Disclaimer
This Report, including the data and information contained in this Report, is provided to you on an "as is" and "as available" basis at the sole discretion of the Government of Alberta and subject to the terms and conditions of use below (the "Terms and Conditions"). The Government of Alberta has not verified this Report for accuracy and does not warrant the accuracy of, or make any other warranties or representations regarding, this Report. Furthermore, updates to this Report may not be made available. Your use of any of this Report is at your sole and absolute risk.

This Report is provided to the Government of Alberta, and the Government of Alberta has obtained a license or other authorization for use of the Reports, from:

> Shell Canada Energy, Chevron Canada Limited. and Marathon Oil Canada Corporation, for the Quest Project
>
> (collectively the "Project")

Each member of the Project expressly disclaims any representation or warranty, express or implied, as to the accuracy or completeness of the material and information contained herein, and none of them shall have any liability, regardless of any negligence or fault, for any statements contained in, or for any omissions from, this Report. Under no circumstances shall the Government of Alberta or the Project be liable for any damages, claims, causes of action, losses, legal fees or expenses, or any other cost whatsoever arising out of the use of this Report or any part thereof or the use of any other data or information on this website.

Terms and Conditions of Use
Except as indicated in these Terms and Conditions, this Report and any part thereof shall not be copied, reproduced, distributed, republished, downloaded, displayed, posted or transmitted in any form or by any means, without the prior written consent of the Government of Alberta and the Project.

The Government of Alberta's intent in posting this Report is to make them available to the public for personal and non-commercial (educational) use. You may not use this Report for any other purpose. You may reproduce data and information in this Report subject to the following conditions:

- any disclaimers that appear in this Report shall be retained in their original form and applied to the data and information reproduced from this Report
- the data and information shall not be modified from its original form
- the Project shall be identified as the original source of the data and information, while this website shall be identified as the reference source, and
- the reproduction shall not be represented as an official version of the materials reproduced, nor as having been made in affiliation with or with the endorsement of the Government of Alberta or the Project

By accessing and using this Report, you agree to indemnify and hold the Government of Alberta and the Project, and their respective employees and agents, harmless from and against any and all claims, demands, actions and costs (including legal costs on a solicitor-client basis) arising out of any breach by you of these Terms and Conditions or otherwise arising out of your use or reproduction of the data and information in this Report.

Your access to and use of this Report is subject exclusively to these Terms and Conditions and any terms and conditions contained within the Report itself, all of which you shall comply with. You will not use this Report for any purpose that is unlawful or prohibited by these Terms and Conditions. You agree that any other use of this Report means you agree to be bound by these Terms and Conditions. These Terms and Conditions are subject to modification, and you agree to review them periodically for changes. If you do not accept these Terms and Conditions you agree to immediately stop accessing this Report and destroy all copies in your possession or control.

These Terms and Conditions may change at any time, and your continued use and reproduction of this Report following any changes shall be deemed to be your acceptance of such change.

If any of these Terms and Conditions should be determined to be invalid, illegal or unenforceable for any reason by any court of competent jurisdiction then the applicable provision shall be severed and the remaining provisions of these Terms and Conditions shall survive and remain in full force and effect and continue to be binding and enforceable.

These Terms and Conditions shall: (i) be governed by and construed in accordance with the laws of the province of Alberta and you hereby submit to the exclusive jurisdiction of the Alberta courts, and (ii) ensure to the benefit of, and be binding upon, the Government of Alberta and your respective successors and assigns.

Heavy Oil

Controlled Document

Quest CCS Project

Closure Plan- 3rd year update

Project	Quest CCS Project
Document Title	Closure plan- 3rd year update
Document Number	07-3-AA-5706-0005
Document Revision	0
Document Status	Issued for Information
Document Type	5706 – Assurance plan
Control ID	NA
Owner / Author	Mauri Smith
Issue Date	2014-02-27
Expiry Date	None
ECCN	EAR 99
Security Classification	Unclassified
Disclosure	None

Revision History shown on next page

Revision History

REVISION STATUS			APPROVAL		
Rev.	Date	Description	Originator	Reviewer	Approver
0	2014-02-27	For information	Mauri Smith	Sean McFadden	Sean McFadden

- All signed originals will be retained by the UA Document Control Center and an electronic copy will be stored in Livelink

Signatures for this revision

Date	Role	Name	Signature or electronic reference (email)
	Originator	Mauri Smith	M Smith
	Reviewer	Sean McFadden	Sean McFadden
	Approver	Sean McFadden	Sean McFadden.

Summary

Keywords

Shell Canada Limited
400-4th Avenue S.W.
Calgary AB T2P 2H5
Mark MacKay
Ph. (403) 691-4523
Email to Mark.Mackay@shell.com

24 February 2014

Alberta Department of Energy – Carbon Sequestration
11th Floor, North Petroleum Plaza
9945 108th Street
Edmonton AB T5K 2G6

Dear Ms. Wong,

RE: Application for Renewal of MMV and Closure plan related to Shells QUEST Carbon Capture and Storage Project. Lease: 5911050001, 591105002, 591105003, 5911050004, 5911050005, 5911050006,

Please find attached Shell Canada Limited's updated Closure Plan and Monitoring Measuring and Verification ("MMV") plan (Appendix A) as the "third anniversary of the date on which the plan was approved" is set to come up on May 27th, 2014. As per section 16 and 19 of the Carbon Sequestration Tenure Regulation and Mines and Mineral Act Shell is seeking approval from the Minister for above mentioned updated Closure and MMV plans for its QUEST project. If you have any further questions or concerns please contact the undersigned at Mark.Mackay@shell.com or at 403-384-6372.

Thank you for your time and consideration.

Yours Truly,
SHELL CANADA ENERGY
SHELL CANADA LIMITED

Mark MacKay
Land Representative

Quest Carbon Capture and Storage Project

CLOSURE PLAN

3rd Year Update

Prepared by:
Shell Canada Limited
Calgary, Alberta

February 2014

Table of Contents

List of Tables

List of Figures

Acronyms and Abbreviations

ADOE	Alberta Department of Energy
AENV	Alberta Environment
AER	Alberta Energy Regulators
AOR	area of review
AOSP	Athabasca Oil Sands Project
BCS	Basal Cambrian Sands
BGWP	base of ground water protection
C&R	conservation and reclamation
CCS	carbon capture and storage
CCS Act	*Carbon Capture and Storage Act*
CEAA	*Canadian Environmental Assessment Act*
CO_2	carbon dioxide
DNV	Det Norske Veritas
EA	environmental assessment
EPEA	*Environmental Protection and Enhancement Act*
EPP	Environmental Protection Plan
HMU	hydrogen manufacturing unit
InSAR	Interferometric Synthetic Aperture Radar
IPCC	Intergovernmental Panel on Climate Change
MMA	Mines and Minerals Act
MCS	Middle Cambrian Shale
MMV	measurement, monitoring and verification
Mt/a	million tonnes per year
PI	Productivity Index
RFA	Regulatory Framework Assessment
ROW	right-of-way
Shell	Shell Canada Limited
Shell Scotford	Shell Scotford Complex
SLA	Sequestration Lease Area
TDS	total dissolved solids
the Project	injection and storage of CO_2 in the BCS saline aquifer
UWI	unique well identifier

1. Introduction

1.1. Scope of Closure Plan

Shell Canada Limited (Shell), on behalf of the Athabasca Oil Sands Project (AOSP), which is a joint venture between Shell Canada Energy, Chevron Canada Limited, and Marathon Oil Canada Corporation, has received approval from the Alberta Energy Regulator (AER) under Approval Number 11837A (the “Approval”) to construct, operate and reclaim the Quest Carbon Capture and Storage (CCS) Project (the Project). The Project will capture, transport and store carbon dioxide (CO_2) from the existing Scotford Upgrader, which is located about 5 km northeast of Fort Saskatchewan, Alberta (see Figure 1-1).

As part of the Project, the Alberta Minister of Energy, pursuant to Section 116 of the *Mine and Minerals Act* (the MMA or the Act), granted Shell six (6) Carbon Sequestration Leases that together comprise the single proposed Quest Carbon Capture and Storage (CCS) Project (Figure 1-1). This lease approval required the submission of an initial project closure plan and subsequent closure plan updates. On April 28, 2011, the initial closure plan was submitted as a key component of the sequestration lease applications.

The content of this document is in accordance with Part 9 of the MMA [1], Section 19 of the *Carbon Sequestration Tenure Regulation 68/2011*[2] as well as the 2013 Alberta Government Carbon Capture & Storage Summary Report of the Regulatory Framework Assessment [3]. The scope of the closure plan update is limited to the storage component of the Project, which includes well pads, injection wells, observation wells, monitoring infrastructure and the storage complex, for the permanent storage of CO_2 in a deep saline geological formation.

Following the completion of site closure activities, Shell will apply for a Site Closure Certificate, under Section 120 of the MMA. The post-closure period will begin with the issue of a Site Closure Certificate, which will transfer the long-term liability and any further post-closure activities requested by the Government from Shell to the Crown in accordance with Section 121 of the MMA [1].

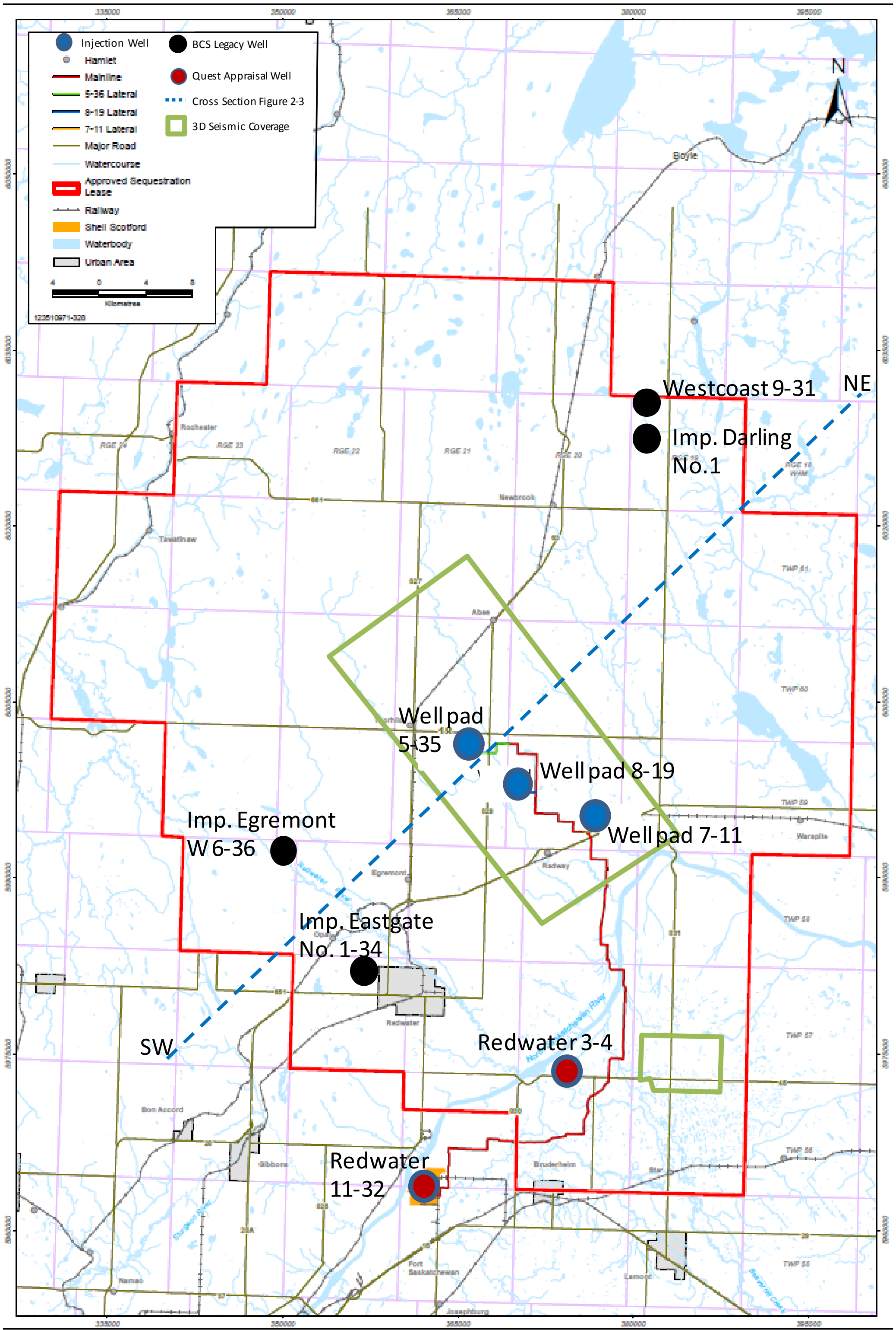

Figure 1-1 Quest CCS Project Components and Sequestration Lease

1.2. Timeline of Proposed Closure Activities

The current expectation for the beginning of commissioning and start of operations ramp-up of the full Project is in the second quarter of 2015. Full, sustained operations will occur by the fourth quarter of 2015 and will continue for the life of the Scotford Upgrader, which will be greater than 25 years. Around that time, CO_2 injection will cease, a final closure plan and MMV plan will be submitted to the Regulator and closure activities will begin in accordance with recommendation 60 of the RFA. The injection wells and storage infrastructure will remain in place to continue the monitoring and verification processes as planned during the closure period, which will occur over a minimum period of 10 years unless otherwise agreed with the Government of Alberta (Recommendation 62 for the RFA).

Towards the end of the closure period, Shell will abandon the injection wells and reclaim the surface in accordance with the regulatory requirements in place at the time.

Following site closure activities, Shell will apply for a site closure certificate provided no significant issues arise from Project operations and that storage performance and CO_2 and brine containment in the BCS storage complex are demonstrated to the satisfaction of the Crown in accordance with pre-agreed upon criteria as per RFA Recommendation 58.

The post-closure period will occur following the issuance of a site closure certificate, which will transfer the long-term liability from Shell to the Crown. At that time, Shell will transfer any monitoring technologies requested by the Government for its long-term monitoring approach and share its accrued knowledge and experience of those technologies with the government prior to this transfer. Figure 1-3 shows a timeline for the proposed closure activities.

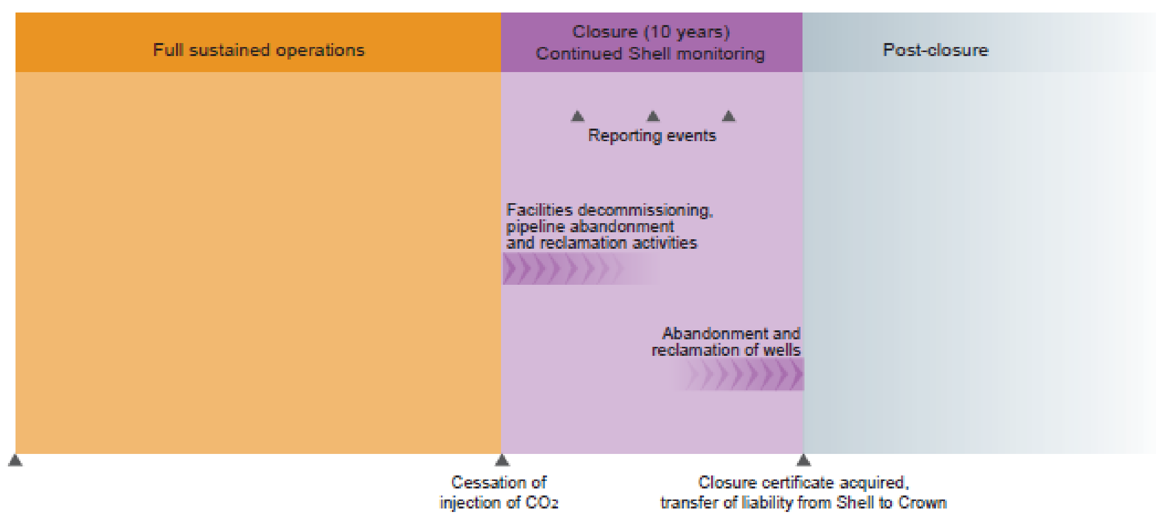

Figure 1-3 Proposed Timeline for Project Operations, Closure and Post-Closure

1.3. Closure Requirements

Shell is committed to closure of the Project in accordance with applicable regulatory requirements in force at the time of closure. Current obligations to the Government of Alberta are outlined in the MMA and in the Alberta *Carbon Sequestration Tenure Regulation 68-2011*.

The Alberta Energy's Regulatory Framework Assessment (RFA) was completed in December 2012. However, the recommendations from this report are still under review by the Minister of Energy. The RFA recommendations may result in new regulatory requirements that Shell has voluntarily incorporated into this closure plan update (Table 1-1).

Shell is committed to meet the requirements of all applicable regulations under the MMA or other new requirements that apply to CCS projects.

Table 1-1 Concordance Table of Quest Closure Requirements

Requirement as listed in Alberta Government Carbon Capture & Storage Regulatory Framework Assessment	Section
29a) Project Overview	2.0
b) Storage performance criteria for site closure	3.0
c) Storage Performance evidence	4.0
d) Operating Plan Update	5.0
e) Description of current and potential surface or subsurface interactions	4.4.2.3
f) proposed closure activities	6.0
g) any other information required by the regulator, other departments or agencies of the Government of Alberta	N/A
59) Interim and final closure plans include assessment of all the wells that have penetrated the sequestration complex within the area of review to ensure that the evolution of the CO_2 plume or pressure front over the life of the project has not introduced potential leakage pathways that were not anticipated.	4.4.2.2
Requirement as listed in Alberta Carbon Sequestration Tenure Regulation 68/2011	**Section**
19(1) A closure plan that is approved by the Minister under section 18 ceases to have effect on the earlier of:	-
(a) the third anniversary of the date on which the plan was approved, and	May 27 2014
(b) the date that the carbon sequestration lease is renewed.	May 27, 2026
(2) A lessee must submit a new closure plan for approval no fewer than 90 days before the date that an approved plan ceases to have effect.	Feb. 27, 2014
(3) The Minister may approve a closure plan submitted under subsection (2), or received under section 11, in relation to a carbon sequestration lease if the plan sets out a description of the activities satisfactory to the Minister that the lessee will undertake to close down sequestration operations and facilities, and contains the following:	-
(a) a summary of the activities that have been conducted by the lessee on the location of the carbon sequestration lease since it was issued;	2.2, 4.4.2, 5.0
(b) the quantity of captured carbon dioxide that has been injected;	N/A
(c) an evaluation of whether the injected captured carbon dioxide has behaved in a manner consistent with the geological interpretations and calculations the lessee submitted to the Regulator pursuant to Directive 65 in its application for approval of the injection scheme under the *Oil and Gas Conservation Act*;	N/A
(d) the most recent geological interpretations and calculations that may have been made by the lessee with respect to the injected carbon dioxide and any associated pressure front;	4.3.3, 4.3.4
(e) a description of the location, condition, plugging procedures and integrity testing results for every well that has been used for the injection of captured carbon dioxide under the lease;	6.2
(f) a description of any decommissioning, abandonment or reclamation activities undertaken by the lessee in the location of the lease;	N/A
(g) an inventory of the reports and documents that the lessee has submitted to the Regulator or a department or agency of the Crown in right of Alberta or the Crown in right of Canada since the approval of the first closure plan related to the carbon sequestration lease, whether or not those reports and documents were required to be submitted;	8.0
(h) advice and recommendations about the monitoring, measurement and verification activities that should be conducted after the issuance of a closure certificate is issued for the carbon sequestration lease under section 120 of the Act.	7.0

2. Project Overview

Shell Canada Limited, which is the managing partner of Shell Canada Energy, will hold all necessary regulatory approvals in respect of the Project. Shell Canada Energy will operate the Project, on behalf of the AOSP. The goal of the Quest CCS Project is to separate, capture and permanently store CO_2, thereby reducing greenhouse gas emissions from the existing Scotford Upgrader. The Scotford Upgrader is located about 5 km northeast of Fort Saskatchewan, Alberta, within Alberta's Industrial Heartland, which is zoned for heavy industrial development.

The three components of the Quest CCS Project are:

- CO_2 capture infrastructure, which will be connected to the Scotford Upgrader. The method of capture is based on a licensed Shell amine system called ADIP-X.
- A pipeline, which will transport the CO_2 from the Scotford Upgrader 60 km to the injection wells north of the upgrader. The CO_2 injection wells are located in the center of the storage site.
- An approved D65 storage scheme consisting of up to 8 injection wells that can be used to inject the CO_2 into the Basal Cambrian Sands (BCS), a deep underground formation, for permanent storage at a depth of about 2 km below ground level. Although 8 wells were approved as part of the D65 approval 11837A [4], the current development plan requires only 3 injection wells at this time. The security of storage will be ensured through a program of Measurement, Monitoring and Verification (MMV).

The injection policy consists of injecting 1.08 million tonnes of CO_2 per annum for 25 years using three vertical wells with a spacing of approximately 5 km. The distribution of injection between the injection wells will be managed to satisfy the maximum bottom hole injection pressure constraint of 30 MPa in accordance with the Directive 65 approval 11837A [4]. It is relevant to note that with the current modeling and results of 2012/2013 well evaluations, the flowing bottom hole pressure is not expected to exceed 22 MPa over the life of the project (see Section 4.2.1.2.1)

2.1. Sequestration Lease Rights

The CO_2 Sequestration Lease Area (SLA) granted by the Carbon Sequestration Leases is defined as the full extent of the 39 townships plus 12 sections. Table 2-1 shows the townships included in the SLA.

Table 2-1 Townships Included Within the SLA

Township	Ranges (W of 4th Meridian)
63	22, 21, 20
62	23, 22, 21, 20, 19
61	24, 23, 22, 21, 20, 19, 18
60	24, 23, 22, 21, 20, 19, 18
59	23, 22, 21, 20, 19, 18
58	23, 22, 21, 20, 19
57	22, 21, 20, 19
56	20, 19 and 21 (sections 25 to 36 only)

In order to meet requirements outlined in the *Carbon Sequestration Tenure Regulation 68-2011*, the SLA was separated into six (6) contiguous Carbon Sequestration Leases that together comprise the single Quest CCS Project. The leases granted by Alberta Energy are shown in Table 2-2 and Figure 2-1.

Table 2-2 SLA Separated into Carbon Sequestration Lease Blocks

Lease Block	Alberta Energy Lease Number	Township - Range (W of 4th Meridian)
1	5911050006	61-22, 61-23, 61-24, 62-22, 62-23, 63-22
2	5911050003	60-21, 61-20, 61-21, 62-20, 62-21, 63-20, 63-21
3	5911050001	59-18, 59-19, 60-18, 60-19, 60-20, 61-18, 61-19, 62-19
4	5911050002	56-19, 56-20, 57-19. 57-20, 58-19, 58-20, 59-20
5	5911050004	57-21, 57-22, 58-21, 58-22, 59-21, 56 -21 (Sections 25 to 36 only)
6	5911050005	58-23, 59-22, 59-23, 60-22, 60-23, 60-24

2.1.1. Extent of Zone of Interest

The approved zone of interest (ZOI) for the SLA, pursuant to Section 116 of the MMA, was granted to Shell on behalf of the AOSP Joint Venture by Alberta Energy on May 27, 2011. The ZOI includes the interval from the top of the Elk Point Group to the Precambrian basement (Figure 2-2). The ZOI includes two complexes of strata used for CO_2 storage and MMV, respectively:

The BCS storage complex is defined as the series of formations from below the top of the Upper Lotsberg Salt to the basement. The injected CO_2 will be permanently contained within the BCS storage complex (Figure 2-2).

The Winnipegosis (WPGS) Complex is defined as the series of Formations from the top of the Elk Point Group to the top of the Upper Lotsberg Salt. The WPGS Complex was the primary target for pressure monitoring in deep monitoring wells adjacent to injection wells. However, based on results from the 2012/2013 drilling program, the Cooking Lake Formation was chosen as the deep monitoring formation as the WPGS is impermeable in the vicinity of the injection wells.

On May 24, 2012 Shell received approval from Alberta Energy to monitor the Cooking Lake formation in all three deep monitoring wells (DMW) DMW 7-11, DMW 8-19 and DMW 5-35 (See Table 2-4).

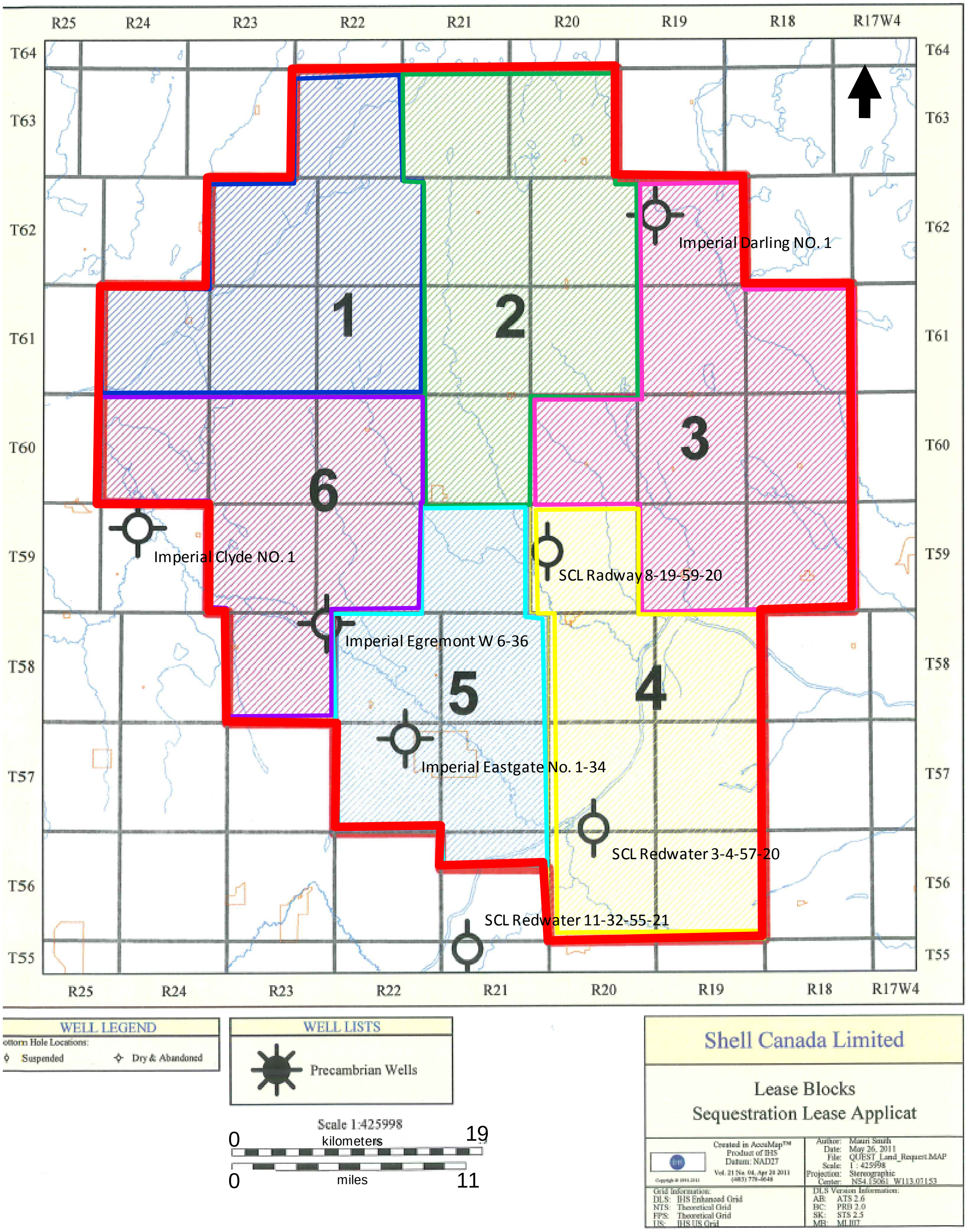

Figure 2-1 Quest CCS Project Carbon Sequestration Lease Blocks as Approved by Alberta Energy

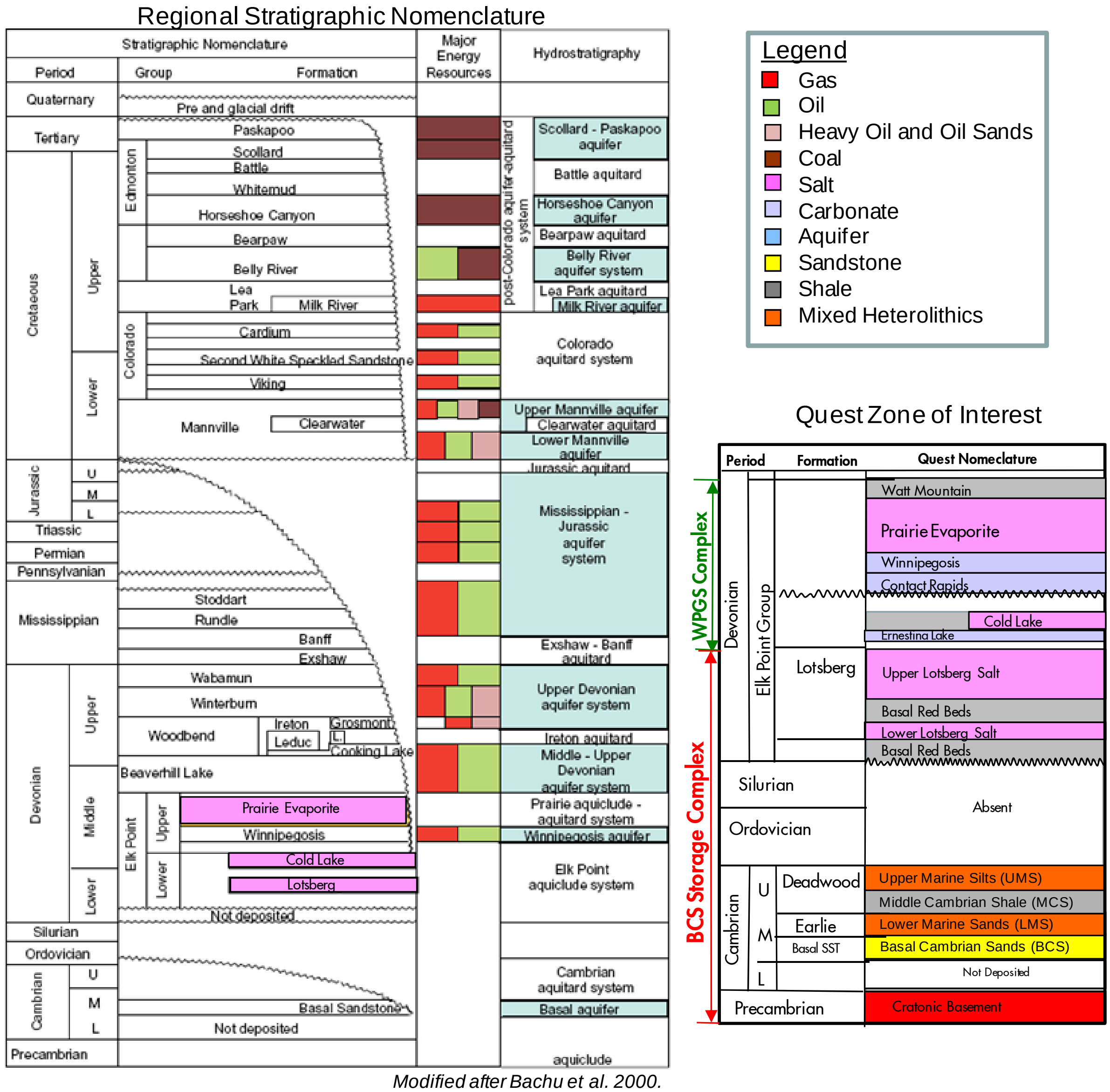

Figure 2-2 Stratigraphy and Hydrostratigraphy of the Southern and Central Alberta Basin

2.2. Project Wells Inventory

The only land disturbance associated with the Quest Project in the SLA is situated on the well pads.

There are three injection well pads associated with the Quest Project each approximately 130 m by 130 m in size. Each of these well pads has one BCS injection well, one deep monitoring well located ~40m from the injection well and between two to five groundwater wells that are less than 150 m deep and approximately 25 m from the injection well (Table 2-3).

There is a fourth well pad, the 03-04-057-20W4 well pad, 21 km south of the closest injection well (IW 7-11) that only has one deep monitoring well Redwater 3-4 that will be used to monitor the pressure in the BCS and potentially the Cooking Lake Fm. This is not an injection well.

Table 2-3 Pad and well UWIs for Quest injection and monitoring wells

Pad	UWI	Well type	Well name in this report	TD formation
Outside SLA (no longer part of Quest)	1AA/11-32-055-21W400	Appraisal (Abandoned)	Redwater 11-32	Precambrian
03-04-057-20W4	100/03-04-057-21W400	Observation	Redwater 3-4	Precambrian
08-19-059-20W4	100/081905920W4/00	Injection	IW 8-19	Precambrian
	102/081905920W4/00	Deep Monitoring	DMW 8-19	Ernestina Lake
	1F1/081905920W4/00	Groundwater	GW 1F1/8-19	Lea Park
	UL1/081905920W4/00*	Groundwater	GW UL1/8-19	Foremost
	UL2/081905920W4/00*	Groundwater	GW UL2/8-19	Foremost
	UL3/081905920W4/00*	Groundwater	GW UL3/8-19	Foremost
	UL4/081905920W4/00*	Groundwater	GW UL4/8-19	Oldman
05-35-059-21W4	102/053505921W4/00	Injection	IW 5-35	Precambrian
	100/053505921W4/00	Deep Monitoring	DMW 5-35	Ernestina Lake
	1F1/053505921W4/00	Groundwater	GW 1F1/5-35	Lea Park
	UL1/053505921W4/00*	Groundwater	GW UL1/5-35	Foremost
07-11-059-20W4	103/071105920W4/00	Injection	IW 7-11	Precambrian
	102/071105920W4/00	Deep Monitoring	DMW 7-11	Ernestina Lake
	1F1/071105920W4/00	Groundwater	GW 1F1/7-11	Lea Park
	UL1/071105920W4/00*	Groundwater	GW UL1/7-11	Foremost

3. Storage Performance Criteria for Site Closure

The Alberta Department of Energy (ADOE) RFA recommended further development of technical criteria for site closure (Recommendation 58 [3]). In the meantime, the high-level qualification goals for site closure put forward in the RFA process Appendix D2 have been used [3].

To meet these Storage performance goals, MMV activities will be designed to deliver against the following targets during the site closure period.

3.1. CO_2 Inventory Accuracy Target

Shell has approval from AER to inject up to 27 million tonnes of CO_2 (14,500 million cubic meters at standard conditions of 15ºC and 101.325KPa) into the BCS formation with the constraint that the shut-in reservoir pressure will not exceed 26 MPa and that the CO_2 is to be permanently stored within the BCS storage complex.

To establish confidence that the conditions for site closure have been met, the accuracy of the reported inventory of CO_2 stored will comply with regulations and protocol. Currently, the Alberta Protocol for the Capture of CO_2 and Permanent storage in Deep Saline Aquifers is pending final Government approval [5]. The sources/sinks associated with the subsurface and monitored as part of the MMV plan that is included in the protocol is:

- *Emissions from subsurface to atmosphere- Under normal operation, this source/sink may be neglected, however to account for leakage events, this source/sink is included. A measurement, monitoring and verification plan, as described in Section 5.0 shall be used to identify emissions from the subsurface to the atmosphere.*

Table 3-1 describe quantification methods as explained in the draft protocol that Shell expects to have to report against.

Table 3-1 Quantification Methodology from Table 7 in draft protocol [5]

P20 Emissions from Subsurface to Atmosphere	Emissions $_{\text{Subsurface to Atmosphere}}$ = Mass $CO_{2\ \text{leaked}}$					
	Mass of CO_2 leaked from the Subsurface to Atmosphere/ Mass $CO_{2\ \text{leaked}}$	kg	Estimated	If a leakage event occurs, the mass of CO_2 leaked from the subsurface to the atmosphere shall be estimated with a maximum overall uncertainty over the reporting period of ±7.5%. In case overall uncertainty of the applied quantification approach exceeds ±7.5%, an adjustment shall be applied. Refer to Appendix D for further guidance.	N/A	Estimation would be required for reporting to the regulatory authority. Direct measurement is likely not possible, but the use of engineering estimates and uncertainty would be a reasonable approach in the event leakage occurs.

3.2. Conformance Performance Target

It is also essential to assess whether injected CO_2 and BCS brine behave as expected and how site performance has evolved relative to the predictions. As such, the following conformance performance targets are used:

- Actual storage performance conforms to predicted storage performance within the range of uncertainty.
- Knowledge of actual storage performance is sufficient to distinguish between two classes of possible future performance: those that result in permanent stable storage of the target mass of CO_2 inside the BCS storage complex, and those that do not.

