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Shell Quest Carbon Capture and Storage Project

MEASUREMENT, MONITORING AND VERIFICATION PLAN

UPDATE

Prepared by:
Shell Canada Limited
Calgary, Alberta

January 31, 2015

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Executive Summary

The Quest Carbon Capture and Storage Project (Quest CCS Project) will make a material early contribution to reducing CO_2 emissions generated by upgrading bitumen from the Alberta oil sands. The climate benefits and societal acceptability of this Project both require long-term secure storage of the 1.08 million tonnes of CO_2 captured per annum within the Basal Cambrian Sands (BCS) storage complex.

The Quest Project has a responsibility to carefully monitor activity within the storage area and to confirm that an acceptable risk to health, safety, and the environment is maintained for the storage site. To that end, a measurement monitoring and verification plan (MMV) has been developed to monitor even at the deepest levels of the storage site. The monitoring results will be transparent and publically available to demonstrate that the Quest storage site is inherently safe. This MMV Plan is designed according to a systematic risk assessment to achieve two distinct objectives:

Ensure Containment to demonstrate the *security* of CO_2 storage and to protect human health, groundwater resources, hydrocarbon resources, and the environment.

Ensure 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 behaviour inside the storage complex;

MMV will achieve this in two ways. First, by verifying the expected effectiveness of existing safeguards created by site selection, site characterization, and engineering designs. Second, by creating additional safeguards using the same monitoring systems to provide an early warning to trigger timely control measures designed to reduce the likelihood or the consequence of any leakage from the storage site. These control measures include re-distribution of injection rates, drilling additional injection wells and, if necessary, stopping injection and deploy groundwater remediation systems.

Transfer of long-term liability, in accordance with the Closure Plan, is supported by MMV activities designed to verify that the observed storage performance conforms to model-based forecasts and that these forecasts are consistent with permanent secure storage at an acceptable risk. These same monitoring systems will also provide early warning of any potential for loss of conformance to allow timely updates to subsurface models. An update to the Storage Development Plan would also be undertaken if required to mitigate any risk associated with non-conformance in order to ensure timely site closure and transfer of long-term liability to the crown.

The selected monitoring plan for conformance and containment are subject to different value drivers. Conformance risks affect project monetary value so conformance monitoring plans were selected according to their value of information. Containment risks affect project safety so containment monitoring plans were selected to ensure these risks are as low as reasonably practicable.

This is the fourth update of the MMV plan submitted to AER since the start of the project. The first conceptual plan was submitted as part of the D65 disposal application in 2010. In fulfillment of the D65 approval condition 7, the pre-baseline MMV plan was submitted in October 15, 2012 and an interim update requested by the AER December 3, 2013 was submitted on February 14, 2014. In fulfillment of D65 approval condition 15e, this pre-injection MMV plan will be submitted January 31, 2015. This plan contains updates based on the baseline data acquisition program conducted through 2012 – 2014, the data acquired from the 2012 – 2013 drilling campaign and the results from ongoing or completed technology feasibility studies.

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Abbreviations

AEC .... atmospheric eddy correlation
AER .... Alberta Energy Regulator
ALARP .... as low as reasonably practicable
AOR .... Area of Review of MMV activities for the Project
APM .... annulus pressure monitoring
ARC .... Alberta Research Council
BCS .... Basal Cambrian Sands
BGWP .... Base of Groundwater Protection
BGS .... British Geological Survey
CBL .... cement bond logs
CCS .... carbon capture and storage
CDM .... Clean Development Mechanism
CO_2 .... carbon dioxide
CSA .... Canadian Standards Association
DAS .... fiber-optic distributed acoustic sensing
DHMS .... downhole microseismic monitoring
DHPT .... downhole pressure-temperature gauge
DNV .... Det Norske Veritas
DTS .... fiber-optic distributed temperature sensing
EPA .... Environmental Protection Agency
ESS .... ecosystem studies
GHG .... greenhouse gas
GPS .... global positioning system
GPZ .... groundwater protection zone
HIA .... satellite or airborne hyper-spectral image analysis
HSE .... United Kingdom Health and Safety Executive
HSSE .... Health Safety Security and Environment
HUD .... hold-up depth
IEA .... International Energy Agency
INJ .... injection wells
InSAR .... Interferometric Synthetic Aperture Radar
IPAC .... International Performance Assessment Centre
IPAC-CO_2 .... International Performance Assessment Centre for CO_2
IPCC .... Intergovernmental Panel on Climate Change
IRM .... injection rate metering at wellhead
KPI .... key performance indicator
LOSCO_2 .... line-of-sight gas flux monitoring
MCS .... Middle Cambrian Shale
MIA .... satellite or airborne multi-spectral image analysis
MMV .... measurement, monitoring and verification
MNA .... Monitored Natural Attenuation
MWIT .... mechanical well integrity pressure testing
NETL .... National Energy Technology Laboratory
OBW .... observation wells in Winnipegosis (WPGS)
PTRC .... Petroleum Technology Research Centre
Quest CCS project .... Quest Carbon Capture and Storage Project
RIA .... satellite or airborne radar image analysis

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
SPH .... soil pH surveys
SSAL .... soil salinity surveys
TNO .... Netherlands Organisation for Applied Scientific Research
UK .... United Kingdom Department of Energy and Climate Change
UNSED .... United Nations Conference on Environment and Development
USIT .... time-lapse ultrasonic casing imaging
VSP .... vertical seismic profiling
VSP2D .... time-lapse 2D vertical seismic profiling
WEC .... downhole electrical conductivity monitoring
$WHCO_2$ .... wellhead CO_2 detectors
WHPT .... wellhead pressure-temperature gauge
WPGS .... Winnipegosis
WPH .... downhole pH monitoring
WRI .... World Resources Institute
WRM .... well and reservoir management

1 Project Description

Shell Canada Limited, which will hold all necessary regulatory approvals in respect of the Project, is the managing partner of Shell Canada Energy. Shell Canada Energy will operate the Project, on behalf of the Athabasca Oil Sands Project ("AOSP"), which is a joint venture between Shell Canada Energy (60%), Chevron Canada Limited (20%) and Marathon Oil Canada Corporation (20%). The goal of the Quest CCS Project is to separate, capture, and permanently store CO_2, thereby reducing greenhouse gas emissions from the existing Scotford Upgrader. The Scotford Upgrader is located about 5 km northeast of Fort Saskatchewan, Alberta within Alberta's Industrial Heartland, which is zoned for heavy industrial development.

The three components of the Quest CCS Project are:

- CO_2 capture infrastructure, which will be connected to the Scotford Upgrader. The method of capture is based on a licensed Shell amine system called ADIP-X.
- A CO_2 pipeline, which will transport the CO_2 from the Scotford Upgrader 60 km to the injection wells north of the upgrader. The CO_2 injection well locations are located in the center of the storage site.
- An approved storage scheme consisting of up to eight injection wells that can be used to inject the CO_2 into the Basal Cambrian Sands (BCS), a deep underground formation, for permanent storage at a depth of about 2 km below ground level. Although eight were approved as part of the D65 approval 11837A [1], the current development plan requires only three injection wells at this time. The security of storage will be ensured through a program of Measurement, Monitoring and Verification (MMV).

The injection policy consists of injecting 1.08 million tonnes of CO_2 per annum for 25 years using three to eight vertical wells with a typical spacing of 5 km. The maximum injection pressure will not exceed 30 MPa. The distribution of injection between the injection wells will be managed to satisfy this pressure constraint in accordance with the Directive 65 application.

Figure 1-1 shows the Quest Project Sequestration Lease Area (SLA). It displays the Quest Project well sites, area of the 3D surface seismic survey, and legacy wells within the SLA. Note that the Quest Project SLA and Area of Review (AOR) are currently equivalent in size and footprint.

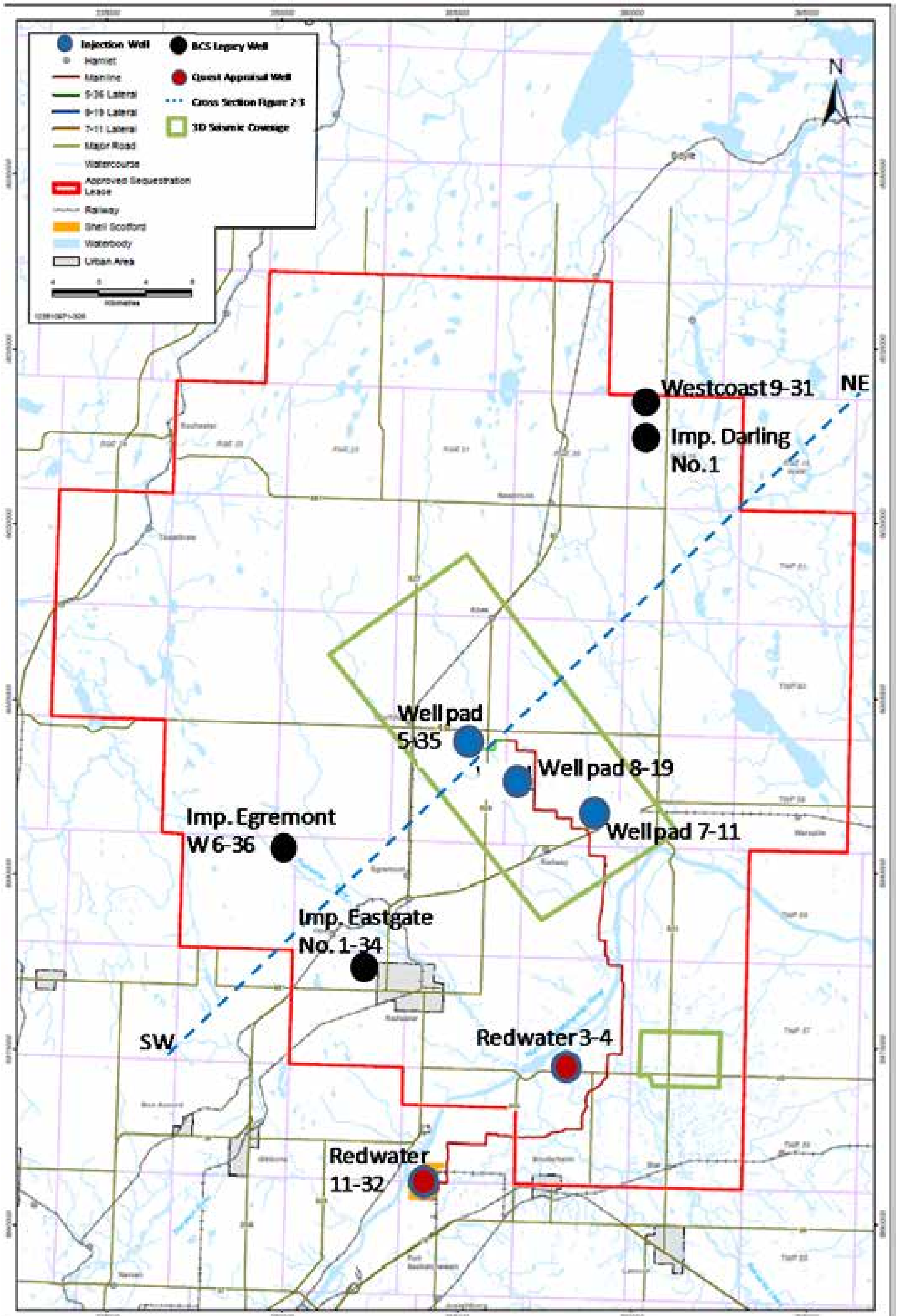

Figure1-1: Location Map of the Quest Sequestration Lease Area (SLA). It displays the Quest Project well sites, area of the 3D surface seismic survey, and legacy wells within the SLA.

2 The Purposes of MMV

The selected storage site is believed to be inherently safe; however, it is incumbent on Shell / the Operator to manage and minimize storage risks. MMV is central to the framework for storage risk management (Figure 2-1). There are two independent storage risks, loss of containment and loss of conformance, and these are reflected in the two primary objectives of MMV for the Quest CCS Project.

Ensure Containment to demonstrate the *current security* of CO_2 storage, *i.e.*

1) *Verify containment, well integrity, and the absence of any environmental effects outside the storage complex.*
2) *Detect early warning signs of any unexpected loss of containment.*
3) *If necessary, activate additional safeguards to prevent or remediate any significant environmental impacts as defined by the Environmental Assessment.*

Ensure Conformance to indicate the *long-term security* of CO_2 storage, *i.e.*

1) *Show pressure and CO_2 development inside the storage complex are consistent with models and, if necessary, calibrate and update these models.*
2) *Evaluate and, if necessary, adapt injection and monitoring to optimize storage performance.*
3) *Provide the monitoring data necessary to support CO_2 inventory reporting.*

Well-established industry practices for well and reservoir management and environmental monitoring provide the key capabilities necessary to fulfill these requirements.

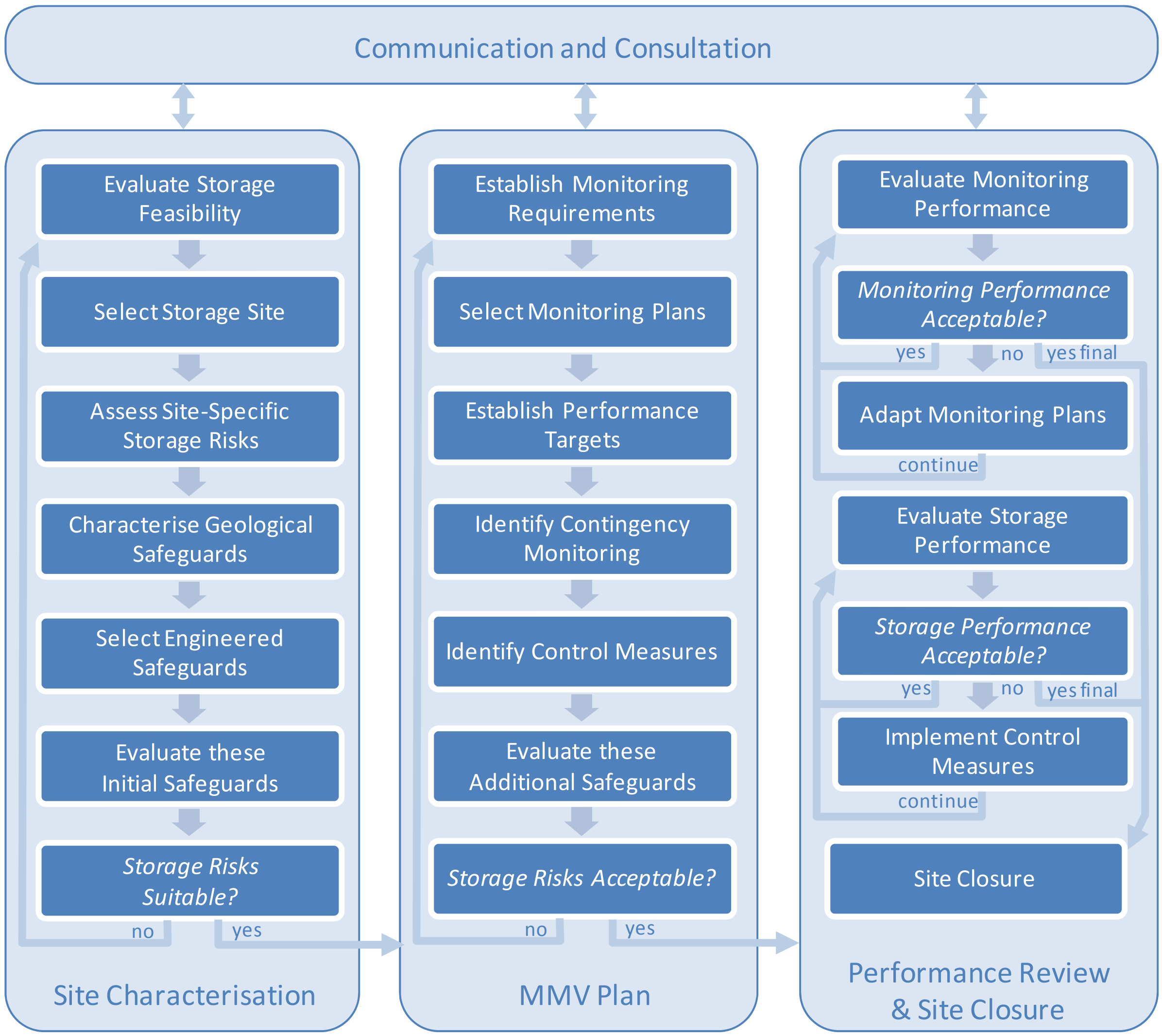

Figure 2-1: Framework for Storage Risk Management

2.1 Area of Review

MMV will operate within an AOR (Figure 1-1). The area of review as defined in Regulatory Framework Assessment (RFA) report [2] as :

The surface area within which potential adverse effects may occur due to CO_2 plume migration or pressure elevation. The purpose of the AOR is to assist the regulator and all stakeholders in assuring that sequestration risks have been appropriately managed.

- *Within the AOR the operator is obliged to show that the risk associated with any event has been reduced to an acceptable level for the proposed injection plan.*
- *Specific monitoring methodologies will be chosen to address specific risks in the area of review and may only address a subset of the total area of review.*
- *The AOR should account for geological uncertainties that impact CO_2 plume expansion or pressure elevation.*

Consistent with this definition, Shell is proposing an AOR that extends to 10 km radially from the injection wells. This is based on the perceived risk of potentially having CO_2 in the BCS reservoir at some future time. This takes into account the uncertainty in the plume radius. This is a conservative estimate based on the chart below which shows that in the high relative permeability case the plume could extend to a maximum 8 km from the injection wells (Figure 2-2a)

The pressure in the BCS is not expected to reach a level that would lift BCS brine to the ground water zone (i.e. less than 3.5 MPa) over the life of the project even at the injection wells. (Figure 2-2b). Therefore, the increased pressure does not create any risk of potential adverse effects.

The 10 km radius is shown in Figure 2-3 in relation to the expectation plume size at the end of project life.

Observed storage performance will be used to verify the size and shape of the AOR and, if necessary, the AOR will be updated as part of a revised MMV Plan submitted to regulatory agencies on a regular basis.

a. b.

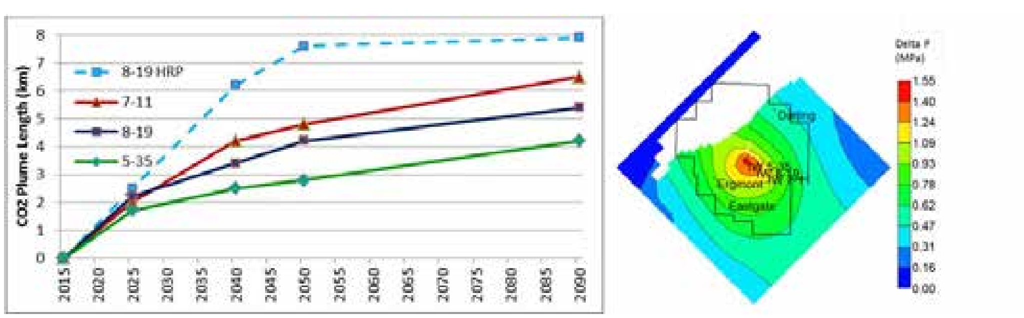

Figure 2-2: a. Maximum CO_2 plume extent per well over time and b. the BCS reservoir pressure increase at end of injection (2040)

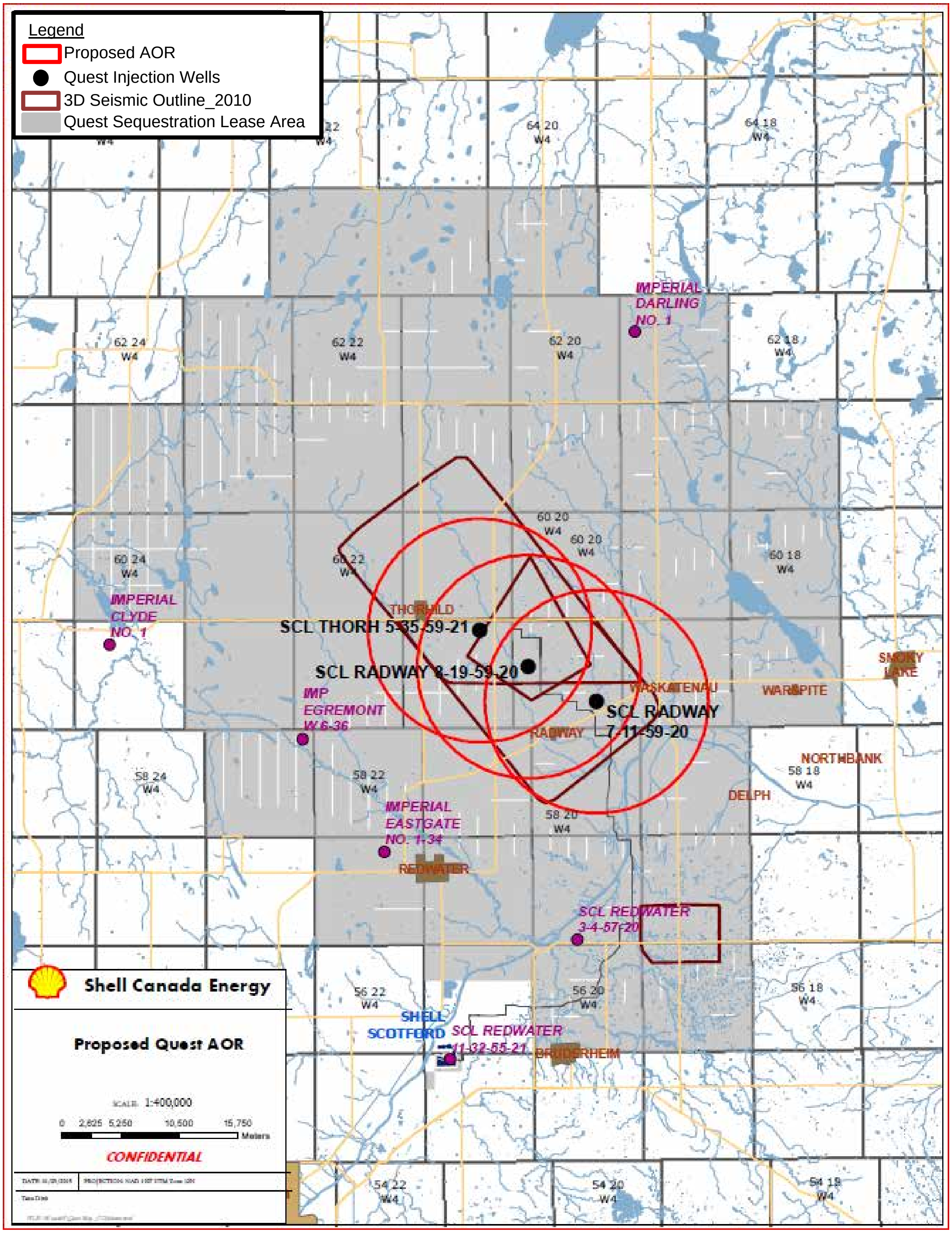

Figure 2-3: Proposed QUEST AOR (red circles)

2.2 Domains of Review

MMV will span four distinct environmental domains:

- **Atmosphere**: The local air mass where any changes to air quality matter, and the global air mass where any changes influencing climate matter.
- **Biosphere**: The domain containing ecosystems where living organisms exist.
- **Hydrosphere:** The subsurface domain which covers ground surface to base of groundwater protection (BGWP) zone. In essence, this domain covers the subsurface from ground to top of the Lea Park Formation.
- **Geosphere**: The subsurface domain below the BGWP zone including the Basal Cambrian Sands (BCS) storage complex (Figure 2-4). The geological 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 two additional deep saline aquifers, the Beaverhill Lake Group and the Cooking Lake Formation that provide potential opportunities for MMV. Proven oil resources exist within the Leduc, Nisku, and Wabamun formations and proven gas resources within the Nisku, Mannville Group, and Colorado Group.

The SLA for the Quest Project extends from the top of the Elk Point Group located just above the Prairie Evaporite to the Precambrian basement.

2.3 Timeframe of Review

MMV activities will be adapted through time to meet the different requirements during five distinct phases of the project life cycle (Figure 2-5):

Pre-Injection Phase: Monitoring tasks are identified, monitoring solutions evaluated and selected, risks are characterized, and baseline monitoring data are acquired.

Injection Phase (Full Sustained Operations): Monitoring activities are undertaken to manage conformance and containment risks, and, if necessary, are adapted through time to ensure their continuing effectiveness.

Closure Phase: In accordance with the Closure Plan, some monitoring activities will continue during this phase to manage containment risk and to demonstrate storage performance is consistent with expectations for long-term secure storage. The duration of the closure phase before transfer of liability will be determined according to the strength of evidence obtained from the monitoring program that actual storage performance conforms to the predicted performance. Site closure activities will be executed including facilities decommissioning, pipeline abandonment and reclamation, and wells abandonment and reclamation (Figure 2-5).

Site Closure: Shell will apply for a Site Closure Certificate following the execution of site closure activities. Shell anticipates receipt of a Site Closure Certificate ten years post injection cessation, provided there are no significant issues that arise from Project operations and that storage performance and CO_2 and brine containment in the BCS storage complex are demonstrated to the satisfaction of the Crown in accordance with agreed criteria.

Post-Closure Phase: Closure certificate is acquired and liability transferred from Shell to Crown. The Crown may independently elect to continue some monitoring activities for reasons such as scientific research to understand long-term storage mechanisms for CO_2 within the BCS formation.

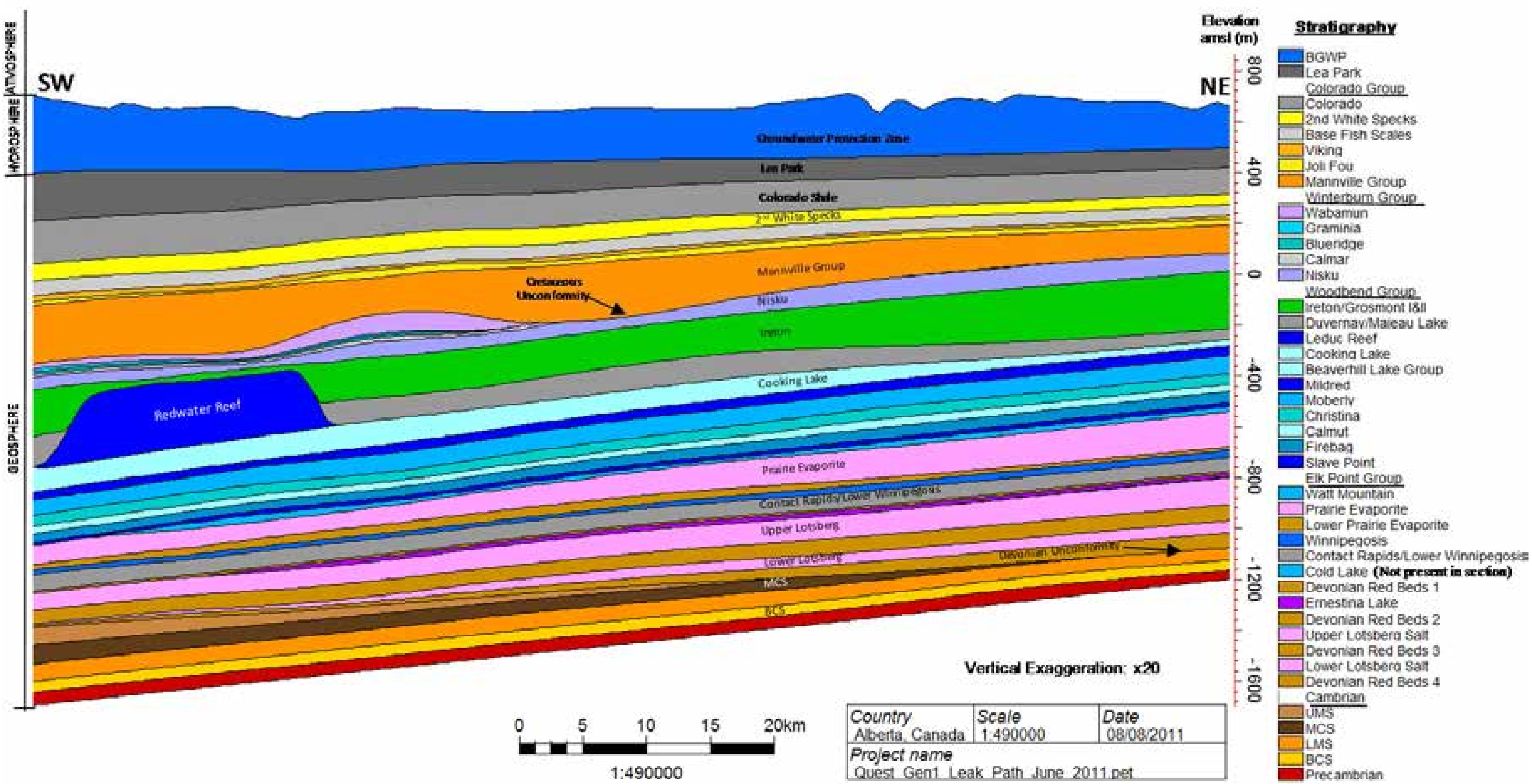

Figure 2-4: Cross section through the BCS storage complex and overlying geological formations. Figure 1-1 shows the location of this cross-section

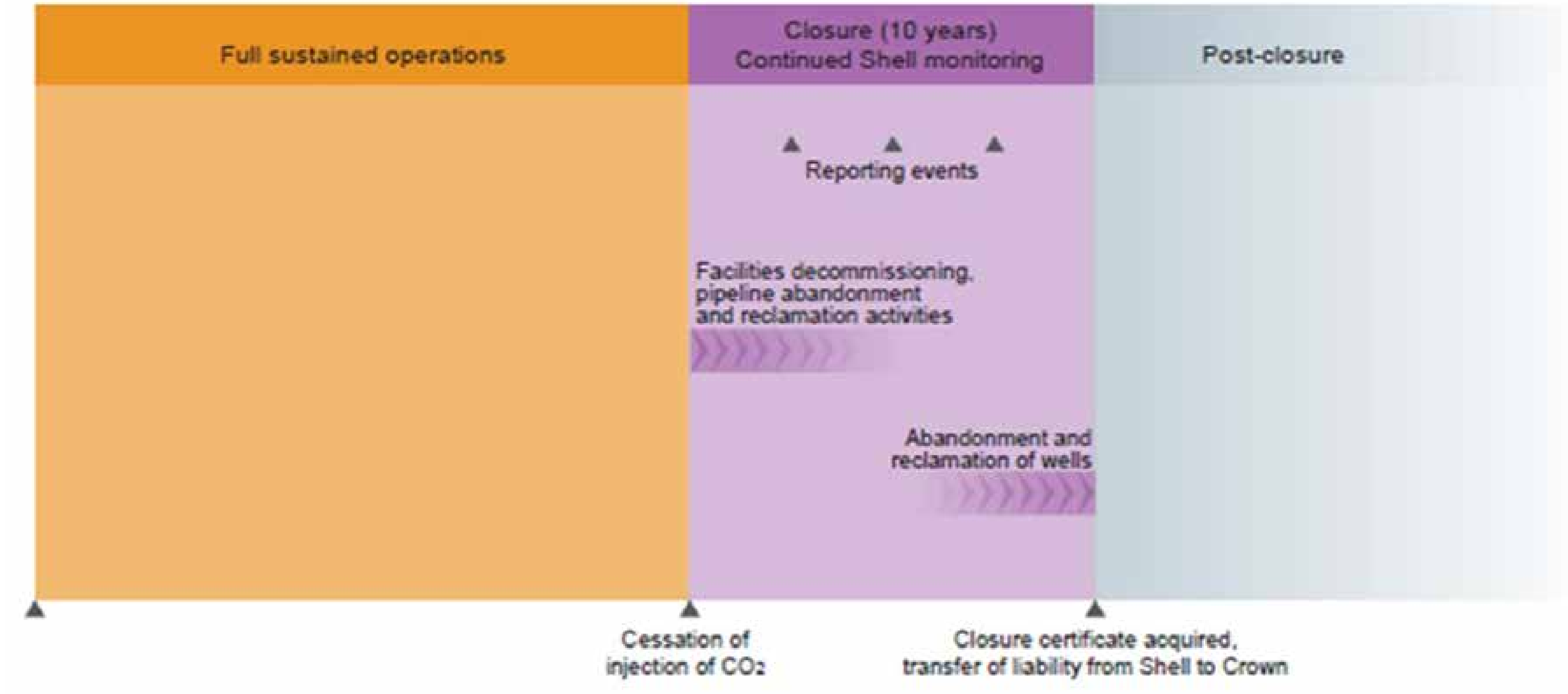

Figure 2-5: Proposed timeline for site closure activities

2.4 Timeframe of Updates

2.4.1 Alberta Energy Regulator Updates

MMV plan updates to AER will be submitted in accordance with the conditions of AER Approval 11837A received August 8, 2013 [1], ERCB Hearing Decision Report [3] and the subsequent AER Approval Conditions received by Shell December 3, 2013 in response to the October 15, 2012 pre-baseline MMV plan [4]. Summary of AER Approval 11837A Conditions relating to MMV plan updates are summarized as follows:

1) Condition 7 - Shell must provide updates of the MMV Plan as required by the AER and at minimum at critical milestones (commencement of injection, closure, and post closure) [1]. As per the December 3, 2013 Approval Condition 2 Shell must submit an MMV update on January 31, 2014[3].
2) Condition 8 – Shell must submit a complete pre-baseline MMV Plan by September 30, 2012. This condition has been completed with the final submission sent October 15, 2012 as per approved submission date change.
3) Conditions 10d and 17 - Shell must also provide annual operations reports that are aligned to the most current MMV plan and discuss any need for changes to the current MMV plan.
4) Condition 15e – Shell must provide the MMV Plan as part of the third annual status report to be submitted January 31, 2015.
5) Condition 18 – Shell must 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.
6) Condition 19 – Shell must submit a post closure report, which includes an update of its MMV plan.
7) Condition 25 – Shell must submit MMV plans referenced in Conditions 6, 7, 8, 15, 18, and 19 to Alberta Environment and Sustainable Resource Development for review – now part of AER.

