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.

Quest Carbon Capture and Storage Project

ANNUAL SUMMARY REPORT - ALBERTA DEPARTMENT OF ENERGY: 2011

March 2012

Executive Summary

This annual report summarizes the progress and status of the Quest Carbon Capture and Storage (CCS) Project as it pertains to the initial full project proposal submitted in March 2009 to the Alberta Department of Energy by Shell Canada Limited. That submission was for funding from the Alberta CCS Fund and as a requirement for CCS Funding Agreement – Quest Project that was signed on June 24, 2011.

The purpose of the Quest Project is to deploy technology to capture CO_2 produced at the Scotford Upgrader and to transport, compress and inject the CO_2 for permanent storage in a saline formation near Thorhild, Alberta. Over one million tonnes of CO_2 per year will be captured, representing greater than 35% capture of the CO_2 produced from the Upgrader. Quest is a part of the Athabasca Oil Sands Project (AOSP), an oil sands joint venture operated by Shell and owned by Shell Canada, Chevron Canada and Marathon Oil.

According to Shell's Opportunity Realization Manual (ORM) process, the Quest Project has completed the Define phase whereby the Project scope is finalized and the Front End Engineering and Design (FEED) is completed. The project now moves into the Execute phase when the detailed engineering is completed and construction occurs.

With the completion of FEED, the process design is finalized. The CO_2 will be captured from three existing steam methane reformers used to generate hydrogen at the Scotford Upgrader. A commercially proven activated amine process will be used in which the CO_2 is absorbed (captured) into the amine solution and then regenerated to produce at least 95% CO_2 purity. The CO_2 will then be compressed by an electrical drive compressor to a maximum dense-phase pressure of approximately 14 megapascals. At this pressure, the CO_2 will be transported through a 12-inch diameter pipeline to a location approximately 80 kilometers north of the Scotford Upgrader. No further compression or pumping is required to transport the CO_2 to the injection site. Safeguarding of the pipeline includes line break valves stationed at regular intervals, flow meters used to detect material loss, cathodic corrosion protection and other internal and external inspection activities.

By means of three to eight injection wells, CO_2 will be injected approximately 2 km underground into the Basal Cambrian Sands (BCS) geological formation. The BCS formation is situated below layers of impermeable, continuous and thick cap rock, which will keep CO_2 isolated within the formation and will prevent any upward migration. The CO_2 will be trapped within the pore spaces of the rock formation in the same way that geological formations have naturally contained large reservoirs of oil and gas for millions of years.

Storage properties of the BCS complex have been validated through analysis of the data obtained from drilling a test well into the planned storage location. Risks of CO_2 containment loss have been comprehensively detailed along with mitigation activities.

A detailed measurement, monitoring and verification (MMV) Plan has been developed and will be implemented by Shell to monitor the storage of CO_2 and to protect public health and safety. The MMV Plan will be integrated with the GHG reporting system in place at the Scotford Upgrader.

Regulatory approvals for construction and operation are proceeding. A bundled application of provincial approvals for the capture, transportation and drilling activities has been assessed by the Government of Alberta. Three rounds of information requests have been responded to by Shell. A regulatory hearing was held by the Energy Resources Conservation Board (ERCB) in March 2012. In a parallel activity, the Project has been assessed within the federal jurisdiction of the Canadian Environmental Assessment Act (CEAA). Two reports are expected as a result of these reviews: the CEAA assessment is undergoing a 30-day public comment process prior to issuing a completed report and the ERCB Hearing report is anticipated in mid-2012 and these two pending reports are the basis for Shell's determination that regulatory approvals have been given, in principle. Upon the release of the two reports, a Final Investment Decision (FID) will be taken by the AOSP joint venture owners as to whether or not to proceed with the Project.

Shell has conducted a thorough public engagement and consultation program for Quest. Open houses were held in March and November 2010 and September 2011 in the communities of Thorhild, Lamont, Bruderheim and Fort Saskatchewan. Two Quest Cafe events were held in 2011, which were designed to bring in local municipal representatives and key community leaders for smaller, in-depth two-way dialogues. County and Town Council Quest updates were given twice in 2011 to councils in Thorhild, Strathcona, Lamont and Sturgeon County.

The current estimate of capital costs is about $910 million dollars that will be spent from 2012 to 2015. The current estimate of operating costs is about $41 million per year. Project revenues will be zero during construction and will be $30 million per year during operations from the sale of carbon credits at current carbon prices.

The project is proceeding on the expected timeline with completion of construction in 2015 and startup immediately thereafter. The only significant milestone change has been the delay in the FID from March 2012 point to mid-2012. A risk based decision has been taken to proceed with detailed engineering prior to the FID in order to continue to meet the 2015 startup date.

The Project has experienced a number of successes in the past reporting period, including:

- obtaining fiscal support from the governments of Alberta and Canada
- applying for and receiving pore space tenure for the planned storage zone
- completing the FEED phase and passing the accompanying internal assurance review
- drilling of the BCS test well into the storage area to verify the geological properties
- obtaining positive stakeholder engagement
- routing finalization of the pipeline
- obtaining independent certification of the Storage Development Plan, including the MMV program
- completing the ERCB regulatory hearing

Project challenges included:

- finding creative ways to manage the capital cost pressures
- managing the increased staffing requirements as the project team expanded
- accommodating a delay (from November to March) in the regulatory hearing
- continuing Project planning within the uncertain boundaries of some aspects of the regulatory frameworks

These challenges have been successfully managed with the result that the Project remains on track.

Within the next reporting period, AOSP joint venture owners will determine FID after reports are released. With a positive decision outcome, Shell will continue detailed engineering leading to construction. Completion of the permitting process will also occur, with ongoing reporting to the governments of Alberta and Canada to keep them apprised of the Quest CCS Project progress.

Table of Contents

List of Tables

List of Figures

List of Appendices

Abbreviations

2D	2-Dimensional
3D	3-Dimensional
4D	4-Dimensional
AEW	Alberta Environment and Water
AFN	Alexander First Nation
AOI	Area of Interest
AOSP	Athabasca Oil Sands Project
ARC	Alberta Research Council
ASRD	Alberta Sustainable Resources Development
BCS	Basal Cambrian Sands
BDEP	Basic Design Engineering Package
BHP	Bottom Hole Pressure
BLCN	Beaver Lake Cree Nation
CCS	Quest Carbon Capture and Storage
CEAA	Canadian Environmental Assessment Act
CRC	Calgary Research Center
D51	Directive 51 application
D56	Directive 56 application
D65	Directive 65 application
DNV	Det Norske Veritas
EAP	Enhanced Approval Process
EC	Executive Committee
ERCB	Energy Resources Conservation Board
FEED	Front End Engineering and Design
FEP	fracture extension pressure
FID	Final Investment Decision
GHG	Greenhouse Gases
HDD	horizontal directional drilling
HMU's	hydrogen manufacturing units
HVP	high vapor pressure
InSAR	Interferometric synthetic aperture radar
LBV	line break valve
LMS	Lower Marine Sand
LRDF	long running ductile fracture
MCS	Middle Cambrian Shale
MMV	measurement, monitoring and verification
ORM	Opportunity Realization Manual
OSCA	*Oil Sands Conservation Act*
PSA	pressure swing adsorber
RFA	Regulatory Framework Assurance
ROW	right-of way
SDP	Storage Development Plan
SGSI	Shell Global Solutions Inc.
SIRs	Supplemental Information Requests
SLCN	Saddle Lake Cree Nation
TEG	triethylene glycol

UMS .... Upper Marine Siltstone
VAR .... Value Assurance Review
VSP .... vertical seismic profile
WCSB .... Western Canada Sedimentary Basin
WIIP .... water initially in place

1 Overall Facility Design

Facility design at this point has reached the completion of the Front End Engineering and Design (FEED) and is beginning the detailed engineering necessary prior to commencement of construction.

1.1 Design Concept

The Athabasca Oil Sands Project (AOSP) is an oil sands joint venture that operates the Scotford Upgrader located at Shell Scotford, located in the Alberta Industrial Heartland, northeast of Edmonton. The design concept of the Quest CCS Project is to remove CO_2 from the process gas streams of the three hydrogen manufacturing units (HMUs), which are a part of the Upgrader infrastructure, by using amine technology and to dehydrate and compress the captured CO_2 to a dense-phase state to allow for efficient pipeline transportation to the subsurface storage site.

The three HMU's comprise two identical existing HMU trains in the Base Plant Upgrader and third one constructed as part of the Upgrader Expansion 1 Project, which has been operational since May 2011.

1.2 Design Scope

The design scope for the facilities include:

- modifications on the three existing HMUs
- modifications on the three existing pressure swing adsorbers (PSAs)
- three amine absorption units located at each of the HMUs
- a single common CO_2 amine regeneration unit (amine stripper)
- a CO_2 vent stack
- a CO_2 compression unit
- a triethylene glycol (TEG) dehydration unit
- Shell Scotford utilities and offsite integration
- CO_2 pipeline, laterals, and surface equipment
- Five to eight injection wells

1.3 ORM Design Framework and Quest Project Maturity

The design framework followed by the Quest Project is the standard Shell approach in project design, called the Opportunity Realization Manual (ORM). The ORM process manages a project as it matures through its lifecycle from initial concept to remediation following closure. ORM divides this lifecycle into stages as shown in Figure 1-1. Each phase has required deliverables that are developed and completed and then reviewed, to ensure proper quality of these deliverables before proceeding to the next phase.

Figure 1-1 ORM Phases with current Quest Maturity

Quest technical Project activities in past year correspond within the Define phase. This includes the engineering work required to deliver key project documents of this phase, including the Basic Design Engineering Package (BDEP), the Project Execution Plan (PEP) and the Storage Development Plan (SDP).

In September 2011, Shell completed the Define phase, which culminated with the required value assurance review (VAR). The VAR examined the status of the Project, including the Define phase deliverables and concluded that the Project was ready to proceed to the next decision gate.

Under normal circumstances, the successful conclusion of the Define phase is followed by the Final Investment Decision (FID) prior to moving to the next phase. However, Quest at that point did not have the required project provincial and federal regulatory approvals that the Shell Executive Committee (EC) set as a condition for approving FID. These approvals were delayed by the Energy Resources Conservation Board (ERCB) regulatory hearing dates from planned November 2011 to March 2012. A subsequent hearing report that recommends regulatory approval would satisfy the condition set by the Shell EC. Following this anticipated positive hearing report, a submission to the EC will be made for an FID, which is expected to occur in mid-2012. Deferring the Execute phase until after this FID represents a significant project delay and threat to meeting the major project requirement of startup in 2015. Therefore, a risk-based decision was made to proceed into the Execute phase before final regulatory approvals in order to hold to the Project schedule.

The Execute phase concludes with the completion of the facilities construction and subsequent handover to Shell Scotford operations for startup and operation. This is planned to occur in mid-2015.

1.4 Facility Locations and Plot Plans

The Quest CCS Project facility locations are shown in Figure 1-2.

The capture facility is situated within the Scotford Upgrader. The proposed pipeline routing is shown as the dotted line in Figure 1-2, while the stars indicate the location of the potential maximum number of eight wells. The actual number of wells drilled may be less and will be dependent on the actual injectivity and porosity characteristics of the formation. Three injection wells are planned initially and additional ones drilled only as they are required to store the CO_2 into the storage area.

Within the Upgrader complex, the capture unit is located adjacent to two of the upgrader HMU’s. See Figure 1-3 for a schematic view of the capture unit location.

