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## Revision History

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<th>Reviewer</th>
<th>Approver</th>
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<td>01</td>
<td>2012-10-15</td>
<td>Final</td>
<td>Mauri Smith</td>
<td>Carolyn Milne</td>
<td>Sean McFadden</td>
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## Signatures for this revision

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<tr>
<th>Date</th>
<th>Role</th>
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<td></td>
<td>Originator</td>
<td>Mauri Smith</td>
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<td>Reviewer</td>
<td>Carolyn Milne</td>
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<tr>
<td></td>
<td>Approver</td>
<td>Sean McFadden</td>
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## Summary

This is the Measurement Monitoring and Verification Plan (MMV) for the Quest Project as of October 15, 2012. This document also includes the first Hydrosphere, Biosphere Monitoring Plan (HBMP) to be carried out as part of the MMV plan. This document is also located in Appendix A of the ERCB Special Report #1 submitted October 15, 2012 (Controlled Document Number (07-3-AA-5880-0001).

## Keywords

MMV, Measurement Monitoring and Verification, CO2, Quest, Hydrosphere Biosphere Monitoring Plan, HBMP, Special Report #1

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**MMV Update and HBMP as part of Special Report #1 October 15, 2012**

**Final**

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Shell Quest Carbon Capture and Storage Project

MEASUREMENT, MONITORING AND VERIFICATION PLAN

FINAL

Prepared by:
Shell Canada Limited
Calgary, Alberta

October 15th 2012
Executive Summary

The Quest Carbon Capture and Storage Project (Quest CCS Project) will make a material early contribution to reducing CO₂ 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 CO₂ captured per annum within the Basal Cambrian Sands (BCS) storage complex.

The Quest CCS Project will ensure secure storage through selection of a site with ideal storage characteristics, a comprehensive data gathering and characterization of the site and a state of the art program for Measurement, Monitoring and Verification (MMV).

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, monitoring systems have been developed to operate 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 Conformance** to indicate the *long-term effectiveness* of CO₂ storage by demonstrating actual storage performance is consistent with expectations about injectivity, capacity and CO₂ behaviour inside the storage complex;

- **Ensure Containment** to demonstrate the *security* of CO₂ storage and to protect human health, groundwater resources, hydrocarbon resources, and the environment.

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 (also referred to in this MMV Plan as ‘injectors’) and, if necessary, stopping injection and deploying 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 or updates to the Storage Development Plan to maintain conformance and ensure timely site closure and transfer of long-term liability to the crown.

The selected monitoring plans for conformance and containment are subject to different value drivers. Conformance risks affect project 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.

Some commitments for monitoring already exist for each of the major environmental domains based on responses provided to Shell Response to the Groundwater Review Submission – Tab B (exhibit #134.04) in March 2012 (Table 1-1-1). The estimated cost of this updated MMV Plan depends on the number of injection wells required according to the phased storage development plan:

- **3 injection wells**: 4.0 CAD per tonne of CO₂
- **4 injection wells**: 4.4 CAD per tonne of CO₂
- **5 injection wells**: 4.8 CAD per tonne of CO$_2$

Table 1-1  
**MMV commitments made in Exhibit #134.04: Shell Response to the Groundwater Review Submission – Tab B**

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
</tr>
</thead>
</table>
| MMV Plan updates                  | - The MMV Plan will be site-specific and adaptive; this means it remains subject to change in response to new information from:  
  - technical feasibility studies  
  - baseline measurements  
  - monitoring during the injection and closure periods  
  - An update to the MMV Plan will be submitted for review before commencing baseline measurements, and thereafter every three years, coincident with the required submission of the updated Closure Plan to Alberta Energy. |
| Deep monitoring wells             | - Shell proposes to drill a minimum of three deep monitoring wells.  
  - The planned target is the Winnipegosis Formation. The suitability of this formation will be verified by logging and testing these deep monitoring wells.  
  - Monitoring within these wells will include continuous pressure measurements.  
  - **One of these wells will also include a down-hole microseismic monitoring system.** |
| Distributed temperature sensing   | - Shell will install a distributed temperature sensing system outside the production casing in all injection wells.                                                                                          |
| Time-lapse seismic                | - Shell will acquire time-lapse seismic surveys designed to monitor the CO$_2$ plume.  
  - A 3D surface seismic baseline survey has been acquired already.  
  - Repeat 3D vertical seismic profile (VSP) surveys designed to monitor the CO$_2$ plume will be acquired until the CO$_2$ plume exceeds the radius of investigation for a VSP seismic survey. Thereafter, at least one repeat 3D surface seismic survey will be acquired. |
| Interferometric synthetic aperture radar (InSAR) | - Shell will acquire InSAR data designed to monitor surface heave induced by CO$_2$ storage.                                                                                                         |
| Project groundwater monitoring wells | - Shell proposes to drill three groundwater monitoring wells for each injection well.  
  - Each of these groundwater monitoring wells will include a continuous water electrical conductivity measurement system.  
  - Annual fluid sampling and analysis will be performed.  
  - At least one of these groundwater wells will be located on each injection well pad; the remaining groundwater wells may be located elsewhere. |
<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
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<tbody>
<tr>
<td>Landowner monitoring wells</td>
<td>Subject to landowner consent, a network of landowner groundwater wells will also be used for monitoring groundwater quality. These will include:</td>
</tr>
<tr>
<td></td>
<td>1. All existing landowner wells within 3.2 km of the proposed injection wells.</td>
</tr>
<tr>
<td></td>
<td>2. Existing landowner wells within close proximity the BCS legacy wells.</td>
</tr>
<tr>
<td></td>
<td>3. A regional network of existing landowner wells sparsely distributed across the remaining AOR at a density of approximately one per township.</td>
</tr>
<tr>
<td>Tracers for BCS brine and CO₂</td>
<td>Water geochemistry appraisal work has identified that the BCS brine has a unique formation fluid chemistry. In the unlikely event of a potential loss of containment, water geochemistry analysis is expected to verify the presence or absence of BCS brine within protected groundwater resources.</td>
</tr>
<tr>
<td></td>
<td>An artificial tracer will be co-injected with the CO₂ contingent on a satisfactory conclusion to ongoing technical and operational feasibility evaluations.</td>
</tr>
<tr>
<td>Groundwater sampling and analysis</td>
<td>Shell proposes a tiered approach to monitoring groundwater quality within the project and landowner groundwater monitoring wells.</td>
</tr>
<tr>
<td></td>
<td>Tier 0. Continuous monitoring of water electrical conductivity within the Project groundwater monitoring wells.</td>
</tr>
<tr>
<td></td>
<td>Tier 1. Groundwater sample collection from project and landowner groundwater monitoring wells and standard water quality analysis for bulk parameters, major ions, nutrients and halogens as tracers for BCS brine. Headspace gas sample collection, where possible, from the same wells and analysis for standard gas composition and the presence of artificial tracer co-injected with the CO₂.</td>
</tr>
<tr>
<td></td>
<td>Tier 2. Repeat the Tier 1 sample collection and analysis. Additional alternative analysis for halogens, and standard analysis for dissolved metals</td>
</tr>
<tr>
<td></td>
<td>Tier 3. Repeat the Tier 2 sample collection and analysis. Additional analysis for standard isotopes, such as strontium, oxygen, hydrogen, carbon, halogen isotope ratios.</td>
</tr>
<tr>
<td></td>
<td>Tier 4. In the event of Tiers 0, 1, 2 and 3 indicating an change in water quality potentially attributable to the Project a variety of site-specific measurements will be acquired to delineate the contaminant plume delineation and support risk management activities.</td>
</tr>
<tr>
<td></td>
<td>Tiers 1, 2 and 3 will be measured at regular intervals and no less frequently than once every 2 years.</td>
</tr>
<tr>
<td></td>
<td>Each tier constitutes an independent set of water quality measurements and so provides successively increasing levels of confidence.</td>
</tr>
<tr>
<td>Bios</td>
<td>Remote sensing</td>
</tr>
<tr>
<td></td>
<td>Shell will acquire remote sensing data designed to detect environmental change. This will include multi-spectral optical images.</td>
</tr>
<tr>
<td>Item</td>
<td>Description</td>
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<td>------------------------------------------------</td>
<td>-------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Sample plots</td>
<td>• Sample plots will be utilized to calibrate the remote sensing data designed to detect environmental changes</td>
</tr>
<tr>
<td>Atmosphere line of sight CO₂ gas flux monitoring</td>
<td>• A field trial of the line-of-sight CO₂ gas flux monitoring technology will be deployed in Q4 2011. It will verify the technical capability of this technology for continuous detection and mapping and any CO₂ emissions from the BCS storage complex into the atmosphere.</td>
</tr>
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## Abbreviations

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<tr>
<td>AEC</td>
<td>atmospheric eddy correlation</td>
</tr>
<tr>
<td>ALARP</td>
<td>as low as reasonably practicable</td>
</tr>
<tr>
<td>AOI</td>
<td>Sequestration Lease Area / Area of Interest for the Project</td>
</tr>
<tr>
<td>AOR</td>
<td>Area of Review of MMV activities for the Project</td>
</tr>
<tr>
<td>APM</td>
<td>annulus pressure monitoring</td>
</tr>
<tr>
<td>ARC</td>
<td>Alberta Research Council</td>
</tr>
<tr>
<td>BCS</td>
<td>basal Cambrian Sands</td>
</tr>
<tr>
<td>BGWP</td>
<td>Base of Groundwater Protection</td>
</tr>
<tr>
<td>BGS</td>
<td>British Geological Survey</td>
</tr>
<tr>
<td>CBL</td>
<td>cement bond logs</td>
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<tr>
<td>CCS</td>
<td>carbon capture and storage</td>
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<td>CDM</td>
<td>Clean Development Mechanism</td>
</tr>
<tr>
<td>CO₂</td>
<td>carbon dioxide</td>
</tr>
<tr>
<td>CSA</td>
<td>Canadian Standards Association</td>
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<td>DAS</td>
<td>fibre-optic distributed acoustic sensing</td>
</tr>
<tr>
<td>DHMS</td>
<td>down-hole microseismic monitoring</td>
</tr>
<tr>
<td>DHPT</td>
<td>down-hole pressure-temperature gauge</td>
</tr>
<tr>
<td>DNV</td>
<td>Det Norske Veritas</td>
</tr>
<tr>
<td>DTS</td>
<td>fibre-optic distributed temperature sensing</td>
</tr>
<tr>
<td>EPA</td>
<td>Environmental Protection Agency</td>
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<tr>
<td>ERCB</td>
<td>Energy Resources Conservation Board</td>
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<tr>
<td>ESS</td>
<td>ecosystem studies</td>
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<tr>
<td>GHG</td>
<td>greenhouse gas</td>
</tr>
<tr>
<td>GPS</td>
<td>global positioning system</td>
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<tr>
<td>GPZ</td>
<td>groundwater protection zone</td>
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<tr>
<td>HIA</td>
<td>satellite or airborne hyper-spectral image analysis</td>
</tr>
<tr>
<td>HSE</td>
<td>United Kingdom Health and Safety Executive</td>
</tr>
<tr>
<td>HSSE</td>
<td>Health Safety Security and Environment</td>
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<tr>
<td>HUD</td>
<td>hold-up depth</td>
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<tr>
<td>IEA</td>
<td>International Energy Agency</td>
</tr>
<tr>
<td>INJ</td>
<td>injection wells</td>
</tr>
<tr>
<td>InSAR</td>
<td>Interferometric Synthetic Aperture Radar</td>
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<tr>
<td>IPAC</td>
<td>International Performance Assessment Centre</td>
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<td>IPAC-CO₂</td>
<td>International Performance Assessment Centre for CO₂</td>
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<tr>
<td>IPCC</td>
<td>Intergovernmental Panel on Climate Change</td>
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<td>IRM</td>
<td>injection rate metering at wellhead</td>
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<tr>
<td>KPI</td>
<td>key performance indicator</td>
</tr>
<tr>
<td>LOSCO₂</td>
<td>line-of-sight gas flux monitoring</td>
</tr>
<tr>
<td>MCS</td>
<td>Middle Cambrian Shale</td>
</tr>
<tr>
<td>MIA</td>
<td>satellite or airborne multi-spectral image analysis</td>
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<tr>
<td>MMV</td>
<td>measurement, monitoring and verification</td>
</tr>
<tr>
<td>MNA</td>
<td>Monitored Natural Attenuation</td>
</tr>
<tr>
<td>MWIT</td>
<td>mechanical well integrity pressure testing</td>
</tr>
<tr>
<td>NETL</td>
<td>National Energy Technology Laboratory</td>
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<tr>
<td>OBW</td>
<td>observation wells in Winnipegosis (WPGS)</td>
</tr>
<tr>
<td>PTRC</td>
<td>Petroleum Technology Research Centre</td>
</tr>
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<td>Quest CCS project</td>
<td>Quest Carbon Capture and Storage Project</td>
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RIA .................................................................satellite or airborne radar image analysis
SEIS2D ............................................................time-lapse surface 2D seismic
SEIS3D ............................................................time-lapse surface 3D seismic
Shell .................................................................Shell Canada Limited
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
VSP3D .............................................................time-lapse 3D vertical seismic profiling
WEC .................................................................down-hole electrical conductivity monitoring
WHCO₂ ..........................................................wellhead CO₂ detectors
WHPT .............................................................wellhead pressure-temperature gauge
WPGS .............................................................Winnipegosis
WPH ...............................................................down-hole 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 CO₂, 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:

- CO₂ 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 CO₂ pipeline, which will transport the CO₂ from the Scotford Upgrader to the injection wells, up to about 80 km north of the upgrader. The CO₂ injection well locations are located in the center of the storage site.
- a storage scheme consisting of 3 to 8 injection wells, which will inject the CO₂ into the Basal Cambrian Sands (BCS), a deep underground formation, for permanent storage at a depth of about 2 km below ground level. 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 CO₂ 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 90% of the measured fracture pressure of the injection formation. The distribution of injection between the injection wells will be managed to satisfy this pressure constraint and reduce the plume size in each well in accordance with the Directive 65 application. This project does not include additional wells for production and disposal of brine for pressure management.
2 The Purposes of MMV

The selected storage site is believed to be inherently safe, however it is responsible to manage the residual storage risks no matter how small. MMV is central to the framework for storage risk management (Figure 2-1). There are two independent storage risks, loss of conformance and loss of containment and these are reflected in the two primary objectives of MMV for the Quest CCS Project.

- **Ensure Conformance** to indicate the *long-term security* of CO₂ storage, *i.e.*
  1) Show pressure and CO₂ 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 CO₂ inventory reporting.

- **Ensure Containment** to demonstrate the *current security* of CO₂ 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.

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 Area of Review (AOR) which has sufficient extent to include the area where there is potential risk for adverse impacts due to CO₂ storage including the displacement of brine. The initial AOR is equal to the initial Sequestration Lease Area, elsewhere referred to as the Area of Interest (AOI) (see Figure 2-2). 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.

2.2 Domains of Review

MMV will span four distinct environmental domains (see Figure 2-3).

- **Geosphere**: The subsurface domain below the base of the groundwater protection zone including the BCS storage complex. The geological storage complex comprises a primary storage formation (Basal Cambrian Sands, 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 three additional deep saline aquifers, the Winnipegosis/Contact Rapids, the Beaverhill Lake Group and the Cooking Lake Fm., 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.

- **Hydrosphere**: The subsurface domain within the groundwater protection zone where water salinity measured as the concentration of total dissolved solids is less than 4,000 milligrams per litre. The Alberta Environment (AENV) Water Act defines saline groundwater as that containing greater than 4000 milligrams per litre (mg/L) total dissolved solids.

- **Biosphere**: The domain containing ecosystems where living organisms exist.

- **Atmosphere**: The local air mass where any changes to air quality matter and the global air mass where any changes influencing climate matter.

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

The Hydrosphere and Biosphere Monitoring Plan is provided in Appendix A.

2.3 Timeframe of Review

MMV activities will be adapted through time to meet the different requirements during five distinct phases of the Project lifecycle:

- **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 2-4).

- **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 10 years post injection cessation, provided there are no significant issues that arise from Project operations and that storage performance and CO₂ 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 CO₂ within the BCS formation.

### 2.4 Timeframe of Updates

According to the ERCB D65 final approval conditions dated August 24, 2012, Shell must provide updates of the MMV Plan as required by the ERCB and at minimum at critical milestones (commencement of injection, closure and post closure). Shell must also provide annual operations reports that are aligned to the most current MMV. In addition, Shell is required to submit an updated MMV and closure plan every 3 years as a stipulation of its Sequestration Lease. If necessary, the MMV Plan will be adapted in response to new information gained from:

- Well Data
- Site-specific technical feasibility assessments
- Baseline monitoring measurements taken during the pre-injection period
- Monitoring during the injection and closure periods
Section 2: The Purposes of MMV

Shell Quest Carbon Capture and Storage Project
Measurement, Monitoring and Verification Plan

Figure 2-2 Location Map of the Quest Sequestration Lease Area
Figure 2-3 Cross section through the BCS storage complex and overlying geological formations. Figure 2-2 shows the location of this cross-section.
Figure 2-4  Proposed timeline for site closure activities
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 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 Characterisation**: 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.

- **MMV**: This provides an additional layer of risk assessment and implements additional safeguards through monitoring to verify 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, Appendix E of the Update to Directive 65 application 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 threats¹ and consequences ii associated with these risk events.

2) **Characterise 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 6 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).

¹ Possible mechanisms that could cause the occurrence of an unwanted event.
² Possible adverse outcomes due to the occurrence of an unwanted event.
3.3 Influences on MMV Design

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

- The existing regulatory environment
- A review of the existing global guidelines (see Appendix B)
- Knowledge-sharing with existing and developing projects (see Appendix D)

Alberta’s existing regulations for the permitting and oversight of Acid Gas Disposal projects have proved effective for more than 40 schemes involving CO\textsubscript{2} over the last 20 years. The ERCB intends to use the same processes for regulating any CCS projects in Alberta, and these may be updated by the ongoing Regulatory Framework Assessment (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 projects in Canada create important precedents for MMV: the Weyburn-Midale CO\textsubscript{2} enhanced oil recovery project in Saskatchewan and Pembina Cardium CO\textsubscript{2} enhanced oil recovery (EOR) project in Alberta.

Outside Canada, there are four notable examples of commercial-scale CO\textsubscript{2} injection projects with ongoing MMV activities: Sleipner and Snøhvit in Norway, In Salah in Algeria, Rangely in the United States. See Appendix D for further details. Other commercial-scale CCS projects under development with more mature MMV plans include Gorgon in Australia and Goldeneye in the UK.
4 Storage Risks before MMV

This section reviews the assessment of storage risks after site selection and site characterisation 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 2-2) and extends from the Precambrian basement to the surface (Figure 2-3) including the following key components.

