in previous years.

5.2 Mass of CO_2 Transferred to OEHI (C_t)

OEHI will use all of the CO_2 obtained from HECA for the Oxy CO_2 EOR project. Since this CO_2 is purchased through a commercial transaction involving a custody transfer meter and contractually stipulated CO_2 composition requirements, OEHI intends to use the quarterly flow data from purchase invoices to determine the mass of CO_2 transferred to OEHI. Accordingly, the total volumetric gas rate (volume per unit of time) will be measured utilizing a custody transfer meter at the point of custody transfer. The CO_2 volumetric rate will be calculated by multiplying the total gas volumetric rate by the CO_2 volumetric composition. The CO_2 volumetric rate will be converted to a mass rate on a quarterly basis and all four quarters will be summed and reported annually as metric tons for MRV purposes.

5.3 Mass of CO_2 in Sales Products Transferred Offsite (C_p)

OEHI will transfer the various sales products (oil, HC, NGL) through commercial contracts calling for use of custody transfer meters and stipulating product composition specifications. OEHI intends to use the quarterly flow data from the invoices for these sales to determine the mass of CO_2 transferred to offsite in sales products. Accordingly, the total volumetric rate of CO_2 in sales products transferred offsite will be measured utilizing a custody transfer meter at each point of custody transfer. The CO_2 volumetric rate will be calculated by multiplying the total gas volumetric rate by the CO_2 volumetric composition. The CO_2 volumetric rate will be converted to mass rate on a quarterly basis and all four quarters will be summed and reported annually as metric tons for MRV purposes.

5.4 Mass of CO_2 Released or Vented from Surface Equipment (C_{fv})

OEHI intends to track all CO_2 released or vented from surface equipment for the entire EHU under Subpart W of EPA's GHG Reporting Rule and the analogous state provisions at Division 3, Chapter 1, Subchapter 10 of Title 17 of the California Code of Regulations, as applicable. OEHI will allocate the portion of this CO_2 directly attributable to the Oxy CO_2 EOR Project by subtracting out the volumes associated with the equipment located: (1) between the custody meter where CO_2 is transferred to OEHI and the injection facilities, and (2) between the production wells and the custody meters through which sales products are transferred offsite.

5.5 Mass of CO_2 Emitted to the Surface Through Leakage

OEHI will calculate and report the total annual mass of CO_2 emitted to the surface from leakage using an approach that is tailored to specific leakage events, if they arise. Generally, OEHI is prepared to address the potential for leakage in a variety of settings. Estimates of the amount of CO_2 leaked to the surface will depend on the nature of the equipment and an estimation of the duration and concentration of the leak.

Generally, this process would entail using best engineering principles, emission factors or direct measurement. Given that such leakage would be an extraordinary event, OEHI cannot predict in advance which approach will be appropriate in various scenarios. In the event leakage to the surface occurs, OEHI will disclose the specific method(s) used to estimate or measure the volume leaked when DOGGR is notified of the leak (either within 30 days or in an annual MRV Report).

5.6 Internal Cross-Check on Mass-Balance Equation

OEHI proposes to cross-check the results of the sequestration mass balance described above by using a calculation based on data from its in-field operations flow meters, corrected for any fugitive or vented CO_2. Similar to the methods used to derive well production and injection data for reporting to DOGGR, OEHI will calculate a mass of CO_2 injected by summing the product of flow and CO_2 concentration at the meters going into the CO_2 Facility. OEHI intends to allocate the mass of CO_2 injected to each injection well based on the ratios established from the individual well-injection data.

OEHI will calculate the mass of CO_2 produced by summing the product of flow and CO_2 measured at the meters going into the CO_2 Facility from the production wells and measured at the custody-transfer meters for fluids leaving the EHU. This will include the sum of mass from the individual test-well separators as well as the multi-well gathering stations. OEHI intends to allocate the mass of CO_2 produced to each production well based on the ratios established from the individual well tests which are conducted at least once a month for each well.