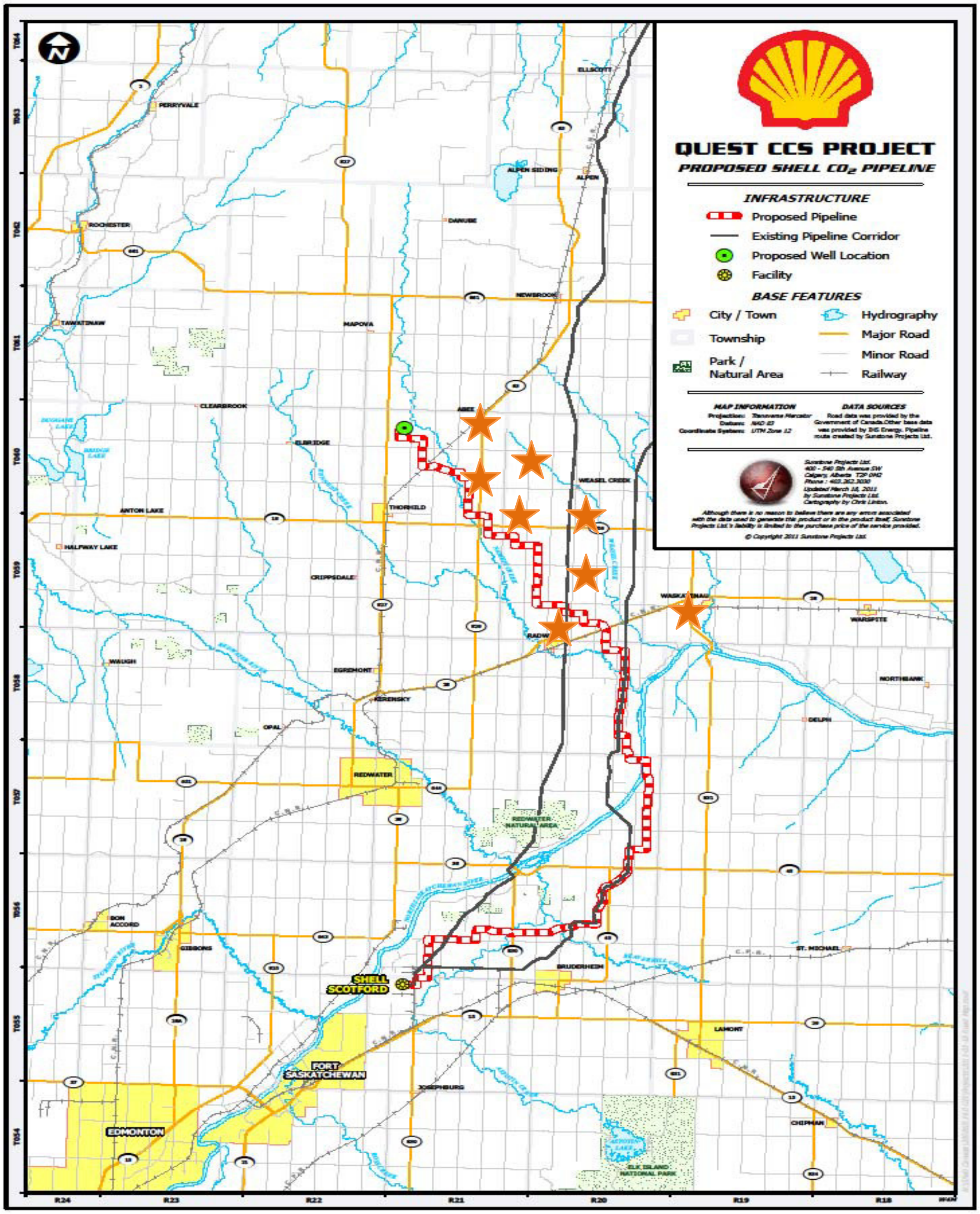

Figure 1-2 Quest Facility Locations

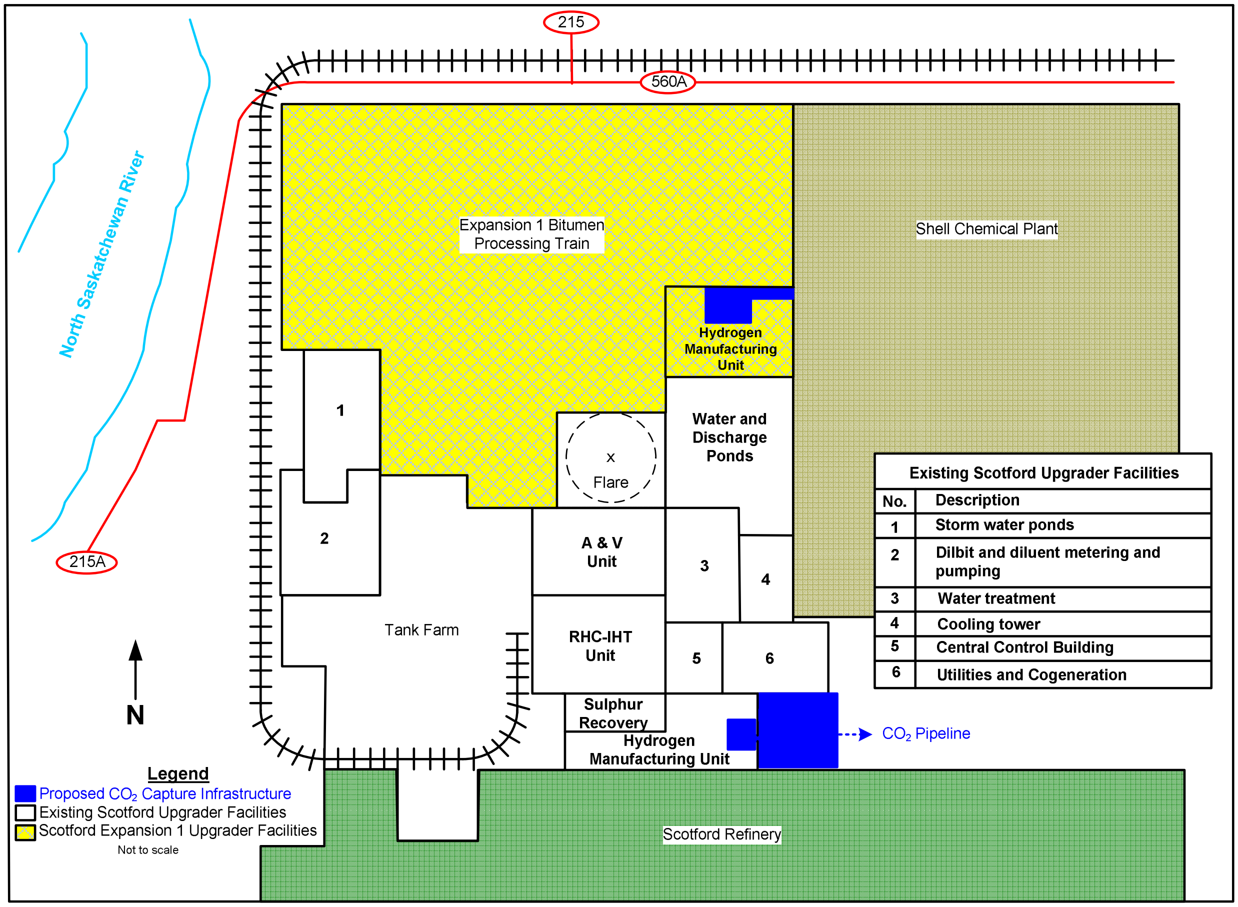

Figure 1-3 Quest Capture Unit Location Schematic

Detailed plot plans of the capture unit are in Appendix A – Quest Capture Unit Plot Plans.

Extensive work was done during the Define phase to validate the Basal Cambrian Sands (BCS) formation CO_2 storage properties and to establish the optimum storage location. Figure 1-4 shows the BCS formation zone. Discussion of the BCS storage properties are in Section 3 – Geological Formation Selection.

Figure 1-5 shows the final storage location, highlighted by the red line. Criteria for this selection included validating the BCS properties within the location, minimizing the number of legacy wells into the BCS zone (to reduce risk of potential leak paths), and avoiding proximity to densely populated areas (to minimize the number of landowner consents for the pipeline and injection wells).

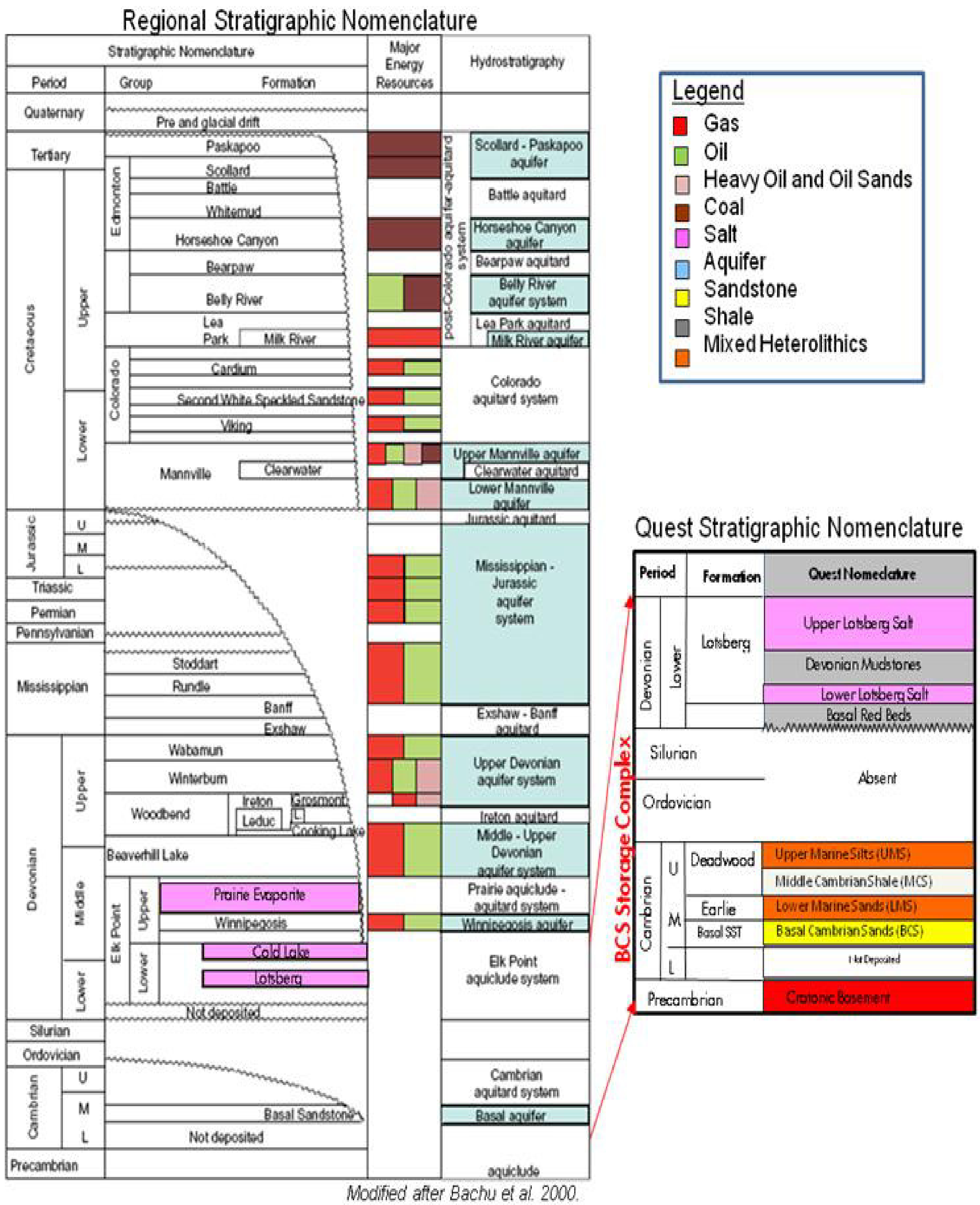

Figure 1-4 Quest BCS Zone within Regional Stratigraphy

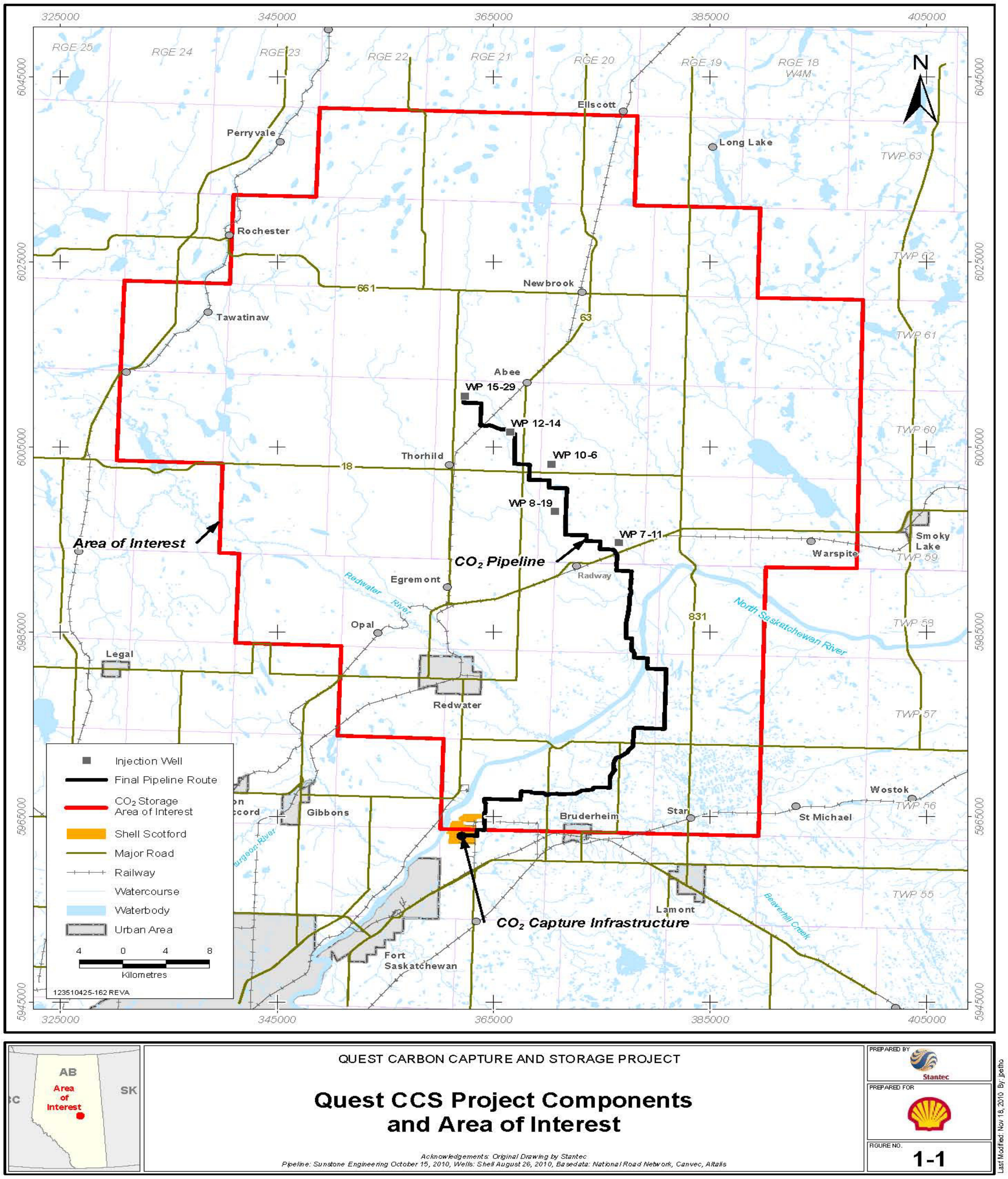

Figure 1-5 Quest Area of Interest

Once the optimal storage zone location (the area of interest) was determined, a critical requirement of the Project was that this zone be available for use and not be impeded by other future CCS projects. To that end, pore space tenure was applied for by Shell to the Province of Alberta immediately after CCS pore space regulations were passed. This tenure granted exclusive use by Shell for the Quest CCS Project of the BCS formation within the boundary depicted in Figure 1-5. This exclusive use allows Shell to store the design volumes of CO_2 into the formation without the risk of another CCS operator storing CO_2 in proximity to the Quest area of interest (this would raise the required injection pressures and threaten the storage zone viability). This tenure was granted in May 2011.

1.5 Process Design

The process flow scheme for the Project is shown in Figure 1-6. For a large scale flow scheme, see Appendix B – Quest Full Process Flow Schematic.