- **The BCS Storage Complex:** In ascending stratigraphic order, the BCS storage complex comprises the following formations (see also Table 4-2).
  1) Precambrian basement: Basal bounding formation
  2) BCS: CO2 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

- **Geosphere:** Above the BCS storage complex, the geosphere also contains numerous additional permeable formations and seals including, in ascending stratigraphic order, the following (Table 4-1).
  1) Winnipegosis/Contact Rapids (Winnipegosis or WPGS): Auxiliary storage
  2) Prairie Evaporite: Major regional seal
  3) Beaverhill Lake Group: Potential Auxiliary storage
  4) Cooking Lake: 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

- **Hydrosphere:** In ascending stratigraphic order, the following units each contain locally important aquifers above the base of groundwater protection.
  1) Foremost Formation of the Belly River Group: About 1,584 wells inside AOI
  2) Oldman Formation of the Belly River Group: About 1,576 wells inside AOI
3) **Surficial Deposits**: About 2,165 wells inside AOI

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

- **Injection Wells**: The Storage Development Plan allows for the phased development of between 3 and 8 injectors. The base case development plan includes 5 injectors with an opportunity to reduce to 3 injectors.

- **Exploration and Appraisal Wells**: The Project drilled two exploration wells and one appraisal well:
  1) *Redwater IAA-11-32-055-21W400 (Redwater 11-32)*: Exploration well located just outside the AOI,
  2) *Redwater 100-03-04-057-20W400 (Redwater 3-4)*: Exploration well located just inside the AOI
  3) *Radway 100-8-19-059-20W400 (Radway 8-19)*: Appraisal well located close to the center of the AOI. This well is proposed to be used as a CO2 injector.

- **Legacy Wells**: Figure 2-2 and Table 4-1 describe the legacy wells within the AOI.
  1) *BCS wells*: Four abandoned wells penetrate the BCS inside the AOI.
  2) *Lotsberg wells*: There are no legacy wells that penetrated the entire Lotsberg Salt inside the AOI other than the BCS legacy wells described above.
  3) *Winnipegosis wells*: Two abandoned wells penetrate down to the Winnipegosis Formation inside the AOI 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 AOI.
  5) *Groundwater wells*: Available records indicate there are more than 5300 wells drilled and completed within the groundwater protection zone.
Table 4-1  Geologic description of the formations above the potential Winnipegosis Monitoring Complex. Starting at surface.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Quest Name</th>
<th>Type</th>
<th>Composition and Depositional Environment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quaternary</td>
<td>Groundwater Protection Zone</td>
<td>Aquifer</td>
<td>Pre-glacial channel fill deposits, glacial drift and other glacially derived sediments deposited above the bedrock surface.</td>
</tr>
<tr>
<td>Oldman</td>
<td>Aquifer</td>
<td>Belly River Group</td>
<td>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 AOI.</td>
</tr>
<tr>
<td>Foremost</td>
<td>Aquifer</td>
<td>Marine and continental shale, with sandstone members forming regionally extensive aquifers. Distinctive coal-bearing zones also present (i.e. McKay and Taber coals). The Foremost sub-crops beneath portions of the NE and central areas of the AOI.</td>
<td></td>
</tr>
<tr>
<td>Lea Park</td>
<td>Seal</td>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>Colorado</td>
<td>Seal</td>
<td>Thick, grey regional marine shale present across entire AOI with an average thickness of 134m.</td>
<td></td>
</tr>
<tr>
<td>2nd White Specks</td>
<td>Gas Reservoir &amp; Seal</td>
<td>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 AOI reaching porosities of up to 8%. The average thickness in the AOI is 67m.</td>
<td></td>
</tr>
<tr>
<td>Base Fish Scales</td>
<td>Seal</td>
<td>Abundant fish remains within finely laminated, generally non-bioturbated sandstone, siltstone and shale. Within the AOI it is predominantly shale averaging 50m.</td>
<td></td>
</tr>
<tr>
<td>Viking</td>
<td>Oil and Gas Reservoir</td>
<td>Derived from Cordilleran erosion in the West. In the western portion of the AOI it is shallow shelf deposits with dominantly sandstone to the West and shale dominating towards the East. There is Viking Production in the AOI (Oil in the SW corner only) in a thin 2m sandstone at top of section that reaches porosities of 20%. Viking thickness averages 14m.</td>
<td></td>
</tr>
<tr>
<td>Joli Fou</td>
<td>Seal</td>
<td>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.</td>
<td></td>
</tr>
<tr>
<td>Upper Mannville</td>
<td>Mannville Group</td>
<td>Baffle</td>
<td>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 AOI.</td>
</tr>
<tr>
<td>Glaucnitic</td>
<td>Gas Reservoir</td>
<td>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 AOI as the Wainwright Highlands were finally covered. Gas Production in the AOI, predominantly to the SW half of the AOI.</td>
<td></td>
</tr>
<tr>
<td>Ostracod Zone</td>
<td>Baffle</td>
<td>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 AOI along the Wainwright Highlands (Devonian).</td>
<td></td>
</tr>
</tbody>
</table>

Shell Quest Carbon Capture and Storage Project Measurement, Monitoring and Verification Plan
Section 4: Storage Risks before MMV

Shell Canada Limited
October 15th 2012
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### 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 AOI. Absent towards the NE of the AOI along the Wainwright Highlands (Devonian). Thickness of the Ellerslie inside the AOI reaches a maximum of 90m. depending on the unconformity and the presence of channel sands.

### Wabamun
- **Gas Bearing**
- Characterized by Dolomite, brown, finely crystalline, porous in part; with subsidiary inter-beds of brown, micritic, peloidal limestone. Only exists in the W-NW half of the AOI due to erosion by the sub-cretaceous unconformity. However, there is some gas production within the AOI. Thickness ranges from 0m to 100m.

### Graminia
- **Baffle**
- A silt unit at the top of the Winterburn. Exists predominantly in the W-NW of the AOI. Thin and patchy across the rest of the AOI due to irregularities in the Pre-Cretaceous unconformity.

### Blueridge
- **Gas Bearing**
- Last widespread carbonate cycle in Western Canada. Exists predominantly in the W-NW of the AOI. Exists predominantly in the W-NW of the AOI due to irregularities in the Pre-Cretaceous unconformity. Has some minor porosity within the AOI. Production in the Eastern part of the AOI commonly mislabeled as Wabamun Production.

### 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 AOI. Thin and patchy across the rest of the AOI due to irregularities in the Pre-Cretaceous unconformity.

### Nisku
- **Oil and Gas Reservoir**
- A mixed carbonate-siliciclastic deposited during a lowstand. Within the AOI the Nisku is a porous light brown to light grey crystalline dolomite with lesser amounts of brownish grey dolomitic siltstones, green shales and anhydrite. It is commonly truncated by the pre-Cretaceous unconformity. Within the AOI oil production is only above and to the West of the Redwater reef, some minor gas exists in the NE portion of the AOI. The Nisku has a relatively constant thickness of the AOI at 57m.

### Ireton
- **Ireton / Grosmont I&II Seal**
- Only the Lower Ireton exists in the AOI represented by a cyclic succession of basin filling shales 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 AOI.

### Duvernay
- **Seal**
- Grades from a bituminous rich shale to a shale to a dolomite towards the NE of the Basin. Within the AOI 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.

### Leduc
- **Oil Reservoir**
- Within the AOI is the Redwater Reef and the Morinville Reef trend associated with the Rimby-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.

### Majeau Lake
- **Seal**
- In the AOI 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 AOI.
Cooking Lake

Intermediate Aquifer

Major regional aquifer made up of extensive sheet like shelf carbonates and a equivalent basin-fill shale (Majeau Lake). Consists of peloidal and skeletal limestones (bracs, crinoids, stromatoporoids, bryzoans). Unlike most younger Woodbend carbonates it is predominantly undolomitized (except directly under the Leduc-Homeglen-Rimby-Meadowbrook reef chain). The AOI 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.

Table 4-2

<table>
<thead>
<tr>
<th>Formation</th>
<th>Quest Name</th>
<th>Type</th>
<th>Composition and Depositional Environment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Watt Mountain</td>
<td>Seal</td>
<td>Top of the Elk Point Group represented by a thin (10m to 40m) green/greyish shale with thinly inter-beded 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.</td>
<td></td>
</tr>
<tr>
<td>Prairie Evaporite</td>
<td>Ultimate Seal WPGS Complex</td>
<td>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 AOI, 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 AOI.</td>
<td></td>
</tr>
<tr>
<td>Winnipegosis</td>
<td>Regional Aquifer</td>
<td>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 reliable aquifer above the BCS storage complex that can potentially be used for MMV purposes.</td>
<td></td>
</tr>
<tr>
<td>Contact Rapids</td>
<td>Contact Rapids/ Lower Winnipegosis</td>
<td>Regional Aquifer / Baffle</td>
<td>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 AOI 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 AOI there is good porosity within this zone as it is predominantly dolomite.</td>
</tr>
</tbody>
</table>
### Section 4: Storage Risks before MMV

<table>
<thead>
<tr>
<th>BCS Storage Complex</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Cold Lake</td>
<td>Seal</td>
</tr>
<tr>
<td></td>
<td>Thin halite interval represented in the far eastern portion of the Quest AOI. 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 were included in the Contact Rapids Formation.</td>
</tr>
<tr>
<td>Red Beds</td>
<td>Devonian Red Beds 1</td>
</tr>
<tr>
<td></td>
<td>Baffle</td>
</tr>
<tr>
<td></td>
<td>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.</td>
</tr>
<tr>
<td>Ernestina Lake</td>
<td>Baffle</td>
</tr>
<tr>
<td></td>
<td>Anhydrite, light grey at top, underlain by light grey-brown, crypto-to-micro-grained limestone, locally anhydritic with salt plugged porosity.</td>
</tr>
<tr>
<td>Red Beds</td>
<td>Devonian Red Beds 2</td>
</tr>
<tr>
<td></td>
<td>Baffle</td>
</tr>
<tr>
<td></td>
<td>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.</td>
</tr>
<tr>
<td>Lotsberg</td>
<td>Upper Lotsberg Salt</td>
</tr>
<tr>
<td></td>
<td>Ultimate Seal</td>
</tr>
<tr>
<td></td>
<td>Almost pure halite that acts as an aquiclude, ranging in thickness from 53m to 94m across the AOI and thickening to 150m up-dip, NE of the AOI in the Central Alberta Sub-Basin.</td>
</tr>
<tr>
<td>Red Beds</td>
<td>Devonian Red Beds 3</td>
</tr>
<tr>
<td></td>
<td>Baffle</td>
</tr>
<tr>
<td></td>
<td>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.</td>
</tr>
<tr>
<td>Lotsberg</td>
<td>Lower Lotsberg Salt</td>
</tr>
<tr>
<td></td>
<td>2nd Major Seal</td>
</tr>
<tr>
<td></td>
<td>Almost pure halite that acts as an aquiclude, ranging in thickness from 9m to 41 across the AOI and thickening to 60m up-dip, NE of the AOI in the Central Alberta Sub-Basin.</td>
</tr>
<tr>
<td>Red Beds</td>
<td>Devonian Red Beds 4</td>
</tr>
<tr>
<td></td>
<td>Baffle</td>
</tr>
<tr>
<td></td>
<td>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.</td>
</tr>
<tr>
<td>Upper Deadwood</td>
<td>Upper Marine Silts</td>
</tr>
<tr>
<td></td>
<td>Baffle</td>
</tr>
<tr>
<td></td>
<td>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 AOI due to the Pre-Cretaceous unconformity.</td>
</tr>
<tr>
<td>Lower Deadwood</td>
<td>Middle Cambrian Shale</td>
</tr>
<tr>
<td></td>
<td>1st Major Seal</td>
</tr>
<tr>
<td></td>
<td>The first major seal composed of shale deposited in an offshore shelf environment associated with continued flooding of the basin. Present across the entire AOI ranging in thickness from 21m to 75m. The MCS is absent due the Pre-Cretaceous unconformity just to the NE of the AOI.</td>
</tr>
<tr>
<td>Earlie</td>
<td>Lower Marine Sands</td>
</tr>
<tr>
<td></td>
<td>Baffle</td>
</tr>
<tr>
<td></td>
<td>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 AOI.</td>
</tr>
<tr>
<td>Basal Sandstone</td>
<td>Basal Cambrian Sands</td>
</tr>
<tr>
<td></td>
<td>CO2 injection zone</td>
</tr>
<tr>
<td></td>
<td>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.</td>
</tr>
<tr>
<td>Precambrian Basement</td>
<td>Basal Bounding Formation</td>
</tr>
<tr>
<td></td>
<td>Cratonic basement on which the BCS unconformably lies on top of. Considered an aquiclude.</td>
</tr>
</tbody>
</table>
4.2 Initial Conformance Risks

4.2.1 Loss of Conformance Definition

A loss of conformance exists if:

- The observed distribution of CO2 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 CO2 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 CO2 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 unrecognised bias in either 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 CO2 in Canada. Selecting a site within the top-ranked region minimises 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 characterisation** based on a dedicated and comprehensive appraisal program including 2D and 3D seismic and an appraisal well at the center substantially improved the reliability of a broad range of subsurface models. These models will be updated in response to data acquired from each development well.
The residual risk associated with the possibility of all these independent safeguards failing is judged to be low (see Table 4-3).

### Table 4-3 Classifications for describing the likelihood of an event.

<table>
<thead>
<tr>
<th>Classification</th>
<th>Event Likelihood</th>
</tr>
</thead>
<tbody>
<tr>
<td>Very Low</td>
<td>0-5%</td>
</tr>
<tr>
<td>Low</td>
<td>5-20%</td>
</tr>
<tr>
<td>Medium</td>
<td>20-50%</td>
</tr>
<tr>
<td>High</td>
<td>50-80%</td>
</tr>
<tr>
<td>Very High</td>
<td>80-100%</td>
</tr>
</tbody>
</table>

| 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 CO2 and the native BCS brine remain inside the storage complex. Consequently a loss of containment is defined as:

> A migration of CO2 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 CO2 or BCS brine migrate above the base of groundwater protection to reduce groundwater quality.
- **Soil contamination** if sufficient quantities of CO2 or BCS brine migrate into the soil to reduce soil quality.
- **CO2 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. Each are considered unlikely but are, in principle, capable of allowing CO2 or BCS brine to migrate upwards out of the BCS storage complex:

- **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
- **Migration along an injector** due to a poor or subsequently degraded cement bond or corrosion of the casing and completion

- **Migration along an observation well**: Any such wells drilled into the BCS storage complex pose a threat similar to the injectors

- **Migration along a rock matrix pathway** due to unexpected changes in the depositional environment or erosional processes

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

- **Induced stress reactivates a fault** creating a new permeable pathway out of the BCS storage complex

- **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

- **Acidic fluids erode geological seals**: Injected CO2 will acidify formation fluids which may react in contact with geological seals to locally enhance permeability within the seal

- **Third Party Activities** may induce environmental changes that cannot be distinguished from the potential impacts of CO2 storage that might trigger a perceived loss of containment from the BCS storage complex

### 4.3.4 Initial Safeguards to Ensure Containment

Following extensive site characterisation, 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 AOI.

- **The second seal**, the Lower Lotsberg Salt provides a 10 to 35 m thick seal over the entire AOI.

- **The ultimate seal**, the Upper Lotsberg Salt provides a 55 to 90 m thick seal over the entire AOI.

- **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 injectors from BCS legacy wells significantly reduces the chance of CO2 or sufficient BCS pressure reaching these wells.

Lateral separation is a significant safeguard as dynamic reservoir models show that CO2 will never reach the legacy wells. Also in the expectation reservoir scenario the pressure will never exceed the threshold to lift BCS brine to the groundwater protection zone.
Only in the extremely unlikely (< 5 % probability) low reservoir quality and low communication subsurface scenario, the BCS legacy wells may experience a short period of time near the end of the injection period when pressure is high enough to lift brine into BGWP. This scenario is likely to be disproved with the data from the 2012 injection wells.

- **Multiple cement plugs** seal the abandoned BCS legacy wells.
- **Multiple casing strings** within the injectors 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 are likely to reseal any fault or fracture unexpectedly induced by CO2 storage.
- **Acidic fluids** cannot erode either Lotsberg Salt Formation which are made of pure halite that does not react with CO2 saturated brine.

The corrective measures in-place include:

- **The Winnipegosis/Contact Rapidus aquifer** provides an auxiliary storage formation able to dissipate pressures and store CO2 or BCS brine.
- **The Prairie Evaporite** is a major regional seal, 100 to 150 m thick over the AOI.
- **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 CO2 or BCS brine. This is the most likely auxiliary storage formation because it already has some pressure depletion due to nearby production.

Dynamic leak path modeling indicates that due to the pressure depletion of the Cooking Lake, as well as flow into other deep aquifers, BCS brine cannot reach the ground water protection zone unless it flows along an open migration pathway unconnected to the Cooking Lake Aquifer.

- **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 AOI including above the injection zones.
• **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 AOI and a thickness of about 120 m at Radway 8-19.

The residual likelihood of all these multiple independent safeguards failing is judged to be *very low* (see Table 4-3). Table 4-4 provides a summary of the relationship between all these threats safeguards and consequences.
Table 4-4  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.

- CO2 Inventory Accuracy Target
  1) The accuracy of the reported CO2 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 CO2 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 CO2 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 CO2 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 CO2 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 CO2 emissions into the atmosphere

This list does not include monitoring to determine the contribution of individual storage mechanisms such as structural, capillary, solution, and mineralisation 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 summarised 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 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.

Several actions are ongoing to reduce key uncertainties about the expected performance of key monitoring technologies included in the base-case monitoring plan.

• **Time-lapse seismic** repeatability is expected to be sufficient to monitor the CO2 plumes, but uncertainty remains due to the site-specific sources of noise that might limit repeatability. Seismic repeatability tests are were completed around the Radway 8-19 well and results are in-line with expected feasibility of time-lapse seismic monitoring.
• **InSAR** monitoring of surface displacements depends on the number, distribution, and reliability of features in the landscape able to scatter InSAR signals back to the InSAR satellite. Data acquisition and feasibility studies are ongoing to Dec. 2013.
• **Light Source monitoring, previously referred to as Line-of-sight CO2 gas flux** monitoring, is a novel application of existing technology. A field trial is ongoing on the Radway 8-19 well pad and will continue through to 2013.
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 base-case monitoring plan for the wells and the storage complex. 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, Figure 6-1). This diversified monitoring program eliminates dependence on any single monitoring technology [Note that tracer injection and monitoring is dependent on the outcome of ongoing feasibility studies]. The diversity of monitoring technologies mitigates the risk of any one technology failing.