6. Monitoring Quality Assurance / Quality Control

6.1 Data Handling

As discussed later in this section, OEHI will maintain onsite, a complete record of the parameters used in calculating sequestered CO_2 as indicated in this MRV Plan. These data will be collected as generated and aggregated as required for reporting purposes. Among the data will be volumetric flow rates, pressures, temperature, gas compositions and any other data used in calculating sequestered CO_2.

6.2 Missing Data Procedures

In the event data cannot be collected according to plan, OEHI will determine the length of specific periods where data were unavailable (e.g., during periods of maintenance or equipment failure) and use the following procedures to supply data for those periods.

1. The quantity of new CO_2 transferred onto the EHU from HECA will be estimated using the quantity of new CO_2 flow based on OEHI's internal operations meter.
2. For all CO_2 except for new CO_2 (addressed in (1), above) transferred onto the EHU, the quantity of CO_2 metered will be estimated using the quantity of CO_2 metered from the nearest previous time period (at similar conditions).
3. CO_2 concentration values will be estimated using a concentration value from the nearest previous time period.
4. For fugitive or vented CO_2 emissions from surface equipment at the facility, values will be estimated using methods specified in Subpart W of the GHG Reporting Rule and the analogous state provisions at Division 3, Chapter 1, Subchapter 10 of Title 17 of the California Code of Regulations, as applicable.

6.3 Reporting and Recordkeeping

OEHI will develop the annual MRV Report to include the following information:

(1) Facility name and physical street address.
(2) Year and months covered by the report.
(3) Date of submittal.
(4) Annual emissions of CO_2, and CH_4 for the facility (the Oxy CO_2 EOR Project) and individual source units within the Oxy Project.

OEHI will store the full set of records to validate that report for ten (10) years after the project is closed. OEHI will store those records in electronic and hard-copy format (as appropriate) and will comply with recordkeeping requirements. At a minimum, OEHI anticipates storing the following:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type, including: (i) the GHG emissions calculations and methods used; (ii) analytical results for the development of site-specific emissions factors; (iii) the results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters; and (iv) any facility operating data or process information used for the GHG emission calculations.
(3) The annual GHG reports.
(4) Missing data computations and a record of actions taken to restore malfunctioning monitoring equipment, the cause of the event, and the actions taken to prevent or minimize occurrence in the future.
(5) A written GHG Monitoring Plan listing: (i) the staff positions and people responsible for collecting emissions data, (ii) an explanation of the processes and methods used to collect the necessary data for the GHG calculations, and (iii) a description of the procedures and methods used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the reported GHGs.
(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data.
(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported in the MRV plan.

Ten years after the Oxy CO_2 EOR Project is closed, OEHI will work with appropriate regulators to determine what will happen to stored records.

6.4 Monitoring System Maintenance and Calibration

For custody-transfer meters, OEHI's maintenance and calibration protocols will follow the prevailing industry standard(s) promulgated by the API and the AGA. OEHI will operate flow meters as specified in the UIC Class II permits that are issued for injection operations. OEHI will comply with the maintenance requirements for these meters. Any updates to applicable UIC Class II permit requirements or regulations will be incorporated into this MRV Plan when they are finalized and become available. All flow meters will be operated continuously except as necessary for maintenance and calibration.

6.5 MRV Plan Revisions

OEHI will maintain and update the MRV Plan as needed or as set forth herein. Each year, OEHI will file a statement with the annual MRV Report indicating that it has reviewed the monitoring and operational data. Such review will document any data or information that is relevant to a decision on whether or not to revise the MRV Plan. OEHI anticipates revising the MRV plan if there is a material change in the monitoring or operational plan, there is a regulatory requirement necessitating a revision, or as otherwise indicated throughout this plan. If an update is warranted or required, it will be submitted to DOGGR. Further, OEHI will comply with any regulatory requirements, including timelines, to revise an annual MRV report in the event OEHI us notified by DOGGR or US EPA of any errors in the report.