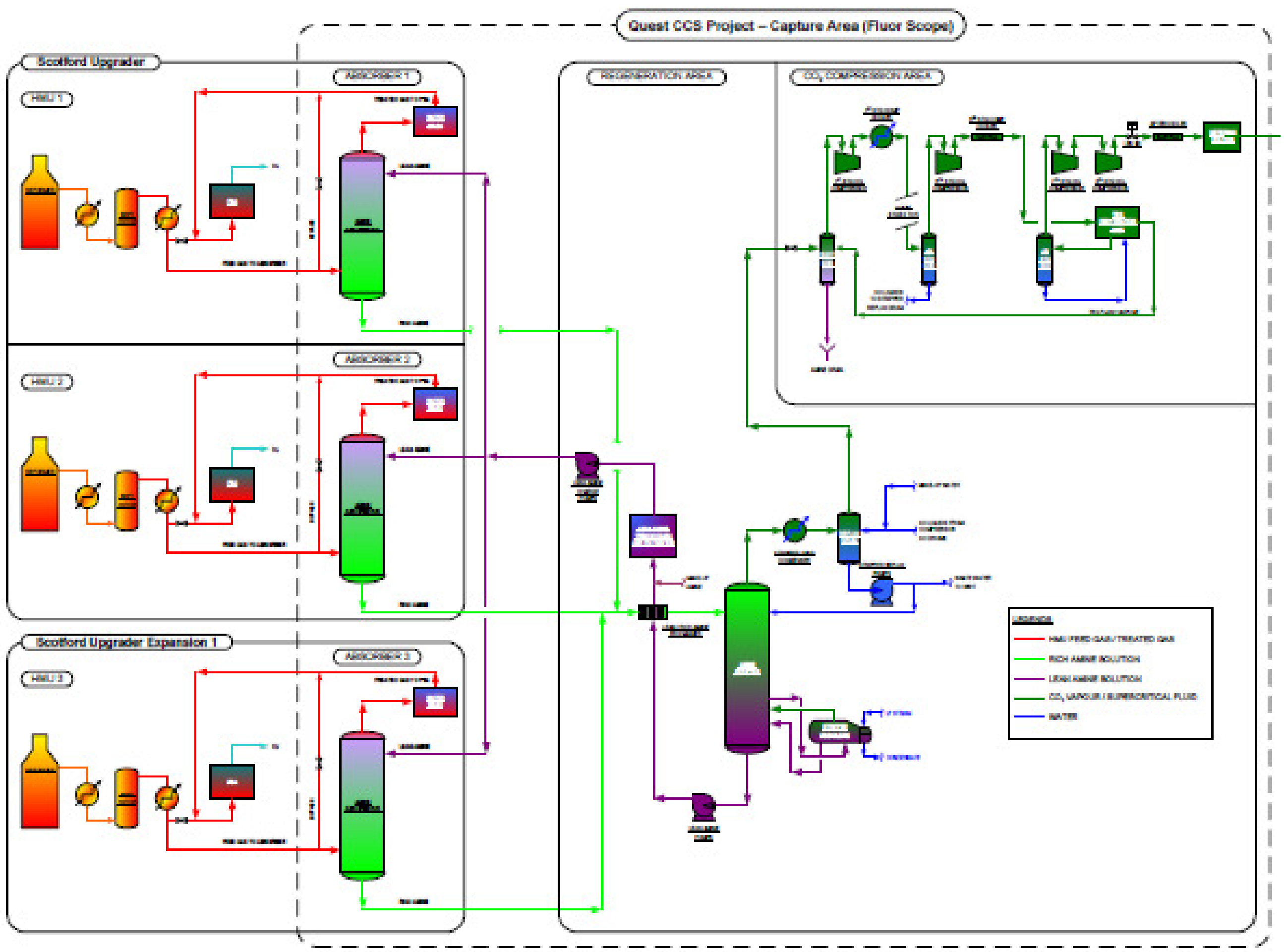

Figure 1-6 Quest Capture and Compression Process Design

Process Description

Process flow diagrams are provided in Appendix C: Quest Process Flow Diagrams.

CO_2 Absorption Section

Amine absorbers located within HMU 1 (Unit 241), HMU 2 (Unit 242) and HMU 3 (Unit 441) treat hydrogen raw gas at high pressure and low temperature to remove CO_2 through close contact with a lean amine (ADIP-X) solution.

The hydrogen raw gas enters the 25-tray absorbers below tray 1 of the column at a pressure of approximately 3,000 kPag. Lean amine solution enters at the top of the column on flow control.

The CO_2 absorption reaction is exothermic. The bulk of the heat generated within the absorber is removed through the bottom of the column by the rich amine. Rich amine from the three absorbers is collected into a common header and sent to the amine regeneration section.

Warm treated gas exits the top of the absorbers and enters the 9-tray water wash vessels below tray 1, where a circulating water system is used to cool the treated gas. Pumps draw warm water from the bottom of the vessel and cool it in shell and tube exchangers using cooling water as the cooling medium. The cooled circulating water is returned to the water wash vessel above tray 6 to achieve the treated gas temperature specification. A continuous supply of wash water is supplied to the top of the water wash vessel in the polishing section. The purpose of the water wash is to remove entrained amine to less than 1 ppmw; thereby, the downstream PSA unit adsorbent is protected from contamination.

A continuous purge of circulating water, approximately equal to the wash water flow, is sent from HMU 1 and HMU 2 to the reflux drum in the amine regeneration section for use as makeup water to the amine system. The purge of circulating water from HMU 3 is sent to the existing process steam condensate separator, V-44111.

Amine Regeneration Section

Rich amine from the three absorbers is heated in the lean/rich exchangers by cross-exchange with hot, lean amine from the bottom of the amine stripper. The lean/rich exchangers are Compabloc design to reduce plot requirements. The hot, lean amine is maintained at high pressure through the lean/rich exchangers by a back pressure controller, which reduces two-phase flow in the line. The pressure is let down across the 2 x 50% back-pressure control valves and fed to the amine stripper.

The two-phase feed to the amine stripper enters the column through two Schoepentoeter inlet devices, which facilitate the initial separation of vapour from liquid. As the lean/rich amine flows down the trays of the stripper, it comes into contact with hot, stripping steam, which causes desorption of the CO_2 from the amine.

The amine stripper is equipped with 2 x 50% kettle reboilers that supply the heat required for desorption of CO_2 and produce the stripping steam required to reduce the CO_2 partial pressure. The low-pressure steam supplied to the reboilers is controlled by a feed-forward flow signal from the rich amine stream entering the stripper and is trim-controlled by a temperature signal from the overhead vapour leaving the stripper.

The CO_2 stripped from the amine solution leaves the top of the amine stripper saturated with water vapour at a pressure of 54 kPag. This stream is then cooled by the overhead condenser. The two-phase stream leaving the condenser enters the reflux drum, where separation of CO_2 vapour from liquid occurs.

In addition to the vapour/liquid stream from the overhead condenser, the reflux drum also receives purge water from the HMU 1 and HMU 2 water wash vessels, as well as knockout water from the CO_2 compression area. The reflux pumps draw water from the drum and provide reflux to the stripper for cooling and wash of entrained amine from the vapour. Column reflux is on flow control, with drum level control managed by purging excess water to wastewater treatment.

CO_2 is stripped from the rich amine to produce lean amine by kettle-type reboilers and collected in the bottom of the amine stripper. Hot, lean amine from the bottom of the stripper is pumped by the lean amine pumps to the lean/rich exchanger, where it is cooled by cross-exchange with the incoming rich amine feed from the HMU absorbers. The lean amine is then further cooled by the lean amine coolers, which are shell and tube exchangers. The lean amine is then cooled to the final temperature by the lean amine trim coolers, which are plate and frame exchangers.

A slipstream of 25% of the cooled lean amine flow is filtered to remove particulates from the amine. A second slipstream of 5% of the filtered amine is then further filtered through a carbon bed to remove degradation products. A final particulate filter is used for polishing of the amine and removing carbon fines from the carbon-bed filter.

The filtered amine is then pumped by the lean amine charge pumps to the three amine absorbers in HMU 1, HMU 2, and HMU 3.

Anti-Foam Injection

An anti-foam injection package is provided to supply anti-foam to the amine absorbers and amine stripper. Because there are no hydrocarbons present in the system and the service is considered clean, it is anticipated that foaming issues should be minimal. Should the need arise, anti-foam can be injected into the lean amine lines going to each of the absorbers, as well as the rich amine line supplying the amine stripper.

The anti-foam chemical currently identified for use in this system is polyglycol-based anti-foam. The actual anti-foam injection chemical required cannot be confirmed until the facility is operating.

Amine Storage

Two amine storage tanks along with an amine make-up pump supply pre-formulated concentrated amine as make-up to the system during normal operation. The concentrated amine will be blended off-site and provided by an amine supplier.

The amine storage tanks will also be used for storage of lean amine solution during maintenance outages. The size of the amine storage tanks provides sufficient volume for the amine stripper contents during an unplanned outage. Permanent amine solution storage is not provided for the entire amine inventory, which would require supplemental temporary storage. For major T/A, when the entire system needs to be de-inventoried, a temporary tank will be required for the duration of the T/A. The amine system can be recharged with the lean amine solution using the amine inventory pump. This pump will also be used to charge the system during start-up.

The amine storage tanks are equipped with a steam coil to maintain the temperature of the tank contents. A nitrogen blanketing system maintains an inert atmosphere in the tank, which prevents degradation of the amine. The storage tanks will be vented to atmosphere.

Compression

The CO_2 from amine regeneration is routed to the compressor suction by the compressor suction KO drum to remove free water. The CO_2 compressor is an eight-stage, integrally geared centrifugal machine. Further details of compressor performance will be developed through collaboration with the selected vendor and integrated with the control requirements of the pipeline system. Increase in H_2 impurity from 0.67% to 5% in the CO_2 increases the minimum discharge pressure required (to keep CO_2 in a dense-phase state) to about 8,500 kpag. Though the compressor design is still under development, H_2 impurity greater than 5% may lead to potential surge situations. To avoid this situation, it is proposed to put compressor in recycle mode when the H_2 content reaches 2.5%.

Cooling and separation facilities are provided on the discharge of the first five compressor stages. The condensed water streams from the interstage KO drums are routed back to the stripper reflux drum to be degassed and recycled as make up water to the amine system. The condensed water from the compressor 5th and 6th Stage KO drums and the TEG inlet scrubber are routed to the compressor 4th stage KO drum. This routing reduces the potential of a high pressure vapour breakthrough on the stripper reflux drum and reduces the resulting pressure drops. The 7th Stage KO drum liquids are routed to the TEG flash drum due to the likely presence of TEG in the stream.

The saturated water content of CO_2 at 36°C approaches a minimum at approximately 5,000 kPaa. Consequently, an interstage pressure in the 5,000 kPaa range is specified for the compressor. This pressure is expected to be obtained at the compressor 6th stage discharge. At this pressure, the wet CO_2 is air cooled to 36°C and dehydrated by triethylene glycol (TEG) in a packed bed contactor.

The dehydrated CO_2 is compressed to a discharge pressure in the range of 8, 000 to 11,000 kPag, resulting in a dense-phase fluid. The CO_2 compressor is able to provide a discharge pressure as high as 14,790 kPa at a reduced flow for start-up and other operating scenarios. The dense-phase CO_2 is cooled in the compressor after cooler to 43°C, and routed to the CO_2 pipeline. This dense-phase CO_2 is transported by pipeline from the Scotford Upgrader to the injection locations, which are located approximately 80 km north.

Dehydration

A lean triethylene glycol (TEG) stream at a concentration greater than 99% wt TEG contacts the wet CO_2 stream in an absorption column to absorb water from the CO_2 stream. The water-rich TEG from the contactor is heated and letdown to a flash drum that operates at approximately 270 kPag. This pressure allows the flashed portion of dissolved CO_2 from the rich TEG to be recycled to the compressor suction KO drum.

The flashed TEG is further preheated and the water is stripped in the TEG stripper. The column employs a combination of reboiling, by a stab-in reboiler using low temperature

HP steam, and nitrogen stripping gas to purify the TEG stream. Nitrogen stripping gas is required to achieve the TEG purity required for the desired CO_2 dehydration because the maximum TEG temperature is limited to 204°C to prevent TEG decomposition. Stripped water, nitrogen and degassed CO_2 are vented to atmosphere at a safe location above the TEG stripper.

Though the system is designed to minimize TEG carryover, it is estimated that 27 ppmw of TEG will escape with CO_2. The dehydrated CO_2 is analyzed for moisture and composition at the outlet of TEG unit.

The lean TEG is cooled in a lean/rich TEG exchanger. The lean TEG is then pumped and further cooled to 39°C in the lean TEG cooler with cooling water and returned to the TEG absorber.

Pipeline

The pipeline design is a 12-inch high vapor pressure (HVP) pipeline for transporting the dehydrated, compressed, and dense-phase CO_2 from the capture facility to injection wells 80 km north of the Upgrader. Also included are pigging facilities, line break valves, and monitoring and control facilities. The line is buried to a depth of 1.5 m with the exception of the line break valve locations, which are located a maximum of 15 km apart.

In the Select phase of the project a detailed route selection process was undertaken with the objective to:

- limit the potential for line strikes and infrastructure crossings
- align with the proposed CO_2 disposal area
- use existing pipeline rights-of-way and other linear disturbances, where possible, to limit physical disturbance
- limit the length of the pipeline to reduce the total area of disturbance
- avoid protected areas and using appropriate timing windows
- avoid wetlands and limit the number of watercourse crossings
- accommodate landowner and government concerns to the extent possible and practical.

The outcome of this process is the routing shown in Figure 1-2.

The proposed pipeline route extends east from Shell Scotford along existing pipeline rights of way through Alberta's Industrial Heartland and then north of Bruderheim to the North Saskatchewan River. The route then crosses the North Saskatchewan River and continues north along an existing Enbridge pipeline corridor for approximately 10 km and then travels northwest to the endpoint well, approximately 8 km north of the County of Thorhild, Alberta. The total pipeline length is about 80 km.

This pipeline will be located in the counties of Strathcona, Sturgeon, Lamont and Thorhild.

There are 256 crossings by the pipeline:

- 40 road crossings
- 4 railroad crossings

- 18 watercourse crossings
- 73 pipeline crossings
- 121 utility crossings.

CO_2 Storage

The storage facilities design and construction activities consist of:

- The drilling and completion of three to eight injection wells equipped with fibre optic monitoring systems
- A skid mounted module on each injection well site to provide control, measurement and communication for both injection and MMV equipment
- The drilling and completion of a minimum of three deep observation wells
- The conversion of Redwater Well 3-4 to a deep BCS pressure monitoring well
- The drilling of three groundwater wells per injection well (although not all will be located on the well pads)
- A field trial of the line-of-sight CO_2 gas flux monitoring technology with an option to include this at each injection well site location.

1.6 Modularization Approach

A key feature of the FEED work for the Project was the decision to use a modularization approach for the CO_2 capture infrastructure. This decision was made on the basis of schedule and cost saving benefits.

The modularization approach for the Project is to use Fluor Third Generation Modular^{SM} design practices. The project is designed with a maximum module size of 7.3 m (wide) x 7.6 m (high) x 36 m (long) modules that are assembled in the Alberta area and transported by road to the Shell Scotford site by the Alberta Heavy Haul corridor.

Third Generation Modular^{SM} execution is a modular design and construction execution method that is different from the traditional truckable modular construction execution methods, as limitations exist to the number of components that are to be installed onto the truckable modules. The modules are transported and interconnected into a complete processing facility at a remote location including all mechanical, piping, electrical and control system equipment.

2 Facility Construction Schedule

As of March 2012, no construction activities have occurred except the drilling of the first injection well, which occurred in September 2010 to test and validate the expected BCS storage complex properties. Capture and transportation facilities construction readiness activities have commenced as detailed engineering continues throughout the next reporting period. Some early underground, piping and electrical capture construction is planned for mid-2012, and full construction is scheduled to begin in mid-2013. The second and third injection wells in addition to several deep monitoring wells are planned to be drilled in late 2012 and early 2013. Pipeline construction is scheduled to begin in mid-2013. All construction activities are phased to meet the planned startup in mid-2015.

3 Geological Formation Selection

3.1 Storage Site Selection

A site screening process resulted in a preferred area of interest (AOI) that was initially selected for further appraisal and studies in 2010 and 2011 by submitting an exploration tenure request with the regulator on December 16, 2009. The subsequent process of site characterization comprised a period of intensive data acquisition, resulting in storage site endorsement prior to submitting the regulatory applications on November 30, 2010 and culminating in the award of a sequestration lease by Alberta Energy on May 27, 2011.

Site selection for the AOI was mainly based on data, analyses and modelling of the two Quest CO_2 appraisal wells with supplemental data from legacy wells, seismic and study reports. Site selection criteria for CCS projects are still in the process of being developed by CCS authorities at international, national and provincial levels. One set of criteria has been developed by the Alberta Research Council (ARC) and the properties of the Basal Cambrian Sands (BCS) are compared with those criteria in Table 3-1.