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

<table>
<thead>
<tr>
<th>Monitoring</th>
<th>Coverage</th>
<th>Pre-Injection</th>
<th>Injection</th>
<th>Closure</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Atmosphere</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Line-of-sight CO2 gas flux monitoring</td>
<td>Within 6 km of every injector</td>
<td>Continuous</td>
<td>Continuous</td>
<td>Continuous</td>
</tr>
<tr>
<td><strong>Biosphere</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Remote Sensing (^a)</td>
<td>Entire AOR</td>
<td>Multiple Images</td>
<td>Once per year</td>
<td>Once every two years</td>
</tr>
<tr>
<td>Soil monitoring (for remote sensing calibration)(^a)</td>
<td>Discrete locations across the AOR</td>
<td>Every year</td>
<td>As required</td>
<td>As required</td>
</tr>
<tr>
<td><strong>Hydrosphere</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Down-hole pH monitoring (^a)</td>
<td>Project groundwater wells</td>
<td>Continuous</td>
<td>Continuous</td>
<td>Continuous</td>
</tr>
<tr>
<td>Down-hole electrical conductivity monitoring(^a)</td>
<td>Project groundwater wells</td>
<td>Continuous</td>
<td>Continuous</td>
<td>Continuous</td>
</tr>
<tr>
<td>Natural tracer monitoring (^a)</td>
<td>Project and Private landowner groundwater wells</td>
<td>At least every year</td>
<td>TBD(^b)</td>
<td>TBD(^b)</td>
</tr>
<tr>
<td>Artificial tracer monitoring (^a, c)</td>
<td>Project and Private landowner groundwater wells</td>
<td>At least every year</td>
<td>TBD(^b)</td>
<td>TBD(^b)</td>
</tr>
<tr>
<td><strong>Geosphere</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Time-lapse 3D vertical seismic profiling (^d)</td>
<td>Within 600 m of every injector</td>
<td>2013</td>
<td>2016, 2018</td>
<td>None</td>
</tr>
<tr>
<td>Time-lapse 3D surface seismic</td>
<td>Each entire CO2 plume</td>
<td>2010</td>
<td>2022, 2029, 2039</td>
<td>2048</td>
</tr>
<tr>
<td>Interferometric Synthetic Aperture Radar</td>
<td>Entire AOR</td>
<td>Monthly</td>
<td>Monthly</td>
<td>Monthly</td>
</tr>
</tbody>
</table>

NOTES:
\(^a\) See HBMP Appendix A for details
\(^b\) TBD = to be determined, based upon findings from first year pre-injection (baseline) monitoring phase
Table 6-2  Summary of the monitoring plan for deep observation wells and CO₂ injectors

<table>
<thead>
<tr>
<th>Monitoring</th>
<th>Pre-Injection</th>
<th>Injection</th>
<th>Closure</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>WPGS Observation Wells</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Down-hole pressure-temperature monitoring</td>
<td>None</td>
<td>Continuous</td>
<td>Continuous</td>
</tr>
<tr>
<td>Down-hole microseismic monitoring (8-19 well pad only)</td>
<td>6 months</td>
<td>Continuous</td>
<td>None</td>
</tr>
<tr>
<td>Cement bond log</td>
<td>Once</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td><strong>BCS Observation Well (Redwater 100-03-04-057-20W400)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Down-hole pressure-temperature monitoring</td>
<td>None</td>
<td>Continuous</td>
<td>Continuous</td>
</tr>
<tr>
<td>Cement bond log</td>
<td>Once</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td><strong>Injectors</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Well-head pressure-temperature monitoring b</td>
<td>None</td>
<td>Continuous</td>
<td>Continuous</td>
</tr>
<tr>
<td>Time-lapse ultrasonic casing imaging</td>
<td>Once</td>
<td>Every 5 years</td>
<td>Every 10 years</td>
</tr>
<tr>
<td>Time-lapse electromagnetic casing imaging</td>
<td>Once</td>
<td>Every 5 years</td>
<td>Every 10 years</td>
</tr>
<tr>
<td>Time-lapse casing calliper logs</td>
<td>Once</td>
<td>Every 5 years</td>
<td>Every 10 years</td>
</tr>
<tr>
<td>Time-lapse cement bond log b</td>
<td>Once a</td>
<td>Every 5 years</td>
<td>Every 5 years</td>
</tr>
<tr>
<td>Mechanical well integrity testing (packer isolation test) b and tubing calliper log</td>
<td>Once</td>
<td>Every year</td>
<td>Every 3 years</td>
</tr>
<tr>
<td>Injection rate monitoring b</td>
<td>None</td>
<td>Continuous</td>
<td>None</td>
</tr>
<tr>
<td>Distributed temperature sensing</td>
<td>None</td>
<td>Continuous</td>
<td>Continuous</td>
</tr>
<tr>
<td>Down-hole pressure-temperature monitoring</td>
<td>None</td>
<td>Continuous</td>
<td>Continuous</td>
</tr>
<tr>
<td>Distributed acoustic sensing</td>
<td>None</td>
<td>Continuous</td>
<td>Continuous</td>
</tr>
<tr>
<td>Annulus pressure monitoring b</td>
<td>None</td>
<td>Continuous</td>
<td>Continuous</td>
</tr>
<tr>
<td>Routine well maintenance c</td>
<td>Every year</td>
<td>Every year</td>
<td>Every year</td>
</tr>
</tbody>
</table>

NOTES:

- A D51 current regulatory commitment for Class III wells.
- A possible future D51 regulatory commitment for Class III wells (current requirement for Class I wells).
- A maintenance task related to the wells, included in this table for completeness.
This diversified monitoring program eliminates dependence on any single monitoring technology [Note that tracer injection and monitoring is dependent on the outcome of ongoing feasibility studies].
6.2 Monitoring Coverage

The coverage of most monitoring systems is centered on, or confined to, one of the several different types of Project wells (Table 6-3). The number and location of these Project wells depends on the number of injectors required according to the phased Storage Development Plan. The coverage expected from each monitoring system varies considerably – some cover the entire AOI, whilst others cover regions of varying distance from each injector (Figure 6-3, Figure 6-4, Figure 6-5).

6.2.1 Observation Wells within the Basal Cambrian Sands Formation

The existing appraisal well, Redwater 3-4, located towards the southern boundary of the AOR, is proposed to be the only direct observation point within the BCS besides the injectors. 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 and InSAR. The perceived benefits are limited because BCS observation wells have no ability to verify containment 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 CO2 plume geometry as it will only provide information about the CO2 front at one time in one location. To provide conformance information comparable to time-lapse seismic requires several BCS observation wells per plume.

The option of locating one or more BCS observation wells within a single CO2 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. Time-lapse seismic is expected to image the CO2 plume geometry with a lateral resolution of 25 to 50 m. This is difficult to calibrate with an observation well because in-well logging techniques are not sensitive to saturation distributions on this scale and narrow sand bodies may channel the CO2 towards or around the well. Moreover, time-lapse seismic is routinely used for Well and Reservoir Management without the need for calibration by observation wells because the failure case is easily recognised as an image dominated by incoherent noise.

The benefits of multiple BCS observation wells located outside the expected CO2 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 and the existing Redwater 3-4 well.

The option to drill BCS observation wells is retained under contingency plans (section 8) in case time-lapse seismic or InSAR monitoring performance falls short of requirements.

---

1 Monitoring inside the storage complex provides no ability to detect fluids migrating outside the complex.
6.2.2 Deep Observation Wells

The prime role of the three Deep observation wells is to support pressure monitoring to verify containment. The Winnipegosis/Contact Rapids is the preferred deep monitoring well target interval because:

- It is the deepest aquifer above the BCS storage complex
- The interval is regionally isolated from the zones above by the Prairie Evaporite and is not affected by pressure changes associated with regional hydrocarbon production (i.e. Cooking Lake).
- Shell has approval via the Sequestration Lease Approval to use this interval as a monitoring interval.

However, Shell is evaluating three aquifers (WPGS, BHL and CKLK) in the 2012/2013 drilling campaign to determine which will be used for monitoring going forward. For the purpose of this document, it is assumed that the Winnipegosis (WPGS) aquifer, which includes the underlying Contact Rapids, will be used as the target of the Deep Monitoring Well Program.

The current development plan provides for drilling 3, 4 or 5 injectors prior to start-up in order to ensure sufficient injectivity. In the case of:

- **3 injectors**, one WPGS observation well will be located on each injection well pad. Injection well Radway 8-19 already exists. Injection wells two (Thorhild 5-35-59-21W4) and then three (Radway 7-11-59-20W4) are to be drilled starting Q4 2012, as are the deep monitoring wells on the same well pads. The 7-11 deep monitoring well is at the end of the drilling sequence as the decision to drill it will depend on the log evaluation and production test in Thorhild 5-35 injection well and the log evaluation of Radway 7-11 injection well. If the results are favourable and the cement bonds are good then the third deep monitoring well on the Radway 7-11 well pad will be drilled immediately in the same drilling campaign. If it appears that a 4 well scenario is likely, drilling of the Radway 7-11 deep monitoring well will be postponed to follow the scenarios discussed below.

- **4 injectors**, these 3 WPGS observation wells will be located on the well pads of the 3 injectors expected to have the smallest injectivity according to existing appraisal data. This is a risk-based choice as these three locations are expected to develop greater BCS pressures. This initial choice is based on the expectation that all injectors will achieve the same cement bond quality. If cement bond logs show this not to be the case, then this choice will be revised to include injection wells judged to be at slightly higher risk due to pressure and cement bond quality.

- **5 injectors**, these 3 WPGS observation wells will be located on the well pads of the central 3 injectors. Again, this is a risk-based choice as these injectors are expected to develop greater BCS pressures due to pressure support from their many neighbouring injectors. Furthermore, this choice may be revised in response to unexpected differences in cement bond quality between these 5 injectors.

In addition to the pressure monitoring, one of these WPGS observation wells will be instrumented with a conventional permanent down-hole geophone array to support microseismic monitoring. This again is a risk-based choice. The selected well, depends on the number of injectors to ensure it will monitor that part of the BCS storage complex expected to develop some of the greatest pressures. Contingency plans exist to revise this
selection based on the results of water production tests and log evaluations for the injectors that will be completed prior to drilling the third WPGS observation wells (Radway 7-11).

The base-case monitoring plan does not include a WPGS observation well for every injector because the network of three observation wells described above is judged to be sufficient to verify containment. Contingency plans exist to increase the number of WPGS observation 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).

6.2.3 Project Groundwater Wells

Three Project groundwater wells will be drilled per injector and at least one of these wells will be located on the injection well pad (see MMV commitment - Table 1-1).

The current plan is to use the existing 5 groundwater wells located on the 8-19 well pad. As each of the 5 wells has been completed at a different depth, this network of wells enables us to investigate vertical variations in groundwater geochemistry at a local scale. In addition, there will be 2 deep (down to 140m BGL) and 2 shallow (~20m BGL) project groundwater wells drilled on each of the Thorhild 5-35 and Radway7-11 well pads. These deep wells will give the earliest warning of any leakage into the ground water protection zone as they are situated at the base of the protected groundwater zone. The shallow wells, are situated at the typical depth for most local private landowner groundwater wells in the area and may provide insight into shallow fluid variations.

This is a risk-based choice as the injectors present the highest risk of potential migration pathways from the BCS storage complex and will also encounter the highest pressures within the AOR. However, due to the presence of multiple independent safeguards the likelihood of fluids migrating out of the BCS storage complex along any potential pathway is very low.

The proximity of these groundwater wells to the injection wells will provide monitoring to verify containment and, in the event of an unexpected migration of fluids along an injection well, will provide an early warning to trigger effective control measures. The lateral offset of the project groundwater wells from the injectors is sufficiently small to ensure effective groundwater monitoring regardless of the direction of local groundwater flow.

As part of the risk-based approach, placement of project groundwater wells next to legacy wells will not be implemented prior to injection. (see section 4.3.4). BCS pressure monitoring, during the operating phase, will provide early warning of pressure increases trending towards values high enough to lift BCS brine to the BGWP via legacy wells, far in advance of any risk of occurrence (See Section 7.2.1). Therefore, locations for project groundwater wells are identified in all the Figures as a contingency in the event they are required, to be evaluated on an annual basis in the annual operations report to the ERCB.

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. For the details on the planned locations and sampling programs associated with the Project Groundwater wells see the HBMP in Appendix A.
Table 6-3  The number and location of Project wells that support the MMV plan depend on the development scenario.

<table>
<thead>
<tr>
<th></th>
<th>3 Injectors</th>
<th>4 Injectors</th>
<th>5 Injectors</th>
<th>8 Injectors</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>7-11-59-20W4</td>
<td>7-11-59-20W4</td>
<td>7-11-59-20W4</td>
<td>7-11-59-20W4</td>
</tr>
<tr>
<td></td>
<td>15-16-60-21W4</td>
<td>15-16-60-21W4</td>
<td>10-6-60-20W4</td>
<td>15-16-60-21W4</td>
</tr>
<tr>
<td>BCS Observation Well</td>
<td>Redwater 3-4</td>
<td>Redwater 3-4</td>
<td>Redwater 3-4</td>
<td>Redwater 3-4</td>
</tr>
<tr>
<td>WPGS Observation Wells</td>
<td>1 well on each of these 3 well pads:</td>
<td>1 well on each of these 3 well pads:</td>
<td>1 well on each of these 3 well pads:</td>
<td>1 well on each of these 3 well pads:</td>
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<tr>
<td></td>
<td>7-11-59-20W4</td>
<td>15-16-60-21W4</td>
<td>10-6-60-20W4</td>
<td>15-16-60-21W4</td>
</tr>
<tr>
<td>Project Groundwater Wells</td>
<td>9 wells in total</td>
<td>12 wells in total</td>
<td>15 wells in total</td>
<td>24 wells in total</td>
</tr>
</tbody>
</table>

NOTE:
*Denotes the single WPGS observation well equipped with down-hole geophones for microseismic monitoring.

Three distinct types of injection well pads are required to support the MMV Plan. These are characterised by the different wells present on each type of well pad:

- **Type 1**: Includes:
  1) *Injection well*
  2) *Project groundwater well*

- **Type 2**: As Type 1, but also includes:
  1) *WPGS observation well with down-hole pressure monitoring*

- **Type 3**: As type 2, but also includes:
  1) *Down-hole microseismic monitoring within the WPGS observation well*

Table 6-4 describes the allocation of these injection well pad types under the different development scenarios. In addition to these, the Redwater 3-4 well pad requires conversion from an exploration well to a BCS observation well with support for continuous pressure monitoring.
Table 6-4 The type of well pad required at each injector location depends on the development scenario

<table>
<thead>
<tr>
<th>Development Scenarios</th>
<th>Injection Well Pads</th>
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<tbody>
<tr>
<td>3 Injectors</td>
<td>4 Injectors</td>
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<tr>
<td>Type 3</td>
<td>Type 2</td>
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<td>Type 2</td>
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</table>

6.2.4 Landowner Groundwater Wells

Access to landowner groundwater wells will greatly increase the coverage of the groundwater well monitoring network. However, this is contingent on permission from the landowner and the status of the well as active and that it is safe to sample. The landowner groundwater wells proposed for inclusion in the current monitoring program include:

- Landowner groundwater well within 3.2 km of each injector and those in close proximity to abandoned BCS legacy well inside the AOR (Figure 6-6).
- A regional network of groundwater wells, sparsely distributed across the remaining AOR at a density of approximately one per township (Figure 6-6)
- Any additional landowner water wells where such landowners have requested to participate in the program, in accordance with ERCB D65 final approval and Shell’s commitment made during the ERCB hearing.

For the details on the proposed well locations and sampling programs associated with the landowner groundwater wells see the HBMP in Appendix A. Appendix A provides specific details only for the baseline monitoring and data gathering period. Once the baseline data is gathered, and variability understood, it is expected that the number of water wells involved in the program will be modified, subject to the ERCB D65 final condition for approval referenced above.
Figure 6-2  Maps showing the location of observation wells for the different development scenarios. Coordinates show kilometres in the NAD27 UTM Zone 12N datum. Project groundwater at legacy well locations are considered a contingency.
**Figure 6-3** Maps showing the coverage of different monitoring methods for the base-case modeling plan. Coordinates show meters in the NAD27 UTM Zone 12N datum.

**Legend**

- DHPT Down-hole pressure-temperature monitoring within a deep observation well
- MIA Remote sensing Multi-Spectral Image Analysis
- OBG Project groundwater observation wells (considered a contingency at legacy well locations)
- VSP3D Time-lapse 3D Vertical Seismic Profile surveys
- DHMS Down-hole microseismic monitoring within a deep observation well
- INSAR InSAR measurements of surface displacements to monitor BCS pressure changes
- LOSCO2 Line-of-sight CO2 flux monitoring
- SEIS3D Time-lapse 3D surface seismic monitor surveys; transparent green box denotes baseline survey
- CO2 Expected CO2 plume radius after 25 years injection for 5 well scenario
- OBB BCS observation well
- Legacy wells Abandoned wells that penetrate the BCS
- OBL Landowner groundwater wells
Figure 6-4  As Figure 6-3, enlarged to demonstrate the coverage of monitoring around each injector.
Figure 6-5 Schematic cross-section showing the expected coverage of different monitoring methods for the base case development scenario of 5 injectors. See Figure 6-3 for the location of this cross-section and an explanation of the legend.
Figure 6-6 Distribution of landowner water wells proposed for inclusion in the groundwater monitoring network. Black dots refer to wells near legacy wells; cyan (light blue) dots refer to wells around injector wells; green dots refer to regional network.
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 technical feasibility assessments.

7.1 Performance Targets for Conformance Monitoring

7.1.1 Monitoring CO2 Plume Development

Time-lapse seismic (VSP3D, SEIS3D) will be used to monitor the development of the CO2 plume inside the BCS storage complex. Repeat seismic surveys are expected to yield an image of the CO2 plume geometry around each CO2 injector. CO2 entering the pore space within the Basal Cambrian Sandstones will replace some of the brine. Because the injected CO2 is much more compressible than brine, the speed of seismic p-waves traveling through the BCS will be reduced in those places containing CO2 and will remain unchanged elsewhere. Differences in seismic images of the BCS obtained before and during CO2 injection will arise due to the presence of CO2 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 CO2 saturation of up to 5 or 10% of the pore-space cause significant velocity reductions (c. 8%) but thereafter additional CO2 within the same pore-space causes very little additional velocity change. Consequently, time-lapse seismic is expected to monitor the shape of the CO2 front but not the distribution of CO2 saturation inside the plume.

Evaluation of seismic data acquired during the appraisal period and site-specific feasibility studies indicated CO2 will be detectable in those places where CO2 fills at least 5% of the pore-space and the thickness of a contiguous CO2 plume exceeds 5 m. The expected lateral and vertical resolution of the CO2 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 land 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 distributed acoustic sensing along a permanent fibre 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 temporary geophone array. Based on successful field trial results at Radway 8-19 this technology is included in the base-case monitoring plan and conventional VSP surveys are retained in the contingency monitoring plans.
7.1.2 Monitoring Pressure Development

**Down-hole pressure gauges** (DHPT) will be used to ensure down-hole injection pressures do not exceed their agreed maximum values. This is a mature industry standard technology and any failed gauge will be replaced during a scheduled well work-over.

**InSAR** is a satellite remote sensing method designed to map even the smallest displacements of the Earth’s surface. Pressure increases expected inside the BCS storage complex will cause the BCS and LMS to increase in thickness by 1 to 10 mm per MPa. This small deformation at depth results in a smaller and smoothly distributed displacement of the Earth’s surface. These displacements are so small that they can only be detected by very sensitive instruments specifically designed for this purpose. The moment CO2 injection stops, pressures inside the BCS will begin to relax and surface displacements will begin to reverse.

