

2026

Enhance Clive MMV Plan Amendment

Enhance Energy Inc.

MEASUREMENT, MONITORING & VERIFICATION PLAN
JULY 2026



enhance

EXECUTIVE SUMMARY

This document provides the rationale and specific details of the Monitoring, Measurement, and Verification (MMV) Plan for the Enhance Clive Carbon Capture, Utilization and Storage (CCUS) Project in Central Alberta.

The guiding principles of the MMV Plan are:

- Monitoring, measurement, and verification activities will meet or exceed applicable Alberta Energy Regulator (AER) requirements and approval conditions.
- Monitoring will provide timely assurance that injected CO₂ remains confined within the storage complex and does not adversely affect the geosphere, hydrosphere, biosphere, or atmosphere.
- Leakage and conformance/containment risks will be identified and quantified, and monitoring and mitigation measures will be selected to reduce risk to as low as reasonably practical.
- Monitoring technologies, locations, and frequencies will be tailored to site geology, infrastructure, and operational conditions, while also considering potential cumulative and regional effects.
- Proven, monitorable methods will be used to provide early indication of CO₂ containment or conformance anomalies and to enable appropriate action before migration outside the storage complex.
- Best Available Technologies Economically Achievable (BATEA) and defensible methods will be applied to demonstrate the long-term safety and effectiveness of storage.
- The MMV program will be adaptive through successive project stages, will support issue identification and mitigation, and will be implemented and reported in a transparent manner to support stakeholder confidence.

CLIVE MMV PLAN OVERVIEW

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INTRODUCTION

Enhance Energy Inc. (“Enhance”, “the Operator”) submits this MMV Update to amend the existing Enhance Energy Inc. MMV Plan, approved under Enhanced Oil Recovery (EOR) Scheme No. 12832, which currently applies to the Clive Leduc D-3A and Clive Nisku D-2A Pools. This amendment is submitted in accordance with Section 2.1.4 of AER Directive 065 (D065) and Section 39(1)(a) of the Oil and Gas Conservation Act.

The proposed amendment aligns with AER D065 and Alberta’s EOR policy framework and is aligned with the Oil and Gas Conservation Act by promoting the economic, orderly, efficient, and responsible development of the oil and gas resources of Alberta.

The primary purpose of this amendment is to update the MMV monitoring frequencies and locations following baseline data collection to achieve the most efficient and effective monitoring program while maintaining data quality, public and environmental safety, and ensuring containment of the CO₂ injection and storage activities under the existing Clive Leduc Carbon Capture, Utilization, and Storage (CCUS) Project.

BACKGROUND

Enhance Energy operates an advanced, integrated CCUS project in Central Alberta. The Clive CCUS Sequestration Facility (“Clive”) utilizes captured CO₂ for the dual purpose of enhanced oil recovery and permanent geological sequestration. Since 2020, the Clive CCUS Project has injected over 9 million tonnes of CO₂ from industrial sources, that would have otherwise been emitted into the atmosphere. The captured CO₂ is injected into a deep geological formation that was largely depleted of oil and gas resources decades ago, making it an ideal storage project.

Enhance holds 100% ownership and operatorship of both the Clive D-3A Unit (Leduc Formation) and the Clive D-2A Unit (Nisku Formation). All non-abandoned wells within these units are operated by Enhance, and any non-unitized wells are either Enhance-operated or were abandoned prior to unitization. This consolidated ownership and operatorship structure provides full operational oversight and supports the efficient implementation of ongoing operations and future project expansions.

In 2018, Enhance obtained approval from the AER for enhanced recovery of oil by miscible displacement using CO₂ and water injection in the Clive D-3A Pool, along with the containment of injected CO₂ within both the Clive D-3A and D-2A Pools, located in Townships 39 to 41, Range 24W4. The approval included the 2019 MMV Plan that was originally approved by the Government of Alberta and is now part of the D065 regulatory approval under the AER.

For CCUS projects, the MMV Plan sets out the monitoring, measurement, and verification activities for the lifetime of the project in response to the risks identified in the site-specific risk assessment. The MMV Plan contents are developed by the project operator in response to the risks identified and enable regulatory requirements to be met and conditions specified in project approvals to be satisfied. Measurement and monitoring of the injection facilities, geological sequestration site, and surrounding environment provide assurance that CO₂ is confined to the storage complex (i.e., containment).

This document is a summary of changes to be made with respect to the original MMV Plan for the Enhance Clive project approved in 2019, found in Appendix A. The changes outlined are based on data collected during 2019 to 2026 during pre-injection baseline monitoring, the initial years of active injection operations, and proposed changes for post-injection periods of the project lifecycle.

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The MMV Plan reflects a thorough understanding of the reservoir, developed through decades of data gathering from oil and gas operations within the reef complex. Enhance and expert consultants have carefully designed the plan to monitor the CO₂ plume development within the storage complex, and to provide safeguards ensuring CO₂ storage is secure and effective for the entirety of the injection operations and beyond.

1 MMV PLAN DESIGN

The 2019 MMV Plan and 2026 MMV Plan Update outline the approach to public and regulatory assurance of containment through monitoring, measurement and verification for the Enhance Clive CCUS Project. The MMV Plan ensures that CO₂ injection into the storage complex is contained so that the geosphere, hydrosphere, biosphere, and atmosphere are protected. The core intent and function of the MMV Plan remains intact, with updates to monitoring locations and frequencies based on data collected and operational observations.

Enhance utilizes a risk-based approach to MMV and public protection. The risk-based approach:

- Enhance will identify and evaluate potential CO₂ migration pathways using a site-specific conceptual model supported by detailed geological characterization and defensible engineering and reservoir modelling.
- Enhance will select fit-for-purpose, cost-effective, and reliable monitoring and mitigation measures that are economically achievable and appropriate to the identified risks and potential consequences.
- Enhance will implement proven monitoring tools and response processes that provide timely warning of containment or conformance anomalies and enable appropriate intervention and mitigation, if required.

Enhance has been operating the Clive CO₂ CCUS project in Central Alberta since 2019. This project has provided valuable learnings and practical experience to support development of the MMV Plan update.

The MMV Plan Update is based on the best available guidance and information to date and is in accordance with Appendix P of AER D065: Resources Applications / MMV Principles and Objectives for CO₂ Sequestration Projects (July 2023).

The following steps were taken to design and update the MMV Plan:

- **Assess site-specific storage risks:** Establish definitions for loss of conformance and loss of containment. Identify and review potential threats and consequences associated with these risk events using a risk assessment method.
- **Characterize geological safeguards:** Identify and appraise the integrity of each geological seal within and above the storage complex. Identify and appraise potential secondary storage and seal/caprock units.
- **Select engineered safeguards:** Identify and assess engineering concept selections that provide preventative safeguards against unexpected loss of containment (e.g., well integrity, geological seal integrity).
- **Evaluate geological and engineered safeguards:** Evaluate the expected efficacy of initial safeguards in relation to the identified conformance, containment and induced seismicity threats, and their potential consequences.
- **Establish monitoring requirements:** Define monitoring tasks to verify the performance of these initial safeguards and, if necessary, trigger timely corrective measures.
- **Select monitoring technologies:** Select monitoring technologies considering leak-path scenarios, potential induced seismicity scenarios and confidence for all stakeholders. Incorporate learnings

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from other projects and apply cost-benefit ranking. Evaluate the expected monitoring capabilities and establish performance targets.

- **Identify contingency monitoring:** Develop contingency monitoring measures to evaluate suspected anomalies from baseline conditions and to support timely, appropriate corrective actions.

1.1 TECHNICAL STUDIES AND ASSESSMENTS

Enhance has commissioned and completed extensive scoping and technical studies to evaluate the long-term sequestration of CO₂ associated with the Clive CCUS Project. Results from the original baseline and from studies completed since the commencement of injection demonstrate effective containment of injected CO₂ within the injection reservoir and confirm the effectiveness of the MMV Plan. These findings support the updates proposed in this amendment.

The Project Area covered by the MMV Plan is identified in AER D065 Approval No. 12832.

Table 1: List of Technical Studies and Assessments

Technical Study or Assessment	Last Updated	Conducted By
Geological, Hydrogeological and Mineralogical Characterization of the Sedimentary Succession Overlying the Leduc (D3-A) and Nisku (D-2) Oil Reservoirs in the Clive Oil Field in Alberta	December 2011	Alberta Innovates Technology Futures
Geochemical Effects on Deep Strata in Case of CO₂ Leakage from the Leduc D3-A and Nisku D2 Oil Reservoirs in the Clive Oil Field in Alberta	March 2012	Alberta Innovates Technology Futures
Geochemical Analysis of the Effects of CO₂ Injection in the Clive Leduc and Clive Nisku Reservoirs in the Clive Field	March 2012	Alberta Innovates Technology Futures
Assessment and Interpretation of Data Collected in Phase 11 of the Alberta Carbon Trunk Line Project: Development of a Site Conceptual Model and Risk Considerations	March 2013	Alberta Innovates Technology Futures
Baseline Shallow (Non-Saline) Groundwater Monitoring (Clive)	April 2019	Golder & Associates
Clive Field and Bashaw Regional Characterization and Geocellular Modeling	September 2024	Petrel Robertson Consulting Ltd.
Offset Wellbore Risk Assessment (OWRA) (ongoing)	2024	Enhance Energy Inc. and Noble Ventures Inc.
Reservoir Simulation Modeling	2024	Enhance Energy Inc.

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Geomechanical Study	2024	RESPEC Company LLC
MICP – Caprock Entry Pressure	2025	Core Labs
Conceptual Site Model	2025	Integrated Sustainability Consultants
Clive MMV Plan Standard Operating Procedure	2025	Integrated Sustainability Consultants

1.2 MMV STAGES

The MMV Plan is designed as a living document that follows the lifecycle of the CCUS project, as illustrated in Figure 1 below:

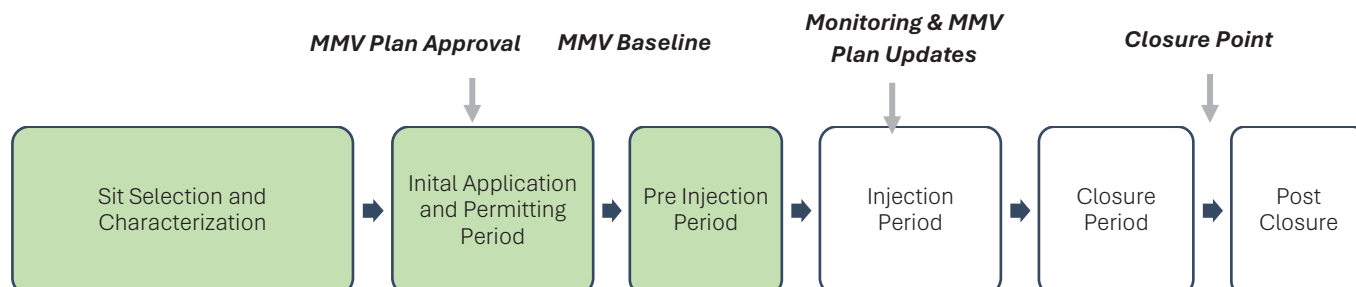


Figure 1: CCUS Project Development Phases (Adapted from Figure 7 of the Alberta Energy Regulatory Framework Assessment, 2013).

2 BASELINE

2.1 DATA COLLECTED

Baseline data has been collected since 2019. The 2019 baseline year consisted of pre-injection data. Data collected after the commencement of injection is early active injection data. This data contributes to the baseline dataset and the ability to run statistical analysis. Annual data collected includes formation pressure from the Leduc and Nisku Formations, gas composition and isotope fingerprinting from the Leduc, Nisku, Mannville, Coalbed Methane (CBM), fresh groundwater, and soil gas.

2.1.1 2019 PRE-INJECTION

Data collected in 2019 was pre-injection baseline data. This data is used to compare data collected after the initiation of injection to determine if results have shifted from the data prior to injection. Soil gas and groundwater data was collected by Golder Associates Ltd. Groundwater monitoring was completed within a 1.6 km radius from the three injection wells at the time with surface locations SW-02-040-24W4M, NE-35-039-24W4M and NE-26-039-24W4M. Baseline sampling occurred in Q3 and Q4 2019. Monitoring wells included three (3) dedicated monitoring wells and nine (9) private landowner wells. The three (3) dedicated monitoring wells were installed in July 2019 by Golder at the existing 10-35-039-24W4M well pad. In 2019, a total of twenty-six (26) groundwater samples were taken, including four (4) duplicates. Analysis included routine parameters, dissolved metals, carbon-13 dissolved inorganic carbon isotope, total iron, total sulphur, bromide, biological parameters, gas compositions, and isotopes. Groundwater samples had pH values of 7.12 to 9.31 and generally exhibited oxidizing-reducing conditions. Carbon isotope $\delta^{13}\text{C}_{\text{DIC}}$ sample values ranged from -11.72‰ to -14.12‰, suggesting that H_2CO_3 weathering of carbonates dominates the groundwater.

Soil gas sampling locations for baseline sampling were selected based on proximity to the Clive EOR Injection wells and providing a broad geographic coverage within the study area. Soil gas sample probes were installed with a sample collection depth of 1.5 mbgs at each lease. In some locations, 1.5 mbgs installations did not yield gases due to tight clay layers and probes were re-installed at 2.0 or 1.0 mbgs. Probes rested a minimum of 24 hours after installation, prior to sampling.

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Gas samples from producing CBM, Nisku and Leduc formations were collected by AGAT and analyzed for composition and carbon isotope analysis. Two (2) carbon dioxide sources were sampled for baseline analysis; the Nutrien Fertilizer Plant in 2019, and the NWR Refinery once it became operational. Source samples were collected by AGAT and analyzed for composition and carbon isotope analysis. Three (3) CBM samples were collected from the 10-34-039-24W4 header in 2019, with one sample being analyzed for $\delta^{13}\text{C}$ and F^{14}C . Eight (8) Nisku fluid samples were collected from the 01-02-040-23W4, 12-01-040-24W4 and 16-02-040-24W4 wells. Five (5) Leduc fluid samples were from the 04-11-040-24W4, 10-35-039-24W4 and 16-03-040-24W4 wells.

2.1.2 2020 – 2025 ACTIVE INJECTION

MMV sampling has continued since 2019, with regular sampling from 2020 to 2025. Spring and summer sample data was added to the baseline data as injection did not start until June 2020. Soil gas and groundwater sampling programs have occurred twice per year since 2021. The soil and groundwater portion of the MMV Plan was executed by Golder in 2020 and by Integrated Sustainability Consultants Ltd. since 2021. Additional groundwater wells and soil gas probes were added to the program as the Clive CCUS injection and production field expanded.

The number of soil gas sampling events decreased from three (3) per year in 2019 to two (2) per year once injection started. This was due to sampling probes being waterlogged in early spring. In addition, sulphur isotopes were added to the program to improve source gas identification. Eighteen (18) soil gas probes were installed for baseline in 2021, with one being replaced in the fall of 2022. As the project expanded, more soil gas probes were installed. In 2023, two (2) new locations were requested for sampling at 25-039-24W4M and 32-040-24W4M and in 2024 at 07-15-040-24W4 and 05-21-040-24W4. Enhance has a total of fifty-eight (58) soil gas sampling locations with thirty-six (36) locations having sufficient data that statistical analysis can be utilized to identify parameter trends and 22 still in “Baseline Status”, meaning they have fewer than eight (8) sampling events over the course of the project.

Groundwater sampling has occurred twice (2) per year since 2021. Enhance currently acquires data from thirty (30) landowner wells. Since the initiation of the project, seven (7) landowner locations have been removed from the project for reasons such as house fire, loss of power, wells being abandoned, new wells being drilled, or landowners no longer being interested in participating in the program. Those well locations have been replaced with nearby wells where possible. In addition to the thirty (30) landowner wells, Enhance monitors five (5) dedicated water wells, three (3) at 10-35-039-24W4, one (1) at the 04-15-040-24W4 battery and one (1) at 12-25-039-24W4.

Enhance has been collecting gas samples and isotope fingerprinting from three (3) CBM gas headers since baseline in 2019, in accordance with the 2019 MMV Plan. Samples are currently collected for composition analysis monthly and isotope analysis annually. CBM samples act as an additional source of containment confirmation in the shallow geosphere. Data collected since 2019 indicates that CO_2 levels in CBM gas range from 0.12% to 0.86% and the $\delta^{13}\text{C}$ isotope fingerprinting indicated that the gas is not of Devonian origin. This data confirms no breach of containment of injected CO_2 .

Although Enhance did not have a regulatory requirement or commitment to collect Mannville gas samples until November 2025, samples for composition and isotope analysis have been collected since 2022. Two (2) samples for composition analysis and one (1) for isotope analysis are collected each year. Mannville sampling

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is an additional layer of monitoring within the geosphere to ensure early detection in the unlikely event of a breach of containment. Carbon fingerprinting from this formation indicates a distinct difference from fingerprinting of injected CO₂. Carbon isotope analysis is an excellent tool to indicate the origin of a gas if a CO₂ increase were to be observed.

Samples have been collected from various Nisku monitoring wells for composition and isotope analysis since 2019. In addition to sample collection, Enhance has conducted static gradient testing in the Nisku D-2A Pool for the Clive CCUS Project since 2019; however, formation pressure data goes back to 1953.

Monitoring within the Leduc D-3A injection pool allows Enhance to ensure the CO₂ being injected is contained and that formation pressure is within regulatory requirements. Samples are taken from the Leduc D-3A twice per year for composition analysis and annually for isotopic fingerprinting since 2019. In addition to sample collection, formation and injection pressures are monitored. Static gradients are conducted in accordance with Directive 40 (D040) on the D-3A Pool, and three (3) injection wells are outfitted with downhole pressure gauges.

2.2 ANALYSIS AND REPORTS

2.2.1 BASELINE

2019/2020 Baseline Soil Gas and Groundwater reports were issued by Golder in March of 2021. The report states that groundwater samples had circumneutral to alkaline pH, with generally oxidizing-reducing conditions, and that samples were classified as a “calcium-bicarbonate” water type and “sodium-bicarbonate” water type. The carbon isotope range of $\delta^{13}\text{C}_{\text{DIC}}$ in samples was -11.5‰ to -14.61‰, suggesting that H₂CO₃ weathering of carbonates dominates the groundwater.

The 2019/2020 Soil Gas Baseline Report summarized five seasons of sampling. Over 50 soil probes were installed as part of the baseline program and over 150 samples collected and analyzed. The processes controlling soil gas CO₂ geochemistry in the MMV study area were dominated by soil organic matter respiration, CO₂ dissolution and interaction with groundwater, and exogenous sources of soil gas CH₄ and CO₂. Exogenic CH₄ is biogenic and not related to production from Devonian sources.

Baseline data for geosphere monitoring consists of sample collection for composition and isotopic analysis. Isotopic analysis allows for development of a fingerprinting data set used to compare gas samples and determine origin.

Baseline CBM, Nisku and Leduc data included gas composition analysis from each formation. Isotopic fingerprinting utilized $\delta^{13}\text{C}$ and F^{14}C analysis in each formation gas, water chemistry analysis, and formation pressure testing in the Leduc and Nisku. Baseline data for these formations was dictated by D065 Approval No. 12832. Baseline Mannville monitoring started in 2022 with gas composition and isotopic analysis.

Annual containment reports have been produced by Integrated Sustainability Consultants Ltd. since 2021 for the current MMV program.

2.2.2 SOIL GAS

Soil gas samples have been collected twice per year since 2021. Table 2 outlines the number of samples collected per year.

Table 2: Quantity of Soil Gas Samples Collected.

Year	Spring	Fall
2021	52	59
2022	48	44
2023	29	30
2024	31	32
2025	34	32

Soil gas compositional analysis data continually provides evidence that the CO₂ injected into the Leduc formation is contained and remains consistent with natural baseline conditions in the area. Review of N₂, O₂, CO₂, CH₄ (and related isotopes) indicates conditions are consistent with soil respiration processes as the driver of the range and variability of values observed.

Seasonal variation in soil gas CO₂ is evident and expected each year, with higher values in the spring during the early part of the growing season, when soil respiration rates are higher than during the fall program.

Anomalous CH₄ values were detected at the 12-25-039-24W4, 11-26-039-24W4 and 14-23-039-24W4 soil monitoring locations in 2021. Follow-up data from 2022 indicates that data from 11-26-039-24W4 was within expected ranges and suggests that the 12-25-039-24W4 anomalies are from the lower Mannville Formation and were later confirmed in 2024 based on gas composition and isotopic evidence. In 2022, CH₄ values at 14-23-039-24W4 were aligned with a biogenic source with a $\delta^{13}\text{C}_{\text{CH}_4}$ value of -69.4‰. The same was determined in 2023 with a biogenic source emanating from coal layers or coal fragments in the underlying sediments based on the $\delta^{13}\text{C}_{\text{CH}_4}$ measurement (-69.4‰).

In 2022, the addition of $\delta^{34}\text{SO}_4$ isotope analysis was used to resolve detections of free phase H₂S gas concentrations that were too low for suitable sample collection.

In 2025, sample locations started reaching sufficient data collection to allow for statistical analysis and move from baseline status to ongoing monitoring status. Locations with more than eight (8) samples were sampled once, either in the spring or fall. No new soil gas probes were installed in 2025.

Samples could not be collected from the 10-22-039-24W4M and 16-20-040-24W4M in 2025 because the locations had been disturbed. Sample location 12-36-039-24W4M could not be located in 2024 or 2025 as access has been removed due to reclamation work. 16-16-040-24W4M could not be accessed due to well work during the 2025 fall program.

2.2.3 GROUNDWATER

Groundwater samples have been collected twice per year since 2021 at the same time as soil gas samples. Table 3 outlines the number of samples collected per year.

Table 3: Quantity of Groundwater Samples Collected

Year	Spring	Fall
2021	10	40
2022	34	32
2023	21	25
2024	26	26
2025	21	23

In 2021, groundwater sample analysis had been typical of bedrock waters in Alberta with slightly alkaline pH (7.5 or more), low mineralization (TDS range of 300 to 750 mg/L) and very high hardness values (>180 mg/L as CaCO₃) in most cases. No major anomalies were noted for parameters currently listed in the Guidelines for Canadian Drinking Water Quality (2023). In 2025, groundwater sampled from the upper bedrock can generally be described as fresh, low in mineralization (total dissolved solids = 514 ± 174 mg/L), alkaline (pH = 7.6 ± 0.6), and very hard (230 ± 166 mg/L as CaCO₃). The results align with ranges of historic data collected in previous years' programs, as well as being consistent with the expected range of water quality parameters in the shallow bedrock formations of southern Alberta (Cheung et al. 2010).

In 2022, dissolved gases were identified in nine (9) groundwater samples with CO₂ values up to 22,700 ppmv and CH₄ values up to 44,100 ppmv. The location with the highest CH₄ values also had SO₄, Fe and Mn and confirmed sulphate reducing bacteria. In 2023, 2024 and 2025, notable exceptions from typical values include some instances of elevated Fe and Mn, likely due to well maintenance issues and the presence of detectable bacteria. Isotopes confirmed that methanogenic conditions were responsible. δ¹³C_{DIC} values are consistent with natural mineralization of soil organic carbon. No anomalies were noted for parameters currently listed in the Guidelines for Canadian Drinking Water Quality (2023). As of the 2025 monitoring year, 253, or 92%, of statistically significant trends of composition parameter concentrations identified were in a downward direction, and 21, or 8%, were in an upward direction; however, all trends are still within expected ranges and will continue to be monitored.

2.2.4 GEOSPHERE

As expected, CO₂ concentrations have been increasing in the Leduc Formation since the start of activities in March 2020 as shown in Figure 2. Naturally occurring CO₂ concentrations have been identified within normal ranges in the overlying Nisku interval, confirming containment of injected CO₂ within the Leduc.

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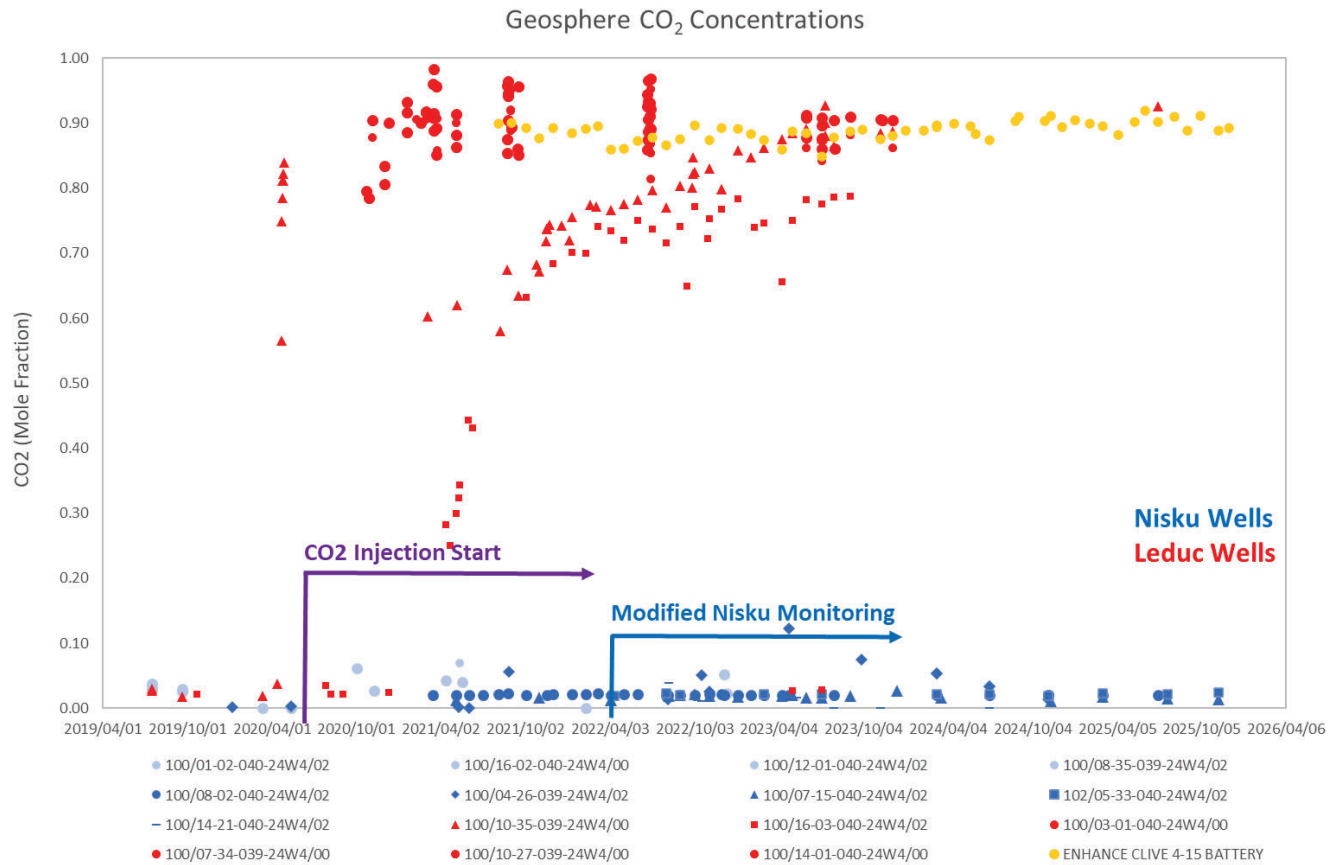


Figure 2: Leduc and Nisku CO₂ Concentrations Over Time.

Annual containment reports confirm that CO₂ concentrations have not increased in the Nisku Formation or in other shallower formations. This supports the conclusion that injected CO₂ remains contained within the storage complex and that the Ireton Formation caprock is structurally intact.

The 100/04-26-039-24W4/02 Nisku monitoring well showed CO₂ concentrations increasing to 13.1% in 2021, decreasing to 1.4% in early 2022, increasing again to 12.2% in April 2023, declining to 1.3% in November 2024, and remaining consistent through 2025 at approximately 2.5%. N₂ concentrations in the samples are indicative of sample contamination and/or well disturbance. The variation in CO₂ concentrations at the 04-26 Nisku monitoring well is not consistent with a loss of containment of injected CO₂ from the underlying Leduc. Evidence is provided by the $\delta^{13}\text{C}_{\text{CO}_2}$ values, which are not consistent with the injected CO₂. The 2024 and 2025 annual containment reports state that this variation in CO₂ concentrations at this monitoring location is inferred to be attributed to swabbing activities that were required to collect samples for analysis (Integrated Sustainability 2025).

Increased variability of CO₂ and CH₄ in shallower formations is not consistent with gases moving upward from either the Mannville or deeper Devonian formations. One detection of H₂S observed in 2025 was confirmed by further sampling to be anomalous. The lack of detectable H₂S originating from the deeper Devonian and/or a lack of similarity in $\delta^{13}\text{C}\text{-CH}_4$ and $\delta^{13}\text{C}\text{-C}_2\text{H}_6$ measurements provides evidence that injected CO₂ is contained

within the storage complex and that identified containment mechanisms are working effectively and as expected.

3 WELLBORE RISK ASSESSMENT

Enhance initiated a field-wide Offset Wellbore Risk Assessment (OWRA) in 2024 and has completed Parts A, B, C, and D to date. The OWRA analyzes the risk of loss of containment into the Nisku, Deep Leak Potential (DLP), the occurrence of a Surface Casing Vent Flow (SCVF), migration into the Base of Groundwater Protection (BGWP) and release to the atmosphere. Details of the methodology can be found in the Clive Wellbore Risk Assessment in Appendix B. The proposed monitoring frequency is the minimum recommended frequency for monitoring. Frequency increases will be on an individual well basis with respect to the risk in a specific area; SCVF, BGWP and atmosphere outlined in the OWRA.

4 STANDARD OPERATING PROCEDURES FOR MONITORING

A Standard Operating Procedure (SOP) was developed in 2024 for the soil gas and groundwater monitoring program for Clive. The SOP outlines the escalation procedure if anomalous data is detected during sampling. This document is in Appendix C.

5 MMV PLAN AMENDMENTS

As described in section 2, the data collected to date has provided a sufficient and statistically significant set of baseline measurements for the project. Enhance is now amending the MMV Plan to reflect the project's mature operational state.

5.1 INJECTION FORMATION MONITORING

The injection well pressure is continuously monitored using downhole pressure and temperature gauges on select wells and maximum wellhead pressure limits outlined in D065, tied into the Supervisory Control and Data Acquisition (SCADA) system. The fresh CO₂ injection fluid flows through an analyzer and a flow meter measuring the composition and volumetric flow rate of the dense phase fluid being injected. Injection formation monitoring includes annual isotopic analysis to maintain the isotopic fingerprinting data set. Formation pressure is also determined with annual static gradients in accordance with D040.

5.2 GEOSPHERE MONITORING UPDATES

Geosphere Monitoring updates include the following:

The **Monitor Physical status of all wells per AER Directives 13, 20, 51, and 65, ID2003-1 or as applicable at the time** changes from the current scheme approval under heading “Active EOR” monitoring frequency of “Monitor SCVF and casing pressure on existing wells minimum two times per year. Evaluate Frequency after two years if no issues seen” to “Monitor SCVF and casing pressure on existing wells minimum one time per year. Evaluate frequency with each MMV Plan Update.” The change is requested based on the reasoning that SCVs on all existing wells within the D065 Approval No. 12832 have been monitored twice per year since 2019. Flows detected have either remained consistent or diminished since initial discovery and are confirmed to not be Devonian in origin based on compositional and isotopic analysis. Consistent with AER requirements, surface casing vents are monitored annually, except for wells within 50 m of CO₂ injection wells, which are

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subject to the requirements of Approval No. 12832. Enhance will maintain monitoring wells with vent flows and those within 50 m of CO₂ injection wells, twice per year.

Conduct reservoir simulation and day-to-day flood management changes from the current approval Active EOR wording of “*day-to-day monitoring of EOR performance. Annual (minimum) updates to simulation for two years, then as required. Monitor voidage replacement ratio (not to exceed 1.0 cumulative)*” to “*As per Approval No. 12832*” since the D065 approval already dictates the frequency in which simulation modeling is required. As Approval No. 12832 already specifies the frequency for simulation modelling, this update is proposed to align the MMV Plan with current project development and to avoid duplication of requirements. Annual pressure monitoring is referred to in the Leduc and Nisku Pressure Monitoring section.

Nisku Monitoring Wells change from the current approval Active EOR “*isotopes annually, and gas analysis bi-annually. Evaluate frequency of isotope and gas analysis after two years. Annual Reservoir Pressure*” to “*Isotope and gas analysis as directed in the D065 Approval No. 12832*” as the D065 approval dictates the frequency in which Nisku monitoring wells should be sampled and which samples should be obtained. As Approval No. 12832 already specifies the frequency of Nisku monitoring well sampling, this update is proposed to align the MMV Plan with current project development and to avoid duplication of requirements. Annual pressure monitoring is referred to in the *Leduc and Nisku Pressure Monitoring* section.

Leduc Monitoring Wells change from the current approval Active EOR frequency of “*Isotopes annually, and gas analysis bi-annually. Evaluate frequency of isotope and gas analysis after two years*” to “*annual isotope analysis*”. Data within the Leduc has been collected since 2019 and shows that the injected CO₂ has mixed with the host gases and thus composition sampling is not unique to the Leduc. Figure 2 shows the composition shift to equilibrium over time from prior to injection to 2025. Annual isotopic analysis will remain the same, ensuring isotopic fingerprinting data is current as it is valuable to the overall program. Annual pressure monitoring is referred to in the *Leduc and Nisku Pressure Monitoring* section.

Leduc and Nisku Pressure Monitoring wording will change from the current approval Active EOR “*Annual*” to “*As directed in D065 Approval No. 12832*”. The frequency will not change; however, the requirement is referenced in a single document for greater efficiency. The D065 approval dictates the frequency and requirements for Leduc and Nisku Pressure monitoring and is in accordance with D040. As Approval No. 12832 already specifies the frequency for Leduc and Nisku formation pressure monitoring, this update is proposed to align the MMV Plan with current project development and to avoid duplication of requirements.

Analyze Produced Liquids and Gas & Analyze Produced and Recycle gas - Monitoring for produced and injection fluids is changed to fit current operations while maintaining data collection and integrity.

Source gas continues to be sampled annually for isotopic analysis and will maintain continuous CO₂ composition data collection from Nutrien and Northwest Redwater Partnership.

Recycle gas continues to be sampled for composition monthly and the **Combined Injection Stream** (fresh CO₂ and Recycle gas) is sampled monthly for compositional analysis. Enhance will change sampling injection fluids at each injection wellhead from monthly to sampling at each well-pad, semi-annually in accordance with the Directive 017 exception Application No. 10135519, received on September 11, 2025.

Produced Gas at all production wells change from being sampled “*Periodically prior to breakthrough, every three months post breakthrough*” to being only sampled as an “*investigation technique if abnormalities are found in the recycle gas*”. Produced Liquids from all the production wells will change from being sampled “*Periodically prior to breakthrough, every three months post breakthrough*” to being sampled “*quarterly for oil analysis*”.

Table 4: Geosphere MMV Activities

Monitoring Activity	Testing Technique	Frequency of Testing		
		Baseline	Active Injection	Post Injection
Most recent AER D065 CCUS Approval	Meet all clauses and requirements specified within Approval No. 12832	As per Approval No. 12832	As per Approval No. 12832	Refer to Directive 065
Monitor physical status of all wells per AER Directives 13, 20, 51, and 65, ID2003-1 or as applicable at the time	All Enhance wells	Verify no SCVF or casing pressure on existing wells prior to CO ₂ injection.	Monitor SCVF and casing pressure on existing wells minimum one time per year, or as guided by the OWRA and required by applicable Directives. Evaluate frequency with each MMV Plan Update.	Per AER requirements at time.
Conduct reservoir simulation and day-to-day flood management	Entire EOR operation with focus in specific areas, as required.	History match of Central Leduc Area prior to CO ₂ injection and baseline CO ₂ EOR performance prediction.	As per Approval No. 12832	Refer to Directive 065
Seismic	Acquire existing 3D seismic over project area as per AER D065 during original project approval.	Process and interpret baseline seismic. Confirmed no faults transect the seals.	Evaluate as required based on event trigger.	N/A
Nisku Monitoring Wells	Isotope & gas analysis, water chemistry and reservoir pressure as per AER D065 project approval.	Once. Gas carbon isotope. Water chemistry (from Nisku pool).	Isotope and gas analysis as directed in the D065 Approval No. 12832.	N/A
Leduc Monitoring Wells	Isotope & gas analysis, water chemistry and reservoir pressure as per AER D065 project approval	Once. Gas carbon isotope. Water chemistry (from Leduc pool).	Annual isotope analysis	N/A
Leduc and Nisku Reservoir Pressure monitoring	Annual stabilized formation pressure per AER D040 requirements and D065 project approval.	Once.	As directed in D065 Approval No. 12832	N/A

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Monitor tubing and annulus pressure on injection wells	All injection wells	N/A	Continuous tied into SCADA	N/A
Injection well hydraulic isolation testing	All injection wells	Pressure test packer, hydraulic isolation log and cement bond log.	Annual packer pressure tests. Hydraulic isolation logging as per approval No. 12832.	N/A
Mud Log new surface and build drills	Three new project drills within the MMV Plan Area	Once C1-C5, including isomers and CO ₂ .	N/A - may be considered if infill or replacement well is required.	N/A
Measure Injected and produced fluids	All injection and production wells.	N/A	Follow measurement requirements as outlined by AER D017.	N/A
Analyze Produced Liquids	All production wells at battery (oil analysis)	N/A	Quarterly	N/A
Analyze Produced Gas	Individual wells	Baseline – quarterly	Sampling individual wells will be an investigation technique if abnormalities are found in the recycle gas.	N/A
Analyze Recycle gas	Recycle gas stream at the battery	N/A	Monthly	N/A
Analyze Injected source gas	Nutrien and Northwest Redwater Partnership (NWR)	Once for chemistry and isotopes	Annual isotopic analysis. Continuous composition analysis	N/A
Injection Fluid (combined stream)	Combined recycle and fresh gas to be injected	N/A	Monthly analysis or calculation at the battery. Individual wells: 2021 to 2025 – Monthly (in accordance with Directive 017) Semi-annually (In accordance with Directive 017 exception application no. 10135519)	N/A

5.3 Hydrosphere Monitoring

As the deepest monitored layer in the MMV Plan, the geosphere provides the primary containment safeguard; therefore, protecting the geosphere also supports protection of the overlying hydrosphere. Additional monitoring is implemented in the hydrosphere to confirm containment. The purpose of the groundwater monitoring program is to establish baseline conditions for groundwater quality in the area, which can then be compared to samples collected during the project in the event of possible CO₂ migration.

The hydrosphere is defined as surface and subsurface freshwater. Monitoring of the hydrosphere will occur within selected intervals above the BGWP, which is the depth where freshwater has a total dissolved solids concentration of less than 4,000 mg/L.

The BGWP at the Clive Facility is 311.09 m asl, with the Edmonton Group being the deepest protected geological unit. The hydrosphere monitoring program operates on multiple fronts, including dedicated water well monitoring, landowner water well monitoring and shallow gas monitoring. Baseline sampling will include chemical composition, electrical conductivity, pH, and isotopic analysis.

- **Dedicated Water Well Monitoring** – Dedicated water wells are utilized to monitor the BGWP and protect freshwater aquifers. Dedicated water wells allow for high quality, consistent data throughout the lifetime of the project.
- **Landowner Water Well Monitoring** – Landowner water wells are selected based on location, well completions, landowner cooperation and general suitability. Samples from these wells are collected as close as possible to the source, avoiding treatment systems. The purpose of sampling landowner wells is not to determine water quality but to ensure no migration of CO₂ into freshwater aquifers.
- **Shallow Gas Monitoring** – Headers and gathering systems from shallow gas producing formations in cooperation with operators.

5.3.1 SUMMARY OF CHANGES FOR HYDROSPHERE MONITORING

Monitor CBM wells for carbon isotope signature updated to **Monitor CBM Network**. No changes to CBM testing frequency during active EOR.

Post Injection: Annually

Post Injection Update: Annually during closure period. None post closure.

Conduct Landowner water well surveys updated to **Landowner Water Well Monitoring**

Testing Technique: Nine (9) Landowner water wells within MMV Plan Area.

Testing Technique Update: Selected landowner water wells, where permission is obtained, within MMV Plan Area

Active EOR: Quarterly in 2020. Evaluate frequency at YE 2020 Analyses per baseline.

Active EOR Update: Annual. Evaluate frequency with MMV updates. Composition analysis with each sampling event. Isotope analysis if required.

Reasoning: Baseline monitoring of landowner water wells has occurred twice per year since 2021 and more frequently during baseline in 2019. Water well data is consistent over the years, and statistical trend increases have been attributed to water well maintenance which is out of the control of

ENHANCE CLIVE CCUS PROJECT – MMV PLAN AMENDMENT

Enhance. The data continues to show no CO₂ is present in groundwater samples from the Clive CCUS project.

Post Injection: Evaluate frequency based on results to date.

Post Injection Update: No monitoring post injection

Reasoning: Groundwater monitoring frequency will be reduced post injection, and dedicated water wells will be used for monitoring each aquifer, thus landowner water wells are no longer required.

Dedicated Monitoring Water Wells

Active EOR: Quarterly in 2020. Evaluate after two years.

Active EOR Update: Semi-annually. Evaluate frequency with MMV Plan updates. Composition analysis with each sampling event. Isotope analysis if required.

Reasoning: Dedicated water wells were sampled quarterly in 2019 and 2020. They were sampled bi-annually from 2021 – 2025. Water wells will continue to be sampled and undergo compositional analysis twice per year.

Post Injection: Evaluate frequency based on results to date.

Post injection Update: TBD based on MMV data throughout the project

Table 5: Hydrosphere MMV Activities

Monitoring Activity	Testing Technique	Frequency of Testing		
		Baseline	Active Injection	Post Injection
Monitor CBM network	Gas-gathering system encompassing well clusters for the entire MMV Plan Area and at main gas plant	Once	Annual isotope analysis and monthly composition analysis.	Annually during closure period. None post closure.
Landowner water well surveys	Selected landowner water wells, where permission is obtained, within MMV Plan Area	Spring, summer and fall prior to injection. Water and headspace gas (if obtainable) chemistry at each event. Isotopes once on all samples and spring, summer, fall on sub-set. Supplement with Baseline Water Well Testing for CBM Development.	Annual. Evaluate frequency with MMV updates. Composition analysis with each sampling event. Isotope analysis if required.	No monitoring post injection

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Dedicated water wells	Three dedicated monitoring wells completed at 20, 40 and 80 m BGS for chemistry and pressure monitoring. Low flow sampling and downhole pressure recorder.	Spring, summer and fall. Water and headspace gas (if obtainable) chemistry at each event. Isotopes once on all samples and spring, summer, fall on sub-set.	Semi-annually. Evaluate frequency with MMV Plan updates. Composition analysis with each sampling event. Isotope analysis if required.	TBD based on MMV data throughout the project.
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5.4 BIOSPHERE MONITORING

Monitoring the biosphere uses soil gas monitoring to provide assurance that CO₂ is not migrating from the storage complex to surface through gas migration. The protection of the biosphere is supported by the protection of the geosphere and hydrosphere. The possible paths of migration to the biosphere include geological features and wellbores. The purpose of soil gas monitoring is to establish baseline conditions for soil in the area during various seasons, which can then be compared to sampling during the active injection phase, in the event of possible CO₂ migration. The selection of specific soil gas monitoring locations is determined based on the OWRA, simulation modeling, geological structure, and surface access availability. Samples will be analyzed for chemical composition and isotopic analysis. Isotopic analysis from baseline data collection and historical data collection from 2019 to present for the Clive CO₂ CCUS project will be used to determine unique isotopic fingerprints for distinct zones of interest. Isotopic fingerprinting allows for accurate determination of the source of CO₂ within a gas sample.

5.4.1 SUMMARY OF CHANGES FOR BIOSPHERE MONITORING

Soil Gas Surveys

Active EOR: Spring, summer and fall. Evaluate frequency after two years. Analysis per baseline

Update: Gas chemistry annually. Isotope analysis as needed. Evaluate frequency with MMV updates.

Reasoning: Soil gas data has been collected twice per year since 2020 and data analysis has concluded that the composition remains consistent with natural baseline conditions in the area. Soil gas monitoring along with other monitoring activities will be continued to ensure containment of injected CO₂ and maintain monitoring of wellbore integrity.

Table 6: Biosphere MMV Activities

Monitoring Activity	Testing Technique	Frequency of Testing		
		Baseline	Active Injection	Post Injection
Soil Gas Surveys	19 locations within MMV Plan Area during baseline. Subset of baseline sampled locations, appropriately spaced within the MMV Area. Planned during unfrozen ground conditions to obtain the most reliable and representative samples.	Spring, summer and fall prior to injection. Gas chemistry at each event. Isotopes once on all samples and spring, summer, fall on sub-set.	Gas chemistry annually. Isotope analysis as needed. Evaluate frequency with MMV updates.	TBD based on MMV data throughout the project.

SUMMARY OF AMENDED MMV PROGRAM

GEOSPHERE				
Monitoring Activity	Testing Technique	Frequency of Testing		
		Baseline	Active Injection	Post Injection
Most recent AER D065 CCUS Approval	Meet all clauses and requirements specified within Approval No. 12832	As per Approval No. 12832	As per Approval No. 12832	Refer to Directive 065
Monitor physical status of all wells per AER Directives 13, 20, 51, and 65, ID2003-1 or as applicable at the time	All Enhance wells	Verify no SCVF or casing pressure on existing wells prior to CO ₂ injection.	Monitor SCVF and casing pressure on existing wells minimum one time per year, or as guided by the OWRA and required by applicable Directives. Evaluate frequency with each MMV Plan Update.	Per AER requirements at time.
Conduct reservoir simulation and day-to-day flood management	Entire EOR operation with focus in specific areas, as required.	History match of Central Leduc Area prior to CO ₂ injection and baseline CO ₂ EOR performance prediction.	As per Approval No. 12832	Refer to Directive 065
Seismic	Acquire existing 3D seismic over project area as per AER D065 during original project approval.	Process and interpret baseline seismic. Confirmed no faults transect the seals.	Evaluate as required based on event trigger.	N/A
Nisku Monitoring Wells	Isotope & gas analysis, water chemistry and reservoir pressure as per AER D065 project approval.	Once. Gas carbon isotope. Water chemistry (from Nisku pool).	Isotope and gas analysis as directed in the D065 Approval No. 12832.	N/A
Leduc Monitoring Wells	Isotope & gas analysis, water chemistry and reservoir pressure as per AER D065 project approval	Once. Gas carbon isotope. Water chemistry (from Leduc pool).	Annual isotope analysis	N/A
Leduc and Nisku Reservoir Pressure monitoring	Annual stabilized formation pressure per AER D040 requirements and D065 project approval.	Once.	As directed in D065 Approval No. 12832	N/A

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Monitor tubing and annulus pressure on injection wells	All injection wells	N/A	Continuous tied into SCADA	N/A
Injection well hydraulic isolation testing	All injection wells	Pressure test packer, hydraulic isolation log and cement bond log.	Annual packer pressure tests. Hydraulic isolation logging as per approval No. 12832.	N/A
Mud Log new surface and build drills	Three new project drills within the MMV Plan Area	Once C1-C5, including isomers and CO ₂ .	N/A - may be considered if infill or replacement well is required.	N/A
Measure Injected and produced fluids	All injection and production wells.	N/A	Follow measurement requirements as outlined by AER D017.	N/A
Analyze Produced Liquids	All production wells at battery (oil analysis)	N/A	Quarterly	N/A
Analyze Produced Gas	Individual wells	Baseline – quarterly	Sampling individual wells will be an investigation technique if abnormalities are found in the recycle gas.	N/A
Analyze Recycle gas	Recycle gas stream at the battery	N/A	Monthly	N/A
Analyze Injected source gas	Nutrien and Northwest Redwater Partnership (NWR)	Once for chemistry and isotopes	Annual isotopic analysis. Continuous composition analysis	N/A
Injection Fluid (combined stream)	Combined recycle and fresh gas to be injected	N/A	Monthly analysis or calculation at the battery. Individual wells: 2021 to 2025 – Monthly (in accordance with Directive 017) Semi-annually (In accordance with Directive 017 exception application no. 10135519)	N/A

HYDROSPHERE				
Monitoring Activity	Testing Technique	Frequency of Testing		
		Baseline	Active Injection	Post Injection
Monitor CBM network	Gas-gathering system encompassing well clusters for the entire MMV Plan Area and at main gas plant.	Once	Annual isotope analysis and monthly composition analysis.	Annually during closure period. None post closure.
Landowner water well surveys	Selected landowner water wells, where permission is obtained, within MMV Plan Area.	Spring, summer and fall prior to injection. Water and headspace gas (if obtainable) chemistry at each event. Isotopes once on all samples and spring, summer, fall on sub-set. Supplement with Baseline Water Well Testing for CBM Development.	Annual. Evaluate frequency with MMV updates. Composition analysis with each sampling event. Isotope analysis if required.	No monitoring post injection
Dedicated water wells	Three dedicated monitoring wells completed at 20, 40 and 80 m BGS for chemistry and pressure monitoring. Low flow sampling and downhole pressure recorder.	Spring, summer and fall. Water and headspace gas (if obtainable) chemistry at each event. Isotopes once on all samples and spring, summer, fall on sub-set.	Semi-annually. Evaluate frequency with MMV Plan updates. Composition analysis with each sampling event. Isotope analysis if required.	TBD based on MMV data throughout the project.

BIOSPHERE				
Monitoring Activity	Testing Technique	Frequency of Testing		
		Baseline	Active Injection	Post Injection
Soil Gas Surveys	19 locations within MMV Plan Area during baseline. Subset of baseline sampled locations, appropriately spaced within the MMV Area. Planned during unfrozen ground conditions to obtain the most reliable and representative samples.	Spring, summer and fall prior to injection. Gas chemistry at each event. Isotopes once on all samples and spring, summer, fall on sub-set.	Gas chemistry annually. Isotope analysis as needed. Evaluate frequency with MMV updates.	TBD based on MMV data throughout the project.

APPENDIX

Appendix A: 2019 MMV Plan

Appendix B: Wellbore Risk Assessment

Appendix C: Standard Operating Procedure

ATTACHMENTS

Attachment 1: Current Clive CCUS Approval No. 12832Q

Attachment 2: Clive MMV Map

APPENDIX A: 2019 MMV PLAN



enhance



**ENHANCE ENERGY INC.
CLIVE LEDUC FIELD
MONITORING, MEASUREMENT
& VERIFICATION PLAN**

July, 2019

Cover Photo by Isabella Hills

MONITORING, MEASUREMENT & VERIFICATION (MMV) PLAN

MISSION STATEMENT

This document provides the rationale for, and specific details of, Enhance Energy's MMV Plan for its CO₂ EOR and storage project at Clive, Alberta. The MMV Plan's guiding principles are as follows:

- Protect the public and other lessees by ensuring CO₂ containment;
- Provide public assurance CO₂ is confined to the Leduc Formation, and poses no threat to shallow aquifers, biosphere, and atmosphere;
- Address the highest-risk events and select monitoring techniques to reduce these risks to as low as reasonably practical;
- Tailor monitoring and measurement techniques to the site's specific attributes, including geology and infrastructure;
- Ensure early warning, using proven methods, to provide the opportunity to intervene before 'significant leakage' occurs outside of the Leduc reservoir;
- Locate and remediate the source should leakage out of the reservoir be detected;
- Meet or exceed regulatory requirements and provide assurance for the long-term safety and efficacy of the Clive Project; and
- Be adaptive, ensuring Enhance's ability to react to issues appropriately and mitigate them, should they arise.

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EXECUTIVE SUMMARY

Enhance Energy (“Enhance” or “the Company”) is a privately-owned Alberta-based oil company specializing in **CARBON DIOXIDE** (CO₂) **ENHANCED OIL RECOVERY** (EOR) initiatives. The company’s leadership team has extensive experience in the oil and gas industry, particularly with large-scale EOR projects using CO₂ injection.

*Throughout this document, full definitions for words appearing in **GREEN ALL CAPS** can be found in Section 8: References and Glossary.*

The Alberta Carbon Trunk Line will be built to transport CO₂ captured from sources in the Alberta Industrial Heartland and inject it into the Clive Leduc D-3A (“Clive Leduc”) pool for EOR and permanent geological storage of CO₂.

CO₂ injection into oil reservoirs is a widely used, proven and safe technique for EOR, and has been used by the oil industry for more than 45 years with no widespread or persistent issues associated with **CONTAINMENT**. As of 2012, it is estimated that CO₂ EOR operations in North America have injected up to 65 million tonnes per year of CO₂ through more than 7,200 injection wells. Cumulative CO₂ injection in the United States is estimated to be 800 to 900 million tonnes.

The project will increment oil recovery of 1 billion barrels, generate \$15 billion in royalties for the Province of Alberta and safely store 2 billion tonnes of CO₂ that would otherwise be emitted into the atmosphere.

Enhance has conducted extensive geological studies to evaluate the suitability of the Clive Leduc reservoir for CO₂ EOR and storage. These studies confirm the Clive Leduc reservoir is highly suitable for CO₂ storage, with no possibility of migration to surface through geological pathways. The Ireton Formation, which is the confining seal for the project, has contained a large gas cap within the Leduc reservoir over geological time scale, and will provide the same confining seal for CO₂.

Enhance constructed a geological model of the Leduc reservoir and overlying Ireton cap rock and Nisku reservoir. The model was built from all available core and log data, with petrophysical input from 180 wells. The model confirmed the Leduc and Nisku formations are distinctly separate hydrocarbon accumulations, separated by the Ireton Formation’s impermeable tight lime **SHALES**. The Ireton seal’s integrity is proven by the existence of a gas cap of up to 11m and an oil column of 18.5m on discovery of the Leduc Formation, overlain by water in the Nisku.

Enhance has built a robust **RESERVOIR SIMULATION** model of the Leduc Formation. The model was history matched to over 50 years of production and injection history with minimal adjustment to geological and fluid property data, thereby validating Enhance’s geological characterization of the reservoir.

The same simulation model was run for a period of 475 years following injection to demonstrate CO₂ remained stable and safely stored in the Leduc reservoir. Due to the density difference between CO₂ and the reservoir fluids, the CO₂ will rise to the top of the Leduc reservoir, where it will be structurally trapped against the impermeable Ireton cap rock. Enhance has proved the same conditions that have trapped gas in the reservoir for millions of years will enable storage of CO₂ over similar timeframes.

SECONDARY SEALS above the Nisku reservoir provide assurance there is no quantifiable likelihood of geological containment failure of CO₂ to the surface at Clive. These seals include the Nisku and Wabamun anhydrites, and the Joli Fou, Colorado and McKay shales.

A geomechanical assessment of the host and cap rock at Clive has guided the design and planned operating conditions. Enhance will ensure Ireton cap rock integrity is not compromised by utilizing horizontal injection wells operating safely below virgin reservoir pressure.

Enhance undertook geochemical modelling to evaluate the potential interactions of CO₂ with reservoir **BRINES** and aquifer waters. Results from this study were utilized to design the planned monitoring program, which will provide assurance of containment through independent and complimentary analysis of soil, water well and **COAL BED METHANE** (CBM) gases and analysis of water samples from domestic wells and shallow groundwater monitoring wells.

Enhance will drill all new horizontal injection and production wells for the project to mitigate risk of CO₂ leakage through wellbores. These wells will be drilled and completed to the highest industry standards and will meet or exceed all regulatory requirements set by the Alberta Energy Regulator (AER) for sour fields, thereby mitigating any risk of CO₂ migration.

Existing wellbores present the only possible risk to CO₂ containment at Clive. Enhance has completed a comprehensive study of all existing wells in Clive to evaluate the current status of the existing wellbores, including review of cement bond logs and **SURFACE CASING VENT FLOW (SCVF)** history, both of which confirm hydraulic isolation over the Leduc Formation exists in all existing wellbores.

By meeting or exceeding regulatory compliance governing sour fields, Enhance can demonstrate the highest possible safety standards for CO₂ containment at Clive. Enhance will continue to zonally abandon existing wells to the Level A standards set out in Directive 20, which, in most cases, exceeds the current requirements.

A formal and independent risk assessment of 69 existing wells within the project area has been completed. The study concluded these wells have been managed to high standards, with 65 wells identified as low risk and requiring minimal monitoring. Two wells are medium risk and two wells are characterized as high risk, requiring mitigation prior to CO₂ injection.

Enhance has built an MMV plan that will ensure the Clive Leduc pool is safe for long-term CO₂ storage. This plan is designed to provide public assurance of **HYDROSPHERE**, **BIOSPHERE**, and **ATMOSPHERE** protection, to verify containment in the **GEOSPHERE**, below the Ireton seal, and to monitor existing wellbores for potential leakage pathways.

Enhance has taken a risk-based approach, considering both probability and consequence of occurrence, in selecting monitoring tools and placement of safeguards within the MMV plan.

The Company will gather and analyze data throughout its EOR program to ensure Ireton seal competency and enable simulation modelling as a means of detecting possible CO₂ **CONFORMANCE** or containment issues.

Enhance will monitor the Nisku Formation directly overlying the Ireton seal to provide verification of long-term CO₂ containment within the Leduc Formation.

The probability of geological containment failure to the hydrosphere and biosphere is practically zero, nevertheless, because the consequences of CO₂ reaching these environments have been quantified, Enhance will place safeguards here, too. Monitoring producing CBM wells will provide early detection warning. Likewise, domestic water well monitoring and soil gas sampling will provide public assurance CO₂ is contained to the geosphere.

Wellbore failure presents risks that are somewhat independent of geologically driven factors, as failure here can bypass inherent protection. As existing wellbore leakage has been identified as the only potential risk in the project, Enhance will focus a large part of its monitoring efforts on wellbores. In particular, the Company will monitor for SCVF, which has been identified as the probable outcome in the case of wellbore failure.

Any reservoir-sourced CO₂ leakage will contain hydrogen sulfide (H₂S) in quantities high enough to be detected by H₂S monitors currently employed at Clive. All future injection and production facilities at Clive will incorporate H₂S protection, which will provide a robust method of potential CO₂ leak detection.

Enhance will gather baseline data in all monitoring environments prior to CO₂ injection. One very powerful tool that will be utilized in all environments is **CARBON ISOTOPE SIGNATURE**. Different sources of CO₂ may exhibit different amounts of radioactive carbon isotopes ($\delta^{13}\text{C}$ & ^{14}C) that effectively allow samples to be fingerprinted. Enhance will establish baseline analysis of $\delta^{13}\text{C}$ and ^{14}C contained within the source CO₂ and compare it to baseline $\delta^{13}\text{C}$ and ^{14}C in CO₂ in produced gas from existing Leduc, Nisku and CBM wells, in soil gas and in headspace gas and/or dissolved inorganic carbon from domestic water wells.

In addition to the **PASSIVE SAFEGUARDS** provided by the characteristics of the site itself and the **ACTIVE SAFEGUARDS** that Enhance will implement, the regulatory regime in Alberta provides ancillary safeguards that afford significant benefit. Including its predecessors, the AER has been in existence for almost 80 years and is widely recognized for its excellence in regulating industry to promote safe, efficient and effective resource recovery. CO₂ EOR and other injection processes are proven, safe and effective techniques. There are over 17,000 wells licensed for various forms of injection in Alberta with no evidence of widespread or persistent containment issues, speaking to the efficacy of regulations and industry practices in the province. Enhance will meet or exceed all regulatory requirements to ensure CO₂ is safely injected and contained within the Clive Leduc reservoir.

Carbon Capture and Storage (CCS) in deep saline **AQUIFERS** and storage in EOR projects both provide for excellent opportunities to remove greenhouse gases from the atmosphere through capture and geological storage. Between CCS and EOR, there are similarities in the injection wells but there are differences in the storage risks and mitigation procedures, meaning different MMV plans are required. This MMV plan is specifically designed to account for the unique setting of the Clive Leduc pool and the characteristics of CO₂ EOR.

Enhance's CO₂ EOR and storage project at Clive will be safe, effective, environmentally responsible and will provide a number of outstanding benefits to Albertans.

The table following provides a summary of the monitoring techniques to be used within Enhance's MMV Plan.

Enhance MMV Plan

GEOSPHERE				
Routine Monitoring Technique	Testing Technique Details	Frequency of Testing to Establish Baseline	Frequency of Testing During ACTIVE EOR	Frequency of Testing POST INJECTION
Most recent AER D-65 EOR Approval	Meet all clauses and requirements specified within Approval No. 12832	As per approval	As per approval	N/A
Monitor physical status of all wells per AER Directives 13, 20, 51 and 65, ID2003-1 or as applicable at the time	All Enhance wells within MMV Plan Area .	Verify no SCVF or casing pressure on existing wells prior to CO ₂ injection.	Monitor SCVF and casing pressure on existing wells minimum two times per year. Evaluate frequency after two years, if no issues seen.	Per AER requirements at time. SCVF and casing pressure to be checked and remediated (if required) at final abandonment.
Conduct reservoir simulation and day-to-day flood management	Entire EOR operation with focus in specific areas, as required.	History match of Central Leduc Area prior to CO ₂ injection and baseline CO ₂ EOR performance prediction.	Day-to-day monitoring of EOR performance. Annual (minimum) updates to simulation for two years, then as required. Monitor voidage replacement ratio (not to exceed 1.0 cumulative).	N/A
Seismic	Acquire existing 3D seismic over project area as per AER D65 project approval.	Process and Interpret baseline seismic. Confirm no faults transects the seals.	Evaluate as required based on event trigger.	N/A
Nisku monitoring wells	Isotope & gas analysis, water chemistry and reservoir pressure as per AER D65 project approval.	Once. Gas carbon isotope. Water chemistry (from Nisku pool).	Isotopes annually, and gas analysis bi-annually. Evaluate frequency of isotope and gas analysis after two years. Annual reservoir pressure.	N/A
Leduc monitoring well	Isotope & gas analysis, water chemistry and reservoir pressure as per AER D65 project approval.	Once. Gas carbon isotope. Water chemistry (from Leduc pool).	Isotopes annually, and gas analysis bi-annually. Evaluate frequency of isotope and gas analysis after two years. Annual reservoir pressure.	N/A
Leduc and Nisku Reservoir Pressure	Annual stabilized formation pressure per AER D-40 requirements	Once.	Annual.	N/A

	and D-65 project approval.			
Monitor tubing and annulus pressure on injection wells	All injection wells.	N/A	Continuous tied into SCADA.	N/A
Injection well hydraulic isolation testing	All injection wells.	Pressure test packer, hydraulic isolation log and cement bond log.	Annual pressure test packer, hydraulic isolation log every five years.	N/A
MUD LOG new surface and build drills	Three project new drills within the MMV Plan Area	Once C ₁ -C ₅ , including isomers and CO ₂ .	N/A- may be considered if infill or replacement well required.	N/A
Measure injected and produced fluids	All injection and production wells.	N/A	Follow measurement requirements as outlined by AER D-17.	N/A
Analyze produced liquids and gas	All production wells.	N/A	Periodically prior to breakthrough, every three months post breakthrough.	N/A
Analyze injected source gas	Nutrien and Northwest Redwater Partnership (NWR).	Once for chemistry and carbon isotopes.	Annual isotopic and continuous CO ₂ concentration.	N/A
Analyze produced and recycled gas	Produced gas at individual wells and recycle streams.	Baseline (including isotope) on existing Leduc producers.	Minimum quarterly gas analysis on production wells and monthly on recycle stream & combined injection stream.	N/A

BIOSPHERE				
Routine Monitoring Technique	Testing Technique Details	Frequency of Testing to Establish Baseline	Frequency of Testing During Active EOR	Frequency of Testing Post Injection
Conduct soil gas surveys	19 locations within MMV Plan Area. Planned during unfrozen ground conditions to obtain the most reliable and representative samples	Spring, summer and fall prior to injection. Gas chemistry at each event. Isotopes once on all samples and spring, summer, fall on sub-set.	Spring, summer and fall. Evaluate frequency after two years. Analyses per baseline.	Evaluate frequency based on results to date.

HYDROSPHERE				
Routine Monitoring Technique	Testing Technique Details	Frequency of Testing to Establish Baseline	Frequency of Testing During Active EOR	Frequency of Testing Post Injection
Monitor CBM wells for CARBON ISOTOPE SIGNATURE	Gas-gathering system encompassing well clusters for the entire MMV Plan Area and at main gas plant.	Once	Annual isotope analysis and monthly composition.	Annually
Conduct landowner water well surveys	9 Landowner water wells within MMV Plan Area .	Spring, summer and fall prior to injection. Water and headspace gas (if obtainable) chemistry at each event. Isotopes once on all samples and spring, summer, fall on sub-set. Supplement with Baseline Water Well Testing for Coalbed Methane Development.	Quarterly in 2020. Evaluate frequency at YE 2020. Analyses per baseline.	Evaluate frequency based on results to date.
Dedicated monitoring wells	Three dedicated monitoring wells completed at 20, 40 and 80m BGS for chemistry and pressure monitoring. Low flow sampling and downhole pressure recorder.	Spring, summer and fall. Water and headspace gas (if obtainable) chemistry at each event. Isotopes once on all samples and spring, summer, fall on sub-set.	Quarterly. Evaluate after two years.	Evaluate frequency based on results to date.

CONTRIBUTORS

The information reported in this document is the culmination of research by numerous individuals and specialist companies that have been involved with the project, in addition to Enhance Energy's work.

In particular, Enhance would like to acknowledge the contributions by **Alberta Innovates Technology Futures (AITF)**, now known as **InnoTech Alberta**, a subsidiary of Alberta Innovates. As part of the early-stage due diligence for the project, Enhance enlisted AITF to conduct a number of studies on the suitability of the Clive Leduc pool for CO₂ storage. **Dr. Stefan Bachu**, a recognized authority in the area of carbon capture and storage and co-winner of a 2007 Nobel Peace Prize for his work with the Intergovernmental Panel on Climate Change, contributed to and/or oversaw much of AITF's work.

Avasthi & Associates Inc. completed a full review of Enhance's simulation model for correctness of inputs, specifically residual oil saturations, **RELATIVE PERMEABILITY** curves and rock fluid interactions.

Enhance has chosen **Golder Associates (Golder)** to conduct program design, sampling and interpretation of soil gas and shallow aquifer monitoring programs based on their technical strength and experience providing similar services to the Shell Quest Aquifer Storage Project.

Other significant data contributors include **Jeff Packard** PhD. (Geology), **Bill May** (Petrophysics), **Core Laboratories**, and **Computer Modelling Group** (CMG).

Finally, Enhance would like to recognize its own technical contributors: **Dave Hassan**, P. Eng. (MMV development); **David Hills**, M Sc., P. Geol. (Geology and Modelling); **Amir Ghadari**, Ph.D., P. Eng. (Simulation); **Chris Markwart**, P. Eng. (Reservoir Specialist); **Brendan McGowan**, P. Eng. (Project Manager); **Kevin Meyer**, P. Eng. (Production and Drilling); and **Sunita Sood**, P. Eng. (Exploitation Engineer).

ABBREVIATIONS

ACTL	Alberta Carbon Trunk Line
AER	Alberta Energy Regulator
AITF	Alberta Innovates Technology Futures
BGWP	Base of Groundwater Protection
CBL	Cement Bond Log
CBM	Coal Bed Methane
CCS	Carbon Capture and Storage
CMG	Computer Modelling Group
CO₂	Carbon dioxide
EOR	Enhanced Oil Recovery
H₂S	Hydrogen sulphide
MMV	Measurement, Monitoring and Verification
SCADA	Supervisory Control And Data Acquisition
SCVF	Surface Casing Vent Flow
WAG	Water-Alternating-Gas

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- C: Geochemical Effects on Deep Strata in Case of CO₂ Leakage from the Leduc D3-A and Nisku D2 Oil Reservoirs in the Clive Oil Field in Alberta, March 2012, AITF
- D: Geomechanical Analysis of the Effects of CO₂ Injection in the Clive Leduc and Clive Nisku Reservoirs in the Clive Field, Phase 2 Report, March 2012 Phase 2 Report, AITF
- E: Characterization of the Wells that Penetrate the Leduc (D-3A) and Nisku (D-2) Oil Reservoirs in the Clive Oil Field in Alberta CO₂
- F: Risk Assessment of Clive Existing Wells, VZFox
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- K: Golder Associates Groundwater and Gas Monitoring Program July, 2019
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1 INTRODUCTION

Enhance Energy Inc. (“Enhance” or “the Company”) is a privately owned, Alberta-based oil and natural gas development company founded in 2005. Enhance specializes in Carbon Dioxide Enhanced Oil Recovery initiatives. The Company’s leadership team has extensive experience in the oil and gas industry, particularly with large-scale EOR projects using CO₂ injection.

CO₂ injection into oil **RESERVOIRS** is a widely used, proven and safe technique for EOR, and has been used by the oil industry for more than 45 years. The first commercial CO₂ EOR flood was initiated in the Permian Basin of Texas, United States, in 1972. Since then, the number of CO₂ EOR projects in the world has nearly doubled in each of the past three decades, with approximately 40 projects in 1984, 78 projects in 1994 and 142 projects in 2012. To date, over 600 million metric tonnes of CO₂ have been safely shipped by pipeline and injected into oil fields of the Permian Basin alone, producing an incremental 1.4 billion barrels of oil which would not otherwise have been produced.

In Canada, the Alberta Carbon Trunk Line (ACTL) has been designed with ultimate capacity of 40,000 tonnes per day (14.6 million tonnes per year) of CO₂ delivery from the Alberta Industrial Heartland near Fort Saskatchewan. The ACTL is expected to revitalize the EOR industry in Central Alberta. As an additional benefit, it will significantly reduce the carbon footprint of oil sands production through permanent storage of CO₂

produced from refining and upgrading facilities. The ACTL will ultimately enable the production of one billion barrels of light oil while storing two billion tonnes of CO₂. This will create an impactful economic stimulus for the province, creating thousands of jobs for Albertans and generating a new revenue stream of up to \$15 billion in royalties for the Province of Alberta.

The goal of the project is to reduce Alberta’s greenhouse gas footprint by capturing, transporting and permanently storing CO₂ emissions from the North West Redwater Partnership’s Sturgeon Refinery and the Nutrien (formerly Agrium) Redwater fertilizer complex. The ACTL will transport CO₂ approximately 220 km from the Redwater area to the Clive oil field, located eight kilometers southeast of Clive, Alberta. The Clive oil field is owned and operated by Enhance and has been in operation since its discovery in 1952.

As well as increasing oil recovery while reducing carbon emissions, there are a number of advantages to CO₂ EOR storage: oil companies possess a long record of know-how to manage, inject and track CO₂; depleted oil fields offer known reservoir capacities and injectivity, and can accept large volumes of CO₂ for tertiary oil production and subsequent storage; oil fields are proven traps, known to



Figure 1-1 ACTL Route

The Alberta Carbon Trunk Line will carry CO₂ from the Alberta Industrial Heartland to the Clive oil field for injection and permanent storage, while enhancing oil recovery.

hold oil and gas for millions of years; the process takes place in areas where the public is already accustomed to oil and gas activities; the sale of CO₂ provides value to capturing companies; increased oil recovery, royalties and job creation provide value to the EOR operator and the province; multiple injection and production wells offer the potential to manage the subsurface CO₂ plume; and additional surface disturbance is minimized because existing infrastructure is used, such as leases, roads and facilities.

CO₂ will be utilized for EOR in the Clive Leduc reservoir. Situated approximately 1,900m below the surface, the Clive Leduc reservoir is overlain by the Ireton shale, which provides a strong, contiguous confining seal for the reservoir. The large gas cap of 10 billion cubic feet, securely contained within the reservoir for millions of years, demonstrates the seal's effectiveness. The reservoir has been under production since the early 1960s; the gas cap and 47 MMbbls of oil have since been produced, thereby reducing the reservoir pressure from 17.5 Mpa to the current pressure of 13.5 MPa. Enhance plans to inject 1.6 million tonnes of CO₂ into the Clive field per year in a manner that will not materially increase the current pressure, providing assurance the integrity of the overlying Ireton confining seal will not be compromised during the operation, and confidence that CO₂ will be permanently stored during and post CO₂ injection.

CO₂ EOR starts with injection of compressed CO₂ into the reservoir through dedicated injection wells. The CO₂ advances through the reservoir, contacts the remaining oil and mobilizes it to the production wells. The pore space that was once filled with oil is replaced by the CO₂, which remains permanently stored within the reservoir. The overlying impermeable reservoir cap rock physically traps the CO₂, ensuring it remains contained within the formation. Based on the Clive Leduc reservoir's history of trapping oil and gas for millions of years prior to discovery, the reservoir is proven to be an excellent storage **CONTAINER**.

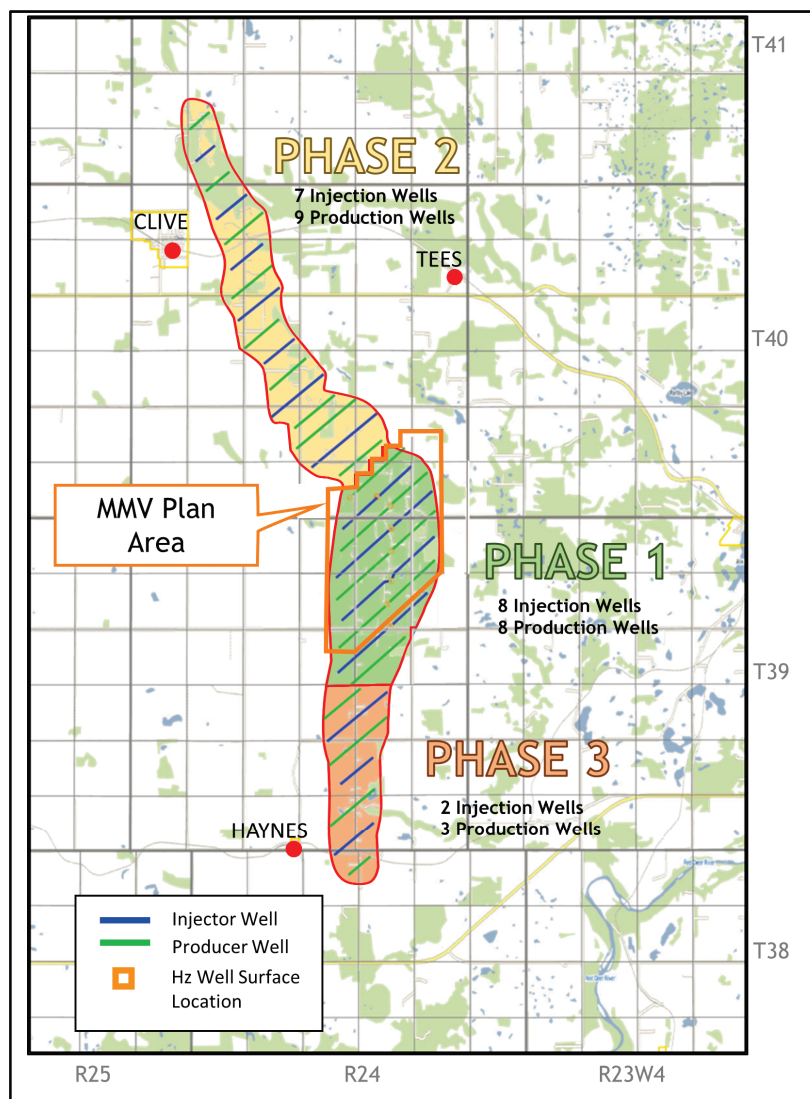


Figure 1-2 Project Phases

The Clive EOR project will take place in three stages, beginning with a 12-well program in the **MMV Plan Area**. Operations in North Clive will begin within two to three years, and development in South Clive will follow.

The extensive geological information and operational history available for the Clive Leduc reservoir provide for minimal uncertainty and risk with regards to CO₂ injection. This MMV plan applies to the initial development with six horizontal injection wells covering a large portion of the Phase 1 Area in the central portion of the Clive Unit. Enhance defines this as the **MMV Plan Area** of the project; the plan will be expanded to include the remainder of the Central Area and subsequent phases as they are developed over a 10-year time frame.

Development of the **MMV Plan Area** will begin with the drilling of 12 new horizontal wells, of which six will be dedicated to CO₂ injection. Later phases in the program will include drilling the remaining 4 wells in the Central Area (2 injectors and 2 producers), expansion into North Clive for Phase 2 and South Clive in Phase 3. Future development of the Clive Field will include expansion into the overlying Nisku Formation.

Injection pressures will conform to regulatory requirements and be maintained at levels that ensure the injection formation and overlying seals remain unaltered, thus maintaining full confidence in long-term CO₂ storage. At the conclusion of the injection phase, a period of continued monitoring will take place, after which the project wells will be plugged and abandoned to establish long-term permanent CO₂ storage.

The MMV plan relies on a thorough understanding of the reservoir, developed through decades of production data and dense well control. Enhance and expert consultants have carefully designed the plan to detect and provide early warning in the unlikely event of CO₂ migration outside of the storage reservoir or EOR project area, and to provide safeguards ensuring CO₂ storage is secure and effective for the entirety of the project and beyond.

2 CLIVE GEOLOGY AND FORECASTS FOR CO₂ EOR AND STORAGE

In preparation for the Clive CO₂ EOR project, Enhance has conducted extensive geological studies to characterize hydrocarbon and CO₂ trapping and **HYDRODYNAMICS**, and to provide a robust **GEO-MODEL** for reservoir simulation.

