Shell Quest Carbon Capture and Storage Project

MEASUREMENT, MONITORING AND VERIFICATION PLAN

OCTOBER 2023 UPDATE

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Executive Summary

The aim of the Quest CCS Project is to capture, transport and permanently store CO_2 securely, reducing greenhouse gas emissions from the existing Scotford Upgrader where bitumen from the Alberta oil sands is processed. The Scotford Upgrader is located northeast of Fort Saskatchewan Alberta within Alberta's Industrial Heartland, which is zoned for heavy industrial development.

After capture, the CO_2 is compressed and transported north along a 65 km long pipeline to the injection well sites. CO_2 is injected into a 2 km deep saline aquifer, the Basal Cambrian Sands (BCS), and securely stored within the BCS storage complex.

The Quest Project has a responsibility to carefully monitor activity within the sequestration lease area (SLA) and to confirm that an acceptable risk to health, safety, and the environment is maintained. To that end, a Measurement Monitoring and Verification (MMV) plan has been developed which addresses the following key principles:

- Compliant to all regulatory requirements
- Quest Project-specific
- Site-specific (regarding the Injector Wellsites, associated Areas of Review, the SLA, and potential cumulative and regional impacts)
- Risk-based, fit for purpose, and transparent
- Adaptive
- Provision of timely warnings towards CO_2 stream containment and conformance anomalies
- Ability to monitor every domain of review
- Based on sound science and engineering – use best available technologies economically achievable (BATEA)

The goal of the MMV plan is to achieve the following objectives:

Demonstrate CO_2 Inventory Accuracy to ensure the reported CO_2 stored complies with regulations and protocols.

Provide evidence in support of Containment to demonstrate the *security* of CO_2 storage and to protect human health, the environment including groundwater resources, and industrial activities including other CCS operators, oil & gas, minerals, disposal, geothermal, storage, etc.

Provide evidence in support of Conformance to indicate the *long-term effectiveness* of CO_2 storage by demonstrating actual storage performance is consistent with expectations about injectivity, capacity, and CO_2 behavior inside the storage complex.

Provide suitable evidence that there are no significant adverse effects of CO_2 injection on health, the environment or other resources.

These objectives will be achieved by:

- Measuring/Monitoring/Verifying the composition and flow of the injection stream
- Measuring/Monitoring/Verifying the effectiveness of existing barriers created by site selection, site characterization, and engineering designs

- Regular updating of monitoring barriers and their optimization (e.g., sensors, decision logic, corrective measures) by identifying additional MMV technologies and effective barriers while removing MMV technologies and barriers demonstrated to be ineffective based on current subsurface risk assessment
- Using monitoring systems to provide an early warning to trigger timely control measures (barriers) designed to reduce the likelihood or the consequence of adverse effects of the CO_2 sequestration project.

This version of the MMV plan, submitted September 8th, 2023, builds on learnings from monitoring activities in the operational/injection phase. Previous versions of the MMV plan are available at the Alberta Government Carbon Capture and Storage knowledge sharing website [1].

This document focuses on addressing CO_2 inventory accuracy, containment, and conformance in relation to the injection wells and injection target reservoir - the Basal Cambrian Sands - located at a depth of about 2 km below ground. It does not address monitoring of pipeline integrity within the Quest Sequestration Lease Area.

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Acronyms and Abbreviations

AER .... Alberta Energy Regulator
AGS .... Alberta Geological Survey
AOR .... Area of Review of MMV activities for the Project
BATEA .... Best Available Technologies Economically Achievable
BCS .... Basal Cambrian Sands
BGWP .... Base of Groundwater Protection
CBL .... Cement Bond Log
CCS .... Carbon Capture and Storage
CO_2 .... Carbon Dioxide
CSM .... Conceptual Site Model
CSM .... Carbon Sequestration Tenure Regulation
DAS .... (Fiber-optic) Distributed Acoustic Sensing
DHMS .... Downhole Microseismic Monitoring
DHPT .... Downhole Pressure-Temperature Gauge
DMW .... Deep Monitoring Well
DTS .... (Fiber-optic) Distributed Temperature Sensing
FSP .... Fault Slip Potential
GC .... Gas Chromatography
GoA .... Government of Alberta
GM .... Gas Migration
GPS .... Global Positioning System
GWW .... Ground Water Well
HRAM .... High Resolution Aeromagnetic
HUD .... Hold-Up Depth
IW .... Injection wells
InSAR .... Interferometric Synthetic Aperture Radar
IPCC .... Intergovernmental Panel on Climate Change
IRM .... Injection Rate Metering at wellhead
ISM .... Induced Seismicity Monitoring
LMS .... Lower Marine Sands
MCS .... Middle Cambrian Shale
MMV .... Measurement, Monitoring and Verification
MS .... Microseismic
MSM .... Microseismic Monitoring
M_L .... Local Magnitude
M_W .... Moment Magnitude
MWIT .... Mechanical Well Integrity pressure Testing
P&NG .... Petroleum & Natural Gas
Quest CCS project .... Quest Carbon Capture and Storage Project
SCVF .... Surface Casing Vent Flow
SEIS2D .... Time-lapse surface 2D Seismic Data
SEIS3D .... Time-lapse surface 3D Seismic Data
Shell .... Shell Canada Limited
SLA .... Sequestration Lease Area for the Project
SMA .... Seismicity Monitoring Area
SSO2 .... Subsurface Order No. 2
TDS .... Total Dissolved Solids
USIT .... Time-lapse Ultrasonic casing imaging

VSP ....Vertical Seismic Profiling
VSP2D ....Time-lapse 2D Vertical Seismic Profiling
WEC...Downhole Electrical Conductivity monitoring
WHPT ....Well Head pressure-temperature gauge
WPH...Downhole pH monitoring

1 Project Description

Shell Canada Limited, which currently holds all necessary regulatory approvals to the Quest CCS Project, is the managing partner of Shell Canada Energy. Shell Canada Energy operates the Project, on behalf of the Athabasca Oil Sands Project ("AOSP") Joint Venture and its participants, comprising Canadian Natural Upgrading Limited (60%), Chevron Canada Oil Sands Partnership (20%) and 1745844 Alberta Ltd (20%), as amended.

The aim of the Quest CCS Project is to capture, transport and permanently store CO_2 securely, reducing greenhouse gas emissions from the existing Scotford Upgrader. The Scotford Upgrader is located northeast of Fort Saskatchewan, Alberta within Alberta's Industrial Heartland, which is zoned for heavy industrial development.

The key components of the Quest CCS Project are:

- CO_2 capture infrastructure connected to the Scotford Upgrader. The method of capture is based on a licensed Shell amine system called ADIP-X.
- A CO_2 pipeline that transports the CO_2 from the Scotford Upgrader to the injection wells along a 65km pipeline. The CO_2 injection wells are located in the center of the sequestration lease area.
- An approved storage scheme to inject the CO_2 into the Basal Cambrian Sand (BCS) Formation, a deep underground saline aquifer, for permanent storage at a depth of about 2km below ground level. Eight injection wells had been approved as part of the D65 approval 11837C [2] and three wells were drilled and are currently on injection. Figure 1-1 shows the Quest CCS Project Sequestration Lease Area (SLA).
- A site-specific, risk-based, fit for purpose, adaptive, and transparent Measurement, Monitoring and Verification (MMV) plan has been in place since 2013, with a purpose of addressing health, safety and environmental risks, to evaluate sequestration performance and to provide evidence that the site is suitable for closure. The selected storage site is assessed to be inherently safe with the MMV Plan activities designed to manage and minimize any residual storage risks. The two independent storage risks of loss of containment and loss of conformance are the primary MMV objectives for the Quest CCS Project:

  1. Provide evidence in support of Containment to demonstrate the *current security* of CO_2 storage.
     - Verify containment, well integrity, and the absence of any environmental effects outside the storage complex.
     - Detect early warning signs of any unexpected loss of containment.
     - Activate additional barriers as required to prevent or remediate any significant environmental impacts as defined by the Environmental Assessment.
  2. Provide evidence in support of Conformance to indicate the long-term security of CO_2 storage.

  - Show that pressure and CO_2 development inside the storage complex are consistent with models and, if necessary, calibrate and update these models as required.
  - Provide the monitoring data required to support CO_2 inventory reporting.

3. Provide suitable evidence that CO_2 injection does not have significant adverse effects on health, the environment or other resources
   - Show that seismicity (including microseismicity) is confined below the Lower Lotsberg Salt seal
   - Provide sufficient seismicity monitoring data required to manage induced seismicity to acceptable limits

Additional information about Quest CCS project is available at the Alberta Government Carbon Capture and Storage knowledge sharing website [1].

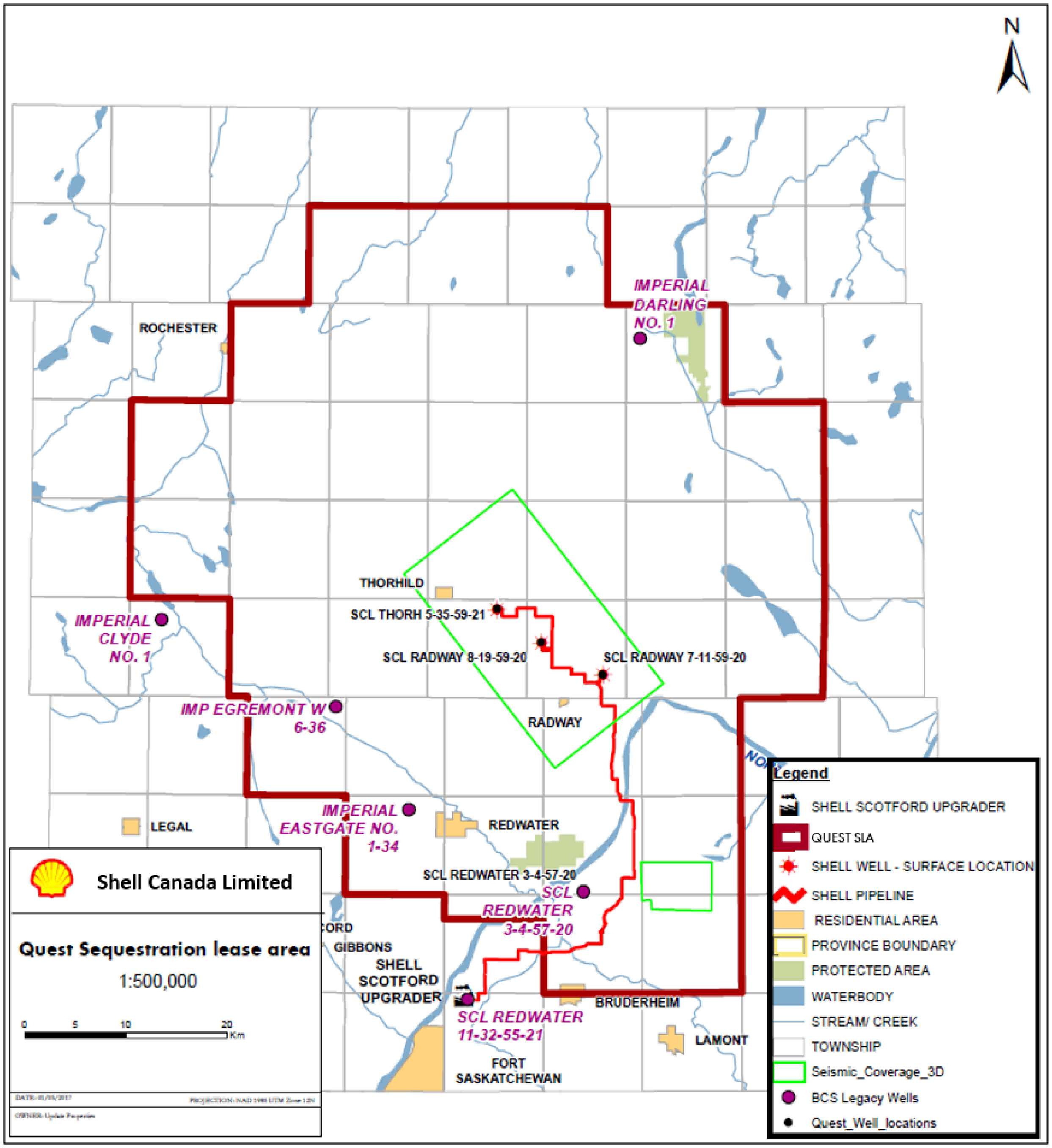


Figure 1-1: Location Map of the Quest Sequestration Lease Area (SLA)

Map includes Quest pipeline (red line), Quest Project well sites, 3D surface seismic coverage, and legacy wells (abandoned wells that penetrate the BCS) within the SLA.

2 Aim and Timeframe of MMV updates

2.1 Aim

The 2023 Quest MMV Plan has the following objectives:

- Outline activities related to monitoring the injection stream composition.
- Outline integrity and activities related to CO_2 Injection Wells.
- Outline activities that address **containment** and **conformance** in relation to the CO_2 storage within the Basal Cambrian Sands.
- Outline activities that address monitoring related to seismic activity.

The MMV Plan does not address monitoring of pipeline integrity within the Quest Sequestration Lease Area. This is covered within the Pipeline Integrity Management Plan as per the Alberta Regulation 91/2005 Pipeline rules section 7.

The MMV Plan complies with both the Mines and Minerals Act and all applicable AER Regulations.

2.2 Timeframe of MMV Updates

2.2.1 Alberta Energy Regulator (AER) Updates

MMV plan updates are submitted in accordance with the conditions of AER Approval 11837C received May 12th, 2015. Remaining conditions relating to MMV plan updates are summarized as follows:

- Condition 7 - Requirement to submit MMV plan updates as required by the AER; at a minimum, updates are required at the critical milestones for commencement of injection, closure and post closure.
- Conditions 10d and 17 - Provide annual operations reports that are aligned to the most current MMV plan and discuss any need for changes to the current MMV plan.
- Condition 18 – Submit a closure report in 2040 that includes an MMV plan update, with specific attention to any performance problems evident in the 25 years of operations.
- Condition 19 – Submit a post closure report, which includes an update of its MMV plan.
- Condition 25 – Submit MMV plans to Alberta Environment and Sustainable Resource Development for review – now part of AER.

2.2.2 Alberta Energy and Minerals Updates

According to the Carbon Sequestration Lease Approval(s) Section 2(2) (a) The Lessee (Shell) shall comply with the provisions of the Mines and Mineral Act.

In Section 9(2) of the Alberta Regulation 68/2011 Mines and Minerals Act Carbon Sequestration Tenure Regulation, referring to Carbon Sequestration Leases,

“The Minister may issue to an applicant an agreement under section 116 of the Mines and Minerals Act in the form of a carbon sequestration lease if the Minister receives from the applicant.

9(2)(e) a monitoring, measurement and verification plan that meets the requirements set out in Section 15:

> *15) The Minister may approve a monitoring, measurement and verification plan received under section 9 or 11 in relation to a carbon sequestration lease if the plan*
> *(a) sets out the monitoring, measurement and verification activities that the lessee will undertake while the plan is in effect,*
> *(b) contains an analysis of the likelihood that the operations or activities that may be conducted under the carbon sequestration lease will interfere with mineral recovery, based on the geological interpretations and calculations the lessee is required to submit to the Regulator pursuant to Directive 65 in its application for approval of the injection scheme under the Oil and Gas Conservation Act, and*
> *(c) contains any other information requested by the Minister*

9(2)(f) a closure plan that meets the requirements set out in section 18.”

Shell submitted an MMV Plan and a Closure Plan as part of the Sequestration Lease Application submitted April 28, 2011 and approved by the Minister May 27, 2011. The latest approved MMV plan and Closure Plan were submitted in February 2020 and approved on November 25, 2020.

According to Section 16(1) and 19(1) of the Carbon Sequestration Tenure Regulation (CSTR) 68/2011 on Duration and Renewal of the monitoring, measurement and verification plan and the Closure plan respectively, *the plans approved by the Minister in relation to a carbon sequestration lease ceases to have effect on the earlier of*

(a) the third anniversary of the date on which the plan was approved, and

(b) the date that the lease is renewed.

As for timing, Sections 16 (2) and 19(2) state that “A lessee must submit a new monitoring, measurement and verification plan and closure plan for approval under Section 15 no fewer than 90 days before the date on which the approved plan ceases to have effect.

Shell is required to submit an updated MMV and closure plan every three years as a stipulation of its Sequestration Lease Approval from Alberta Energy and Minerals.