Table 3-1 Assessment of the BCS for Safety and Security of CO_2 Storage

Criterion Level	No	Criterion	Unfavourable	Preferred or Favourable	BCS Storage Complex
Critical	1	Reservoir-seal pairs; extensive and competent barrier to vertical flow	Poor, discontinuous, faulted and/or breached	Intermediate and excellent; many pairs (multi-layered system)	Three major seals (Middle Cambrian Shale [MCS], Lower Lotsberg and Upper Lotsberg Salts) continuous over entire CO_2 storage AOI. Salt aquicludes thicken up dip to NE.
	2	Pressure regime	Overpressured pressure gradients >14 kPa/m	Pressure gradients less than 12 kPa/m	Normally pressured <12 kPa/m
	3	Monitoring potential	Absent	Present	Present
	4	Affecting protected groundwater quality	Yes	No	No
Essential	5	Seismicity	High	≤ Moderate	Low
	6	Faulting and fracturing intensity	Extensive	Limited to moderate	Limited. No faults penetrating major seal observed on 2D or 3D seismic.
	7	Hydrogeology	Short flow systems, or compaction flow, Saline aquifers in communication with protected groundwater aquifers	Intermediate and regional-scale flow	Intermediate and regional-scale flow-saline aquifer not in communication with groundwater
Desirable	8	Depth	< 750-800 m	> 800 m	> 2,000 m
	9	Located within fold belts	Yes	No	No

Table 3-1 Assessment of the BCS for Safety and Security of CO_2 Storage (cont'd)

Criterion Level	No	Criterion	Unfavourable	Preferred or Favourable	BCS Storage Complex
Desirable (cont'd)	10	Adverse diagenesis	Significant	Low	Low
	11	Geothermal regime	Gradients ≥35°C/km and low surface temperature	Gradients <35°C/km and low surface temperature	Gradients <35°C/km and low surface temperature
	12	Temperature	<35°C	≥35°C	60°C
	13	Pressure	<7.5 MPa	≥7.5 MPa	20.45 MPa
	14	Thickness	<20 m	≥20 m	>35 m
	15	Porosity	<10%	≥10%	16%
	16	Permeability	<20 mD	≥20 mD	Average over AOI 20-500 mD
	17	Caprock thickness	<10 m	≥10 m	Three caprocks MCS 21 m to 75 m L. Lotsberg Salt 9 m to 41 m U. Lotsberg Salt 53 m to 94 m
	18	Well density	High	Low to moderate	Low
SOURCE: CCS Site Selection and Characterization Criteria – Review and Synthesis: Alberta Research Council, Draft submission to IEA GHG R&D Program June 2009.					

3.2 Geological Framework

The BCS is at the base of the central portion of the Western Canada Sedimentary Basin (WCSB), directly on top of the Precambrian basement. The BCS storage complex is defined herein as the series of intervals and associated formations from the top of the Precambrian basement to the top of the Upper Lotsberg Salt (see Figure 3-1).

The BCS storage complex includes, in ascending stratigraphic order:

- Precambrian granite basement unconformably underlying the Basal Cambrian Sands
- Basal Cambrian Sands (BCS) of the Basal Sandstone Formation – the CO_2 injection zone
- Lower Marine Sand (LMS) of the Earlie Formation – a transitional heterogeneous clastic interval between the BCS and overlying Middle Cambrian Shale
- Middle Cambrian Shale (MCS)of the Deadwood Formation – thick shale representing the first major regional seal above the BCS
- Upper Marine Siltstone (UMS) likely Upper Deadwood Formation – progradational package of siliciclastic material made up of predominantly green shale with minor silts and sands
- Devonian Red Beds – fine-grained siliciclastics predominantly composed of shale
- Lotsberg Salts – Lower and Upper Lotsberg Salts represent the second and third (ultimate) seals, respectively, and aquiclude to the BCS storage complex. These salt packages are predominantly composed of 100% halite with minor shale laminae. They are separated from each other by 50 m of additional Devonian Red Beds.

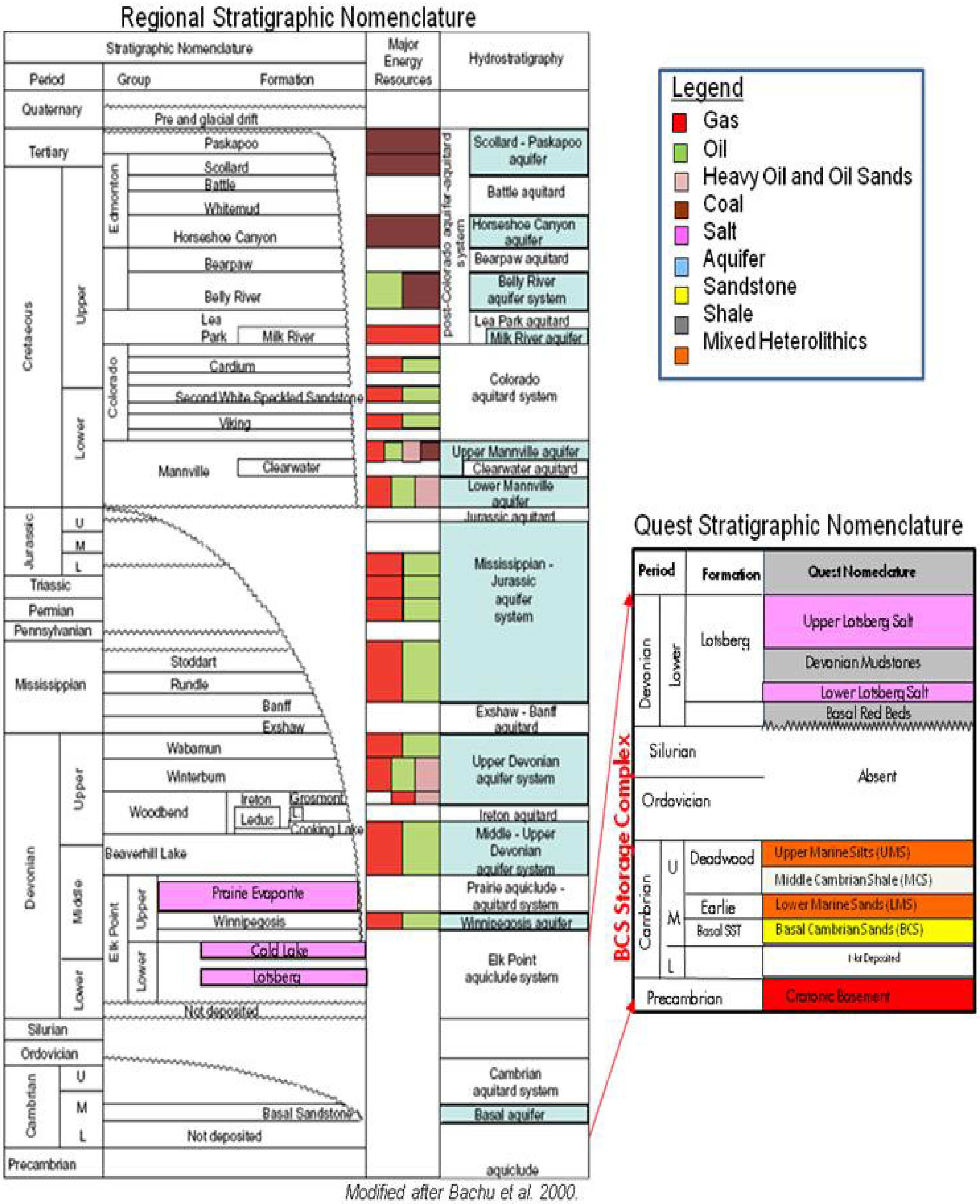

Figure 3-1 Stratigraphy and Hydrostratigraphy of Southern and Central Alberta

The rocks that comprise the BCS storage complex in the CO_2 storage AOI were deposited during the Middle Cambrian to Early Devonian directly atop the Precambrian basement. The erosional unconformity between the Cambrian sequence and the Precambrian represents approximately 1.5 billion years of Earth history. Erosion of the Precambrian surface during this interval likely resulted in a relatively smooth but occasionally rugose gently southwest dipping (<1 degree) top Precambrian surface. Within the AOI, the Cambrian clastic packages pinch out towards the northeast, while the Devonian salt seals thicken towards the northeast. For a cross-section of the WCSB showing the regionally connected BCS storage complex in relation to regional baffles and sealing overburden, see Figure 3-2. The AOI is within a tectonically quiet area; no faults crosscutting the regional seals were identified in 2D or 3D seismic data.

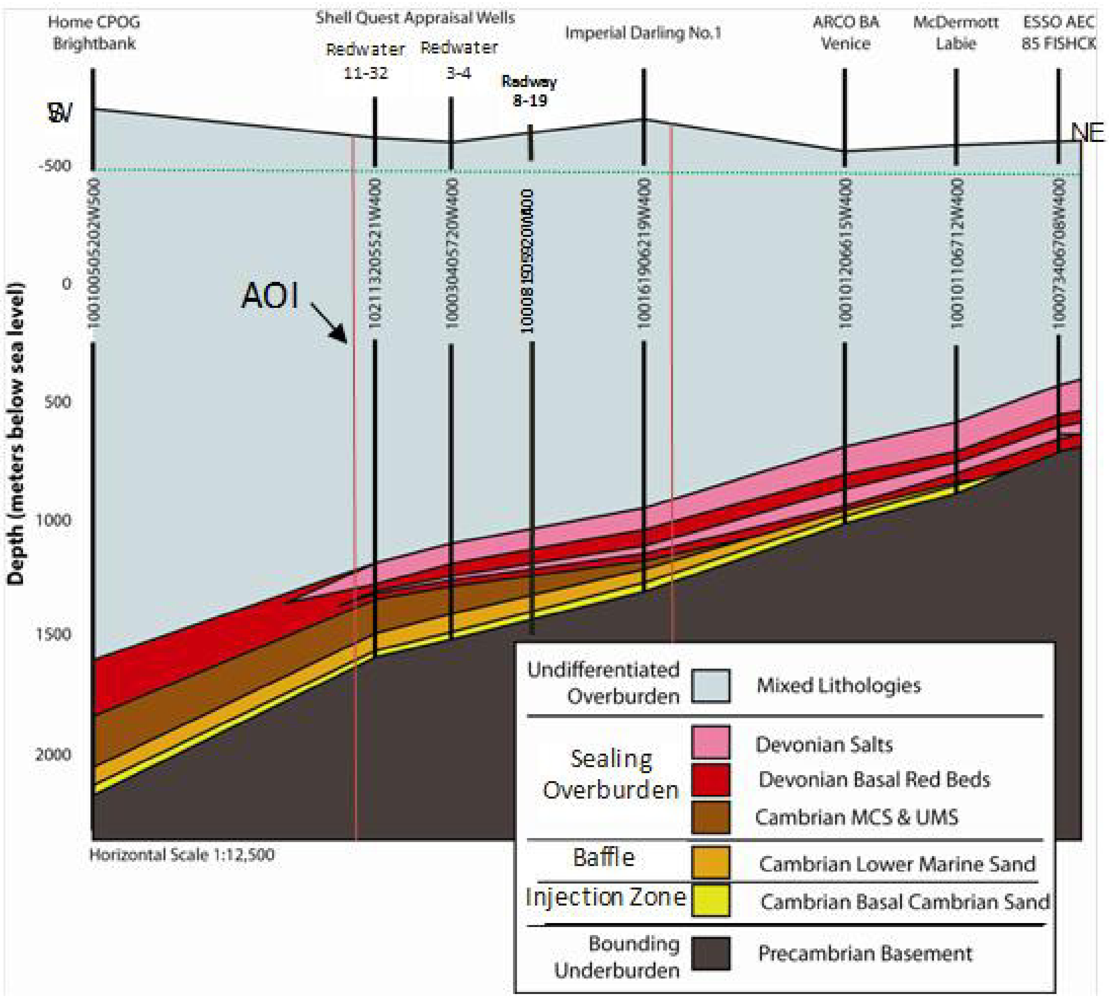

Figure 3-2 Cross-Section of the WCSB Showing the BCS Injection Zone

3.3 Site-Specific Risk to Containment

This section describes the various potential conduits that could permit migration of fluids out of the BCS storage complex. Mitigation measures are included, where applicable, for each risk.

Migration Along a Legacy Well

The status and condition of existing wells penetrating the BCS has been reviewed from multiple data sources. There are no known issues with legacy well integrity other than the uncertainty that arises from the age of the cement plugs and the inability to pressure test old cement plugs.

The following mitigation measures were implemented during site selection to reduce this risk:

- selection of an AOI with few BCS penetrations
- selection of an injection site within the AOI to maximize the offset to legacy wells (21 km from the Quest Radway Well to the Egremont Well down-dip and 31 km from the Quest Radway Well to the Imperial Darling Well up-dip).

The following barriers are in place in the known 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

The probability of legacy wells being intersected by the plume or pressures high enough to lift CO_2 into the groundwater is very low because most of them are outside the AOI with four penetrations through the MCS seal inside the AOI, towards the boundaries of the AOI away from the central injection area (see Figure 3-3 for all wells that penetrate through the geological seals) The MMV Plan provides additional options for early warning through pressure monitoring (e.g., interferometric synthetic aperture radar (InSAR), with a BCS pressure calibration point at Redwater Well 3-4).