Regional geological analysis confirms the Clive Leduc pool is an ideal EOR target and storage reservoir for CO₂. The Devonian Leduc Formation injection target is part of the Bashaw Platform, an extensive **CARBONATE** reef complex. Clive is a localized structural high in the Leduc Formation, associated with differential compaction between tidal shoals at Clive, the neighbouring lagoon to the west and the tidal channel to the east. Overlying formations of the Ireton mudstones and the Nisku platform **DOLOMITES** are also affected by the drape, leading to the configuration of the Leduc and Nisku reservoirs, capped by the Ireton and Upper Nisku **ANHYDRITES**, respectively. The Ireton's effectiveness as a seal to the Leduc is demonstrated by the geological containment of up to 11m of gas and 18.5m of Leduc oil. Above the Nisku, extensive sheet anhydrites of the Devonian Wabamun and regionally extensive Cretaceous shales of the Joli Fou, Colorado and McKay Formations form a series of secondary seals, ensuring no quantifiable likelihood of geological containment failure to surface at Clive.

Enhance has built a robust geo-model to simulate the Clive Leduc pool. The geo-model was constructed by combining knowledge from geological studies with the **PETROPHYSICAL** and **CORE** data from 180 wells. Next, laboratory testing of fluids under reservoir conditions created a fluid property model governing the dynamics of CO₂, oil and water in the geo-model. These tests also demonstrated that CO₂ is less than half the **DENSITY** of Devonian Formation waters, thus ensuring the inherent buoyancy of CO₂ will prevent its migration out of the pool. The simulation model was history matched to over 50 years of production and injection history with minimal adjustment to geo-model and fluid properties, thereby validating the accuracy of the geo-model.

Finally, the simulator was used to help select the most efficient and cost-effective EOR development scenario. The simulator was also used to forecast long-term distribution of CO₂ at Clive. In one model run 475 years after injection, CO₂ was maintained buoyantly capped within the Clive Leduc pool.

The geological studies confirm the Clive Leduc reservoir is highly suitable for CO₂ storage. The Ireton Formation contained a large gas cap within the Leduc over a geologic time scale and will do the same for CO₂. Simulation confirms the Leduc reservoir will safely store injected CO₂, which will rise to the top of the reservoir due to buoyancy effects and be contained by the Ireton cap rock.

REGIONAL GEOLOGY

The Clive Leduc A Pool is located on the Leduc Bashaw Platform, an isolated but extensive reef complex of more than 3,500 km² and up to 285m thick, which includes Bashaw, Chigwell, Haynes, Innisfail, Nevis and Wimborne fields (Figure 2-1). Most of the hydrocarbon reservoirs on the Bashaw Platform are located along raised margins generated by differential compaction (Mossup, 1972). One of the Bashaw Reef Complex's prominent features is the north-south extending Clive channel, a localized trough that opens to the north and tapers and shallows to the south. The combination of the Clive channel's orientation, which is near-perpendicular to the direction of **DIP**, and the accompanying raised edge along its southern margin has created

a significant hydrocarbon trap at Clive. The overlying Ireton and Nisku mimic Leduc entrapment geometry (Mossop and Shetsen, 1994).

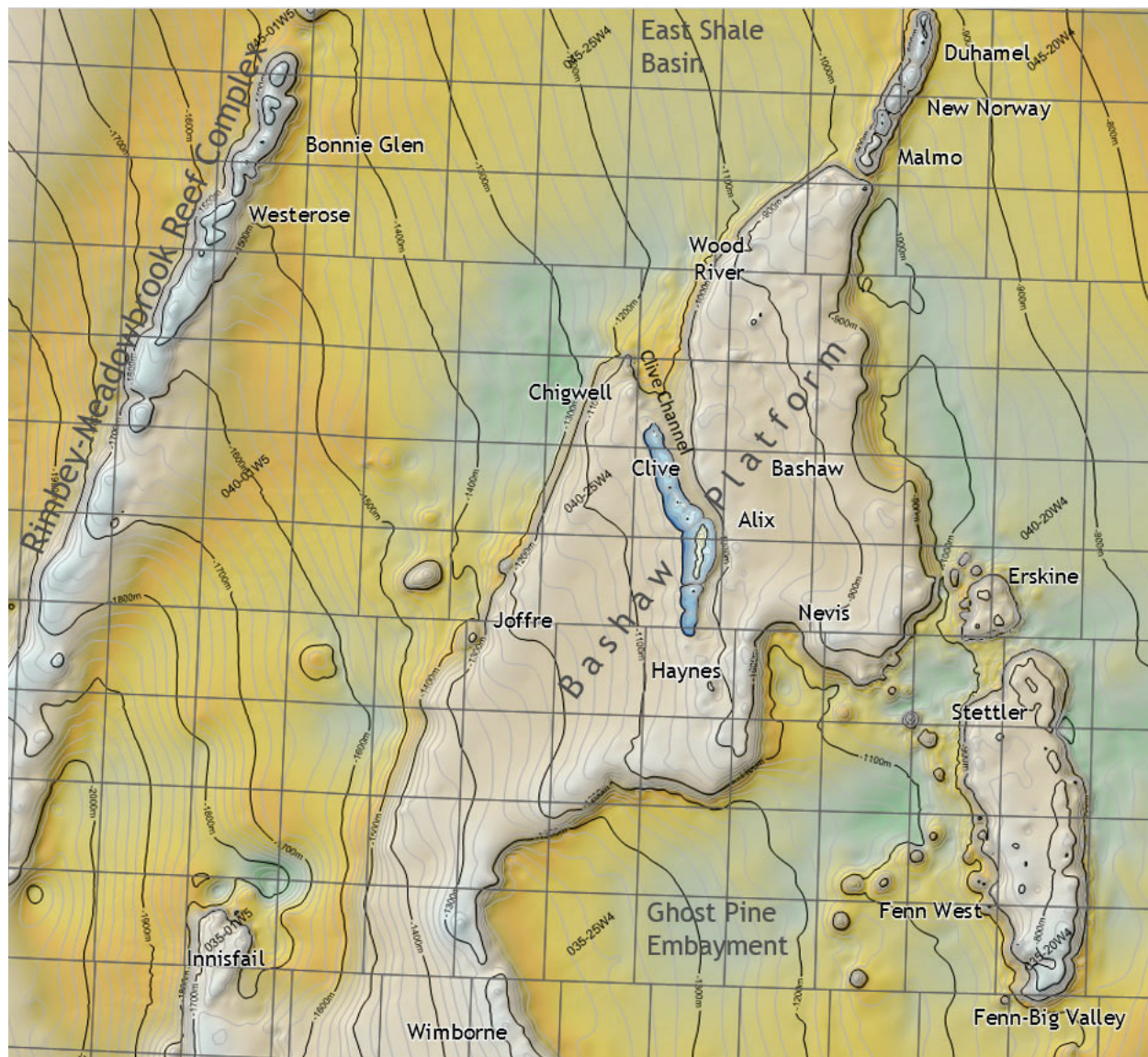


Figure 2-1 Sub-Sea Structure of the Leduc Bashaw Platform

Clive is located on the Bashaw Platform, a large Devonian carbonate reefal system that was surrounded by the Duvernay's deep-water basins. Major Leduc and Nisku fields are located around the raised margins of this and neighbouring banks. Colour fill is a residual of the Leduc Structure. Dip is to the southwest.

The Frasnian-aged Woodbend Group is a stratigraphic sequence consisting of a widespread, shallow marine platform of the Cooking Lake Formation, which is overlain by the Leduc's localized carbonate buildups (Figure 2-2). The Duvernay Formation's shales and deep-water basin-filling limestones are laterally equivalent to the Leduc, which are succeeded by the Ireton Formation's argillaceous (clay-rich, resulting in low **PERMEABILITY**) limestones and shales. The Ireton Formation represents the majority of the basin-filling sediment, which eventually encroached onto, and capped, the Leduc platform. Following Woodbend Group/Ireton deposition, the Winterburn Group deposition was initiated with a return to clean carbonate deposition of the Nisku

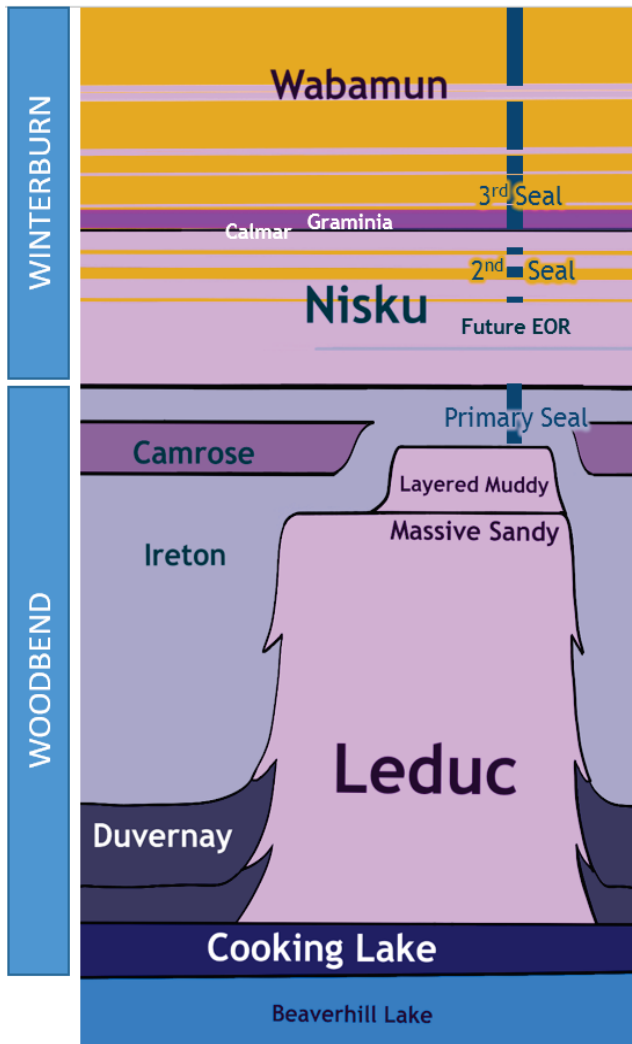


Figure 2-2 Devonian Woodbend Group and Winterburn Group Stratigraphic Sequence at Clive

Duvernay shales sourced oil to the Leduc, which is capped by the Ireton's carbonate shales (grey) that comprise the primary seal encasing the platform. As the Nisku grew, extensive sheets of anhydrites (orange) blanketed the area, adding further vertical seals.

Formation. Continued basin-filling throughout the Nisku led to widespread **EVAPORITE** (anhydrite) deposition in the top part of the Nisku. Calmar shales and Graminia Formations cap the sequence. Ireton shales are the **PRIMARY SEAL** for the Leduc storage reservoir, while evaporites and shales in overlying formations are secondary seals.

Cooking Lake Formation

The Cooking Lake Formation is a widespread, sheet-like, locally dolomitized carbonate that reaches a maximum of 100m in east-central Alberta. No wells reach the Cooking Lake at Clive, but regional extrapolation suggests a thickness of between 55m and 75m. The nearest cored section of Cooking Lake at Bashaw, 16-36-041-23W4, reveals the formation to be a relatively tight limestone with an average **POROSITY** of only 3% (9% max) and permeability of 0.24 mD (1.3 mD max). Gentle topographic highs formed by localized shoals in the Cooking Lake platform gave rise to the Leduc Formation's isolated reef complexes (Wendte, 1994).

Leduc Formation

A handful of deep wells around Clive indicate the Leduc Formation is comprised of approximately 250m of pervasively dolomitized platform carbonates. By contrast, the topmost 35m of Leduc is very well represented at Clive, with 83 cored wells totalling 1,100m of recovery.

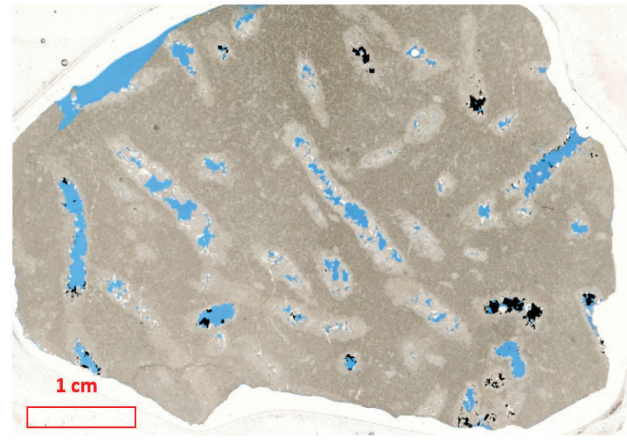


Figure 2-3 Typical Leduc Reservoir Rock

At left, an example of leached *amphipora* fossil-moldic grainstone from the Leduc Formation's Layered Muddy zone. FD 122 at 1,884m. 3.5" diameter core.

Pictured above, a low mag photomicrograph of typical fossil-moldic porosity found in Leduc at Clive (5-14-39-24W4).

DOLOMITIZATION and leaching have obscured original depositional fabric to such a degree that reliable and consistent assignment of depositional **FACIES** is not possible at Clive.

Despite this, one aspect of the original fabric that has survived is the presence of leached **AMPHIPORA** fossil-**MOLDIC POROSITY** in a significant proportion of the core. By analogy with innumerable prior studies of Devonian-age carbonate platform complexes, the near ubiquitous presence of *amphipora* suggests the uppermost Leduc at Clive was lagoon or near lagoon in provenance (Figure 2-3). Enhance's own detailed study of these cores (Packard, internal docs) reveals the majority of Clive reservoir rock to be of shoal, lagoon and tidal sequences. This is atypical of Alberta's Leduc reservoirs, including those on the periphery of the Bashaw Bank, which usually consist of rigid framework fossils associated with reefal zones on the platform edge.

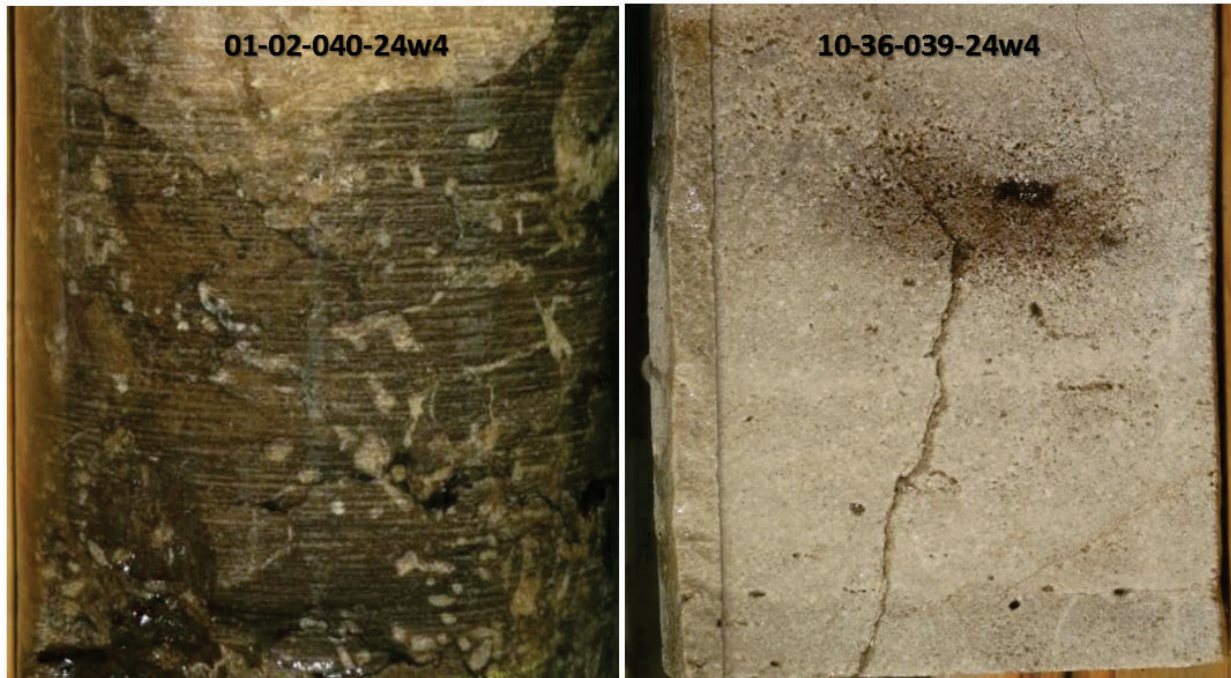


Figure 2-4 Two Representative Examples of Clive Core

At left, the Layered Muddy Zone includes common muddy *amphipora*-dominated lagoon sediments. Pictured at right, a carbonate sand typical of the Massive Sandy Zone showing light-coloured grain-stone with relatively well-distributed leached fossil porosity. Both cores are 3.5 inches in diameter.

The uppermost Leduc can be divided into two zones: a lower, Massive Sandy Zone of granular and variably leached carbonate shoal sands; and an upper Layered Muddy Zone, which exhibits multiple, discontinuous and thinly bedded carbonate mud layers (Figure 2-4). The best reservoir rock is found in the Massive Sandy, which is generally the more homogenous of the two, with relatively well-distributed granular porosity and high vertical permeability. The Massive Sandy Zone extends well below the oil/water contact at Clive's structural peak, and the true thickness is not known. Above this, the Layered Muddy Zone is approximately 10m thick throughout Central and South Clive but thins to the north of the field. This zone incorporates rock similar to the Massive Sandy but is commonly interrupted by thin, discontinuous muddy layers. The transition between the Massive Sandy and Layered Muddy often incorporates a 2m to 3m heavily cemented layer characterized by reduced porosity.

From detailed examination of core data throughout Clive, Enhance has been able to build on the geological history of this part of the Bashaw Platform. Clive owes its current prominence to its association with the Clive Channel. Ebbing, fast-flowing tidal water from the platform interior maintained long-lived shoals on the bank of the channel throughout deposition of the Massive Sandy Zone. Later on, possibly even as the Ireton was filling surrounding basins, the Layered Muddy recorded a period of alternating energy environments and reduced accommodation. Finally, the Leduc carbonate factory was shut down, as it was smothered by the Ireton's silts. Using Ireton thickness as a proxy for depositional environment, a maximum water depth for the top of the platform is estimated of up to 25m, typically around the platform margin (Hearn *et al.*, 2011).

Ireton Formation

The Ireton Formation's **CALCAREOUS** shales represent westwardly regressive infilling of basinal areas between the Leduc Reef sequence, conformably overlying the Duvernay at up to 130m thick (north of Clive). Three Ireton stages have been recognized, with the first two stages concurrent with Leduc deposition and a third stage post-dating the Leduc (Oliver and Cowper, 1963, Stoakes, 1980). On the platform, the Ireton filled to a near planar surface that covered all but the highest points of the platform (Haynes and Nevis areas). While the Ireton is mostly considered to be a largely **TERRIGENOUS** unit, the portion that covers the Bashaw Bank has a high carbonate content of approximately 75% (Hearn, 1996) and is commonly observed to be dark brown **BIOTURBATED** mudstones that are interpreted as bank slope to more basinal environments towards the north. The Camrose Member of the Ireton Formation represents a depositional switch to clean carbonate deposition, before switching back again. The Camrose is typically tight and does not form a reservoir at Clive. The package of impermeable rocks that make up the Ireton has created an effective seal for hydrocarbon accumulation in the Leduc; as such, it will provide a similarly effective seal for CO₂ injection.

Nisku Formation

The Nisku Formation is characterized by porous, dolomitic open marine platform carbonates, which are capped by layered dolomites and anhydrites. The lower part of the Nisku is a clean dolomite with typically low porosity, followed by 20m of the porous Middle Nisku reservoir zone. At the top is approximately 16m of predominantly layered anhydrites with lesser intervening dolomites. These anhydrites layers are consistent across the Clive Field and act as secondary containment for the Leduc reservoir.

GEOLOGICAL CONTAINMENT

Due to the relatively low density of CO₂ in the reservoir, buoyancy effects will cause it to migrate towards the top seal. The following description of geological containment investigates the possibility of CO₂ leakage as a buoyant fluid.

Enhance has identified the Ireton as the primary seal for the **MMV Plan Area** and for the entire Leduc injection program. Numerous **AQUITARDS** have been identified as secondary seals, which are considered redundant barriers in the unlikely event of a primary seal breach.

Primary Seal: Ireton Aquitard

The Ireton aquitard is the primary seal for Enhance's Phase 1 injection program into the Leduc. The Ireton's effectiveness as a seal is demonstrated by the pool configuration upon discovery, having held down as much as 11m of gas and 18.5m of oil below that from moving up into the Nisku (Figure 2-5). As the EOR program will not exceed original discovery pressures, the Ireton can be expected to provide an excellent barrier for CO₂ containment.

A series of maps based on petrophysical log analysis and a representative cross-section of the Ireton at Clive is included in Appendix A. Mapping includes Ireton structure, **ISOPACH**, net shale thickness and net cap thickness.

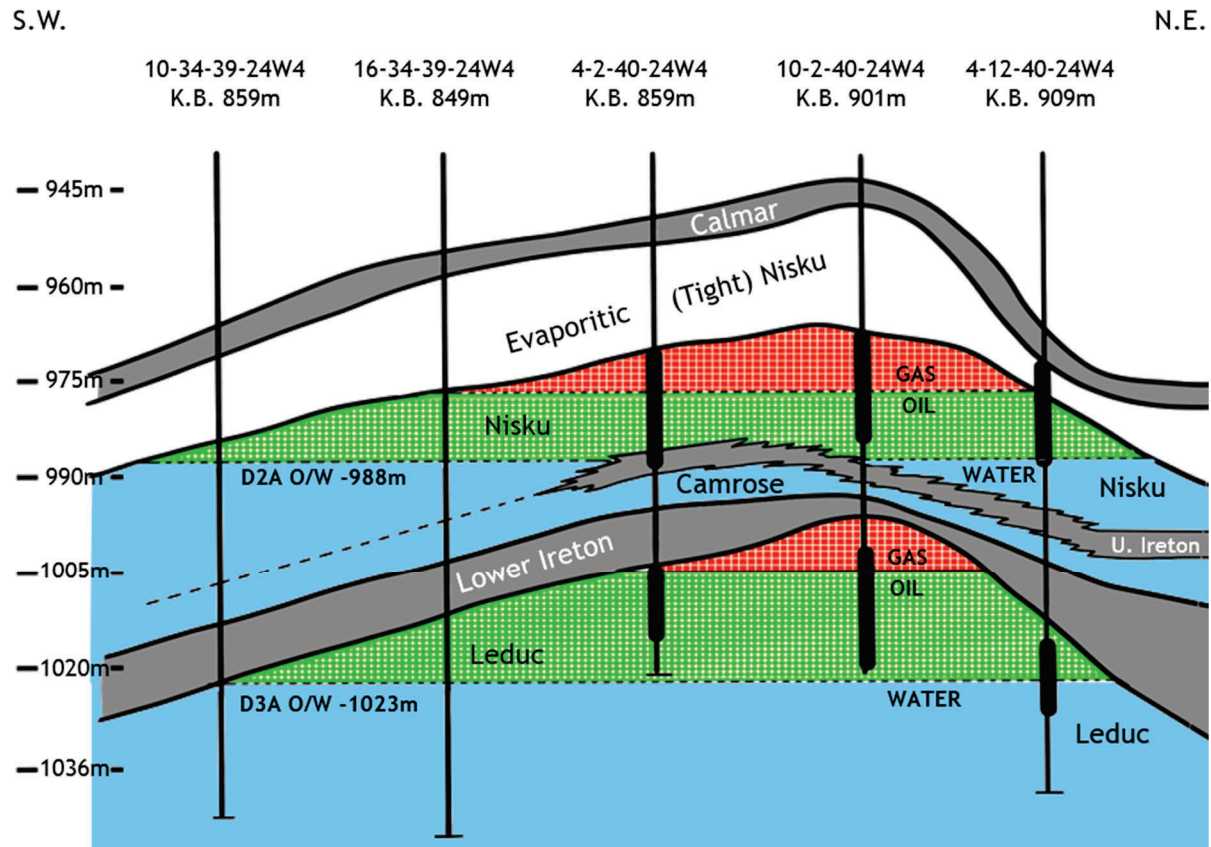


Figure 2-5 Schematic Structural Cross-Section through Clive Central

The Nisku oil/water contact is 35m higher than the Leduc oil/water contact, suggesting the Ireton is an effective and geologically long-term barrier.

Total Ireton thickness across the field is approximately 10m in Central and South Clive, thickening to approximately 17m in the north in response to the presence of the Camrose and Upper Ireton. To better understand the capping mechanism throughout Clive, clean and porous carbonate layers are discounted (i.e. excluding thickness of Ireton with V_{shale} less than 25% and porosity greater than 2%) from the Isopach Map to show a Net Cap Map (see excerpt in Figure 2-6). The thinnest Ireton Cap across Clive is located on the boundary of sections 2, 3 and 11 of Township 40-24W4, where total cap is 4.3m at its minimum (04-11 location). The Ireton held down a 13m column of oil and gas at this location.

Within a 3.2-kilometer radius of the proposed injection well, 102/15-35-039-24W4, neutron-density cross-plot log interpretation (Moradi *et al.*, 2016) was supplemented by the review of 22 core analyses where all, or most, of the Ireton Formation was cored. Selected cores were physically examined for evidence of a breach in Ireton

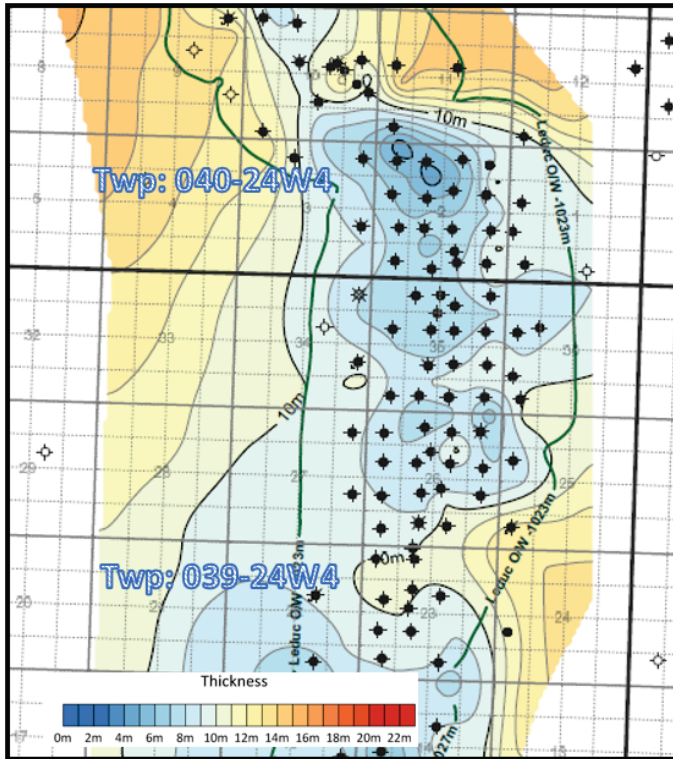


Figure 2-6 Ireton Cap Thickness

Cap is thinnest over the top of Central Clive but has not been breached since oil and gas emplacement. See **Appendix A** for full version.

rocks between the Leduc and the Nisku; no evidence of breaching was found. Enhance has examined select cores where core reports indicated porosity existed in the Ireton Formation and determined the cores were off-depth and that significant Ireton aquitard exists in all cases.

Enhance's detailed examination of Ireton seal integrity was undertaken to evaluate the Ireton aquitard's effectiveness, following review of a paper by Hearn, Machel and Rostron (2011). Enhance's more refined core evaluation and geological mapping confirmed no breach in the Ireton cap rock exists at Clive. Elsewhere on the Bashaw Bank, Hearn *et al.* demonstrate that breaches are indeed present by observed absence of Ireton in the Haynes and Nevis areas, thus explaining pressure communication across the Ireton.

The presence of a competent barrier to the Clive Leduc pool is demonstrated by gas and

oil entrapment of the pool on discovery; without the barrier, gas and oil would have leaked away over the tens of millions of years since hydrocarbon emplacement.

While there is evidence of pressure communication between the Leduc and Nisku at Clive, this communication is via documented Ireton cap rock breaches elsewhere on the Bashaw Platform. A detailed investigation of cap rock properties confirmed no hydrocarbons breached the Ireton at Clive. The Ireton cap rock will retain CO₂ injection at Clive.

Lateral Seals

The primary updip lateral seal on the eastern side of the Clive Field is the Clive Channel (Figure 2-7). The channel creates a gentle roll off the raised margin into a structural low along Clive's updip edge. The Clive Channel's dimensions are difficult to quantify because well control is lacking, but it is at least 25km long and approximately 1.5 km wide in the Central Clive area. Only one vertical well penetrates close to the axis of the channel, at 10-4-41-24W4, which shows the Leduc at a depth of -1040m sub-sea, 17m below the oil/water contact of the Clive A Pool. Further south, the central axis of the channel shallows but remains well below the Clive Leduc's **SPILL POINT**.

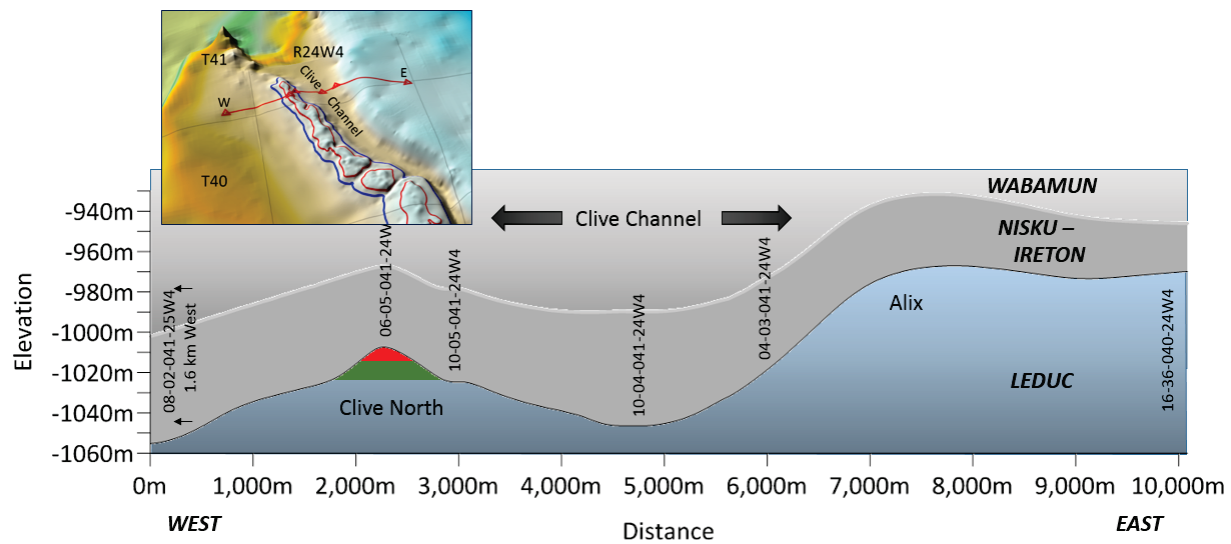


Figure 2-7 East to west slice-through of the Devonian at Clive

The Clive Channel creates the updip barrier for hydrocarbon accumulation at Clive.

As described above, Clive's location is the product of a raised rim associated with the Clive Channel. As such, Clive, Chigwell and Haynes pools are all part of the same linear ridge of the Leduc but have hydrocarbon reservoirs that are separated by saddles along the ridge (Figure 2-8). These lows provide likely spill points between these fields. The saddles have been identified by well penetration and/or inferred by a change in original contacts on either side. The saddles' shape indicates they were small tributary tidal channels that directed ebbing waters from the platform interior eastwards across the shoals and into the Clive Channel. The northern tip of the Clive Leduc pool is defined by an apparently significant low (**S1**, possibly 17m below contact at 10-7-41-24W4) bridging it from the Chigwell Field. The southern tip is a less pronounced saddle (**S4**), possibly only deeper by a few metres below the -1,027m SS Clive South Oil Water contact. This (**S4**) is the Leduc spill point for Clive. Between these saddles that bound the Clive Field, smaller saddles compartmentalise the Clive Central from Clive North (**S2** - at least to -1,014m deep, separating gas contact) and Clive South (**S3** to at least -1,027m deep, separating oil contact). Separation between Central and South Clive (via **S3**) provides another layer of containment during the first phase of CO₂ development between the injection wells and the field spill point. By the time Enhance moves into South Clive, gas dynamics observation will have had the chance to corroborate modelled, or expected, behaviour.

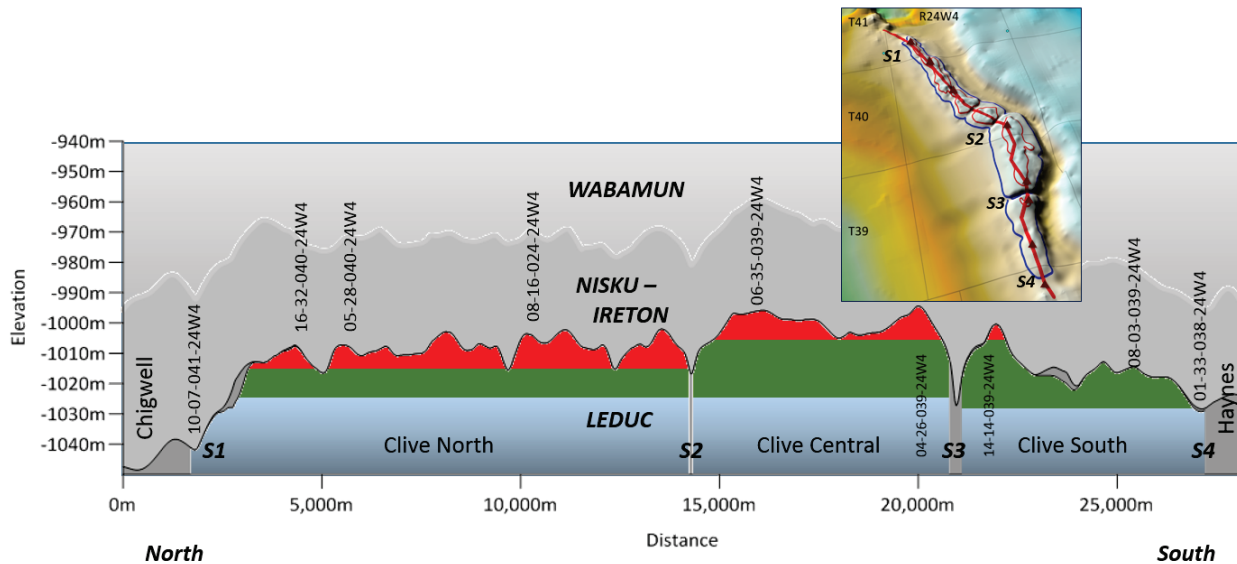


Figure 2-8 North to south slice-through of the Leduc to Wabamun layers at Clive

Saddles bisecting the reservoir give rise to differences in oil/water contacts along the length of the field.

The trapping mechanism that held oil and gas at Clive for tens of millions of years is evident from Leduc surface mapping. A combination of the raised porous Leduc abutted against the Clive Channel's tight Ireton forms the updip seal. Ireton-filled saddles cut across the Leduc pool, segregating it from the Chigwell and Haynes fields. The saddle at Clive's southern point is the field's spill point.

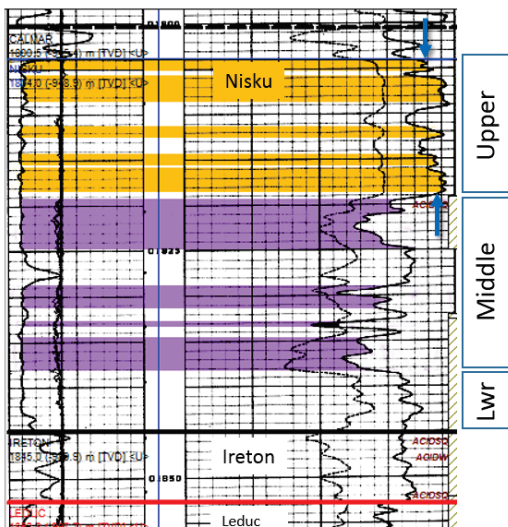


Figure 2-9 Density Log

Density log reveals dense layers of anhydrite (yellow) in the Upper Nisku that blanket the Middle Nisku reservoir (purple).

Full understanding of the reservoir geometry and seal as a container allows Enhance to confidently predict viability and CO₂ storage risk. As such, the geology of the Clive Leduc A Pool can be demonstrated as a safe location for long-term CO₂ storage.

Secondary Seals

As the Ireton shales provide the primary seal for the Leduc reservoir, there are a number of geological formations above the shales that play a role as secondary seals – formations that, in the unlikely event of CO₂ entering the Nisku, would prevent any losses from reaching shallow aquifers. An evaluation of the main barriers' (aquitards) competence to cross-formational flow has been the subject of a detailed hydrogeological characterization by AITF, which used formation waters analysis, **DRILLSTEM** tests and core analyses. The full results are presented in **Appendix B**.

Period	Group	Aquifer/Aquitard		
Cenozoic			Shallow Aquifer System	
Cretaceous	Edmonton	Surficial		
		Paskapoo		
		Whitemud-Battle		
		Horseshoe Canyon		
		Bearpaw		
	Belly River	Upper Belly River		
		McKay		
	Colorado	Basal Belly River		
		Colorado - Lea Park		
Mannville	Viking			
	Joli Fou - Upper Mannville			
	Lower Mannville			
Devonian	Wabamun	Calmar - Wabamun	Deep Aquifer System	

Aquifer
 Aquitard

Aquifers and aquitards are represented by the blue and grey layers, respectively, in the column at right. From AITF as found in **Appendix B**.

A very thick package of Paleozoic, Mesozoic and Cenozoic sediments (approximately 2,000 m thick) overlies the Nisku pool in the study area (Figure 2-10). All the geological, hydrogeological and mineralogical evidence collected and interpreted in this study indicates the Clive Leduc and Nisku reservoirs are capped by strong and thick seals of the Calmar-Wabamun aquitard (which includes, in places, remnants of the Carboniferous shales of the Exshaw and Lower Banff formations). This is overlain in turn by a succession of aquifers, listed in ascending order: Lower Mannville, Viking, Basal Belly River and Upper Belly River. These aquifers are separated by strong intervening aquitards – Joli Fou, Colorado, McKay and Bearpaw – which constitute secondary traps and secondary barriers. The deep aquifers and aquitards in the study area are overlain by a succession of shallow aquifers which are within the depth of protected groundwater in the area: Horseshoe Canyon, Scollard-Paskapoo and Surficial.

In the unlikely event of CO₂ leakage, the formation water will become acidic locally, resulting in reactions with the rock minerals and potential formation of new minerals. The Leduc, Nisku, Calmar and Wabamun strata are primarily carbonate- and/or sulphate-mineral-containing formations. The overlying strata are all siliciclastics (sandstones and shales) and can only be distinguished by the amount of other phases present. Some of the carbonate minerals present in the overlying formations (calcite, dolomite and/or siderite) will likely dissolve. Illite and potassium feldspar would likely react to form kaolinite and slightly change the formation water composition. The presence of plagioclase suggests that, as it dissolves into the more acidic formation water, the increased levels of calcium in the formation will result in calcite precipitation (AITF, **Appendix B**).

The aquitards' strength in the sedimentary succession indicates there is no quantifiable likelihood of leakage through the natural geological and hydrogeological system in the Clive study area.

HYDROGEOLOGY

The Clive Leduc field is located within the Lacombe County in south-central Alberta. The County lies within the Red Deer River watershed, which encompasses 11 sub-basins. Most of the Project area falls within the “Red Deer River Near Nevis” basin, as illustrated in Figure 2-11.

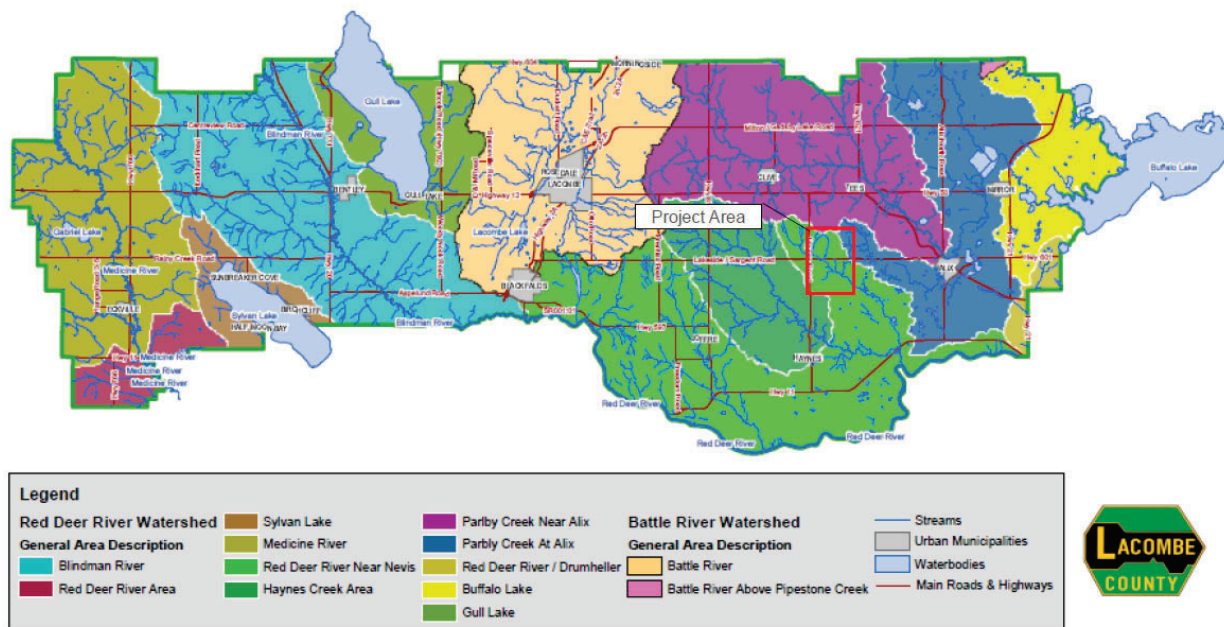


Figure 2-11 Lacombe County Drainage Basins (Lacombe County 2019, internet site)

Surficial Deposits

According to the Regional Groundwater Assessment completed for the Lacombe County (HCL 2001), surficial deposits in the County are typically less than 20 to 30 metres thick and include pre-glacial materials and pre-glacial fluvial and lacustrine deposits. Within the **MMV Plan Area**, the main aquifers are shallow bedrock as the surficial sediments are either absent or relatively thin, i.e., up to 5 m in thickness (Figure 2-12).

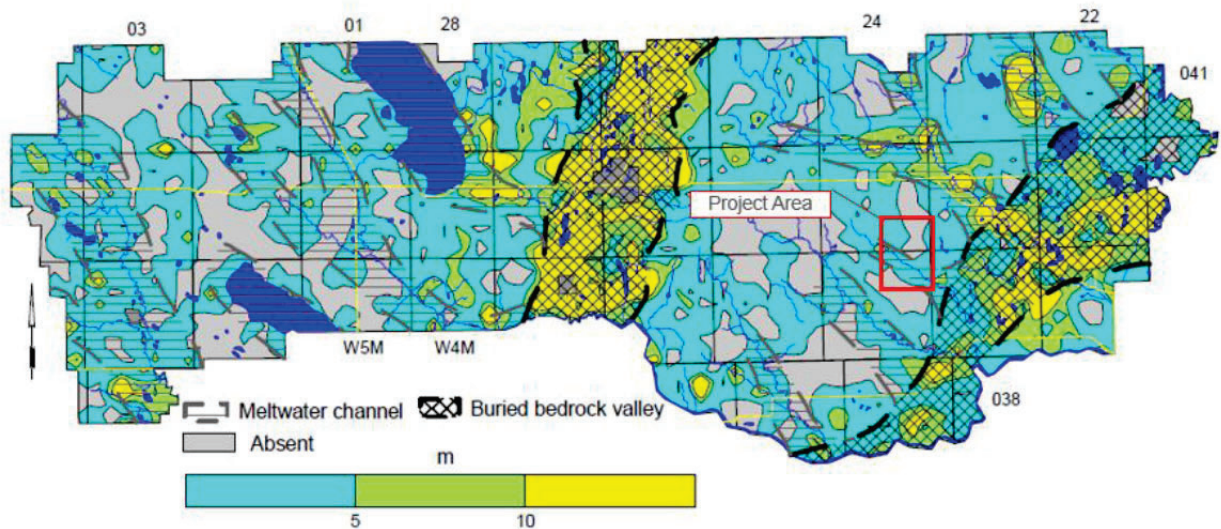


Figure 2-12: Thickness of Sand and Gravel Deposits (HCL 2001)

Water wells completed in surficial deposits are found primarily along the Buried Red Deer and Buffalo Lake valleys (eastern and central side of the County, respectively) and the Gilby Meltwater Channel (western side of the County). Within the **MMV Plan Area**, however, there appears to be few (if any) water wells completed in surficial deposits (Figure 2-13), which may be explained by the absence or low thickness (<5 m) of sand and gravel deposits observed in the Project Area (refer to the previous Figure 2-12).

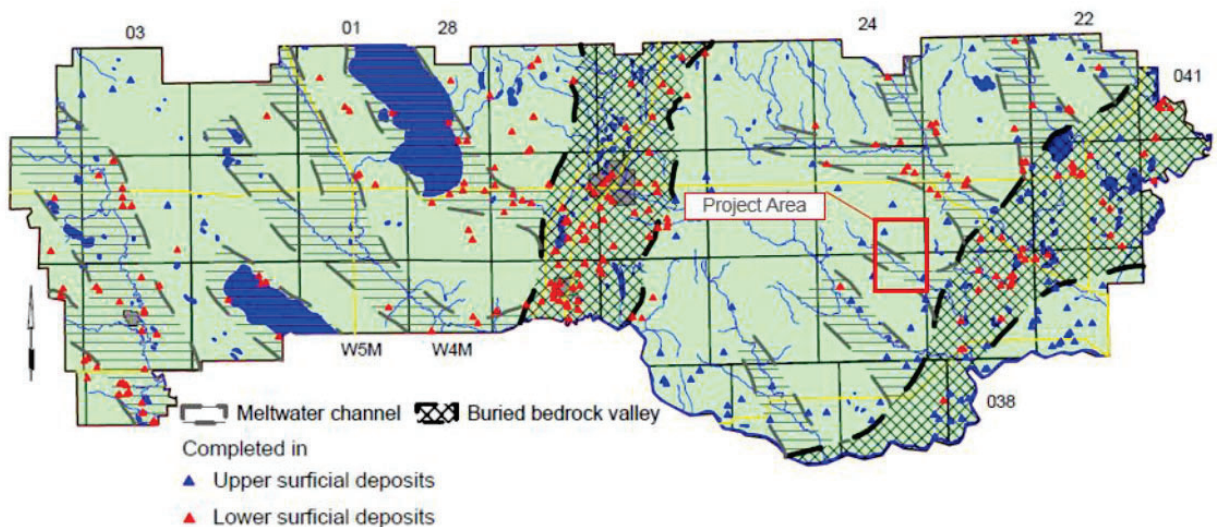


Figure 2-13: Water Wells Completed in Surficial Deposits (HCL 2001)

Bedrock Geology

The upper bedrock in the County consists of the Paskapoo, Scollard, Whitemud, Battle, and Upper Horseshoe Canyon Formations (HCL 2001). Of these, the project area is underlain by the Lower Lacombe and Haynes Member, both of which are members of the Paskapoo Formation (Figure 2-14).

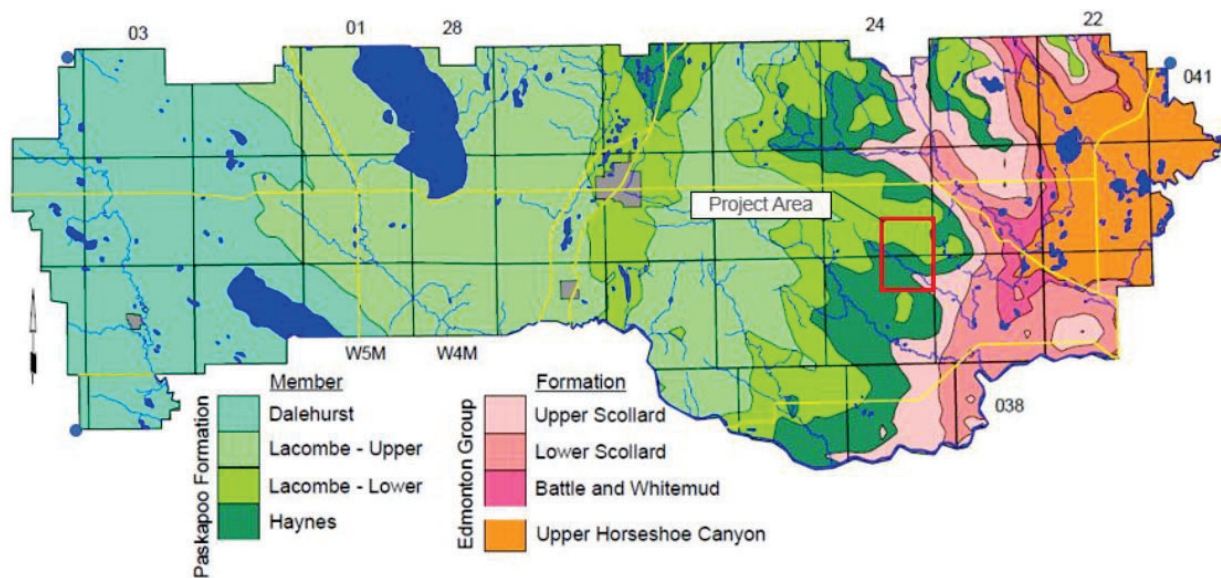


Figure 2-14: Bedrock Geology (HCL 2001)

The Lower Lacombe Member has a maximum thickness of approximately 100 m (average is 50 m) and is comprised of sandstone and a coal zone in the middle. The depth to the top of the Lower Lacombe Member ranges from less than 10 metres below ground surface (mbgs) in the eastern part of the County (**MMV Plan Area**) to more than 250 mbgs in the western side of the County.

The Haynes Member (which lies underneath the Lacombe Member) has a maximum thickness of approximately 100 m (average is 40 m) and is comprised of sandstone with some siltstone, shale and coal. The depth to the top of the Haynes Member ranges from less than 10 mbgs in the eastern part of the County (Project area) to more than 300 mbgs in the western side of the County.

Bedrock water wells within Project area (Figure 2-15) are completed in the Lower Lacombe Member and Haynes Member, as previously shown in Figure 2-14.

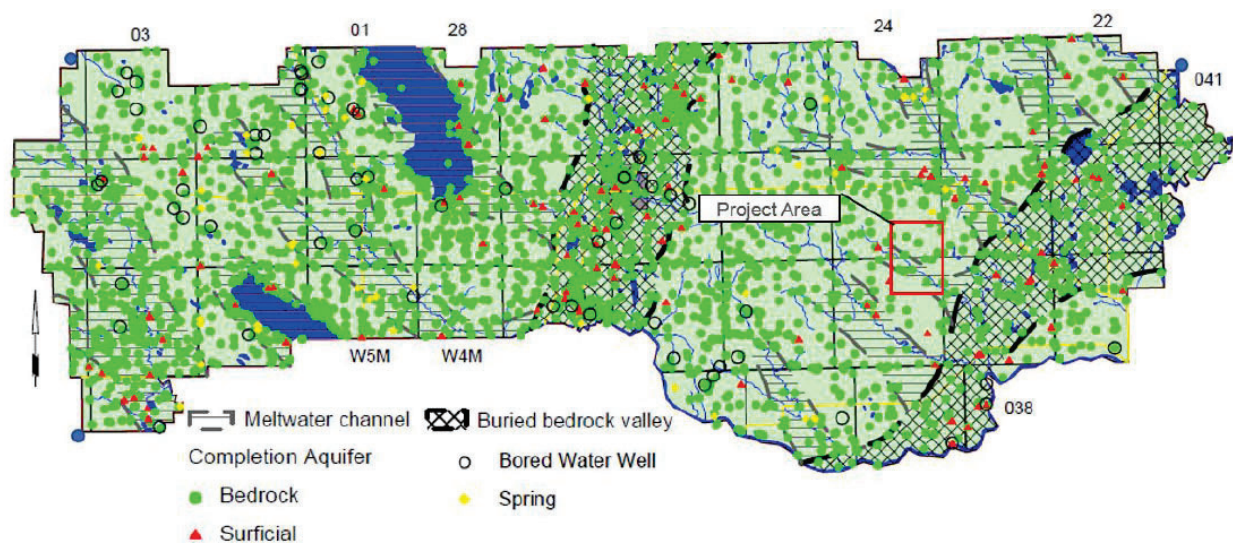


Figure 2-15 Water Wells Location (HCL 2001)

GEOCHEMICAL EFFECTS ON DEEP FORMATIONS IN CASE OF CO₂ LEAKAGE

The following summarizes the findings of AITF's report entitled *Geochemical Effects on the Deep Strata in Case of CO₂ Leakage from the Clive Leduc and Clive Nisku Oil Reservoirs in the Clive Oil Field in Alberta* (authors Stephen Talman, Ph.D.; and Stefan Bachu, Ph.D., P.Eng), which evaluates the potential CO₂ interactions with reservoir rock and brine in the unlikely event of containment loss. Please refer to **Appendix C** for full document and updated information.

The study's objective was to assess the likely geochemical interactions between the injected CO₂ and the rocks and water contained in the Leduc and Nisku oil reservoirs and in overlying saline aquifers, assuming that CO₂ or CO₂-rich water leakage from the reservoir may occur.

Within the oil reservoirs, in both of which the host rock is relatively pure dolomite, the interaction between CO₂ and reservoir minerals will lead to the breakdown of feldspars, present in minor amounts, to form clays. There is also some transformation of the carbonate minerals within the reservoir; however, this will be minor. Overall, the predicted geochemical reactions will lead to a trivial decrease in porosity in the oil reservoirs, with no expected impact on reservoir characteristics, particularly permeability.

Leaking fluids would interact with formation water and minerals in a succession of saline aquifers. These are, in ascending order: Lower Mannville, Viking, Basal Belly River and Upper Belly River. These overlying aquifers, being of siliciclastic nature, are mineralogically more complex than the carbonate oil reservoirs, therefore the resultant geochemical reactions are accordingly more complex. In the case of pure CO₂ leakage into these aquifers, the general tendency will be for the pre-existing feldspars and complex clays to break down, forming the simpler, more acidic clay mineral kaolinite and a pure silica phase. As well, significant quantities of the magnesium carbonate, magnesite, are predicted to form within the Basal and Upper Belly River aquifers.

The capacity of the aquifers overlying the oil reservoirs to trap CO₂, either within mineral phases or as bicarbonate in the water, is greater in the upper two aquifers (Basal and Upper Belly River) than in the lower ones (Lower Mannville and Viking). One reason is the markedly lower salinity in the former than in the latter. Calculations indicate that, following equilibration with a free-phase CO₂, free CO₂ will continue to exist within the Mannville and Viking aquifers but not in the Basal and Upper Belly River aquifers. Leakage through any of these aquifers would also result in some dispersion and dilution of any vertical CO₂ **FLUX** into each of these aquifers.

Acidified brines leaking into these aquifers would result in a more complex set of reactions. The flow of cation-laden brines can induce acid-forming reactions. As such, the pH of waters resulting from the mixing of CO₂-enriched, reservoir-derived water with that from the overlying aquifers will generally be lower (the water will be more acidic) than in the case of pure CO₂ flow. This has implications when considering trace metal mobility within affected aquifers; generally, the mobility increases as pH decreases.

The hydraulic gradient and water chemistry analyses completed in this study show strong evidence of five effective aquitards which would prevent upward migration of CO₂ and four significant aquifers that are isolated from one another, which could absorb and dissipate any CO₂ should upward migration occur. The planned monitoring program's chemistry-related components will provide additional assurance of containment

through independent and complementary analysis of soil, water well and CBM gases, and analysis of water samples from domestic wells.

GEOMECHANICAL ANALYSIS OF THE EFFECTS OF CO₂ INJECTION

The following summarizes the findings of the AITF report entitled *Geomechanical Analysis of the Effects of CO₂ Injection in the Clive Leduc and Clive Nisku Reservoirs in the Clive Field, Phase 2 Report* (authors Hamidreza Soltanzadeh, Ph.D., P.Eng.; Alireza Jafari, Ph.D.; and Tyler Hauck, M.Sc., P.Geol), which assesses potential geomechanical effects from CO₂ injection. Please refer to **Appendix D** for full document and updated information.

Injecting CO₂ into a hydrocarbon reservoir or deep saline aquifer results in pore pressure and temperature changes, both of which may induce deformations and stresses in the injection zone and the rocks that surround it. Geomechanical analysis is required to predict the effects of these induced deformations and stresses on the injection zone's bounding seal mechanical, or hydraulic, integrity. The study's primary objective was to characterize the rock mechanical properties and in situ stresses within the sedimentary succession above the Leduc and Nisku oil reservoirs in the **MMV Plan Area** (more specifically, from the base of the Calmar Formation to ground surface), and to construct a two-dimensional mechanical earth model (2D MEM). This model included geomechanical characterization of the geological units from the Cooking Lake Formation to the surface. Then, 3D numerical modelling was conducted to study the geomechanical response of the Clive Leduc and Clive Nisku reservoirs to historical oil and gas production and future CO₂ injection.

To study the effects of pressure changes, a 3D geomechanical model was developed for the entire study area. The results indicated the potential for fracturing and fault reactivation has been low during the historical producing life of the field. Therefore, it is less likely the integrity of the cap rock has been disturbed during this period. The results also showed low potential for fracturing or fault reactivation induced by future CO₂ injection. The modelling predicted a maximum surface heave of 2.4mm as a result of CO₂ injection pressure build-up.

Sensitivity analysis confirms the variations in the mechanical rock properties do not lead to meaningful changes in the modelling results regarding the low potential for fracturing and fault reactivation induced by pressure changes. The effects of these variations on the predicted reservoir deformation and surface heave are only in order of millimetres.

To study the effects of temperature changes induced by CO₂ injection at temperatures lower than reservoir temperature, a single vertical well geomechanical model was developed. The modelling was performed based on two scenarios: of 15°C and 30°C for the injected CO₂ temperatures. The results indicate that, for both cases, tensile fractures are likely to occur due to cooling effects within the reservoir. However, simulation of the cap rock's integrity, which is a key factor contributing to the Leduc being an ideal storage container, was not considered under these conditions. To mitigate these effects, Enhance will exclusively use horizontal injection wells, for which the long-term impacts of cold CO₂ injection on cap rock integrity have been modelled through a variety of different geological scenarios, with results showing cooling *does not significantly affect the cap rock* (Vilarrasa *et al.*, 2014). Further to this, Enhance's simulation modelling shows injection pressures with horizontal wells will be 75% lower than what was modelled in the AITF geomechanical study, further mitigating risk of injection-induced fracturing.

CLIVE LEDUC PRESSURE HISTORY AND BASHAW PLATFORM AQUIFER SUPPORT

The Bashaw Platform's **HYDROGEOLOGY** has been researched at length (Tsang and Springer, 1983; Hearn, 1995; Hearn *et. al*, 2011; Rostron *et. al*, 1997; Paul, 1994; Schwark and Laenen, 2000), not least because of the role it played in the conveyance of massive volumes of hydrocarbons between Duvernay source and Upper Cretaceous deposits. The Clive Leduc pool, like other pools along the reef complex, receives pressure support from the Bashaw Platform Aquifer. In 1962, it was first recognized pressures were dropping in all of the platform's D3 pools and the cause was extensive gas drawdown in the Nevis Field (Figure 2-16). The drawdown was recognized as far away as Innisfail, 100km from Nevis (Tsang and Springer, 1983). In response to the pressure decline, the Clive Leduc pool was **UNITIZED** in 1970 and a bottom-water injection pressure maintenance scheme was approved. Clive's original reservoir pressure was 17,485 kPa (2,535 psi). Fresh-source water, as well as produced water, was injected to supplement the bottom-water drive until 1996, but the injected volumes did little to offset the pressure decline. In 1996, fresh-source water injection was discontinued and only produced water was injected. The reservoir pressure stabilized at approximately 13,500 kPa (1,960 psi) in the early 1990s and, since then, pressure has changed little, as hydrocarbon production and natural recharge appear to be balanced.

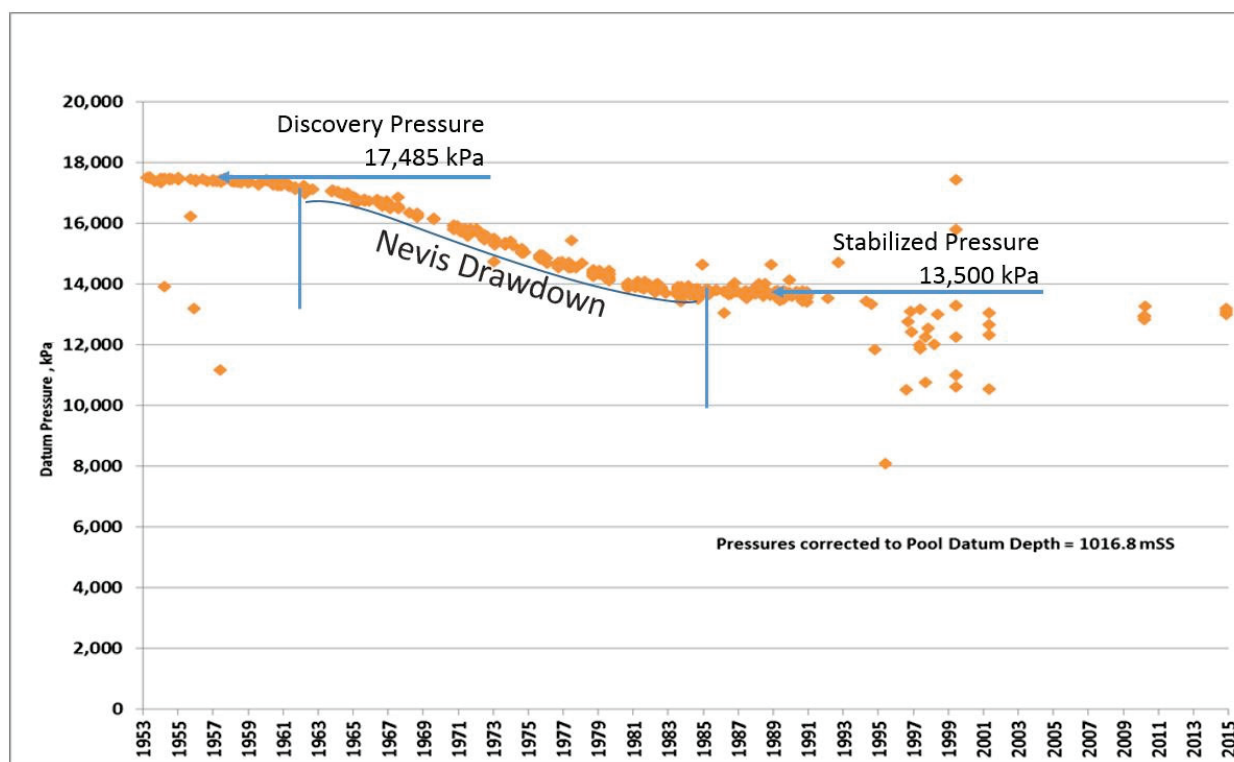


Figure 2-16: Clive Leduc Pressure History

Pressure decline due to the Nevis Field blow-down confirms the connectivity of reservoirs on the Bashaw platform. Post-Nevis blow-down, natural recharge has been sufficient to stabilize pressure.

Despite the drawdown causing issues on the Bashaw Platform's other fields, its effects highlighted three aspects of the aquifer. First, the aquifer is extremely well connected throughout its extent, allowing for pressure communication over large distances. Second,

the aquifer is very large but finite. The Bashaw Platform's pore volume is massive (30km³ based on an average porosity of 4%). However, this was not enough to prevent the pressure drop of the entire aquifer, which in turn suggests that, third, external connectivity is limited. This final aspect suggests the Cooking Lake Formation does not significantly support the platform.

Hydrogeological conditions of discoveries on the platform provide further evidence of a lack of significant drive. Figure 2-17 shows discovery pressure for all of Bashaw Platform's major D2 and D3 fields (and Erskine, which is separate). Fields mostly align on a **GRADIENT** of 10.8 Kpa/m, which conforms to the weight of the average Leduc brine. A match between gradient and fluid weight suggests the aquifer is static and there is no significant mobility in the system on discovery. Additionally, elevated brine salinities indicate there has been little fresh water dilution, as might be the case if the aquifer was open to freshwater circulation from the surface.

The Bashaw Platform Aquifer is both vast and isolated. Historical pressure measurements at Clive and other fields connected to the aquifer suggest there was little natural fluid drive prior to development and, despite connectivity in the aquifer, under-pressured conditions caused by the Nevis Drawdown have been very slow to recover.

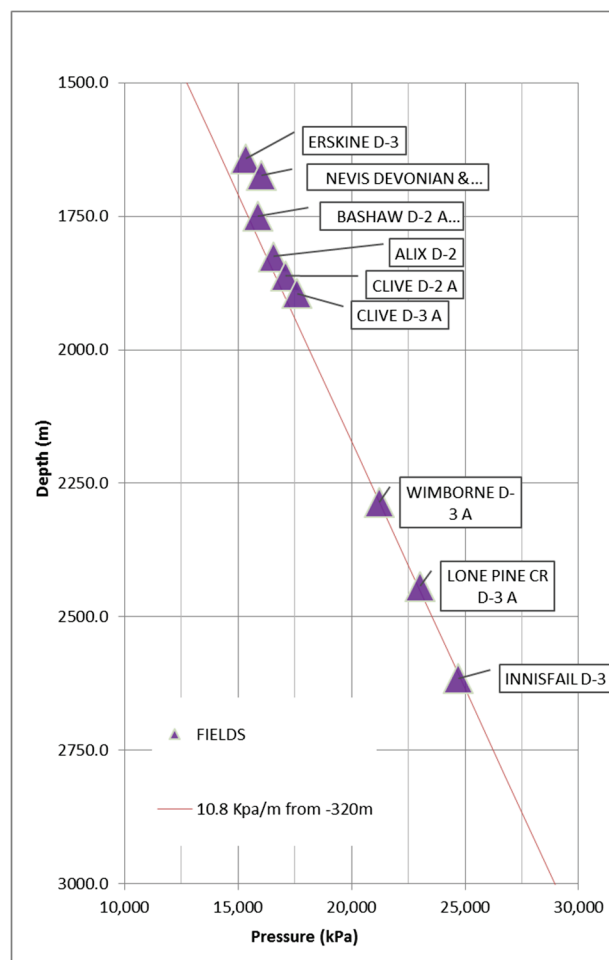


Figure 2-17: Pressure/Depth Chart of Bashaw Platform Fields
Alignment of the fields suggests they have a common Leduc aquifer, while the match of the gradient and the brine density suggest the waters are static (adapted from Tsang and Springer, 1983).

CLIVE LEDUC PRODUCTION HISTORY

The Clive Leduc discovery well was drilled in 1952. The pool has since been delineated and developed, with the drilling of 168 wellbores. At peak production in 1979, the daily oil rate was 912 m³/d (5,735 bopd) from 82 wells (Figure 2-18). Three **STATIC GRADIENTS** taken in November 2014 confirm the current reservoir pressure remains at 13,500 kPa (1,960 psi). Enhance conducted **SLIM TUBE TESTS**, the results of which confirmed CO₂ will be **MISCIBLE** with the oil at this pressure, supporting the feasibility of CO₂ EOR at Clive. Furthermore, there will be no need to increase pressure to achieve miscibility. This means that Enhance can conduct the CO₂ flood at close to current conditions, eliminating any risk of containment issues related to over-pressuring the reservoir.

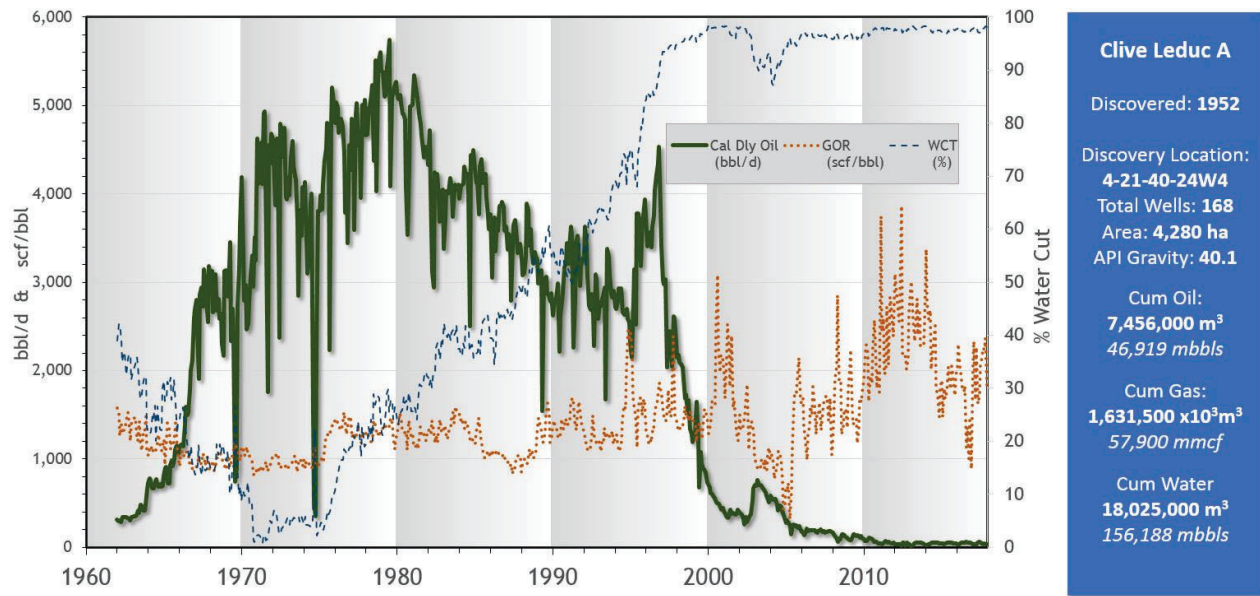


Figure 2-18: Clive Leduc Production History

The field was rapidly developed in the 1960s and continued to improve until 1980. From that point on, water production has increased, resulting in many wells to water out and reduced oil recovery. Recent production is concentrated along the highest points of the reservoir, as the field approaches its end of life.

CLIVE GEO-MODEL

The geological study's primary goal was to understand and characterize fluid flow through the reservoir. Building a Clive geo-model, which can be used to test different development scenarios, was the most successful way to achieve the goal. Complex relationships that recorded constantly fluctuating conditions during platform growth at Clive have to be distilled from observations from core and well logs.

Included Geological Components in this Study:

1. A detailed 16-well Leduc core study describing depositional and diagenetic fabrics and establishing an environmental framework. Dr. Jeff Packard conducted this study. Ongoing observations of the remaining central Clive cores have used the designations and framework set forth in the initial study.
2. Petrophysical analysis of 180 well logs at Clive, with a range of vintages from the 1950s to the late 2000s. An in-house processing tool was developed to calibrate core data with various petrophysical analysis methods on a well-by-well basis. Output from the tool included porosity, permeability (lateral and vertical) and water saturation (SW).
3. Construction of a geo-model. The geological study's ultimate goal was to construct a geo-model that can be used to build a reservoir model with the highest degree of confidence possible. This constrains the simulation to ensure the best possible history match and predictions. As well as input from the petrophysical analysis, the geo-model incorporated lateral facies distribution parameters and vertical facies associations, and a particular focus was made on baffles and aquitard lenses to better approximate the reservoir's true flow dynamic in simulation.

Petrophysical Study

Existing wells at Clive provide outstanding coverage of the Leduc complex that, coupled with over 50 years of production and injection data, allow for an excellent understanding of the formation's properties. Using Petrel

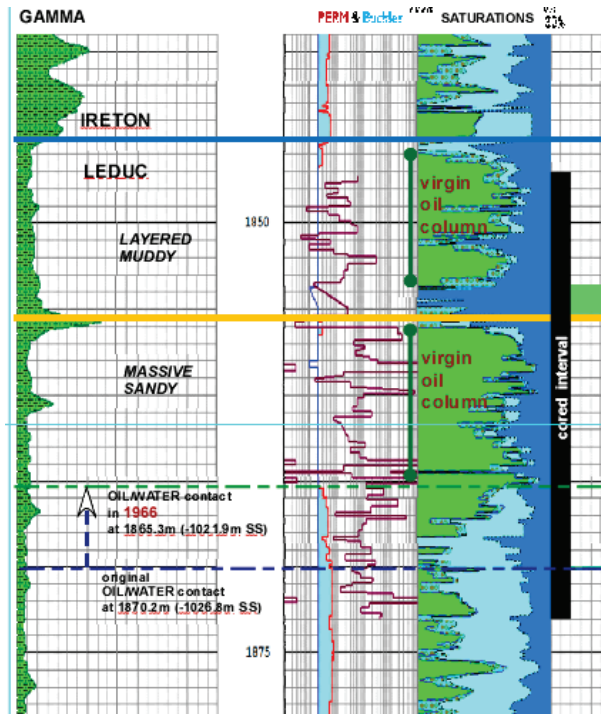


Figure 2-19; Example of Log Analysis Data

The results are graphically presented in the saturations column, where the dark blue fill represents irreducible water, the light blue fill; represents movable water and the light green fill represents hydrocarbons. From 2-35-039-24W4.

geological modelling software that allows input of geological and petrophysical properties into a framework, Enhance has constructed a refined geological model of the Clive Leduc pool based on log and core data from 180 wells. Petrophysical analysis was conducted on 2,800m of log data, and permeability and porosity data extracted from 3,700 core samples. Advanced modelling techniques were used to construct a 3D geological model based on porosity, permeability, water saturation and facies correlations.

To standardize output data from greatly varying input data, a number of challenges had to be addressed, including the need to utilize and cross-calibrate log suites of various vintages (ranging from the 1950s to 2000s). Only 31% of the penetrations were drilled after 1985 and have a relatively complete log suite available. Specific challenges with the older logs included reliance on thermal neutron logs for porosity (if available) for wells drilled in the 1950s and correcting sonic logs for wells drilled in the 1960s where porosities are grossly underestimated as the result of sonic logs' inability to detect vuggy porosity.

Integration of core and log data, utilization of Archie variable 'm' and 'n' methods in solving for water saturations and utilization of the Buckles method (Buckles, 1965) allowed for the identification of various fluid contacts at the time of drilling (Figure 2-19). As well, the recognition of an original oil/water contact in many wells, despite hydrocarbon migration and water flooding, coupled with the identification of residual water saturation profiles for differing pore system types, has allowed for a reassessment of the original hydrocarbon in place.

The Clive field is split into three separate models, each with a grid size of 25m by 25m by 1m at a 45-degree angle to match horizontal well azimuth. Grid cells are bound to structural surfaces and extend to a base at -1,040m, giving 17m of aquifer.

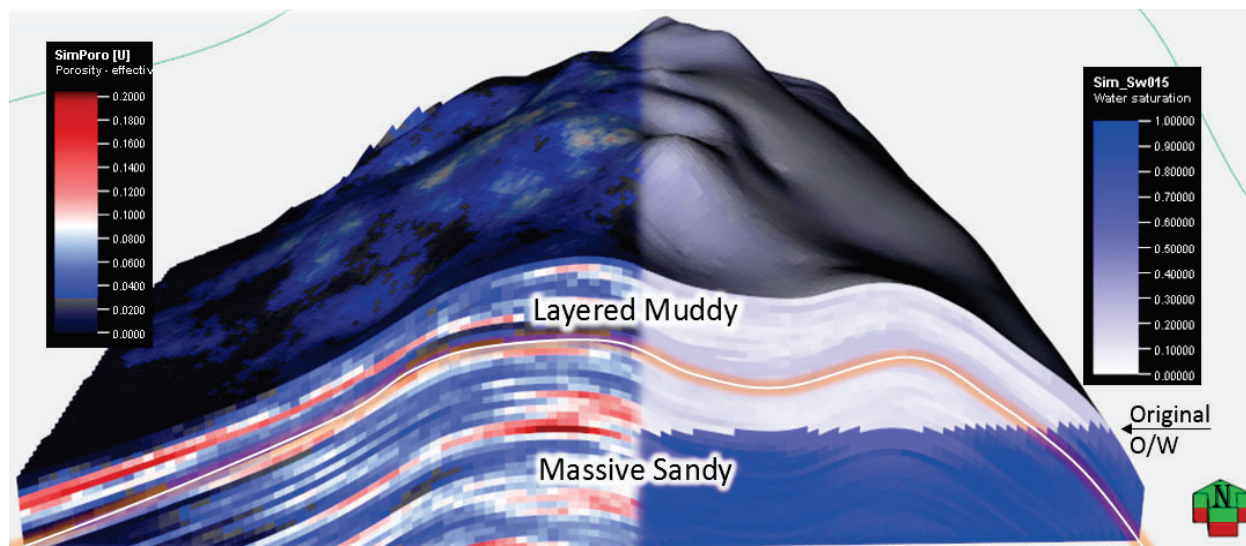


Figure 2-20: Clive Central Area Petrel Geo-Model Looking North

The porosity model is on the left and the saturation model is on the right. 25x vertical exaggeration.