In addition, Quest will share with the Government of Alberta it's Knowledge and experience of MMV activities and outcomes according to the terms in the CCS Funding Agreement for the Quest project.

2.2.3 General Updates

In both of the CSTR and Mines and Minerals Act, Section 9, as cited in Section [2.2.2], it is understood that, as the project progresses, the MMV Plan will be adapted as necessary in response to new information gained from or mandated by:

- Reservoir and well performance data
- Site-specific technical feasibility assessments
- Monitoring during the injection and closure periods

- Newly published guidelines

As per the design principles of MMV, the MMV plan contains updates based on ongoing learnings from injection operations. This document includes an update to the risk profile with the introduction of phase/time dependence for risk management (Baseline vs Operational vs. Closure vs. Post Closure) and including the supporting MMV monitoring. The tiered approach to MMV technologies has been proven successful and continues to be used in this version. The MMV and Closure Plan continue to be aligned, with both plans submitted September 8th, 2023.

3 Risk Assessment

This section reviews the assessment of the storage risks, historical and current, to the Quest project. The scope of this assessment includes containment [3.1] and conformance [3.2] risks as well as risks stemming from induced seismicity [3.3]. Shell, as the operator for Quest, has applied its well-established Risk Management System, which is consistent with CSA Z741. The methodology for risk assessment relies on an evidence-based evaluation of potential threats to containment, conformance and seismicity, their potential consequences, and a review of the effectiveness of barriers in place.

The risk assessment methodology entails reviewing the Project and Operational risks on the cycle of the MMV and Closure Plan updates at minimum and/or as necessary as a response to MMV data and/or activities. MMV activities are executed to mitigate, manage or respond to these risks.

This risk assessment provides a clarification between Project risks (all identified pre-injection risks) and the current Operational risks. The Operational risks are informed based on injection operations performance, MMV data acquired, and conformance indicators.

A review of the Bowtie Method of Risk Management in MMV is in Appendix C of the 2010 MMV Plan [1].

3.1 Containment Risks

3.1.1 Loss of Containment Definition

For Quest, containment is defined as: the injected CO_2 and the native BCS brine remain inside the storage complex. Consequently, a loss of containment is described as:

A migration of CO_2 or BCS brine into environmental domains above the Upper Lotsberg Salt, which is the ultimate seal of the BCS storage complex.

3.1.2 Potential Consequences Due to a Loss of Containment

A loss of containment is not expected, but if it were to occur, it may result in some of the following negative consequences:

- **Hydrocarbon resources affected** in the overburden (e.g., in parts of the Devonian, Mississippian, Permian, Triassic, Jurassic, and Cretaceous strata) due to a slight increase in the salinity or acidity of the produced fluids
- **Groundwater impacts** if sufficient quantities of CO_2 or BCS brine migrate above the base of groundwater protection to reduce groundwater quality
- **Soil contamination** if sufficient quantities of CO_2 or BCS brine migrate into the soil to reduce soil quality
- **CO_2 emissions into the atmosphere** will impact the effectiveness of the Project's contribution to climate change mitigation

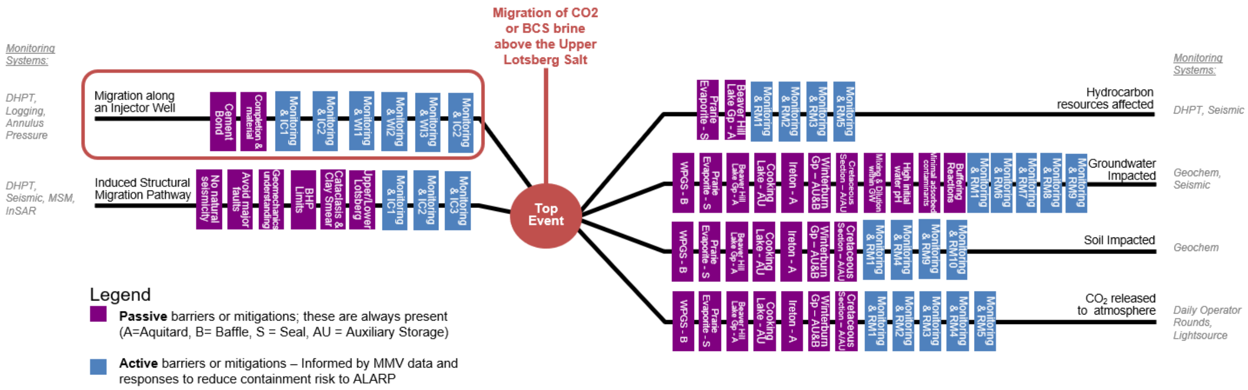


Figure 3-1: Operations' Phase Bowtie.

This bowtie summarizes barriers in place to reduce the likelihood (left side) and consequence (right side) of any unexpected loss of containment during the Operations phase.

Highlighted (by the orange outline in Figure 3-1) is the key risk identified for Quest managed through this Bowtie.

The acronyms IC1 to IC3 and WI1 to WI3 refer to control response options to prevent any unexpected migrations of fluids out of BCS storage complex (Table 2); RM1 to RM10 refer to control response options to correct any unexpected migrations of fluids out of BCS storage complex (Table 3). Monitoring systems listed are the MMV technologies available to assess threats and consequences. MMV data together with a decision logic and a control response make up an active barrier.

3.1.3 Potential Threats to Containment – Operations

The 2023 MMV Plan risk assessment update has identified two key threats to containment:

1. Migration along an injection well
2. Migration along a Structural Migration Pathway

Migration along an injection well

Consistent with the 2017 and 2020 MMV Plans, the key threat to containment at the Quest site is "Migration along an injection well" that penetrates the storage complex. This risk is considered very low, based on the following observations:

- The conceptual site model (CSM) (Quest 2014 and 2015 MMV Plans, [1]) for the Quest Project SLA does not foresee a pathway connecting the source 'CO_2 within BCS storage complex' to any of the overlying aquifers. No pathway has been identified through which CO_2 or saline brine from the BCS storage complex could reach aquifers above the BGWP zone. Furthermore, pressures are too low for BCS brine to be lifted to above the BGWP zone (Appendix F, 2012 MMV Plan [1]) including at the IWs.
- The evaluation of the pre-injection cement bond in IWs 100-08-19-059-20W4 and 103-07-11-059-20W4 behind both the intermediate casing and the main casing shows isolation of the BCS storage complex with a good bond across all three seals (MCS and the Lower

and Upper Lotsberg Salts). This isolation evaluation was confirmed with the repeat of the cement bond on the main casing of the IWs 100-08-19-059-20W4 and 103-07-11-059-20W4 completed in 2021; for details see 2021 Annual Summary Report [1].

- In IW 102-05-35-059-20W4 there is good cement from the top of the BCS to the intermediate casing shoe providing an effective isolation of the BCS. The evaluation of the cement bond log indicated non-ideal cement bond across part of the MCS which could potentially extend into the LMS baffle below. The good cement across the Lotsberg Salts also provides significant additional isolation of the BCS storage complex. Consequently, the risk of a leakage pathway developing at the 102-05-35-059-20W4 injection well is considered very low. This isolation evaluation was confirmed with the repeat of the cement bond on the main casing of the IW 102-05-35-059-20W4 completed in 2022; for details see 2022 Annual Status Report [1].
- Surface casing vent flows (SCVFs) and gas migrations (GMs) have been detected in the IWs and have been reported to the AER on an annual basis to the end of 2021. Analytical results (composition and isotopic values) confirm that SCVFs and GMs are independent of each other. GMs originate from a biogenic shallow zone, while the SCVFs originate from just below the surface casing shoe, from a mixture of thermogenic and biogenic sources.
- The composition of the SCVFs and GMs confirm that there is no contribution from deeper formations (i.e. below Mannville). Due to the shallow depths of the sources of the SCVFs and GMs, there is no evidence of a pathway that is considered a threat to containment or isolation of the BCS storage complex. SCVF and GM testing is currently evaluated at a 3-year frequency up until 2024 as per AER approval letter dated September 28th, 2020. For further information on the planned SCVF and GM testing frequencies consult section [4.10.3].

Table 1 provides a list of causes that may lead to the threat of migration along an injection well, and the approaches used to address this threat/assess/monitor potential causes.

Table 1: Assessment of threat 'Migration along an injection well'.

Threat causes	Description	Techniques to assess/monitor cause
Compromised cement	Initial cement bond, or deterioration of the cement bond through time due to stress cycling, or chemical alteration may allow upward fluid migration outside the casing. Note that the cement condition was re-evaluated in the inspection campaign of the injection wells in 2021 and 2022 showing consistent production casing cement quality.	CBL, DTS [1]
Compromised casing	Casing corrosion through time due to oxygen ingress, or contact with saline or acidic fluids may allow upward fluid migration inside or outside the casing. Note that the casing condition was re-evaluated in the inspection campaign of the injection wells in 2021 and 2022 showing consistent production casing integrity.	Pressure monitoring, Casing inspections
Compromised completion or wellhead	Loss of integrity of the completion or wellhead due to undetected flaws in the initial design or execution or subsequent degradation due to corrosion, or deterioration of seals in the presence of CO_2 may allow fluids to escape through the wellbore.	Well Plan Maintenance, Daily Operator Rounds, , DTS [1]
Well interventions	During the course of normal operations, routine well interventions may result in loss of well control	Shell safety standard practices during operations, minimized interventions

Notes: [1] DTS is utilized for qualitative assessment

Migration along a Structural Migration Pathway.

A second threat line has been generated to represent the potential, although improbable, risk of "Migration along a Structural Migration Pathway". This threat combines previous risks related to the following that were identified prior to commercial operations:

- "Migration along a fault", "Induced stress re-activates a fault", and "Induced stress opens fractures":

These threat lines were combined because they have shared potential events and barriers. This combined risk is considered very low based on the following observations and conditions:

- Geophysical data over the Quest AOR, including 3D seismic, 2D regional seismic and HRAM, do not show any faults that transect the storage complex.
- Any potential sub-seismic faults or induced fractures at these depths are highly unlikely to be open and conductive, or remain so, at these depths, due to overburden pressures.
- Operational pressures are limited to well below the Fracture Pressures for the Storage Complex (BCS, LMS etc.) with significant safety factors to account for any potential cooling effects.
- Pressure performance to date has demonstrated limited pressure build up within the reservoir, with current pressure models predicting less than 2 MPa of differential pressure (ΔP) at the injection wells at the end of injection.

- These conditions result in an environment where the generation of stress induced fractures is unlikely.
- These stress conditions result in an environment where the reactivation of faults within/across the BCS is unlikely (no faults identified that offset the BCS) and those faults with susceptibility to reactivation are expected to be constrained within a narrow range of orientations.
- Even if a fault within the BCS were to be reactivated, the Upper/Lower Lotsberg salt would be expected to maintain an impermeable fault seal.
- Even if a fault within the BCS were to be reactivated, cataclasis and/or clay smear effects along the fault plane would be expected to impede fluid migration.

3.1.4 Potential Threats to Containment – Project

Prior to commercial operation in 2015, a total of nine potential threats to containment were identified. Each potential threat was considered highly unlikely but, in principle, with the right conditions, capable of allowing CO_2 to migrate upwards from the storage complex. These were:

1) Migration along a legacy well,

2) Migration along an injection well,

3) Migration along a deep monitoring well,

4) Migration along a rock matrix pathway,

5) Migration along a fault,

6) Induced stress re-activates a fault,

7) Induced stress opens fractures,

8) Acidic fluids erode geological seals, and

9) Third Party activities.

Migration along an injection well and Migration along a structural migration pathway have been assessed to be the only remaining Operational threats, as in Section [3.1.3] above.

All remaining threats to Containment identified are retained below within the Project Risk Register and no longer carried within the Operational Bowtie for Containment. The pre-injection 2015 MMV Plan [1] details a complete description and risk assessment for all nine identified potential threats to containment. These threats will be carried in the Project Risk Register and assessed, at minimum, on the MMV and Closure Plan update cycles to understand if the risks have changed significantly enough to be addressed by an MMV or Closure Plan activity.

The following is a brief summary of the threats and their barriers and their very low probability of occurrence (<5% chance of occurring).

"Migration along a rock matrix pathway":

The conceptual site model (CSM) (Quest 2014 and 2015 MMV Plans, [1]) for the Quest Project SLA does not foresee a CO_2 pathway connecting the source 'CO_2 within BCS' to any receptor (e.g., overlying aquifers or above the BGWP zone).

Site specific geologic passive barriers are present within the Quest SLA and Storage Complex, including low regional dip and multiple continuous seals (MCS, Lower and Upper Lotsberg).

"Acidic fluids erode geological seals":

The seals present within the Storage Complex (MCS, Lower and Upper Lotsberg) are non-reactive with CO_2. Salt (halite) is inherently non-reactive with saturated brine and to acids such as CO_2.

Laboratory testing of the MCS indicates capillary entry pressure is very high, with precipitation of halite occurring in any void/fault space (modelled and induced in core). In addition, CO_2 diffusion takes place, leading to mineralogical alteration in the core sample and precipitation of calcite which could further improve sealing capacity.

"Migration along a legacy well":

In the Quest SLA, there are four legacy wells that penetrate through all seals in the BCS storage complex. The closest one to an injection well is 18 km away. This is more than three times the distance the CO_2 plume is expected to extend at end of injection.

The status and condition of existing wells penetrating the BCS has been reviewed from multiple data sources and all BCS legacy wells have been abandoned with multiple large cement plugs. (Appendix F, 2012 MMV Plan [1])

"Migration along a deep monitoring well":

All deep monitoring wells drilled to date in the vicinity of the injection wells terminate above the Upper Lotsberg Salt, the ultimate seal in the Storage Complex. The intent of these deep monitoring wells is to detect fluid migrating above the BCS storage complex and monitor seismicity.

"Third Party Activities":

According to the Sequestration Lease Rights, the Operator has the exclusive right to drill through and store within the Zone of Interest (ZOI) (below the Elk Point Group). There are P&NG rights held by third-parties within the SLA that extend to the basement including within the Quest ZOI. As a result the Alberta Energy and Minerals has flagged the Quest Project in their system and will not be giving out new P&NG rights within the ZOI within the SLA. The Alberta Energy and Minerals will notify the Operator of any third party attempting to drill into the ZOI to allow risks to be assessed on a case by case basis.

3.1.5 Barriers to Ensure Containment

Prior to implementing any MMV, several barriers were already in-place to reduce the risk of any unexpected loss of containment due to an unknown migration pathway.

Initial storage risk reductions were achieved through multiple independent barriers implemented through site selection, site characterization, and engineering concept selections. These initial passive barriers are sufficient on their own to make the loss of containment extremely unlikely. Details of these barriers can be found in previous MMV submissions and examples include the presence of multiple geological seals and baffles, well design, and operational pressure limitations [1].

For example, there is evidence for seal integrity and hydraulic isolation of the BCS aquifer from all the overlying aquifers within and in close proximity to the Quest AOR based on the analysis of downhole fluid samples from the BCS and other overlying aquifers (Section 3 of the 2017 MMV Plan, [1]).

The MMV plan provides a comprehensive and reliable means to verify the effectiveness of the initial passive barriers. In the extremely unlikely case that monitoring indicates a potential loss of containment, then a wide range of control measures can be deployed effectively, in a timely fashion, to prevent, mitigate, or remediate any actual loss of containment (Table 2 and Table 3). These additional active barriers are triggered by monitoring and are designed to be sufficiently numerous and diverse to yield significant additional storage risk reduction. For the Well Interventions identified in Table 2 and Table 3, the first response intervention scope would focus on making the well safe followed by a second intervention scope to implement the long term repair within the identified timeframe.

Table 2: Control response options to prevent any unexpected migrations of fluids out of the BCS storage complex, including a time estimate to implement a control response.

Injection Controls:	
IC1: Stop Injection	minutes
IC2: Redistribute injection across existing wells	minutes to hours
IC3: Drill new vertical or horizontal injectors	18 -24 months
Well Interventions:	
WI1: Repair leaking well by re-plugging with cement	1 - 12 months
WI2: Repair leaking injector by replacing completion	1 - 12 months
WI3: Plug and abandon leaking wells that cannot be repaired	1 - 12 months

Table 3: Control response options to correct any unexpected migrations of fluids out of the BCS storage complex, including a time estimate to implement a control response.