3.3. Containment Performance Target

It is essential to assess whether any migration of injected CO_2 or BCS brine out of the BCS storage complex has occurred and whether any identified migration has damaged the environment or human health. The following performance target is used:

- Measurements of any changes within the hydrosphere, biosphere, and atmosphere caused by CO_2 injected into the BCS storage complex are sufficient to demonstrate the absence of any significant impacts as defined by the Baseline Monitoring Data.

The approved MMV Plan (see Appendix A) will provide more details regarding performance targets for containment.

3.4. Current MMV Plan Overview

The MMV plan attached in Appendix A is the 3rd update of the MMV plan submitted to the AER since the start of the project. The first conceptual plan was submitted as part of the D65 disposal application in 2010 [7]. In fulfillment of AER condition 7, the pre-baseline MMV plan was submitted in Oct.15 2012 [8] and the pre-injection MMV plan will be submitted January 31, 2015. This MMV plan is an interim update requested by the AER Dec. 3, 2013 for submission February 14, 2014 [9].

This 2014 MMV plan was updated to a 3 injection well case based on the results of the 2012/2013 drilling campaign and associated production test results. The other main updates to the plan are the addition of all AER conditions required for the pre-baseline monitoring plan to be approved (e.g. inclusion of monitoring requirements for surface casing vent flows and gas migrations) as per AER Pre-baseline MMV approval and conditions letter received Dec. 3, 2013 [9].

The 2014 interim MMV plan has areas to be developed as the baseline study results and technology development required to establish some monitoring thresholds will only be completed in 2014. The pre-injection update will incorporate final alarm thresholds and any other changes to the MMV plan that result from the above work.

The next (pre-injection) version of the MMV Plan will also include a re-assessment of risk profiles based the 2012/13 drilling results, Gen-5 modeling results and the independent injection well integrity study (Section 4.3.1).

As new information about conformance and containment monitoring performance becomes available through time, the MMV plan will be adapted to ensure it continues to be effective. Any changes to the plan will affect the shape and content of the MMV plan but not the outcomes, which must meet the performance targets.

4. Storage Performance Evidence

Storage performance evidence includes all the information on conformance and containment that support the Storage Criteria discussed in Section 3.

4.1. Injection Performance Update

4.1.1. Mass and Volume of CO_2 Injected per Well

Injection wells IW 7-11 and 5-35 have been drilled, production tested and then suspended with a plug in the packer tail and a column of inhibited fluid (KCl). IW 8-19 is suspended as above but it underwent a water injection test as opposed to a production test.

After D-51 approval, the wells will be unsuspended and conditioned for injection by pumping them full of CO_2 prior to commencement of injection in 2015.

No CO_2 has been injected into any of the Quest injection wells as of this submission date. Injection of CO_2 into the BCS will begin in 2015. In the next closure plan update submitted in February 2017, this section will address the quantity of captured CO_2 that has been injected as per 19(3)b in the Alberta *Carbon Sequestration Tenure Regulation 68-2011*.

Wellhead injection rate metering will occur on each injection well and rate metering will occur at the compressor outlet in Scotford, with a minimum technical accuracy of 0.5%

4.1.2. Injectivity Estimate

The injectivity estimates were updated as a result of the 2012/2013 drilling and production testing programs. In summary, the project requires an initial water productivity index (PI) greater than 380 m3/d/MPa to confidently inject 1.08Mt/a of CO_2 to meet project objectives. The results of the well tests support initial PI's of each individual injection well (IW 7-11, IW 5-35, IW 8-19) greater than the full project requirement. Table 4-1 summarizes the PI assessments for all of the wells tested in the BCS.

Table 4-1 Summary of all PI assessments in the BCS Formation

Well Name	Rate m3/d	DeltaP kPa	Injectivity m3/d/MPa
IW 7-11	396	0.19	2085
IW 5-35	342	0.33	1036
IW 8-19	360	0.95	379
Redwater 11-32	492	12.13	41

With similar petrophysical log responses in IW 5-35, IW 7-11 and IW 8-19 it can be inferred that the initial PI in IW 8-19 is understated. As it was an injection test with known near well bore formation damage it is likely that the PI for IW 8-19 is a minimum initial PI. The project total initial PI can be calculated as 9 times the quoted requirement of 380 m3/d/MPa.

- Project initial PI = 379+1036+2085 = 3500 m3/d/MPa of water.
- Average Initial PI = 1167 m3/d/MPa of water

It is very probable that the project will be capable of sustaining PI's greater than the 380 m3/d/MPa for the duration of the project life; therefore no further well development should be required for injectivity requirements.

4.1.3. CO_2 Emission Measurements

Once injection begins, this Section will quantify any of the following that occur over the reporting period as per the draft Alberta Protocol [5]:

- *Emissions from subsurface to atmosphere*

4.2. Conformance Performance

Conformance means that the storage complex is behaving in a predictable manner, consistent with the subsurface model-based predictions. Conformance monitoring tasks verify storage performance. For example, that the increase of pore fluid pressures and CO_2 migration through time remain consistent with the range of forecasts and monitoring results provide the necessary information to revise and narrow the range of forecasts whenever appropriate.

4.2.1. Current Model Descriptions

The static and dynamic models were updated since submission of the original D65 application in November 2010 from Generation 3 (Gen-3) to Generation 4 (Gen-4) models [6].

The main reasons for updating the static model to Gen-4 were:

1. Implementation of the IW 8-19 well and core data into the models (routine analyses and facies descriptions). The results confirmed that environment of deposition (EoD) consists of Tide-dominated Bay Margin, Proximal Bay and Distal Bay. In addition, fluvial influenced tide dominated margin was identified at the base of the BCS in IW 8-19 which increased the contribution of associated High Energy Dunes from 5% to now 10% distributed consistently at the base of the BCS interval.
2. The first injection well IW 8-19, had better reservoir properties than predicted in the previous Gen-3 models, although still within the range of uncertainty predicted. Incorporation of this new information into the Gen-4 model was required to confirm Shell's understanding of potential risks associated with capacity, conformance and containment.
3. Completion of the full 3D seismic survey and associated reprocessing once IW 8-19 was tied to seismic. One update was the incorporation of a possible thinning or absence of the BCS reservoir towards the Northeast corner of the model area. The variations in the thickness of the BCS in this area were accounted for in the range of

models that were completed as part of Gen-4 and results indicate that this has no tangible impact on the current conclusions.

The dynamic models were re-run to incorporate the updates associated with the Gen-4 static model. The only update to the Gen -4 dynamic model was an update of the relative permeability Corey model. The key difference, if compared to the Gen-3 version, is the use of imbibitions relative permeability experimental data to define the Corey exponents of the CO_2 brine primary drainage relative permeability curves, rather than using drainage relative permeability data. In contrast to the Gen-3 models, high and low case capillary pressure curves were introduced in addition to a slightly updated base case.

4.2.1. Pressure Prediction

Prior to start up there will not be any measured data on formation pressure or CO_2 plume extents. However, modeling of CO_2 plume extent and formation pressure has been enhanced since the initial D65 application. The Gen-4 expectation case concluded that three wells are more than adequate to sustain an injection plateau of 1.08 Mtpa for 25 years without ever reaching bottom hole pressure constraints. However, the Gen-4 work illustrated a pressure build that is higher than actually expected. As a conservative approach, the Gen-4 model of the BSC aquifer was limited to 100 x 100 km with no flow boundaries at all 4 sides. In reality, the aquifer extends beyond these boundaries and is most likely infinite acting on one or more boundaries. Figure 4-1 shows the flowing bottom hole pressure (FBHP) build up for an average well using the expectation case with an analytical aquifer, infinite acting on the SW boundary, attached for pressure relief.

With an initial reservoir pressure of 20.5 MPa, at IW 8-19, it can be concluded that a delta pressure (DeltaP) of approximately 1 MPa is required for the planned injection rate; as illustrated in Figure 4-1 which shows an initial flowing bottom hole pressure at IW 8-19 of approximately 21.5 MPa. As effective reservoir pressure slowly builds over 25 years the associated flowing bottom-hole pressure (FBHP) at IW 8-19 climbs to approximately 22 MPa to maintain the 1 MPa DeltaP.

The DeltaP will vary from well to well based on the local reservoir quality by approximately +/- 0.5 MPa. Furthermore, if one of the wells is shut-in the remaining wells will require higher pressures (i.e. +/- 0.5 MPa) to accommodate this increased well rate. However, based on the recent injectivity assessments discussed in Section 4.1.2 the DeltaP values are expected to be reduced in the Gen-5 model (See Section 4.2.4.2).

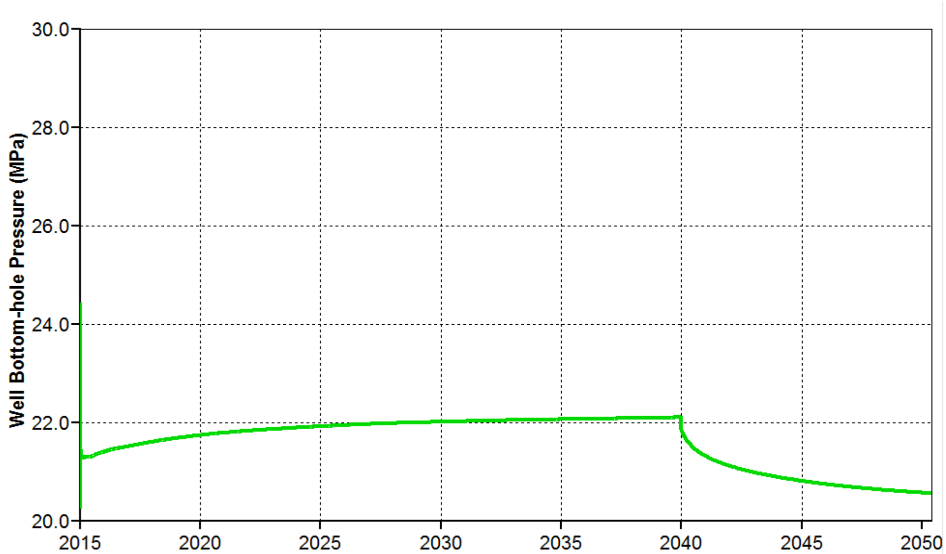

Figure 4-1 25 Year IW 8-19 FBHP Forecast for the mid property, mid connectivity case with analytic aquifer

Clause 5a of AER Approval No. 11837a states [4]:

5) The Approval Holder must conduct the CO_2 injection only through the well(s) referred to in claus 3)(1) a) in accordance with the following requirements and those of Table 1:

> *a) the BCS Formation stabilized shut-in reservoir pressure in each injection well listed in clause 3)(1) a) must not exceed 26 000 kilopascals (gauge).*

The expectation is that the Quest Project will not raise the stabilized reservoir pressure at any injection well to the 26 MPa limit within the life of the project. As it is not expected that the flowing bottomhole pressure will exceed 26Mpa, the associated stabilized pressure will be less. Therefore the full 27 Mt of CO_2 is expected to be sequestered without ever approaching the maximum shut-in formation pressure specified in clause 5) a) of AER Approval No. 11837A [4].

The Gen-4 dynamic model results indicate that the pressure build up in the BCS over the initial pressure at IW 8-19 (20.5 MPa) is expected to be elevated by 1 to 2 MPa DeltaP after 25 years. A map of the area of elevated pressure after 25 years of injection for the Gen-4 expectation case with an analytic aquifer, infinite acting on SW boundary, is included in Figure 4-2. Recent well results from IW 5-35 and IW 7-11 indicate an even lower DeltaP may occur. However, an updated pressure forecast will be included in the January 2015 AER annual report submission following the fifth generation of modeling which will incorporate results from these wells (Section 4.2.4.2).

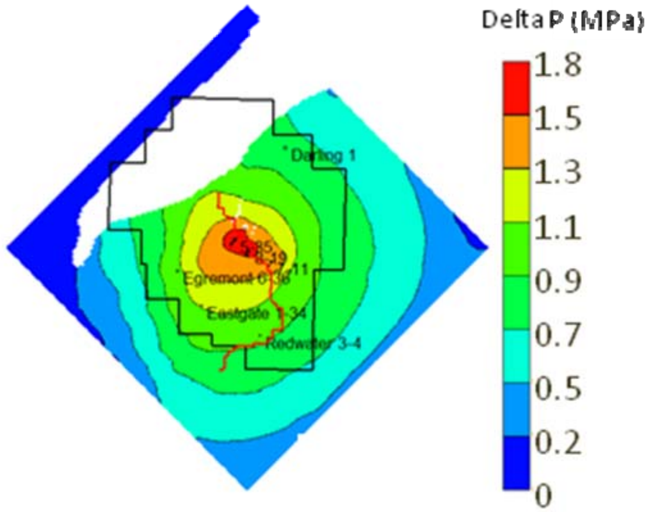

Figure 4-2 Gen-4 Pressure Distribution after 25 Years of Injection in the Mid Property / Mid Connectivity Case with an analytical aquifer extension

4.2.2. CO_2 Plume Prediction

The primary CO_2 plume metric for the Gen-4 modeling exercise was the maximum plume extent away from an injection well, typically referred to as plume length. The maximum plume length is defined as where the plume edge is at 10% CO_2 saturation. Figure 4-3 illustrates how the maximum length corresponds to a non-unique plume shape.

The overall strategy to assess the uncertainty in maximum plume length was to run a Monte Carlo probabilistic approach, simulating multiple subsurface realizations to assess plume size distribution and supported by a sensitivity study to understand the relative impact of all the various individual subsurface uncertainties. All subsurface uncertainties were assigned three outcomes, high, mid and low. The combination of different outcomes for different uncertainties permits definition of unique subsurface realizations.

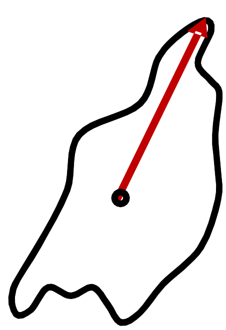

Figure 4-3 Maximum Plume Length (plume shape for one realisation).

Detailed Gen-4 CO_2 plume migration modeling of a 3 injection well scheme concluded a P50 CO_2 plume length of 4100m at the end of injection in 2040 (Figure 4-4). The range of uncertainty is large and is heavily driven by the range of uncertainty in the relative permeability. A revision of this estimate will be reported in the January 2015 annual report as Shell is currently developing the Gen-5 models. This latest model will incorporate new well control data, but the uncertainty on relative permeability will remain until post start-up.

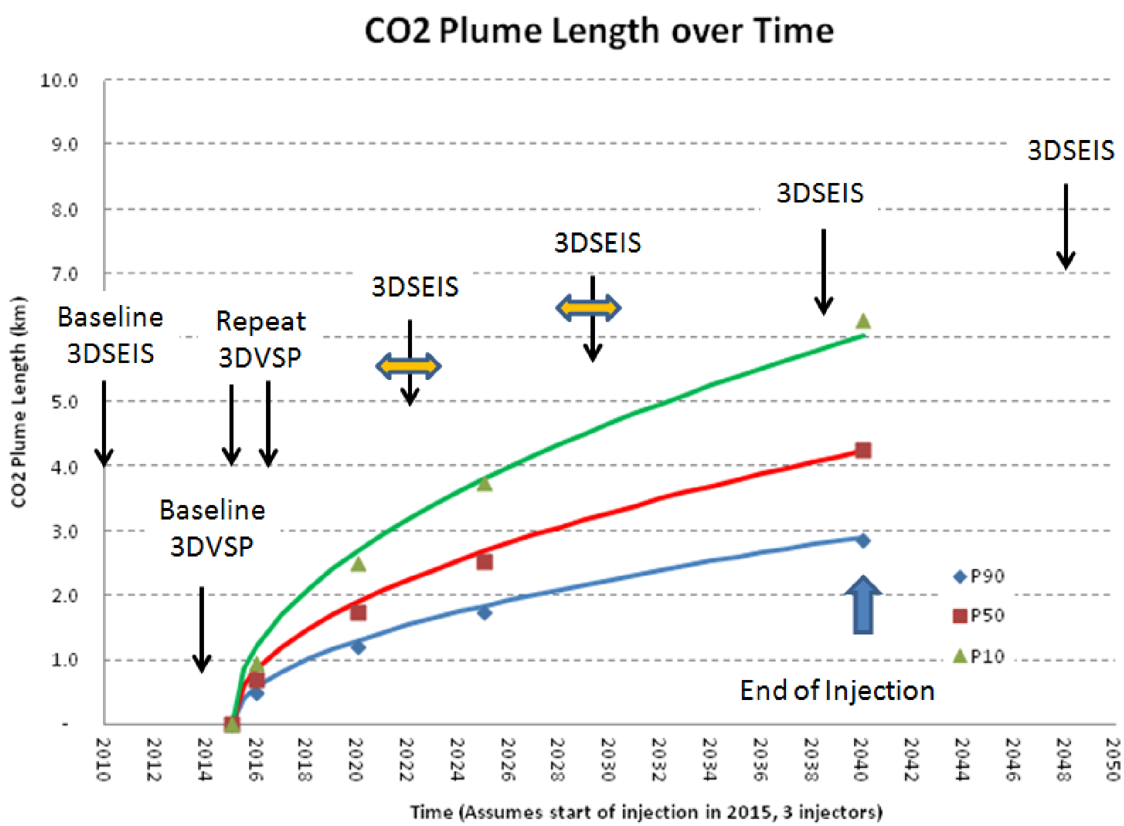

Figure 4-4 CO_2 plume length and seismic survey timings from Gen-4 modeling.

4.2.3. Conformance Monitoring Results

The conformance monitoring program comprises:

- base-case activities that follow a planned schedule
- contingent activities that only occur if conformance monitoring does not perform to expectations or changes to the monitoring system need to be made due to non-conformance

There will be no injection until 2015 and therefore no MMV results to compare to pre-injection model predictions for assessment of conformance. Therefore, Shell has provided the status updates and results of the development work completed on the technologies that are expected to be used for conformance monitoring at the start of injection.

For its base-case conformance monitoring activities, Shell is using time-lapse seismic, Interferometric Synthetic Aperture Radar (InSAR) and BCS pressure monitoring at the Redwater 3-4 well and injection wells.

4.2.3.1. Time Lapse Seismic Results

Time-lapse seismic and vertical seismic profiles (VSP) are expected to track the CO_2 plume. The timing of the 3D seismic monitoring programs will be decided according to the rate of expected CO_2 movements therefore, 3D seismic surveys might be appropriate every 5 to 10 years after VSPs are no longer effective. The variability in 3D seismic timing reflected the range of uncertainty in the existing models of plume movement.

Early VSP data will help calibrate plume movement and determine the timing of the first repeat 3D survey (Figure 4-4 above). It is reasonable to carry out a 3D survey close to the end of injection and at the end of the closure period. Depending on the timing of the first 3D survey and the almost linear development of the plume dimensions potentially only one additional survey would be sufficient to calibrate plume movement (see Figure 4-4) unless the plume behaviour is very different from the predicted by the current range of models. Timing of surveys can be adjusted appropriately depending on results of the first repeat 3D surface seismic and will be reflected in plan updates.

Shell attained a baseline surface seismic survey in 2010 and plans to carry out a VSP baseline survey in fall 2014.

4.2.3.2. InSAR Results

InSAR is expected to provide essentially continuous monitoring of the footprint of pressure changes inside the BCS. Shell completed an InSAR feasibility study in association with Special Report #2 submitted January 31, 2013 to AER [10]. This activity included an external feasibility study performed by TRE. The results of this study indicate that there is a sufficiently large population of reliable natural reflectors to characterize the displacement field without the installation of corner reflectors near the injection wells. In addition, the precision of the ground deformation measurements is currently close to ±2 millimetres per year and based on the characteristics of the SAR imagery acquired to date TRE estimates that millimetric precision will be attained after 32 months of image acquisitions – which will be acquired prior to start of injection [10].

4.2.3.3. BCS Pressure Monitoring Results

Shell will use IW 7-11 and IW 5-35 as BCS Formation monitoring wells prior to commencement of injection, when feasible. At start-up, the first injector (IW 8-19) will be progressively ramped up until stable injectivity is achieved. An interference test will follow with pressure in the BCS being monitored at IW 7-11 and IW 5-35. Afterwards, the other IWs will be started sequentially to ensure they all reach stable injectivity before the end of 2015 so that the contractual obligation for sustained operations can be achieved.

Furthermore, Shell plans to monitor the BCS pressures across the SLA, in the BCS, continuously at the three injection wells (IW 8-19, IW 7-11, and IW 5-35 and one observation well (Redwater 3-4). This long-term continuous pressure monitoring will be the basis for history matching dynamic reservoir models

4.2.4. Reconciliation

Consistency between predicted and observed storage performance is required. This means demonstrating that no significant discrepancy exists between model-based predictions, the observed behaviour of the CO_2 plume and the region of elevated fluid pressure inside the BCS storage complex. The definition of significance in the above remains to be discussed between the regulator and the Project proponents. One possible measure of a significant discrepancy indicating a loss of conformance could be that the discrepancy must exceed a certain threshold representing the combined uncertainties associated within an agreed detectable range of modelling and monitoring results. Otherwise, unsuitably large modeling or monitoring uncertainty may lead to undetected fluid migration within the storage complex.

It is expected that over time and with additional data availability the understanding of the reservoir will improve narrowing the range of predicted results as to reliably predict future behaviour so that by the time of closure all parties will be satisfied with the level of understanding of the reservoir.

4.2.4.1. Planned Static Model Updates

This section will be updated at regular intervals as agreed upon with the appropriate regulatory agencies and will be based on the need for updated and recalibrated models as results and data become available.

At the time the Gen-4 models were built, it was still uncertain on whether the IW 8-19 results were representative of the mid or high end of the range of uncertainty for reservoir properties. As a result, the Gen-4 models maintained a conservative approach in the scenarios presented for the static model. However, the results of the recent 2012/2013 drilling campaign suggest that all three injection well results are representative of the mid or high end of the Gen-4 range of uncertainty for reservoir properties. Therefore, the low case presented in Gen-4 is no longer plausible at the location of the injection wells and is a low probability of occurring away from these wells due to the consistent regional geology. Therefore a fifth Generation of static model (Gen-5) is required.

Furthermore, in 2013, Shell completed the BCS core descriptions and associated paleo-depositional environment updates for IW's 7-11 and 5-35 drilled in 2012/2013. The results are in line with pre-drill expectation and are also being incorporated into the fifth generation (Gen-5) static model update that is currently under construction.

4.2.4.2. Planned Dynamic Model Updates

In association with the static model update, the Gen-5 dynamic model will also be updated in 2014. A fifth generation (Gen-5) of dynamic modeling is currently under construction to incorporate the Gen 5 static model updates and the results of the injection tests in IW 5-35 and IW 7-11. The results of pressure and plume predications based on the Gen-5 dynamic models will be submitted January 2015 in the Third Annual Status Report to AER.

Once injection starts, the dynamic models will be re-run annually. The need for full dynamic model updates will be based on the need for recalibrated models as injection performance and MMV data become available.

4.3. Containment Performance

The Project is designed for permanent secure containment of CO_2 and BCS brine within the BCS storage complex. Section 4.3.3 of the MMV Plan discusses the potential threats to containment and Section 7.2 Performance targets for containment

4.3.1. Containment Risks

There are nine potential threats to containment identified and explained detail in Section 4.3.3 of the MMV Plan. Each are considered unlikely but are, in principle, capable of allowing CO_2 or BCS brine to migrate upwards out of the BCS storage complex. The potential risk events that could lead to loss of containment and their current risk assessment are summarized here as follows:

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

   The probability of legacy wells being intersected by the CO_2 plume or brine pressures high enough to lift brine into the groundwater is very low.

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

   The risk of leakage from the Storage Complex along a leakage pathway in the injection wells is considered very low. However, in 2014 Shell is contracting an independent external review of the integrity of the injection wells and an associated update of the leakage risk assessment for the QUEST injection wells to ensure that Shell's risk assessment is still appropriate post drilling:

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

   This is risk is currently considered very low due to the termination depths of Quest DMWs above the storage complex, large distance between propsed BCS monitoring well Redwater 3-4 and injection wells (21 km) and the use of injection wells for pressure monitoring.

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

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

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

The risk of migration along a fault is considered low as there is no evidence of faults on 2D or 3D seismic that cross-cut any of the regional seals covering the full SLA.

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

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

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

The risk of inducing fractures in the Quest project is low according to the Gen-4 modeling results, the expected injection pressure will be less than 22.5 MPa at the end of project life which is only 12% of the Delta Pressure required to exceed the BCS fracture extension pressure.

.

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

Based on the regional geology, the choice of using three regional seals for the storage container and results of geochemical modeling and core analysis the risk of acidic fluids eroding geological seals is very low.

9) **Third Party Activities:** third party activities could generate a risk of leakage from the BCS storage complex.

This risk is considered to be very low because Shell holds the Sequestration rights from top Elk Point Group to the Precambrian basement and there are no other 3rd party CCS projected proposed in the area.

As previously mentioned, this risk assessment is based on pre-baseline and pre-2012/2013 drilling campaign. The next (pre-injection) version of the MMV Plan will include a re-assessment of risk profiles based the 2012/13 drilling results, Gen-5 modeling results and the independent injection well integrity study.

4.3.2. Containment Monitoring Results

Once the pre-injection MMV Plan is completed as discussed in Section 3.4, and injection has commenced, the results of the data gathered through the MMV Plan will be compared with thresholds set prior to start of injection to assess containment performance. Until that time, Shell has included information on some of the ongoing baseline activities and technology development work that will be used to define the final pre-injection MMV plan and determine associated monitoring frequencies and thresholds required to meet containment performance objectives.

4.3.2.1. Baseline Monitoring Results to Date

4.3.2.1.1. Atmospheric Monitoring

LightSource: A field trial was successfully completed between September 8th and 13th, 2013. In addition, Boreal laser delivered a new enhanced performance single line-of-sight CO_2 sensor which was successfully tested in this field trial. Compilation of the field trial data is ongoing along with final hardware (laser) and software development work. The information from the field trial is being used as input to calibrate the monitoring system and to help set detection thresholds that will be used for LightSource atmospheric CO_2 monitoring. These detection thresholds will be confirmed in the pre-injection MMV Plan Update January 2015.

4.3.2.1.2. Biosphere Monitoring Activities

Soil and Vegetation Sampling for Remote Sensing Calibration: 14 soil and vegetation plots were sampled over 3 different field events in the spring, summer and fall timeframes with an additional soil survey carried out later in the fall. A summary of the campaign completed to date, is provided in Appendix E of the 2nd Annual status report submitted to AER [12]. A similar baseline campaign with be undertaken in 2014 and final baseline results compiled.

Soil Gas and Soil Surface CO_2 Flux Sampling: A significant soil gas and soil surface CO_2 flux sampling program has been carried out by Golder Associates since Q3-2012 in order to support the baseline monitoring program. The first soil gas and soil surface CO_2 flux sampling campaign took place in Q3-2012 and was followed by 4 sampling campaigns in 2013, distributed throughout the year.

A summary of the soil gas and soil surface CO_2 flux sampling campaign completed to date is provided in Section 3.6 of Appendix E of the 2nd Annual status report submitted to AER [12]. Another baseline soil gas and soil surface CO_2 flux sampling campaign will be undertaken in 2014, which will complete the soil gas and soil surface flux CO_2 data gathering program.

4.3.2.1.3. Hydrosphere Monitoring Activities

Artificial and Natural Tracers: PFC tracer feasibility studies are ongoing – preliminary results are available in Appendix D of the 2nd Annual status report submitted to AER [12]and final results will be submitted to AER by June 2014 as Special Report #3. The aim of this study is to identify potential scavenging and losses of the PFC tracer due to the interaction of the parent fluid (i.e. CO_2, with different rock matrices and other subsurface fluids). The experimental study for this research was conducted in collaboration with The Commonwealth Scientific and Industrial Research Organization (CSIRO). The preliminary conclusion is that PFCs may remain in sufficient detectable amounts in its parent CO_2 phase at shallow depth in the hydrostratigraphic column. The data confirm that PFCs have very low solubility in water and are not retained at significant/critical amounts during migration by matrices prone to adsorb organic compounds such as clays. Hence, experimental data obtained so far suggest that PFCs are a suitable reliable passive/conservative tracer of injected CO_2. Experimental measurements are continuing to explore the behavior of organic substrate adsorption and CO_2/water/hydrocarbons partitioning.

In addition to the artificial PFC tracer study, the use of the natural abundance C isotopic composition of CO_2 is being investigated as a potential natural tracer. As part of the baseline monitoring activities, the isotopic composition of CO_2 in soil gas and well gas are being determined. Samples from the Scotford Upgrader are also being collected for analysis. Furthermore, the University of Calgary was contracted to undertake laboratory and modelling studies to assess whether or not the isotopic composition of the injection gas may change along the stratigraphic column in case of a hypothetical leakage event. Draft reports for the laboratory and modelling studies have been received, and are currently under review.

Water Well Sampling: A significant groundwater sampling program has been carried out since Q4-2012 in order to support the baseline monitoring program. The first groundwater sampling campaign took place in Q4-2012 and was followed by 4 sampling campaigns in 2013, distributed throughout the year. To date, a total of 246 groundwater samples have been collected from 121 wells and submitted for Tier 1 + 2 analysis (routine parameters and dissolved metals) and a total of 132 groundwater samples have been collected and submitted for Tier 3 (isotopic analysis).

In addition to water and gas sampling, water quality data loggers were installed in each of the nine Project groundwater wells, completed in 2013, to provide a continuous record of groundwater levels and select hydrochemical parameters. In-Situ® Multi-Parameter TROLL 9500 probes are used to collect water level and basic water chemistry (pH, temperature, conductivity and oxidation-reduction potential) from the Project wells on a daily basis. The data loggers were installed at two wells (8-19/03 and 8-19/04) in early 2011; the remaining loggers were installed in early 2013. Download and maintenance (i.e., calibration, inspection and battery replacement) were performed by Golder Associates each quarter.

A summary of the water well sampling campaign completed to date is provided in Section 4.0 of Appendix E of the 2nd Annual status report submitted to AER [12]. Another baseline water well sampling campaign will be undertaken in 2014.

In April 2013, Alberta Innovates – Technology Futures (AITF) started a study entitled 'GROUND WATER STUDY FOR QUEST CCS PROJECT' to support the baseline monitoring campaign. During 2013, the main focus has been on revising and updating the conceptual geological model from surface to the Lea Park Formation for the QUEST Sequestration Lease area. A key focus of this study is to assess the characteristics of potable groundwater aquifers across the Quest project area and to evaluate potential trigger conditions which may suggest a deviation from established baseline conditions. Final observations from the AITF study are expected by the end of 2014.

4.3.2.1.4. Geosphere Monitoring Activities

3D VSP: Shell is in the process of designing the 3D VSPs scheduled for 2014 by modeling the response for different shot spacing and locations. The information gained from that modeling will be aimed at optimizing processing and reservoir imaging.

The baseline survey is planned to be acquired October/November 2014 after the farmers have harvested their crops. This will help to reduce stakeholder impact and complete a baseline survey prior to the 2015 injection. It is not advantageous to do this survey earlier in 2014 due to unnecessary noise attributed to heavy construction on the sites.

InSAR: Shell acquired 15 RadarSat2 satellite images for InSAR baseline data in 2013 and will continue through 2014. The full set of over 30 images acquired as of Q3 2014 will be re-processed, in a similar process as used in 2012, prior to the start of injection to complete the baseline phase. In addition, Shell received Approval from the AER on October 4, 2013 that corner reflectors are not required for InSAR monitoring subject to the following:

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

4.3.2.1.5. In-Well Monitoring Activities

Microseismic: Shell received AER approval on November 29th 2013 for the Special Report #1 and MMV plan. This approval recognizes that no requirements are needed at this time for revisions or changes to the planned downhole microseismic monitoring (DHMS) and contingency monitoring in the deep observation wells (See Appendix A Section 7.2.3 for current plan for 1 DHMS array in DMW 8-19).

Shell has been working to finalize a vendor contract to construct and deploy the microseismic array which will be complete by Q1 2014. Guidelines for an appropriate vendor include their ability to supply instruments that can handle high salinity environments and an array that can be installed using magnets. Contracting and Procurement activities are on-going for this contract with a plan for installation to occur in June/July 2014. This planned timing for installation will allow Shell to record baseline seismicity prior to 2015 injection.

DAS/DTS: The optical fibers cemented in the injection wells on each well pad will be used for these technologies. These fibers were successfully deployed and initial testing shows that they are functional. Shell will test the fibers again prior to implementing hardware associated with DAS or DTS data collection. Studies completed to date support DTS/DAS for the use in the following:

- DTS as a temperature log that can be used to for hydraulic isolation testing across the BCS storage complex when the well has been shut-in for a short period of time.

- The DAS system in Quest has been demonstrated to be similar quality to a conventional walkaway VSP and Shell plans to use DAS for the baseline 3D VSP's that will be acquired in Q4 2014.

The remaining feasibility work is focused on the ability to use DTS/DAS to detect potential leaks real time while injection is occurring.

DMW Pressure Monitoring: The original plan was to monitor pressure in the Winnipegosis/Contact Rapids. However, post 2012/2013 drilling and data collection, it was evident that the WPGS/Contact Rapids are tight in the vicinity of the injection wells. Therefore, the MMV plan was updated to monitor pressure in the Cooking Lake Formation.

Discrete pressure measurements were acquired in the Cooking Lake in all Deep monitoring wells through MDT/XPT sampling during the 2013/2013 drilling campaign. In 2013, the Cooking Lake was perforated in DMW 5-35 and DMW 7-11 and gauges installed. Continuous baseline pressure data acquisition will start in Q1 2014 to assist in determining the detection thresholds to be submitted as part of the pre-injection MMV plan update in January 31, 2015.

4.3.2.2. Third Party Wells Penetrating Sequestration Lease

The Section specifically refers to the RFA recommendation 59 which specifically requests that the:

Interim and final closure plans include assessment of all the wells that have penetrated the sequestration complex within the area of review to ensure that the evolution of the CO2 plume or pressure front over the life of the project has not introduced potential leakage pathways that were not anticipated. [3]

This is in relation to risk assessment number 9 above concerning third party activities within the vicinity of the Quest Project. Shells current assessment is discussed in the sections below.

4.3.2.2.1. Third party wells inventory

As of February 2, 2014 no additional third party wells (Legacy wells) have been drilled into the BCS storage complex since the time of the original D65 application. Currently there are 4 wells within the SLA that penetrate through all the major seals in the BCS Storage Complex (Middle Cambrian Shale, Lower and Upper Lotsberg Salts). All BCS legacy wells are greater than 18 km away from any injection well and are listed below with further completions details listed in Appendix E of the MMV Plan (Appendix A).

- Imperial Eastgate 100-01-34-057-22W400
- Imperial Egremont 100-06-36-058-23W400
- Imperial Darling #1100-16-19-062-19W400
- Westcoast et al Newbrook 100-09-31-062-19W40 (only drilled to top LMS not throught he BCS)

In addition, as per the time of original D65 submission, there are 2 wells in the SLA that penetrate the Upper Lotsberg Salt but do not penetrate the other two seals.

- Amoco Thorhild 100-16-09-06-022W400
- Mosaic Thorhild 100-16-22-059-22W400

There is one new well drilled since time of D65 submission (Nov. 2010) that penetrates the Quest ZOI (top Elk point group to basement) but does not penetrate the BCS storage complex. Well 100-02-17-058-20W400 was drilled by South Bay Resources to a depth of 1628 m (Contact Rapids). This well was licensed in Nov 10, 2010 and rig released December 3, 2010. This well adds no additional containment risk to the Project.

4.3.2.2.2. Update of Containment Risk via Legacy Wells

The calculated pressure required to life BCS brine to the Base Groundwater Protection (BGWP) from the Gen-4 study work are shown in Table 4-2. Conservative estimates of 3.3 to 4.2 MPa of DeltaP is required to lift brine from the BCS into the BGWP.

Table 4-2 Calculated DeltaP required to life BCS brine to BGP at the BCS legacy well locations

Well Name	Surface elevation (mBSL)	BGP depth (mBSL)	Hydrostatic pressure at BGP (kPaa)	Extrapolated BCS pressure at BGP (kPaa)	Delta P (kPa)
Imperial Eastgate No. 1-34	-641.3	-401	2,456	996	3,452
Imperial Egremont W 6-36	-627.9	-408	2,259	1,175	3,334
Imperial Darling No. 1	-704.4	-469	2,406	1,795	4,201
Westcoast 9-31	-699	-471	2,338	1,808	4,146
NOTE: mBSL – metres below sea level					

Current Gen-4 dynamic models indicate that the pressure increase expected in the BCS at the locations of the legacy wells will be considerably less than that required to lift BCS brine into the BGWP. The DeltaP with time, at the legacy well locations, is shown in Figure 4-5 for the mid case with an analytical aquifer. The maximum DeltaP over the life of the project is just above 1 MPa at the legacy wells (Figure 4-5).