Primary facies distribution at Clive is vertical, so the model was split into four vertical layers: three representing the Layered Muddy Zone and one for the Massive Sandy Zone. A **GAUSSIAN RANDOM FUNCTION** simulation method was used to grid the porosity model, with a *well search area* set to encompass the typical 400m inter-well distance. Lateral and vertical permeability were gridded in conjunction with the porosity grid to maintain a porosity/permeability relationship in calculated cells. As fluid saturation varies according to the date of logging, well data was not used to build the saturation model. Instead, Buckles formula was used, applying an inverse relationship between porosity and water saturation to create an on-discovery water saturation average of 0.15. A transition zone is included in the water saturation grid below the oil/water contact to aid in the integration of the aquifer with the oil zone during simulation (Figure 2-20).

The completed geo-model was exported to CMG's reservoir simulator, IMEX.

SIMULATION MODELLING

Enhance constructed a robust simulation model of the entire Central Area. The model was history matched to over 50 years of production and injection history, with minimal adjustment to geological and fluid property data.

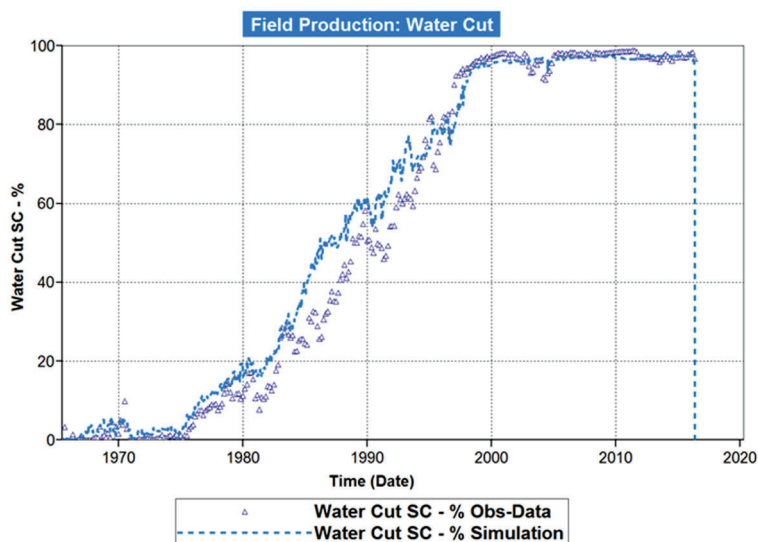
History Matching and CO₂ EOR Prediction

In addition to rock properties, the other important factors to consider in reservoir simulation are the properties and interaction of fluids within the reservoir; initially oil, gas and water, during historical production, followed by the addition of CO₂ during the planned EOR project. The initial oil, gas and water properties for Clive were determined based on produced fluid samples adjusted to reservoir temperature and pressure conditions and were used during the **BLACK OIL MODEL** history match phase of the project. Core Labs conducted slim tube tests and other studies to predict properties during CO₂ EOR. The slim tube tests confirmed that CO₂ is miscible with Clive Leduc oil at current reservoir conditions and provided the data needed to model **COMPOSITIONAL BEHAVIOUR** of oil, gas and CO₂. These relationships were input to the simulator for CO₂ EOR performance

prediction. Core testing derived relative permeability and **RESIDUAL SATURATION**. Modelling of these parameters in the simulator was performed in consultation with Avasthi & Associates Inc., an organization that provided expert review and assistance in appropriately describing these properties in the simulator.

The aforementioned data related to rock and fluid properties and interactions is necessary to construct a valid reservoir model and has been obtained from actual logs, core and fluid analyses. Enhance considers this hard data and has honoured these inputs to the simulation model by making minimal changes to them when **HISTORY MATCHING**. The high-quality history match that was obtained gives confidence in the predictive capability of the simulation model. The Petrel 3D geological model and basic fluid properties were imported into simulation software that Enhance then used to conduct a black oil history match, where the model was tuned to over 50 years of historical oil, water and gas production and pressures.

The Clive Leduc history match was achieved through the application of liquid rate constraint matching historical oil rate, water rate, gas rate, water cut (percentage of water in total produced liquid) and gas-oil-ratio (GOR) at individual wells. Pressure within the model was matched to historical measurements. Changes to the geological model parameters and the relative permeability curves determined from laboratory testing on core samples were deliberately avoided. History was matched through reasonable adjustments to the Leduc aquifer properties and some minor adjustments to permeability at the wells to allow fluid rates to be matched. As shown in Figure 2-21, a good match on produced water cut indicates the aquifer adjustments were valid. Gas and oil profiles offer similarly close results with very minimal differences for the first 25 years. After 1980, there is some divergence, but the close agreement between the overall shapes of the actual and simulated production curves, and only a minor difference in cumulative recovery over the long production history, give confidence the model will provide reliable predictive capability for the CO₂ flood.



This match was obtained with minimal adjustments to the geological model and relative permeability curves, providing additional assurance of its validity.

Figure 2-21 Cumulative Water Production History Match

A very close match between simulated and actual confirms the geo-model is representative of the Clive Leduc pool and can be used as a predictive tool in ongoing planning.

The initial oil, gas and water saturations (i.e. after history matching with the black oil model) for the GEM model are shown in Figure 2-22.

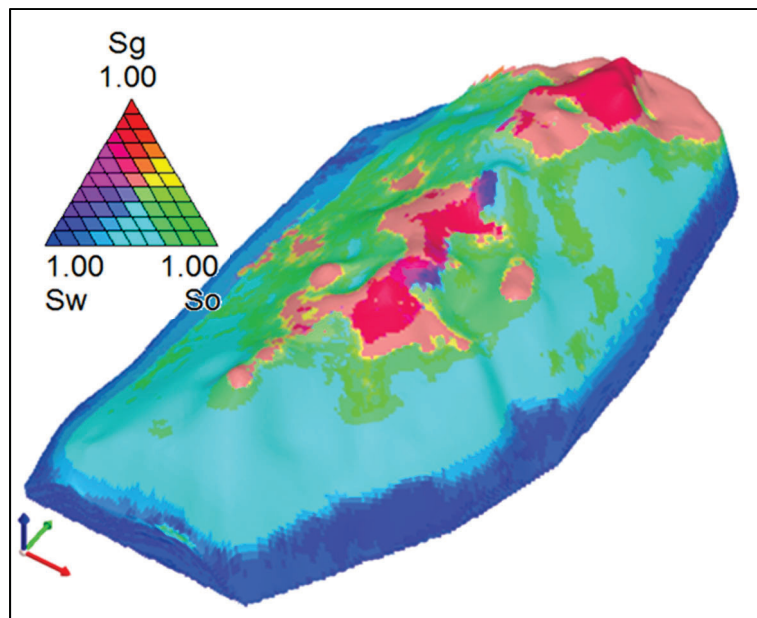


Figure 2-22: Clive Central Model showing Fluid Distribution at end of Black Oil History Match

Free gas, represented by red areas, occurs at the top of the reservoir due to its low density. Water tends to lie towards the bottom and the oil occurs in varying saturations between the free gas and free water phases.

The phase and composition distribution from the final state of the history match model was used to build the initial state of the forecast scenario for compositional modelling; this is referred to as explicit initialization. Incorporation of the CO₂ interaction with oil requires compositional (equation of state) simulation with a modified fluid model that can account for CO₂-hydrocarbon interactions such as the oil swelling effect (density alteration) and oil **VISCOSITY** reduction as a function of CO₂ solubility in oil. The history matched reservoir simulation was used to initialize the compositional model in CMG's **GEM SOFTWARE**; compositional modelling was chosen for CO₂ injection forecast scenarios because it best captures the interactions between the CO₂ and the oil under miscible reservoir conditions.

Enhance contracted CMG to derive the inputs required to describe these interactions in their simulator.

GEM simulations predict CO₂ movement and interactions across the model by applying relatively simple calculations to realize the relative density, and therefore movement, of water, oil and CO₂ between every cell in a model, of which there are millions. Figure 2-23 shows the density of CO₂, brine and oil at reservoir temperature and a range of pressures. Of note, the CO₂ curve shows much greater density dependence on pressure than it does on oil (oil density decreases with increasing pressure, as these calculations are for a live oil containing natural gas; as pressure increases, more gas dissolves into the oil and decreases its density). Although the CO₂ will be injected in dense phase, having some properties similar to a liquid, it is still highly compressible and behaves like a gas, in some respects.

At the expected range of EOR operating pressures, Clive Leduc brine is double the density of CO₂. This will cause CO₂ to rise to the top of the reservoir, where it will be structurally trapped against the confining Ireton cap rock.

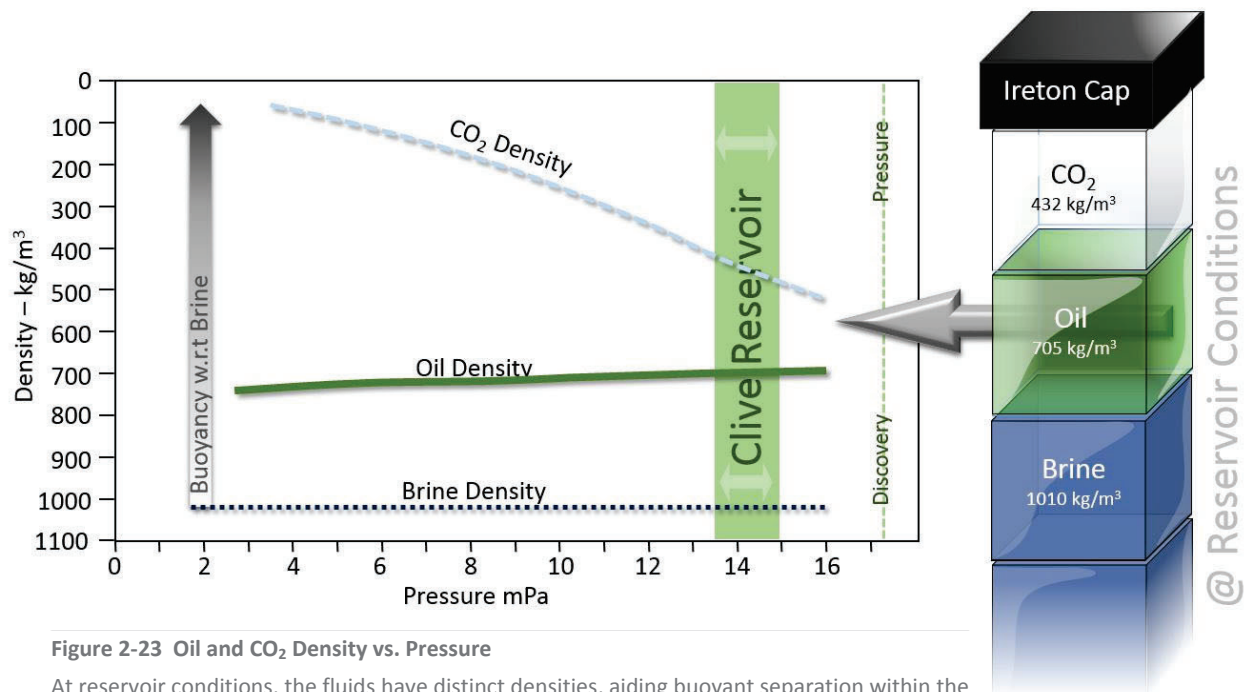


Figure 2-23 Oil and CO₂ Density vs. Pressure

At reservoir conditions, the fluids have distinct densities, aiding buoyant separation within the reservoir. CO₂ trapping long after EOR has finished is assured because CO₂ has less than half of the brine density.

Development Planning

Enhance's goal with EOR is to use CO₂ as efficiently as possible, while maintaining the long-term storage of CO₂ in the formation. To that end, a multitude of different well configurations and production scenarios have been run in the model, each evaluating sequestered CO₂, recycled gas, water production and oil recovery, among others, to establish the best possible development plan. Having considered almost every conceivable development scenario, the chosen plan is to drill horizontal injection and production wells oriented in a northeast-southwest direction; this orientation was selected to take advantage of the reservoir's orientation. Horizontal wells offer broad reservoir access with minimal surface disturbance and achieve higher injectivity and productivity than vertical wells due to the amount of reservoir penetrated. Simulation was run based on the planned schedules for Nutrien and NWR CO₂ supply tie-in. The Central Area model, or Clive Phase 1 development, consists of eight injection wells and eight producing wells (Figure 2-24). Central Area development will commence in the **MMV Plan Area** with six injection wells and six production wells.

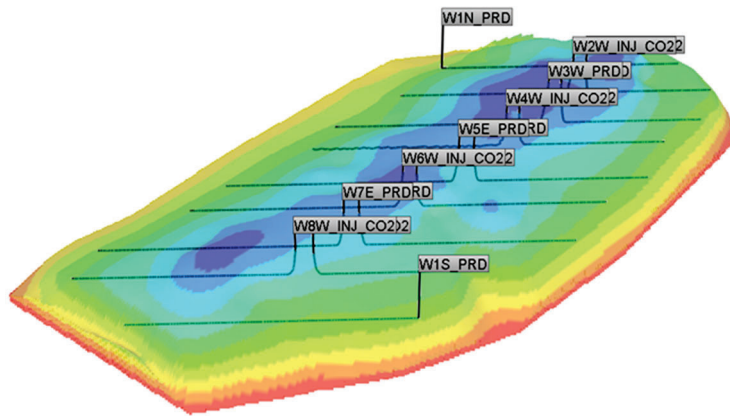


Figure 2-24 Clive Central (MMV Plan Area) Model As Seen From the Southeast

Eight injection wells and eight producing wells, all horizontal, are to be drilled in the NE-SW direction, mostly in the form of well pairs from the central axis.

Injection rates will be maintained at an equivalent injection rate of 30% **HYDROCARBON PORE VOLUME (HCPV)** per year to accommodate the planned volumes.

CO₂ injection will continue for 25 months, until the total injected CO₂ volume reaches approximately 0.50 of the HCPV. Thereafter, a **WATER-ALTERNATING-GAS (WAG)** process starts with conversion of the CO₂ injectors on the east pattern to water injectors. Six months later, the water injection begins on the west injectors, while the east injectors convert back to gas injection. This cyclic conversion happens

every six months and injection proceeds until a total injection gas volume of 3.5 HCPV is realized.

To track and account for fluid mobility over the program life cycle, the simulation was run for decades until the reservoir reaches its economic limit, and then for 475 years after development. Figure 2-25 shows the results in three snapshots of CO₂ distribution to represent the initial state during injection (two years), at the end of injection (25 years), and the long-term state (500 years). The decrease in CO₂ saturation from 25 to 500 years is due to continued CO₂ dissolution into the residual oil and water phases in the model, which will diminish as local brines become more saturated.

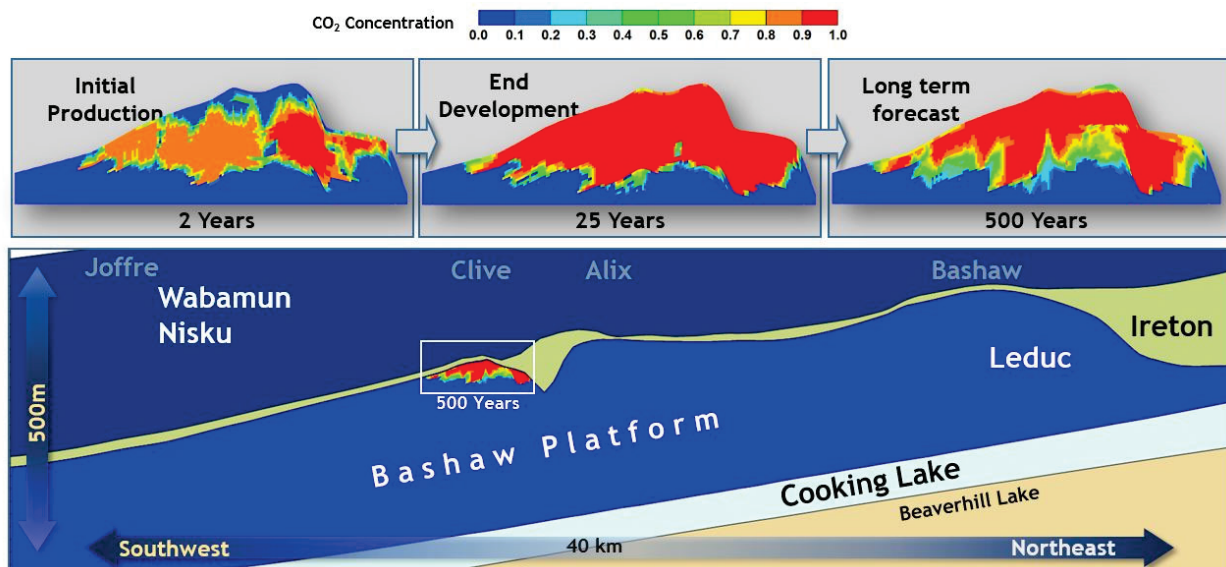


Figure 2-25 Structural Containment of CO₂ for the Long Term

Simulated CO₂ distribution slice-through Central Clive at two, 25 and 500 years, in context of the entire Bashaw Platform (bottom).

The limited CO₂ mobility from end of development through the following 475 years shows containment is stable in the Clive Leduc pool. Enhance concludes there is little risk for loss of geological containment, even over geological time scales.

For this study, Enhance used a version of GEM that does not account for mineralization or ionic trapping of CO₂. However, AITF investigated these phenomena and found they trapped approximately 9% of CO₂ in rock containing only CO₂ and residual water.

Careful injection and production volume monitoring, which can be compared to the simulator's predictions, will achieve pressure maintenance during EOR. The injected fluids volume will be balanced with the produced fluids volume, eliminating the chance of over-pressuring the reservoir and resulting in the reservoir pressure being approximately 20% below initial conditions. Active monitoring and injection/production management allow Enhance to understand CO₂ distribution in the reservoir and to identify any anomalous conditions as a possible early indication of containment or conformance issues. Average reservoir pressure is expected to remain relatively stable and well below the discovery pressure of 17,400 kPa (2,535 psi). Once injection ceases, in approximately 25 to 30 years, pressure declines and stabilizes at slightly over 14,100 kPa (2,050 psi). It is worth noting that deliberate attempts at pressurizing the pool during the 1980s and 1990s failed because of the Bashaw Platform Aquifer's influence. Therefore, it is extremely unlikely that any part of the reservoir will exceed the initial pressure state.

Enhance has constructed a robust simulation model of the entire Central Area, which includes the **MMV Plan Area**. The model was history matched to over 50 years of production and injection history with minimal adjustment to hard input data, such as the geo-model and fluid properties and saturation-dependent behaviours such as relative permeability. The high-quality history match obtained means the model will be a valuable tool for reservoir and CO₂ containment and conformance monitoring. The model's predictive capabilities have shown that CO₂ will rise to the top of the reservoir and remain trapped by the impenetrable Ireton seal.

SECTION SUMMARY

Enhance conducted extensive regional and local geological analyses of the Clive Leduc zone, confirming it to be an ideal storage reservoir for CO₂. Highlights from the analyses include the following conclusions:

- The Ireton Formation's impermeable tight lime shales separate the Clive Leduc and Clive Nisku pools in the Clive area, which are distinctly separate hydrocarbon accumulations.
- Ireton seal integrity is confirmed by the existence of a gas cap of up to 11m and an oil column of 18.5m on discovery in the Leduc, overlain by water in the Nisku.
- Secondary seals ensure there is *no quantifiable likelihood of geological containment failure* of CO₂ to the surface at Clive. These seals include the Nisku and Wabamun anhydrites, Joli Fou, Colorado and McKay shales.
- To understand the effects and dynamics of CO₂ injected into the reservoir, Enhance has built and simulated a detailed geological model of the Clive Leduc pool. The geological model was built using all available core and log data, with petrophysical input from 180 wells. Core and fluid properties for

the CO₂ EOR predictions were derived from Core Labs' laboratory analysis and reviewed and validated by Avasthi & Associates.

- Results of the fluid analysis shows that sequestered dense-phase CO₂ will remain significantly buoyant with respect to the Leduc aquifer brine. This ensures the confining Ireton cap rock will keep CO₂ trapped in the Clive Leduc pool.
- The simulation model was history matched to over 50 years of production and injection history, with minimal adjustment to geo-model and fluid properties, thereby validating the accuracy of the geo-model.
- Periodic updates to the history match as the CO₂ EOR scheme progresses will provide a means of understanding and optimizing EOR performance and will also provide evidence of containment or conformance issues, should matches be unobtainable with reasonable adjustments to the simulation parameters.
- Results of the simulation validate CO₂ will remain contained in the Clive Leduc pool throughout the period of EOR and beyond. Simulations run to 500 years in the future show no appreciable CO₂ migration from the scheme area, validating containment within the storage reservoir.

3 EXISTING WELLBORES

The Clive Leduc Unit includes 163 existing wells drilled over the last 55 years for the purpose of primary oil recovery. Existing wells will not be used for EOR, with the exception of monitoring purposes. Currently, Clive is an operating oil field with producing oil wells, water injection wells, suspended wells and zonally and fully **ABANDONED WELLS**. Producing Leduc wells or wells where the Leduc has not been zonally abandoned, will require conversion to monitoring or abandonment prior to CO₂ injection. Furthermore, the physical condition of all Leduc and Nisku penetrations has been investigated to assess risk of cross-formational flow and CO₂ surface leakage.

In addressing the risks associated with future CO₂ storage at Clive, it should be noted the presence of naturally occurring H₂S in the Leduc and Nisku of Clive has historically required the highest safety standards to be employed when drilling, completing, operating, suspending or abandoning wells. As the Alberta government's regulations that govern H₂S management are designed to prevent even the smallest containment failure of this gas, the Clive field benefits from already meeting these stringent safety and regulatory standards. The AER specifies well design and operating practices through established directives and guidelines that ensure the safe operation of sour oil and gas fields.

By meeting or exceeding regulatory compliance governing H₂S, Enhance can demonstrate the highest-possible safety standards for CO₂ containment at Clive.

Enhance's review of existing wellbores has been conducted in two stages: AITF's initial study and Enhance's more recent detailed review. The AITF review employed public domain data to provide an initial screening of wells (Please see **Appendix E, Characterization of the Wells that Penetrate the Clive Leduc and Clive Nisku Oil Reservoirs in the Clive Oil Field in Alberta** by Faltinson, Jafari, Hauk and Bachu.). This work used software developed by TL Watson and Associates Ltd. that calculates an empirically derived risk score for a well, based on vintage, well type, and construction details. **AITF concluded the only possible risk to CO₂ containment at Clive is through existing wellbores.** Enhance has addressed AITF's recommendations and completed more exhaustive and detailed analysis, using proprietary information from internal well records.

Enhance has reviewed the 163 existing wells in the Clive Unit, inclusive of the 71 wells in the **MMV Plan Area**, using proprietary data for well integrity and CO₂ containment in the Leduc Formation to ensure appropriate engineered passive safeguards are in place. The study evaluated the history and current status of the wellbores, cement integrity via **CEMENT BOND LOGS (CBLs)**, identification and cataloguing of SCVF events, and surface casing depths.

As further assurance, Enhance contracted a third-party engineering firm, VZFox Canada, to facilitate a formal independent risk analysis. This work has detailed a well-specific monitoring and mitigating plan for every existing well in the **MMV Plan Area** (Figure 3-1).

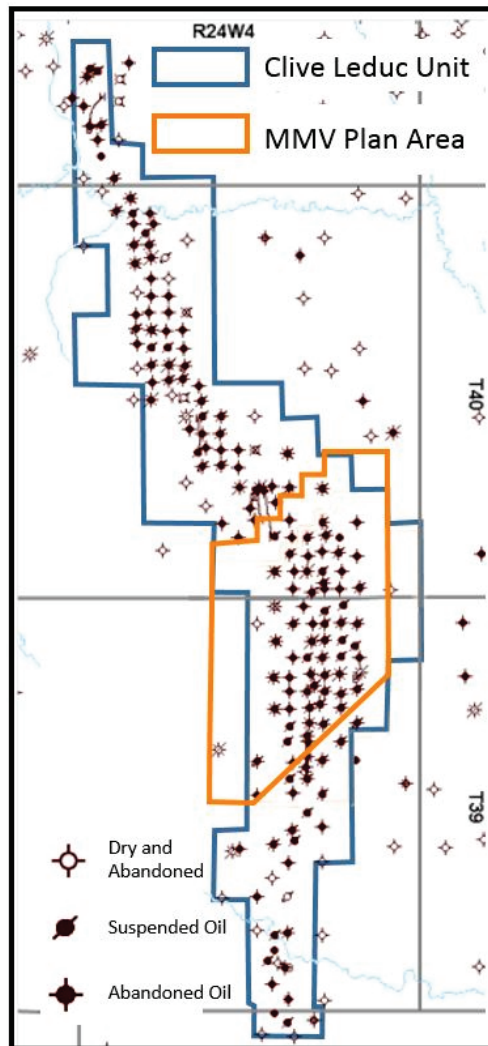


Figure 3-1 Existing Well Review / MMV Plan Area
This map shows the area Enhance reviewed for the categorization of existing wells.

CLIVE WELLBORE STATUS

As part of the risk assessment, Enhance has reviewed every existing well in the Clive Leduc Unit to assure that all wells conform to current provincial regulatory standards.

Enhance divided existing wells into four categories for review purposes:

- **Abandoned:** Wells that are fully abandoned and cut and capped.
- **Zonally Abandoned:** Wells that have previously been abandoned in the Leduc Formation.
- **Suspended:** Wells that have not been zonally abandoned. These typically have had a **BRIDGE PLUG** set but no cement cap.
- **Currently Operating:** Operating wells that are currently producing oil or disposing water.

Of the above, the **Zonally Abandoned** wells were further divided according to the AER Directive 20 versions that were applicable at the time of their **ZONAL ABANDONMENT**. Directive 20, the directive governing well abandonments, has had three revisions, effective December 7, 2007, July 1, 2010, and March 15, 2016. A major change occurred in the July 1, 2010, revision with the introduction of Level A intervals. Level A intervals are zones that contain hazardous fluids, including those with an H₂S concentration over 15%, and require specific abandonment safeguards. Wells that have been zonally abandoned before July 1, 2010, are not subject to be re-abandoned but may require additional remediation. Enhance will bring these wells into compliance (minimum 30m cement column or 1 m³ of cement on top of the existing abandonment) with current D-20 requirements.

Review of existing Unit wells found that:

Total Unit Wells					
Leduc Formation					
Well Mode	# of Wells	D20 2016/03/15	D20 2010/07/01	D20 2007/12/07	CBL Log
Abandoned	23	0	0	23	8
Zonally Abandoned	108	6	5	90	72
Suspended	24	0	0	0	15
Operating	8	8	0	0	2
Totals	163	14	5	113	97

Table 3- 1 Summary of Enhance's Study of Clive Unit Wells

- 23 of the wells were abandoned prior to the introduction of the July 1, 2010, Level A wells.
- 90 of the wells were zonally abandoned prior to the introduction of the July 1, 2010, Level A wells.
- 11 of the wells were abandoned or zonally abandoned following the introduction of the Level A wells on July 1, 2010.

Although the pool H₂S level averages 12.6%, the individual well gas and fluid analysis can exceed the H₂S limit of 15%.

Enhance Energy has, and will, continue to zonally abandon Clive Unit wells to the Level A standards set out in Directive 20, which, in most cases, exceeds the current regulatory requirements.

Wells that were zonally abandoned with a bridge plug capped with cement, prior to the introduction of Level A intervals, are acceptable for containment and are considered a low risk for failure as no failure of this type of well has been observed to date. Any of these wells lacking sufficient cement column above the bridge plug will be brought into compliance (minimum 30m cement column or 1 m³ of cement on top of the existing abandonment) with current D-20 Level A requirements. As the project progresses, inactive wells will be zonally abandoned or fully abandoned per current requirements. Any wells lacking a cement bond log will have one run to determine cement tops at the time of abandonment. Furthermore, any porous zones (as defined by AER D-20) above the cement top will have remedial cementing completed per AER D-20. All wells will be monitored during operations for possible failures; any failures would be addressed immediately.

Full abandonment of wells per AER D-20 Level A will meet regulatory requirements for closure of the project. Monitoring of wells during project operation will ensure that any issues are detected and dealt with in an expedient fashion and provide learnings to assist in project closure. As per the AER D-65 EOR Approval, all non-abandoned wells that are completed in the Leduc and/or Nisku zones and within the Approval Area must be abandoned by a Level A method in accordance with Directive 020 upon completion of the CO₂ injection operations. The abandonment program must be submitted to the Closure & Liability (Oil & Gas) Group in the AER Closure and Liability Branch and approved by the AER.

ENHANCE'S WELLBORE REVIEW

Potential Leak Paths in Existing Wells

Enhance's formal wellbore review incorporated every well in the **MMV Plan Area** to evaluate its construction method and each component's likelihood of failure. Potential leakage pathways can be broadly grouped into four types, as shown in Figure 3-2 and discussed below.

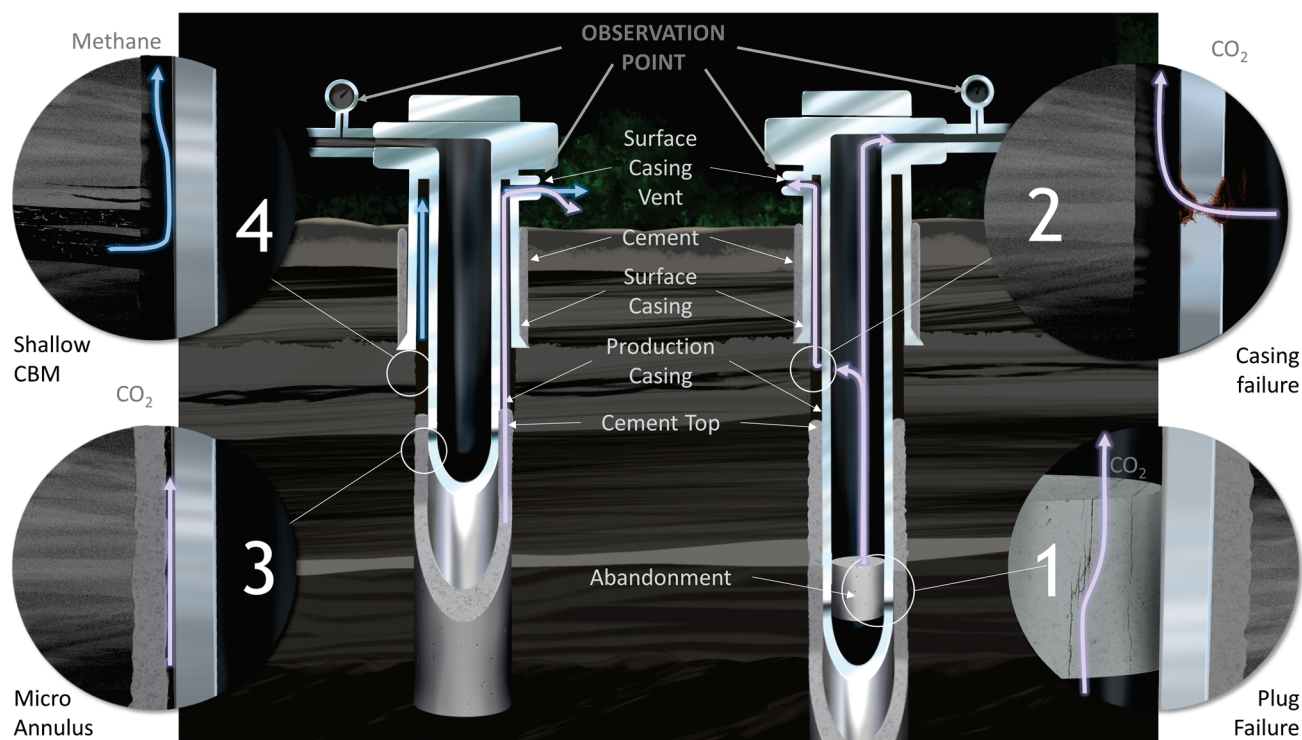


Figure 3-2 Potential Wellbore Leakage Scenarios

1. Abandonment Plug Leak: CO₂ leaks past the abandonment plug within the production casing.
2. Abandonment Plug Leak and Production Casing Failure: As above, but the CO₂ encounters a casing failure up-hole.
3. Leak through Micro-Annulus Flow in the Production Casing: CO₂ enters a micro-annulus.
4. Shallow Gas Zone Annular Flow: Shallow sweet gas, likely CBM, enters the annulus above the cement top.

1. Abandonment Plug Leak

In this scenario, CO₂ leaks past the **ABANDONMENT PLUG** within the production casing and would be detected as pressure build-up on the production casing pressure gauge.

2. Abandonment Plug Leak and Production Casing Failure

Like the first scenario, CO₂ leaks past the abandonment plug within the production casing but encounters a casing failure above the cement top up-hole, enabling CO₂ to leak into the annulus. In this case, the leak would be detected as a SCVF.

3. Leak through Micro-Annulus Flow in the Production Casing

CO₂ enters a micro-annulus, a small gap between the casing and the surrounding cement. In this case, the CO₂ would be detected as a SCVF, or Nisku monitoring wells would detect cross-flow into the overlying Nisku zone.

4. Shallow Gas Zone Annular Flow

Shallow sweet gas, likely CBM, enters the annulus above the cement top. This would be identified as a SCVF and gas analysis would confirm the source is from a shallow zone rather than the Leduc; this would not pose a threat to CO₂ storage. Enhance would follow the requirements of AER ID 2003-1.

Enhance's detailed review of existing wellbore risks indicates that the first and third scenarios are extremely unlikely, while the second and fourth scenarios have limited likelihood of occurrence.

Cement Top and Bond Log Review

Typical drilling methods at Clive involved cementing the production casing from the total depth up to the Cretaceous Joli Fou and Colorado Shales. This method isolated the producing Leduc and Nisku zones from porous intervals at the base of the Cretaceous. VZFox has reviewed all wells that indicate a cement top to show, on average, Clive existing wells have a cement column of 619m, isolating the Leduc from shallow producing zones (Figure 3-3).

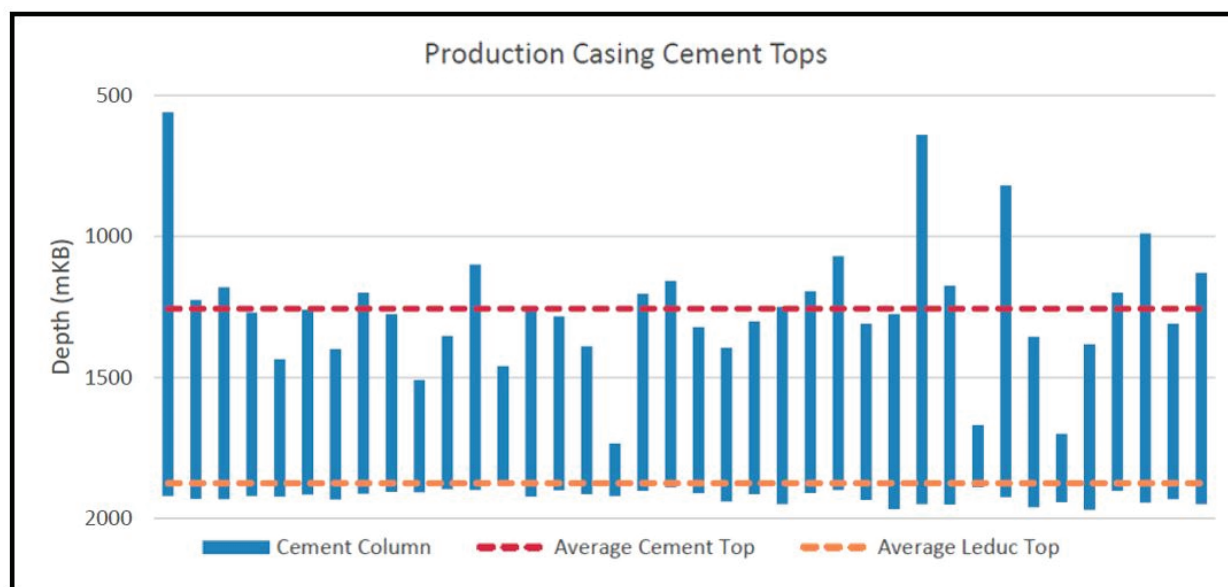


Figure 3-3 Results of Production Casing Cement Tops Review.

Thirty-eight wells indicated cement top depth with an average top at 1,256m Kb. This gives an average cement column of 619m, isolating the Leduc from up-hole zones. Courtesy of VZFox.

Existing CBLs were reviewed to understand cement quality in these wells. CBLs use an acoustic signal to gauge the quality of cement behind the casing. Good cement, as CBLs indicate, provides assurance the cement is an effective seal against fluid migration between the well casing and rock formations.

Enhance has reviewed the available CBLs from 97 existing wells and confirmed they have hydraulic isolation. The Company also provided CBLs from 10 randomly chosen wells to Reliance Oilfield Services for expert review, which confirmed Enhance's analysis.

Surface Casing Vent Flows (SCVF)

A SCVF is the flow of gas out of the surface casing/casing annulus. As the surface casing is purely a secondary barrier to protect from leakage into shallow aquifers, a flow of gas from inside the surface casing indicates a failure of either the well casing or cement (Figure 3-4). Casing breaches are the most common SCVF cause, as failure can be a single point, typically via localized corrosion, above the cement top. In comparison, cement failures are less common, as they require a continuous path of failure between the cement lining and the casing from the reservoir to the cement top. Clive existing wells have an average distance of 619m between the Ireton top and the cement top, rendering this type of failure less likely.

All SCVF events at Clive have been investigated, with particular attention given to sour gas events (containing H₂S) that would suggest Devonian gasses were a component. SCVF of sour gas was noted in only six cases where the casing had failed above the cement top, allowing gas to pass through the breach in the casing and to migrate to the surface casing vent; the wells were not plugged at the time. These wells have been repaired by squeezing cement. All recorded SCVF events were due to casing failure above the cement top (i.e. where the casing was not protected by cement), not cement failure. The absence of any cement-failure-related SCVF confirms existing cement has hydraulically isolated the Leduc for over 50 years. The absence of any casing

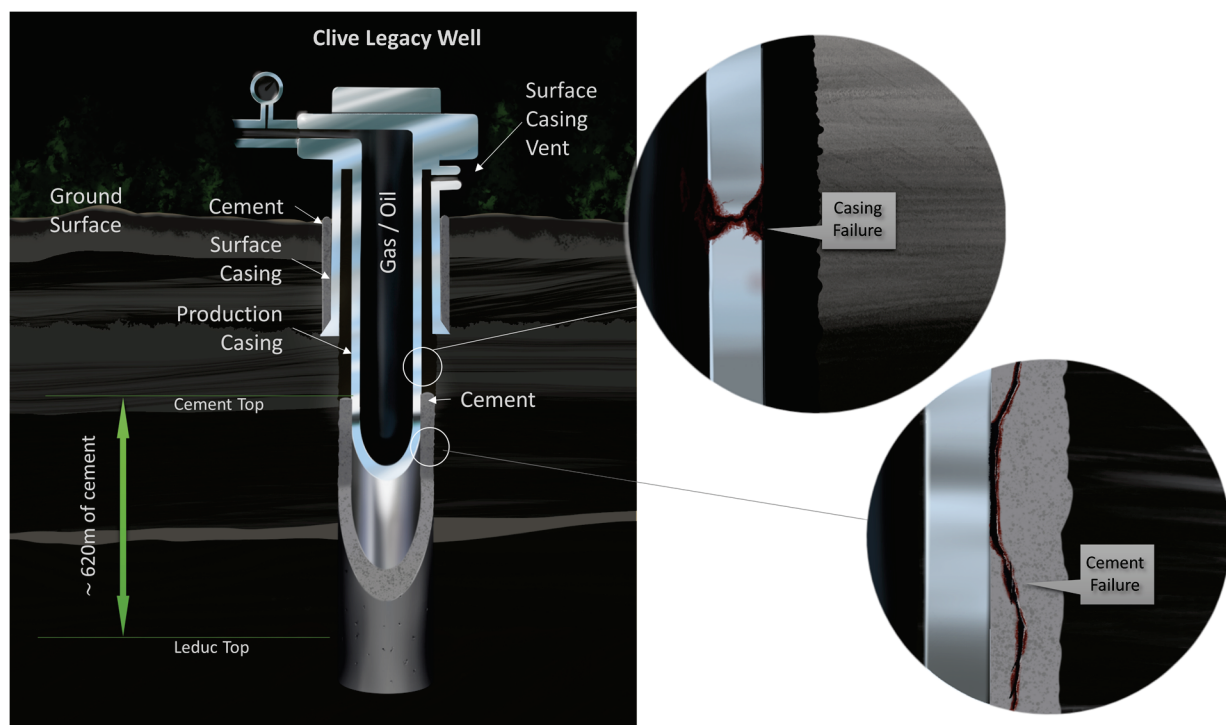


Figure 3-4 Possible Wellbore Leakage Scenarios

Existing wells represent the only possible containment risk. Casing failures accounted for all previous SCVF events at Clive involving sour gas. In each case, the production string was open to Leduc or Nisku fluids. Those fluids escaped via a breach in the production casing, migrated up and were detected at the surface casing vent. Every instance has since been mitigated. Enhance has recorded no instances of a cement failure at Clive. The absence of any cement-failure-related SCVF indicates that existing cement has hydraulically isolated the Leduc for over 50 years.

failures below the cement top also indicates that cement protects the casing from external corrosion. Since cement protects casing from external corrosion and the inside of abandoned wells will be protected by bridge

plugs, cement caps and inhibited fluids, the possibility of casing corrosion will be limited to sections of the well where cement has degraded sufficiently to enable CO₂ to make contact with the steel. Studies by the International Energy Agency (IEA Greenhouse Gas R&D Programme, “Long Term Integrity of CO₂ Storage – Well Abandonment”) concluded that penetration of CO₂ through cement over a 10,000 year period would range from a few centimeters to 12.6 m. This study included a 2007 paper (Carey, *et al.*, 2007) that examined cement cores taken from a 55-year-old well with more than 30 years of CO₂ exposure in the SACROC field in West Texas; the paper concluded that Portland cement will withstand and prevent CO₂ migration. The SACROC field is comparable to the Clive Unit in age, well design, temperature and pressure, although the Clive Unit will be operating at a lower pressure, approximately 14 MPa vs 18 MPa at SACROC. Studies by Watson and Bachu (2007, 2008) have generally concluded that well vintage and CO₂ or H₂S content have little to no influence on leakage potential. Based on these studies and experience to date at Clive, Enhance concludes that properly abandoned wells present a low level of risk of containment failure.

As Enhance brings all existing wells in the Unit up to current AER D-20 requirements, the presence of 30m of cement inside the well and the existing cement columns, minimum 186m identified within the VZFox wellbore risk assessment, will protect the casing from corrosion and provide adequate hydraulic isolation of the uphole horizons.

Enhance has also reviewed existing wellbore surface casing setting depths in the Central Area and found the shallowest surface casing to be set at approximately 190m. The deepest domestic/agricultural water wells in the area are approximately 100m deep. Therefore, the existing wells adequately protect the aquifers that are being used for domestic/agricultural purposes.

EXISTING WELLBORE RISK ASSESSMENT

Enhance retained the services of engineering firm VZFox to undertake a formal third-party risk assessment of existing wells within the **MMV Plan Area** (see **Appendix F**). Wells were investigated for current status,

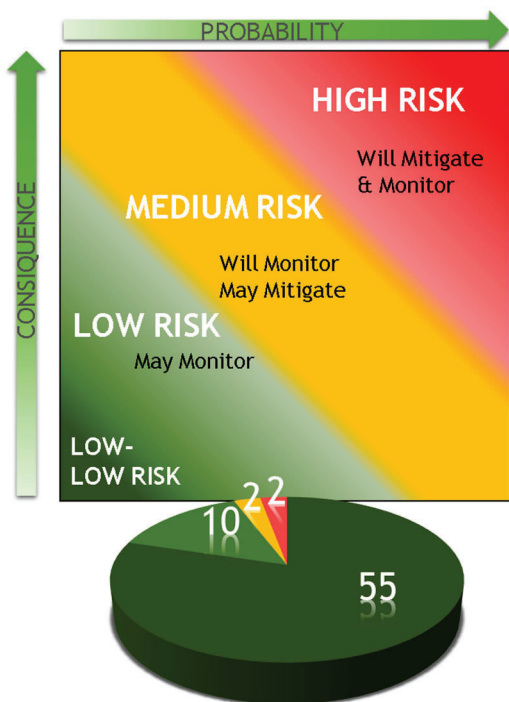


Figure 3-5 Risk Matrix Field

Enhance will identify the risk associated with every existing well and make plans to mitigate and/or monitor each, depending on the need. Enhance’s goal is to move all existing wells into the *Low Risk* category. VZFox assessed 69 wells, including 65 deemed to be, at most, *Low Risk*.

abandonments, abandonment methodology, and casing and cement integrity. At the time of publication, the review-assessed 69 wells within the **MMV Plan Area** (Figure 3-1). Fifty-five of the wells are deemed Low-Low Risk, where the Leduc Zone has been abandoned and the Leduc is hydraulically isolated from zones above. Ten wells are Low Risk, where the Leduc has been suspended with a bridge plug and the Leduc is hydraulically isolated from above zones. All Low Risk wells will be monitored for SCVFs. Two wells are characterized Medium Risk, in which the Leduc Zone is open and capable of production or there may be segregation issues between the Leduc and above Nisku. Finally, VZFox characterized two wells High Risk.

The *Medium Risk* and *High Risk* wells were deemed such because the Leduc Zone is open and capable of production, with the *High Risk* wells in closer proximity (within 800 m) to the new injectors. Enhance will either mitigate these wells to a lower risk category prior to commencement of CO₂ injection, or convert them to monitoring wells as required by the AER in the D-65 EOR Approval.

VZFox advises casing pressures should be regularly monitored for the wells characterized as medium and high risk, wellheads pressures tested, and in the event communication with the injection wells is observed, the Leduc zone be suspended or abandoned with a bridge plug. Enhance will follow the monitoring procedures recommended by VZFox, and is currently evaluating these wellbores for full mitigation to low risk prior to commencement of CO₂ injection.

Inclusive within the risk assessment, VZFox also reviewed coverage of porous intervals in wells with CBL and concluded, in every case, the cement is providing hydraulic isolation between the Leduc and all porous intervals above it. VZFox also concluded that it is reasonable to assume that this isolation holds true for the wells that do not have a CBL.

CONCLUSIONS

Based on the detailed assessments undertaken on existing wellbores at Clive, Enhance submits the following conclusions:

- By meeting or exceeding regulatory compliance governing H₂S, Enhance can demonstrate the highest-possible safety standards for CO₂ containment at Clive.
- Existing wells represent the only possible risk to CO₂ containment at Clive.
- Enhance has completed a comprehensive well-by-well review of existing wells at Clive. All information collected and analyzed during this review concludes that existing and planned abandonments on these wells will mitigate risk of CO₂ containment loss to the maximum practical extent.
- As further assurance, Enhance contracted VZFox Canada, a third-party engineering firm, to facilitate a formal independent risk analysis of all wells in the **MMV Plan Area**. An assessment of wells in the **MMV Plan Area** concluded that 65 wells are *Low Risk* or *Low-Low Risk*, while two wells are *Medium Risk* and two wells are characterized *High Risk*. The *Medium Risk* and *High Risk* wells were deemed such because the Leduc Zone is open and capable of production with the *High Risk* wells simply being closer (within 800 m) to the new injectors. Enhance will either mitigate these wells to a lower risk category prior to commencement of CO₂ injection, or convert them to monitoring wells as required by the AER in the D-65 EOR approval.

- Enhance has completed extensive work evaluating the existing wells within the project area, concluding existing wells present the only possible risk to CO₂ containment, the active monitoring program will focus on these wells.
- Ninety-seven (~60%) of 163 wells in the field were found to have cement bond logs (CBLs), all of which confirmed hydraulic isolation between the Nisku/Leduc and uphole porous zones. The fact that 100% of wells with CBLs proved isolation, combined with the fact that no cases of sour SCVFs have been noted due to cement failure over the life of the field, supports the conclusion that the Nisku/Leduc is hydraulically isolated from uphole horizons in all existing wells. An independent Engineering assessment completed by VZFox confirmed this conclusion.
- Existing wells not in compliance with AER D-20 requirements will be brought into compliance as the project progresses. As per the AER D-65 EOR Approval, all non-abandoned wells that are completed in the Leduc and/or Nisku zones and within the approval area must be abandoned to Level A method in accordance with Directive 20 upon completion of the CO₂ operations.

4 CENTRAL CLIVE LEDUC AREA MEASUREMENT, MONITORING AND VERIFICATION (MMV) PLAN

The MMV plan outlines actions and responsibilities Enhance will undertake to ensure the Clive Leduc pool is safe for long-term storage of CO₂. Enhance has developed this plan in consultation with industry experts and consideration of current literature. The MMV plan has been designed to account for the Clive Leduc reservoir's unique setting and the characteristics of CO₂ EOR.

Protecting the environment, particularly soil, potable water sources and atmospheric emission, is the MMV Plan's primary purpose at Clive. Enhance also has financial incentive to effectively utilize every tonne of CO₂ for EOR. In the context of EOR, high-purity CO₂ is a commodity that requires resources and infrastructure, resulting in cost to the operator. Therefore, dual incentives – environmental protection and good resource management – drive the need for careful monitoring and accounting of CO₂ in the reservoir.

The MMV plan is built upon passive safeguards that will ensure safe, long-term storage. The plan utilizes a proven existing geological hydrodynamic trap in the Clive Leduc pool. The sealing Ireton Formation has prevented upward migration of oil and gas from the Leduc for millions of years – and will offer the same containment for future CO₂ storage. Above the Ireton, impenetrable and self-sealing anhydrite sheets cap another hydrocarbon trap in the Nisku, providing a secondary level of containment. Above this, numerous aquitards and aquifers present barriers to upward migration of fluids, ensuring the probability of CO₂ migration into potable water through natural pathways is effectively zero. By safely managing the EOR scheme – in particular, maintaining reservoir pressure to below original levels -- Enhance will preserve these inherent safeguards throughout the project's lifetime.

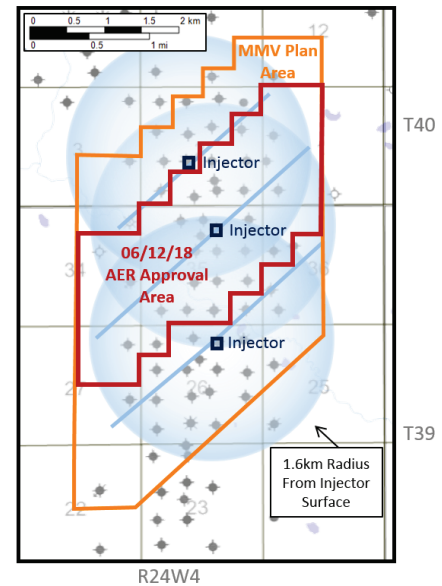
Enhance and AITF have identified existing wellbore leakage as the only possible containment risk associated with the project. Enhance has mitigated, and will continue to mitigate, this risk and will undertake a monitoring program designed to verify and provide confidence in containment.

The monitoring component of the project will encompass every geological level, from the reservoir to the surface, and include a variety of techniques. Prior to injection, a **BASELINE** of carbon isotope samples will be taken to serve as a carbon fingerprint database. These samples will then be compared to both injected gas samples and future samples of unknown origin, should the need arise. Reservoir monitoring and simulation will ensure the Leduc responds within expected parameters to the introduction of CO₂. Furthermore, Nisku Formation production monitoring will verify Ireton seal containment. Shallow production monitoring in the Cretaceous CBM zones will monitor CO₂ at the **BASE OF GROUNDWATER PROTECTION (BGWP)**. Sampling domestic potable water wells and dedicated monitoring wells will ensure public safety and confidence in containment. Soil gas sampling will take place throughout the **MMV Plan Area** as to give full public assurance. As wellbores have been identified as the only possible risk to containment, they will be the main focus of monitoring efforts; all wellheads will be monitored for surface casing vent flow events, as this is the most probable outcome of downhole failure. At surface, **SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA)** systems will monitor and shut down injection wells, should a failure be detected. Air quality and safety systems designed to alert and prevent an escape of H₂S, which is present in Leduc and Nisku production, will inherently monitor for CO₂ leakage.

AER D-65 EOR APPROVAL

In December 2018, the Alberta Energy Regulator granted Scheme Approval No. 12832 for enhanced recovery of oil by miscible displacement using miscible fluid (CO₂) and/or water injection in the Clive D-3 A (Leduc) Pool and containment of CO₂ within the Clive D-3 A and D-2 A (Nisku) Pools. The December 2018 Approval Area is incorporated entirely within the boundary of the MMV Plan Area (See Right). Prior to CO₂ injection, Enhance will apply to expand the AER Approval Area to coincide with the MMV Plan Area.

The approval is subject to several terms and conditions. Many of these conditions are specifically stated within the MMV Plan. Inherent within Enhance's MMV Plan is to meet or exceed all conditions specified within the approval, or subsequent amendments to the approval. The full details of the conditions contained with the AER D-65 Approval is included within the MMV Plan as **Appendix N**.



The approval specifies 1) required baseline and project data gathering requirements in the Leduc, Nisku, overlying aquifers and CBM, 2) baseline seismic data and reservoir simulation requirements, 3) deep Leduc and Nisku monitoring well requirements, 4) minimum reservoir operating pressures to ensure miscibility is achieved and maximum reservoir pressure constraint to ensure cap rock integrity maintained, 5) injection wellbore design and operational monitoring requirements.

Prior to commencement of CO₂ injection, the approval requires Enhance to complete and submit a risk assessment of all the Leduc and/or Nisku wells, including abandoned, suspended or active, in the approval area to assess the possibility of leakage based on the vintage of the wells, diagnostic tools run and abandonment practice applied (including porous zone isolation). Wellbores found to have medium and high risks as detailed within the MMV Plan should be mitigated prior to the expected time of CO₂ reaching the locations.

All suspended wells that are completed in the Leduc and/or Nisku zones and within the Approval Area must meet the High-Risk Type 2 suspension requirements of Directive 013 prior to commencement of CO₂ injection.

All non-abandoned wells that are completed in the Leduc and/or Nisku zones and within the approval area must be abandoned to Level A method in accordance with Directive 20 upon completion of the CO₂ operations. The abandonment program must be submitted to the Closure & Liability (Oil & Gas) Group in the AER Closure and Liability Branch and approved by the AER.

As specified in Clause 4)I) of the approval, if injection facilitates the movement of injected fluids into any zone above the base of groundwater protection or any zone other than the Leduc and Nisku zones, Enhance will immediately inform the Resource Compliance Group in the AER Environmental & Operational Performance Branch, and the AER Red Deer Field Centre.

Clause 9 of the approval provides detailed requirements for annual reporting and presentation on the CO₂ EOR scheme to the Resource Compliance Group in the AER Environmental & Operational Performance Branch. The first report is required within one year of commencement of injection.

ENVIRONMENTS AND AREA OF OBSERVATION

In terms of monitoring, five environments are discussed: reservoir, geosphere, hydrosphere, biosphere and atmosphere (Figure 4-1). The reservoir is defined as the area that hydrocarbon accumulation dominates – the Leduc reservoir – whereas the geosphere is everything else in the deep subsurface that brines dominate. The hydrosphere overlies the geosphere from the BGWP, locally defined by the AER as the Base of the Edmonton Group, at approximately 500-600m to the surface. The biosphere comprises soils and surface biota, while the atmosphere overlaps this environment, up from the surface.

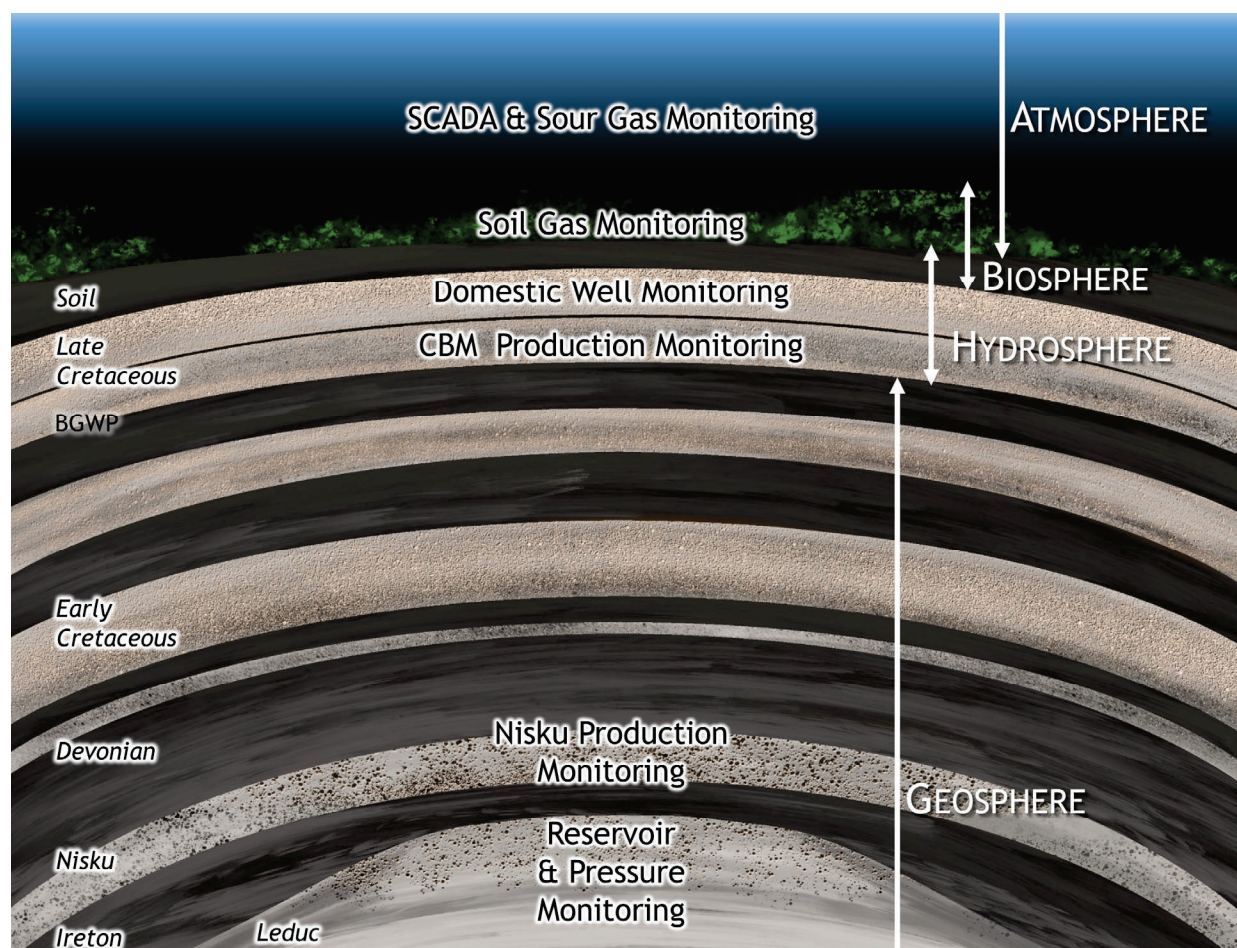


Figure 4-1 The Clive MMV Plan's Fluid Environments and Observation Targets

The MMV plan targets key intervals around the reservoir, geosphere, hydrosphere, biosphere and atmosphere. Deep geosphere observation is established through careful Leduc and Nisku production monitoring, as well as Leduc pressure monitoring. A series of safeguards – CBM, domestic water wells and soil gas monitoring – protects the hydrosphere and biosphere shallow aquifer systems. The continued use of H₂S monitoring will provide atmospheric monitoring in key areas.

RISK ASSESSMENT

Enhance has undertaken a formal risk assessment of the Clive project in order to select appropriate monitoring techniques. The focus of the risk assessment is the failure of the Clive Leduc reservoir to contain the CO₂, resulting in leakage into the geosphere, hydrosphere, biosphere or atmosphere. Expertise in all areas of project development were utilized in this assessment, including CO₂ EOR, drilling, completions and workovers, geology,

geo-modelling, geomechanics, reservoir engineering, reservoir simulation and project development. Furthermore, the assessment was informed by studies conducted internally by Enhance Energy, AITF and VZFox. A total of 61 possible leakage scenarios through geological and wellbore pathways were categorized by the two deterministic properties of risk; probability and consequence, and the resulting assessment is summarized in the matrix shown in Figure 4-2. The risk assessment is produced in full in **Appendix G**.

In describing safeguards within the MMV plan, it is necessary to evaluate **RISK** as a product of **PROBABILITY OF OCCURRENCE AND CONSEQUENCE**, where some degree of both components must be present to establish meaningful risk. Numerical values of probability and consequence were assigned as follows:

PROBABILITY:

1. Extremely unlikely to occur
2. Unlikely to occur
3. Chance of taking place
4. Likely to occur
5. Almost certain to manifest

CONSEQUENCE:

1. No Impact
2. Leak identified and mitigated
3. Contained to geosphere with no environmental impact
4. Potential temporary shut-down of pattern or project resulting from environmental concern
5. Unacceptable environmental impact with no feasible mitigation

Final risk scores were calculated by multiplying the probability ranking by the consequence ranking.

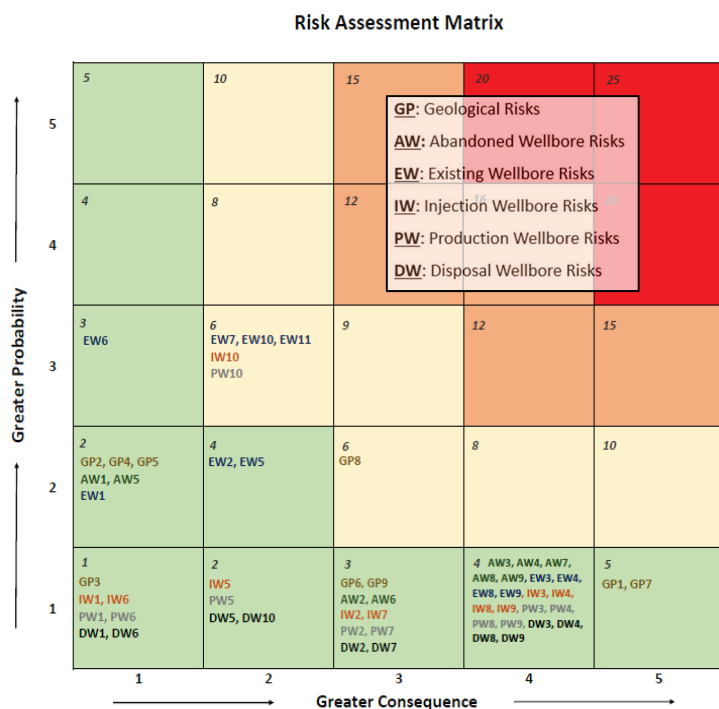


Figure 4-2: Risk Assessment Matrix

Green: Low Risk- 1/25 to 5/25; extremely unlikely to occur and/or low consequence. No monitoring or mitigation required.

Yellow: Medium Low Risk – 6/25 to 10/25; some probability of occurrence and/or high consequence. Monitoring required.

Orange: Medium High Risk 11/25 to 15/25; reasonable chance of occurrence with higher consequences. Mitigation and/or monitoring required.

Red: High Risk - Score exceeding 20/25; high probability of occurrence and high consequence. Mitigation required.

There are no high or medium high-risk scenarios identified in the Clive EOR scheme.

Six scenarios received the Medium-Low *risk score* value of 6 out of 25. Three of these scenarios related to existing wellbores, particularly, casing failure into a saline aquifer (EW7) or atmosphere (EW10), and a possible leak at the wellhead (EW11). In these cases, historical records show that similar failure types have occurred at Clive, justifying a *probability score* of 3/5. The consequence score for each scenario was 2/5, reflecting the likely speed of detection based on planned monitoring, and a variety of engineering mitigation options available. Two scenarios depicting leakage in new wellheads for production and injection wells, scored a *Risk level* of 6/25 (IW10, PW10). As with existing wellbores, historical evidence suggests that there is a chance of leakage, this time with the installation of new equipment, however, in-place monitoring will quickly detect a leak of this type and mitigation options are available. The last of the six Medium Low Risk scenarios is that of CO₂ loss through migration beyond the reservoir spill point (GP8). Clive's spill point is in the south end of the field with its boundary to the Haynes D3 Pool. Aside from the actual loss of containment, there is unlikely to be any environmental damage, as any leak would be absorbed into the vast Bashaw Platform aquifer. Probability of occurrence of spill point loss is low, as this type of containment breach can be prevented by close reservoir supervision.

Monitoring Tool Cost Benefit Analysis and Selection

Selection of monitoring techniques for Clive was driven by the unique characteristics of the reservoir, geology, existing infrastructure and the planned CO₂ EOR and storage process, guided by the formal risk assessment and studies by AITF. Some of the potential monitoring techniques considered were based on the National Energy Technology Laboratory (NETL) Best Practices Manual for Monitoring (BPM), Verification, and Accounting (MVA) for Geologic Storage Projects 2017 Revised Edition ([BPM-MVA-2012.pdf](#)). As the BPM was written for geologic storage projects it does not include additional techniques available for CO₂ EOR; these were also included in the selection process. The Monitoring Tool Cost Benefit Analysis and Selection are reproduced in full in **Appendix H**. The selected monitoring techniques are discussed in the remainder of this section.

As Clive is a sour field (H₂S present) and will be a CO₂ EOR field, a number of techniques are mandated by regulation for safety and flood management. These techniques include H₂S detection, monitoring of new injection and production wells drilled for the project, monitoring of existing production wells (Nisku and Leduc), monitoring of zonally abandoned existing wells and ongoing simulation and history matching of the flood response. Enhance will meet or exceed regulatory requirements. Since these techniques provide a strong foundation of monitoring techniques, additional methods were evaluated on both a stand-alone basis and based on the incremental cost and benefit provided.

Tools and procedures selected prior to the commencement of the EOR flood are considered to be relevant to that stage of development. Over time, all tools should be evaluated for effectiveness and assessed on an ongoing basis.

Routine Monitoring Techniques

Routine Monitoring Techniques encompass those techniques that Enhance has chosen to implement for baseline and ongoing monitoring. Should these techniques identify a possible containment issue or trigger

event that cannot be resolved using the information that they provide, additional or contingent methods can be employed. Some potential contingent techniques are discussed in the ‘Monitoring Techniques Considered but Deemed Unnecessary’ section.

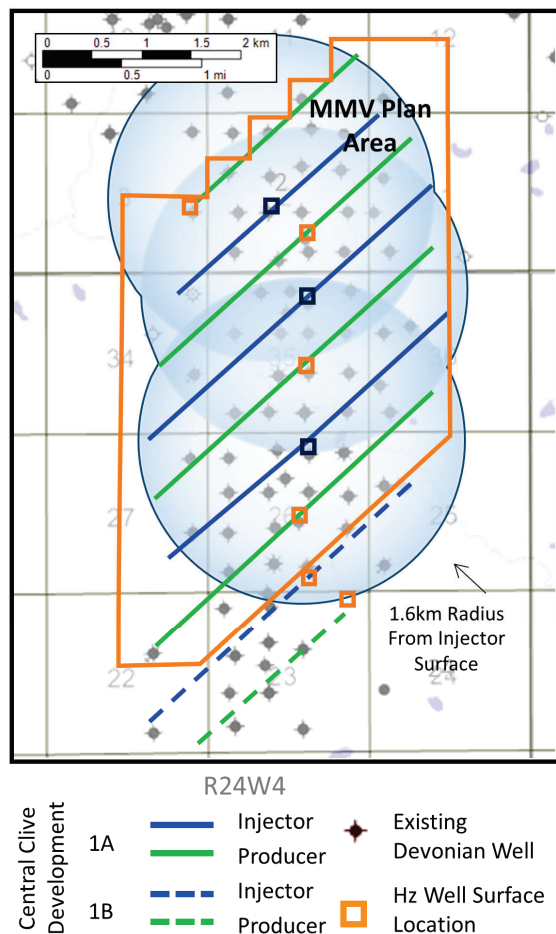


Figure 4-3: Phase 1 Monitoring Area

Enhance will focus monitoring efforts within a 1.6 km radius around the planned injection well surface locations, as the injection wells will represent the highest-pressure points during EOR operations.

Geographic Area Extent of Monitoring

Enhance will focus monitoring efforts within a 1.6 km radius around the planned injection well surface locations, as the injection wells will represent the highest-pressure points during EOR operations. Due to the structural trap’s relatively narrow nature, the 1.6 km radius will essentially cover the entire reservoir (Figure 4-3).

Carbon Isotope Analysis

Enhance will establish a baseline analysis of $\delta^{13}\text{C}$ and ^{14}C contained within the source CO_2 prior to injection and compare it to baseline $\delta^{13}\text{C}$ and ^{14}C in produced gas CO_2 from existing Leduc, Nisku and CBM wells, soil gas and headspace gas from domestic water wells, and dissolved inorganic carbon (DIC) in water samples.

Different CO_2 sources may exhibit different amounts of radioactive carbon isotopes ($\delta^{13}\text{C}$ and ^{14}C) that effectively allow samples to be fingerprinted. ^{14}C can also be used to differentiate **BIOGENIC** and **PETROGENIC** sources. The ratio of CO_2 to O_2 and N_2 in samples can also provide independent attribution to the source of CO_2 in soil gas samples (discussed further in the **Soil Gas Monitoring** section).

RESERVOIR MONITORING

Active Reservoir Monitoring and Simulation

Enhance has constructed detailed geological and reservoir models of the entire Clive Central Area. These models have been validated through history matching and will be used as an active tool for reservoir management, and for containment and conformance monitoring. As the CO_2 flood continues to progress, the compositional simulation model will enable Enhance to conduct further history matching to actual CO_2 flood performance. Not only is history matching a useful tool for flood optimization, but ‘anomalies vs. expected’ performance can also serve as a means of detecting issues with CO_2 conformance or containment.

To illustrate how simulation could detect issues with containment or conformance, Enhance ran a scenario on 10% leakage of CO₂. The leakage is quickly reflected in actual vs. expected gas-to-liquids ratio response for the production wells offset to the injectors (Figure 4-4, left). Similar differences can be seen in instantaneous oil response (Figure 4-4, right). If the actual delayed response could not be matched by reasonable adjustments to the model, an indication of potential containment or conformance issues would be identified and Enhance would investigate and evaluate data from other monitoring techniques.

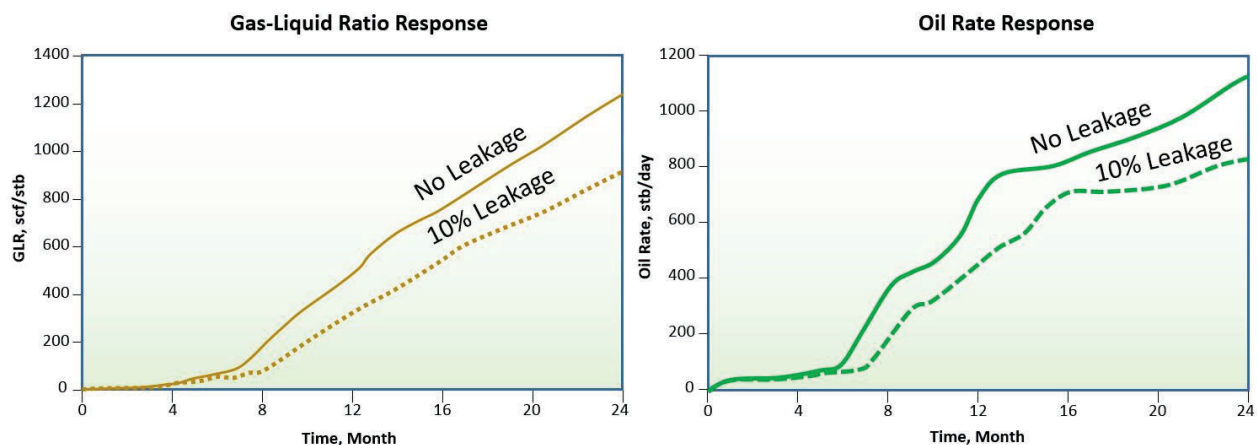


Figure 4-4: Simulation of 10% Leakage Scenario

At left, predicted gas-liquid ratio, base case and 10% leakage results show Enhance's simulation model will quickly identify issues with CO₂ conformance or containment. The difference between the actual and expected gas-to-liquids ratio response in producing wells would trigger investigation. At right, predicted oil rate, base case and 10% leakage simulations show that, similarly, differences in actual and expected oil rate responses in producing wells would indicate potential containment issues and prompt further investigation.

The AER has recognized the importance of simulation modelling as a monitoring tool for the CO₂ injection project, the D-65 EOR Approval requires Enhance to complete a history match for the Leduc reservoir in the Approval Area prior to commencement of CO₂ injection. Enhance is required to update reservoir simulations in the Approval Area annually, the frequency is to be re-evaluated after two years. Progress reports must be provided to the Resource Compliance Group in the AER Environmental & Operational Performance Branch annually, including CO₂ plume extent and pressure distribution models.

Injection Well Pressure Monitoring

Simulation modeling predicts the CO₂ flood will operate approximately 20% below original reservoir pressure, and the peak maximum pressure at an injection well to be approximately 5,100 kPa above the average reservoir pressure, operating safely below formation fracture pressure. The pressure at these wells will be continuously monitored and will not exceed the reservoir or seal fracture pressure (simulation shows the peak injection pressure to be approximately 55% of the mean formation fracturing pressure). Furthermore, the injection wells themselves will be constructed to meet or exceed regulatory requirements, resulting in minimal leakage risk. Enhance is required by the AER D-65 EOR Approval to provide evidence that the most suitable surface and downhole casing, tubulars and equipment are employed in the new wells drilled for injection.

As per the AER D-65 EOR Approval, Enhance must immediately report any loss of containment, anomalies that indicate fracturing out of the Leduc and Nisku formations, or anomalous pressure changes occurring anywhere within the Clive D-3 A Pool to Resource Compliance.

Project injection wells will be equipped with continuous monitoring of pressure on the injection string and annulus at the wellhead. Output will be tied to the project's SCADA system, which will be continuously monitored and set to alarm if pressures fall outside expected operating ranges or experience sudden changes not correlated to changes in injection volume. Continuous monitoring will provide immediate indication of any issues with these wells so that remedial action can occur.

Integrity of the injection wells will be further verified by annual packer isolation tests and zonal isolation logging every five years.

Measuring Produced and Injected Fluid Volumes

Enhance will follow approved oilfield well test and measurement techniques to ensure produced and injected fluid volumes are accurately measured. In AER's Directive 17, standards are established for what and how volumes must be measured and the expected level of measurement accuracy. While based on a regulatory requirement, it is a necessary component of field monitoring and provides a basis for flood management, as well as for reservoir simulation model updates to improve recovery and storage while monitoring for containment issues.

Analyzing Produced, Recycle and Source Gas

Gas sourced from Nutrien and NWR will be analyzed annually for carbon isotopes and continuously for CO₂ concentration. An extensive database of historical analyses from the Nutrien source is provided in **Appendix I**, it is expected to be 99% pure CO₂ with traces of CH₄, H₂ and N₂. It is expected that the NWR CO₂ stream will be 99.5% CO₂ with traces of H₂, CO, CH₄, N₂, MeOH and AR. Likewise, gas produced at individual production wells will be sampled quarterly and the composite recycle stream sampled monthly. These gases will contain increasing proportions of the reservoir gas (which consists primarily of CH₄, C₂-C₆, H₂S and CO₂) as the EOR project progresses. Understanding the gas stream compositions aids in identifying the source of any anomalous readings from the active monitoring techniques. Baseline gas analysis of existing Leduc producers will include isotopic testing.

GEOSPHERE MONITORING

Nisku Monitoring Wells

Monitoring the overlying Nisku will verify Ireton seal containment. Enhance will use a combination of passive and active Nisku monitoring wells within the **MMV Plan Area**. The designated Nisku monitoring wells and requirements are prescribed within the AER D-65 EOR Approval (**Appendix N**), they are:

- 02/02-35-039-24W4/02
- 00/16-02-040-24W4/00
- 00/01-02-040-24W4/02
- 00/12-01-040-24W4/02

Baseline data will include Nisku water chemistry, reservoir pressure and carbon isotope signature ($\delta^{13}\text{C}$ and ^{14}C) in the produced gas. During the monitoring phase reservoir pressure will be obtained annually in

accordance with AER D-40 requirements, annual isotope analysis ($\delta^{13}\text{C}$ and ^{14}C) on the produced fluids and bi-annual gas samples for chemical compositional analysis.

Enhance will immediately inform the Resource Compliance Group in the AER Environmental & Operational Performance Branch if the injection into the Leduc facilitates the movement of fluids into the Nisku zone, observed in any Nisku monitoring well. If an event was triggered, Enhance would continue to monitor the movement of fluids within the Nisku zone while taking direction from the AER to continue, suspend, or reverse the injection.