Well Interventions:	
RM1: Repair leaking well by re-plugging with cement	1 - 12 months
RM2: Repair leaking injector by replacing completion	1 - 12 months
RM3: Plug and abandon leaking wells that cannot be repaired	1 - 12 months
Exposure Controls	

RM4: Inject fluids to increase pressure above leak	1 - 12 months
RM5: Inject chemical sealant to block leak	1 - 12 months
RM6: Contain contaminated ground water with hydraulic barriers	1 - 3 months
Remediation Measures	
RM7: Pump and treat	4 – 8 months
RM8: Chemical oxidation	4 – 8 months
RM9: Permeable reactive barriers	4 – 8 months
RM10: Treat acidified soils with alkaline supplements	1 - 3 months

3.2 Conformance Risks

3.2.1 Loss of Conformance Definition

A loss of conformance exists if:

- The observed distribution of CO_2 and pressure build-up inside the storage complex deviates from the model-based predictions outside the range of uncertainty; or
- Knowledge of the actual storage performance is insufficient to provide confidence in the long-term effectiveness of CO_2 storage within the storage complex.

3.2.2 Potential Consequences Due to a Loss of Conformance

A loss of conformance is not expected but if it does occur it may result in some of the following consequences:

- **Trigger investigation of non-conformance** and mitigation and/or remediation activities as required.
- **Delay in site closure** until long-term behavior of the CO_2 stream and affected fluids within the storage complex is stable and predictable.
- **Reduction in the efficiency of storage** if CO_2 plumes spread further than expected.

3.3 Seismicity Risks

This section describes how risks associated with seismicity are managed at Quest. The time extent of seismicity observed in response to Quest fluid injection is currently insufficient to support a reliable application of site-specific, data-driven methods for Quantitative Probabilistic Seismic Risk Assessment. The Quest microseismic monitoring system observes seismicity and is building a catalogue of seismic event origin times, hypo-central locations, and magnitudes that occur in proximity to the injection locations. There is also a short baseline period of seismicity monitoring pre-injection which shows low levels of seismicity at distance to the injection locations. The observed seismicity within 30 km of the microseismic monitoring well is all below magnitude 2.0 and does not represent a significant seismic risk. Any unexpected future changes in the rates or magnitudes of induced seismicity will be reliably detectable by the microseismic monitoring system which will provide an early opportunity to effectively control the induced seismicity, such as, if necessary, by changing the injection rates. A Quantitative Probabilistic Seismic Risk Assessment for Quest would require quantitative statements about the future rates and magnitudes of seismic events induced by the Quest injection process, conditional on the previously observed seismicity and fluid injection process. The current data set of seismicity observed in response to Quest fluid injection is currently insufficient to support a reliable application of these site-specific, data-driven methods for Quantitative Probabilistic Seismic Risk Assessment. Continuous operation of the microseismic monitoring and control system ensures future induced seismicity risks remain acceptable within the framework of the current qualitative induced seismicity bow-tie risk assessment.

3.3.1 Seismicity Definitions

'Seismicity' refers to the occurrence frequency, magnitude (M) and spatial distribution of areas of seismic events (dynamic slip along a fault plane) in a region due to a release or transfer of stress in the subsurface. The magnitude scales with the product of mean seismogenic slip and the area of the seismogenic slip surface. Detecting seismic events over any finite region requires that their size ('magnitude') meet some detectability threshold.

Seismicity is driven by subsurface stress changes and induced seismicity is the subset of seismicity driven by subsurface stress changes due to anthropogenic activity. Examples of common industry activities that may create such changes are the injection and production of subsurface fluids, mining, and reservoir impoundment (e.g., filling a dam at surface).

3.3.2 Potential Consequences Due to Induced Seismicity

A risk bowtie for managing the likelihood and potential consequences of induced seismicity is shown (Figure 3-2). The top event is defined as:

"$M \geq 4$ seismicity with significant effects at surface within 50km of the Quest 08-19 monitor well".

This definition is chosen for the following reasons:

1. A M< 4 seismic event is unlikely to cause structural damage to the exposed built environment and allows for timely and effective interventions to reduce induced seismicity rates and the probability of larger magnitude events to avoid any potentially damaging seismicity (Shell is not aware of any confirmed cases of structural damage due to either the Fox Creek M_L=4.8 or Peace River M_L = 5.6 events).
2. A M= 4 seismic event has potential to be felt over a larger area than lower magnitude seismicity, thereby creating a greater potential concern for the exposed community.
3. A 50 km distance from the DMW 8-19 (102081905920W400) covers the Quest SLA.

This level of seismicity near Quest poses two main consequences to the safe and socially responsible operation of CO_2 storage in the subsurface:

- **Ground Motion (public concern):** Felt seismicity at surface

- **Ground Motion (asset damage):** Damage to property or infrastructure

Impacts of ground motion on health/safety are also a potential consequence of induced seismicity. However, physical harm to people as a consequence of induced seismicity more frequently results from injury caused by damaged property/infrastructure rather than harm suffered directly from ground motion. Such injury is best mitigated by preventing or minimizing asset damage.

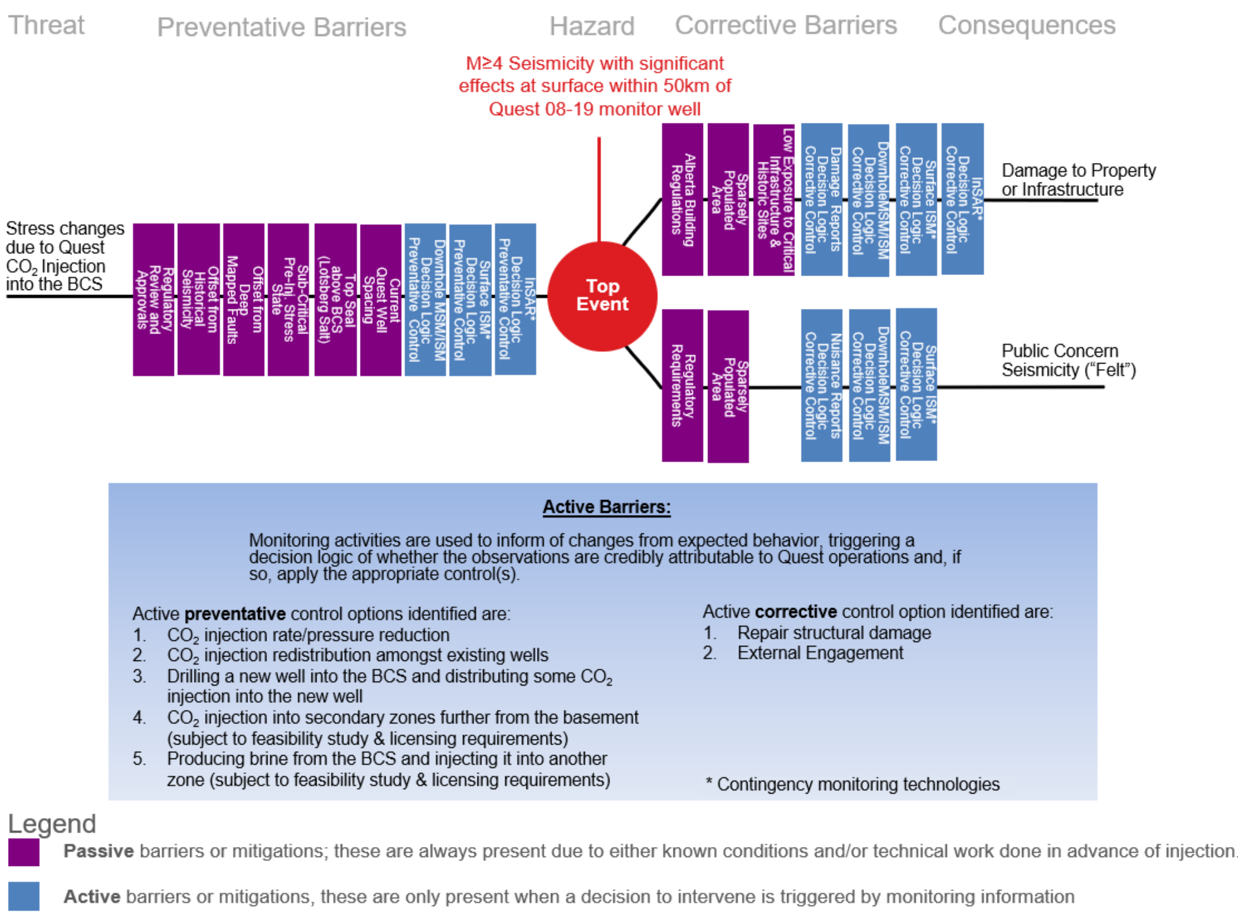


Figure 3-2: Induced seismicity risk bowtie.

3.3.3 Potential Threat of Seismicity Near Quest

Injection of fluid volumes into the subsurface changes the stresses and strains in the subsurface which may reactivate pre-existing, critically stressed faults and induce seismicity which on rare occasions may include sufficiently large events with the potential to have effects at the surface. Based on the following criteria, it is assessed that there is potential for seismicity to have effects at the surface as a result of Quest CO_2 injection into the BCS:

- Several locations within North America have reported ground motion at surface due to seismicity associated with large volume fluid injection into the subsurface [5][6][7][8][9].

- A review of historical seismicity recorded by the Alberta Geological Survey (AGS) seismicity network indicates relatively low levels of seismicity in the Quest region. However, seismicity recently identified by the Quest downhole microseismic monitoring array suggests there has been an increase of low-magnitude regional seismicity (outside the AOR, but within 50km of Quest) beginning approximately two - three years after CO_2 injection began at Quest.
- The BCS storage complex is located directly atop the pre-Cambrian basement, with no known pressure barrier between them. Pressure communication with the basement is a known risk factor for generating seismicity due to injection operations if induced seismicity migrates downwards into the basement with time [5][6][7][8][9].
- Using wellbore density logs, borehole break-outs and well pressure tests, the in situ stress state of the basement at Quest is assessed to be strike-slip (S_H>S_v>S_h) with a maximum horizontal stress (S_H) orientation of ~45° east of north (N045E). In the assessed stress condition, the faults most susceptible to slip have strikes of ~75° east of north (N075E) and ~15° east of north (N015E) with vertical dip. These orientations, particularly the N015E orientation, are approximately aligned with regional north-northeast to northeast-trending basement terrane boundaries [11], making them potentially more susceptible to slip than other fault orientations.

3.3.4 Barriers to Manage Seismicity Due to Quest CO_2 Injection

Preventative barriers are in place to reduce the likelihood of the seismicity top event occurring and corrective barriers are in place to reduce the potential impact of the seismicity top event (Figure 3-2).

3.3.4.1 Preventative Barriers

A number of factors were considered during the Quest site selection that serve to reduce the likelihood of the induced seismicity top event.

Passive Preventative Barriers:

Offset from historical seismicity:

Quest is located in the Western Plains of Alberta, approximately 250 km east of the closest active natural seismically zone, the Cordilleran Deformation Front [11]. Alberta's Western Plains have low levels of recorded historical seismicity, which indicates the Quest area is not prone to significant levels of natural seismicity. Within ~100km of Quest, only three seismic events (M_L = 2.44-2.62) were detected by the AGS network [10] between 2006-2015 (inclusive). None of these events were within 50 km of the Quest 08-19 monitoring well and all occurred prior to Quest injection in August, 2015. Shell is not aware of any of these seismic events being reported as felt by the public.

From 2014 to present, the AGS has had a seismicity station near Quest ("ATHA" station from 2014-2019, "THORA" station from 2022-present). This improved the detectability of seismicity in the area, identifying fourteen seismic events (M_L=1.62-3.0) within 100 km of the Quest monitoring well from 2016-April, 2023 (inclusive). Eleven of these events were within 50km of the Quest monitoring well (maximum M_L=2.43) and none were within the Quest 10km AOR[i]. Shell is not aware of any of these seismic events being reported as felt by the public, which is as expected with low magnitude events.

As described in the Quest 2022 Annual Status Report [1], the downhole microseismic monitoring array deployed in the Quest 08-19 deep monitoring well at Quest indicates that there is no seismicity in the BCS storage complex within the 10 km AOR and that minor seismicity observed in the basement is occurring at a relatively steady rate.

In 2021, Shell, as Quest Operator, chose to use its existing downhole microseismic array to detect and locate seismic events that were outside the required 10 km AOR (‘regional seismicity’), with a focus on seismicity within 10 - 40km of the monitor well. As this is beyond the originally designed purpose of the microseismic monitoring array, the results from this analysis require further investigation and verification in order to support a thorough analysis. During the baseline monitoring period prior to injection (~10 months), five M ≤ 0.65 seismic events were detected between 10 and 50 km from the Quest monitoring well and two seismic events (M ≤ 1.67) were detected at distances between 50 and 100 km. Hence, the Quest baseline monitoring is in agreement with the AGS data in establishing low levels of seismicity prior to Quest injection in the region, which can be reasonably attributed to natural seismicity. The Quest seismicity data indicate that an increase of regional seismicity (~10 to 40km from the Quest monitoring well) began in 2018 (Quest 2022 Annual Status Report [1]). This highlights the importance of seismicity monitoring to detect early indications of any initial fault activation.

Offset from deep mapped faults:

Pre-exiting faults are necessary to generate induced seismicity. For this reason, the Quest CO_2 injection sites are located in areas that are offset significantly from any known faults in the basement or BCS storage complex. There are no mapped faults within the BCS Storage Complex near Quest. Regional basement terrane boundaries have been interpreted using aeromagnetic data [11] and regional seismic data. At their closest point, these terrane boundaries come to within ~15km of the Quest injection wells and present the most credible corridors along which to anticipate basement faults. Smaller basement faults, particularly those dipping steeply and with a large strike-slip component, are challenging to identify and map on the available seismic data. Interpretation of the Quest 3D seismic (~400 km^2) has identified only one confidently mapped basement fault, with an estimated vertical throw of ~20m and strike of north 5° east (N005E) located ~8 km NNE of the Quest 05-35 well. As this fault is within the 10km AOR, it has been monitored by the downhole microseismic array and has shown no evidence of being a focus of seismicity (or microseismicity). Many minor structural lineaments, striking ~north 20° east to north 50° east (N020E-N050E) are also identified on the Quest 3D seismic data, but it is uncertain if they have any fault offset at all. The 2D seismic data available over the region are sparce and generally of low quality. Although sufficient to image the major basement terrane boundaries, smaller faults are challenging to identify and impossible to correlate reliably from one 2D line to the next.

Although it is worthwhile to choose a CO_2 storage location, such as Quest, that is offset from mapped basement faults favorably-oriented to slip, industry experience in North America has shown that faults that slip during subsurface fluid injection are commonly not identified prior to being highlighted by induced seismicity. This is evidence of the difficultly of identifying faults with our current technology and highlights the importance of seismicity monitoring to detect early signs of fault activation.

[i] Shell has not assessed a magnitude of completeness (M_c) for the AGS array in the Quest area, though it has demonstrated an ability to detect local magnitudes as low as M_L=1.7 within 50km of Quest.

Sub-critical pre-injection stress state:

The closer a geological fault system is to a critical stress state, the more likely it is that a seismic event may be induced due by fluid injection that perturbs this stress state. Wellbore density logs, borehole break-outs and well pressure tests were used to characterize the pre-injection BCS and basement stress state. A commonly used coefficient of friction of 0.6 and zero fault strength cohesion were used. Under these conditions, no faults within the BCS storage complex or basement are assessed to be critically stressed at Quest, though the basement is closer to critically stressed than the BCS. suggesting that some pore pressure increase can be tolerated by any exposed faults before frictional fault failure is expected. However, each of the parameters used as input to the pre-injection stress calculation has an associated uncertainty and the subsurface is heterogeneous.

Top seal above the BCS storage complex:

Larger seismic events typically result from the activation of larger faults. Even if faults were encountered within the BCS complex, it is expected that the ductile, Lotsberg salts that form part of the seal complex would restrict the vertical extent of any seismogenic fault slip zone associated with reactivation of a pre-existing fault by promoting gradual creep rather than the dynamic slip required to generate seismicity. Furthermore, the Lotsberg salts form an impermeable barrier that are judged to prevent pressure communication above the BCS storage complex, thereby preventing reactivation of any pre-existing faults above the BCS storage complex, although no such faults have been observed.