7. EXHIBITS

The following exhibits contain supplementary information as referenced throughout this MRV Plan. Such information is accurate as of the date indicated. These exhibits may be updated, over the course of the Oxy CO_2 EOR Project as new information becomes available. Each updated exhibit replaces all previous versions of that exhibit and is herein incorporated by reference.

List of Exhibits

#	Exhibit Title	Version Update
1	Review of MRV Plan Development Process	January 2011
2	Site Characterization Studies - Stevens Reservoirs on the 31S and NWS Structures	January 2011
3	Background Information – Initial Full-Field Simulations	January 2011
4	Waterflood History	January 2011

EXHIBIT 1

Review of the Process to Develop the Oxy Elk Hills CO_2 EOR Project MRV Plan

Regulations and guidance governing the development of an MRV plan for business-as-usual EOR using CO_2 which results in sequestration were only recently developed. OEHI was aware of the preliminary versions of these regulations and guidance, and used an iterative process to develop this MRV Plan. It involved the following steps:

- Reviewing existing Class II regulations in place in California, proposed and recently finalized language for the federal EPA UIC Class VI regulations, proposed language for the federal EPA GHG Reporting requirements Subparts W, RR, and UU of 40 CFR Part 98, and publicly filed comments on all three rules from the multi-stakeholder discussion group.

- Reviewing existing and planned operations (including monitoring) at EHOF.

- Reviewing presentations on monitoring at other sequestration projects including the projects being conducted by the US DOE Regional Carbon Sequestration Partnership Program, and the In Salah (Algeria), Weyburn (Canada), and Sleipner (Norway) projects.

- Consulting with outside experts to review key technical questions.

- Consulting with a group of environmental non-government organizations (ENGOS) to obtain feedback on the MRV Plan at several stages throughout its development.

In the course of these reviews and discussions, the OEHI team reviewed monitoring options utilized by existing sequestration operations or in rulemaking proceedings, or by third party experts and decided in some cases that specific techniques would not be useful in the EHOF setting. In particular, the use of repeat seismic surveys and groundwater monitoring were determined to be ineffective for the Oxy CO_2 EOR Project.

4D Seismic

One of the prominent discussions regarded the use of repeat seismic surveys over time to develop 4-D imaging of the injected CO_2. Such 4-D imaging has been useful in several other projects for identifying the location of CO_2 and has proven to be a useful tool in detecting changes in the subsurface fluids under the right circumstances.

Seismic surveys remain an integral source of data for OEHI's best business practices. In addition to the 1998 3D survey acquired at Elk Hills, OEHI and its affiliates have additional seismic data for areas throughout the San Joaquin and Los Angeles basins, and currently hold the largest coverage of seismic data in the state of California. When asked to evaluate the viability of 4D seismic for reservoir management and surface monitoring, key OEHI technical managers cited a variety of concerns based on their knowledge of the existing 3D survey at Elk Hills. These included the following:

- The current survey's signal to noise ratio and frequency content were low within the Stevens reservoirs in the CO_2 project area due to attenuation effects of the low velocity Tulare air sand and noise on the recorded data from surface activity. In considering future attempts to acquire seismic at Elk Hills, both influences could not be mitigated to produce a data set reliable for monitoring CO_2 movement either within the Stevens, or above the SOZ for near-surface leakage detection.
- The resolution of surface seismic has been reported to be approximately 75feet. Given the fact that the issues cited above preclude good imaging above the MYA sands (see Figure 18), 4D seismic would ultimately not provide the needed resolution to identify CO_2 pathways to the surface.
- In addition to active development drilling, ongoing operations in the overburden include alkaline surfactant flooding, waterflooding, gas blowdown, and water disposal. Repeat seismic volumes would be influenced by these other ongoing operations, and would likely result in signal changes independent of CO_2 movement.