Leduc Monitoring Well

Enhance has identified an existing Leduc vertical well, located within the **MMV Plan Area** at 00/10-35-039-24W4/0, that will be utilized as a Leduc monitoring well. Enhance will continue to produce this well until economically viable, and thereafter convert to a static monitoring well.

As per the AER D-65 EOR Approval, Enhance will include Leduc water chemistry, reservoir pressure and carbon isotope signature ($\delta^{13}\text{C}$ and ^{14}C) in the produced gas as baseline data gathering requirements. During the monitoring phase reservoir pressure will be obtained annually in accordance with AER D-40 requirements and bi-annual gas samples for chemical compositional analysis.

Gas Chromatograph Logging of New Drills

Gas chromatographic logging instrumentation will be employed during the drilling of Enhance's first three wells (03/06-02-40-24W4, 16-02-40-24W4 and 15-34-39-24W4) to record various gas concentrations throughout the subsurface. This continuous gas sampling analyzed for $\text{C}_1\text{-C}_5$ (i.e. methane, ethane, propane, butane, pentane and hexane, which are low-density hydrocarbons), including isomers (different arrangements of the hydrogen and carbon atoms) and CO_2 . This data will be added to the baseline library for consultation in the event of a future anomaly.

Seismic Baseline Gathering

Enhance has obtained a 2004 3D Seismic program across a large portion of the Clive Field (Figure 4-5), including the entire **MMV Plan Area**. This survey will act as a baseline for comparison if an event triggers requirement for further investigating into possible containment loss into shallower porous intervals.

As per the AER D-65 EOR Approval, Enhance will evaluate the baseline seismic data to indicate that no faults transect the seals in the Approval Area.

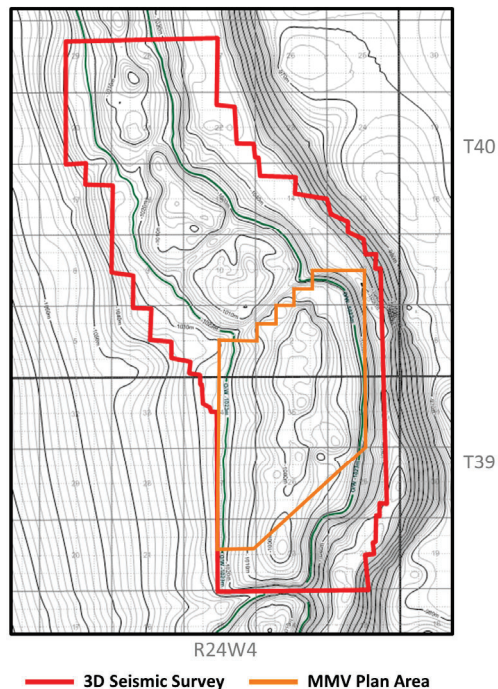


Figure 4-5: Location of Enhance's 3D Seismic Survey

A geophysical study was undertaken at Clive to investigate the geophysical response of entry of CO₂ into various stratigraphic intervals (Leduc reservoir, Mannville, Viking, Belly River). The study report is attached as **Appendix J**. Seismic response is determined by the physical and elastic properties of rocks and their constituent fluids. If the reservoir changes from a static to dynamic state, changes in pressure, temperature, and fluid content can cause measurable changes to the seismic response.

At Clive, the trade 3D survey serves as the baseline, and various concentrations of CO₂ fluid replacement modelling was conducted to determine at what concentration, and in what zones would CO₂ injection result in a change in the seismic response. This would allow the determination of CO₂ movement outside of the reservoir zone. Fluid replacement modelling was used to determine the theoretical response of adding varying concentrations of CO₂ as a function of total reservoir fluid at *InSitu* temperatures and pressure. An example synthetic trace from the study in Figure 4-6 shows modelled responses of CO₂ emplacement into the Mannville, Viking and Belly River intervals, based off the 100/06-02-040-24W4 sonic and density

logs. In the Leduc and Nisku reservoirs, as the effective pressure is such that the CO₂ remains in a liquid state, the slight change in bulk modulus (replacing a portion of one liquid with a different liquid with similar physical properties) results in a very slight change in the acoustic impedance. The strength of signal by the fluid change may not necessarily be identifiable by comparison with a new 3D shoot. However, in the shallower horizons (Mannville, Viking and Belly River) as the effective pressure on the fluids in the reservoir lessens and causes the CO₂ to transition to a gaseous state, the bulk modulus of the reservoir is reduced significantly, resulting in a more pronounced seismic response.

There are considerations to be made when translating from model to real world application. The primary of these is the use of an existing trade seismic survey as a baseline. Best results for '4D seismic' are typically gained when baseline and repeat shoots are acquired with the same method and spacing. Divergence from this ideal will result in noise created by the differences in acquisition that have no association with the underlying strata. In order to justify the use of trade data, it is important that the signal of CO₂ emplacement is stronger than the expected noise. This study suggests that a weaker signal in the Nisku and Leduc intervals, a product of CO₂ maintained in a liquid state and a very low porosity, will be difficult to interpret by comparing the 2004 baseline shoot with a future 3D. However, the combination of CO₂ filling far greater pore space in a gaseous state in shallower Cretaceous zone would result in a far stronger signal to noise ratio, and would make detection and even quantification of CO₂ possible.

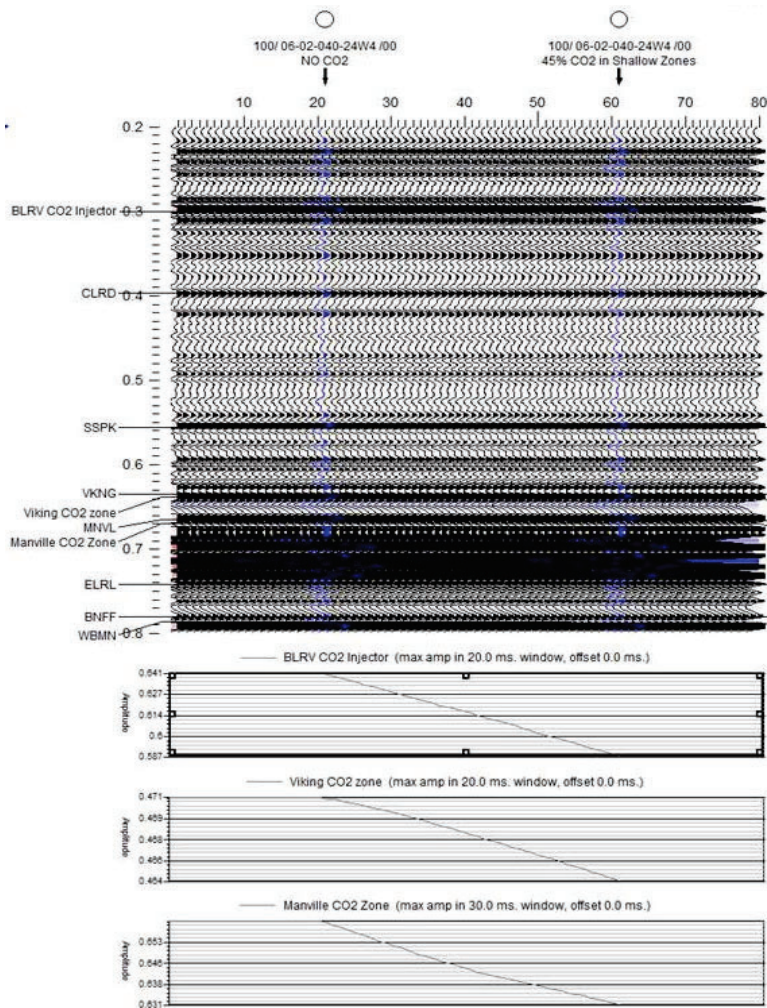


Figure 4-6: Amplitude response to fluid change in three shallow porous intervals above the Clive Leduc Field. Modelling based of the central Clive location of 100/06-02-040-24W4

The results of the Seismic Study show that a leak into any of the Cretaceous porous zones would be detectable as a marked amplitude change from the 3D Seismic Baseline. The strength of the expected amplitude change is significant enough to surpass noise generated by differences in acquisition, rendering the acquired 3D seismic baseline suitable to task.

Availability of the 2004 Clive 3D gives Enhance the option for a future 4D investigation. If widespread leakage of CO₂ into shallow intervals were suspected at Clive, and no other monitoring methods were able to adequately describe the extent of loss, Enhance would be able to shoot a new survey for comparison and to create a snapshot of fluid distribution at that time. The study outlined above suggests that this would prove an effective tool in determining CO₂ distribution and concentrations in shallow zones, if the need arose.

HYDROSPHERE MONITORING

The protection afforded to the geosphere will, for the most part, be inherent for the hydrosphere. However, due to the consequences of contamination, it is necessary to add further safeguards. The purpose of the groundwater monitoring program is to establish baseline conditions for groundwater quality in the area, which can then be compared to sampling during the project conditions in the event of possible CO₂ migration.

From the Base of Groundwater Protection at around 600m depth to the surface, hydrosphere monitoring program will commence on three fronts; Coalbed Methane Monitoring, Landowner Water Well Monitoring and a Dedicated Groundwater Monitoring Well nest, located in the center of the **MMV Plan Area**.

Coal Bed Methane (CBM) Monitoring

CBM production in the area offers an excellent opportunity to provide sampling over a large area from geological horizons above the EOR complex. CBM wells will sample three geological horizons, namely the Belly River, Edmonton and Horseshoe Canyon. CBM wells are generally completed within, the BGWP at 600m depth (Figure 4-7) having an average depth of approximately 450 m.

Enhance operates compression on behalf of the CBM operator and has extensive historical records of CBM sales gas analysis on a monthly basis. Enhance will continue to collect this data but will also collect data from a more focused area largely coincident with the **MMV Plan Area**. This more focused sampling is possible as the CBM gas gathering system collects from segregated areas in the Clive area; one of these collection areas largely overlays the **MMV Plan Area**. As shown by the existing analyses, the CBM gas has a stable composition, contains little CO₂ (<0.2%) and no detectable H₂S, making monitoring of CBM well gas analyses an ideal early detection tool for loss of CO₂ containment before it can reach the shallow hydrosphere. CBM well sampling over a wide area will provide a reliable method of detecting CO₂ containment loss while the gas is still within hydrocarbon-producing horizons. This monitoring technique has a high probability of identifying containment loss, such that leakage can be mitigated prior to any impacts on the biosphere or the shallower hydrosphere.

Enhance will gather baseline carbon isotopes. During project operations, Enhance will sample annually for isotopic analysis and monthly for gas composition.

Registered Landowner Water Well Monitoring

Landowner water well selection and monitoring methods are detailed in full in **Appendix L: Baseline Shallow Groundwater Monitoring**. The selection of Landowner water wells for baseline groundwater monitoring included the following approach:

- Review the hydrogeological conditions of the project area to identify sampling locations that are representative of the local groundwater system;

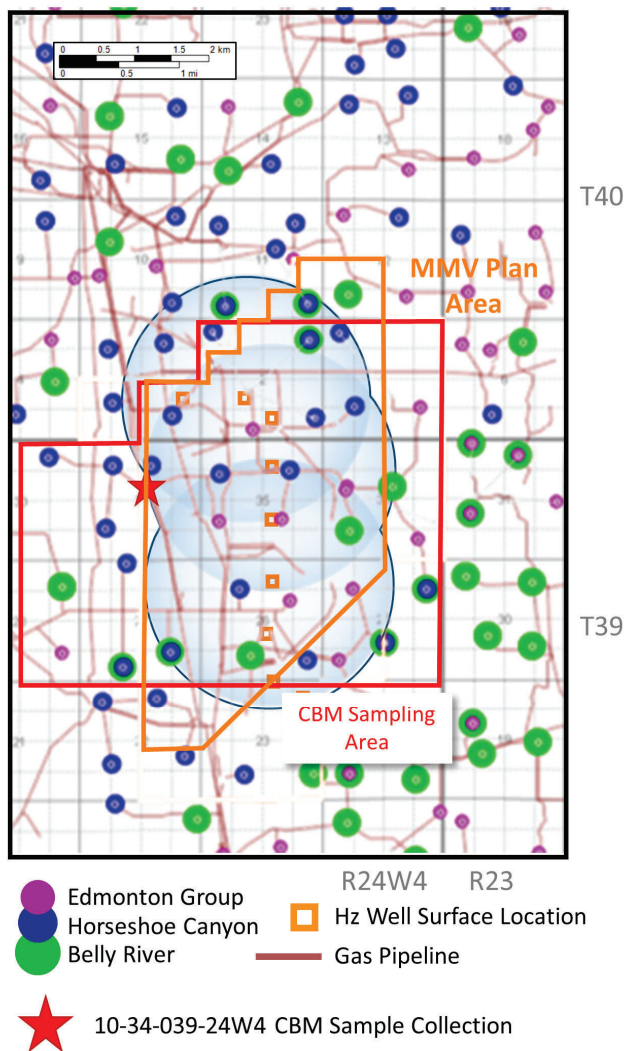
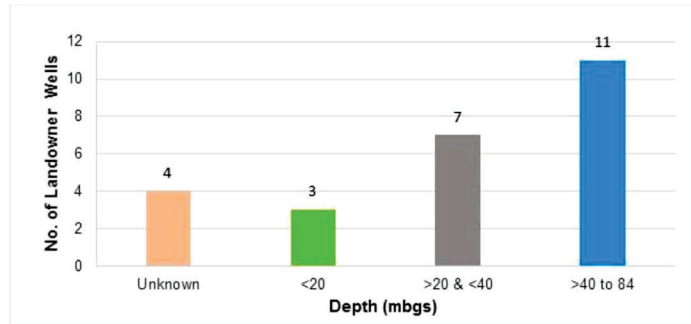


Figure 4-7: CBM Wells and Phase 1 Monitoring Area

Active coal bed methane wells within the **MMV Plan Area** will provide an excellent opportunity to sample produced gas from zones above the EOR complex. This monitoring technique will provide independent and complementary assurance of CO₂ containment.

- identify all registered water wells within 1.6km radius from the injection pad sites;
- review available water well drilling reports to identify completion zones; and
- select Landowner water wells that are representative of local hydrogeological conditions and are spatially distributed throughout the project area.

According to Alberta's Water Well Information Database (AEP WWID 2019, internet site), there are currently 45 registered water wells within a 1.6-km radius from the Project injection well pads. Of these, 25 were completed for domestic and/or stock use. The remaining wells (20) are listed as being primarily for industrial (17) purposes, as well as investigation (1), other (1) or unknown (1).



Based on the available drilling reports, the depth of the Landowner water wells (domestic & stock) ranges between 15 and 84 mbgs, with the majority (18) being completed in upper bedrock and below 20 mbgs. Figure 4-8 illustrates the number of Landowner water wells (domestic & stock) for different reported depths, including: <20 mbgs, >20 and <40 mbgs, >40 to 84 mbgs, and unknown.

Selected Landowner Water Wells

A review of the hydrogeological information and the available water well drilling reports indicated that most Landowner water wells within the **MMV Plan Area** are completed in the Lower Lacombe Aquifer or Haynes Aquifer, both of which are members of the Paskapoo Formation. On this basis, a representative number (>25%) of Landowner water wells were selected for each depth ranges outlined earlier (i.e., <20 mbgs, >20 and <40 mbgs, >40 to 84 mbgs). In total, nine Landowner water wells (36% of the total wells) have been selected for

GIC Well ID ^(a)	BWWT	CBM Testing	Reported Depth (m)	Drainage Basin	Inferred Surface Bedrock Geology ^(b)
97476	-	-	42.67	Red Deer River Near Nevis	Haynes
97505	1163875	Yes	27.43	Red Deer River Near Nevis	Lacombe
159670	1208075 & 2002341	Yes	24.38	Red Deer River Near Nevis	Lacombe
273119	-	-	15.24	Red Deer River Near Nevis	Lacombe
273122	-	-	73.15	Red Deer River Near Nevis	Haynes
273147	-	-	18.29	Red Deer River Near Nevis	Surficial deposits & Lacombe
286609	1194455	Yes	78.64	Red Deer River Near Nevis	Haynes
290202	-	-	73.15	Red Deer River Near Nevis	Haynes
297942	-	-	54.86	Red Deer River Near Nevis	Haynes

Notes:

^(a) GIC – Groundwater Information Centre; BWWT – baseline water well testing; "-" unknown

^(b) Inferred well completion bedrock geology based on reported water well depth and/or bedrock geologic map

baseline groundwater monitoring. The wells are representative of local geological conditions, are spatially distributed throughout the area of interest at a density of about four wells per 1.6-km radius, cover the depth range of domestic wells, and include the two members of the Paskapoo Formation that are intersected by the registered domestic wells. A list of the selected wells is included in Table 4-1 and the associated drilling reports are attached.

The locations of the selected nine Landowner water wells are illustrated in Figure 4-9. It should be noted that the selected Landowner water wells may be subject to change following an assessment of their current condition and/or Landowner commitment to participate in the baseline monitoring program.

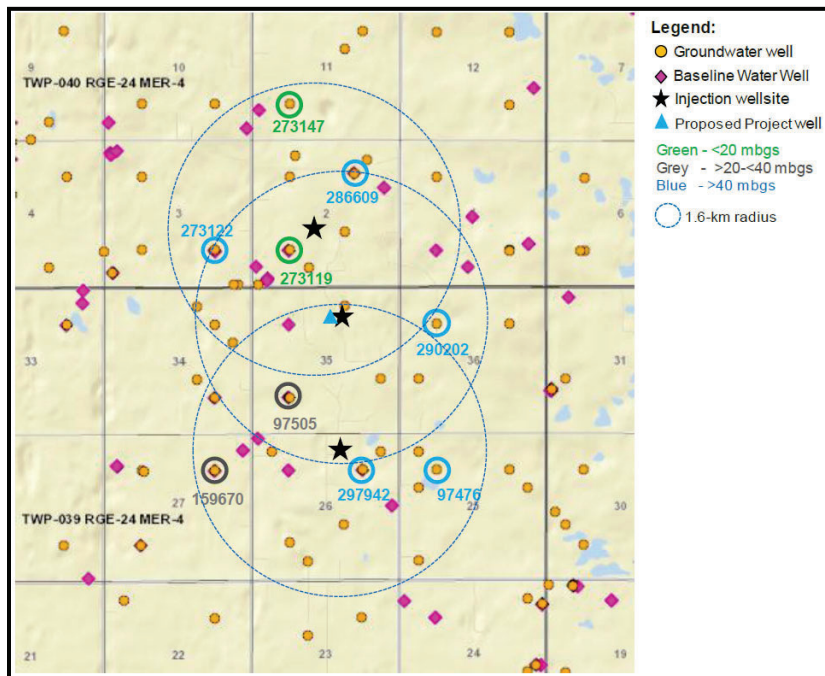


Figure 4-9: Location of Selected Domestic Water Wells for Baseline Monitoring (WWID 2019, internet site)

Water will be analyzed for routine potability: pH, alkalinity, bicarbonate, carbonate, hydroxide, electrical conductivity, fluoride, chloride, nitrite, nitrate, sulphate, calcium, magnesium, potassium, sodium, iron, manganese, Total Dissolved Solids (TDS), hardness, ion balance, nitrate+nitrite-N, nitrate-N, Nitrite-N and Sodium Adsorption Ratio (SAR). Since leaking CO₂ may not initially appear as free gas due to dissolution in water or interactions with various minerals, baseline analysis will also include dissolved metals: aluminum, antimony, arsenic, barium, beryllium, boron, cadmium, calcium, chromium, cobalt, copper,

iron, lead, lithium, magnesium, manganese, molybdenum, nickel, phosphorus, potassium, selenium, silicon, silver, sodium, strontium, thallium, tin, titanium, uranium, vanadium and zinc. If practical, headspace gas will be captured for isotopic analysis, or alternatively measurements can also be made from water samples. These analyses will establish initial conditions, allow monitoring for potential interactions of injected CO₂ with brines and/or rock matrices and fingerprint various formation waters based on their chemical profiles. Following review and analysis of initial results, monitoring plans for these wells will be finalized. Water well sampling will follow methodology established by the Alberta Research Council; *The Free Gas Sampling Standard for BWWT* (ARC, March, 2009).

Enhance will collect three events per year (spring/summer/fall) for two years. Enhance will re-evaluate at the end of 2020.

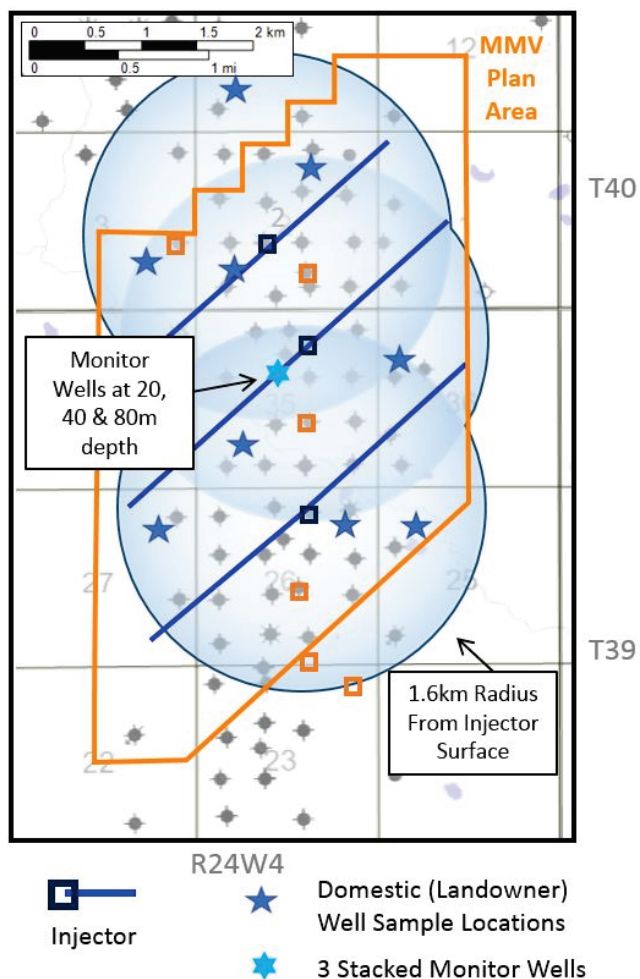
Baseline Water Well Testing for Coalbed Methane Development

Enhance will supplement its own analysis with the *Baseline Water Well Testing for Coalbed Methane Development*, a database of water samples taken from the mid-2000s as a baseline for CBM development. When choosing candidate wells for its program, Enhance will preference wells included in the database (pink locations in Figure 4-9, adding complementary information on long-term variability of gas composition).

These historic analysis, which includes seventeen wells within the **MMV Plan Area**, were conducted beginning in 2006 and include parameters such as bicarbonate, Ca, carbonate, Cl, conductivity, I. Coli, FI, hydroxide, ionic balance, Fe, iron related bacteria, Mg, Mn, Nitrate, pH, k, Na, sulphate, sulphate reducing bacteria, alkalinity, total coliforms, TDS and total hardness.

Three of the Landowner water wells selected to be sampled within Enhance's program have been tested as part of the Baseline Water Well Testing (BWWT) for CBM development in the area. Copies of these historic analyses are included in **Appendix O**.

Dedicated Monitoring Well Nest



Enhance will drill three nested observation wells completed in the surficial, Lacombe and Haynes aquifers (~20, 40 and 80 mBGS) to allow sampling and monitoring of fluid levels and temperatures to in these horizons (full details in **Appendix L**). These wells will be located on an inactive well lease at 11-35-39-24W4 (Figure 4-10) and completed in the Lower Lacombe and Haynes Aquifers. Given that the bedrock and topographic positions are similar amongst the registered Landowner water wells, the main differentiator is depth. Therefore, the three nested dedicated water wells (completed at different screen intervals) will serve to capture water quality changes with depth. These wells will be sampled three times per year, spring/summer/fall during baseline and monitoring operations. Enhance will re-evaluate frequency after two years.

Figure 4-10: Groundwater Monitoring Program in the MMV Plan Area. Nine domestic wells will be sampled, in addition to 3 stacked Monitor wells in the centre of the Area that sample at 20, 40 and 80m below ground surface.

BIOSPHERE MONITORING

Soil Gas Monitoring

Soil gas sampling is a proven and reliable means of providing additional assurance CO₂ is not migrating to surface. Enhance will install 21 permanent soil sample probes at 19 well locations within the **MMV Plan Area** (due to overlap of the monitoring areas, this will provide 10 sample points within 1,600m of each injection pad), which will be sampled three times per year prior to CO₂ injection (in spring, summer and fall) to establish the baseline. No sampling will be conducted in the winter due to frozen soil conditions. Seasonal sampling of these wells is important because soil gas composition may change with seasons due to variations in biological activity in the soil (Romanak, 2016). Sampling will continue for two years to provide enough data to characterize soil gas concentrations. Monitoring frequency will be re-evaluated after two years, depending on the results seen to that time. Further details of the soil gas monitoring program can be found in **Appendix K**.

During each field program the soil vapour probes will be sampled in-situ in real time for CH₄ and CO₂ concentrations using a Los Gatos Research Ultra-portable GHG Analyzer. Including the ability to detect methane (CH₄) in soil gases is recommended since:

surficial deposits in central Alberta may contain coal seams that naturally produce methane (i.e., coal bed methane); and, methane oxidation by soil microbes can elevate soil gas CO₂ concentrations.

Off-site laboratory analysis of the soil gas samples will include determinations of their N₂, O₂, CO, CH₄, CO₂ and, if applicable, F1 hydrocarbon (nC₆-nC₁₀) concentrations. Analysis of F1 hydrocarbons helps to confirm the presence of an exogenous geological (i.e., coal bed methane may contain F1 hydrocarbons) or biological methane source (e.g., from methanogenesis).

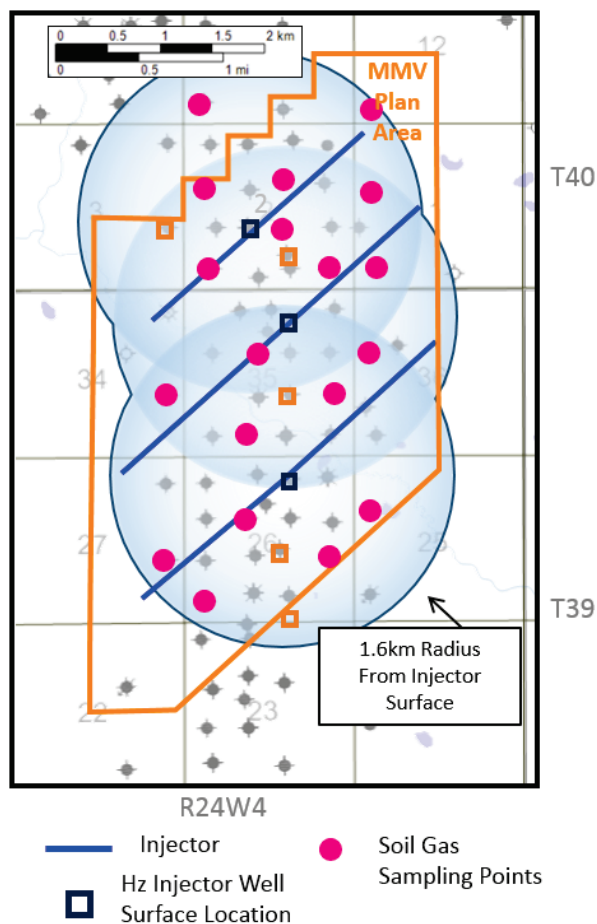


Figure 4-11: Nineteen Soil Gas Monitoring Locations

Selected well locations are tabulated below.

User-Format Well ID	Prod./Inject. Frmtn	Date Well Spudded	Surf-Hole Latitude (NAD83)	Surf-Hole Longitude (NAD83)	Ground Elevation (m)
100/12-25-039-24W4/00	Deduc	1966/08/16	52.38570N	113.33720W	838.2
100/04-26-039-24W4/00	Deduc	1967/08/19	52.37783N	113.36029W	882.7
100/08-26-039-24W4/00	Deduc	1984/07/04	52.38180N	113.34281W	860.9
100/11-26-039-24W4/00	Deduc	1985/10/23	52.38509N	113.35435W	870.3
100/08-27-039-24W4/00	Deduc	1967/06/15	52.38144N	113.36562W	865.3
100/08-34-039-24W4/00	Deduc	1968/01/06	52.39591N	113.36537W	855
100/03-35-039-24W4/00	Deduc	1985/10/23	52.39153N	113.35435W	856.4
100/08-35-039-24W4/00	Deduc	1984/07/02	52.39598N	113.34239W	856.8
100/11-35-039-24W4/00	Deduc	1988/02/23	52.39957N	113.35253W	850.5
100/12-36-039-24W4/00	Dnisku	1966/05/29	52.39958N	113.33718W	864.1
100/04-01-040-24W4/00	Deduc	1966/07/29	52.40700N	113.33624W	891.5
100/12-01-040-24W4/00	Deduc	1966/08/28	52.41366N	113.33711W	909.8
100/01-02-040-24W4/00	Deduc	1985/12/31	52.40698N	113.34301W	891.2
100/04-02-040-24W4/00	Deduc	1966/07/11	52.40696N	113.35936W	855.9
100/07-02-040-24W4/00	Deduc	1988/02/07	52.41059N	113.34931W	879.1
100/10-02-040-24W4/00	Deduc	1965/05/23	52.41475N	113.34927W	897
100/12-02-040-24W4/00	Deduc	1965/10/02	52.41419N	113.36028W	864.4
100/04-11-040-24W4/00	Deduc	1965/01/28	52.42150N	113.36040W	875.1
100/04-12-040-24W4/00	Dnisku	1967/02/12	52.42089N	113.33706W	905

Note: Highlighted wells 11-35 and 4-1 will have radioisotope testing at each sampling event.

The soil gas monitoring program will provide excellent coverage, with approximately 75 baseline data points prior to injection.

Soil Isotopic Baseline

In the event anomalous soil gases are detected outside of expected levels, complimentary geochemical techniques will be used to determine the CO₂ source in soil gas samples. Cenovus Energy Inc. successfully applied such geochemical techniques at its Weyburn CO₂ flood in Saskatchewan.

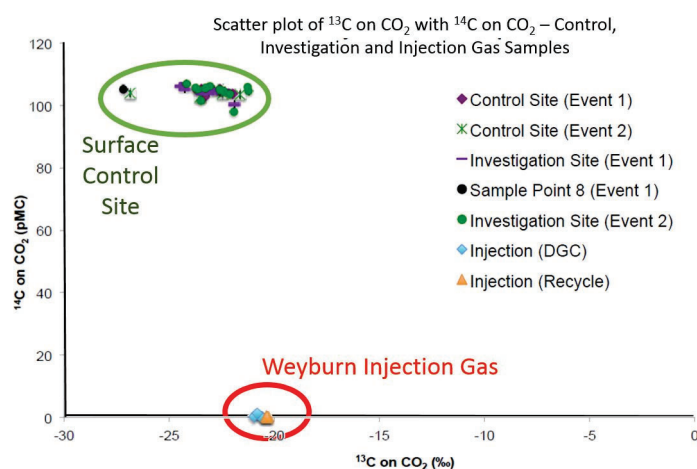


Figure 4-12: ¹⁴C on CO₂ vs. ¹³C on CO₂ from Cenovus Weyburn Study

Soil gas samples (upper left quadrant of the graph) show approximately 100% modern ¹⁴C, indicating a biogenic source (i.e. no DGC or recycle gas is present in the soil gas, as this would dilute the values below 100% modern ¹⁴C). The soil gases also show a slight difference in δ¹³C vs. the DGC and recycle streams, providing additional evidence the CO₂ in soil gas is biogenic in origin.

In the study, the origin of gas samples recovered from soils close to the injection site were in question. To resolve the problem, Cenovus turned to carbon isotopes present in the samples. Carbon 14 (^{14}C) is a radioactive carbon isotope that is taken up by plants through photosynthesis. Over long periods of time, the unstable isotope reverts to more stable Carbon 13 (^{13}C). As this rate of decay is predictable (the half-life of ^{14}C is 5,730 years), the ratio of ^{14}C and ^{13}C can be used to date a sample. Analysis results (Figure 4-12) showed that ^{14}C levels were consistent with CO_2 generated by modern plant decay, as well as with that of baseline samples. Conversely, samples taken from the Weyburn injection gas stream have virtually zero ^{14}C , as the constituent carbon was synthesised millions of years ago.

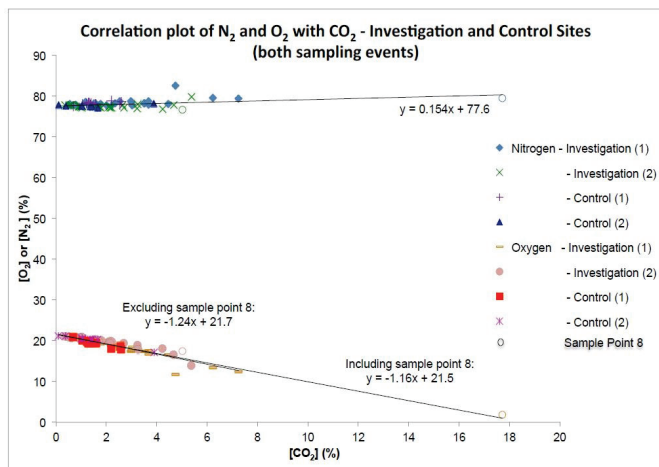


Figure 4-13: Oxygen and Nitrogen vs. CO_2 Concentrations from Cenovus Weyburn Study

The plot shows nitrogen in the soil gas samples as steady (upper line), while percent CO_2 increases and oxygen declines, indicating that biological processes in the soil are consuming oxygen and producing CO_2 . If leaking CO_2 were displacing soil gas, both nitrogen and oxygen would decline as CO_2 concentration increases.

Cenovus furthered its case by testing the relative elemental gasses abundances. Microbial activity in soils consumes oxygen (O_2), converting it to CO_2 , which means that biogenic CO_2 will have an inverse relationship with O_2 , while nitrogen (N_2) will remain constant and consistent with atmospheric concentrations. If leaking CO_2 displaces soil gas, both O_2 and N_2 will show an inverse relationship to CO_2 (Figure 4-13). Cenovus's example demonstrated these geochemical techniques provide a definitive means of differentiating CO_2 sources independent of environmental variability.

The planned Clive program to establish baseline soil gas will provide a sufficient data set to compare with that obtained during the monitoring phase. To institute a baseline independent of seasonal variability, Enhance will take isotopic samples to provide the most valid and concise means of differentiating CO_2 from fossil fuel sources, versus that from biological activity. Baseline CO_2 concentration and $\delta^{13}\text{C}$ will also be established.

Carbon isotopes will be analyzed for all locations during the spring baseline program and then a sub-set of 2 locations for the summer and fall baseline program. Sampling and analyses for project monitoring will follow the same procedures as the baseline program and will be re-evaluated after two years.

Although there have been no recorded instances of sour gas migration outside the surface casing at Clive (i.e. gas migration), this soil gas monitoring program, along with ongoing H_2S monitoring and surveillance will provide detection of this type of event should it occur.

ATMOSPHERIC MONITORING

Surface Facility Monitoring

Injection and production facilities will be equipped with H₂S alarms. Since leaking CO₂ would contain H₂S from the reservoir, these alarms will provide a robust method of potential leak detection.

WELLHEAD MONITORING

Monitoring existing wells for SCVF will provide the primary protection against leakage out of the geosphere at its most likely point. Should this prove not to be the case (meaning one of the secondary techniques shows that leakage has occurred that was not detected by SCVF monitoring), Enhance will first locate and repair the leak and then evaluate why the SCVF monitoring did not detect the leakage. Should this evaluation show that SCVF monitoring does not provide a reliable means of leakage detection, Enhance will evaluate additional techniques to provide detection while CO₂ is still in the geosphere.

Surface Casing Vent Flow and Casing Pressure Buildup on Existing Wells

To monitor for potential of CO₂ leakage, all of the existing wells within the active MMV Plan Area will be monitored for SCVF and pressure build-up in the production casing a minimum of twice per year, using procedures as outlined in AER ID 2003-1 and D-20 ..

Small vent flows require specialized detection methods (SCVF testing involves running a tube from the surface casing vent into a jar of water and watching for bubbles for 10 minutes; if any are observed, a meter must then be installed to quantify the vent rate) unless they are apparent due to odours from carried H₂S. High volumes of CO₂ leakage would be apparent from any or all of the following:

- odour;
- noise from the vent;
- visible shimmer caused by the differing optical properties of vented gas versus the atmosphere; and
- ice plumes associated with cooling CO₂ as it expands to atmospheric pressure from the casing vent.

Operations staff are trained and qualified to observe these conditions during their daily field surveillance.

If SCVF and/or pressure build-up is noted, Enhance will follow response procedures outlined in AER Interim Directive ID 2001-03, which directs how the magnitude of the issue is to be determined and the corrective actions required. These procedures are discussed in *Action Triggers and Mitigation Plans* section.

Based on an extensive review of the cement bond integrity of the 64 existing wells within the planned Phase 1 development area, the leakage risk is extremely low. This work has shown excellent cement bond across the Leduc, Nisku and Ireton cap rock zones, confirming strong zonal and cap rock isolation. Approximately 75% of all zonally abandoned or fully abandoned wells had a cement bond log, and no wells had any history of SCVF from the Nisku or Leduc formations due to cement failure. No history of SCVF in more than 50 years of operation is a strong indication of good cement bonding and integrity through the Leduc, Ireton, Nisku and overlying cap rock.

Gas from the Leduc reservoir is sour, containing over 12% H₂S. Any leakage from the reservoir would be obvious due to the strong odour of this gas; none has been noted to date, except for those wells where casing failure above the cement top was detected and repaired. During EOR operations, CO₂ will blend with existing gas and make odour detection of leaks possible. If the source of any SCVF is not obvious, Enhance will sample the flow for chemical and/or isotopic analysis and may conduct downhole investigation.

Changes Due to Formal Risk Assessment

Enhance will continue its undertaking a formal risk assessment on existing wells outside the **MMV Plan Area**. Should this assessment identify wells that cannot be mitigated to a low-risk, Enhance will implement additional monitoring.

Timing of Baseline Data Gathering

Baseline soil and domestic water well sampling is planned for the spring, summer and fall, prior to any CO₂ injection, based on the current project schedule. Baseline sampling of the CBM wells, gathering system and the CO₂ sources (Nutrien and the Sturgeon Refinery) will occur prior to CO₂ injection, in conjunction with the soil and water well sampling program. Existing wells within the **MMV Plan Area** will be monitored for SCVF and casing pressure prior to CO₂ injection.

Summary of Planned Monitoring Program

The following table provides a summary of the monitoring techniques to be used within Enhance's MMV Plan.

GEOSPHERE				
Routine Monitoring Technique	Testing Technique Details	Frequency of Testing to Establish Baseline	Frequency of Testing During ACTIVE EOR	Frequency of Testing POST INJECTION
Most recent AER D-65 EOR Approval	Meet all clauses and requirements specified within Approval No. 12832	As per approval	As per approval	N/A
Monitor physical status of all wells per AER Directives 13, 20, 51 and 65, ID2003-1 or as applicable at the time	All Enhance wells within MMV Plan Area .	Verify no SCVF or casing pressure on existing wells prior to CO ₂ injection.	Monitor SCVF and casing pressure on existing wells minimum two times per year. Evaluate frequency after two years, if no issues seen.	Per AER requirements at time. SCVF and casing pressure to be checked and remediated (if required) at final abandonment.
Conduct reservoir simulation and day-to-day flood management	Entire EOR operation with focus in specific areas, as required.	History match of Central Leduc Area prior to CO ₂ injection and baseline CO ₂ EOR performance prediction.	Day-to-day monitoring of EOR performance. Annual (minimum) updates to simulation for two years, then as required. Monitor voidage replacement ratio (not to exceed 1.0 cumulative).	N/A
Seismic	Acquire existing 3D seismic over project area as per AER D65 project approval.	Process and Interpret baseline seismic. Confirm no faults transects the seals.	Evaluate as required based on event trigger.	N/A
Nisku monitoring wells	Isotope & gas analysis, water chemistry and reservoir pressure as per AER D65 project approval.	Once. Gas carbon isotope. Water chemistry (from Nisku pool).	Isotopes annually, and gas analysis bi-annually. Evaluate frequency of isotope and gas analysis after two years. Annual reservoir pressure.	N/A
Leduc monitoring well	Isotope & gas analysis, water chemistry and reservoir pressure as per AER D65 project approval.	Once. Gas carbon isotope. Water chemistry (from Leduc pool).	Isotopes annually, and gas analysis bi-annually. Evaluate frequency of isotope and gas analysis after two years. Annual reservoir pressure.	N/A

Leduc and Nisku Reservoir Pressure	Annual stabilized formation pressure per AER D-40 requirements and D-65 project approval.	Once.	Annual.	N/A
Monitor tubing and annulus pressure on injection wells	All injection wells.	N/A	Continuous tied into SCADA.	N/A
Injection well hydraulic isolation testing	All injection wells.	Pressure test packer, hydraulic isolation log and cement bond log.	Annual pressure test packer, hydraulic isolation log every five years.	N/A
MUD LOG new surface and build drills	Three project new drills within the MMV Plan Area	Once C ₁ -C ₅ , including isomers and CO ₂ .	N/A- may be considered if infill or replacement well required.	N/A
Measure injected and produced fluids	All injection and production wells.	N/A	Follow measurement requirements as outlined by AER D-17.	N/A
Analyze produced liquids and gas	All production wells.	N/A	Periodically prior to breakthrough, every three months post breakthrough.	N/A
Analyze injected source gas	Nutrien and Northwest Redwater Partnership (NWR).	Once for chemistry and carbon isotopes.	Annual isotopic and continuous CO ₂ concentration.	N/A
Analyze produced and recycled gas	Produced gas at individual wells and recycle streams.	Baseline (including isotope) on existing Leduc producers.	Minimum quarterly gas analysis on production wells and monthly on recycle stream & combined injection stream.	N/A

BIOSPHERE

Routine Monitoring Technique	Testing Technique Details	Frequency of Testing to Establish Baseline	Frequency of Testing During Active EOR	Frequency of Testing Post Injection
Conduct soil gas surveys	19 locations within MMV Plan Area . Planned during unfrozen ground conditions to obtain the most reliable and representative samples	Spring, summer and fall prior to injection. Gas chemistry at each event. Isotopes once on all samples and spring, summer, fall on sub-set.	Spring, summer and fall. Evaluate frequency after two years. Analyses per baseline.	Evaluate frequency based on results to date.

HYDROSPHERE

Routine Monitoring Technique	Testing Technique Details	Frequency of Testing to Establish Baseline	Frequency of Testing During Active EOR	Frequency of Testing Post Injection
Monitor CBM wells for CARBON ISOTOPE SIGNATURE	Gas-gathering system encompassing well clusters for the entire MMV Plan Area and at main gas plant.	Once	Annual isotope analysis and monthly composition.	Annually
Conduct landowner water well surveys	9 Landowner water wells within MMV Plan Area .	Spring, summer and fall prior to injection. Water and headspace gas (if obtainable) chemistry at each event. Isotopes once on all samples and spring, summer, fall on sub-set. Supplement with Baseline Water Well Testing for Coalbed Methane Development.	Quarterly in 2020. Evaluate frequency at YE 2020. Analyses per baseline.	Evaluate frequency based on results to date.
Dedicated monitoring wells	Three dedicated monitoring wells completed at 20, 40 and 80m BGS for chemistry and pressure monitoring. Low flow sampling and downhole pressure recorder.	Spring, summer and fall. Water and headspace gas (if obtainable) chemistry at each event. Isotopes once on all samples and spring, summer, fall on sub-set.	Quarterly. Evaluate after two years.	Evaluate frequency based on results to date.

Action Triggers and Mitigation Plans

As part of MMV planning and preparedness, Enhance has undertaken analysis of potential action triggers and mitigation plans in the risk assessment (**Appendix G**). The list of triggers, actions and mitigations in **Appendix G** is not intended to include every conceivable scenario but gives examples of these events and steps that could be taken to understand and respond any CO₂ migration.

Action triggers and mitigation plan details listed in this section are in addition and complementary to those stipulated in the AER D-65 EOR Approval (**Appendix N**). Foremost of these is that, Enhance will immediately suspend injection operations if the injection facilitates the movement of injected fluids into any zone above the base of groundwater protection or any zone other than the Leduc and Nisku zones, and immediately inform the Resource Compliance Group in the AER Environment & Operational Performance Branch, and the AER Red Deer Field Centre.

The two most likely scenarios that would trigger action, as well as the general approach that would be taken if anomalous monitoring results are observed are discussed below.

As a general rule, unexpected or anomalous results from any of the active safeguards would trigger action beyond routine monitoring activities. Unless the issue is readily apparent, the first step will be to confirm the data to verify that an issue exists. This could involve re-sampling and analysis, for techniques such as soil gas monitoring, or re-calibrating pressure sensors, for techniques such as injection well pressure monitoring. This step is necessary to ensure that actions are not being taken based on a false positive.

If the anomaly is confirmed, further steps will be taken to identify and remediate the source of the suspected CO₂ leak. As each technique being used is independent of the others, results from the trigger technique would be compared to the other monitoring methods. If necessary, for techniques where only periodic measurements are taken, new samples or measurements would be taken to compare to the trigger event.

If the preceding actions indicate the trigger event is valid, Enhance will conduct tighter areal sampling to determine the leak's source. For example, should project CO₂ be detected at the inlet to the CBM gas plant, the event would trigger systematic sampling along the gathering system and sampling of individual wells to isolate the leak's geographic location so that remediation could occur. If it was suspected that CO₂ had migrated above the CBM producing zones, Enhance would conduct soil and/or water well sampling, or use technologies such as additional shallow aquifer dedicated monitoring wells, as an alternative to, or complement for, individual well checking.

Should Enhance be unable to resolve the issue itself, external resources and support will be engaged, such as service companies, consultants, academia, regulators or other specialists.

Enhance has provided examples of two possible well-related that would be readily apparent, how they would manifest, and how the Company would respond.

1. The first potential trigger event would be the presence of SCVF.

There are two potential sources that have the highest probability of manifesting as a SCVF in the Clive field. The first potential source is sweet methane gas from the shallow coalbed zones that are being produced in the area (Scenario 4 in Figure 3-2). This scenario is possible because existing wells did not

have full cement coverage over these zones. The second potential source is a leaking plug in the wellbore combined with a possible casing leak. This scenario would result in sour gas and CO₂ being detected at surface (Scenario 2 in Figure 3.2).

The AER defines SCVFs in two classifications, serious and non-serious, both of which are detailed in ID2003-01.

In the event a SCVF is detected, Enhance would take the following action:

- If there was any danger to the public or environment, Enhance's Emergency Response Plan would be activated, and the SCVF would be tested to determine its classification.
- Enhance would report the SCVF to the AER through the Digital Data Submission Surface Casing Vent Flow/Gas Migration (DDS SCVF/GM) system.
- If the SCVF were deemed to be serious (based on several criteria, including flow rate, presence of H₂S and/or liquids and proximity of potable water wells), the problem would be repaired as soon as possible and not later than 90 days from discovery. The type of repair required would depend on the leak's source. In general, the gas would be sampled and analyzed to determine the geological zone that it is likely leaking from. A service rig would be moved onto the well and downhole sensing tools (logging tools) would be used to confirm the leak's source. The actual repair method would depend on where the leak occurred, equipment in the well and the condition of the well, but it would usually involve placing and/or squeezing additional cement into the well or using mechanical sealing devices such as a bridge plug or casing patch. All of these are routine well-repair methods.

2. The second potential trigger event would be any abnormal annulus or tubing pressure readings from injection wells.

The injection wells will have an initial tubing/casing annulus pressure test of 7,000 kPa prior to injection. The packer will be tested annually to 1,400 kPa and reported to the AER. These testing requirements are specified by AER D-51. The tubing and casing/tubing annulus pressures will be continuously monitored through SCADA, which exceeds regulatory requirements.

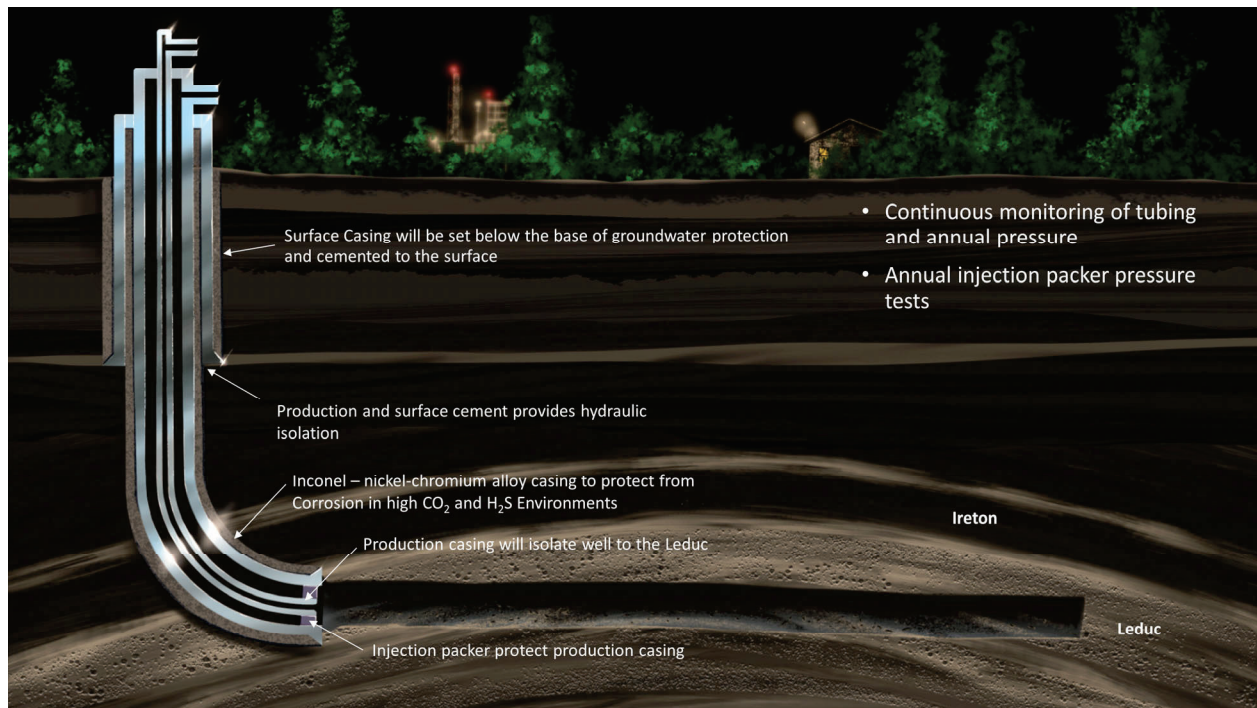


Figure 4-14 CO₂ EOR Injection Well Diagram

Any abnormal annulus or tubing pressure would result in troubleshooting and repair to remediate the issue. The wells will be equipped with an Emergency Shut-Down technology that will shut-in the well, in the event of a failure. Enhance will then diagnose the problem and develop a plan to remediate the issue. Operations to repair the issue will commence within 90 days.

Monitoring Techniques Considered but Deemed Unnecessary

In establishing the appropriate and optimal monitoring techniques to be used within the MMV Plan, Enhance conducted an extensive review of all available monitoring technologies. Based on this review, the Company determined the following techniques were not necessary to implement on a routine basis to achieve its MMV goals. However, should routine monitoring techniques identify issues that cannot be resolved using the data they provide, some of these methods or others not identified could be implemented to assist in analysis. These methods are considered contingent techniques.

1. Routine Time Lapse (4D) Seismic

Enhance investigated using 4D seismic as a routine tool for tracking the progress of CO₂ in the reservoir over the period of injection, primarily to understand the efficiency of the flood. A geophysical study conducted by Enhance (see above - Seismic Baseline Gathering) (**Appendix J**), showed tracking CO₂ at Leduc and Nisku depth would be difficult due to the lack of acoustic variation between the supercritical (liquid) CO₂, and the water it would displace. The capability of the tool is further debilitated by the low porosity of these zones, as this reduces the amount of fluid that can be recognised. Furthermore, a cost-benefit analysis of repeat 3D seismic shoots showed that the information gained would be too late to have any actionable consequence. To make a meaningful impact on EOR management, a desired tool would require a quicker rate than would be feasible from repeat 3D surveys, with much of the required information obtainable using downhole real time surveillance.

Having understood the limitations of routine 4D seismic, Enhance has chosen to utilize it as a contingent monitoring tool in the specific case of suspected CO₂ loss into Cretaceous horizons.

2. Areal atmospheric monitoring techniques

Areal atmospheric monitoring tools generally measure changes in infrared light transmission due to varying CO₂ concentration in the atmosphere. Any reservoir-sourced leakage of CO₂ will contain H₂S in quantities high enough to be detected by H₂S monitors currently employed at Clive. Furthermore, the pipeline that will be used to transport CO₂ from the source to Clive will also be equipped with a comprehensive leak detection system incorporating pressure, temperature, and input and outlet volume measurement, and SCADA will continuously monitor surface systems. Combined, the personnel safety systems that are designed for H₂S leakage detection provide superior coverage for CO₂ monitoring versus a dedicated atmospheric system making this an unlikely tool for contingent monitoring purposes.

3. Dedicated Lower Mannville Aquifer observation wells

Enhance has studied the theoretical effect of CO₂ migration into the Lower Mannville Aquifer, which is the deepest aquifer above the **MMV Plan Area**, in order to evaluate the potential utility of deep observation wells above the Leduc. The methodology and assumptions used for the purposes of this study are discussed in **Appendix M**.

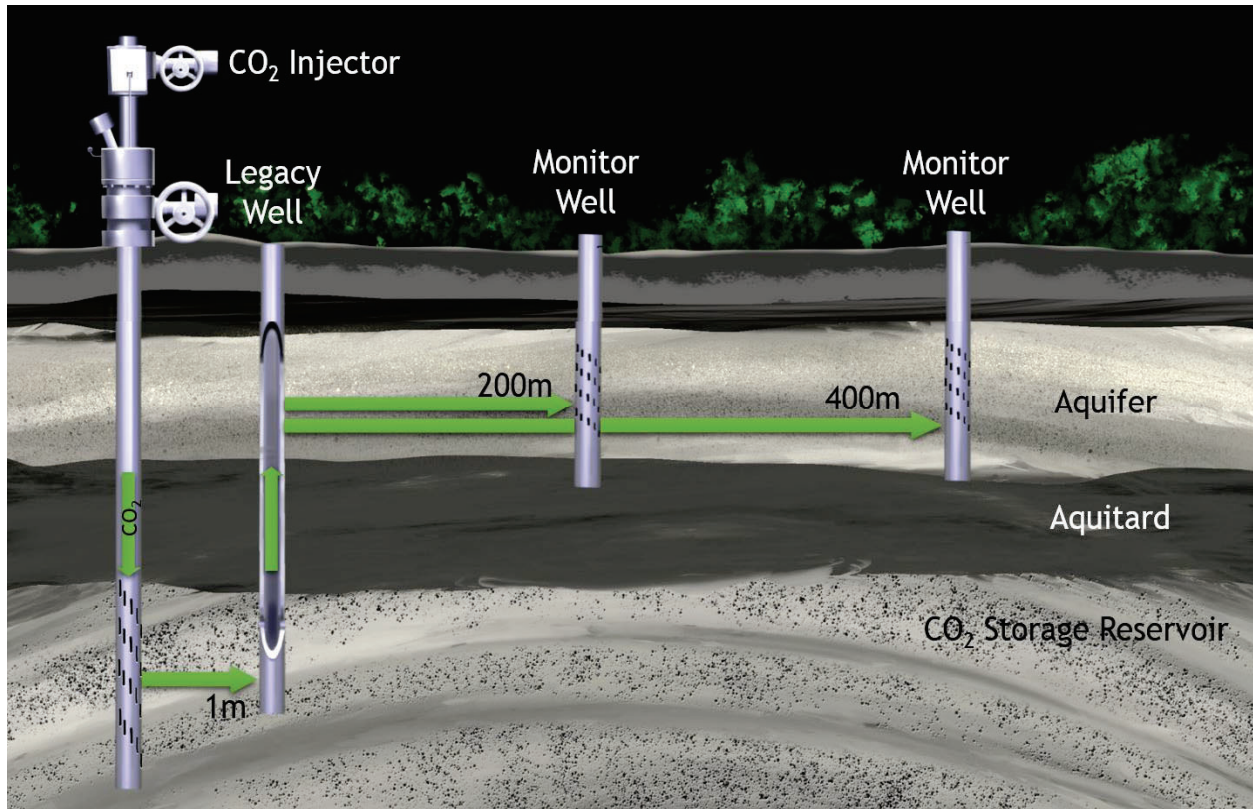


Figure 4-15: A Worst-Case Scenario Pressure Response Model

Enhance has analyzed expected pressure changes due to injection into a reservoir cross-flowing into an aquifer through a leaky pathway (a well) and found them too small for the instrument to detect at a monitoring well.

A potential worst-case scenario was evaluated (Figure 4-15), which assumed that a well is leaking within 1m of the injection well and there is a casing failure or channel in the existing cement. This work concludes pressure changes in the aquifer would be extremely small (Figure 4-16) and would be below the tolerance of instrument accuracy (piezometers are generally accurate within 0.1% of full scale with a resolution of 0.025%)¹. Calculated pressure changes for this CO₂ migration would not be detectable. As a result, the observation well would not be effective.

¹ <http://www.geokon.com/Piezometers>

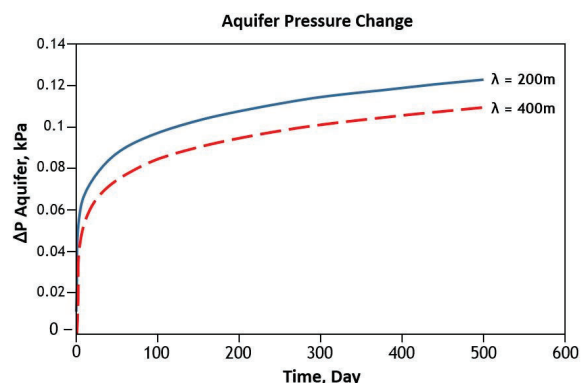


Figure 4-16: Aquifer Pressure Change vs. Time at 200m and 400m Offset

Based on these analyses, Enhance determined that dedicated Lower Mannville observation wells are impractical from both logistics and economic viability perspectives, are disruptive from a surface impact perspective, and, most importantly, have an extremely low chance of detecting CO₂ migration. Plans to monitor existing wells, Nisku producing wells, CBM wells, domestic and the planned dedicated groundwater well(s) and response from the CO₂ flood will provide extensive and dependable coverage.

4. Remote sensing techniques

There are many possible remote sensing techniques that could be used to monitor conditions such as changes in surface elevations or vegetation health. Given that average reservoir pressure will remain relatively constant during operations, Enhance does not expect to see changes in surface elevation. Changes in vegetation health could be due to factors other than CO₂ leakage to the biosphere, such as climate conditions, agricultural practices or other natural causes. The monitoring techniques Enhance plans to use will provide more immediate and reliable indication of containment issues than these methods could afford.

ACCURACY TARGETS

Monitoring techniques selected by Enhance are typical of oilfield practice. Accuracy targets, where appropriate, are specified below:

Technique	Accuracy
SCVF testing	No bubbles observed in 10 minutes flow into water filled container.
Tubing and casing pressure	Gauge pressure typically accurate to 0.02% of full scale.
Isotopic analysis	Dependent on variation in isotope signature which is not yet established and the relative concentration of gases. Utility TBD once baseline analyses are complete.
Soil gas analysis	Dependent on isotopic data. Ratios of O ₂ , N ₂ and CO ₂ can provide independent attribution of CO ₂ source.
Production and injection volumes	Enhance will meet or exceed provisions of AER D-17. Flow computers calculating gas volumes and densities will use AGA-3 and NIST-14 calculations.
CO ₂ concentration	Grab samples by accredited laboratories. Continuous analysis device not yet selected but IR devices typically accurate to 1% with resolution to 0.1%.
H ₂ S detection	Commercially available detectors have resolution of +/- 1 ppm.

All chemical analyses will be conducted by laboratories accredited to ISO/IEC 17025 using procedures based on recognized Provincial, Federal or US method compendia such as ASTM, CGSB, EN, GPA and/or SM.

PIPELINE AND PROJECT MASS BALANCES

Accurate measurement and accounting for injection and production fluids is critical from both a CO₂ storage perspective and to ensure accurate data is available for ongoing assessment of project performance.

Each source (NWR and Nutrien) will be equipped with continuous flow meters and CO₂ analyzers to accurately measure the mass of CO₂ delivered to the ACTL (Figure 4-17). A continuous flow meter will be installed at the delivery point of Clive to enable accurate measurement as close to injection site as practically possible. The concentration of CO₂ delivered to Clive will be calculated based on a mass averaged concentration delivered to the pipeline by the two sources. Further discussion of pipeline leak detection is outside the scope of the Clive MMV Plan.

New CO₂ delivered to Clive from the ACTL will be blended with recycled gas from the EOR production wells, which will be composed of a mixture of solution gas and CO₂. Injection wells will be equipped with continuous

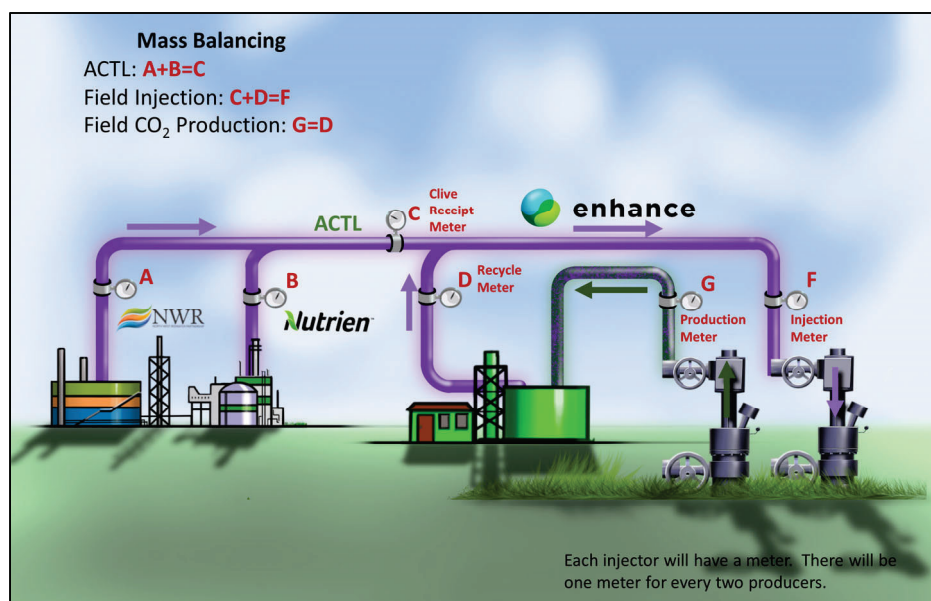


Figure 4-17: Mass Balance Calculation of the ACTL Project

assist in understanding reservoir performance, and in estimated mass of CO₂ lost in the event of a leak. CO₂ from the NWR source is expected to be approximately 99.5% pure with traces of H₂, CO, CH₄, N₂, MeOH and AR. Post dehydration, Nutrien CO₂ is 99% pure with traces of CH₄, H₂ and N₂. Recycle gas will be dehydrated and will contain varying proportions of the source gases and reservoir gas which consists primarily of methane, C₂-C₆, H₂S and CO₂ with trace amounts of helium and nitrogen. None of these substances represent potential added risks; produced gas is successfully handled in the field today.

flow meters. A mass balance between injection at each of the individual well meters and the total combined new and recycle stream will account for any CO₂ losses encountered within the field injection system. The recycle gas stream will be sampled monthly and individual production wells quarterly post-CO₂ breakthrough for compositional analysis. Gas compositional sampling and analysis will

The Clive Leduc reservoir contains an average of 12.6% H₂S, requiring all wells and production facilities meet high standards of fluid containment to prevent release of this gas. As blended gas is produced from the CO₂ EOR project, it will contain H₂S and must be contained to meet regulatory standards. All production facilities, from the initial free water knockout and plant inlet separator to the sales tanks will be equipped with vapour recovery to ensure all gas evolved is recovered and routed to the recycle compressor for re-injection. As produced gas is blended with source gas from NWR and Nutrien, the blended stream going from the Clive battery to the injection wells will also contain H₂S. The presence of H₂S in both produced fluids and injected CO₂ will provide an additional means of ensuring the system does not leak, as even small leaks will be readily detected by odour.

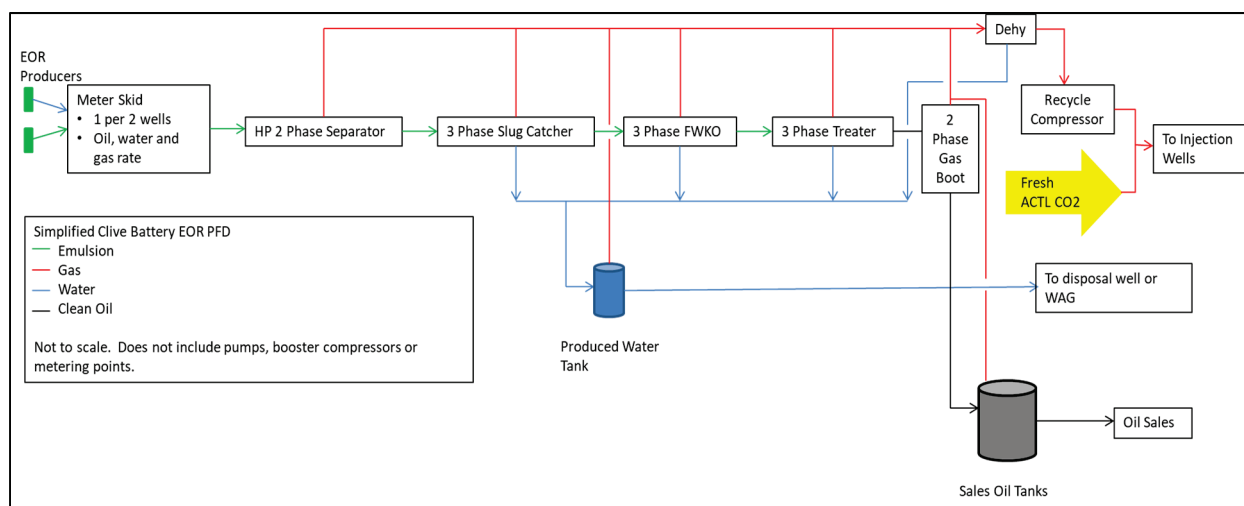


Figure 4-18: Fluid Management at Clive

Figure 4-18 shows a simplified process flow diagram (PFD) of facilities design for the Clive CO₂ EOR project. All vessels used in emulsion separation and oil treating will be tied-into a vapour recovery system, as will the produced water and sales oil tanks. As the gas blanket on the tanks will operate at approximately 0.5 oz/in² gauge, entrained gas in these liquids will be minimal. The gas blanket on the tanks will have pressure safety valves set to 4 oz/in², and will vent to a low-pressure flare, not shown, to protect against tank rupture; this system would only operate under upset conditions and CO₂ losses would be accounted for following procedures outlined in AER D-60. As noted in the Figure 4-18, there are a number of booster compressors not shown on the diagram that allow the various vessels and tanks to operate at differing pressures and balance pressures feeding into the recycle compressor. The recycle stream will be dehydrated using the DexPro™ process, and water content monitored to ensure that no free water accumulates in injection lines that could lead to corrosion and failure. Other than a facility upset flare condition, the entire system is closed loop, all CO₂ and gas produced will be captured, compressed, dehydrated and combined with the new CO₂ stream for re-injection.

CONCLUSIONS

The MMV Plan outlines actions and responsibilities that Enhance will undertake to ensure the **safe and long-term containment of CO₂ in the Clive Leduc pool**. **The plan is designed to verify CO₂ is contained within the Leduc reservoir and to provide public assurance the hydrosphere and biosphere are protected**. Enhance considered AITF's recommendations, its own expertise and that of expert consultants in assessing the probability of different potential leakage pathways, the monitoring techniques that could be used (as well as those deemed unnecessary), and in crafting a monitoring plan that will provide assurance CO₂ remains contained in the reservoir for the duration of the project and beyond. This plan has been developed to address areas of the project that present a material probability of occurrence and/or a high consequence of leakage.

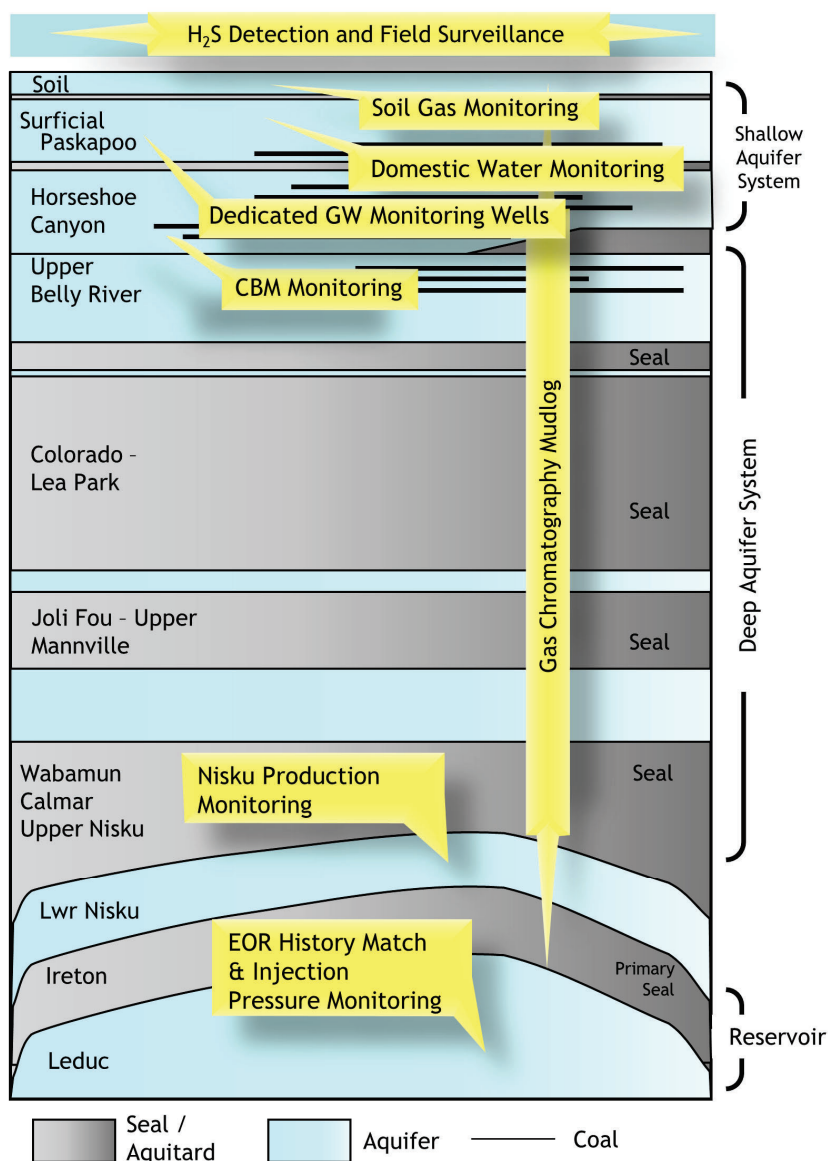


Figure 4-19: Clive Field MMV Plan Summary

Enhance evaluated all monitoring tools and techniques for this project; the MMV plan is designed for the Clive's unique properties and the attributes of CO₂ EOR (see Figure 4-19 Clive Field MMV Plan Summary).

- The plan is designed to maximize EOR project performance, verify Ireton seal containment, provide public assurance of hydrosphere and biosphere protection, and monitor existing wellbores, which present the only reasonable leakage probability.
- Enhance employed a risk-based approach to designing the MMV plan, considering both probability and consequence of occurrence in selecting the appropriate monitoring environments.
- Carbon isotope analysis is the most powerful tool available for monitoring and verification, and it will be utilized in every aspect of the MMV plan. Baseline carbon isotopes will be established for source CO₂, Leduc, Nisku and CBM gas, soil gas and headspace from

domestic water wells.

- Extensive data gathering and analysis from reservoir monitoring techniques will ensure Ireton seal integrity is not compromised and enable simulation modelling as a means of detecting possible CO₂ conformance or containment issues.
- Nisku production monitoring will verify Ireton seal containment or potential cross-flow through existing wellbores.
- Coal bed methane sampling will monitor three geological horizons above the Leduc pool over a large geographic area.
- Dedicated water wells, landowner wells and soil gas sampling within 1,600m of the injection well sites will provide public assurance CO₂ is contained within the geosphere. Baseline samples will be collected spring, summer and fall prior to CO₂ injection.
- The Leduc is a sour field. Therefore, a CO₂ leak from the reservoir would contain H₂S. Surface facilities will be equipped with H₂S alarms, providing a robust method of leak detection. As well, operations staff are trained and qualified to detect an H₂S leakage.
- Surface casing vent flow monitoring on existing wells will provide the primary protection against potential leakage out of the geosphere.

5 ALBERTA REGULATIONS AND INDUSTRY EXPERIENCE

In addition to the passive safeguards provided by the characteristics of the site itself and the active safeguards that Enhance will implement, the regulatory regime in Alberta provides ancillary safeguards that afford significant benefit.

HIGH STANDARDS OF OIL AND GAS REGULATION IN ALBERTA

Current industry practices and AER well drilling, completion, repair, monitoring and abandonment requirements have been continually refined and updated based on experience gained from operating and regulating wells in Alberta. Including its predecessors, the AER has been in existence for almost 80 years and is widely recognized for its excellence in regulating industry to promote efficient and effective resource development while, at the same time, ensuring environmental and public protection. This is especially important given the extensive sour gas and oil production and sour gas disposal operations in the province. Meanwhile, operating and service companies have been continually learning how best to drill, complete and operate wells; a failed well represents a loss of potential oil or gas production, as well as a liability requiring repair, providing additional incentive to ensure that industry best practices are used and continually upgraded. Enhance Energy staff includes experts in drilling and completions, facility design, construction and operation, and reservoir management, with experience gained at the Cenovus (now Whitecap) Weyburn project and other oil and gas developments.

OPERATION, TESTING AND MONITORING OF WELLS PER AER DIRECTIVES

The AER prescribes extensive operational, testing and monitoring requirements for production, injection and suspended wells, or those wells on which operations have been discontinued. These requirements ensure well integrity to protect against contamination of the hydrosphere, biosphere or atmosphere. Enhance's MMV plan focuses on well integrity, ensuring containment and protecting potable groundwater. Enhance will meet or exceed all requirements, current and future, for operated and owned wells in the EOR project. Current requirements include:

- **Directive 13 Suspension Requirements for Wells:** Deals with suspension of wells that are not to be immediately abandoned (i.e. they are retained for potential future use) and specifies down-hole suspension methods and ongoing monitoring requirements specific to the well type. <https://www.aer.ca/rules-and-regulations/directives/directive-013>.
- **Directive 20 Well Abandonment:** Specifies how wells that are no longer required must be tested, remediated (if leakage is apparent during testing) and abandoned, with the ultimate goal of protecting potable groundwater. Enhance will meet or exceed all of these requirements when abandoning existing wells as active EOR areas are developed. <https://www.aer.ca/rules-and-regulations/directives/directive-020>.
- **Directive 051 Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements:** Specifies how injection wells are to be constructed, monitored and operated. Enhance will meet or exceed all the Directive 051 requirements, which include ensuring wellbore isolation of the CO₂ to the injection zone (Leduc), injecting below formation fracture pressure, confirming casing

and cement integrity, and ensuring the injection packer and tubing are not leaking. This directive requires an initial pressure test on the casing-tubing annulus and annual pressure tests to confirm integrity of the annulus. Enhance will exceed these requirements by having continuous pressure monitoring tied to the SCADA and alarm system for the project. <https://www.aer.ca/rules-and-regulations/directives/directive-051>.

- **Interim Directive 2003-1 1) Isolation Packer Testing, Reporting, and Repair Requirements 2) Surface Casing Vent Flow / Gas Migration Testing, Reporting and Repair Requirements 3) Casing Failure Reporting and Repair Requirements:** Specifies testing, reporting and remediating requirements for wells with SCVF, gas migration or casing issues. Enhance will exceed these requirements by monitoring existing wells in the EOR area for SCVF and casing pressure a minimum of twice per year. <https://www.aer.ca/rules-and-regulations/interim-directives/id-2003-01>.

Enhance will also follow a number of additional guidelines and regulations that ensure safe and efficient recovery of resources. These regulations are not specific to the MMV plan and include, but are not limited to:

- **Directive 65 Resources Applications for Oil and Gas Reservoirs:** Establishes requirements to ensure efficient resource recovery.
- **Directive 56 Energy Development Applications and Schedules:** Sets out procedures to be followed for petroleum industry energy development that includes facilities, pipelines or wells.
- **Directive 8 Surface Casing Depth Requirements:** Sets requirements for the surface casing depth on new wells to assist in well control and groundwater protection.
- **Directive 9 Casing Cementing Minimum Requirements:** Prescribes required cementing procedures for casing strings.
- **Directive 10 Minimum Casing Design Requirements:** Establishes standards for casing design to ensure well integrity.
- **Directive 60 Upstream Petroleum Industry Flaring, Incinerating and Venting:** Deals with requirements to eliminate or reduce the potential and observed impacts and to ensure that public safety concerns and environmental impacts are addressed.
- **Directive 71 Emergency Preparedness and Response Requirements:** Establishes a decision framework and action plan to ensure quick and effective emergency response in order to protect public safety and minimize environmental impacts through implementation of an Emergency Response Plan.
- **Directive 80 Well Logging:** Establishes minimum logging requirements to ensure relevant geological data is collected to allow evaluation of aquifers, to confirm the completion/production intervals and to provide sufficient data to estimate resources and reserves of the well and allow assessment of other zones penetrated by the well. Also establishes format for submission of this data to the AER.