2.4.2 Government of Alberta Energy Updates

According to the Carbon Sequestration Lease Approval(s) Section 2(2) (a) [5] The Lessee (Shell) shall comply with the provisions of the Mines and Mineral Act [6].

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

> *"The Minister may issue to an applicant an agreement under section 116 of the 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, and…*

Section 15 states:

> *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 [7] approved by the Minister May 27, 2011[5].

According to Section 16(1) and 19(1) of Act 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, Section 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.

2.4.3 General Updates

In both of the agreements cited in Section 2.4.2, it is understood that the MMV Plan will be adapted if necessary in response to new information gained as the project progresses from:

- Well Data
- Site-specific technical feasibility assessments
- Monitoring during the injection and closure periods

This MMV plan contains updates based on the baseline data acquisition program conducted through 2012 - 2014, the data acquired from the 2012 - 2013 drilling campaign and the results from ongoing or completed technology feasibility studies. In 2014 the BCS static and dynamic models were updated (Gen-5) to incorporate the new well data from IW 5-35 and 7-11. The results of this modelling have also been taken into account in this MMV plan update.

The next update will take place as required for the Closure Report update due on the February 27, 2017. The update will include data acquired for the initial two years of monitoring during the injection period.

3 MMV Design

3.1 MMV Design Principles

The MMV Plan is designed according to the following principles that build on guidelines published by DNV:

- **Regulatory-Compliance**: The MMV Plan will comply with regulatory requirements as they mature.
- **Risk-Based**: Monitoring tasks are identified through a systematic risk evaluation based on the collective expert judgment and validated by independent experts. The scope and frequency of monitoring tasks depend on the outcome of this risk assessment. Project safeguards are implemented to reduce storage risks to as low as reasonably practicable.
- **Site-Specific**: Monitoring technologies are selected for each monitoring task based on the outcome of site-specific feasibility assessments and then custom-designed to ensure optimal monitoring performance under local conditions particular to the storage site.
- **Adaptive**: The performance of the storage site and the monitoring systems are continuously evaluated. Contingency plans exist with clear trigger points for implementing control measures to ensure effective responses to any unexpected events.

3.2 MMV Design Process

MMV is central to the framework developed for storage risk management (Figure 2-1). There are three principle parts to this framework.

- **Site Characterization**: This is the initial risk assessment and implementation of initial safeguards through site selection, site appraisal, and engineering concept selections. The Directive 65 regulatory application describes the outcome of this process [8].
- **MMV**: This provides an additional layer of risk assessment and implements additional safeguards through monitoring to verify containment and the expected storage performance and, if necessary, trigger appropriate control measures.
- **Performance Reviews and Site Closure**: Annual performance reviews provide a continuation of the risk management process during the injection and closure phases of the project to support site closure and transfer of long-term liability. The Closure Plan, submitted to the GOA on the February 27, 2014 describes this process in detail.

The MMV design process works within this risk management framework and starts after site selection by evaluating site-specific storage risks before proceeding to implement additional safeguards supported by monitoring in the following stepwise approach.

1) **Assess site-specific storage risks**: Establish definitions for loss of conformance and loss of containment. Identify potential threats[i] and consequences[ii] associated with these risk events.
2) **Characterize geological safeguards**: Identify and appraise the integrity of each geological seal within and above the storage complex.
3) **Select engineered safeguards**: Identify and assess the engineering concept selections that provide safeguards against unexpected loss of well integrity.
4) **Evaluate these initial safeguards**: Evaluate the expected efficacy of these initial safeguards in relation to the identified conformance and containment threats, and their potential consequences.
5) **Establish monitoring requirements**: Define monitoring tasks to verify the performance of these initial safeguards and, if necessary, trigger timely control measures.
6) **Select monitoring plans**: Select monitoring technologies according to a cost-benefit ranking where benefits are judged according to how effective each technology is at each task. This includes baseline monitoring as well as monitoring during the injection and closure phases.
7) **Establish performance targets**: Evaluate the expected monitoring capabilities.
8) **Identify contingency monitoring**: Develop alternative monitoring plans to replace any under-performing monitoring system and establish clear criteria for when to implement these contingencies.
9) **Identify control measures**: Design interventions designed to reduce the likelihood or the consequence of any unexpected loss of conformance or containment. These include operational controls and updates to model-based predictions.
10) **Evaluate these additional safeguards**: Systematic evidence-based evaluation of the expected efficacy of the additional safeguards and demonstrate that storage risks are as low as reasonably practicable.

The structure of this document reflects these steps: Section 4 reviews storage risks before MMV (steps 1 to 4), Section 5 identifies the monitoring tasks (step 5), Section 0 describes the monitoring plans (step 6), Section 7 evaluates the monitoring performance targets (step 7), Section 8 provides contingency monitoring plans (step 8) and Section 9 identifies control measure and evaluates storage risk after MMV (steps 9 and 10).

[i] Possible mechanisms that could cause the occurrence of an unwanted event.
[ii] Possible adverse outcomes due to the occurrence of an unwanted event.

3.3 Influences on MMV Design

Standards for MMV are still evolving for Carbon Capture and Storage projects. The main influences on the MMV program for the Quest CCS Project are:

- The existing Alberta regulatory environment
- Continuing review of the existing global guidelines. (Appendix A).
- Continued knowledge-sharing with existing and developing projects (Appendix C).

Alberta's existing regulations for the permitting and oversight of Acid Gas Disposal projects have proved effective for more than 40 schemes involving CO_2 over the last 20 years. The AER intends to use the same processes for regulating any CCS projects in Alberta, and these may be updated by the RFA. Therefore, the Quest CCS Project MMV plan will use these existing standards as a minimum requirement and will comply with any additional requirements that may follow from the RFA process.

There are many different directives applicable to Acid Gas Disposal in Alberta. The following directives are particularly relevant for MMV as they specify requirements for measurements and monitoring.

- **Directives 7 & 17:** Specify requirements for measuring and reporting the amounts of acid gas injected.
- **Directive 20:** Specifies minimum requirements for well abandonment, testing to detect leakage and mitigation measures in the event of detecting leakage.
- **Directive 51:** Classifies injection and disposal wells according to the injected or disposed fluid and specifies design, operating, and monitoring requirements for each class of wells.
- **Directive 65**: Addresses enhanced hydrocarbon recovery, natural gas storage and acid gas disposal. For acid gas disposal projects, this directive specifies requirements to ensure confinement of the disposed fluid and its isolation. This directive also requires the applicant to prove that disposal will not affect hydrocarbon recovery.

Two existing CCS project in Canada create important precedents for MMV: the IEA GHG Weyburn-Midale CO_2 enhanced oil recovery project (EOR) in Saskatchewan and the Pembina Cardium CO_2 EOR project in Alberta.

Outside Canada, there are four notable examples of commercial-scale CO_2 injection projects with ongoing MMV activities: Sleipner and Snøhvit in Norway, In Salah in Algeria, and Rangely in the United States. See Appendix C for further details. Other commercial-scale CCS projects under development with more mature MMV plans include Gorgon in Australia and Goldeneye in the UK. There are also a number of US Department of Energy (DOE) sponsored projects which, although not on a commercial scale, have extensive MMV programs for research purposes. The Illinois Basin – Decatur Project in this category.

4 Storage Risks before MMV

This section reviews the assessment of storage risks after site selection and site characterization but before the implementation of a MMV Plan. The scope of this risk assessment includes both conformance and containment risks. The method of this risk assessment relies on an evidence-based evaluation of the potential threats and consequences and the effectiveness of safeguards in-place. To provide the necessary context for these risk assessments, we begin by describing the storage site in more detail.

4.1 Storage Site Description

The Quest storage site is bounded laterally by the approved Sequestration Lease Area (Figure 1-1) and extends from the Precambrian basement to the surface (Figure 2-4) including the following key components.

Biosphere: Land use in the area is primarily agricultural with some industrial and transportation corridors and small areas of natural vegetation.

Hydrosphere: In ascending stratigraphic order, the following units each contain locally important aquifers above the BGWP zone.

1) *Foremost Formation of the Belly River Group: About 1,550 wells inside AOR*
2) *Oldman Formation of the Belly River Group: About 1,550 wells inside AOR*
3) *Surficial Deposits: About 2,150 wells inside AOR*

Geosphere: Above the BCS storage complex, the geosphere also contains numerous additional seals and permeable formations /regional aquifers that can be considered as auxiliary storage units thus acting as additional barriers to CO_2 or BCS brine reaching BGWP zone including, in ascending stratigraphic order, the following (Table 4-1).

1) *Winnipegosis/Contact Rapids (Winnipegosis or WPGS): Regional aquifer however, very low permeability near the injection wells.*
2) *Prairie Evaporite: Major regional seal*
3) *Beaverhill Lake Group: regional aquifer therefore potential auxiliary storage*
4) *Cooking Lake: Regional aquifer that act as auxiliary storage*
5) *Leduc: Contains proven oil resources*
6) *Ireton: Major regional seal*
7) *Nisku and Wabamun Formations: Contains proven oil resources*
8) *Nisku, Mannville Group and Colorado Group: Contains proven gas resources*

The BCS Storage Complex: In ascending stratigraphic order, the BCS storage complex comprises the following formations (Table 4-2).

1) *Precambrian basement: Basal bounding formation*
2) *BCS: CO_2 injection zone*
3) *LMS: Baffle*
4) *MCS: The first major seal*
5) *Upper Marine Sand: Baffle*
6) *Lower Lotsberg Salt: The second major seal*
7) *Upper Lotsberg Salt: The third major (ultimate) seal*

Exploration and Appraisal Wells: The Project drilled two exploration wells (Figure 1-1, Table 4-3):

1) *Redwater 1AA-11-32-055-21W400 (Redwater 11-32): Exploration well located just outside the SLA. Cambrian section currently abandoned and well being used as a Nisku disposal well.*
2) *Redwater 100-03-04-057-20W400 (Redwater 3-4): Exploration well located just inside the SLA. Plan to be used as a BCS monitoring well during injection as per* Table 4-3 *below.*

Table 4-1: Geologic description of the formations above the Elk Point Group (sequestration rights). Starting at surface.

	Formation		Quest Name	Type	Composition and Depositional Environment
Hydrosphere	Quaternary		Groundwater Protection Zone	Aquifer	Pre-glacial channel fill deposits, glacial drift and other glacially derived sediments deposited above the bedrock surface.
Hydrosphere	Belly River Group	Oldman	Groundwater Protection Zone	Aquifer	Belly River Group forms the uppermost bedrock in the region, and hosts aquifers above Base Ground Water Protection (BGWP). The Oldman Formation is composed of continental deposits of inter-bedded sandstone, siltstone, shale and coal. It sub-crops beneath the SLA.
Hydrosphere	Belly River Group	Foremost	Groundwater Protection Zone	Aquifer / Aquitard	Marine and continental shale, with sandstone members forming regionally extensive aquifers. Distinctive coal-bearing zones also present (i.e. Taber coals - at top of Foremost and McKay coals - base of Foremost).. The Foremost sub-crops beneath portions of the NE and central areas of the SLA.
Geosphere Above the Winnipegosis Complex	Lea Park			Seal	Medium to dark grey shale with minor amounts of silt deposited during a marine transgression. Based on estimated depth from Top Colorado to BGWP as specified by the Alberta Government in Deep Rights Reversion, the thickness ranges from 92m to 170m thinning towards the NE.
Geosphere Above the Winnipegosis Complex	Colorado Group	Colorado		Seal	Thick, grey regional marine shale present across entire SLA with an average thickness of 134m.
Geosphere Above the Winnipegosis Complex	Colorado Group	2nd White Specks		Gas Reservoir & Seal	Calcareous mudstone deposited in a marine setting. The uppermost ~5m of the Second White specks is represented by a thin sandstone layer that is a gas reservoir in the central part of the SLA reaching porosities of up to 8%. The average thickness in the SLA is 67m.
Geosphere Above the Winnipegosis Complex	Colorado Group	Base Fish Scales		Seal	Abundant fish remains within finely laminated, generally non-bioturbated sandstone, siltstone and shale. Within the SLA it is predominantly shale averaging 50m.
Geosphere Above the Winnipegosis Complex	Colorado Group	Viking		Oil and Gas Reservoir	Derived from Cordilleran erosion in the West. In the western portion of the SLA it is shallow shelf deposits with dominantly sandstone to the West and shale dominating towards the East. There is Viking Production in the SLA (Oil in the SW corner only) in a thin 2m sandstone at top of section that reaches porosities of 20%. Viking thickness averages 14m.
Geosphere Above the Winnipegosis Complex	Colorado Group	Joli Fou		Seal	Dark grey, non-calcareous marine shale with minor inter-bedded fine to medium grained sandstone deposited unconformably on top of the Upper Mannville. Major flooding surface that covered most of WCSB averaging a thickness of 21m.
Geosphere Above the Winnipegosis Complex	Upper Mannville	Upper Mannville	Mannville Group	Baffle	Upper Mannville is predominantly shale with grey silt inter-bedded with fine-grained, moderately sorted, silty, sandstone with local coal seams deposited as part of a prograding deltaic sequence with sediment transport towards the N-NE transitioning upward to be more fluvial in nature. There is porosity within the sandstones portion of this heterogeneous interval. Exists across the entire SLA.
Geosphere Above the Winnipegosis Complex	Upper Mannville	Glauconitic Sandstone	Mannville Group	Gas Reservoir	Inter-bedded shale, siltstone, and fine-grained sandstones. The sandstones range from glauconitic to salt-and-pepper. Absent in the very N-NE of the SLA as the Wainwright Highlands were finally covered. Gas Production in the SLA, predominantly to the SW half of the SLA.

	Formation			Type	Composition and Depositional Environment
	Lower Mannville	Ostracod Zone		Baffle	Inter-bedded fine clastics and limestone. Predominantly composed of shale, siltstones and lenticular sandstones with locally occurring limestone representing deposition in a low-energy, brackish, subaqueous environment. Minor patchy porosity associated with sand lenses. Absent towards the NE of the SLA along the Wainwright Highlands (Devonian).
	Lower Mannville	Ellerslie		Gas Reservoir	Fluvial deposit of fine to medium grained quartz with chert sandstone with fairly good porosity deposited in the Edmonton Valley likely under brackish water conditions. Sediment transport towards the N-NW. Gas Production in SLA. Absent towards the NE of the SLA along the Wainwright Highlands (Devonian). Thickness of the Ellerslie inside the SLA reaches a maximum of 90m, depending on the unconformity and the presence of channel sands.
	Winterburn Group	Wabamun		Gas Bearing	Characterized by Dolomite, brown, finely crystalline, porous in part; with subsidiary inter-beds of brown, micritic, pelloidal limestone. Only exists in the W-NW half of the SLA due to erosion by the sub-cretaceous unconformity. However, there is some gas production within the SLA. Thickness ranges from 0m to 100m.
	Winterburn Group	Graminia		Baffle	A silt unit at the top of the Winterburn. Exists predominantly in the W-NW of the SLA. Thin and patchy across the rest of the SLA due to irregularities in the Pre-Cretaceous unconformity.
	Winterburn Group	Blueridge		Gas Bearing	Last widespread carbonate cycle in Western Canada. Exists predominantly in the W-NW of the SLA. Exists predominantly in the W-NW of the SLA. Thin and patchy across the rest of the SLA due to irregularities in the Pre-Cretaceous unconformity. Has some minor porosity within the SLA. Production in the Eastern part of the SLA commonly mislabeled as Wabamun Production.
	Winterburn Group	Calmar		Baffle	Predominantly silts and clays likely the result of reworking of the underlying lowstand Nisku siliciclastics. Exists predominantly in the W-NW of the SLA. Thin and patchy across the rest of the SLA due to irregularities in the Pre-Cretaceous unconformity.
	Winterburn Group	Nisku		Oil and Gas Reservoir	A mixed carbonate-siliciclastic deposited during a lowstand. Within the SLA the Nisku is a porous light brown to light grey crystalline dolomite with lesser amounts of brownish grey dolomitic siltstones, green shale and anhydrite. It is commonly truncated by the pre-Cretaceous unconformity. Within the AOl oil production is only above and to the West of the Redwater reef, some minor gas exists in the NE portion of the SLA. The Nisku has a relatively constant thickness of the SLA at 57m.
	Woodbend Group	Ireton	Ireton / Grosmont I&II	Seal	Only the Lower Ireton exists in the SLA represented by a cyclic succession of basin filling shale considered to be a regional aquitard. The Lower Ireton is thin on top of the Leduc Reefs (~10m) and thickens to an average of 160m away from the reef. Grosmont Carbonates begin to appear within the Upper part of the Ireton to the East of the SLA.
	Woodbend Group	Duvernay		Seal	Grades from bituminous rich shale to a shale to a dolomite towards the NE of the Basin. Within the SLA represented by dark brown shale and limestones to the west and as you move towards 8-19 it is predominantly tight argillaceous limestone with shale interbeds. Relatively uniform thickness across basin (~160m) except it is absent over the Leduc Reefs.
	Woodbend Group	Leduc		Oil Reservoir	Within the SLA is the Redwater Reef and the Morinville Reef trend associated with the Rimbey-Arc. The Morinville reef trend is a tight dolomitic structure except for a localized field just west of the Redwater reef called the fairydell-Bon Accord Field. In contrast, the Redwater pinnacle reef is a major oil producing limestone and the focus for this study.
	Woodbend Group	Majeau Lake		Seal	In the SLA only the Lower Majeau Lake is present. Characterized by greenish grey and dark brown shale that are time equivalent to the Cooking Lake (West of and underlying the reef chain). Only exists to the

					West of the SLA.
		Cooking Lake		Inter-mediate Aquifer	Major regional aquifer made up of extensive sheet like shelf carbonates and an equivalent basin-fill shale (Majeau Lake). Consists of pelloidal and skeletal limestones (bracs, crinoids, stromatoporoids, and bryzoans). Unlike most younger Woodbend carbonates it is predominantly undolomitized (except directly under the Leduc-Homeglen-Rimbey-Meadowbrook reef chain). The SLA is at the intersection of all three facies. There is a sharp edge to the West of the reef chain where the Cooking lake is non-existent, replaced by Majeau Lake, it is thickest under the reefs and then thins to the NE.
	Beaverhill Lake Group	Waterways	Mildred	Baffle	The Firebug, Calmut, Christina, Moberly and Mildred Members make up the Waterways Formation deposited during a regressive basin fill phase of the Waterways Basin. Composed of a series of shallowing upwards shale-carbonate clinothem cycles deposited in a basin slope depositional setting. Each cycle is composed of a shale base that grades vertically to argillaceous carbonate. The Waterways and Slave Point are combined to form the Beaverhill Lake Group Aquifer System.

Table 4-2: Continuation of geological descriptions over zones included in the Quest Sequestration Lease rights of with focus on the BCS storage complex.

	Formation		Quest Name	Type	Composition and Depositional Environment
WPGS Monitoring Complex	Elk Point Group	Watt Mountain		Seal	Top of the Elk Point Group represented by thin (10 m to 40m) green/greyish shale with thinly inter-bedded limestone units that overlie the sub-watt mountain unconformity. It is absent to the west and North of the study area because it is commonly mapped as part of the Muskeg Fm. which is equivalent to the Prairie Evaporite.
		Prairie Evaporite		Ultimate Seal WPGS Complex	Regional Seal for the WPGS complex. The Prairie Evaporite is predominantly halite with thin anhydrite layers in middle and at base. There is a marked increase in dolomite and shale laminae near the base of the Formation. Within the SLA, the Prairie Evaporite increases in thickness from 80m to 145m towards the NE and acts as a regional aquiclude. There are no known hydrocarbons below this point within the SLA.
		Winnipegosis		Regional Aquifer	Fossiliferous carbonates decreasing in thickness towards the SE grading into the silty/sandy dolostone of the underlying Contact Rapids. The Winnipegosis-Contact Rapids regional aquifer is the first regional aquifer above the BCS storage complex. However, it has very low permeability near the Quest injection wells.
		Contact Rapids	Contact Rapids/ Lower Winnipegosis	Regional Aquifer / Baffle	Correlation between the Contact Rapids and overlying Winnipegosis is poorly defined within the region and are therefore treated as one Regional aquifer. Within the heart of the SLA Contact Rapids is characterized by porous dolostone that transitions towards the basin edges to a grey to green, argillaceous dolomite and dolomitic shale, and towards the base of the section it grades to red shale. The porous intervals are referred to here as the Lower Winnipegosis. In the SLA there is good porosity within this zone as it is predominantly dolomite.
		Cold Lake		Seal	Thin halite interval represented in the far eastern portion of the Quest SLA. Where it exists, it acts as an additional seal. In central Alberta it grades westward into red, dolomitic shale overlying the Ernestina Lake Formation which for this study was included in the Contact Rapids Formation.
		Red Beds	Devonian Red Beds 1	Baffle	Devonian Red Beds confined to the Central Alberta Sub-Basin characterized by a thin 10m red dolomitic shale that merges at the basin margins with the other Devonian Red Beds. Commonly stratigraphically described as the part of the Cold Lake Salts.
		Ernestina Lake		Baffle	Anhydrite, light grey at top, underlain by light grey-brown, crypto-to-micro-grained limestone, locally anhydritic with salt plugged porosity.
		Red Beds	Devonian Red Beds 2	Baffle	Devonian Red Beds confined to the Central Alberta Sub-Basin characterized by a thin, maximum 11m red dolomitic shale that merges at the basin margins with the other Devonian Red Beds. Only occurs in the lows of the underlying Lotsberg Salt. Equivalent to Elk Point Group, Member 6 in the CSPG Western Canadian Lexicon.
BCS Storage Complex		Lotsberg	Upper Lotsberg Salt	Ultimate Seal	Almost pure halite that acts as an aquiclude, ranging in thickness from 53m to 94m across the SLA and thickening to 150m up-dip, NE of the SLA in the Central Alberta Sub-Basin.
		Red Beds	Devonian Red Beds 3	Baffle	Devonian Basal Red Beds confined to the Central Alberta Sub-Basin. Basal Red Bed intervals exist between and below the Lotsberg Salts, merging at the basin margins together with the Devonian Red beds above. Brick red dolomitic or calcareous silty shale that grade downwards through to red sandy shale into greenish fine to coarse grained quartzose sandstone.
		Lotsberg	Lower Lotsberg Salt	2nd Major Seal	Almost pure halite that acts as an aquiclude, ranging in thickness from 9m to 41 across the SLA and thickening to 60m up-dip, NE of the SLA in the Central Alberta Sub-Basin.

		Red Beds	Devonian Red Beds 4	Baffle	Devonian Basal Red Beds confined to the Central Alberta Sub-Basin. Basal Red Bed intervals exist between and below the Lotsberg Salts, merging at the basin margins together with the Devonian Red beds above. Brick red dolomitic or calcareous silty shale that grade downwards through to red sandy shale into greenish fine to coarse grained quartzose sandstone. This is the base of the Elk Point Group.
	Upper Deadwood		Upper Marine Silts	Baffle	Flow baffle composed of greenish shale and minor silty and sandy interludes deposited in the offshore shelf in response to either an increase in sediment supply or a relative sea level fall. Absent in the Eastern part of the SLA due to the Pre-Cretaceous unconformity.
	Lower Deadwood		Middle Cambrian Shale	1st Major Seal	The first major seal composed of shale deposited in an offshore shelf environment associated with continued flooding of the basin. Present across the entire SLA ranging in thickness from 21m to 75m. The MCS is absent due the Pre-Cretaceous unconformity just to the NE of the SLA.
	Earlie		Lower Marine Sands	Baffle	Regional flow baffle created by these transgressive, heterogeneous subtidal clastics representative of transition from marginal marine sediments of the BCS to the more distal environment of the MCS above. Present across the entire SLA.
	Basal Sandstone		Basal Cambrian Sands	CO2 injection zone	The BCS is transgressive sheet sand, deposited in a tide dominated bay margin that acts as a basin-scale saline aquifer. Existing data internal and external to Shell indicates the BCS saline aquifer has suitable injectivity, capacity, and containment for CO2. The BCS is the primary target for the potential CO2 storage operation.
	Precambrian Basement			Basal Bounding Formation	Cratonic basement on which the BCS unconformably lies on top of. Considered an aquiclude.

Injection Wells and Monitoring Wells: The Storage Development Plan allowed for the phased development of up to eight injection wells (Table 4-3). The base case development plan is now three injection wells at start-up with contingency plan to increase to eight if deemed necessary to meet approved injection targets. Note that groundwater monitoring wells starting with “UL” are unlicensed wells that are less than 150 m total depth.

Legacy Wells: Figure 1-1 and Appendix D describe the legacy wells within the SLA.

1) *BCS wells: Four abandoned wells penetrate the BCS inside the SLA.*
2) *Lotsberg wells: There are no legacy wells that penetrated the entire Lotsberg Salt inside the AOR other than the BCS legacy wells described above.*
3) *Winnipegosis wells: Two abandoned wells penetrate down to the Winnipegosis Formation inside the SLA with partial penetrations of the Upper Lotsberg Formation.*
4) *Viking wells: More than 3000 active and abandoned wells penetrate down to the Viking Formation inside the SLA.*
5) *Groundwater wells: Available records indicate there are more than 5300 wells drilled and completed within the groundwater protection zone.*

Table 4-3: Pad and Well UWIs for Quest injection and monitoring wells.