As a result of these concerns, OEHI concluded not to pursue repeat 4D seismic imaging as a core part of its MRV Plan. If monitored anomalies indicate potential unanticipated migration of injected CO_2, OEHI might undertake seismic imaging to assess subsurface conditions. Further, if OEHI decides to undertake seismic imaging for other purposes, it will consider the results in evaluating monitored and modeled results of the Oxy CO_2 EOR Project.

Groundwater Monitoring

Groundwater monitoring is thought to be a useful indicator of migration of CO_2 into the near-surface zone. OEHI considered the potential for such monitoring of the Oxy CO_2 EOR Project and determined that it would not add valuable information or information that could be obtained earlier, in the event of leakage, from other monitoring efforts. Additional background on groundwater follows.

The main groundwater bearing unit at the EHOF is the Plio-Pleistocene Tulare formation, which is located well above the Reef Ridge Shale and the SOZ. Groundwater presence within the Tulare formation has been documented in a series of cross-sections, based on electronic logs taken from oil wells drilled throughout the oil field. A lower, confined aquifer is separated from an upper unconfined zone by a clay layer in areas of the central and western sections of the EHOF. Groundwater depths range from 200 feet below ground surface on the north flank of the EHOF (section 23S) to almost 1,000 feet below ground surface at the crest (section 35R). EPA approved a DOGGR request to designate the Tulare Formation within the EHOF as an exempt aquifer because of its hydrocarbon production, and because it contains a total dissolved solids content exceeding 3,000 parts per million (i.e., it is not reasonably expected to supply a public water system). The exempted portion of the aquifer generally coincides with EHOF boundaries.

Due to its shallow location, far above the Reef Ridge Shale and the SOZ, monitoring of the Tulare groundwater to detect movement of CO_2 beyond the Reef Ridge Shale offers no advantage compared to monitoring the SOZ and assessing individual wellbores. Any potential leakage of CO_2 to the atmosphere would first be identified through the monitoring of these other potential pathways. Consequently, monitoring of the Tulare groundwater is not included in this MRV Plan.

EXHIBIT 2

Site Characterization Studies for Stevens Reservoirs on the 31S and NWS Structures

1. Walker, T., Kerns, S., Scott, D., White, P., Harkrider, J., Miller, C., Singh, T.: 2002, "Fracture Stimulation Optimization in the Redevelopment of a Mature Waterflood, Elk Hills, California", SPE 76723-MS, SPE West.Regional/AAPG Pac Sec. Joint Mtg., 20-22 May, Anchorage, Alaska, 22 pp.
2. Sullwold, H.H.: 1961, "Turbidites in Oil Exploration". in Peterson, J.A. and Osmond, J.C., Geometry of Sandstone Bodies, A Symposium, 45th Annual Meeting AAPG. P. 63-81.
3. Bandy, O.L. and Arnal, R.E.: 1969, "Middle Tertiary Basin Development, San Joaquin Valley, California", Bull. Geol. Soc. Amer., v. 80, p. 783-820.
4. Macpherson, B.A.: 1978, "Sedimentation and trapping mechanism in upper Miocene Stevens and older turbidite fans of southern San Joaquin Valley, California", AAPG Bulletin, v. 62, p. 2243.
5. Webb, G.W.: 1977, "Stevens and earlier Miocene turbidite sandstones, southern San Joaquin Valley, California", AAPG Bulletin, v. 65, p. 438-465.
6. Harding, T.P.: 1976, "Tectonic significance and hydrocarbon trapping consequences of sequential folding synchronous with San Andreas faulting, San Joaquin Valley, California", AAPG Bulletin, v. 60, p. 356.
7. California Dept. of Conservation, Division of Oil, Gas and Geothermal Resources: 1998, "California Oil and Gas Fields", v. 1, p. xii.
8. Harrison, C.P. and Graham, S.A.: 1999 "Upper Miocene Stevens Sandstone, San Joaquin Basin, California: Reinterpretation of a petroliferous, sand-rich, deep-sea depositional system", AAPG Bulletin, v. 83, p. 898-924.
9. Scott, R.M.: 1979, "Facies Analysis of the Deep Water Stevens Sandstones, Southern San Joaquin Valley, California; A Core Study", Cities Service Co. (internal publication) Technical Report #71, Contrib. G79-01, 152 pp
10. Scott, R.M. and Tillman, R.W.: 1981, "Stevens sandstone (Miocene), San Joaquin Basin, California", in C.T. Seimers, R.W. Tillman, and C.R. Williamson, eds., Deep Water Clastic Sediments: a Core Workshop: SEPM Core Workshop No. 2, San Francisco, CA, p. 116-248.
11. Lamb, M.A., Anderson, K.S., Graham, S.A.: 2003, "Stratigraphic Architecture of a Sand-rich, Deep-sea Depositional System: The Stevens Sandstone, San Joaquin Basin, California", Pacific Section AAPG, Pub. MP-47, 64 pp.
12. Reid, S.A.: 1990, "Trapping characteristics of upper Miocene turbidite deposits, Elk Hills Field, Kern County, California", in J.G. Kuespert and S.A. Reid, eds., Structure, stratigraphy and hydrocarbon occurrences of the San Joaquin basin, California: Pacific Section, SEPM, Book 64, p. 141-156.
13. Lowe, D.R.: 2004, "Deep-Water Sandstones: Submarine Canyon to Basin Plain, Western California", Pacific Section AAPG, Pub. GB-79, 79 pp.