Quest well spacing:

The three CO_2 injector wells at Quest are spaced apart to allow the planned CO_2 injection rates to be injected at lower downhole operating pressures relative to injecting the same volume via a single injector well or three more closely spaced wells . This reduces the expected pore pressure increases and also reduces any induced seismicity driven by increasing pore pressures over the life of the project.

Regulatory review and approvals:

The regulator has an application review and approval process to manage risks associated with CO_2 injection into the subsurface. This framework establishes injection pressure limitations and total injected volumes for each proposed project. There is also a ‘statement of concern’ opportunity for an operator to raise concerns prior to the approval of neighbouring developments that have the potential to compromise the safety of their operations. In addition, the regulator has the ability to monitor seismicity via the AGS seismic network, which as a demonstrated capability to detect M_L>2 seismicity near Quest[i], providing an opportunity to respond to changes in seismicity with further regulatory controls, if necessary. All of these controls are intended to act as fundamental barriers to reduce the risk of injection/production operations impacting seismicity across the province.

Active Preventative Barriers:

A subset of the preventative barriers are active, meaning that they are triggered when a MMV technology detects something that is a departure from the expected state (e.g. development of an observed seismicity trend towards future unacceptable seismicity). Upon detecting such a seismicity trend, the monitoring data

[i] Shell has not assessed a magnitude of completeness (M_c) for the AGS array in the Quest area, though it has demonstrated an ability to detect local magnitudes as low as M_L=1.7 within 50km of Quest.

are assessed and a decision is taken on whether the observed seismicity trend is due to Quest operations. If so, a further analysis will identify the most appropriate control measure to change the trend of future induced seismicity to ensure it remains acceptable (Table 4). We expect the responsiveness of induced seismicity to each potential control measure will vary depending on uncertain, site-specific, local conditions that may influence the timing, size, and extent of the response. Quest will learn through monitoring which control measures are most effective under the given circumstances. If acceptable induced seismicity is not achievable through adaptive and progressive implementation of these control measures, then cessation of injection operations will immediately lower and then stop until an effective control measure is identified and implemented. This may involve a coordinated industry response.

Table 4: Summary of active preventative barriers.

Active Preventative Barriers				
MMV		**Preventative Controls**		
MMV Technology	**Detection Response Time**	**Preventative Control**	**Deployment Response Time**	**Reservoir Response Time*****
MSM/ISM (08-19)	1 day	CO_2 injection rate/pressure reduction	Hours	Scales with distance to the injector wells
ISM (surface)*	1 day	CO_2 injection redistribution	Hours	
*InSAR**	3 months	CO_2 injection into new BCS well	~24- 36 months	
		CO_2 injection into secondary zone**	~18-36 months	
		Produce H_2O from BCS and inject into other zone**	~24- 36 months	

* Denotes contingency monitoring technologies (no plan to perform on a regular schedule, unless initiated by a trigger event from other MMV technologies, or pre-closure conformance verification).

** The feasibility of these controls is contingent on further analysis and licensing requirements.
*** Expected timeframe for pressure effects at distance is highly uncertain. At initial start-up, it took ~45 days for Quest IW 05-35 to observe 0.1 MPa of pressure change from the combined 08-19 (5.5km offset) and 07-11 (12 km offset) injection. In 2016, during relatively consistent and stable injection operations, it required ~140 days to observe the same change in pore pressure.

<u>CO_2 injection rate/pressure reduction:</u>

Reducing injection rate/pressure into the subsurface is a direct mitigation of seismicity induced by fluid injection. A localized example of the effectiveness of this mitigation was demonstrated at Rangely, Colorado [28]. A large scale demonstration of the effectiveness of fluid injection rate reduction on mitigating seismicity has been seen by the industry-wide response to seismicity associated with fluid injection in Oklahoma [29].

CO_2 injection redistribution amongst existing wells:

Redistributing injection volumes between existing wells into the BCS storage complex will change the pressure field and stresses in the subsurface. This is expected to be effective in cases where the faults experiencing induced seismicity are significantly closer to some but not all available injection wells.

Drilling a new well into the BCS and distributing some CO_2 into the new Well:

Changing the injection pattern and/or adding a fourth well by drilling a new well to redistribute injection volumes into the BCS storage complex will change the pressure field in the subsurface. This could have an effect of reducing the likelihood of seismicity.

CO_2 injection into secondary zones further from the basement:

Improving pressure isolation between the injection zone and basement by either moving the injection completion interval higher in the storage zone or injecting into a shallower stratigraphic level has been demonstrated in North America to have an impact on reducing induced seismicity originating from the basement caused by fluid injection into overlying zones [27]. A feasibility analysis and satisfaction of licensing requirements at Quest are required to establish the expected effectiveness of this potential control measure.

Producing brine from the BCS and injecting it into another zone:

Producing brine from the BCS storage complex would provide more storage potential within the BCS for CO_2 injection. This would allow CO_2 injection to continue into the BCS storage complex at a given injection rate at lower injection pressures, thereby reducing the pore pressure increases in the BCS storage complex and basement. A feasibility analysis and satisfaction of licensing requirements at Quest are required to establish the expected effectiveness of this potential control measure.

3.3.4.2 Corrective Barriers

Corrective barriers are in place to reduce the severity of the seismicity top event consequences (Figure 3-2: Induced seismicity bowtie.). A number of passive corrective barriers are in place for both the ‘Damage to Property’ and ‘Public Concern’ risk threads:

Passive Corrective Barriers:

Damage to Property:

Alberta building regulations:

Shell is not aware of any damage from either the Fox Creek M_L =4.8 or Peace River M_L = 5.6 events. This is evidence of the robustness of the Alberta building codes against damage due to ground motion. Structures that are in disrepair (old/abandoned) and any structures that were not build to code would represent a group of structures prone to higher fragility.

Sparsely Populated Area (within 50km of Quest):

The potential impact of seismicity with significant effects at the surface is greater in areas with more buildings and higher populations. Quest is located in a sparsely populated region. Fort Saskatchewan (population ~27,000) is the only city within 50km of Quest. The remainder of communities are more sparsely populated [24], with many locals living kilometers apart adjacent to agricultural lands. If structural effects at surface were to occur, Shell would take any adverse effects experienced by members of the public due to its operations seriously and would be committed to working with the community toward positive outcomes.

Exposure to infrastructure and historic sites (within 50km of Quest):

Infrastructure that is of note when assessing the potential impacts of seismicity includes hospitals, dams, historic buildings, and industry infrastructure. There are no hydroelectric dams in the area, with only a few small reservoirs identified that potentially have an associated minor dam structure. Three hospitals and one Provincial or National Historic site (Victoria Settlement Provincial Historic Site) are located within 50 km of Quest.

The Quest area is a heartland of oil and gas activity with numerous pipelines, wells and oil/gas industry infrastructure. Two gas-powered (>100MW) electricity generation plants are located within 50km of Quest. There is one oil refinery, seven natural gas processing plants and multiple pipelines and wells (production and injection) within 50 km of Quest. The ATCO gas storage well is approximately 40 km SSW of Quest injectors.

Shell is not aware of any confirmed structural damage due to either the Fox Creek $M_L = 4.8$ or Peace River $M_L = 5.6$ events, which is evidence of the resilience of the Alberta infrastructure to safely withstand exposure to ground motions associated with events of these magnitudes.

Public Concern:

Regulatory barriers:

Adjusting local regulatory requirements (Subsurface Order #2 and Subsurface Order #7) likely have had a positive effect addressing public concern about seismicity induced by industry activity in Alberta (e.g. community engagement expectations and seismicity traffic light protocols for Fox Creek, Red Deer areas).

Sparsely Populated Area:

See above regarding the Damage to Property consequence.

Active Corrective Barriers:

Corrective barriers are triggered when a MMV technology identifies a behaviour of the storage site that significantly departs from the expected behaviour. Upon identifying a potential unexpected behaviour, the situation will be assessed and a decision taken on whether the observed change away from expected behaviour is due to Quest operations. If so, a further assessment will determine the most appropriate control measure to deploy (Table 5).

Table 5: Summary of active corrective barriers.

Active Corrective Barriers				
Consequence	**MMV**		**Corrective Controls**	
	MMV Technology	**Detection Response Time**	**Corrective Control**	**Response Time**
Damage To Property	Damage Reports MSM/ISM Surface ISM* InSAR*	1 day 1 day 1 day 3 months	Repair Structural Damage	1 month -1 year**
			External Engagement	1 day***
Public Concern	Public Concern Reports MSM/ISM Surface ISM*	1 day 1 day 1 day	External Engagement	1 day***
* Denotes contingency monitoring technologies (no plan to perform on a regular schedule, unless initiated by a trigger event from other MMV technologies, or pre-closure conformance verification). ** Subject to individual case. *** For initial response. Continued engagement may occur over a prolonged period.				

Repair Structural Damage:

If damages attributable to ground motion from seismicity induced by Quest occur, they can be remediated.

External Engagement:

Communication with both the regulator and community are believed to have a positive effect on the public response, particularly those closest to the affected area, to seismicity due to industry activity.

4 MMV Plan

4.1 Background

MMV operates within the AOR (Section [4.2]) of the Quest SLA (Figure 1-1). The SLA for the Quest Project extends from the top of the Precambrian basement up to the top of the Elk Point Group, located just above the Prairie Evaporite (Figure 4-1, Figure 4-2).

MMV to assess containment and conformance within the BCS storage complex spans four key domains:

- **Atmosphere:** The air mass above the ground surface.
- **Biosphere:** The domain containing ecosystems where living organisms exist.
- **Hydrosphere:** The subsurface domain from ground surface to the base of groundwater protection (BGWP) zone (top of the Lea Park Formation).
- **Geosphere:** The subsurface domain below the BGWP zone including the Basal Cambrian Sands (BCS) storage complex. The BCS storage complex comprises a primary storage formation (BCS), the first major seal (Middle Cambrian Shale, MCS), the second major seal (Lower Lotsberg Salt), and the ultimate seal (Upper Lotsberg Salt). Above the storage complex the geosphere also contains additional deep saline aquifers, e.g. the Cooking Lake Formation, which provides opportunities for MMV. In the SLA, proven oil resources exist within the Leduc, Nisku, and Wabamun formations and proven gas resources exist within the Nisku, Mannville Group, and Colorado Group.

The MMV Plan is designed on the basis of the following principles and following the guidance provided by the monitoring, measurement, and verification principles published in April of 2023 [26].

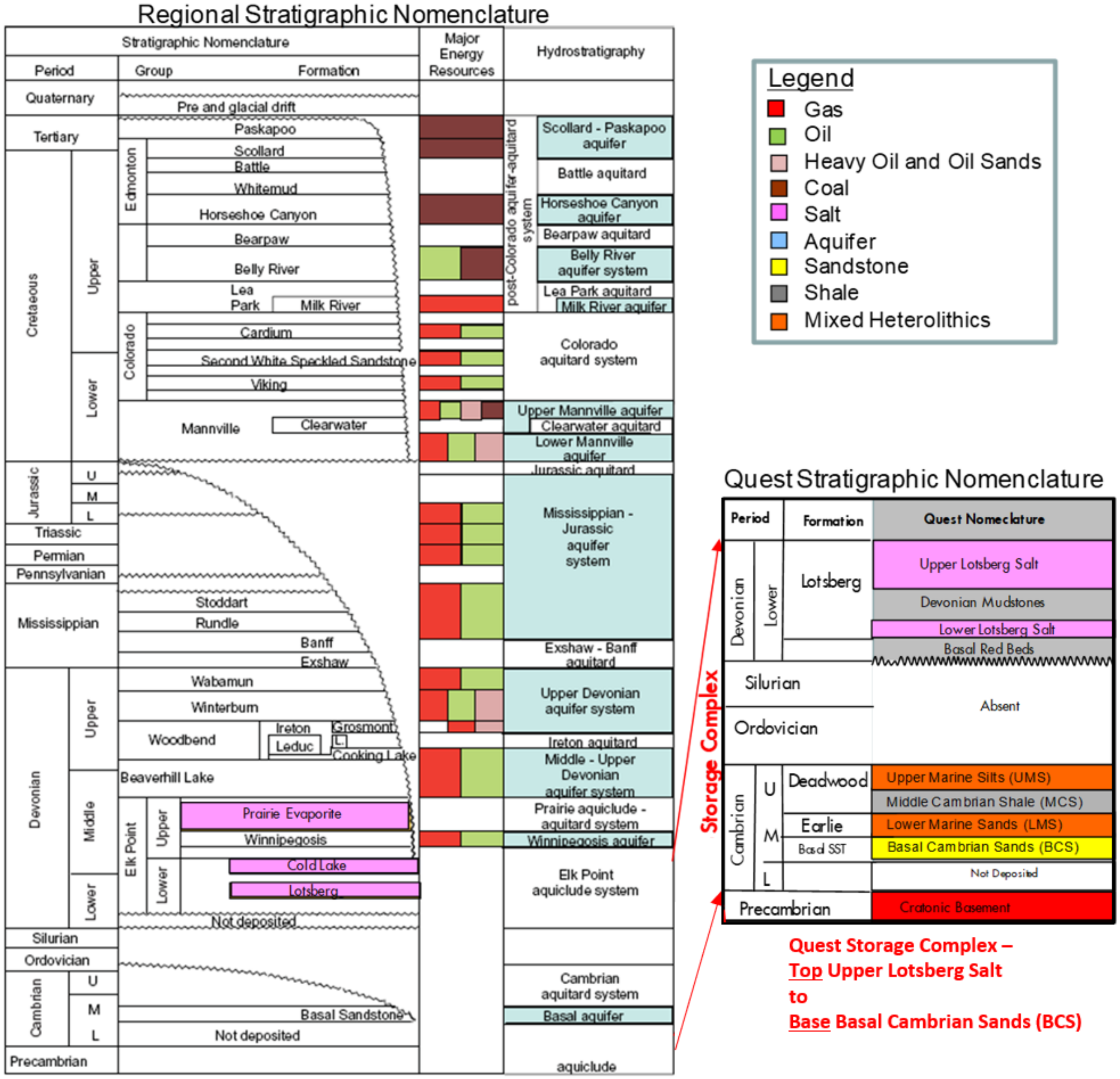
Monitoring tasks are designed to verify the effectiveness of the passive barriers described previously and, if necessary, to trigger the timely deployment of active control measures, in order to reduce the risk and/or consequence of a loss of conformance or containment. Established industry practices and regulations for well and reservoir management and environmental monitoring provide guidance on steps that can be taken to fulfill the monitoring tasks.

MMV activities are scheduled to streamline interfaces with on-site activities at Scotford to maximize operational efficiency and minimize downtime of Quest capture facilities.

As necessary, the MMV Plan has been and will be adapted in response to new information gained from:

- Reservoir and well performance data;
- Site-specific technology feasibility assessments;
- Findings from continuing monitoring activities;
- Learnings from trials deployed at Quest.

Adaptations to the MMV plan may entail changes in the frequency and/or number of techniques being deployed, after review with the appropriate agencies. The need for changes to the MMV plan is discussed within the Annual Status Reports submitted to the AER, as per condition 10 d) vi) of the approval No. 11837C [2].



Modified after Bachu et al. 2000.

Figure 4-1: Stratigraphic column of the Quest SLA.

4.2 Areas of Review

4.2.1 Area of Review – Containment and Conformance

MMV operates within an area of review (AOR) based on an expected injection volume of 27 MT of CO_2 during the course of the project (Figure 4-2). The Quest AOR extends 10 km radially outwards from an active injection well.

The AOR is based on the estimated likelihood of having CO_2 in the BCS reservoir at some future time, including the Closure and Post-Closure periods. It takes into account potential uncertainty in the plume radius and represents a conservative estimate. The estimated likelihood is based on the current dynamic reservoir model, which incorporates injection well rates & pressure data to the end of 2022. The current model assumes uniform injection in all wells (IW 8-19, IW 7-11, and IW 5-35) for the forecast period and predicts maximum plume sizes in 2040 of 2 to 3 km. The end-of-life plumes are illustrated in Figure 4-3, and represent a mid-case scenario from the 2022 Model Update that is realistic in both the property model and resulting radius of the plumes.

The pressure in the BCS is not forecast to reach a level that could displace BCS brine up to the ground water zone over the life of the project. Thus, the limited pressure increase in the BCS due to injection does not create a probable risk of adverse effects to the ground water zone through Brine lift. By the end of project life, the pressure build-up in the BCS is forecast to be less than 2 MPa of differential pressure (ΔP) at the injection wells (Figure 4-4). This pressure increase represents less than 12% of the delta pressure required to exceed the BCS fracture extension pressure and less than 25% of the pressure increase required to exceed the AER Approval operating constraint on bottom hole pressure [2]. The model that forecasted the pressure increase (Figure 4-4) utilizes the pressure response history to the end of Q3 2022 and assumes an equal amount of CO_2 will be injected in each of the three injection wells for the remainder of the life of the project.