Pad	UWI	Well Type	Well Name in Report	TD Formation
N/A	1AA/11-32-055-21W400	Appraisal (Abandoned)	Redwater 11-32	Precambrian
03-04-057-20W4	100/03-04-057-21W400	Appraisal (suspended)	Redwater 3-4	Precambrian
08-19-059-20W4	100/081905920W4/00	Injection	IW 8-19	Precambrian
	102/081905920W4/00	Deep Monitoring	DMW 8-19	Ernestina Lake
	1F1/081905920W4/00	Groundwater	GW 1F1/8-19	Lea Park
	UL1/081905920W4/00*	Groundwater	GW UL1/8-19	Foremost
	UL2/081905920W4/00*	Groundwater	GW UL2/8-19	Foremost
	UL3/081905920W4/00*	Groundwater	GW UL3/8-19	Foremost
	UL4/081905920W4/00*	Groundwater	GW UL4/8-19	Oldman
05-35-059-21W4	102/053505921W4/00	Injection	IW 5-35	Precambrian
	100/053505921W4/00	Deep Monitoring	DMW 5-35	Ernestina Lake
	1F1/053505921W4/00	Groundwater	GW 1F1/5-35	Lea Park
	UL1/053505921W4/00*	Groundwater	GW UL1/5-35	Foremost
07-11-059-20W4	103/071105920W4/00	Injection	IW 7-11	Precambrian
	102/071105920W4/00	Deep Monitoring	DMW 7-11	Ernestina Lake
	1F1/071105920W4/00	Groundwater	GW 1F1/7-11	Lea Park
	UL1/071105920W4/00*	Groundwater	GW UL1/7-11	Foremost

4.2 Initial Conformance Risks

4.2.1 Loss of Conformance Definition

A loss of conformance exists if:

- The observed distribution of CO_2 and pressure build-up inside the storage complex does not agree with model-based predictions within the range of uncertainty; or
- Knowledge of the actual storage performance is insufficient to distinguish between two classes of possible future performance: those that result in permanent stable storage of the target mass of CO_2 inside the BCS storage complex, and those that do not.

These criteria are taken from the agreed Closure Plan.

4.2.2 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 negative consequences:

- **Cost of additional monitoring** activities required to re-establish conformance
- **Delay in site closure** until long-term storage risks are understood to be acceptable
- **Loss of storage efficiency** if CO_2 plumes spread further than expected

4.2.3 Potential Threats to Conformance

There are two potential threats that may cause a loss of conformance:

- **The original models are wrong** due to unexpected geological heterogeneities, or incorrect representation of the physical or chemical processes governing fluid transport, or insufficient analysis of uncertainties within the models
- **The monitoring is wrong** due to an unrecognized bias in the acquisition, processing, or interpretation of monitoring data.

4.2.4 Initial Safeguards to Ensure Conformance

Prior to implementing MMV, several safeguards are already in-place to reduce the likelihood or consequence of any unexpected loss of conformance. These safeguards include:

- **Basin-scale screening** studies ranked the top opportunities for geological storage of CO_2 in Canada. Selecting a site within the top-ranked region minimizes the risk of complex geology causing unpredictable storage behaviour.
- **Site selection** was based on a feasibility study of the pre-existing appraisal data to reduce the likelihood of insufficient injectivity, capacity or containment.
- **Site characterization** based on a dedicated and comprehensive appraisal program including 2D and 3D surface seismic data, two appraisal wells and three injection wells drilling to the basement, three deep monitoring wells and nine shallow ground

water wells. Five generations of modelling have been concluded for the BCS injection zone as new data was acquired.

The residual risk associated with the possibility of all these independent safeguards failing is judged to be *low* (Table 4-4).

Table 4-4: Classifications for describing the likelihood of an event.

Very Low	Low	Medium	High	Very High
0-5% Occurs in almost no projects (extremely unlikely)	5-20% Occurs in some projects (low but not impossible)	20-50% Occurs in projects (fairly likely)	50-80% Occurs in most projects (more likely than not)	80-100% Expected to occur in every project (almost certain)

4.3 Initial Containment Risks

4.3.1 Loss of Containment Definition

Containment means that the injected CO_2 and the native BCS brine remain inside the storage complex. Consequently a loss of containment is defined 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.

This is a natural choice as it represents the top of the BCS storage complex. Prior to this event, the migrating fluids remain inside the intended geological formations. After this event, consequences due to loss of containment may arise if fluid migration continues upwards uncontrolled. Therefore, the MMV plan focuses on providing verification of containment and an early detection of any loss of containment.

4.3.2 Potential Consequences Due to a Loss of Containment

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

- **Hydrocarbon resources affected** 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 reduce the effectiveness the Project's contribution to climate change mitigation.

4.3.3 Potential Threats to Containment

There are nine potential threats to containment identified and explained detail in Section 4 of the MMV Plan. Each are considered highly unlikely but are, in principle, capable of allowing CO_2 to migrate upwards out of the BCS storage complex.

Evaluation of data from the 2012 – 2013 drilling campaign and the most recent GEN -5 modelling of the BCS has confirmed that the pressure increase in the BCS will not reach a level sufficient to lift BCS brine to the BGWP zone even at the injection wells (Third Annual Status Report: Section 5.3.1). Therefore, there is no risk of brine leakage impacting groundwater unless there is a severe loss of conformance. BCS pressure monitoring will be used to ascertain if there is a loss of conformance that would give rise to a potential threat related to brine leakage far in advance of any impact above the storage complex. At that time, MMV plans would be updated appropriately.

Even if there was sufficient pressure, dynamic leak path modelling indicates that due to the pressure depletion of the Cooking Lake Formation, as well as flow into other deep aquifers, BCS brine cannot reach the BGWP zone unless it flows along an open migration pathway unconnected to the Cooking Lake Aquifer.

The potential risk events that could lead to loss of containment are summarized as follows:

1) **Migration along a legacy well:** Due to an insufficient number, thickness, and depth of cement plugs placed during abandonment or their subsequent degradation through time or a behind casing leak path that was not remediated before abandonment.

   Risk Assessment:

   The probability of legacy wells being intersected by the CO_2 plume is very low.

   - In the Quest SLA, there are four legacy wells that penetrate through all seals in the BCS storage complex with the closest one to an existing injection well located 18 km away. This is more than three times the distance the CO_2 plume is expected to extend. Taking into account the main uncertainty of relativity permeability this still more than twice the distance the plume could extend with the high relative permeability case (Figure 2-3). Therefore, there is no risk of CO_2 leakage at these wells unless there is a severe loss of conformance.
   - The status and condition of existing wells penetrating the BCS has been reviewed from multiple data sources. There are no known issues with legacy well integrity other than the uncertainty that arises from the age of the cement plugs and the inability to pressure test old cement plugs. The following barriers are in place in the BCS legacy wells:
     - Multiple cement plugs of significant length at various intervals
     - Open hole abandonment across the salt allows for the opportunity for hole closure by salt creep
     - Impermeable plugs may have formed through settlement of solids out of drilling mud in the well bore
   - BCS plume monitoring will be used to ascertain if there is a loss of conformance which would give rise to a potential threat to containment associated legacy wells far in advance of any impact above the storage complex. At that time, MMV plans would be updated appropriately.
   - Use of the BCS injection wells as monitoring wells for the project life to monitor pressure build-up and interference will ensure reservoir pressure are not high

enough to raise brine to the base of groundwater protection long before a potential problem arises.

2) **Migration along an injection well** due to a poor or subsequently degraded cement bond or corrosion of the casing and completion

Explanation:

Any well injecting CO_2 into the storage complex creates a threat to containment as it punctures the geological seals directly above the CO_2 plume. Any loss of external or internal well integrity will potentially allow migration of CO_2 and BCS brine out of the storage complex. This threat may arise for any of the following five reasons.

- **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.
- **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.
- **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 interventions:** During the course of normal operations, routine well interventions may result in loss of well control.
- **Compromised abandonment:** Injection and observation wells will be properly abandoned prior to site-closure. Undetected flaws in the design or execution of well abandonment or subsequent degradation of materials may allow upwards migration of fluids.

Risk Assessment:

The risk of leakage from the storage complex along a leakage pathway in the injection wells is considered very low. However, in 2014 Shell contracted an independent external review of the integrity of the injection wells and an associated update of the leakage risk assessment for the Quest Project injection wells to ensure that Shell’s risk assessment, with the below information included, is still appropriate. The report of the independent external review was received on September 22, 2014 and was submitted to the AER with the D51 application for IW 5-35 and 7-11 on the October 16, 2014.

- The evaluation of the cement bond in all injection wells both behind 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) with the exception of IW 5-35. At IW 5-35, a poor bond has been interpreted across the MCS which could extend into the LMS baffle below. The poor bond is interpreted from 1891 m MD (below the lower Lotsberg Salt) down to a depth of 1967 m MD which was the total depth to which the log was acquired. The casing shoe is set at 2004 m MD and the top of the LMS is at 1988 m MD. There is 50 m of good cement from the top of the BCS to the intermediate casing shoe which provides an effective isolation of the BCS. Regardless, the good cement across the Lotsberg Salts provides isolation of the BCS storage complex.

- The excellent cement bond over the all three seals in IW 8-19 and 7-11 is supported by the conclusion of the Independent Review. Quoted from the Independent Review Report:

  "Cement maps of the wells were collected with the USI ultrasonic imager when the wells were constructed. The logs contain cement maps and cement bond information that was used to categorize each cemented annulus into poor, questionable, and good zones. Each of the wells appear to have sufficiently competent cement from the basal Cambrian sand (BCS) to well above the upper marine siltstone (UMS) to provide isolation of the long string from injected CO_2. SCL Radway 8-19-59-20 and SCL Radway 7-11-59-20 have good intermediate cement between the bottom of the logs to above the reservoir seals".*

- Schlumberger also recognize the cement bond issue across the MCS in IW 5-35 and designated this as falling in their "questionable" category. Quoted from the Independent Review Report:

  "Cement maps of the wells were collected with the USI ultrasonic imager when the wells were constructed. The logs contain cement maps and cement bond information that was used to categorize each cemented annulus into poor, questionable, and good zones. Each of the wells appear to have sufficiently competent cement from the basal Cambrian sand (BCS) to well above the upper marine siltstone (UMS) to provide isolation of the long string from injected CO_2. SCL Radway 8-19-59-20 and SCL Radway 7-11-59-20 have good intermediate cement between the bottoms of the logs to above the reservoir seals. SCL Thorhild 5-35-59-21 shows questionable cement in the intermediate casing from the bottom of the log at 1975 m through the UMS to the second seal (1887 m) where there is a zone of good cement".*

  In the Quest Project, Surface Casing Vent Flows (SCVFs) and Gas Migrations (GMs) were detected and reported to AER in IW 5-35 and IW 7-11. Upon further review, IW 8-19 was also determined to have a SCVF. Analytical results from data acquired in both Q2 2013 and 2014 show that the SCVFs and GMs are independent of each other and that the GMs originate from the ground water zone while the SCVFs originate just below the surface casing (shallow source < 200 m depth). Due the shallow depth of the source of the SCVFs and GMs, these minor leaks to surface are not considered a threat to containment and isolation of the BCS storage complex.

- The independent review confirms the interpretation of the isotope data and the sources of the SCVFs and GMs. Quoted from the report:

  "Carbon isotope and hydrocarbon concentration data were collected during drilling and collected from the wells with GMs and SCVFs. These data were used to help establish the source zones for the gas samples collected since completion. The results of data comparisons of the GM and SCVF data to data collected during drilling imply that the GM gas sources in both wells are behind the surface casing and the SCVF sources are not far below the bottom of the surface casing"

3) **Migration along a deep monitoring well:** Any such wells drilled into the BCS storage complex pose a threat similar to the injection wells.

Risk Assessment:

This is risk is currently considered very low because:

- All deep monitoring wells drilled to date, in the vicinity of the injection wells, terminate above the Ultimate Seal with the goal to detect CO_2 or brine migrating above the BCS storage complex
- It is noted here that this risk would increase in the event that Shell is required to drill additional monitoring wells in the BCS as per AER approval 11837A Conditions 10i and 10j [1]. Those wells would have the same risk factors as injection wells described above.

4) Migration along a rock matrix pathway due to unexpected changes in the depositional environment or erosional processes.

Risk Assessment:

The careful site selection process for the Quest SLA was used to optimize the presence of natural barriers. In addition, the 3D surface seismic survey as well as subsurface static models created based on well and core data were used to show that as far as the data indicates there are no such migration pathways for CO_2 or brine to escape the BCS storage complex. This is the result of an extensive BCS reservoir, a thick heterogeneous baffle in the LMS that has negligible vertical permeability as well as the three thick regional seals (MCS, Lower an Upper Lotsberg salts) that all extend beyond the SLA showing no discontinuities on 3D or 2D seismic data.

Nonetheless, although the probability is very low, permeable pathways could exist as sedimentary processes may sometimes result in complex heterogeneities that interconnect to allow fluids under pressure to migrate up and out of the storage complex.

5) **Migration along a fault** that extends out of the BCS storage complex and provides a permeable pathway

Risk Assessment:

The risk of migration along a fault is considered low due to the following evidence:

- Faults exist as discontinuities over a range of length-scales in many rock formations. However, large faults that transect regional scale geological seals within the Quest SLA of the Alberta Basin are rare (more than 100 km separates the Snowbird Tectonic Zone from the Hay River Shear Zone to the north).
- There is no evidence of faults with throws greater than 15 m crossing the seal complex from 2D and 3D seismic data covering the full SLA. The 2D seismic data

spans the entire SLA with an approximate 3 km spacing and 435 km^2 of 3D seismic data is available over the central portion of the SLA (Figure 1-1).

- There is a period of approximately 1.5 billion years between the granite and the deposition of the BCS. Therefore, it is unlikely that any Precambrian faults were active in the BCS time of deposition.
- Even when present, many faults are sealing and retain fluids under pressure over geological time-scales.
- Mechanisms associated with fault slip, such as clay smear and cataclysis, reduce permeability within the fault zone. Other mechanisms, such as dilation and fracturing may enhance fault permeability.

6) **Induced stress re-activates a fault** creating a new permeable pathway out of the BCS storage complex.

Explanation:

Any pre-existing sealing faults may re-activate due to stress changes induced by CO_2 injection. Effective normal stresses will decrease and may de-stabilize any pre-existing weak fault. In addition, shear stress loading these faults will increase or decrease depending on the fault orientation and the sense of residual shear stress held on the fault due to friction. Any decrease in shear stress will stabilize the fault making re-activation less likely and vice versa.

Renewed fault slip might increase local permeability by dilation or fracturing within the fault damage zone and perhaps allow the fault to propagate upwards. Equally likely is a reduction of permeability due to clay smear or cataclysis along the fault surface.

Risk Assessment:

In line with the very low likelihood of the presence of faults intersecting either the BCS or any of the seals in the storage complex, there is a low likelihood of fault reactivation.

- The SLA is not an area of active natural seismicity. There has been a regional seismic monitoring network in place for more than 80 years with a capability of detecting a moment magnitude (Mo) 3 event within the SLA. None were detected over this period as indicated by the Alberta Geological Society Tectonic activity map for Alberta: http://www.ags.gov.ab.ca/geohazards/earthquakes.html.
- A microseismic array was installed in IW 8-19 on the November 7, 2014 and to date has not recorded any seismic events in the Quest SLA.
- The Lotsberg salts are ductile and expected to creep and reseal any unexpected small faults

7) **Induced stress opens fractures:** Increased pressures and decreased temperatures may initiate fractures that propagate vertically to create a new permeable pathway out of the BCS storage complex.

Explanation:

CO_2 injection may induce open fractures due to pore fluid pressure increase and temperature decrease inside the BCS aquifer close to the well. Occurrence of any such fracturing does not constitute a threat to containment. In order for fluid flow these fractures would need to:

- Propagate upwards sufficiently to transect the geological seals and
- Remain at least partially open to provide an enduring permeable pathway.
- Connect with a formation with a large enough horizontal permeability and net sand to permit material flow rates.

Risk Assessment:

The risk of inducing fractures in the Quest Project is low according to the Gen-4 modelling results. The expected reservoir pressure will be less than 23 MPa at the end of project life which is only 12% of the delta pressure required to exceed the BCS fracture extension pressure.

8) **Acidic fluids erode geological seals**: Injected CO_2 will acidify formation fluids which may react in contact with geological seals to locally enhance permeability within the seal

Explanation:

Injected CO_2 will acidify formation fluids in contact with geological seals. Depending on the mineralogy of the seals there is potential for many different chemical reactions to occur. Many of these reactions yield products that occupy a greater volume and will most likely reduce permeability; but the converse is also possible. For acidic fluids to erode geological seals, minerals must be present that react, and these reactions must increase not decrease permeability.

Risk Assessment:

Based on the regional geology, the choice of using three regional seals for the storage container and results of geochemical modelling and core analysis the risk of acidic fluids eroding geological seals is very low based on the following data:

- There are three regional seals and a series of baffles that are over 350 m thick from the top of the perforations to the top of the ultimate seal (Upper Lotsberg Salt) that would need to be eroded for acidic fluids to escape the BCS storage complex
- The secondary and ultimate seals, the Upper and Lower Lotsberg salts respectively, comprise greater than 90% pure halite. Salt is not known to be affected by the acidity of the formation brine. The BCS brine is already salt saturated and unable to dissolve significant volumes of salt.

The Quest Project used geochemical reactive transport modelling (RTM) and lab experiments to assess this risk and the results indicate that the MCS (the primary seal) is a very good seal:

- Reactive Transport Modelling (RTM) of CO_2 flow at the LMS/ MCS interface, via a hypothetical fault through the LMS, results in dissolution of carbonate minerals, felsic minerals, and precipitation of clay minerals. The rate of dissolution and precipitation stays slow and impacts on rock properties are negligible unless open conduits such as permeable fractures/ faults are assumed to exist. In that case, CO_2 can break through and dry out the conduit leading to precipitation of salt from evaporating brine initially in the conduit as well as from brine replenishment from the rock matrix through diffusion. Ultimately, in the RTM modeled case of a hypothetical faults/ fracture pathway through the LMS, the open conduits are eventually sealed up by salt precipitation.
- Independent core analysis results for MCS capillary entry pressure also support the RTM conclusion that carbonate minerals precipitate in the MCS based on the entry pressure experiment in which supercritical CO_2 was placed in immediate contact with the MCS under the reservoir pressure. The experiment illustrates that:
    - The capillary entry pressure of the MCS is very high (higher than 999 psi, the top constrained pressure of the experiment) indicating that the MCS is a good seal
    - The micro cracks in the core sample which were induced during handling were blocked (partially or fully) by salt precipitation during the experiment which was confirmed by elemental mapping on the SEM images. This is consistent with TOUGHREACT modelling which showed that salt precipitation can plug any natural fractures in the seal. Note that there is no evidence of any natural fractures in the MCS.
    - Diffusion of CO_2 takes place, leading to mineralogical alteration in the core sample and precipitation of calcite which could further improve sealing capacity

9) **Third Party Activities** may induce environmental changes that cannot be distinguished from the potential impacts of CO_2 storage that might trigger a perceived loss of containment from the BCS storage complex.

Explanation:

Third party activities that could create a threat to leakage from the BCS storage complex include – wells drilled into or through the Lotsberg salts, salt cavern construction in the Lotsberg salts, and nearby CCS projects.

Any nearby *third-party C*CS projects will induce additional pressure increases in the BCS which increase the risk of leakage from the BCS storage complex.

Risk Assessment:

This risk is considered to be very low for the following reasons:

- According to the Sequestration Lease Rights Shell has the exclusive right to drill through and store within the Zone of Interest (below the Elk Point Group).

However, there are P&NG rights held by third-parties within the SLA that extend to the basement including Shell's ZOI. As a result, the ADOE has flagged the Quest Project in their system and will not be giving out new P&NG rights within the ZOI within the SLA. In addition, Shell would be notified of any third party attempting to drill into the ZOI so risk could be assessed on an individual basis. As per the AER Decision report [3] number [180] the panel concluded that this is extremely unlikely to happen taking into account the current state of knowledge and the fact that there are no hydrocarbons below the Elk Point Group in the SLA.

- There are no other third party CCS projects proposed in the vicinity of the Quest Project. Any new CCS project would be accessed on the impact created by the overall pressure increase in the BCS.
- A conceptual site model (CSM) of the Quest Project SLA does not foresee a pathway connecting the source to any receptor (Figure 4-1). Hence, no pathway has been identified through which saline brine from the injection interval may reach aquifers above the base of the groundwater protection zone. Furthermore, pressures are too low for BCS brine to be lifted to above the BGWP zone.

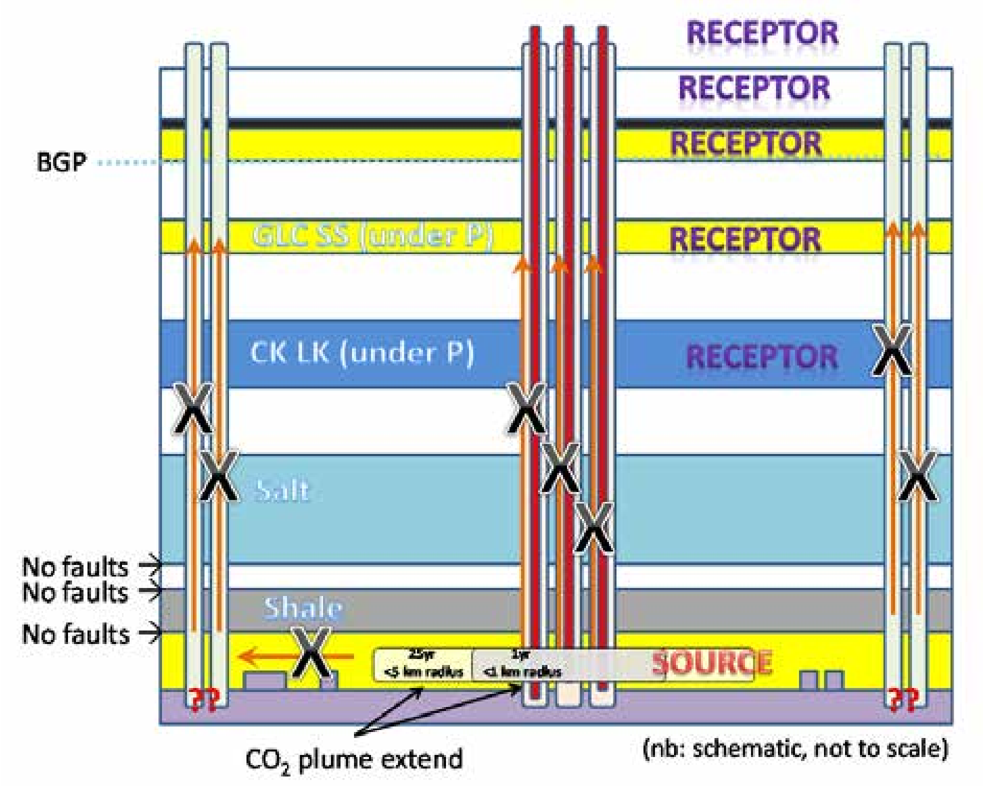

Figure 4-1: CSM for the Quest Project SLA. Note: BGWP refers to base groundwater protection; under P refers to under-pressured formation.

4.3.4 Initial Safeguards to Ensure Containment

Following extensive site characterization, there are no known migration pathways for fluids to escape upwards out of the BCS storage complex. Prior to implementing MMV, several safeguards are already in-place to reduce the risk of any unexpected loss of containment due to an unknown migration pathway. There are two distinct types of safeguards: *preventative* measures that reduce the likelihood and *corrective* measures that avoid, mitigate or remediate the potential consequence of any loss of containment

The *preventative* measures in-place include:

- **The first seal**, the Middle Cambrian Shale provides a 20 to 55 m thick seal over the entire SLA
- **The second seal,** the Lower Lotsberg Salt provides a 10 to 35 m thick seal over the entire SLA.
- **The ultimate seal,** the Upper Lotsberg Salt provides a 55 to 90 m thick seal over the entire SLA.
- **Geochemistry** of the BCS brine is distinct from the brine found within shallower formations providing strong evidence of no long-term fluid migration in or out of the storage complex.
- **Lateral separation** of injection wells from BCS legacy wells significantly reduces the chance of CO_2 or sufficient BCS pressure reaching these wells.

  Lateral separation is a significant safeguard as dynamic reservoir models show that CO_2 will never reach the BCS legacy wells. Also in the expectation reservoir scenario the pressure will never exceed the threshold to lift BCS brine to the BGWP zone.
- **Multiple cement plugs** seal the abandoned BCS legacy wells.
- **Multiple casing strings** within the injection wells provide three barriers against corrosion.
- **Chrome casing** over the injection intervals provides additional corrosion resistance.
- **Cement placement** along the entire wellbore of each injector creates the largest possible cement barrier to fluids migrating upwards outside the casing.
- **Injection pressures** will never exceed the measured pressure required to open fractures.
- **Mechanical barriers** to vertical fracture propagation are provided by multiple clay-rich layers within the LMS and larger compressive stresses within the first seal.
- **No faults** across any of these geological seals are detectable on the 3D and 2D seismic data.
- **No recorded earthquakes** indicates there is no current tectonic activity that might re-activate an unknown fault.
- **Limited shear stress** is induced inside the storage complex during injection which reduces the likelihood of re-activating an unknown fault.
- **Ductile creep** within the Lotsberg Salts is likely to re-seal any fault or fracture unexpectedly induced by CO_2 storage.

- **Acidic fluids** cannot erode either Lotsberg Salt Formation which is made of pure halite that does not react with CO_2 saturated brine.

The *corrective* measures in-place include:

- **The Winnipegosis/Contact Rapids** will act as a potential baffle to migration of CO_2 above the BCS storage complex near the injection wells where it low permeability. It is possible that this interval serves as auxiliary storage on a regional scale in permeable areas away from the wellbores.
- **The Prairie Evaporite** is a major regional seal, 100 to 150 m thick over the SLA.
- **The Beaver Hill Lake Group** provides a series of baffles and auxiliary storage to inhibit vertical migration of fluids.
- **The Cooking Lake Formation provides** another major auxiliary storage formation, able to dissipate pressures and store CO_2 or BCS brine. This is the most likely auxiliary storage formation because it already has some pressure depletion due to nearby production.
- **The Ireton Formation** seals the Redwater Reef Oil field, is about 10 m thick above the reef and about 90 m thick elsewhere within the SLA including above the injection wells.
- **The Mannville Group** offers auxiliary storage capacity within multiple producing clastics reservoirs
- **The Colorado Group** is a proven seal for the hydrocarbon accumulations
- **The Lea Park** is a marine shale with a lateral extent greater than the SLA and a thickness of about 120 m at the Radway 8-19 -59-20 well pad.

The residual likelihood of all these multiple independent safeguards failing is judged to be *very low* (Table 4-4). Figure 4-2 provides a summary of the relationship between all these threats, safeguards and consequences.

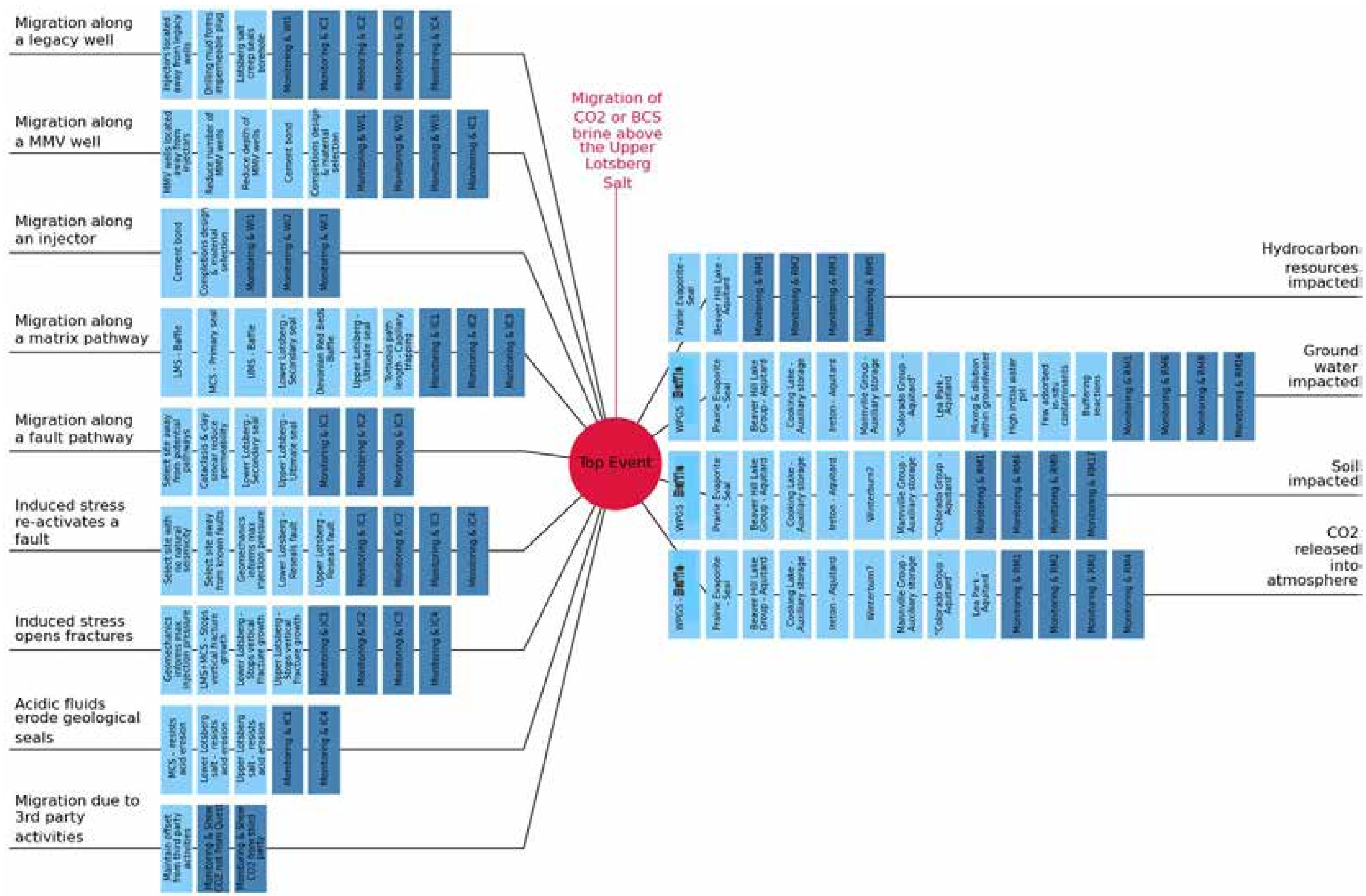

Figure 4-2: Summary of the safeguards in place to reduce the likelihood (left side) and consequence (right side) of any unexpected loss of containment. The active safeguards are supported by the monitoring plan (Section 6) and control measures (Section 9).