14. Tillman, R.W.: 1976, “Deep Water Sedimentation”, p. S1-S14; In. Cities Service Co. (internal publication) Geol. Contrib. No. 27, G76-17, 205 pp.

The following List of Appendices have been filed with the CEC with the preliminary permit application / project description

Appendix A: Elk Hills Stevens CO_2 Class II UIC Permit Supplement

Appendix B: DOGGR Dual Steamflood / Waterflood Project Stevens Zone Permit #22800006 and DOGGR Dual Waterflood / CO_2 Project Permit # 22800021

Appendix C: Completion and status map of all wells that have penetrated the Reef Ridge Shale indicating active or inactive producers and injectors, and abandoned wellbores.

Appendix D: Wellbore and casing diagrams within a ¼ mile radius of proposed project boundaries of all wells penetrating the Reef Ridge Shale (Cap Rock).

Appendix E: List of wells within a ¼ mile radius of the proposed permit area that do not penetrate the Reef Ridge Shale. Included are API#, year of completion, status, and TD
(TVDss).

Appendix F: Structural contour maps for each unit and sub-unit from the Reef Ridge Shale (cap rock) to the BLW (base of the injection zone).

Appendix G: Isochore maps for the reef ridge (cap rock) and all major zones of injection through the BLW (base of the injection zone).

Appendix H: Northwest – Southeast cross section and a Northeast – Southwest cross section through the proposed permit area

Appendix I: A 2-inch type log of 355A-35S with interpreted geologic markers listed.

Appendix J: Zumberge, J. E. , Russell, J. A., and S. E. Reid, *Charging of Elk Hills Reservoirs as Determined by Oil Geochemistry,* AAPG Bulletin, v. 89, no. 10 (October 2005), pp 1347-1371.

EXHIBIT 3

Background Information – Initial Full-Field Simulations

The static model of the Stevens reservoirs consists of 2.86 million total grid cells, of which 1.18 million grid cells are active. The model is composed of five identifiable reservoirs, each corresponding to a range of layers within the Stevens. The 26R reservoir is comprised of layers 2-28, the NA fractured shale is comprised of layers 29-55, the MBB reservoir is comprised of layers 56-72, the W31S reservoir is comprised of layers 73-89 and the CD fractured shale is comprised of layers 90-106. The model includes reservoir-specific data for porosity, horizontal and vertical permeability, pressure, pore volume and oil/water/gas saturations.