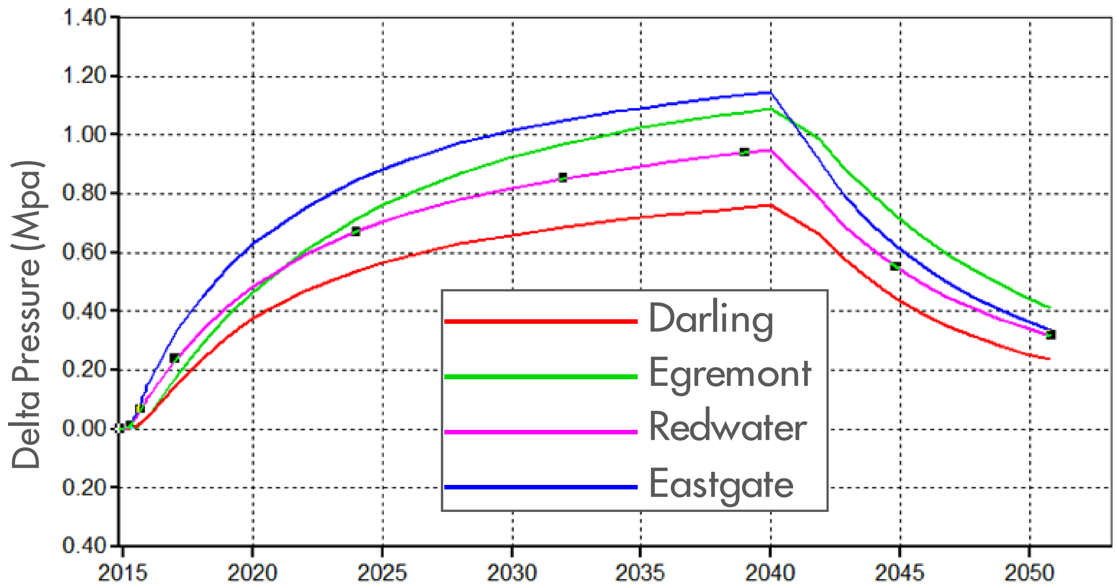

Figure 4-5 Pressure build at the BCS legacy well locations for the mid case with analytical aquifer.

Even in the GEN-4 low reservoir property and low connectivity scenario with analytical aquifer extension, the DeltaP does not exceed the DeltaP threshold at the BCS legacy wells [6]. Given the results of IW 5-35 and IW 7-11, this scenario is no longer considered a possibility. If there are property changes away from well control, which could lead to higher BCS pressures, they will be detected by the pressure monitoring program and input to appropriate model updates.

4.3.2.3. Update on any Surface or Subsurface Interactions

There have been no interaction between brine in the BCS storage complex and the surface. There has been no CO_2 injection to date. However, this section will be updated appropriately to describe any current or potential surface or subsurface interactions according to RFA recommendation 29e [3].

Although there is no interaction between the BCS storage complex and the surface, Shell would like to inform Alberta Energy that surface casing vent flows (SCVF) were identified in all Shell injection and deep monitoring wells as well as gas migrations (GM) in IW 5-35 and IW 7-11. All activities and information has been disclosed by Shell to the AER in 2013 and discussed with AER in additional documents [13, 14]. Due to the SCVFs and GMs the following AER conditions [9, 13] have been integrated as changes in the February 14, 2014 MMV plan update (Appendix A):

- Annual SCVF testing as per AER ID 2003-01 for non-serious SCVF, until time of well abandonment or until SCVF dies out.
- Annual Gas Migration testing as per procedure given in AER Directive 020, Appendix 2, until time of well abandonment or until the GM disappears.

- Annual monitoring using existing project groundwater monitoring wells on each injection pad, including head gas composition, and until time of well abandonment, as per the project HBMP. Monitoring technologies must include the ability to detect contamination due to SCVF's and GM's.
- Annual reporting to the AER of the results of the monitoring activities as long as both issues exist on the wells must be submitted to the AER.
- Should any environmental, public safety, water contamination issue or landowner concern arise at any time due to these SCVF or GM issues, the AER will be notified and the SCVF or GM remediation will be immediately initiated.

4.3.3. Discussion of Mitigation Measures

Shell has identified several potential risks resulting in the loss of containment and has developed a comprehensive framework to manage these risks using the "bowtie" method. As outlined in its MMV Plan (see Appendix A), the bowtie method is a systematic risk assessment of events with the potential to affect storage performance, which has been used by Shell to identify how a risk might arise and the effectiveness of each control response option for preventing events arising or mitigating any consequences.

In the future, this section will document if any of the preventative measures that Shell has identified for avoiding, limiting, or recovering from any loss of containment have been put into operation. The potential mitigation measures are:

- injection controls to change the manner of CO_2 injection into the storage complex: These include re-distributing injection rates across existing wells, drilling additional injectors, drilling producers and re-injectors to manage reservoir pressures, and stopping injection.
- well interventions to restore well integrity: These include repairing the cement bond, replacing the completion, or abandoning a well that cannot be repaired.
- exposure controls to prevent contaminants reaching sensitive environmental domains where significant impacts might occur such as the protected groundwater zone. Examples of such controls include interim provision of potable water supplies and hydraulic barriers to contain any groundwater contamination.
- Remediation measures to recover from any significant impacts in the unlikely event of an uncorrected loss of containment, e.g., pump and treat, air sparging or vapour extraction, multiphase extraction, chemical oxidation, and bioremediation (see Appendix A, Section 6.3).

5. Operating Plan Update

This section provides a summary of the activities conducted by Shell on the location of the SLA since it was issued.

Although the Capture unit and pipeline are not included in the Sequestration Lease, an update has been provide in this submission due to the relevance to start of injection.

5.1. Project Construction and Operations Update

Overall progress for Capture and Pipeline as of December 31, 2013 include:

- Engineering: 99% complete
- Procurement: 96% complete
- Module fabrication: 55% complete
- Capture site Construction: 30% complete
- Pipeline construction : 34% complete
- Approximately 1.03 million Construction field man hours to date (including the module yard), with 2 medical aid incidents and 19 First Aids
- 957 engineering work packages issued for construction in capture areas and all drawing issued for construction for the pipeline. Majority (or 84%) of major equipment has been received at site or at the module yard.
- D 56 regulatory approve received for the pipeline laterals. .
- Horizontal drill under the North Saskatchewan River is complete. Pipeline construction has cleared, graded and strung pipe for the full right of way including laterals. Welding has completed 21 kilometers, installed and backfilled 4.5 kilometers.
- 42 of 336 crossing are complete on the pipeline
- Early works site construction completed the underground cooling water, CO_2 pipeline, firewater and potentially oily water server line installations as well as the underground electrical cable installation. All piling and concrete foundations are installed.
- Flue gas Recycle in HMU #2 steam methane reformer was installed and tested
- During the 2013 turnaround in HMU #2 low NOx burners were installed, the fill replaced in the pressure swing absorbers and all tie ins for the project were completed.
- 9 piperack modules have been received set at site, with addition three modules ready to ship and 33 others in various stages of erection.

Current schedule forecasts show that mechanical completion will occur in Q1 of 2015. Commissioning and start up activities will follow in Q2 2015 as well as the final shutdown of the HMU #1 area and Base Upgrader allowing the final tie ins to those areas. The capture unit and HMU3 absorber will start up late in Q2 2015. Filling of the pipeline and first injection will come from HMU3 in early Q3 2015. HMU1 and 2 absorbers will be commissioned next and full production is expected Q4 of 2015.

5.2. Development Plan Updates

5.2.1. Project Design Updates

Since the submission of the original Storage Development Plan (SDP) [15], previously referred to as the Field Development Plan (FDP), very few changes have occurred in the Project design. A brief explanation of each of the updates is as follows:

1. **Injection Well Count:** At the time of the SDP, the recommended base case plan was for a 5 well injection scheme with the opportunity to decrease to 3 wells based on the results of IW 8-19. As a result of the 2012/2013 drilling campaign which included drilling two additional injection wells IW 5-35 and IW 7-11, the decision was taken that only 3 injection wells are required.
2. **Injection Well Completions Design:** Although it was originally proposed to complete the injection wells with a temporary 3 ½” J55 tubing for testing purposes and subsequently suspend the wells and complete them at a later date (2014) with up to 4 ½” inch tubing, the preliminary log analysis indicated that the reservoir quality had sufficiently high permeability that the 3 ½” J55 tubing could be left as the final completion. The packer assembly (packer + packer tail + on-off tool) are IPC 3000 coated, which is suitable for (wet) CO_2 service. After D-51 approval, the wells will be unsuspended and conditioned for injection by pumping them full of CO_2 prior to commencement of injection in 2015.
3. **Bottomhole Pressure Limit:** Shell originally proposed a bottomhole pressure limit of 32 MPa. The AER approved a maximum bottom hole injection pressure of 30 MPa.
4. **Pipeline Length:** As a result of the decrease in injection well count, the main pipeline length has been decreased from 85 km to 60 km.
5. **Deep Monitoring Well Design:** At the time of the SDP submission, it had not been decided whether the deep monitoring wells would be slim well bores (Type A) or large well bores (Type B). Shell can confirm that all Deep monitoring wells are large well bores capable of running pressure gauges and microseismic arrays if required.
6. **Downhole Pressure and Temperature (DHPT) Monitoring Interval:** The initial Project design had chosen to monitor the Winnipegosis/Contact Rapids formations as the primary DHPT monitoring interval in the Deep monitoring wells, as it is the first regional aquifer above the BCS storage complex. However, as a result of the data acquisition program in the 2012/2013 drilling campaign it was determined that this interval is impermeable in the vicinity of the injection wells. Therefore, Shell has chosen its secondary target, the Cooking Lake Formation for pressure monitoring. The Cooking Lake has proven regional connectivity and sufficient porosity and permeability near the injection wells for monitoring purposes.
7. **Groundwater Well Locations:** Project groundwater wells are only located on the Quest Injection well pads (5 on IW 8-19, 2 on IW 7-11 and 2 on IW 5-35 well pad). 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 6.2.3 of the Appendix A). 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. The latter will be evaluated on an annual basis in the annual operations report to the AER.

8. **Commissioning and Start-up Timeline:** As the well results support injection capacity in excess of the project demands Shell has the opportunity to constantly utilize one of the injection wells as a monitoring well. At start up, Q3 2015, if only HMU#3 is available, than injection will commission into the center well, IW 8-19, until ready to bring on HMUs 1 & 2; then IW 7-11 will be brought on. This deviates from the SDP as it was expected to need to bring on all three wells to meet the full project rate which is no longer required.

   However, if HMU #1, 2 and 3 are all available at start-up then injection will commission into IW 5-35 and IW 7-11 with monitoring occurring at the center well IW 8-19.

9. **Conformance radius definition** – in the SDP it was stated that if the CO_2 plume is forecasted to migrate outside the 4.8 km consultation radius within the 25 years of injection a decision would be made to either drill more wells to minimize the plume size or allow for larger plumes with all associated stakeholder issues. According to the Gen-4 range of uncertainty the expectation case is that the plume radius will be approximately 4.1 km. However, it is a possible that if the high case is realized that the plumes may exceed a 4.8 km radius extending closer to 6 km away from the wellbore. However, now that the Sequestration Lease rights have been attained there is no obligation to keep the plume within the 4.8 km radius or to complete any additional stakeholder engagement if it does indeed exceed this radius as long as the CO_2 stays within the Sequestration Lease area.

5.2.2. Uncertainty and Risk Assessment Updates

Shell carried out two Independent Panel Reviews (IPR) of CO_2 storage for the Quest CCS Project.

The first review was carried out in October 2010 prior to the November 2010 submission of the D65 application. This review was conducted by a panel of six CCS experts subcontracted and managed by Det Norske Veritas (DNV). At that stage, the injection plan and MMV plan had not been finalized. The first review concentrated on the characterization of the storage site (including capacity, injectivity, containment, conformance and risk management). The deliverable from this review was a report.

A second review was conducted in September 2011 when the injection and conceptual MMV Plan were finalized. This review covered all aspects of the Quest CO_2 storage and the panel consisted of seven experts, four of whom where members of the first review panel with DNV performing a similar role. The second review used the DNV guideline document for CO_2 storage (CO2 QUALSTORE) as a reference for the review. The outcome of this review was a certificate of fitness for purpose of the storage site, the injection plan and MMV Plan, which was issued by DNV.

The next risk assessment will be completed internally in 2014, after Gen-5 model updates are complete and the majority of baseline monitoring data is gathered and in time for the 2015 pre-injection MMV plan update to AER.

5.2.3. Area of Review Update

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 CO_2 storage. The initial AOR, prior to commencement of the baseline period and the 2012/13 drilling campaign, was set equal to the Sequestration Lease Area (SLA) and this is retained for this update.

Evaluation of data from the 2012/13 drilling campaign has confirmed that the pressure increase in the BCS will not reach a level sufficient to lift BCS brine to the base of the ground water protection zone even at the injection wells. There is therefore no area where brine leakage can potentially impact groundwater. Shell will therefore review, after completion of the GEN-5 modeling effort in 2014, the risks associated with brine leakage and update the AOR and MMV plan accordingly. The AOR will not be changed for the baseline period.

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.

6. Closure Activities

The stages of planning, implementing and closing of CCS projects have been developed by several organizations and government agencies to ensure that these projects are approached and executed in a safe and sustainable way, that is clear and transparent, and acceptable to stakeholders and regulators. According to Section 19(3) of the *Carbon Sequestration Tenure Regulation 68-2011*:

19 (3) The Minister may approve a closure plan submitted under subsection (2), or received under section 11, in relation to a carbon sequestration lease if the plan sets out a description of the activities satisfactory to the Minister that the lessee will undertake to close down sequestration operations and facilities, and contains the following:

a) summary of the activities that have been conducted by the lessee on the location of the carbon sequestration lease since it was issued;
b) the quantity of captured carbon dioxide that has been injected;
c) an evaluation of whether the injected captured carbon dioxide has behaved in a manner consistent with the geological interpretations and calculations the lessee submitted to the Regulator pursuant to Directive 65 in its application for approval of the injection scheme under the Oil and Gas Conservation Act;
d) the most recent geological interpretations and calculations that may have been made by the lessee with respect to the injected carbon dioxide and any associated pressure front;
e) a description of the location, condition, plugging procedures and integrity testing results for every well that has been used for the injection of captured carbon dioxide under the lease;
f) a description of any decommissioning, abandonment or reclamation activities undertaken by the lessee in the location of the lease;
g) an inventory of the reports and documents that the lessee has submitted to the Regulator or a department or agency of the Crown in right of Alberta or the Crown in right of Canada since the approval of the first closure plan related to the carbon sequestration lease, whether or not those reports and documents were required to be submitted;
h) advice and recommendations about the monitoring, measurement and verification activities that should be conducted after the issuance of a closure certificate is issued for the carbon sequestration lease under section 120 of the Act.

This closure plan focuses on the storage component of the Project and does not address the CO_2 capture infrastructure and the CO_2 pipeline as these are covered under separate legislation.

6.1. Storage Site

The subsurface infrastructure will be abandoned in accordance with the AER's Directive 020: Well Abandonment and Directive 072: Well Abandonment Notification Requirements, and any other requirements that are applicable at the time of closure.

The surface abandonment of the wells, well sites and access roads will be completed in accordance with the regulatory requirements of the day.

6.2. Well Decommissioning

Shell has developed a completion design for the Project wells, which adheres to both the regulatory requirements (Directive 20 for disposal in Level A interval) and Shell's internal requirements. The abandonment of the Quest wells will follow a phased approach that will consist of:

- An observation period following the cessation of injection, keeping in-well monitoring of the BCS possible to support conformance.
- The isolation of the BCS followed by another observation period, in order to support containment of the BCS storage complex while keeping the ability to re-enter the well if required.
- The final subsurface and surface abandonment of all wells, where all in-well MMV will stop.

Figure 6-1 shows the injection well status during the three phases of abandonment and the details are discussed below.

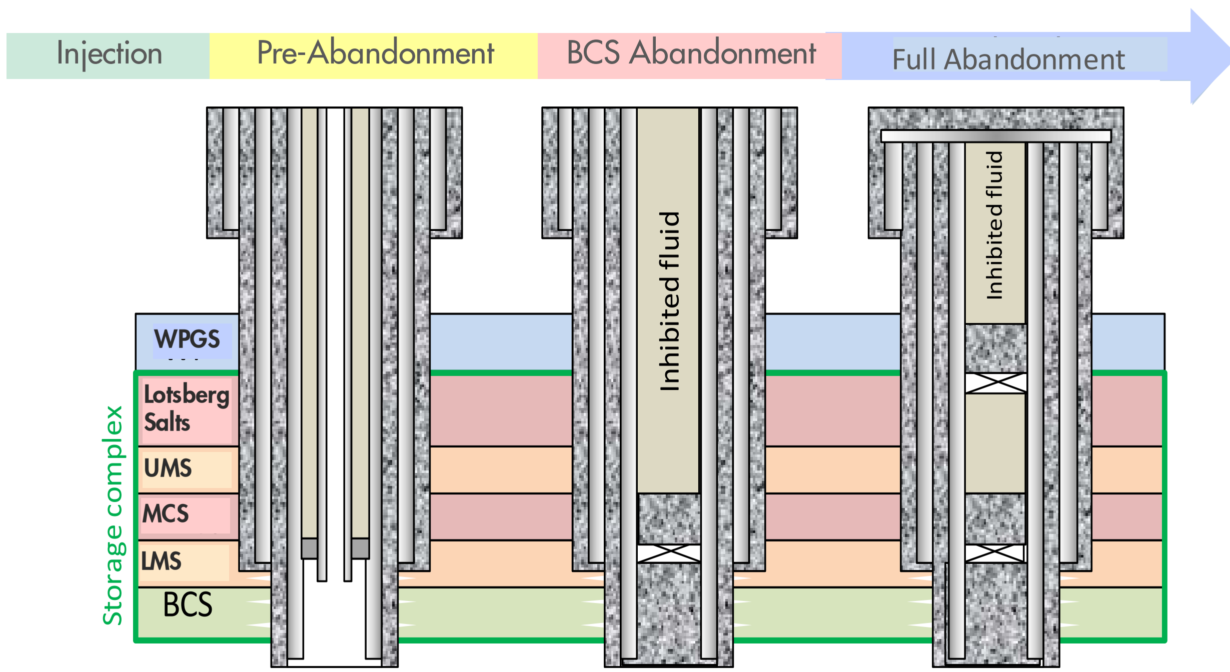

Figure 6-1 IW Schematic During the Three Phases of Well Abandonment

6.2.1. Pre-Abandonment Period

Shell to notify authorities and submit the final closure plan for approval in accordance with RFA recommendation 60 [2].

After CO_2 injection ends, an observation period will take place to monitor the BCS storage complex, during which time all injection wells will be suspended with the exception of their monitoring systems, which will continue to operate. The monitoring wells and all other active monitoring technologies will continue normal operational monitoring until authorized by the Regulator in review of the final closure plan. Once authorization of the final closure plan has occurred, it is considered the start of the minimum 10 year closure period (Recommendation 60) [2].

The pre-decommissioning period ends once Shell has sufficiently demonstrated that the CO_2 behaviour is predictable and trending towards stability for the site as per the following RFA Recommendation 63 [2]:

63) The Government of Alberta should require the following performance criteria for closure of a project:

> *a) Sequestered CO_2 and affected fluids are conforming to the objectives and regulatory requirements as described in the project application and approvals.*
>
> *b) There is no significant adverse effect of sequestered CO_2 or affected fluids to health, the environment and other resources (including but not limited to hydrocarbons, non-saline groundwater and pore space outside of the operator's sequestration lease).*
>
> *c) Sequestered CO_2 and affected fluids are contained in the sequestration complex.*
>
> *d) Sequestered CO_2 is behaving in a predictable manner.*
>
> *e) Sequestered CO_2 is expected to continue to behave in a predictable manner and is trending towards stability.*
>
> *f) The project-specific risk profile is decreasing and the risk of future leakage or adverse effects on health, the environment or other resources is acceptable.*

Recommendations 63g and 63h will occur in the full abandonment and well pad reclamation phases respectively.

6.2.2. BCS Abandonment Period

Once the pre-decommissioning period ends, a cement plug will be set inside each injection well to isolate the BCS. At this time, monitoring inside the BCS ends but the injection wells can still be re-entered at this stage if necessary.

Another observation period follows to confirm successful isolation of the BCS. Monitoring within injection wells will likely measure pressure and temperature changes above the cement plug.

The BCS isolation period ends once monitoring demonstrates the isolation of the BCS has been effective.

6.2.3. Full Abandonment Period

Once the BCS isolation period ends, cement plugs will be set inside all project wells (injection wells and MMV wells) and then these will be abandoned according Directive 020 requirements or the regulatory requirements of the day. Specifically, Shell will have to meet the following performance criteria continued from RFA Recommendation 63[2]:

63) The Government of Alberta should require the following performance criteria for closure of a project:

g) Decommissioning and abandonment is complete as required by the regulator.

It is Shell's recommendation that all in-well monitoring will end at this time.

However, these plans may be modified to allow some in-well monitoring systems to be transferred to the Crown for monitoring during the post-closure period as per Section 19h of the *Carbon Sequestration Tenure Regulation 68-2011*.

6.3. Well Pad Reclamation

Alberta's *Environmental Protection and Enhancement Act* and the Conservation and Reclamation Regulation require that, after an upstream oil and gas facility has been decommissioned, the operator must obtain a reclamation certificate.

Goals outlined by Shell in its C&R Plan for well pads include:

- returning the land disturbed by the Project to equivalent land capability at closure
- ensuring a stable, self-sustaining closure landscape (including landforms, soil, vegetation and hydrological regime)
- obtaining reclamation certificate for all disturbed areas after final decommissioning, abandonment and reclamation continued from RFA Recommendation 63 above:

  63) The Government of Alberta should require the following performance criteria for closure of a project

  h) Surface reclamation is complete to the extent agreed upon with the regulator for the post-closure period.

The basic activities for final reclamation and establishing the closure landscape include, but are not limited to:

- abandoning and decommissioning facilities
- removing infrastructure
- remediating contaminated areas (if required)
- restoring grade and drainage
- alleviating compaction
- replacing subsoil and topsoil
- re-vegetating

Shell will monitor reclamation of soils and vegetation according to AENV's 2010 Reclamation Criteria for Well sites and Associated Facilities for Forested Land.

According to Section 13.3 of the RFA:

Complete site reclamation in the closure period may not be desired for CO_2 sequestration projects as MMV equipment and access to the site may be required by the regulator for *monitoring in the post-closure period. Arrangements are made between the regulator and the operator for the transfer of any MMV equipment that the regulator requires to be left in place at the point of closure. It must be assured that any down-hole MMV equipment left in place will not compromise the long term integrity of the abandoned wells. Proposed reclamation activities will be included in the final closure plan and will be approved by the regulator* [2].

6.4. Monitoring Infrastructure Decommissioning

Shell expects that monitoring infrastructure will be decommissioned at the end of the closure period with the exception of any monitoring infrastructure that will be transferred to the Crown by prior agreement.

All monitoring infrastructure is associated with wells or well pads and will be decommissioned as part of the well abandonment and well pad reclamation process described above.

7. Site Closure Certification

7.1. Site Closure Certificate

Shell will apply for a site closure certificate following the execution of site closure activities and submission of a final closure and MMV report as per RFA recommendation 64 [2]. The closure period before transfer of liability to the Crown will be determined according to the strength of evidence obtained from the monitoring program that actual storage performance conforms to predicted performance. The performance metrics are described in Section 3.

Shell anticipates receipt of a site closure certificate 10 years after the start of the closure period agreed with Regulators, provided there are no significant issues arising from Project operations and that storage performance and CO_2 and brine containment in the BCS storage complex are demonstrated to the satisfaction of the Crown in accordance with pre-agreed criteria.

The post-closure period will occur following the issuance of a site closure certificate, which will transfer the long-term liability from Shell to the Crown.

7.2. Post-Closure Government Monitoring

Prior to transfer of liability, Shell will transfer any technologies requested by the Government to remain open during the post closure period as per Section 19h of the *Carbon Sequestration Tenure Regulation 68-2011*. In addition, Shell will share its accrued knowledge and experience on those technologies requested by the Government so that they can gain the expertise to utilize the chosen technologies. It is anticipated that this will be communicated during the closure period and included in the final MMV report.

Shell will abandon all other wells and infrastructure and reclaim the surface towards the end of the closure period, according to the regulatory requirements in place at the time. The liability for the monitoring technology will also transfer to the Government as described in Section 14.2 and 14.4of the RFA:

14.2 The Mines and Minerals Act 118 sets out the liabilities and obligations that the Government of Alberta will assume when it issues a closure certificate. When issuing a closure certificate, the Government of Alberta becomes the owner of all injected CO_2, and assumes all obligations of the lessee, including responsibilities related to wells and facilities, the environment and land. [3]

14.4 Post-closure monitoring and remediation (in the case of unforeseen CO_2 release from the sequestration complex) is important for developing and maintaining public support for CCS development. Once a CO_2 sequestration project is closed, and ownership and liability for the CO_2 has been transferred to the Government of Alberta, the province will be responsible for conducting post-closure monitoring and any potential remediation. The degree and type of post-closure monitoring will be determined on a site-specific and risk-based basis. [2]

7.2.1. Transfer of Measurement, Monitoring and Verification Capability

According to the RFA, Appendix D2 on Closure and Transfer of Liability, the final closure report will be accompanied by all data required for the Government of Alberta to act as licensee, and any other information requested by the Government or Regulator [2].

In addition, Shell will provide the Government of Alberta with its knowledge and experience of MMV activities and outcomes according to the terms in the CCS Funding Agreement for the Quest Project, before the transfer of liability. This may take the form of workshops, provision of documents and/or presentations as determined by the appropriate parties at the time.

8. Reporting and Documentation

In accordance with Section 19) (3)g of the *Carbon Sequestration Tenure Regulation 68/2011*, Appendix B contains an inventory of the reports and documents that Shell has submitted to the Regulator or a department or agency of the Crown in right of Alberta or the Crown in right of Canada since the approval of the first closure plan in April 2011, related to the carbon sequestration lease, whether or not those reports and documents were required to be submitted.

9. References

[1] Province of Alberta Mines and Mineral Act. Revised Statutes of Alberta 2000 Chapter M-17. Alberta Queen's Printer, Edmonton Alberta. Current as of June 17, 2013.

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

[3] Carbon Capture and Storage: Summary Report of the Regulatory Framework Assessment. Alberta Energy. 2013.

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

[5] Draft Quantification Protocol for the Capture of CO2 and Storage in Deep Saline Aquifers. Public Draft Version. Government of Alberta. December 2011.

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

[7] Shell Canada Limited Quest Carbon Capture and Storage Project, Directive 65: Application for a CO2 Acid Gas Storage Scheme. Submitted to Energy Resources Conservation Board of Alberta November 2010.

[8] Quest Carbon Capture and Storage Project Radway Field & Surrounding Areas AER Approval No. 11837A, AER Decision 2012 ABERCB 008 Special Report #1 & Pre-baseline MMV Plan. Submitted to AER October 15, 2012.

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

[10] Shell Canada Limited Quest Carbon Capture and Storage Project, Special Report #2: Suitability of InSAR Baseline Data for MMV. Submitted to Alberta Energy Regulators January 31, 2013.

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

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

[13] Shell Canada Energy: Proposed Resolution for the Surface Casing Vent Flows and Gas Migrations on the wells SCL 102/05-35-059-21W4/00 and SCL 103/07-11-059-20W4/00. Letter submitted to AER August 28, 2013.

[14] Surface Casing Vent Flow (SCVF) and Gas Migration Repair (GM) – Deferral Request. AER Approval and Conditions. Received by Shell September 4, 2013.

[15] Quest Storage Development Plan Controlled Document No. 07-0-AA-5726-0001. Oct. 6, 2011.

Appendix A - Measurement Monitoring and Verification Plan Feb. 2014

Shell Quest Carbon Capture and Storage Project

MEASUREMENT, MONITORING AND VERIFICATION PLAN

UPDATE

Prepared by:
Shell Canada Limited
Calgary, Alberta

February 14, 2014

Executive Summary

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

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

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

Ensure Conformance to indicate the *long-term effectiveness* of CO_2 storage by demonstrating actual storage performance is consistent with expectations about injectivity, capacity and CO_2 behaviour inside the storage complex;

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

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

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

This is the 3rd update of the MMV plan submitted to AER since the start of the project. The first conceptual plan was submitted as part of the D65 disposal application in 2010. In fulfillment of AER condition 7, the pre-baseline MMV plan was submitted in Oct.15 2012 and the pre-injection MMV plan will be submitted January 31, 2015. This plan an interim update requested by the AER Dec. 3, 2013 for submission February 14, 2014.

Page intentionally left blank

Table of Contents

Abbreviations

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

SEIS2D .... time-lapse surface 2D seismic
SEIS3D .... time-lapse surface 3D seismic
Shell .... Shell Canada Limited
SLA .... Sequestration Lease Area for the Project
SPH .... soil pH surveys
SSAL .... soil salinity surveys
TNO .... Netherlands Organisation for Applied Scientific Research
UK .... United Kingdom Department of Energy and Climate Change
UNSED .... United Nations Conference on Environment and Development
USIT .... time-lapse ultrasonic casing imaging
VSP .... vertical seismic profiling
VSP3D .... time-lapse 3D vertical seismic profiling
WEC .... down-hole electrical conductivity monitoring
WHCO$_2$ .... wellhead CO_2 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 CO_2, thereby reducing greenhouse gas emissions from the existing Scotford Upgrader. The Scotford Upgrader is located about 5 km northeast of Fort Saskatchewan, Alberta, within Alberta's Industrial Heartland, which is zoned for heavy industrial development.

The three components of the Quest CCS Project are:

- CO_2 capture infrastructure, which will be connected to the Scotford Upgrader. The method of capture is based on a licensed Shell amine system called ADIP-X.
- A CO_2 pipeline, which will transport the CO_2 from the Scotford Upgrader 60 km to the injection wells north of the Upgrader. The CO_2 injection well locations are located in the center of the storage site.
- an approved storage scheme consisting of up to 8 injection wells that can be used to inject the CO_2 into the Basal Cambrian Sands (BCS), a deep underground formation, for permanent storage at a depth of about 2 km below ground level. Although 8 were approved as part of the D65 approval 11837A [1], the current development plan requires only 3 injection wells at this time. The security of storage will be ensured through a program of Measurement, Monitoring and Verification (MMV).

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

2 The Purposes of MMV

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

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

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

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

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

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

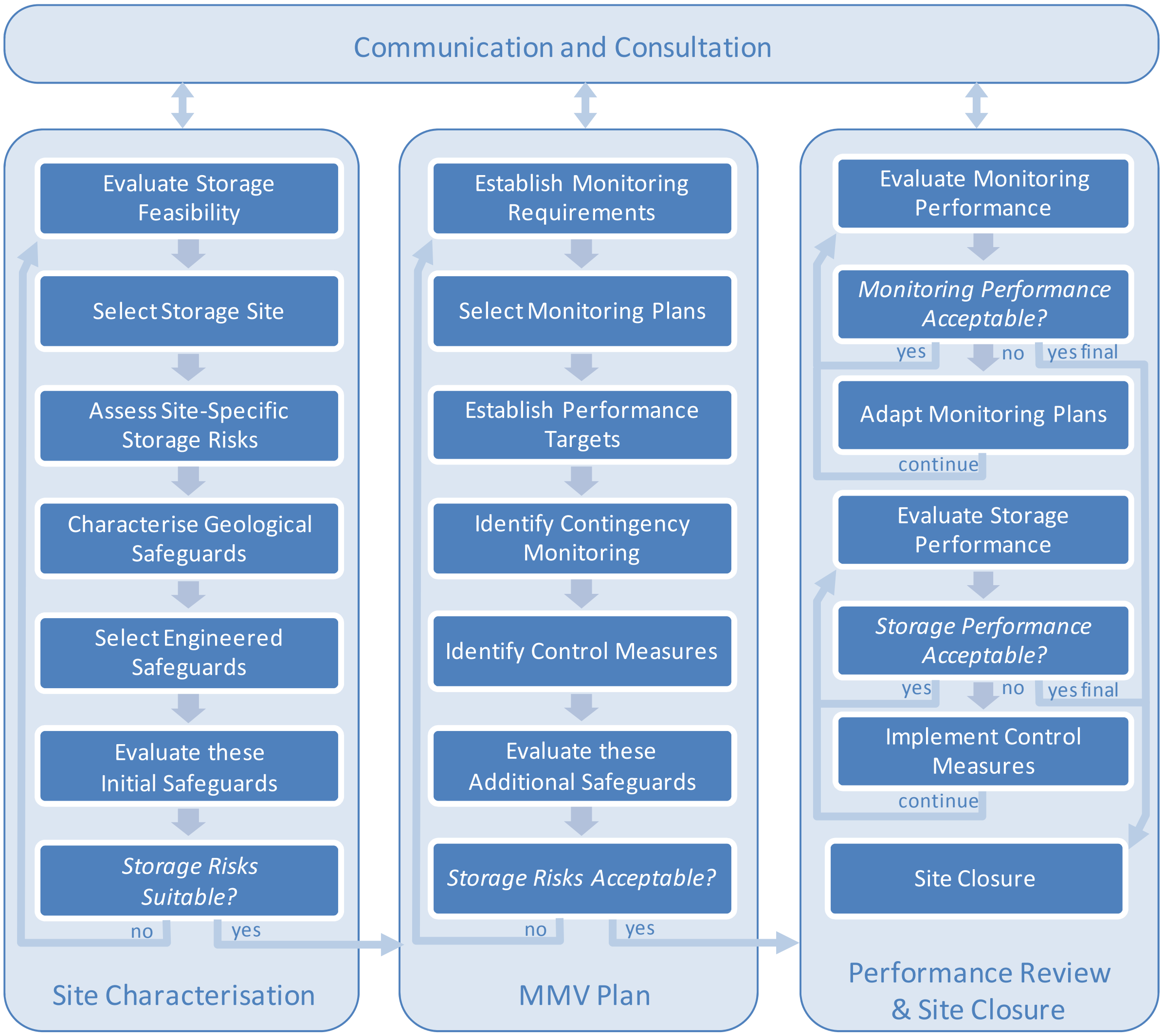

Figure 2-1 Framework for Storage Risk Management

2.1 Area of Review

MMV will operate within an Area of Review (AOR) which has sufficient extent to include the area where there is potential risk for adverse impacts due to CO_2 storage. The initial AOR, prior to commencement of the baseline period and the 2012/13 drilling campaign, was set equal to the Sequestration Lease Area (SLA). The AOR will not be changed for the baseline period and remains the same as reflected in this MMV plan update. (See Figure 2-2) [8].

Evaluation of data from the 2102/13 drilling campaign has confirmed that the pressure increase in the BCS will not reach a level sufficient to lift BCS brine to the base of the ground water protection zone even at the injection wells. There is therefore no area where brine leakage can potentially impact groundwater. Shell will therefore in 2014, after completion of the GEN-5 modeling effort and update of BCS pressure forecasts, review the risks associated with brine leakage and update the AOR and MMV plan accordingly.

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 two additional deep saline aquifers, 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 CO_2 and brine containment in the BCS storage complex are demonstrated to the satisfaction of the Crown in accordance with agreed criteria.

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

2.4 Timeframe of Updates

2.4.1 Alberta Energy Regulator Updates

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

1) Condition 7 - Shell must provide updates of the MMV Plan as required by the AER and at minimum at critical milestones (commencement of injection, closure and post closure) [1]. As per the December 3, 2013 Approval Condition 2 Shell must submit an MMV update on January 31, 2014[3].

2) Condition 8 – Shell must submit a complete pre-baseline MMV Plan by Sept 30, 2012. This condition has been completed with the final submission sent Oct 15, 2012 as per approved submission date change.

3) Conditions 10d and 17 - Shell must also provide annual operations reports that are aligned to the most current MMV plan and discuss any need for changes to the current MMV plan.
4) Condition 15e – Shell must provide the MMV Plan as part of the third annual status report to be submitted January 31, 2015.
5) Condition 18 – Shell must submit a closure report in 2040 that includes an MMV plan update, with specific attention to any performance problems evident in the 25 years of operations.
6) Condition 19 – Shell must submit a post closure report, which includes an update of its MMV plan.
7) Condition 25 – Shell must submit MMV plans referenced in Conditions 6, 7, 8, 15, 18, and 19 to Alberta Environment and Sustainable Resource Development for review – now part of AER.

2.4.2 Government of Alberta Energy Updates

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

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

"*The Minister may issue to an applicant an agreement under section 116 of the Act in the form of a carbon sequestration lease if the Minister receives from the applicant….*

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

Section 15 states:

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

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

Shell submitted an MMV Plan and a Closure Plan as part of the Sequestration Lease Application submitted April 28, 2011 [6] approved by the Minister May 27, 2011[2].

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

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

(b) the date that the lease is renewed.

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

Shell is required to submit an updated MMV and closure plan every 3 years as a stipulation of its Sequestration Lease Approval from Alberta Energy.