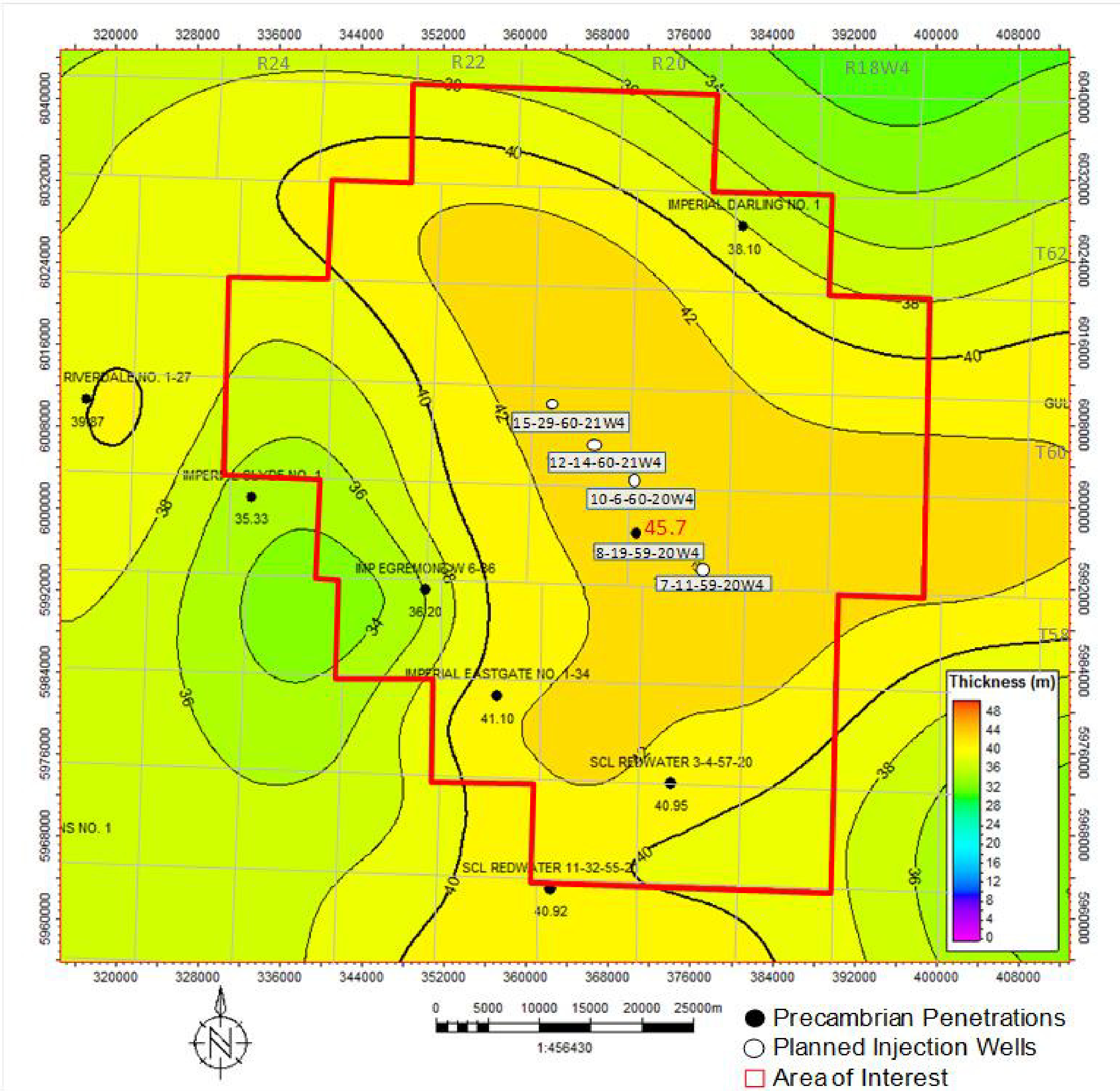

Figure 3-3 Legacy Wells in or near the AOI and Project Wells

Migration along an MMV Well

The Storage Development Plan does not include the addition of dedicated BCS MMV observation well penetrations for the following reasons:

- The selected MMV technologies of 4D seismic and InSAR are expected to provide conformance information with much better aerial coverage than any single well penetration can provide without the additional risk of having to penetrate the seals of the BCS storage complex.
- The perceived benefits of additional BCS observation wells are limited because they have no ability to verify containment and are ineffective at conformance monitoring unless used in large numbers.

The following mitigation measures are in place to address this risk:

- the use of Redwater Well 3-4 as a BCS pressure observation well
- all injectors wells will be used as BCS observation wells
- pressure build up and interference will be monitored during the start-up period
- the well sparing philosophy allows for regular sequence of annual fall-off tests in injection wells (to be included in the operating guidelines)
- bottom-hole pressure (BHP) will be monitored during the closure period and sampling and logging are also possible
- InSAR, vertical seismic profile (VSP) and seismic are part of the initial base case MMV Plan
- InSAR will be calibrated to BCS pressure measurements from the Redwater Well 3-4 BCS observation well

Migration along an Injection Well

Interpretation of data from drilling the first two appraisal wells (Well 11-32 and Well 3-4), regional drilling experience, and wellbore stability and mud testing led to Well 8-19 being drilled, cased and cemented with hydraulic isolation over all three seals. Drilling a gauge hole has proved critical to achieving good cement integrity over the seals of the BCS storage complex and the use of oil-based mud, combined with an intermediate casing setting depth just below the base of the MCS, will likely be done for the other injection wells.

Migration along a Stratigraphic Pathway

This risk has been substantially reduced by proving the continuity of all three seals of the BCS storage complex through 3D and 2D seismic and a central well penetration in the AOI (Radway Well 8-19).

The following mitigation measures are in place to address this risk:

- 2D seismic covers (with a spacing of 2 km to 3 km) the entire AOI and shows continuity of the geological seals.
- Every well in the AOI has confirmed the presence of all three seals.

- Lotsberg seal thickness LL 9-41m and UL 53-94m suggest low likelihood of local gaps.
- Tortuosity of leak path show that seal breaches are unlikely to align.
- Buffering effects of a long leak path reduce the risk.
- BCS and WPGS water chemistry differences suggest long term isolation of these aquifers from each other.
- The cleanest shales are at the bottom of the MCS section and will erode last, by the Devonian unconformity towards the NE

Migration along an Open Fault Pathway

The 3D seismic data now covers approximately 415 km^2, which is about 11% of the AOI. The latest processed data, available since April 2011, indicate increased frequency content of the data (up to 100 Hz) that for the first time allows for an interpretation of an event near the top BCS. The absence of interpreted faults continuing from the top Precambrian interval to the top of BCS on the 3D seismic dataset reduces the probability of the presence of faults across the BCS reservoir or any of the seals, which could act as migration paths out of the BCS storage complex.

The following mitigation measures are in place to address this risk:

- Faults are picked on the Precambrian granite seismic interval.
- Evidence of no faults with throws greater than 15 m crossing the seal complex from 2D and 3D seismic covering the full AOI. The 2D seismic spans the entire AOI with an approximate 3 km spacing and 415 km^2 of 3D seismic is available over the central portion of the AOI.
- 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.
- 3D seismic will help place injection wells away from features that may represent faults at the Precambrian basement level.
- The Lotsberg salts are ductile and expected to creep and reseal any unexpected small faults.

Induced Stress Reactivates a Fault

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 very low likelihood of fault reactivation.

The following mitigation measures are in place to address this risk:

- The Quest AOI 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 AOI. None were detected over this period (Reference: AGS Tectonic activity map for Alberta).

- No faults offsetting the MCS or Lotsberg seals were mapped in the AOI using 2D seismic, which spans the entire AOI with an approximate 3 km spacing and 415 km^2 of 3D seismic over the AOI.
- 3D seismic will help place injection wells away from features that may represent faults at the Precambrian basement level.
- The Lotsberg salts are ductile and expected to creep and reseal any unexpected small faults.
- Compressor discharge pressure is limited to 14.5 MPa (900# pipe class)
- Down-hole gauges will be deployed to ensure that injection wells stay within pressure constraints using well head chokes to control pressure.
- Under normal operating conditions, injection will be distributed over final number of injection wells. The system will be designed to stay below the maximum injection pressure constraint one less than the number of injection wells, resulting in pressures below the maximum constraint for most of the time at the injection wells.
- Down-hole microseismic monitoring will detect any fault reactivation within 600 m of an injection well; injection pressure will be reduced if any reactivation is detected.

Induced Stress Opens Fractures

Minifrac data from Redwater Well 11-32 and Radway Well 8-19 suggest good alignment of the BCS fracture extension pressure (FEP) between these wells that are 36 km apart. A conservative approach has been taken by setting the BHP limitation at 28 MPa, based on the weaker LMS fracture gradient and including a 4 MPa safety margin to account for the reduction in fracture gradient due to the thermal impact of CO_2 injection.

Acidic Fluid Erodes Seals

Several MCS cores were acquired in the first few Quest wells. The first seal (MCS) contains small quantities of dolomite and K-feldspar. The dissolution of these minerals in a low-pH CO_2 environment could be offset by the creation of clays in this reaction, resulting in a net loss of permeability, although there is uncertainty about the timing of precipitation (10 days to 10 years).

Shell was granted permission from ATCO Gas and Pipelines Ltd. in March 2011, to take nine plugs from their Upper Lotsberg core at 100-07-34-055-21W400 (located on the southern border of the AOI) for SCAL analysis. A SCAL program comprising the following elements in ongoing:

- high resolution photos of the core and the salt plugs, including proper depth marking.
- thin section and petrography to determine salt composition

The following mitigation measures are in place to address the risk:

- Thickness of seals and baffles that need to be eroded are 350 m from top perfs to the top ultimate seal.
- Buffering materials (mostly clay minerals) in the seals and baffles between the salt seals and the top perfs are abundant. CO_2 leaking into the seals/baffles will lose moisture and acidity.

- The secondary and ultimate seals, the Upper and Lower Lotsberg salts respectively, are comprised of 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.
- Seal integrity relies on stresses and may not be affected by seal embrittlement.

Third Party Induced Migration

This risk includes the drilling of new wells and pressurizing of the BCS as separate causes, both of which could lead to loss of containment. The risk of third-party drilling into the AOI has been minimized because the Carbon Sequestration Lease, granted to Shell on May 27, 2011, prohibits the drilling by third-parties below the Prairie Evaporite within the AOI. A request was issued separately to stop the creation of new Lotsberg salt caverns within the AOI.

The risk of pressurization of the BCS resulting in increased legacy well risk is also much reduced through the size of the approved Carbon Sequestration Lease AOI, which provides a minimum 25 km offset from the development area to the AOI boundary.

3.4 Estimate of Storage Potential

The uncertainty in the capacity of the primary container, the BCS, has been reduced considerably over time due to appraisal data gathering (three appraisal wells, 2D seismic, 3D seismic and the ongoing reservoir modelling and feasibility studies). There is continued strong evidence for the BCS having the capacity to store the required volume for 25 years of injection. The residual uncertainty in pore volume is unlikely to decrease much further until several years of injection performance can be used to calibrate the existing reservoir models.

The latest full-field static reservoir models describe the range of subsurface uncertainty in terms of reservoir quality and reservoir connectivity, both key uncertainties that influence the maximum achievable injection rates into the reservoir (i.e., k*h), the plateau length of that injection rate and the total amount of CO_2 that can be injected.

The range of uncertainty in BCS pore volume equates to water initially in place (WIIP), given 100% water saturation. The range is presented in Table 3-2 and can be related to three main variables:

- the presence of a depositional trend affects reservoir quality
- the thickness of the BCS unit
- risk of systematic error in the measurement of porosity from well logs

Table 3-2 BCS Pore Volume Range Within the Quest AOI

Case	Reservoir Connectivity	Reservoir Quality	Sum Pore Volume in Quest AOI (m^3)
P90	High	High	1.62E+10
P50	Mid	Mid	1.43E+10
P10	Low	Low	1.08E+10

Using a simple material balance calculation:

$$\mathbf{G_{CO2} = A\ h_g\ f_{tot}\ r\ (c_p + c_w)\ (p\text{-}p_0)}$$

Using the mid-case properties:

Pres = 20 Mpa, Pmax = of 28 MPa, Temp = 60°C,
Cp = 1.45 E-7, Cw = 2.78 E-7, r = 814 kg/m^3.

A base case pore volume of 14.3 billion m^3 within the AOI boundary could store 27 million tonnes of CO_2 at just under 70% potential storage capacity.

3.5 Initial Injectivity Assessment

Two water injection tests were conducted during the exploration and appraisal phase. Injectivity was estimated using average pressures and flow rates for the last stable flow period of the Redwater Well 11-32 water injection test and the 5^{th} and final Radway Well 8-19 water injection test. A summary of these results is provided in Table 3-3.

Table 3-3 Injectivity Estimates for Redwater Well 11-31 and Radway Well 8-19 Water Injection Tests

Well	**Rate** [m^3/d]	**DeltaP** [kPa]	**Injectivity** [m^3/d/MPa]
Redwater Well 11-32	492	12.13	41
Radway Well 8-19	360	0.95	379

Injectivities can be used to extrapolate estimated water injection rates to the pressure differential associated with normal operating conditions. In this case, operating conditions were assumed to correspond to a flowing bottom-hole pressure of approximately 26 MPa, about 6 MPa above initial reservoir pressure at top of the BCS in Radway Well 8-19. Water injection rates are converted to CO_2 injection rates by making assumptions on the fluid property differences between the injected water and the CO_2 (i.e., viscosity) and the CO_2/brine displacement model (relative permeabilities). Taking these factors into account, CO_2 is expected to inject at rates that are a ratio of 1.5 to 3 higher than water injection rates (expressed in reservoir volume). Figure 3-4 illustrates the several steps required to compare well test rates to estimate injection requirements.

Figure 3-4 illustrates that Radway Well 8-19 is expected to provide sufficient initial injectivity to take the full Quest CO_2 volume into a single well.

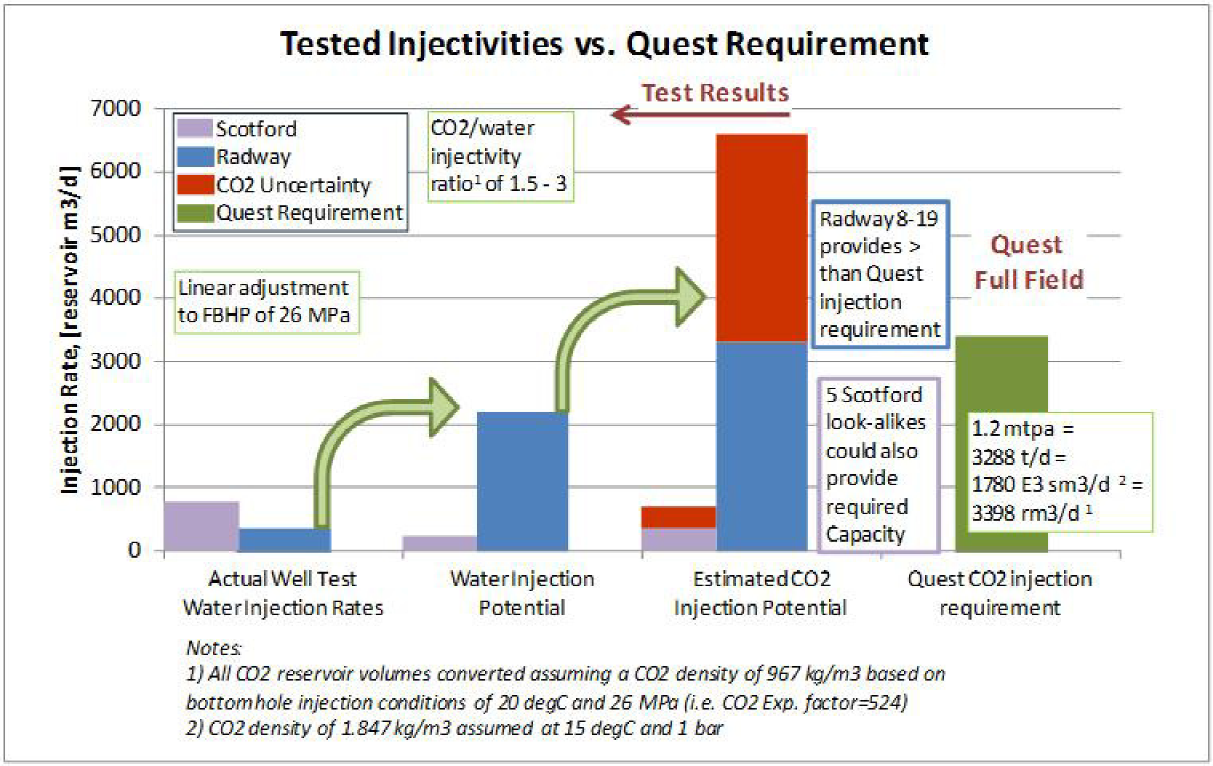

Figure 3-4 Actual Well Test Injectivity Versus Full Quest Project Injection Requirements

4 Facility Operations – Capture Facilities

4.1 Operations Activities

Operations activities in the past reporting period have focused on preparing key documents that pertain to the operation of the facilities. Foremost of these is the Emergency Response Plan that deals with responses to incidents that may occur in the Project operating period. Additionally, preliminary drafts of the Operations and Maintenance documents have been developed.