Through the Operations phase, observed storage performance and specific injection well volumetric assumptions will be used to verify the size and shape of the AOR and, if necessary, the AOR will be updated as needed.

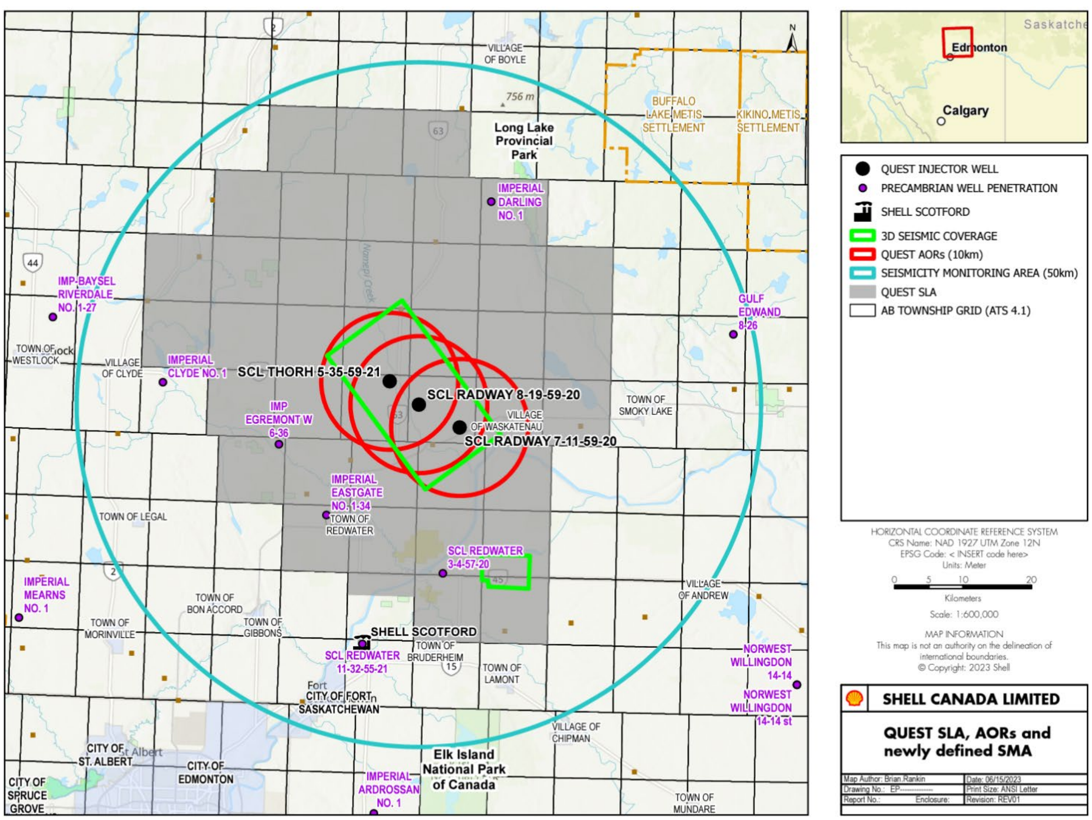
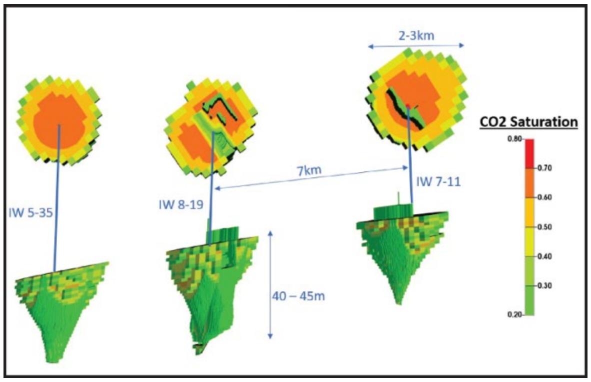


Figure 4-2: Quest SLA with AORs and newly defined Seismicity Monitoring Area (SMA).

Please note: The Quest AOR is defined by a10km radius around each injector well as red circles. The SMA has a radius of 50km around the downhole geophone array in Quest 08-19 shown as teal circle in Figure 4-2.



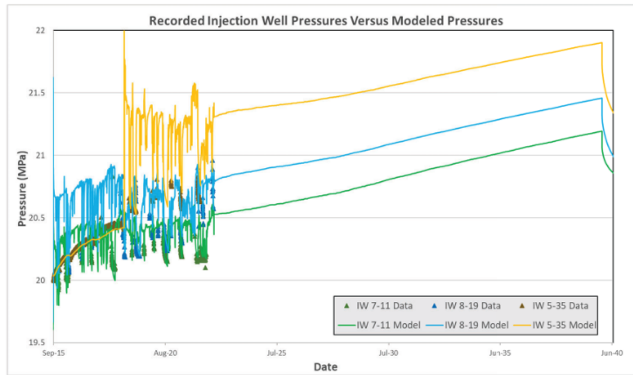


Figure 4-3: Predicted CO_2 plume in 2040 **Figure 4-4:** Forecast reservoir pressure

Figure 4-3: Schematic map view and 3D views of the predicted CO_2 plume in 2040 from the 2022 Model Update; Figure 4-4: Forecast reservoir pressure increase (derived from shut-in BHP) at the three injection wells.

4.2.2 Seismicity Monitoring Area (SMA)

The recently recognized increase of regional seismicity outside the Quest AOR has highlighted the importance of continued seismicity monitoring outside the AOR. For this reason, Shell (as operator of Quest) will continue to monitor seismicity within a Seismicity Monitoring Area (SMA) defined by a 50km radius around the downhole geophone array located in the Quest 08-19 deep monitoring well (Figure 4-2). Reasons for this SMA definition are:

- It captures the areas of increased regional seismicity observed to date.
- It includes the full Quest SLA.
- It is a reasonable limit within which the downhole geophone array can be expected to detect seismicity that could be of consequence.

4.3 Monitoring Performance Targets

In accordance with the Closure Plan, the monitoring performance targets are defined as follows:

CO_2 Inventory Accuracy Target

1) The accuracy of the reported CO_2 stored will comply with regulations and protocols.

Conformance Monitoring Targets

1) Observed storage performance conforms to predicted storage performance within the range of uncertainty.
2) Knowledge of the actual storage performance is sufficient to provide confidence in the long-term effectiveness of CO_2 storage within the storage complex.

Containment Monitoring Targets

1) Measurements of any changes within the MMV datasets caused by CO_2 injection are sufficient to demonstrate the absence of any significant impacts as defined in the Environmental Assessment.
2) Measurements of any changes within the MMV datasets caused by CO_2 injection are sufficient to trigger effective control measures to protect human health and the environment.

Induced Seismicity Monitoring Targets

1) Measurements of consequential changes in seismicity within the SMA to trigger effective control measures to protect the public, assets, communities and the environment.

4.3.1 Tiered System Approach for Monitoring Technologies

The assessment of loss of containment and induced seismicity is based on a "Tier System" of the various technologies deployed as part of the MMV Plan. There is no tiered system for conformance technologies.

- Table 8: This table provides a list of the containment technologies and their assigned tier.
- Table 9: Overview of seismicity MMV Technologies and performance targets.
- Trigger events will be used to initiate any control responses, if required.

Tier development and assignment is based on the following criteria:

Tier 1 technologies:

- Address critical risks to loss of containment through direct, continuous monitoring. These technologies monitor data closest to the Storage Complex or along the wellbore with immediate action to address any trigger events. These barriers are actively maintained, include decision logic and a corrective measure.

Tier 2 technologies:

- Address potential critical risks to loss of containment and induced seismicity, though less directly tied to the Storage Complex. These technologies have a longer sample time or surveillance frequency, with analysis and longer response time to the trigger event. These barriers are actively maintained.

Tier 3 technologies:

- Contingency based monitoring that can be triggered as a potential response to Tier 1 or Tier 2 based monitor activities. Discontinuous monitoring or frequency of analysis may occur, with some technologies requiring re-deployment if triggered. Comprehensive baseline data (i.e., InSAR, GW discrete sample profiles) can be utilized for any trigger events that re-establish utilization of Tier 3 technologies.

4.4 Monitoring Tasks

The monitoring tasks identified to fulfill these monitoring targets are:

- Monitor the composition and flow of the injection stream.
- Monitor CO_2 plume development inside the storage complex.
- Monitor pressure development inside the storage complex.
- Monitor injection well integrity.
- Monitor indications of loss of geological seal integrity.
- Monitor for any hydrosphere impacts.
- Monitor for any CO_2 emissions into the atmosphere.
- Monitor for induced seismicity and its impacts.

4.5 Monitoring Schedule

The monitoring schedule to address conformance and containment is designed to monitor across the AOR within each of the domains (Figure 4-5). The MMV program is designed to mitigate the risks to monitoring performance targets (Section [4.3]) utilizing the following: comprehensive baseline data, continuous acquisition of key data, and contingency monitoring plans available. The monitoring systems are continually assessed for their value, and require continuance, applying sound science and engineering and the usage of the best available/economic technologies with changes to be communicated to the GoA and AER as required (Section [5.1]).

MMV activities are generally executed as per Figure 4-5. Details of specific timing and dates for acquisition and frequency of certain monitoring activities are determined on a continuing basis and communicated in Quest Annual Status Reports.

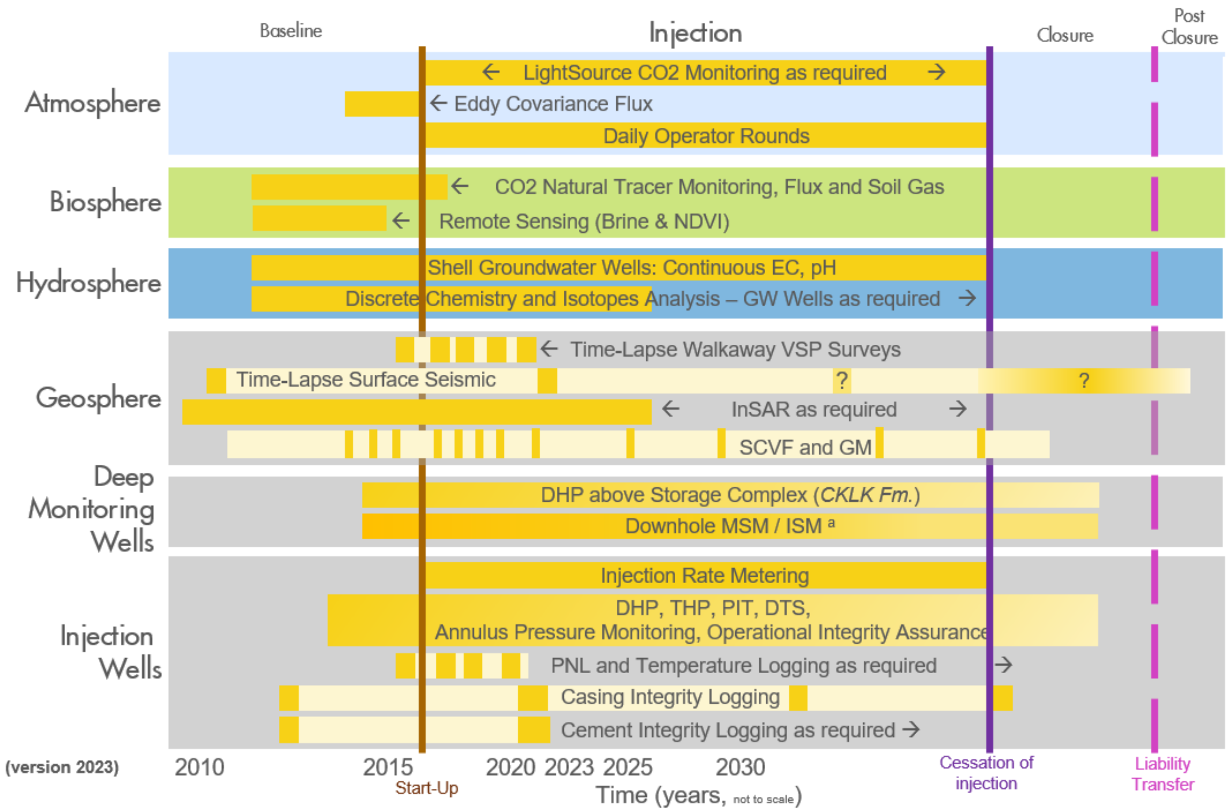


Figure 4-5: Schematic Plan of Quest's monitoring program

Additional note, geophone array lifetime ([a]) is based on reliability and lifespan. The array was replaced in 2022. Additional replacement decision upon failure will be made based on operational risk profile at time of failure, in consultation with the regulator and government.

4.6 Monitoring Technologies

4.6.1 Injection Stream Composition and Flow Rate

The composition of the injection stream is continuously measured using an online GC analyzer at the Quest capture facility located at stage 7 of the compressor. In addition, regular samples of the injection stream from stage 7 at the compressor are taken for laboratory analysis. Coriolis-type mass flow meters at the Shell Scotford boundary limit and at the injection well skids continuously measure the injection stream flow to determine mass of CO_2 injected.

4.6.2 Atmosphere

Above-ground CO_2 levels are monitored on a daily basis as a part of visual and audible checks during operator daily rounds.

Line of sight atmospheric CO_2 monitoring called 'Lightsource', is a contingency based technology, that occurs on a regular basis and is deployed on each injection well pad. A Boreal

Laser GasFinder sensor is located in one corner of each injection well pad and three reflectors positioned at the opposite corners. The system also includes weather station equipment (e.g. anemometer) that records wind direction, speed, etc. on a continuous basis.

4.6.3 Biosphere

CO_2 flux, soil gas, and soil sampling and analysis will be conducted on an as needed basis. For instance, in the event other monitoring technologies indicate the need to take samples within the biosphere. Note that monitoring the biosphere is challenging due to natural variability in soil gas and flux, as described in the special report on baseline data and analysis of biogenic flux of CO_2 submitted in fulfillment of condition 15) of the Approval 11837C [2].

4.6.4 Hydrosphere

4.6.4.1 Project Groundwater Wells

Shallow groundwater wells (GWW, < 200 m below ground surface) on each injection well pad were drilled and completed within different aquifers above the BGWP zone.

On each pad one of the groundwater wells is completed as close as possible to the BGWP zone. The other well(s) are completed at a typical depth of most local private landowner groundwater wells in the area.

Each GWW is equipped with a downhole multi-parameter water quality probe for continuous measurement of pH and WEC.

Discrete sampling of project GWWs will be executed alongside regular monitoring activities for the next three years (2024, 2025, and 2026).

4.6.4.2 Landowner Groundwater Wells

Besides the GWWs, a number of private landowner groundwater wells have historically been monitored at a frequency determined by proximity to the injection wells, anticipated plume development, and seismic related acquisitions. An extensive baseline of data were collected and analyzed to end of 2018. Additionally, landowner wells were sampled on 2021/2022 as part of the seismic campaign.

Discrete sampling events at landowner groundwater wells have been retained within the MMV Plan as a contingency monitoring technology that can be deployed as necessary, based on the tiered system to assess loss of containment (Section [4.10.2]).

4.6.4.3 Laboratory Analysis for Discrete Samples

Should discrete sampling events be triggered, Table 6 provides the list of key analytes for which the discrete water samples collected from the project and landowner groundwater wells will be analyzed for. Well gas samples will be collected using a flow-through cell, if possible, for well gas compositional (CO_2, N_2, O_2, C_n) and isotopic ($\delta^{13}C$-CO_2, $\delta^{13}C$-C_1) analyses.

Table 6: List of parameters considered priority for ongoing monitoring.