2.4.3 General Updates

In both of the above agreements 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

It is expected that there will be a significant MMV plan update January 31, 2015 as all baseline data will have been acquired and a site specific data driven plan that is consistent with the risk profile of the newly drilled injection wells and associated pressure profile predictions can be proposed.

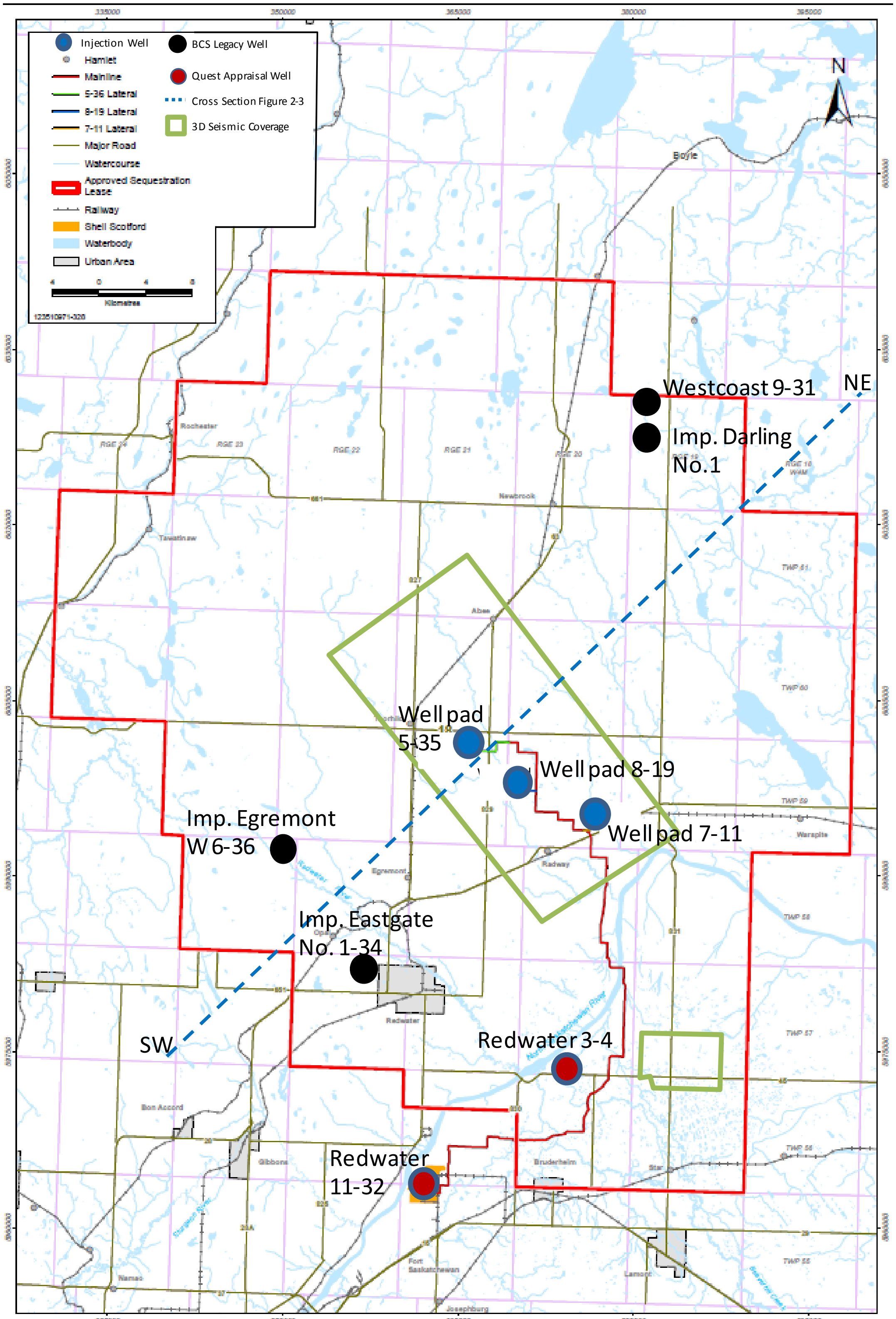

Figure 2-2 Location Map of the Quest Sequestration Lease Area

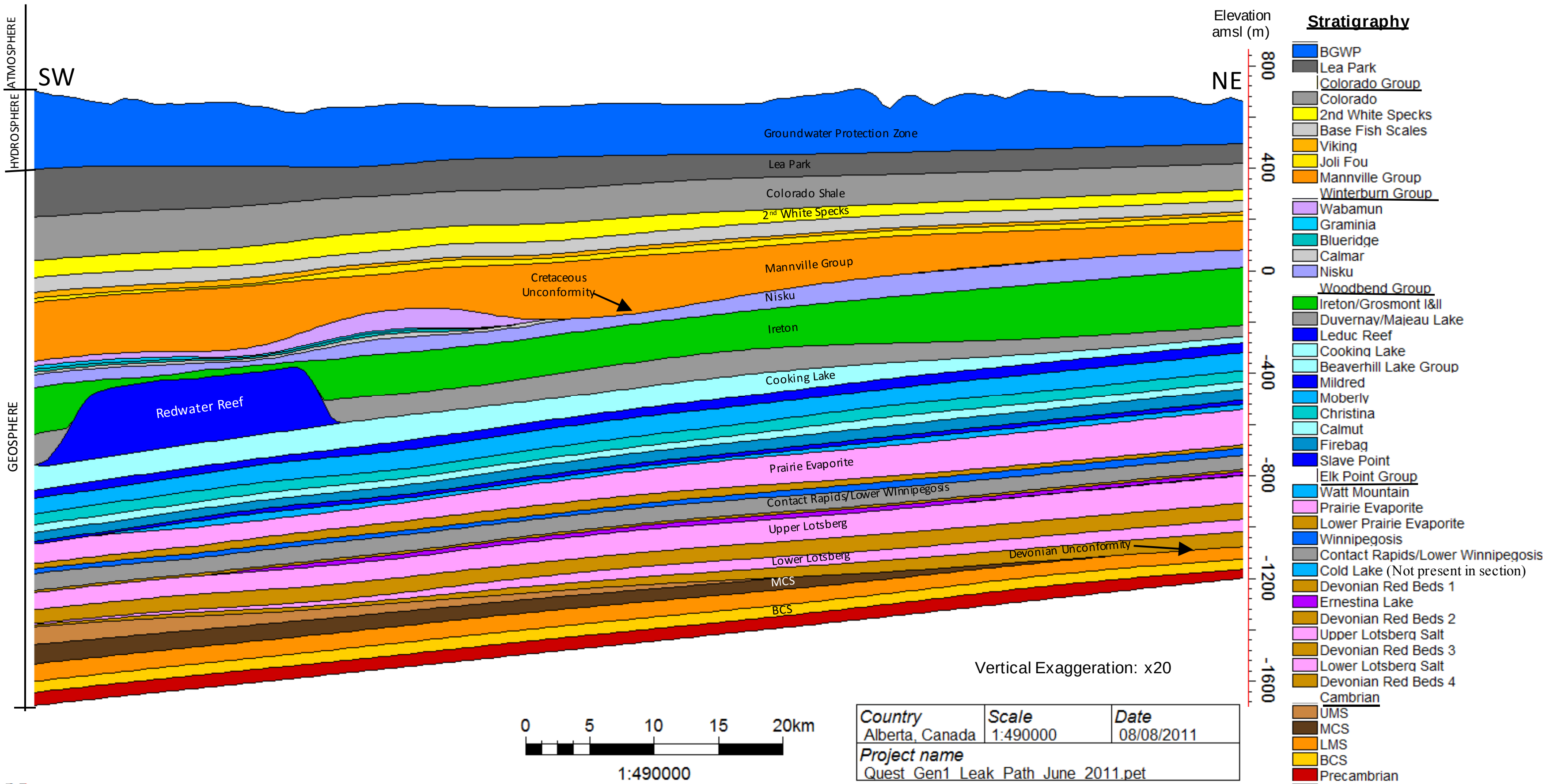

Figure 2-3 Cross section through the BCS storage complex and overlying geological formations. Figure 2-2 shows the location of this cross-section

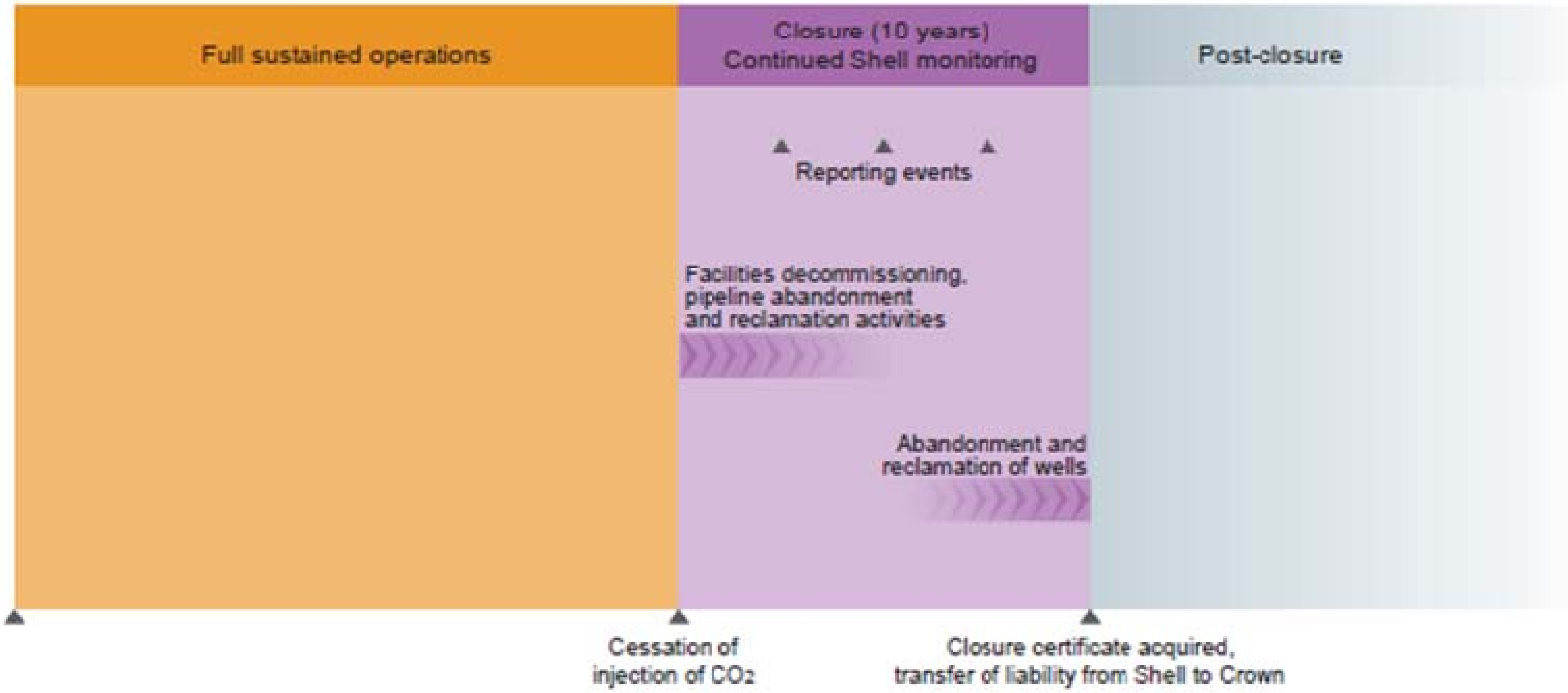

Figure 2-4 Proposed timeline for site closure activities

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 by independent experts. The scope and frequency of monitoring tasks depend on the outcome of this risk assessment. Project safeguards are implemented to reduce storage risks to as low as reasonably practicable.
- **Site-Specific**: Monitoring technologies are selected for each monitoring task based on the outcome of site-specific feasibility assessments and then custom-designed to ensure optimal monitoring performance under local conditions particular to the storage site.
- **Adaptive**: The performance of the storage site and the monitoring systems are continuously evaluated. Contingency Plans exist with clear trigger points for implementing control measures to ensure effective responses to any unexpected events.

3.2 MMV Design Process

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

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

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

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

3.3 Influences on MMV Design

Standards for MMV are still 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_2 over the last 20 years. The AER intends to use the same processes for regulating any CCS projects in Alberta, and these may be updated by the 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 project in Canada create important precedents for MMV: the Weyburn-Midale CO_2 enhanced oil recovery project (EOR) in Saskatchewan and the Pembina Cardium CO_2 EOR project in Alberta.

Outside Canada, there are four notable examples of commercial-scale CO_2 injection projects with ongoing MMV activities: Sleipner and Snøhvit in Norway, In Salah in Algeria, and Rangely in the United States. See Appendix 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 4-33).

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

Geosphere: Above the BCS storage complex, the geosphere also contains numerous additional seals and permeable formations /regional aquifers that can be considered as auxiliary storage units thus acting as additional barriers to CO_2 or BCS brine reaching base groundwater protection zone including, in ascending stratigraphic order, the following (Table 4-2).

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

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

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 allowed for the phased development of up to 8 injection wells. The base case development plan is now 3 injection wells at start-up with contingency plan to increase to 8if deemed necessary to meet approved injection targets.

- **Exploration and Appraisal Wells:** The Project drilled two exploration wells:

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

- **Injection Wells and Monitoring Wells:** See Table 4-1 below. Note that Groundwater monitoring wells starting with “UL” are unlicensed wells that are less than 150 m total depth.
- **Legacy Wells:** Figure 2-2 and Appendix E describe the legacy wells within the SLA.

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

Table 4-1: Pad and Well UWIs for Quest injection and monitoring wells.

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

Table 4-2 Geologic description of the formations above the Elk Point Group (Sequestration rights). Starting at surface.

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

		Ellerslie		Gas Reservoir	Fluvial deposit of fine to medium grained quartz with chert sandstone with fairly good porosity deposited in the Edmonton Valley likely under brackish water conditions. Sediment transport towards the N-NW. Gas Production in SLA. Absent towards the NE of the SLA along the Wainwright Highlands (Devonian). Thickness of the Ellerslie inside the SLA reaches a maximum of 90m, depending on the unconformity and the presence of channel sands.
	Winterburn Group	Wabamun		Gas Bearing	Characterized by Dolomite, brown, finely crystalline, porous in part; with subsidiary inter-beds of brown, micritic, pelloidal limestone. Only exists in the W-NW half of the SLA due to erosion by the sub-cretaceous unconformity. However, there is some gas production within the SLA. Thickness ranges from 0m to 100m.
		Graminia		Baffle	A silt unit at the top of the Winterburn. Exists predominantly in the W-NW of the SLA. Thin and patchy across the rest of the SLA due to irregularities in the Pre-Cretaceous unconformity.
		Blueridge		Gas Bearing	Last widespread carbonate cycle in Western Canada. Exists predominantly in the W-NW of the SLA. Exists predominantly in the W-NW of the SLA. Thin and patchy across the rest of the SLA due to irregularities in the Pre-Cretaceous unconformity. Has some minor porosity within the SLA. Production in the Eastern part of the SLA commonly mislabeled as Wabamun Production.
		Calmar		Baffle	Predominantly silts and clays likely the result of reworking of the underlying lowstand Nisku siliciclastics. Exists predominantly in the W-NW of the SLA. Thin and patchy across the rest of the SLA due to irregularities in the Pre-Cretaceous unconformity.
		Nisku		Oil and Gas Reservoir	A mixed carbonate-siliciclastic deposited during a lowstand. Within the SLA the Nisku is a porous light brown to light grey crystalline dolomite with lesser amounts of brownish grey dolomitic siltstones, green shale and anhydrite. It is commonly truncated by the pre-Cretaceous unconformity. Within the AOI oil production is only above and to the West of the Redwater reef, some minor gas exists in the NE portion of the SLA. The Nisku has a relatively constant thickness of the SLA at 57m.
	Woodbend Group	Ireton	Ireton / Grosmont I&II	Seal	Only the Lower Ireton exists in the SLA represented by a cyclic succession of basin filling shale considered to be a regional aquitard. The Lower Ireton is thin on top of the Leduc Reefs (~10m) and thickens to an average of 160m away from the reef. Grosmont Carbonates begin to appear within the Upper part of the Ireton to the East of the SLA.
		Duvernay		Seal	Grades from bituminous rich shale to a shale to a dolomite towards the NE of the Basin. Within the SLA represented by dark brown shale and limestones to the west and as you move towards 8-19 it is predominantly tight argillaceous limestone with shale interbeds. Relatively uniform thickness across basin (~160m) except it is absent over the Leduc Reefs.
		Leduc		Oil Reservoir	Within the SLA is the Redwater Reef and the Morinville Reef trend associated with the Rimbey-Arc. The Morinville reef trend is a tight dolomitic structure except for a localized field just west of the Redwater reef called the fairydell-Bon Accord Field. In contrast, the Redwater pinnacle reef is a major oil producing limestone and the focus for this study.
		Majeau Lake		Seal	In the SLA only the Lower Majeau Lake is present. Characterized by greenish grey and dark brown shale that are time equivalent to the Cooking Lake (West of and underlying the reef chain). Only exists to the West of the SLA.
		Cooking Lake		Inter-mediate Aquifer	Major regional aquifer made up of extensive sheet like shelf carbonates and an equivalent basin-fill shale (Majeau Lake). Consists of pelloidal and skeletal limestones (bracs, crinoids, stromatoporoids, and bryzoans). Unlike most younger Woodbend carbonates it is predominantly undolomitized (except directly under the Leduc-Homeglen-Rimbey-Meadowbrook reef chain). The SLA is at the intersection of all three facies. There is a sharp edge to the West of the reef chain where the Cooking lake is non-existent, replaced by Majeau Lake, it is thickest under the reefs and then thins to the NE.

	Beaverhill Lake Group	Waterways	Mildred	Baffle	The Firebug, Calmut, Christina, Moberly and Mildred Members make up the Waterways Formation deposited during a regressive basin fill phase of the Waterways Basin. Composed of a series of shallowing upwards shale-carbonate clinothem cycles deposited in a basin slope depositional setting. Each cycle is composed of a shale base that grades vertically to argillaceous carbonate. The Waterways and Slave Point are combined to form the Beaverhill Lake Group Aquifer System.
			Moberly	Inter-mediate Aquifer	
			Christina	Baffle	
			Calmut	Inter-mediate Aquifer	
			Firebag	Baffle	
		Slave Point	Slave Point	Baffle	The Slave Point Fm. is a distinct, non-contemporaneous event from the Waterways Fm. above, deposited in a transgressive "reefal" phase dominated by restricted to open-marine carbonates. In the SLA Slave Point is a thin, limestone unit that contains some minor porosity. Although represented here as a baffle, on a regional scale it is included in the Beaverhill Lake Group Aquifer System.

Table 4-3 Continuation of geological descriptions over zones included in the Quest Sequestration Lease rights of with focus on the BCS storage complex.

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

		Red Beds	Devonian Red Beds 2	Baffle	Devonian Red Beds confined to the Central Alberta Sub-Basin characterized by a thin, maximum 11m red dolomitic shale that merges at the basin margins with the other Devonian Red Beds. Only occurs in the lows of the underlying Lotsberg Salt. Equivalent to Elk Point Group, Member 6 in the CSPG Western Canadian Lexicon.
BCS Storage Complex		Lotsberg	Upper Lotsberg Salt	Ultimate Seal	Almost pure halite that acts as an aquiclude, ranging in thickness from 53m to 94m across the SLA and thickening to 150m up-dip, NE of the SLA in the Central Alberta Sub-Basin.
		Red Beds	Devonian Red Beds 3	Baffle	Devonian Basal Red Beds confined to the Central Alberta Sub-Basin. Basal Red Bed intervals exist between and below the Lotsberg Salts, merging at the basin margins together with the Devonian Red beds above. Brick red dolomitic or calcareous silty shale that grade downwards through to red sandy shale into greenish fine to coarse grained quartzose sandstone.
		Lotsberg	Lower Lotsberg Salt	2nd Major Seal	Almost pure halite that acts as an aquiclude, ranging in thickness from 9m to 41 across the SLA and thickening to 60m up-dip, NE of the SLA in the Central Alberta Sub-Basin.
		Red Beds	Devonian Red Beds 4	Baffle	Devonian Basal Red Beds confined to the Central Alberta Sub-Basin. Basal Red Bed intervals exist between and below the Lotsberg Salts, merging at the basin margins together with the Devonian Red beds above. Brick red dolomitic or calcareous silty shale that grade downwards through to red sandy shale into greenish fine to coarse grained quartzose sandstone. This is the base of the Elk Point Group.
	Upper Deadwood		Upper Marine Silts	Baffle	Flow baffle composed of greenish shale and minor silty and sandy interludes deposited in the offshore shelf in response to either an increase in sediment supply or a relative sea level fall. Absent in the Eastern part of the SLA due to the Pre-Cretaceous unconformity.
	Lower Deadwood		Middle Cambrian Shale	1st Major Seal	The first major seal composed of shale deposited in an offshore shelf environment associated with continued flooding of the basin. Present across the entire SLA ranging in thickness from 21m to 75m. The MCS is absent due the Pre-Cretaceous unconformity just to the NE of the SLA.
	Earlie		Lower Marine Sands	Baffle	Regional flow baffle created by these transgressive, heterogeneous subtidal clastics representative of transition from marginal marine sediments of the BCS to the more distal environment of the MCS above. Present across the entire SLA.
	Basal Sandstone		Basal Cambrian Sands	CO_2 injection zone	The BCS is transgressive sheet sand, deposited in a tide dominated bay margin that acts as a basin-scale saline aquifer. Existing data internal and external to Shell indicates the BCS saline aquifer has suitable injectivity, capacity, and containment for CO_2. The BCS is the primary target for the potential CO_2 storage operation.
	Precambrian Basement			Basal Bounding Formation	Cratonic basement on which the BCS unconformably lies on top of. Considered an aquiclude.

4.2 Initial Conformance Risks

4.2.1 Loss of Conformance Definition

A loss of conformance exists if:

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

These criteria are taken from the agreed Closure Plan.

4.2.2 Potential Consequences Due to a Loss of Conformance

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

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

4.2.3 Potential Threats to Conformance

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

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

4.2.4 Initial Safeguards to Ensure Conformance

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

- **Basin-scale screening** studies ranked the top opportunities for geological storage of CO_2 in Canada. Selecting a site within the top-ranked region minimizes the risk of complex geology causing unpredictable storage behaviour.
- **Site selection** was based on a feasibility study of the pre-existing appraisal data to reduce the likelihood of insufficient injectivity, capacity or containment.
- **Site characterisation** based on a dedicated and comprehensive appraisal program including 2D and 3D seismic and the first injection well candidate (IW 8-19) at the center substantially improved the reliability of a broad range of subsurface models.

These models are being updated in 2014 in response to data acquired from 2 additional development wells (IW 5-35 and IW 7-11).

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

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

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

4.3 Initial Containment Risks

4.3.1 Loss of Containment Definition

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

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

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

4.3.2 Potential Consequences Due to a Loss of Containment

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

- **Hydrocarbon resources affected** due to a slight increase in the salinity or acidity of the produced fluids
- **Groundwater impacts** if sufficient quantities of CO_2 or BCS brine migrate above the base of groundwater protection to reduce groundwater quality.
- **Soil contamination** if sufficient quantities of CO_2 or BCS brine migrate into the soil to reduce soil quality.
- **CO_2 emissions into the atmosphere** will reduce the effectiveness the Project's contribution to climate change mitigation.

4.3.3 Potential Threats to Containment

There are nine potential threats to containment identified and explained detail in Section 4 of the MMV Plan. Each are considered unlikely but are, in principle, capable of allowing CO_2 or BCS brine to migrate upwards out of the BCS storage complex. The potential risk events that could lead to loss of containment are summarized as follows:

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

Risk Assessment:

The probability of legacy wells being intersected by the CO_2 plume or brine pressures high enough to lift brine into the groundwater is very low.

- In the Quest SLA, there are 4 legacy wells that penetrate through all seals in the BCS storage complex with the closest one to an existing injection well being 18 km away. This is more than 3 times the distance the CO2 plume is expected to extend so there is no risk of CO2 leakage at these wells unless there is a severe loss of conformance.
- The status and condition of existing wells penetrating the BCS has been reviewed from multiple data sources. There are no known issues with legacy well integrity other than the uncertainty that arises from the age of the cement plugs and the inability to pressure test old cement plugs. Te following barriers are in place in the BCS legacy wells:
  - multiple cement plugs of significant length at various intervals
  - open hole abandonment across the salt allows for the opportunity for hole closure by salt creep
  - impermeable plugs may have formed through settlement of solids out of drilling mud in the well bore
- Evaluation of data from the 2102/13 drilling campaign has confirmed that the pressure increase in the BCS will not reach a level sufficient to lift BCS brine to the base of the ground water protection zone even at the injection wells. There is therefore no risk of brine leakage at the legacy wells impacting groundwater unless there is a severe loss of conformance.
- BCS pressure monitoring and plume monitoring will be used to ascertain if there is a loss of conformance which would give rise to a potential threat to containment associated legacy wells far in advance of any impact above the storage complex. At that time, MMV plans would be updated appropriately.

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

Explanation:

Any well injecting CO2 into the storage complex creates a threat to containment as it punctures the geological seals directly above the CO2 plume. Any loss of external or internal well integrity will potentially allow migration of CO2 and BCS brine out of the storage complex. This threat may arise for any of the following five reasons.

- **Compromised cement:** Initial cement bond, or deterioration of the cement bond through time due to stress cycling, or chemical alteration may allow upward fluid migration outside the casing.

- **Compromised casing:** Casing corrosion through time due to oxygen ingress, or contact with saline or acidic fluids may allow upward fluid migration inside or outside the casing.
- **Compromised completion or wellhead:** Loss of integrity of the completion or wellhead due to undetected flaws in the initial design or execution or subsequent degradation due to corrosion, or deterioration of seals in the presence of CO2 may allow fluids to escape through the wellbore.
- **Well interventions:** During the course of normal operations, routine well interventions may result in loss of well control.
- **Compromised abandonment:** Injection and observation wells will be properly abandoned prior to site-closure. Undetected flaws in the design or execution of well abandonment or subsequent degradation of materials may allow upwards migration of fluids.

Risk Assessment:

The risk of leakage from the Storage Complex along a leakage pathway in the injection wells is considered very low. However, in 2014 Shell is contracting an independent external review of the integrity of the injection wells and an associated update of the leakage risk assessment for the QUEST injection wells to ensure that Shell's risk assessment, with the below information included, is still appropriate:

- The evaluation of the cement bond in all injection wells both behind the intermediate casing and the main casing shows isolation of the BCS storage complex with a good bond across all three seals (MCS and the Lower and Upper Lotsberg Salts), with the exception of IW 5-35. At IW 5-35, a poor bond is interpreted across the MCS which could extend into the LMS baffle below. The poor bond is interpreted from 1891 m MD (below the lower Lotsberg Salt) down to a depth of 1967 m MD which was the total depth to which the log was acquired. The casing shoe is set at 2004 m MD and the top of the LMS is at 1988 m MD. There is 50m of good cement from the top of the BCS to the intermediate casing shoe which provides an effective isolation of the BCS. Regardless, the good cement across the Lotsberg Salts provides isolation of the BCS storage complex.
- In the Quest Project Surface Casing Vent Flows (SCVFs)and Gas Migrations (GMs) were detected and reported to AER in IW 5-35, IW 7-11. Upon further review, IW 8-19 was also determined to have a SCVF. Analytical results show that the SCVFs and GMs are independent of each other and that the GMs originate from the ground water zone while the SCVFs originate just below the surface casing (shallow source < 200m depth). Due the shallow depth of the source of the SCVFs and GMs, these minor leaks to surface are therefore not considered a threat to containment and isolation of the BCS reservoir.

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

Risk Assessment:

This is risk is currently considered very low because:

- All deep monitoring wells drilled to date, in the vicinity of the injection wells, terminate above the Ultimate Seal with the goal to detect CO2 or brine migrating above the BCS storage complex
- The closest proposed BCS monitoring well is the Redwater 3-4 well (21 km south west of IW 7-11). The risk to migration of brine out of the BCS storage complex would be treated the same as for legacy wells. The only difference being that it is a Shell well and the well integrity is known and it can be abandoned if and when required.
- Use of the Redwater 3-4 well and the BCS injection wells as monitoring wells for the project life to monitor pressure build up and interference to ensure pressure are not high enough to raise brine to the base of groundwater protection long before a potential problem arises.
- It is noted here that this risk would increase in the event that Shell is required to drill additional monitoring wells in the BCS as per AER approval 11837A Conditions 10i and 10j. Those wells would have the same risk factors as injection wells described above.

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

Risk Assessment:

The careful site selection process for the Quest SLA was used to optimize the use of natural barriers. In addition, the 3D seismic survey as well as subsurface static models created based on well and core data were used to show that as far as the data indicates there are no such migration pathways for CO2 or brine to escape the BCS storage complex. This is the result of an extensive BCS reservoir, a thick heterogeneous baffle in the LMS that has negligible vertical permeability as well as the three thick regional seals (MCS, Lower an Upper Lotsberg salts) that all extend beyond the SLA showing no discontinuities on 3D or 2D seismic.

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

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

Risk Assessment:

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

- Faults exist as discontinuities over a range of length-scales in many rock formations. However, large faults that transect regional scale geological seals within the Quest area of the Alberta Basin are rare (more than 100 km separates the Snowbird Tectonic Zone from the Hay River Shear Zone to the north).
- There is no evidence of faults with throws greater than 15 m crossing the seal complex from 2D and 3D seismic covering the full SLA. The 2D seismic spans the entire SLA with an approximate 3 km spacing and 415 km2 of 3D seismic is available over the central portion of the SLA.
- There is a period of approximately 1.5 billion years between the granite and the deposition of the BCS. Therefore, it is unlikely that any Precambrian faults were active in the BCS time of deposition.
- Even when present, many faults are sealing and retain fluids under pressure over geological time-scales.
- Mechanisms associated with fault slip, such as clay smear and cataclysis, reduce permeability within the fault zone. Other mechanisms, such as dilation and fracturing may enhance fault permeability.

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

Explanation:

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

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

Risk Assessment:

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

- The SLA is not an area of active natural seismicity. There has been a regional seismic monitoring network in place for more than 80 years with a capability of detecting a magnitude 3 event within the SLA. None were detected over this period as indicated by the Alberta Geological Society Tectonic activity map for Alberta: http://www.ags.gov.ab.ca/geohazards/earthquakes.html.
- The Lotsberg salts are ductile and expected to creep and reseal any unexpected small faults

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

Explanation:

CO2 injection may induce open fractures due to pore fluid pressure increase and temperature decrease inside the BCS aquifer close to the well. Occurrence of any such fracturing does not constitute a threat to containment. In order for fluid flow these fractures would need to:

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

Risk Assessment:

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

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

Explanation:

Injected CO2 will acidify formation fluids in contact with geological seals. Depending on the mineralogy of the seals there is potential for many different chemical reactions to occur. Many of these reactions yield products that occupy a greater volume and therefore most likely reduce permeability; the converse is also possible. For acidic fluids to erode geological seals, minerals must be present that react and these reactions must increase not decrease permeability.

Risk Assessment:

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

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

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

- Reactive Transport Modeling (RTM) of CO2 flow at the LMS/MCS interface, via a hypothetical fault through the LMS, results in dissolution of carbonate minerals, felsic minerals and precipitation of clay minerals. The rate of dissolution and precipitation stays slow and impacts on rock properties are negligible unless open conduits such as permeable fractures/faults are assumed to exist. In that case, CO2 can break through and dry out the conduit leading to precipitation of salt from evaporating brine initially in the conduit as well as from brine replenishment from the rock matrix through diffusion. Ultimately, in the RTM modeled case of a hypothetical faults/fracture pathway through the LMS, the open conduits are eventually sealed up by salt precipitation.
- Independent core analysis results for MCS capillary entry pressure also support the RTM conclusion that carbonate minerals precipitate in the MCS based on the entry pressure experiment in which supercritical CO2 was placed in immediate contact with the MCS under the reservoir pressure. The experiment illustrates that:
    - The capillary entry pressure of the MCS is very high (higher than 999 psi, the top constrained pressure of the experiment) indicating that the MCS is a good seal
    - The micro cracks in the core sample which were induced during handling were blocked (partially or fully) by salt precipitation during the experiment which was confirmed by elemental mapping on the SEM images. This is consistent with TOUGHREACT modeling which showed that salt precipitation can plug any natural fractures in the seal. Note that there is no evidence of any natural fractures in the MCS.
    - Diffusion of CO2 takes place, leading to mineralogical alteration in the core sample and precipitation of calcite which could further improve sealing capacity

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

Explanation:

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

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

Risk Assessment:

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

- According to the Sequestration Lease Rights Shell has the exclusive right to drill through and store within the Zone of Interest (below the elk point group). However, there are P&NG rights held by third-parties within the SLA that extend to the basement including Shell's ZOI. As a result, the ADOE has flagged the

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

- There are no other 3rd party CCS projects proposed in the vicinity of the Quest Project. Any new CCS project would be accessed on the impact created by the overall pressure increase in the BCS.

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

  Lateral separation is a significant safeguard as dynamic reservoir models show that CO_2 will never reach the BCS legacy wells. Also in the expectation reservoir scenario the pressure will never exceed the threshold to lift BCS brine to the groundwater protection zone.
- **Multiple cement plugs** seal the abandoned BCS legacy wells.
- **Multiple casing strings** within the injection wells provide three barriers against corrosion.
- **Chrome casing** over the injection intervals provides additional corrosion resistance.
- **Cement placement** along the entire wellbore of each injector creates the largest possible cement barrier to fluids migrating upwards outside the casing.
- **Injection pressures** will never exceed the measured pressure required to open fractures.

- **Mechanical barriers** to vertical fracture propagation are provided by multiple clay-rich layers within the LMS and larger compressive stresses within the first seal.
- **No faults** across any of these geological seals are detectable on the 3D and 2D seismic data.
- **No recorded earthquakes** indicates there is no current tectonic activity that might re-activate an unknown fault.
- **Limited shear stress** is induced inside the storage complex during injection which reduces the likelihood of re-activating an unknown fault.
- **Ductile creep** within the Lotsberg Salts is likely to re-seal any fault or fracture unexpectedly induced by CO_2 storage.
- **Acidic fluids** cannot erode either Lotsberg Salt Formation which is made of pure halite that does not react with CO_2 saturated brine.

The *corrective* measures in-place include:

- **The Winnipegosis/Contact Rapids** will act as a potential baffle to migration of CO_2 above the BCS storage complex near the injection wells where it low permeability. It is possible that this interval serves as auxiliary storage on a regional scale in permeable areas away from the wellbores.
- **The Prairie Evaporite** is a major regional seal, 100 to 150 m thick over the SLA.
- **The Beaver Hill Lake Group** provides a series of baffles and auxiliary storage to inhibit vertical migration of fluids.
- **The Cooking Lake Formation provides** another major auxiliary storage formation, able to dissipate pressures and store CO_2 or BCS brine. This is the most likely auxiliary storage formation because it already has some pressure depletion due to nearby production.

  Even if there was sufficient pressure, 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 SLA including above the injection wells.
- **The Mannville Group** offers auxiliary storage capacity within multiple producing clastics reservoirs
- **The Colorado Group** is a proven seal for the hydrocarbon accumulations
- **The Lea Park** is a marine shale with a lateral extent greater than the SLA and a thickness of about 120 m at the Radway 8-19 -59-20 well pad.

The residual likelihood of all these multiple independent safeguards failing is judged to be *very low* (see Table 4-44). Figure 4-1 provides a summary of the relationship between all these threats, safeguards and consequences.