Evaluation of data acquired during the appraisal period and site-specific feasibility studies indicate InSAR will measure surface displacements with a precision of 1-2 mm/yr. 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 the region subject to a pressure increase sufficient to lift brine above the base of groundwater protection (c. 3MPa). Observed monitoring performance during the injection period will be used to validate or update these values.

Down-hole pressure gauges and InSAR (DHPT, INSAR) will be used to monitor the development of fluid pressure inside the BCS storage complex at and away from the injectors. Continuous pressure measurements will be made inside the BCS within every injector and a dedicated observation well, Redwater 3-4, located just inside the southern edge of the sequestration lease area. These gauges will provide accurate direct measurements of pressure changes at these discrete locations. InSAR will provide monthly measurements to indicate the areal distribution of BCS pressure changes between the gauge locations and across the entire sequestration lease area.

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 CO2 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.

7.2.1 Pressure Monitoring to ensure Legacy Well Integrity

Dedicated BCS pressure monitoring near the legacy wells is not considered a requirement as the monitoring of pressure development in the BCS Storage Complex (see 7.1.2 above) will provide early warning in the very unlikely event the system is trending towards a scenario where the BCS pressure could exceed the threshold pressure to lift BCS brine to the ground water protection zone at the legacy wells. In which case Shell would be able to implement contingency monitoring plans (Section 8).
7.2.2 Monitoring Injection Well Integrity

**Mechanical Well Integrity Testing**, which consists in annually pressure testing the packer for 10 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 ERCB D51 injection approval in effect at the time.

**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.

**Routine well maintenance**, which consists in 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.

**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 5 years during the injection period to verify continuing cement bond and casing integrity. Although it is not currently a regulatory requirement for Class III injection well, hydraulic isolation logging every 5 years could be required by the authorities in the future (as per Directive 51 Class I wells). If this occurs, the DTS (referred to, below) should provide continuous evidence supporting hydraulic isolation and therefore time-lapse hydraulic isolation logging could be removed from the Monitoring plan.

**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.

**Distributed Temperature Sensing** (DTS) along an optical fibre permanently deployed from the surface down to the first seal on the outside of the intermediate casing will provide a continuous means of verifying cement bond integrity, hydraulic isolation, and the absence of CO2 outside the casing. In the unexpected event of a loss of cement bond integrity, any upward migration of CO2 outside the casing will lower the temperature on the adjacent portion of the DTS fibre due to increased thermal insulation from the in-situ formation temperature provided by the out-of-place CO2.

Evaluation of data acquired at Radway 8-19 during the appraisal period and a site-specific feasibility study indicate DTS will detect temperature changes with a precision of 0.1 degrees Celsius and a vertical resolution of 1 m. This allows detection of CO2 flux of at least 10 kg/day through a micro-annulus within the external cement bond. Observed monitoring performance during the injection period will be used to validate or update these values. A static blanket of CO2 cannot be directly distinguished from a flux of CO2 outside the casing. However, a flux may be inferred in the case the temperature anomaly extends upwards to but not beyond a permeable formation.

**Distributed Acoustic Sensing** (DAS) along an optical fibre deployed alongside the DTS fibre will provide continuous 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 fibre. Evaluation of data acquired at Radway 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. This should allow detection of a fluid flux through a conduit within the external cement bond. Observed monitoring performance during the injection period will be used to validate or update these values. Acoustic noise due to flow through a micro-annulus is readily distinguished from microseismic events as the former is continuous and ubiquitous along the affected portion of the well whilst the latter are episodic with distinct p- and s-waves arrivals that travel along the fibre.

7.2.3 Monitoring Geological Seal Integrity

**Deep observation wells** will be drilled from 3 of the injection well pads and completed within the first major permeable zone above the BCS storage complex.

**Continuous pressure measurements** (DHPT) within the deep observation wells will provide a means of detecting any unexpected migration of injected CO2 or brine out of the BCS storage complex. Within the Winnipegosis/Contact Rapids Formations, the current preferred Deep MV target, just 6 kg/day of fluid migration into this deep formation will likely cause a detectable sustained pressure rise. This is based on log evaluations of the Radway 8-19 injection well. The time to detection depends on the distance through the permeable formation between the fluid entry point and the pressure gauge. A fluid entry point will likely be detected within 5-20 days if located within 1 km of the pressure gauge, and 100-300 days for 3.5 km. These deep monitoring wells will be drilled from 3 injection well pads (Table 6-3) selected, based on risk, according to which injectors are expected to develop the greatest pressures inside the BCS. The preferred target monitoring zone is the Winnipegosis/Contact Rapids aquifer (1800 m deep) which is expected to transmit pressure changes over sufficient distances and to experience no other sources of notable pressure change. However, should the Winnipegosis prove insufficient for pressure monitoring, the Beaverhill Lake Group (~1260 m TVD) or Cooking Lake Formation (1200 m TVD) may provide a suitable alternative; although there are potential complications due to the gaining the necessary regulatory permissions and the ongoing regional pressure depletion.

**Time-lapse seismic** (VSP3D, SEIS3D) will be used to verify the absence of CO2 above the ultimate seal of the BCS storage complex. Any CO2 unexpectedly entering the Winnipegosis Formation, or other overlying permeable formation, will affect the seismic image due to the same physical effects previously described for CO2 entering the BCS (Section 7.1.1). Due to different formation properties and different in-situ temperature and pressure conditions that affect the properties of CO2, the magnitude of anticipated time-lapse seismic changes in the unexpected event of CO2 entering these formations varies. CO2 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 impedance changes by c. 7% and c. 4% within these two formations respectively. Seismic modeling studies indicate this velocity reduction will likely be detectable within time-lapse seismic images for a contiguous CO2 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 CO2 saturation of 20-40% within such a CO2 plume, this corresponds to an expected detection limit of 100,000 to 60,000 tonnes of CO2. This expected sensitivity is based on a typical amount of non-repeatable noise being present
within the two land seismic images. Additional information about formation properties gained by logging each injection well and reconciliation of observed and predicted monitoring performance will be used to validate or update these values.

**Microseismic** (DHMS) monitoring using a conventional down-hole array with 8 levels of three-component retrievable geophones spaced 10 m apart that is deployed within one of the deep observation wells will verify the absence of any induced microseismic activity within the vicinity of this injector. Induced microseismicity results from fracture propagation or fault slippage.

The microseismic monitoring performance of a conventional down-hole geophone array is well-established through observed field performance elsewhere. Microseismic events with moment magnitudes of −2 should be detectable out to 800m, events with magnitude -1 should be detectable out to a distance of 3000 m and events with magnitude 0 should be detectable out to a distance of 10000 m from the geophone array. Observed monitoring performance during the injection period will be used to validate or update these values. Similar down-hole geophone arrays have operated now elsewhere for more than 10 years without failure.

**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 meters with +/-0.5% minimum accuracy.
- The temperature will be measured with meters with +/-0.25 degrees Celsius minimum accuracy.

These are conservative estimates based on the technical specifications of the flow rate, pressure, and temperature monitoring systems. These performance targets will be updated based on the selected meter performance and will ensure regulatory compliance.

**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 brine or CO2 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. Because the Cooking Lake is under-pressured relative to the BCS pressure gradient, any leakage reaching this depth is likely to preferential move into this formation.
• Fault slippage: There were no faults detected on 3D or 2D seismic 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.

• Alberta is a potentially challenging environment for InSAR due to extended periods of snow cover, but these potential difficulties should be readily overcome by deploying a limited number of artificial corner reflectors and GPS receivers across the AOR. Acquisition of InSAR data over the AOR started in 2010 to evaluate the number of reliable monitoring targets within the existing landscape. According to the ERCB D65 final approval and conditions, if required, Shell will install corner reflectors where necessary 15 months prior to injection.

The observed performance of geological seal integrity monitoring during the injection period will be used to validate or update these performance values.

7.2.4 Monitoring the Hydrosphere

Continuous water electrical conductivity monitoring (WEC) is planned within the Project groundwater monitoring wells. This will enable detection of changes in water salinity, which could potentially indicate an influx of brine due to a leakage event from the BCS storage complex which will verify the absence of high salinity water, such as BCS brine, at these locations. These sensors will detect a change in conductivity of at least 0.1 μS/cm corresponding to an increase in salinity of at least 0.1 mg/kg. Observed monitoring performance during the baseline monitoring period will be used to validate or update these monitoring performance values. These data will also provide the basis to establish a trigger value for any sustained conductivity increase that requires further investigation.

For any anomalous conductivity increase, fluid and gas samples will be collected from that well and analyzed to determine the presence or absence of tracers uniquely associated with the BCS brine and the injected CO₂.

Continuous water pH monitoring (WPH) is planned within the Project groundwater monitoring wells. This will enable detection of changes in pH, which could potentially be associated with increased levels of dissolved CO₂ within the groundwater. For any anomalous pH reduction, fluid and gas samples will be collected from that well and analyzed to determine the presence or absence of tracers uniquely associated with the BCS brine and the injected CO₂.

Discrete water/gas sampling and analysis (NTM, ATM) within the Project groundwater monitoring wells and a selection of accessible/active landowner groundwater wells present within the AOR will be used to verify the absence of BCS brine and injected CO₂ within the groundwater at those locations.

• BCS tracers: Between 50 parts per million and 3 parts per thousand of BCS brine unexpectedly appearing within a groundwater sample will be detected using a combination of chemical and isotopic indicators uniquely associated with BCS brine and not initially present within the groundwater or indeed other aquifers above the BCS storage complex.
- **CO2 tracer:** Just 1 part per thousand of injected artificial CO2 tracer unexpectedly appearing within a groundwater sample can be detected using an artificial tracer injected with the CO2. However, feasibility studies on Artificial tracers, and the decision to use them, will only be complete by January 2014. Feasibility of natural CO2 tracers are also being assessed.

Evidence for the absence of these tracers within groundwater fluid samples is the most reliable and sensitive method available for demonstrating groundwater quality remains unaffected by CO2 injection into the BCS storage complex. Observed monitoring performance during the baseline monitoring and injection periods will be used to validate or update these monitoring performance values.

Further details regarding the monitoring of the hydrosphere can be found in the Hydrosphere, Biosphere Monitoring Plan (Appendix A).

### 7.2.5 Monitoring the Biosphere

**Remote sensing** using radar image analysis (RIA) and multi-spectral image analysis (MIA) methods will help track any annual changes across the entire sequestration lease to help indicate the absence of BCS brine and Project CO2 within the near surface soil and vegetation. Local changes in the dielectric constant of the soil due to increased salinity or moisture content will affect the back-scattered amplitude and polarisation of radar data even during periods of snow cover. The same monthly data acquired for InSAR monitoring of surface displacements can also be used for this purpose. Optical methods based on multi-spectral image data, such as the normalised difference vegetation index (NDVI), may indicate vegetation stress due to soil salinization or acidification. However the potential for confounding effects is not insignificant especially due to extensive agricultural activities across the AOR.

These remote sensing techniques offer the potential for affordable wide-area coverage but they may prove insufficiently reliable for environmental change detection. The performance of these methods will be 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.

**Soil surveys** to measure near surface electrical conductivity using EM38 at a sufficient number of discrete locations to calibrate the ability of radar image analysis to measure soil salinity variations. Any indications of anomalous change from remote sensing will be subject to ground-based verification using EM38 and, if necessary, soil samples will be analysed to determine the presence or absence of BCS brine tracers.

**Vegetation surveys** to measure any indications of vegetation stress at a sufficient number of discrete locations to calibrate the ability of multi-spectral image analysis to measure vegetation stress. Any indications of anomalous change from remote sensing will be subject to ground-based verification and, if necessary, soil samples will be analysed to determine the presence or absence of BCS brine tracers, natural CO2 tracers and if utilized, the artificial PFC tracer injected with the CO2.

**Field Spectra Surveys** to measure spectral signatures for each vegetation group identified at a number of discrete locations in the AOR to provide ground calibration for the optical data used for multi-spectral image analysis (MIA). The survey will be competed using a portable field reflecting spectrometer (PFRS).
Soil Gas and Soil Surface CO2 Flux Measurements are included in the biosphere pre-injection data gathering program in order to gain an understanding of the magnitudes and temporal / spatial variability of those parameters in the AOR. However, during the injection phase, the analyses are considered a response tool and not a monitoring tool. For further details regarding the monitoring of the biosphere, see Appendix A.

7.2.6 Monitoring the Atmosphere

LightSource (previously referred to as ‘Line-of-sight CO2 gas flux’ monitoring’ or LOSCO2) based on LIDAR technology will provide a method to verify the absence of any unexpected atmospheric CO2 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 CO2 emissions up to 6 km from each injector. This is beyond the current anticipated radius of a CO2 plume developed around each injector at the end of the injection period. The expected sensitivity and resolution of CO2 emission mapping depends on distance from the sensor system:

- **2 km**: At least 250 kg/hour (0.9 kilo-tonnes/year) of CO2 from a point source will be detected within days and mapped with a resolution of 100 m.
- **6 km**: At least 600 kg/hour (5 kilo-tonnes/year) of CO2 from a point source will be detected within days and mapped with a lateral resolution of 200 m.

For any anomalous CO2 emissions detected, samples of soil gas will be collected from that location and analyzed to determine the presence or absence of natural and/or artificial tracers uniquely associated with the injected CO2. Observed monitoring performance during the baseline monitoring period and controlled CO2 release tests will be used to validate or update these monitoring performance values.

The selected monitoring technologies provide complementary capabilities in terms of detection sensitivity, detection time and detection range (Figure 7-1). 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.

A preliminary list of alarm thresholds for a number of monitored parameters to trigger control responses designed to safeguard containment is given in Table 7-1. Baseline monitoring data will be used to verify, and if necessary, updated these values.
Figure 7-1  A comparison, where possible, of the expected detection time, detection sensitivity and detection range for a range of different monitoring technologies.

Legend:
LOSCO2  Line-of-sight CO2 flux monitoring (LightSource),
DTS  Distributed Temperature Sensing,
DHPT WPGS  Down-hole pressure-temperature monitoring within the Winnipegosis (or alternative monitoring formation)
SEIS3D  Time-lapse surface 3D seismic
VSP3D  Time-lapse 3D vertical seismic profiles
SGRAV  Time-lapse surface gravity (regretted due to insufficient sensitivity and detection time)
7.3 Modeling

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.

A list of models already in use for the Quest CCS project, and expected to be required during the project’s lifecycle, is shown below, in addition to the accountable discipline.

<table>
<thead>
<tr>
<th>Model</th>
<th>Accountable Discipline</th>
</tr>
</thead>
<tbody>
<tr>
<td>Static Reservoir Model (3D) and Maps (2D)</td>
<td>Production Geosciences</td>
</tr>
<tr>
<td>Dynamic Reservoir Model</td>
<td>Reservoir Engineering</td>
</tr>
<tr>
<td>Integrated Production System Model</td>
<td>Production Technologist</td>
</tr>
</tbody>
</table>

See the Closure Plan for more details.

7.4 Preliminary Alarm Thresholds

Table 7-1 provides a summary of preliminary alarm thresholds that will be used to trigger control responses designed to safeguard containment. These thresholds will be verified, and if required, updated and once baseline data has been obtained.
### Table 7-1: Preliminary alarm thresholds to trigger control responses designed to safeguard containment. Baseline monitoring data will be used to verify, and if necessary, updated these values.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Indicator</th>
<th>Frequency</th>
<th>Baseline</th>
<th>Sensor Error</th>
<th>Threshold</th>
<th>Alarm</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>[mean]</td>
<td>[std]</td>
<td>[mean]</td>
<td>[std]</td>
<td>[value]</td>
</tr>
<tr>
<td>LightSource 2x2</td>
<td>CO2 Emission Mass Rate</td>
<td>Every day</td>
<td>0</td>
<td>0</td>
<td>631</td>
<td>25000</td>
<td>0</td>
</tr>
<tr>
<td>LightSource 6x6</td>
<td>CO2 Emission Mass Rate</td>
<td>Every day</td>
<td>0</td>
<td>0</td>
<td>5256</td>
<td>25000</td>
<td>0</td>
</tr>
<tr>
<td>SPH</td>
<td>Soil pH</td>
<td>Every year</td>
<td>8</td>
<td>0</td>
<td>0.10</td>
<td>7.47</td>
<td>0.0</td>
</tr>
<tr>
<td>SSAL</td>
<td>Soil Salinity Change</td>
<td>Every year</td>
<td>0</td>
<td>0</td>
<td>0.10</td>
<td>0.53</td>
<td>0.0</td>
</tr>
<tr>
<td>WPH</td>
<td>Water pH</td>
<td>Every day</td>
<td>8</td>
<td>0</td>
<td>0.10</td>
<td>6.3</td>
<td>0.0</td>
</tr>
<tr>
<td>WEC</td>
<td>Water Salinity</td>
<td>Every day</td>
<td>4000</td>
<td>0</td>
<td>0.10(^{\text{iii}})</td>
<td>4001.67(^{\text{iii}})</td>
<td>0.0</td>
</tr>
<tr>
<td>VSP3D</td>
<td>CO2 Mass above Ultimate Seal</td>
<td>Every 2 years</td>
<td>0</td>
<td>0</td>
<td>40.0</td>
<td>190.5</td>
<td>0.0</td>
</tr>
<tr>
<td>SEIS3D</td>
<td>CO2 Mass above Ultimate Seal</td>
<td>Every 5 years</td>
<td>0</td>
<td>0</td>
<td>80.0</td>
<td>296.3</td>
<td>0.0</td>
</tr>
<tr>
<td>DHMS</td>
<td>Microseismic Depth Decrease</td>
<td>Every day</td>
<td>0</td>
<td>0</td>
<td>10.0</td>
<td>170</td>
<td>0.0</td>
</tr>
<tr>
<td>DHPT WPGS</td>
<td>Fluid Mass Rate into WPGS</td>
<td>Every day</td>
<td>0</td>
<td>0</td>
<td>2.2</td>
<td>37</td>
<td>0.0</td>
</tr>
<tr>
<td>INSAR</td>
<td>Fluid Mass increase above Ultimate Seal</td>
<td>Every month</td>
<td>0</td>
<td>0</td>
<td>83</td>
<td>617</td>
<td>0.0</td>
</tr>
<tr>
<td>DTS</td>
<td>CO2 Mass Rate outside Casing</td>
<td>Every day</td>
<td>0</td>
<td>0</td>
<td>3.5</td>
<td>58</td>
<td>0.0</td>
</tr>
</tbody>
</table>

**NOTES:**

\(^{\text{i}}\) Threshold based on maximum IPCC emission limits range of 100-1000 ppm/year for 27 Mt CO2 stored.

\(^{\text{ii}}\) WEC sensor error based on Aqua Troll sensitivity specification for conductivity measurements, Schlumberger regression with salinity, and ignoring need to distinguish natural changes.