Commissioning and startup planning has begun and the final operations organization chart has been completed.

4.2 Next Steps

Upcoming operations work will include:

- continuing to engage stakeholders in order to refine the Emergency Response Plan
- hiring operations staff to prepare for ramping up to startup
- developing training packages for operations and maintenance staff
- training existing Shell Scotford personnel regarding subsurface operations
- engaging the technical team in design and operability reviews
- finalizing the Operations and Maintenance documents

5 Facility Operations - Transportation

5.1 Pipeline Design

The pipeline has the general design conditions as outlined in Table 5-1. Discussion of the design specifications follow.

Table 5-1 Quest Pipeline Design and Operating Conditions

Characteristic	Specification	Units	Value
General			
Pressure	Normal:	MPa	8.5 to 14 – Pending Flow Assurance Study Results and Well Results
At Inlet:	Design Min:		8 MPa
	Design Max:		14.8 MPa
Estimated Delta P to well site			0.4 (for 5-well scenario)
Temperature:	(@ Comp Discharge)	Deg C	
	Normal (Winter)		43
	Normal (Summer)		43
	Upset Condition		60 (Max – Summer, cooling unit down)
Flow Rates:	Normal:	Mt/a	1.2
	Design Min:		0.36
Main Flow Line Data			
	Length		~80
	Size	In NPS	12
	Wall Thickness	mm	12.7 (11.4 +1.3 CA)
Laterals Data			
	Length		Variable
	Size	In NPS	6
	Wall Thickness	mm	7.9 (6.6+1.3 CA)
Reservoir Pressure		MPa	22 – 33.3
Reservoir Temperature		Deg C	63
Well Bore Tubing Diameters		NPS/ID mm	4.5/99.06
Well Depth		m	2070

Pipeline Fluid Composition

The composition is described in Table 5-2. The amount of water will be maintained at 4 lb/MMSCF in the winter and 6 lb/MMSCF in the summer.

Table 5-2 Pipeline Fluid Composition

Component	Normal Composition	Upset Composition
CO_2	99.23	95.00
H_2	0.65	4.27
CH_4	0.09	0.57
CO	0.02	0.15
N_2	0.00	0.01
Total	**100.00**	**100.00**

Pipeline Pressure Data

Pipeline Design Pressure	14.8 MPa @ 60°C
Maximum Operation Pressure	14.0 MPa
Minimum Operation Pressure (10% higher than Critical Pressure	8.5 MPa
CO_2 Critical Pressure	7.4 MPa

Pipeline Operating Temperature

The temperature of the CO_2 leaving the Scotford Upgrader will be approximately 43°C. As the CO_2 travels in the pipeline, heat is transferred to the soil. At approximately 20 km from Shell Scotford, the CO_2 will be at ground temperature. For the basis of design, a ground temperature of 4°C was assumed during summer and 0°C during winter.

Due to the CO_2 being cooled throughout the pipeline length, it is deemed unnecessary to provide for thermal relief.

Flow Rate Requirements

Design capacity of the pipeline throughput is to be 1.2 million tonnes per annum. The CO_2 pipeline is designed so that it could receive and transport up to an additional 2.2 Mt/a of CO_2, in excess of the 1.2 Mt/a of CO_2 that would be captured and stored.

Water Content and CO_2 Phase Change Management

The CO_2 will be dehydrated to a water content of 6 lb/MMSCF during summer and 4 lb/MMSCF during winter within the capture facilities. A moisture analyzer will be installed between the 6th and 7th stages of the compressor. There will be a sampling procedure to confirm the moisture analyzer measurement.

Design Life

Design life for the pipeline and associated surface facilities is for the remaining life of the Upgrader, approximately 25 years.

Pipeline Steel Grade

Items that have been identified as a possible concern for CO_2 pipelines include long running ductile fracture (LRDF) and explosive decompression of elastomers.

Shell Global Solutions, through Shell's Calgary Research Center (CRC), has performed material testing in order to determine the appropriate elastomers to minimize explosive decompression and the appropriate grade of steel with sufficient toughness to resist LRDF.

Results from the LRDF testing show that the toughness requirements for the line pipe are quite achievable in commercially available steel grades, as verified by past history. Specifically, CSA Z245.1 Gr. 386 Cat II pipe would need a minimum wall thickness of 11.4 mm plus corrosion allowance (1.3 mm), and a minimum toughness of 60J at –45°C.

5.2 Pipeline Safeguarding Considerations

Line Break Valves

As per Class 2 requirements for CSA Z662, line break valves (LBVs) will be spaced at no greater than 15 km intervals.

The line break valves will be placed in areas near secondary roads, which allows for ease of access by operations and maintenance personnel. Because the LBVs are located in populated areas, they will be fenced for security. Currently, the fencing is planned to be 5 foot chain link with three barbed wires on top to discourage unauthorized entry.

The LBV stations are expected to be enclosed in a cabinet style enclosure for weather protection. The cabinets will be designed to keep the valve elevations at a working height from the ground surface.

In the event of a line break valve closure, the line break valve computer will send a signal to all line break valves to close, thus minimizing loss of containment. The rate of closure should take 30 seconds from the open position to the fully closed position. This slow rate of closure will minimize the pressure surge (caused by the kinetic energy of the fluid) at an LBV.

After emergency shutdown due to a pipeline leak or rupture, the depressurized section will be brought up to temperature and pressure again slowly by the line break bypass valves, which also serve as temperature-controlled vents in the case of emergency.

Flow Meters

Leak detection will be based upon the principles laid out in CSA Z662 Annex E as pertaining to HVP lines. Basically, the leak detection is based on material balance. The mass flow meter being considered at the Shell Scotford boundary limit and at the well head will be of custody transfer accuracy, typically a Coriolis-type flow meter.

Both automated and manual emergency shutdown systems will be installed. Automated shutdown will be initiated when pressure transmitters indicate operating parameters outside of acceptable limits. Both (not just a single PIT) pressure transmitters at each LBV, must indicate a low pressure trip in order to confirm a line break incident.

Emergency shutdowns can be initiated manually from each of the well sites or from Shell Scotford when pressure, temperature, and flow transmitters indicate upset conditions.

Corrosion Protection

As per regulatory requirements and the Quest Pipeline Integrity Management Plan, cathodic protection will be installed for the pipeline; it is planned to be an impressed current system for the entire line.

Inspection

An in-line inspection tool (smart pig) run of the Quest Pipeline will be performed within the first year from startup to verify pipeline integrity. Frequency of repeat inspections will be based on results from this inspection, other surface inspections, and ongoing monitoring results.

Other inspection activities will include:

- non-destructive examination (ultrasonic thickness test) on above ground piping to identify possible corrosion of the pipeline
- internal visual examination of open piping and equipment evaluated for evidence of internal corrosion; this will be done during routine maintenance activities when parts of the surface facilities will be accessible
- pipeline right-of way (ROW) surveillance including, for example, aerial flights to check ROW condition for ground or soil disturbances and third Party activity in the area

6 Facility Operations - Storage and Monitoring

As of March 31, 2012, no storage activities have occurred. Monitoring has occurred in the form of seismic work as part of the baseline gathering for the MMV activities that are integral to the Project. The MMV Plan has been developed in the past year and baseline measurement work will continue into the next year as monitoring wells are drilled to depths just above the BCS.

6.1 MMV Plan

The MMV Plan is designed according to a systematic risk assessment to achieve two distinct objectives:

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

MMV will achieve this in two ways. First, the expected effectiveness of existing safeguards created by site selection, site characterization and engineering designs will be verified. Second, additional safeguards will be implemented, which will use the same monitoring systems to trigger control measures for reducing the likelihood or the consequence of any leakage from the BCS storage complex. These control measures include re-distribution of injection rates, drilling additional injectors and, if necessary, stopping injection and deploying groundwater remediation systems.

Commitments in the MMV Plan have been made as a response to the Supplemental Information Requests (SIRs). A summary of these commitments is shown in Table 6-1.

The MMV Plan is a key component of the risk mitigation strategy regarding CO_2 storage containment. Figure 6-1 summarizes these risks and mitigation measures; also, see Appendix D for a larger version.

Table 6-1 MMV commitments in response to Supplemental Information Requests

MMV and Closure Plan Updates
1. Updates to be submitted to regulators before commencing baseline monitoring in 2012, and then every 3 years
Wells
2. Distributed temperature sensing system outside the production casing on all injectors to verify well integrity
3. Deep monitoring wells (3), drilled from injection well pads to monitor pressure in the Winnipegosis Formation
Geosphere
4. Time-lapse seismic: First 3D VSP then 3D surface seismic designed to monitor the CO_2 plume from each injector
5. Remote sensing: Monthly InSAR monitoring designed to monitor pressure build-up inside the storage complex
Hydrosphere
6. Groundwater monitoring wells (3 per injector): Water electrical conductivity and water chemistry
Biosphere
7. Remote sensing: Annual multi-spectral imaging designed to detect environmental changes
Atmosphere
8. Line-of-sight CO_2 flux monitoring field trial at Radway Well 8-19 starting Q3 2011 to measure CO_2 emissions

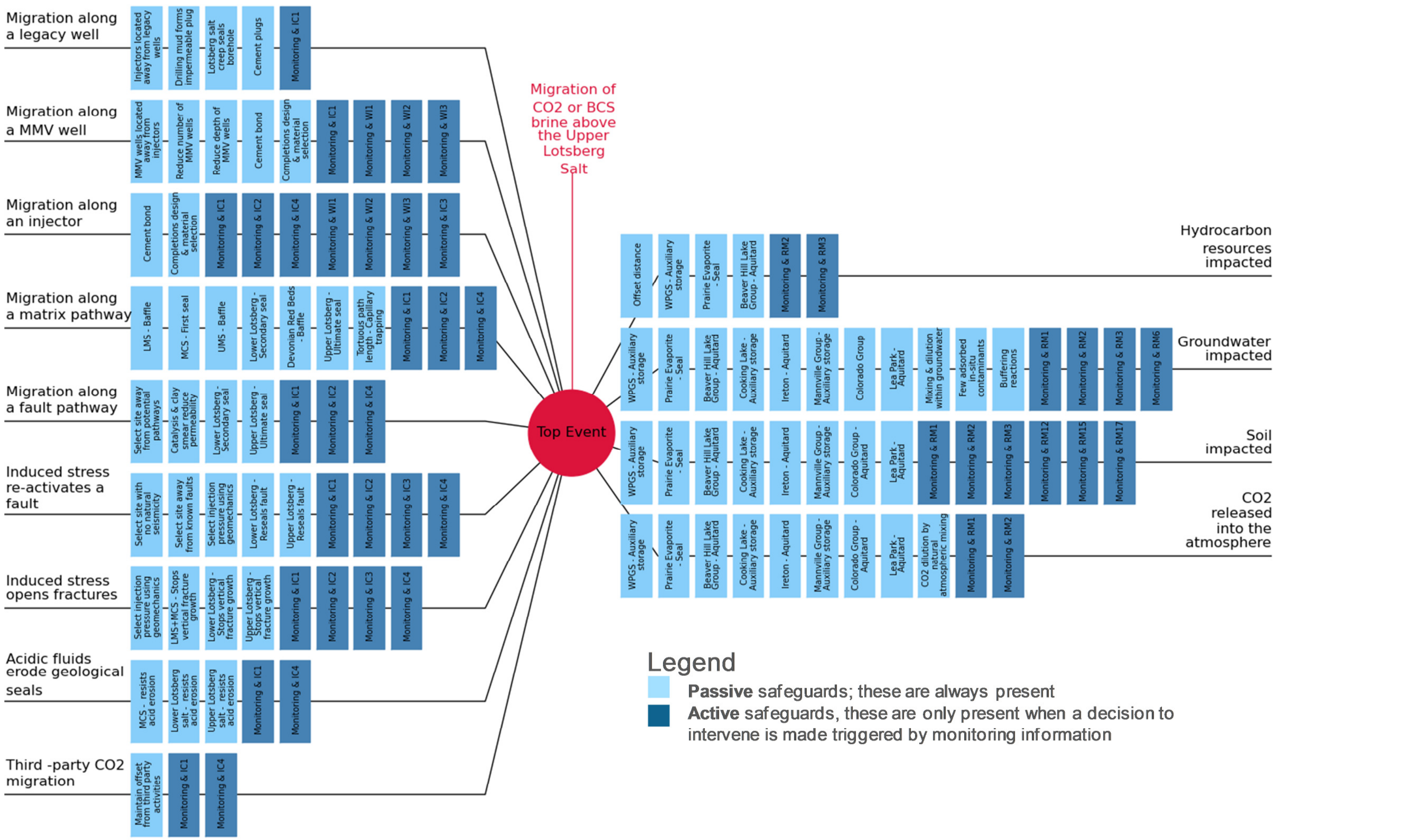

Figure 6-1 CO_2 Containment Loss Risk and Mitigation Diagram

The dark and light boxes indicate the safeguards in place to reduce the likelihood (left side) and consequence (right side) of any unexpected loss of containment. The additional active safeguards are supported by the monitoring plan and control measures.

The MMV Plan is comprehensive because it covers the pre-injection, injection and closure phases. Table 6-2 summarizes the MMV Plan schedule with Table 6-3 covering in more detail the subsurface activities.