A nine component equation-of-state model, used in an existing OEHI model designed to evaluate the enhanced oil recovery potential of the MBB reservoir, has been modified to six components using the Computer Modeling Group's (CMG) WinProp phase property program to reduce the run time for this large model. The resulting components are CO_2, N2+C1+C2, C3-C4, C5-C6, C7-C13, and C14+.

Three of four CO_2 trapping mechanisms in the CMG Geochemical Equation-of-State Compositional Simulator (GEM) model are:
1) trapped as a mobile phase (usually a supercritical fluid) by the reservoir structure,
2) trapped as an immobile fluid due to relative permeability hysteresis, and
3) dissolved as a soluble component in the reservoir brine.

A fourth mechanism – geochemical conversion of CO_2 into carbonate minerals – is omitted to improve the model's numerical performance and ensure a conservative result. This is done on the assumption that geochemical conversion is relatively unimportant for the first 100-200 years of storage and typically accounts for 10% or less of injected CO_2 after 1,000 years.

CO_2 solubility in the reservoir brine is modeled with Henry's Law. Gas phase relative permeability hysteresis is modeled with a maximum residual gas saturation of 0.25. A vertical equilibrium initialization is first done to establish a pressure versus depth profile, producing water saturations which are the connate water saturation values from the water-oil relative permeability curve. However, since some of these reservoirs have already been water flooded, the current water saturation is much higher than connate water saturation, appropriate adjustments are made. Grid cells with a pore volume of less than 20,000 ft^3 are nulled-out from the model to improve numerical performance.

Regarding the finite element geomechanics module, GEOMECH, coupled with CMG'S GEM compositional reservoir simulator, was used to model failure of the Reef Ridge Shale (cap rock). This was done by increasing pressure in the underlying reservoir via CO_2 injection. A two dimensional model was constructed with 411 grid blocks in the X-direction and 33 grid blocks in the Z-direction encompassing a length of 43,100 ft and a thickness of 2,460 ft. The model represents a dual-permeability system, however, matrix and fracture collocated blocks exist only in and around the cap rocks. Elsewhere the fracture grid blocks are nulled-out. CO_2 is introduced through a hypothetical injector that is perforated throughout the reservoir. In the model, increasing pressure in the reservoir is expected to push up and bend the overlying cap rock to create a tensile stress around the high pressure region. As gas continues to be injected, the normal effective stress in the cap rock is expected to continually decrease. When it reaches a threshold value, defined as zero in this model, a crack will appear in the cap rock.

EXHIBIT 4

Waterflood History

Recovery from the Stevens reservoirs (MBB/W31S) on the 31S structure was enhanced through water injection operations initiated soon after production began in 1976. Pressure maintenance efforts were accomplished through peripheral water injection and crestal gas injection.

Crestal gas injection, which started in 1978, was discontinued in late 1987. A peripheral waterflood pilot was also initiated in 1978. Due to success in the pilot, the peripheral waterflood was expanded around the entire 31S structure by 1983 (Figure E5-1). The peripheral water injection design was ideal for the steeply dipping flanks of the structure and complimented the favorable mobility ratio of the light crude oil of the Stevens reservoirs.