These directives may be viewed at the AER website: <https://www.aer.ca/rules-and-regulations/directives>.

EXTENSIVE EXPERIENCE WITH INJECTION IN ALBERTA

Alberta has a long-standing practice of successfully utilizing the deep sedimentary sequence for a variety of fluid injection purposes, while protecting potable groundwater and ensuring orderly and efficient resource development. As of March 2017, the following statistics were available for active wells (not suspended or abandoned) licensed for various injection and disposal purposes in Alberta (source IHS AccuMap):

MODE	FLUID	NUMBER
Disposal	Acid Gas	44
Disposal	Waste	78
Disposal	Water Disposal	1,783
Industrial	Waste	28
Injection	Air	5
Injection	CO ₂	46
Injection	Gas	3
Injection	Gas Injection	57
Injection	Solvent	144
Injection	Steam	354
Injection	Water Injection	7,026
SAGD	Steam	1,661
Storage	Gas Storage	174
Storage	LPG	58
Cyclical	Oil	3
Cyclical	Heavy Oil	5,631
TOTAL		17,095

Table 2 Injection and Disposal Wells in Alberta

AccuMap shows a total of over 17,000 wells licensed for various types of injection. This includes solvent and CO₂ injection wells associated with 59 projects as of June 2011. The high level of injection activity – without widespread or persistent issues – speaks to the effectiveness of well construction, abandonment requirements and regulation in Alberta. The CO₂ EOR flood at SACROC, which has been in operation for more than 45 years, also has a low incidence of wellbore-related issues (as reported by Carey, *et al*, 2016). The success at SACROC, with wells that are a similar vintage to the wells at Clive, provides additional confidence that historic drilling and completions methods are competent in providing CO₂ containment.

DIFFERENCES BETWEEN CO₂ INJECTION FOR EOR SCHEMES AND SALINE AQUIFER STORAGE

The risk profile for CO₂ EOR is different than for saline aquifer storage. Clive Leduc pool and most other CO₂ EOR projects are proven containers that have stored hydrocarbons for millions of years, and have tight well control and decades of production and injection history, allowing for detailed geological and history matched simulation models to be constructed. These models, as Enhance has built, provide a thorough understanding and response prediction during CO₂ injection; the models will trigger investigation when they cannot explain variations in field performance during CO₂ EOR. Saline aquifers, on the other hand, generally have poor well

control and limited understanding of hydrodynamics, as they have been of little economic interest prior to using them for storage.

As the AITF studies referenced in this plan have noted, and as Hovorka (2009) recently noted, existing wellbores in a CO₂ EOR scheme represent the most likely risk for containment loss. Conversely, Hovorka also noted, existing wells and the EOR process allow for much better monitoring and management of reservoir pressure than saline aquifer storage due to the presence of tighter well control and fluid production and recycling (Figure 5-1).

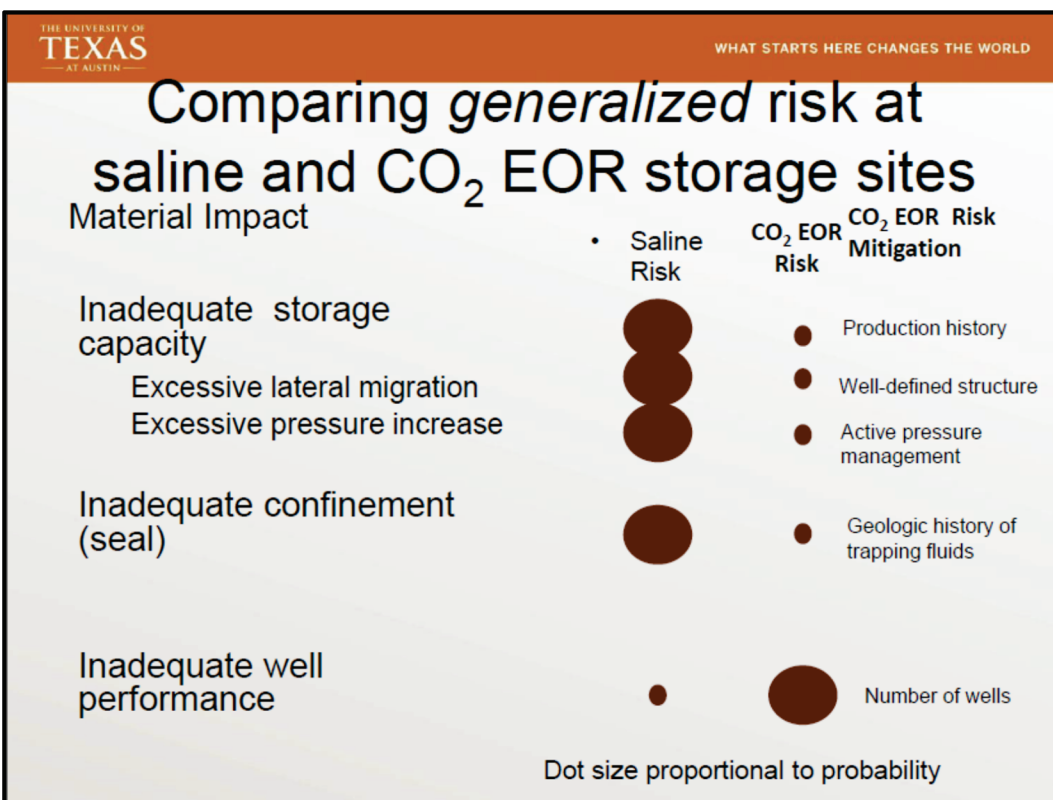


Figure 5-1: General Risks of Aquifer Storage versus CO₂ EOR

(From Hovorka's presentation, used with permission)

Deep saline aquifer storage typically has less containment loss risk from existing wells, but it does not benefit from the detailed reservoir information these wells provide in terms of understanding and predicting storage performance. In EOR storage, distribution of injected CO₂, or conformance, can be monitored and interpreted through production well response and reservoir simulation matching. Aquifer storage does not offer extensive injection or production history, leaving much more uncertainty in forecasting performance. The lack of production means that injection tracking typically requires the use of time lapse (4D) seismic and/or dedicated observation wells. Since aquifers are not proven hydrocarbon traps, the expected ultimate distribution of injected CO₂ may be less certain.

Hovorka also notes that “fluids produced from shallower zones may be (an) ideal and low-cost monitoring option”, which is consistent with AITF’s conclusions and Enhance’s plan to use analysis from Nisku producers and CBM wells as a monitoring technique.

In both types of storage schemes, however, if the geological setting can be shown to provide a strong passive safeguard for CO₂ containment, wellbores are the biggest risk. Enhance recognizes this risk and has built a comprehensive plan to minimize potential leakage from existing wells through rigorous risk assessment that has provided engineered passive safeguards, as well as the suspension and/or abandonment procedures for inactive wells within EOR development areas. Existing wells represent a lower risk in saline aquifer storage because, typically, there are fewer of them that penetrate the storage horizon. In both cases, drilling and completing new wells to meet or exceed regulatory requirements mitigates the risk associated with wells drilled for injection – and, in the case of EOR, production – and/or for observation.

Enhance has designed its MMV program factoring in all of these considerations.

NORTH AMERICAN CO₂ EOR EXPERIENCE

CO₂ EOR is well understood and has been utilized safely for decades in North America. In the continental U.S. alone, injecting CO₂ for EOR has been a successful practice for nearly 50 years. As of 2012, it is estimated that CO₂ EOR operations in North America have injected up to 65 million tonnes per year of CO₂ through more than 7,200 CO₂ injection wells. Cumulative CO₂ injection in the United States is estimated at 800 to 900 million tonnes and annual incremental production at over 128 million barrels (<http://hub.globalccsinstitute.com/sites/default/files/publications/118951/bridging-gap-analysis-comparison-legal-regulatory-frameworks-eor-ccs.pdf>).

One of the most comprehensive studies of shallow aquifer protection was conducted by the Gulf Coast Carbon Center of the University of Texas at Austin on the SACROC project. SACROC is located in the Permian Basin in Scurry County, Texas, was discovered in 1948, and was rapidly developed over the following two years, making many of the wells in the field over 65 years old (older than the majority of Clive wells, which were largely drilled in the mid-1960s). CO₂ EOR began in 1972 and more than 175 million tonnes of CO₂ have been injected to date. The SACROC oil reservoir ranges in depth between 1,830 and 2,130 metres (6,000 to 7,000 feet), which is a similar depth range to Clive. The Gulf Coast Carbon Center concluded:

“Our field-based study of shallow (<500 ft) groundwater overlying and within an ~1,000 mi² area of SACROC shows no impacts to drinking water quality as a result of over 35 years of deep subsurface (6,000 to 7,000 feet) CO₂ injection. Modelling of stable carbon isotopes (d13C) of injectate CO₂ gas, DIC in shallow and deep groundwater, carbonate mineral matrix, and soil zone CO₂ suggests that no significant injectate CO₂ has been introduced to the shallow groundwater.”

The success in the SACROC oil reservoir, which is of a similar depth and vintage to the Clive field, and numerous other studies provide confidence that drilling and completion practices provide excellent CO₂ containment.

CONCLUSIONS

Alberta is one of the best-regulated oil and gas producing areas in the world. Enhance's CO₂ EOR project and MMV plan will benefit from the following:

- Current industry practices and AER well drilling, completion, repair, monitoring and abandonment requirements have been continually refined and updated based on experience gained from operating and regulating wells in Alberta. They have proven highly effective in safeguarding the public, oil and gas workers, and the environment.
- Including its predecessors, the AER has been in existence for almost 80 years and is widely recognized for its excellence in regulating industry to promote safe, efficient and effective resource recovery. CO₂ EOR and other injection processes are proven, safe and effective techniques.
- There are over 17,000 wells licensed for various forms of injection in Alberta with no evidence of widespread or persistent containment issues, speaking to the efficacy of regulations and industry practices in the province. Enhance's Phase 1 project will make use of this industry expertise to meet or exceed regulatory requirements to ensure safe and effective CO₂ EOR and storage at Clive.
- CO₂ EOR has been practiced safely for decades in North America, is well understood, and has had no widespread or persistent containment or conformance challenges.
- CCS in deep saline aquifers and storage in EOR projects both provide for excellent opportunities to remove greenhouse gases from the atmosphere through capture and geological storage. There are similarities in the injection wells but there are differences in the storage risks and mitigation procedures, meaning different MMV plans are required.

6 FINAL CONCLUSIONS

Enhance is confident the Clive CO₂ EOR and storage project will be safe, effective and environmentally responsible, and will provide a number of outstanding benefits to Albertans.

The Enhance team created this MMV plan with great care for the public, the environment and all stakeholders. The plan relies on a thorough understanding of the EOR storage reservoir, developed through decades of production, tight well control and third-party expert review of the Clive Leduc pool's suitability for CO₂ storage. Enhance personnel have extensive CO₂ EOR experience and have engaged industry experts to assist in constructing and validating the Company's models and plans.

In addition to its environmental benefits, injecting CO₂ into the Clive field will profoundly increase oil recovery. In terms of expected EOR results, the project will extend the Clive unit operational life for more than 20 additional years. Using CO₂ to produce oil will create a new revenue stream for the Alberta Government of up to \$15 billion in royalties, based on up to one billion barrels of CO₂ EOR potential along the first leg of the ACTL pipeline system for which Clive is the anchor project. All Albertans will benefit from the royalties and taxes the ACTL EOR projects will generate, in the form of education, essential services, health care, infrastructure, social programs and transportation.

Job creation will be another significant project win. Based on a Canadian Energy Research Institute study, construction and operation of EOR projects enabled by the ACTL will create more than 30,000 man-years of employment, directly and indirectly. These jobs will be heavily concentrated in rural Alberta and will provide local community members with opportunities for construction jobs, full-time operating and maintenance positions, local contracting and procurement roles, leadership in green technology for Alberta, and more.

CO₂ EOR and other injection processes are proven, safe and effective techniques. There are over 17,000 wells licenced for various forms of injection in Alberta and over 7,200 CO₂ injection wells operating in North America, with some CO₂ EOR projects having been in operation for over 40 years, and no evidence of widespread or persistent containment issues.

Both Enhance and AITF conducted geological analysis of the Clive Phase 1 area confirming the Clive Leduc pool's suitability as an excellent CO₂ storage container. The overlying Ireton Formation's role in containing gas and oil within the Leduc reservoir for geologically significant periods of time demonstrates effective primary sealing. Enhance also operates the Nisku Formation, which is directly above the Ireton and is unitized, and has plans to flood it with CO₂ in the future. Four strong aquitards overlying the Nisku's anhydrite-rich top provide secondary barriers and five saline aquifers could absorb and dissipate any leakage that might occur.

Enhance's interpretation of core and petrophysical log data from 163 existing wells has enabled a robust geological model to be built. The geo-model was imported into a reservoir simulation model in which over 50 years of production and injection data was used to derive a history match, while adjustments to data from the geo-model and laboratory fluid studies were avoided. This provides a high degree of confidence in the model's quality and predictive capability. The simulator will be used to compare production and injection well response with predictions; the model will provide an understanding of CO₂ distribution that is not available in dedicated storage projects with no production.

Enhance has also conducted a detailed review of the existing wells within the Central Clive Area and concluded they show good hydraulic sealing, indicating an extremely low chance of leakage. Engineering company VZFox has completed a third-party risk assessment of all existing wells in the **MMV Plan Area**. More wells will be added to the risk assessment prior to injection outside of the **MMV Plan Area**. This work has detailed a well-specific monitoring and mitigating plan for every existing well within the **MMV Plan Area**. New wells will be drilled and completed using industry best practices to meet or exceed regulatory requirements, thereby mitigating leakage risks. As additional assurance, Enhance will undertake Nisku and CBM production, soil gas and domestic water well sampling.

Enhance is dedicated to the success of the Clive project and to the implementation of its robust MMV plan. Although both CO₂ EOR and saline aquifer storage present opportunities to mitigate CO₂ emissions through geological storage of CO₂, they each have unique challenges and strengths that dictate the most appropriate and effective monitoring techniques to be used. Enhance's plan relies on multiple proven and practical techniques geared specifically towards CO₂ EOR that will provide redundant and complementary early detection of potential containment issues. The safe and effective use of CO₂ injection will reduce greenhouse emissions, enhance oil recovery, and create significant societal and economic benefits for Albertans.

Annual project updates will be provided to Alberta Energy and the AER. These updates will present data and interpretations to date, and they will inform updates to this MMV plan based on new information and learnings.

7 ENHANCE AND CONSULTANT EXPERTISE AND RESEARCH

For the design and development of the Clive Project, as well as the associated MMV Plan, Enhance enlisted its internal team of engineers and geologists, and numerous external consultants.

Enhance Energy: Enhance has extensive internal expertise in all aspects of CO₂ EOR. Key team members provided expertise in drilling, completions and workovers, facility construction and operations, carbonate geology, reservoir modelling, simulation and management, and CO₂ storage verification for the Weyburn project and other CO₂ pilots.

Alberta Innovates Technology Futures (AITF): AITF is now known as InnoTech Alberta, a subsidiary of Alberta Innovates. For more information about AITF and InnoTech, including its expertise and research teams, please see InnoTech Alberta's website at <http://www.innotechalberta.ca/>. Dr. Stefan Bachu, a recognized authority in the area of CCS and co-winner of a 2007 Nobel Peace Prize for his work with the Intergovernmental Panel on Climate Change, contributed to and/or oversaw much of the work that AITF developed. Dr. Bachu's biography can be found at: <http://www.albertatechfutures.ca/Corporate/StefanBachubio.aspx>.

Avasthi & Associates Inc.: Avasthi & Associates is a Houston-based international group of over 100 consultants with specialization in many areas, including CO₂ EOR. Dr. Sam Avasthi is an engineering alumnus of the Indian Institute of Technology (Indian School of Mines), Imperial College London, and Texas A&M University (where he earned a Ph.D. degree in Petroleum Engineering). Dr. Avasthi has over 45 years of worldwide oil and gas industry experience in petroleum engineering, reservoir engineering and simulation/modelling, EOR/IOR project design, evaluation and optimization, revitalizing mature oil fields, and related projects. He has been providing consulting and training services to the worldwide oil and gas industry since 1970 and has been involved in conducting reservoir engineering and simulation studies of some of the major EOR/IOR projects. The organization completed a full review of Enhance's simulation modelling for correctness of inputs, specifically residual oil saturations, relative permeability curves and rock fluid interactions.

Bill May and Dr. Jeffrey Packard: Bill May is a geologist and petrophysicist who has worked on every major play in the basin over a career of 40 years. Mr. May has been V.P. for Excite Energy, Circumpacific Energy and more recently for W.R. May & Associates and has also been president of the Canadian Society of Petroleum geologists. Jeff Packard has had an established career in the Canadian oil patch for over 35 years. Dr. Packard's work has been instrumental in understanding of hydrothermal reservoirs in the Wabamun and Devonian, as well as understanding of Devonian reef systems. He has held positions of Senior Geologist at Conoco Phillips and Senior Carbonate Specialist for Talisman Energy, and co-founder of Rhomb Carbonate Consulting. He has also been president of the Canadian Society for Petroleum Geologists and is a research associate for the Pembina Institute. Mr. May and Dr. Packard completed the petrophysical work and the core correlations for the geo-model.

Golder Associates (Golder): Golder is an employee-owned, global organization of more than 6,500 people operating from 165 offices providing consulting, design, and construction services in specialist areas of earth, environment, and energy through technical excellence, innovative solutions and award winning client service. Golder's clients represent the world's major industries and drivers of development: Oil and Gas, Mining, Manufacturing, Power, and Infrastructure. Golder has extensive experience in hydrosphere and biosphere

monitoring for CO₂ injection projects in Alberta developed through their involvement with the Shell Quest Aquifer Storage Project.

Computer Modelling Group (CMG): The organization completed the equation of state modelling utilized in the compositional simulation. CMG also developed and supports the simulation software Enhance uses for history matches and CO₂ EOR performance predictions.

Core Laboratories (Core Labs): Core Laboratories has been in business for over 80 years and has developed many of the techniques used to describe the properties of oil and gas reservoirs and the properties of hydrocarbon fluids. Core Labs completed all laboratory testing for the project.

Reliance Oilfield Services: With headquarters in Tulsa, Oklahoma, Reliance provides drilling, completions, and production services to the oil and gas industry. Reliance provided expert review of cement bond logs for a subset of Clive existing wells to confirm Enhance's interpretation of excellent cement bond.

The University of Saskatchewan: The University of Saskatchewan team that developed the geomechanical earth model subsequently used by AITF worked under the supervision of Dr. Christopher Hawkes, Associate Professor of Civil and Geological Engineering. Dr. Hawkes specializes in petroleum geomechanics, rock mechanics and numerical modelling and conducted geomechanical investigations for the Cenovus Weyburn CO₂ EOR project.

VZFOX Canada Engineering: VZFOX assists clients with developing strategies and navigating across various regulations to obtain the necessary regulatory approvals and permits. It also provides regulatory consulting and application services tailored to various regulatory bodies in Canada, such as the AER.

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GLOSSARY

NOTE: Enhance has chosen the definition of these terms most relevant to oil and gas operations, CO₂ EOR and storage, and the Alberta regulatory environment as the terms are used in this document.

Abandoned well: An abandoned well has been completely abandoned, the wellhead removed, and the casing strings cut and capped below ground level.

Abandonment plug: An abandonment plug is a device or substance placed in a well when the well is no longer needed for production, injection, observation or other purposes. There are many types of plugs that can be used, dependent on the type and condition of the well; abandonment requirements in Alberta are specified by the AER in Directive-20. The primary purpose of abandonment is to seal-off all deep formations that could potentially produce fluids that could contaminate potable groundwater, ensure the potable groundwater is sealed-off and protected, and to prevent flow of these fluids to the surface.

Active EOR: Period during which the CO₂ EOR project is injecting CO₂ and recovering oil until all injection and/or production has ceased and project abandonment has commenced.

Active safeguard: This includes active monitoring techniques that would indicate potential loss of containment or conformance and would allow further investigation and remedial action, if required.

Amphipora: A sponge-like creature with a calcium carbonate exoskeleton that contributed to carbonate rock formation (much like coral reef building).

Amplitude Curve: The distance between the peak and trough of a sound wave. The greater the distance, the louder the sound. [NTD: amplitude isn't used in the document, but amplitude curve is mentioned below]

Anhydrite: A calcium sulfate mineral (CaSO₄) deposited during evaporation of sea water. The ductile properties and low-to-zero permeability of anhydrite make it an ideal seal for CO₂ storage.

Aquifer: A permeable geological formation that is water-saturated. The water may be either saline or non-saline. In Alberta, non-saline (potable) water is defined as having a Total Dissolved Solids content of less than 4,000 ppm.

Aquitard: A geological formation of low- to non-existent permeability (i.e. highly resistant or impervious to fluid flow) that forms a barrier to fluid movement.

Argillite: A massive (non-layered) rock composed of fine grained (muddy) materials. A precursor to shale. Argillite has low-to-zero permeability.

Atmosphere: The gaseous envelope surrounding the earth.

Base of groundwater protection (BGWP): This marks the transition between potable and non-potable (saline) water in the earth. In Alberta, the BGWP is defined at the level where TDS in groundwater exceeds 4,000 mg/l (ppm w/V).

Baseline: Condition prior to CO₂ injection.

Biogenic: Produced by biological activity.

Biosphere: The realm that supports living organisms. The shallow geosphere, where soil microbes and other organisms are found, is also considered part of the biosphere.

Bioturbated: Refers to sediments that have been disturbed (i.e. churned-up) by biological activity. An example would be sediment disturbed by worm burrows.

Black Oil Model: A type of fluid model that simulates the different interactions of fluid within a reservoir at different pressures and temperatures. A Black Oil Model is a relatively simple fluid model that considers only three fluids: oil, gas and water. A Compositional Model is more complex, and tracks more fluids, including various hydrocarbons, CO₂, H₂S, and more.

Bridge plug: A mechanical device which grips the inside of the casing and which has sealing elements that press against the inside of the casing to prevent fluid flow.

Brine: In Alberta, brine is defined as saline or brackish water having more than 4,000 mg/l of total dissolved solids.

Buckles Number: Method for estimating the amount of unmovable (irreducible) water in a rock with a given porosity (Porosity x Irreducible Water Saturation = Buckles Constant). [NTD: is Buckles Number isn't referenced in document but Buckles Method is – consider revising this term]

Calcareous: Describes rock containing calcium carbonate.

Carbon isotope signature analysis: This is a generic term Enhance uses to refer to any number of techniques that rely on differences and/or known relationships of various isotopes of carbon in the CO₂ molecule. Atoms contain a balanced number of protons and electrons but may contain varying numbers of neutrons. Carbon has 6 electrons and 6 protons. The most common isotope, carbon 12 or ¹²C, contains 6 neutrons as well (12 is the total count of protons and neutrons). In keeping, carbon 13 (¹³C) has 7 neutrons and carbon 14 (¹⁴C) has 8. The amount and ratios of isotopes can provide fingerprints, or signatures, that allow different sources of CO₂ (or other elements or molecules) to be uniquely identified.

Carbonate: Rock having a carbonate molecule (CO₃) as part of its composition. Examples include limestone (CaCO₃) and dolomite (Ca-Mg-CO₃).

Cement bond log (CBL): A wellbore logging technique that uses acoustic energy to provide an assessment of the quality of the cement bond between the steel casing of the well and geological formations. This cement provides the primary sealing mechanism that prevents vertical fluid movement in this area. The Cement Bond Log is a valuable source of data about the effectiveness of the cement sheath surrounding the casing. This data is obtained by evaluating the effect of the casing, the cement sheath, and the formation on an acoustic wave emanating from the CBL instrument. The amplitude curve (i.e. the strength) of the reflected acoustic wave is maximum in unsupported casing (i.e. it “rings”) and minimum in those sections in which the cement is well-bonded to the casing and the formation (since this dampens any “ringing” effect).

The CBL uses conventional sonic log principals of refraction to make its measurements. The sound travels from the transmitter, through the wellbore fluid, refracts along the casing-fluid interface and refracts back to the receivers. In fast formations (faster than the casing), the signal travels up the cement-formation interface, and arrives at the receiver before the casing refraction. To get formation arrivals, there must be good bond from cement to casing and cement to formation, therefore if there is fast formation arrival there is good bond on both sides of the cement.

CO₂ enhanced oil recovery (CO₂ EOR): The process of injecting CO₂ into an oil reservoir to improve oil recovery. Under the proper conditions of reservoir temperature and pressure and oil properties, the CO₂ acts as a solvent mobilizing oil that cannot be produced by conventional primary and waterflood techniques. This process has been used extensively in the Permian Basin of Texas for over 40 years and is also being used in the world's largest CO₂ EOR and storage project at Weyburn, Saskatchewan, which began CO₂ injection in 2000.

The CO₂ EOR process involves seven steps, as follows:

1. CO₂ is injected into the reservoir via injection wells.
2. The CO₂ reduces the oil viscosity (i.e. makes it more like water than honey) and swells the trapped oil so it flows more easily.

3. Produced water can be injected in alternating cycles (known as WAG) with CO₂ to help sweep the oil to the producing wells.
4. Production wells pump the oil, along with CO₂, produced water and any associated natural gas to the surface.
5. The CO₂ and associated natural gas are separated at the production satellite facility so that volumes of each substance produced at individual wells can be measured. The fluids then flow to the central treating facility.
6. The oil, gas (which consists of both solution gas from the reservoir and CO₂) and produced water are separated at the central treating facility. The oil is piped to holding tanks where it is metered and sold. CO₂ and solution gas are recycled for reinjection. No CO₂ is released to the atmosphere; this is a closed-loop system.
7. The produced water is also re-injected.

Coal bed methane: Natural gas that is adsorbed onto the surface of coal and that is produced when the pressure in the coal seam is reduced via a production well.

Compositional behaviour: Describes how fluids such as oil, water, CO₂ and natural gas interact and behave at various mixing ratios, temperatures and pressures.

Conformance: This relates to the areal distribution of CO₂. Ensuring conformance, whereby CO₂ stays within an EOR project area, maximizes the efficient use of CO₂ within the EOR operations and protects against offset producer risks. This requires an understanding of the expected areal distribution of CO₂ during and after active EOR (i.e. where is the CO₂ plume?). The structure, or underground topography of the pool, can be an important determinant of conformance. Buoyancy effects will cause injected CO₂ to rise towards the top of this structural trap due to its low density. This will prevent it from migrating into the water leg which connects various oil pools on this geological trend.

Containment: Maintaining containment, or ensuring that CO₂ does not leak vertically out of an EOR and storage reservoir, is the primary goal of a MMV program. Keeping CO₂ in the reservoir protects against biosphere and/or hydrosphere contamination, safety risks, and CO₂ contamination of vertically offset hydrocarbon resources. Containment also ensures CO₂ is being efficiently used for EOR; containment of the CO₂ to the injection zone is critical for the technical and economic success of the EOR project, as it is the miscible action of CO₂ on the oil that improves recovery to offset the added costs of implementing CO₂ EOR. As part of any EOR scheme, regardless of a storage component, the scheme operator would focus significant resources, capital and technology to ensure CO₂ is contained to the injected zone to ensure the best possible oil production response.

Container: A term used in this document to define a geologic horizon in which CO₂ can be stored. In order to ensure long-term, safe storage, a solid container is better than a leaky one.

Core: Samples of the reservoir obtained while drilling a well using a specialized core barrel. Rock plugs may be cut from the core to measure physical rock properties such as porosity and permeability. Core- and log-derived reservoir properties can be compared to confirm the validity of the log correlations.

Density: The weight or mass of a given volume of material.

Dip: The direction and angle of the highest upwards and downwards changes in elevation of a geological formation. Analogous to the fall line in skiing. The direction at right angles to dip is known as the strike.

Dolomite: A calcium-magnesium carbonate (Ca-Mg-CO₃).

Dolomitization: The process whereby calcium in limestone is replaced by magnesium, creating dolomite.

Drillstem: Drillstem test is a measurement of fluid inflow and formation pressure obtained during drilling by isolating a portion of the hole and reducing pressure. This allows a fluid sample to be obtained and formation permeability and pressure to be calculated as pressure builds up after the initial inflow.

Enhanced oil recovery (EOR): EOR is an improved hydrocarbon recovery method that usually occurs after all possible oil is pumped out of the ground using traditional methods. Primary and secondary recovery methods have been used for over a hundred years, while EOR—also termed tertiary recovery— has been used commercially for over 50 years. Numerous EOR methods can be used, dependent on reservoir properties and the costs of the various options. There are many methods: heating, surfactant flooding, polymer flooding, solvent flooding and CO₂ flooding are among the options.

Evaporite: Minerals laid down through the evaporation of sea water. Examples include halite (NaCl) and anhydrite (CaSO₄).

Facies: A term that describes a geological environment such as offshore, near shore, beach, etc.

Flux: The rate of fluid flow.

Gaussian Random Function: A mathematical function used to generate a statistical variation of properties between known points. The function is used to fill in the unmeasured rock properties between wells.

GEM Software: An industry-leading equation of state model that allows the complex fluid interactions associated with CO₂ EOR to be simulated. GEM has been referenced in over 770 technical papers. See <https://www.cmgl.ca/gem/resource-library> for more information.

Geo-model: A geo-model (short for geological model) incorporates rock properties developed through petrophysical analysis of log and core data to develop a digital model that provides a framework of rock properties and initial fluid saturations that are used to initialize a reservoir model for simulation studies.

Geosphere: All geological horizons located below the BGWP. The term shallow geosphere is sometimes used to refer to the shallow subsurface where soil microbes and other organisms are found and where seasonal and climatic variations can impact conditions (and may be above the BGWP). The shallow geosphere is also considered part of the biosphere

Gradient: The change in pressure over a given distance.

History matching: This is the replication of the historical performance of a reservoir via a numerical model to ensure the validity of predictions that it might make; if a model cannot match historical data, then predictions cannot be considered valid. However, as a complex non-linear inverse problem it is critical to constrain the model to some actual measured values in order to have confidence in predictions. In other words, the more measured hard data used, the better confidence there will be in predictions.

Hydrocarbon pore volume (HCPV): This is the amount of hydrocarbon (oil and/or gas) contained within the pore space of a given volume of rock.

Hydrodynamic: Pertaining to fluid movement (within the geosphere).

Hydrogeology: The study of fluid distribution and flow within the geosphere.

Hydrosphere: Geological horizons within the groundwater protection zone containing water with a TDS less than 4,000 mg/l (defined as potable water in Alberta). The deepest horizon within the hydrosphere is considered the BGWP.

Initial solution gas oil ratio (Initial GOR): The amount of gas that is dissolved in the oil at initial reservoir temperature and pressure much like the CO₂ dissolved in a carbonated beverage. Just like a carbonated beverage, reducing the pressure (opening the bottle or can) allows the gas to evolve from the liquid.

Isopach: Thickness of a geological layer. Isolines connects points of equal thickness to create an isopach map.

Log: Data obtained from specialized tools run into wells that infer rock properties based on magnetic, natural and/or induced radioactive response and electrical properties.

Miscible: Capable of forming a single fluid when mixed. In terms of CO₂, this fluid is miscible with oil under pressure, deep underground, but is immiscible – will not mix – at surface conditions.

MMV Plan Area: The geographic area of Clive for which the monitoring, measurement and verification plan has been designed. The MMV Plan Area is located within the Clive Central Area, and consists of the initial development utilizing six horizontal injection wells and six horizontal production wells.

Moldic porosity: Porosity that is created in a rock through dissolution of a component of the rock. An example would be dissolution of shell fragments within a sedimentary rock. The dissolution leaves behind molds of the original fragment.

Mud log: Mud logging is the creation of a detailed record, or well log, of a borehole by examining the cuttings of rock and fluids brought to the surface by the circulating drilling medium (most commonly drilling mud).

Passive safeguard: This includes site-specific geological considerations as well as engineered safeguards built into project wells.

Permeability: A rock property that controls the ease with which fluids can flow through the reservoir. Usually expressed as Darcies (D) or milliDarcies (mD).

Petrogenic: Produced from a petroleum source.

Petrophysical: Petrophysics is the study of rock and fluid properties that defines interactions between the two, meaning how fluids flow (or not) through rock, and the rock features that control flow and correlations between core and log properties.

Pool: In oil and gas terminology, a pool is a distinct and separate oil and/or gas reservoir. Production from a pool will not produce oil and/or gas from another pool. In Alberta, pools are designated by the AER.

Porosity: The space between grains of rock. Expressed as a percentage of the total volume.

Post-abandonment: Not specifically addressed in this document but is the period in which the Crown holds liability for CO₂ storage. The Crown may choose to conduct new MMV activities or continue ones initiated by Enhance.

Post-injection: Period during which injection in a phase has ceased. Depending on reservoir response, there may be a short period of continued production (any produced CO₂ would be recycled into a following phase) until an economic limit is reached and facility and well de-commissioning and abandonment are completed.

Primary seal: The seal or cap rock immediately above the storage formation. The Ireton is the primary seal for Phase 1 of Enhance's project.

Probability of occurrence and consequence: Enhance's MMV plan is built on a foundation of understanding failure risks. Risk is the product of probability of occurrence and consequence, so high risk is the product of high probability and high consequence and vice versa.

Relative permeability: Relative permeability controls how various fluids flow through the reservoir as relative saturations of the fluids changes. For example, if part of the pore space is occupied by water, the effective (or relative) permeability for other fluids is reduced, since the water restricts the size of pore openings left for the other fluids to move through.

Reservoir: A geological formation containing economically recoverable quantities of oil and/or gas (reserves).

Reservoir simulation: This is a tool used by petroleum engineers and geo-scientists to understand and monitor fluid flow and displacement mechanisms and pathways, in order to optimize economic hydrocarbon recovery.

Simulation considers rock and fluid properties, initial saturations of oil, water and gas in the rock and the interactions that occur as conditions change. Once a model is constructed, the first step is to conduct a history match to validate the input parameters and tune them to actual reservoir performance. The validated, history matched model is then used to project future performance. It is also possible to construct a purely predictive model where there is no production history, but this type of simulation has a much higher degree of uncertainty and is not applicable to Clive Leduc given the extensive production history.

A well-developed reservoir simulation can also provide a valuable monitoring tool. As reservoir development continues, variations between actual vs. predicted performance can provide early warning of containment or conformance issues that can then be investigated through additional field monitoring.

Residual saturation: The amount of a given fluid left in a pore space after maximum practical displacement of that fluid has occurred. For example, CO₂ EOR reduces the amount of residual oil left in a reservoir after waterflood.

Risk: Potential harm or loss resulting from a failure. Risk is characterised with this MMV plan as a product of probability and consequence.

SCADA (Supervisory Control And Data Acquisition): This is a control system that uses a network of local and remote sensing and control devices for process control and alarm functions.

Secondary seal: Permeability barriers (cap rocks) located above the primary seal that would prevent upward CO₂ migration in the unlikely event the primary seal leaks.

Shale: A low- to zero-permeability layered sedimentary rock derived from fine grained muddy materials.

Slim tube test: A test of the displacement characteristics of oil saturated rock samples with CO₂ at reservoir conditions (temperature and pressure). This test is used to confirm miscibility under expected CO₂ EOR conditions.

Spill point: A low point in a cap rock. As long as buoyant fluid stays above the spill point, it is trapped. Once the fluid fills to the level of the spill point, it can flow under it and continue moving up-dip.

Static gradient: A pressure measurement taken in a shut-in well by lowering a pressure recording device into the well. This allows the reservoir (pool) pressure to be determined at a point in time.

Surface casing vent flow (SCVF): A surface casing vent flow is a condition where fluid or gas is flowing from the surface casing vent assembly. A well that has an integrity problem may exhibit signs of SCVF.

Terrigenous: A sediment or rock originating from a terrestrial (land-based) source as opposed to marine (sea), lacustrine (lake) or fluvial (river).

Total dissolved solids (TDS): This is the total amount of solids (e.g. salt) dissolved in a volume of water. In Alberta, a TDS over 4000 mg/l (or parts per million on a weight/volume basis) is considered saline or non-potable.

Unitization: A consolidation of interests of mineral lease holders within a pool to allow efficient development and conservation of the resource.

Viscosity: The thickness of a fluid that controls how easily it can flow. For example, molasses is more viscous than water.

Water-alternating-gas (WAG): WAG is a widely used and proven technique that assists in achieving more uniform movement of CO₂ through the reservoir to improve oil recovery. CO₂ and water are injected in alternating slugs. The water moves preferentially into channels in the rock with higher gas saturation, reducing the relative permeability to the subsequent slug of gas. This forces the gas into new areas of the rock, improving contact with un-swept oil, thereby increasing recovery.

Wellbore basics: Although it has been documented that some of the earliest oil wells were drilled in China over 1,650 years ago (https://en.wikipedia.org/wiki/Oil_well) using percussion spring pole methods, the most relevant description of drilling techniques applicable to Clive is that of rotary drilling.

Rotary drilling uses a rotating drill bit to drill through subsurface rock formations to reach oil reservoirs, just like one would use a cordless drill to drill a hole in a piece of wood. The main difference (apart from the size, cost, power and complexity of the equipment), is that rotary drilling uses hollow pipe “joints” (generally approximately 10m long and screwed together) to allow drill bit extension as it penetrates further into the earth. The hollow pipe also allows circulation of drilling mud, a liquid which can be water- or hydrocarbon-based and which contains specialized additives to control its viscosity and density. Circulation of drilling mud means pumping the mud down through the drill pipe and circulating it back up to surface through the space between the hole and the drill string (the entire assembly of pipe joints and the drill bit). The space between the drill string and the hole is termed the annulus. Drilling mud serves four main purposes:

1. It provides cooling to the drill bit (drilling through solid rock generates tremendous frictional heat that would otherwise damage the bit);
2. It carries the rock fragments dislodged by the bit (cuttings) back to surface where they are separated from the mud (and often mud logged to determine the geology of the subsurface and assist in determining what formations are being drilled through and the types of fluids encountered). The mud is then pumped back into the hole by mud pumps;
3. It provides stability to the hole by exerting hydrostatic pressure (i.e. the pressure exerted by the weight of the column of mud) against the sides of the open hole; and
4. It prevents influx of unwanted fluids from formations that are being drilled through by exerting hydrostatic pressure to hold the fluids in their formations.

In some cases, the mud is also used to drive a mud motor, which rotates the drill bit downhole, making it unnecessary to rotate the entire drill string, using energy provided by the mud pumped through the drill string by the mud pumps.

After a section of the well has been drilled, joints of hollow pipe called casing are run into the hole and cemented in place. Casing serves five main purposes:

1. To protect potable aquifers from contamination by produced oil, water and gas;
2. To stabilize the section of the hole that has just been drilled so that material does not fall, or slough, into the hole as the hole is deepened;
3. To provide a means of well control within the well should an unexpected flow of oil, water or gas from other underground formations occur;
4. To provide a conduit that allows production to surface or facilitates the injection of fluids into the reservoir; and
5. To prevent flow between formations.

There are three main types of casing that are generally used in Alberta wells. Each series of pipes is referred to as a string, which is the basis for the term casing string(s). The three types of casing are as follows:

1. **Conductor pipe:** This casing string is generally set to 10 to 20 metres depth to prevent excess sloughing of poorly cemented surface formations (i.e. the crumbly layers of soil that could easily become unstable and fall into the hole) for the surface hole drilling.
2. **Surface casing:** This casing string provides primary protection of aquifers and well control while drilling the next section of the well. The surface casing is set or run to a depth that is calculated based on the maximum reservoir pressure expected to be encountered while drilling the next section of the well or

to a minimum depth of 25m below the depth of the deepest potable water well within 200m of the well, whichever is greater. If the preceding calculation shows the surface casing could be set shallower than the BGWP, the owner of the well may elect to set the surface casing deeper in order to isolate the BGWP (the typical procedure). Alternately, the owner must ensure the BGWP is completely protected when cementing the next casing string.

3. **Production casing:** This casing string is run into or slightly below the formation targeted by the well to allow the production or injection of fluids. In very deep or complex wells, intermediate casing strings may be run to a shallower depth than the final production string to improve the stability of the hole and to provide well control.

Casing strings are cemented in place after being run to a programmed depth. While there are many different types of oil field cement and additives depending on the specific application, using cement prevents fluid from moving on the outside of each casing string by providing a strong bond between the string and the rock formation. Once the casing has been run into the hole, cement is circulated down inside the casing and displaced with fluid, pushing it upwards outside the casing until the space (or annulus) between the outside of the casing string and the rock formations is fully covered by cement. Once the cement sets, it provides a seal along the length of the casing string to prevent unwanted fluid movement along the well.

Oil field cements have different compositions and physical properties than cements used in typical construction projects and are formulated for quick curing time and high strength to provide hydraulic isolation.

Zonal abandonment: This is the plugging of a specific interval that was formerly open to a geological horizon inside or down hole in a given well.

APPENDIX B: WELLBORE RISK ASSESSMENT



enhance

Clive D-3A Pool CO₂ EOR Scheme

**Offset Wellbore Risk Assessment
Part A**

Prepared for:

Well Integrity Team

Alberta Energy Regulator

Prepared by:

Enhance Energy Inc.

November 2024

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1. Introduction

Enhance Energy Inc. has been granted approval (No.12832N) for amendment of CO₂ enhanced oil recovery scheme in Clive D-3 A Pool by Alberta Energy Regulator on October 11, 2024. Section 17a of the approval stipulates that:

“Offset wellbore risk assessment must be submitted to the AER Well Integrity inbox, welloperations@aer.ca, by November 30, 2024 for all wells within the area designated as Part 2 in Appendix A that will be encompassed by the free phase CO₂ plume after 18 months of CO₂ injection into the 04/03-15-040-24W4/0 and 02/05-15-040-24W4/0 wells.”

In support of the approval, Enhance Energy has developed and applied wellbore risk assessment methodology to evaluate CO₂ containment risk at all offset wells within prescribed area boundary and CO₂ injection timelines. Figure 1 illustrates all 31 offset wells that fit criteria outlined in Section 17a. Results of this risk assessment guided identification of wells with higher CO₂ containment risk and development of appropriate preventative barriers.

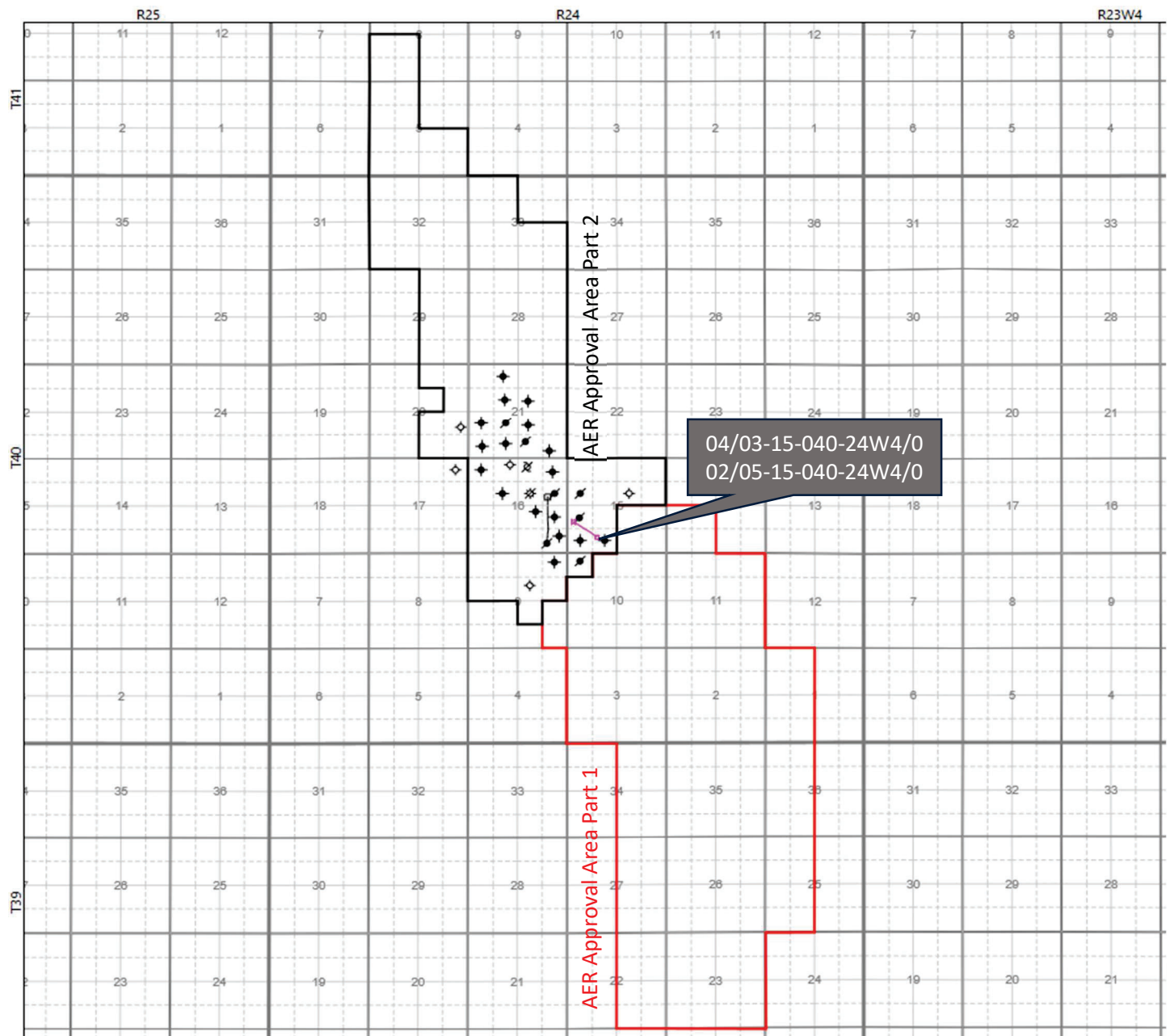


Figure 1. Offset wells within designated AER Part 2 area that will be encompassed by the free phase CO₂ plume after 18 months of CO₂ injection into the 04/03-15-040-24W4/0 and 02/05-15-040-24W4/0 wells

2. Wellbore Risk Assessment Methodology

The risk of CO₂ leaking out of injection zone (Leduc formation) through offset wellbores was assessed using classical risk matrix approach whereby the product of risk likelihood and risk consequence determine the risk level. Enhance Energy used a 5 by 5 matrix to determine risk level of CO₂ leaking out of the injection zone through offset wellbore into five different receptors as depicted by Figure 2. Based on calculated risk level value, the well was classified into four coloured-coded risk categories:

1. Green: $1 < \text{risk level} < 5$
2. Yellow: $5 \leq \text{risk level} < 10$
3. Orange: $10 \leq \text{risk level} < 20$
4. Red: $20 \leq \text{risk level} \leq 25$

By ranking and colour-coding the risk level value, the assessment provides a clear prioritization of offset wells, highlighting the areas where mitigation measures should be prioritized. This ranking serves as a guideline for monitoring efforts, preventive strategies, and response planning to ensure the safe and effective injection of CO₂ into the EOR scheme. Such a systematic approach helps identify and address the highest risks associated with potential leakage, thereby enhancing confidence in the long-term containment of CO₂ in the Leduc formation.

Risk consequence value was assigned to each of the five out-of-zone CO₂ migration pathways (see Figure 3) based on magnitude of impact the leak would have on human health, safety, environment and subsurface resources:

1. CO₂ migration into Nisku formation: consequence = 1
2. CO₂ migration into porous intervals between Nisku formation and base of groundwater: consequence = 2
3. CO₂ migration out of surface casing vent (SCVF): consequence = 3
4. CO₂ migration into groundwater: consequence = 4
5. CO₂ migration through soil to atmosphere (GM): consequence = 5

Risk likelihood value was assigned for each possible CO₂ migration pathway and hence each offset well has five likelihood values. To quantify likelihood value for each migration pathway, Enhance Energy developed a likelihood methodology that accounts for a range of possible wellbore completion scenarios, honours impact of increasing number of flow barriers as CO₂ migrates uphole and leverages leakage potential concepts from relevant public literature. This likelihood methodology is summarized below and detailed within subsequent sub-sections that address risk likelihood calculation for each CO₂ migration pathway.

1. Nisku Formation: wells with varying degrees of zonal isolation between the Leduc and Nisku formations were ranked based on their likelihood of leakage
2. Other Porous Formations: modified deep leak potential model was used to assess leakage likelihood with wells lacking isolation above the Nisku receiving the highest risk ranking
3. Surface Casing Vent Flow (SCVF): likelihoods of shallow leak potential and deep leak potential were used to evaluate cumulative likelihood of CO₂ migration out of surface casing vent
4. Groundwater: analysis of surface casing depth and cement barriers combined with deep leak potential were used to evaluate cumulative likelihood of CO₂ migration into groundwater
5. Gas Migration (GM): likelihood of CO₂ migrating through soil and shallow formations to the atmosphere was assessed by considering the likelihood of CO₂ migration via SCV and the presence of any barriers to that flow path

$$\text{Risk Level} = (\text{Likelihood Value}) * (\text{Consequence Value})$$

Likelihood

Very High	5	5	10	15	20	25
High	4	4	8	12	16	20
Medium	3	3	6	9	12	15
Low	2	2	4	6	8	10
Very Low	1	1	2	3	4	5
	Consequence	1	2	3	4	5
		Very Low	Low	Medium	High	Very High
	CO2 migration pathway	CO2 migration into Nisku	CO2 migration into other porous formations b/w Nisku and base of groundwater protection	CO2 migration out of Surface Casing Vent (SCVF)	CO2 migration into Groundwater	CO2 migration through soil to Surface/Atmosphere (GM)

Figure 2. Risk matrix used to evaluate risk level of CO₂ leakage out of injection zone through offset wellbores

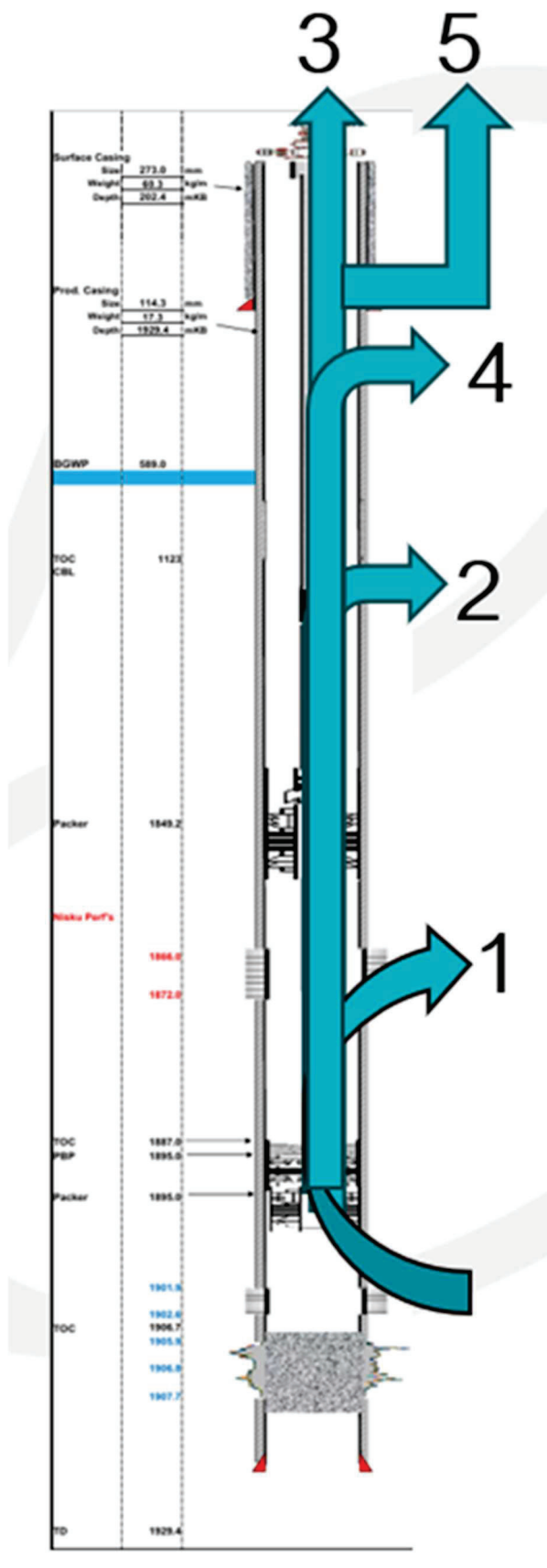


Figure 3. CO₂ migration pathways

2.1 CO₂ migration into Nisku formation

The likelihood of a leak developing from the Leduc Formation to the Nisku Formation was assessed by categorizing wells based on the methods used to achieve zonal isolation between the two formations. Each well was assigned a ranking between 0 to 5, reflecting the likelihood of leakage associated with its configuration:

- **Rank 0 (marginal):** Wells that drilled only into the Nisku Formation and did not intersect the Leduc Formation
- **Rank 1 (very low):** Wells drilled and abandoned with cement plugs isolating the formations, or cased wells with perforations limited to one or neither of the formations
- **Rank 2 (low):** Wells where both formations had been perforated in the past but were subsequently sealed with cement plugs or squeezed were rated as moderate risk
- **Rank 3 (moderate):** Wells with open perforations in one of the formations while the other has been cement squeezed
- **Rank 4 (high):** Wells with open perforations in both formations, separated only by a bridge plug
- **Rank 5 (very high):** Wells with open perforations in both formations and no barriers, resulting in commingling of fluids between the Leduc and Nisku formations

The consequence of a leak into Nisku was evaluated as the lowest category and given a value of 1. Therefore, multiplying the likelihood by the consequence would result in a risk level range of 0 to 5.

2.2 CO₂ migration into porous intervals between Nisku formation and base of groundwater protection

The likelihood of leak developing into porous intervals between Nisku and groundwater was determined by leveraging deep leak potential (DLP) concept from publications by Watson T.L. and Bachu S. In these publications the authors calculate DLP value by multiplying together four factors and based on this score the authors classified them into four likelihood categories: low, medium, high, very high. Considering DLP is the potential of a leak from any deep formation, Enhance Energy made a conservative assumption that over long period of time CO₂ would eventually reach the Nisku Formation and hence both formations (Leduc and Nisku) could be potential CO₂ sources.

The DLP methodology proposed in the publication was modified slightly to account for larger range of wellbore design possibilities. Specifically, a new category was added to account for wells with no isolation above the Nisku Formation. Wells in this category were assigned a multiplier value of 4 in the DLP calculation, reflecting their elevated risk due to the lack of zonal isolation. Table 1 provides a summary of deep leak potential factors and criteria for assigning values that are used to calculate DLP value. Detailed discussion of these four factors is presented at the bottom of the subsection.

Table 1. Deep Leak Potential Factors

Factor	Criterion	Value	Default
Fracture	count=1	1.5	1
Fracture	count>1	2	1
Acid	count=1	1.1	1
Acid	count=2	1.2	1
Acid	count>2	1.5	1
Abandonment Type	No Plug	4	1
Abandonment Type	Bridge Plug	3	1
Abandonment Type	Not Abandoned	2	1
Number of Perforated Intervals	Count>1	2	1

This adjustment led to a revised scoring system, with the output values expanded to include a new highest ranking of 5 for wells. This updated ranking better captures the increased risk posed by poorly isolated wells, ensuring a more accurate assessment of potential CO₂ leakage pathways into intermediate formations. Table 2 summarizes how deep leak potential score was translated into likelihood of CO₂ migration into porous intervals between Nisku and base of groundwater.

Table 2. Deep Leak Potential Likelihood and Score Conversion

Deep Leak Potential (DLP)	Score
1 –Very Low	<2
2 –Low	2-6
3 –Moderate	6-10
4 - High	10-12
5 - Very High	>12

Considering the consequence of CO₂ migration into porous intervals between Nisku and base of groundwater was assigned value of 2, its multiplication with likelihood would result in a risk level range of 2 to 10.

2.3.1 Fracture and Acid

Stimulation treatments like hydraulic fracturing and acidizing, as well as the number of completed intervals in wellbores, can impact long-term wellbore integrity. High pressures from hydraulic fracturing and acidizing, or chemical reactions from acid gas, may weaken the cement sheath or corrode the steel casing, increasing the risk of leakage. Hydraulic fracturing uses high pressure to fracture rock and inject proppants like sand, creating a permeable flow path. Acidizing dissolves wellbore scales and damages near-wellbore zones, enhancing flow potential.

Injected CO₂ may preferentially migrate through fractures, bypassing intact reservoir rock due to the fractures' higher permeability. Wells with multiple completions or perforated intervals are more vulnerable to crossflow between geological zones, which could facilitate leakage. Wells that have undergone more stimulation treatments are considered to have a higher risk, as repeated fracturing or acid treatments increase the likelihood of damage to the casing, cement, or cap rock. Multiple completions also raise the risk of crossflow between zones, further compounding the potential for leakage.

2.3.2 Abandonment type

The wells were categorized into three methods for zonal abandonment of cased wells: cement plugs (extending at least 15 meters above and below the perforated interval), cement squeeze through the perforations (with or without a retainer), and the most common method, a mechanical bridge plug capped with 8 meters of cement. Bridge plug abandonment is considered to have a shorter lifespan due to potential mechanical failure, changes in reservoir pressure from CO₂, or chemical changes below the bridge plug. Materials like cast iron and nitrile elastomers in bridge plugs are vulnerable to CO₂ or acid gas degradation, leading to seal failure.

Cement caps placed above bridge plugs are often dump-bailed into place, but previous studies found that cement caps are only intact in about 50% of cases, with lab tests showing that dump-bailing may not provide an effective seal. As a result, the effectiveness of dump-bailed cement plugs is considered negligible for maintaining a seal above the bridge plug in this study.

Zonal abandonment methods between the Leduc and the Nisku were evaluated for their potential to permit crossflow and their contribution to deep well leakage. Wells that are drilled and abandoned (without casing) were analyzed for the placement depth of the plugs relative to porous formations and surface casing point.

2.3.3 Number of Perforated Intervals

Wells with multiple sets of perforations increase likelihood of cross flow between different formations

2.3 CO₂ migration out of surface casing vent

To assess the overall likelihood of CO₂ flow into a surface casing vent, the deep leak potential was combined with shallow leak potential (SLP) – a concept that was also leveraged from the same publications. This approach integrates both shallow and deep leakage considerations to create a comprehensive risk profile for surface casing vent flow.

SLP likelihood value was determined in a similar way as DLP whereby multiple factors are multiplied together to obtain a score that is converted into a likelihood based on a conversion table. SLP calculation entailed nine factors, which were quantified based on specified criteria as summarized in Table 3. Detailed discussion of these nine factors is presented at the bottom of the subsection. The resultant SLP score was converted into SLP likelihood value as per Table 4. If a well has a documented history of surface casing vent flow (SCVF) leakage, the SLP likelihood value was assigned maximum rating of 5 to honour higher probability of SCVF on wells that have previously exhibited these issues as argued in section 2.3.10.

The SLP and DLP likelihood values are multiplied together, and the score is converted into likelihood (value from 1 to 5) of CO₂ migration out of surface casing vent. This combined approach accounts for the independent layers of protection within the well system, reflecting the progressively decreasing likelihood of CO₂ leakage as it travels farther from the source and encounters additional barriers. Table 5 presents how this independent layer protection methodology is used to convert two likelihood values into a single cumulative likelihood.

Table 3. Shallow Leak Potential Factors

Factor	Criterion	Value	Default
Spud Date	1965-1990	3	1
Abandonment Date	<1995	5	1
Surface Casing Size	>=244 mm	1.5	1
Well Type	Cased	8	1
Geographic Location	Special Test Area	3	1
Well Total Depth	>2500m	1.5	1
Well Deviation	1.2-1.8	1.5	1
Cement to Surface	No	5	1
Cement to Surface	Unknown	4	1
Additional Plug	No	2	1
Additional Plug	Unknown	1.5	1

Table 4. Shallow Leak Potential Likelihood and Score Conversion

Shallow Leak Potential (SLP)	Score
1 – Very Low	<50
2 – Low	50-200
3 –Moderate	200-400
4 - High	>400
5 - Very High	SCVF = Yes

Table 5. Independent Layers of Protection Conversion Methodology

Cumulative likelihood value	Score
1 – Very low	1 - 4
2 - Low	5 - 9
3 – Moderate	10 - 14
4 – High	15 - 19
5 – Very high	20 - 25

Considering the consequence of CO₂ migration out of a Surface Casing Vent was assigned value of 3, its multiplication with likelihood would result in a risk level range of 3 to 15.

2.3.1 Spud date

The date a well was spudded is an important factor in evaluating its potential for leakage, as it reflects the regulatory, technological, and operational conditions of the time. Wells with spud dates within certain timeframes have been found to show higher instances of surface casing vent flow (SCVF) and gas migration (GM). This trend may be linked to heightened drilling activity and the practices common during those periods.

During boom periods of drilling, when spud dates are clustered, the focus on efficiency and speed can sometimes overshadow meticulous well construction and sealing practices. High activity levels may lead to challenges such as inexperienced crews, rushed cementing operations, or inconsistent adherence to best practices, all of which increase the likelihood of leakage.

Moreover, the regulatory environment during these active drilling periods may have been less stringent compared to modern standards. Wells spudded during years with looser regulations often lack the rigorous testing and preventative measures now required to ensure long-term wellbore integrity. Technological limitations at the time could also contribute, as older drilling and abandonment methods may not have addressed all potential leakage pathways effectively.

Another contributing factor could be the age of these wells. Over time mud contained in the annulus may dehydrate, reducing hydrostatic pressure, allowing gas to flow. This combined with changes in testing requirements may impact the likelihood of detecting a SCVF. The combination of these factors underscores the importance of considering spud date data in risk assessments and monitoring programs for well integrity.

2.3.2 Abandonment date

The date a well was abandoned plays a significant role in its potential for leakage, as regulatory standards and abandonment practices have evolved over time. Wells abandoned before 1995 were not subject to the same rigorous requirements for leakage testing or groundwater protection that later became standard under updated Alberta regulations. This regulatory gap has left many older wells at a higher risk for integrity issues.

Wells abandoned before 1995 may lack proper cement barriers or other protective measures that are now mandatory. Without testing for surface casing vent flow (SCVF) or gas migration (GM), many of these wells were abandoned without confirming whether they posed a risk to surrounding formations or the environment.

Additionally, the absence of groundwater protection measures means these wells might not have adequate barriers to prevent fluid migration into aquifers. Over time, geological shifts, material degradation, or poor initial sealing can create pathways for liquids or gasses to leak, potentially contaminating drinking water sources or escaping into the atmosphere.

In contrast, wells abandoned after 1995 were subject to more comprehensive regulations, including mandatory leakage tests and groundwater safeguards. These changes significantly reduced the likelihood of leaks by emphasizing proper

cementing, testing, and long-term well integrity. However, the legacy of pre-1995 wells remain a concern, demonstrating the value of monitoring and waiting to abandon wells with practices that are proven to reduce risk.

2.3.3 Surface casing size

The size of the surface casing is closely tied to the size of the production hole, and this relationship has been identified as a factor influencing well leakage. Larger production hole size can present challenges that may contribute to leakage risks.

For instance, larger casing diameters can make achieving proper cementing more difficult. Ensuring full and effective cement coverage in the annular space becomes more challenging as the diameter increases, potentially leaving gaps where gas or fluids can migrate. This issue is further compounded by the profile of the borehole, which can cause decentralization, making it harder to achieve a uniform cement sheath.

2.3.4 Well type

Wells that are abandoned open-hole show a significantly lower potential for leakage compared to wells that are cased. This reduced risk can be attributed to several factors inherent in open-hole abandonment practices.

Without casing, the wellbore allows for better cement placement directly against the formation, which can create a more effective and continuous seal. This eliminates potential micro-annuli or gaps that can form between the casing and the cement, a common pathway for leaks in cased wells.

Open-hole abandonment also simplifies the wellbore geometry, minimizing the risk of incomplete cement coverage, which is more likely in cased wells due to decentralized casings or poor cement bonding. Moreover, the absence of casing eliminates the potential for external corrosion—a key cause of casing failure and associated leakage.

2.3.5 Geographic location

Certain areas in the province of Alberta have a history of having higher probability of SCVF/GM compared to the rest of the province. The Clive D-3A unit is outside of this test area and therefore did not play a factor in this evaluation.

2.3.6 Well total depth

Wells drilled to depths exceeding 2,500 meters have been found to carry a greater risk of leakage. This heightened potential for leakage may be attributed to several factors associated with greater depths.

Firstly, deeper wells often experience higher pressures and temperatures, which can put additional stress on the wellbore materials, such as the casing and cement. Over time, these extreme conditions can lead to material degradation, creating pathways for fluids or gases to escape.

Secondly, achieving effective cementing becomes more challenging in deeper wells. Incomplete or poorly bonded cement can leave gaps, increasing the chance of leakage.

Lastly, the increased depth requires longer casing strings, which introduces more opportunities for operational errors during installation and creates additional joints where potential weak points can develop. These factors collectively contribute to the elevated risk of leakage in wells drilled beyond 2,500 meters.

2.3.7 Well deviation

Previous studies suggest that deviated wells (those angled but not fully horizontal) are more prone to leaking. This might be due to difficulties with centering the casing and cementing in non-vertical wells. The risk is assessed using a ratio of the well's total measured depth to its true vertical depth.

2.3.8 Cement to surface

The absence of cement extending to the surface is a significant factor contributing to wellbore leakage. This gap leaves the wellbore vulnerable to several issues. Without cement sealing the annulus, pathways can form for gas to escape, resulting in SCVF/GM.

Additionally, this lack of a protective cement barrier exposes the casing to external elements, increasing the risk of corrosion. Over time, external corrosion can weaken the casing, causing structural failures and further compromising the well's integrity. These issues highlight the importance of achieving a complete cement seal to minimize leakage risks and ensure long-term wellbore stability.

2.3.9 Additional plug

Adding extra cement plugs across or above abandoned porous zones provides an additional layer of defense to prevent CO₂ migration up the wellbore. These plugs act as physical barriers that can block the upward movement of gas or fluids, enhancing the overall integrity of the well. Such measures are particularly critical in wells where CO₂ sequestration or acid gas is present, as they help minimize the risk of gas escaping into shallower formations, groundwater aquifers, or the surface environment.

In this context, wells with supplementary cement plugs placed above the Nisku Formation, extending for at least 30 meters, were assessed as having a significantly reduced likelihood of losing containment of CO₂.

2.3.10 Surface casing vent flow history

Wells that have experienced surface casing vent flow (SCVF) in the past, or are known to have had SCVF, are considered to have a higher likelihood of allowing CO₂ to flow to the surface if there is a leak deeper in the well. SCVF occurs when gas or other fluids escape through the surface casing, typically indicating that there are existing pathways for gas migration within the wellbore. These pathways are often caused by issues such as poor cementing, casing failure, or cracks in the casing, which can provide channels for gases like CO₂ to travel up from deeper sections of the well.

If a leak develops in the deeper parts of the well, such as in the production casing or reservoir, it is more likely to reach the surface if there are already weak points in the surface casing, especially in wells with a history of SCVF. The presence of vent flows suggests that the well's surface casing is already compromised to some extent, which means that any new leakage from deeper zones could more easily migrate to the surface through the same pathways that were previously used by the escaping gas.

2.4 CO₂ migration into groundwater

To assess the likelihood of CO₂ leakage into groundwater, DLP was combined with a ranking system that incorporated barriers restricting flow into formations above the Base of Groundwater Protection (BGWP):

- **Rank 1:** Wells with surface casing extending deep enough to cover the BGWP.
- **Rank 2:** Wells where the top of cement on the production casing was above the surface casing point, wells with a >30 m cement plug set below the top of cement, or wells abandoned open hole with >30 m of cement above the Nisku Formation.
- **Rank 3:** Wells lacking surface casing that extends below the BGWP and with the top of cement on the production casing below the BGWP. This category also included wells with previously repaired casing leaks.
- **Rank 4:** Wells that were perforated above the top of cement.
- **Rank 5:** Wells left open hole between the Leduc/Nisku formations and formations above the BGWP.

The ranking system recognizes the critical relationship between surface casing depth and BGWP. Wells with surface casing set above the BGWP are more vulnerable to CO₂ migration into exposed aquifers, particularly if the production casing develops a leak. In such cases, CO₂ or other fluids could potentially flow into groundwater sources.

The ranking value was multiplied by DLP likelihood value, and the score is converted to determine the likelihood of CO₂ migration into water-bearing formations as per independent layer protection methodology conversion methodology that was discussed earlier in Table 5. In a scenario where this calculated likelihood value was lower than the likelihood of CO₂ migration through soil to atmosphere (see section 2.5), it was overridden by the likelihood value of CO₂ migration through soil to atmosphere to honour general trend of increasing leakage probability closer to the source.

Considering the consequence of CO₂ migration into groundwater was assigned value of 4, its multiplication with likelihood would result in a risk level range of 4 to 20.

2.5 CO₂ migration through soil to atmosphere

The likelihood of CO₂ migrating around the surface casing through soil and shallow formations, known as gas migration, was evaluated by considering the potential for flow out of a surface casing vent and adjusting it based on whether a barrier was present to prevent the flow from reaching the surface and causing pressure buildup.

If the well had an active wellhead or was abandoned with a vented surface casing cap, the likelihood of flow to the surface casing vent flow (SCVF) was reduced by one level. If the well had a welded plate or a cement squeeze above the surface casing point (SCP) that could prevent a leak from being contained within the surface casing, the likelihood value remained unchanged.

Wells with active wellheads tend to have a lower likelihood of developing gas migration (GM) issues because any gas flow up the surface casing is vented, allowing it to be detected more easily. When gas migrates up the surface casing, it releases the gas to the surface, preventing it from accumulating in the wellbore or surrounding soil. This venting action serves as an immediate indicator of a wellbore leak, making it easier to identify and address potential issues before they escalate. The ability to detect and vent gas as it rises up the surface casing significantly reduces the risk of prolonged gas migration into surrounding geological formations or the atmosphere. By monitoring for any signs of leakage or pressure changes, active wellheads provide a proactive approach to maintaining wellbore integrity, ensuring that any gas flow is quickly identified and managed. Historically wells have been abandoned with a welded cap. The welded casing cap serves as the final barrier preventing reservoir gases from escaping into the overlying soil and atmosphere. However, investigations into well re-entry have shown that these caps are often unreliable. Failures of the casing cap may help reduce the risk of over-pressurizing the surface casing shoe, uncemented formations, and groundwater aquifers. Small leaks in the cap can act as an early warning sign that the wellbore integrity is compromised. These leaks are typically detected as soil gas migration, often indicated by areas of dead vegetation directly above the abandoned wellbore.

Considering the consequence of CO₂ migration through soil to atmosphere was assigned value of 5, its multiplication with likelihood would result in a risk level range of 5 to 20.

3. Risk Assessment Results

All the raw input data, the performed calculations and the results of this risk assessment for 31 offset wells that fit criteria outlined in Section 17a of EOR approval No.12832N are provided in an excel spreadsheet attachment. Table 6 presents overall statistics for how many wells fall under four colour-coded risk level categories for each CO₂ migration pathway. Figure 4 illustrates risk level for each CO₂ migration pathway on a well-by-well basis. It can be observed that only one well falls under the highest risk red category and there are four unique wells that fall on the low to medium range of the orange risk level category. Figure 5 helps visualize where geographically these higher risk wells are located. Note that this risk level map shows highest risk level amongst five different CO₂ migration paths. Hence there are no low level risk wells (green) as the inherent nature of the 5 x 5 risk matrix (Figure 2) and associated risk level color-coding does not allow for the following scenarios to exist:

1. CO₂ migration into Nisku formation: no orange or red risk levels
2. CO₂ migration into porous intervals between Nisku formation and base of groundwater: no red risk level
3. CO₂ migration out of surface casing vent (SCVF): no red risk level
4. CO₂ migration through soil to atmosphere (GM): no green risk level

Table 6. Risk Assessment Results Well Count Summary

	Nisku	Other porosity	SCVF	Groundwater	GM
Red (risk level: 20 - 25)	0	0	0	1	1
Orange (risk level: 10 – 19)	0	3	2	3	4
Yellow (risk level: 5 – 9)	0	12	15	21	26
Green (risk level: 1 – 4)	31	16	14	6	0
Total	31	31	31	31	31

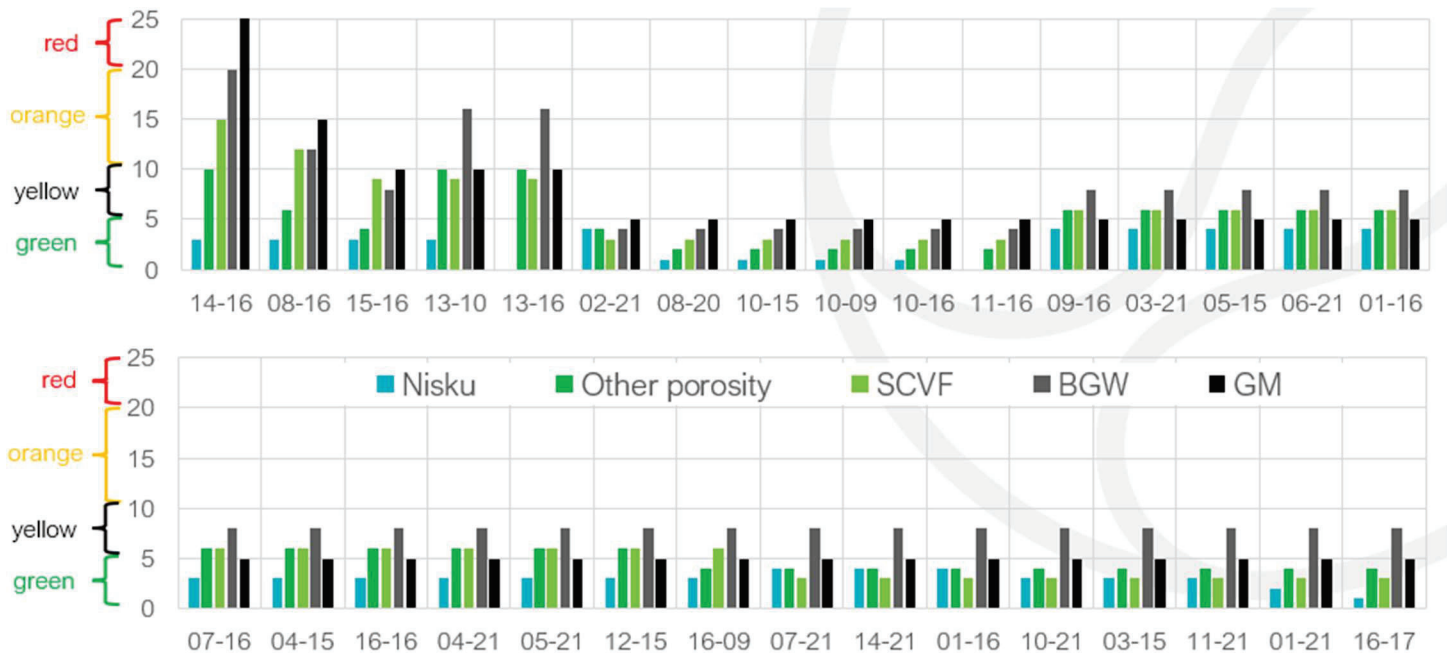


Figure 4. Well risk level for all five CO₂ migration pathways

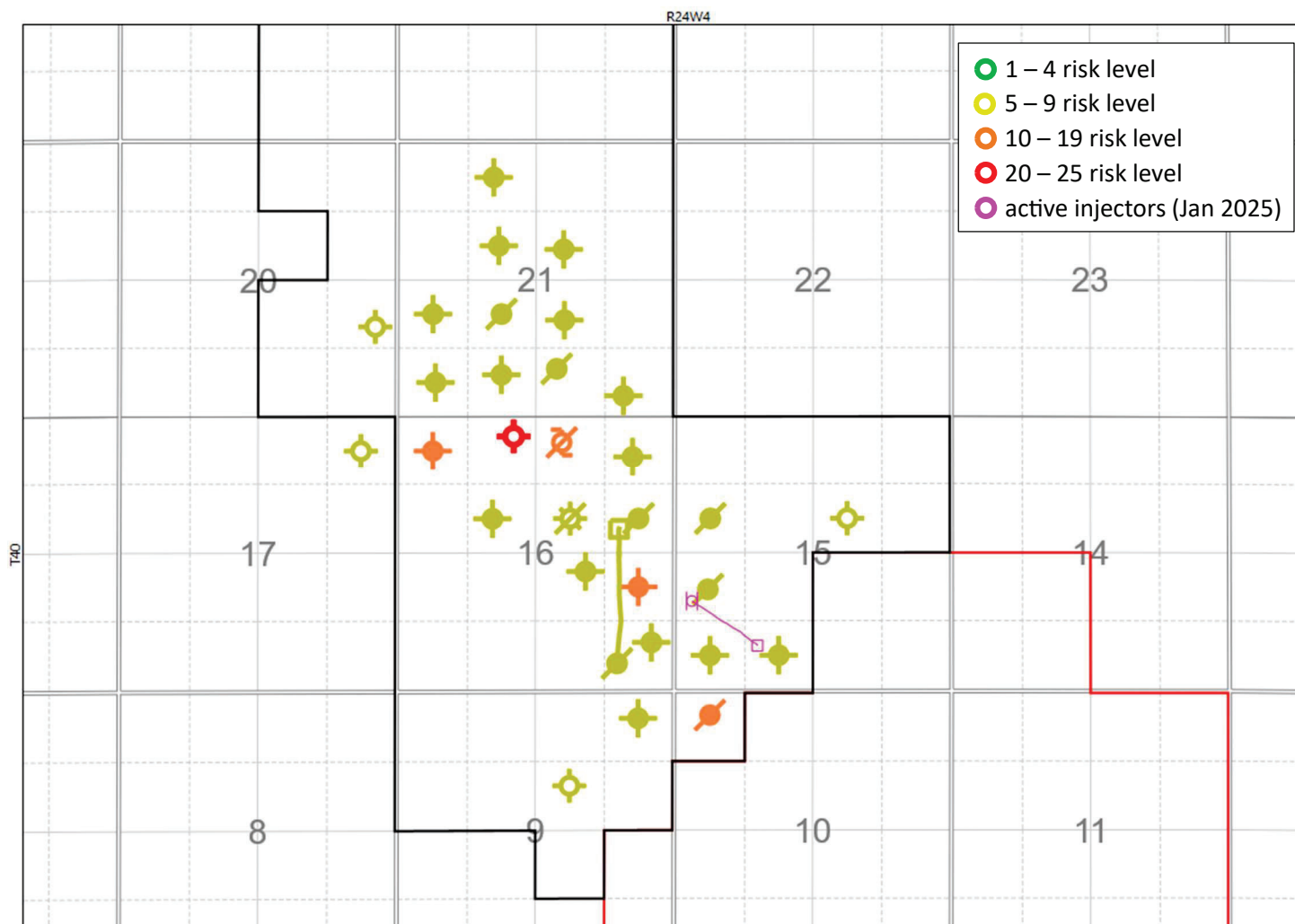


Figure 5. Well risk level map

4. Preventative Barriers

Preventative barriers for loss of fluid containment consist of implementing a monitoring program to be able to detect a potential leak in the first place and then taking appropriate actions to confirm and eliminate it.