Table 6-2 MMV Plan Schedule Excluding Well Activities

Monitoring	Coverage	Pre-Injection	Injection	Closure
Atmosphere				
Line-of-sight CO_2 gas flux monitoring [a]	Within 6 km of every injection well	Continuous	Continuous	Continuous
Biosphere				
Remote Sensing [a]	Entire AOI	Twice a year	Twice a year	Twice a year
Soil monitoring	Discrete locations across the AOI	Every year	Every year	Every 2 years
Natural BCS brine tracer monitoring	Discrete locations across the AOI	Every year	Every year	Every 2 years
Artificial tracer monitoring	Discrete locations across the AOI	Every year	Every year	Every 2 years
Hydrosphere				
Down-hole pH monitoring [a]	Project groundwater wells	Continuous	Continuous	Continuous
Down-hole electrical conductivity monitoring [a]	Project groundwater wells	Continuous	Continuous	Continuous
Natural tracer monitoring [a]	Project and Private groundwater wells	At least every year	Every year	Every 2 years
Artificial tracer monitoring	Project and Private groundwater wells	At least every year	Every year	Every 2 years
Geosphere				
Time-lapse 3D vertical seismic profiling [a, b]	Within 600 m of every injection well	2013	2016 to 2018	None
Time-lapse 3D surface seismic [a]	Each entire CO_2 plume	2010	2022 to 2029 to 2039	2048
Interferometric Synthetic Aperture Radar [a]	Entire AOI	Monthly	Monthly	Monthly

Table 6-3 Subsurface MMV Plan Schedule

Monitoring	Pre-Injection	Injection	Closure
WPGS Observation Wells			
Down-hole pressure-temperature monitoring [c]	None	Continuous	Continuous
Down-hole microseismic monitoring (Well 8-19 pad only)	None	Continuous	None
Cement bond log	Once	None	None
BCS Observation Well			
Down-hole pressure-temperature monitoring	None	Continuous	Continuous
Cement bond log	Once	None	None

Table 6-3 Subsurface MMV Plan Schedule (cont'd)

Monitoring	Pre-Injection	Injection	Closure
Injectors			
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 calliper logs	Once	Every 5 years	Every 10 years
Mechanical well integrity testing (packer isolation test)[a] and tubing calliper log	Once	Every year	Every 3 years
Injection rate monitoring [b]	None	Continuous	None
Distributed temperature sensing [c]	None	Continuous	Continuous
Down-hole pressure-temperature monitoring	None	Continuous	Continuous
Distributed acoustic sensing	None	Continuous	Continuous
Cement bond log	Once[a]	Every 5 years[b]	Every 5 years
Annulus pressure monitoring [b]	None	Continuous	Continuous
Artificial tracer injection	None	Quarterly	None
Routine well maintenance [d]	Every 6 months	Every 6 months	Every 6 months

Figure 6-2 provides a pictorial representation of the overall MMV activities and schedule across the range of examined spheres.

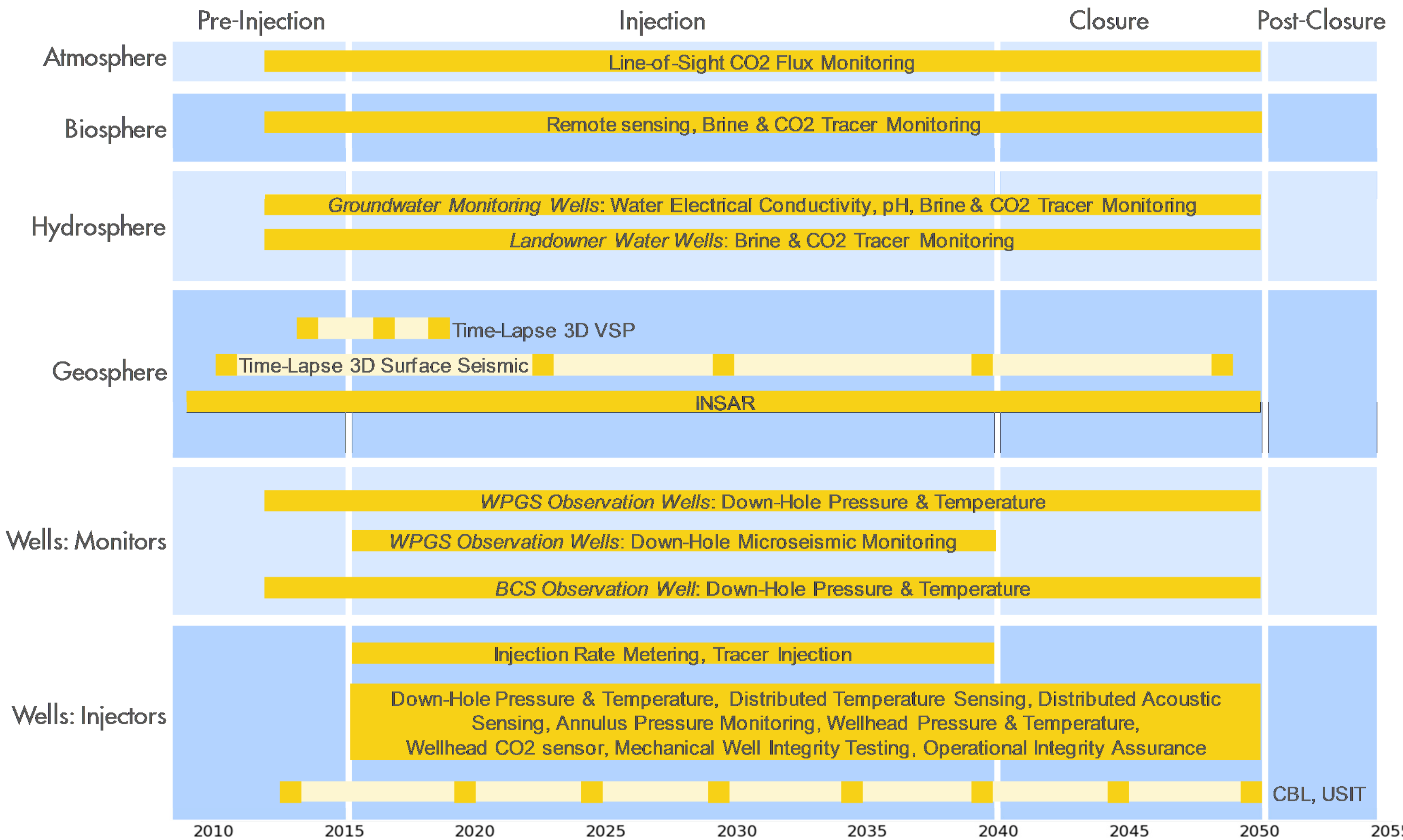

Figure 6-2 Quest MMV Plan Schedule

7 Facility Operations - Maintenance and Repairs

With three years before startup occurs, maintenance activities have been restricted at this point to the development of preliminary documentation that outlines the maintenance philosophy that will be used for the Project. Maintenance plans and activities will be expanded in the Execute phase as the Project nears the Operate phase planned for mid-2015.

8 Regulatory Approvals

8.1 Regulatory Overview

In this past reporting period, work was conducted in preparing the required regulatory approval applications for the Project, which are further detailed in Section 8.3 - Regulatory Filings Status. Major regulatory applications for the Project include amendments to the existing Scotford Upgrader licence to include the CO_2 capture facility, a Directive 56 application (D56) for the pipeline, a Directive 65 application (D65) for the storage scheme and a Directive 51 application (D51) for the injection wells. These were submitted in November 2010 along with a harmonized federal/provincial Environmental Assessment.

In November 2010, the Province of Alberta passed the CCS Act and the affiliated Carbon Sequestration Tenure Regulation in April 2011. Shell applied for and received pore space tenure for the Quest CCS Project in May 2011.

Following this, Shell received a round of Information Requests and two subsequent Supplemental Information Requests regarding the bundled applications described above. These requests were responded to and submitted to the Province for consideration prior to the ERCB regulatory hearing held in March 2012.

Regulatory work continues on two fronts. First, the Regulatory Framework Assurance (RFA) process is addressing gaps in the regulations in the areas of long term liability, MMV requirements, post closure activities and others. This work is expected to be complete in mid-2012. Second, updated GHG protocols regarding the quantification of offset credits are being developed. This is also expected to be finalized in mid-2012. On both fronts, Shell is providing input to the development of these regulatory developments. The timing of the finalization of these activities incurs some risk to the Project as a Final Investment Decision (FID) will be made prior to their conclusion. This risk will be managed by maintaining an active role in the regulatory development process and assessing the status of the work at FID as part of the overall decision.

8.2 Regulatory Hurdles

While filing the submissions for permits and approvals for the Project, two major hurdles where encountered. The first concerned the filing of PLA submissions through the Enhanced Approval Process (EAP) for ASRD. The Quest CCS Project PLAs were some of the first applications to go through the EAP and there was some unfamiliarity with how the submission would pass through the system. This was further complicated by some staff turnover at ASRD at the time of the submissions.

The second hurdle related was related to the timing of the Carbon Sequestration Tenure Regulation coming into force. The ERCB required the Carbon Sequestration Leases in order to process the Directive 65 application for the storage scheme or the Directive 51 applications for the injection wells. The *Carbon Sequestration Tenure Regulation* was passed on April 27, 2011, which allowed Shell to submit the Sequestration Lease Application on April 28, 2011. The Carbon Sequestration Leases were issued on May 27, 2011, which allowed the ERCB to proceed with processing the Directive 65 application for the Project.

8.3 Regulatory Filings Status

Table 8-1 lists the regulatory approval processes relevant to the Project.

Table 8-1 Regulatory Approval Status

Approval or Permit	Regulator	Status and Timing of Approval/Permit	Comments
Project			
CEAA Screening Decision pursuant to Section 20 of CEAA	NRCan	Posted for public comment: March 12, 2012 Public comments period ends: April 13, 2012	
Determination of completeness pursuant to Section 53 of *EPEA*	AEW	Received December 1, 2011 Duration: 51 weeks	Two rounds of Supplemental Information Requests were received and responded to
CO_2 Capture Infrastructure			
Decision regarding Application No. 013-49587 pursuant to Division 2, Part 2 of *EPEA*	AEW	Notice of Application issued August 29, 2011	Advancement in regulatory process dependent on results of hearing
Decision regarding Application No. 1671615 pursuant to Section 13 of the *Oil Sands Conservation Act,* and to amend Approval No. 8255	ERCB	Notice of Hearing issued December 22, 2011	Additional Information Requests received on the application
CO_2 Pipeline			
Determination that four named crossings are not subject to the *Navigable Waters Protection Act*	Transport Canada	Received on March 10, 2011 Duration: 11 weeks	
Approval pursuant to subsections 5(1) and (3) of the *Navigable Waters Protection Act* for the HDD crossing of the North Saskatchewan River	Transport Canada	Received March 22, 2011 Duration: 13 weeks	
PLAs pursuant to the *Public Lands Act*	ASRD	Received on April 26, 2011: • PLA110611 • PLA110737 • PLA110615 Duration: 12 days Received on May 26, 2011: • PLA110614 • PLA110749 Duration: 6 weeks	Some challenges with new Electronic Application Process, including lack of familiarity of approach
Decision regarding Application No. 011-284507 pursuant to *EPEA*	AEW	Notice of Application issued August 29, 2011	Advancement in regulatory process dependent on results of hearing
No Authorization pursuant to Section 35(2) of the *Fisheries Act* required	DFO	Received: August 30, 2011 Duration: 39 weeks from assessment filing	SIRs received

Table 8-1 Regulatory Approval Status (cont'd)

Approval or Permit	Regulator	Status and Timing of Approval/Permit	Comments
CO_2 Pipeline (cont'd)			
Decision regarding Application No. 1689376 pursuant to Part 4 of the *Pipeline Act*	ERCB	Notice of Hearing issued December 22, 2011	Additional Information Requests received on the application
CO_2 Injection and Storage			
Carbon Sequestration Leases pursuant to the *Carbon Sequestration Tenure Regulation under the Mines and Minerals Act*	Alberta Energy	Received on May 27, 2011: • No. 5911050001 • No. 5911050002 • No. 5911050003 • No. 5911050004 • No. 5911050005 • No. 5911050006 Duration: 4 weeks	Submission of application was dependent on legislation coming into force
Historical Resources Act Clearance	ACCS	Received: October 24, 2011 for seven injection wells in response to Statement of Justification submission Duration: 10 weeks	
Decision regarding Application No. 1670112 pursuant to Section 39(1)(b) and (d) of the *Oil and Gas Conservation Act* and Unit 4.2 of Directive 065	ERCB	Notice of Hearing issued December 22, 2011	Additional Information Requests received on the application

8.4 Next Regulatory Steps

In the upcoming period, the project will obtain the permits discussed above and finalize the ongoing RFA and GHG protocols.

9 Public Engagement

9.1 Background

Shell conducted a thorough public engagement and consultation program for the Project that has been ongoing since 2008, beginning with initial stakeholder engagement that included meetings with regulatory agencies and local authorities before the formal commencement of the public consultation process for the Project. Regulatory agencies and local authorities provided input on the planned participant involvement program. The Project was publicly disclosed in October, 2008 by way of a booklet and news release, followed by a publicly advertised open house in Fort Saskatchewan on October 16, 2008.

9.2 Shell's Stakeholder Engagement Strategy

Shell's stakeholder engagement is guided by our Good Neighbour Policy which states:

- Shell's objective is to develop a mutually prosperous, long-term relationship with our neighbours living in close proximity to our operations.
- We will earn trust and respect at an early stage through honest, open and proactive communication.
- We will, on an ongoing basis, involve our neighbours in decisions that impact them with the objective of finding solutions that both parties view as positive over the long term.
- We will construct and operate our oil sands operations in an environmentally responsible and economically robust manner.
- We will use and encourage local businesses – where they are competitive and can meet Shell's requirements.
- We will ensure that the jobs created by our oil sands operations are filled by its neighbours whenever possible – but always on a strictly merit basis. To help make this happen, we will as necessary work with our neighbours, contractors, educational institutions and other producers to develop the skills required.

An extensive and open consultation program was initiated in January 2010 before filing Project applications in November 2011. The consultation program included stakeholders such as:

- directly affected landowners and occupants along the proposed pipeline route and within 450 m of either side of the right of way
- landowners and occupants within the seismic activity area
- landowners and occupants within a 5 km radius of Shell Scotford
- municipal districts/local authorities
- industry stakeholders

- provincial and federal regulators
- Aboriginal communities

Face-to-face consultation with landowners and occupants along the proposed route and within the seismic activity area was undertaken and all were provided with a project information package. All stakeholders were provided with Project update mailers and invitations to open houses, which were also publicly advertised.

The comprehensive project information package included:

- letter introducing Shell and the Quest CCS Project
- Project Overview booklet
- map outlining the proposed route
- pipeline construction and operation booklet
- 3D seismic backgrounder
- Shell CCS DVD
- Welcome to Shell Scotford brochure
- privacy information notice
- letter from the Chairman of the ERCB
- ERCB brochure Understanding Oil and Gas Development in Alberta
- ERCB publication EnerFAQs No. 7: Proposed Oil and Gas Development: A Landowner's Guide
- ERCB publication EnerFAQs No. 9: The ERCB and You: Agreements, Commitments and Conditions

Open houses were held in March and November 2010 and September 2011 in the communities of Thorhild, Lamont, Bruderheim and Fort Saskatchewan. A successful Quest Cafe event, held in June 2011 and aimed at local municipal representatives and key community leaders was initiated to encourage more in-depth two-way dialogue in a smaller group setting. The event was repeated in October 2011.

Shell also attended a series of local community events throughout the summer (2011) to provide more of a community presence and information about Quest, which allowed for a broader reach of community members.

Local Shell Scotford landowners and neighbours (residential and industrial) were provided with a high-level project update every six months at community meetings since the Quest CCS Project public disclosure was announced. The most recent community meeting was held in November 2011.