5 Monitoring Technology Selection

Monitoring technologies are selected for inclusion in the MMV Plan according to a cost-benefit analysis. Monitoring costs are estimated according to current unit costs and a monitoring frequency appropriate for each individual technology. Monitoring benefits are estimated according to the expected effectiveness of each monitoring technology at each monitoring task. The identified monitoring tasks are risk-based and designed to verify the effectiveness of the passive safeguards described previously and if necessary to trigger the timely deployment of active control measures, such as reducing or stopping injection, to reduce the risk of a loss of conformance or containment.

5.1 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 actual storage performance is sufficient to distinguish between two classes of possible future performance: those that result in permanent stable storage of the target mass of CO_2 inside the BCS storage complex, and those that do not.*

Containment Monitoring Targets

1) *Measurements of any changes within the hydrosphere, biosphere, and atmosphere 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 geosphere, hydrosphere, biosphere, and atmosphere caused by CO_2 injection are sufficient to trigger effective control measures to protect human health and the environment.*

5.2 Monitoring Tasks

The monitoring tasks identified to fulfill these monitoring targets are:

- Monitor CO_2 plume development inside the storage complex
- Monitor pressure development inside the storage complex
- Monitor injection well integrity
- Monitor geological seal integrity
- Monitor for any hydrosphere impacts

- Monitor for any biosphere impacts
- Monitor for any CO_2 emissions into the atmosphere

This list does not include monitoring to determine the contribution of individual storage mechanisms such as structural, capillary, solution, and mineralization trapping. This is not part of the conformance monitoring target because there is no evidence that any one mechanism is any less secure than another within the BCS storage complex. The relative contribution of these trapping mechanisms should not impact the transfer of liability which depends on a demonstration of containment and conformance.

5.3 Monitoring Technologies

More than 50 candidate technologies were considered including many geophysical, geochemical, in-well, and surface monitoring methods. The expected effectiveness of each monitoring technology at each monitoring task is evaluated using a systematic evidenced-based logic approach that relies on collective expert judgment. The outcome of this evaluation is summarized in a cost-benefit ranking (Figure 5-1).

Following this ranking, the notable regrets from the base-case monitoring plan are:

- **Multiple BCS observation wells**: Time-lapse seismic data and InSAR are more effective at conformance monitoring.
- **Surface gravity** monitoring due to insufficient sensitivity to monitor conformance or containment monitoring.
- **Surface microseismic** monitoring due to insufficient sensitivity to monitor containment.
- **Surface electromagnetic** monitoring methods due to insufficient sensitivity for conformance or containment monitoring.
- **GPS** for surface displacement monitoring as InSAR is equally effective and lower cost.
- **Artificial Tracers:** Both artificial and natural tracers were assessed for monitoring implementation. In accordance with AER Condition 13 [1], a report entitled "Special Report #3: Tracer Feasibility Report" [9] was compiled to present and discuss the findings with regards to tracers. This report recommended that artificial tracers not be used on a regular scheduled basis during injection over the life of the Quest Project. As a result, Shell will rely on natural tracers to monitor CO_2 containment.
- **Remote Sensing:**
    - **Rader Image Analysis (RIA)** was assessed for use in biosphere monitoring for BCS brine detection using RIA (RadarSat2 Image). (section 7.2.2.1). This feasibility study demonstrated poor correlation between imagery and samples collected for calibration. As a result of the 2012 – 2013 drilling campaign and GEN-5 modelling of the BCS reservoir , the predicted pressure increase in the BCS will not reach a level sufficient to lift BCS brine to the BGWP zone even at the injection well sites through the life of the project. Therefore, RIA is also not required to monitor for BCS brine.

- **Multispectral Image Analysis (MIA)** was assessed for CO_2 leakage using RapidEye imagery through the 2012-2014 baseline period (Section 7.2.2.1). Direct use of MIA for real-time monitoring and detection of CO_2 releases in the atmosphere is insufficient due to spectral and spatial resolution of available sensors.

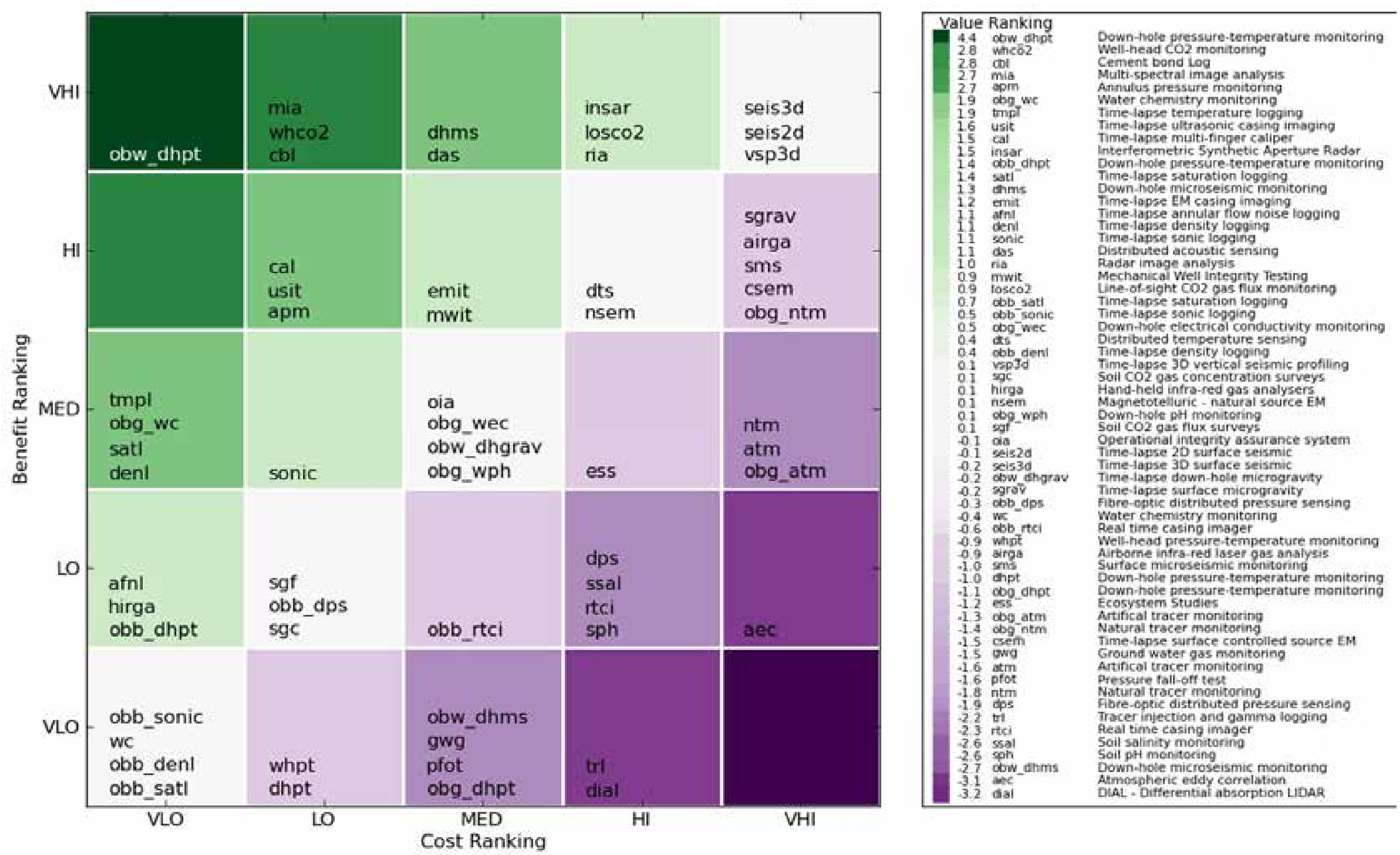

Figure 5-1: Ranking of monitoring technology options according to expected benefits and costs. Colours denote the difference between the benefit and cost rankings as an indicator of value.

6 Monitoring Plan

This section describes the type, frequency and coverage of monitoring activities included in the monitoring plan for the four domains, namely the Atmosphere, Biosphere, Hydrosphere, and Geosphere. Subsequent sections describe the expected performance of these monitoring technologies (Section 7) and the contingency plans (Section 8) in case these are not realized.

6.1 Monitoring Schedule

The monitoring schedule allows for multiple independent monitoring systems with comprehensive coverage through time and across the AOR within each of the environmental domains (Table 6-1, Table 6-2, and Figure 6-1). The diversity of monitoring technologies mitigates the risk of a particular technology failing to work at optimal levels for the project.

Table 6-1: Summary of the monitoring plan for the atmosphere, biosphere, hydrosphere, and geosphere

Monitoring	Coverage	Pre-Injection	Injection	Closure
Atmosphere				
Line-of-sight CO_2 gas flux monitoring	At each injection wellsite	Testing at IW8-19	Continuous (all injectors)	Continuous (all injectors)
Biosphere				
Remote Sensing - multispectral image acquisition via Rapideye Satellite for MIA	Entire SLA	3 times/year	Discontinued[a]	Discontinued[a]
Remote Sensing – radar image acquisition via RadarSat2 for RIA	Entire SLA	Monthly	Discontinued[b]	Discontinued[b]
Surface CO_2 flux & soil gas	Discrete locations across the SLA during pre-injection phase; at injection pads during injection	Quarterly	During 2015 & 2016: Semi-annually Post-2016: to be determined	TBD, based on outcome of monitoring during injection period
Hydrosphere				
Down-hole pH and WEC monitoring	Project groundwater wells	Continuous	Continuous	Continuous
Natural tracer monitoring	Project and Private landowner groundwater wells	At least every year	During 2015-2016: quarterly for Project groundwater wells and landowner wells within 1km of each injection well pad; once per year for landowner wells located within expected CO_2 plume size; landowner wells associated with VSP surveys: pre- and post-campaign Post-2016: To be determined	TBD, based on outcome of monitoring during injection period
SCVF/GM related water and gas sampling, including isotopic analyses [c]	Project and Private landowner groundwater wells	Annually before April 1st 2014	Annually by June 30th	Annually (if required)

Monitoring	Coverage	Pre-Injection	Injection	Closure
Geosphere				
Time-lapse walkaway VSP surveys [d]	Within 600 m of every injector	Feb 2015	Dec 2015, TBD[e]	None
Time-lapse 3D surface seismic surveys	Entire CO_2 plume	2010	2022, 2029, 2039	2048
InSAR	Entire AOR	Monthly	Monthly	Monthly

NOTES:

[a] MIA image acquisition is discontinued post baseline as it is inadequate for real-time monitoring and CO_2 leak detection.

[b] RIA is discontinued post baseline as the risk of brine leakage is significantly reduced and feasibility of the methodology yielded poor calibration of the data set.

[c] Annual monitoring using existing project groundwater monitoring wells on each injection pad, including head gas composition, until time of well abandonment, as per the project HBMP. Monitoring technologies must include the ability to detect contamination due to SCVF's and GM's. Note that this monitoring activity falls within Natural Tracer Monitoring activities, but was highlighted as a separate item, as it's a specific AER requirement related to the SCVF and GM issue. Annual reporting to AER is required. See AER letter from December 3rd 2013 regarding approval of the MMV plan for full details.

[d] Baseline data will be acquired using the DAS system, it is expected that subsequent surveys will be acquired with the DAS system. Conventional geophones arrays will be used as contingency.

[e] The second VSP survey timing will be based on the observed CO_2 plume growth rate rather than a preset date.

Table 6-2 Summary of the monitoring plan for deep monitoring wells and CO_2 injection wells

Monitoring	Pre-Injection	Injection	Closure
Deep Monitoring Wells			
Down-hole pressure-temperature monitoring in the Cooking Lake Formation[i]	12 months	Continuous	Continuous
Downhole microseismic monitoring (8-19 well pad only)	4.5 – 6 months[j]	Continuous	None
Cement bond log	Once	None	None
SCVF testing as per AER ID 2003-01 [f]	Annually (before April 1st 2014)	Annually by June 30th	Annually (if required)
Gas migration testing as per AER Directive 020 [g]	Annually (before April 1st 2014)	Annually by June 30th	Annually (if required)
Injection Wells			
Wellhead pressure-temperature monitoring [b]	None	Continuous	Continuous
Time-lapse ultrasonic casing imaging	Once	Every 5 years	Every 10 years
Time-lapse electromagnetic casing imaging	Once	Every 5 years	Every 10 years
Time-lapse casing caliper logs	Once	Every 5 years	Every 10 years
Time-lapse cement bond log	Once[a]	Every 5 years[b]	Every 5 years
Mechanical well integrity testing (packer isolation test) and tubing caliper log [a]	Once	Every year	Every 3 years
Injection rate monitoring [b]	None	Continuous	None
Distributed temperature sensing	None	Continuous	Continuous
Downhole pressure-temperature monitoring[d]	As Available	Continuous	Continuous
Distributed acoustic sensing	None	Continuous	Continuous
Annulus pressure monitoring [b]	None	Continuous	Continuous
Routine well maintenance [c]	Every year	Every year	Every year
SCVF testing as per AER ID 2003-01 [f]	annually (before April 1st 2014)	annually	annually (if required)
Gas migration testing as per AER Directive 020 [g]	annually (before April 1st 2014)	annually	annually (if required)
Temperature and RST logs) (same time as mechanical well integrity testing above)[h]	Once per well (baseline)	After 6 months except IW 5-35 after 3 months then annually for 2 years and then as required.	None

[a] A D51current regulatory commitment for Class III wells.
[b] A possible future D51 regulatory commitment for Class III wells (current requirement for Class I wells).
[c] A maintenance task related to the wells, included in this table for completeness.
[D] Shut-in stabilized pressure fall off tests are a subset of the data collected via DHPT gauges
[E] Shell will use IW 7-11 and IW 5-35 for temporary DHPT monitoring until injection starts in these wells.
[f] Annual SCVF testing as per AER ID 2003-01 for non-serious SCVF, until time of well abandonment or until SCVF dies out. Annual reporting to AER is required. See AER letter from December 3rd 2013 regarding approval of the MMV plan for full details.
[g] Annual Gas Migration testing as per procedure given in AER Directive 020 until time of well abandonment or until the GM disappears. Annual reporting to AER is required. See AER letter from December 3rd 2013 regarding approval of the MMV plan for full details.

[h] AER D65 approval Condition 5c which requires hydraulic isolation logs on IW and DMWs 2 years after start of injection. The need for further testing to be determined on annual basis by the Regulator

[i] DMW 7-11 and DMW 8-19 have been collecting data in the CKLK since Jan 2014. DMW 8-19 and Redwater 3-4 are schedule for a Q1 2015 completion; Redwater 3-4 is still conditional to approval of consent to monitor.

[j] Dependent on CO_2 injection start date. Microseismic monitoring commenced November 6, 2014.

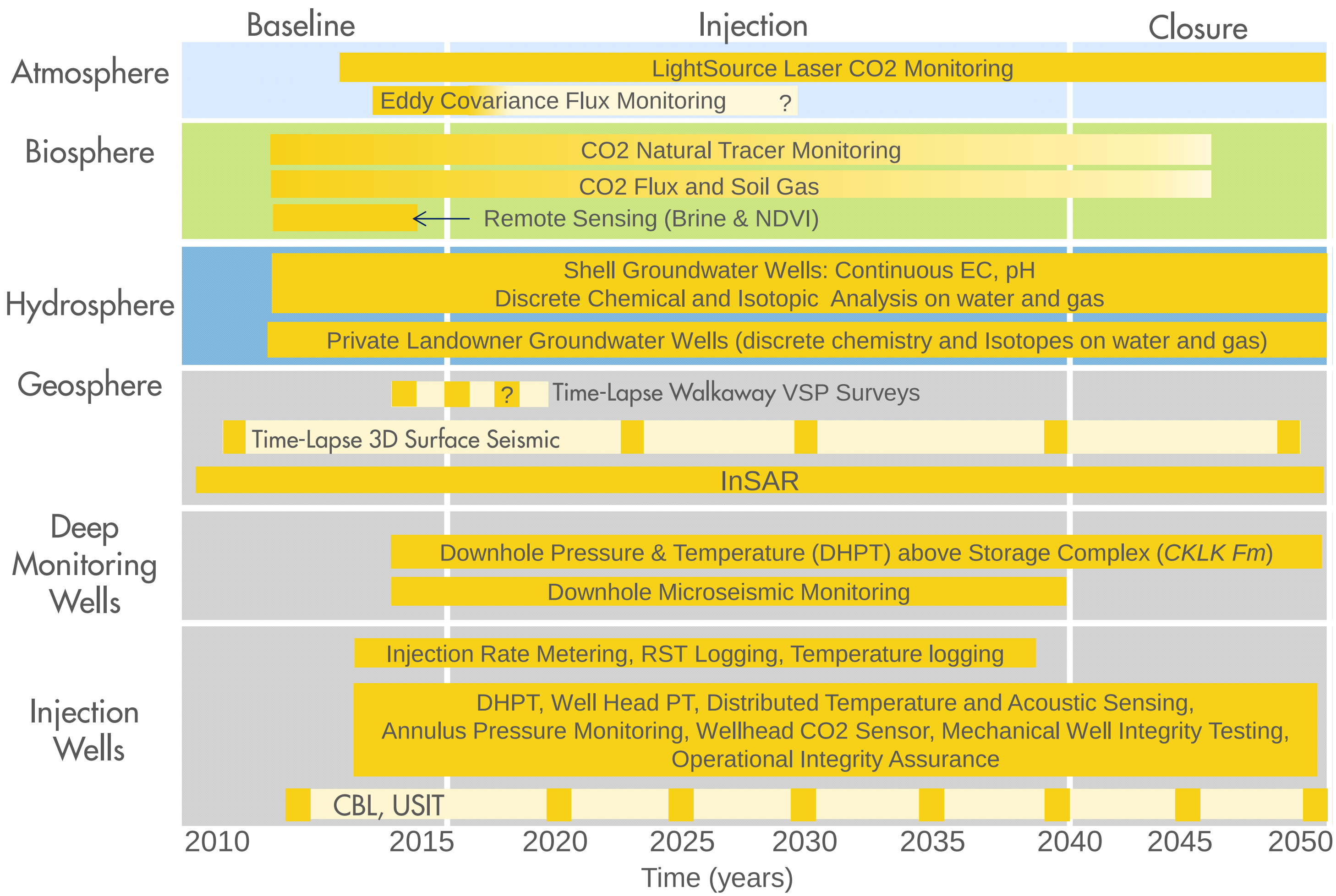

Figure 6-1: Outline of Quest's diversified monitoring program. This eliminates the dependence on any single monitoring technology. Note: Some monitoring is dependent upon outcome of ongoing feasibility studies (Section 5.3).

6.2 Monitoring Coverage

As described in Section 2.2, four domains are being monitored as part of the Quest MMV Plan, namely the Atmosphere, Biosphere, Hydrosphere, and Geosphere. Specific monitoring systems are being used to monitor each of these domains with varying temporal and spatial coverage.

6.2.1 Atmosphere

During the baseline (pre-injection) monitoring period, LightSource and eddy co-variance measurements were undertaken on the IW 8-19 well pad. During 2015 and 2016 of the injection phase monitoring, LightSource measurements will continue on the 8-19 pad and will commence at the 5-35 and 7-11 well sites. Eddy co-variance measurements are planned to continue on the 8-19 well pad during part of 2015 (Table 6-1). The measurement schedule for post-2016 will be assessed after evaluation of data collected during injection in 2015 and 2016.

6.2.2 Biosphere

During the baseline (pre-injection) monitoring period, the HBMP was responsible for the collection, processing, and analysis of baseline environmental data for remote sensing calibration and characterization of pre-injection environmental conditions. There were five components involved in the biosphere program: vegetation, soils, soil conductivity (as measured with electromagnetic data), soil gas and surface flux, and remote sensing.

Based on the outcome of the baseline data collection that was completed in 2014 and feasibility studies associated with the Biosphere Program, the monitoring plans for the injection phase (starting in 2015) has been revised. During 2015 and 2016, the biosphere monitoring program will include (Table 6-1):

- One additional soil sampling event at existing and new plots with a 6 km radius of the injection well pads.
- Targeted soil gas and soil surface CO_2 flux measurements at each of the injection well pads.

The 2015 – 2016 sampling schedule for the HBMP will include two sampling events per year of soil gas and soil surface CO_2 flux measurements, and a one-time soil sampling event below tiling depth (Table 6-1). The sampling schedule post-2016 will be assessed after evaluation of data collected during the initial injection from 2015 – 2016.

6.2.3 Hydrosphere

6.2.3.1 Project Groundwater Wells

As per Shell’s hearing commitments Table 1-1 in exhibit #134.04 [10], three project groundwater wells will be drilled per injector. With, at least one of these wells located on each injection well pad, and the remaining groundwater wells may be located elsewhere.

In fulfillment of the above commitment Shell drilled and completed five groundwater wells on injection well pad 8-19, two groundwater wells on each of the injection pads 5-35 and 7-11 (Table 4-3). On each pad, the groundwater wells were equipped with a downhole Troll 9500 multi-parameter water quality probe for continuous measurement of pH and WEC. The probes also included sensors for redox potential, pressure, and temperature. Each well was also completed at a different depth. This enabled the project to investigate and to monitor groundwater geochemistry in different water bearing zones above the BGWP. Note that on each pad, one of the groundwater wells was drilled and completed as close as possible to the BGWP zone. This provides an opportunity for an early warning of any leakage into the ground water protection zone. The other wells were completed at a typical depth of most local private landowner groundwater wells in the area.

The proximity of these groundwater wells to the injection wells provides monitoring to verify containment. In the event of an unexpected migration of fluids along an injection well, they may provide an early warning based on trigger control measures (Section 7). The lateral offset of the project groundwater wells from the injection wells is sufficiently small to ensure effective groundwater monitoring.

Shell believes that the number and location of the project groundwater wells is sufficient to monitor containment. If in the future it is deemed necessary to drill additional wells to monitor a potential risk to containment, Shell will identify specific locations at that time.

The project groundwater well sampling schedule includes continuous and discrete measurements. The former referring to the Troll 9500 water quality probes, and the latter to water and gas sampling for laboratory analysis. During the baseline (pre-injection) monitoring period, continuous readings of the Troll 9500 probe were taken on a daily basis and discrete sampling was executed on a quarterly basis. The baseline monitoring period has been completed and covered Q4 2012 to Q4 2014. During the 2015 and 2016 of the injection phase monitoring, the sampling schedule for the project groundwater wells will remain the same as during the baseline monitoring phase (Table 6-1). The sampling schedule post-2016 will be assessed after evaluation of data collected during the initial injection phase in 2015 and 2016.

6.2.3.2 Landowner Groundwater Wells

The planned pre-injection (baseline) groundwater sampling program was completed in Q4 2014. During the baseline monitoring period, private landowner groundwater wells included two categories of wells, namely:

1. Local landowner groundwater wells, which included:
    a. Groundwater wells near the injection wells (within 3.2 km radius)
    b. Groundwater wells near legacy wells
2. Regional landowner groundwater wells, sparsely distributed across the remaining AOR at a density of approximately one per township

When the injection phase monitoring commences in 2015, the categories of groundwater wells will be modified compared to the baseline phase monitoring, and will include:

- Landowner wells within a 1 km radius of the injection wells (referred to as LIW)
- Landowner wells that will be selected dependent upon plume size (+buffer zone) for assurance monitoring; hence, the number of wells is expected to change over time (referred to as LAM)
- Landowner wells associated with VSP surveys (referred to as LVSP)

The reasons for the change in the groundwater wells categories between pre-injection and injection phase monitoring are:

- Improved understanding of actual risk associated with CO_2 injection within the Quest SLA
- Implementation of appropriate monitoring adjacent to the actual CO_2 injection sites
- Implementation of monitoring for the SCVF/ GMs observed at the injection well pads
- Implementation of monitoring for the VSP surveys

Note that any additional landowner water wells where such landowners have requested to participate in the program were and will be included in the sampling program as per AER Approval 11837A [1].

The private landowner groundwater wells sampling schedule include discrete measurements during the injection phase, as was the case during the pre-injection phase; however, the sampling schedule will vary depending on the groundwater well category. The following sampling schedule will be implement during 2015 and 2016 of the injection phase monitoring (Table 6-1):

- LIW: on a quarterly basis
- LAM: once per year
- LVSP: pre- and post-VSP survey campaigns

The sampling schedule for post-2016 will be assessed after evaluation of data collected during injection in 2015 and 2016.

6.2.4 Geosphere

6.2.4.1 Time-lapse Seismic Surveys

The baseline 3D time-lapse surface seismic survey for the project was acquired in the winter months of 2010 and 2011 and covers an area of 435 km^2 (Figure 1-1). It is expected that a survey of this size will be adequate to monitor the CO_2 plumes as they develop at each of the injection wells. The footprint of future time-lapse surveys will be adjusted to cover the expected plume size as the project moves forward.

Eight walkaway VSP surveys will be acquired at each injection well using the Distributed Acoustic Sensors (DAS) fibers in Q1 2015. Each of the survey lines will be separated by roughly 45^o in order to provide multi-azimuthal coverage at the each injection site. The maximum source offset for each line will be approximately 2400 m, and the expected maximum imaging offset at the BCS is approximately 600 m.

6.2.4.2 INSAR

For the baseline period InSAR data was acquired over the entire AOR. The acquisition frames are shown in Figure 6-2. During the injection phase the acquisition area will be optimized to suit the expected area of deformation.

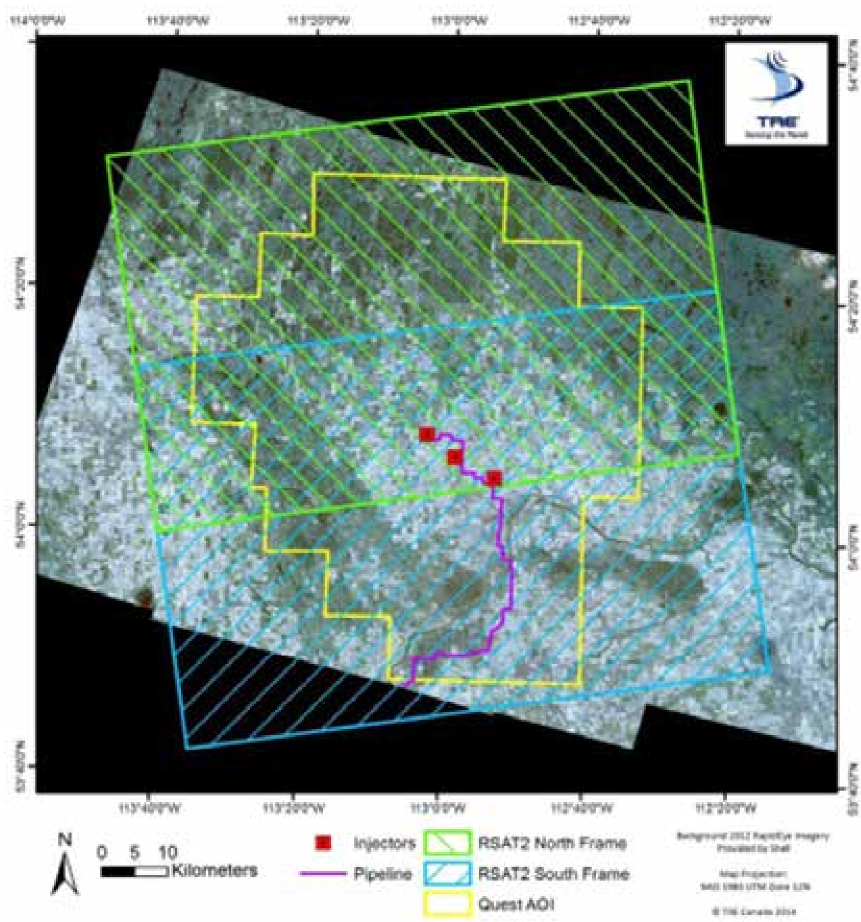

Figure 6-2: InSAR acquisition area during the baseline period

6.2.4.3 Observation Wells within the Basal Cambrian Sands Formation

As previously submitted January 31, 2013 as part of the first annual status report [11], and in accordance with AER Condition 11a, Shell will use IW 7-11 and IW 5-35 as BCS Formation monitoring wells prior to commencement of injection when feasible. At start-up, IW 8-19 will be progressively ramped up until stable injectivity is achieved. An interference test will follow with pressure in the BCS being monitored at IW 7-11 and or IW 5-35. Afterwards, the other injection wells will be started sequentially to ensure they all reach stable injectivity.

Furthermore, Shell plans to monitor the BCS pressures continuously at the three injection wells (IW 8-19, IW 7-11, and IW 5-35). This long-term continuous pressure monitoring will be the basis for history matching dynamic reservoir models.

The injection wells are proposed to be the only direct observation point within the BCS. However, in accordance with AER Condition 10i, this decision will be re-assessed on an annual basis. The reason for this choice is that additional BCS observation wells provide insufficient benefits to justify the incremental costs and containment risks relative to alternative monitoring methods such as time-lapse seismic surveys and InSAR. The perceived benefits are limited because BCS observation wells have no ability to verify containment[i] and are ineffective at conformance monitoring unless used in large numbers. Moreover, drilling a BCS observation well to measure geochemical reactions and calibrate the trapping mechanism is of limited value because these are expected to be negligible within the BCS and, if necessary, may be measured by logging injection wells during the closure period.

For example, one BCS observation well per injector would be insufficient to map the CO_2 plume geometry, as it will only provide information about the CO_2 front at one time in one location. To provide conformance information comparable to time-lapse seismic data requires several BCS observation wells per plume.