4.1 Containment Assurance

Enhance Energy recognizes the importance of the Measurement, Monitoring and Verification (MMV) program in identifying any loss of CO₂ containment. The MMV program has been operational at Clive since CO₂ was first injected into Leduc formation in 2020 and has been expanded over time to ensure coverage over the CO₂ plume area as it advances within the reservoir out from the injector locations. The MMV program consists of:

1. Static gradient: measurement of reservoir pressures in the Leduc and Nisku zones evaluating pressure against predicted trends.
2. Gas sampling: gas composition analysis identifies composition changes from the baseline values and isotope analysis is used to identify the source of CO₂ in the sample.
3. Bubble test: indicates a SCVF.
4. Water sampling: water composition analysis identifies composition changes from baseline values in aquifers and isotope analysis is used to identify the source CO₂ in the sample.
5. Soil gas sampling: gas composition analysis identifies composition changes from expected values in the biosphere and isotope is isotope analysis is used to identify the source of CO₂ in the sample.
6. Atmospheric monitoring: soil flux sampling is used to collect samples of the gas being released from the biosphere into the atmosphere. The gas composition analysis identifies composition changes from expected values.
7. Casing pressure: monitoring casing pressure helps identify possible migration through a packer, hole in tubing or cross-flow between formations

Currently, there is a significant baseline of monitoring in AER Area Part 2 that will be utilized to provide containment assurance as the CO₂ plume advances from injection into 04/03-15-040-24W4/0 and 02/05-15-040-24W4/0 wells as illustrated in Figure 6. Enhance Energy will continue refining its MMV program to ensure wellbore locations characterized with high risk level are appropriately monitored by adjusting its scope to meet criteria outlined in Table 6.

Current MMV Program Map

- 1 – 4 risk level
- 5 – 9 risk level
- 10 – 19 risk level
- 20 – 25 risk level
- CBM header sampling location
- Soil gas sampling locations
- Landowner water well
- SCVF locations
- Dedicated water wells

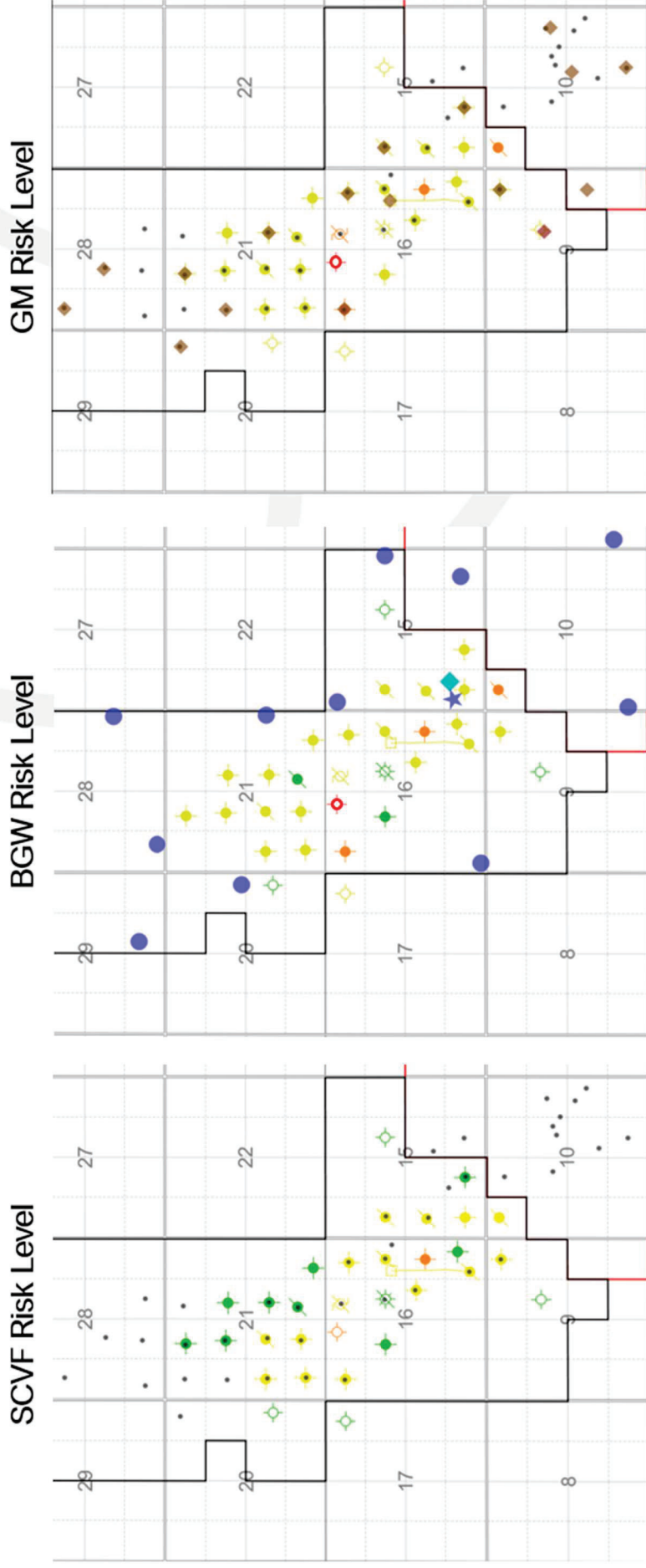


Figure 6. Current monitoring locations over area of interest

Table 6. Monitoring and Diagnostic Program Scope

CO ₂ migration pathway		Monitoring or Diagnostic Activity	Green	Yellow	Orange	Red
Nisku		Static gradient	-	1 per year	N/A	N/A
		Gas sampling	-	2 per year	N/A	N/A
		Gas sampling	-	-	1 per year	N/A
Other porosity		Bubble test	Up to 1 per year	Up to 2 per year	Up to 3 per year	N/A
Surface casing vent flow						
Groundwater		Water sampling	1 per year	2 per year	2-3 per year	2-4 per year
		Shallow gas sampling	2 per year from header	4 per year from header	Monthly from header	Monthly from header and proximal sampling (1 per year)
		Wellbore intervention	-	-	-	Well specific evaluation
		Atmospheric monitoring	N/A	-	-	Up to 2 soil flux tests per year
Gas Migration		Soil gas sampling	N/A	-	Up to 1 per year	Up to 2 per year
		Casing pressure	N/A	Up to 1 per year	Up to 2 per year (with bubble test)	Up to 3 per year (with bubble test)
		Wellbore intervention	N/A	-	-	Well specific evaluation

The scope and frequency of monitoring activities increase with risk level for each CO₂ migration pathway to maximize probability of detecting leaks early for higher risk wells and then taking appropriate mitigative actions. Considering broad array of wellbore designs within Clive D3 A pool boundary, the wellbore intervention plan will focus on case specific wellbore diagnostics followed by appropriate mitigative actions as required.

The provided range for monitoring activities seeks to honour individual circumstances for each well that will influence the decision for coupling the MMV program with the appropriate frequency. These individual circumstances include presence of a wellhead, the access rights to land or well, proximity to injectors and geological structural highs. Some cells within Table 6 contain not-applicable (N/A) category, because of the inherent nature of the 5 x 5 risk matrix the associated risk level color-coding does not allow for some scenarios to exist as discussed in section 3.

4.2 Response Triggers and Actions

Data acquired from the MMV program has been and will continue to be analyzed to ensure CO₂ containment within the injection zone. Any deviation of results from expected ranges will serve as triggers to take appropriate response actions as summarized in Table 7. The general chronological steps that will be taken include:

1. Results validation: ensure samples were collected properly and test equipment was calibrated
2. Re-test: re-do test, collect a sample and send for appropriate laboratory analysis (fluid composition, isotope analysis, etc.)
3. Notify stakeholders: notify AER, landowners or subsurface resource owners
4. Wellbore diagnostics: develop and execute on well-specific plan for wellbore diagnostics such as pressure testing a bridge plug, running casing inspection log, etc. If wellbore diagnostics confirm a wellbore leak, reverse order of steps 5 and 6
5. Monitor: evaluate if monitoring program scope or frequency needs to be revised, and continue to monitor for defined period of time to determine if deviation from expected ranges persists
6. Broader investigation: develop and execute on well-specific plan for wellbore leak remediation. Conduct holistic investigation into nearby area which could include deep diving into geological structure, tuning reservoir simulation models, conducting more testing (sample collection, pressure testing, etc.) in offset wells

Table 7. MMV Response Triggers and Actions

MMV activity	CO ₂ migration pathway	Response trigger	Response actions					
			Step #1	Step #2	Step #3	Step #4	Step #5	Step #6
Static gradient	Nisku	Deviation from projected pressure trend	Results validation (incl. re-testing)	Gas sample - gas analysis	Wellbore diagnostics	Notify AER	Monitor for 3 - 6 mo., repeat #1-2	Broader study
Gas sample	Nisku Other porosity Groundwater	Deviation from baseline composition	Results validation	Gas sample - carbon isotope	Wellbore diagnostics	Notify AER	Monitor for 3 - 6 mo., repeat #1-2	Broader study
Bubble test	Surface casing vent flow	Presence of gas bubbles (Dir.#087)	Re-test	Gas sample - carbon isotope	Notify AER	Wellbore diagnostics		
Water sample	Groundwater	Deviation from baseline composition	Re-test	Water sample- composition & carbon isotope	Notify AER and landowners	Water sample from nearby well - composition & carbon isotope	Broader study	
Soil gas sample	Gas migration	Deviation from baseline composition, plant growth	Results validation	Gas sample - carbon isotope	Wellbore diagnostics	Notify AER and landowners	Monitor for 6 - 12 mo., repeat #1-2	Broader study
Atm-re Monitor	Gas migration	Deviation from seasonal average, rotten smell	Results validation (incl. re-testing)	Gas sample - carbon isotope	Wellbore diagnostics	Notify AER and landowners	Monitor for 6 - 12 mo., repeat #1-2	Broader study
Casing pressure	Gas migration	Deviation (spike up) from previous valid pressures	Results validation (incl. re-testing)	Gas sample – composition & carbon isotope (if warranted)	Wellbore diagnostics	Notify AER and landowners	Monitor for 3 - 6 mo., repeat #1-2	Broader study

5. References

1. Watson, T.L., Bachu, S., Evaluation of the Potential for Gas and CO₂ Leakage Along Wellbores; SPE 106817, Presented at the 2007 SPE E&P Environmental and Safety Conference held in Galveston, Texas, USA, 5–7 March 2007.
2. Watson, T.L., Bachu, S., Identification of Wells With High CO₂-Leakage Potential in Mature Oil Fields Developed for CO₂-Enhanced Oil Recovery; SPE 112924, Presented at the 2008 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, Oklahoma, USA, 20-23 April 2008
3. Bachu, S., & Watson, T. (2009, 1). Review of Failures for Wells used for CO₂ and Acid Gas Injection in Alberta, Canada. Energy Procedia, 3565.
4. Watson, T.L., Evaluation of Wellbore Integrity In Wells Penetrating the Redwater Reef, 28 February 2009
5. Chalaturnyk, Rick J., Carbon Storage – A Summary of Experience and Lessons Learned from Publicly Support Projects
6. Rajesh J. Pawar, Theresa L. Watson, Carl W. Gable, (2009), Numerical Simulation of CO₂ Leakage through Abandoned Wells: Model for an Abandoned Site with Observed Gas Migration in Alberta, Canada, Energy Procedia 1,3625–3632
7. J. William Carey, Marcus Wigand, Steve J. Chipera, Giday Wolde Gabriel, Rajesh Pawar, Peter C. Lichtner, Scott C. Wehner, Michael A. Raines, George D. Guthrie Jr., Analysis and performance of oil well cement with 30 years of CO₂ exposure from the SACROC Unit, West Texas, USA 28 December 2006

6. Attachment List

Attachment 1: Clive Wellbore Risk Assessment Part A Spreadsheet



enhance

Clive D-3A Pool CO₂ EOR Scheme

**Offset Wellbore Risk Assessment
Part B**

Prepared for:

Well Integrity Team

Alberta Energy Regulator

Prepared by:

Enhance Energy Inc.

June 2025

1. Introduction

Enhance Energy Inc. has been granted approval (No.12832N) for amendment of CO₂ enhanced oil recovery scheme in Clive D-3 A Pool by Alberta Energy Regulator on October 11, 2024. Sections 17a-b of the approval stipulate that:

“a) Offset wellbore risk assessment must be submitted to the AER Well Integrity inbox, welloperations@aer.ca, by November 30, 2024 for all wells within the area designated as Part 2 in Appendix A that will be encompassed by the free phase CO₂ plume after 18 months of CO₂ injection into the 04/03-15-040-24W4/0 and 02/05-15-040-24W4/0 wells.

b) Offset wellbore risk assessment must be submitted to the AER Well Integrity inbox, welloperations@aer.ca, by March 31, 2025 for all wells within the area designated as Part 2 in Appendix A not reviewed under subclause a).”

A timeline extension has been granted to Enhance Energy to submit offset wellbore risk assessment Part B by June 15, 2025 to acknowledge outstanding questions to resolve for Part A submission.

In support of the approval, Enhance Energy has developed and applied wellbore risk assessment (WRA) methodology to evaluate CO₂ containment risk at all offset wells within prescribed area boundary and CO₂ injection timelines. The risk WRA methodology and preventative barriers have been described in detail in the Offset Wellbore Risk Assessment Part A document, submitted on November 30, 2024. Figure 1 illustrates all 43 offset wells that fit criteria outlined in Section 17b. Results of this risk assessment guided identification of wells with higher CO₂ containment risk and development of appropriate preventative barriers.

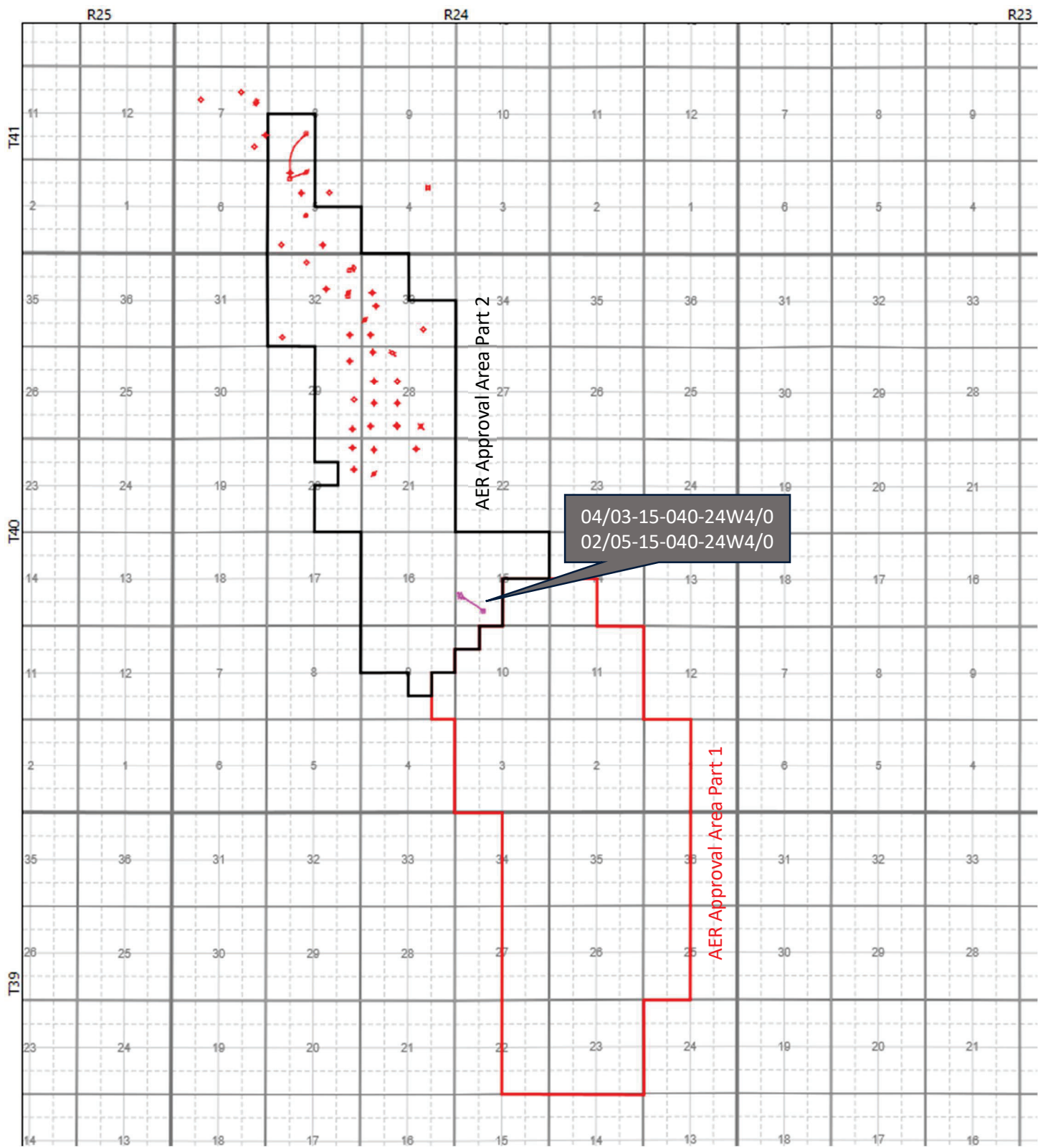


Figure 1. Offset wells within the area designated as Part 2 not reviewed under subclause 17a)

2. Risk Assessment Results

All the raw input data, the performed calculations and the results of this risk assessment for 43 offset wells that fit criteria outlined in Section 17b of EOR approval No.12832N are provided in an excel spreadsheet attachment. Table 1 presents overall statistics for how many wells fall under four colour-coded risk level categories for each CO₂ migration pathway. It can be observed that there are no wells that fall under the highest risk red category and there are four unique wells that fall on the low to medium range of the orange risk level category. Figure 2 helps visualize where geographically these higher risk wells are located. Note that this risk level map shows highest risk level amongst five different CO₂ migration paths. Hence there are no low level risk wells (green) as the inherent nature of the 5 x 5 risk matrix and associated risk level color-coding does not allow for the following scenarios to exist:

1. CO₂ migration into Nisku formation: no orange or red risk levels
2. CO₂ migration into porous intervals between Nisku formation and base of groundwater: no red risk level
3. CO₂ migration out of surface casing vent (SCVF): no red risk level
4. CO₂ migration through soil to atmosphere (GM): no green risk level

Table 1. Risk Assessment Results Well Count Summary

	Nisku	Other porosity	SCVF	Groundwater	GM
Red (risk level: 20 - 25)	0	0	0	0	0
Orange (risk level: 10 – 19)	0	17	19	17	15
Yellow (risk level: 5 – 9)	0	7	24	10	28
Green (risk level: 1 – 4)	43	19	0	16	0
Total	43	43	43	43	43

Currently, there is a significant baseline of monitoring in AER Area Part 2 that will be utilized to provide containment assurance as the CO₂ plume advances Northward from injection into 04/03-15-040-24W4/0 and 02/05-15-040-24W4/0 wells as illustrated in Figures 3 to 5. Data acquired from the MMV program has been and will continue to be analyzed to ensure CO₂ containment within the injection zone. Any deviation of results from expected ranges will serve as triggers to take appropriate response actions as described previously in section 4 of Offset Wellbore Risk Assessment Part A document, submitted on November 30, 2024

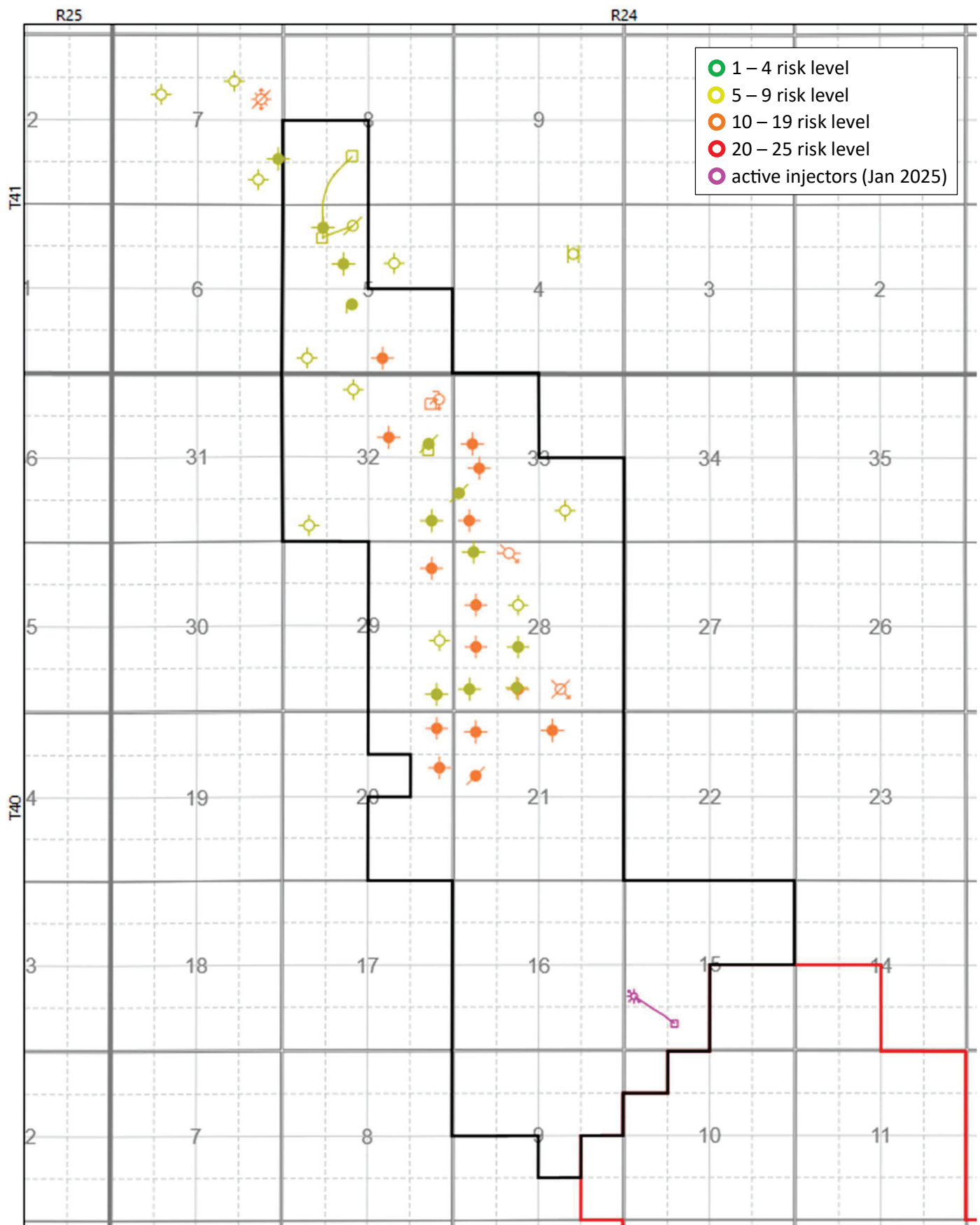


Figure 2. Well risk level map

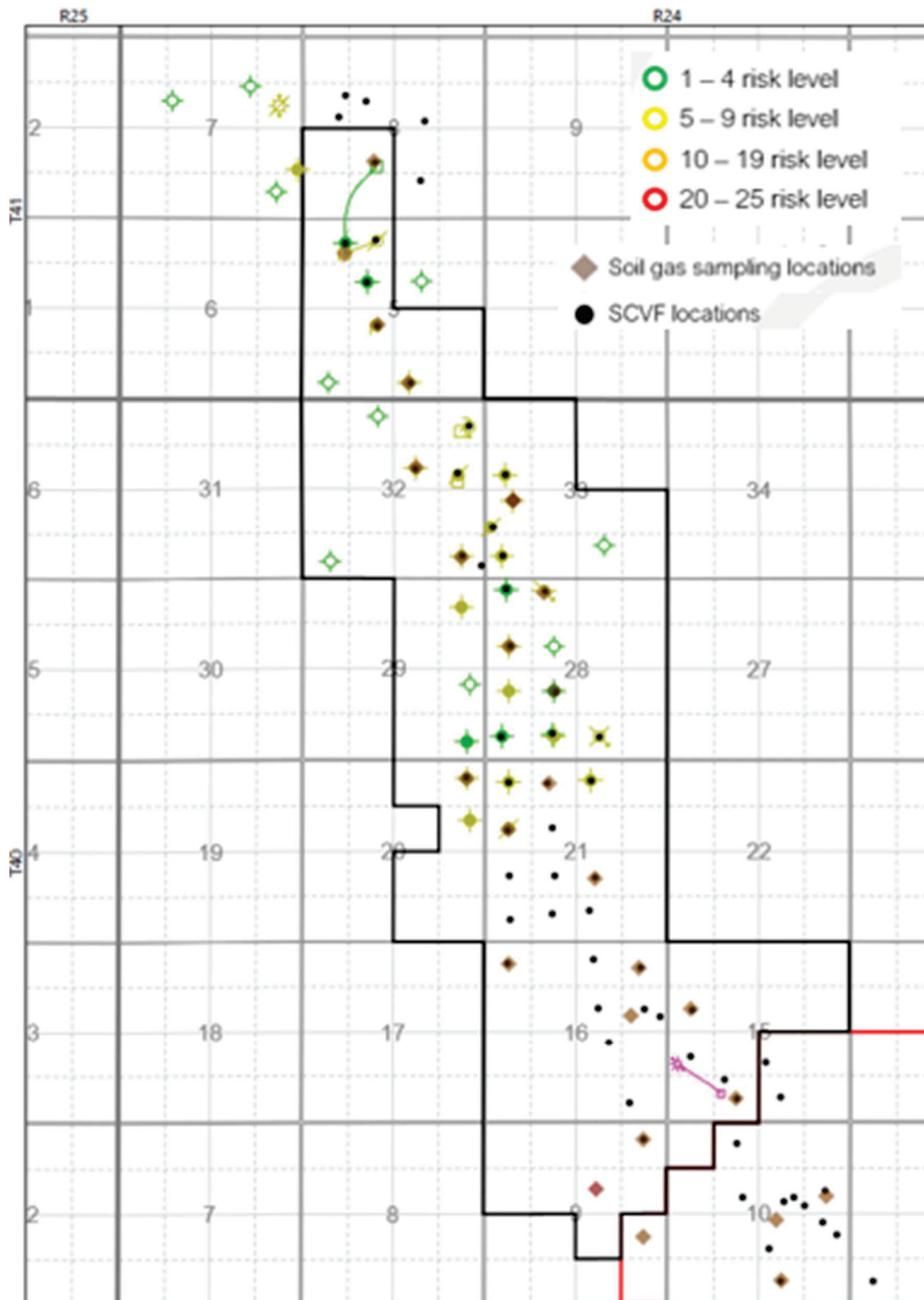


Figure 3. Risk level of leak through SCVF with current monitoring locations over area of interest

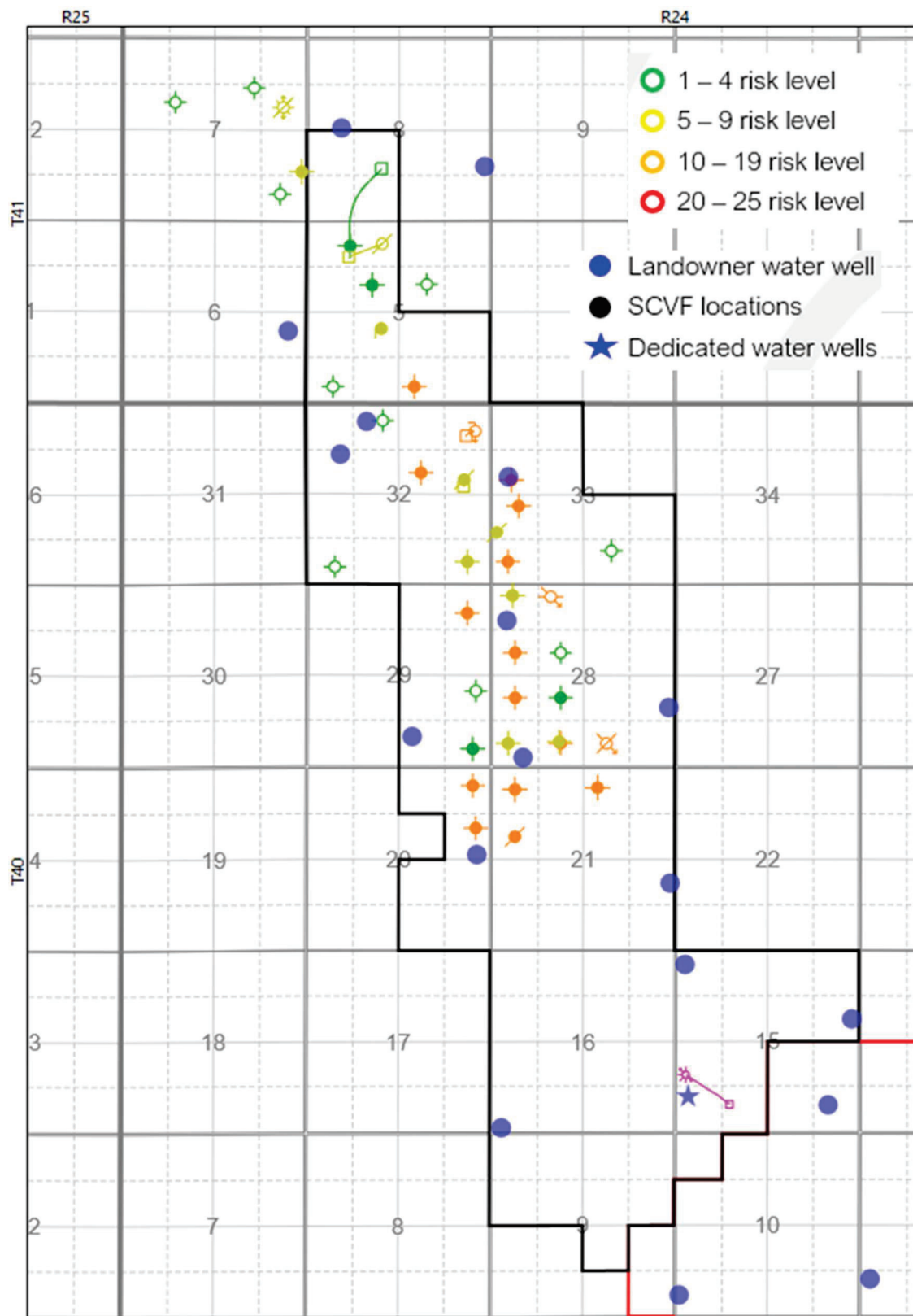


Figure 4. Risk level of leak to groundwater with current monitoring locations over area of interest

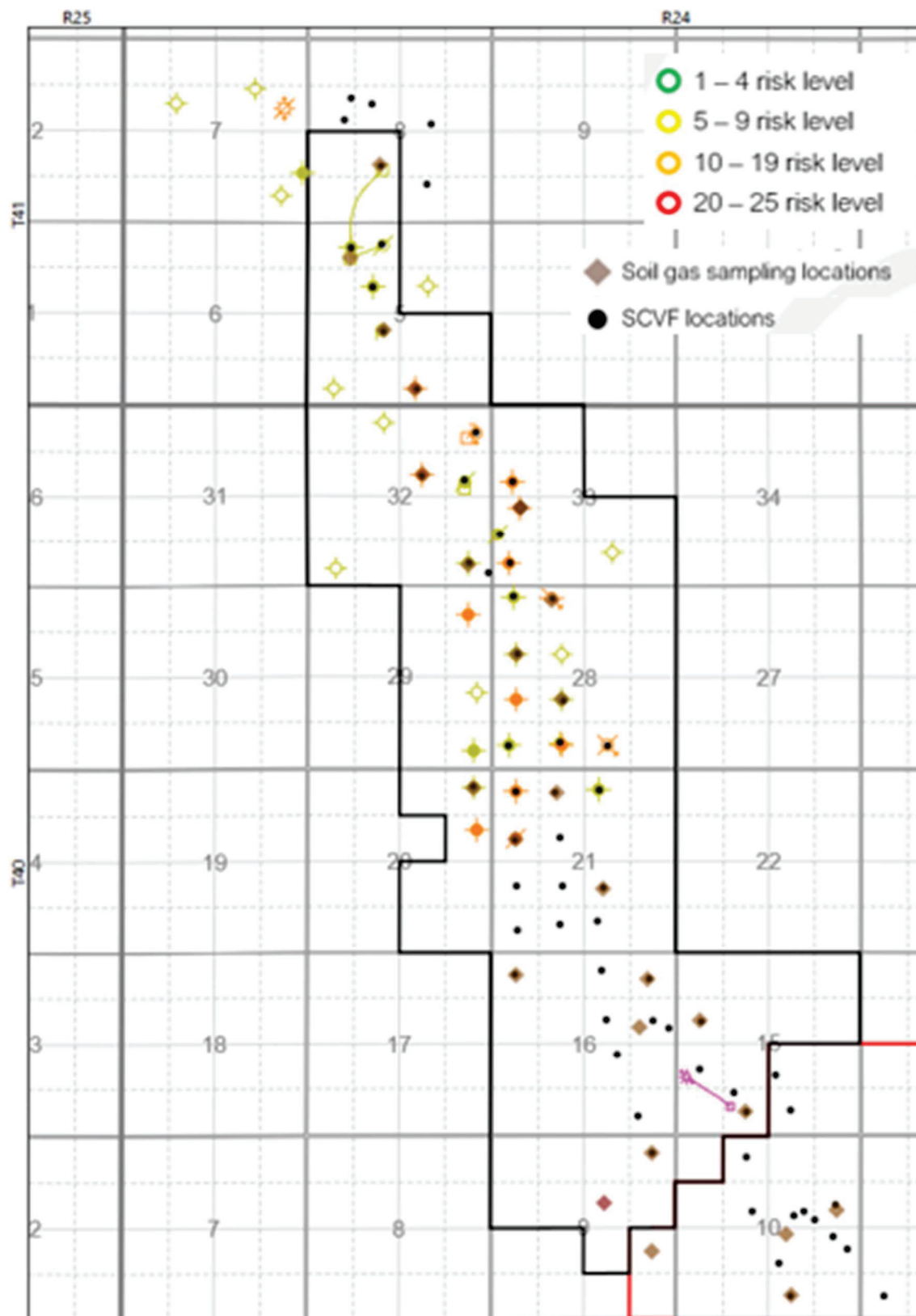


Figure 5. Risk level of leak to atmosphere through gas migration with current monitoring locations over area of interest

If you have any questions, please do not hesitate to contact the undersigned at alatypov@enhanceenergy.com

Date: June 13, 2025

Name: Azat Latypov

Signature: 

3. Attachment List

Attachment 1: Clive Wellbore Risk Assessment Part B Spreadsheet



enhance

Clive D-3A Pool CO₂ EOR Scheme

**Offset Wellbore Risk Assessment
Part C**

Prepared for:

Well Integrity Team

Alberta Energy Regulator

Prepared by:

Enhance Energy Inc.

September 2025

1. Introduction

Enhance Energy Inc. has been granted approval (No.12832N) for amendment of CO₂ enhanced oil recovery scheme in Clive D-3 A Pool by Alberta Energy Regulator on October 11, 2024. Section 17c of the approval stipulated that:

“c) Offset wellbore risk assessment must be submitted to the AER Well Integrity inbox, welloperations@aer.ca, by June 30, 2025 for all wells within the area designated as Part 1 in Appendix A.”

A timeline extension has been granted to Enhance Energy to submit offset wellbore risk assessment Part C by September 15, 2025.

In support of the approval, Enhance Energy has developed and applied wellbore risk assessment (WRA) methodology to evaluate CO₂ containment risk at all offset wells within prescribed area boundary and CO₂ injection timelines. The risk WRA methodology and preventative barriers have been described in detail in the Offset Wellbore Risk Assessment Part A document, submitted on November 30, 2024. Figure 1 illustrates 61 offset wells that fit criteria outlined in Section 17c. Results of this risk assessment guided identification of wells with higher CO₂ containment risk and development of appropriate preventative barriers.

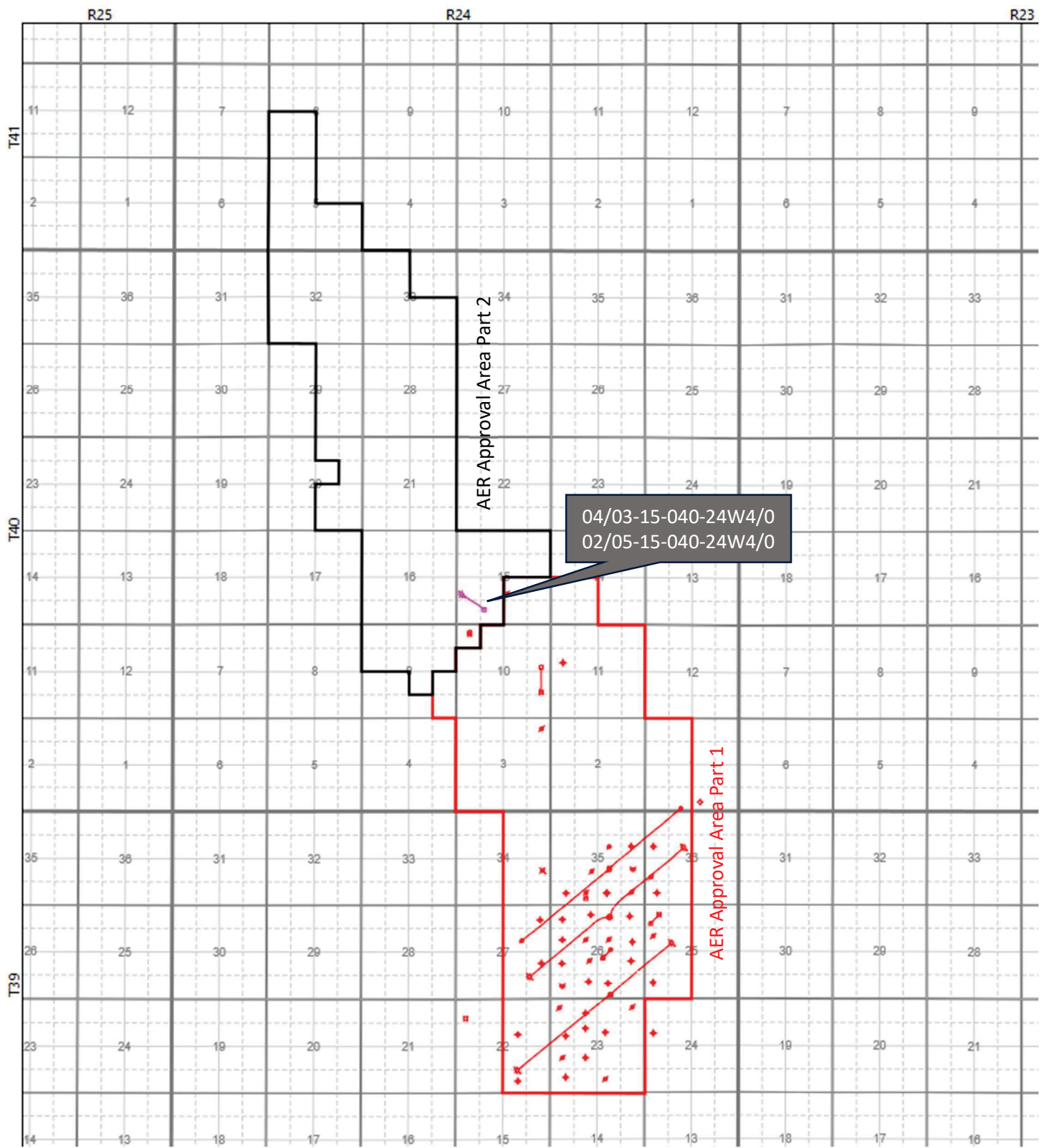


Figure 1. Offset wells within the area designated as AER Part 1

2. Risk Assessment Results

All the raw input data, the performed calculations and the results of this risk assessment for 61 offset wells that fit criteria outlined in Section 17c of EOR approval No.12832N are provided in an excel spreadsheet attachment. Table 1 presents overall statistics for how many wells fall under four colour-coded risk level categories for each CO₂ migration pathway. It can be observed that there are no wells that fall under the highest risk red category and there are four unique wells that fall on the low to medium range of the orange risk level category. Figure 2 helps visualize where geographically these higher risk wells are located. Note that this risk level map shows highest risk level amongst five different CO₂ migration paths. Hence there are no low level risk wells (green) as the inherent nature of the 5 x 5 risk matrix and associated risk level color-coding does not allow for the following scenarios to exist:

1. CO₂ migration into Nisku formation: no orange or red risk levels
2. CO₂ migration into porous intervals between Nisku formation and base of groundwater: no red risk level
3. CO₂ migration out of surface casing vent (SCVF): no red risk level
4. CO₂ migration through soil to atmosphere (GM): no green risk level

Table 1. Risk Assessment Results Well Count Summary

	Nisku	Other porosity	SCVF	Groundwater	GM
Red (risk level: 20 - 25)	0	0	0	0	0
Orange (risk level: 10 – 19)	0	31	2	32	32
Yellow (risk level: 5 – 9)	0	7	33	29	29
Green (risk level: 1 – 4)	61	23	26	0	0
Total	61	61	61	61	61

Currently, there is a significant baseline of monitoring in AER Area Part 1 that will be utilized to provide containment assurance as the CO₂ plume advances Northward from injection into 04/03-15-040-24W4/0 and 02/05-15-040-24W4/0 wells as illustrated in Figures 3 to 5. Data acquired from the MMV program has been and will continue to be analyzed to ensure CO₂ containment within the injection zone. Any deviation of results from expected ranges will serve as triggers to take appropriate response actions as described previously in section 4 of Offset Wellbore Risk Assessment Part A document, submitted on November 30, 2024

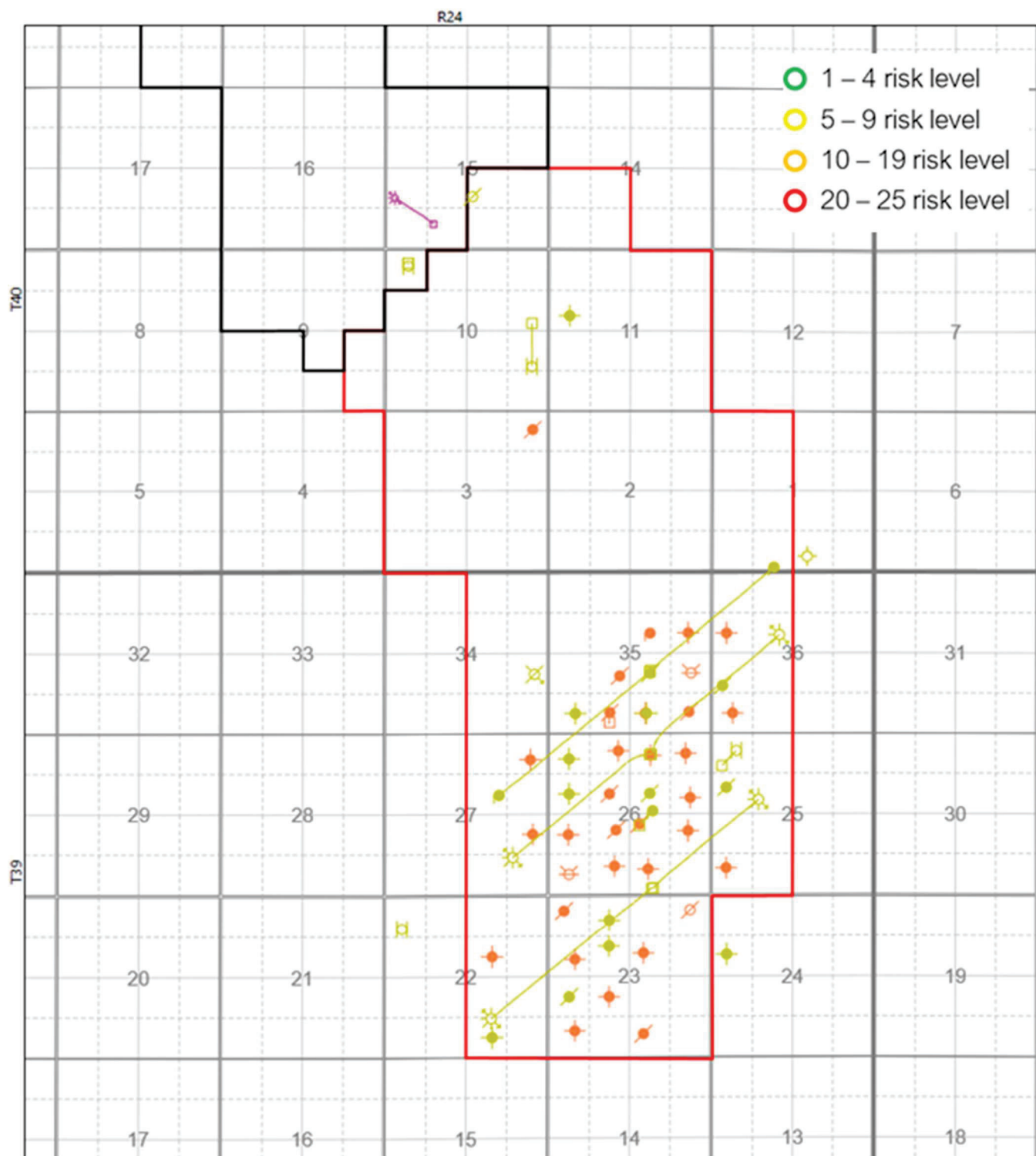


Figure 2. Well risk level map

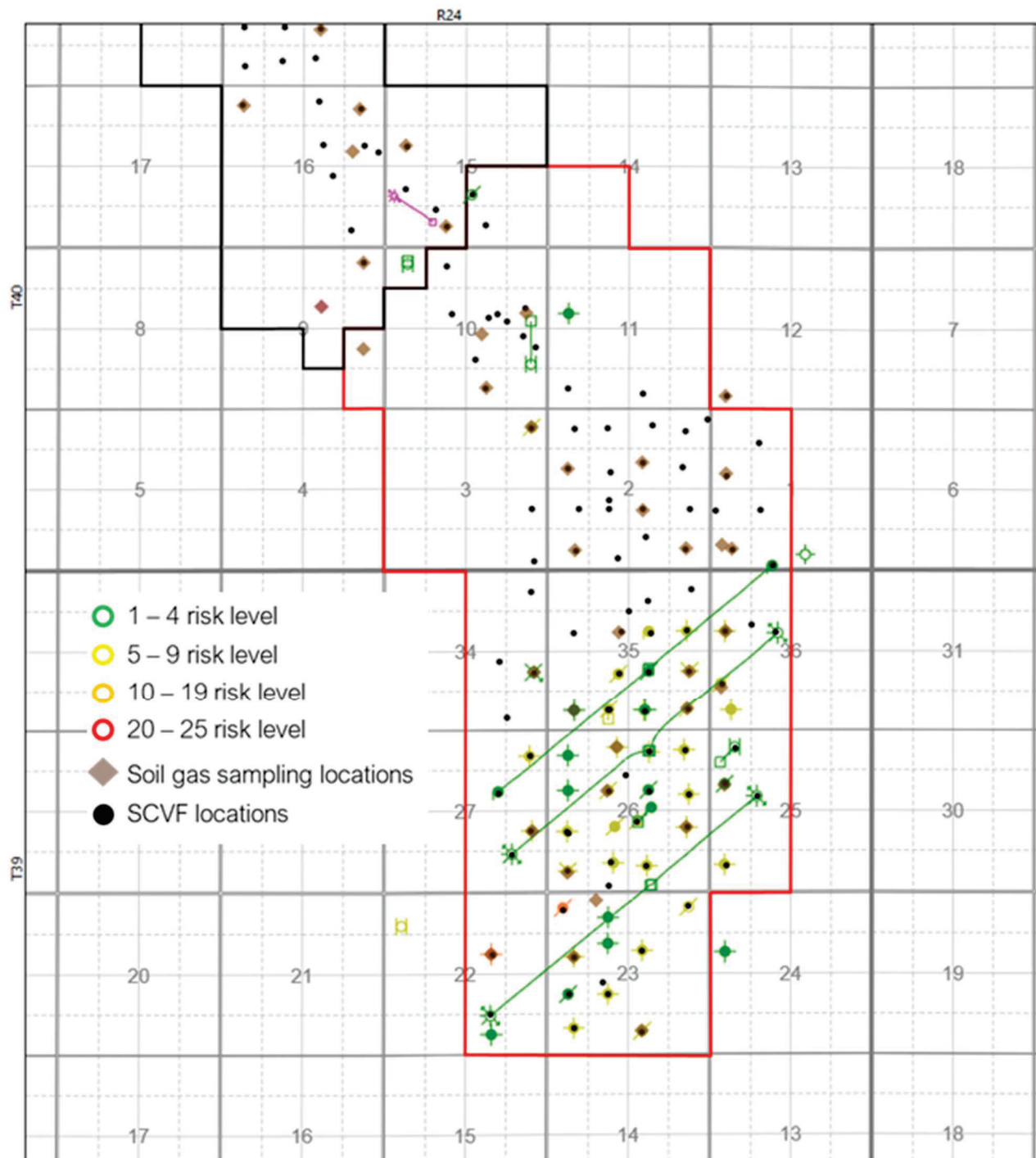


Figure 3. Risk level of leak through SCVF with current monitoring locations over area of interest

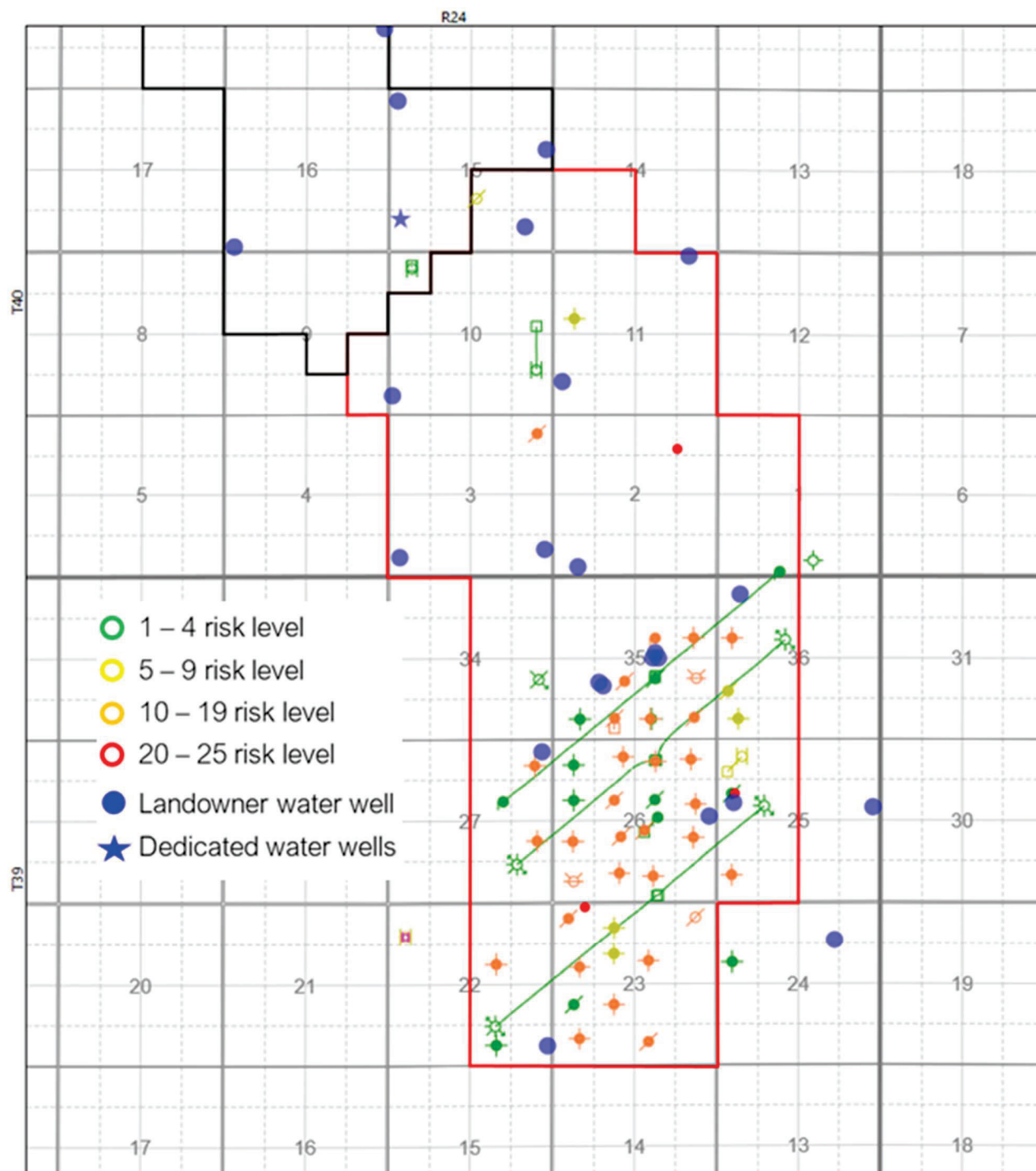


Figure 4. Risk level of leak to groundwater with current monitoring locations over area of interest

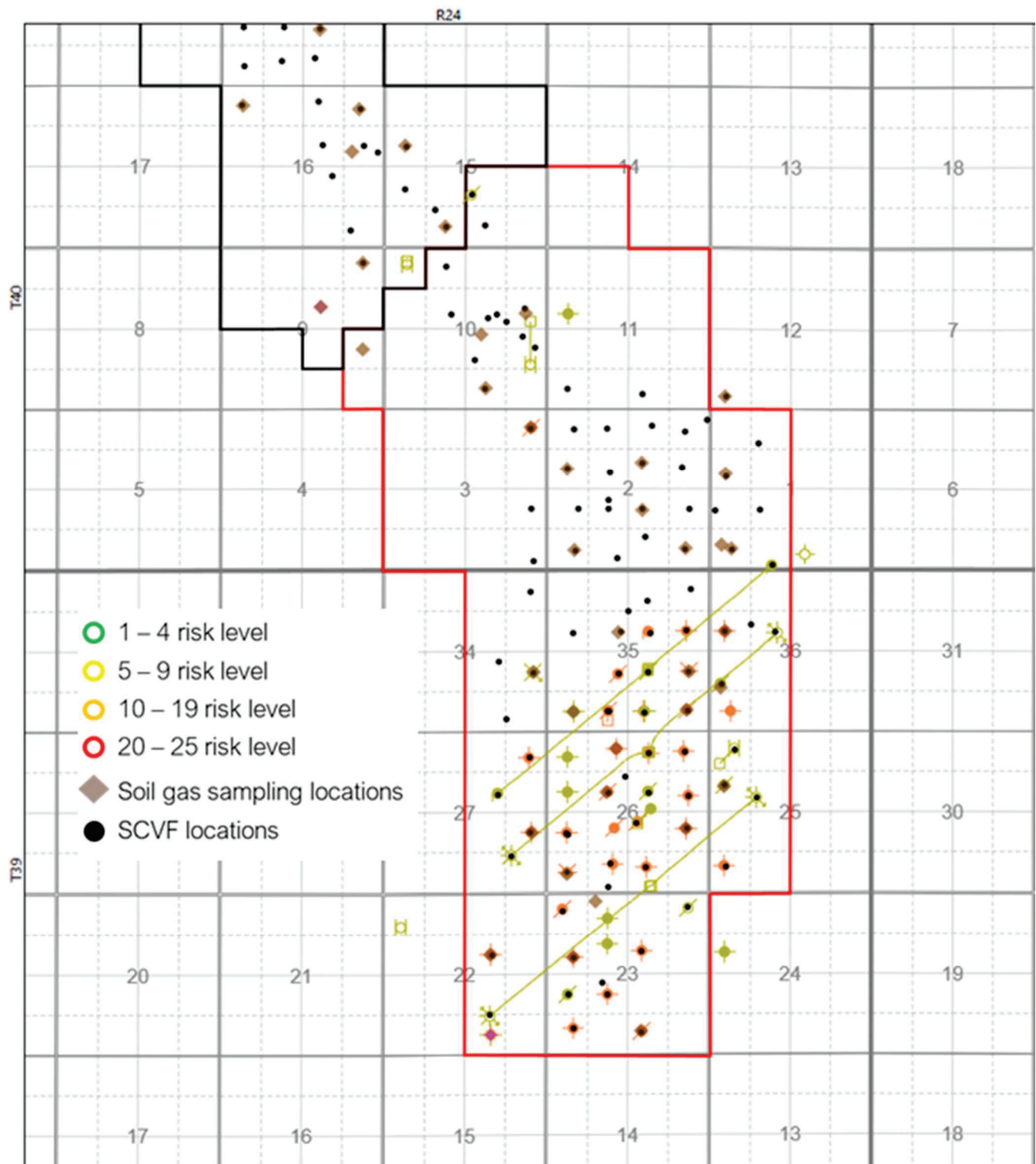


Figure 5. Risk level of leak to atmosphere through gas migration with current monitoring locations over area of interest

If you have any questions, please do not hesitate to contact the undersigned at alatypov@enhanceenergy.com

Date: September 15, 2025

Name: Azat Latypov

Signature: 

3. Attachment List

Attachment 1: Clive Wellbore Risk Assessment Part C Spreadsheet



enhance

Clive D-3A Pool CO₂ EOR Scheme

**Offset Wellbore Risk Assessment
Part C Subpart 2**

Prepared for:

Well Integrity Team

Alberta Energy Regulator

Prepared by:

Enhance Energy Inc.

October 2025

1. Introduction

Enhance Energy Inc. has been granted approval (No.12832N) for amendment of CO₂ enhanced oil recovery scheme in Clive D-3 A Pool by Alberta Energy Regulator on October 11, 2024. Section 17c of the approval stipulates that:

“c) Offset wellbore risk assessment must be submitted to the AER Well Integrity inbox, welloperations@aer.ca, by June 30, 2025 for all wells within the area designated as Part 1 in Appendix A.”

A timeline extension has been granted to Enhance Energy to submit offset wellbore risk assessment Part C Subpart #2 by October 31, 2025.

In support of the approval, Enhance Energy has developed and applied wellbore risk assessment (WRA) methodology to evaluate CO₂ containment risk at all offset wells within the prescribed area boundary and CO₂ injection timelines. The WRA methodology and preventative barriers have been described in detail in the Offset Wellbore Risk Assessment Part A document, submitted on November 30, 2024. Figure 1 illustrates the remaining 48 offset wells that fit criteria outlined in Section 17c. Results of this risk assessment guided identification of wells with higher CO₂ containment risk and development of appropriate preventative barriers.

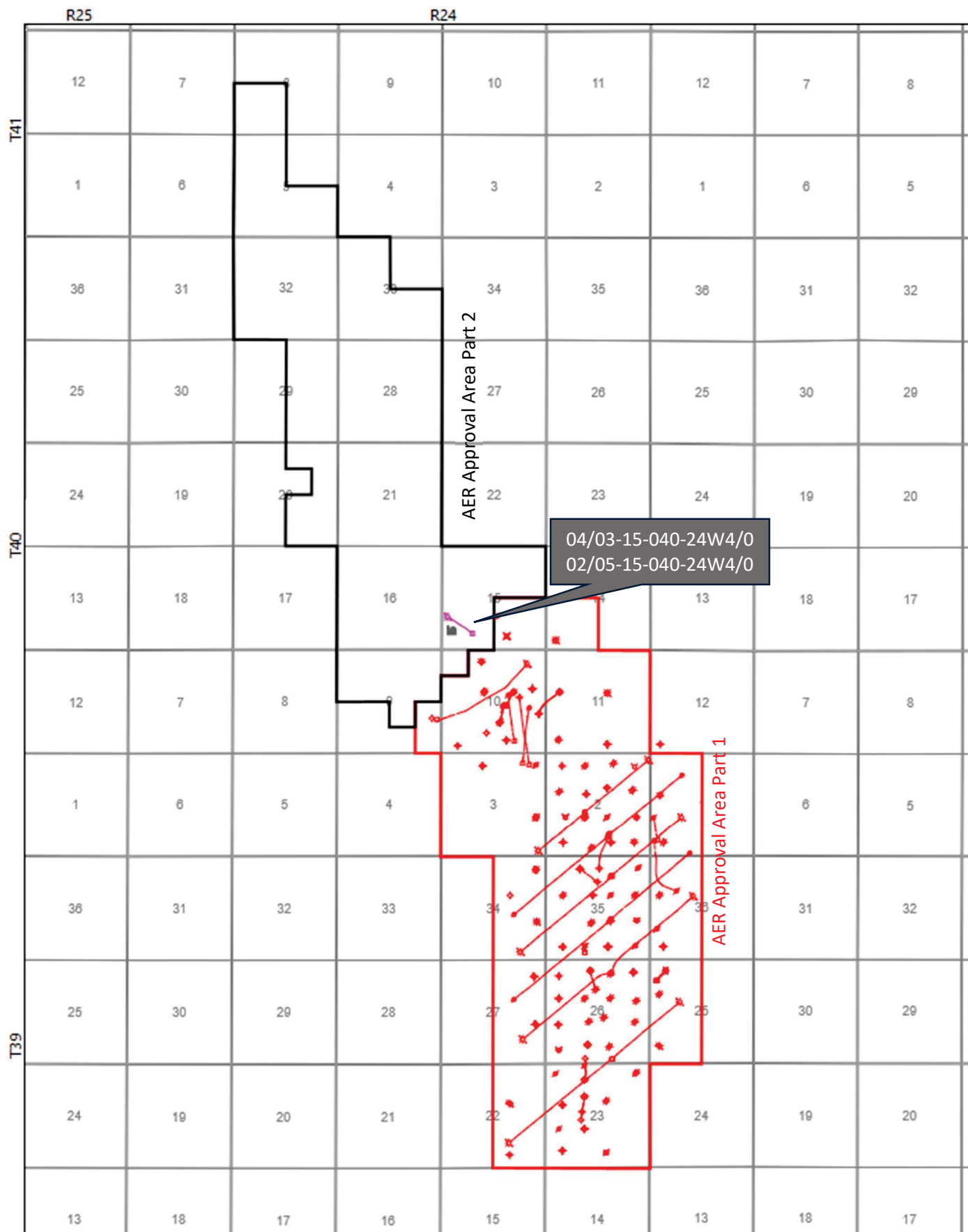


Figure 1. Offset wells within the area designated as AER Part 1

2. Risk Assessment Results

All the raw input data, the performed calculations and the results of this risk assessment for 48 offset wells that fit criteria outlined in Section 17c of EOR approval No.12832N are provided in an excel spreadsheet attachment. Table 1 presents overall statistics for how many wells fall under four colour-coded risk level categories for each CO₂ migration pathway. One red risk level well (100/07-10-040-24W4/00) was identified due to an existing surface casing vent flow. Deployed preventative barriers in place include on-going gas migration (soil gas sampling) and SCVF monitoring at its surface pad location. Figure 2 helps visualize where geographically these higher risk wells are located. Note that this risk level map shows highest risk level amongst five different CO₂ migration paths. Hence there are no low level risk wells (green) as the inherent nature of the 5 x 5 risk matrix and associated risk level color-coding does not allow for the following scenarios to exist:

1. CO₂ migration into Nisku formation: no orange or red risk levels
2. CO₂ migration into porous intervals between Nisku formation and base of groundwater: no red risk level
3. CO₂ migration out of surface casing vent (SCVF): no red risk level
4. CO₂ migration through soil to atmosphere (GM): no green risk level

Table 1. Risk Assessment Results Well Count Summary

	Nisku	Other porosity	SCVF	Groundwater	GM
Red (risk level: 20 - 25)	0	0	0	0	1
Orange (risk level: 10 – 19)	0	24	1	24	4
Yellow (risk level: 5 – 9)	0	1	23	6	43
Green (risk level: 1 – 4)	48	23	24	18	0
Total	48	48	48	48	48

Currently, there is a significant baseline of monitoring in AER Area Part 1 that will be utilized to provide containment assurance as the CO₂ plume advances Northward from injection into 04/03-15-040-24W4/0 and 02/05-15-040-24W4/0 wells as illustrated in Figures 3 to 5. Data acquired from the MMV program has been and will continue to be analyzed to ensure CO₂ containment within the injection zone. Any deviation of results from expected ranges will serve as triggers to take appropriate response actions as described previously in section 4 of Offset Wellbore Risk Assessment Part A document, submitted on November 30, 2024.

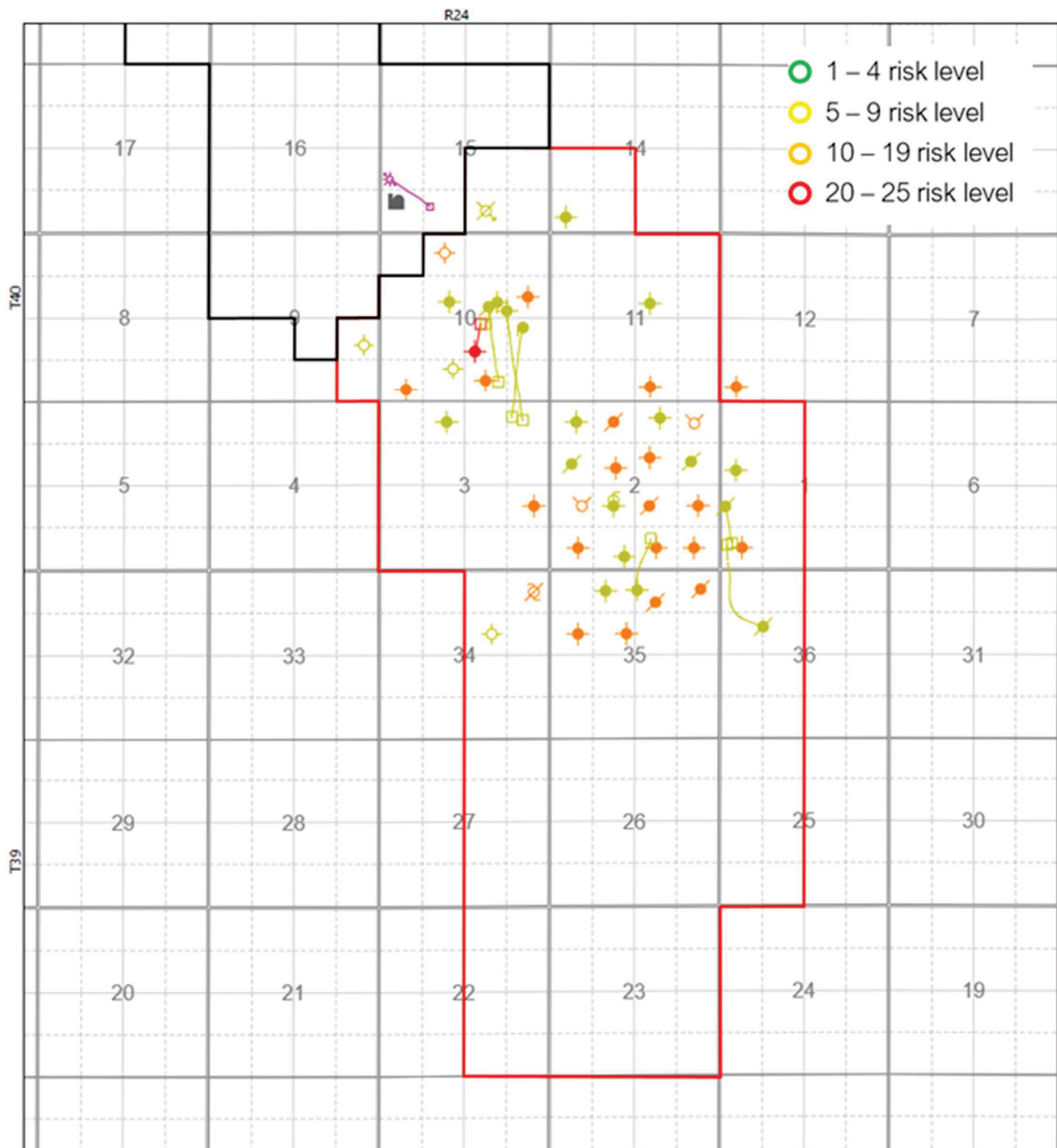


Figure 2. Well risk level map

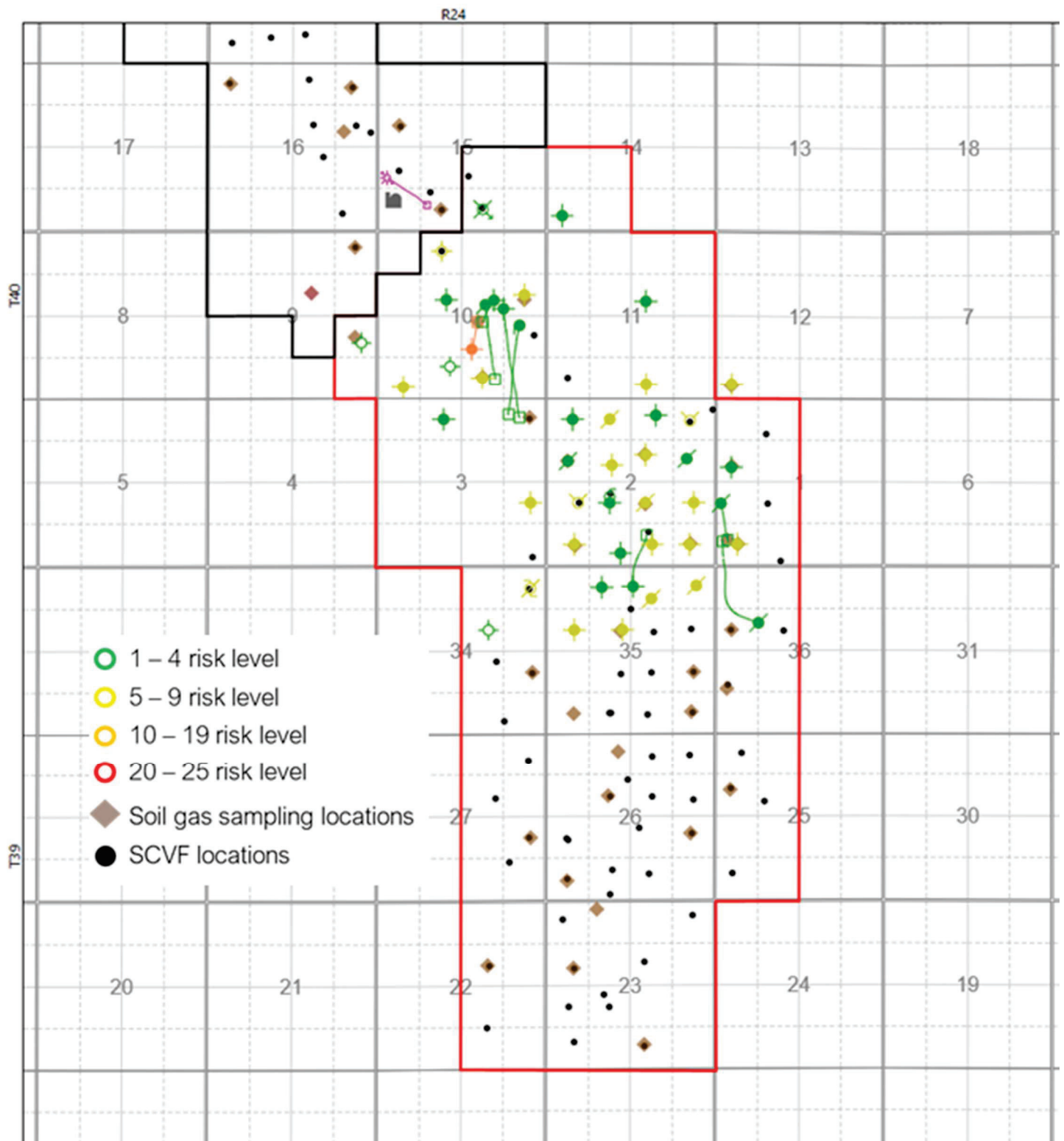


Figure 3. Risk level of leak through SCVF with current monitoring locations over area of interest

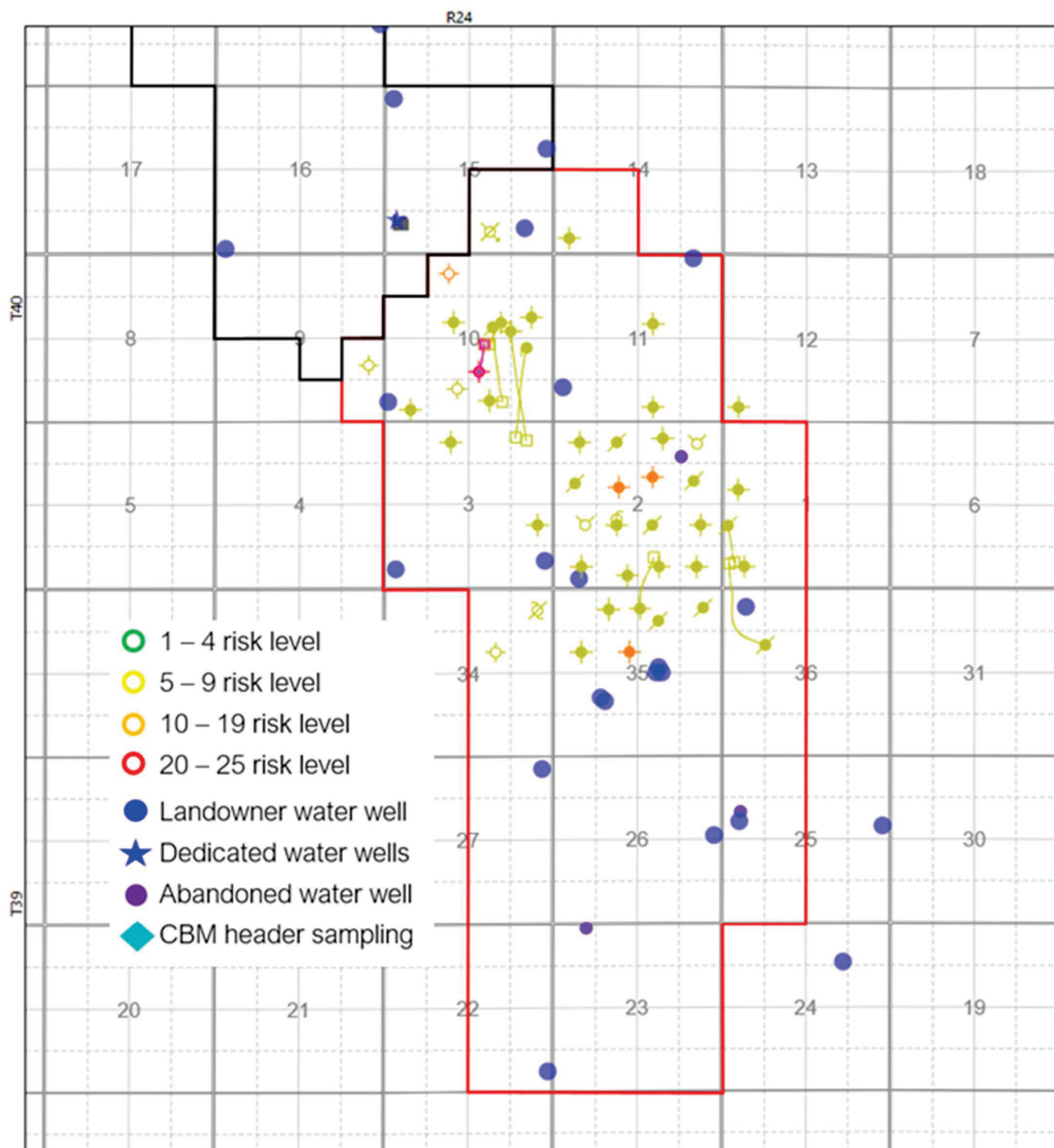


Figure 4. Risk level of leak to groundwater with current monitoring locations over area of interest

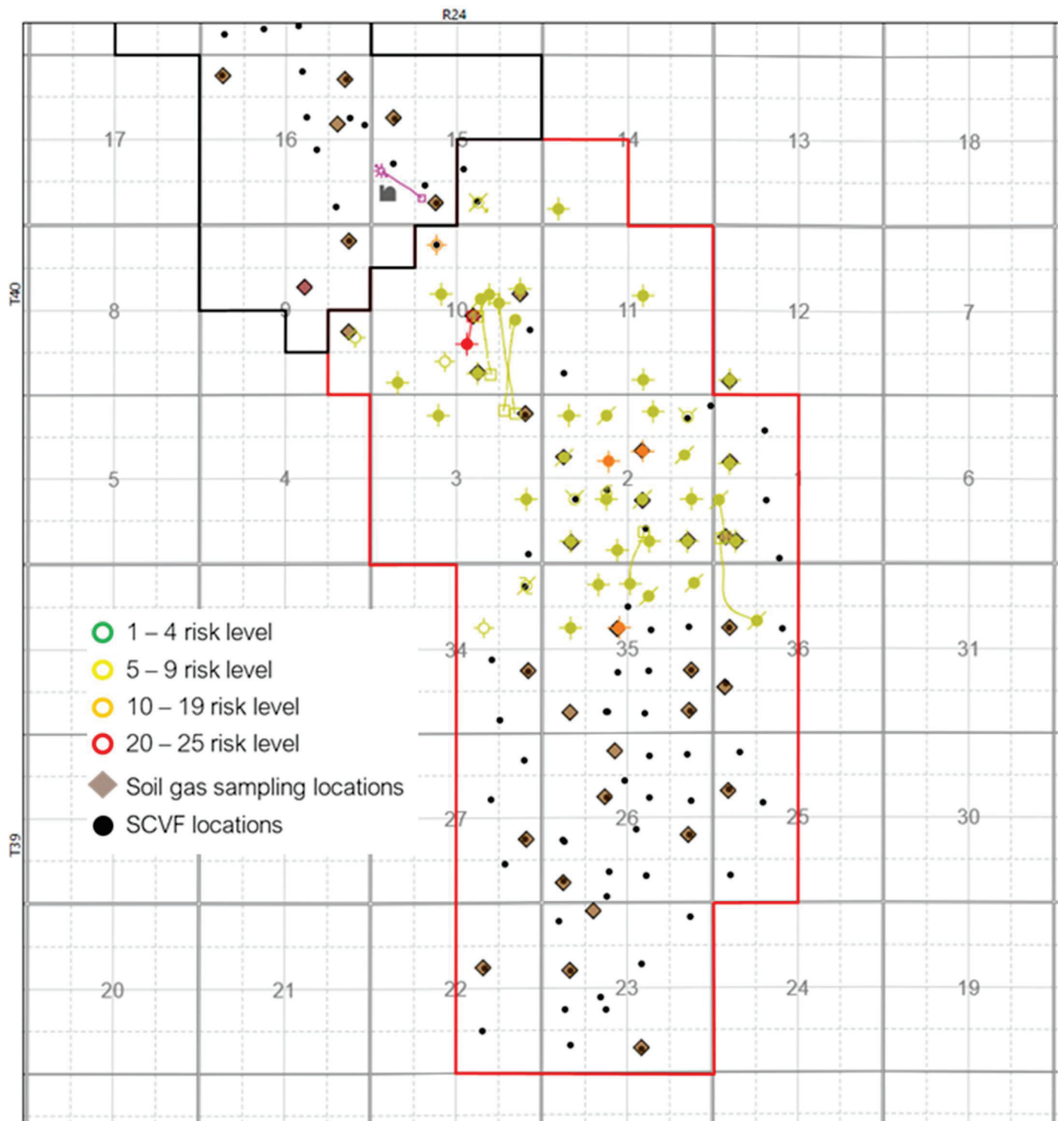


Figure 5. Risk level of leak to atmosphere through gas migration with current monitoring locations over area of interest

If you have any questions, please do not hesitate to contact the undersigned at alatypov@enhanceenergy.com

Date: October 31, 2025

Name: Azat Latypov

Signature:



3. Attachment List

Attachment 1: Clive Wellbore Risk Assessment Part C Spreadsheet #2

APPENDIX C: STANDARD OPERATING PROCEDURE

Standard Operating Procedure for Evaluation of Monitoring Data

**Clive CO₂ Injection &
Enhanced Oil Recovery
Project**

**Prepared for
Enhance Energy Inc.**

Report Submission To: Franki Race

Legal Company Name: Enhance Energy Inc.