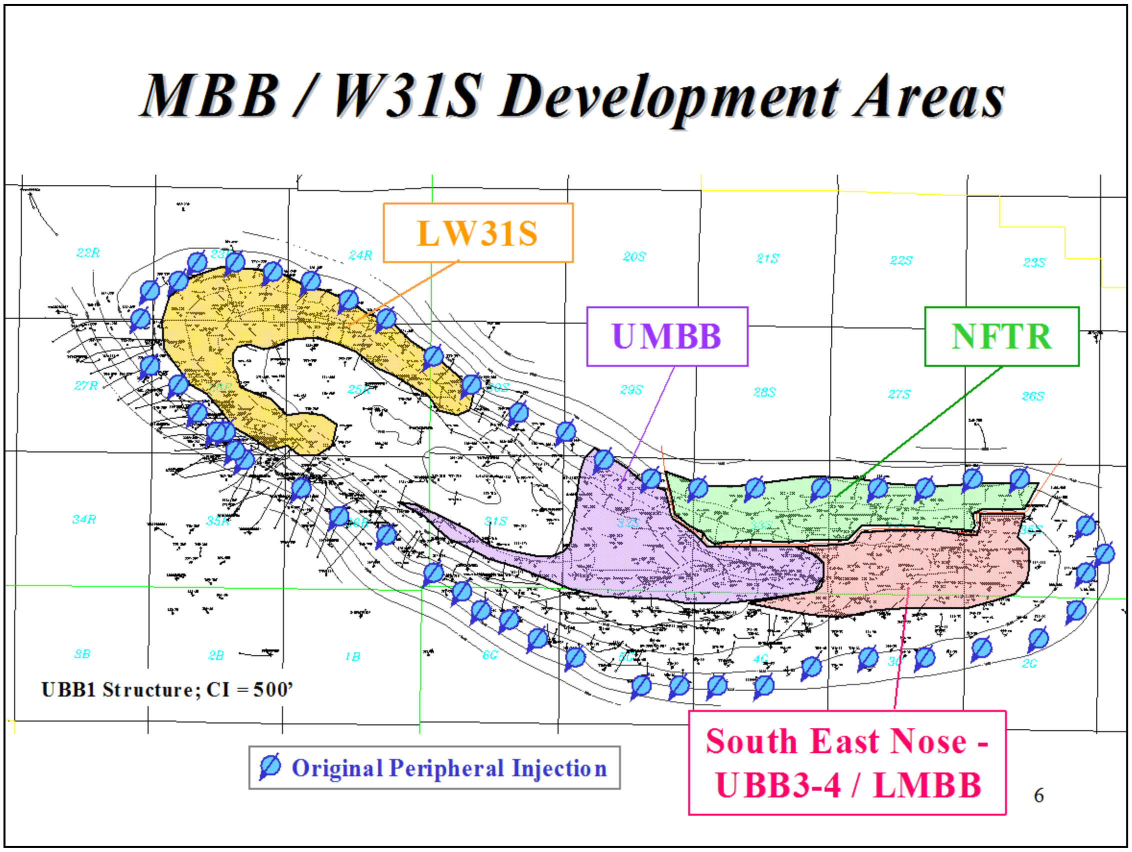


Figure E4-1: MBB/W31S Waterflood Development

Water injection wells near the oil-water contact were perforated in all Stevens reservoir-quality sands. Development wells were drilled ahead of the flood front to capture oil banked by water moving up the structural flanks. Wells that watered out as the flood front advanced were either shut-in or recompleted to shallower zones (e.g. B or NA Shale) to avoid cycling water. Logs acquired post-1998 revealed unswept zones, and additional development then focused on “by-passed” oil in lower permeability sandstone or laterally discontinuous sands that were not in communication with the peripheral waterflood injectors. Subsequent detailed characterization studies integrated with acquired reservoir surveillance data justified conversion to mid-flank water injection and, ultimately, pattern waterflooding. The Stevens reservoirs on the NWS structure have a similar history of primary depletion followed by waterflooding operations.

Glossary

Anticline – An arch-shaped fold in the rock layers in a geologic formation in which the layers are upwardly convex, forming something like a dome or bell shape. Anticlines form many excellent hydrocarbon traps, particularly in folds that have with rocks with high injectivity in their core and high impermeability in the outer layers of the fold.

Dip – The angle between of the rock layer relative to the horizontal plane. Buoyant fluids will tend to move up the dip, or up dip, and heavy fluids will tend to move down the dip, or down dip.

EOR – Enhanced Oil Recovery **–** A method of enhancing the recovery of the original oil in place through a combination of restoring or increasing pressure in an oil field and/or altering the chemical properties of that oil. Its purpose is to improve oil displacement or fluid flow in the reservoir. There are several types of EOR in use today including chemical flooding (ASP), immiscible and miscible displacement (CO_2), and thermal recovery (steamflood). The optimal application of each type depends on reservoir temperature, pressure, depth, net pay, permeability, residual oil and water saturations, porosity and fluid properties such as oil API gravity and viscosity.