The option of locating one or more BCS observation wells within a single CO_2 plume to validate and calibrate the time-lapse seismic response was also rejected due to the expectation of insufficient benefits to justify the incremental costs and containment risk. A seismic trace represents a composite response from an area of approximately 25 m x 25 m that can be used to image the CO_2 plume geometry through amplitude changes. This is difficult to calibrate with an observation well because in-well logging techniques are not sensitive to saturation distributions away from the immediate vicinity of the wellbore. Therefore, a seismic response may indicate the presence of CO_2 that can not be seen or has a different concentration than that measured in the well (i.e. narrow sand bodies may channel the CO_2 towards or around the well). Moreover, time-lapse seismic data is routinely used for well and reservoir management without the need for calibration by observation wells because the failure case is easily recognized as an image dominated by incoherent noise.

The benefits of multiple BCS observation wells located outside the expected CO_2 plumes to monitor pressure conformance are also limited compared to the value of information expected from InSAR that provides low-cost coverage of the entire AOR and will be calibrated by BCS pressure measurements within every injector.

The option to drill BCS observation wells or complete the existing Redwater 3-4 is retained under contingency plans (Section 8) in case time-lapse seismic surveys or InSAR monitoring performance falls short of requirements.

6.2.4.4 Deep Monitoring Wells (Above BCS Storage Complex)

Currently, Shell has one deep monitoring well (DMW) on each injection well pad, each DMW is drilled to the Ernestina Lake Formation (Table 4-2 and 4-3). AER Approval 11837A Conditions 10i and 10j require Shell to address the potential need for installing additional monitoring wells towards the periphery of the area of pressure increase later in the project life and evaluate the need for additional deep monitoring wells adjacent to the four legacy wells in the approval area.

At this time, Shell considers additional monitoring wells situated towards the periphery of the area of pressure increase unnecessary as there is no indication that BCS pressure will reach levels that would provide a threat to containment. Therefore, Shell considers the current pressure monitoring program adequate until future injection information indicates otherwise.

The primary role of the three deep monitoring wells is to support pressure monitoring to verify containment.

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[i] Monitoring *inside* the storage complex provides no ability to detect fluids migrating *outside* the complex.

Shell evaluated three regional aquifers (Winnipegosis Formation, Beaverhill Lake Group, and Cooking Lake Formation) in the 2012 – 2013 drilling campaign and determined that the Winnipegosis/ Contact Rapids formations were tight and that the Cooking Lake Formation was the best monitoring interval as per the Shell application to monitor the Cooking Lake Formation and subsequent approval granted from Alberta Energy in May 2012. However, it is noted that due to the regional third party activity in the Cooking Lake Formation, pressure monitoring is more complicated and the alarm thresholds are yet to be fully understood. Additional baseline data acquired over time and at multiple locations will reduce the uncertainty regarding pressure alarm threshold for the project.

To aid in the interpretation of pressures observed in the Cooking Lake Formation, the project proposes to complete the Redwater 3-4 well in Q1 2015 to monitor far field pressures. The completion of the Cooking Lake Formation in Redwater 3-4 for pressure monitoring is conditional on the consent to monitor from Alberta Energy (AE). The first application in 2014 was declined. A second application is currently under consideration.

The current plan is to start injection using the three injection wells already drilled in addition to one deep monitoring well per injection well pad that has been drilled to the Ernestina Lake Formation. All three DMWs are expected to have downhole pressure and temperature gauges monitoring the Cooking Lake Formation.

In addition to the DMW pressure monitoring, DMW 8-19 has been instrumented with a conventional permanent eight level downhole geophone array to support microseismic monitoring. IW 8-19 was selected as it is at the centre of the development, and it is also expected to have the highest injection pressure. (Section 7.2.5). The current approved plan is to only have a microseismic array in IW 8-19. However, contingency plans exist to revise this selection based on actual injection performance.

Contingency plans also exist to increase the number of deep monitoring wells and microseismic monitoring systems, in the unexpected event that pressure or microseismic monitoring indicates the appearance of an increased threat to containment (Section 8).

7 Monitoring Performance Targets

This section describes the expected capabilities of each selected monitoring technology and sets monitoring performance targets based on the outcome of the baseline monitoring period data collection results and technical feasibility assessments.

7.1 Performance Targets for Conformance Monitoring

7.1.1 Monitoring CO_2 Plume Development

7.1.1.1 Time-lapse Seismic Data

Time-lapse seismic data (VSP2D, SEIS3D) will 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 image of the CO_2 plume geometry around each CO_2 injector. CO_2 entering the pore space within the BCS will displace some of the brine. Since the injected CO_2 is much more compressible than brine, the velocity of seismic p-waves traveling through the BCS will be reduced in those places containing CO_2 and will remain unchanged elsewhere. Differences in seismic images of the BCS obtained before and during CO_2 injection will arise due to the presence of CO_2 in two characteristics ways:

- Travel-time across the BCS will become longer (c. 8%) due to the slower p-wave velocity inside the BCS.
- Reflections from the base of the BCS will become stronger (c. 8%) as the impedance contrast with the underlying granite basement increases. The contribution of bulk density changes is negligible.

Increases in CO_2 saturation of up to 5 or 10% of the pore-space cause significant velocity reductions (c. 8%); thereafter, additional CO_2 within the same pore-space causes very little additional velocity change. Consequently, time-lapse seismic data is expected to monitor the shape of the CO_2 front qualitatively but not the distribution of CO_2 saturations inside the plume.

Evaluation of seismic data acquired during the appraisal period and site-specific feasibility studies indicated CO_2 will be detectable in the BCS where CO_2 fills at least 5% of the pore-space and the thickness of a contiguous CO_2 plume exceeds 5 m. The expected lateral and vertical resolution of the CO_2 plume geometry are 25 m and 10 m, respectively. This expected sensitivity and resolution is based on a typical amount of non-repeatable noise being present within the two seismic images. Observed monitoring performance during the injection period will be used to validate and, if necessary, update these values.

New borehole seismic recording technology using a DAS permanent fiber optic system inside each injector provides an opportunity to acquire time-lapse VSP data on demand without the cost or risk associated with well interventions to deploy a conventional retrievable geophone array. Based on the results of a successful field trial at IW 8-19, this technology has been included in the monitoring plan. The use of conventional geophones tools in the DMWs remain in the contingency monitoring plan.

7.1.2 Monitoring Pressure Development

7.1.2.1 Downhole Pressure Temperature Gauges

Downhole Pressure Temperature (DHPT) gauges in the injection wells and InSAR will be used to monitor the development of fluid pressure inside the BCS storage complex at and away from the injection wells.

The DHPT gauges will provide accurate direct and continuous measurements of pressure changes at these discrete locations. InSAR will provide monthly measurements to indicate the aerial distribution of BCS pressure changes between the gauge locations and across the area of elevated pressure.

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 will be completed on an annual basis. The initial baseline BCS fall-off test for IW 8-19 was submitted as part of the second annual status report submitted to AER January 31, 2014 [12]; furthermore, BCS build-up test for both IW 5-35 and 7-11 were also submitted. Both of these wells have had considerably more extensive testing.

7.1.2.2 InSAR

InSAR is a satellite remote sensing method designed to map even the smallest displacements of the Earth’s surface. This small deformation at depth results in a smaller and smoothly distributed displacement at the Earth’s surface. These displacements are so small that they can only be detected by very sensitive instruments specifically designed for this purpose.

Alberta is a potentially challenging environment for InSAR due to extended periods of snow cover. Acquisition of InSAR data over the AOR started in 2011 in order to evaluate the number of reliable natural monitoring targets within the existing landscape. Shell submitted Special Report #2 as per Conditions 9e and 12 to AER January 31, 2013 with evidence showing corner reflectors are not required for monitoring the AOR due to a sufficient number and spacing of natural targets. However, installation of artificial corner reflectors remains in the contingency monitoring plan (Section 8.1). The AER approved the current plan on October 4, 2013 under the following conditions:

When the InSAR section is reviewed in the annual status reports, Shell must:

- *Confirm a data-processing method has been used that captures sufficient natural coherent targets within the SLA and,*
- *Confirm they are keeping track of how fast the area of deformation at the surface is expanding. If it appears it will extend beyond the SLA in the lifetime of the project, Shell shall either demonstrate the existence of adequate natural stable targets outside the SLA, or revisit the question whether artificial corner reflectors may be required.*

Radar imagery has now been collected for over three years across the Quest AOR with the Radarsat-2 satellite. Two sets of 45 images acquired between June 3, 2011 and July 5, 2014 were processed with TRE's proprietary SqueeSAR™ algorithm (Third Annual Status Report: Appendix F). The results of this processing indicate that InSAR will measure surface displacements with a precision of +/ 0.87 mm/year. The InSAR coverage and the density of natural reflectors is shown in Figure 7-1 with an increase of 14,369 reflectors compared to the processing carried out in 2012.

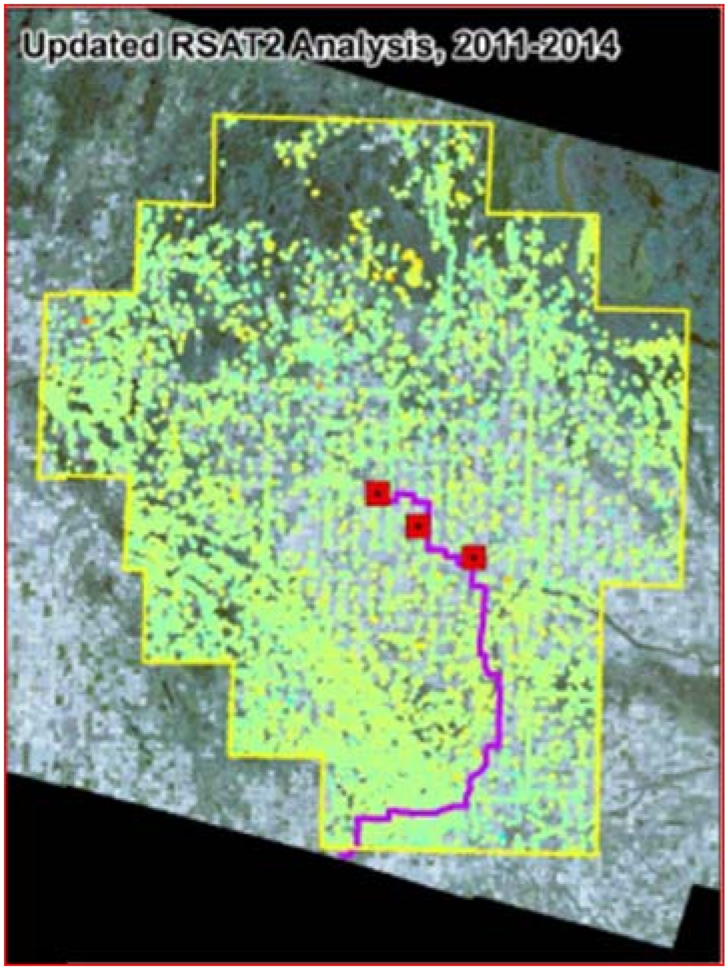

Figure 7-1: RadarSat image analysis showing the density of natural reflectors across the QUEST AOR from the TRE processing carried out in 2014.

Based on the geomechanical properties of the BCS/ LMS the surface deformation associated with injection in the BCS is expected to be 1 to 10 mm per MPa of pressure increase. This reflects the order of magnitude uncertainty in these properties. Based on the InSAR sensitivity this allows temporal pressure changes of 0.1 to 1 MPa to be detected and spatial pressure changes to be mapped with a lateral resolution of 1 to 3 km. This is sufficient to delineate any region subject to a pressure increase sufficient to lift brine above the BGWP (c. 3 MPa). Observed monitoring performance during the injection period will be used to validate or update these values.

Surface deformation modelling was updated based on the Gen-5 BCS pressure predictions [Third Annual Status Report: Section 5.3.1]. This modelling was based on the expectation pressure increases over the life of the project, but the high case of geomechanical properties of the reservoir. The maximum surface heave is shown in Figure 7-2 over the project life along with a map of the deformation expected after the first year of injection. These updated results indicate that in the best case (high case geomechanical properties) InSAR can detect surface deformation within the first year of injection. However, as this modelling represents the maximum displacements based on geomechanical properites with an uncertainty of one order of magnitude deformation may be too small to be captured within the first number of years of injection.

The moment CO_2 injection stops, pressures inside the BCS will begin to relax and surface displacements will begin to reverse.

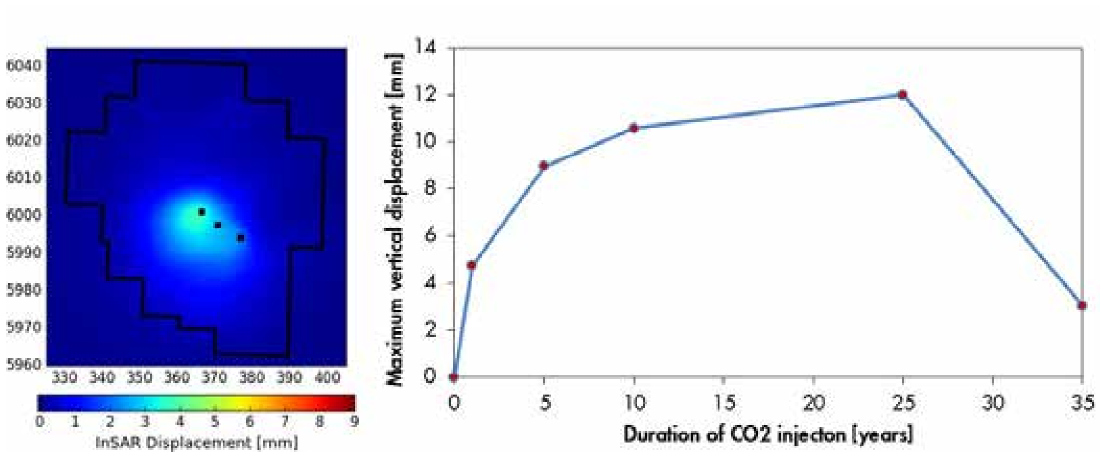

Figure 7-2: Surface heave after one year of injection (left) and maximum surface heave over the life of the project (right).

7.2 Performance Targets for Containment Monitoring

The containment monitoring system is designed to:

- Verify the continuing containment of fluids inside the BCS storage complex
- Verify the absence of any adverse environmental effects due to CO_2 storage
- Provide early warning should fluids migrate out of the BCS storage complex
- To ensure the necessary reliability, this monitoring capability is provided by many independent technologies intended to detect change above the BCS storage complex.

The selected monitoring technologies discussed above provide complementary capabilities in terms of detection sensitivity, detection time, and detection range. The most sensitive technologies typically provide limited coverage whereas technologies with broader coverage are typically less sensitive. The diverse monitoring plan combines these systems to provide an integrated capability that spans all these monitoring requirements.

7.2.1 Monitoring the Atmosphere

7.2.1.1 LightSource

LightSource (previously referred to as 'Line-of-sight CO_2 gas flux monitoring') will provide a method to verify the absence of any unexpected atmospheric CO_2 emissions potentially originating from the BCS storage complex. One monitoring system will operate continuously on each injection well pad and is expected to detect and map CO_2 emissions up to 1 km from each injector. This radius has been updated based on the controlled release test conducted in 2013 and subsequent modelling in 2014.

The current expected sensitivity and resolution of CO_2 emission mapping depends on distance from the sensor system:

- **'On Well Pad' (500 x 500 m grid):** A 45 kg/ hour (1 tonne/ day) release rate of CO_2 from a point source will be detectable and locatable from a range of about 100 m, and mapped with a resolution of approximately 100 m subject to prevailing wind directions and relative beam locations.
- **2 x 2 km grid:** A release rate of 800 kg/ hr (200 tonnes/ day) would be detectable and locatable from a range of approximately 1 km (Figure 7-3).

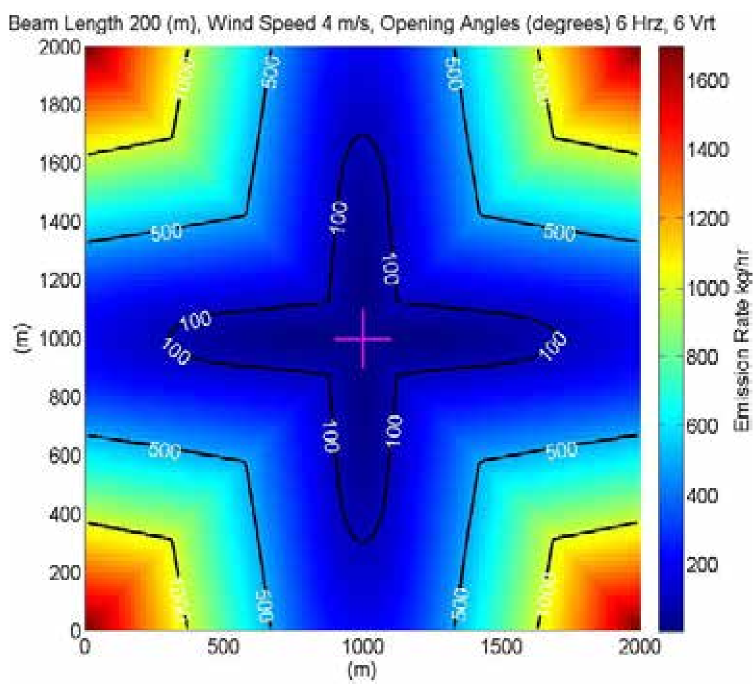

Figure 7-3: Minimum detectable CO_2 source emissions on a 2 x 2 km grid.

Any anomalous CO_2 emissions detected would trigger a similar response as for the hydrosphere and biosphere (Section 10).

Currently, no known technology is capable of monitoring and quantifying atmospheric CO_2 emissions from a storage site over areas as large as the Quest AOR, as Lightsource was proposed to do in initial feasibility studies. The International Panel on Climate Change

(IPCC) expectation on containment performance are better than 99% retained over 100 years. A 1% loss of containment of 27 Mt over 100 years corresponds to 308 kg/ hr (2700 tons/ year). CO_2 mass emissions however could be quantified by relocation of the LightSource monitoring system to the location of any know leak site for direct measurement.

Observed monitoring performance during the early 2015 at the 8-19 well pad and a second controlled CO_2 release tests, planned for May 2015, will be used to validate or update the monitoring performance values.

7.2.1.2 Eddy Covariance CO_2 Flux Measurements

Eddy covariance (EC) CO_2 Flux Measurements were collected from May 2012 to present, at the 8-19 well site providing baseline surface CO_2 flux data (Figure 7-4). These measurements capture the variability of background eco-physiological carbon fluxes on the pad area and establish a baseline of background signal prior to injection and that can be used to calibrate the LightSource measurements. The Third Annual Status Report: Sections 6.2.1 and 6.5.1 and Appendix B further discuss this technology and results of the program.

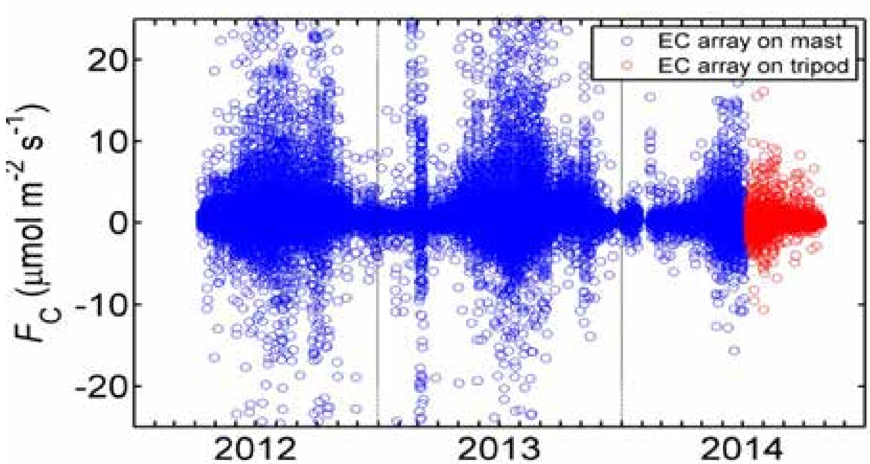

Figure 7-4: Half-hourly eddy-covariance measurements of CO_2 flux (F_C) for May 2012 to October 2014 at the 08-19 well road. The EC sensors moved from the southwest quadrant to the southeast quadrant and lowered from the 2 m height to the 1 m height on July 4, 2014 to improve pad coverage of the flux measurements.

EC data collection will be continued until June 2015 and will cover the controlled release test of the LightSource system in May 2015.

7.2.2 Monitoring the Biosphere

7.2.2.1 Radar image analysis and multi-spectral image analysis

Remote sensing data, using radar image analysis (RIA) and multi-spectral image analysis (MIA) methods was collected during the baseline period (2012 – 2014) to investigate if these technologies could track any annual changes across the AOR, to help indicate the absence of BCS brine and project CO_2 within the near surface soil and vegetation. The same monthly data acquired for InSAR monitoring of surface displacements is utilized for this purpose.

At initial ranking (Figure 5-1), these remote sensing techniques offered the potential for affordable wide-area coverage if feasible. The performance of these methods was evaluated and calibrated using ground based soil and vegetation survey techniques at a representative set of discrete locations across the AOR acquired and calibrated during the baseline period. The Quest specific feasibility studies on RIA and MIA demonstrated the following:

RIA: Utilizing RIA for brine leak detection (SAR) technical feasibility was completed in Q4 2014 (Third Annual Status Report: Appendix E). Data was collected and correlated over four seasons (Fall 2013, Spring, Summer and Fall 2014). Severe limitations of the data were required to demonstrate any correlation between soil moisture and conductivity. Surface roughness variations and ongoing anthropogenic activity (principally agriculture) also resulted in poorer correlation. As such, resulting poor correlation coefficients were achieved from season to season as well as for individual plots with presence of elevated salinity or water saturations as would be expected in the case of a brine leak. Resulting scatter plots of soil conductivity versus SAR amplitude show no apparent correlation and a general spread of data at lower conductivity values that does not correlate to SAR amplitude (Figure 7-5).

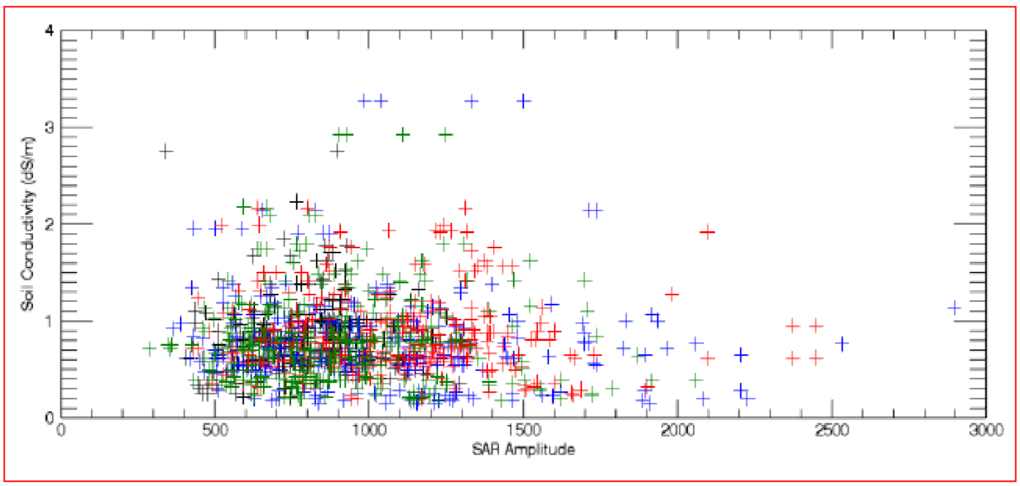

Figure 7-5: 2D scatter plot of soil conductivity vs. SAR amplitude (black- Fall 2013, blue – Spring 2014, red – Summer, 2014, green – Fall 2014)

In conjunction with the updated Gen-5 modelling that demonstrates reservoir pressures will not reach levels sufficient to lift BCS brine to the base of groundwater, limitations of the SAR technology does not support continued inclusion in the MMV plan.

MIA: The MIA component of the Quest Project focused on characterizing the baseline vegetation conditions within the AOR and assess the feasibility of monitoring for leak detection at the injection sites.

The baseline program (2012 – 2014) collected spectral data seasonally at discreet sites in the AOR, PIF's (pseudo-invariant features), and artificial targets. This baseline were consistent across vegetation types and displayed expected inter-seasonal spectral variability.

However, direct observations of CO_2 using MIA are not feasible due to the spectral and spatial resolution of the available sensors, the influence of the atmosphere on the spectral signatures.

Based on the above, these remote sensing technologies have proved insufficiently reliable for environmental change detection and as such are removed from the injection phase MMV plan.

Soil (EM38) and Vegetation surveys were collected during the baseline period (2012 – 2014) to calibrate the remote sensing to measure vegetation stress and soil salinity as well as establish a baseline of vegetation stress and soil variability. These surveys will be discontinued in the injection phase, as the baseline has been established and remote sensing technologies will not be continued. Any stakeholder concerns or leak indications from other monitoring technologies will be subject to ground-based verification where this baseline data could have potential applications (Section 10.1, Figure 10-1).

Field Spectra Surveys to measure spectral signatures for each vegetation group identified at a number of discrete locations in the AOR were recorded during the baseline campaign to provide calibration for the optical data used for MIA. No further spectral surveys will be completed as the baseline data is complete, and further MIA data calibration is not required.

7.2.2.2 Soil sampling

During the baseline period, the soil sampling program was focused on supporting the vegetation and biophysical monitoring in support of the remote sensing calibration efforts (MIA and RIA). As such, characterization was based only on the shallow soil data (0 – 15 cm). This will be discontinued as per Section 7.2.2.1.

A revised soil monitoring program will be undertaken near the three injection wells for the 2015 pre-injection period. The focus will be on a one-time soil pH measurement campaign (pre-injection) below tilling depths at selected plots near the injection well sites.

7.2.2.3 Soil Gas and Soil Surface CO_2 Flux Measurements

During the baseline period from Q4 2012 to Q4 2014, a very extensive set of geochemical analyses was compiled related to the soil gas and soil surface CO_2 flux sampling program. Measurements included CO_2 flux, CO_2 concentration and isotopic composition of CO_2 ($\delta^{13}C$). Besides the soil gas and soil surface CO_2 flux measurements related to the HBMP baseline sampling campaign, an additional sampling campaign took place in July 2014 using state-of-the-art field deployable instrumentation. The in-situ field measurements included soil gas probes, CO_2 flux chambers, and walk-over surveys close to the injection wells. The state-of-the-art field deployable instrumentation enabled collection of in-situ field measurements of CO_2 flux, CO_2 concentration and isotopic composition of CO_2 ($\delta^{13}C$).

A detailed report on all baseline data from the HBMP as well as the additional July 2014 field campaign and analysis of surface CO_2 flux and soil gas data collected for different soil types throughout the Quest Project SLA from 2012 – 2014 has been compiled [Third Annual Status Report: Appendix D]. Key findings from this report are that "off-pad" measurements of soil surface CO_2 fluxes determined as part of the HBMP ranged from -0.42 to 24.09 μmol m^{-2} s^{-1}. A seasonal trend was clearly visible, as expected, with the highest CO_2 fluxes being measured in the summer and the lowest in the winter. Differences in soil surface CO_2 fluxes were also observed between land use types. Meadow, pasture and wetland tended to have higher CO_2 fluxes compared to annual crop or forest (coniferous, deciduous). "On-pad" measurements at the 8-19 well pad indicated that the CO_2 flux from the pad is small (< 0.3 μmol m^{-2} s^{-1}). Above ground atmosphere (ambient air) CO_2 concentrations measured in the field during the 2012 – 2014 HBMP activities ranged from 340 to 435 and 337 to 400 ppmv at 0.1 and 1 m elevation above ground surface, respectively. Soil gas CO_2 concentrations determined as part of the HBMP activities ranged from 879 to 118,450 ppmv and 500 to 71,600 ppmv based on in-field analysis and laboratory analysis, respectively. Corresponding, soil gas $\delta^{13}C\text{-}CO_2$ values ranged from -29.3 to -10.6‰, with most values falling within the range of C3 vegetation.

During 2015 – 2016, soil gas and soil surface CO_2 flux measurements will continue with a focus on each of the injection well pads. Semi-permanent soil gas probes will be installed in a radial fashion around and up to 10 m away from each injector well, with 5 probes along a north, south, west, east direction each. Similarly, CO_2 flux measurements will be done using a radial design around each injector well. The following key compositional and isotopic analyses are included in the 2015 – 2016 injection phase sampling program: CO_2, C_n, N_2, O_2, and $\delta^{13}C\text{-}CO_2$, $\delta^{13}C\text{-}C_1$, respectively. Note that inclusion of CH_4 analyses also supports the GM monitoring on the injection well pads.

Data collected during the injection phase will be compared to those from the baseline phase [Third Annual Status Report: Appendix D]. As will be discussed in Section 7.2.3.3, the soil gas data will also be evaluated relative to the isotopic composition of the injected CO_2.

7.2.3 Monitoring the Hydrosphere

There are three key approaches used to monitor the hydrosphere:

- **Continuous water electrical conductivity monitoring** (WEC) at each of the project groundwater monitoring wells. This enables to detect 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 deeper formations below the base of groundwater protection zone. Note that there is no risk of brine leakage from the BCS storage complex above the BGWP (Section 4.3.3).
- **Continuous water pH monitoring** (WPH) 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.

- **Discrete water/ gas sampling and analysis** (NTM) within the project groundwater monitoring wells and a selection of accessible/active landowner groundwater wells (Section 6.2.3.2) are used to verify the absence of any impact upon water quality due to CO_2 injection.

7.2.3.1 Continuous pH and WEC measurements

As described in Section 6.2.3.1, Troll 9500 multi-parameter probes are used to record daily values of pH and WEC within each of the project groundwater wells.