\(^{\text{iii}}\) Salinity threshold of 2 ppm increases corresponds to 7 ppm of BCS brine at the base of groundwater protection.
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

Insufficient population of reliable monitoring targets

- **Reason**: Too few objects within the landscape, such as buildings, act as reliable monitoring targets for surface displacement monitoring using this space-borne remote sensing technique. This means the gaps between reliable monitoring targets at the surface are so large that they create blind-spots within the measured distribution of volume changes inside the BCS storage complex due to increased fluid pressures within the BCS and LMS.

- **Indicator**: Less than one reliable surface monitoring target exists every 4 square kilometres inside the AOR based on the appraisal data (2010-2011) and the baseline monitoring data (2012-2014).

- **Mitigation**: Deploy the minimum number of corner reflectors required to eliminate the gap in monitoring coverage. Corner reflectors are compact passive metal objects (less than 0.5 m across) mounted on a stable foundation in the ground and designed to provide a reliable InSAR monitoring target. Consider the value of information gained by supplementing these corner reflectors with a limited number of GPS stations.

- **Response time**: The time required to gain land access and deploy corner reflectors is expected to be less than 6 months. However, according to the ERCB D65 final approval and conditions, Shell will provide a Special Report #2 by January 31, 2013 providing evidence of the feasibility. If insufficient, corner reflectors will be installed 15 months prior to start of injection.
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 1mm/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. Consider placing one such observation well close to the most vulnerable BCS legacy well. Note if pressure increases are expected to remain below 3.3 MPa at the injectors then these observation wells may not be required as they would never be sufficient pressure to lift BCS brine above the base of groundwater protection.

According the ERCB D65 final approval and conditions, Shell must address the need to drill additional monitoring wells in the BCS and the WPGS 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.

### 8.2 Time-Lapse Seismic

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

- **Reason:** DAS fibre performance is less than expected based on initial field trials at the Radway 8-19 well.

- **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 repeatability of conventional VSP data acquired is insufficient**

- **Reason:** Environmental non-repeatable noise sources are larger than expected based on initial field trials at the Radway 8-19 well.

- **Indicator:** The ratio of relative repeatability (RRR) of conventional geophone data exceeds 0.4.

- **Mitigation:** Rely on modeling plume dimensions and or evaluate the value of information and containment risk associated with drilling additional BCS observation wells designed to monitor the future areal extent of the CO2 plumes.
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.

- **Indicator**: Down-hole pressure at an injector not covered by microseismic monitoring are consistently limited to the maximum injection pressure.

- **Mitigation**: Deploy recording systems to monitor microseismic activity using deep arrays within the WPGS monitoring wells near the identified injectors.

- **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 a spatial pattern indicative of fracturing are observed by the single conventional down-hole 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 CO2 injectors.

- **Indicator**: Sustained microseismic activity located within and above the Lower Lotsberg Salt with spatial patterns indicative of fracturing.
8.4 Pressure Monitoring

Permeability within the Winnipegosis Formation is insufficient to support pressure monitoring to verify containment

- **Reason:** The Winnipegosis is a carbonate formation and the observation wells might encounter zones of locally limited permeability.
- **Indicator:** The measured permeability is less than 5 mD.
- **Mitigation:** Consider well stimulation or drilling a side-track. If this does not succeed then abandon upwards and re-complete within Beaverhill Lake Group or the Cooking Lake Formation.
- **Response time:** This mitigation could be implemented before any CO2 injection but requires regulatory approval of well license amendment application.

The number of pressure gauges within the Winnipegosis Formation is insufficient to support pressure monitoring to verify containment

- **Reason:** Only three injectors have Winnipegosis observation wells located directly on their well pads. In a development scenario of 5 injectors, the closest deep observation wells to the other two injectors are 5 km away.
- **Indicator:** To achieve required injection rates, down-hole injection pressures are continuously higher at an injector that does not have a Winnipegosis observation well located on its well pad.
- **Mitigation:** Drill and complete a deep observation well with a down-hole pressure gauge from the identified well pad.
- **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

Gauge malfunction prevents down-hole pressure monitoring

- **Reason:** DHPG’s can stop working with time due to various reasons, usually later in life (>10 years).
- **Indicator:** Continuous pressure recordings become sporadic, and eventually stop recording.
- **Mitigation:** Shell to calibrate the bottom-hole pressure with the wellhead pressure while the DHPG is working. After a DHPG failure, the operator could decide to install a memory DHPG in a down-hole nipple that could be retrieved periodically to ensure wellhead pressures are still calibrated to bottom-hole pressures. This should continue until the failed gauge is replaced.
9 Storage Risks after MMV

Initial storage risk reductions are achieved through multiple independent safeguards implemented through site selection, site characterisation and engineering concept selections. These initial passive safeguards are sufficient on their own to make the loss of containment extremely unlikely (Table 4-3).

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. 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 summarises the number, type and expected effectiveness of these additional active safeguards.

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 CO2 plumes or pressure build-up exceeds their model-based predictions.

CO2 plume development

- **Monitoring:** Time-lapse seismic.
- **Intervention Indicator:** The observed CO2 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 injectors 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. Redistribution of injection between existing wells is available on demand. Drilling additional injectors will take 12-18 months and is 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 CO2 inventory measurements are available and that the target CO2 inventory is achieved.

### Injected mass of CO2

- **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 CO2 injection volumes for all injectors 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.

### Emitted mass of CO2

- **Monitoring:** LightSource (Line-of-sight CO2 flux metering)
- **Intervention Indicator:** Annual controlled release tests of 250 kg/hour at 2 km and 600 kg/hour at 4 km are not detected.
- **Control Options:** Recalibrate or, if necessary, replace meters.
- **Response Time:** 1-3 months.

### Target inventory of CO2

- **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 (28 MPa) before the end of the injection period.
- **Control Options:** Drill additional injectors.
- **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 4-3).
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 WPGS observation 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, WPGS pressure monitoring, time-lapse seismic
- **Intervention Indicators:** Poor cement bond, sustained annulus pressure, failed well integrity test, sustained temperature or noise anomaly outside casing, sustained WPGS pressure, or a time-lapse seismic anomaly around the injector within the WPGS.
- **Control Options:** 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 (see 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, WPGS pressure monitoring, time-lapse seismic, InSAR, down-hole microseismic
- **Intervention Indicator:** BCS injector pressure exceed agreed limits, sustained WPGS pressure, WPGS time-lapse seismic anomaly, InSAR anomaly due to volume changes above the ultimate seal, sustained microseismic activity indicative of fracturing located above the first seal.
- **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 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 analysis for natural BCS brine tracers and potentially an artificial tracer injected with the CO2 within all project groundwater wells and a representative selection of private 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. Stop injection at all wells suspected to be the source of these impacts.

• **Response Time:** 1-3 months are likely required to conduct these investigations and deploy the appropriate controls measures.

Safeguards supported by biosphere monitoring

• **Monitoring:** Remote sensing, LightSource, soil and/or vegetation sampling and tracer analysis at locations of potential change indicated by remote sensing and LightSource.

• **Intervention Indicator:** Project-specific tracers measured at concentrations above established detection limits from samples collected at locations indicated by remote sensing or LightSource.

• **Control Options:** Conduct soil investigations, implement exposure controls and remediation measures. If required, stop injection at all wells suspected to be the source of these impacts.

• **Response Time:** 1-3 months are likely required to conduct these investigations and deploy the appropriate controls measures.

Safeguards supported by atmosphere monitoring

• **Monitoring:** LightSource (Line-of-sight CO2 gas flux monitoring)

• **Intervention Indicator:** Sustained localised increase in CO2 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 injectors 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\(^1\).

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\(^1\) 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 judgement. 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

10.1 Operating Procedures in Response to Monitoring Alarms

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 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. Check correlation too.

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.
Chemical injection alarm

- **Alarm indicates:** Chemical injection is off. In the case that continuous artificial tracer injection is used.
- **Alarm response:** Scotford operations to investigate and restore tracer injection.

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.

LightSource (Line-of-sight CO2 gas flux monitoring alarm)

- **Alarm indicates:** Localised CO2 flux exceeds threshold established after baseline monitoring period from 2012 to 2014 is completed.
- **Alarm response:** Environmental Team will investigate this location, collect samples suitable for BCS and CO2 tracer analysis.

Water electrical conductivity monitoring alarm

- **Alarm indicates:** Water electrical conductivity exceeds threshold established after baseline monitoring period from 2012 to 2014 is completed.
- **Alarm response:** Environmental Team will investigate this location, collect samples suitable for BCS and CO2 tracer analysis.

Water pH monitoring alarm

- **Alarm indicates:** Water pH exceeds threshold established after baseline monitoring period from 2012 to 2014 is completed.
- **Alarm response:** Environmental Team will investigate this location, collect samples suitable for BCS and CO2 tracer analysis.

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 an appropriate well work-over, before re-starting injection.

Down-hole microseismic monitoring alarm

- **Alarm indicates:** Within a 10-day period, more than 10 microseismic events occur that are located above the base of the Lower Lotsberg Salt with a confidence estimate of greater than 95%.
• **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.
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Appendix A Hydrosphere and Biosphere Monitoring Plan
Quest Carbon Capture and Storage Project

Hydrosphere and Biosphere Monitoring Plan (HBMP)

October 15 2012

Prepared By:
Shell Canada Limited
Calgary, Alberta

Special thanks go to Stantec Consulting Ltd., Calgary, Alberta for their help with establishing the HBMP, as well as to Golder Associates, Calgary, Alberta
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1 Introduction

1.1 Background

Shell Canada Energy operates the Quest CCS project the goal of which is to capture, transport via pipeline and permanently store CO₂ from the Scotford Upgrader located about 5 km northeast of Fort Saskatchewan, Alberta. For more detailed information about the Quest CCS project refer to Shell (2010a).

The Quest CCS project is a fully integrated project and includes a Measurement, Monitoring and Verification Plan. The MMV plan covers four distinct domains, namely the Geosphere, Hydrosphere, Biosphere, and Atmosphere, as discussed in the main body of the MMV document.

Monitoring activities take place during distinct phases of the QUEST project:

- Pre-injection phase (baseline) monitoring: Q4 2012 to Q4 2014.
  During the pre-injection phase, risks will be characterized, monitoring tasks will be identified, methods will be selected, and baseline monitoring data will be acquired and reported.

- Injection phase (operations) monitoring: Q1 2015 to Q4 2039.
  During the injection phase, HBMP monitoring activities monitor risks to containment. Monitoring frequency and technologies will be adapted periodically based on observed results and changing risk profiles.

- Post-injection phase (closure) monitoring: Q1 2040 to Q4 2049.
  During the closure phase, some monitoring activities will continue to monitor risks to containment, while some activities will be scaled back or cease if the injection phase monitoring demonstrated storage performance is consistent with expectations.

The HBMP is one line of evidence used to demonstrate that the injected CO₂ stream and Basal Cambrian Sands (BCS) brine stays contained within the BCS storage complex. Additional lines of evidence originate from other monitoring activities planned for the Geosphere and Atmosphere as discussed within the MMV plan. The HBMP also provides one means to detect, and, where possible, to confirm and delineate, in the unlikely event, a leak from the storage complex to the base of the ground water protection zone or above that zone.

1.2 Aim of report

The aim of this report is to describe and to discuss the Hydrosphere and Biosphere Monitoring Plan (HBMP) implemented as part of the MMV plan.

The HBMP presented in this document is based on a three injection well scenario for the following injection wells 100-08-19-059-20W400, 100-07-11-059-20W400, and 100-05-35-059-21W400. The first well has already been drilled, and that the other two wells are to be drilled during the 2012-2013 QUEST drilling campaign (Figure 1-1).
Figure 1-1: Quest sequestration lease area (red outline). Also shown: location of planned injection wells 08-19-059-20W4, 07-11-059-20W4, and 05-35-059-21W4 (red dots), pipeline route (gray solid line).
1.3 Adaptive HBMP

The HBMP presented in this document is an adaptive plan expected to undergo modifications, on an annual basis, as data become available and risk profiles change. The first review of the current HBMP will occur prior to completion of the 1st year of baseline monitoring followed by another review near the end of the baseline data-gathering period. Technologies and sampling frequencies for the injection phase will be re-assessed and adapted once a comprehensive baseline database of hydrosphere and biosphere parameters is established and the spatial and temporal variation of those parameters are understood, prior to start of the injection phase.

The injection phase monitoring program will be evaluated in each annual operations report, with the first report due March 31, 2016. Monitoring will be evaluated on an annual basis in order to:

- report on modifications to the monitoring program
- report on the performance of the MMV program.

1.4 Outline of report

The HBMP includes monitoring activities focused on two domains, namely the Hydrosphere and the Biosphere. Within each of these two domains various types of sampling and monitoring will be undertaken.

The structure of this report is as follows:

- Chapter 1 is a general introduction to the topic addressed.
- Chapter 2 describes and discusses the monitoring activities related to the Hydrosphere, which targets the area between the ground surface and the base of the groundwater protection zone (BGWP) where water salinity, measured as total dissolved solids, is less than 4,000 mg/L.
- Chapter 3 describes and discusses the monitoring activities related to the Biosphere, which targets the soil surface and the soil zone down to a depth of about 1m.
- Chapter 4 describes and discusses an integrated Hydrosphere and Biosphere Response Plan to address situations in which base-case monitoring (or other information) suggest a potential impact to the environment due to Quest activities.
- Chapter 5 lists the cited references.

2 Hydrosphere monitoring

2.1 Introduction

Hydrosphere monitoring focuses on shallow aquifers that contain non-saline groundwater resources in the Quest AOR. The hydrosphere domain is the subsurface region vertically bound by the ground surface as the uppermost surface and the base of groundwater protection (BGWP) as the lowermost surface. The lateral extent of the hydrosphere
monitoring area is determined by the AOR as defined in the MMV plan (i.e. the boundary of the Quest sequestration lease area (Fig. 1-1)).

A detailed overview of the hydrogeology in the Quest sequestration lease area is available in Shell (2010b). Shell utilized a simplified approach for development of the conceptual hydrostratigraphic framework for the assessment area via consolidation of individual units within the surficial deposits and the formations of the Belly River Group. The stratigraphic intervals considered in the hydrosphere monitoring include:

1) Surficial Deposits: defined as any unconsolidated material deposited above the consolidated upper bedrock surface (Figure 2-1).

2) The Oldman Formation: mapped at the formation level and not separated into the Comrey, Upper Siltstone and Dinosaur Members.

3) The Foremost Formation: mapped as one unit due to correlation complexities between individual sandstone members across the Quest sequestration lease area. The individual sandstone members include the Birch Lake, Ribstone Creek, Victoria and Brosseau Members. Correlation of individual members within the Foremost Formation is complicated by thinning of continental deposits and thickening of marine deposits within the Foremost toward the eastern portion of the Quest sequestration lease area.

4) Lea Park Formation: The upper surface of the Lea Park Formation is used to approximate the BGWP beneath the Quest sequestration lease area. A threshold TDS concentration of less than 4,000 mg/L is used to define the BGWP.

---

**Figure 2-1: Stratigraphic column showing Hydrosphere monitoring targets (green highlight)**

### 2.2 Previous work

A review of chemical composition data, attained prior to April 2012, from groundwater wells within the Quest sequestration lease area was completed. The data for this regional groundwater assessment originated from the AENV Water Well Information Database.
and landowner wells sampled by Shell as part of the Quest 3D seismic program (Shell, 2010b).

In 2010, Shell sampled approximately 190 domestic water wells, where accessible, in the Quest 3D seismic area before and after completion of the seismic program. Not all wells were re-sampled after the seismic program was completed as some landowners elected not to participate in the re-sampling of their well. Results from the ‘seismic well sampling’ campaign were added to the chemical analysis records extracted from the AENV Water Well Information Database.

In 2011, Shell determined the chemical composition of groundwater samples obtained from five wells installed by Shell on the 08-19-059-20W4 well pad. The data obtained from those five wells though were not part of the regional groundwater assessment related to the AENV Water Well Information Database.

The regional groundwater assessment focused on:

- Surficial Deposits
- the Oldman Formation
- the Foremost Formation

Table 2-1 summarizes the results of the regional groundwater assessment. Please refer to Shell (2010b) for further details on the methodology used to characterize regional groundwater chemistry and the findings from that study.

Table 2-1: Summary of Regional Groundwater Chemistry Analysis

<table>
<thead>
<tr>
<th>Formation</th>
<th>Number of Samples</th>
<th>Groundwater Quality Characterization</th>
<th>Median Total Dissolved Solids (mg/L)</th>
<th>Total Hardness Concentration (mg/L of CaCO$_3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surficial deposits</td>
<td>1,055</td>
<td>Moderately fresh</td>
<td>768</td>
<td>360</td>
</tr>
<tr>
<td>Oldman Formation</td>
<td>679</td>
<td>Moderately fresh</td>
<td>1,010</td>
<td>65</td>
</tr>
<tr>
<td>Foremost Formation</td>
<td>602</td>
<td>Moderately fresh</td>
<td>1,091</td>
<td>59</td>
</tr>
</tbody>
</table>

2.3 Design of pre-injection Hydrosphere Monitoring Plan

2.3.1 Introduction

The hydrosphere monitoring plan includes sampling and monitoring of both groundwater and well headspace gas at Shell Quest project wells and selected existing and active landowner wells. In addition to discrete sample collection and analysis of groundwater and well headspace gas samples, continuous measurement of water quality parameters using a downhole water quality instrument will be done at the Shell Quest groundwater wells.

Discrete samples will be collected for chemical and/or isotopic analyses. A phased assessment approach of the natural variability of water geochemistry was adopted when designing the hydrosphere monitoring plan.

Note that the hydrosphere monitoring plan discussed below focuses on the pre-injection (baseline) period. The monitoring plan for the injection and post-injection phases will be designed based on findings from the baseline period, as discussed in section 2.5.2.
2.3.2 Well selection

2.3.2.1 Introduction

The wells selected for the hydrosphere monitoring plan have been grouped into three categories including:

- Shell Quest project groundwater wells (9 in total)
- Local landowner groundwater wells (164 in total)
- Regional groundwater wells (34 in total).

All 207 wells are included in the current hydrosphere monitoring program as part of the well monitoring network. However, not all of these wells will be sampled during each sampling event, as discussed in Section 2.5. Details on the approach used to select the wells' monitoring network are presented in the following sections.

For clarification, local landowner and regional groundwater wells are previously existing landowner domestic wells. As such, it may not be possible to sample all of the selected wells pending landowner consent to sampling and the physical conditions of the wells (i.e. well needs to be active and safe to test). As per ERCB condition 20 (ERCB, 2012), any additional landowners that wish their wells to be part of the study can be included.

2.3.2.2 Shell Quest project groundwater wells

Shell committed to drill three groundwater monitoring wells for each injection well drilled, and that at least one of those wells will be located on an injection well pad with the remaining wells potentially located elsewhere Shell (2012).

For the design of this HBMP, a 3 injection wells’ scenario was selected, hence, a total of 9 project specific wells are to be drilled by Shell:

- 5 groundwater wells have already been drilled at 08-19-059-20W4 (Fig. 2-2), with completion depths of 20, 38, 63,101,159 mBGL targeting Surficial Deposits, the Oldman and Foremost formations.