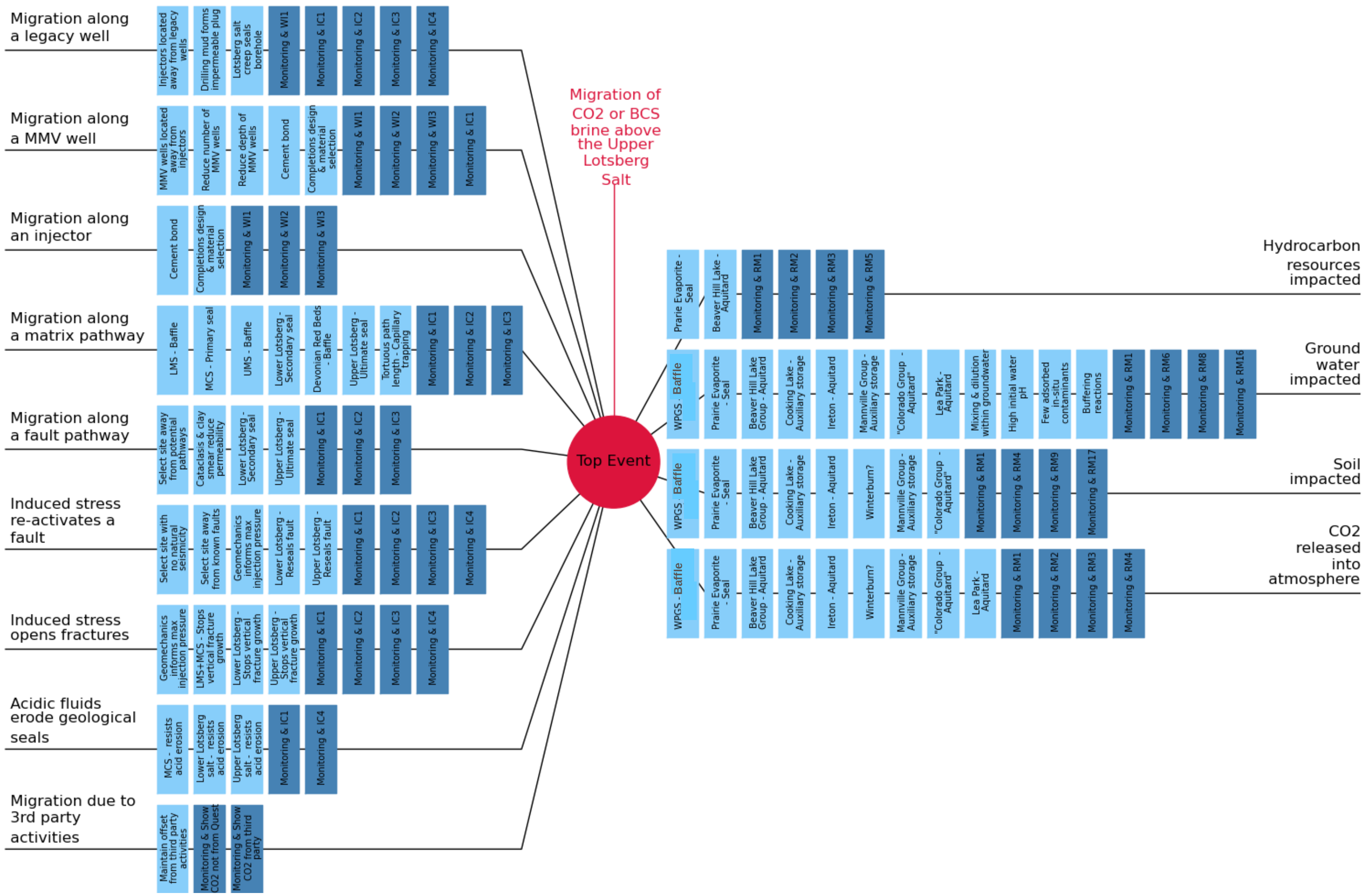

Figure 4-1 Summary of the safeguards in place to reduce the likelihood (left side) and consequence (right side) of any unexpected loss of containment. The active safeguards are supported by the monitoring plan (Section 0) and control measures (Section 9).

5 Monitoring Technology Selection

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

5.1 Monitoring Performance Targets

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

CO_2 Inventory Accuracy Target

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

Conformance Monitoring Targets

1) *Observed storage performance conforms to predicted storage performance within the range of uncertainty.*
2) *Knowledge of actual storage performance is sufficient to distinguish between two classes of possible future performance: those that result in permanent stable storage of the target mass of CO_2 inside the BCS storage complex, and those that do not.*

Containment Monitoring Targets

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

5.2 Monitoring Tasks

The monitoring tasks identified to fulfill these monitoring targets are:

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

- Monitor for any biosphere impacts
- Monitor for any 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 mineralization trapping. This is not part of the conformance monitoring target because there is no evidence that any one mechanism is any less secure than another within the BCS storage complex. The relative contribution of these trapping mechanisms should not impact the transfer of liability which depends on a demonstration of containment and conformance.

5.3 Monitoring Technologies

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

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

- **Multiple BCS observation wells**: Time-lapse seismic 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 such as:

- **Tracers,** both artificial and natural tracers, are currently undergoing feasibility assessment for monitoring implementation.

  The usefulness of artificial PFC tracers co-injected at some CO_2 storage sites has been demonstrated; however, uncertainties remain with regards to potential scavenging and losses of the PFC tracer due to the interaction of the parent fluid, (i.e. CO_2, with different rock matrices and other subsurface fluids). Experimental work supporting the PFC tracer feasibility study is being conducted in collaboration with The Commonwealth Scientific and Industrial Research Organisation (CSIRO) and the Institute for Energy Technology (IFE).

  In addition to the artificial PFC tracer study, the use of the natural abundance of C-isotopic composition of CO_2 is being investigated as a potential natural tracer of the injected CO_2. As part of the HBMP activities, the isotopic composition of CO_2 in soil gas and well gas are being determined. Samples from the Scotford Upgrader are also being collected for analysis. Furthermore, the University of Calgary was contracted to undertake a laboratory and modelling study to assess whether or not the isotopic composition of the injection gas may change along the stratigraphic column in case of a hypothetical leakage event.

The chemical and isotopic composition of formation fluids is also being investigated as potential tracers as part of the Alberta Innovates – Technology Futures (AITF) study entitled 'GROUND WATER STUDY FOR QUEST CCS PROJECT'. A key focus of this study is to assess the characteristics of potable groundwater aquifers across the Quest project area and to evaluate potential trigger conditions which may suggest a deviation from established baseline conditions.

In accordance with AER Condition 13 [1] a special report on the feasibility of using an artificial tracer for CO_2 injection or an alternative will be provided.

- **Remote Sensing** is being assessed for use in biosphere monitoring for CO_2 and BCS brine detection using multispectral image analysis (Rapideye Image) and Radar Image Analysis (RadarSat2 Image) respectively. The feasibility study on the use of RadarSat2 imagery for biosphere monitoring for increased soil salinity in the case of a BCS brine leak in still ongoing. Although this technology has been proven elsewhere, it still requires site-specific calibration to see if it is able to sufficiently monitor changes across such a large SLA. However, it is noted that although this technology is still being assessed, the risk of BCS brine leakage has been considerably reduced as a result of the 2012/2013 drilling program results.
- **Light Source** monitoring, is a novel application of existing technology. A field trial, combined with hardware (lasers) and software development work is ongoing on the IW 8-19 well pad and will continue through to 2014. All testing to date indicates that this technology will be highly effective at monitoring for atmospheric releases of CO_2 in the vicinity of each of the injection well pads.

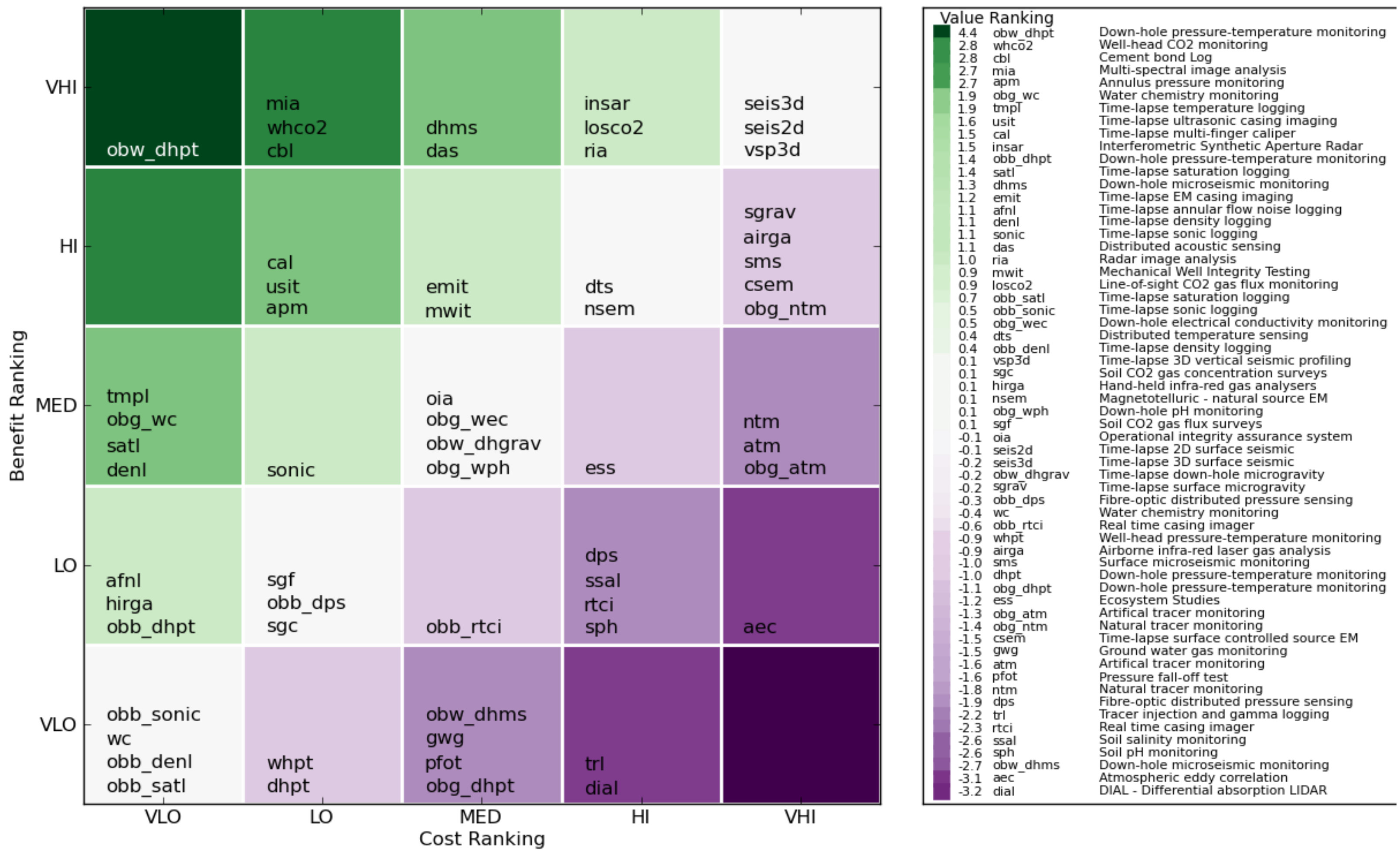

Figure 5-1 Ranking of monitoring technology options according to expected benefits and costs. Colours denote the difference between the benefit and cost rankings as an indicator of value.

6 Monitoring Plan

This section describes the type, frequency and coverage of monitoring activities included in the monitoring plan for the wells and the storage complex. Subsequent sections describe the expected performance of these monitoring technologies (Section 7) and the contingency plans in case these are not realized.

6.1 Monitoring Schedule

The monitoring schedule allows for multiple independent monitoring systems with comprehensive coverage through time and across the AOR within each of the environmental domains (Table 6-1 Table 6-2 and Figure 6-1). The diversity of monitoring technologies mitigates the risk of any one technology failing.

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

Monitoring	Coverage	Pre-Injection	Injection	Closure
Atmosphere				
Line-of-sight CO_2 gas flux monitoring	Within 6 km of every injector	Continuous	Continuous	Continuous
Biosphere				
Remote Sensing - RadarSat2 Satellite acquisition for Radar Image Analysis (soil salinity)	Entire AOR	Same as InSAR (same image)	Same as InSAR or once per year if no InSAR	Same as InSAR or once every two years
Remote Sensing - multispectral image acquisition via Rapideye Satellite	Entire AOR	3 times/year	Once per year	Once every two years
Vegetation monitoring (for remote sensing calibration)[a]	Discrete locations across the AOR	3 times/year	As required	As required
Soil monitoring (for remote sensing calibration)[a]	Discrete locations across the AOR	3 times/year	As required	As required
Surface CO_2 flux & soil gas	Discrete locations across the AOR	Quarterly	not applicable	not applicable
Hydrosphere				
Down-hole pH and EC monitoring [a]	Project groundwater wells	Continuous	Continuous	Continuous
Natural tracer monitoring [a]	Project and Private landowner groundwater wells	At least every year	TBD[b]	TBD[b]
Artificial tracer monitoring [a, c]	Project and Private landowner groundwater wells	At least every year	TBD[b]	TBD[b]
water and gas sampling, including isotopic analyses [f]	Project groundwater wells	annually before April 1st 2014	annually	annually (if required)
Geosphere				
Time-lapse 3D vertical seismic profiling [d]	Within 600 m of every injector	2014	2015, TBD[e]	None
Time-lapse 3D surface seismic	Entire CO_2 plume	2010	2022, 2029, 2039	2048
Interferometric Synthetic Aperture Radar	Entire AOR	Monthly	Monthly	Monthly

NOTES:

[a] See HBMP Appendix A for details

[b] TBD = to be determined, based upon findings from first year pre-injection (baseline) monitoring phase

[c] inclusion of artificial tracer monitoring depends upon outcome of feasibility study early 2014

[d] Baseline data will be acquired using conventional down-hole geophones and the DAS system, it is expected that subsequent surveys will be acquired with the DAS system only with conventional geophones as contingency.

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

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

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

Monitoring	Pre-Injection	Injection	Closure
Deep Monitoring Wells			
Down-hole pressure-temperature monitoring	None	Continuous	Continuous
Down-hole microseismic monitoring (8-19 well pad only)	6 months	Continuous	None
Cement bond log	Once	None	None
SCVF testing as per AER ID 2003-01 [f]	annually (before April 1st 2014)	annually	annually (if required)
Gas migration testing as per AER Directive 020 [g]	annually (before April 1st 2014)	annually	annually (if required)
BCS Monitoring Well (Redwater 100-03-04-057-20W400)			
Down-hole pressure-temperature monitoring	None	Continuous	Continuous
Cement bond log	Once	None	None
Injection Wells			
Well-head pressure-temperature monitoring [b]	None	Continuous	Continuous
Time-lapse ultrasonic casing imaging	Once	Every 5 years	Every 10 years
Time-lapse electromagnetic casing imaging	Once	Every 5 years	Every 10 years
Time-lapse casing caliper logs	Once	Every 5 years	Every 10 years
Time-lapse cement bond log	Once[a]	Every 5 years[b]	Every 5 years
Mechanical well integrity testing (packer isolation test) and tubing caliper log [a]	Once	Every year	Every 3 years
Injection rate monitoring [b]	None	Continuous	None
Distributed temperature sensing	None	Continuous	Continuous
Down-hole pressure-temperature monitoring[d]	As Required[E]	Continuous	Continuous
Distributed acoustic sensing	None	Continuous	Continuous
Annulus pressure monitoring [b]	None	Continuous	Continuous
Routine well maintenance [c]	Every year	Every year	Every year
SCVF testing as per AER ID 2003-01 [f]	annually (before April 1st 2014)	annually	annually (if required)
Gas migration testing as per AER Directive 020 [g]	annually (before April 1st 2014)	annually	annually (if required)
Hydraulic Isolation logging (same time as mechanical well integrity testing above)[h]	Once per well	2016, 2017, then as required	None

[a] A D51current regulatory commitment for Class III wells.

[b] A possible future D51 regulatory commitment for Class III wells (current requirement for Class I wells).

[c] A maintenance task related to the wells, included in this table for completeness.

[D] Shut-in stabilized pressure fall off tests are a subset of the data collected via DHPT gauges

[E] Shell will use IW 7-11 and IW 5-35 for temporary DHPT monitoring until injection starts in these wells.

[f] Annual SCVF testing as per AER ID 2003-01 for non-serious SCVF, until time of well abandonment or until SCVF dies out. Annual reporting to AER is required. See AER letter from December 3rd 2013 regarding approval of the MMV plan for full details.

[g] Annual Gas Migration testing as per procedure given in AER Directive 020, Appendix 2, until time of well abandonment or until the GM disappears. Annual reporting to AER is required. See AER letter from December 3rd 2013 regarding approval of the MMV plan for full details.

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

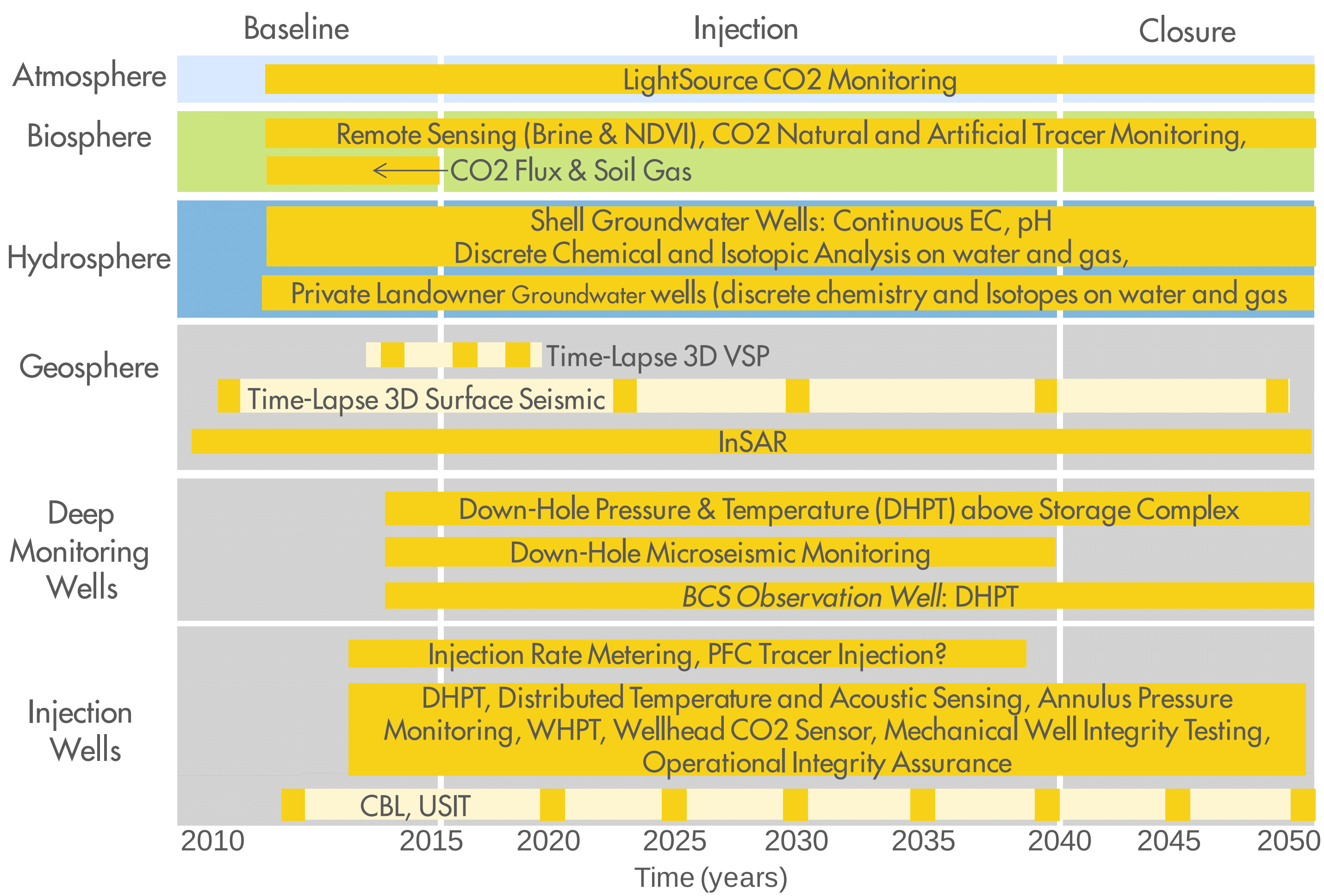

Figure 6-1 Outline of QUEST's diversified monitoring program. This eliminates the dependence on any single monitoring technology. Note: some monitoring is dependent upon outcome of ongoing feasibility studies (Section 5.3).

6.2 Monitoring Coverage

The coverage of most monitoring systems is centered on, or confined to, one of the several different types of Project wells (Table 4-1). The coverage expected from each monitoring system varies considerably – some cover the entire SLA, whilst others cover regions of varying distance from each injection well (Figure 6-2, Figure 6-3, and Figure 6-4).

6.2.1 Observation Wells within the Basal Cambrian Sands Formation

As previously submitted January 31, 2013 as part of the first annual status report, and in accordance with AER Condition 11a, Shell will use 103-07-11-059-20W400 and 102-05-35-59-21W400 injection wells as BCS Formation monitoring wells prior to commencement of injection, when feasible. At start-up, the first injector (IW 8-19) will be progressively ramped up until stable injectivity is achieved. An interference test will follow with pressure in the BCS being monitored at IW 7-11 and IW 5-35. Afterwards, the other IWs will be started sequentially to ensure they all reach stable injectivity before Q4 2015 so that the contractual obligation for sustained operations can be achieved before the deadline of end 2015.

Furthermore, Shell plans to monitor the BCS pressures across the SLA, in the BCS, continuously at the three injection wells (IW 8-19, IW 7-11, and IW 5-35 and one observation well (Redwater 3-4) (Figure 6-2). This long-term continuous pressure monitoring will be the basis for history matching dynamic reservoir models

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 injection wells. However, in accordance with AER Condition 10i, this decision will be re-assessed on an annual basis and is at the discretion of the AER. 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[i] and are ineffective at conformance monitoring unless used in large numbers. Moreover, drilling a BCS observation well to measure geochemical reactions and calibrate the trapping mechanism is of limited value because these are expected to be negligible within the BCS and, if necessary, may be measured by logging injection wells during the closure period.

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

The option of locating one or more BCS observation wells within a single CO_2 plume to validate and calibrate the time-lapse seismic response was also rejected due to the expectation of insufficient benefits to justify the incremental costs and containment risk. . A seismic trace represents a composite response from an area of approximately 25m * 25m that can be used to image the CO_2 plume geometry through amplitude changes. This is difficult to calibrate with an observation well because in-well logging techniques are not sensitive to saturation distributions away from the immediate vicinity of the wellbore. Therefore, a seismic response may indicate the presence of CO2 that are not seen or are

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

different concentration than that measured in the well (i.e. narrow sand bodies may channel the CO_2 towards or around the well). Moreover, time-lapse seismic is routinely used for Well and Reservoir Management without the need for calibration by observation wells because the failure case is easily recognized as an image dominated by incoherent noise.

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

6.2.2 Deep Monitoring Wells (Above BCS Storage Complex)

Currently, Shell has one deep monitoring well (DMW) on each injection well pad, each DMW is drilled to the Ernestina lake Formation (Figure 6-2). AER Approval 11837A Conditions 10i and 10j require Shell to address the potential need for installing additional monitoring wells towards the periphery of the pressure build up area later in the project life and evaluate the need for additional deep monitoring wells adjacent to the four legacy wells in the approval area.

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

The prime role of the three Deep monitoring wells is to support pressure monitoring to verify containment. The Winnipegosis/Contact Rapids was 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 evaluated three regional aquifers (WPGS, BHL and CKLK) in the 2012/2013 drilling campaign and determined that the WPGS/CRPD was tight and that the Cooking Lake Formation was the best monitoring interval as per Shell application to monitor the Cooking Lake and subsequent approval granted from Alberta Energy May 2012. However, it is noted that due to the regional 3rd party activity in the Cooking Lake, pressure monitoring is more complicated and the alarm thresholds are yet to be determined. This will occur after baseline monitoring studies are complete.

The current plan is to start up the project using the 3 injection wells already drilled plus one deep monitoring well on each injection well pad, drilled to the Ernestina lake formation. All three are expected to have downhole pressure and temperature gauges monitoring the Cooking Lake Formation.

In addition to the DMW pressure monitoring, one of these deep monitoring 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 injection wells to ensure it will monitor that part of the BCS storage complex expected to develop some of the greatest pressures. The current approved plan is to only have a microseismic array in IW 8-19. However, contingency plans exist to revise this selection based on actual injection performance. .

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

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 as per the Shell's hearing commitments Table 1-1 in exhibit #134.04 [9].

In fulfillment of the above commitment Shell has used the 5 existing groundwater wells located on the 8-19 well pad (Figure 6-3). 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 are 2 deep (down to about 125m BGL) and 2 shallow (about 20 to 30m 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 injection wells 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 injection wells is sufficiently small to ensure effective groundwater monitoring.

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 near legacy wells are identified in all the Figures as a contingency in the event they are required. The latter will be evaluated on an annual basis in the annual operations report to the AER.

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.

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 6-2).
- A regional network of groundwater wells, sparsely distributed across the remaining AOR at a density of approximately one per township (Figure 6-2).
- Any additional landowner water wells where such landowners have requested to participate in the program, in accordance with AER Approval 11837A.

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.

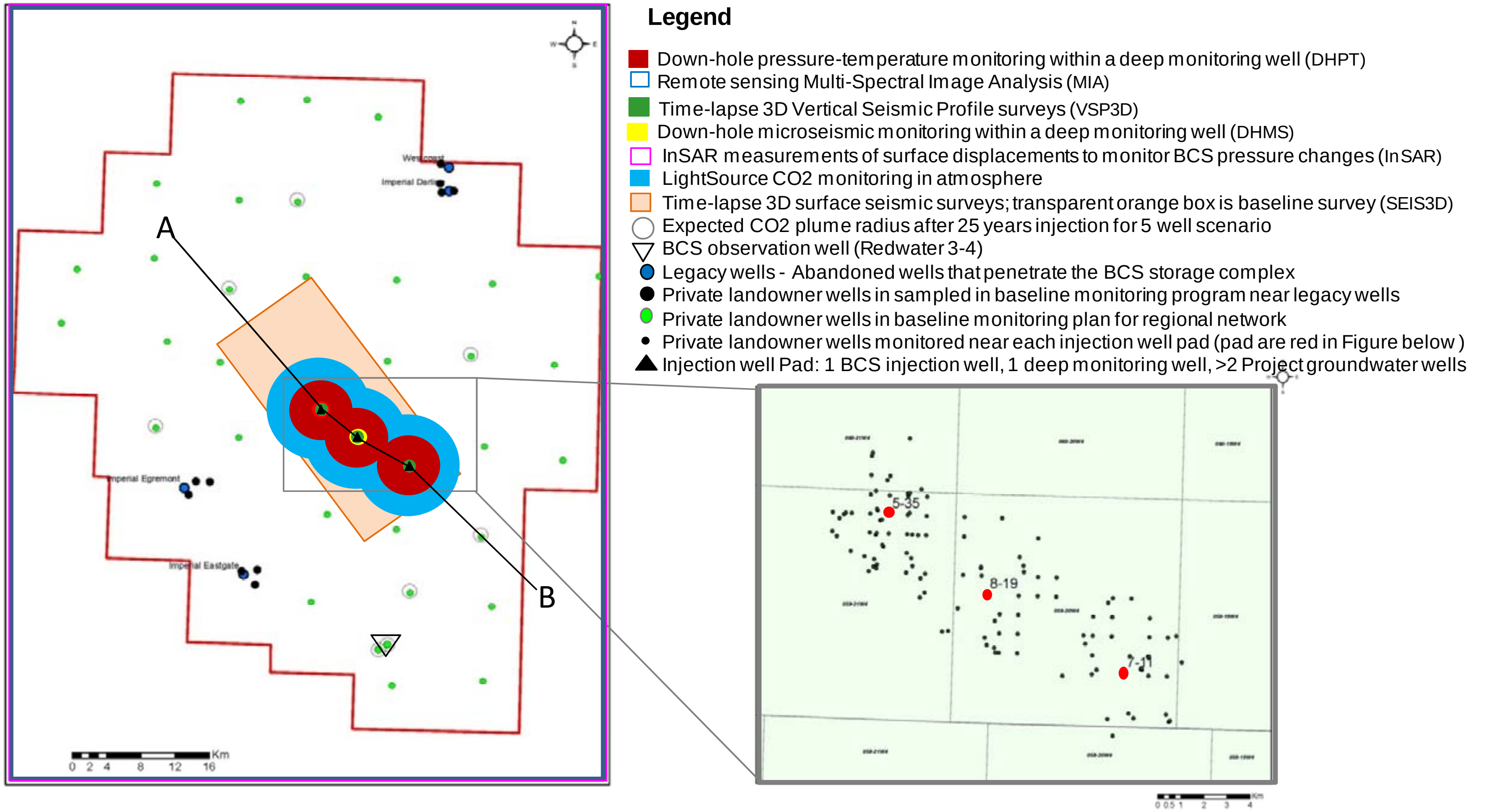

Figure 6-2 Maps showing the coverage of different monitoring methods for the base-line monitoring plan. Updates, to the plan for injection period will be submitted as part of the January 31, 2015 MMV plan update

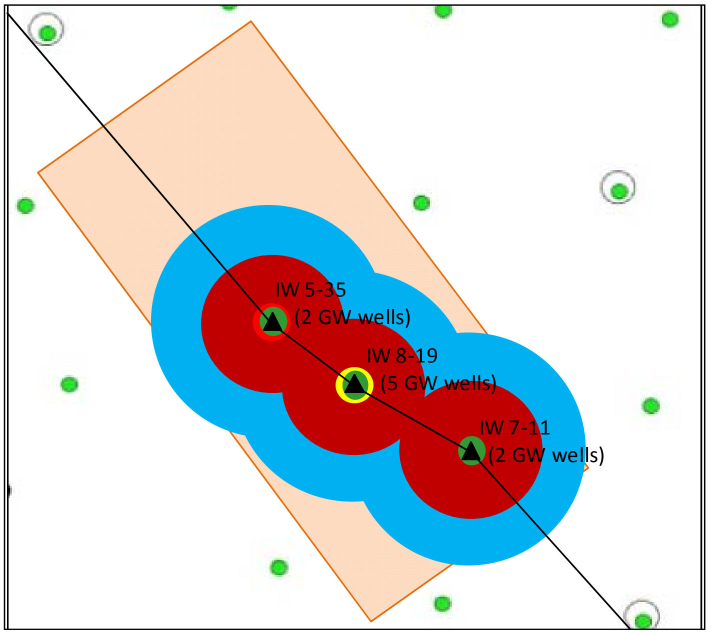

Figure 6-3 Same as in Figure 6-2, enlarged to demonstrate the coverage of monitoring around each injection well (Project groundwater wells near injection wells not shown.

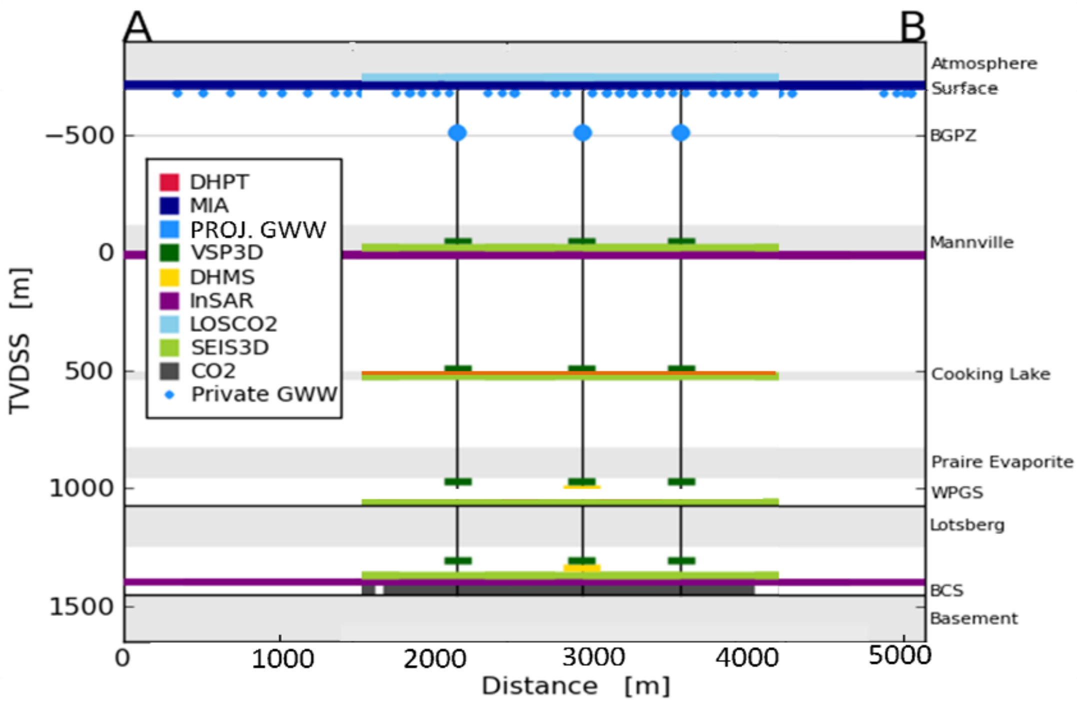

Figure 6-4 Schematic cross-section showing the expected coverage of different monitoring methods for the baseline monitoring plan. See Figure 6-2 for the location of this cross-section and an explanation of the legend.

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 CO_2 Plume Development

Time-lapse seismic (VSP3D, SEIS3D) will be used to monitor the development of the CO_2 plume inside the BCS storage complex. Repeat seismic surveys are expected to yield an image of the CO_2 plume geometry around each CO_2 injector. CO_2 entering the pore space within the Basal Cambrian Sandstones will replace some of the brine. Because the injected CO_2 is much more compressible than brine, the speed of seismic p-waves traveling through the BCS will be reduced in those places containing CO_2 and will remain unchanged elsewhere. Differences in seismic images of the BCS obtained before and during CO_2 injection will arise due to the presence of CO_2 in two characteristics ways:

Travel-time across the BCS will become longer (c. 8%) due to the slower p-wave velocity inside the BCS.

Reflections from the base of the BCS will become stronger (c. 8%) as the impedance contrast with the underlying granite basement increases. The contribution of bulk density changes is negligible.

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

Evaluation of seismic data acquired during the appraisal period and site-specific feasibility studies indicated CO_2 will be detectable in those places where CO_2 fills at least 5% of the pore-space and the thickness of a contiguous CO_2 plume exceeds 5 m. The expected lateral and vertical resolution of the CO_2 plume geometry are 25 m and 10 m respectively. This expected sensitivity and resolution is based on a typical amount of non-repeatable noise being present within the two 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 (DAS) 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 the results of a successful field trial at IW 8-19, this technology is included in the monitoring plan. The use of conventional geophones in the DMWs is a contingency.

7.1.2 Monitoring Pressure Development

Down-hole pressure temperature 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.

As per AER Conditions 4d, 5b, 6a, 10b, 11c, and 17g collection and analysis of shut-in stabilized pressure fall-off tests (or analytical equivalent) and pressure transient analyses will be completed on an annual basis. The initial baseline BCS fall-off test for the 100-08-19-059-20W400 well was submitted as part of the second annual status report submitted to AER January 31, 2014; furthermore, BCS build-up test for both the 102/05-35-059-21W400 and 103/07-11-059-20W400 wells were also submitted. Both of these wells had considerably more extensive testing

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 CO_2 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. This allows temporal pressure changes of 0.1 to 1 MPa to be detected and spatial pressure changes to be mapped with a lateral resolution of 1 to 3 km. This is sufficient to delineate any region subject to a pressure increase sufficient to lift brine above the 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 injection wells. 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 CO_2 storage
- Provide early warning should fluids migrate out of the BCS storage complex
- To ensure the necessary reliability, this monitoring capability is provided by many independent technologies intended to detect change above the BCS storage complex.

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 AER 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 diffe**r**ent 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.

Hydraulic Isolation Testing will be possible every year using temperature logging when the well is shut in for mechanical integrity testing (See DTS below).

Hydraulic isolation logging is required after 2 years of injection and thereafter the need will be determined by the annual reporting and presentation process as per AER approval condition 5c

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 surface down to 11m above the 1st seal (MCS) in IW 5-35, 2m above the MCS in IW 7-11 and 10m above the base of the MCS in IW 8-19. All fiber optic cables, situated on the outside of the intermediate casing, will provide a continuous means of verifying cement bond integrity, hydraulic isolation, and the absence of CO_2 outside the casing and across the second and ultimate seals (Lower and Upper Lotsberg salts). In the unexpected event of a loss of cement bond integrity, any upward migration of CO_2 outside the casing will lower the temperature on the adjacent portion of the DTS fiber due to increased thermal insulation from the in-situ formation temperature provided by the out-of-place CO_2.

Evaluation of data acquired at IW 8-19 during the appraisal period and 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 CO_2 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 CO_2 cannot be directly distinguished from a flux of CO_2 outside the casing.

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

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

7.2.3 Monitoring Geological Seal Integrity

Deep monitoring wells have been drilled from 3 of the injection well pads and completed within the first major permeable zone above the BCS storage complex, the Cooking Lake formation. The need for additional Deep monitoring wells on the periphery of the pressure build up and near legacy wells, as per Condition 10i and 10j respectively, will be evaluated on an annual basis in the annual operations report to the AER.

Continuous pressure measurements (DHPT) within the deep monitoring wells will provide a means of detecting any unexpected migration of injected CO_2 or brine out of the BCS storage complex. Based on data obtained in the 2012/2013 drilling campaign, the Cooking Lake Formation is the interval that will be monitored for pressure. The amount of fluid migration into this the Cooking Lake that will cause a detectable sustained pressure rise still needs to be determined through baseline pressure data gathering and dynamic modeling work. The time to detection will depend on the distance through the permeable formation between the fluid entry point and the pressure gauge and the amount of gauge noise and impact from offset regional production in the Leduc reefs.