During the injection phase, measured data are transferred from each well pad to the Shell network for on-line interactive visualization using a web-based toolkit. Data collected during the injection phase will be compared to those from the baseline (pre-injection) phase to check that WEC values do not exceed and pH values do not fall below the expected range(s). Note that significant variability among individual wells for both pH and WEC values exists based on the baseline dataset, as illustrated in Table 7-1 for the time period October 2013 to October 2014.

Table 7-1: Average pH and WEC values at each project groundwater well recorded between October 2013 and 2014.

Well-ID	pH		WEC (uS/cm)	
	N	average	N	average
1F1-08-19-059-20W4	34^	10.75	194^	27784
UL1-08-19-059-20W4	230	8.50	230	22546
UL2-08-19-059-20W4	229	7.93	229	13657
UL3-08-19-059-20W4	115	9.59	115	1985
UL4-08-19-059-20W4	165^	9.10	273	1985
1F1-05-35-059-21W4	196^	8.37	210^	20120
UL1-05-35-059-21W4	189^	8.46	225	1921
1F1-07-11-059-20W4	234^	8.63	252^	12332
UL1-07-11-059-20W4	194^	8.69	195	1732

^ Preliminary quality checks (QA/QC) of WEC and pH have identified issues with the data logged. Questionable data points have been removed from the statistics accordingly.

Based on reactive transport modelling for data collected at well pad 8-19, it was determined that pH values of < 6 indicate CO_2 intrusion into a shallow aquifer above the base of groundwater protection.

7.2.3.2 Discrete water/gas sampling

During the baseline period from Q4 2012 to Q4 2014, a very extensive set of geochemical analyses was compiled. The following chemical and isotopic analyses were included in the pre-injection monitoring program:

Water:

- pH, WEC, TDS, alkalinity, ion balance, total hardness
- Na, K, Ca, Mg, HCO_3, CO_3, OH, SO_4, NO_2, NO_3, P, DIC, Cl, Br, I, F (added in 2014)
- Al, Sb, As, Ba, Be, B, Cd, Cr, Co, Cu, Fe, Hg, Pb, Li, Mn, Hg, Mo, Ni, Se, Si (SiO_2), Ag, Sr, Tl, Sn, Ti, U, V, Zn
- $^{87}Sr/^{86}Sr$, $\delta^{18}O$ & $\delta^{2}H$-H2O, $\delta^{13}C$-DIC, $\delta^{37}Cl$, $\delta^{81}Br$ and $\delta^{11}B$

Well Gas:

- CO_2, C_1 to C_{10+}, N_2, O_2, He
- $\delta^{13}C$-CO_2, $\delta^{13}C$-CH_4, and $\delta^{13}C$-C_{2+}, $\delta^{2}H$-CH_4

The data collected as part of the baseline sampling campaign in conjunction with other datasets, such as Alberta Groundwater Information Centre and the Shell 3D surface seismic campaign prior to 2012, were evaluated as part of a contract with Alberta Innovates – Technology Futures (AITF) to understand hydro-geochemical characteristics and establish trigger parameters [13].

Over 3000 chemistry records were gathered, processed, and evaluated. Key findings are that groundwater types vary across the Quest SLA from Ca-Mg-HCO_3 to NaCl and Na-SO_4 with a quite range in TDS (58 to 18,300 mg/L). Descriptive statistics (e.g. min, max, average) were calculated for the various aquifers above the base of the groundwater protection zone, as well as for individual wells (1510 wells were processed). The descriptive statistics formed the basis for setting thresholds/ triggers post baseline monitoring. Furthermore, a number of parameters (Table 7-2) were identified as being important for ongoing monitoring for containment assessment and assurance monitoring purposes. During 2015 – 2016 of the injection phase, monitoring will focus on the key parameters listed in Table 7-2 for project and landowner groundwater wells. These key parameters include a mixture of the tiers of parameters defined in the previous MMV plan. In addition, well gas compositional (CO_2, N_2, O_2, C_n) and isotopic ($\delta^{13}C$-CO_2, $\delta^{13}C$-C_1) data will be collected. Two key points to note are:

a. For landowner groundwater wells associated with the VSP campaign, sampling protocol will follow established guidelines (e.g. pump test)

b. Limited noble gas and ^{14}C analyses will be investigated during 2015.

Table 7-2: List parameters considered important 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

7.2.3.3 Thresholds/ Trigger Events

Evaluated aquifers are situated above the BGWP as defined in Alberta, and their water compositions ranged from dilute fresh waters to saline brines. Concentrations of some analytes within the brines were above Drinking Water Quality guidelines. Hence, the concept of Water Quality Limits cannot be applied to the evaluated aquifers for establishing triggers. For this reason, triggers are considered as Quest Project-specific triggers and do not imply meeting a regulatory condition, but rather exceeding a limit defined by the historically observed concentrations, which may include samples taken up to the time of initial CO_2 injection.

Project triggers are based upon comparing analytical results with parameter and analyte concentration statistics calculated from the baseline survey data for aquifers and individual wells. The results of the trigger calculation (equations 1 and 2) are a numerical value which is either greater than 1 or less than or equal to 0. If the calculated value is less than or equal to 1, it should be stored as a null value.

For all parameters:

- *"MAX" triggers: the trigger value for any measurement is: Value = Measured value divided by the aquifer, well or mixture maximum value.*

$$MAX_{trigger} = \frac{measured\ sample\ value}{maximum\ value\ for\ aquifer, well\ or\ mixture} \quad \textit{(Equation 1)}$$

- *"MIN" triggers: the trigger value for any measurement is: Value = The aquifer, well or mixture minimum value divided by the measured value.*

$$MIN_{trigger} = \frac{minimum\ value\ for\ aquifer, well\ or\ mixture}{measured\ sample\ value} \qquad \textit{(Equation 2)}$$

These two formulations have been chosen because all trigger events are indicated by a calculated number greater than one (1.0). This allows easy selection for graphical display with a subjective scale where the larger the calculated number, the potentially more significant the trigger event.

Triggers are established on an aquifer and a well specific basis. They include:

- Aquifer-specific triggers that refer to comparison of concentration of an aqueous constituent or isotope ratio versus the maximum or minimum value observed across the area of investigation for the aquifer that it was sampled from.
- Well-specific triggers refer to:
    a. A comparison of concentration of an aqueous constituent or isotope ratio versus the maximum or minimum value observed for the well that it was sampled from.
    b. A comparison of concentration of an aqueous constituent or isotope ratio versus a formation water specific test value for the well that it was sampled from. The formation water specific test value is calculated using 95% of the maximum concentration for the well it was sampled from plus 5% of the average formation water concentration.

Note that $\delta^{13}C$ data will also be evaluated relative to the isotopic composition of the injected CO_2. A monitoring program of CO_2 at the Quest site at Scotford has been implemented since August 2013 [9] and is on-going.

7.2.4 Monitoring Injection Well Integrity

7.2.4.1 Mechanical Well Integrity Testing

Mechanical Well Integrity Testing consists of annually pressure testing the packer for ten minutes at a minimum pressure of 7 MPa (as per current Directive 51 for Class I wells, which is the most conservative. Class III wells only required 1.4 MPa), or at minimum pressure required pursuant to the AER D51 injection approval in effect at the time.

7.2.4.2 Corrosion Monitoring

Corrosion coupons at the injection skid to confirm the dehydration specs are being adhered to and corrosion is not occurring in the pipeline and wellbore completion.

7.2.4.3 Routine Well Maintenance

Routine well maintenance consists of yearly maintenance of the wellhead valves (not a regulatory requirement but a standard Shell practice) and the measurement of the pressure on the different casing annuli.

7.2.4.4 Time-lapse Logging

Cement Bond Logs, Ultrasonic Casing Logs and Electromagnetic Casing Logs (CBL, MWIT, USIT, EMIT) will verify the initial integrity of the cement bond and well completion along the entire length of each injector. These will be re-acquired every five years during the injection period to verify continuing cement bond and casing integrity.

Hydraulic isolation testing will be carried out initially using temperature logs and RST logging after 3 – 6 months of injection to prove the initial integrity of the cement bond, and it is possible to repeat every year when the well is shut in for mechanical integrity testing (Section 7.2.4.6). RST logging has been used on a large number of CCS Projects to identify CO_2 accumulations behind casing.

Hydraulic isolation logging is required after two years of injection. Thereafter, the need will be determined by the annual reporting and presentation process as per AER approval condition 5c.

7.2.4.5 Hold-Up Depths

Hold-up Depths (HUD) should be measured at every wire-line entry in a well, and every 5 years before the CBL/MWIT/USIT/EMIT logs are run, to ensure no plugging exists across the perforation interval.

7.2.4.6 Distributed Temperature Sensing

Distributed Temperature Sensing (DTS) along an optical fiber permanently deployed from surface down to 11m above the first seal (MCS) in IW 5-35, 2 m above the MCS in IW 7-11 and 10 m above the base of the MCS in IW 8-19. All fiber optic cables, situated on the outside of the intermediate casing, will provide a continuous means of verifying cement bond integrity, hydraulic isolation, and the absence of CO_2 outside the casing and across the second and ultimate seals (Lower and Upper Lotsberg salts). In the unexpected event of a loss of cement bond integrity, any upward migration of CO_2 outside the casing will lower the temperature on the adjacent portion of the DTS fiber due to increased thermal insulation from the in-situ formation temperature provided by the out-of-place CO_2.

Evaluation of data acquired at IW 8-19 during the appraisal period and an initial site-specific feasibility study indicate DTS could detect temperature changes with a precision of 0.1^{o}Celsius and a vertical resolution of 1 m. This may allow detection of CO_2 flux of at least 10 kg/ day through a micro-annulus within the external cement bond. Further feasibility work is being carried out by Lawrence Berkley National Laboratories (LBNL) to refine these thresholds and the results are expected in February 2015. Observed monitoring performance during the injection period will also be used to validate or update these values. A static blanket of CO_2 cannot be directly distinguished from a flux of CO_2 outside the casing.

The DTS can also be used as a temperature log during hydraulic isolation testing; however, as it does not cover the MCS seal a standard temperature log will be run during such tests to comply with AER Condition 5i to report fluid movement into or above the MCS [1].

7.2.4.7 Distributed Acoustic Sensing

DAS along an optical fiber deployed alongside the DTS fiber may provide an independent means of verifying cement bond integrity and the absence of fluid flow outside the casing. In the unexpected event of a loss of cement bond integrity, any upward migration of fluids outside the casing will generate acoustic noise that reaches the adjacent portion of the DAS fiber. It is not known whether the amount of acoustic noise that would be generated for small flow would be sufficient to be detectable. Evaluation of data acquired at IW 8-19 during the appraisal period and site-specific feasibility studies indicate DAS will detect changes in the magnitude of acoustic noise with a vertical resolution of 1 to 5 m. Testing of acoustic levels during the injection period will be used to validate the possibility of using DAS acoustic monitoring for leak detection.

Other applications of the DAS technique are currently being developed and will also be tested during the injection period:

- Detection of small temperature changes which would give an improved sensitivity over the DTS
- Continuous microseismic acquisition and data analysis (on the DAS fiber)
- Using DAS to determine the mechanical integrity of the cement. This is a collaboration with LBNL that is expected to commence in early 2015

7.2.5 Monitoring Geological Seal Integrity

7.2.5.1 Continuous Pressure Measurements

Continuous pressure measurements (DHPT) within the deep monitoring wells will provide a means of detecting any unexpected migration of injected CO_2 or brine out of the BCS storage complex. Based on data obtained in the 2012 – 2013 drilling campaign, the Cooking Lake Formation is the interval that will be monitored for pressure.

DMW 5-35 and DMW 7-11 have both been completed with DHPTs in the Cooking Lake Formation. Pressures have been continuously monitored in these two wells since January 24, 2014. The installation of the third DHPT in DMW 8-19 has been delayed until Q1 2015 and will coincide with the re-installation of the microseismic monitoring array.

The pressure data collected from the two active DMW’s are displayed in Figures 7-6 and 7-7. Figure 7-6 illustrates a slight pressure building trend in the Cooking Lake Formation in DMW 7-11. It is premature to interpret the data as representative of the reservoir pressure changes or gauge drift at this point in time. However, this is an excellent example of the importance of collecting baseline data. If the baseline pressure data had not been recorded, then this trend may have been interpreted as evidence for CO_2 migration out of the storage complex and into the Cooking Lake Formation. Although, the gauges are measuring very precise pressures, Figure 7-7 illustrates that the accuracy of the gauges is about +/- 100 kPa. Therefore, an alarm trigger of +/- 200 kPa from the median value could be used to kick-off further evaluation.

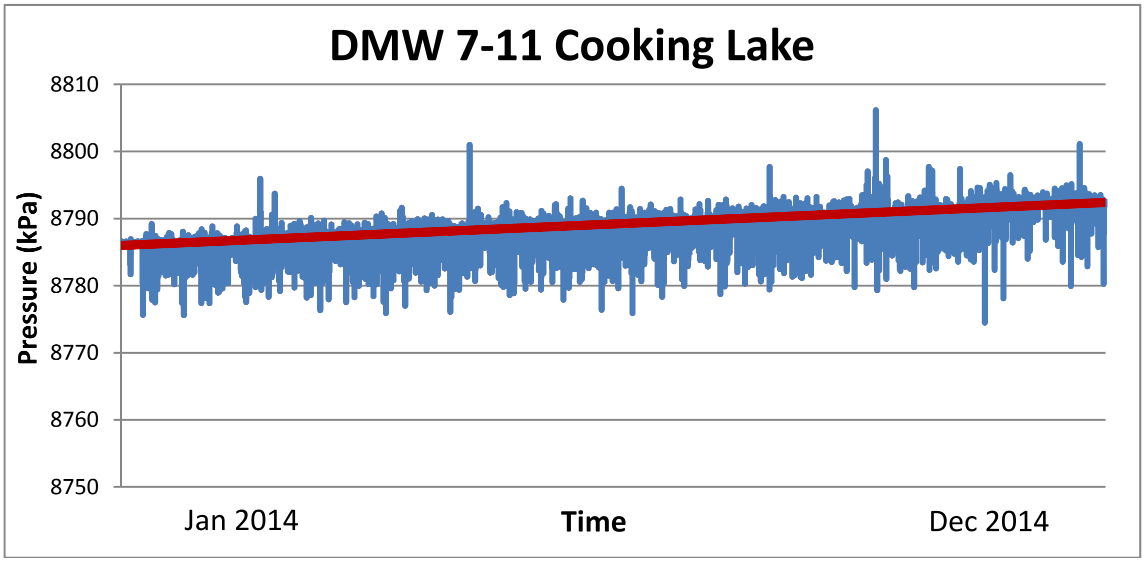

Figure 7-6: Bottomhole pressure for the DMW 7-11 in the Cooking Lake Formation. Pressures show an upward trend over time.

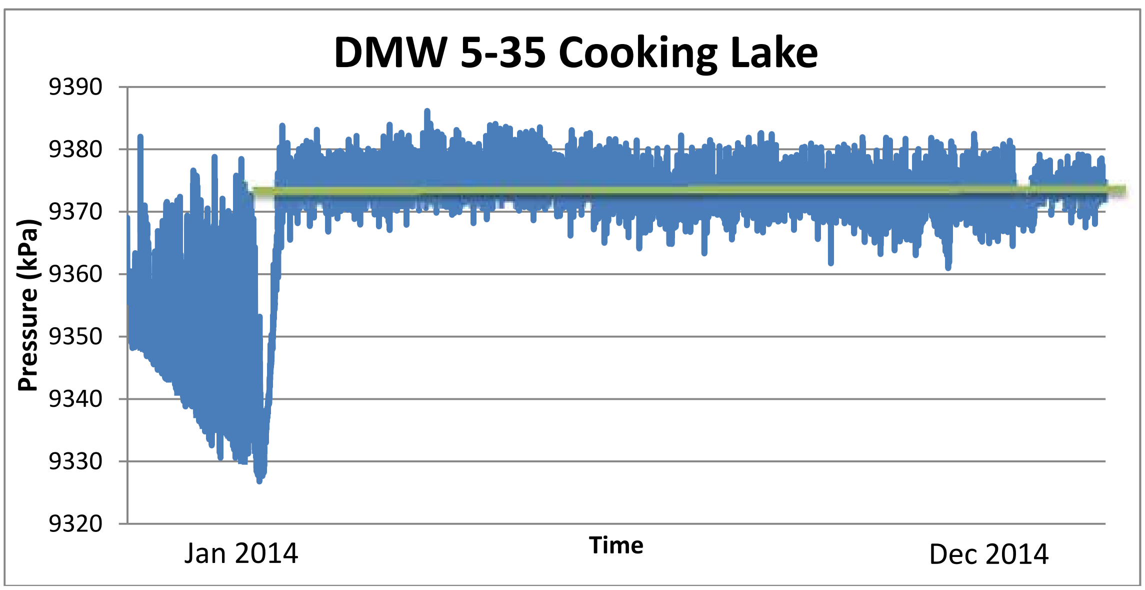

Figure 7-7: Bottomhole pressure for the DMW 5-35 in the Cooking Lake Formation.

Reservoir modelling has indicated that the pressure may be increasing in the Cooking Lake Formation at the DMWs as a result of the aquifer re-equilibrating itself after an extended period of production from the Leduc Reef. The amount of fluid migration into the Cooking Lake Formation that will cause a detectable sustained pressure rise has been assessed with the limited baseline pressure data available. The time to detection will depend on the distance through the permeable formation between the fluid entry point and the pressure gauge as well as the amount of gauge noise and impact from offset regional production in the Leduc reefs.

As the Redwater 3-4 well is located considerably closer to the Leduc Reef, any pressure data collected there could be used as a proxy for the Leduc Reef pressure response; this could greatly increase the project's ability to interpret what is actually happening within the Cooking Lake Formation. Therefore, Shell has requested Alberta Energy to include Redwater 3-4 into the scope of the previous consent to monitor pressures in the Cooking Lake Formation. This request is currently being reviewed .

7.2.5.2 Time-lapse Seismic Data

Time-lapse seismic data (VSP2D, SEIS3D) will be used to verify the absence of CO_2 above the ultimate seal of the BCS storage complex. In the vicinity of the wells, it is the Cooking Lake Formation that would be used to verify the absence of CO_2 above the storage complex as the Winnipegosis/ Contact Rapids formation is impermeable. However, away from the well control, other formations may be used (i.e. Winnipegosis/Contact Rapids, Beaverhill Lake Group etc.) as they are known to have reasonable permeability on a regional scale. Any CO_2 unexpectedly entering an overlying formation, will affect the seismic image due to the same physical effects previously described for CO_2 entering the BCS (Section 7.1.1.1). Due to different formation properties and different in-situ temperature and pressure conditions that affect the properties of CO_2, the magnitude of anticipated time-lapse seismic changes in the unexpected event of CO_2 entering these formations varies.

CO_2 saturation exceeding 5 to 10% is expected to reduce the velocity of seismic p-waves by *c.* 6% within the Winnipegosis Formation and 3% within the Cooking Lake Formation. The expected acoustic impendence changes by *c.* 7% and *c.* 4% within these two formations respectively. Seismic modelling studies indicate this velocity reduction will likely be detectable within time-lapse seismic images for a contiguous CO_2 plume of at least:

- *Winnipegosis Formation: 10 m thick and a lateral extent of at least 100-200 m*
- *Cooking Lake Formation: 10 m thick and a lateral extent of at least 100-200 m*

For an assumed average CO_2 saturation of 20 – 40% within such a CO_2 plume, this corresponds to an expected detection limit of 100,000 to 600,000 tonnes of CO_2. This expected sensitivity is based on a typical amount of non-repeatable noise being present within the two land seismic images which will only be confirmed after the monitor walkaway VSP surveys are acquired and is processed.

However, MDT sampling carried out in intervals below the Cooking Lake Formation indicate very low permeability in these formations at the well locations. The Contact Rapids core results in DMW 8-19 also shows permeability of the order on nanodarcies so it would take considerably more time for CO_2 saturation in these zones to reach a detectable level.

7.2.5.3 Microseismic Monitoring

Microseismic (DHMS) monitoring using an eight level conventional downhole geophone array that contains three-component retrievable geophones was deployed in DMW 8-19 in early 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 now elsewhere for more than ten years without failure.

Induced microseismicity results from fracture propagation, fault slippage, fluid movement, and pressure relaxation in a formation caused by pressure changes and associated stress states within the storage complex. Specifically with regard to the geologic seals within the storage complex, the microseismic array will be used to microseismic activity above the BCS that may be indicative of fracture propagation into the Lotsberg Salts.

Feasibility modelling predicts that microseismic events with M_o of –2 should be detectable out to 800 m, events with M_o = -1 should be detectable out to a distance of 3000 m and events with M_o = 0 should be detectable out to a distance of 10,000 m from the geophone array. Observed monitoring performance during the injection period will be used to validate or update these values.

The array began recording pre-injection data on November 6, 2014 in order to verify the absence of any induced microseismic activity within the vicinity of this injector prior to CO_2 injection. As of the end of January 2015, no ambient microseismic events have been detected within the monitoring range of the array.

7.2.5.4 Injection Pressure and Rate Monitoring

Injection pressure and rate monitoring (IRM, WHPT) are well and reservoir Shell standard critical equipment and will provide a continuous means to verify the absence of injection induced fracturing within the BCS:

- The flow rate at Scotford and on well sites will be measured with a coriolis mass flow meter with a minimum accuracy of +/ -0.5% of reading (typical ± 0.1%).
- The pressure will be measured with gauges with +/- 0.1% accuracy.
- The temperature will be measured with meters gauges+/- 0.5 ^oC accuracy.

These estimates are based on the technical specifications 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 will be used to ensure downhole injection pressures do not exceed their approved maximum values of 30 MPa [1]. The expected injection pressures based on the well test results and Gen-5 modelling are considerably lower than this threshold over the life of the project.

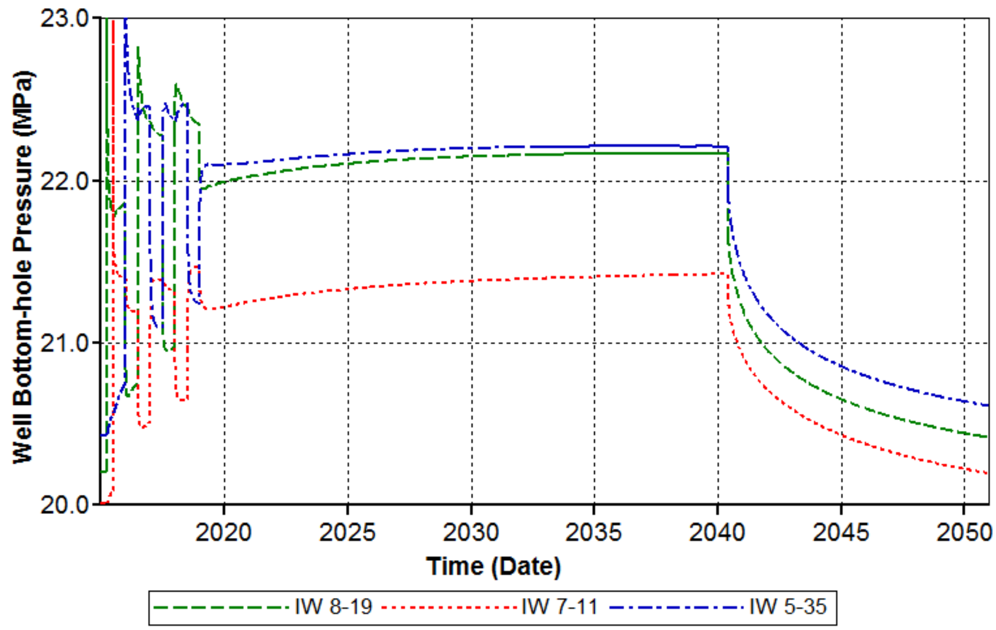

Figure 7-8: Expected injection pressures per well

7.2.5.5 InSAR

InSAR will provide monthly measurements of temporal and areal changes in surface displacements to verify the absence of any induced deformations above the storage complex that indicate a loss of containment. InSAR provides coverage across the whole sequestration lease with two distinct detection capabilities for containment verification:

- Escaped fluids: Unexpected migration of CO_2 upwards from the BCS storage complex will cause volume changes within any overlying permeable formations that receive these fluids. Any such volume changes above the ultimate seal will result in surface displacements additional to those expected due to pressure development inside the BCS storage complex. These additional surface displacements will be more localized in lateral extent. A feasibility study indicates migration of more than 250,000 tonnes of fluid from the BCS into the Mannville Group or Cooking Lake Formation are likely detectable. Due to the limited depth resolution achievable from surface displacement data, any unexpected volume changes inside the Winnipegosis Formation are too close in depth to be distinguished from the expected volume changes inside the BCS and LMS. However, any volume changes inside the shallower Cooking Lake Formation are likely to be detectable. Since the Cooking Lake Formation is under-pressured relative to the BCS pressure gradient, any leakage reaching this depth is likely to preferentially move into this formation.
- Fault slippage: There were no faults detected on 3D or 2D seismic data in the BCS storage complex. However, unexpected induced fault slippage will cause shear distortion within the subsurface resulting in a characteristic pattern of surface displacements distinct from those induced by subsurface volume changes. Evaluation of appraisal data and feasibility studies indicate fault slippage of at least 1 m over a fault length of 200 m that extends from the BCS to above the Lotsberg Salt will likely be detectable.

The observed performance of geological seal integrity monitoring during the injection period will be used to validate or update these performance values. As per ERCB Decision clause [346] in the case of loss of containment or unexpected surface heave, Shell will: *conduct and submit the results of, more comprehensive project modelling using site specific parameters to re-evaluate the issue of deformation caused by pressure changes* [3].

In addition, *on an annual basis and in the event of monitoring showing loss of containment or unexpected surface heave, Shell must address the feasibility and need for additional geomechanical testing on the remaining 1.5 m of preserved MCS core [4]*.

7.3 Modelling

A series of models will be run on a regular basis to provide an ongoing assessment of injection performance and if required updated to integrate the results of monitoring. These models will allow for early trending information on storage performance.

The models already in use for the Quest Project that are expected to be required during the project's lifecycle are shown below along with the accountable discipline (Table 7-3).

Table 7-3: Models currently in use for the Quest Project

Model	Accountable Discipline
Static Reservoir Model (3D) and Maps (2D)	Production Geosciences
Dynamic Reservoir Model	Reservoir Engineering
Integrated Production System Model	Production Technologist

Models will be updated in accordance with AER conditions 4, 6, 10c, 17f. In addition, Model updates will be submitted to the Minister of Energy as per of Regulation 19 3) c in accordance with the mines and mineral act Carbon Sequestration Tenure Regulation 68/2011.

7.4 Trigger Events and Detection Thresholds

Table 7-4 provides a description of events that will be used to trigger control responses designed to safeguard containment.

Table 7-4: Trigger events designed to safeguard containment. Continued performance monitoring of these technologies and data will be used to verify, and if necessary, update these events.

Technology	Indicator	Surveillance Frequency	Trigger Event	CO_2 Detection Capability
LightSource	CO_2 emission rate	Daily	Sustained locatable anomaly above background levels	~1 tonnes/day (well pads)
InSAR	Surface heave	Every Month	Unexpected localized surface heave	~250 kilo-tonnes
DTS	Temperature outside of intermediate casing	Daily	Sustained temperature anomaly outside casing	~0.01 t/d[i]
VSP2D	Seismic amplitude	Every year, maximum of 3[ii]	Identification of a coherent and continuous amplitude anomaly above the storage complex	100 – 600 kilo-tonnes
SEIS3D	Seismic amplitude	Every 5 to 10 years	Identification of a coherent and continuous amplitude anomaly above the storage complex	100 – 600 kilo-tonnes
DHPT CKLK	Pressure	Daily	Pressure increase 200 Kpa above background levels	20 tonnes/day[v]
DHMS	Locatable MS events	Daily	Sustained clustering of events with a spatial pattern indicative of fracturing upwards	0 tonnes
WPH	Water pH	Daily[iii]	Sustained decrease in baseline pH values	For a well 30m away from an injector it takes ~0.5 years for CO_2 to arrive for a 1 T/day leakage rate and ~0.07 years for CO_2 to arrive for a 10 T/day leakage rate [vi]
WEC	Water Salinity (electrical conductivity)	Daily[iii]	Sustained increase in baseline WEC values	
Geochemical Analyses	Table 7.2	Quarterly[iv]	Outside established baseline range	
Tracer	$\delta^{13}C$ value	Quarterly[iv]	Outside established baseline range	
Soil Gas	CO_2 concentration	Twice per year	Outside established baseline range	
Surface CO_2 Flux	CO_2 Flux	Twice per year	Outside established baseline range	

i – TBD - to be determined based upon ongoing DTS feasibility study expected by Q2 2015

ii - The second VSP timing will be based on the observed CO_2 plume growth rate rather than a preset date (i.e. it may occur 2 years after the previous one if plume migration is slow).

iii – Troll 9500 gauges in project wells (Section 6.2.3.1)

iv – Quarterly monitoring of project wells and those within the 1 km radius (Section 7.2.3.2)

v – A 1 MPa leak in the Cooking Lake Formation at an IW was modeled to trigger an event after about a month at the associated DMW.

vi - based on modeling work done for well 1F1-08-19-059-20W4 data.

8 Contingency Monitoring Plans

This section describes how the monitoring plan will be adapted in response to a range of unexpected but possible scenarios for under-performance of the monitoring systems. The monitoring plan comprises many diverse monitoring technologies. Each was selected on the basis of site-specific technical feasibility evaluations that indicate its likely suitability for the task. Because containment monitoring is a safety-critical task, multiple independent monitoring systems are designed to fulfill each containment monitoring task. This multiple-redundancy is designed to mitigate the risk of unexpected under-performance of an individual monitoring system – this form of contingency is built into the base-case monitoring plan.