- 2 groundwater wells at well pad 05-35-059-21W4 are to be drilled before the end of 2012. One well will be completed in the deepest monitorable sand above the Lea Park (~ 140 mBGL) and one well to be completed in a shallower sandy unit (~ 20 mBGL) which corresponds to the ‘typical completion depth’ of landowner wells within the AOR. The locations of the ‘deep’ and ‘shallow’ wells were chosen to be as close as possible to the injection well in order to detect any potential changes in water quality as early as possible. The ‘deep’ and ‘shallow’ wells will be about 25 and 35 m, respectively, away from the injection well along the same radial line from the centre of the injection well.

- 2 groundwater wells at well pad 07-11-059-20W4 are to be drilled before the end of 2012. One well to be completed in the deepest monitorable sand above the Lea Park(~ 130 mBGL) and one well to be completed in a shallower sandy unit (~ 20 mBGL) which corresponds to the ‘typical completion depth’ of landowner wells within the AOR. The locations of the ‘deep’ and ‘shallow’ wells were chosen to be as close as possible to the injection well in order to detect any potential changes in water quality as early as possible. The ‘deep’ and ‘shallow’ wells will be about 25
and 35 m, respectively, away from the injection well along the same radial line from the centre of the injection well.

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.

**Figure 2-2: 08-19-059-20W4 groundwater monitoring wells’ network with completion depths (mBGL)**

### 2.3.2.3 Local landowner groundwater wells

The local landowner groundwater wells are split into two categories:

1) Groundwater wells within a 3.2km radius of the injection wells: 100-08-19-059-20W400, 100-07-11-059-20W400, and 100-05-35-059-21W400.

2) Groundwater wells near legacy wells. A legacy well is defined as any pre-existing, Energy Resources Conservation Board (ERCB) licensed well (deeper than 150 m) that meet the following criteria:

- is located in the Quest sequestration lease area
- was drilled before the Quest application was submitted
- was not drilled as part of the Quest project.

Four legacy wells, which penetrate through one or more seals in the BCS storage complex have been identified within the Quest Sequestration Lease area. These include Imperial Eastgate 100-01-34-057-22W400, Imperial Egremont 100-06-36-058-23W400, Imperial Darling No. 1 100-16-19-062-19W400, Westcoast et al. Newbrook 100-09-31-062-19W400.
2.3.2.3.1 Wells near injection wells

Injection wells will present a greater risk, however small, to long-term containment of fluids in the BCS storage complex because they will penetrate the seals in the BCS storage complex and are located in the area of highest pressure.

All landowner groundwater wells within a 3.2km radius from an injection well were identified. The 3.2 km radius of the circular area centered at a proposed injector well location was based on generally accepted radii for notifications and water well searches associated with relevant regulatory applications (e.g., for well licences or water diversions). During the compilation of the well database, a formation descriptor (‘Surficial Deposits’, ‘Oldman’, or ‘Foremost’) was also attached to each well.

The total number of wells identified near the injection wells within a 3.2km radius was 154 wells (Fig. 2-3), with

- 44 wells around 100-08-190-059-20W400
- 45 wells around 100-07-11-059-20W400
- 67 wells around 100-05-35-059-21W400.

Note that 2 wells are each part of the 08-190-059-20W4 and 05-35-059-21W4 3.2 km radius; hence, only 65 wells will be considered for 05-35-059-21W4.

![Figure 2-3: Existing groundwater wells within 3.2 km of injector wells.](image-url)
Based on the large number of wells identified within a 3.2 km radius (67 wells for 100-05-35-059-21W400, 44 wells for 100-08-19-059-20W400, 45 wells for 100-07-11-059-20W400), a sub-set of wells was identified for regular monitoring. Note though that all active domestic water wells identified within the 3.2 km radius will be sampled at least once. The following criteria were taken into account to determine the sub-set of wells:

- monitor primarily wells that penetrate the deepest formation (Foremost Formation)
- attempt to obtain data for each formation at each proposed injector well
- target wells sampled as part of the seismic survey program undertaken during the planning stages of the Quest Project
- sampling approach with professional judgement
- maintain practical implementation of monitoring
- develop monitoring that is economically sustainable.

The ‘sub-set’ number of wells selected within a 3.2 km radius of an injector well are 13 for 5-35-059-21W4, 16 for 8-19-059-20W4, and 14 for 7-11-059-20W4. This sub-set of wells is still large considering a hypothetical radial leakage scenario, which is very unlikely, around an injection wellbore. In that hypothetical case, a minimum of 1 well penetrating the deepest permeable formation above the base of the groundwater protection zone and positioned as close as possible to the injection wellbore is needed to detect the leakage. This is achieved by the groundwater monitoring wells that Shell will install on each injection wellpad. A larger number of wells were selected for monitoring in order to understand spatial variability in groundwater quality around the injection wells during the pre-injection (baseline) phase.

### 2.3.2.3.2 Wells near legacy wells

In the vicinity of the four BCS legacy wells, all located greater than 21 km away from the injectors, Shell will conduct adequate groundwater monitoring in order to understand the current groundwater quality. The risk of leakage from the legacy wells and monitoring requirements will be addressed in annual reporting as new data and injection performance results become available. The following approach was used to identify the groundwater wells to be monitored near the legacy wells:

- 0.5 km search radius away from legacy well
- if no wells within 0.5 km radius, use next closest wells
- for 06-36-058-23W4 and 01-34-057-22W4 preferentially select wells located on the N side of a NW-SE trend
- for 16-19-062-19W4 and 09-31-062-19W4 select wells located on the S side of a NW-SE trend
- monitor primarily wells that penetrate deepest formation (Foremost Formation)
- attempt to obtain data for each formation near each legacy well
- maintain practical implementation of monitoring
- develop monitoring that is economically sustainable.

The total number of wells selected near the legacy wells is 10 wells, with
3 wells around each of the wells 06-36-058-23W4, 01-34-057-22W4, and 16-19-062-19W4 (Fig. 2-4); with 1 well per target interval (Surficial Deposits, Oldman Formation, Foremost Formation) near each legacy well

1 well near 09-31-062-19W4 (completed in Surficial Deposits, closest well at ~ 1km); one well was determined to be sufficient, as 09-31-062-19W4 located straight N of 16-19-062-19W4 where any unlikely impact would be expected to be detected first

Figure 2-4: Groundwater Sampling wells

(Legacy well locations - black dots
Regional network - green dots.)
Regional network wells selected for isotopic analyses -open circle

Location of legacy and injector wells -blue & red dots)

2.3.2.4 Regional landowner groundwater wells

A series of domestic groundwater wells regionally distributed in the AOR (excluding those sampled around the injection and legacy wells) will be included in the hydrosphere monitoring program. These wells were selected to provide data coverage over the entire AOR, allowing for the interpretation of regional trends. As these domestic wells are situated at considerable distances (≥7km) from the injection well sites, they will allow for measurements of possible fluctuations in water level/quality outside areas under the greatest influence of injection operations.

A total of 34 wells have been identified for the group of regional landowner wells (Fig. 2-4). The following criteria were used to select the wells:

- well completion depth within the Foremost Formation; which is the ‘key’ formation to be monitored for early detection of any potential changes in water quality between ground surface and base of groundwater protection zone due to upward movement of fluid/gas, as the Foremost formation is closest to the base of the groundwater protection zone.
- spacing of approximately one per township.

The domestic wells identified are suspected to exist (based on the AENV water well database). However, the current status of those wells has not been confirmed. Landowner consent will also need to be secured before the exact position of these wells can be finalized. In cases where the proposed well cannot be used, another well at a nearby location will be selected (using the same selection criteria), to maintain the overall density of the regional landowner well network distributed across the AOR.

2.3.3 Well headspace gas - discrete measurements

Gas sampling forms an integral part of a monitoring, measurement and verification plan for a CCS project (e.g. Klusman, 2011), as changes in the concentration or isotopic composition of gaseous compounds (e.g. CO₂) can help to identify or refute a leakage event from the BCS storage complex. Hence, well headspace gas is included within the hydrosphere monitoring program, which will be collected prior to taking a groundwater sample.

2.3.3.1 Sampling protocol

The following approach will be taken to collect a well headspace gas sample:

- lowering tubing down the well (preferably a short distance above the groundwater level)
- gas sample obtained at atmospheric pressure by creating a small opening in the wellhead that allows ambient air to replace wellhead air as sampling progresses
2.3.3.2 Compositional and Isotopic Analyses

The following chemical and isotopic analyses will be performed during the pre-injection phase (baseline) monitoring.

Compositional analysis of a well headspace gas sample will include:
- CO₂, C₁ to C₁₀⁺, N₂, O₂, He

Isotopic analysis of a well headspace gas sample will include:
- δ¹³C-CO₂ and δ¹³C-CH₄, δ²H-CH₄

For the injection and post-injection phases, the ‘baseline’ suite of analyses will be revised and adjusted as necessary depending upon the findings from the pre-injection monitoring phase.

Analyses will be performed by a qualified laboratory in Alberta with appropriate QA/QC procedures.

2.3.3.3 Sampling Frequency

See Section 2.5.

2.3.4 Groundwater - discrete measurements

Groundwater sampling forms an integral part of a monitoring, measurement and verification plan for a CCS project, as changes in pH for instance or the concentration / isotopic composition of solutes (e.g. HCO₃⁻; Klusman, 2011) can help to identify or refute a leakage event from the BCS storage complex.

2.3.4.1 Sampling Protocol

A sampling protocol for field staff will be developed and include the following:
- sample methodology;
- QA/QC protocol;
- standard sampling forms developed for the project;
- naming convention for all samples to be collected;
- well water parameter stabilization protocol;
- description of field parameters to be measured prior to sample collection.
- decontamination procedures, if required
- equipment calibration procedures and frequency, where required
- sample frequency and scheduling.

Prior to collecting a water sample, the well headspace gas will have been sampled and checked for methane concentrations. If methane concentrations greater than the lower explosive limit are detected, the cap will be removed and the well allowed to vent to the atmosphere prior to groundwater monitoring to ensure adequate venting of the well casing.

Depth to water will then be measured in the well followed by groundwater sampling after sufficient water has been removed from the well in order to allow for collection of a representative water sample. A low flow sampling protocol will be used whereby water quality parameters (e.g., pH, EC) will be measured by a field multimeter equipped with a flow-through cell. Once the measurements in the cell have stabilized, the field measured parameters will be recorded and a groundwater sample will be collected using appropriate QA/QC procedures.

### 2.3.4.2 Chemical and Isotopic Analyses

The following chemical and isotopic analyses will be performed during the pre-injection phase (baseline) monitoring.

Chemical analysis of a groundwater sample will include:

- pH, EC, TDS, alkalinity, ion balance, total hardness
- Na, K, Ca, Mg, HCO₃, CO₃, OH, SO₄, NO₂, NO₃, P, DIC, Cl, Br, I
- Al, Sb, As, Ba, Be, B, Cd, Cr, Co, Cu, Fe, Hg, Pb, Li, Mn, Hg, Mo, Ni, Se, Si (SiO₂), Ag, Sr, Ti, Sn, Ti, U, V, Zn

Isotopic analysis of a groundwater sample will include:

- ⁸⁷Sr/⁸⁶Sr, ⁶⁰⁸O & ²H-H₂O, ²¹³C-DIC, ⁸¹¹Br, ³⁷Cl, ¹¹B

For the injection and post-injection phases, the ‘baseline’ suite of analyses will be revised and adjusted as necessary depending upon the findings from the pre-injection monitoring phase.

Analyses will be performed by a qualified laboratory in Alberta with appropriate QA/QC procedures.

### 2.3.4.3 Sampling Frequency

See Section 2.5.

### 2.3.5 Groundwater - continuous measurements

#### 2.3.5.1 Downhole water quality probe

At each of the 9 Shell Quest groundwater wells, a Troll 9500 multiparameter water quality probe or similar instrument will be installed. Each probe will have the capability to measure electrical conductivity, pH, redox potential, pressure, and temperature.
2.3.5.2 Sampling Frequency

Measurements will be taken on an hourly basis during the various monitoring phases. Note that depending upon the findings from the baseline period, the number of the Shell Quest groundwater wells to be monitored and the measurements to be performed on a continuous basis will be reviewed and adjusted.

2.4 Tiered approach for post baseline monitoring

2.4.1 Introduction

The Hydrosphere monitoring program includes analytical parameters referred to as indicator or tracer parameters associated with a release of CO₂ and/or BCS brine.

**Indicator Parameters** are parameters capable of broadly characterizing general groundwater quality (e.g. pH, EC). Indicator parameters can be used to understand the relation of local monitoring values to regional groundwater quality. Indicator parameters are also used to evaluate the suitability of the groundwater for potable consumption or other uses through comparison with risk-based guideline values and can also be used over time to track changes in hydrochemistry at a given location. Indicator parameters cannot provide unique information on the source of changes.

**Tracer Parameters** are parameters that can uniquely identify fluids originating from the BCS complex, including the native brine and injected CO₂ (or a mixture thereof) (e.g. isotopic compositions).

These parameters have one or more of the following characteristics:

- anticipated to be present in injected CO₂ stream or in fluids native to the BCS
- could potentially be released to the hydrosphere in the event of an unexpected malfunction or unplanned event
- could be released to the hydrosphere through secondary reactions between the hydrosphere and BCS fluids.
- measurable: numerically quantifiable and relatively easy to measure using standard equipment
- reproducible: reliable measurement with standard field protocols and equipment
- sensitive: response to broad range of groundwater conditions relevant to potential environmental effects in a meaningful timeframe
- resolution: measureable with a high degree of precision
- representative: useful for characterization of groundwater quality and detecting potential changes
- cost effective: can be measured by commercial laboratories at reasonable cost, and equipment involved in sample collection is readily available.

2.4.2 Tiered approach for post baseline monitoring

Review of the analytical parameters reveals that some can be considered relatively easy to measure both practically and economically (e.g. major ions), and may only suggest, but not conclusively identify, potential changes in water quality (indicator parameters).
Other analytical parameters (e.g. isotopic analyses) that can provide a greater degree of confidence regarding the cause(s) responsible for potential changes in water quality can be more challenging to measure reliably and/or have a higher analytical cost (tracer parameters). Because of this wide variation in ease of measurement and associated monitoring value, a tiered approach to the ongoing measurement of groundwater parameters after the pre-injection (baseline) monitoring phase. Figure 2-5 shows the concept of the tiered approach indicating the hierarchy of tiers and associated relative characteristics of the tiered approach.

Five tiers of parameters have been defined for hydrosphere monitoring, as shown in Figure 2-5 and described further in Table 2-2. Note that the current proposal of the tiered system will be revised and updated accordingly based upon findings from the pre-injection (baseline) monitoring phase.

![Figure 2-5: Parameter Tier Concept](image.png)
Table 2-2: Parameters associated with tiered system

<table>
<thead>
<tr>
<th>parameter tier</th>
<th>medium</th>
<th>type of sampling</th>
<th>analytical parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tier 0</td>
<td>groundwater</td>
<td>continuous</td>
<td>• electrical conductivity, pH</td>
</tr>
<tr>
<td>Tier 1</td>
<td>groundwater</td>
<td>discrete</td>
<td>• pH, EC, TDS, alkalinity, ion balance, total hardness</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Na, K, Ca, Mg, HCO₃, CO₂, OH, SO₄, NO₂, NO₃, P, DIC, Cl, Br, I</td>
</tr>
<tr>
<td>Tier 1</td>
<td>well headspace gas</td>
<td>discrete</td>
<td>• CO₂, C₁ to C₁₀, N₂, O₂, He</td>
</tr>
<tr>
<td>Tier 2</td>
<td>groundwater and/or well headspace gas</td>
<td>discrete</td>
<td>• re-do Tier 1</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Al, Sb, As, Ba, Be, B, Cd, Cr, Co, Cu, Fe, Hg, Pb, Li, Mn, Hg, Mo, Ni, Se, Si (SiO₂), Ag, Sr, Ti, Sn, Ti, U, V, Zn</td>
</tr>
<tr>
<td>Tier 3</td>
<td>groundwater and/or well headspace gas</td>
<td>discrete</td>
<td>• re-do Tier 2</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• δ¹⁸O, δ¹³C-DIC, δ¹³C-H₂O, δ¹⁸O-H₂O, δ¹⁸¹Br, δ¹³⁷Cl, δ¹¹B</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• δ¹³C-CO₂ and δ¹³C-C₂H₆, δ¹³H-C₂H₆</td>
</tr>
<tr>
<td>Tier 4</td>
<td>groundwater and/or well headspace gas</td>
<td>discrete</td>
<td>• variety of site-specific parameters required to support contaminant plume delineation and risk management activities; may include parameters already measured in lower tiers</td>
</tr>
</tbody>
</table>

Note:
- Analysis of (an) artificial perfluorinated carbon (PFC) compound(s) potentially added to the injection CO₂ stream may also be included within the analytical parameters of the tiered system. A decision regarding this will be taken after completion of a PFC feasibility study, which will be submitted in Special Report #3 Jan. 31st 2014 (ERCB condition # 13; ERCB, 2012).
- At the end of the pre-injection (baseline) period, threshold values for the various tiers will be defined that indicate a change which may suggest a leakage event from the BCS storage complex. Defining the threshold values is also necessary to decide when to initiate the next tier of measurements.

2.5 Sampling Schedule

The sampling schedule is identical for both groundwater and well headspace sampling.

2.5.1 Pre-injection (baseline) phase

The sampling schedule for the discrete measurements during the pre-injection (baseline) monitoring phase is presented in Table 2-4. For the continuous measurements, please refer to section 2.3.5.2.

The overall sampling strategy is to collect samples at least once every season at regular intervals, in order to capture potential temporal variations in water quality. During the 1st year of the baseline period, wells completed within ‘Surficial Deposits’, the ‘Oldman Formation’, and the ‘Foremost Formation’ will be sampled in order to get an overview of water quality between the ground surface and the base of the groundwater protection zone. During the 2nd year of the baseline phase, the focus will be on sampling the Foremost Formation. For early detection of any potential changes in water quality due to
upward movement of fluid/gas, the Foremost Formation is the ‘key’ formation to be monitored as it is closest to the base of the groundwater protection zone.

Table 2-4 presents the currently proposed sampling schedule for the 2-year baseline period. Note that after the W2012 sampling event, the sampling schedule may be modified based upon findings from the first sampling event.