Company Address: 3300 - 333 7 Avenue S.W. Calgary AB, T2P 2Z1

Contact Phone Number: +1 (403) 984-0217

Contact Email Address: frace@enhanceenergy.com

Submitted By: Aaron Petrowitsch

Legal Company Name: Integrated Sustainability

Company Address: 400, 1305 11th Avenue S.W. Calgary, Alberta T3C 3P6

Contact Phone Number: +1 (403) 369-1678

Contact Email Address: Aaron.Petrowitsch@integratedsustainability.com

Document Number: CP25-EEI-03-00-WR-RPT-2025_SOP_Rev0

Document Path: P:\EEI\CP25-EEI-03-00\5.0_Tech_Exec\5.6_GeoSci\SOP\Rev0\CP25-EEI-03-00-WR-RPT-2025_SOP_Rev0.docx

Document Revision Number: 0

WATER | WASTE | ENERGY

Disclaimer

The information presented in this document was compiled and interpreted exclusively for the purposes stated in Section 1 of the document. Integrated Sustainability provided this document for Enhance Energy Inc. solely for the purpose noted above.

Integrated Sustainability has exercised reasonable skill, care, and diligence to assess the information acquired during the preparation of this document, but makes no guarantees or warranties as to the accuracy or completeness of this information. The information contained in this document is based upon, and limited by, the circumstances and conditions acknowledged herein, and upon information available at the time of its preparation. The information provided by others is believed to be accurate but cannot be guaranteed.

Integrated Sustainability does not accept any responsibility for the use of this document for any purpose other than that stated in Section 1 and does not accept responsibility to any third party for the use in whole or in part of the contents of this document. Any alternative use, including that by a third party, or any reliance on, or decisions based on this document, is the responsibility of the alternative user or third party.

Any questions concerning the information or its interpretation should be directed to Aaron Petrowitsch.

Document Revision History

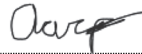
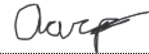
Rev No.	Rev Description	Author	Reviewer	Approver	Rev Date
0	Issued as Final	 Aaron Petrowitsch	 Jon Fennell	 Aaron Petrowitsch	03-Dec-2025

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Appendices

APPENDIX 1 - OTHER USEFUL DATA EVALUATION METHODS

1 INTRODUCTION

1.1 Project Background

Enhance Energy Inc. (Enhance) is an Alberta-based company that specializes in enhanced oil recovery (EOR) and carbon capture, utilization, and storage (CCUS). Enhance's Clive Project (the Project) is a CCUS operation located in Lacombe County, Alberta, near the village of Clive.

Monitoring at the Clive Project has been occurring since 2019 to fulfill the objectives of Enhance's approved Monitoring, Measurement & Verification (MMV) plan. Enhance has requested Integrated Sustainability to create a standard operating procedure (SOP) for data collection, management, evaluation, and reporting of water and soil gas samples.

The USEPA (2007) defines a SOP as follows:

"An SOP is a set of written instructions that document a routine or repetitive activity followed by an organization. The development and use of SOPs are an integral part of a successful quality system as it provides individuals with the information to perform a job properly and facilitates consistency in the quality and integrity of a product or end-result."

Monitoring programs often benefit from implementing standard operating procedures to ensure they can provide the necessary consistency to ensure high-quality and meaningful results. This SOP was developed so that internal Enhance personnel and their contracted qualified professionals (QPs) follow a consistent approach when conducting Data Collection, Analysis, and Reporting activities related to the Clive CCUS project.

1.2 Scope

This document represents the procedures to be used for collection of water samples from landowner wells, other dedicated monitoring wells, and soil gas sampling stations conducted by Enhance as part of the MMV plan. This SOP document outlines the following activities required to support the MMV plan:

- Identification of primary and secondary key indicator parameters (KIPs) for both groundwater and soil gas analysis.
- Revision of the analytical schedule to ensure relevance and cost efficiency.
- Outlining of the methods for selection of soil gas and groundwater monitoring locations and subsequent classification process.
- Develop data validation, assimilation, and screening processes, including how to deal with data anomalies and non-detects.
- Development of a process to establish background/baseline conditions, including the natural range of variability (NRV) and statistical evaluation to determine when a deviation from these conditions has occurred.
- A process to investigate and determine the source, cause, or reason(s) for a departure of measured monitoring values from established baseline conditions.
- A methodology for continued program optimization.

- Recommendations for the use of new monitoring technologies to provide more timely and effective detection and response for detected departures from baseline conditions.

2 DIAGNOSTIC INDICATOR PARAMETERS

Monitoring programs need to identify and select diagnostic indicator parameters that can identify the presence of operational-related constituents in samples collected during routine monitoring. The indicator parameters represent the more mobile, persistent, and potentially toxic constituents that are easily detectable and distinguishable from natural conditions using standard laboratory methods. Indicator parameters are site-specific to each operation, and those selected must consider the substances used, generated, and managed at a given site.

Indicator parameters are used in a tiered approach as follows:

- Primary indicators – used as a screening tool to identify where further investigation is warranted (i.e. routinely sampled, analyzed and assessed)
- Secondary indicators – used to support the investigation of concerns identified from the assessment of primary indicators (i.e. not routinely assessed unless primary indicator assessments suggest further examination is warranted)
- Tertiary indicators – more sophisticated analytical techniques to support a more refined investigation of source, cause, or reason for a detected monitoring anomaly.

Primary indicators are routinely assessed once a sufficient database of a more comprehensive set of parameters is obtained to determine if any changes have occurred to local system. In the scenario that primary indicators suggest that conditions are outside of established limits or have unacceptable trends, then the additional secondary, and possibly tertiary, indicators are assessed to determine the source, cause, and/or reason for the situation at hand.

2.1 Primary Indicators

Primary groundwater indicator parameters monitored, assessed and used as part of the annual monitoring report include the following:

- Soil gases including O₂, CO₂, CH₄, ethane (C₂H₆), and nitrogen (N₂).
- Dissolved gas in water samples, including carbon dioxide [CO₂], methane [CH₄], and hydrogen sulphide.
- Isotopic compositions (i.e. $\delta^{13}\text{C}_{\text{DIC}}$, $\delta^{13}\text{C}_{\text{CO}_2}$, $\delta^{13}\text{C}_{\text{CH}_4}$, and $\delta^{34}\text{S}_{\text{SO}_4}$), which are to be used for fingerprinting during baseline period before transitioning to being used as a secondary indicator.
- Field measured parameters (temperature, conductivity, pH, dissolved oxygen [DO] and oxidation-reduction potential [ORP]).
- Routine water quality parameters including total dissolved solids (TDS), pH, hardness, chloride, nitrate, and dissolved metals (e.g. iron [Fe] and manganese [Mn]).

While these primary indicator parameters are collected during each monitoring event, all parameters are not required to be assessed at all locations, unless required through investigative processes. The primary indicators used by Enhance are:

Free Phase Gases

- CO₂, O₂, N₂, CH₄, H₂S

Water

- Ion balance
- pH and Total alkalinity (as CaCO₃)
- Hardness (as CaCO₃)
- Major ions
 - Cations: Ca, Mg, Na, K
 - Anions: HCO₃, CO₃, SO₄, Cl
- Metals and trace elements
 - Fe, Mn
 - As, Cu, Pb, Hg

2.2 Ancillary Indicators

The assessment of secondary and tertiary level indicator parameters is only required if subsequent phases of an investigation are required. The assessment of secondary indicator parameters is intended to supplement the understanding provided by primary indicators, and so on. Secondary groundwater indicator parameters used by Enhance include:

Free Phase Gases

- Stable sulphur isotopes in hydrogen sulphide ($\delta^{34}\text{S}_{\text{H}_2\text{S}}$)
- Stable carbon isotopes for:
 - Carbon dioxide ($\delta^{13}\text{C}_{\text{CO}_2}$)
 - Methane ($\delta^{13}\text{C}_{\text{CH}_4}$)
 - Ethane ($\delta^{13}\text{C}_{\text{C}_2\text{H}_6}$) , if present
- Radiogenic Carbon-14 isotope in CO₂

Water

- Stable carbon isotopes in dissolved inorganic carbon ($\delta^{13}\text{C}_{\text{DIC}}$)
- Stable sulphur isotopes in sulphate ($\delta^{34}\text{S}_{\text{SO}_4}$)
- Bacteriological parameters
 - Slime-forming
 - Iron-reducing

– Sulphate-reducing

The bacteria-related parameters are not indicative of activities associated with Enhance's CCUS program and are likely linked to landowner water well maintenance issues that can generate CO₂, CH₄, and H₂S. This information, along with the data provided by the primary indicators, is used to decipher well issues from potential impacts related to CCUS activities.

Isotopic compositions in water samples are used for targeted evaluation to determine if variations in water chemistry are the result of gas migration from deeper bedrock formations (i.e. Colorado and Mannville group formations), including CO₂ injected into the Leduc Formation.

Isotopic compositions in soil gas samples are assessed for similar reasons as the water samples, where variations in soil gas chemistry are mostly related to natural biological processes but could indicate deeper gas migration to surface through open and active pathways.

3 MMV MANAGEMENT METHODS

3.1 Status Tracking

The monitoring status of a groundwater well or soil gas probe should be tracked during each monitoring year and changed when conditions warrant. The defined monitoring well status can be any of the following:

- **Baseline:** once the effects of installation and development (if applicable) have dissipated (i.e. successful data equilibration/"break-in" period), then the monitoring results are used to establish natural compositional quality at the monitored location, including natural range of variability.
- **Surveillance:** monitoring locations are used for routine assessment of site soil gas, water levels, and compositional quality to ensure consistency with expected baseline conditions and natural range of variability and facilitate detection of any anomalous changes that may occur to that condition.
- **Verification:** a change in compositional quality has been detected at the monitoring station and the results are under review to establish if this is a potential concern for further investigation.
- **Follow-up:** a monitoring location where the change in observed compositional quality is verified and further assessment is required. The location is placed into follow-up status, and an investigation into the unanticipated change is initiated. A monitoring location can go through the follow-up process and undergo risk management or remedial action, if required.
- **Suspended/Inactive:** monitoring activities at the location cease, and it is no longer an active part of the MMV program, but monitoring could resume if required.
- **Abandoned/Decommissioned:** the location is no longer required or can no longer be used due to irreparable compromise and has been sealed using proper abandonment procedures and materials.

The process for determining the status of a monitoring station and how the status can transition from one to another is outlined in Figure A.

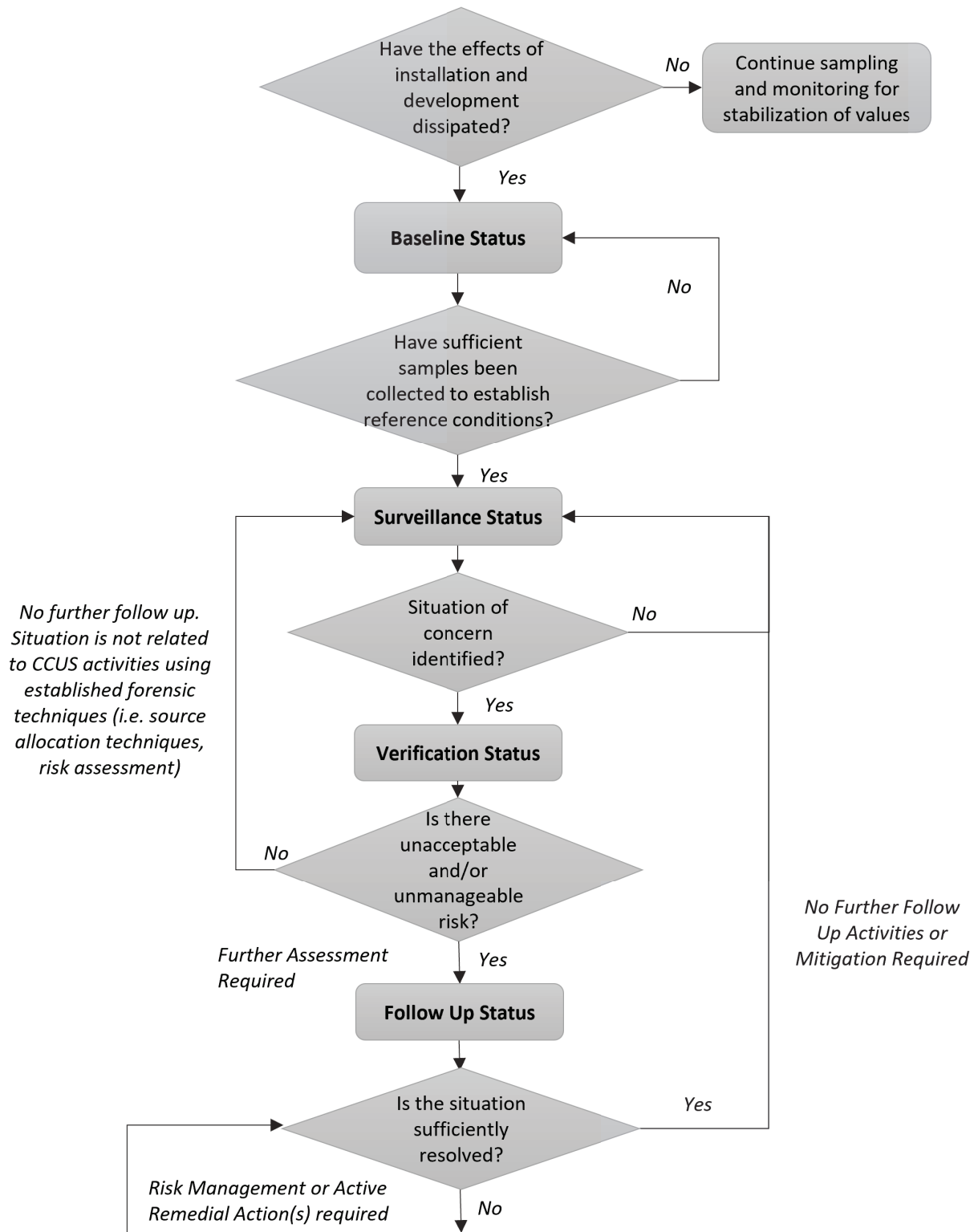


Figure A. Process Flow for MMV Status Tracking

3.1.1 Suspension and Recommissioning

There may be situations where a monitoring location is not sampled for a period of greater than two years. Suspension of a monitoring location will be based on, but not limited to:

- Area access limitations (e.g. safe access to the location is not possible)
- Well redundancy (e.g. the location provides similar results as another nearby location, and the additional information provided does not enhance knowledge and understanding of the setting or situation)

These locations may be sampled and not reported on, or just not sampled. If a sample is collected from this location, they will be removed from suspension status and reported on. If a monitoring location has been suspended for five or more years, then a decision regarding whether to keep the monitoring location as part of the monitoring network, or to abandon the monitoring location, is to be made. The assessment should include (at minimum) consideration of the location's:

- Integrity
- Purpose
- Redundancy
- Risk profile (high, medium, low, negligible)

If a decision to abandon a soil gas probe or dedicated monitoring well is made, the appropriate procedures must be followed to ensure a proper seal over the depth interval affected by the monitoring installation. Landowner water wells used as part of the program will not be abandoned and will instead be removed from the program.

Re-assessment of a monitoring location's integrity and usefulness to the program is to be completed once every five years if the location is to remain part of the monitoring network, but remain in an inactive (suspended) status. If the location is to resume active monitoring, then the initial monitoring results should be reviewed to confirm that conditions are representative of expected baseline for the surficial soils and/or aquifer being assessed. Results collected during this period of re-activation may require another initial "break-in" period consistent with the methodology detailed in Section 8.2.

3.1.2 Abandonment and Replacement

An abandoned monitoring location is one that has come to the end of its operational life. These locations are removed from service, which ends the data collection and evaluation period.

A monitoring location that requires abandonment also requires a decision as to whether the location will be replaced. If the monitoring location remains safe and accessible, serves an important purpose, and is not redundant, the abandoned location may be replaced. If the monitoring location is no longer safely accessible, no longer serves a purpose, or is found to be redundant, then the monitoring location may be abandoned and not replaced.

Replacement monitoring locations are those used to re-establish the local soil gas and water quality conditions at roughly the same location. These locations should be positioned no closer than 3 m to the original location, and no further away than 15 m. The data collected at a

replacement location may not directly align with the data collected from the abandoned location due to variability in soil, rock, or porewater conditions. Nevertheless, the data sets of an abandoned and replacement location can be combined to continue the local monitoring efforts if they are reasonably comparable. A suitable alignment is defined as no more than a 20% deviation from a 1:1 line comparison of pre-abandonment and post-replacement values (following a requisite period of equilibration, or break-in period, if applicable).

A replacement monitoring location that is located more than 15 m from an abandoned location or has data that does not align with the nearby abandoned location is to be treated as a new location. This will require the proper break-in period to ensure that the results are representative of local baseline conditions. Data from the abandoned location may be used to help define baseline conditions for the new location if deemed suitable by a QP.

3.2 Monitoring Frequency

Monitoring events should be planned to collect temporally independent samples of soil gas or water from designated sampling locations. Sampling too frequently can result in the repeated sampling from a similar set of conditions within an aquifer or surficial soils, although this would be reasonable if the sampling objective were re-testing and validating a result. Conversely, sampling over too long a period can miss a potentially significant change in water or soil gas chemistry (United States Environmental Protection Agency (USEPA) 2009). Local conditions, like the type of sediments, groundwater flow velocity, site sensitivity and/or risk profile will dictate the optimum sampling frequency. If suitable, this may include frequencies of intra-annual (e.g. seasonal), annual, or multi-year.

Baseline locations are typically sampled at a higher frequency, ranging from monthly to annually (once per year). This facilitates a quicker break-in process and allows baseline data to be collected in a more reasonable time frame, while still honouring temporal independence. Once initial break-in effects have dissipated at a new monitoring location, if applicable, and a sufficient number of baseline values have been obtained (at least 8), sampling can be reduced to a more suitable frequency based on the location's properties (e.g. when a notable change is recorded in deeper bedrock monitoring).

Locations for monitoring, detection and evaluation purposes should be sampled at least once every year for higher risk areas, to once every two to three years in lower risk areas while the project is operational. Monitoring activities during the post-closure period when the project is complete are often reduced, as well until such time as it is appropriate to close down activities altogether, following appropriate regulatory approval.

Monitoring locations in Follow-up status, being used to evaluate a potential CCUS containment issue, are to be sampled at frequencies up to monthly at sensitive locations (e.g. close to the source, close to a sensitive receptor, identification of a high-risk contaminant).

The required sampling frequency is provided in Table A, which highlights a standard approach suitable for soil gas and groundwater monitoring.

Table A. Standard Sampling Frequency Summary

Well Status	Soil Gas Monitoring	Groundwater Monitoring
Baseline	Twice a year	Twice a year
Surveillance	Once a year	Once every two years for local residential water wells
Follow-up (until situation resolved)	Twice a year	Once a year in local residential water wells

When in the Follow-Up status, the sampling frequency for identified monitoring locations will be defined within an established risk management and/or remedial action plan submitted for regulatory approval.

3.3 Analytical Methods

All water and soil gas samples collected as part of the MMV program are to be analysed by a laboratory accredited by the Canadian Association for Laboratory Accreditation (CALA).

Applying proper analytical methods is crucial to the success of any monitoring program, as this will affect the ability to detect and quantify the constituents being assessed appropriately. Not all analytes have the same method detection limit, and some analytical methods produce different detection limits for the same measured parameters. Another complicating factor is the possibility of matrix interference issues with the samples that require dilution so that measurements can be safely made with the laboratory instruments.

Therefore, it is crucial that the proper method of analysis for each analyte be selected to meet the Data Quality Objectives (DQOs, which include Canadian drinking water guidelines and/or Alberta Tier 1 guidelines for agricultural land use). One example of a key data quality objective for this MMV program is that samples are to be analyzed within the required hold times for the analytical method to be used.

The Method Detection Limits (MDL) are at least one order of magnitude lower than the associated DQO limits. To ensure the achievement of program DQOs, the selection of appropriate laboratory methods and associated detection limits is necessary to facilitate reliable quantification of the parameter being measured (i.e. reliable detection limits, or RDLs).

4 DATA VALIDATION PROCESS

4.1 Goals and Objectives

The goal of data validation is to ensure that a database of high-integrity field and laboratory measurements is maintained and is as free from errors as possible. Questions can often come up during the data evaluation process concerning data quality. Problems with data integrity can arise due to improper sampling and handling procedures, problems during transport to the laboratory, and issues during the laboratory analysis of the sample. The goal is to have a process

that can help resolve these questions before the data is entered into a database. When data integrity issues are encountered, notes are to be routinely documented in the database for future reference and investigation, if needed.

4.2 Chain of Custody

A chain of custody (COC) document is required documentation to track sample handling history and support legal verification processes. Sample shipments from the field to the laboratory (including the COCs) need to meet standard requirements for:

- Sample transit time (suitable so hold time errors can be identified, and systemic issues can be appropriately managed to ensure DQOs are met)
- Appropriate sign-off when samples are transferred from one holder to another
- Appropriate arrival temperature (<10°C for water samples)
- Suitably descriptive sample naming (sample name meeting analytical schedule)
- Suitability for analysis:
 - Sufficient volume
 - Suitably filtered and preserved in the field, as required.
 - Reduced sediment so as not to create issues with laboratory analysis.

Tracking of laboratory issues via a Sample Integrity Failure (SIF) reporting process provides necessary information to identify and reconcile any systemic issues that may compromise data quality and integrity. SIFs are used to ensure that the data is of the highest quality prior to the execution of data evaluation processes and forensic investigation.

4.3 Laboratory Certificate of Analysis

A certificate of analysis (COA) is a certified document issued by the accredited laboratory completing the analysis that documents:

- The analytical tests and methodologies requested and employed.
- The analytical test results and any sample remarks (e.g. dilution).
- General sample comments (e.g. hold time exceedances).
- Laboratory quality assurance (QA) and quality control (QC) results based on laboratory duplicates, spiked blanks, method blanks, and matrix spikes and that they meet the appropriate acceptance criteria.

Laboratory-reported validation and QAQC issues are to be noted in the COAs and the project database for future reference and investigation, if required.

4.4 Data Quality Review Process

The Data Quality Review (DQR) process is to be completed following the completion of each sampling program. The intent of the DQR process is to complete a screening of results to confirm that the sampling round was complete, that the results are fit for use, and to document any

spurious/unexpected results that may require follow-up actions in a timely manner (i.e. document samples or locations that may not be representative of baseline conditions). This is a critical step in the data evaluation process as it allows for the identification and resolution of issues before the data is evaluated and reported.

Laboratory data, once received in the form of a COA and electronic data deliverable (EDD) file, is entered into the database and is to be listed as “DQR Pending” until the DQR process for each sampling round is complete. The DQR process is then completed by addressing follow-up concerns.

Once the DQR process is complete and identified issues have been rectified, then each laboratory COA is to be updated to “DQR Complete” status, meaning the data associated with the COA has been reviewed and is considered fit for use. Any specific samples identified as suspicious/potentially non-representative or anomalous to baseline conditions are to be identified and documented at this time. Regardless of the DQR outcome, all data generated should be retained in a project-specific database for future reference and communications.

Various validation aspects of the DQR process and the associated DQO and related follow-up actions are summarized in Table B

Table B. Field and Laboratory Data Quality Review Process

Data Assessment	Description	DQO	Follow-up Action
Monitoring schedule	Evaluate monitoring round completeness	Alignment with planned sampling schedule and actual work completed	Identify and document deviations from the planned program; determine suitable mitigation to preserve quality of the MMV program
Soil gas probe and water well condition	Document the structural integrity of the monitoring network	To ensure intact condition and collection of appropriate measurements	Identify and document integrity concerns; plan and execute required mitigation or maintenance, as required
Laboratory QAQC results	Evaluate for any potential issues with laboratory analysis program	All values within acceptable ranges and measured values	Identify and document laboratory issues

Data Assessment	Description	DQO	Follow-up Action
Blind duplicate samples	Evaluate sample reproducibility	Relative percent difference (RPD) less than 20% for ppm-level measurements and less than 50% for sub-ppm measurements	- Identify RPDs greater than acceptance criteria, document the occurrences and follow-up with the field and laboratory teams to determine possible cause - RPDs in excess of acceptance criteria are tracked to identify systemic issues
Ion balance	Evaluate that water quality analyses are performed correctly, and results are of suitable quality for use	Difference between sum of cations and sum of anions less than 15%	Follow-up if in excess of $\pm 20\%$ (recalculate including trace elements) and check with laboratory to determine possible cause
pH	Evaluate similarity of field- and laboratory-measured values to identify possible errors (see below for extended narrative)	Ratio of field pH to lab pH between 0.8 and 1.2	pH changes are expected by the time samples are tested in the laboratory; document excursions outside the acceptance criterion, evaluate field records for possible errors, and track for systemic issues
	Identify waters with unusual pH results	pH outside the range of 6.0 to 9.0 standard units	Field pH results outside the acceptance criterion are checked for field errors and equipment calibration issues; sampling probe or monitoring well integrity checks may be required

Data Assessment	Description	DQO	Follow-up Action
Mineralization	Evaluate similarity of field- and laboratory-measured EC values to identify possible deviations	Ratio of field to lab EC between 0.5 and 0.9	Document excursions outside the DQO range, evaluate field records for possible error, and track for systemic issues
	Calculated TDS to lab EC ratio	Ratio to be between 0.5 to 0.9	Document excursions outside the acceptance criterion, evaluate field records for possible error and equipment issues, and track for systemic issues
	Measured vs. calculated TDS	Ratio of measured to calculated TDS is between 0.8 and 1.2	Document excursions outside the acceptance criterion, evaluate field records for possible error and track for systemic issues

The preceding table is an example of some of the DQO checks completed to ensure correctness of analysis prior to the data evaluation process. Monitoring programs for different projects and for different companies may vary somewhat from this standard, including the QAQC process and related DQOs. All deviations will be communicated in program documentation to ensure transparency of process.

4.4.1 Field Versus Laboratory Measurements

Measurements for certain parameters are measured in the field, as they are subject to change once a sample is removed from its natural environment. For water samples, this includes temperature, pH, EC, dissolved oxygen (DO), and oxidation-reduction potential (or redox). For soil gas samples, this includes compositions of O₂, nitrogen (N₂), CO₂, CH₄, and H₂S.

Some of the equipment used for field measurements will require calibration prior to use to ensure reliable measurements. For example, a pH probe requires the use of laboratory-grade buffer solutions of either pH 4, 7, or 10, depending on the range of pH values anticipated, and a two- or three-point calibration. Electrical conductivity probes are also calibrated with a standard solution of known salinity, while ORP requires the use of a laboratory-grade solution (e.g. Zobell's or Light's) and a manual correction, which is device-specific.

Although some changes in the field-measured parameters are expected once a sample has made its way to the contracted laboratory, the differences should not be significant.

Comparison of field-measured versus laboratory-reported parameters, or manually calculated versus laboratory-reported results, is one way to test if anything has occurred to the sample following collection and analysis. Differences between field-measured and laboratory-reported values are expected but should be minimal, and if not, this warrants some follow-up investigation into the cause.

5 DATA ASSIMILATION PROCESS

5.1 Goals and Objectives

The data assimilation process entails incorporating new laboratory results into the project database. The goal is to retain all data, but to identify QAQC issues and identify validated data for use in evaluation and reporting processes. As noted previously, this is completed through the DQR process.

5.2 Linking Field Measurements & Laboratory Records

Field data is collected during the monitoring program, which is digitally entered at the conclusion of the field work and stored with an associated Sample ID. The Sample ID is used to track samples and their results as they are collected and reported on from the field and laboratory.

Laboratory results, once received in an EDD format, are then compared with the field data entries related to the associated Sample ID for the date and time sampled. If the two do not sufficiently align, the discrepancy is identified and the sample is to be identified for further scrutiny and results reconciliation. Reconciliation is done by either re-issuing the corrected laboratory result or by correcting the field data entry to reflect the correct sample link.

5.3 Units, Detection Limits and Method Validation

Consistency in units, detection limits, and laboratory methods are the first criteria that field-reported data and laboratory results must pass. The analytical schedule is to include this information, and the details need to be confirmed with the laboratory prior to the sampling program commencing. This data should be included in laboratory EDDs and COAs provided; however, they may not always align. Communication with the laboratory is essential in advance of the field program to ensure alignment with the laboratory program.

Once results have been received from the laboratory, each COA is to be inspected to ensure that it is consistent with program requirements. Currently, this is done manually within the database, where the following pieces of data are reviewed:

- Appropriate methods of analysis and associated MDLs
- Consistent measurement units
- Acceptable laboratory QAQC recoveries
- Acceptable results for laboratory method blanks and/or spikes

Where the results are inconsistent with expectations, data is first reviewed to determine if they fall within the acceptable methodological parameters as outlined by the laboratory. If necessary,

they may be rejected or updated where possible and marked within the database itself for irregularities. Follow-up actions include having the laboratory re-analyze the sample if a sufficient volume of water remains on hand. If this is not possible, it may be necessary to collect another sample and resubmit for analysis. These follow-up activities are to be performed in the event that a sample analysis is not within the acceptable criteria established in the sampling methodology agreed upon by the contracted laboratory.

5.4 Data Incorporation Process

The process for data incorporation is as follows:

- Collect field measurements and update project database with digital entries at the conclusion of each field program.
- Deliver samples and completed required COC listing samples names, dates and times of collection, sampler's initials, required analytical schedule, and any other special instructions or notes, to the contracted laboratory within required holding times.
- Receive laboratory Sample Reception Confirmation (SRC).
- Receive laboratory COA in EDD and PDF format.
- Compare field and laboratory Sample IDs, dates and times, etc., to ensure consistency and necessary corrections.
- Screen results using the DQR Process (Section 4):
 - Identify and document data that does not meet DQO expectations. If possible, rectify the issues identified (e.g. obvious field transcription error, missing laboratory analysis).
 - Once correct, upload data into the database.
- At the end of each sampling round/event, review field-measured and laboratory-reported data for completeness and alignment with COAs.
- Sign-off DQR forms indicating that the data is appropriate for use in the evaluation and reporting. Then:
 - Update the database to indicate that the DQR process is complete, and
 - Document any potential non-representative samples identified by the DQR process within the database.

5.4.1 Issues Identification & Documentation

Data quality concerns that are identified using the DQR process are to be recorded and reconciled, as necessary. This is to be recorded in the database system as a “use with caution” status to the result. In some cases, other data associated with the flagged results may still be useful in analysis, but the weight placed on it may be less than other properly validated data.

Specific data that does not meet DQO requirements after being through the DQR process should be identified as having a Data Quality Concern (DQC), but should not be omitted from the database system. These entries should only be omitted if they violate the following:

- The result is not possible based on physical and/or chemical principles, as well as judgement from a QP.
- The follow-up process determines that the data are incorrect.
- There is a known outside cause responsible for the incorrect data (e.g. obvious contamination from an outside source or a data entry issue, such as a decimal point error).

Data Quality Concerns occasionally occur and require a clear rationale to omit an entry from the database. To reconcile noted DQCs, re-sampling and re-analysis may be required.

6 ADDRESSING DATA ANOMALIES

6.1 Goals and Objectives

The goal of the monitoring at Enhance's Clive project, whether it be soil gases, bedrock gases, or groundwater, is to ensure containment and quickly detect and respond to anomalies that are identified during the sampling programs. This includes both field-measured and laboratory-reported data from established monitoring stations deployed across the MMV area. The purpose, or objective, of these actions is to manage any situation linked to CCUS activities that may be developing and ensure that CO₂ containment in the Leduc Formation is maintained, as well as compliance with existing regulatory conditions.

The following subsections identify how to respond to data anomalies such as non-detections, false detections that could lead to unnecessary response actions, and outlier data that may similarly provoke unwarranted investigation activities.

6.2 Data Reliability

6.2.1 Appropriate Method Detection and Reporting Limits

Establishing appropriate reporting limits for parameter measurements is an important aspect of meaningful interpretation, communication of results and ensuring appropriate reaction to a particular reading in relation to an established criterion. MDLs are established in the laboratory to ensure that analytical methods are used appropriately to determine concentrations of various constituents being assessed. Typically, this involves the measurement of spiked samples of various concentrations and documentation of the intensity of response at an instrument detector. Limits are often set at a particular height of a signal intensity curve to the background instrument noise signal (i.e. signal to/noise ratio). The MDL is the lowest concentration that can be detected by an analytical instrument and that a laboratory can report with a 99% confidence that the analyte is greater than zero.

Laboratories also report the Reliable Reporting Limit (RRL), which is the concentration of an analyte that can be measured within specific limits of precision and accuracy. The RRL is typically selected as the lowest non-zero value in the MDL calibration process. Depending on the analyte, the lowest reliable measurement can be anywhere from 3 to 10 times the MDL (USEPA 2009). An RRL is used to trigger a response for parameters that are expected to be non-detect for each indicator parameter assessed. Enhance defines the RDL for the Clive MMV program as follows:

$$RRL = MDL \times 5$$

In some cases, it may be warranted the use of a lower multiplier, but it will be a site-specific decision to deviate from the 5x standard. Documentation of any deviations are to be made in the project database system to ensure full transparency of process.

6.2.2 False Detections

False detections are a risk to any monitoring program and can lead to the initiation of unnecessary follow-up actions. It is important to keep in mind that a range of possible errors can occur in the field and in the laboratory. These include, but are not limited to:

- Improper sampling procedures
- Sample mislabeling
- Sample contamination after collection
- Use of inappropriate preparatory procedures or methods of analysis
- Sequencing errors at the laboratory
- Improper calibrations and instrument errors
- Misinterpretation of results
- Transcription errors

Such errors can lead to false positive detections for measured parameters, when in actual fact there would normally be no such detection.

If a new positive detection occurs when the parameter was expected to be non-detect, then it is necessary to conduct verification steps to validate the measurement. These steps typically include a review of field notes, equipment calibrations, laboratory QAQC results, and field duplicates and blanks. In some cases, collection of a new sample may be required to confirm the result. If the detection is found to be false (or unrepeatable), then the data is noted through the DQR process and addressed in the Verification stage. However, if the detection is confirmed to be real, this likely signals the presence of a normally non-detect indicator parameter, thus triggering an investigation into the source, cause, or reason.

6.2.3 Non-Detects

There are many parameters that occur in very small concentrations, can be difficult to measure, or are simply not present in the analyzed media. This situation will lead to non-detects (NDs) or measurements with a high degree of analytical uncertainty. The following provides a description of how non-detect results are to be handled during the data evaluation process.

Percentage Method

The percentage method is one way to deal with data entries that often produce ND values. When analyzing a data set with statistical methods (e.g. trend analysis), no more than 50% of the data entries are to have values below the RDL (USEPA 2009). In doing so, this will maintain the integrity

of the data evaluation process. In essence, datasets containing more than 50% non-detect values will not be evaluated using statistically methods and instead are to be assessed by the detection frequency method outlined in the following sub-section.

Statistical methods of analysis are only to be applied to datasets containing less than 50% non-detects. To facilitate the process a non-detect value will be replaced with one-half of the RDL value (e.g. if the RDL = 1 mg/L, then a value of 0.5 mg/L is used) so that useful statistical analyses can be performed.

Detection Frequency Method

The occurrence of high-frequency non-detect readings for an indicator parameter does present a challenge for setting quantifiable management levels or limits. A general rule for dealing with data sets having frequent non-detect values is provided by the EPA Unified Guidance (USEPA 2009), and is described as follows:

"A confirmed exceedance is registered if any well-constituent pair in the 100% non-detect group exhibits quantified measurements (i.e. at or above the reporting limit [RL]) in two consecutive sample and resample events."

For the Enhance Clive MMV program, this detection frequency approach will be used for those parameters consistently exhibiting non-detect values.

6.2.4 Outliers

Outliers are data values that are often discounted because of their departure from an expected outcome. However, outliers can signal events that exist outside current understanding and are therefore not be discounted unless for good reason. Monitoring data is not always well behaved with respect to temporal variability. In particular, analytes that are typically detected at lower concentrations, like microgram per liter ($\mu\text{g/L}$) or nanogram per liter (ng/L), can sometime display wildly varying results from one sampling event to the next. As such, the occurrence of a data "outlier" may not be an uncommon occurrence.

In more strict terms, outliers may be described as data values that fall outside of an established range of values or statistical confidence interval (CI), e.g. like a 95% or 99% CI, depending on the situation. This does not necessarily mean there is something wrong with the results, but it is an indication that something is not consistent with the expected outcome.

The approach to be used when outliers are detected is to identify the data for a Verification review with the field personnel and/or laboratory contact. Review of field calibrations or notes may indicate the reason for the outlier reading. Similarly, a review of the laboratory QA/QC report or a reanalysis of the sample may resolve the issue.

If a measurement outlier passes the necessary verification step, then it is to be retained and used in the data evaluation process. This will likely provoke further response actions, such as re-sample, re-analyze, and/or investigate.

Where the data validation stage of the evaluation process indicates that a measurement may be an outlier, and this interpretation is confirmed by two successful sample results falling outside the inter-well or intra-well criteria, the data point will then be classified as a formal “outlier” and flagged accordingly in the project database system.

7 DATA SCREENING PROCESS

To assist in the monitoring and evaluation process, a system for the detection of monitoring performance concerns (MPCs) has been developed. This system is designed to identify and locate situations that fall outside of established baseline conditions or specific management criteria (e.g. AB Tier 1 and/or Canadian drinking water guidelines). When applying data screening criteria, it is extremely important to understand the range of conditions that can be attributed to the natural setting, because site conditions can fall outside of the more generic quality criteria provided in regulatory guidance documents.

7.1 Location Comparisons

Indicators should be differentiated according to whether or not they are naturally present in groundwater or soil gas samples or can be linked to a source resulting from human activities. Indicators that are not present naturally in groundwater or soil gas include substances that are introduced due to a failure to isolate them from the surrounding environment through engineered means.

One potential difficulty is ambiguity that can occur with respect to a substance that can be clearly differentiated from a natural source. For the Enhance Clive project, CO₂ is a prime example. This gas is ubiquitous in the subsurface due to natural processes. However, it requires containment monitoring measures to verify it remains within geological formations.

Background, or baseline, concentrations of a substance are the natural amounts of that substance in a natural, unaffected system. In some situations, baseline concentrations of certain substances can exceed desired management limits. Accordingly, to identify soil gas or groundwater impacted by Enhance's CCUS activities, it is important to understand the natural system and its variability both spatially and temporally so that meaningful comparisons with monitoring data can be made. In doing so this will avoid unnecessary complications and actions.

Inter-location

When sufficient numbers of monitoring locations exist in an area, baseline conditions at a particular site can be defined using data from multiple locations across a project area. This screening method does, however, require that similarities exist in the physical and chemical conditions across an investigation area. For soil gas samples, this requires probes installed in the same type of soil material, terrain, drainage, and land use, which can be complicated due to inherent variability. For groundwater, this requires wells installed in the same aquifer unit, at roughly the same depth, and isolated from human influences. This can also be complicated unless dedicated systems for the sole purpose of the intended monitoring goals are put into place.

An inter-location comparison is considered appropriate when limited data is available for individual locations, and when the monitoring is established in a known unimpacted area. The benefit of this approach is that the spatial, versus temporal, conditions can be used to define expected outcomes at individual sites lacking sufficient measurements to determine the natural range of variability. If, for example, a monitoring well is established in a location suspected of being influenced by human activities, but it is unclear if an impact has occurred, numerical limits derived from a review of other locations can be used as a guide to clarify the situation. As such, the assessment of numerous locations across an area of investigation can help establish the conditions necessary to facilitate comparison and detection of change at new locations. It is nevertheless imperative to ensure that data are not getting mixed across dissimilar environments to ensure accuracy and effectiveness of the method.

Intra-location

The chemistry associated with soil gas and groundwater, even within similar systems, can often vary spatially and temporally and therefore adversely influence interpretations and actions when using the inter-location method of comparison. It is therefore important to understand the setting and the possibility for such anomalies to occur.

For example, within a given aquifer interval, the presence of a natural trend or variability can lead to the accidental identification of water quality being outside expected conditions and cause the initiation of potentially unwarranted management actions. Therefore, if sufficient data has been collected from a monitoring location, and that data is considered representative of baseline conditions (i.e. unaffected by anthropogenic activities), then future assessments of chemistry results at that location be used to make statements about change. This is commonly referred to as intra-location comparison.

This process effectively uses temporal data collected from the same location for various parameters to determine if there are any departures from normally expected variability and/or statistical limits. Consideration needs to be given to seasonality of the data collected, as this may also affect decisions regarding response actions and follow-up measures. Examples of these situations where this consideration should be taken is for soil gases subject to seasonal changes in CO₂ due to natural respiration processes during the growing season, or shallower groundwater systems influenced by seasonal recharge of fresher water.

7.2 Trend Assessment

A potential concern may also be identified following the detection of a trend in groundwater or soil gas quality data. Enhance uses the Mann-Kendall (M-K) test for trends (Gilbert 1987) to assess for the presence of trending indicator parameter concentrations, which may reflect a developing water or soil gas quality concern. The M-K test for trend is a non-parametric approach that is used to assess for a linear trend based on the idea that a lack of trend should correspond to a time series plot fluctuating randomly about a constant central value, with no visually apparent upward or downward pattern. This type of analysis method is useful for completing intra-location comparisons for primary indicator parameters and does not require the underlying data to follow a specific data distribution (USEPA 2009). The process for trend analysis is defined in Section 6.

The Theil-Sen slope estimator is often used in combination with the M-K test to provide an idea of the rate of change of a parameter. This entails determining the slope of a line between all forward comparisons and then taking the median slope. When combined with the M-K test, this is a powerful indicator to initiate follow-up investigation into the source, cause, or reason for the change.

A potential situation would be identified where the M-K analysis and Theil-Sen Slope indicator identify a statistically significant trend in one of more indicator parameters. A statistically significant trend is identified when a key indicator parameter (e.g. CO₂ and/or $\delta^{13}\text{C}_{\text{CO}_2}$) exhibits a trend with at least a 95% level of confidence and a normalized slope of $\pm 10\%$ or more per year. Once identified, this would prompt further investigation as per the progressive Follow-up process.

7.3 Anomaly Identification

The objective of the anomaly identification process is to direct investigative and management efforts to potentially unacceptable conditions in a timely manner.

Following the processing of data and evaluation against calculated performance criteria (as described in Section 8.5), monitoring results should be displayed in visual array in plan view mapping to identify locations and the number and/or patterns of data excursions from baseline conditions (including natural range of variability). A risk map showing higher risk areas based on geology, structure, and presence of existing problem wells would be helpful in this regard. Coloured symbols can then be used to identify locations of concern and the associated indicator parameter(s) falling outside of established performance limits.

To aid in the indication of data concerns from a potential loss of containment, a simple “stop-light approach” is proposed. This process is described below and is included here as a guide to be used as a tool to grade locations to help identify those requiring further investigation or actions.

- Green colouring indicates that all monitoring in Geosphere, Hydrosphere, and Biosphere is normal, with no concerns identified. Also, no statistically significant trends have been identified outside normal variability.
- Yellow colouring indicates that one of more indicators in Geosphere, Hydrosphere or Biosphere monitoring have been identified as a “suspected” issue. However, geochemical and isotopic fingerprinting cannot clearly verify a link to injected CO₂. There are possible increasing statistical trends, but confirmation is still required through additional monitoring.
- Red colouring indicates that deep monitoring clearly signifies that there is a presence of injected CO₂ with an increasing statistical trend, but shallower Geosphere wells do not show an indication. Response is in accordance with the Directive 065 Approval No. 12832 and succeeding amendments, which state that *“the operator must immediately suspend injection operation if the injection facilitates the movement of injected fluids into any zone above the base of groundwater protection or any zone other than the Leduc and Nisku Zones and Immediately inform the AER.”*

As discussed previously in Section 7, concerns can arise either as a statistically significant trend, a performance limit exceedance, an established guideline exceedance, or some combination thereof.

7.4 Evaluation Process

The evaluation of groundwater and soil gas quality data using developed performance criteria is critical to identify the need for verification or further assessment (e.g. review of secondary or tertiary indicators). Section 8 describes the processes to be used when such situations arise.

8 DATA EVALUATION PROCESS

8.1 Goals and Objectives

Employing a standardized approach for the evaluation and investigation of monitoring data is essential to understand if baseline conditions have been achieved and to identify changes to those conditions that warrant follow-up investigation. This allows for situations to be linked to natural conditions or CCUS operations.

The objective of having a standardized data evaluation process is to ensure a consistent and reliable approach to data comparisons between sampling programs. This will ultimately focus attention on situations requiring further scrutiny. Figure B provides a summary of the process flow for this part of the evaluation and reporting process.

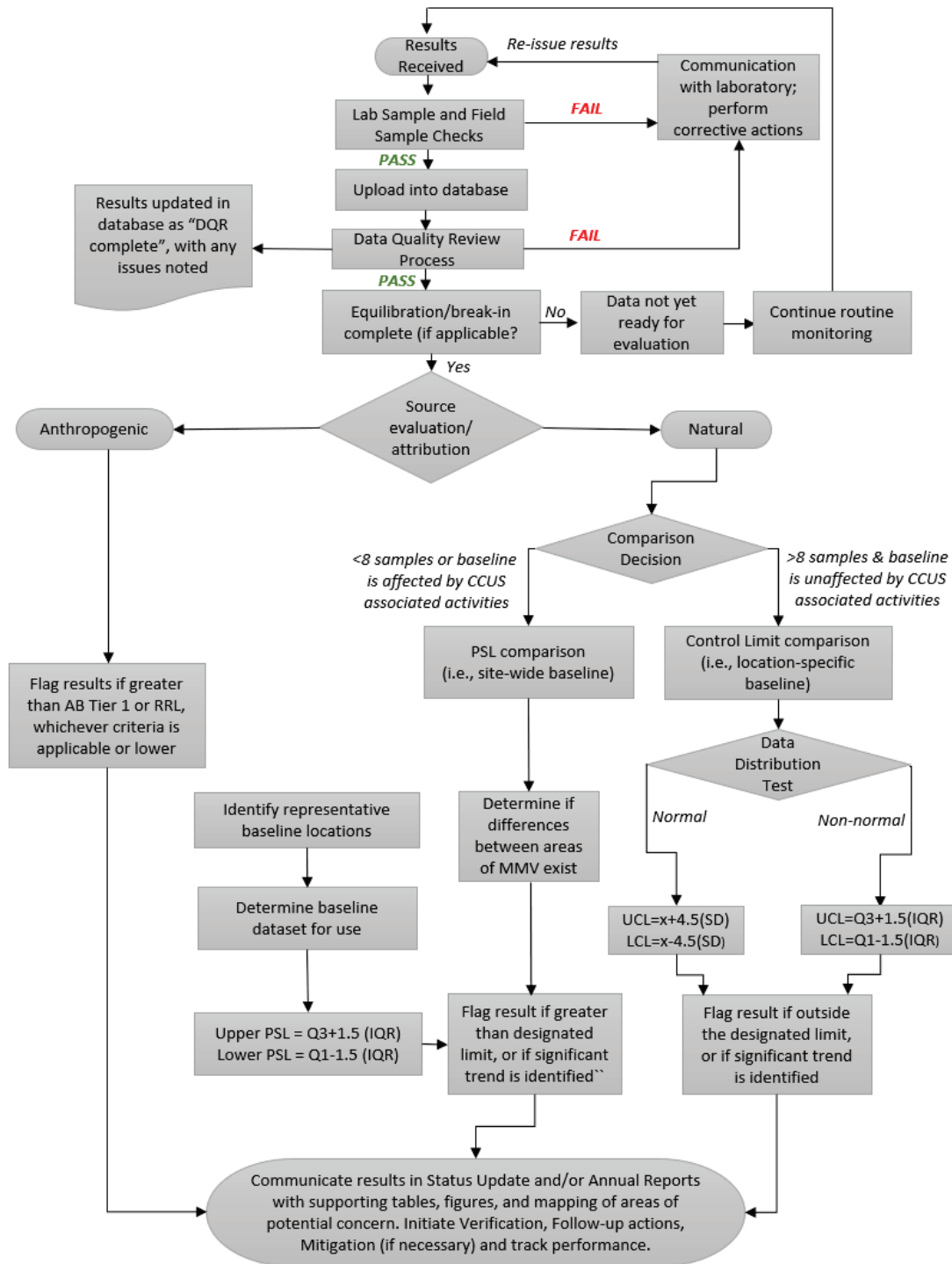


Figure B. Process Flow for Data Evaluation Process

8.2 Establishing Background or Baseline Conditions

In order to establish the presence of data anomalies in a data set, it is imperative to establish a suitable baseline condition to facilitate such detections. In environmental monitoring, this is considered the initial set of critical observations used for comparison or as a control to measure against. Rarely can baseline conditions, for either groundwater or soil gas quality, in an area be established from one sampling location or one sampling event due to inherent subtleties of landscape, physiography, and subsurface conditions. Differences in natural groundwater or soil gas quality from one location to another are generally attributed to subtle changes in physical, chemical, and biological characteristics, as well as the amount of time that gases or water have been in contact with sediments and/or rock formations. However, in the context of this SOP, a change in local conditions can also affect local pathways and receptors. Therefore, having a sufficient database to capture the range of natural variability, combined with a process to graph and evaluate the results against monitoring data, is critical.

It is important to keep in mind that the detection of an outlier in a data set may not necessarily indicate the occurrence of an event warranting further action and instead may represent nothing more than an event falling within the range of natural variability for the parameter being measured. At least eight observations of water or soil gas quality over a sufficient period of time is therefore needed to establish baseline conditions, so long as the monitoring locations have stabilized following commissioning. However, the USEPA cautions that the occurrence of anomalous data values in data sets with less than 20 observations may not necessarily indicate an upset condition (USEPA 2009). Therefore, when such occurrences are detected, it is important to resist the temptation to simply exclude outlier data values unless it can be clearly established that the detection is related to a human-related cause, process, or influence. In doing so, this will maintain the necessary statistical power of the baseline data set to truly identify a change beyond anticipated conditions.

It is important to note that baseline condition differs from background conditions in that it may be associated with areas that have been subject to some level of disturbance and is therefore not in its natural state. In areas that have been subject to human development (such as the oil & gas and agricultural development that has occurred on the Clive CCUS area), natural background conditions may become disturbed as a result of surface or subsurface alterations. As such, the physical, chemical, and biological disturbances must be accommodated for in comparison data sets used to detect an excursion from anticipated or normal conditions.

The process of establishing a baseline is virtually the same as for a background, as it requires the collection of a suitable number of readings to place reasonable bounds around the variability of physical, chemical, and biological conditions. Once established, deviations from these normal conditions can be noted and forensic analysis and source attribution can be achieved.

The presence of anthropogenic substances in a system known to be devoid of such substances is usually a clear sign that an event has occurred that warrants further investigation. In the context of this SOP, this includes the detection of increased concentrations of CO₂ gases and/or dissolved inorganic carbon with a stable carbon isotope signature consistent with the injected CO₂. An additional indicator of a potential situation of concern would be the detection of H₂S gases

and/or dissolved sulphate, both with a stable sulphur isotope signature consistent with a Devonian source.

8.3 Stabilization of Monitoring Conditions

The act of installing and developing a monitoring station, whether it be a soil gas probe or groundwater well, is an invasive and disruptive process to the natural lithologic conditions. Notable effects include, but are not limited to:

- Altered permeability and hydraulic conductivity (e.g. reduction due to smearing effects)
- Altered geochemistry (e.g. liberation of previously immobile constituents or introduction of atmospheric gases)

Another important consideration, especially in low permeability media, is the introduction of foreign materials (e.g. filter sand, bentonite) that are of different chemical character than the surrounding soil or rock.

All of these effects can alter the local geochemical conditions. It is therefore common to develop or test the integrity of a newly installed monitoring station to mitigate installation effects and ensure that representative samples are obtained. For water wells, purging of the standing water in a well that has been sitting for some period of time is a standard practice to ensure that non-representative water is removed prior to sample collection. It is imperative that hydrochemical stabilization be obtained before groundwater quality results can be evaluated with confidence (i.e. “break-in” period). For soil gas probes, testing with a helium tracer at surface is required to ensure that a sufficient seal from atmospheric gases is achieved (and maintained) to ensure confidence that samples collected are representative of the soil horizon being assessed.

The length of time to achieve an appropriate “break-in” can vary significantly from almost immediately for soil gas probes, to several weeks (e.g. in coarse-grained media) or several years (e.g. in very fine-grained media) for monitoring wells. The length of time is dependent on the degree of disruption to the lithology and geochemical conditions surrounding a well completion interval, and by the magnitude of the hydraulic conductivity (K) in soil or rock material. Sediments or rock with higher K values (e.g. unconsolidated sand & gravel) have the ability to produce soil gases and/or water more easily than lower K formations (e.g. silt and clay). As such, the ability to establish stabilized conditions, or complete the “break-in” period, should take less time. Another consideration for deeper monitoring wells where the geochemical conditions in the porewater may be in a reducing state is the introduction of air either in a free state or entrained in drilling fluids. This can alter local redox conditions for some time and can affect free phase and dissolved gas compositions and metals, and trace element mobility. This also needs to be taken into consideration when monitoring for sufficient stabilization of conditions.

Each newly installed monitoring station will therefore have its own “break-in” period that will need to be substantiated before confidence can be gained that the location is providing useful information for further data evaluation. As such, setting a defined period of time or number of sampling events before “break-in” is achieved is not viable.

For the purpose of this SOP, measurements and samples collected from newly installed monitoring wells within a minimum of three weeks following well development or redevelopment should not

be used as part of the baseline dataset (Yeskis and Zavala 2002). They may be collected and used for other purposes, but their usefulness in defining baseline conditions will be limited unless determined otherwise.

Stabilization of monitoring well conditions is considered to be achieved once three separate samples, which are collected at least one month apart (and preferably longer), have a measured (or calculated) TDS that does not vary by more than +/-20% between events. Once achieved, these three readings can be used to define baseline TDS conditions along with any other parameters measured, so long as they meet the same criterion.

8.4 Soil Gas Attribution

Carbon dioxide is a fairly ubiquitous gas in the subsurface environment. In the surficial soil, CO₂ is produced through biological processes of respiration as plants carry through their annual life cycles. Similarly, when organic matter is broken down by soil microbes one of the byproducts is CO₂. Deeper in the subsurface, below the water table, similar biological processes produce CO₂ that eventually dissolves into the water to become various carbonate species. Examples of cross-plots that can identify various processes and sources of soil gas CO₂ are provided in Figure C.

When biological processes create soil gas CO₂, and related dissolved carbonate species in groundwater the isotopic character of the starting organic matter will influence the resulting values. In the case of Enhance's CCUS project the decay of natural vegetation, soil organic matter, and coal fragments derived from the underlying bedrock formations (all with a $\delta^{13}\text{C}$ values around -25‰) will influence the resulting $\delta^{13}\text{C}_{\text{CO}_2}$ and $\delta^{13}\text{C}_{\text{DIC}}$ values. Cross-plots of gas compositions and/or isotopic measurements are therefore used to determine the source of CO₂. An example is provided in Figure D.

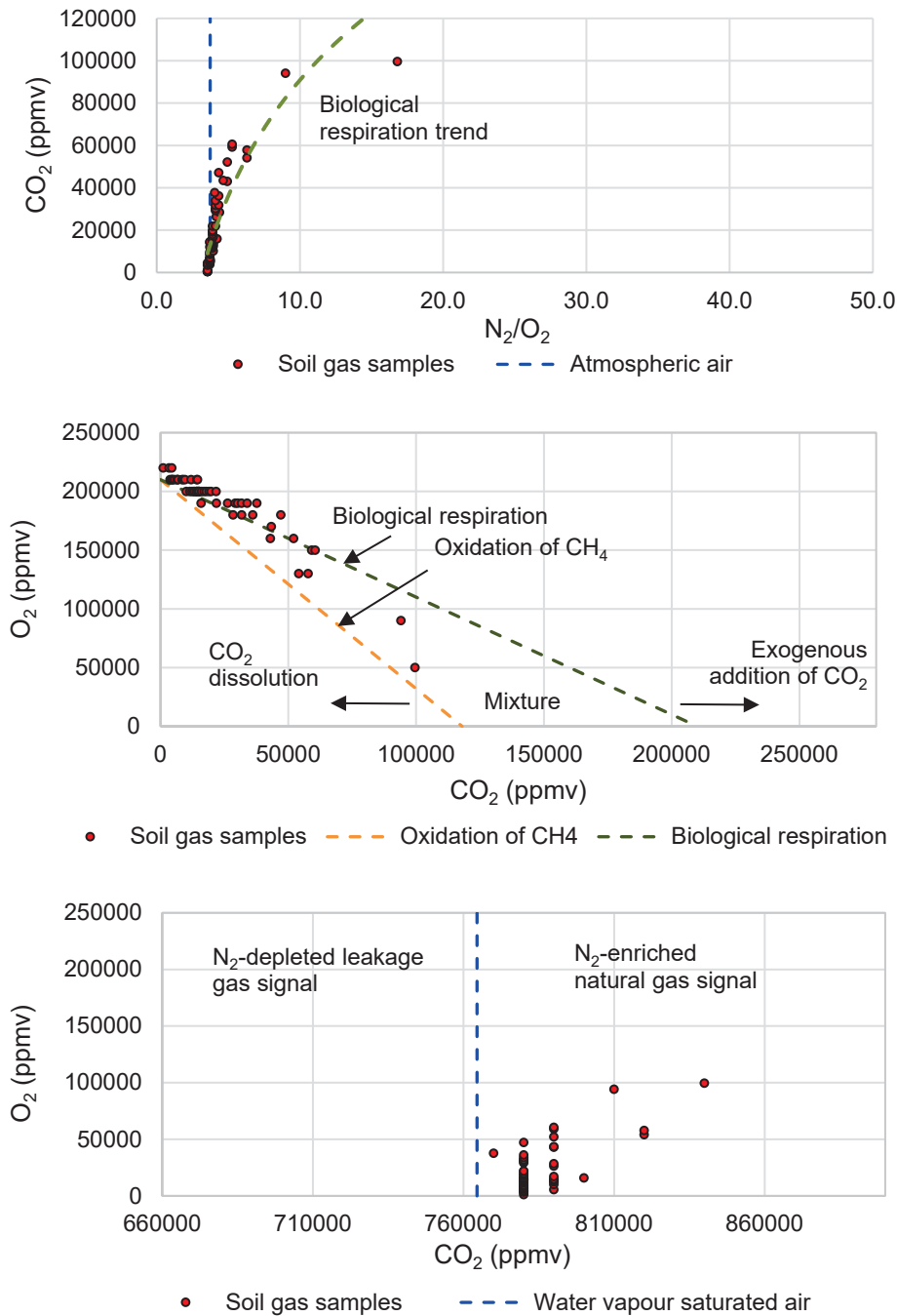


Figure C. Examples of Soil Gas Plots to Determine the Source(S) Of CO₂.

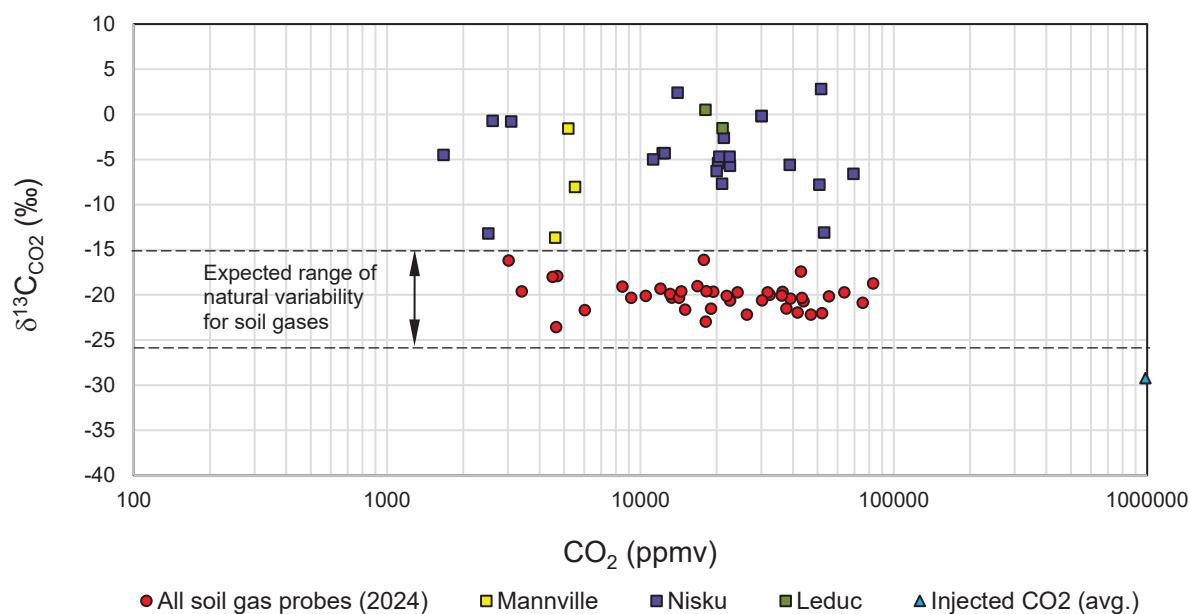


Figure D. Example CO_2 and Stable Carbon Isotope Plot To Determine The Source Of CO_2 .

8.5 Hydrochemical Characterization

Hydrochemical characterization, or typology, is a method of differentiating and categorizing data into groups of similar character. With respect to water, this is related to identifying characteristic groupings of water types based on their major ion composition. This differentiating of water types is a powerful way of identifying differences between samples from an otherwise similar groupings that may indicate the occurrence of change outside of natural variability (e.g. mixing between different source waters; influence from a released contaminant).

There are a number of different approaches to evaluate water quality results, ranging from Stiff diagrams to Schoeller plots to Bar or Pie percentage diagrams. Two of the most acceptable industry-standard plotting methods are the Piper plot and the extended Durov diagram, which includes additional information regarding the pH and TDS of a sample. Descriptions of each are provided below.

8.5.1 Piper Plot

A Piper Plot graphs the distribution of major cations (Ca, Mg, Na + K) and anions ($\text{HCO}_3 + \text{CO}_3$, SO_4 , and Cl) as a percentage of the total ion make-up of a water sample. The plot consists of two triangular plots associated with the cations and anions, and a central diamond that assimilates projections from data points in the triangles and then groups them according to their water type. An example is provided in Figure E.

To do this, each ion concentration needs to be converted to milliequivalents, which takes into consideration the mass and charge of the element. Each cation and anion ion value is then converted to a percentage of the total anion or cation group and plotted accordingly in the Piper Plot. When determining water types, the selected cut-off to accept an ion as a major contributor is 20% or more of its respective cation or anion group.

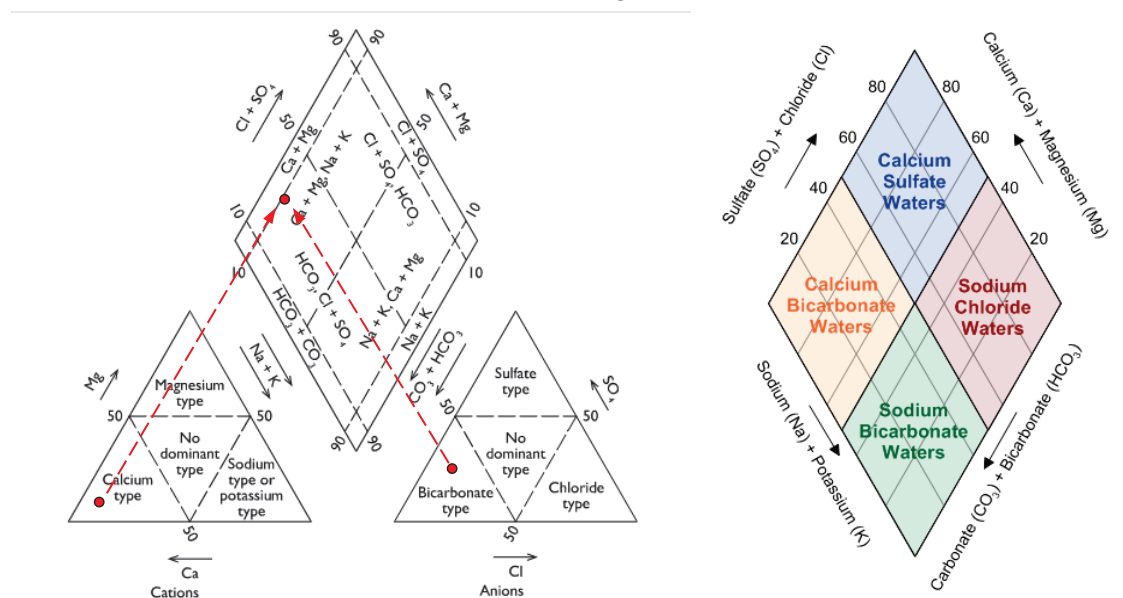


Figure E. Example of a Piper Plot

One of the benefits of this visual assessment is that changes in major ion composition at a given monitoring well can be noted over time as samples are collected from different site visits. For example, a shift from a Ca-Mg-HCO₃ type water toward a Na-Cl-SO₄ type water might signal an influence from deeper Devonian sources, with the sulphate component sourced from dissolution of anhydrite.

One of the limitations of this approach is the lack of other descriptive information like pH or mineralization; however, this can be partially overcome by displaying the data points as graduated symbols associated with varying degrees of mineralization and/or coloured symbols displaying differences in pH ranges (e.g. blue = 6 to 7, green = 7-8, red = 8-9, etc.).

8.5.2 Durov Plot

Durov plots are another useful way to determine water types graphically and identify differences and trends between collected samples. An example is shown in Figure F. These plots follow a similar methodology of identifying milliequivalents for major cations and ions. Major ion species are plotted in the tri-linear plots for the major cations and the major anions located on the left and top of the diagram. The point in each tri-linear plot is then projected into designated fields within the middle box that indicate the type of water process(es) responsible.

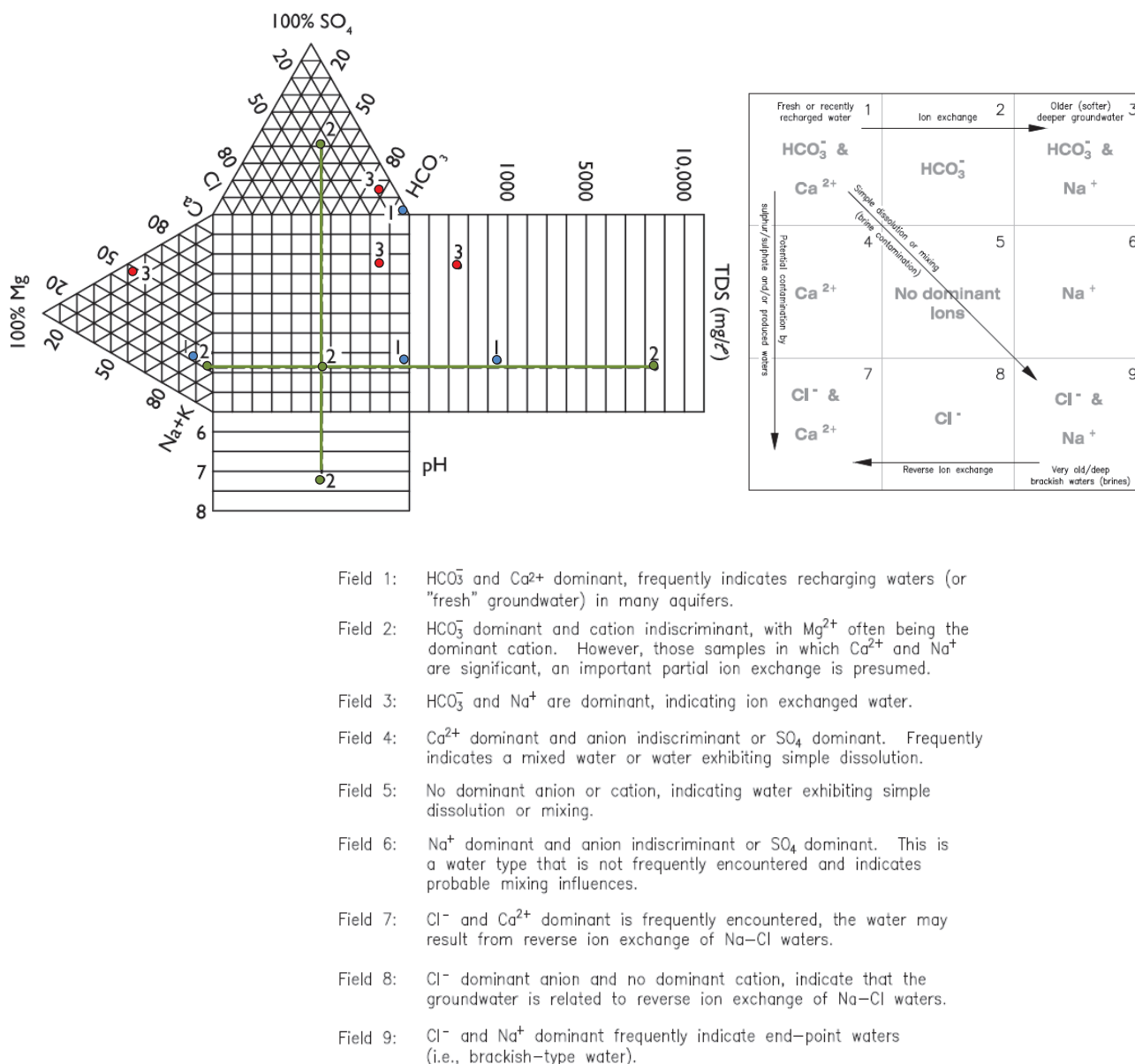


Figure F. Example of Extended Durov Diagram (Lloyd and Heathcote 1985)

The extended portion of the Durov plot is related to the degree of mineralization, which is plotted (as TDS in mg/L) to the right of the central grouping area on a logarithmic scale and the pH of each individual sample, which is plotted in an area below the central grouping area. The same advantages in identifying temporal changes as those noted for the Piper Plot apply here, with the added benefit of tracking mineralization and changes to pH conditions in a more graphical manner.

8.6 Statistical Evaluation

The data evaluation process outlined in this SOP is predicated on multiple different statistical methods and approaches to data evaluation and graphing (e.g. time-series and trend assessments) to identify changes from established baseline conditions and determine if follow-up actions are required. The following sub-sections outline the methods to be used when assessing Enhance's monitoring data.

8.6.1 Establishing Data Normality

Data measurements will naturally fall within a certain type of population distribution. If normally distributed, a histogram of the data will form a bell-shaped pattern with the peak in the middle of the distribution. If the data is distributed in a non-normal manner, the histogram will form some other shape that may have a greater frequency of readings at either end of the of the diagram, or could perhaps be bi-modal, multi-modal, flat and uniform.

Establishing the normality of a data set is critical to the success of the statistical methods applied. For normally distributed data, the use of parametric statistical methods will yield the highest statistical power or the likelihood of detecting a significant effect or change when one truly exists. However, if the data is distributed in a non-normal manner, then parametric statistical methods cannot be used unless the data is transformed to better represent a normal distribution. This might involve a log-transformation or some other approach to better achieve the closest to a normal distribution.

Because water and soil gas quality data are often non-symmetrical, or skewed, it is more appropriate to employ nonparametric statistical methods. These methods do not require any particular type of data distribution and are less sensitive to outliers. However, they are limited by having a lower statistical power than parametric statistics.

Therefore, prior to conducting any analysis of monitoring data, tests for skewness need to be performed to identify the data distributions that are being assessed so that appropriate statistical methods can be selected and used.

Skewness

There are some very simple ways to determine whether or not a data set is normally distributed. For example, in a normal data set the mean (average), median (middle), and mode (most frequent) values will all be located at the centre of the bell-shaped distribution. If, however, the dataset is skewed to the right, the mean and the mode values will be larger than the median. The opposite will occur if the data is skewed to the left.