Time-lapse seismic (VSP3D, SEIS3D) will be used to verify the absence of CO_2 above the ultimate seal of the BCS storage complex. In the vicinity of the wells, it is the Cooking Lake that would be used to verify the absence of CO_2 above the storage complex as the Winnipegosis/Contact Rapids is impermeable. However, away from the well control, other formations may be used (i.e. Winnipegosis/Contact Rapids, Beaverhill Lake Group etc.) as they are known to have reasonable permeability on a regional scale. Any CO_2 unexpectedly entering an overlying Formation, will affect the seismic image due to the same physical effects previously described for CO_2 entering the BCS (Section 7.1.1). Due to different formation properties and different in-situ temperature and pressure conditions that affect the properties of CO_2, the magnitude of anticipated time-lapse seismic changes in the unexpected event of CO_2 entering these formations varies.

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

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

For an assumed average CO_2 saturation of 20-40% within such a CO_2 plume, this corresponds to an expected detection limit of 100,000 to 60,000 tonnes of CO_2. This expected sensitivity is based on a typical amount of non-repeatable noise being present within the two land seismic images which will only be confirmed after the second 3D VSP is processed.

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

Microseismic (DHMS) monitoring using a conventional down-hole array with 8 levels of three-component retrievable geophones that is deployed within one of the deep monitoring 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 geophone array will be deployed in DMW 8-19.

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 gauges with +/-0.1% accuracy.
- The temperature will be measured with meters gauges+/-0.5 degrees Celsius accuracy.

These estimates based on the technical specifications of the flow rate, pressure, and temperature monitoring systems.

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 CO_2 upwards from the BCS storage complex will cause volume changes within any overlying permeable formations that receive these fluids. Any such volume changes above the ultimate seal will result in surface displacements additional to those expected due to pressure development inside the BCS storage complex. These additional surface displacements will be more localized in lateral extent. A feasibility study indicates migration of more than 250,000 tonnes of fluid from the BCS into the Mannville Group or Cooking Lake Formation are likely detectable. Due to the limited depth resolution achievable from surface displacement data, any unexpected volume changes inside the Winnipegosis Formation are too close in depth to be distinguished from the expected volume changes inside the BCS and LMS. However, any volume changes inside the shallower Cooking Lake Formation are likely to be detectable. Because the Cooking Lake is under-pressured relative to the BCS pressure gradient, any leakage reaching this depth is likely to preferentially move into this formation.
- Fault slippage: There were no faults detected on 3D or 2D seismic 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. However acquisition of InSAR data over the SLA started in 2010 to evaluate the number of reliable natural monitoring targets within the existing landscape. Shell submitted Special Report #2 as per Conditions 9e and 12 to AER January 31, 2013 with evidence showing corner reflectors are not required for monitoring the SLA due to a sufficient number and spacing of natural targets. However, installation of artificial corner reflectors remains in the contingency monitoring plan (Section 8.1). The AER approved the current plan on Oct 4 2013 under the following conditions:

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

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

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

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. Based on Gen-4 modelling, though, this risk is highly improbable. Threshold WEC values will be determined as part of the baseline monitoring program and associated feasibility studies as discussed in section 5.3.

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 CO_2 within the groundwater. Threshold WPH values will be determined as part of the baseline monitoring program and associated feasibility studies as discussed in section 5.3.

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 CO_2 within the groundwater at those locations. This will be achieved through measurement and evaluation of various indicator and tracer parameters (see section 2.7 of HBMP plan) during the baseline monitoring program. Threshold values will be determined as part of the baseline monitoring program and associated feasibility studies as discussed in section 5.3

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 AOR to help indicate the absence of BCS brine and Project CO_2 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 polarization 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 normalized 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.

Evaluation of data from the 2102/13 drilling campaign has shown that the pressure increase in the BCS will not reach a level sufficient to lift BCS brine to the base of the ground water protection zone even at the injection wells. Therefore, after completion of Gen-5 Modelling Shell will review the requirement to continue RIA monitoring into the injection 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 analyzed 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 analyzed to determine the presence or absence of BCS brine tracers, natural CO_2 tracers and if utilized, the artificial PFC tracer injected with the CO_2.

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 CO_2 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 CO_2 gas flux monitoring' or LOSCO2) will provide a method to verify the absence of any unexpected atmospheric CO_2 emissions potentially originating from the BCS storage complex. One monitoring system will operate continuously on each injection well pad and is expected to detect and map CO_2 emissions up to 6 km from each injector. This is beyond the current anticipated radius of a CO_2 plume developed around each injector at the end of the injection period. The expected sensitivity and resolution of CO_2 emission mapping depends on distance from the sensor system:

- **1 km:** A 100 kg/hour (0.9 kilo-tonnes/year) release rate of CO2 from a point source will be detectable and locatable from a range of about 1km, within days and mapped with a resolution of approximately 100 m, subject to prevailing wind directions and relative beam locations.
- **2 km:** A release rate of 250 kg/hr (2.19 Kt/year) would be detectable and locatable from a range of approximately 2 km with a proportionately lesser resolution of approximately 200 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 CO_2 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 CO_2. Observed monitoring performance during the baseline monitoring period and controlled CO_2 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.

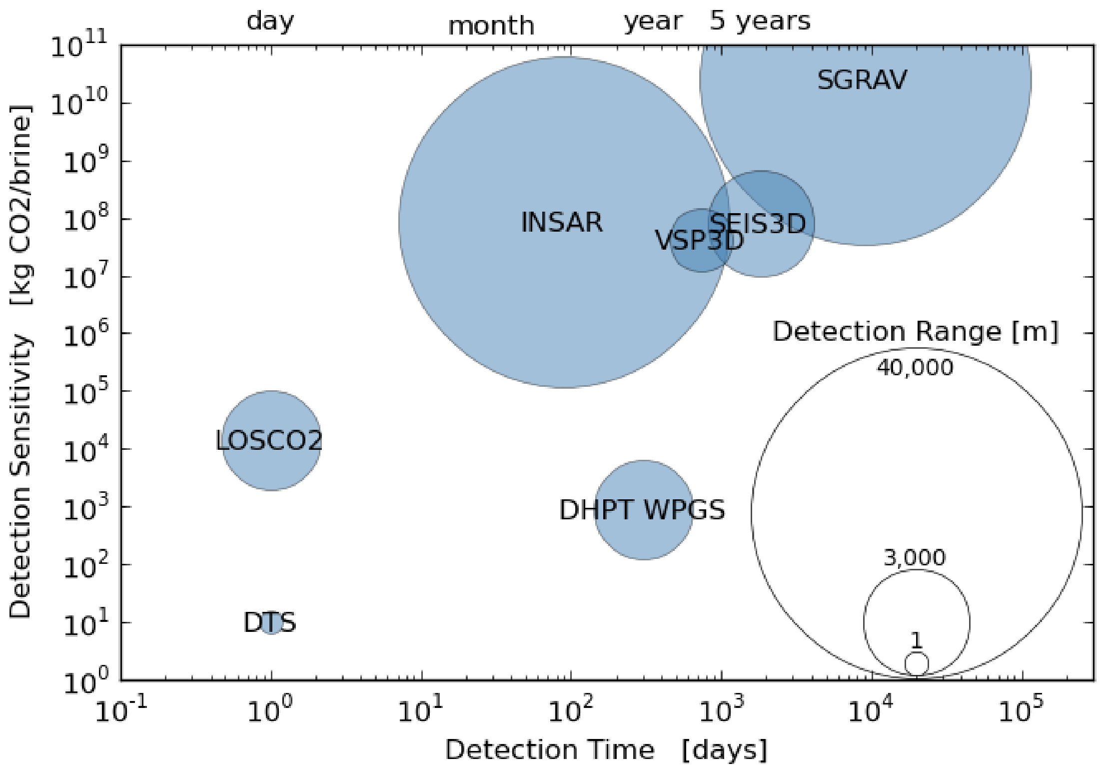

Figure 7-1 A comparison, where possible, of the expected detection time, detection sensitivity and detection range for a range of different monitoring technologies. Figure will be updated in 2014 when detection thresholds finalized.

Legend:

$LOSCO_2$ Line-of-sight CO_2 monitoring (LightSource),

DTS Distributed Temperature Sensing,

DHPT CKLK Down-hole pressure-temperature monitoring within the Cooking Lake 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.

The list of models already in use for the Quest CCS project that are expected to be required during the project's lifecycle are shown below along with the accountable discipline.

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

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

7.4 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 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, update the frequency and threshold values.

Technology	Indicator	Frequency	Baseline		Sensor Error	Threshold		Alarm	Units
			[mean]	[std]	[std]	[mean]	[std]	[value]	
LightSource 2x2	CO_2 Emission Mass Rate	Every day	0	0	631	25000[i]	0	23500	tonnes/ year
LightSource 6x6	CO_2 Emission Mass Rate	Every day	0	0	5256	25000[i]	0	23500	tonnes/ year
SPH	Soil pH	Every year	TBD [ii]						pH units
SSAL	Soil Salinity Change	Every year	TBD [ii]						ppm
WPH	Water pH	Every day	TBD [ii]						
WEC	Water Salinity	Every day	TBD [ii]						
VSP3D	CO_2 Mass above Ultimate Seal	Every year, maximum of 3[iii]	0	0	40.0	190.5	0.0	89.5	kilo-tonnes
SEIS3D	CO_2 Mass above Ultimate Seal	Every 5 to 10 years	0	0	80.0	296.3	0.0	118.5	kilo-tonnes
DHMS	Microseismic Depth decrease	Every day	0	0	10.0	170	0.0	160	m
DHPT CKLK	Fluid Mass Rate into CKLK	Every day	0	0	TBD [ii] 2014	TBD [ii] 2014	0.0	TBD [ii] 2014	tonnes/ year
InSAR	Fluid Mass increase above Ultimate Seal	Every month	0	0	83	617	0.0	444	kilo-tonnes
DTS	CO_2 Mass Rate outside intermediate casing	Every day	0	0	TBD [ii] 2014	TBD [ii] 2014	0.0	TBD [ii] 2014	tonnes/ year

NOTES:
[i] Threshold based on maximum IPCC emission limits range of 100-1000 ppm/year for 27 Mt CO_2 stored.
[ii] TBD - to be determined based upon HBMP baseline monitoring findings and feasibility studies
[iii] The second VSP timing will be based on the observed CO_2 plume growth rate rather than a preset date (i.e. it may occur 2 years after the previous one if plume migration is slow).

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.

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 2mm/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 injection wells then these observation wells may not be required as there would never be sufficient pressure to lift BCS brine above the base of groundwater protection.

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

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

- **Reason:** The input data for the current site-specific homogeneous linear elastic half-space geomechanical model are not appropriate.
- **Indicator:** The observed maximum uplift is greater than 60 mm which is the greatest amount of surface heave predicted by the low reservoir property case Gen-4 models.
- (However, it is noted that the most recent well information, acquired in 2012/2013 indicates that 60 mm of surface heave is highly unlikely due to the fact that the low property outcome is unlikely to exist. This maximum uplift will be updated in 2014 based on the Gen-5 pressure predictions.
- **Mitigation:** Unexpected surface uplift would first trigger an attempt at model updating to restore conformance. These model updates would include updating the pressure build-up within the storage complex using site-specific pressure measurements and updating the elastic parameters (e.g. Young's modulus - only significant remaining uncertainty) of the formations that experience this pressure build-up.

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

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

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

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 IW 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 seismic changes are too small to image the CO_2 plume

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

The rate of CO_2 plume growth is different than expected

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

8.3 Microseismic Monitoring

The selected microseismic monitoring well provides insufficient coverage

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

A single microseismic monitoring system provides insufficient coverage

- **Reason:** Unexpected microseismic events that appear to have 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 CO_2 injection wells.
- **Indicator:** Sustained microseismic activity located within and above the Lower Lotsberg Salt with spatial patterns indicative of fracturing.
- **Mitigation:** Deploy recording systems to monitor microseismic activity using deep arrays within the deep monitoring wells near every injector
- **Response time:** 6-12 months are likely required to deploy these recording systems on every injection well pad.

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 4-4).

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

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

9.1 Additional Safeguards to Ensure Conformance

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

CO_2 plume development:

- **Monitoring:** Time-lapse seismic.
- **Intervention Indicator:** The observed CO_2 plume is larger than the baseline 3D seismic area, or there is a clear temporal trend towards this state.
- **Control Options:** Update models and rely on only model based predictions. If necessary increase the areal extent of the baseline 3D seismic survey. Consider re-distributing injection across existing wells or drilling additional injection wells to keep the plume within the footprint of the original 3D seismic area.
- **Response Time:** 3-6 months for model updates or additional seismic surveys. Re-distribution of injection between existing wells is available on demand. Drilling additional injection wells will take12-18 months and are subject to additional regulatory approvals and land access consents.

Pressure development:

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

- **Response Time:** 3-6 months for model updates. 1-3 months to schedule additional InSAR data acquisition.

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

Injected mass of CO_2:

- **Monitoring:** Wellhead injection rate metering on each injector and rate metering at the compressor outlet in Scotford, minimum technical accuracy of 0.5%
- **Intervention Indicator:** Based on existing acid gas disposal regulations, a difference greater than 5% between the sum of monthly CO_2 injection volumes for all injection wells and the Scotford fence-line meter. This is subject to revision as the regulatory framework assessment is ongoing.
- **Control Options:** Recalibrate or, if necessary, replace meters or revise the performance target.
- **Response Time:** 1-3 months.

Emitted mass of CO_2

- **Monitoring:** LightSource (Line-of-sight CO_2 flux metering)
- **Intervention Indicator:** Controlled release tests, planned during major service visits using small “fire extinguisher” calibration tests are not det*ected.*
- **Control Options:** Recalibrate or, if necessary, replace meters.
- **Response Time:** 1-3 months.

Target inventory of CO_2

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

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

9.2 Additional Safeguards to Ensure Containment

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

Safeguards supported by Pressure Monitoring

- **Monitoring:** BCS pressure gauges and InSAR.
- **Intervention Indicator:** BCS pressure increase at a legacy well is sufficient to lift brine above BGP or there is a clear temporal trend towards this state.
- **Control Options:** Re-distributing injection across existing wells, increase frequency of groundwater fluid/soil sampling and analysis next to the legacy well, consider drilling a deep monitoring well and/or a project groundwater well at this location.
- **Response Time:** Injection rates can be re-distributed immediately. Additional groundwater fluid samples and soil and vegetation data can be acquired within 2 weeks. 3-6 months are likely required to drill a project groundwater well and 6-12 months to drill an additional deep monitoring well at the legacy well locations.

Safeguards supported by injection well integrity monitoring

- **Monitoring:** Cement bond logging, tubing-casing annulus pressure monitoring, casings annuli pressure monitoring, mechanical well integrity monitoring, corrosion coupons, distributed temperature sensing, distributed acoustic sensing, Cooking Lake formation pressure monitoring, time-lapse seismic
- **Intervention Indicators:** significant deterioration of cement bond, increase in sustained annulus pressure above expectation, failed well integrity test, sustained temperature or noise anomaly outside casing, sustained CKLK pressure, or a time-lapse seismic anomaly around the injection well within the WPGS or shallower.
- **Control Options:** Cross-check information with other monitoring data. If data indicative of loss of containment re-distribute injection away from this well, repair the well by changing the failed completion component(s) or re-plugging with cement, or plug and abandon an injector that cannot be repaired, and drill a replacement well.
- **Response Time:** Continuous pressure monitoring supports an automated instant control response to re-distribute injection (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, CKLK pressure monitoring, time-lapse seismic, InSAR, down-hole microseismic
- **Intervention Indicator:** BCS injector pressure exceeds agreed limits, sustained CKLK pressure, time-lapse seismic anomaly above BCS storage complex, InSAR anomaly due to volume changes above the ultimate seal or within a 10-day period more than 10 microseismic events occur that are located above the base of the lower Lotsberg Salt with a spatial pattern indicative of fracturing.

- **Control Options:** Re-distribute injection across existing wells, drill an additional injector, or stop injection. Consider reservoir fluid extraction to reduce pressures inside the BCS storage complex.
- **Response Time:** Continuous pressure monitoring supports an automated instant control response to re-distribute injection (see Section 10.1). Microseismic monitoring requires 1 month for processing and interpretation. Time-lapse seismic 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 CO_2 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 CO_2 gas flux monitoring)
- **Intervention Indicator:** Sustained localized increase in CO_2 flux confidently exceeds background levels established during the baseline monitoring period.

- **Control Options:** Conduct soil and groundwater investigations at the site of the indicated anomaly. Implement exposure controls. If required, stop injection at all wells suspected to be the source of these emissions.
- **Response Time:** 1-3 months are likely required to conduct these investigations and deploy the appropriate controls measures.

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

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

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

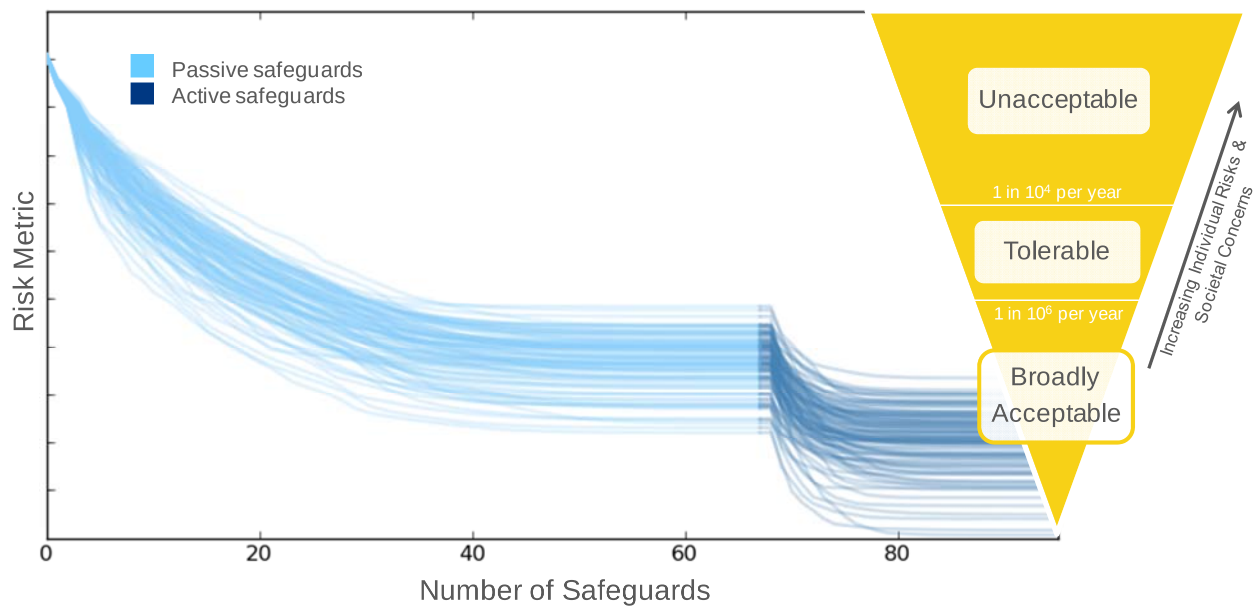

Figure 9-1 Representation of the expected containment risk reductions achieved through implementation of passive and active safeguards.

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

10 Operating Procedures

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

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

10.1 Operating Procedures in Response to Monitoring 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 the well-choke closes automatically

Down-hole pressure and temperature gauge alarm

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

Annulus pressure gauge alarm

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

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

Pressure drop across filter alarm

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

Emergency shut-down (ESD) valve status alarm

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

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 such as:

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

- **Alarm indicates:** Localized CO_2 flux exceeds threshold established after baseline monitoring period from 2012 to 2014 is completed.
- **Alarm response:** Environmental Team will investigate this location and collect samples suitable for BCS and CO_2 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 and collect samples suitable for BCS and CO_2 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 and collect samples suitable for BCS and CO_2 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 spatial pattern indicative of fracturing
- **Alarm response**: Stop injection at the adjacent injector. The Surveillance Team will investigate and, if appropriate re-start injection at lower rates and only increasing injection rates when no further microseismic activity is detected above the base of the *Lower Lotsberg Salt.* The injection rate in other wells would then need to be similarly reduced. In accordance with Condition 6 of the AER approval Shell would submit an incident report to ResourceCompliance@aer.ca and WellOperations@aer.ca within 90 days of detecting the incident.

11 References

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

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

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

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

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

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

[7] Shell Canada Limited Quest Carbon Capture and Storage Project, Directive 65: Application for a CO2 Acid Gas Storage Scheme. Submitted to Energy Resources Conservation Board of Alberta November 2010.

[8] Quest Carbon Capture and Storage Project Radway Field & Surrounding Areas AER Approval No. 11837A, AER Decision 2012 ABERCB 008 Special Report #1 & Pre-baseline MMV Plan. Submitted to AER October 15, 2012.

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

ERCB Processes Related to Carbon Capture and Storage (CCS) Projects. **22**, (2010).

Bachu, S. et al. *Suitability of the Alberta Subsurface for Carbon-Dioxide Sequestration in Geological Media*. *Earth Sciences Report* (Alberta Energy and Utilities Board. Alberta Geological Survey, Edmonton, Alberta, Canada: 2000).

Shell Canada Limited *Update to Directive 65: Application for a CO2 Acid Gas Storage Scheme*. (Quest CCS Project, Heavy Oil Development, Shell Canada Limited, 2011).

Shell Canada Limited *Quest Carbon Capture and Storage Project: Environmental Assessment*. (2010).

DNV *CO2QUALSTORE Report: Guideline for Selection, Characterization and Qualification of Sites and Projects for Geological Storage of CO2*. 79(Det Norske Veritas AS, Oslo, Norway: 2010).at <http://www.dnv.com/binaries/CO2QUALSTORE_guideline_tcm4-412142.pdf>

Zeidouni, M., Moore, M. & Keith, D. Guidelines for a Regulatory Framework to Accommodate Geological Storage of CO2 in Alberta. *SPE 121000* (2009).

PTRC *IEA GHG Weyburn CO2 Monitoring & Storage Project Summary Report 2000-2004*. (From the proceedings of the 7th International Conference on Greenhouse Gas Control Technologies. Vancouver, Canada, September 5-9: 2004).

ARC *Cardium CO2 Monitoring Pilot: A CO2-EOR Project, Alberta, Canada*. (Alberta Research Council (ARC), Geoscience Publishing, Canada: 2009).

Bachu, S. & Gunter, W.D. Overview of Acid Gas Injection Operations in Western Canada. (2005).at <http://uregina.ca/ghgt7/PDF/papers/peer/588.pdf>

Mathieson, A. et al. CO_2 sequestration monitoring and verification technologies applied at Krechba, Algeria. *The Leading Edge* **503**, (2010).

Shell Canada Limited *Storage Development Plan*. (Heavy Oil Development Controlled Document, Shell Canada Limited, 2011).doi:07-0-AA-5726-0001

Mestayer, J. et al. Field Trials of Distributed Acoustic Sensing for Geophysical Monitoring. *Society of Exploration Geophysics* (2011).

Bourne, S. *Quest CCs Project: Technical Feasibility of InSAR for CO2 Storage Monitoring and Leak Detection*. *Change* (Heavy Oil Controlled Document Shell Canada Limited, 2011).doi:07-3-ZG-7180-0016

Hugonet, V. *Quest CCS Project: Feasibility of Distributed Temperature Sensing for CO2 Leak Detection*. *Design* 1-24(Heavy Oil Controlled Document Shell Canada Limited, 2011).doi:07-3-AA-8211-0003

Bourne, S. *Quest CCS Project: Technical Feasibility of Pressure Monitoring for Leak Detection*. (Heavy Oil Controlled Document Shell Canada Limited, 2011).doi:07-3-ZG-7180-0013

Bourne, S. *Quest CCS Project: Technical Feasibility of Microseismic Monitoring*. (Heavy Oil Controlled Document Shell Canada Limited, 2011).doi:07-3-ZG-7180-0014

HSE. 2001. Reducing Risks, Protecting People. UK Health and Safety Executive (HSE). http://www.hse.gov.uk/risk/theory/r2p2.pdf.

Kyoto Protocol Kyoto Protocol to the United Nations Framework Convention on Climate Change. (1998).at <http://unfccc.int/resource/docs/convkp/kpeng.pdf>

IEA *Carbon Capture and Storage in the CDM*. (Environmental Directorate, International Energy Agency: 2007).

IPCC *IPCC Special Report on Carbon Dioxide Capture and Storage*. 442(Prepared by Working Group III of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA: 2005).

IPCC *IPCC Guidelines for National Greenhouse Gas Inventories: Chapter 5 Carbon Dioxide Transport, Injection and Geological Storage*. (2006).

Hepple, R.P. & Benson, S.M. Geologic storage of carbon dioxide as a climate change mitigation strategy: performance requirements and the implications of surface seepage. *Environmental Geology* **47**, 576-585(2004).

Shaffer, G. Long-term effectiveness and consequences of carbon dioxide sequestration. *Nature Geoscience* **3**, 464-467(2010).

Quintessa *A Generic FEP Database for the Assessment of Long-Term Performance and Safety of the Geological Storage of CO 2*. 73(Greenhouse Gas R&D Programme, International Energy Agency: 2004).at <www.ieaghg.org/docs/QuintessaReportIEA.pdf>

IEA Monitoring Selection Tool. *IEA Greenhouse Gas R&D Programme* (2006).at <http://www.co2captureandstorage.info/co2tool_v2.1beta/index.php>

DNV *CO2QUALSTORE Workbook with examples of applications*. (Det Norske Veritas AS, Oslo, Norway: 2010).at <http://www.dnv.com/binaries/CO2QUALSTORE_Workbook_tcm4-436659.pdf>

WRI *CCS Guidelines: Guidelines for Carbon Dioxide Capture, Transport, and Storage*. (World Resources Institute (WRI): Washington, DC, USA, 2008).

CSA Worlds first standard for deep-earth storage of industrial carbon emissions to be developed by CSA Standards and IPAC-CO2 Research. (2010).at <http://www.csa.ca/cm/ca/en/news/article/deep-earth-storage-industrial-carbon-emissions>

OSPAR *OSPAR Convention for the Protection of the Marine Environment of the Noerth-East Atlantic: OSPAR Guidelines for Risk Assessment and Management of Storage of C)2 Streams in Geological Formations*. *Framework* **1**, (2007).

EC *Directive of the European Parliment and of The Council on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No 1013/2006*. (Eurpoean Union: 2009).at <http://ec.europa.eu/environment/climat/ccs/pdf/st03739_en08.pdf>

UK *A consultation on the proposed offshore carbon dioxide storage licensing regime*. 29(UK Department of Energy and Climate Change: 2009).

UK *Towards Carbon Capture and Storage : Government Response to Consultation*. 96(UK Department of Energy & Climate Change: 2009).at <www.berr.gov.uk/files/file46810.pdf>

BGS *Measurement, Monitoring & Verification of CO2 Storage: UK Requirements Study - Final Report : Vol 1 (Draft)*. **1**, 295(British Geological Survey Commercial Report: 2010).

BGS *Measurement, Monitoring & Verification of CO2 Storage: UK Requirements Study - Final Report : Vol 2 (Draft)*. **2**, 135(British Geological Survey Commercial Report: 2010).

EPA *Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide*. *Environmental Protection* 85(U.S. Environmental Protection Agency. EPA430-R-08-009. July 10: 2008).

NETL *Monitoring, Verification and Accounting of CO2 Stored in Deep Geologic Formations*. 132(National Energy Technology Laboratory (NETL), U.S. Department of Energy: 2009).at <www.netl.doe.gov>

IEA *Review of gaps in knowledge from the IPCC special report on CO2 capture and storage*. (IEA Greenhouse Gas R&D Programme: 2006).at <http://www.cslforum.org/publications/documents/Final_Report_MMV_Task_Force.pdf>

EPA *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells*. 1-51(U.S. Environmental Protection Agency, Federal Register, Vol. 73, No. 144, July 25: 2008).

Chadwick, R.A. et al. *Best practice for the storage of CO2 in saline aquifers - observations and guidelines from the SACS and CO2STORE projects*. 267(British Geological Survey Occasional Publication No. 14., Nottingham, UK: 2008).

Pearce, J. et al. *Quest CCS Project: Potential Applications of the Real-Time Compaction Imager for Monitoring Carbon Capture Sequestration and Acid Gas Injection Wells*. *Carbon* (Heavy Oil Controlled Document Shell Canada Limited,).doi:07-3-AA-8211-0004

Bourne, S. *Quest CCS Project: Feasibility of Gravity Surveys for CO2 Storage Monitoring and Leak Detection*. (Heavy Oil Controlled Document Shell Canada Limited, 2011).doi:07-3-AA-8211-0002

Ostermeier, R.M., Skelton, W.K. & Grae, A.D. *Identifying and Quantifying Well Logging Technologies for Monitoring the Quest ScotFord Upgrader CCS Project*. *Personnel* (Heavy Oil Controlled Document Shell Canada Limited, 2008).doi:07-3-ZG-7180-0015

Jonathan, P., with B. Hirst A method for remotely measuring surface gas fluxes above an onshore CO2 sequestration project. *EP 2010-5293* (2010).

HSE *Failure rates for underground gas storage: Significance for land use planning assessments*. *Health (San Francisco)* (UK Health and Safety Executive: 2008).

IEA *Carbon Capture and Storage: Progress and Next Steps*. 44(International Energy Agency: 2010).

Hugonet, V. *Quest Legacy Wells Analysis*. (Heavy Oil Controlled Document Shell Canada Limited, 2011).doi:07-3-ZW-7180-0002

Appendix A Hydrosphere and Biosphere Monitoring Plan

SHELL CANADA LIMITED
Quest Carbon Capture and Storage Project

HYDROSPHERE AND BIOSPHERE MONITORING PLAN

February 2014

Page Intentionally Left Blank

Table of Contents

List of Tables

List of Figures

1. Introduction

The aim of this document is to describe and to discuss the Hydrosphere and Biosphere Monitoring Plan (HBMP) implemented as part of the Quest MMV plan, with a focus on the baseline (pre-injection) monitoring activities.

The HBMP is one line of evidence used to demonstrate that the injected CO_2 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

The HBMP presented in this document is based on the following three injection wells 100-08-19-059-20W400 (IW 8-19), 103-07-11-059-20W400 (IW 7-11), and 102-05-35-059-21W400 (IW 5-35). These wells have been drilled, as well as the associated deep monitoring wells and groundwater monitoring wells located on the same well pads. (Figure 1-1).

The HBMP is an adaptive plan expected to undergo modifications, on an annual basis, as data becomes available and risk profiles change. The first review of the current HBMP was done after completion of the 1st year of baseline monitoring. This will be 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 to AER, with the first report due March 31, 2016[1]. 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.
- 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 remaining chapters of this report cover the following topics:
- 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 1 to 2 m.

- 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.

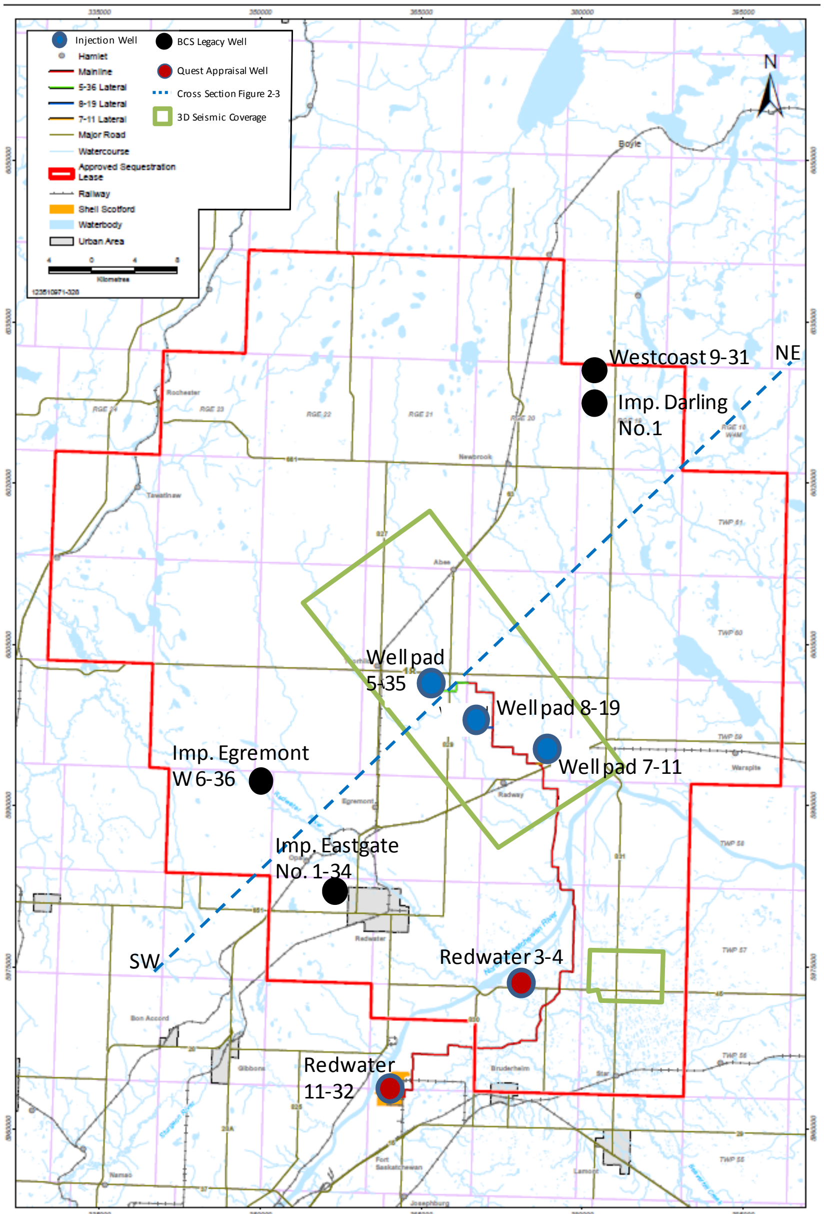

Figure 1-1: Quest SLA (Sequestration Lease Area, red outline). Also shown: location of the injection well pads 08-19-059-20W4, 07-11-059-20W4, and 05-35-059-21W4 (red dots), pipeline route (gray solid line).

2. Hydrosphere Monitoring

2.1 Introduction

The stratigraphic intervals (Figure 2-1) considered in the hydrosphere monitoring include:

- Surficial Deposits.
- The Oldman Formation
- The Foremost Formation, which includes a lower unit referred to as the Basal Belly River Sands

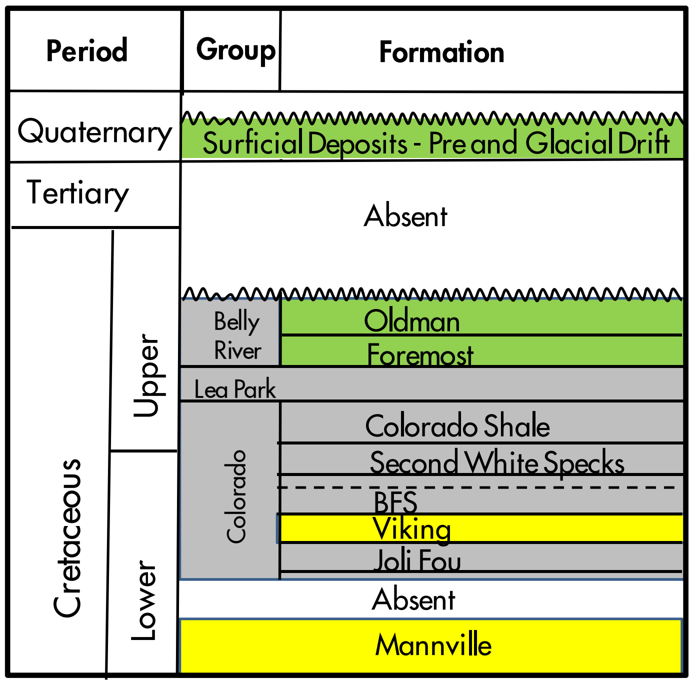

Figure 2-1: Stratigraphic column showing Hydrosphere monitoring targets (green highlight)

The hydrosphere monitoring plan includes sampling and monitoring of both groundwater and gas at Shell Quest project wells and selected existing and active landowner wells. In addition to discrete sample collection and analysis of groundwater and gas samples, continuous measurement of water quality parameters using a downhole water quality instrument is undertaken 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 baseline (pre-injection) 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 2.6.2.

2.2 Well Selection

2.2.1 Introduction

The wells selected for the hydrosphere monitoring plan can be grouped into three categories including:

- Shell Quest project groundwater wells (9)
- Local landowner groundwater wells (about 160)
- Regional groundwater wells (34).

All of the approximately 200 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 AER Condition 20, any additional landowners that wish their wells to be part of the study can be included in the monitoring program [1]

2.2.2 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 [2].