### Table 2-4: Pre-injection (baseline) phase monitoring schedule for both discrete groundwater and well headspace gas samples

<table>
<thead>
<tr>
<th>Tier 2</th>
<th>1st year baseline # wells</th>
<th>2nd year baseline # wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>project</td>
<td>9 9 9 9</td>
<td>9 9 9 9</td>
</tr>
<tr>
<td>LMW - 3.2km - 5-35</td>
<td>65 13 13</td>
<td>3 * 3 * 3 *</td>
</tr>
<tr>
<td>LMW - 3.2km - 7-11</td>
<td>45 14 14</td>
<td>3 * 3 * 3 *</td>
</tr>
<tr>
<td>LMW - 3.2km - 8-19</td>
<td>44 16 16</td>
<td>3 * 3 * 3 *</td>
</tr>
<tr>
<td>LMW - 6-36</td>
<td>3 ^ 1 * 3 ^ 1 *</td>
<td>1 * 1 * 1 *</td>
</tr>
<tr>
<td>LMW - 1-34</td>
<td>3 ^ 1 * 3 ^ 1 *</td>
<td>1 * 1 * 1 *</td>
</tr>
<tr>
<td>LMW - 9-31</td>
<td>1 1 1</td>
<td>1 1 1</td>
</tr>
<tr>
<td>LMW - 16-19</td>
<td>3 ^ 1 * 3 ^ 1 *</td>
<td>1 * 1 * 1 *</td>
</tr>
<tr>
<td>Regional network</td>
<td>34 34 34 34</td>
<td>18 18 18 18</td>
</tr>
<tr>
<td><strong>Total Wells</strong></td>
<td>207 46 96 46</td>
<td>21 27 21 27</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Tier 3</th>
<th>1st year baseline # wells</th>
<th>2nd year baseline # wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>project</td>
<td>9 9 9 9</td>
<td>9 9 9 9</td>
</tr>
<tr>
<td>LMW - 3.2km - 5-35</td>
<td>3 ^ 3 ^ 3 ^</td>
<td>1 * 1 * 1 *</td>
</tr>
<tr>
<td>LMW - 3.2km - 7-11</td>
<td>3 ^ 3 ^ 3 ^</td>
<td>1 * 1 * 1 *</td>
</tr>
<tr>
<td>LMW - 3.2km - 8-19</td>
<td>3 ^ 3 ^ 3 ^</td>
<td>1 * 1 * 1 *</td>
</tr>
<tr>
<td>LMW - 6-36</td>
<td>3 ^ 1 * 3 ^ 1 *</td>
<td>1 * 1 * 1 *</td>
</tr>
<tr>
<td>LMW - 1-34</td>
<td>3 ^ 1 * 3 ^ 1 *</td>
<td>1 * 1 * 1 *</td>
</tr>
<tr>
<td>LMW - 9-31</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LMW - 16-19</td>
<td>3 ^ 1 * 3 ^ 1 *</td>
<td>1 * 1 * 1 *</td>
</tr>
<tr>
<td>Regional network</td>
<td>9 9 9 9</td>
<td>9 9 9 9</td>
</tr>
<tr>
<td><strong>Total Wells</strong></td>
<td>36 21 36 21</td>
<td>15 9 15 9</td>
</tr>
</tbody>
</table>

^ 1 well per Surficial Deposits / Oldman Fm / Foremost Fm); 'Foremost well' closest to injection or legacy well
* completed within Foremost Fm
# primary target completion depth is Foremost Fm

Notes:

- Tier 2 includes Tier 1 analyses
- project refers to the groundwater wells installed by Shell
- LMW refers to landowner wells in vicinity of injection and legacy wells
- UWI of injection and legacy wells have been shortened to LSD and section.
- regional network refers to landowner wells distributed across the AOI
- schedule assumes that wells are accessible and active
- W refers to winter; Sp refers to Spring; Su refers to summer; F refers to fall

#### 2.5.2 Injection and post-injection phases

The sampling schedules for the discrete measurements during the injection and post-injection monitoring phases is dependent upon the outcomes of the pre-injection
monitoring phase. Hence, a detailed sampling schedule cannot be provided at present for the injection and post-injection phases.

The overall strategy for designing the sampling schedule for the injection and post-injection phases will include the following:

- integrate findings from the pre-injection monitoring phase to decide spatial and temporal coverage needed to optimize the monitoring network; it is expected that this will result in a reduction of the number of wells sampled and parameters analyzed compared to the baseline period
- Tiers 0 and 1 are the primary targets regarding sample analysis on a regular basis
- Tiers 2 and 3 sample analysis will be undertaken on a less frequent basis than Tier 1 sample analysis
- maintain practical implementation of monitoring
- develop appropriate monitoring that is economically sustainable over the course of the Quest project
- adhere to conditions set out in the ERCB D65 approval and conditions, Aug. 24, 2012.

3 Biosphere monitoring

3.1 Introduction

The MMV Plan and the EIA identified three probable primary effects of loss of containment on the biosphere:

- an increase in soil salinity levels due to the movement of brine from deeper geological formations
- a direct reaction between the escaping CO$_2$ and soil minerals, which would result in soil acidification and a reduction in pH
- a potential change in soil gas composition and soil surface CO$_2$ flux.

Remote Sensing is expected to monitor changes in soil salinity as well as indirectly monitor soil acidification and reduction in pH. Remote sensing is a monitoring tool used to verify the absence of Quest CO$_2$ or BCS brine from the biosphere over a large regional area.

Soil gas analysis and soil surface CO$_2$ flux measurements are included within the biosphere pre-injection data gathering program in order to gain an understanding of the magnitudes and temporal / spatial variability of those parameters in the AOR. However, during the injection phase, the analyses are considered a response tool and will only be used in case of a suspected incident.

It is important to remember that biosphere monitoring is only one line of evidence used for verification of containment, with the majority of early warning data obtained via monitoring of the geosphere and hydrosphere.
3.2 Regional Overview of the Biosphere

This is a brief overview of the biosphere domain relevant to the Quest sequestration lease area, for further details refer to Shell (2010c).

Soils in the Quest sequestration lease area range from Luvisols in the north to Chernozems in the center and south. Brunisolic soils occur wherever very coarse textured materials are found. Localized areas of Solonetze soils are found in areas that were once or still are salt-effected, particularly near the village of Thorhild. Organic and Gleysolic soils occur in favorable topographic settings throughout the Quest sequestration lease area, where poor drainage discourages decomposition or favors peat-forming vegetation.

In general, soil salinity occupies minor extents of the Quest sequestration lease area (Pettapiece and Eilers, 1990): although most of the Quest sequestration lease area has non-saline soils (electrical conductivity values are less than 4 dS/m in the upper 1 m), areas with saline soils do occur. However, the extent of subsurface salinity and related sodicity is much greater, and varies vertically and spatially. Solonetzic soils and Solonetzic intergrades of other soil orders are widespread over parts of the Quest sequestration lease area, especially near the Local Monitoring Areas associated with the proposed Quest injection wells.

Much of the soil in the Quest sequestration lease is used for agriculture. The effect of agriculture on soil quality has included additions of chemical fertilizer, loss of organic matter, and changes to soil drainage, including ditching to lower water tables. Within the Quest sequestration lease area, soil salinity is expected to be most closely related to topography and underlying geology, as the Quest sequestration lease area is generally flat. Glacial meltwater channels are therefore locations where elevated levels of soil salinity are very close to the land surface.

The Quest sequestration lease crosses three natural regions and subregions: the Dry Mixedwood Subregion and Central Mixedwood Natural Subregion of the Boreal Forest Natural Region and the Central Parkland Natural Subregion of the Parkland Natural Region (Natural Regions Committee 2006).

3.3 Remote sensing

3.3.1 Introduction

Remote sensing is the primary means of biosphere monitoring specifically monitoring changes in plant stress and soil salinity related to Quest CO2 or BCS brine (MMV Plan Section 7.2.5). Remote sensing allows data collection over a large geographical area compared to groundwater sampling or soil and vegetation sampling for instance. Interpretation of remote sensing data relies on the information collected during ground-based sampling programs used to provide control points, or ground truthing, required for calibration of the remote sensing data.

Data collected during the pre-injection (baseline) monitoring phase from the ground-based sampling and calibrated to the remote sensing images will establish a range of natural variability of biosphere conditions, particularly relating to soil salinity and vegetation cover, class and health. Figure 3-1 illustrates the connection between baseline (pre-injection) data collection, remote sensing (RS), and injection phase (operational)
monitoring. Expectation is that during the operational phase, as the sample data library increases, soil and vegetation mapping will be minimal until they are no longer required to monitor for Quest CO₂ or BCS brine in the biosphere via remote sensing (Figure 3-1). One exception would be if verification were required as a response to a suspected incident, in which case, appropriate sample plots will be established.

Figure 3-1: Schematic overview of the ‘remote sensing’ monitoring concept

### 3.3.2 Satellite Imagery

The satellite platforms and the acquisition/processing frequencies will be assessed on an annual basis to ensure that they are adequate for the existing risk profile. Currently, two different image analyses are expected to be used for biosphere monitoring:

1) Radar Image Analysis (RIA) attained via Radarsat2 satellite platform. RIA indirectly monitors soil salinity and moisture via the dielectric constant.

The Radarsat 2 is the same satellite platform used for InSAR monitoring that is currently acquiring an image of the AOR every 24 days or 15 images per year. Although the images are from the same satellite, they are processed differently. Processing of the SAR data for biosphere monitoring will occur on a different frequency than the InSAR data. It is expected that the RIA will be processed as follows:

- **Baseline**: 15 images in 2012, 12 in 2013 and 8 in 2014 in order to attain a sufficient image stack to provide a baseline of the natural conductivity and seasonal fluctuations in the area.
- **Injection**: 1 scheduled image per year or as required. Image to be taken either prior to or after growing season to avoid fertilizers such as potassium chloride which are conductors and may create false positives.
- **Closure**: 1 scheduled image per year, every second year. Image to be taken either prior to or after growing season to minimize false positives.
During injection, it is suggested that only one image per year is required for the following reasons:

- Biosphere monitoring is an active safeguard situated at the far right side of the risk bowtie. In the unlikely event of a leak, the geosphere and hydrosphere would be used as the earliest warning.
- Biosphere monitoring via remote sensing provides an aerial view of the AOR to double check that there are not anomalous areas and provide additional confidence in the monitoring results in the other domains.
- Satellite images are used to guide water and ground sampling activities as opposed to an early warning system for leak detection.

2) Multi-spectral Image Analysis (MIA) attained via Rapideye satellite platform. MIA is used to monitor vegetation stress due to soil salinization or acidification via the normalized difference vegetation index (NDVI). This technology is only appropriate when there is no snow on the ground. Therefore, the frequency of image acquisition is as follows:

a. Baseline: One image per season is acquired (spring, Summer, Fall), in order to provide a natural spectral baseline for the AOR. Therefore, 1 image each in the post-snow melt/pre-seeding (spring), peak growth (summer) and post harvest –pre snow fall (fall) for a total of 3 per year. For 2012, there will only be 1 image acquired in the fall.

b. Injection: 1 image during peak growth (summer) as per the same reasoning as for RadarSat2 images.

c. Closure: 1 image during peak growth (summer), acquired every second year.

### 3.3.3 Ground-based sampling

#### 3.3.3.1 Introduction

The ground-based (field) measurements acquired at various sample plot locations, within the AOR, will be used to calibrate remote sensing data obtained from satellite. The sample plots will provide sufficient soil and vegetation data to classify and characterize the soil type, salinity values and vegetation class by the end of the baseline period. Ground-based sampling involves four major “calibration” activities discussed in the following Sections:

1) Soil Mapping – describe material producing spectra
2) Vegetation Mapping - describe material producing spectra and map and document vegetation for the NDVI
3) Field Spectra Surveys – MIA calibration
4) Ground based electromagnetic conductivity surveys – RIA calibration
3.3.3.2 Sample Plots Locations

The ground-based sampling will use both permanent and transient sampling plots. For remote sensing purposes, transient sample plots are preferred over permanent plots as they are more representative of the changing, predominantly agricultural, environment.

The size of the plot is based on that required for calibration of the remote sensing images. Remote sensing images have spatial resolutions ranging from 2-12m, therefore sample plot sizes of 100m * 100m (10000 m²) are required. The current plan includes the following plot types and locations:

1) Transient Sample Plots: Each plot covers an area of 100 m x 100 m (10000 m²) and is located in an area identified on the remote sensing images that requires ground-truthing. The number and location of the plots will change from year to year, decreasing as the sample data library increases. The current plan is as follows:
   a. Baseline: 10 sample plots per Rapideye image acquisition decreasing to 8 plots in 2014 for a total of 30 in 2013 decreasing to 24 in 2014 (Table 3-1). During the Baseline period, plots sampled for Rapideye Calibration data will also be used to collect RadarSat2 calibration data.
   b. Injection: Total of 4 sample plots in 2015 decreasing to a total of 2 sample plots per year in 2016, or as required, to address specific anomalies above set background thresholds or for incident response.
   c. Closure: 2 transient sample plot per year, every second year.

2) Permanent Sample Plots: Two permanent plot locations will be chosen in order to collect field data on an ongoing basis. At least one of the permanent sample plots will be located within the Quest Sequestration Lease. Current expectation is that the other plot may be located outside the Quest sequestration lease area but still within the satellite image footprint. However, final plot locations will be chosen by Q2 2013, after analysis of the data from the fall 2012 field program is complete.

The sampling frequency from the permanent plots will be as follows:
   a. Baseline: Each of the 2 permanent plot sampled once per Rapideye acquisition for a total of 6 sampling events per year (excludes 2012 event). Calibration of RadarSat2 will occur in the pre and post growing season sampling events.
   b. Injection: Each permanent plot sampled 2 times per year. per .
   c. Closure: Each plot sampled once every second year
Table 3-1: Sample acquisition schedule for biosphere monitoring program used for Remote Sensing Calibration.

<table>
<thead>
<tr>
<th>Monitoring Task</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>Injection (2015-2039)</th>
<th>Closure (2041, 2043, ...2049)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>F  Sp  Su F  W</td>
<td>F  Sp  Su F  W</td>
<td>Sp  Su F  W</td>
<td>Sp  Su F  W</td>
<td></td>
</tr>
<tr>
<td>RadarSat2 Processing (RIA)</td>
<td>15 3 3 3 3</td>
<td>2 2 2 2 2</td>
<td>1</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Rapideye Processing (MIA)</td>
<td>1 1 1 1 1</td>
<td>1 1 1 1 1</td>
<td>1</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Transient Plots (MIA)</td>
<td>10 10 10 8 8</td>
<td>2</td>
<td>2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transient Plots (RIA)²</td>
<td>* * * * *</td>
<td>2</td>
<td>2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Permanent Plots (MIA)¹</td>
<td>2 2 2 2 2</td>
<td>2</td>
<td>2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Permanent Plots (RIA)²</td>
<td>* * * * *</td>
<td>2</td>
<td>2</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* Calibration program for alternate remote sensing analysis method completed on the same plots
Example: Spring 2013 10 plots will be sampled, each for soil and vegetation, EM38 and Field Spectra Mapping

¹ Soil and vegetation mapping, and field spectral surveys via PFRS completed
² Soil and vegetation mapping and EM38 surveys completed
F = Fall, Sp = Spring, SU = Summer, W= Winter

Figure 3-2: Map showing location of permanent sample plots used for calibrating remote sensing data (for 1st sampling event fall 2012)
3.3.3.3 Soil Mapping

At each of the transient and permanent sample plots, soil types and horizons will be characterized based on 10 sampling points within each 10000 m² study area. At two of these 10 points, common soil classification properties (soil horizon, texture, color, moisture, consistence, structure, and parent material) will be described in detail. At the remaining 8 sampling points, topsoil depth, color and upper soil horizons will be recorded. The soils characterization program will follow the standards for sampling intensity and characterization set by Alberta Environment Alberta Environment Pre-Disturbance Assessment (PDA) guidelines (AENV 2009).

Detailed sites will entail the excavation of soils to the depth of the parent material and a maximum of 1.2 meters. For each soil horizon, soils will be collected and placed in plastic bags and numbered according to date, location and horizon. A commercial environmental soil testing laboratory will be used to analyze the chemical and physical attributes of 10 soils samples per transient plot. The analyses include:

- % moisture
- particle size
- pH
- soil cation exchange capacity
- soluble cations
- C:N ratio.

The findings from the investigations at the 10 sampling points at each sample plot will be used to develop a soil map at a scale of 1:15000 to calibrate the RIA and MIA images.

3.3.3.4 Vegetation mapping

Prior to in-field mapping of vegetation, a desktop assessment of each site will be performed to pre-determine vegetation communities. Each vegetation community will be mapped using high resolution (1 m or less) aerial photography and developed into a geographic information system (GIS) polygon layer. In addition, the location of any land features (i.e. wetlands, ponds, roads, etc.) will be identified and mapped. Each polygon will be classified to the ecosite level using the Guide to Range Plant Community Types and Carrying Capacity for the Dry and Central Mixedwood Subregions in Alberta (Willoughby et al., 2006).

Within each of the 100 m x 100 m transient and permanent sample plots, vegetation subplots will be chosen to represent each polygon (ecosite) type. If only one ecosite is identified within a sample plot, a minimum of two subplots will be established within this vegetation type. A nested plot design is used to establish monitoring subplots. Subplots will represent the primary sampling unit for the monitoring program. The sample subplots will be established within representative areas and positioned entirely within a given ecosite whenever possible. For each of the subplots, the following sampling hierarchy will be used:

- one, 10 m x 10 m tree canopy plot
- two, 5 m x 5 m nested shrub subplots
- two, 1 m² nested ground subplots.
Each corner of the 10 m × 10 m permanent subplot will be recorded via GPS. The corners of all shrub subplots and ground subplots will be flagged with biodegradable flagging.

For each subplot level the following will be recorded as a baseline for vegetation characteristics:

- species composition (after Moss, 1983; ACIMS, 2011)
- percent cover (after Daubenmire, 1959)
- estimation of plant health on a growth form level (tree, shrub, forb, and grass)

Each subplot and corresponding nested subplots will be photographed to allow for visual assessments over time.

3.3.3.5 Field Spectra Surveys

A portable field reflecting spectrometry (PFRS) instrument will be used to gather spectral signatures for each vegetation group identified during vegetation mapping to calibrate the optical data used for MIA. Vegetation groups will be dependent on vegetation structural functional types (i.e., trees, shrubs, forbs, grasses). Since spatial resolution of the associated imagery is 6.5 m × 6.5 m, small communities or individual members of a species may not be detected by satellites. Spectral signatures will be limited to grouping functional types of at least 5 m × 5 m. If communities are composed of a matrix of more than one functional type, spectral imagery will be made of the community as a whole.

Spectral reflectance profiles will be collected over preselected Pseudo Invariant Features (PIFs) using an Ocean Optics Spectroradiometer (USB-2000 VIS-NIR). Several PIFs within the study area will be selected using the following criteria:

- PIF surfaces will be appropriate size for the spatial resolution of the satellite
- PIF will be pseudo-Lambertian reflectors (asphalt, concrete, uniform gravel road, etc.)
- PIF will be located where the contribution of the surrounding land cover will be minimal on the at-ground-level upwelling radiance
- PIF signatures can be collected a few days before or after the image collection.

3.3.3.6 Electromagnetic Conductivity Surveys

On all sampling plots, an EM38 terrain conductivity meter survey will be done to assess soil salinity, using a EM38-MK2 (Geonics Ltd.). The data obtained will be used for calibration of the SAR satellite data used for RIA.