The same approach is not required for conformance monitoring systems as any unexpected under-performance in this domain is not immediately safety-critical. This means the risk of failed conformance monitoring may be mitigated by developing alternative monitoring systems that are ready to be deployed only in the unexpected event that they are required. The following sections describe these contingency plans for conformance monitoring and for selected containment monitoring systems that require adaptation or replacement should they under-perform.

8.1 InSAR

Surface displacements are too small to support reliable imaging of volume changes inside the BCS storage complex

- **Reason:** Volumes changes inside the BCS storage complex are smaller than expected due to smaller than expected pressure increases or larger than expected bulk stiffness of the BCS or LMS.
- **Indicator:** The observed maximum rate of surface displacement is less than 0.87 mm/year.
- **Mitigation:** Evaluate the value of information associated with drilling additional BCS observation wells designed to monitor the areal distribution of pressure changes inside the AOR. Note if pressure increases are expected to remain below 3.3 MPa at the injection wells then these observation wells may not be required as there would never be sufficient pressure to lift BCS brine above the base of groundwater protection.

  According the AER D65 final approval and conditions, Shell must address the need to drill additional deep monitoring wells near legacy wells and need for additional monitoring wells the periphery of the pressure build up area in the Annual Operations Reports due March 31 of each year.
- **Response time:** 12 months are likely required to agree land access, gain well licenses and to drill and complete these wells. Note: Although GPS and optical leveling methods provide alternatives means of monitoring surface displacements, neither are able to detect surface displacement rates less than 1mm/year.

Unexpected surface uplift cannot be reconciled by volume changes inside the storage complex

- **Reason:** The input data for the current site-specific homogeneous linear elastic half-space geomechanical model are not appropriate.
- **Indicator:** The observed maximum uplift is greater than 12 mm, the maximum computed surface uplift expected after injection of 27 million tonnes of CO_2 over 25 years based on the Gen-5 model and InSAR Feasability update [reference to draft report].
- **Mitigation:** Unexpected surface uplift would first trigger an attempt at model updating to restore conformance. These model updates would include updating the pressure build-up within the storage complex using site-specific pressure measurements and updating the elastic parameters (e.g. Young's modulus - only significant remaining uncertainty) of the formations that experience this pressure build-up.

  If the unexpected uplift still cannot be reconciled with volume changes inside the storage complex then additional model updates studies to investigate the possibility of a shallower source would be appropriate. Subject to the results of these studies, contingency monitoring such as a time-lapse seismic survey might be appropriate depending on the particular circumstances at that time.

  As per ERCB Decision clause [346] in the case of loss of containment or unexpected surface heave, Shell will: *conduct and submit the results of, more comprehensive project modelling using site specific parameters to re-evaluate the issue of deformation caused by pressure changes* [3].

  In addition, Shell: *will evaluate the feasibility and need for additional geomechanical testing on the remaining 1.5 m of MCS core currently preserved and stored by Shell on an annual basis* [4].

8.2 Time-lapse Seismic Data

Time-lapse repeatability of VSP data acquired using the DAS system is insufficient

- **Reason:** DAS fiber performance is less than expected based on initial field trials at IW 8-19.
- **Indicator:** The relative repeatability ratio (RRR) of DAS data exceeds 0.4.
- **Mitigation:** Acquire additional repeat VSP surface using a temporarily-deployed conventional down-hole geophone array.
- **Response time:** 3 – 9 months are likely required to identify the problem and mobilize a conventional geophone array for a repeat survey.

Time-lapse seismic data changes are too small to image the CO_2 plume

- **Reason:** The reduction in seismic velocity of the BCS due to the presence of CO_2 is smaller than expected.

- **Indicator:** The ratio of relative repeatability (RRR) is less than 0.4 but time-lapse changes observed around the injector are indistinguishable from time-lapse noise observed away from the injector.
- **Mitigation:** Rely on modelling plume dimensions and or evaluate the value of information and containment risk associated with drilling additional BCS observation wells designed to monitor future areal extent of the CO_2 plumes.
- **Response time:** For additional observation wells 12 – 18 months are likely required to select locations, receive necessary consents for land access, obtain well licenses and to drill and complete these wells

The rate of CO_2 plume growth is different than expected

- **Reason**: Uncertainty about reservoir properties such as relative permeability result in a CO_2 plume growing at a rate substantially different from the median predicted rate.
- **Indicator:** According to the observed plume size, VSP coverage is expected to be insufficient to image at least half of the CO_2 front at the time of the next scheduled VSP survey.
- **Mitigation:** Switch from VSP to surface seismic for monitoring the CO_2 plume.

8.3 Microseismic Monitoring

The selected microseismic monitoring well provides insufficient coverage

- **Reason:** Observed BCS pressure build-up around an injector not covered by microseismic monitoring has the potential to induce microseismicity that poses a risk to containment.
- **Indicator:** Down-hole pressure at an injector not covered by microseismic monitoring is consistently limited to the maximum injection pressure.
- **Mitigation:** Deploy recording systems to monitor microseismic activity using deep arrays within the deep monitoring wells near the identified injection wells.
- **Response time**: 3 – 6 months are likely required to deploy these recording systems on a single injection well pad.

A single microseismic monitoring system provides insufficient coverage

- **Reason:** Unexpected microseismic events that appear to have an upward spatial pattern indicative of fracturing are observed by the single conventional downhole geophone array. The spatial pattern may be indicative of an event common to all injection wells and there is a reasonable possibility of similar unexpected microseismic events associated with the other CO_2 injection wells.
- **Indicator:** Sustained microseismic activity located within and above the Lower Lotsberg Salt with spatial patterns indicative of fracturing.

- **Mitigation:** Deploy recording systems to monitor microseismic activity using deep arrays within the deep monitoring wells near every injector
- **Response time:** 6 – 12 months are likely required to deploy these recording systems on every injection well pad.

8.4 BCS Direct Pressure Monitoring

The Redwater 3-4 appraisal well, located just inside the southern edge of the sequestration lease area may be completed in the BCS if there is evidence of far field pressure increase. With the low injection pressures expected for this project the associated pressure response at the Redwater 3-4 will be too small to measure. After a couple of years of injection it should be clear that the pressure will never rise to a detectable level.

Reservoir pressure increase to levels that can be measure in the far field.

- **Reason:** Lower than expected reservoir properties result in a smaller tank to store CO2.
- **Indicator:** The pressures are increasing at the injection wells quicker than expected and extrapolate to higher pressures than expected.
- **Mitigation:** Complete the Redwater 3-4 well in the BCS to collect far field pressure response data.
- **Response time:** 3 – 6 months are likely required to identify the opportunity and mobilize a completion rig.

9 Storage Risks after MMV

Initial storage risk reductions are achieved through multiple independent safeguards implemented through site selection, site characterization, and engineering concept selections. These initial passive safeguards are sufficient on their own to make the loss of containment extremely unlikely (Table 4-4).

The monitoring plan provides a comprehensive and reliable means to verify the effectiveness of these initial passive safeguards. In the extremely unlikely case that this monitoring indicates a potential loss of containment then a wide range of control measures can be deployed in a timely fashion to effectively prevent, mitigate, or remediate any actual loss of containment (Table 9-1 and 9-2). These additional active safeguards must be triggered by monitoring and are designed to be sufficiently numerous and diverse to yield significant additional storage risks reductions.

This section summarizes the number, type and expected effectiveness of these additional active safeguards.

Table 9-1: Control response options to prevent any unexpected migrations of fluids out of the BCS storage complex

Injection Controls:
Redistribute injection across existing wells
Drill new vertical or horizontal injectors
Extract storage formation fluids to reduce pressure
Stop injection
Well Interventions
Repair leaking well by re-plugging with cement
Repair leaking injector by replacing completion
Plug and abandon leaking wells that can not be repaired

Table 9-2: Control response options to correct any unexpected migrations of fluids out of the BCS storage complex

Well Interventions:
Repair leaking well by re-plugging with cement
Repair leaking injector by replacing completion
Plug and abandon leaking wells that can not be repaired
Exposure Controls
Inject fluids to increase pressure above leak
Inject chemical sealant to block leak
Contain contaminated ground water with hydraulic barriers
Replacement of potable water supplies
Remediation Measures
Pump and treat
Air sparging or vapour extraction
Multi-phase extraction
Chemical oxidation
Bioremediation
Electrokinetic remediation
Phytoremediation
Monitored natural attenuation
Permeable reactive barriers
Treat acidified soils with alkaline supplements

9.1 Additional Safeguards to Ensure Conformance

The following monitoring-supported safeguards are planned to prevent or correct a situation where the lateral extent of the CO_2 plumes or pressure build-up exceeds their model-based predictions.

CO_2 plume development

- **Monitoring:** Time-lapse seismic data
- **Intervention Indicator:** The observed CO_2 plume is larger than the baseline 3D seismic area, or there is a clear temporal trend towards this state.
- **Control Options:** Update models and rely on only model based predictions. If necessary increase the areal extent of the baseline 3D seismic survey. Consider re-

distributing injection across existing wells or drilling additional injection wells to keep the plume within the footprint of the original 3D seismic area.

- **Response Time:** 3 – 6 months for model updates or additional seismic surveys. Re-distribution of injection between existing wells is available on demand. Drilling additional injection wells will take 12 – 18 months and are subject to additional regulatory approvals and land access consents.

Pressure development

- **Monitoring:** BCS pressure gauges and InSAR.
- **Intervention Indicator:** The observed lateral extent of pressure rise sufficient to lift BCS brine above the base of groundwater protection is larger than the current monitoring area or there is a clear temporal trend towards this state.
- **Control Options:** Update models and rely on only model based predictions. If necessary, increase the areal extent of the InSAR data acquisition.
- **Response Time:** 3 – 6 months for model updates. 1-3 months to schedule additional InSAR data acquisition.

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

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%
- **Intervention Indicator:** 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. This is subject to revision as the regulatory framework assessment is ongoing.
- **Control Options:** Recalibrate or, if necessary, replace meters or revise the performance target.
- **Response Time:** 1 – 3 months.

Target inventory of CO_2

- **Monitoring:** Down-hole pressure monitoring for each injector.
- **Intervention Indicator:** The rate of pressure increase on each injector is large enough to reach the maximum down-hole injection pressure (26 MPa) before the end of the injection period.
- **Control Options:** Drill additional injection wells.
- **Response Time:** 6 –12 months are likely required to drill an additional injector in one of the remaining pre-selected locations.

Each aspect of conformance is managed by a single monitoring system designed to trigger one of several possible control measures. This collection of control measures is expected to be effective at ensuring conformance provided the monitoring systems perform as expected. The possibility of unexpected poor monitoring performance is mitigated by contingency monitoring plans that will provide timely alternative systems to monitor conformance (Section 8). The likelihood of an unexpected loss of conformance despite the control measures in-place is judged to be low (see Table 4-4).

9.2 Additional Safeguards to Ensure Containment

The following monitoring supported safeguards are planned to prevent or correct any potential loss of containment.

Safeguards supported by Pressure Monitoring

- **Monitoring:** BCS pressure gauges and InSAR.
- **Intervention Indicator:** BCS pressure increase at a legacy well is sufficient to lift brine above BGP or there is a clear temporal trend towards this state.
- **Control Options:** 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. 3 –6 months are likely required to drill a project groundwater well and 6 – 12 months to drill an additional deep monitoring well at the legacy well locations.

Safeguards supported by injection well integrity monitoring

- **Monitoring:** Cement bond logging, tubing-casing annulus pressure monitoring, casings annuli pressure monitoring, mechanical well integrity monitoring, corrosion coupons, distributed temperature sensing, distributed acoustic sensing, Cooking Lake Formation pressure monitoring, time-lapse seismic data
- **Intervention Indicators:** significant deterioration of cement bond, increase in sustained annulus pressure above expectation, failed well integrity test, sustained temperature or noise anomaly outside casing, sustained Cooking Lake Formation pressure, or a time-lapse seismic anomaly around the injection well within the Winnipegosis Formation or shallower.

- **Control Options:** 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 re-plugging with cement, or plug and abandon an injector that cannot be repaired, and drill a replacement well.
- **Response Time:** Continuous pressure monitoring supports an automated instant control response to re-distribute injection (Section 10.1). 1 – 3 months are likely required to plan and execute a well intervention. 6 – 12 months are likely required to drill an additional injector in one of the remaining pre-selected locations.

Safeguards supported by geological seal integrity monitoring

- **Monitoring:** BCS pressure monitoring, Cooking Lake Formation pressure monitoring, time-lapse seismic data, InSAR, downhole microseismic monitoring
- **Intervention Indicator:** BCS injector pressure exceeds agreed limits, 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.
- **Control Options:** 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 (see Section 10.1). Microseismic monitoring requires 1 month for processing and interpretation. Time-lapse seismic data and InSAR monitoring requires 2 – 4 months for processing and interpretation. 6 –12 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 24 months.

Safeguards supported by hydrosphere monitoring

- **Monitoring:** Project groundwater wells with continuous water electrical conductivity and pH measurements, regular groundwater sampling and geochemical analyses of all project groundwater wells and a selection of private landowner groundwater wells.
- **Intervention Indicator:** Sustained increase in water electrical conductivity, sustained decrease in pH, presence of project-specific tracers within groundwater samples.
- **Control Options:** 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.

Safeguards supported by biosphere monitoring

- **Monitoring:** Soil gas flux and tracer analysis at well locations
- **Intervention Indicator**: Soil gas flux and /or project-specific tracers measured outside of expected range.
- **Control Options:** 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.

Safeguards supported by atmosphere monitoring

- **Monitoring:** LightSource (Line-of-sight CO_2 gas flux monitoring)
- **Intervention Indicator:** Sustained localized increase in CO_2 flux confidently exceeds background levels established during the baseline monitoring period.
- **Control Options:** 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.

Figure 9-1 illustrates these additional active safeguards and their relationship to the identified threats and consequences. The diversity of monitoring within the injection wells and inside the BCS storage complex provides multiple means to trigger many different preventative controls without relying on any single monitoring system. This is expected to provide a significant additional containment risk reduction. Furthermore, the multiple monitoring systems designed to verify the absence of environmental impacts provide additional triggers, if necessary, to deploy timely mitigation or remediation of potential effects within the hydrosphere and biosphere. This is expected to provide a further additional containment risk reduction.

The reduction in containment risk achieved by additional active safeguards is judged to be commensurate with the risk reduction already achieved through initial passive safeguards (Figure 9-1). Moreover, the trend of diminishing risk reductions achieved for each additional safeguard provides a clear indication that efforts to implement additional safeguards are not expected to result in any appreciable further risk reduction[i].

[i] This is one possible means of demonstrating storage risk is reduced to as low as reasonably practicable.

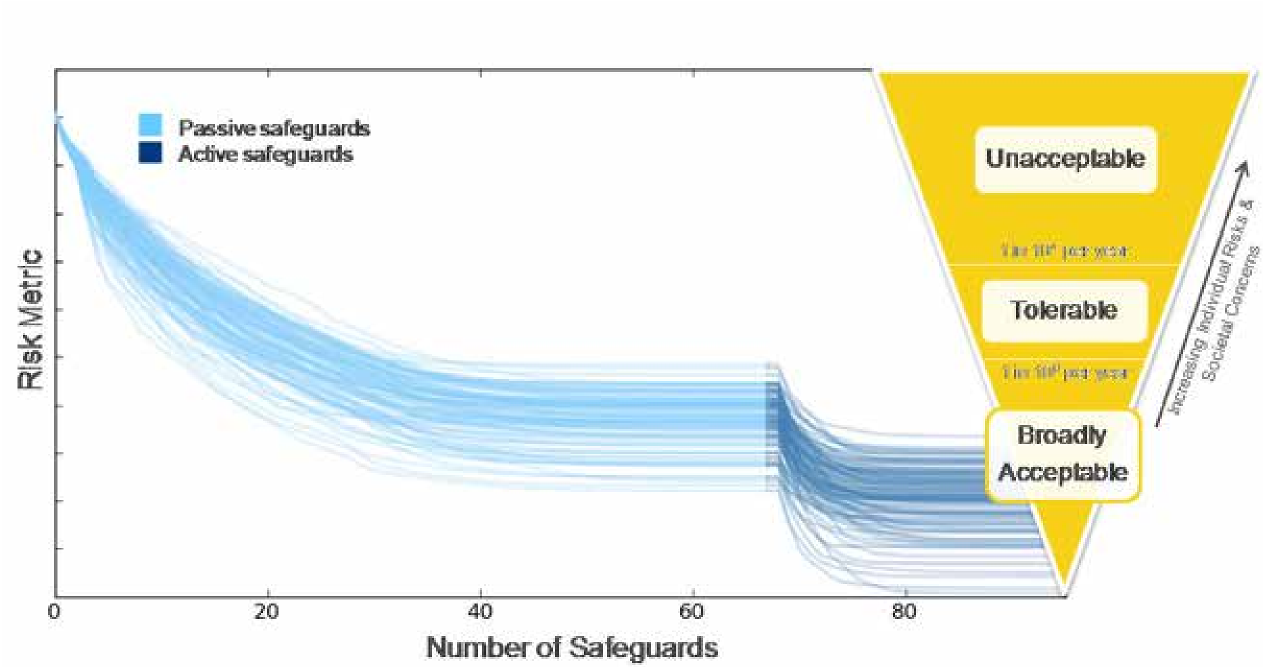

Figure 9-1 Representation of the expected containment risk reductions achieved through implementation of passive and active safeguards.

Note - Passive safeguards depend on site selection and engineering concept selections. Active safeguards are control measures triggered by monitoring for unexpected storage behaviour. This risk assessment is a systematic evidence-based process reliant on collective expert judgment. Uncertainty in this assessment is represented by the multiple lines showing the range of possible scenarios. Note that vertical scale is logarithmic. Increasing individual risks and Societal Concerns values are from UK Health Safety Executive, 2001.

10 Operating Procedures

Shell will operate the Project in accordance with AER Approval 11837A Conditions [1], the decision report [3] and the Mines and Minerals Act Carbon Sequestration Tenure AR 68/2011 [5]. According to the AER Approval Conditions [1] 5f, 5g, 5i, & 6 specifically relate to operation procedures and will be adhered to as follows:

8) Condition 5f – inform WeIlOperations@aer.ca if leak or potential leak detected in the tubing/casing annulus or packer in the injection well
9) Condition 5g – immediately suspend injection and notify WeIlOperations@aer.ca if fluid movement above BGWP or any zone outside the BCS storage complex
10) 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 WeIlOperations@aer.ca
11) Condition 6 and 25 – provide written incident report within 90 days to ResourceCompliance@aer.ca, WeIlOperations@aer.ca and AESRD 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
12) Condition 26 – immediately notify the Ministry of Environment and Sustainable Resources Development 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.

10.1 Operating Procedures in Response to Monitoring Trigger Events

Several continuous monitoring systems on each injection well may trigger automated alarms in the Scotford Control Room. The operating procedures to immediately response to these alarms are as follows.

Wellhead pressure and temperature gauge alarm

Case 1:

- **Alarm indicates:** Injection pressure exceeds maximum injection pressure.
- **Alarm response:** The well-choke will automatically starts to close until the injection pressure is below the maximum injection pressure.

Case 2:

- **Alarm indicates:** wellhead pressure is below minimum allowable wellhead pressure

- **Alarm response:** alarm goes off at Scotford and the well-choke closes automatically

Down-hole pressure and temperature gauge alarm

- **Alarm indicates**: down-hole injection pressure exceeds maximum injection pressure.
- **Alarm response**: Alarm goes off at Scotford, operator to check wellhead pressure for consistency and contact SCAN Surveillance team.

Annulus pressure gauge alarm

- **Alarm indicates:** sustained annulus pressure above defined threshold.
- **Alarm response**: Alarm goes off at Scotford, operator to check gauge on location for consistency and contact SCAN Surveillance team.

  (Note: this applies to the tubing annulus gauge (in the base plan) but also to any annular gauges installed in case a casing shoe is tested leaking below 15 MPa.)

Pressure drop across filter alarm

- **Alarm indicates:** pressure drop across filter above maximum allowable value
- **Alarm response:** Alarm goes off at Scotford. Scotford to check on location status of the filter and plan for maintenance.

Emergency shut-down (ESD) valve status alarm

- **Alarm indicates:** ESD is closed.
- **Alarm response:** Alarm goes off at Scotford to confirm closed status of ESD.

Uninterruptible Power Supply (UPS) status alarm

- **Alarm indicates:** UPS is down.
- **Alarm response:** Scotford to investigate and restore UPS on location.

Other continuous monitoring systems may trigger automated alarms in Calgary that require an initial prompt response from the Surveillance Team such as:

LightSource (Line-of-sight CO_2 gas flux monitoring alarm

- **Alarm indicates:** Localized CO_2 *flux exceeds threshold established* **Alarm response:** Environmental Team will investigate this location and collect samples suitable for CO_2 tracer analysis.

Hydrosphere or Biosphere trigger event

- **Trigger event indicates:** Water electrical conductivity above expected threshold/ trigger values, water pH below expected threshold/ trigger values, and/or project trigger greater than 1 for hydrosphere; landowner complaint for hydrosphere and biosphere
- **Alarm response:** Environmental Team will investigate using an integrated response plan-IRP (Figure 10-1) with primary and secondary checks. Skill, experience, and project-specific judgment is required for secondary checks.

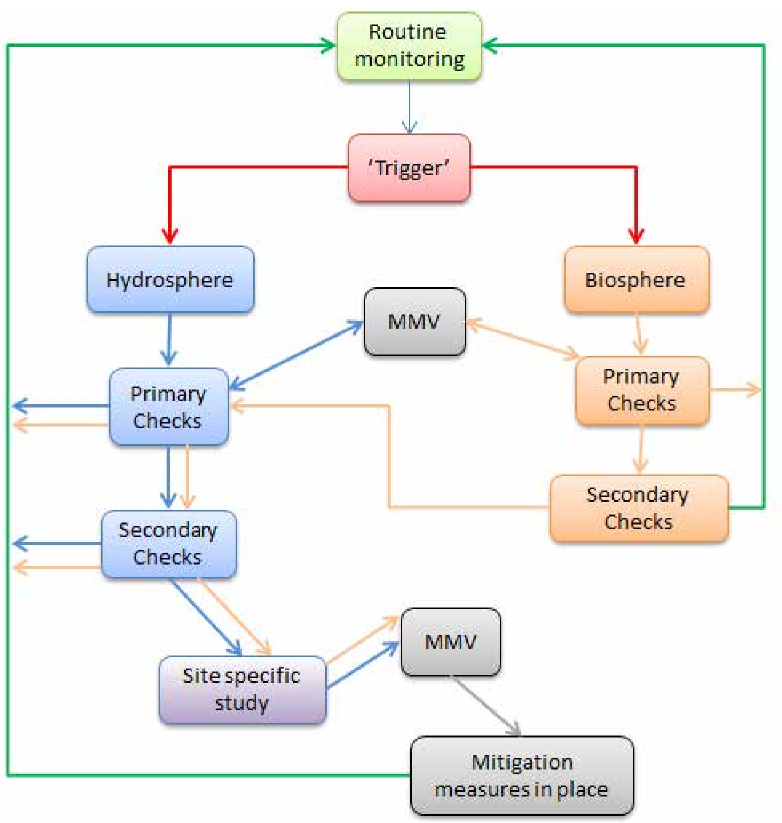

Figure 10-1: Schematic overview of Integrated Response Plan

Nb:

Primary checks, e.g. [13]:

- Check for data issues (e.g. misidentified well name, wrong sample number, transcription errors, unit errors etc.).
- Check the Quest database integrity.

Secondary checks, e.g. [13]:

- Assess whether or not groundwater wells in the vicinity of the trigger event are also indicative of an HBMP trigger event or changes, even if a trigger has not been flagged.
- If a second analysis of the sample causing the trigger is required, but no sample is available, an additional field sample would be required.

The IRP relies on a sequential process to evaluate anomalous monitoring results observed during the routine monitoring program of the injection or closure periods. The integrated response plan provides a means to:

i. assess whether the observed change is 'real' or not
ii. in the case of 'real change' assess what cause(s) are responsible for the change
iii. suggest mitigation measures to protect the environment.

The IRP operates as follows when a Hydrosphere or Biosphere 'trigger' event occurs:

a. Trigger event within Hydrosphere:
   - Primary checks and other monitoring domains of the MMV plan
     - OK: return to routine monitoring
     - AMBIGUOUS: perform secondary checks
   - Secondary checks:
     - OK: return to routine monitoring
     - NOT OK: initiate site specific study
   - Site specific study
     - Undertake in-depth site specific study
     - Integrate findings from other monitoring domains of the MMV plan
     - Identify and implement mitigation measures
     - Return to routine monitoring

b. Trigger within Biosphere:
   - Primary checks and other monitoring domains of the MMV plan
     - OK: return to routine monitoring as per current MMV plan
     - AMBIGUOUS: perform secondary checks
   - Secondary checks:
     - OK: return to routine monitoring as per current MMV plan
     - AMBIGUOUS: perform hydrosphere primary checks
   - Primary checks (hydrosphere)
     - OK: return to routine monitoring
     - AMBIGUOUS: perform secondary checks
   - Secondary checks (hydrosphere)
     - OK: return to routine monitoring
     - NOT OK: initiate site specific study
   - Site specific study
     - undertake in-depth site specific study
     - integrate findings from other monitoring domains of the MMV plan
     - identify and implement mitigation measures
     - return to routine monitoring

Distributed temperature sensing alarm

- **Alarm indicates:** Sustained low temperature anomaly migrating upwards above the first seal.
- **Alarm response:** Stop injection at this well. The Surveillance Team will investigate and, if necessary plan additional logging or an appropriate well work-over, before re-starting injection.

Down-hole microseismic monitoring alarm

- **Alarm indicates:** Sustained clustering of microseismic events with an upward spatial pattern indicative of fracturing
- **Alarm response**: Stop injection at the adjacent injector. The Surveillance Team will investigate and, if appropriate re-start injection at lower rates and only increasing injection rates when no further microseismic activity is detected above the base of the *Lower Lotsberg Salt.* The injection rate in other wells would then need to be similarly reduced. In accordance with Condition 6 of the AER approval Shell would submit an incident report to ResourceCompliance@aer.ca and WellOperations@aer.ca within 90 days of detecting the incident.

References

[1] Alberta Energy Regulator Carbon Dioxide Disposal & Containment Approval No. 11837A. Issued to Shell Canada Limited August 8, 2013.

[2] Carbon capture & Storage - Summary Report of the Regulatory Framework Assessment- Government Of Alberta

[3] Energy Resources Conservation Board Decision 2012 ABERCB 008: Shell Canada Limited, Application for the Quest Carbon Capture and Storage Project, Radway Field. Energy Resources Conservation Board, Calgary Alberta. July 10, 2012.

[4] Alberta Energy Regulators. Quest Carbon Capture and Storage Project Radway Field & Surrounding Areas AER Approval No. 11837A, AER Decision 2012 ABERCB 008 Special Report #1 & Pre-baseline MMV Plan October 15, 2012 Submission. Updated Approvals and Conditions. Received December 3, 2013.

[5] Government of Alberta Energy Carbon Sequestration Lease No. 5911050001, 5911050002, 5911050003, 5911050004, 5911050005, 5911050006, granted by Her Majesty to Shell Canada Limited on the commencement date of May 27, 2011. CCSLSE 01/05/11.

[6] Alberta Regulation 68/2011, Mines and Minerals Act, Carbon Sequestration Tenure Regulation. 10/1/2012.

[7] Carbon Sequestration Lease Application – Shell Quest Carbon Capture and Storage Project. Submitted to Alberta Energy Tenure Branch. April 28, 2011.

[8] Shell Canada Limited Quest Carbon Capture and Storage Project, Directive 65: Application for a CO_2 Acid Gas Storage Scheme. Submitted to Energy Resources Conservation Board of Alberta November 2010.

[9] SPECIAL REPORT #3 - Tracer Feasibility Report submitted to the AER on 16th June 2014.

[10] Quest Carbon Capture and Storage Project, Shell Response to the Groundwater Review Submission. Tab B. AER hearing 2012 ABERCB 008 exhibit 134.04. sent by Shell February 28, 2010.

[11] Shell Quest Carbon Capture and Storage Project: First Annual Status Report. Submitted to AER January 31, 2013 as per Carbon Dioxide Disposal Approval 11837A Conditions 10 and 11.

[12] Shell Quest Carbon Capture and Storage Project: Second Annual Status Report. Submitted to AER January 31, 2014 as per Carbon Dioxide Disposal Approval 11837A Conditions 10 and 14.

[13] Brydie, J., Jones, D., Perkins, E., Jones J-P, and Taylor, E., 2014. Draft Final Report: Groundwater Study for the Quest Carbon Capture and Storage (CCS) Project, Confidential Client Report to Shell Canada Energy, Alberta Innovates – Technology Futures.

Appendix A: Emerging MMV Guideline

Emerging MMV Guidelines

A.1 Introduction

According to the Kyoto Protocol and the Copenhagen Accord, project activities under the Clean Development Mechanism (CDM) must result in emission reductions that are "real, measurable and long-term". CCS offers one route towards achieving such emissions reductions. The Intergovernmental Panel on Climate Change found that existing technologies are sufficient to meet these requirements for monitoring and verification of underground geological storage of CO_2.

The Greenhouse Gas Inventory Guidelines consider underground storage sites to be a source of CO_2 emissions. This means the difference between the amount of injected and emitted CO_2 is a measure of the inventory of stored CO_2. For potential CCS CDM projects to be an effective mitigation for climate change, annual CO_2 emissions rates should be less than 0.01% of the mass of CO_2 stored underground, or perhaps less than 0.001%. The IPCC evaluated a wide range of feasible monitoring methods for detecting emissions from an underground storage site and concluded the performance of each individual method will be site specific.

The IEA Greenhouse Gas Research and Development Program supported the development of guidelines in three key areas related to monitoring for verification of geological storage of CO_2:

Risk assessment,

Monitoring tool selection

Site selection, characterization and qualification

The latter, developed by a joint industry project (JIP) including Shell and led by Det Norske Veritas (DNV), represent the most comprehensive guidelines and examples yet for safe and sustainable geological storage of CO_2. This JIP advocates a site-specific risk-based approach.