Parameter	Reason to Monitor
Alkalinity / Dissolved Inorganic Carbon (DIC)	Water type and water quality
As	Aquifer acidification
Ca	Water type and water quality
Cl	Potential brine indicator
$\delta^{13}C$	CO_2 isotopic fingerprint
Water Electrical Conductivity (WEC)	Potential brine indicator
K	Water type and water quality
Mg	Water type and water quality
Na	Potential brine indicator
pH	Water quality, CO_2 impact
SO_4	Water type and water quality
TDS	Potential brine indicator

4.6.5 Geosphere

4.6.5.1 Microseismic (MSM) and Induced Seismicity (ISM) Monitoring

A downhole microseismic monitoring (MSM) geophone array deployed in the Quest 08-19 deep monitoring well at a depth above the storage complex monitors vertical containment of CO_2 below the Lotsberg salt within the 10 km AOR. The same array has also proven useful for detecting and providing approximate locations for larger seismic events in the region.

4.6.5.2 Time-lapse Seismic Surveys

Time-lapse seismic data (VSP2D, SEIS2D, SEIS3D) can be used to monitor the development of the CO_2 plume inside the BCS storage complex. Time-lapse seismic surveys are expected to yield an anomaly at each CO_2 injector owing to the substitution of brine with CO_2.

A baseline 3D seismic survey was acquired in the winter months of 2010 and 2011 and covers an area of 435 km^2 (Figure 4-6). It is expected this areal coverage will be adequate to monitor the CO_2 plumes over the lifespan of the project until the end of the injection period. Any migration during the closure period would still fall within the image area of the baseline 3D seismic survey.

Eight 2D walkaway VSP survey lines in eight azimuths radially were acquired at each injection well using the Distributed Acoustic Sensors (DAS) fibers in Q1 2015. The survey lines are separated by roughly 45^o to provide multi-azimuthal coverage at the each injection site. The maximum source offset for each line is approximately 2400 m, and the expected maximum distance illuminated by the VSP2D at the BCS is approximately 800 m. The feasibility of time-lapse walkaway DAS VSP has been demonstrated on the 2015 baseline and 2016/2017/2019/2021 monitor VSP surveys. The maximum reliable image to interpret 4D differences is approximately 500 meters from each well. The criteria for the maximum reliable image is qualitative and derived from interpretations of synthetic modeling, VSP2D amplitudes at the base of the BCS and deviation of base of BCS picks interpreted from VSP2D data vs SEIS3D baseline data.

In Q1 of 2017, 2D surface seismic (SEIS2D) was acquired alongside the VSP2D at IW 7-11 and IW 8-19. This was the first SEIS2D acquisition. In Q1 of 2019, SEIS2D was acquired at IW 5-35 and again at IW 8-19. The second SEIS2D dataset acquired at IW 8-19 was used to assess the feasibility of surface seismic as a time-lapse seismic method. In Q4 2021 a subset of the Quest baseline 3D of approximately 200 km^2 was acquired over IW 5-35 and IW 8-19 to provide a 3D image of the seismic anomalies associated with the plumes at these two wells and further our understanding of conformance. At this time, a VSP2D was also acquired at IW 5-35 with its coincident SEIS2D survey. Two regional SEIS2D lines were acquired running west to east through the IW 5-35 and north to south through IW 8-19 (Figure 4-6).

Time-lapse seismic surveys have included the utilization of VSP2D, SEIS2D, and SEIS3D technologies (Figure 4-6, Table 7). The footprint of future time-lapse surveys will be adjusted to cover the expected plume size growth with continued injection. VSP2D has proven to be a robust time-lapse technology for measuring the seismic anomaly associated with the plumes. It had been demonstrated that the plumes at all wells have outgrown the reliable time-lapse image area of the VSP2D therefore, this technology will no longer be used for conformance going forward. However, it can be used for containment purposes within the image area if deemed necessary for the life of the asset. Assessment of long term seismic monitoring technologies is included in Quest's Optimization and Effectiveness initiatives.

The timing and deployment of time-lapse seismic surveys are continually assessed to manage containment and conformance risk and to ensure monitoring compliance while minimizing disturbance to surface stakeholders.

This is a function of:

- Measured plume growth and shape from previous measurements.
- Predicted plume growth and shape based on conformance modelling.

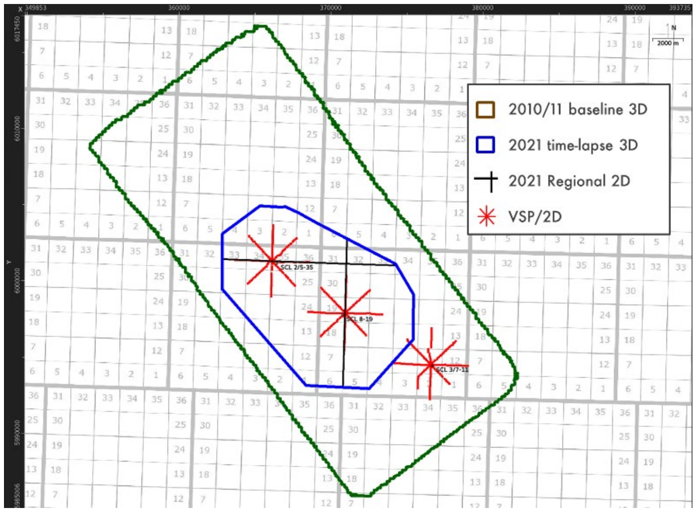


Figure 4-6: Shell Quest Seismic Campaigns as of 2023

Table 7: Shell Quest Seismic Acquisition Timing

Data type	2010	2015	2016	2017	2018	2019	2020	2021
3D surface seismic	full baseline							Subset of baseline
DAS VSP		baseline at all 3 wells	7-11, 8-19	7-11, 8-19		5-35, 8-19		5-35
2D during VSP				7-11, 8-19		5-35, 8-19		5-35
'Regional 2D'								E/W 5-35, N/S 8-19

4.6.5.3 InSAR

InSAR is a satellite remote sensing method designed to map displacements of the Earth's surface that may be related to displacements at depth. InSAR was evaluated as a technique to be used within the Quest MMV program. Based on the outcome of the special report on InSAR efficacy [8], the InSAR technology will be considered a contingency monitoring technology. It will only be processed and analyzed in the event of another MMV technology or observation indicating the need for further investigation. Satellite image programming and acquisition is planned to continue over the next three years using a single frame centered over the three injection well pads.

4.6.5.4 Observation Wells within the Basal Cambrian Sand Formation

The BCS pressures are being monitored continuously at wells IW 8-19, IW 7-11 and IW 5-35. Long-term continuous pressure monitoring is the basis for history matching dynamic reservoir models.

The wells IW 8-19, IW 7-11 and IW 5-35 are currently the only direct observation points within the BCS. In accordance with AER Condition 10 i), the potential need for installing additional monitoring wells will be re-assessed on an annual basis and commented on in the Annual Status reports.

4.6.5.5 Deep Monitoring Wells (Above BCS Storage Complex)

Three regional aquifers (Winnipegosis Formation, Beaverhill Lake Group, and Cooking Lake Formation) were evaluated for monitoring pressure above the BCS in the event of loss of containment. It was determined that the Winnipegosis / Contact Rapids Formations were tight and that the Cooking Lake Formation was the best monitoring interval. On each injection well pad there is one deep monitoring well (DMW) completed in the Cooking Lake Formation with downhole pressure and temperature gauges.

Owing to regional third party activities in the Leduc and Cooking Lake, there is a continuous pressure increase observed that is not related to CO_2 containment concerns. To aid in the interpretation of pressures observed in the Cooking Lake Formation, the Redwater 3-4 well was completed as an Observation Well in 2015 to monitor far field pressures responses to non-Quest activities.

4.7 Optimization and Effectiveness

Shell continuously monitors available technologies available on the market through regular capability updates from its vendors, participating in academic consortia, performing technical trials and attending industry conferences/workshops with the goal of operating the Best Available Technology Economically Achievable (BATEA [26]) at Quest. In addition to operating the best economic technology, Quest aspires to ensure societal concerns are adequately addressed, the environment is protected and the technologies utilized are effective and efficient. This pursuit, however, must consider implications to baseline and historical monitoring, to ensure consistency, compatibility, and comparability.

Recent examples of such efforts are:

- Well integrity logging optimization by incorporating best practices from the oil & gas industry (this means applying latest technology logging tools, best running procedures, and interpretation methods)
- Well integrity monitoring optimization by adjusting the frequency of SCVF and GM testing as well as integrity logging; both activities started with a higher frequency of data gathering, then the data collection frequency was adjusted based on the data trends
- Utilize gas isotope analysis for determining the SCVF and GM origin (“fingerprinting”)
- Downhole Distributed Acoustic Sensing technology trials (DAS) to detect microseismic events
- Surface node trial to mature surface deployed seismicity monitoring technologies
- Time-lapse onshore surface 3D co-processing for anomaly detection and visualization including compensation for non-repeatable acquisition geometries. Achieving a world class time-lapse RMS Repeatability Ratio of 7%

- Continued maturation of the Lightsource Atmospheric detection technology improving understanding of effectiveness and detection limits in CO_2 wellsite environments which can be applied to new operators and assets in future.

4.8 Performance Targets for CO_2 Inventory Accuracy

4.8.1 Composition of Injection Stream

As per AER Approval No 11837C Condition 5e): The injectant must contain no less than 95 per cent of CO_2 by volume.

4.8.2 Volume of Injected CO_2

As per AER Approval No 11837C Condition 5d): the cumulative injection volume for all approved scheme wells must not exceed 14,500 million cubic meters of CO_2 at standard conditions (15ºC, 101.325 kPa), which is an equivalent mass of 27 million tonnes.

4.9 Performance Targets for Conformance Monitoring

4.9.1 Monitoring CO_2 Plume Development

Time-lapse seismic data (VSP2D, SEIS2D, SEIS3D) are being used to monitor the development of the CO_2 plume inside the BCS storage complex. Time-lapse seismic methods are able to identify the replacement of brine with CO_2 in the BCS, and have demonstrated they are able to image anomalies associated with the plume around each CO_2 injector. The seismic response to the CO_2 plume is not expected to be sensitive to the distribution of CO_2 saturations within the pore space and therefore is utilized for plume anomaly detection and not saturation determination within the anomaly.

Feasibility studies and baseline data acquisition indicate that seismic methods have an anticipated lateral and vertical resolution of 100 m and 25 m, respectively. However, this resolution is sensitive to non-repeatable noise and signal repeatability. Increases in CO_2 saturation of above 5% could be detectable in layers of at least 5-10 m thickness.

Time-lapse results from the surface 3D and DAS VSP have demonstrated we are able to monitor plume anomaly changes over time. Results have shown the plume is growing at a rate consistent with modelled results within the accepted uncertainty range.

4.9.2 Monitoring Pressure Development

4.9.2.1 Injection Well Downhole Pressure Temperature Gauges

Downhole Pressure Temperature (DHPT) gauges in the injection wells are being used to monitor the development of pressure inside the BCS storage complex. The DHPT gauges provide direct continuous measurements of pressure changes at these discrete locations.

As per AER Conditions 4d, 5b, 6a, 10b, 11c, and 17g, collection and analysis of shut-in stabilized pressure fall-off tests (or analytical equivalent) and pressure transient analyses are reported on an annual basis. The initial baseline BCS pressure transient analyses for all three injection wells were submitted as part of the second annual status report submitted to AER

January 31, 2014 [1]. More recently, Annual Status Reports have shared the data gathered from pressure fall offs in the BCS to determine the total pressure increase over time.

4.9.2.2 InSAR

Based on the outcome of the special report on InSAR efficacy [3], the InSAR technology is considered a contingency monitoring technology with a focus on the AOR of the Quest SLA. It will be used in the event of another MMV technology or observation indicating the need for further investigation.

4.9.2.3 Modelling

Models are run and updated on a regular basis to provide an assessment of well and reservoir performance. These models allow for information of trends on storage performance.

Models are updated in accordance with AER conditions 4, 6, 10c, 17f and reported in the relevant AER Annual Status Reports. In addition, model updates will be submitted to Alberta Energy and Minerals as per Regulation 19 (3)c in accordance with Carbon Sequestration Tenure Regulation 68/2011.

4.10 Performance Targets for Containment Monitoring

Table 8: Technologies used to assess loss of Containment at Quest, including surveillance frequency and trigger event definition.

Tier	*Technology*	*Indicator*	*Surveillance Frequency*	*Trigger*	*Magnitude of CO_2 Detection Capability*	*Areal coverage*	*Domain*
Tier 1	IW DHP	Pressure	Continuous	Measuring greater than 27 Mpa or less than 20 Mpa	N/A	IWs	Geosphere
	IW Tubing/Casing Annular Pressure	Pressure	Continuous	Anomalous pressure response	N/A	IWs	Geosphere
Tier 2	Operator Rounds	Visual/Audible	Daily	Observation/detection (noise, liquids, hydrates at equipment)	tonne/day (well pads)	At each Injection well pad	Atmosphere
	DTS	Temperature outside of intermediate casing	Quarterly	Sustained temperature anomaly outside casing	Qualitative	IWs	Geosphere
	DMW DHP	Pressure	Daily	Anomalous pressure increase above baseline trend	deca tonne/day	DMWs	Geosphere
	Casing Inspection Log/ Casing Caliper Log	Log Response	Log 2 of 3 wells up to 15-years after previous logs [h]	Anomalies indicating casing integrity concerns	N/A	IWs	Geosphere
	SCVF	Geochemical composition	2024, and then proposed 5-year frequency [d]	Change in geochemical composition indicating presence of project CO_2	Qualitative	IWs and DMWs	Geosphere
	GM	Geochemical composition	2024, and then proposed 5-year frequency [e]	Change in geochemical composition indicating presence of project CO_2	Qualitative	IW5-35 & IW 7-11	Geosphere
	Packer Isolation Test	Pressure and Liquid Level	Annually	As per Directive 87	N/A	IWs	Geosphere
	Downhole MSM	Locatable MS events	Daily	Cluster of locatable events above the BCS	Qualitative	AOR	Geosphere
Tier 3 [a]	LightSource	CO2 emission rate	As required	Sustained locatable anomaly above background levels	tonne/day (well pads)	At each Injection well pad	Atmosphere
	WPH [ii]	Water pH	Daily	Sustained decrease in baseline pH values	Qualitative	GWWs	Hydrosphere
	WEC [ii]	Water Salinity (electrical conductivity)	Daily	Sustained increase in baseline WEC values	Qualitative	GWWs	Hydrosphere
	GWW: discrete water / gas geochemical analyses [b]	Geochemical composition	Quaterly	Outside expected range	Qualitative	GWWs and landowner wells if required	Hydrosphere
	SEIS3D, SEIS2D, VSP [i]	Seismic amplitude	As required	Identification of a coherent and continuous amplitude anomaly above the storage complex	kilo tonne/day	Area or radius around IWs (expected CO_2 plume extent)	Geosphere
	Cement Bond Log	Log Response	As required	Indication of CO_2 out of zone / identification of casing integrity issue	Qualitative	IWs	Geosphere
	Temperature and Pulsed Neutron Logs	Log Response	As required	Indication of CO_2 out of zone	Qualitative	IWs	Geosphere
	InSAR	Surface heave	As required	Unexpected localized surface heave	Qualitative	AOR plus buffer zone	Geosphere
	CO2 flux, Soil gas, Soil sampling and analysis	Baseline data	As required	Measurements outside of the expected range	Qualitative	At well locations if deemed necessary	Biosphere

Continued performance monitoring of these technologies and data will be used to verify, and if necessary, update these events

i - The time-lapse seismic deployment and timing will be based on the observed and predicted CO_2 plume growth rate and risk assessments, rather than preset dates.

ii – Gauges in GWW project wells only (see section 4.6.2.1).

NOTES:

[a] contingency monitoring technologies will be utilized as triggered by other tiered technologies (Section 6)

[b] discrete sampling events based on triggering events from other technologies and/on request by landonwers (D56)

[c] Continuous Monitoring over the life of the array

[d] As per September 28, 2020 AER approval letter testing frequency to be reviewed after 2024 testing

[e] As per September 28, 2020 AER approval letter testing frequency to be reviewed after 2024 testing

[f] Data acquired using DAS system; baseline survey Q1 2015, with monitor campaigns in 2016, 2017 and 2019.

[g] Timing of subsequent surveys will be determined based on plume growth, reservoir performance, and findings from previous survey.

[h] Following the two-well 15-year logs, assess data and determine future casing and cement integrity logging frequency

4.10.1 Monitoring the Atmosphere

The sensitivity and resolution of detecting and mapping CO_2 emission depends on a number of variables and is discussed in previous MMV Plans. Operational experience to date has demonstrated that daily operator rounds (Tier 2) have detected small leaks associated with surface injection equipment (such as valves, etc.) that are far below the resolution of Lightsource and with faster response times.