Free water level – the level below which water is mobile, available to flow, and not bound to surfaces of grains or minerals in rock.

Injectivity – The ability of an injection well to receive injected fluid (both rate and pressure) without fracturing the formation in which the well is completed. Injectivity is a function of the porosity and permeability of the rock formation and the reservoir pressure in which the injection well is completed.

Plug and abandon – To prepare a well to be closed permanently. Common requirements for plugging require that cement plugs be placed and tested across any open hydrocarbon-bearing formations, across freshwater aquifers, and perhaps several other areas.

Porosity – The percentage of pore volume or void space, or that volume within rock that can contain fluids.

Permeability – The ability, or measurement of a rock's ability, to transmit fluids, typically measured in darcies or millidarcies.

Seal – A relatively impermeable rock that forms a barrier or cap above and around reservoir rock such that fluids cannot migrate beyond the reservoir. The permeability of a seal capable of retaining fluids through geologic time is approximately 10^{-6} to

10^{-8} darcies.

Shale – A fine-grained sedimentary rock formed by consolidation of clay- and silt-sized particles into thin, relatively impermeable layers. It is the most abundant sedimentary rock. The fine grain size and lack of permeability, a consequence of the alignment of its platy or flaky grains, allow shale to form a good cap rock for hydrocarbon traps.

Stratigraphic trap –Hydrocarbon traps that result from changes in rock type or pinch-outs, unconformities, or other sedimentary features such as reefs or buildups.

Structural trap – Hydrocarbon traps that form in geologic structures such as folds and faults.

Waterflooding – A method of recovery in which water is injected into the reservoir formation to displace residual oil. The water from injection wells physically sweeps the displaced oil to adjacent production wells.

Workover – The process of performing major maintenance or remedial treatment on a well. In many cases, workover involves wellbore intervention, including removal and replacement of the production tubing string or other equipment, after a workover rig and associated equipment has been temporarily placed on location.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

AMENDED APPLICATION FOR CERTIFICATION FOR THE HYDROGEN ENERGY CALIFORNIA PROJECT

Docket No. 08-AFC-08A

(Est. 6/4/2012)

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DECLARATION OF SERVICE

I, Dale Shileikis, declare that on June 13 , 2012, I served and filed a copy of the attached *Response to CEC Data Requests 51-55 and Oxy Elk Hills Monitoring, Reporting and Verification Plan* dated June, 2012. This document is accompanied by the most recent Proof of Service list, located on the web page for this project at: www.energy.ca.gov/sitingcases/hydrogen_energy/index.html

The document has been sent to the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit or Chief Counsel, as appropriate, in the following manner:
(*Check all that Apply*)

For service to all other parties:

__X__ Served electronically to all e-mail addresses on the Proof of Service list;

____ Served by delivering on this date, either personally, or for mailing with the U.S. Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses NOT marked "e-mail preferred."

AND

For filing with the Docket Unit at the Energy Commission:

__X__ by sending one electronic copy to the e-mail address below (preferred method); OR

____ by depositing an original and 12 paper copies in the mail with the U.S. Postal Service with first class postage thereon fully prepaid, as follows:

CALIFORNIA ENERGY COMMISSION – DOCKET UNIT
Attn: Docket No. 08-AFC-8
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.ca.gov

OR, if filing a Petition for Reconsideration of Decision or Order pursuant to Title 20, § 1720:

____ Served by delivering on this date one electronic copy by e-mail, and an original paper copy to the Chief Counsel at the following address, either personally, or for mailing with the U.S. Postal Service with first class postage thereon fully prepaid:

California Energy Commission
Michael J. Levy, Chief Counsel
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I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.

Dale Shileikis