Independently, the World Resource Institute issued general guidelines for CCS operators and regulators, including recommendations for monitoring and verifications plans to follow a site-specific risk assessment that allows flexibility to select appropriate monitoring methods adapted through time to suit the different risk profiles at each stage of the project.

A.2 Future Regulatory Expectations

The volume and time-scale of CO2 storage required for CCS to be an effective mitigation for climate change greatly exceeds the existing experience acquired through Acid Gas Disposal projects. In order to make sure that the right regulations are in place before full-scale CCS projects start operating, the Government of Alberta initiated a process called the Regulatory Framework Assessment (RFA) in March 2011. This process looked at the regulations that currently apply to CCS in Alberta as well as regulations and best practices in other parts of the world. It examined in detail the technical, environmental, safety, monitoring and closure requirements that apply to a CCS project. To ensure

that the regulatory review was complete and balanced, many Canadian and international experts from industry, universities, research organizations, environmental groups and provincial and national governments participated. This multi-stakeholder process was guided by a steering committee and included an international expert panel, and four specialized working groups that examined various CCS-related issues in detail. The RFA concluded in December 2012 and a report was published (Carbon capture & storage - Summary Report of the Regulatory Framework Assessment)

The Canadian Standards Association (CSA) developed Canada's first carbon capture and storage standard for the geologic storage of industrial emissions (Z741-12 - Geological storage of carbon dioxide issued in 2012). Shell participated in the review of this standard. An effort is also underway to develop an International Standard with the International Standards Organisation (ISO). Shell is participating in the Canadian Mirror Committee for the development of this standard.

Several international authorities published guiding principles for CCS developments to aid the harmonization of standards between jurisdictions. These are likely to influence future regulations.

A.3 Government Authorities

Many governments are developing country-specific frameworks for CCS regulations: Australia, Brazil, Canada, China, European Union, Germany, Indonesia, Norway, Poland, Qatar, South Africa, The Netherlands, UK, and USA. Some of this initial work adds to the existing guidance from international authorities.

European Union: The European Council Directive on permanent underground CO_2 storage has developed the OSPAR principles for monitoring and stated the following six objectives for monitoring.

Demonstrate CO_2 behaves as expected.

Detect any migration or leakage.

Measure any environmental or health damage.

Determine effectiveness of CO_2 storage as GHG mitigation.

In case of leakage, assess effectiveness of corrective measures.

Update risk assessment and monitoring plan based on performance of the storage site.

Further monitoring requirements arise because the transfer of liability to the authorities after site closure is contingent on demonstrating the permanence of CO_2 storage according to three criteria.

Actual CO_2 behavior conforms to modeled behavior within range of uncertainty.

Absence of any detectable leaks.

Storage site is evolving towards long-term stability.

The European Council Monitoring and Reporting Guidelines (MRG), a draft amendment to the Emissions Trading Scheme (ETS), also stipulate additional monitoring requirements beyond the 2009 EC Directive in the instance of detecting actual emissions from the storage site to quantify the emissions and the efficacy any remediation activities.

United Kingdom: Government response to consultation on CCS accepts four key clarifications of the monitoring requirements for CCS.

Monitoring should cover the volume affected by CO_2 storage rather than just the volume occupied by the CO_2 plume itself.

The post-closure period before transfer of liability will be determined individually for each project depending on the behaviour of the storage site during operation based on evidence from the monitoring program.

The duration and type of post-transfer monitoring will be decided based on evidence from the monitoring program and will determine the 'transfer fee'.

Site closure includes removal of infrastructure and sealing of wells before handover to the authorities with the possible exception of some wells that may be maintained for monitoring purposes.

A subsequent study commissioned by the UK identified technologies and methodologies judged suitable for MMV in the UK.

USA: Environmental Protection Agency (EPA) consultation on Federal requirements for geological storage of CO_2 (EPA 2008) proposed broadly similar monitoring requirements to elsewhere.

The Area of Review (AOR) for monitoring is considered to include the pressure front defined as the region of elevated pressures sufficient to cause movement of formation fluids into the protected groundwater zone.

Determination of the AOR is initially based on predictive models and should be re-determined in the event of any significant discrepancy between predicted and actual performance or within 10 years of the last determination, whichever is the sooner.

Monitoring the CO_2 plume and pressure front may be achieved with a combination of direct and in-direct techniques selected according to site-specific requirements.

Continuous monitoring of injection with automatic alarms and shut-off equipment is recommended as an important safety consideration. The EPA proposes to require down-hole safety shut-off value.

Duration of the site closure period is not specified but anticipated to be determined according to demonstrated performance of the storage site.

EPA proposes a quantitative risk assessment methodology as a high-level approach towards determining the suitability of sites for geological storage of CO_2. The US Department of Energy's National Energy Technology Laboratory (NETL) provides guidance for MMV, including a classification of monitoring technologies according to their readiness for monitoring CO_2 storage sites.

A.4 Industry Authorities

Advocacy by industries and companies with relevant expertise may influence future regulations.

CO_2QUALSTORE: A joint industry project (JIP) led by Det Norske Veritas (DNV) includes partners from a number of sectors; oil and gas companies (BP, BG Group, Petrobras, Shell and Statoil); energy companies (DONG Energy, RWE Dea and Vattenfall); technical consultancy and service providers (Schlumberger and Arup); the IEA Greenhouse Gas Research and Development Programme; and two Norwegian public enterprises (Gassnova/Climit and Gassco). This JIP draws together experience and good practices to generate guidelines and recommendations for geological storage of CO_2 including MMV.

Shell advocates that the IPCC GHG inventory guidelines, the World Resource Institute guidelines and the DNV guidelines form the basis for any MMV program.

Appendix B: Risk Management using the Bowtie Method

Risk Management Using the Bowtie Method

The Bowtie Method provides a framework for a systematic risk assessment of events with the potential to affect storage performance. Figure B-1 illustrates a highly simplified bowtie risk analysis. The bowtie represents the relationship between the five key elements that describe how a risk might arise and how safeguards can provide effective protection against the risk and its associated consequences.

Top Event: This is the unwanted event, placed in the centre of the bowtie.

Threats: These possible mechanisms can lead to the top event.

Consequences: These are the possible adverse outcomes due to the occurrence of the top event.

Preventative safeguards: These decrease the likelihood of a threat leading to the top event.

Corrective safeguards: These decrease the likelihood of significant consequences due to a top event.

The Bowtie Method is a proven and effective method for analyzing and communicating risks.

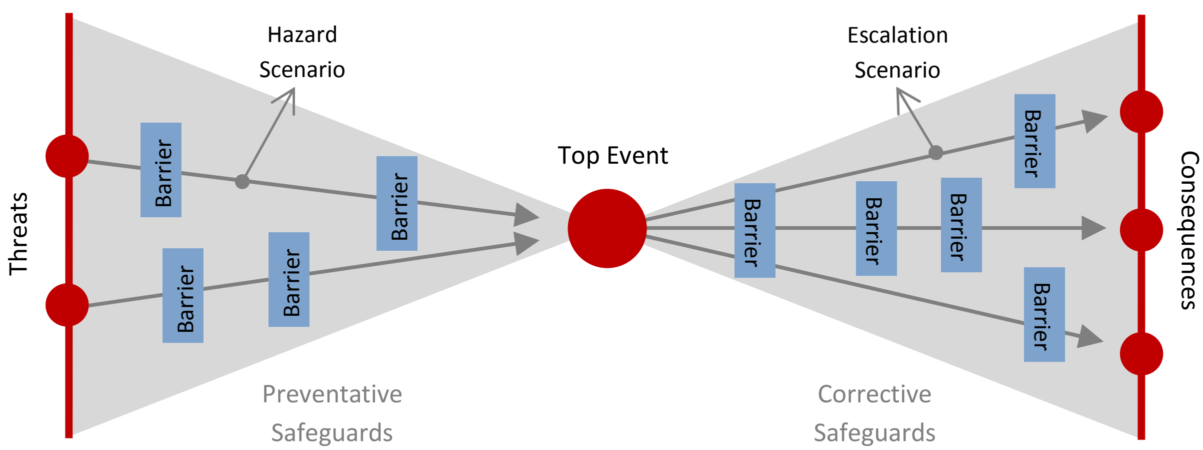

Figure B-1 Schematic Diagram of the Bowtie Method.

Within the context of this MMV Plan both preventative and corrective safeguards take one of two distinct forms:

Passive safeguards: These safeguards are always present from the start of injection and do not need to be activated at the appropriate moment. These passive safeguards exist in two forms:

1) *Geological barriers identified during site characterization;*

2) *Engineered barriers identified during engineering concept selections.*

Active safeguards: These are engineered safeguards, brought into service in response to some indication of a potential upset condition in order to make the site safe. Each active safeguard requires three key components in order to operate effectively:

1) *A sensor capable of detecting changes with sufficient sensitivity and reliability to provide an early indication that some form of intervention is required;*

2) *Some decision logic to interpret the sensor data and select the most appropriate form of intervention;*

3) *A control response capable of effective intervention to ensure continuing storage performance or to control the effects of any potential loss of storage performance.*

This combination of a sensor, decision logic and a control response is the central mechanism for risk management within the MMV Plan.

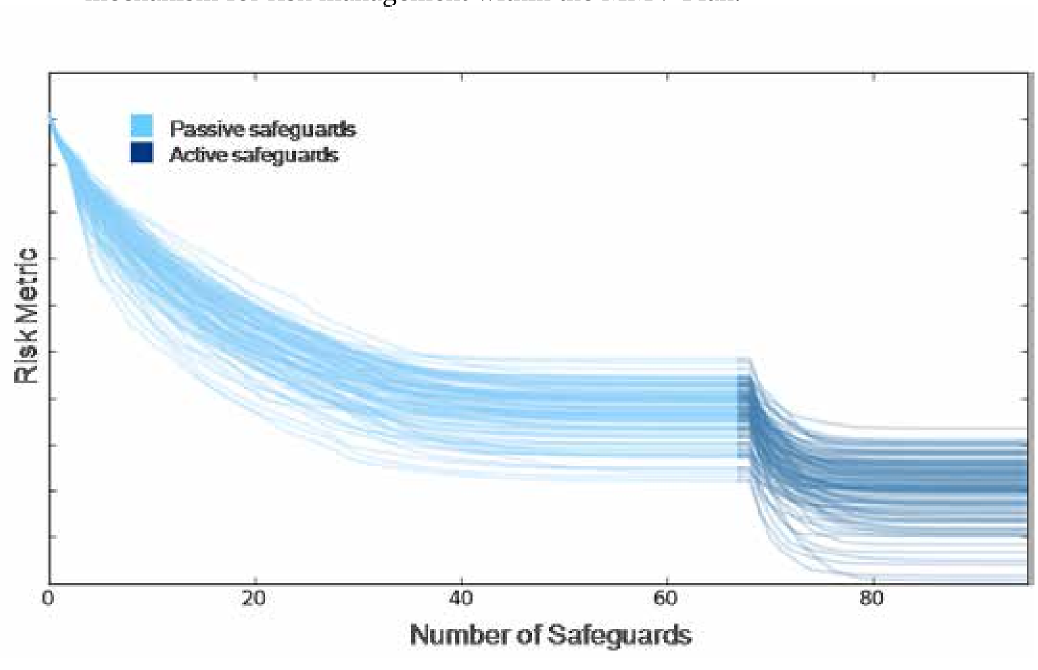

Figure B-2 Reduction in risk computed for increasing number of passive and active safeguards. Each line represents one realization of the anticipated failure rates for each safeguard selected at random from the recognized range of potential failure rates for each safeguard. The 100 realizations shown indicate impact of these uncertainties on risk management. The Risk Metric is shown on a logarithmic scale.

Appendix C: Knowledge Transfer Between CCS Projects

Knowledge Transfer between CCS Projects

C.1 Existing Large-Scale CCS Projects

Five fully-integrated, large scale CCS projects are in commercial operation today storing more than 0.5 million tonnes CO_2 per year. Four projects – Sleipner, In Salah, Snøhvit and Rangely – inject CO_2 from a natural gas production facility where it is separated from the natural gas sent to market. In the first three cases, the CO_2 is injected into saline aquifers, while in the fourth it is used for EOR. A fifth project captures CO_2 at the Great Plains Synfuels Plant and transports it for EOR to the IEA GHG Weyburn – Midale Project. All five are contributing to the knowledge base needed for widespread CCS use. The following summary of these projects was adapted from IEA.

In addition, there have been a number of US DOE-sponsored projects demonstration project. While these projects do not operate on a commercial scale, they have extensive MMV programs for research purposes. The Illinois Basin – Decatur Project in this category.

C.1.1 Sleipner

The Sleipner project began in 1996 when Norway's Statoil began injecting more than 1 million tonnes per year of CO_2 under the North Sea. This CO_2 was extracted with natural gas from the offshore Sleipner gas field. In order to avoid a government-imposed carbon tax equivalent to about USD 55/tonne, Statoil built a special offshore platform to separate CO_2 from other gases. The CO_2 is re-injected about 1 000 meters below the sea floor into the Utsira saline formation located near the natural gas field. The formation is estimated to have a capacity of about 600 billion tonnes of CO_2, and is expected to continue receiving CO_2 long after natural gas extraction at Sleipner has ended.

C.1.2 In Salah

In August 2004, Sonatrach, the Algerian National Oil and Gas Company, with partners BP and Statoil, began injecting about 1 million tonnes per year of CO_2 into the Krechba geologic formation near their natural gas extraction site in the Sahara Desert. The Krechba formation lies 1800 meters below ground and is expected to receive 17 million tonnes of CO_2 over the life of the project. This project suspended injection operations in June 2011.

C.1.3 Snøhvit

Europe's first liquefied natural gas (LNG) plant also captures CO_2 for injection and storage. Statoil extracts natural gas and CO_2 from the offshore Snøhvit gas field in the Barents Sea. It pipes the mixture 160 kilometres to shore for processing at its LNG plant near Hammerfest, Europe's northernmost town. Separating the CO_2 is necessary to produce LNG and the Snøhvit project captures about 700,000 tonnes per year of CO_2. Starting in 2008, the captured CO_2 is piped back to the offshore platform and injected in the Tubåsen sandstone formation 2,600 meters under the seabed and below the geologic formation from which natural gas is produced.

C.1.4 Rangely

The Rangely CO_2 Project has been using $CO_2$for enhanced oil recovery since 1986. The Rangely Weber Sand Unit is the largest oilfield in the Rocky Mountain region and was discovered in 1933. Gas is separated and re-injected with CO_2 from the LaBarge field in Wyoming. Since 1986, approximately 23-25 million tonnes of CO_2 have been stored in the reservoir. Computer modelling suggests nearly all of it is dissolved in the formation water as aqueous CO_2 and bicarbonate. Though Rangely uses CO_2 for EOR, it is considered a CCS project based on the assessed viability of long-term storage of CO_2.

C.1.5 IEA GHG Weyburn – Midale Project

About 2.8 million tonnes per year of CO_2 are captured at the Great Plains Synfuels Plant in the US State of North Dakota, a coal gasification plant that produces synthetic natural gas and various chemicals. The CO_2 is transported by pipeline 320 kilometres (200 miles) across the international border into Saskatchewan, Canada and injected into depleting oil fields where it is used for EOR. Although it is a commercial project, researchers from around the world have been monitoring the injected CO_2. The IEA Greenhouse Gas R&D Programme's Weyburn-Midale CO_2 Monitoring and Storage Project was the first project to scientifically study and monitor the underground behaviour of CO_2. Canada's Petroleum Technologies Research Centre manages the monitoring effort. This effort is now in the second and final phase (2007-2011), of building the necessary framework to encourage global implementation of CO_2 geological storage. The project will produce a best-practices manual for carbon injection and storage.

C.1.6 Illinois Basin – Decatur Project

The Illinois Basin – Decatur Project (IBDP) is a US DOE-funded demonstration project that with the goal of storing 1 million tonnes of CO_2 over a three year period. Carbon dioxide is being captured from the fermentation process used to produce ethanol at ADM's corn processing complex in Decatur. The compressed CO_2 is injected deep into the Mount Simon Sandstone saline formation at a depth of 7,000 feet (2,135 meters). The Mount Simon Sandstone is the thickest and most widespread saline reservoir in the Illinois Basin and one of the most significant potential carbon storage resources in the United States. The project includes deep injection, observation, and geophysical wells, which are instrumented to monitor and further characterize the Mount Simon Sandstone, as well an extensive near-surface monitoring plan.

Near surface MMV technologies deployed over the course of the project have included: surface deformation monitoring, net CO_2 flux monitoring, soil gas sampling, soil CO_2 flux monitoring, high-resolution electrical earth resistivity surveys, and shallow groundwater sampling. Subsurface monitoring efforts include 3D surface seismic and VSP surveys; microseismic monitoring; injection zone temperature, pressure, and fluid monitoring, pressure, fluid monitoring, and cased-hole logging.

Injection ceased at the site in November 2014 after 1 million tonnes of CO_2 injection; however, research monitoring will continue until 2017.

C.2 Joint Industry Project for Knowledge Transfer

The CO2QUALSTORE joint industry project (JIP) led by Det Norske Veritas (DNV) recently compiled a workbook of examples for underground storage of CO_2 including MMV plans (DNV 2010b). The JIP includes the following partners from a number of sectors; oil and gas companies (BP, BG Group, Petrobras, Shell and Statoil); energy companies (DONG Energy, RWE Dea and Vattenfall); technical consultancy and service providers (Schlumberger and Arup); the IEA Greenhouse Gas R&D Programme; and two Norwegian public enterprises (Gassnova/Climit and Gassco). This workbook provides guidance on how site-specific performance targets can be defined and includes practical examples of how to follow the guidance and its various steps. This workbook represents the most recent collection of shared experience and good practices applicable to MMV. This guidance and the good practices illustrated through the examples are central to the approach taken by Shell to all current CCS development projects including the Quest Project.

The key lessons learned applicable to the protection of groundwater resources and users and incorporated by Shell into the Project are:

- site-specific selection of monitoring methods designed to verify containment
- risk-based selection of monitoring methods and monitoring schedules designed to verify containment and to provide early warning in the unlikely event of a potential loss of containment
- adaptive updates to the MMV Plan in response to new information obtained about the performance of the storage complex and the monitoring technologies

C.3 Independent Project Reviews

Shell also incorporated lessons learned from other CCS projects through an Independent Project Review process conducted by a panel of CCS experts selected by DNV. This panel included individuals with particular expertise in groundwater monitoring and protection and lead scientists within the IEA GHG Weyburn – Midale CO_2 Monitoring and Storage Project run by the International Energy Agency Greenhouse Gas Research and Development Program.

Appendix D: Status of Existing Wells

Status of Existing Wells

The status of existing wells that penetrate the BCS storage complex was analyzed based on available documentation. A review of existing documentation for all abandoned BCS legacy wells within and close to the SLA indicates they all contain multiple thick cement plugs (Table D-1). The deepest cement plug is below the Upper Lotsberg Salt Formation in all cases except Imperial Darling No. 1.

Table D-2 describes the current status of Quest Project wells. Table D-3 provides the offset distances between injection wells and the closest hydrocarbon production well. Figure D-1 shows the location of these wells in relation to the SLA and the stratigraphy.

Table D-1 Status of BCS legacy wells

Well name and UWI	History and Distance from pipeline	Seals drilled through	Casings, holes and BGWP	Cement plugs
Imperial Eastgate 100-01-34-057-22W400	• *Drilled and abandoned in 1955* • *21 km from pipeline*	• *Upper Lotsberg* • *Lower Lotsberg* • *- MCS*	• *9 5/8" casing to 277m* • *9" openhole to 2205m (TD)* • *BGWP at 240m bgl*	#1: 265 – 289 m #2: 644 – 710m #3: 887 – 981m #4: 1016 – 1048m #5: 1256 – 1292m #6: 2125 – 2205m
Imperial Egremont 100-06-36-058-23W400	• *Drilled and abandoned in* • *1952* • *21 km from pipeline*	• *Upper Lotsberg* • *Lower Lotsberg* • *MCS*	• *13 3/8" casing to 186m* • *9" openhole to 2242.3m* • *BGWP at 220m bgl*	#1: 172 – 195m #2: 624 – 670m #3: 844 – 875m #4: 969 – 1003m #5: 1178 – 1218m #6: 2140 – 2242m
Imperial Darling #1 100-16-19-062-19W400	• *Drilled and abandoned in* • *1949* • *25 km from pipeline*	• *Upper Lotsberg* • *Lower Lotsberg* • *MCS*	• *13 3/8" casing to 183m* • *9" (supposed) openhole to 2013m* • *BGWP at 235m bgl*	#1: 168 – 198m #2: 525 – 587m #3: 708 – 740m #4: 762 – 792m
Westcoast et al Newbrook 100-09-31-062-19W40	• *Drilled in and abandoned in 1978* • *28 km from pipeline*	• *Upper Lotsberg* • *Lower Lotsberg* • *MCS*	• *9 5/8" casing to 230m* • *- 7" (supposed) openhole to TD at 1923m* • *- BGWP at 228m*	#1: 183 – 366m #2: 518 – 701m #3: 838 – 960m #4: 1082 – 1204m #5: 1280 – 1402m #6: 1524 – 1615m #7: 1707 – 1923m
Imperial Clyde #1 100-09-29-059-24W400	• *Drilled and abandoned in* • *1948* • *43.5 km from pipeline (outside SLA)*	• *Upper Lotsberg* • *Lower Lotsberg* • *MCS*	• *13 3/8" casing to 135m* • *9" openhole to 2295m (TD)* • *BGWP at 232.5m bgl*	#1: 128 – 195m #2: 781 – 945m
Imperial Gibbons #1 100-02-16-056-22W400	• *Drilled and abandoned in* • *1949* • *25 km from pipeline (outside SLA)*	• *Upper Lotsberg* • *Lower Lotsberg*	• *13 3/8" casing to 180m* • *9" openhole to 2024m (TD)* • *BGWP at 258.1m bgl*	#1: 695 – 754m #2: 893 – 983m #3: 1052 – 1113m

Well name and UWI	History and Distance from pipeline	Seals drilled through	Casings, holes and BGWP	Cement plugs
Imperial PLC Redwater LPGS 100-07-17-056-21W400	• *Drilled in 1974 – Converted to LPG reproducer in 1975* • *Abandoned in 2007* • *18.5 km from pipeline*	• *Upper Lotsberg*	• *13 3/8"casing to 188.4m* • *9 5/8" casing to 1778.2m* • *7" casing to 1836m* • *TD at 1861m* • *BGWP at 216m bgl*	#1: 0 – 500m #2: 1435 – 1760m #3: 1760 – 1861m

Table D-2 Status of the Project Injection Wells

Well Name and UWI	Inside SLA	TD (mMD)	Status
1AA/11-32-55-21-W4/00	No	2269m	Well cased and cemented to TD. BCS abandoned and well converted to a water disposal well into the shallower Nisku formation.
Redwater 100/03-04-57-20W4/00	Yes	2190m	Well cased and cemented to TD. Well suspended with 19 joints of drillpipe and liner running tool cemented in hole. Top of cement at 1696.5m with top of fish at 1672m
100/08-19-059-20W400 (IW 8-19)	Yes	2132m	Well cased and cemented to TD. Well completed and awaiting commercial CO_2 injection
102/053505921W4/00 (IW 5-35)	Yes	2143m	Well cased and cemented to TD. Well suspended awaiting D51 approval before recompletion as CO_2 injection well.
103/071105920W4/00 (IW 7-11)	Yes	2105m	Well cased and cemented to TD. Well suspended awaiting D51 approval before recompletion as CO_2 injection well.

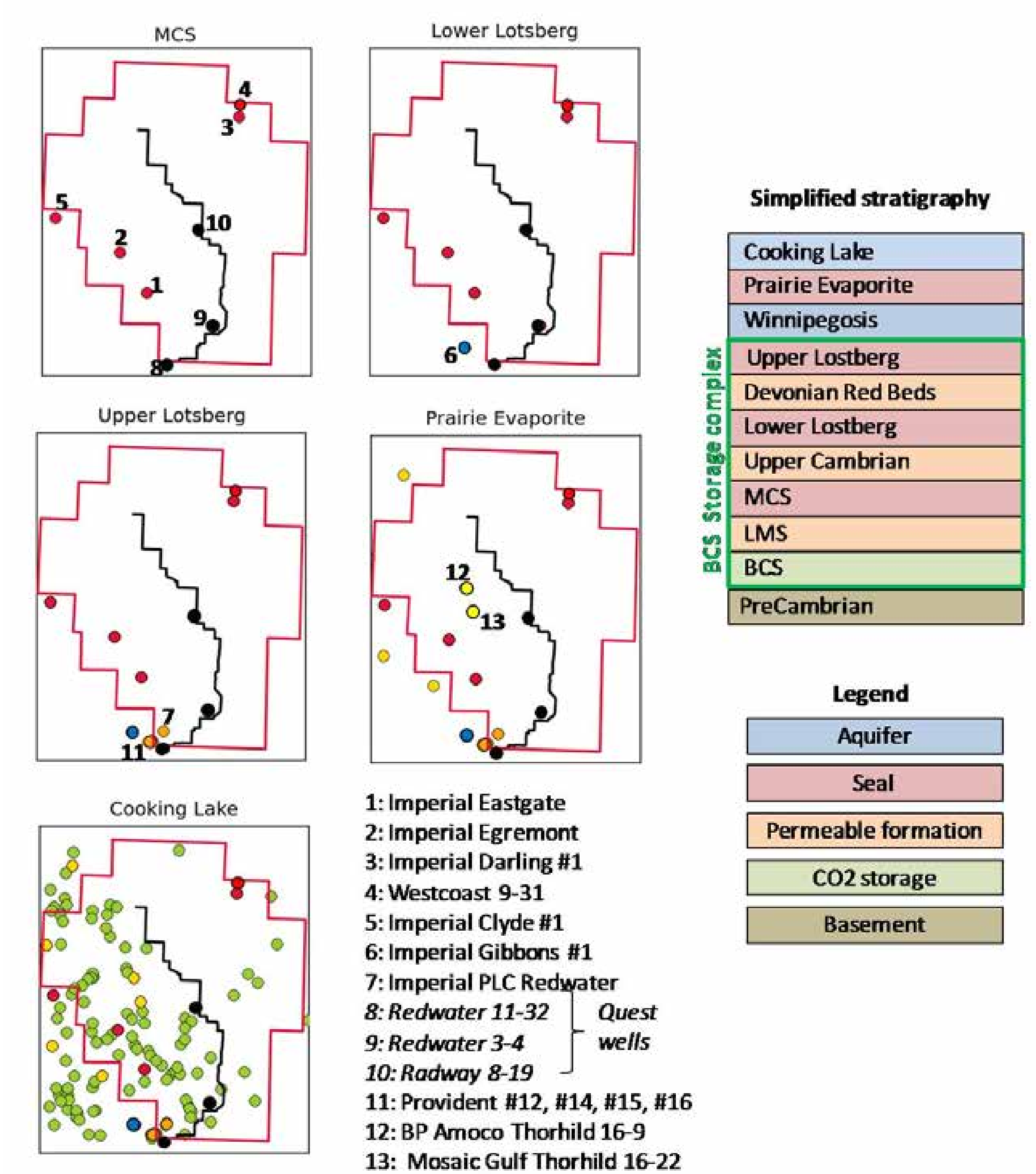

Figure D-1 Summary of existing well locations.

Table D-3 Distance to closest offset hydrocarbon producers.

Formation	Closest offset well	Inside SLA	Average depth to top reservoir in SLA [m]	Distance from IW 8-19-059-20W4 [km]	Comments
Viking	100/09-31-059-20W4/00	Yes	590	3.4	
Joli Fou	100/08-36-059-20W4/00	Yes	615	8.7	
Mannville	100/15-20-059-20W4/00	Yes	623	1.2	Includes Ellerslie, Glauconitic Sands
Wabamun	100/14-29-059-20W4/00	Yes	750	8.2	
Nisku	100/09-06-058-21W4/00	Yes	850	15	Leduc Reef
Ireton	103/06-07-058-21W4/00	Yes	900	15	Leduc Reef
Leduc	100/03-08-058-21W4/0	Yes	1000	15	Leduc Reef
Winnipegosis	-	No	1600	-	Saline Aquifer
BCS	-	No	2000	-	Saline Aquifer

Appendix E: Pressure Required to Lift BCS Brine

Pressure Required to Lift BCS Brine

Table E-1 gives the pressure increase required to lift BCS brine above the BGWP zone at third-party legacy well locations for wells that penetrate through all three major seals in the BCS storage complex (BCS legacy wells) in the SLA. However, BCS brine can only by lifted to the BGWP zone if these legacy wells provide an open conduit from the BCS to surface and this is unlikely because all BCS legacy wells have been abandoned with multiple large cement plugs.

Other third-party legacy wells in the area either do not penetrate the BCS reservoir or are located outside the SLA and would have lower pressures in the BCS than the wells quoted in Table E-1 below. To manage the containment risks associated with legacy wells, it will suffice to focus the modelling and monitoring efforts on the selected BCS legacy wells.

Table E-1 Pressure increase required to lift BCS above the base of groundwater protection.

Well Name	Surface Elevation [mbsl]	BGWP Depth [mbsl]	Delta P[A] [kPa]
Imperial Eastgate 1-34	-641	-401	3,452
Imperial Egremont 6-36	-628	-408	3,334
Imperial Clyde No. 1[B]	-629	-397	3,327
Imperial Darling No. 1	-704	-469	4,201
Westcoast 9-31[C]	-699	-471	4,146

NOTES:
mbsl denotes meters below sea level
[A] Delta P is incremental BCS pressure required to lift BCS brine to BGWP
[B] Imperial Clyde No. 1 is not located in the SLA.
[C] Westcoast et al Newbrook 100-09-31-062-19W40 (Westcoast 9-31) was reclassified as a legacy well that penetrates all three major seals in the BCS storage complex, since submission of the Application.