The design of this HBMP is based on 3 injection wells, hence, a total of 9 project specific wells have been installed by Shell (Table 2.1).

Shell believes that the number and location of the existing 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 in accordance with AER Condition 10i [1].

Table 2.1: Quest Groundwater Well Summary

UWI	Well type	Well name in this report	Spud date [d/m/y]	Rig release [d/m/y]	Total Depth [m MD]	TD formation
1F1/081905920W4/00	Groundwater	GW 1F1/8-19	08/12/2010	08/01/2011	201	Lea Park
UL1/081905920W4/00*	Groundwater	GW UL1/8-19	14/01/2011	17/01/2011	101.0	Foremost
UL2/081905920W4/00*	Groundwater	GW UL2/8-19	12/01/2011	13/01/2011	62.8	Foremost
UL3/081905920W4/00*	Groundwater	GW UL3/8-19	09/01/2011	10/01/2011	37.5	Foremost
UL4/081905920W4/00*	Groundwater	GW UL4/8-19	11/01/2011	11/01/2011	20.0	Oldman
1F1/053505921W4/00	Groundwater	GW 1F1/5-35	08/02/2013	17/02/2013	200	Lea Park
UL1/053505921W4/00*	Groundwater	GW UL1/5-35	17/02/2013	18/02/2013	23	Foremost
1F1/071105920W4/00	Groundwater	GW 1F1/7-11	19/02/2013	26/02/2013	180	Lea Park
UL1/071105920W4/00*	Groundwater	GW UL1/7-11	26/02/2013	27/02/2013	31.0	Foremost

Legend: *: Well name used in Shell but not official UWIs as these wells are not licensed

2.2.3 Local Landowner Groundwater Wells

The local landowner groundwater wells (about 160 wells) are split into two categories:

1) Groundwater wells within a 3.2 km radius of the injection wells: 100-08-19-059-20W400, 103-07-11-059-20W400, and 102-05-35-059-21W400. This was an Regulatory Hearing commitment made by Shell prior to the baseline monitoring period that was to be updated as a result of new information acquired during baseline monitoring [2].
2) Groundwater wells near legacy wells. A legacy well is defined as any pre-existing, Alberta Energy Regulator (AER) licensed well (deeper than 150 m) that meet the following criteria:
   - is located in the Quest Sequestration Lease Area (SLA)
   - 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 SLA. 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.

2.2.3.1 Groundwater Wells Near Injection Wells (3.2 km radius)

Injection wells will present a greater risk, however small, to long-term containment of fluids in the BCS storage complex because they 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 licenses 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 about 150 wells (Fig. 2-2), with:

- about 40 wells around 100-08-190-059-20W400
- 45 wells around 100-07-11-059-20W400
- 65 wells around 100-05-35-059-21W400

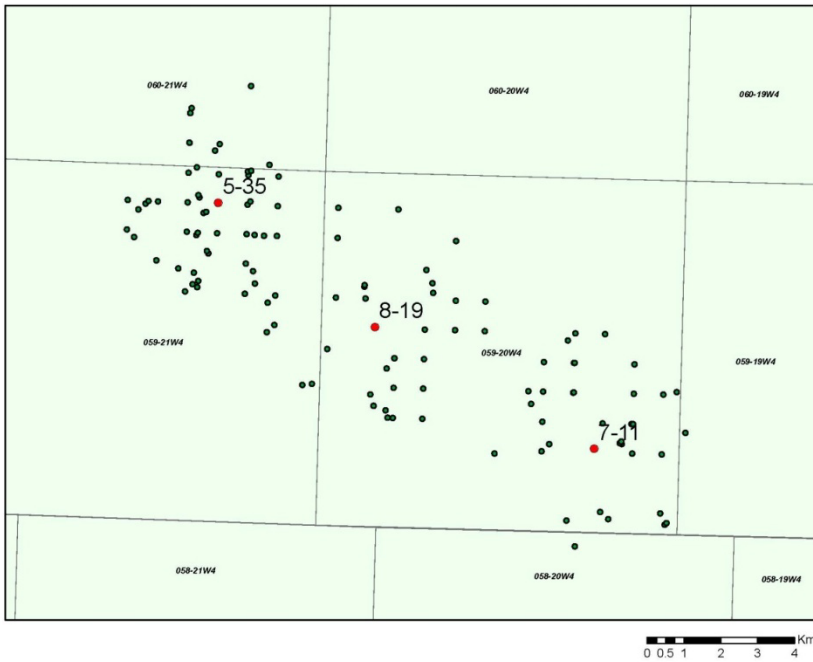

Figure 2-2: Existing groundwater wells within 3.2 km of injector wells.

During the 1st and 2nd year of the baseline monitoring period, an attempt will be made at sampling once all active domestic water wells identified within the 3.2 km radius, and a sub-set of those wells will be sampled on at least one more occasion. 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 injection well
- target wells sampled as part of the seismic survey program undertaken during the planning stages of the Quest Project
- sampling approach with professional judgment
- maintain practical implementation of monitoring
- develop monitoring that is economically sustainable.

The current 'sub-set' number of wells selected within a 3.2 km radius of an injector well is 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 has installed on each injection wellpad. A larger number of wells were selected and sampled for baseline monitoring in order to understand spatial variability in groundwater quality around the injection wells during the baseline (pre-injection) phase.

Further details on well selection are provided in Shell's response to AER's SIR dated March 28th, 2013 [3].

2.2.3.2 Groundwater Wells Near Legacy Wells

In the vicinity of the four BCS legacy wells, all located between 18 and 36 km away from the injection wells, Shell will conduct adequate groundwater monitoring in order to understand the baseline groundwater quality. Note that based on Gen-4 modeling results, pressure increase at the injection wells is not enough to lift BCS brine to the base of the groundwater protection and therefore, there is no risk at the legacy wells [4]. Monitoring changes during the injection phase 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.

Ten wells were selected near the legacy wells for sampling including:

- 3 wells around each of the legacy wells 06-36-058-23W4, 01-34-057-22W4, and 16-19-062-19W4 (Fig. 2-3); 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.

Note that besides the first selection of 10 wells, a number of possible alternate wells have been identified. This was done in order to gather groundwater quality baseline data near the legacy wells in case of well accessibility issues with the original well selection.

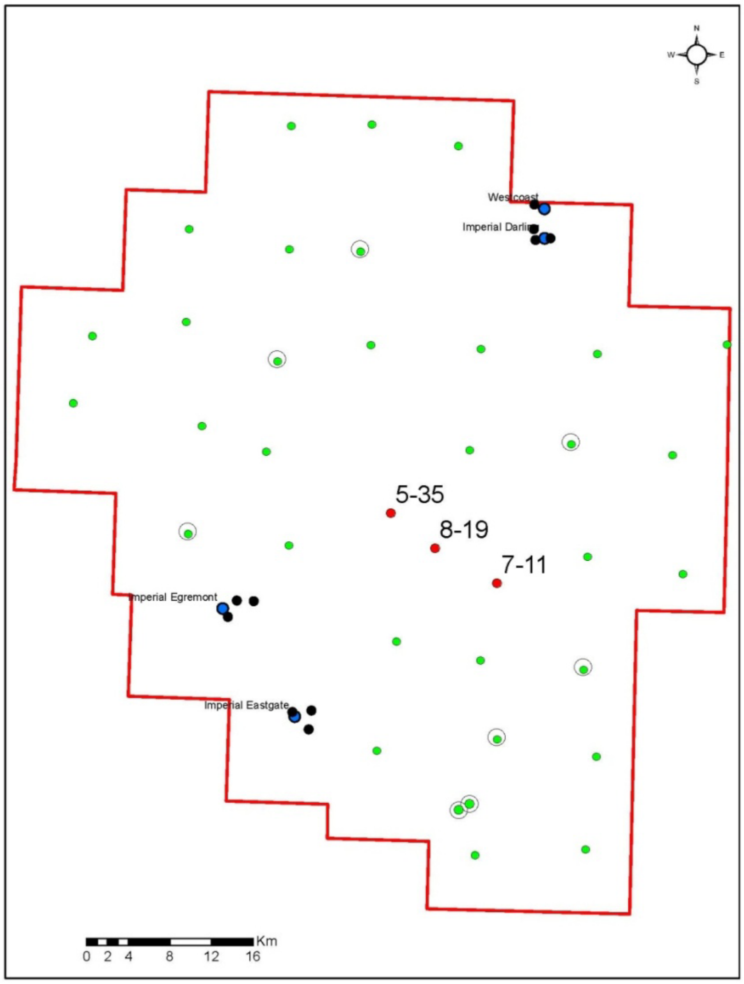

Figure 2-3: Baseline groundwater sampling well network near the legacy well locations (black dots) and for the regional network (green dots). Also shown regional network wells selected for isotopic analyses (open circle), location of legacy wells (black dots) and injector wells (blue dots).

2.2.4 Regional Landowner Groundwater Wells

A series of domestic groundwater wells regionally distributed in the SLA (excluding those sampled around the injection and legacy wells) are included in the baseline hydrosphere monitoring program. These wells were selected to provide data coverage over the entire SLA, allowing for the interpretation of regional trends. As these domestic wells are situated at considerable distances (≥ 7km) from the injection well sites, they allow for measurements of possible fluctuations in water level/quality outside areas that have the higher likely hood of being impacted by injection operations. A total of 34 wells have been included in the regional landowner wells sampling network (Fig. 2-3). 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. This was an Regulatory Hearing commitment made by Shell prior to the baseline monitoring period that was to be updated as a result of new information acquired during baseline monitoring [2].

Note that besides the first selection of the 34 wells, a number of possible alternate wells have been identified

2.3 Well 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. CO_2) can help to identify or refute a leakage event from the BCS storage complex. Hence, well gas is included within the hydrosphere monitoring program, which will be collected prior to taking a groundwater sample.

The original plan was to collect well headspace gas; however, this proved challenging during the 1st year of the baseline monitoring period. As noted in the January 31st 2013 Annual report [5], groundwater well conditions (e.g. presence of tubing, electrical wires) impacted the success of collecting well headspace gas (WHG) samples. During 2013, the WHG sampling protocol was modified to help improve the success rate of gas collection at a groundwater well by including a diffusing baffle rather than an airtight seal at the wellhead to prevent airflow from entering the well. Furthermore in Q4-2013, a flow-through sampling device for gas collection at a select number of wells was tested for gas collection in addition to the established WHG sampling protocol.

Based upon evaluation of the Q4-2013 data, gas sampling at a groundwater well will be done using a flow-through sampling device during the 2014 baseline field campaign.

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

- $\delta^{13}C$-CO_2, $\delta^{13}C$-CH_4, and $\delta^{13}C$-C_2+, $\delta^{2}H$-CH_4

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 baseline monitoring phase.

Whenever possible, analyses will be performed by a qualified laboratory in Alberta with appropriate QA/QC procedures.

Regarding sampling frequency, please refer to Section 2.6.

2.4 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. HCO_3^-; [6]) can help to identify or refute a leakage event from the BCS storage complex.

Prior to collecting a water sample, the well gas will be sampled for chemical and isotopic analyses as outlined in Section 2.3. A number of field measurements will be collected, such as water temperature, pH, depth to water table. In order to collect a water sample for laboratory analyses, 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.

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

1. Chemical analysis of a groundwater sample will include:
   - pH, EC, TDS, alkalinity, ion balance, total hardness
   - Na, K, Ca, Mg, HCO_3, CO_3, OH, SO_4, NO_2, NO_3, P, DIC, Cl, Br, I, F (added in 2014)
   - Al, Sb, As, Ba, Be, B, Cd, Cr, Co, Cu, Fe, Hg, Pb, Li, Mn, Hg, Mo, Ni, Se, Si (SiO_2), Ag, Sr, Tl, Sn, Ti, U, V, Zn
2. Isotopic analysis of a groundwater sample will include:
   - $^{87}Sr/^{86}Sr$, $\delta^{18}O$ & $\delta^{2}H$-H_2O, $\delta^{13}C$-DIC, $\delta^{37}Cl$

Note that during the 1st year baseline monitoring period, $\delta^{81}Br$ and $\delta^{11}B$ were also part of the isotopic analytical suite. These analyses will be removed from the 2014 program onward for redundancy reasons after evaluation of the data collected in 2012 and 2013.

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 baseline monitoring period.

Whenever possible, analyses will be performed by a qualified laboratory in Alberta with appropriate QA/QC procedures.

Regarding sampling frequency, please refer to Section 2.6.

2.5 Groundwater - continuous measurements

At each of the 9 Shell Project groundwater wells, a Troll 9500 multiparameter water quality probe or similar instrument has been installed. Each probe has the capability to measure electrical conductivity and pH. Sensors for redox potential, pressure, and temperature are also part of the probe's setup.

The current plan is to take readings on a daily basis during the three monitoring phases (baseline, injection, and closure). The continuous monitoring started by the end of March 2013. During the baseline monitoring period, the daily recorded data are downloaded every quarter from the internal memory of the Troll probe. During the injection phase, daily data will be transferred via SCADA to Shell. Note that depending upon the findings from the baseline period, the number of the Shell Quest groundwater wells to be continuously monitored and the associated measurements to be taken will be reviewed and adjusted.

2.6 Groundwater Well Sampling Schedule

The sampling schedule is identical for both groundwater and gas sampling at a well.

2.6.1 Baseline Monitoring Period

Continuous readings of the Troll 9500 probe are taken on a daily basis.

Regarding the discrete samples, the overall sampling strategy is to collect samples at least once every season at regular intervals from a select number of wells, in order to capture potential temporal variations in water quality. During the 1st year of the baseline period (Q4 2012 to Q3 2013), wells completed within 'Surficial Deposits', the 'Oldman Formation', and the 'Foremost Formation' were 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 (Q3 2013 to Q3 2014), the primary focus is 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.

The planned sampling schedule for the discrete samples during the baseline (pre-injection) monitoring phase for 2012 and 2013 is shown in Table 2-2. The actual number of wells that were sampled are shown in Table 2-3.

As can be seen by comparing Tables 2-2 and 2-3, not all wells planned for could be sampled. For those wells not sampled, one or more of the following issues were typically encountered:

- unable to contact landowner (after multiple attempts)
- landowner unavailable during the period of sampling
- unable to locate Landowner's well at the specified location
- unsafe or inaccessible location due to conditions such as snow or heavy vegetation or a confined space

- wells without a pump or inoperative pumps and
- access to property denied by Landowner

Table 2-2: Planned 2012-2013 Sampling Schedule

Chemical Analysis										
	Q4 -2012		Q1 - 2013		Q2 - 2013		Q3 - 2013		Q4 - 2013	
Well Type	GW	WHG	GW	WHG	GW	WHG	GW	WHG	GW	WHG
Project	9	9	9	9	9	9	9	9	9	9
Local	154	154	47	47	43	43	0	0	9	9
Legacy	10	10	9(b)	9(b)	10(b)	10(b)	3(a)	3(a)	3(a)	3(a)
Regional	34	34	34	34	34	34	34	34	34	34
Total Wells	207	207	99	99	96	96	46	46	55	55
Isotope Analysis										
	Q4 -2012		Q1 - 2013		Q2 - 2013		Q3 - 2013		Q4 - 2013	
Well Type	GW	WHG	GW	WHG	GW	WHG	GW	WHG	GW	WHG
Project	9	9	9	9	9	9	9	9	9	9
Local	9	9	0	0	9	9	0	0	3	3
Legacy	9	9	3(a)	3(a)	9(b)	9(b)	3(a)	3(a)	3(a)	3(a)
Regional	9	9	9	9	9	9	9	9	9	9
Total Wells	36	36	21	21	36	36	21	21	24	24

(a) Well selection based on geology: A well completed in the Foremost Formation.
(b) Well selection based on geology: One well per surficial/Oldman/Foremost Formations.
GW= groundwater; WHG = wellhead gas.

Table 2-3: Achieved 2012-2013 Sampling Schedule

Year	Sampling Event	Analysis Type	Wells Sampled				
			Regional	Legacy	Local (3.2km radius)	Project Monitoring Wells	Total
2012	Q4	Chemical / Compositional Analysis	9	3	41	4	57
		Isotopic Analyses	9	3	33	4	49
2013	Q1	Chemical / Compositional Analysis	31	8	10	9	58
		Isotopic Analyses	5	3	0	9	17
	Q2	Chemical / Compositional Analysis	21	7	17	9	54
		Isotopic Analyses	5	6	7	9	27
	Q3	Chemical / Compositional Analysis	21	3	4	6	34
		Isotopic Analyses	6	3	1	6	16
	Q4	Chemical / Compositional Analysis	22	3	10	8	43
		Isotopic Analyses	9	3	3	8	23
		Total	138	42	126	72	378

The 2014 sampling program has been revised compared to the proposed plan presented in Section 2.5.1 of Appendix A of Special Report #1 submitted October 15th 2012 [7]. The total number of planned wells for 2014 has been increased to 266 compared to 75 for chemical / compositional analyses and to 115 compared to 33 for isotopic analyses. This is to meet the original commitment to sample every landowner well at least once per year during the two year baseline period. Note that not all planned wells may be sampled as this depends upon a number of factors, such as consent from private well owners, or well status (accessibility, functioning pump), as described above for the 2012-2013 sampling campaign. The planned 2014 sampling schedule is shown in Table 2-4.

Table 2-4: Planned 2014 sampling schedule

Chemical / Compositional Analyses					
	Q1-2014	**Q2-2014**	**Q3-2014**	**Q4-2014**	
Project	9	9	9	9	
Regional	34		9		
Legacy	3		3		
Local	103	10	43	10	
Open House	15				
	164	19	64	19	**total wells:**
					266
Isotopic Analyses					
	Q1-2014	**Q2-2014**	**Q3-2014**	**Q4-2014**	
Project	9	9	9	9	
Regional	9		9		
Legacy	3		3		
Local	10	10	10	10	
Open House	15				
	46	19	31	19	**total wells:**
					115

2.6.2 Injection and Closure Monitoring Periods

The sampling schedules for the discrete measurements during the injection and closure monitoring periods is dependent upon the outcomes of the baseline monitoring program. Hence, a detailed sampling schedule cannot be provided at present for the injection and closure periods.

The overall strategy for designing the sampling schedule for the injection and closure periods will include the following:

- integrate findings from the baseline (pre-injection) monitoring period 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 during 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 AER D65 approval and conditions, August 8 2013 [1].

Please refer to Section 2.7 for an explanation of the Tiers O, 1, 2, and 3.

2.7 Tiered Approach for Post Baseline Monitoring

The Hydrosphere monitoring program includes analytical parameters referred to as indicator or tracer parameters associated with a release of CO_2 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 CO_2 (or a mixture thereof) (e.g. isotopic compositions).

These parameters have one or more of the following characteristics:

- anticipated to be present in injected CO_2 stream or in fluids native to the BCS
- could potentially be released to the hydrosphere in the event of an unexpected leakage from the BCS storage complex
- 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.

Review of the analytical parameters reveals that some (e.g. major ions) can be considered relatively easy to measure both practically and economically, 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 baseline (pre-injection) monitoring phase will be implemented. 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 2-5. Note that the current proposal of the tiered system will be revised and updated accordingly based upon findings from the baseline monitoring phase.

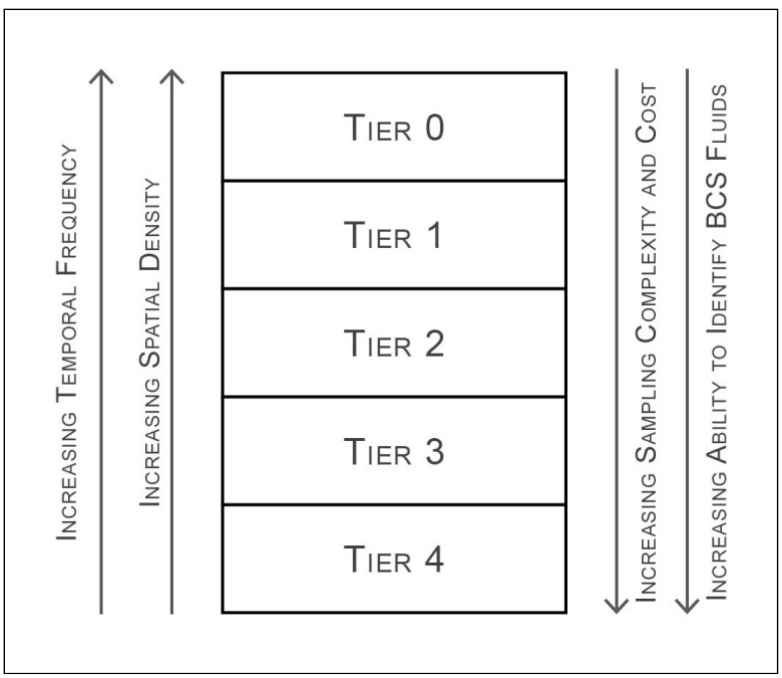

Figure 2-5: Parameter Tier Concept

Table 2-5: Parameters Associated with Tiered System

parameter tier	medium	type of sampling	analytical parameters
Tier 0	groundwater	continuous	• electrical conductivity, pH
Tier 1	groundwater	discrete	• pH, EC, TDS, alkalinity, ion balance, total hardness • Na, K, Ca, Mg, HCO_3, CO_3, OH, SO_4, NO_2, NO_3, P, DIC, Cl, Br, I
Tier 1	well headspace gas	discrete	• CO_2, C_1 to C_{10+}, N_2, O_2, He
Tier 2	groundwater and/or well headspace gas	discrete	• re-do Tier 1 • Al, Sb, As, Ba, Be, B, Cd, Cr, Co, Cu, Fe, Hg, Pb, Li, Mn, Hg, Mo, Ni, Se, Si (SiO2), Ag, Sr, Tl, Sn, Ti, U, V, Zn
Tier 3	groundwater and/or well headspace gas	discrete	• re-do Tier 2 • $^{87}Sr/^{86}Sr$, $\delta^{18}O$ & $\delta^{2}H$-H2O, $\delta^{13}C$-DIC, $\delta^{81}Br$, $\delta^{37}Cl$, $\delta^{11}B$ • $\delta^{13}C$-CO_2 and $\delta^{13}C$-CH_4, $\delta^{2}H$-CH_4
Tier 4	groundwater and/or well headspace gas	discrete	• variety of site-specific parameters required to support contaminant plume delineation and risk management activities; may include parameters already measured in lower tiers

Notes:

- Analysis of (an) artificial perfluorinated carbon (PFC) compound(s) potentially added to the injection CO_2 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.
- At the end of the 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.

3. Biosphere Monitoring

3.1 Introduction

The biosphere program is responsible for collection, processing and analysis of baseline environmental data for remote sensing calibration and to characterize pre-injection environmental conditions. There are five components involved in the biosphere program: vegetations, soils, soil conductivity (EM38), soil gas and surface flux, and remote sensing.

The 2010 MMV Plan and the Environmental Impact Assessment (EIA) [8, 9, 10] 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 SLA. 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 Remote sensing

3.2.1 Introduction

Remote sensing is the primary means of biosphere monitoring specifically monitoring changes in plant stress and soil salinity related to Quest CO_2 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.

Ground-based data collected during the baseline monitoring period, 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 data collection, remote sensing (RS), and injection phase monitoring. Expectation is that during the injection phase, as the sample data library increases, soil and vegetation mapping will be minimal until they are no longer required to monitor for Quest CO_2 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.

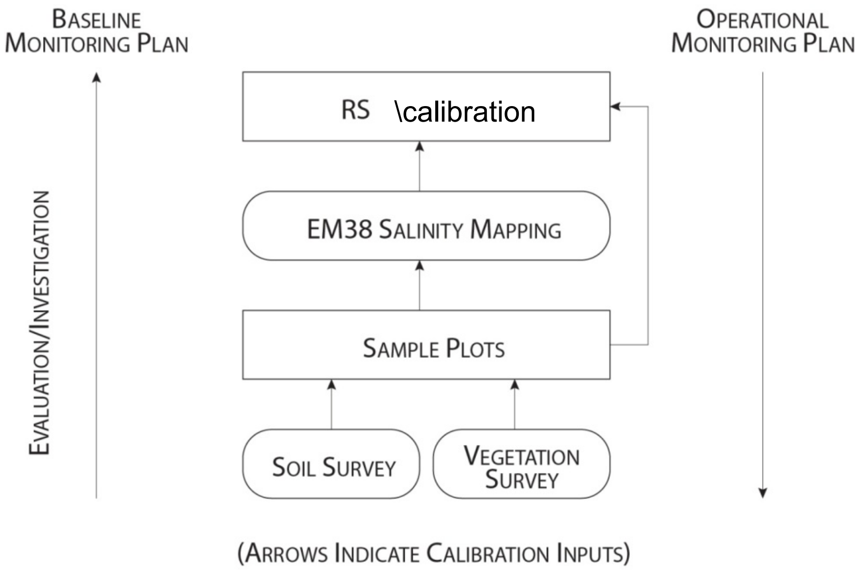

Figure 3-1: Schematic overview of the 'remote sensing' monitoring concept

3.2.2 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 types of image analyses can be used for biosphere monitoring if required including:

1) Radar Image Analysis (RIA) of synthetic aperture radar (SAR) data attained via Radarsat2 satellite platform. RIA indirectly monitors soil salinity and moisture via the dielectric constant.

   The Radarsat2 satellite platform used for RIA is the same as that used for InSAR monitoring. Although the image for each technology is from the same satellite, in each case the SAR data is processed differently.

   Since 2011, Shell has been acquiring a SAR images (RIA and INSAR) of the SLA every 24 days or 15 images per year and will continue to do this through to the end of the baseline period. However, according to current well information attained from the 2012-2013 drilling program, pressures at the injection wells will be insufficient to raise brine to base groundwater protection (to be confirmed with the Generation-5 modeling effort to be carried out in 2014). Once modeling is complete, the need to continue salinity monitoring beyond the baseline period will be reviewed. In the meantime, Shell is advancing the technology as originally planned.

Although SAR data for RIA is acquired as the same frequency as InSAR data, processing for biosphere monitoring occurs on a different frequency:

a. Baseline Period: 15 images are acquired but only one image from 2013 will be used for calibration with field work carried out as part of the HBMP soils/EM38 program. This update is the result of initial assessment of the spring and summer 2013 field calibration data and the conclusion that the original sample design which was for composite samples on each sample plot was insufficient. Therefore, from Fall 2013 onward the sampling procedures has been modified to a grid sampling system on each sample plot.

   In 2014, one image will be calibrated to field samples in order to finalize the technical work to support the use of this technology for the SLA. This work will include detection thresholds and processing frequency potentially required in future. Although only 2 images are calibrated to field data, the ability to go back and process images retroactively at any time still exists. In addition, field calibration sampling will continue to occur 3 times (spring, summer and fall) in 2014 for further calibration if required.

b. Injection Period: 1 scheduled image per year or as required. The image would be taken either prior to or after the growing season to avoid fertilizers such as potassium chloride which are conductors and may create false positives.

c. Closure Period: 1 scheduled image per year would be taken every second year. Image would be taken either prior to or after growing season to minimize false positives.

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 SLA. 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 was only be 1 image acquired in the fall.

   b. Injection: 1 image during peak growth (summer) when vegetation growth it at its peak.

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

   Once all the baseline data has been gathered and interpreted, final detection thresholds for this monitoring technology will be determined.

3.3 Ground-Based Sampling

3.3.1 Introduction

The ground-based (field) measurements acquired at various sample plot locations will be used to calibrate remote sensing data obtained from satellite as well as characterize the vegetation, soils and CO2 flux across the SLA. 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

3.3.1.1 Sample Plot Types

It was recognized that for calibration purposes, especially when trying to reconcile changes in the biosphere over multiple seasons and years, it is more prudent to use semi-permanent plots for baseline information as opposed to the previously reported transient plots. As a result, the plot types have been refined since the October 15th 2012 submission of the HBMP plan as follows:

1) Transient Plots: A series of plots that may or may not be required during the injection phase and are likely a one-time evaluation. These plots may be established to assess a potential anomaly seen on a previous satellite image or another monitoring technology such as hydrosphere monitoring. If the ground-based measurements of the anomaly confirmed a false positive the site would be abandoned. Alternatively, if the anomaly was confirmed as a leak, ongoing monitoring may be required and the site would convert to a semi-permanent/permanent site until the issue was resolved. All plots sampled to date are currently considered semi-permanent plots.
2) Semi-permanent plots: Sample plots that occupy the same location from season to season and year to year to calibrate the remote sensing images both temporally and spatially. However, they are not considered permanent plots for the following reasons:
    a. These plots will continue to be used as per the regular practice in the area and will not be isolated for observation (i.e. farmers will continue to farm as usual, pasture land will remain pasture land). This is favoured over isolated permanent plots because after a few years of monitoring, permanent plots may no longer be representative of the environment from their disuse by the local populations.

b. Sampling on some or all of the semi-permanent may be continued into the injection period, assuming landowner consent, if:

- There is insufficient confidence in the calibration data attained during the baseline period and more is required for calibration.
- There has been a significant change in the land use type in the SLA that was not previously captured and therefore additional calibration data is required.

3) Permanent Plots: Plots that will remain as reference plots for the duration of the project or until such time that it is agreed that the risks to biosphere are so low such that these plots are no longer necessary. These plots are isolated / fenced off and no other activity is allowed to occur on them for the duration of the project to observe natural variations in the environment. Shell stated that there will be 2 permanent sample plots. It will be decided which of the semi-permanent plots, developed in 2012/2013, to convert to permanent plots in Q4 2014 when more baseline data has been attained.

3.3.1.2 Sample Plot Locations

Land cover classification was conducted using 2011 Landsat 5 satellite imagery to identify the dominant land cover classes in the Project are and establish representative distribution of sample plots to be used during the baseline period (Table 3-1). Plot selection was designed around the vegetation land classification to represent the major vegetation classes within the SLA.

Table 3-1: Summary of Land Cover and Plot Distribution within the SLA

Class	Area [ha]	Percentage of Total Project Area	Number of Field Plots (2013)	Percentage of Field Plots (2013)
Annual Crop	132,400	34.8%	5	33.3%
Broadleaf Forest	86,700	22.8%	3	20.0%
Pasture	85,300	22.5%	3	20.0%
Coniferous Forest	37,400	9.8%	2	13.3%
Wetland	27,000	7.1%	2	13.3%
Developed	6,500	1.7%	0	0%
Water	4,600	1.2%	0	0%
Total	**380,000**	**100.0%**	**15**	**100.0%**

As a result, a total of 15 sample plots were selected to be regularly sampled during the baseline period sufficiently covering the major land classification types. The semi-permanent and transient sample plots used for the baseline monitoring period are shown in Figure 3-2.

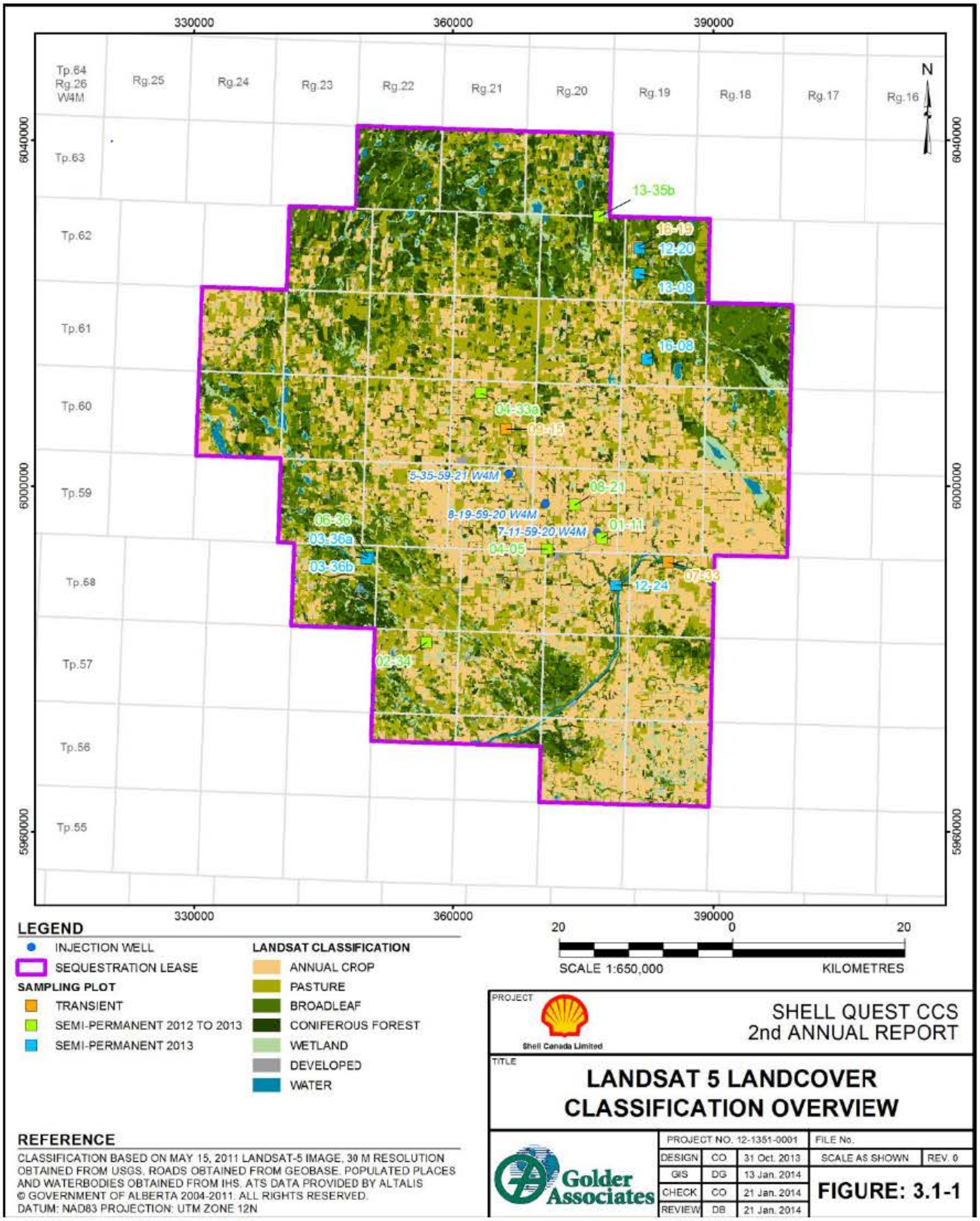

Figure 3-2: Location of Semi-Permanent and Transient Sample Plots used in Baseline Monitoring Period

3.3.1.3 Sample Plot Design

Each sample plot is 50 m by 50 m (2,500 m2) which is sufficient for remote sensing calibration. In addition, each plot has a homogeneous vegetation cover type for ease of calibration and correlation between the various plots. There are two plot designs used depending on the land use type:

1) Annual crops sample plots: have been optimized to reduce trampling effect on the spectral signature of annual vegetation. Therefore, they are each 100 m by 100 m but only one quarter section (50 m by 50 m) will be sampled by field crews in a season. The sampled quarter will change with each season and no quarter will be sampled twice in the same year. The remaining un-trampled quarter will be available for the remote sensing team to develop spectral signatures. The farmers will continue to farm the plot as per the practice in the area.

2) Perennial vegetation plots: will only be 50 m by 50 m area and will not need a rotating quarter design, since these vegetation types can withstand a greater amount of disturbance and the impact of field crews will not affect the spectral characteristics.

   Figure 3-3 shows a 1 ha plot broken down into four quarter sections, with the season of sampling labeled, and a 50 m by 50 m plot for a perennial vegetation plot (non-annual croplands such as pastures, forested, and riparian).

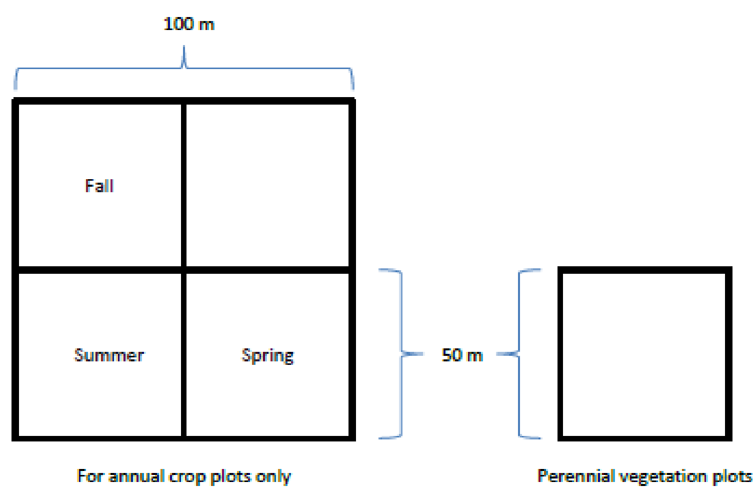

Figure 3-3: Plot Design for Annual Crops and Perennial Vegetation Plots (Non-Annual Croplands)

3.3.1.4 Sample Plot Sampling Frequency

The current planned sample frequency is as follows:

1) Semi-Permanent and Transient Sample Plots: The current sample frequency used for soil, vegetation, EM38 and spectral work is as follows:

a. Baseline: 10 transient sample plots in 2012 and 14 semi-permanent sample plots per Rapideye image acquisition in both 2013 and 2014 (Table 3-2). During the Baseline period, plots sampled for Rapideye Calibration data will also be used to collect RadarSat2 calibration data. EM38 is only completed on 14 sites as one of the sites is too heavily forested to properly complete the work.

b. Injection: Plots will be sampled if required such as finalization of calibration workto address specific anomalies above set background thresholds or for incident response.

c. Closure: As required as per injection period.