Calculation of skewness values is used to determine how asymmetrical a data set may be. The equation for calculating the values is provided below:

$$\frac{n}{(n-1)(n-2)} \sum_{i=1}^n \frac{(X_i - \bar{X})^3}{s^3}$$

where n is the number of measurements and the right-hand term is the cube of the standard deviation (SD). Data sets having a frequency distribution with a skewness value greater than or less than 0 are right-skewed and left-skewed, respectively. There are other tests that can be applied, but the skewness test is a relatively simple and straightforward method and is included in the standard Excel package of statistical equations.

However, the determination of skewness values typically requires a large number of values to be effective. If data sets are limited, calculation of the quartile skew, or Q_s is a robust way to determine how asymmetrical a data set may be (Kenney and Keeping 1954; USGS 2020). The equation to obtain this value is as follows:

$$\frac{(P_{0.75} - P_{0.50}) - (P_{0.50} - P_{0.25})}{P_{0.75} - P_{0.25}}$$

where $P_{0.75}-P_{0.50}$ is the difference between the upper quartile and the median, $P_{0.50}-P_{0.25}$ is the difference between the median and the lower quartile, and $P_{0.75}-P_{0.25}$ is the Inter Quartile Range (IQR).

For a symmetric distribution, like the normal distribution, the first (Q_1) and third (Q_3) quartiles will be at equal distances from the median (Q_2). In other words, (Q_3-Q_2) and (Q_2-Q_1) will be equal. If the data distribution is skewed there will be a difference between those two values. Therefore, positive Q_s values indicate a data distribution skewed to the right, and negative Q_s values indicate a data distribution skewed to the left. There are other tests that can be applied, but the Q_s test is a relatively simple and robust method.

When assessing water and soil gas data, calculation of the Q_s value will be performed to determine which type of statistical tests to apply (i.e. parametric or non-parametric). The criteria to establish the type of data distribution is as follows:

- Normal Distribution: $Q_s = -0.1$ to 0.1
- Non-normal Distribution: $Q_s = <-0.1$ or $>+0.1$

Coefficient of Variation, another useful test for data normality is the coefficient of variation (C_v). This is a simple statistic used to measure the variability of data from the sample mean. The underlying principle of this test is that normally distributed data sets have C_v values close to zero, while larger values indicate a skewed, non-normal population.

To compute C_v values, it is necessary to establish the sample mean ($\bar{x}$) and standard deviation (SD). The value is then calculated as follows:

$$C_v = \frac{SD}{\bar{x}}$$

The criterion to apply when assessing C_v values is as follows:

- Normal distribution: $C_v = 0$ to 0.5
- Non-normal distribution: $C_v > 0.5$

8.7 Confidence

When statistical tests are conducted on data sets, it is common to select a confidence level to attribute to the calculations. In many cases the standard confidence level to ensure against a Type 1 error (false positive) is 95%, which equates to selecting the correct answer 19 times out of 20. Conversely, when assessing for the occurrence of a Type II error (false negative), or the selection of wrong conclusion when the opposite is true, an 80% level of confidence is often used. For the purpose of assessing Enhance's monitoring data, a 95% confidence level will be used to assess for Type 1 errors, and an 80% level of confidence will be used for Type II errors.

When considering non-parametric data, the use of quartiles is an analogous way to represent confidence intervals associated with numbers of standard deviations from the mean, where one SD (or σ) relates to about 68% confidence, and two SD s relates to 95% confidence. The use of the interquartile range is shown in Figure G, where Q3 represents the 75th percentile and Q1 represents the 25th percentile, which together represent a 50% confidence level. Use of a 1.5 multiplier on the upper and lower quartiles results in about a 99% confidence level.

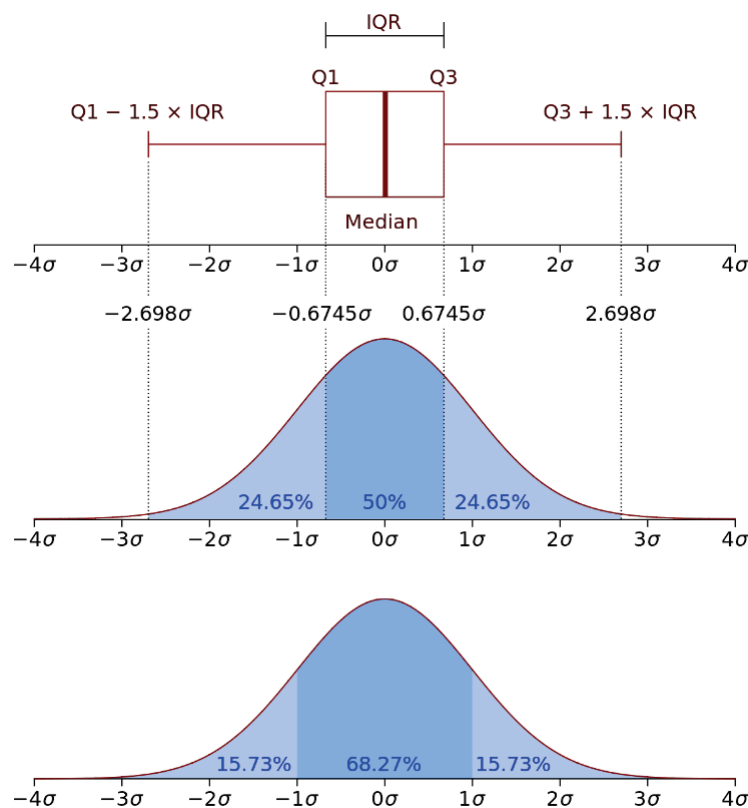


Figure G. Comparison of Parametric and Non-Parametric Significance Levels

8.8 False Positives and False Negatives

Statistical significance is based on the confidence attributed to accepting a false positive, or Type 1 error. For example, accepting that water quality at a downgradient monitoring station is different than “baseline” when the data from that station actually falls within the same data distribution is a Type 1 error, or false positive. In contrast, a Type II error relates to accepting a false negative, or in the same example accepting that a downgradient monitoring station is the same as background when it is not. This means that the detection of a change from baseline when it has actually occurred will be missed.

The acceptable false positive rate for analysis of data is 5%, which translates to a 95% confidence that the data measurement falls within the same population distribution as baseline conditions. As for the false negative rate, a 20% level (or effect size) is acceptable, which translates an 80% confidence that the data measurement does not fall within the same data population as the baseline and is therefore different.

8.9 Action Limits and Control Charting

8.9.1 Reliable Reporting Limits

Anthropogenic parameters (Section 7.1) are compared to the Alberta Tier 1 groundwater remediation guidelines (AEP 2024) when applicable or the RRL, whichever is lower. Results that are greater than the respective trigger limit are identified for further evaluation (i.e. retesting to confirm the reliable detection of an indicator that was expected to be non-detect).

8.9.2 Screening Limits

Instances where there is a lack of data for a monitoring location to establish acceptable statistical power, or where a comparison to a monitoring location's baseline is inappropriate (e.g. a monitoring well installed within a known impact), analysis should be performed using screening-level limits defined using site-wide baseline data from similar soil types or aquifers. This will require the separation of monitoring stations into distinct and comparable units anticipated to have similar physical and chemical characteristics. In terms of the subsurface groundwater environment, this is related to hydrostratigraphic units. Once a sufficient number of samples (at least 20) representative of baseline conditions for a specific soil type or aquifer are available then screening limits can be developed.

An inter-location comparison is to be used where low numbers of sample readings exist for monitoring stations - less than 8 measurements at a given location. In this case, quartile values are to be calculated for each soil type or aquifer and the IQR determined. This approach is analogous to the parametric statistical approach of using the mean $\pm$ 2 standard deviations to reflect the 95% confidence interval (as shown in Figure G).

Once baseline conditions for the soil type or aquifer have been defined, newly acquired results can be compared to the calculated screening limits and anomalies can be identified and attributed accordingly. Determining the upper and lower screening limit values utilizes the

non-parametric approach employing the upper (Q_3) and lower (Q_1) quartiles and the interquartile range ($IQR = Q_3 - Q_1$) as follows:

$$\text{Upper screening limit: } Q_3 + 1.5 (IQR)$$

$$\text{Lower screening limit: } Q_1 - 1.5 (IQR)$$

As noted previously, this approach is considered suitable for locations with a limited amount of data, or those established in areas that may already be impacted and should capture any variability that would naturally occur with a given soil type or aquifer. To facilitate proper screening and ensure confidence in the assessment results, it is imperative that conditions be stabilized at each monitoring location and the data representative of natural conditions.

Routine updating of screening level values is also required to ensure their applicability and continued usefulness. This should be performed when deemed appropriate following routine data evaluations. A review of each year's data and related statistics should be conducted to ensure that notable changes to screening level values have not occurred, and if so, appropriate updates are made.

8.9.3 Control Limits

Control limits are commonly used to determine whether or not an observed value, within a set of 8 measurements or more from a given monitoring location, is significantly different from historical values (Gibbons 1994).

The method commonly used to define control limits is defined by Shewhart (1926). The practice is to calculate both an upper and lower control limit for each location. Once these control limits have been established, they are not to be updated until required, following proper review. As such, control limits are to remain fixed so that proper comparisons can be made.

The equations to derive Shewhart Control limits (Gibbons 1994) for normally distributed data is as follows:

$$\text{Upper limit} = \text{Mean} + 4.5 \times SD$$

$$\text{Lower limit} = \text{Mean} - 4.5 \times SD$$

The 4.5 multiplier comes from a table of Student's t-statistics where a 95% overall confidence for 35 future comparisons is identified (Gibbons 1994). A small selection of those multiplier values is provided in Table C, highlighting the 4.5 multiplier in red. This is the standard used at many monitored facilities and is aligned with the approach outlined in AEP's draft Groundwater Monitoring Directive (2012).

In certain circumstances it may be warranted to reduce the multiplier used to establish control limit values for less future comparisons. In doing so this will provide a more conservative assessment; however, such an approach also runs the risk of triggering more situations where verification and/or follow-up actions are required. For Enhance's MMV, the initial multiplier to use will be three (3) once eight (8) stabilized readings are obtained at each monitoring location. This value will change to lower multipliers as more monitoring data is collected, with these values also listed in

Table C. The standard number of future comparisons will also remain at 5. In doing so, the intent of the monitoring program for timely detection and response to anomalous or changing conditions will be met.

Table C. Multiplier Values for Various Number Readings and Future Comparisons

		Future Comparisons			
No. of Readings		5	10	20	35
	8	3.00	3.50	4.03	4.48
	12	2.71	3.10	3.48	3.79
	16	2.60	2.94	3.28	3.55
	20	2.54	2.86	3.17	3.42

Using this method, any data point that falls outside of the established control is to be taken as a signal that something has occurred that warrants further investigation. This could be the result of a problem with the monitoring location itself, a natural change in conditions, or the detection of false positive or negative readings. It can equally signal a developing situation that warrants investigation. All situations will be treated as suspect and investigated accordingly.

Once eight samples representative of baseline conditions for a specific monitoring location have been collected, use of Shewhart control limits becomes possible. This is the most desirable comparison for local conditions. This method is only reasonable where the location outside of areas know to be impacted, which is the case for Enhance's Clive CCUS project.

The standard for this MMV is to have at least eight measurements from the same location showing an acceptable degree of variability and no identifiable trends beyond natural seasonal variability to have confidence that the location is indicating baseline conditions. This is considered the minimum number of measurements to provide reasonable statistical power in the data evaluation process. It is also imperative that the eight baseline readings be obtained after the monitoring location has achieved stabilized conditions. Any data point identified as not being representative of the location's stabilized condition, or determined to be an outlier, must not be included in any further statistical calculations. However, the data are to be retained in the database for future reference.

8.9.4 Data Charting

Data charting is to be used to visualize results for primary indicator parameters. On each chart, the monitoring results are to be displayed with the applicable screening or control limit(s) shown as horizontal lines . These charts are meant to visualize changes in temporal data in comparison to the established limits. However, all data charts developed for this program must fulfil the following requirements:

- Data associated with duplicates are removed from the output.

- Data associated with the break-in period are clearly marked and are not used in screening or control limit calculations.
- Data identified as an obvious outliers are clearly identified and marked.
- Non-detect results are replaced with one half of the RRL and are clearly identified and marked.
- Appropriate limits are plotted:
 - Screening limits for monitoring locations with less than eight measurements of primary indicators.
 - Control limits for monitoring locations with eight or more measurement of primary indicators.

An example of a data chart, with established control limits shown, is shown in Figure H.

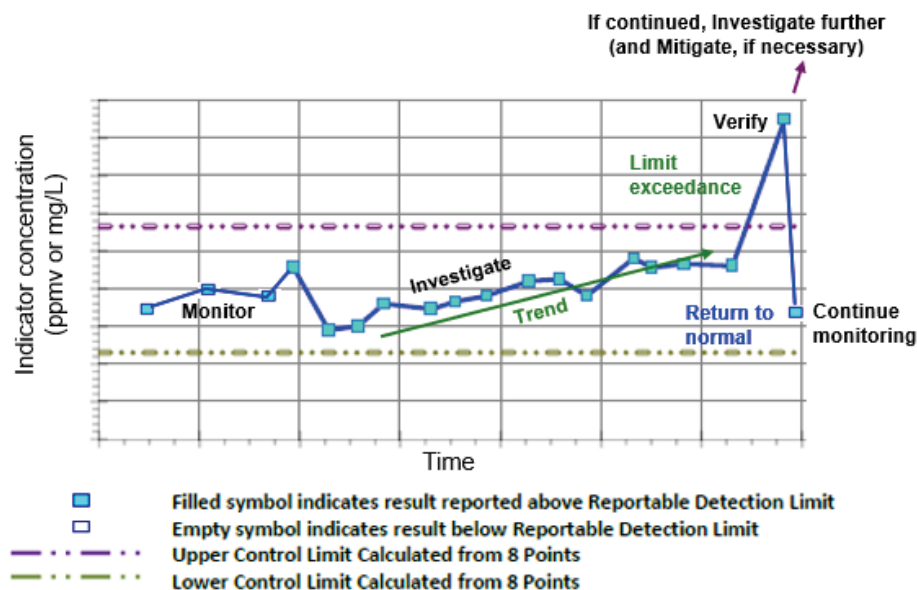


Figure H. Example Data Chart showing Measurements, Control Limits, and Response Actions.

8.10 Trend Analysis

When assessing changes in soil gases or water quality over time, it is common to conduct trend analysis. The practice involves assessing a data set to identify a temporal pattern and allows the direction and rate of change to be established. This provides the ability to make statements about the possible future state of subsequent samples results. The Mann-Kendall test for trend is one such test that determines whether values increase, decrease, or show no evidence of a trend over time. The test is sensitive to changes occurring in a straight line but can also accommodate nonlinear changes.

When combined with the Theil Sen slope estimator, this provides a powerful tool to determine the magnitude and significance of an identified trend. Each method is described in further detail in the following sub-sections.

8.10.1 Mann-Kendall Test

The Mann-Kendall test for trend (Mann 1945; Kendall 1975) is a non-parametric method of analysis used to assess data collected as part of monitoring efforts. The approach is predicated on a series of comparisons between values in a data set to determine the total number of increasing versus decreasing values. The style of comparison is described in Table D.

The process involves ordering the data by sampling date $x_1, x_2, \dots, x_n$ where x_i is the measured value on occasion i . Next, the signs of each of the N' possible differences $x_{i'} - x_i$, where if $i' > i$ are recorded based on the following:

- Each comparison of a data point with another is scored a value of 1 if the earlier measurement is less in magnitude than the later one. Similarly, if the earlier value is greater than the later one, then a value of -1 is used. Meanwhile, two identical values will generate a value of 0.
- Once completed the values are tallied and an S statistic is provided. If the number of comparisons between earlier and later measurements generates a positive number, then there is evidence of an increasing trend. If the opposite occurs then a negative trend is identified. Also, the larger the calculated value of S , the greater the evidence of a trend.
- Data sets with frequent non-detects (i.e. >50%) are not to be assessed using this method and are to be handled differently, as noted previously.

Table D. Mann-Kendall Test Comparisons

Measurements Ordered by Time							
x_1	x_2	x_3	...	x_{n-1}	x_n	No. +	No. -
	$x_2 - x_1$	$x_3 - x_1$		$x_{n-1} - x_1$	$x_n - x_1$		
		$x_3 - x_2$		$x_{n-1} - x_2$	$x_n - x_2$		
				$x_{n-1} - x_3$	$x_n - x_3$		
				$\vdots$	$\vdots$		
				$x_{n-1} - x_{n-2}$	$x_n - x_{n-2}$		
					$x_n - x_{n-1}$		
						<i>Sum of +</i>	<i>Sum of -</i>

where:

$$\text{sgn}(x_{i'} - x_i) = \begin{cases} 1 & \text{if } x_{i'} - x_i > 0 \\ 0 & \text{if } x_{i'} - x_i = 0 \\ -1 & \text{if } x_{i'} - x_i < 0 \end{cases}$$

The Mann-Kendall statistic is then computed as follows:

$$S = \sum_{i=1}^{n-1} \sum_{i'=k+1}^{n-1} \text{sgn}(x_{i'} - x_i)$$

For the purpose of establishing trends and identifying the most statically significant one, the output from the Mann-Kendal analysis is to be filtered using the following criteria:

- The occurrence of a 95% confidence that a trend is occurring for a given indicator parameter

It is important to note that Mann-Kendall analysis alone has some limitations. It is insensitive to the magnitude or rate of change and can therefore identify trends of no particular consequence. It also required at least 4 measurements.

Seasonality

The possibility of seasonality of monitoring data must also be considered. This effect is known affect CO₂ levels in soil gas probes as a result of soil respiration processes during the active growing season. Changes to shallow soil environments and can also occur due to annual recharge events or other surface activities. If applicable, use of the seasonal Mann-Kendall test for trend is required. Seasonality in a data set will usually present itself visually in graphed data by the occurrence of cyclical patterns. The seasonal Mann-Kendal test involves separating the data out by each season

of each year and then performing the same procedures of comparisons and value attribution to get the S statistic for each season.

8.10.2 Theil-Sen Slope Estimator

The Mann-Kendall test for trend, however, does not indicate anything about the magnitude or rate of change. For example, a Mann-Kendall test at a well with a change in chloride from 10 to 13 mg/L over a year would give the same result as a change from 10 to 130 mg/L over the same time period.

To better understand the magnitude of an identified trend, use of the Theil-Sen slope estimator is required (Sen 1968a, Sen 1968b; Theil 1950). This non-parametric method of analysis uses the median versus arithmetic mean of pairwise slopes from individual trend lines between data comparisons using the same approach as that used for the Mann-Kendall test. The equation to describe this method are provided below:

$$Q = \frac{x_{i'} - x_i}{i' - i} \text{ and } N' = \frac{n(n-1)}{2}$$

where x is the measured concentration of individual monitoring events i and $i' > i$, and N' is the number of data pairs where $i' > i$. For non-detect data, the process described in this SOP should be followed. To obtain the median value for Q , the N' values of Q are ranked from smallest to largest and the median slope is computed:

$$\text{If } N' \text{ is odd, } S = Q_{[(N'+1)/2]}$$

or

$$\text{If } N' \text{ is even, } \frac{Q_{(N'/2)} + Q_{[(N'+2)/2]}}{2}$$

For the purpose of establishing a significant change for an established trend, the required output from the Mann-Kendal and Theil-Sen's slope tests use the following criteria:

- At least a 95% confidence of a trend.
- A normalized slope of greater than, or equal, 10% per year.

Trend Assessment Data Requirements

The Mann-Kendall and Theil-Sen tests are to be applied to monitoring data to detect trends in primary indicators; however, the test data must fulfil the following requirements before an assessment can be made:

- Data associated with the break-in periods are removed from the assessment.
- Data identified as obvious outliers are removed from the assessment.
- Data associated with duplicates are removed from the assessment (this includes samples that lack temporal independence from one another, i.e. less than 30 days apart).
- Data effected by seasonality is separated by desired season and tested separately.
- Less than 50% of the results are non-detect (those non-detect results are then replaced with one half of the RRL for the assessment).

Once the above requirements are satisfied, then a trend assessment can be completed so long as there are more than eight sample measurements following the established break-in period.

9 SITUATION RESPONSE

Following the data evaluation process, any concerns identified should be assessed for the need regarding follow-up response. This includes an initial step of Verification to ensure that the concern is legitimate. If the concern is confirmed, then an initial assessment is completed to determine if the situation poses unacceptable risk. If the situation is considered acceptable, then the location is returned to Monitoring status with screening or control limits updated accordingly. If the situation is considered unacceptable, then a more detailed assessment is required, including any update to the conceptual site model. The situation and related monitoring locations are then placed into Follow-up status. The detailed assessment conducted during the Follow-up phase may still find that the situation is the results of a naturally occurring anomaly. If so, the result is documented, area characterization is updated (including limits), and the location is placed back into Monitoring status (i.e. active monitoring). Alternatively, the detailed assessment may find that the situation is related to CCUS processes. If this is the case, then supplementary characterization is to be required to understand the source, cause, and/or reason and may include a comprehensive risk assessment. Depending on the outcome of that risk assessment further mitigative actions may be required.

As summarized in the following sub-sections, status levels are meant to classify each monitoring location with respect to its condition in relation to the established baseline conditions of a given area.

9.1 Verification

A monitoring location should be placed in Verification status if there is a detection of identifiable primary indicator outside of established limits or with statistically significant trend.

The objective of verification status is as follows:

- To confirm the results are repeatable through laboratory re-testing or confirmation sampling.
- Determine, through desktop review of notes and documentation, if the results are related to CCUS activities, due to natural conditions, or some other explanation.
- Complete a risk assessment to evaluate if the suspected influence is of low-risk in a low-risk setting (possibly acceptable), or of unacceptable risk, requiring further management efforts.

If an impact related to CCUS activities is not suspected, then the location returns to Monitoring Status and statistical performance limits may need revaluation and updating to prevent further repeated events. If the situation is suspected to be related to CCUS activities but is a non-issue by virtue of risk level, the event remains in Verification status until confidence is sufficient to update limits and return the location to Monitoring status (documenting the suspected influence). If the situation is suspected to be due to activities related to CCUS activities and may pose unacceptable risk, then the process moves to Follow-up status. Professional judgement and proper rationale for investigative methods will be required at this stage.

Desktop verification activities and evaluation processes to detect and substantiate changes to soil gas and/or groundwater conditions are outlined in Figure I. In general, there are four basic steps to the verification process that need to occur. The steps are sequential, therefore they may not all need to be completed if the verification process is completed at an earlier step:

- **Step 1:** Ensure the sample is being compared with the appropriate limits and that any statistical trend is valid.
- **Step 2:** Ensure the sample is representative and not the manifestation of failed monitoring equipment or other situation causing a deviation from normal operating conditions.
- **Step 3:** Make sure the results can be replicated and confirmed (i.e. not an outlier due to field or laboratory issue).
- **Step 4:** If verified, initiate review of other lines of evidence to determine the source, cause, and/or reason and level of risk associated with the situation (through a formal risk assessment process).

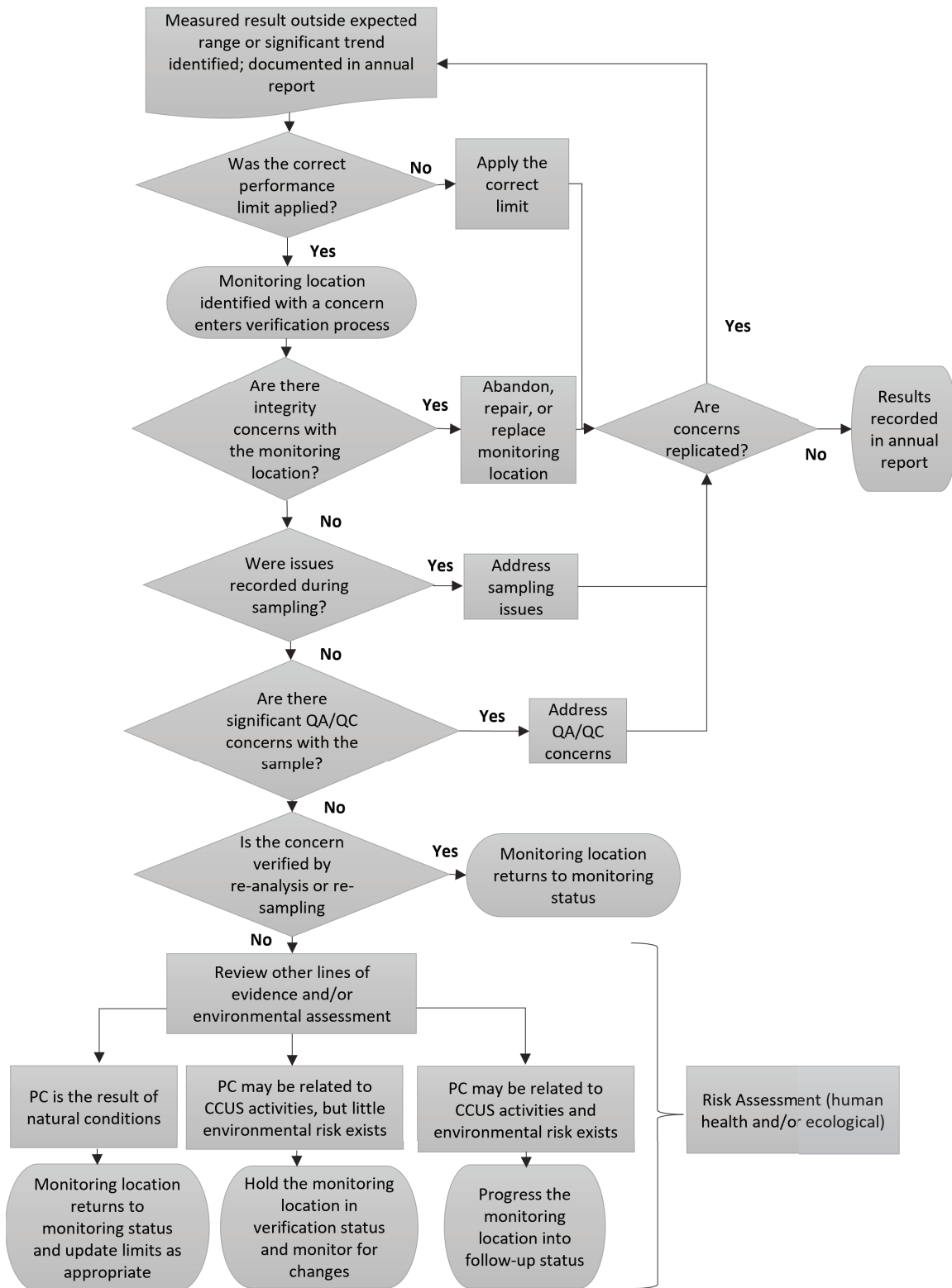


Figure I. Process Flow for Data Verification

9.2 Follow-Up Investigation

If monitoring locations are placed in Follow-up status, this is done so out of an abundance of caution to understand the source, cause, or reason for measurements being outside of the expected baseline range. The initial step completed for the Follow-up status is to update the area's Conceptual Site Model (CSM) to better understand the context of the unexpected condition identified. This includes:

- Description and refinement of baseline conditions.
- Detailed description of potential causes of change or impact, the reasons, and potential implications.
- Detailed description of pathways for impact propagation, including geological and anthropogenic, as well as geochemical and groundwater flow conditions, and attendant soil gas and water quality.
- Detailed description of the impact event (e.g. extent, duration, magnitude, evolution with time, transport and fate, mass flux, reversibility, etc.)
- Detailed description of receptors (i.e. human and ecological) and impact assessments, if conducted.

The process of updating the CSM may identify gaps that preclude the completion of the Follow-up process. Additional investigations are to be undertaken where needed to close critical gaps in data, information, and knowledge.

If the updated CSM reveals that the condition is related to changing, but natural, phenomena then the monitoring location(s) are returned to the Monitoring status and the screening or control limits are updated.

If CCUS activities are suspected of having altered the soil gas or groundwater conditions, then the updated CSM is used to conduct a risk assessment, development of a risk management plan, and the implementation of mitigation strategies, if required.

By following the process flow developed for this SOP, and the steps outlined above, anomalous situations will be identified in a timely manner and attributed accordingly for further verification and investigation. In doing so, this will ensure the proper deployment of effort and resources to ensure long-term success of the CCUS program.

9.2.1 Mitigation

Deployment of engineered controls may be required under certain situations to address unacceptable risk posed by Enhance's CCUS project. If required, due to unacceptable risk, a formal mitigation strategy and plan will be developed ensure alignment with the goals and objectives of CO₂ containment and protection of the environment and local residents. The plan will then be executed accordingly.

For situations requiring more of an emergency response, actions determine to be reasonably justifiable to maintain integrity of the CCUS program will be taken. Enhance will notify the AER accordingly and any further mitigative measures will be deployed pursuant to the documented mitigation plan.

9.3 Communication

All Follow-up activities will be communicated to the AER through the MMV soil and groundwater monitoring annual report, or at other frequencies as agreed to (e.g. status updates).

10 PROGRAM OPTIMIZATION

10.1 Refinement Process

The goal of employing an environmental monitoring program is to identify changes in conditions in a timely manner and attribute the necessary response to potential issues of concern. While aimed at potential concerns, it is also equally important to evaluate the suitability of the monitoring network and individual monitoring locations on an annual basis to identify gaps, as well as eliminate redundancy via unnecessary monitoring.

The refinement process should be completed on the same frequency as the monitoring program itself, and evaluate areas and locations based on:

- Purpose: including the intended potential contaminant sources and potential pathways being monitored.
- Risk: what is the expected timeline of a potential incident and would the monitoring location indicate the presence of impact before or after another monitoring location.

This refinement process is amenable to vulnerability and risk mapping, which can be used to:

- Identify areas with redundant monitoring.
- Identify areas requiring additional monitoring.

Such evaluation should be completed prior to finalization of the analytical schedule for the next sampling year. Following the data evaluation stage, each area and location that has accumulated sufficient data to be in Surveillance status should be evaluated.

10.2 Program Audits

Program audits are a necessary step to ensure procedures are being followed and sample and data integrity are maintained. Periodic audits should also be performed on the data QAQC, database assimilation, data analysis, and reporting aspects of the monitoring program. Program audits should not be completed by the party executing the work, and require the following documentation:

- General observations.
- Indication of tasks not being executed as required.
- Recommendations for improvement.
- Corrective action follow-up.

Outcomes of these program audits are included as recommendations within the annual containment report for the Clive project.

10.3 Change Implementation

As this SOP is an internal supporting document, recommended changes to data analysis and reporting aspects of Enhance's CCUS project and associated MMV plan will be determined internally. However, any changes made to this monitoring program are to be aligned with the approved MMV Plan.

10.4 Review Cycle

This SOP document has been compiled to provide a consistent approach to data evaluation and reporting. It is understood that needs may change with time, or that more appropriate methods or approaches may present themselves. To ensure that the most up-to-date protocols are being employed, and that the process outlined is applicable to the intent of the monitoring programs and related approval conditions, this document should be reviewed from periodically to ensure alignment with the MMV Plan.

Review of this document should occur on a 3-year cycle to align with the schedule of MMV plan updates. However, these reviews may not necessarily result in any changes. If changes do occur, a formal authorization process will be employed, and all necessary stakeholders will be notified.

10.5 Authorization Process

The authorization process for any changes to this document will require sign-off from Enhance to ensure full agreement with the changes made. Version tracking with a brief summary of changes will be used to provide a history to the document development and authorization process.

10.6 Change Implementation

Upon authorization of this SOP document, and any future changes, the most current Version of this document will supersede any previous version. Copies of this SOP, and any changes in the future, will be made available to any person's working with Enhance's monitoring data to ensure full compliance, upon Enhance's approval Suggestion for any changes to this document should be forwarded to the Enhance management team for consideration within the review cycle indicated above.

11 CLOSURE

Integrated Sustainability would like to thank Enhance Energy Inc. for the opportunity to support the development of a standard operating procedure for the Clive CCUS project. We trust that this report meets the needs and expectations of Enhance Energy Inc. If you have any questions please contact the undersigned at any time.

Sincerely,

Integrated Sustainability

Aaron Petrowitsch, M.Sc., P. Geo
Intermediate Hydrogeologist

Jon Fennell, M.Sc., Ph.D., P. Geo
Principal Hydrogeologist and Geochemist

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Appendix 1 - Other Useful Data Evaluation Methods

Appendix 1: Other Useful Data Evaluation Methods

A2-1. Correlation Analysis

There are situations where the change in one indicator parameter will align with the change in another. This can be both positive (a consistent change in one direction) and negative (a consistent change in opposite directions). Correlation analysis is a statistical method used to evaluate the strength of this relationship and provide some additional information to understand processes that may be causing the detected change.

Pearson's correlation coefficient (or r -value) is a statistic that measures the linear correlation between two continuous variables with numerical values. The output values for this statistic range from -1 to 1, with the former indicating a perfect negative correlation (i.e. when one constituent increases the other decreases) and in the latter case a perfect positive correlation (i.e. both constituents increase in tandem). The two hypotheses being test in this case, the null (H_o) and alternative (H_A), are as follows:

$H_o: r = 0$, there is no correlation between the two variables

$H_A: r \neq 0$, there is a correlation between the two variables

This approach is a parametric method and therefore requires the data sets to be normally distributed (Section 8.5.1).

In cases where the data are confirmed as being non-normally distributed, application of the non-parametric statistic, Spearman's ρ -value, is used. This statistic produces similar output value of -1 to 1 and is based on ranked values of ordinal variables. For the purpose of this SOP, evaluating the degree of positive or negative correlation between variables being assessed, the acceptance should be as follows:

<i>0.33 or less</i>	<i>Low</i>
<i>0.33 to 0.67</i>	<i>Medium</i>
<i>>0.67</i>	<i>High</i>

A2-2. Regression Analysis

There are instances where the application of graphical comparison is required to further understand the degree of association between individual constituents. The typical approach is to employ linear regression, which results is an R^2 value (i.e. coefficient of determination). This statistic describes the proportion of variance for a dependent variable that can be explained by an independent variable. For example, a value of 1.0 indicates a perfect fit, and thus a highly reliable model for future projections. Conversely, a value of 0.0 indicates a model that fails to describe the relationship between two variables and is therefore not useful for future projection.

When evaluating Enhance data for linear regression lines in graphical comparisons the same levels of significance as identified for the correlation analysis will apply (low,

medium, high) and the following acceptance criteria should be used to establish significance:

- R^2 of 67% or greater (high to very high)
- An associated p-value of <0.05 (i.e. 95% confidence that graphical model fits the data well)

In certain instance there may be the need to employ non-linear regression techniques. These will be assessed on a case-by-case basis and will follow a similar set of criteria to establish significance.

A2-3. Population Testing

Parametric approach

It is sometimes necessary to determine whether or not different sets of data come from a similar or different data grouping. When the data are distributed normally a common test to identify similarity or dissimilarity is the Student's t-Test. This parametric statistical test is designed to assess whether there is a significant difference between the means of two groups. The two hypotheses being tested in this case, the null (H_0) and alternative (H_A), are stated as follows:

H_0 : sample mean (x) = true population mean (μ)	
H_A : sample mean (x) $\neq$ true population mean (μ)	<i>one-tailed & two-tailed</i>
H_A : sample mean (x) $<$ true population mean (μ)	<i>upper tailed</i>
H_A : sample mean (x) $>$ true population mean (μ)	<i>lower tailed</i>

The purpose of this test is to determine if the null hypothesis should be rejected at some level of significance, or p-value. Low values (commonly 0.05 or less) indicate a decreased support for the null hypothesis, or that the means of the two groups are the same. One limitation of this test is that it can only be used with normally distributed, numerical, and continuous data sets.

It is important to note that obtaining a "statistically significant" results does not necessarily mean that it is "practically significant". Therefore, it is advisable to determine the "effect size", which is a test to determine the magnitude of difference between the means of each data group. This is typically done using Cohen's d-value (Cohen 1998¹), the derivation of which is shown in Figure A2-A, where M2 and M1 are the sample means of the two groups being compared and the pooled SD is the average of the individual squared standard deviation values.

¹ Cohen, J. 1998. Statistical Power Analysis for the Behavioral Sciences. 2nd ed. Hillsdale, NJ: Lawrence Erlbaum Associates.

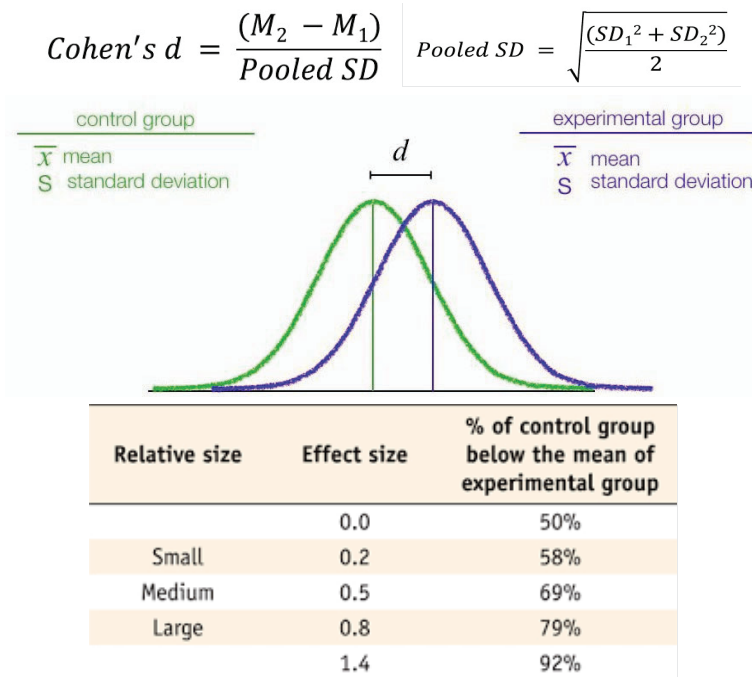


Figure A2-A Cohen's d-value for Establishing Effect Size

When a d-value of 1 is obtained this indicates that the means of two groups differ by 1 SD. And, if the value is 2 then they differ by 2 SDs, and so on. Cohen suggests that a value of 0.2 represents a small effect, 0.5 a medium effect, and 0.8 or greater a large effect. If the means of two groups of data do not differ by at least 0.2 SD, then the difference is trivial even if the result is statistically significant.

Nonparametric approach

There are obviously situations where data sets are not normally distributed, and in such instances a non-parametric analogue to Students t-Test should be used, such as the Wilcoxon sign-rank test or Mann-Whitney test, can be employed. These tests similarly provide a comparison between two related samples, matched samples, or repeated measurements on a single sample to assess whether the rank of their population means differ. This approach does not require numerical or continuous data and instead uses ordinal (or ranked) data.

A2-4. Power and Sample Size

It is important to ensure that a sufficient number of samples exist or order to be able to detect a change. This is where statistical power becomes important. Simply put, statistical power refers to the likelihood of avoiding a Type II error (false negative) in hypothesis testing. Statistical power is the probability of detecting an effect if there is truly an effect present to detect. Therefore, statistical power levels should be examined to ensure that results are not influenced by an insufficient number of measurements.

Figure A2-B provides a summary of required sample sizes to achieve a desired statistical power with a reasonable degree of confidence. It is quite evident that as the signal to noise ratio increases the required number of samples required to substantiate a difference between two data groups decreases.

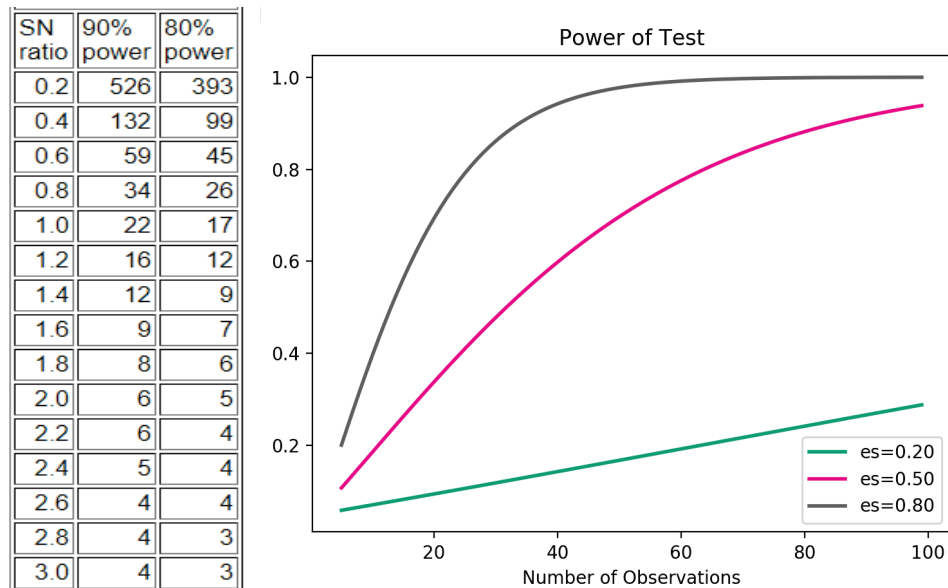


Figure A2-B Required Sample Size as a Function of Signal to Noise (S/N) Ratio, or Cohen's d-value, to Determine Statistical Power (2-sided, 5% Significance)

Note: Table from http://www.3rs-reduction.co.uk/html/6_power_and_sample_size.html

A2-5. Cluster Analysis

Cluster analysis is a technique that identifies relationships between multiple parameters. It starts by treating each observation as a separate cluster. Then, it repeatedly executes the following steps: i) identify the two clusters that are closest together, and ii) merge the two most similar clusters. The process is continued iteratively until all the clusters are merged together. The *distance* between two clusters is computed based on the length of the straight line drawn from one cluster to another. This is commonly referred to as the *Euclidean distance*. Many other *distance metrics* exist that are not utilized here (e.g. Pearson *r*-values, R^2 values, etc.).

Once parameters are clustered into their groupings, a review of the associations can reveal some useful information about some of the sources or causes of these associations as well as physical or chemical processes leading to the given associations. An example of a hierarchical cluster analysis (HCA) tree is provided in Figure A2-C.

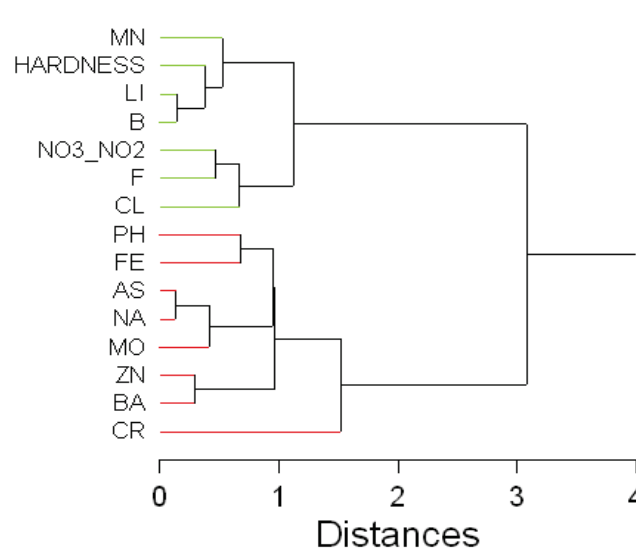


Figure A2-C Example of a Hierarchical Cluster Tree Showing Parameter Groupings

A2-6. Factor Analysis

Factor analysis is another multi-parameter assessment method to group variables and assess their associations. It is used to reduce a large number of variables into fewer numbers of “factors” that extracts maximum common variance from all variables and puts them into a common score. The most commonly employed method is principal component analysis, or PCA.

PCA is a technique used to emphasize variation and bring out strong patterns in a dataset. PCA is often used to make data easier to explore and visualize. The covariance of variables is calculated to determine the extent to which corresponding variables of ordered data move in the same direction. Positive covariance means X and Y are positively related (i.e. as X increases, Y also increases). Negative covariance depicts the exact opposite relation, and zero covariance means X and Y are not related. The results are often rotated to identify Associations between variables will fall into groupings called factors, with each factor explaining a certain amount of the variance. Typically, the first factor will explain most of the variance followed by a bit less in each subsequent factor. It is imperative that data sets be normalized before conducting PCA so that scale-effects are minimized.

An example of the output generated by a PCA analysis is provided in Figure A2-D which includes the table of factor values, the Scree plot for the related eigenvalues, and the factor loading plot visually showing how the variables associate.

Component Loadings

	1	2	3
PH	0.065	-0.247	-0.877
HCO3	-0.286	-0.699	0.426
CL	0.580	-0.069	0.010
F	0.406	0.562	-0.054
NO3_NO2	0.619	0.405	0.469
SO4	0.952	0.137	-0.058
TDS_CALC	0.920	-0.295	0.102
NA	0.638	-0.725	0.005
HARDNESS	0.808	0.111	0.166
AS	0.400	-0.823	0.086
B	0.935	0.177	-0.021
CR	-0.286	0.184	0.273
LI	0.856	0.123	-0.243

Variance Explained by Components

1	2	3
5.631	2.435	1.358

Percent of Total Variance Explained

1	2	3
43.314	18.735	10.446

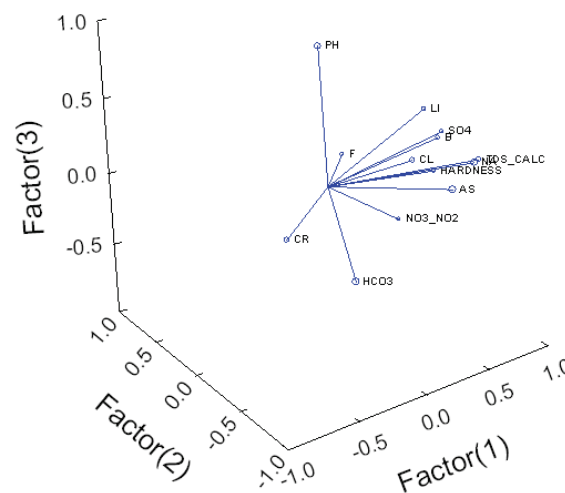
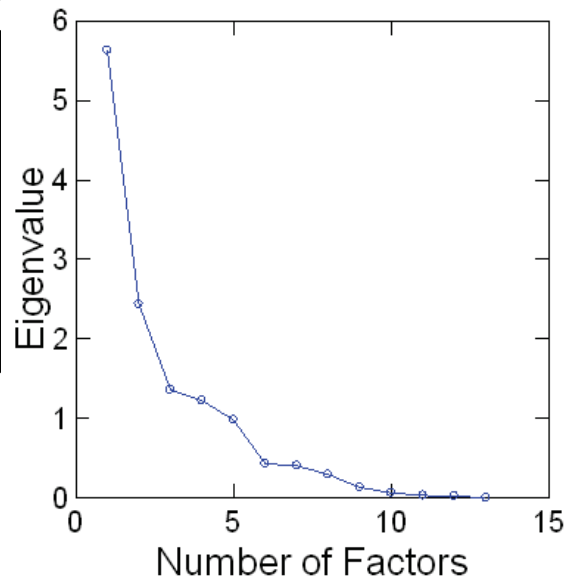


Figure A2-D Example of PCA Component Loading (Factor) Table, Scree Plot, and Factor Loading Plot Showing Associations of Variables in Each of Factor 1, 2, and 3

[ATTACHMENT 1: CURRENT CLIVE CCUS APPROVAL No. 12832Q](#)

MADE at the City of Calgary, in the
Province of Alberta, on
5th day of June 2026.



ALBERTA ENERGY REGULATOR

The Alberta Energy Regulator (AER) pursuant to the *Oil and Gas Conservation Act*, chapter O-6 of the Revised Statutes of Alberta, 2000, orders as follows:

- 1) The scheme of Enhance Energy Inc. (hereinafter called “the Operator”) for enhanced recovery of oil by miscible displacement using miscible fluid (CO₂) and water injection in that part of the **Clive D-3 A and D-2 A Pools** outlined in Appendix A and B¹, respectively, of the approval, as described in

- | | |
|-----------------------------|-----------------------------|
| a) Application No. 1904282, | j) Application No. 1935009, |
| b) Application No. 1917176, | k) Proceeding No. 1936172, |
| c) Application No. 1923727, | l) Application No. 1938203, |
| d) Application No. 1926558, | m) Application No. 1938354, |
| e) Application No. 1927404, | n) Application No. 1948949, |
| f) Application No. 1929837, | o) Application No. 1954174, |
| g) Application No. 1932084, | p) Application No. 1955677, |
| h) Application No. 1932548, | q) Application No. 1958496, |
| i) Application No. 1932625, | r) Proceeding No. 1961556, |

is approved, subject to the terms and conditions herein contained.

GENERAL REQUIREMENTS

- 2) For the purpose of this approval, “miscible fluid” means a mixture that contains:
- a) no less than 0.87 mole fraction of carbon dioxide, with the remainder composed of hydrocarbon components and hydrogen sulphide, at any time.
- 3) The injection of miscible fluid and/or water must not commence or continue in the well(s) referred to in clauses 12 and 19 until the Measurement, Monitoring, and Verification Plan (hereinafter called the MMV Plan) as detailed in Application No. 1904282 or subsequent amendments is approved by the AER or the delegated signing authority.¹
- 4) The Operator must conduct the miscible fluid injection and/or water injection in the well(s) referred to in clauses 12 and 19 in accordance with the following requirements:¹
- a) the injected gas stream shall contain no greater than 0.05 mole fraction of hydrogen sulphide at any time,
 - b) a voidage replacement ratio must not exceed 1.0 on the basis of cumulative production and injection volumes following commencement of production,

- c) a minimum monthly voidage replacement ratio of 0.5 on a twelve-month moving average basis must be maintained,
- d) the composition of the injectant (miscible fluid and/or re-injection gas stream) must be determined monthly,
- e) the Operator must obtain and analyze representative samples of the produced liquid and gas from production wells in the Approval Area to determine where breakthrough occurred,
- f) when breakthrough of the miscible fluid is indicated in any of the producing wells, the Operator must obtain and analyze representative samples from producers in the Approval Area annually for the estimation of the breakthrough volume in the Approval Area,
- g) a hydraulic isolation log must be run on each of the injection well(s) referred to in clause 12, subclause a and clause 19, subclause a, in accordance with *Directive 051* in five years from the date of approval. The need for further hydraulic isolation logging over the life of the injection well(s) will be determined through the annual reporting and presentation process,¹
- h) the Operator must continuously monitor the pressures of the tubing/casing annulus; conduct annual packer isolation tests for the injection well(s) referred to in clause 12, subclause a and clause 19, subclause a, which must be submitted to the AER through the DDS system, and implement appropriate corrosion protection. If a leak, or potential leak, is detected in the tubing/casing annulus or packer in the injection well(s), the Operator must immediately inform ResourceCompliance@aer.ca and the AER Red Deer Field Centre,¹
- i) the Operator must immediately suspend injection operations if the injection facilitates the movement of injected fluids into any zone above the base of groundwater protection or any zone other than the Leduc and Nisku zones, and immediately inform ResourceCompliance@aer.ca and the AER Red Deer Field Centre,
- j) the Operator must immediately suspend injection operations if any injection equipment, monitoring equipment, or safety devices fail that could compromise the safe operation of the scheme,
- k) the Operator must immediately report any loss of containment, anomalies that indicate fracturing out of the Leduc and Nisku formations, or anomalous pressure changes occurring anywhere within the Clive D-3 A Pool and/or Clive D-2 A Pool to ResourceCompliance@aer.ca,
- l) the following information for the new wells drilled within the Approval Area must be included when the Operator files a subsequent *Directive 065* amendment application:
 - i. geological interpretations, which should include updated Leduc, Ireton, Nisku, Calmar, Stettler gross thickness isopach mapping over the Approval Area if new well logs, obtained in accordance with *Directive 080*, demonstrate a substantial variance to current isopach mapping, and

- ii. the maximum injection pressure without fracturing the injecting target formation determined by representative step rate testing if available.
- 5) The Operator must include all the wells that are not cut and capped within 50 m from the injection well(s) referred to in clause 12, subclause a and clause 19, subclause a, and must implement monitoring programs in accordance with the following requirements:¹
 - a) baseline gas migration test,
 - b) baseline surface casing vent flow test and subsequent tests every six months,
 - c) inspection casing and/or tubing pressures every six months,
 - d) sampling tubing and/or casing fluid analysis if available, and
 - e) the Operator must immediately suspend injection operations if a leak, or potential leak, is detected in the tubing/casing annulus or packer in the wells within 50 m from the injection well(s) referred to in clause 12, subclause a and clause 19, subclause a, and immediately inform ResourceCompliance@aer.ca, and the AER Red Deer Field Centre.¹
- 6) The Operator must submit annual progress reports and make presentations on the CO₂ EOR scheme to ResourceCompliance@aer.ca, with the first to occur after one year commencement of the miscible fluid injection. These reports and presentations shall include the following information in metric units:
 - a) a summary of the scheme operations including:
 - i) any new project wells drilled in the reporting period,
 - ii) any workovers/treatments done on the injection and monitoring wells including the reasons for and results of the workovers/treatments,
 - iii) changes in injection equipment and operations,
 - iv) identification of problems, remedial action taken, and impacts on scheme performance, and
 - v) a table of analysis data including baseline values and testing results. The table must include the unique well indicators, sample dates, test dates and results for all soil, CBM, water and deep monitoring wells, and wells for vent flowing tests.
 - b) a full discussion of the pressures of the Leduc and Nisku formations, including stabilized shut-in formation pressures and on how the pressure compares with the formation pressure expected for the cumulative volume of the CO₂ injected, along with an updated estimate of what the actual cumulative injection volume will be at the maximum shut-in formation pressure specified in clause 14, subclause a,¹
 - c) a discussion of the overall performance of the scheme, including the incremental oil recovery and the volume of incremental oil produced as a result of the miscible fluid injection, how the reservoir pressure is changing over time; updated geological maps; and updated CO₂ plume extent and pressure distribution models, if needed. The updated

geological maps should be based on all new data obtained since the commencement of the injection to the end of the reporting period,

- d) a discussion on how an increase pressure due to the miscible fluid injection could have an adverse effect on hydraulic fracturing of the target formation or caprock, and the displacement of brine upward out of the target formation via a conduit such as fracture or fault, and wellbores within the area of influence. In addition, a list of all wells that penetrated the injection target formation surrounding the injection well where the pressure increase could also have an adverse effect,
- e) results and evaluation of all monitoring done during the reporting period including but not limited to: pressure surveys, corrosion protection, fluid analyses, logs and any other data collected that would help in determining the success of the scheme,
- f) a table showing the following data for each month of the reporting period:
 - i) a representative composition for the injected fluids,
 - ii) a representative composition for the re-injection streams,
 - iii) mole fraction of the CO₂ and impurities in the injection stream,
 - iv) standard volume of the CO₂ injected,
 - v) cumulative volume of the CO₂ injected at standard conditions following the commencement of the scheme
 - vi) CO₂ stream formation volume factor,
 - vii) volume of the CO₂ injected at reservoir conditions,
 - viii) cumulative volume of the CO₂ injected at reservoir conditions following the commencement of the scheme,
 - ix) hours on injection,
 - x) the net amount of the CO₂ injected in the reservoir, in reservoir cubic meters and in standard cubic meters, the difference between total CO₂ injected into and that produced from the scheme,
 - xi) maximum daily injection rate at standard conditions,
 - xii) average daily injection rate at standard conditions,
 - xiii) maximum wellhead injection pressure and corresponding wellhead injection temperature,
 - xiv) average wellhead injection pressure and corresponding average wellhead injection temperature,
 - xv) estimated or measured average reservoir pressure in the target formation, and
 - xvi) estimated average bottomhole injection pressure.*

* Include a discussion in detail on how the hydrostatic head of the miscible fluid in the wellbore, friction losses in the tubing, and pressure losses in the reservoir are accounted for in the determination of the average reservoir pressure.

- g) a plot showing ongoing monthly injection volumes and the maximum wellhead injection pressure versus time. The plot must display the scheme on an ongoing basis and not just for the reporting period,
- h) a table showing the calculated net tonnes of the CO₂ injected in reservoir and in standard conditions, which is a difference between the miscible fluid injected into and that produced from the scheme:

- i) on a monthly basis for the reporting period, and
 - ii) on an annual basis since the commencement of injection.
- i) a table and plot of the calculated voidage replacement ratios both on a monthly and cumulative basis from the start of scheme operations, and
 - j) verification that all conditions of this approval have been met during the reporting period. All non-compliance events should be summarized, and should be voluntarily self-disclosed as soon as they occur to ResourceCompliance@aer.ca.
- 7) All non-abandoned wells that are completed in the Leduc and/or Nisku zones and within the Approval Area must be abandoned by a Level A method in accordance with *Directive 020* upon completion of the CO₂ injection operations. The abandonment program must be submitted to the Regulatory Applications Branch via WellOperations@aer.ca and approved by the Well Integrity Team.¹
 - 8) All suspended wells that are completed in the Leduc and/or Nisku zones and within the Approval Area must meet the Medium Risk Type 4 suspension requirements of *Directive 013* once commencement of the CO₂ injection into the Approval Area.
 - 9) The Operator is required to submit to the AER or the delegated signing authority for approval of the MMV Plan updates at critical milestones, such as commencement of the miscible fluid injection, two years after commencement of the miscible fluid injection, closure and post closure of the miscible fluid injection. Specifically, the Operator must submit a closure and a post closure MMV Plan.
 - 10) The AER may require adding additional Leduc and/or Nisku and/or Manville monitoring well(s) offsetting the well(s) referred to in clauses 12 and 19 if, in its opinion, circumstances so warrant.¹
 - 11) The Operator is required to update the Offset Wellbore Risk Assessment within the annual report and presentation to the AER. New information, learnings, and trigger events will be included within the forecasted plume model(s) and subsequent monitoring and mitigation plans as they materialize. If there is an unexpected offset well response, the issue must be addressed as soon as possible in the field to ensure fluid containment and the AER must be notified.
 - a) The Operator will present annually to the AER updates to the Offset Wellbore Risk Assessment.

LEDUC

- 12) Miscible fluid and/or water may be injected into the subject pool through the well(s) with the following unique identifier(s):
 - a) Previously approved injection wells:

Class II & III

02/02-22-039-24W4/0 [10 000] {15 000}
 00/11-25-039-24W4/0 [10 000] {15 000}

Class II & III

00/01-27-039-24W4/0 [10 000] {15 000}
 00/01-34-039-24W4/0 [10 000] {15 000}

02/11-36-039-24W4/0 [10 000] {15 000}
02/06-01-040-24W4/0 [10 000] {15 000}
03/16-02-040-24W4/0 [10 000] {15 000}

02/16-10-040-24W4/0 [10 000] {15 000}
00/01-03-040-24W4/0 [10 000] {15 000}

Class III

04/03-15-040-24W4/0 [10 000]
02/05-15-040-24W4/0 [10 000]

b) Rescinded injection wells:

Class II

00/15-35-039-24W4/0 {14 900}

The class of injection fluid is described in *Directive 051*.

Bracketed values denote the maximum wellhead injection pressure (kilopascals gauge) for the specified well(s) for {water injection} & [miscible fluid].

- 13) The injection of the miscible fluid and/or water injection may commence in the well(s) referred to in clause 12, subclause a once the AER has confirmed in writing that *Directive 051* requirements have been met.¹
- 14) The Operator must conduct the miscible fluid injection and/or water injection in the well(s) referred to in clauses 12, subclause a, in accordance with the following requirements:¹
- a) stabilized bottomhole reservoir pressures of the Clive D-3 A and D-2 A Pools in the Approval Area must be obtained annually, respectively, in accordance with *Directive 040* requirements, the test results must be submitted to the AER through the AER Digital Data Submission (DDS) System. Injection operations must be suspended in the well(s) referred to in clause 12, subclause a, if the Leduc reservoir pressure exceeds 17 500 kilopascals (gauge),¹
 - b) no production may be taken from any wells within the Approval Area subject to active miscible fluid injection wherein the Leduc reservoir pressure is less than 13 000 kilopascals (gauge) unless the AER, upon application, otherwise permits,
 - c) the Operator must monitor the Leduc producing well(s)'s producing gas-oil ratio in the Approval Area to determine when the miscible fluid breakthrough occurs,
 - d) prior to the injection of miscible fluid, the Operator must re-abandon in accordance with *Directive 020* to Level A standards any previously cut and capped abandoned wells completed in the Leduc zone that are located within 50 m of the injection wells referred to in clause 12, subclause a, which do not meet Level A Standards. The need for further re-abandonment requirement of previously cut and capped abandoned wells within 50 m of future injection wells will be determined through subsequent amendments to the subject scheme,
 - e) the Operator must apply to remove the injection well(s) from the list in clause 12, subclause a, before abandoning any injection well in the Approval Area, and¹

- f) the Operator must submit the abandonment plan to the Regulatory Applications Branch via WellOperations@aer.ca and receive approval of the plan from the Well Integrity Team before abandoning any well within the Approval Area.¹
- 15) The Operator must include the 00/01-02-040-24W4/2, 00/16-02-040-24W4/0, 00/04-26-039-24W4/2, 00/14-10-040-24W4/2, 00/07-15-040-24W4/2 and 00/09-16-040-24W4/2 wells completed in the Nisku zone as deep monitoring wells, and must implement monitoring programs in accordance with the following requirement:
- a) stabilized Leduc formation pressures in the greater of four wells or twenty-five percent of active Leduc production wells within the Approval Area from any Leduc deep monitoring well or Leduc injection/production EOR wells equipped with downhole pressure gauges must be obtained annually in accordance with *Directive 040* requirements to monitor pressure development inside the Leduc formation, the test results must be submitted to the AER through the DDS System,
 - b) stabilized Nisku formation pressures in the 00/14-10-040-24W4/2, 00/16-02-040-24W4/0, 00/04-26-039-24W4/2 and 00/09-16-040-24W4/2 wells completed in the Nisku zone within the Approval Area must be obtained annually in accordance with *Directive 040* requirements to monitor pressure development inside the Nisku formation, the test results must be submitted to the AER through the DDS System,
 - c) for chemical compositional analysis to detect CO₂ levels the Operator must collect gas samples three times per year in the 00/07-15-040-24W4/2, 02/05-33-040-24W4/2, 00/04-26-039-24W4/2, 00/09-16-040-24W4/2 and 00/16-20-040-24W4/2 deep monitoring wells. The frequency of sampling and analysis will be re-evaluated after two years of commencement of the miscible fluid injection into the Approval Area. Based on the sampling performances, the AER may require for adding and/or changing Nisku gas sampling well(s),
 - d) the Operator must complete annual isotope analysis ($\delta^{13}\text{C}$) on the producing fluids from the Nisku formation in the 00/07-15-040-24W4/2, 02/05-33-040-24W4/2, 00/04-26-039-04W4/2 and 00/16-20-040-24W4/2 wells. The frequency isotope analysis will be re-evaluated after two years of commencement of the miscible fluid injection into the Approval Area,
 - e) the Operator must update the reservoir simulations in the Approval Area annually. The updated model must incorporate any new information and reconciles recorded pressures, rates, and fluid sampling at both the injection wells and the monitoring wells. The frequency of the simulation update will be re-evaluated after two years of commencement of the miscible fluid injection into the Approval Area,
 - f) the Operator must immediately inform ResourceCompliance@aer.ca if the injection facilitates the movement of fluids into the Nisku zone, which is observed in any deep monitoring wells, while continuing to monitor the movement of fluids within the Nisku zone and taking direction from the AER to continue, suspend, or reverse the injection thereupon based of the monitoring results,

- g) the Operator must fulfil the MMV Plan and/or subsequent amendments to the MMV Plan for the injection operations and deep monitoring wells, until the subject CO₂ injection scheme is rescinded, and
 - h) if the Operator cannot fulfil the requirements for the deep monitoring wells referred to in clause 15, subclauses a, b, c and d, the Operator must have the alternative wells within the Approval Area to carry out the monitoring requirements accordingly.¹
- 16) Prior to commencement of the miscible fluid injection in the well(s) listed in clause 12, subclause a, the Operator must provide a complete baseline data and analysis report to ResourceCompliance@aer.ca by November 30, 2019, which includes the following:¹
- a) baseline data and analysis of carbon isotope signature ($\delta^{13}\text{C}$) contained within different sources, such as source CO₂, CO₂ in producing gas from existing Leduc and Nisku formations, specifically from the deep monitoring wells listed in clause 15, and from coal bed methane (CBM) wells (as per the MMV Plan), CO₂ in soil gas and in headspace gas from domestic water wells (as per the MMV Plan),¹
 - b) baseline water chemistry data for produced water from the Leduc and Nisku formations, groundwater wells as per the MMV Plan, and existing baseline chemistry data from aquifers overlying the Leduc and Nisku formations,
 - c) baseline seismic data to indicate that no faults transect the seals in the Approval Area,
 - d) any baseline measurements to be taken during the pre-injection CO₂ period,
 - e) complete reservoir pressure analysis that includes initial and current Leduc and Nisku formation pressures, a discussion on how the pressures in the reservoirs are expected by the injection of CO₂, and what the safe pressure levels are for the Leduc reservoir,
 - f) history match for the Leduc oil reservoir in the Approval Area prior to the CO₂ injection and CO₂ enhanced oil recovery (EOR) performance prediction,
 - g) the Operator must commit to perform, document, and submit to ResourceCompliance@aer.ca an updated risk assessment of all of the Leduc and/or Nisku wells, including abandoned, suspended or active, in the Approval Area to assess the possibility of leakage based on the vintage of the wells, diagnostic tools run and abandonment practice applied (including porous zone isolation). Wellbores found to have medium and high risks as detailed in the MMV Plan should be mitigated prior to the expected time of CO₂ reaching the locations, and
 - h) discussion of the need for changes to the MMV Plan.
- 17) The minimum *Directive 065* application requirements must include, at a minimum, the following information:
- a) The submission of the *Directive 065* application for undrilled injection wells that received *Directive 056* well license or the submission of *Directive 065* application in accordance with Unit 2 Conservation for completed wells that are also subject to the submission and approval of the *Directive 051* requirements.

- b) The review of legacy wellbores and a full offset wellbore risk assessment will be performed at the time of pre-drill application for undrilled injection wells with the following conditions:
 - i) a comprehensive risk assessment of all wellbores in the forecasted area of influence CO₂ plume must cover the risk to zonal containment containing cement quality and position of the low cement tops through porous zones and protected groundwater zones to any near surface concerns,
 - ii) full offset wellbore risk assessment should also include the assessment of legacy wells with no cement top information, and
 - iii) the average cement top estimates should be conducted for areas small enough to reasonably account for changes in stratigraphic column and formation tops.
 - c) The AER may require additional Leduc or Nisku monitoring wells in an expansion area. The Nisku monitoring wells for the expansion area upon receipt of an application for a pre-drill may include the 00/11-21-040-24W4/2, and/or 00/12-33-040-24W4/2 wells.
- 18) The medium and long-term risks at offset wells must continue to be addressed as per risk processes:
- a) Offset wellbore risk assessment must be submitted to the AER Well Integrity inbox, WellOperations@aer.ca, by October 31, 2025 for all wells within the area designated as Appendix A.

NISKU

- 19) Miscible fluid and/or water may be injected into the subject pool through the well(s) with the following unique identifier(s):

- a) New injection wells:

Class II & III

03/16-02-040-24W4/2 [10 000] {15 000}

02/06-01-040-24W4/2 [10 000] {15 000}

The class of injection fluid is described in *Directive 051*.

Bracketed values denote the maximum wellhead injection pressure (kilopascals gauge) for the specified well(s) for {water injection} & [miscible fluid].

- 20) The injection of the miscible fluid and/or water injection may commence in the well(s) referred to in clause 19, subclause a once the AER has confirmed in writing that *Directive 051* requirements have been met.¹
- 21) The Operator must conduct the miscible fluid injection and/or water injection in the well(s) referred to in clause 19, subclause a, in accordance with the following requirements:¹

- a) stabilized bottomhole reservoir pressures of the Clive D-3 A and D-2 A Pools in the Approval Area must be obtained annually, respectively, in accordance with *Directive 040* requirements, the test results must be submitted to the AER through the AER Digital Data Submission (DDS) System. Injection operations must be suspended in the well(s) referred to in clause 19, subclause a, if the Nisku reservoir pressure exceeds 17 100 kilopascals (gauge),¹
 - b) no production may be taken from any wells within the Approval Area subject to active miscible fluid injection wherein the Nisku reservoir pressure is less than 12 100 kilopascals (gauge) unless the AER, upon application, otherwise permits,
 - c) the Operator must monitor the Nisku producing well(s)'s producing gas-oil ratio in the Approval Area to determine when the miscible fluid breakthrough occurs,
 - d) prior to the injection of miscible fluid, the Operator must re-abandon in accordance with *Directive 020* to Level A standards any previously cut and capped abandoned wells completed in the Nisku zone that are located within 50 m of the injection wells referred to in clause 19, subclause a, which do not meet Level A Standards. The need for further re-abandonment requirement of previously cut and capped abandoned wells within 50 m of future injection wells will be determined through subsequent amendments to the subject scheme,¹
 - e) the Operator must apply to remove the injection well(s) from the list in clause 19, subclause a, before abandoning any injection well in the Approval Area, and¹
 - f) the Operator must submit the abandonment plan to the Regulatory Applications Branch via WellOperations@aer.ca and receive approval of the plan from the Well Integrity Team before abandoning any well within the Approval Area.¹
- 22) The Operator must include the 00/13-34-038-24W4/3, 00-16-34-039-24W4/3 and 04/14-02-042-24W4/0 wells completed in the Mannville zone as deep monitoring wells, and must implement monitoring programs in accordance with the following requirement:
- a) stabilized Nisku formation pressures in the greater of four wells or twenty-five percent of active Nisku production wells within the Approval Area from any Nisku deep monitoring well or Nisku injection/production EOR wells equipped with downhole pressure gauges must be obtained annually in accordance with *Directive 040* requirements to monitor pressure development inside the Nisku formation, the test results must be submitted to the AER through the DDS System,
 - b) for chemical compositional analysis to detect CO₂ levels the Operator must collect gas samples two times per year in the 00/13-34-038-24W4/3, 00/16-34-039-24W4/3 and 04/14-02-042-24W4/0 completed in the Mannville deep monitoring wells. Based on the sampling performances, the AER may require for adding and/or changing Mannville gas sampling well(s),
 - c) the Operator must complete annual isotope analysis ($\delta^{13}\text{C}$) on the producing fluids from the Mannville formation in the 00/13-34-038-24W4/3, 00/16-34-039-24W4/3 and 04/14-02-042-24W4/0 wells,

- d) the Operator must update the reservoir simulations in the Approval Area annually. The updated model must incorporate any new information and reconciles recorded pressures, rates, and fluid sampling at both the injection wells and the monitoring wells. The frequency of the simulation update will be re-evaluated after two years of commencement of the miscible fluid injection into the Approval Area,
 - e) the Operator must immediately inform ResourceCompliance@aer.ca if the injection facilitates the movement of fluids into the Mannville zone, which is observed in any deep monitoring wells, while continuing to monitor the movement of fluids within the Mannville zone and taking direction from the AER to continue, suspend, or reverse the injection thereupon based on the monitoring results,
 - f) the Operator must fulfil the MMV Plan and/or subsequent amendments to the MMV Plan for the injection operations and deep monitoring wells, until the subject CO₂ injection scheme is rescinded, and
 - g) if the Operator cannot fulfil the requirements for the deep monitoring wells referred to in clause 22, subclauses a, b, c and d, the Operator must have the alternative wells within the Approval Area to carry out the monitoring requirements accordingly.¹
- 23) The minimum *Directive 065* application requirements must include, at a minimum, the following information:
- a) The submission of the *Directive 065* application for undrilled injection wells that received *Directive 056* well license or the submission of *Directive 065* application in accordance with Unit 2 Conservation for completed wells that are also subject to the submission and approval of the *Directive 051* requirements.
 - b) The review of legacy wellbores and a full offset wellbore risk assessment will be performed at the time of pre-drill application for undrilled injection wells with the following conditions:
 - i) a comprehensive risk assessment of all wellbores in the forecasted area of influence CO₂ plume must cover the risk to zonal containment containing cement quality and position of the low cement tops through porous zones and protected groundwater zones to any near surface concerns,
 - ii) full offset wellbore risk assessment should also include the assessment of legacy wells with no cement top information, and
 - iii) the average cement top estimates should be conducted for areas small enough to reasonably account for changes in stratigraphic column and formation tops.
- 24) This scheme is approved and must continue to be operated in accordance with *Directive 065* requirements, as may be amended from time to time.
- 25) The AER may at any time vary these terms and conditions or may suspend or revoke this approval if, in its opinion, circumstances so warrant.

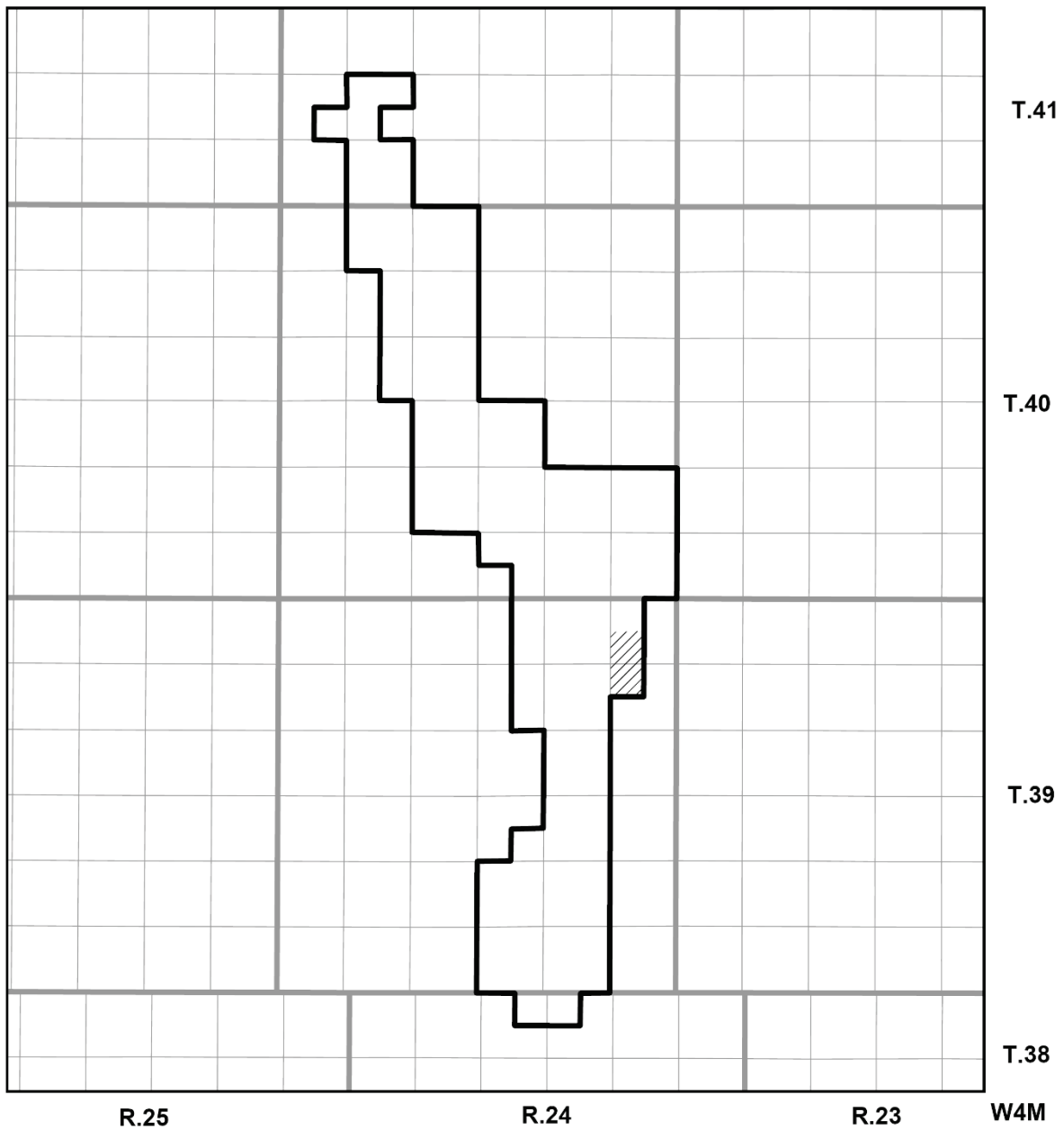
26) Approval No. 12832Q rescinds Approval No. 12832P.

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CLIVE D-2 A POOL
APPENDIX B TO APPROVAL NO. 12832Q

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Area(s) of Change

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ATTACHMENT 2: CLIVE MMV MAP

R25

R24

R23W4



T41

T41

T40

T40

T39

T39

T38

T38

Enhance Energy Inc

Clive MMV Map

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By :
Scale = 1:95000

Date : 2026/07/14
Project : CLIVE (2024-03-06)

VILLAGE OF CLIVE

Legend

Enhance Wells

- Injection Wells
- Leduc Monitoring
- Nisku Monitoring
- EOR Producers

Clive

- 12832 Approval Area
- Clive Battery
- CBM Sampling Location
- Soil Gas Locations
- Ground Water Wells
- Dedicated Water Wells

R25

R24

R23W4