Therefore, Atmospheric monitoring via Daily Operator rounds becomes the primary atmospheric monitoring technology.

Lightsource is designated as a contingency based monitoring system; the system will continue to be deployed at the injection well pads. Should Lightsource be triggered by another technology, the sensitivity and resolution of identifying CO_2 emissions is as follows:

- **On Well Pad**: A sustained 300 kg/ hour (7.2 tonne/day) release rate of CO_2 from a localized source would be detectable and locatable from a range of 100 m, and its location mapped within a resolution of about 10 m under moderate windspeed conditions. This is for daytime acquired data and is subject to the variety of wind directions sampled.

4.10.2 Monitoring the Hydrosphere

Hydrosphere monitoring will involve:

- **Continuous water electrical conductivity (WEC) monitoring** at each of the project groundwater monitoring wells for detection of changes in water salinity. WEC may be impacted due to potential increase in ionic strength associated with acidification of groundwater that could be caused by CO_2 intrusion. It can also indicate an influx of brine from formations below the base of groundwater protection zone. There is no risk of brine leakage from the BCS storage complex above the BGWP (Section [3.1.3]).
- **Continuous water pH (WpH) monitoring** at each of the project groundwater monitoring wells. This enables the detection of changes in pH that could potentially be associated with increased levels of dissolved CO_2 within the groundwater.

Continuous WpH and WEC data are assessed relative to the data collected during the pre-injection phase in order to check whether or not values fall within expected range(s). Quarterly discrete sampling events will be conducted for calibration of these data.

4.10.3 Monitoring the Geosphere

4.10.3.1 Monitoring Injection Well Integrity

Mechanical Well Integrity Testing

Mechanical Well Integrity Testing consists of annual packer isolation testing of the tubing by production casing annulus according to Approval 11837C clause 5 c), AER Directive 51 and AER Directive 87.

Time-lapse Casing Integrity Logging and Corrosion Monitoring

Ultrasonic and Electromagnetic Casing Logs verified the initial integrity of the well completion for each injector. Casing integrity was verified six years after injection start-up for the IW 7-11 and IW 8-19 wells and four years after injection start-up for the IW 5-35 well.

Going forward it is planned to run the third set of Casing Caliper and Electromagnetic Casing Logs on two of the injection wells up to 15 years after the previous logs. Once the third set of casing integrity logs are completed the logging frequency will be reassessed based on the results.

Log interpretations are included in the Annual Status Reports to the AER, and raw logs have been submitted through the standard log submission process.

Time-lapse Cement Integrity Logging

Cement Bond Logs verified the initial integrity of the cement bond for each injector. Cement integrity was again verified six years after injection start-up for the IW 7-11 and IW 8-19 wells and four years after injection start-up for the IW 5-35 well.

Based on the results, cement integrity logging will be a contingency monitoring technology (Tier 3) for future operations.

Log interpretations are included in the annual status reports to the AER, and raw logs have been submitted through the standard log submission process.

Hydraulic Isolation Logging

Hydraulic isolation testing was performed using time-lapse temperature and pulsed neutron logs. Each injection well has a baseline log and three post start-up hydraulic isolation logs confirming CO_2 is contained in the BCS in the near wellbore environment.

Based on the results pulsed neutron and temperature logging will be a contingency monitoring technology (Tier 3) for future operations.

Pulsed neutron logging has been used on a large number of CCS Projects globally to identify CO_2 accumulations behind casing. Log interpretations are included in the annual status reports to the AER, and raw logs have been submitted through the standard log submission process.

Distributed Temperature Sensing

Continuous Distributed Temperature Sensing (DTS) is being recorded along an optical fiber permanently installed in each injection well. All fiber optic cables are clamped to the outside of the production casing and cemented in place.

At present, DTS is utilized for qualitative assessment of wellbore integrity, primarily by observing rates of change in temperature over time, and the integration of temporal data on CO_2 flow into the injection wells.

Distributed Acoustic Sensing

No additional feasibility studies are planned to support other DAS applications for monitoring well bore integrity of the Quest wells. An initial finding of these studies concluded that a combination of the current downhole geophone array located at DMW 8-19 with new surface seismic monitoring stations would enhance the existing Quest monitoring system by increasing the capability to monitor distant seismicity near the periphery of pressure build up area. DAS technology continues to evolve and develop, and the opportunity for future DAS deployment is being assessed.

SCVF and GM (IW and GWW)

Composition of SCVFs and GMs demonstrate source and depth of contributing zones and therefore resulting potential pathways along wellbore. Analysis of composition and isotopic values are also used to determine if SCVFs and GMs are independent or associated.

SCVF and GM was acquired in 2021 (2-year frequency) and will be acquired in 2024 (3-year frequency), for relevant wells as per Table 8. SCVF and GM testing is currently evaluated at a 3-year frequency up until 2024 as per AER approval letter dated September 28th, 2020. If no change is observed over time, it is proposed to be moved to a 5-year frequency. SCVF and GM may also be acquired as a contingency monitoring technology or as triggered by another Tier.

4.10.4 Monitoring Geological Seal Integrity

Downhole Injection Pressure and Rate Monitoring

Injection well downhole pressure and associated rates provide a continuous means to verify the absence of injection induced fracturing within the BCS:

- The flow rate at Scotford and on well sites is measured with a Coriolis mass flow meter with a minimum accuracy of ± 0.5% of reading (typical ± 0.1%).
- The downhole pressure is measured with gauges with ± 1% accuracy.
- The downhole temperature is measured with gauges with ± 2 ºC accuracy.

These accuracy levels are based on the technical specifications and observed calibration checks of the flow rate, pressure, and temperature monitoring systems. This is a mature, industry standard technology and any failed gauge will be replaced during a scheduled well work-over.

Downhole pressure temperature gauges are used to ensure downhole injection pressures do not exceed the approved maximum value of 30 MPa [1] or below minimum pre-injection reservoir pressure. The injection pressures based on current operations and modelling are expected to be considerably lower than this threshold over the life of the project.

Additionally, when injection is halted at a well, the gauges record the pressure fall off. Analysis of this shut-in period can be used to further validate the absence of induced fracturing.

Cooking Lake Formation Continuous Pressure Measurements

Continuous downhole pressure measurements (DHP) within the deep monitoring wells provide a means of detecting material migration of injected CO_2 or brine out of the BCS storage complex. As stated in section [4.6.5.5], the Cooking Lake Formation is the interval that is monitored at all three injection sites.

Since start up, an induced, detectable and sustained pressure rise in the Cooking Lake Formation has been observed and assessed to be related to far field Leduc Activity. As a result there is no indication of migration of injected CO2 or brine out of the BCS and pooling in the Cooking Lake Formation. The baseline Cooking Lake pressure data from these three monitoring wells and pressure trends since start up are available in the latest Annual AER Report [1]. The pressure in the Cooking Lake continues to be monitored for anomalous pressure increase above this base line trend.

Time-lapse Seismic Data

Time-lapse seismic data (VSP2D, SEIS2D, SEIS3D) can be used to verify the absence of CO_2 above the ultimate seal of the BCS storage complex. Time-lapse seismic volumes are investigated for amplitude anomalies occurring above the storage complex that may indicated CO_2 presence. In the vicinity of the wells it is the permeable and under-pressured Cooking Lake Formation that is believed to be the most likely formation CO_2 will enter in the event it escapes above the storage complex (Section [4.1]).

Any CO_2 unexpectedly entering an overlying formation will affect the seismic image due to the same fluid substitution effects demonstrated in the BCS. Due to different formation properties and different in-situ temperature and pressure conditions affecting the properties of CO_2, the magnitude of anticipated time-lapse seismic changes in the unexpected event of CO_2 entering these formations will vary. Feasibility studies indicate that time-lapse effects will likely be detectable from the seismic images for a contiguous CO_2 plume in the Cooking Lake Formation. To date no time-lapse anomaly has been seen in the Cooking Lake Formation.

Microseismic Monitoring

Induced microseismicity can result from fracture propagation, fault slippage, fluid movement, and pressure relaxation in a formation caused by pressure changes and associated changes in stress states within the subsurface. An array is being used to monitor seismic activity within the storage complex. The intended use of this data is to identify any potential fracture propagation into the Lotsberg Salts that may impact the seals of the storage complex.

Downhole Microseismic (DHMS) monitoring using an eight level conventional downhole geophone array with three-component retrievable geophones was first deployed in DMW 8-19 in November 2014. The microseismic monitoring performance of a conventional downhole geophone array is well established through observed field performance elsewhere. Similar downhole geophone arrays have operated elsewhere for more than ten years.

The array began recording pre-injection data in November 2014 in order to identify microseismic activity within the vicinity of the store prior to CO_2 injection. In the pre-injection period, no ambient microseismic events were detected within the monitoring range of the array.

Feasibility modelling predicts that microseismic events with M_w of –2 should be detectable out to 800 m, events with M_w = -1 should be detectable out to a distance of 3000 m and events with M_w = 0 should be detectable out to a distance of 10,000 m from the geophone array. Observed monitoring performance has confirmed this sensitivity.

In September 2022 as part of scheduled casing caliper logging and wellhead integrity testing the downhole array was removed and replaced in kind with a new array of the same configuration. In order to ensure consistency of measurement with the previously recorded data all specifications were replicated and the array was deployed down to the same depth.

InSAR

Based on the outcome of the special report on InSAR efficacy [3], the InSAR technology is considered a contingency monitoring technology (Tier 3) with a focus on the AOR of the Quest SLA. It will be used in the event of another MMV technology or observation indicating the need for further investigation.

4.11 Performance Targets for Induced Seismicity

Downhole MSM/ISM (08-19 Geophone array)

Deployed as Tier 2 for the detection of regional seismicity within the SMA. Reporting frequency of once/day.

Surface ISM (local)

Deploy as a contingency based monitoring system that is triggered by seismic event detection via downhole ISM (Tier 3) to investigate localized areas of seismicity in an effort to improve its characterization (e.g., event locations, depths and magnitudes, delineation of faults). Reporting frequency of once/day.

InSAR

Tier 3 technology, see above discussion of InSAR.

Table 9: Overview of seismicity MMV Technologies and performance targets.

Tier	Technology	Indicator	Surveillance Frequency	Trigger	Capability
Tier 2	Downhole ISM (08-19 monitor well)	Locatable seismic events	Daily	Anomalous seismicity with potential to have significant impact at surface witthin the SMA	**Detection**: Quantitative. Detectability decreases with offset. **Location**: Quantitative. Uncertainty increases with offset **Depth**: Quantitative. Uncertainty increases with offset
Tier 3	Surface ISM [i] (~5 stations)	Locatable seismic events	Daily	Anomalous seismicity with potential to have significant impact at surface witthin the SMA	**Detection**: Quantitative. Best within the array aperature, Detectability decreases with distance outside the array. **Location**: Quantitative. Best within the array aperture Uncertainty increases with distance outside the array aperture. **Depth**: Quantitative. Best within the array aperature. Uncertainty increases with distance outside the array aperture. Additional benefit of ground motion quantificaton.
	InSAR [i]	Surface heave	As required	Anomalous surface heave	Qualitative. Investigation in regions of identifed seismicity clusters.

Continued performance monitoring of these technologies and data will be used to verify, and if necessary, update these events

i - Contingency technologies are only required to be deployed if triggered by Tier 2. They may also be deployed if deemed useful by operator

5 Operating Procedures

Shell will operate the Project in accordance with AER Approval 11837C Conditions [2]. The following AER Approval Conditions specifically relate to operation procedures and are adhered to as follows:

1) Condition 5f – inform WellOperations@aer.ca if leak or potential leak detected in the tubing/casing annulus or packer in the injection well.
2) Condition 5g – immediately suspend injection and notify WellOperations@aer.ca if fluid movement above BGWP or any zone outside the BCS storage complex.
3) Condition 5h – immediately suspend injection operations if failure of any systems that compromise safe operations of the scheme occur.
4) Condition 5i – immediately report any movement of fluids into or above the MCS, or anomalous pressure changes occurring anywhere within the CO_2 disposal approval area to ResourceCompliance@aer.ca and WellOperations@aer.ca.
5) Conditions 6 and 25 – provide written incident report within 90 days to ResourceCompliance@aer.ca, WellOperations@aer.ca and Alberta Environment & Protected Areas Water Policy Branch for the following:
   a. Any movement of fluid out of BCS Formation or above MCS
   b. Any anomalies that indicate fracturing out of the BCS formation
   c. Any indications of loss of containment
   d. Unexpected surface heave, and
   e. Appropriate mitigative measures taken.
6) Condition 26 – immediately notify the Ministry of Environment and Parks at 1-800-222-6514 regarding any loss of CO_2 to the atmosphere, soils or shallow (non-saline) aquifers and provide an incident report as per Condition 6 and 25 above.

5.1 Operating Procedures in Response to Monitoring Trigger Events

Continuous or discrete monitoring systems may cause trigger(s) requiring either an initial prompt response, or an evaluation prior to the response. Examples of these triggers and responses related to each monitoring technology are listed in this section.

It should be noted that in operations it is the intent to use equipment for continuous measurements of specific parameters to address the targets of CO_2 Inventory Accuracy, Containment Monitoring, and induced seismicity in line with high reliability and availability. However, at times due to system maintenance or equipment failure, there can be periods of data outages/gaps that may lead to an offline status resulting in QA/QC issues. A mitigation to some of these data gaps is in place through redundant measurement systems (e.g., collection and analysis of regular discrete samples in addition to continuous measurements) resulting in more than one technology being available to address a specific threat (Figure 3-2). Note that in case safe operation of the injection scheme is compromised due to failure of equipment, injection operations will be suspended as per Approval 11837C condition 5) h) "*immediately suspend injection operations if any injection equipment, monitoring equipment, or safety devices fail that could compromise the safe operation of the scheme*".

5.2 Monitoring Triggers and Response Times to Barriers to Ensure Conformance

The following monitoring-supported barriers are planned to prevent or correct a situation where the lateral extent of the CO_2 plumes or pressure build-up goes beyond the uncertainty ranges set within their model-based predictions.

5.2.1 CO_2 Plume Development

- **Monitoring:** Time-lapse seismic data
- **Trigger:** The observed anomaly is larger than baseline seismic area, or there is a clear temporal trend towards this state.
- **Response Option(s):** Update models and rely on only model based predictions. If necessary, increase the areal extent of the baseline seismic survey. Consider re-distributing injection across existing wells or drilling additional injection wells to keep the plume within the footprint of the baseline seismic area.
- **Response Time:** 3 – 6 months for model updates. 6-12 months for additional seismic surveys due to seasonality and subject to seismic contractor availability. Approximately four months would be required in addition to this to process and interpret a new dataset. Re-distribution of injection between existing wells is available on demand. Drilling additional injection wells will take 18 - 24 months and are subject to additional regulatory approvals and land access consents.

5.2.2 BCS Pressure Plume Development

- **Monitoring:** BCS pressure gauges (Injection well bottom hole gauges).
- **Trigger:** The observed stabilized BCS pressure at the injector wells strongly deviate from the modelled pressure ranges.
- **Response Option(s):** Update models and evaluate the need for installing BCS monitoring wells towards the periphery of the pressure build up area in accordance with condition 10i of *AER Approval 11837C.*
- **Response Time:** 3 – 6 months for model updates. 18-24 months for drilling monitor wells or other injector wells.

The following additional barriers are planned to ensure accurate CO_2 inventory measurements are available and that the target CO_2 subsurface capacity is achieved.

5.2.3 Injected Mass of CO_2

- **Monitoring:** Wellhead injection rate metering on each injector and rate metering at the compressor outlet in Scotford, minimum technical accuracy of 0.5%.
- **Trigger:** Based on existing acid gas disposal regulations, a difference greater than 5% between the sum of monthly CO_2 injection volumes for all injection wells and the Scotford fence-line meter.

- **Response Option(s):** Recalibrate or, if necessary, replace meters or revise the performance target.
- **Response Time:** 1 – 6 months.

5.2.4 Subsurface CO_2 Storage Capacity

- **Monitoring:** Down-hole pressure monitoring for each injector.
- **Trigger:** The modeled rate of pressure increase on each injector is large enough to reach the maximum stabilized down-hole pressure (26 MPa) before cessation of injection.
- **Response Option(s):** Reduce injection rates and investigate additional well locations.
- **Response Time:** 18-24 months are likely required to drill an additional injector in one of the remaining pre-selected locations.