Data will be collected in grid (lines and tie-lines) geometry over a minimum ground area of approximately 100 m × 100 m at each site. Lines will be no more than 8 m and no less than 4 m apart. Tie-lines will be 20 m - 40 m apart. The suggested line spacing is similar to the SAR imagery resolution of 8*12 m.
3.4 Soil gas and soil surface CO₂ flux

3.4.1 Introduction

Soil gas analysis and soil surface CO₂ flux measurements are included within the biosphere pre-injection data gathering program in order to gain an understanding of the magnitudes and temporal / spatial variability of those parameters in the AOR. However, during the injection phase, the analyses are considered a response tool and will only be used in case of a suspected incident.

3.4.2 Sampling sites and schedule

It is expected that soil gas composition and soil surface CO₂ flux will vary across the landscape, as it depends upon a range of factors such as land use type (e.g. forest versus agriculture), or management type within an agricultural setting (e.g. cereal versus legume or unamended versus fertilized with synthetic nitrogen). In turn, it will be difficult to capture all possible scenarios and an attempt will be made at obtaining soil surface CO₂ flux data for specific regions within the AOR.

The sampling sites will be located:

- near injection well pads: 3 sites in total
- at permanent soil plots: 2 sites in total
- at transient soil plots: 10 sites in total.

The type and distribution of the sites permit Shell to attain an understanding of both the temporal and spatial variations of soil gas and soil surface CO₂ flux across the AOR. The sites near the injection well pads and at the permanent soil plots can be used to assess the temporal variation. For a specific sampling date, the data from those sites in addition to the data from the transient plots permit assessment of the spatial variation. Note that the permanent and transient soil plots are identical to those using for the remote sensing monitoring program (see section 3.3).

Discrete measurements will be taken every season (4 sampling events per year at regular intervals) during the pre-injection phase in order to capture expected temporal variations in soil gas and soil surface CO₂ flux.

3.4.3 Sampling protocol

Soil surface CO₂ flux measurements will be taken at 3 randomly chosen sampling points located within a homogeneous soil/vegetation type. It is expected that the soil surface CO₂ flux measurements will be obtained using a LiCor Model 8100A CO₂ flux survey chamber.

Regarding the soil gas measurements, a vertical probe (e.g. AMS Retract-A-Tip gas vapour probe) will be inserted into the soil in order to collect the samples. Samples will be collected from three depths down to about 2 m below the ground surface at each site, except at the transient plot sites. At those sites, only a sample from the ‘middle’ depth will be collected. Soil gas samples will be submitted to a qualified laboratory in Alberta with appropriate QA/QC procedures for compositional and isotopic analyses.

Compositional analysis of a soil gas sample will include:
• CO₂, C₁ to C₁₀+, N₂, O₂, He

Isotopic analysis of a soil gas sample will include:
• δ¹³C-CO₂ and δ¹³C-CH₄, δ²H-CH₄.

4 Integrated Response Plan

During the pre-injection (baseline) phase threshold levels for various triggers (e.g. pH) indicating a change in the baseline conditions prior to start of injection will have been established. During the injection and post-injection phases, routine monitoring activities will be carried out as discussed in section 2 and 3. In situations, where a change has been identified an integrated response plan (Fig. 4-1) will be initiated.

The integrated response plan (IRP) relies on a sequential process to evaluate anomalous monitoring results observed during the routine monitoring program of the injection or post-injection phases, as presented in sections 2 and 3. The integrated response plan provides a means to:

a) assess whether the observed change is ‘real’ or not
b) in the case of ‘real change’ assess what cause(s) are responsible for the change
c) suggest mitigation measures to protect the environment.

The IRP operates as follows:
• threshold level exceeded for a Hydrosphere or Biosphere ‘trigger’
  o example of hydrosphere trigger: Tier 0 EC continuous measurement
  o example biosphere trigger: anomaly on satellite imagery
• if trigger within Biosphere:
  o check/review remote sensing imagery and other monitoring domains of the MMV plan
    ▪ OK: return to routine monitoring
    ▪ AMBIGUOUS: undertake field visit where anomaly detected
  o field visit:
    ▪ OK: return to routine monitoring
    ▪ AMBIGUOUS: undertake soil gas measurement
  o soil gas measurement:
    ▪ OK: return to routine monitoring
    ▪ AMBIGUOUS: check existing groundwater/well headspace data collected within area of anomaly
  o existing groundwater/well headspace data:
    ▪ OK: return to routine monitoring
    ▪ AMBIGUOUS: initiate Tier 2 analyses
o Tier 2 groundwater/well headspace data:
  ▪ OK: return to routine monitoring
  ▪ AMBIGUOUS: initiate Tier 3 analyses

o Tier 3 groundwater/well headspace data:
  ▪ OK: return to routine monitoring
  ▪ NOT OK: initiate Tier 4

o Tier 4:
  ▪ 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

• if trigger within Hydrosphere
  o check/review existing groundwater/well headspace data and other monitoring domains of the MMV plan
    ▪ OK: return to routine monitoring
    ▪ AMBIGUOUS: initiate Tier 2 analyses
  o Tier 2 groundwater/well headspace data:
    ▪ OK: return to routine monitoring
    ▪ AMBIGUOUS: initiate Tier 3 analyses
  o Tier 3 groundwater/well headspace data:
    ▪ OK: return to routine monitoring
    ▪ NOT OK: initiate Tier 4
  o Tier 4:
    ▪ 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
Figure 4-1: Schematic overview of Integrated Response Plan

- **Hydrosphere**
  - Groundwater / Well headspace gas
  - Tier 2
  - Tier 3
  - Tier 4
- **Biosphere**
  - Remote sensing
  - Field visit
  - Soil gas measurement
- **MMV**
  - Monitoring, Monitoring and Verification
  - Mitigation measures in place
- **Routine monitoring**
- **‘Trigger’**
5 References

Appendix B Emerging MMV Guidelines
Emerging MMV Guidelines

B.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 CO₂.

The Greenhouse Gas Inventory Guidelines consider underground storage sites to be a source of CO₂ emissions. This means the difference between the amount of injected and emitted CO₂ is a measure of the inventory of stored CO₂. For potential CCS CDM projects to be an effective mitigation for climate change, annual CO₂ emissions rates should be less than 0.01% of the mass of CO₂ 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 CO₂:

- 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 CO₂. 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.

B.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. This necessitates the development of new standards for CCS projects. The Canadian Standards Association (CSA) and the International Performance Assessment Centre for Geologic Storage of Carbon Dioxide (IPAC-CO₂) recently announced a joint agreement to develop Canada’s first carbon capture and storage standard for the geologic storage of industrial emissions. International and other national authorities, industry and environmental non-governmental organizations will most likely influence the development of these standards.
B.3 International Authorities

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

B.4 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 CO₂ storage has developed the OSPAR principles for monitoring and stated the following six objectives for monitoring.

- Demonstrate CO₂ behaves as expected.
- Detect any migration or leakage.
- Measure any environmental or health damage.
- Determine effectiveness of CO₂ 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 CO₂ storage according to three criteria.

- Actual CO₂ behaviour conforms to modeled behaviour 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 CO₂ storage rather than just the volume occupied by the CO₂ 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) provide guidance for MMV, including a classification of monitoring technologies according to their readiness for monitoring CO\(_2\) storage sites.

### B.5 Industry Authorities

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

• **CO\(_2\)QUALSTORE:** 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 Researech and Development Programme; and two Norwegian public enterprises (Gassnova/Climit and Gassco). This JIP draws together experience and good practises 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 C 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 C-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 analysing and communicating risks.

![Schematic Diagram of the Bowtie Method](image)

**Figure C-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.

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**Figure C-2**  
Reduction in risk computed for increasing number of passive and active safeguards. Each line represents one realisation of the anticipated failure rates for each safeguard selected at random from the recognised range of potential failure rates for each safeguard. The 100 realisations shown indicate impact of these uncertainties on risk management. The Risk Metric is shown on a logarithmic scale.
Appendix D Knowledge Transfer Between CCS Projects
Knowledge Transfer Between CCS Projects

D.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 CO2 per year. Four projects – Sleipner, In Salah, Snøhvit and Rangely – inject CO2 from a natural gas production facility where it is separated from the natural gas sent to market. In the first three cases, the CO2 is injected into saline aquifers, while in the fourth it is used for EOR. A fifth project captures CO2 at the Great Plains Synfuels Plant and transports it for EOR to the 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.

D.1.1 Sleipner

The Sleipner project began in 1996 when Norway’s Statoil began injecting more than 1 million tonnes per year of CO2 under the North Sea. This CO2 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 CO2 from other gases. The CO2 is re-injected about 1 000 metres 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 CO2, and is expected to continue receiving CO2 long after natural gas extraction at Sleipner has ended.

D.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 CO2 into the Krechba geologic formation near their natural gas extraction site in the Sahara Desert. The Krechba formation lies 1 800 metres below ground and is expected to receive 17 million tonnes of CO2 over the life of the project.

D.1.3 Snøhvit

Europe’s first liquefied natural gas (LNG) plant also captures CO2 for injection and storage. Statoil extracts natural gas and CO2 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 CO2 is necessary to produce LNG and the Snøhvit project captures about 700 000 tonnes per year of CO2. Starting in 2008, the captured CO2 is piped back to the offshore platform and injected in the Tubåsen sandstone formation 2,600 metres under the seabed and below the geologic formation from which natural gas is produced.

D.1.4 Rangely

The Rangely CO2 Project has been using CO2 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 reinjected with CO2 from the LaBarge field in
Wyoming. Since 1986, approximately 23-25 million tonnes of CO2 have been stored in the reservoir. Computer modeling suggests nearly all of it is dissolved in the formation water as aqueous CO2 and bicarbonate. Though Rangely uses CO2 for EOR, it is considered a CCS project based on the assessed viability of long-term storage of CO2.

D.1.5 Weyburn-Midale

About 2.8 million tonnes per year of CO2 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 CO2 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 CO2. The IEA Greenhouse Gas R&D Programme’s Weyburn-Midale CO2 Monitoring and Storage Project was the first project to scientifically study and monitor the underground behaviour of CO2. 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 CO2 geological storage. The project will produce a best-practices manual for carbon injection and storage.

D.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 CO2 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 Quest.

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

D.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 Weyburn CO2 Monitoring and Storage Project.
run by the International Energy Agency Greenhouse Gas Research and Development Program.
Appendix E Status of Existing Wells
Appendix E: Status of Existing Wells

Shell Quest Carbon Capture and Storage Project
Measurement, Monitoring and Verification Plan

October 15th 2012
Shell Canada Limited
Status of Existing Wells

The status of existing wells that penetrate the BCS storage complex was analysed based on available documentation. A review of existing documentation for all abandoned BCS legacy wells within and close to the AOI indicates they all contain multiple thick cement plugs (Table E-1). The deepest cement plug is below the Upper Lotsbeg Salt Formation in all cases except Imperial Darling No. 1. Table E-2 describes the current status of Project appraisal wells. Table E-3 provides the offset distances between proposed injectors and the closest hydrocarbon production well. Figure E-1 shows the location of these wells in relation to the AOI and the stratigraphy.
## Table E-1  Status of BCS legacy wells

<table>
<thead>
<tr>
<th>Well name and UWI</th>
<th>History and Distance from pipeline</th>
<th>Seals drilled through</th>
<th>Casings, holes and BGWP</th>
<th>Cement plugs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Imperial Eastgate 100-01-34-057-22W400</td>
<td>• Drilled and abandoned in 1955 21 km from pipeline</td>
<td>• Upper Lotsberg  • Lower Lotsberg  • - MCS</td>
<td>• 9 5/8” casing to 277m  • 9” openhole to 2205m (TD)  • BGWP at 240m bgl</td>
<td>#1: 265 – 289 m  #2: 644 – 710m  #3: 887 – 981m  #4: 1016 – 1048m  #5: 1256 – 1292m  #6: 2125 – 2205m</td>
</tr>
<tr>
<td>Imperial Egremont 100-06-36-058-23W400</td>
<td>• Drilled and abandoned in 1952 21 km from pipeline</td>
<td>• Upper Lotsberg  • Lower Lotsberg  • MCS</td>
<td>• 13 3/8” casing to 186m  • 9” openhole to 2242.3m  • BGWP at 220m bgl</td>
<td>#1: 172 – 195m  #2: 624 – 670m  #3: 844 – 875m  #4: 969 – 1003m  #5: 1178 – 1218m  #6: 2140 – 2242m</td>
</tr>
<tr>
<td>Imperial Darling #1 100-16-19-062-19W400</td>
<td>• Drilled and abandoned in 1949 25 km from pipeline</td>
<td>• Upper Lotsberg  • Lower Lotsberg  • MCS</td>
<td>• 13 3/8” casing to 183m  • 9” (supposed) openhole to 2013m  • BGWP at 235m bgl</td>
<td>#1: 168 – 198m  #2: 525 – 587m  #3: 708 – 740m  #4: 762 – 792m</td>
</tr>
<tr>
<td>Westcoast et al Newbrook 100-09-31-062-19W400</td>
<td>• Drilled in and abandoned in 1978 28 km from pipeline</td>
<td>• Upper Lotsberg  • Lower Lotsberg  • MCS</td>
<td>• 9 5/8” casing to 230m  • 7” (supposed) openhole to TD at 1923m  • - BGWP at 228m</td>
<td>#1: 183 – 366m  #2: 518 – 701m  #3: 838 – 960m  #4: 1082 – 1204m  #5: 1280 – 1402m  #6: 1524 – 1615m  #7: 1707 – 1923m</td>
</tr>
<tr>
<td>Imperial Clyde #1 100-09-29-059-24W400</td>
<td>• Drilled and abandoned in 1948 43.5 km from pipeline (outside AOI)</td>
<td>• Upper Lotsberg  • Lower Lotsberg  • MCS</td>
<td>• 13 3/8” casing to 135m  • 9” openhole to 2295m (TD)  • BGWP at 232.5m bgl</td>
<td>#1: 128 – 195m  #2: 781 – 945m</td>
</tr>
<tr>
<td>Imperial Gibbons #1 100-02-16-056-22W400</td>
<td>• Drilled and abandoned in 1949 25 km from pipeline (outside AOI)</td>
<td>• Upper Lotsberg  • Lower Lotsberg  • MCS</td>
<td>• 13 3/8” casing to 180m  • 9” openhole to 2024m (TD)  • BGWP at 258.1m bgl</td>
<td>#1: 695 – 754m  #2: 893 – 983m  #3: 1052 – 1113m</td>
</tr>
<tr>
<td>Imperial PLC Redwater</td>
<td>• Drilled in 1974 – Converted to</td>
<td>• Upper Lotsberg</td>
<td>• 13 3/8” casing to 188.4m</td>
<td>#1: 0 – 500m</td>
</tr>
</tbody>
</table>
### LPGS 100-07-17-056-21W400
- **LPG reproducer in 1975**
- Abandoned in 2007
- 18.5 km from pipeline
- 9 5/8" casing to 1778.2m
- 7" casing to 1836m
- TD at 1861m
- BGWP at 216m bgl
- #2: 1435 – 1760m
- #3: 1760 – 1861m

---

### Table E-2 Status of the Project appraisal wells.

<table>
<thead>
<tr>
<th>Well Name and UWI</th>
<th>Inside AOI</th>
<th>TD</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCL Redwater 102-11-32-55-21-W4M</td>
<td>No</td>
<td>2269m</td>
<td>Well cased and cemented to TD. BCS abandoned and well converted to a water disposal well into the shallower Nisku formation.</td>
</tr>
<tr>
<td>SCL Redwater 03-04-57-20W4M</td>
<td>Yes</td>
<td>2190m</td>
<td>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</td>
</tr>
<tr>
<td>SCL Radway 8-19-59-20W4</td>
<td>Yes</td>
<td>2132m</td>
<td>Well cased and cemented to TD. Well suspended awaiting D51 and D65 approval before recompletion as a potential commercial CO2 injection well</td>
</tr>
</tbody>
</table>
Figure E-1  Summary of existing well locations.
### Table E-3  Distances to closest offset hydrocarbon producers.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Closest offset well</th>
<th>Inside AOI</th>
<th>Average depth to top reservoir in AOI [m]</th>
<th>Distance from 8-19-059-20W4 [km]</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Viking</td>
<td>100/09-31-059-20W4/00</td>
<td>Yes</td>
<td>590</td>
<td>3.4</td>
<td></td>
</tr>
<tr>
<td>Joli Fou</td>
<td>100/08-36-059-20W4/00</td>
<td>Yes</td>
<td>615</td>
<td>8.7</td>
<td></td>
</tr>
<tr>
<td>Mannville</td>
<td>100/15-20-059-20W4/00</td>
<td>Yes</td>
<td>623</td>
<td>1.2</td>
<td></td>
</tr>
<tr>
<td>Wabamun</td>
<td>100/14-29-059-20W4/00</td>
<td>Yes</td>
<td>750</td>
<td>8.2</td>
<td></td>
</tr>
<tr>
<td>Nisku</td>
<td>100/09-06-058-21W4/00</td>
<td>Yes</td>
<td>850</td>
<td>15</td>
<td></td>
</tr>
<tr>
<td>Ireton</td>
<td>103/06-07-058-21W4/00</td>
<td>Yes</td>
<td>900</td>
<td>15</td>
<td></td>
</tr>
<tr>
<td>Leduc</td>
<td>100/03-08-058-21W4/0</td>
<td>Yes</td>
<td>1000</td>
<td>15</td>
<td></td>
</tr>
<tr>
<td>Winnipegosis</td>
<td>-</td>
<td>No</td>
<td>1600</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>BCS</td>
<td>-</td>
<td>No</td>
<td>2000</td>
<td>-</td>
<td></td>
</tr>
</tbody>
</table>
Appendix F  Pressure Required to Lift BCS Brine
Pressure Required to Lift BCS Brine

Table F-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 AOI. However, BCS brine can only be 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 AOI and would have lower pressures in the BCS than the wells quoted in Table 117-1. 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 F-1 Pressure increase required to lift BCS above the base of groundwater protection.

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Surface Elevation [mbsl]</th>
<th>BGWP Depth [mbsl]</th>
<th>Delta P[^A] [kPa]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Imperial Eastgate 1-34</td>
<td>-641</td>
<td>-401</td>
<td>3,452</td>
</tr>
<tr>
<td>Imperial Egremont 6-36</td>
<td>-628</td>
<td>-408</td>
<td>3,334</td>
</tr>
<tr>
<td>Imperial Clyde No. 1[^a]</td>
<td>-629</td>
<td>-397</td>
<td>3,327</td>
</tr>
<tr>
<td>Imperial Darling No. 1</td>
<td>-704</td>
<td>-469</td>
<td>4,201</td>
</tr>
<tr>
<td>Westcoast 9-31[^c]</td>
<td>-699</td>
<td>-471</td>
<td>4,146</td>
</tr>
</tbody>
</table>

NOTES:
- mbsl denotes metres below sea level
- Delta P is incremental BCS pressure required to lift BCS brine to BGWP
- Imperial Clyde No. 1 is not located in the AOI.
- 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.