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 SLA. However, final plot locations will be chosen by Q4 2014, after analysis of the data from baseline period is complete.

The sampling frequency from the permanent plots will be as follows:

a. Baseline: treated the same as semi-permanent plots above as these locations have not changed.

b. Injection: Each permanent plot sampled 2 times per year.

c. Closure: Each plot sampled once every second year

Table 3-2: Sample acquisition schedule for biosphere monitoring program used for Remote Sensing Calibration.

Monitoring Task	Baseline									Injection				Closure			
	2012	2013				2014				(2015-2039)				(2041, 2043,…2049)			
	F	Sp	Su	F	W	Sp	Su	F	W	Sp	Su	F	W	Sp	Su	F	W
RadarSat2 Acquisition[1]	15	15				15				12				12			
RadarSat2 Processing (RIA)				1		1		I/R		1				1			
Rapideye Aquisition (MIA)	1	1	1	1		1	1	1			1				1		
Rapideye Processing (MIA)			1				I/R				1				1		
Semi-permanent Plots (MIA)[2]		15	15	15		15	15	15			I/R[4]				I/R[4]		
Semi-permanent Plots (RIA)[3]		*	*	*		*	*	*		I/R[4]				I/R[4]			
Permanent Plots (MIA)[2]											2				2		
Permanent Plots (RIA)[3]										2				2			
Transient Plots	10	*As required as part of Tiered response*															

* Calibration program for alternate remote sensing analysis method completed on the same plots
(example: Spring 2013 plots will be sample each for soil and vegeation, EM38 and field Spectra Mapping)

[1] RadarSat2 Acquisition shceulde is driven by InSAR acquisition schedule - image acquired every 24 days

[2] Vegetation mapping and field sprectral survels via PFRS completed - Soil surveys if required

[3] Soil and vegetation mapping and EM38 surveys completed

[4] These may include re-visiting one of the previously used semi-permanent plots or creation of new transient plot

I/R - If Required for completion of image calibration work or to assess an anomaly

F = Fall, Sp = Spring, SU = Summer, W = Winter

3.3.2 Soil Mapping

There are two key components to the soil mapping program including soil profile characterization and a shallow soils program used for RIA calibration:

1) Soil Profile Characterization Program - is used to classify soils within each vegetation land classification across SLA. In addition, this data provides baseline chemical and physical data which are pertinent parameters for soil classification such as organic carbon content and salinity.

   The methodology includes collection of data to classify the soils to sub-group level within the Canadian System of Soil Classification (SCWG 1998) [8]. Soil inspections are completed by digging 1 soil pit, 1 time, on each sample plot to collect the soil horizon information (horizon type, horizon thickness, texture mottling, structure, colour, stoniness, root abundance and parent material).

   Soil samples are acquired and the following laboratory analyses are conducted:

   - Cation exchange capacity
   - Available nutrients
   - Percent organic matter
   - Soil texture and
   - Salinity

2) Shallow Soils Program – is an additional soil sampling program to collect soil moisture data from 0 to 15 cm soil depth for calibration with the SAR data used for RIA. Starting in Fall 2013 to end of baseline, soil salinity, percent saturation and soil moisture data will be collected at each of the sample plot locations to allow correlations with remote sensing spectral signatures.

   The sampling pattern has been established to capture 10 discrete soil samples (0-15 cm) per 50 m by 50 m plot to represent individual satellite pixels (5 m by 5 m). A consistent sampling pattern will be applied to all plots. A sample will be collected at 0 to 15 cm depth and sent to the laboratory for analysis.

3.3.2.1 Vegetation mapping

Vegetation mapping will be performed as per Table 3-2. Vegetation subplots were chosen within each 50 m x 50 m sample plot to characterize the vegetation community represented by the sample plot which includes two levels: tree canopy and shrub/ground cover. Subplots represent the primary sampling unit for the monitoring program.

Site characteristic including vegetation (i.e. species and percent cover) topography, GPS coordinates, time of day, weather, date are recorded for each sample event.

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

- species composition (after Moss, 1983; ACIMS, 2011) [9]
- percent cover (after Daubenmire, 1959) [10]
- estimation of plant health on a growth form level (tree, shrub, forb, and grass)

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

3.3.2.2 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.

3.3.2.3 Electromagnetic Conductivity Surveys

On all sampling plots, an EM38 terrain conductivity meter survey will be attempted 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 CO_2 flux

3.4.1 Introduction

Soil gas analysis and soil surface CO_2 flux measurements are included within the biosphere baseline (pre-injection) data gathering program in order to gain an understanding of the magnitudes and temporal / spatial variability of those parameters in the SLA. 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 CO_2 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 CO_2 flux data for specific regions within the SLA.

The initial plan, as per the October 2012 version of the MMV plan [6], sampling site locations for the soil gas and soil surface CO_2 flux included:

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

Based on the outcome of the first sampling event in Q4-2012, the soil gas and soil surface CO_2 flux program was modified. Transient plots were removed from the baseline monitoring plan and semi-permanent plots were used instead in 2013. For 2014, the same sites as in 2013 will be included in the soil gas / surface flux sampling program, and include:

- 1 site near each injection well pad (3 in total)
- 12 semi-permanent plots, with 3 of the plots being split into two based on land type differences at those plots (15 in total).

Note that the plot selection ensures data collection from the main land use types encountered within the SLA.

The type and distribution of the sites permit Shell to attain an understanding of both the temporal and spatial variability of soil gas and soil surface CO_2 flux across the SLA. Note that the semi-permanent plots are identical to those used for the remote sensing monitoring program (see Section 3.3).

Discrete measurements are taken every season (4 sampling events per year at regular intervals) and started in Fall 2012 during the baseline period in order to capture expected temporal variations in soil gas and soil surface CO2 flux.

3.4.3 Sampling Protocol

Soil surface CO_2 flux measurements will be taken at 3 randomly chosen sampling points located within a homogeneous soil/vegetation type. Soil surface CO_2 flux measurements will be obtained using a field-deployable LiCor Model 8100A CO_2 flux survey chamber.

Regarding the soil gas measurements, a vertical probe (e.g. AMS Retract-A-Tip gas vapour probe) is inserted into the soil in order to collect the samples. Samples are collected from three depths down to about 2 m below the ground surface at the sites near the injection well pads. At the semi-permanent plot sites, only a sample from the 'middle' depth is collected. If possible, soil gas samples are submitted to a qualified laboratory in Alberta with appropriate QA/QC procedures for compositional and isotopic analyses.

Compositional analysis of a soil gas sample includes:

- CO_2, C_1 to C_{10+}, N_2, O_2, He

Isotopic analysis of a soil gas sample includes:

- $\delta^{13}C$- CO_2, $\delta\,^{13}C$-CH_4 and $\delta\,^{13}C$-C_2+, $\delta\,^{2}H$-CH_4

4 Integrated Response Plan

During the baseline monitoring period 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 closure periods, routine monitoring activities will be carried out as discussed in Sections 2 and 3. In situations where an anomolous change in the parameters being monitored is identified and that may be the result of loss of containment associated with Quest CO2 or BCS brine, an integrated response plan will be initiated (Fig. 4-1).

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 closure periods, as presented in Sections 2 and 3. The integrated response plan provides a means to:

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

The IRP operates as follows:

- threshold level exceeded for a Hydrosphere or Biosphere 'trigger'
    - example of hydrosphere trigger: Tier 0 EC continuous measurement
    - example biosphere trigger: anomaly on satellite imagery
- if trigger within Biosphere:
    - 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
    - field visit:
        - OK: return to routine monitoring
        - AMBIGUOUS: undertake soil gas measurement
    - soil gas measurement:
        - OK: return to routine monitoring
        - AMBIGUOUS: check existing groundwater/well headspace data collected within area of anomaly
    - existing groundwater/well headspace data:
        - OK: return to routine monitoring

        - AMBIGUOUS: initiate Tier 2 analyses
    - Tier 2 groundwater/well headspace data:
        - OK: return to routine monitoring
        - AMBIGUOUS: initiate Tier 3 analyses
    - Tier 3 groundwater/well headspace data:
        - OK: return to routine monitoring
        - NOT OK: initiate Tier 4
    - 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
    - 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
    - Tier 2 groundwater/well headspace data:
        - OK: return to routine monitoring
        - AMBIGUOUS: initiate Tier 3 analyses
    - Tier 3 groundwater/well headspace data:
        - OK: return to routine monitoring
        - NOT OK: initiate Tier 4
    - 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

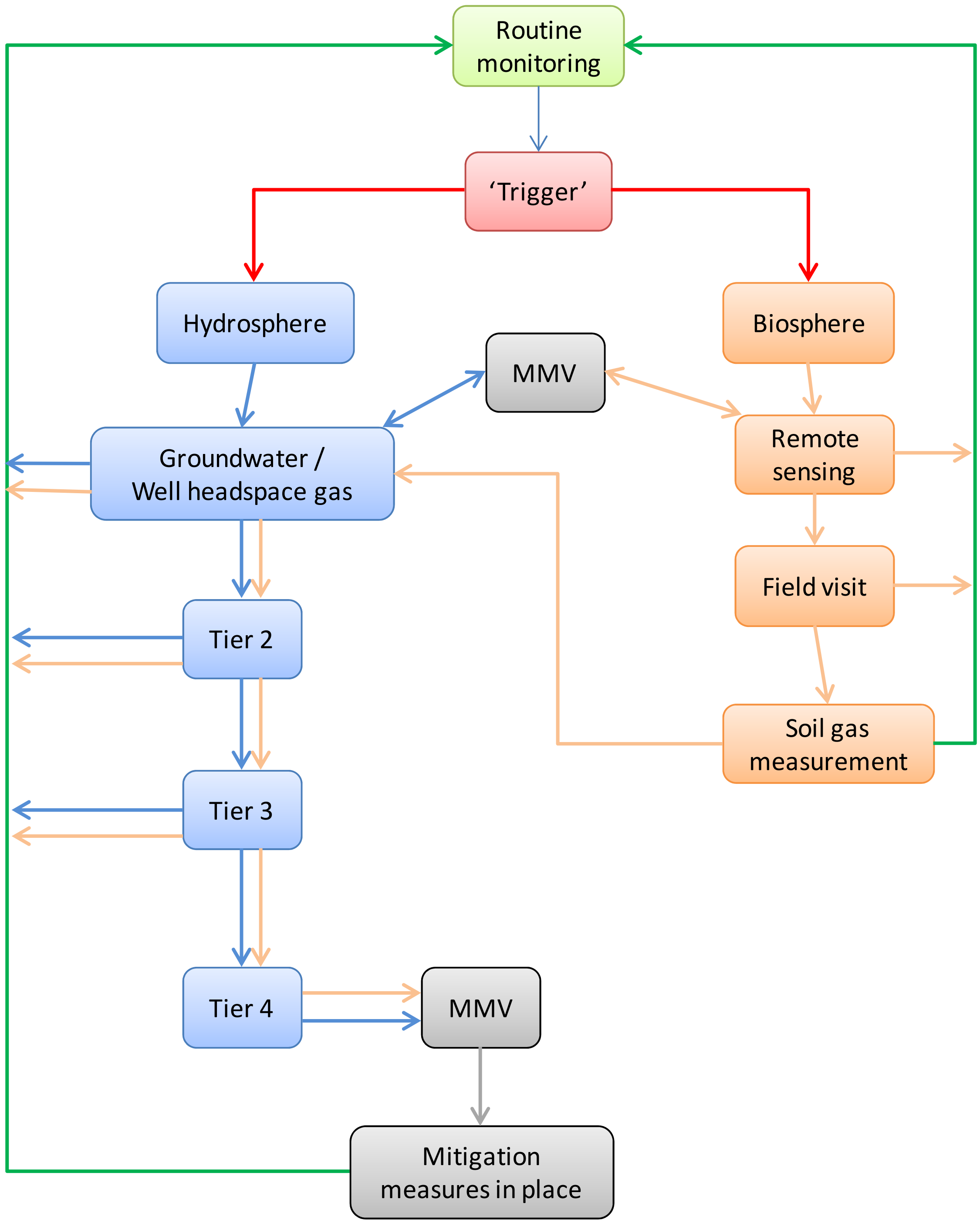

Figure 4-1: Schematic overview of Integrated Response Plan

5 References

1) Alberta Energy Regulator Carbon Dioxide Disposal & Containment Approval No. 11837A. Issued to Shell Canada Limited August 8, 2013. Shell, 2012. EN134.04_2012-02-28 - Shell Response to the Groundwater Review Submission - Tab B_[1806378].
2) Shell Canada Limited, Quest Carbon Capture and Storage Project, Response to AER Request for Additional Information Letter sent March 28th, 2013.
3) Shell Canada Limited, Quest Carbon Capture and Storage Project First Annual Status Report, Appendix A: Generation-4 Integrated Reservoir Modeling Report. Submitted to AER January 31, 2013.
4) Shell Canada Limited, Quest Carbon Capture and Storage Project First Annual Status Report. Submitted to AER January 31, 2013 as per Carbon Dioxide Disposal Approval 11837A.
5) Klusman, R.W. (2011). Comparison of surface and near-surface geochemical methods for detection of gas microseepage from carbon dioxide sequestration. International Journal of Greenhouse Gas Control vol. 5, p. 1369-1392.
6) Shell Quest Carbon Capture and Storage Project: Special Report #1, Appendix A - Measurement Monitoring and Verification Plan, submitted October 15th, 2012.
7) Shell Canada Limited, Quest Carbon Capture and Storage Project Second Annual Report. Submitted to AER January 31, 2014.
8) SCWG (Soil Classification Working Group). 1998. The Canadian System of Soil Classification. Agric. And Agric-Food Can. Publ. 1946 (Revised). NRC Research Press, Ottawa. 187 pp. ISBN: 0660174049. Available at: http://sis.agr.gc.ca/cansis/references/1998sc_html
9) Moss (1983). Flora of Alberta, 2nd Edition. Revised by J.G. Packer. University of Toronto Press, Toronto, Ontario. 687 pp.
10) Daubenmire (1959). A canopy-coverage method of vegetational analysis. Northwest Sci. vol. 33, p. 43-64.

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 CO_2.

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

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

Risk assessment,

Monitoring tool selection

Site selection, characterization and qualification

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

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

B.2 Future Regulatory Expectations

The volume and time-scale of CO_2 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-CO_2) 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 CO_2 storage has developed the OSPAR principles for monitoring and stated the following six objectives for monitoring.

Demonstrate CO_2 behaves as expected.

Detect any migration or leakage.

Measure any environmental or health damage.

Determine effectiveness of CO_2 storage as GHG mitigation.

In case of leakage, assess effectiveness of corrective measures.

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

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

Actual CO_2 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 CO_2 storage rather than just the volume occupied by the CO_2 plume itself.

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

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

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

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

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

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

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

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

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

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

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

B.5 Industry Authorities

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

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

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

Appendix 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 analyzing and communicating risks.

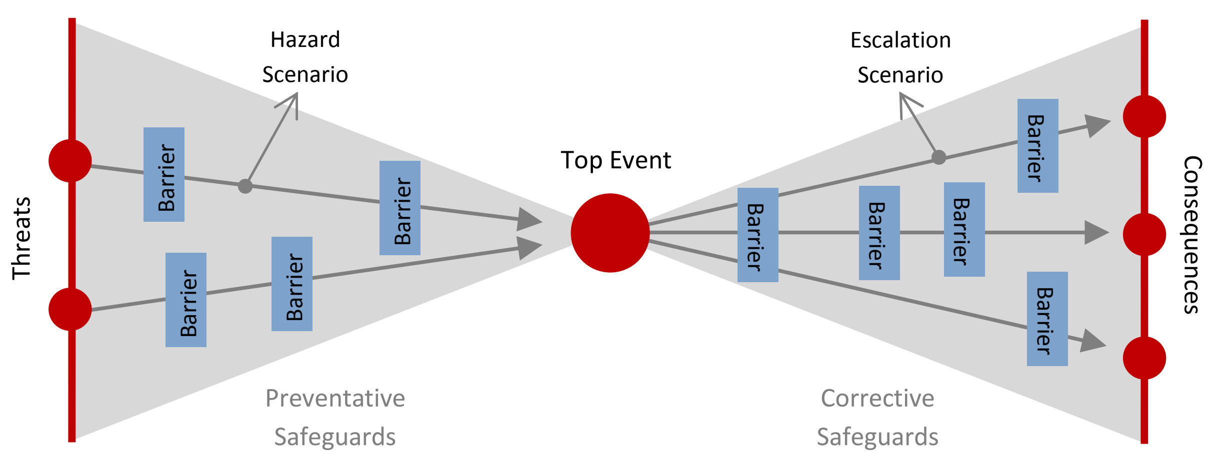

Figure C-1 Schematic Diagram of the Bowtie Method.

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.

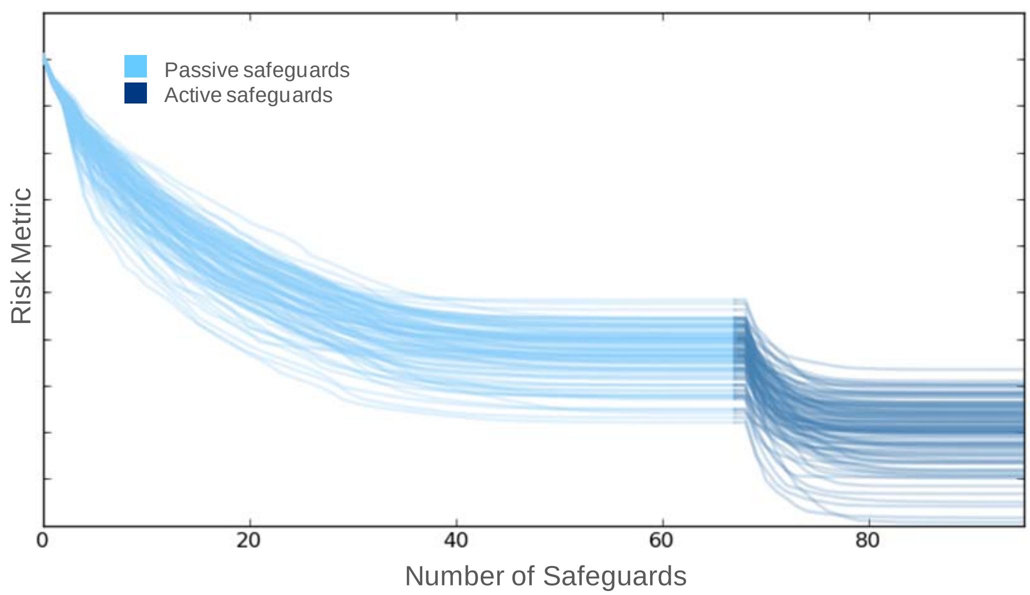

Figure C-2 Reduction in risk computed for increasing number of passive and active safeguards. Each line represents one realization of the anticipated failure rates for each safeguard selected at random from the recognized range of potential failure rates for each safeguard. The 100 realizations shown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

Appendix 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 CO_2 per year. Four projects – Sleipner, In Salah, Snøhvit and Rangely – inject CO_2 from a natural gas production facility where it is separated from the natural gas sent to market. In the first three cases, the CO_2 is injected into saline aquifers, while in the fourth it is used for EOR. A fifth project captures CO_2 at the Great Plains Synfuels Plant and transports it for EOR to the 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 CO_2 under the North Sea. This CO_2 was extracted with natural gas from the offshore Sleipner gas field. In order to avoid a government-imposed carbon tax equivalent to about USD 55/tonne, Statoil built a special offshore platform to separate CO_2 from other gases. The CO_2 is re-injected about 1 000 meters below the sea floor into the Utsira saline formation located near the natural gas field. The formation is estimated to have a capacity of about 600 billion tonnes of CO_2, and is expected to continue receiving CO_2 long after natural gas extraction at Sleipner has ended.

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 CO_2 into the Krechba geologic formation near their natural gas extraction site in the Sahara Desert. The Krechba formation lies 1 800 meters below ground and is expected to receive 17 million tonnes of CO_2 over the life of the project.

D.1.3 Snøhvit

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

D.1.4 Rangely

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

D.1.5 Weyburn-Midale

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

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

Appendix E Status of Existing Wells

Status of Existing Wells

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

Table E-1 Status of BCS legacy wells

Well name and UWI	History and Distance from pipeline	Seals drilled through	Casings, holes and BGWP	Cement plugs
Imperial Eastgate 100-01-34-057-22W400	• *Drilled and abandoned in 1955* • *21 km from pipeline*	• *Upper Lotsberg* • *Lower Lotsberg* • *- MCS*	• *9 5/8" casing to 277m* • *9" openhole to 2205m (TD)* • *BGWP at 240m bgl*	#1: 265 – 289 m #2: 644 – 710m #3: 887 – 981m #4: 1016 – 1048m #5: 1256 – 1292m #6: 2125 – 2205m
Imperial Egremont 100-06-36-058-23W400	• *Drilled and abandoned in* • *1952* • *21 km from pipeline*	• *Upper Lotsberg* • *Lower Lotsberg* • *MCS*	• *13 3/8" casing to 186m* • *9" openhole to 2242.3m* • *BGWP at 220m bgl*	#1: 172 – 195m #2: 624 – 670m #3: 844 – 875m #4: 969 – 1003m #5: 1178 – 1218m #6: 2140 – 2242m
Imperial Darling #1 100-16-19-062-19W400	• *Drilled and abandoned in* • *1949* • *25 km from pipeline*	• *Upper Lotsberg* • *Lower Lotsberg* • *MCS*	• *13 3/8" casing to 183m* • *9" (supposed) openhole to 2013m* • *BGWP at 235m bgl*	#1: 168 – 198m #2: 525 – 587m #3: 708 – 740m #4: 762 – 792m
Westcoast et al Newbrook 100-09-31-062-19W40	• *Drilled in and abandoned in 1978* • *28 km from pipeline*	• *Upper Lotsberg* • *Lower Lotsberg* • *MCS*	• *9 5/8" casing to 230m* • *- 7" (supposed) openhole to TD at 1923m* • *- BGWP at 228m*	#1: 183 – 366m #2: 518 – 701m #3: 838 – 960m #4: 1082 – 1204m #5: 1280 – 1402m #6: 1524 – 1615m #7: 1707 – 1923m
Imperial Clyde #1 100-09-29-059-24W400	• *Drilled and abandoned in* • *1948* • *43.5 km from pipeline (outside SLA)*	• *Upper Lotsberg* • *Lower Lotsberg* • *MCS*	• *13 3/8" casing to 135m* • *9" openhole to 2295m (TD)* • *BGWP at 232.5m bgl*	#1: 128 – 195m #2: 781 – 945m
Imperial Gibbons #1 100-02-16-056-22W400	• *Drilled and abandoned in* • *1949* • *25 km from pipeline (outside SLA)*	• *Upper Lotsberg* • *Lower Lotsberg*	• *13 3/8" casing to 180m* • *9" openhole to 2024m (TD)* • *BGWP at 258.1m bgl*	#1: 695 – 754m #2: 893 – 983m #3: 1052 – 1113m
Imperial PLC Redwater LPGS 100-07-17-056-	• *Drilled in 1974 – Converted to LPG*	• *Upper Lotsberg*	• *13 3/8"casing to 188.4m*	#1: 0 – 500m #2: 1435 –

21W400	*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*	1760m #3: 1760 – 1861m

Table E-2 Status of the Project Injection Wells.

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

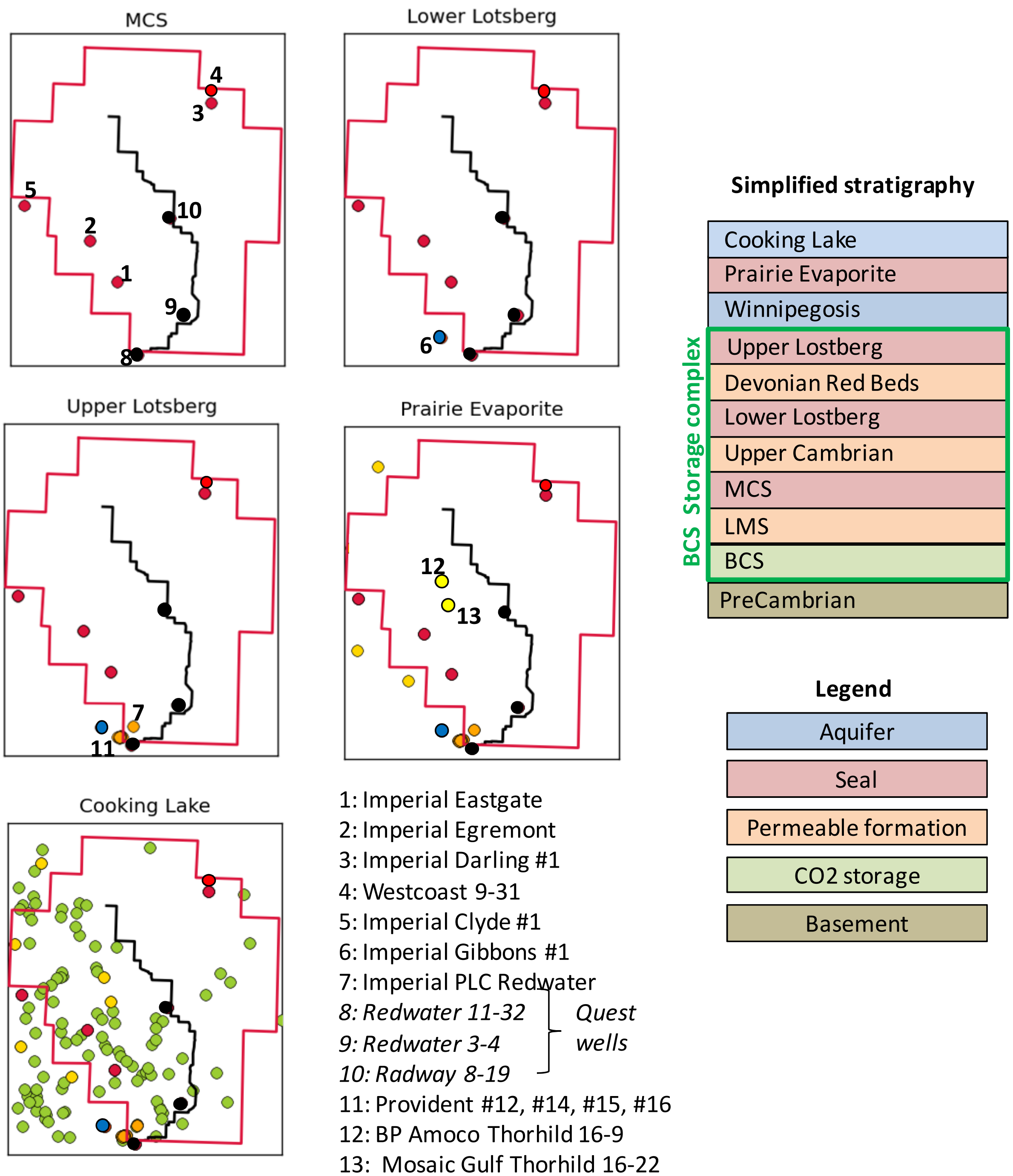

Figure E-1 Summary of existing well locations.

Table E-3 Distance to closest offset hydrocarbon producers.

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

Appendix 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 SLAI. However, BCS brine can only by lifted to the BGWP zone if these legacy wells provide an open conduit from the BCS to surface and this is unlikely because all BCS legacy wells have been abandoned with multiple large cement plugs.

Other third-party legacy wells in the area either do not penetrate the BCS reservoir or are located outside the SLA and would have lower pressures in the BCS than the wells quoted in Table F-1below. 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.

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

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

Appendix B – List of Reports Submitted to Regulatory Agencies

Table B-1: List of Quest documents Submitted to External Parties (* - approvals and information request received by Shell from Regulators)

Requirement	Documents Submitted to Regulators as of February 2014	Key Appendices	Regulatory Agency Alberta Energy Regulators (AER)	Environment and Sustainable Development (ESRD)	Alberta Energy (AE)	Natural Resources Canada (NRCAN)	Canadian Environmental Assessment Agency (CEAA)
Directive 65	Final Quest Directive 65_Submitted to ERCB Nov 2010.pdf	Appendix B - Conceptual MMV Plan	Nov-12				
	D65 Deficiency Letter- response to ERCB-FINAL_6Jun11.pdf	Appendix A- Redwater 11-32 micro and minifrac analysis Appendix B - Pressure Test Data Redwater 11032 micro-minifracs Appendix C - Injection Test Summary Radway 8-19 BJ Fracturing Services	6-Jun-11				
	D65 Update_June_2011.pdf	Appendix E: Initial Closure Plan	Jun-11				
	Response to ERCB Deficiency Letter on MMV Oct21_2011.pdf		21-Oct-11				
	ERCB MMV Deficiency Letter received 2011-10-17-.pdf*		17-Oct-11				
	Response to SIR #2_November 2, 2011.pdf		2-Nov-11				
	Errata to the EA Volume 2, Section 5_November 2, 2011.pdf		2-Nov-11				
	Response to SIR Nov.30 from ERCB_submitted Dec2011.pdf	Appendix B- DNV Independent Project Review of Storage component Final Report	Dec-11				
	ERCB seismic and mmv information request received 2011-11-30 .pdf*		30-Nov-11				
	Shell Response to Ouelette_(2012.02.28)_Groundwater Review Submission-Tab B.pdf	Tab B - MMV commitment Table 1-1 for Regulatory Hearing	28-Feb-12				
	Shell Canada Limited AER Hearing Decision 2012 ABERCB 008.pdf*		10-Jul-12				
	ERCB Approval for Extension of pre-baseline MMV submission date_Sept13_2012.pdf*		13-Sep-12				
	Special Report #1 Submitted to AER Oct 29 2012	Appendix A - Pre baseline MMV Plan Oct 15 2012 (includes HBMP Plan) Appendix B - MCS Geomechanical Core Analysis Report Appendix C - MDA InSAR Feasibility Report	29-Oct-12				
	ESRD_Condition_25_MMV Plan Update_Sent_Nov5_2012.pdf			5-Nov-12			
	ERCB Dec 7 2012 IR_Response_submitted_Jan_9_2013.doc		9-Jan-13				
	Special_Report_#2_Submitted to AER_Jan31_2013.pdf	Appendix A - TRE InSAR Feasibility Report	31-Jan-13				
	First_Annual_Status_Report_to AER_submitted Feb_13 2013.pdf	Appendix B - Generation 4 Integrated Modeling Report Appendix C - Odorant Injection Study (Mercaptans)	13-Feb-13				
	AER Approval for no Mercaptans 2013-12-02.pdf*		2-Dec-13				
	2nd Annual Status Report_to AER Submitted_Jan 31 2014.pdf	Appendix A - BCS Core Descriptions IW 7-11 and IW 5-35 Appendix D - Artificial Tracer Interim Feasibility Report Appendix E - Golder Associates HBMP Results Fall 2012 to end 2013 Appendix F - MCS Co2 Entry Presurre Results for IW 8-19	31-Jan-14				
	ERCB SIR 2_received Shell March 28 2013.pdf*		28-Mar-13				
	Response to ERCB SIR march 20 2013 submitted April 25.pdf		25-Apr-13				
	Storage Rights Clarification Letter Submitted to AER April 25 2013.pdf		25-Apr-13				
	Letter to ERCB for Clarification on Storage Rights_submitted_May29_2013.pdf		29-May-13				
	MMV_Bowtie_submitted with Clarification on Storage Rights Letter May29_2013.pdf		29-May-13				
	ERCB Response to Legal Clarifying Storage Rights received June 3 2013.pdf*		3-Jun-13				
	Response to ERCB email on Special Report #1 submitted April 23-13.pdf		23-Apr-13				
	AER final D65 Approval No 11873A August 8 2013.pdf*		8-Aug-13				
	AER Sept 5 2013 IR response submitted Sept 20, 2013.pdf		20-Sep-13				
	AER Approval and Conditions for InSAR recieved 2013-10-04.pdf*		4-Oct-13				
	Self Disclosure to AER - IW 5-35 perfs out of zone_Nov 25 2013.pdf		25-Nov-13				
	Self Disclosure to AER- IW 5-35 perfs out of zone_add info_ Jan 2014.pdf		Jan-14				
	AER Approval & Clarification Letter RE October 15 2012 MMV Plan & Special Report #1.pdf*		3-Dec-13				
	MMV Plan interim update Feb 14 2014_Submitted.pdf	Appendix A - HBMP Plan	14-Feb-14	14-Feb-14	27-Feb-14		
D51	Shell Response to AER Questions on Well Integrity_Dec 6_2013.pdf	2 - Baker Hughes DTS fiber Test Reports 3- Baker Hughes DTS EOW & Baseline Reports 4- Shell Injection well Drilling Program 5- Quest Well After Actio Review Report 6- Shell CBL evaluations 7 - AFL fiber optic Cable Specs	6-Dec-13				
	D51 Application Radway 8-19-59-20W4-Nov10_submitted to ERCB.docx		10-Nov-10				
	Shells Request to Transfer Directive 051 Submission to Application 1670112_1806713_2011-07-25.pdf		25-Jul-11				
	Directive 051 Closure_1806712 2011-07-29.pdf*		29-Jul-11				
AER ID 2003-01	AER Approval for SCVF and GM Deferral of Repair received Sept4_2013.pdf*		4-Sep-13				
	AER denial of Shell initial Proposal to AER for SCVF and GM resolution proposal received June 12_2013.pdf*		12-Jun-13				
	Shell Approved Proposal to AER for SCVF and GM resolution submitted Aug28_2013.pdf		28-Aug-13				
Alberta Mines and Mineral Act Part 9	Quest Sequestration Lease Application to ADOE April 28 2011				28-Apr-11		
	ADOE Quest Sequestration Lease Approval May 27 2011.pdf*				27-May-11		
	Letter to ADOE for Clarification to monitoring the Cooking Lake submitted March 27 2013.pdf				27-Mar-13		
	ADOE Approval to monitor the Cooking Lake Formation_April 19 2013.msg*				19-Apr-13		
Quest Funding Aggreement	07-0-AA-5726-0001 - Storage Development Plan (Rev 2, 2011-10-06)				Mar-12		
	External Expert Panel Report by DNV				Mar-12		
	07-3-AA-6619-0001 Capacity Risk and Uncertainty Review. Pdf				Mar-12		
	07-3-AA-6619-0004 Containment Risk and Uncertainty Review.pdf				Mar-12		
	07-3-AA-6619-0005 Injectivity Risk and Uncertainty Review.pdf				Mar-12		
	07-3-AA-5726-0001 Integrated Modeling Report (Gen - 4)				Mar-12		
	1161- 07-3-ZW-8780-0001 Well Programme for Completion and Intervention (Rev 1, 2011-08-2011)				Mar-12		
	07-3-ZW-7770-0001- Well Technical Specification (Rev 1, 2011-08-11)				Mar-12		
	07-3-ZW-7770-0002 - Well Technical Specification for Interventions (Rev 2, 2011-08-11)				Mar-12		
	Q1 2011 Quarterly Status Update March 2011				N/A	Mar-11	
	Q2 2011 Quarterly Update June 2011				N/A	Jun-11	
	Q3 2011 Quarterly Update October 2011				N/A	Oct-11	
	Q1 2012 Quarterly Update April 2012				N/A	Apr-12	
	Q2 2012 Quarterly Update July 2012				Jul-12	Jul-12	
	Q3 2012 Quarterly Update October 2012				Oct-12	Oct-12	
	Q1 2013 Quarterly Update March 2013				Mar-13	Mar-13	
	Q2 2013 Quarterly Update September 2013				Sep-13	Sep-13	
	Q3 2013 Quarterly Update December 2013				Dec-13	Dec-13	
	Q4 2013 Quarterly Status Update February 2014				Feb-14	Feb-14	
	2012 Annual Report March 2012				Mar-12	Mar-12	
	2013 Annual Report March 2013				Mar-13	Mar-13	
	2013 Annual Report Presentation March 2013				Mar-13	Mar-13	
	Q2 2013 Quarterly Construction Update June 2013				Jun-13	Jun-13	
	Q3 2013 Quarterly Construction Update October 2013				Oct-13	Oct-13	
	Q4 2013 Quarterly Construction Update February 2014				Feb-14	Feb-14	
Canadian Environmental Assessment Act (mandatory and exempted activities Regulation)	Shell Quest - Screening Report - CEAR ref # 10-01-55916 Final signed.pdf*					Jun-12	Jun-12