5.3 Monitoring Triggers and Response Times to Ensure Containment

The following monitoring supported barriers are used to prevent or correct any potential loss of containment.

5.3.1 Pressure Monitoring and Responses

5.3.1.1 Injection Well Down-hole Pressure Gauges

- **Monitoring**: Injection well downhole pressure gauge on each injection well, just above the injection point to the BCS.
- **Trigger**: 1) High or low pressure recorded from downhole pressure gauge outside the operating limit. (Note: the operating limit is defined inside the regulatory limit) 2) down-hole injection pressure trends towards maximum injection pressure. 3) down-hole injection pressure trends towards the minimum pre-injection reservoir pressure. 4) Erroneous data from down-hole pressure gauge.
- **Response Option(s)**: 1) Shut down injection on that well. Investigate well condition prior to restarting injection. 2,3) Quest Storage team to evaluate and make recommendations to address the pressure anomaly including but not limited to: bringing on additional injection well, reducing injection rate, and/or suspending injection and investigate if a loss of containment event may have occurred. 4) In the case when erroneous or bad data is observed due to function of the bottom hole pressure gauge, conservative pressure limits to be placed on the tubing head pressure as a representation of the injection stream pressure to ensure that maximum bottom hole injection pressure is not exceeded.
- **Response Time:** 1) minutes 2,3) minutes to hours 4) days to months.

5.3.1.2 Pressure Monitoring and Responses for Legacy Wells

- **Monitoring:** Injection well downhole pressure gauge and fall off data.

- **Trigger:** The modelled BCS pressure increase at a legacy well is sufficient to lift brine above BGWP or there is a clear temporal trend towards this state.
- **Response Option(s):** Re-distributing injection across existing wells, increase frequency of groundwater fluid/soil sampling and analysis next to the legacy well, consider drilling a deep monitoring well and/or a project groundwater well at this location.
- **Response Time:** Injection rates can be re-distributed immediately. Additional groundwater fluid samples and soil and vegetation data can be acquired within 2 weeks. 6 months are likely required to drill a project groundwater well and 18-24 months to drill an additional deep monitoring well at the legacy well locations.

5.3.1.3 Tubing-Casing Annulus Pressure Change and Responses

- **Monitoring:** Tubing-Casing Annulus Pressure on injections wells.
- **Trigger:** 1) High or low pressure recorded outside of the operating limit or 2) abnormal pressures observed indicating a potential leak.
- **Response Options:** 1) Investigate the condition of the well. Trend pressure to determine cause of high or low pressure. Consider to shut in well and make safe. 2) Quest storage team to evaluate and implement an Annulus Pressure Investigation to determine potential remediation requirements.
- **Response Time:** 1) Minutes to Hours, 2) 1-3 Months.

5.3.2 Injection Well Integrity Monitoring and Responses

- **Monitoring:** Mechanical well integrity monitoring, corrosion probes, distributed temperature sensing, Cooking Lake Formation pressure monitoring.
- **Trigger:** significant deterioration of casing integrity, failed well integrity test, or a sustained Cooking Lake Formation pressure.
- **Response Option(s):** Cross-check information with other monitoring data. If data indicative of loss of containment, re-distribute injection away from this well, repair the well by changing the failed completion component(s) or remedial cementing, or plug and abandon an injector that cannot be repaired, and drill a replacement well.
- **Response Time:** Continuous pressure monitoring supports an immediate response (minutes to hours) to re-distribute injection (Section [3.1.3]). 1-12 months are likely required to re-instate a safe well and execute a long term repair. If required planning and executing a new drill will likely require 18-24 months in one of the remaining pre-selected locations.

5.3.3 Geological Seal Integrity Monitoring

- **Monitoring:** BCS pressure monitoring, Cooking Lake Formation pressure monitoring, time-lapse seismic data, downhole microseismic monitoring, and supplemented by InSAR when necessary.
- **Trigger:** BCS injector pressure exceeds maximum limit or trends down towards pre-injection pressures, sustained Cooking Lake Formation pressure, time-lapse seismic

anomaly above BCS storage complex, InSAR anomaly due to volume changes above the ultimate seal or within a sustained clustering of microseismic events with an upward spatial pattern indicative of fracturing above the base of the Lower Lotsberg Salt.

- **Response Option(s):** Re-distribute injection across existing wells, drill an additional injector, or stop injection. Consider reservoir fluid extraction to reduce pressures inside the BCS storage complex.
- **Response Time:** Continuous pressure monitoring supports an automated instant control response to re-distribute injection. Microseismic monitoring requires 1 day for processing and interpretation. Time-lapse seismic data will 6-12 months for planning, permitting and deployment (controlled by seasonality as well) with a 4 month processing and interpretation timeline requires 6-12 months for processing and interpretation. 18-24 months are likely required to drill an additional injector in one of the remaining pre-selected locations. Implementing a scheme for reservoir fluid extraction and re-disposal will take at least twenty-four months.

5.3.4 Hydrosphere Monitoring

- **Monitoring:** Project groundwater wells with daily water electrical conductivity and pH measurements and quarterly discrete water samples taken
- **Trigger:** Sustained increase in water electrical conductivity, sustained decrease in pH.
- **Response Option(s):** Conduct groundwater and biosphere investigations including triggering discrete sample events, implement exposure controls and remediation measures. If required, stop injection at the well(s) suspected to be the source of these impacts.
- **Response Time:** 1 – 3 months are likely required to conduct these investigations and deploy the appropriate control measures.

5.3.5 Atmosphere Monitoring

- **Monitoring:** Daily Operator Rounds.
- **Trigger:** Visual ‘on-site’ inspection of all wellhead and surface facilities indicates an observed leak (e.g., hydrate formation on equipment, audible identification of potential pressure release – i.e. ‘hissing’).
- **Response Option(s):** Conduct tightening and or/repair of any surface facilities, trigger further monitoring via contingency Tier 3 technologies (i.e. Lightsource, GW sampling) dependent on investigation, location/extent of leak, and effect on surface equipment (i.e. repairs or clean-up).
- **Response Time:** 1 day to 1 month.

5.4 Monitoring Trigger Events and Response Times to Manage Seismicity

- **Monitoring**: Downhole MSM/ISM
- **Trigger:** Anomalous seismicity (of potential consequence) within the SMA.

- **Response Option(s):**

Within the AOR, Shell is to follow Subsurface Order 2 (SSO2), adjusted[i] for long-term CO_2 storage rather than the hydraulic fracturing operations it was written to address. Outside the AOR, but within the SMA, Shell will review seismicity developments with monitoring data over time and potentially reduce injection pressures/rates/volumes at wells or redistribute injected volumes when appropriate to reduce the likelihood or escalation of seismicity of consequence.

  - *Active Preventative Barriers:*
    - CO_2 injection Rate/Pressure Reduction
    - CO_2 injection re-distribution (change injection pattern) amongst existing wells
    - Inject CO_2 into secondary zone
    - Inject CO_2 into new BCS injector well (change injection pattern)
    - Reduce BCS pressure by producing BCS brine and injecting the brine into shallower zone (pending feasibility and licensing requirements)
  - *Active Corrective Barriers:*
    - External Engagement (public, regulator)
    - Address Susceptible Structures
    - Environmental Remediation

- **Response Times:**
  - *Active Preventative Barriers:*
    - CO_2 injection rates can be reduced within a few hours.
    - CO_2 injection volumes can be re-distributed (change injection pattern) amongst existing wells within a few hours.
    - Identifying/drilling and licensing a new well for CO_2 injection into a secondary zone – 18-36 months.
    - Identifying/drilling and licensing a new well for CO_2 injection into BCS – 24-36 months.
    - Identifying/drilling and licensing a new well for BCS brine injection into another zone – 24-36 months.
  - *Active Corrective Barriers:*
    - Initial public engagements can occur within a few hours. Follow-up and continuing communication may occur over months-years.

i) Shell's commitment to monitor, report and respond to seismicity in alignment with SSO2 is adjusted to recognize the low pressure, long term operations and large fluid volumes (large affected area) associated with carbon sequestration relative to the high pressure, short-term and lower fluid volume (small affected area) operations of hydraulic fracturing that SSO2 is intended to manage. Hence, the Quest commitment to monitor and respond to seismicity applies over a larger area (10km radius) than the 5km radius stipulated in SSO2 for hydraulic fracturing. Additionally, the Quest MMV plan has daily reporting of seismicity rather than the real-time reporting commonly done during shorter-duration hydraulic fracturing operations. For this reason, Quest will notify the AER 'within 24 hours' of reported $M \geq 2.0$ seismicity rather than 'immediately'. Similarly, to align with this timing, operational interventions to mitigate seismicity at Quest will be taken within 24 hours of being aware of the seismicity.

- Susceptible structures can be addressed in months-years.

6 Contingency Monitoring Plans

This section describes the implementation of Tier 3 technologies should any of the Tier 1 or Tier 2 monitoring technologies trigger the necessity for further investigation and includes contingencies for potential underperformance of these monitoring systems. These contingency monitoring options allow for adaptation of the MMV plan and further analysis to ensure suitable demonstration of containment, conformance and induced seismicity monitoring.

The basis for the deployment of contingency technologies results from the expectation that any indications that Tier 1 and Tier 2 technologies would first and foremost manage the key project risks, with immediate and safety-critical responses.

The following contingency monitoring technologies are considered alternative monitoring systems that are ready to be deployed only in the unexpected event that they are required (triggered by another technology).

6.1 Soil Gas Flux and Tracer Analysis

- **Monitoring**: Soil gas flux and tracer analysis at well locations if deemed necessary.
- **Trigger:** Soil gas flux and /or project-specific tracers measured outside of expected range.
- **Response Option(s):** Conduct groundwater and biosphere investigations, implement exposure controls and remediation measures. If required, stop injection at the well suspected to be the source of these impacts.
- **Response Time:** 1 – 3 months are likely required to conduct these investigations and deploy the appropriate control measures.

6.2 Lightsource

- **Monitoring:** Lightsource.
- **Trigger:** Sustained localized anomalous concentrations detected using a statistical process control model followed by an assessment to locate and to quantify an anomaly using a dynamic linear model.
- **Response Option(s):** Investigate location and under-take site specific study as deemed necessary. Conduct soil and groundwater investigations at the site of the indicated anomaly. Implement exposure controls. If required, stop injection at all wells suspected to be the source of these emissions.
- **Response Time:** 1 –3 months are likely required to conduct these investigations and deploy the appropriate controls measures.

6.3 Downhole Sensors Groundwater Wells

- **Monitoring:** Project groundwater wells with continuous water electrical conductivity and pH measurements.
- **Trigger:** Sustained increase in water electrical conductivity, sustained decrease in pH.

- **Response Option(s):** Investigate using an integrated response plan-IRP with primary- (e.g., misidentified well name, wrong sample number, transcription error) and secondary checks (e.g., assess historical information, review data for other parts of AOR, review findings from other MMV monitoring technologies). As needed, conduct groundwater and biosphere investigations including triggering discrete sample events, implement exposure controls and remediation measures. If required, stop injection at the well(s) suspected to be the source of these impacts.
- **Response Time:** 1 – 3 months are likely required to conduct these investigations and deploy the appropriate control measures.

6.4 Discrete Groundwater Sampling

- **Monitoring:** Groundwater sampling and geochemical analyses of project groundwater wells.
- **Trigger:** Presence of project specific tracers within groundwater samples.
- **Response Option(s):** Investigate using an integrated response plan. As needed, conduct groundwater and biosphere investigations, implement exposure controls and remediation measures. If required, stop injection at the well(s) suspected to be the source of these impacts.
- **Response Time:** 1 – 3 months are likely required to conduct these investigations and deploy the appropriate control measures.

6.5 Time-lapse Cement Integrity Logging

- **Monitoring:** Cement integrity.
- **Trigger:** A Well Integrity Tier 1 or Tier 2 trigger (Section [5.3.1] or [5.3.2]) suggests loss of containment in the near wellbore environment.
- **Response Option(s):** Cross-check information with other monitoring data. If data indicative of loss of containment re-distribute injection away from this well, repair the well by changing the failed completion component(s) or remedial cementing, or plug and abandon an injector that cannot be repaired, and drill a replacement well.
- **Response Time:** This logging job must be completed after tubing is pulled out of wells and timing is driven from well intervention timeline noted above (Section [5.3.1]).

6.6 Time-lapse Pulsed Neutron and Temperature Logging

- **Monitoring:** CO_2 migration in the near wellbore environment.
- **Trigger:** A Well Integrity Tier 1 or Tier 2 trigger (Section [5.3.1] or [5.3.2]) suggests loss of containment in the near wellbore environment.
- **Response Option(s):** Cross-check information with other monitoring data. If data indicative of loss of containment re-distribute injection away from this well, repair the well by changing the failed completion component(s) or remedial cementing, or plug and abandon an injector that cannot be repaired, and drill a replacement well.

- **Response Time:** 1 month.

6.7 InSAR

- **Monitoring**: Surface displacements over the Quest area
- **Trigger:**
  - Abnormal seismicity detected by downhole MSM/ISM monitoring array.
  - Observed non-conformance of CO_2 injection (DHPT measurements).
- **Objective**: Measure possible surface effects of subsurface deformation (incl. subsurface seismicity).
- **Response Option(s):** Process and interpret time lapse InSAR data
- **Response Time**: 6 months.

There are a number of potential shortcomings regarding the usage of InSAR for MMV:

- *Surface displacements are too small to support reliable imaging of volume changes inside the BCS storage complex*
- *Unexpected surface uplift cannot be reconciled by volume changes inside the storage complex*

The special report on the efficacy of the InSAR program [3] highlighted the following:

InSAR is a viable technology for assessing unexpected surface heave. Its value, however, is limited for continuous monitoring given the site specific characteristics of the Quest site. Based on the observed and modelled pressure build-up within the BCS, dilation within the BCS storage complex will be small. The resulting surface uplift will likely fall within the noise levels of the measured ground displacement, with shallow subsurface activities providing an additional source of uncertainty. As a result, InSAR has limited value as a continuous monitoring technology for unexpected containment issues.

As injected volumes increase, it may have some value from a conformance perspective. Hence, the InSAR technology will be considered a contingency monitoring technology with a focus on the AOR (area of review) of the Quest SLA (sequestration lease area). It will be used in the event of another MMV technology or observation indicating the need for further investigation.

6.8 Time-lapse Seismic Data

- **Reason**: Uncertainty about reservoir properties such as relative permeability result in a CO_2 plume growing at a rate outside the uncertainty range around median predicted rate.
- **Monitoring**: 3DSEIS or other time-lapse technologies if new options become available/economic.
- **Trigger:** Pressure and temperature measurements indicate a change in reservoir response to injection outside of the acceptable limits.
- **Response Option(s)***:* Deploy a 3D surface seismic monitoring survey.

- **Response Time:** 6-12 months to plan and execute survey (seasonality dependent), with additional 4 months to process and interpret.

6.9 Surface ISM

- **Monitoring**: Seismicity
- **Trigger (Tier2):** Seismicity detected by downhole MSM/ISM monitoring array (with potential for consequence) within SMA.
- **Objective**: Reduce uncertainty associated with seismic event locations, depth, magnitude distribution and/or relationship with pre-existing faults.
- **Response Time**: 6-9 months to deploy ISM surface array.

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7 Emergency Response Plans

As defined in the MMV Principles from GOA version 2 [26] - Adverse impacts to public in the event of a release event. MMV information will be used to define Emergency Planning Zones and inform Emergency Response Plans, as described in Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry.

The Shell ERP "Shell Scotford Quest CO_2 Pipeline and Injection Wells ERP" (ERP Plan Ref# 2604) covers the Quest Transportation (pipeline) and storage components (wells and reservoir) of the asset. This Emergency Response Plan (ERP) was developed to address incidents that have potential to have immediate adverse impacts to the public or environment occurring from the downstream side of the Line Block Valve (LBV) exiting the Shell Scotford facility, up to and including the CO_2 injection wells and monitoring wells.

Incidents relating to carbon capture occurring upstream of the LBV of the CO_2 pipeline exiting the Shell Scotford facility will be addressed by the Scotford Complex Emergency Response Plan (ERP).

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Professional Practice Management

This report entitled "Shell Quest Carbon Capture and Storage Project – Measurement, Monitoring, and Verification Plan" was prepared for the Alberta Energy Regulator in September 2023.
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