County/Town Council Quest specific project updates were given twice a year to councils in Thorhild, Strathcona, Lamont and Sturgeon County as well as the City of Fort Saskatchewan and the Town of Bruderheim.

In addition, Shell provided the following mechanisms where the public could ask questions, voice concerns and provide input regarding the Project:

- a project information phone line (1-800-250-4355, press 3)
- a project email address (quest-info@shell.com)
- project updates posted at www.shell.ca/Quest throughout the regulatory process
- comment cards, evaluation forms and information brochures available at Shell-sponsored public events

9.3 First Nations and Métis Groups

While the Government of Alberta did not require consultation with Aboriginal stakeholders, the Federal government continued to engage aboriginal parties. Shell continued to engage the Regulatory Authority for Aboriginal Consultation, regarding ongoing Aboriginal engagement for the Project.

To date, Shell has conducted a number of activities in keeping with business principles and best practices in respect of Aboriginal engagement:

- Shell has distributed invitations to open houses, information packages and application information to self-identified interested parties including Saddle Lake Cree Nation (SLCN), Alexander First Nation (AFN) and Métis Nation of Alberta Region 4.
- Shell has provided Project information to and sought direction from provincial and federal regulators with respect to First Nations consultation.
- Based on initial project descriptions and subsequent provincial direction, which recommended notification of Beaver Lake Cree Nation (BLCN), Shell provided notification of open houses and information packages to the BLCN consultation office.
- As a result of project design changes, provincial regulators advised that Aboriginal Consultation was not required for the Project; thus, Shell closed its consultation with BLCN at the request of ASRD.
- Shell has advised provincial and federal regulators that it will continue to provide Project information to interested Aboriginal stakeholders and consult with parties upon request.

Shell has continued to keep interested Aboriginal groups informed of its Project activities through direct mail project updates, Quest newsletter to community representatives and invitations to community representatives for open houses.

9.4 Issues Identified

Based on face to face discussions and feedback from stakeholders throughout consultation activities the following issues were raised.

- pipeline/well/ storage failure
- pipeline routing
- containment/leakage

- groundwater contamination
- perception; relatively new technology; unknown in the area
- land use conflicts/value
- incident management/emergency preparedness and safety

9.5 Issue Management

Shell’s Project Issue Resolution Team met regularly from the onset of landowner engagement by land and seismic agents. Any issues arising from stakeholder interactions were identified and mitigation/resolution actions determined and acted upon wherever possible. In response to landowner feedback, several reroutes were undertaken to avoid the Bruderheim Natural Area and re-route through the North Saskatchewan River in response to landowner feedback.

During other consultation activities (such as open houses, community meetings, county council presentations), issues brought forward were vetted through the consultation team and mitigation measures determined, where possible and appropriate.

10 Costs and Revenues

10.1 Capex Costs

Capex costs reflect the current estimate for the Project (Table 10-1). Estimates are subject to change as the Project progresses. The categories follow those to be used by Shell over the life of the project.

Table 10-1 Anticipated Quest Capital Costs (2011 Estimate)

	2011	2012	2013	2014	2015	Total
	April 1 , 2011 - March 31, 2012	April 1 , 2012 - March 31, 2013	April 1 , 2013 - March 31, 2014	April 1 , 2014 - March 31, 2015	April 1 , 2015 - March 31, 2016	
Shell Labour	10,320	33,021	41,116	47,598	14,352	146,406
Tie-in Work /Brownfield Work						
09-SHELL EXECUTED WORK	0	1,599	11,985	7,289	7,205	28,078
CONSTRUCTION INDIRECTS	0	0	2,645	378	0	3,023
Sub Total	0	1,599	14,631	7,667	7,205	31,101
Capture Facility						
Engineering	8,627	34,804	8,550	3,653	0	55,634
Vendor Data	2,138	2,649	0	3,770	0	8,557
Material	3,020	39,414	43,064	95	0	85,593
Site Labor	0	214	16,216	19,842	0	36,272
Subcontracts	0	17,626	14,099	2,861	0	34,586
Mod Yard Labor Including Pipe Fab	0	5,453	64,755	0	0	70,208
Indirects / Freight	0	7,259	40,683	20,776	0	68,718
FGR Mods/HMU Revamps	0	7,893	8,901	0	0	16,794
Sub Total	13,784	115,312	196,269	50,996	0	376,362
SUBSURFACE - Wells						
Injection Wells	1,300	16,330	18,090	700	150	36,570
Monitor Wells	0	3,600	2,550	0	0	6,150
Water Wells	0	1,157	868	0	0	2,025
Other MMV	0	2,646	5,247	3,200	5,327	16,419
Sub Total	1,300	23,733	26,755	3,900	5,477	61,164
PIPELINES - TOE						
Engineering	1,072	1,498	1,059	399	0	4,028
Materials	17	6,170	14,583	0	0	20,770
Services	0	1,815	25,512	8,564	0	35,892
Sub Total	1,089	9,483	41,154	8,963	0	60,689
Total Contingency, Inflation & Mrkt Escalation	1,400	42,990	87,546	81,104	22,070	235,110
Sub Total	1,400	42,990	87,546	81,104	22,070	235,110
Grand Total	27,893	226,138	407,471	200,227	49,103	910,832

10.2 Opex Costs

Opex reflects an average year spend (Table 10-2). All years are anticipated to be similar, based on the injection profile of 1.0 million tonnes/annum of CO_2 injected.

Table 10-2 Anticipated Quest Operating Costs (2011 Estimate)

$000's	Average Costs Per Year
Steam and Electricity	25,893
Chemicals	239
Labour & Maintenance	4,277
insurance	152
Property Tax	2,874
Direct vs indirect costs	172
MMV Costs	4,544
Tariffs	0
Sustaining Capital	1,254
Turnarounds	1,872
	41,277

10.3 Revenues

Revenues reflect funding received and to be received (Table 10-3) until commercial operation. Ongoing revenues during the operations phase are estimated as credits for the 1 million tonnes per year stored, along with the additional credits received as per the multi-credit agreement signed with the Province of Alberta. Using current Alberta carbon prices of $15 per tonne, the approximate revenue is expected to be $30 million per year (2 million credits per year generated multiplied by $15 per tonne).

Table 10-3 Anticipated Quest Revenue 2010 - 2015

	2009	2010	2011	2012	2013	2014	2015
Revenues from CO2 Sold	April 1 , 2009 - March 31, 2010	April 1 , 2010 - March 31, 2011	April 1 , 2011 - March 31, 2012	April 1 , 2012 - March 31, 2013	April 1 , 2013 - March 31, 2014	April 1 , 2014 - March 31, 2015	April 1 , 2015 - March 31, 2016
Transport Tariff	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pipeline Tolls	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenues from incremental oil production due to CO2 injection	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue for providing storage services	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other incomes - Alberta Innovates Grant, NRCan Funding & GoA Funding	$ 3,547,059	$ 1,817,101	$ 1,302,507	$ 238,000,000	$ 115,000,000	$ 53,000,000	$ 149,000,000
	$ 3,547,059	$ 1,817,101	$ 1,302,507	$ 238,000,000	$ 115,000,000	$ 53,000,000	$ 149,000,000

10.4 Funding Status

To date, the project has received a total of $6.6 million from the Alberta Innovates program, which is now concluded. The Project has met the criteria of allowable expenses for the $120 million NRCan funding from the Government of Canada, but this funding will only be paid when the CEAA compliance has been met, which is expected in mid-2012. Within the terms of the NRCan agreement, 10% of the $120 million will be held back pending full completion of the Project work to the end of the NRCan program in 2014.

Funding levels expected in the next reporting period will be $108 million from NRCan, plus two milestone payments from the Province of Alberta of $15 million and $40 million in March and September 2012, respectively. Total funding in this period is expected to be $163 million.

11 Project Timeline

There has been only one significant deviation from the Project timeline as set out in the Funding Agreement and that is the expected date for the Final Investment Decision (FID). This is the point where the Project joint venture owners will make the final decision as to whether to proceed with the Project. The deviation is that this date has moved from the original plan of Q1 2012 to Q3 2012. This deviation occurred due to the regulatory hearing timing moved from the November 2011 planned date to the actual occurrence in March 2012.

This impacts the FID timing because one of the key conditions for a positive FID approval is that all major regulatory approvals be in place prior to that point. The shift in the hearing and anticipated approvals has necessitated this FID shift.

The Project has accommodated this change in the FID point by continuing other necessary Project activities to ensure that the overall timeline of achieving commercial operations in mid-2015 will still be met (Table 11-1). These continued Project activities have introduced some internal cost risk in the event that the Project does not proceed. But, the risk was considered to be acceptable and authorization to maintain the overall schedule was obtained.

The updated schedule has been communicated to the Alberta Department of Energy as part of the quarterly reporting requirements according to the Funding Agreement and accepted as such.

Table 11-1 Quest Project Timeline

	09		2010				2011				2012				2013				2014				2015			
	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
Venture																										
Venture Level Management	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■			
Project Economics	■	■	■	■	■	■	■	■	■	■	■	■	■													
Venture Optimization	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■							
Risk Management	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■			
JV Updates, Communication	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■			
Stakeholder Management	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■			
Project Assurance	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■			
CCS Learning and Knowledge Sharing	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
Capture																										
Complete Basic Design & Engineering			■	■	■	■	■	■	■	■																
Prepare Draft RFP for Long Lead Items						■	■	■	■	■																
Detailed Engineering									■	■	■	■	■	■	■	■	■	■								
Construction															■	■	■	■	■	■	■	■				
Commissioning and Start-up																					■	■	■	■		
Commercial Operation Tests																									■	
Pipeline																										
Pipeline Routing Selection	■	■	■	■	■																					
Pipeline Cost Estimate								■	■																	
Pipeline Define Engineering							■	■	■																	
Pipeline Support/Study Work										■	■															
Detailed Engineering										■	■	■	■	■	■											
Main Pipeline River Cross Construction																		■								
Construction																		■	■	■						
Commissioning and Start-up																						■				

Table 11-1 Quest Project Timeline (cont'd)

	09		2010				2011				2012				2013				2014				2015			
	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
Storage																										
Initial Site Appraisal	■	■																								
MMV Base lining			■	■	■	■	■																			
Aeromagnetic Surveys		■	■	■																						
Seismic Phase 1	■	■	■	■	■	■																				
Seismic Phase 1B - Planning and Scouting					■	■	■	■	■																	
Seismic Phase 2 (optional)						░	░	░	░	░																
Drill appraisal Radway Well 8-19					■																					
Water Injection test Radway Well 8-19					■																					
CO_2 injection test Radway Well 8-19							░																			
Storage Performance Assessment					■				■																	
Produce Quest Field Development Plan								■	■																	
MMV Definition and Planning				■	■	■	■	■	■																	
MMV Baseline Data Acquisition												■	■	■	■	■	■	■	■	■	■	■				
Detailed Well Engineering											■	■	■													
Wells Procurement - rigs, tubulars									■	■			■	■												
Drill Water Monitoring Wells													■													
Pad Prep. for Injector/Monitor Wells												■														
Injection Wells Drilled/Completed													■													
Monitor Wells Drilled/Completed																	■									
Commissioning and Start-up																						■	■	■		
Regulatory Applications																										
Scotford OSCA and EPEA and Environment Review			■	■	■	■	■	■	■	■	■															
Emergency Response Plan						■	■	■	■	■																
D65 Storage application			■	■	■	■	■	■	■	■	■															
Federal Environmental Assessment (EA)		■	■	■	■	■	■	■	■	■	■															

Table 11-1 Quest Project Timeline (cont'd)

	09		2010				2011				2012				2013				2014				2015			
	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
Regulatory Applications (cont'd)																										
Subsurface / Reservoir Approvals																										
Exploration Well ERCB Approval																										
D56 Injection Well Approvals																										
Pore Space Application and Approval																										
Monitor wells - D56 ERCB Approvals																										
D65 Amendment Review																										
Lateral Pipelines D56 ERCB Review																										
											FID												Start-up			

12 General Project Assessment

In general terms, the Project is proceeding as expected. The Project schedule, as noted in Section 11, is being maintained with the plan of achieving commercial operation in mid-2015. Project development costs are on budget and the projected capital and operating costs are within the expected ranges for a Project at this stage.

12.1 Project Successes

Government Fiscal Support

In June 2011, funding agreements were signed with the Province of Alberta for a total of \$745 million and with the Government of Canada for \$120 million. Additionally, an agreement was signed with Alberta allowing the Project to acquire additional credits for the CO_2 stored during the operation of the Project. As noted in the Quest Project's Full Project Proposal to Alberta for funding from the CCS Fund, CCS projects in general face an economic gap given the current costs of building and operating a facility when balanced against the revenue stream such a project acquires. The fiscal support given to the Project acknowledges this gap and has allowed the Project to move into an acceptable economic window for the joint venture owners. Completing the negotiations and signing these agreements is a major milestone and success for the Project.

Pore Space Tenure

In May 2011, the project was granted pore space for the planned CO_2 injection area under the Carbon Sequestration Tenure Regulation. This is the first such lease granted under the regulation and ensures that Quest CCS Project will have unimpeded access to the Basil Cambrian Sands formation in this area for the planned project duration. Without this pore space lease, the project would be at risk of another competing project storing CO_2 into this area and hampering Shell's ability to store the desired quantity of material. This was a required internal condition of the Project approval.

Capture and Pipeline Front End Engineering and Design (FEED) Completion and Assurance

In order to meet the overall Project schedule of commercial operation in 2015, several key sub-milestones must be met. One of these is the Capture and Pipeline FEED being done prior to FID with proper internal assurance that it has been done to Shell's standards such that a decision can be taken to proceed into detailed engineering and construction. This large engineering effort was completed in the fall of 2011 with a Value Assurance Review (VAR) conducted at that point. The VAR assessment is that the Project is ready to proceed to the next phase, pending some relatively minor activities that have been subsequently carried out.

Test Well and Aquifer Property Verification

Extensive subsurface activities had been done in the early project phases to evaluate the suitability of the Basal Cambrian Sands (BCS) for CO_2 storage. Seismic work, modelling efforts and other theoretical activities indicated positive results as did two prior test wells into the BCS formation outside the AOI. The third test well, drilled in September 2010, provided the first direct indication of the BCS properties. The analysis from this well was completed in the summer of 2011 and confirmed that the BCS properties were as good as or better than predicted. The results were sufficiently positive that this test well will become one of the injection wells for the Project.

Stakeholder Engagement

Ongoing stakeholder engagement plans have been considered critical to the project's success. A number of engagements were held, including community open houses, Quest Café's and Council meetings with generally positive reception and good feedback. The ongoing community relations that have been established during these sessions are considered a major success and have significantly contributed to the next two successes.

Pipeline Routing Finalization

Ongoing discussions with landowners over the past reporting period have yielded successful results in that the final CO_2 pipeline route was established with 115 of 117 landowners providing consent at this point. In order to accommodate concerns raised by landowners during this period, there were more than 30 pipeline routing changes. This accommodation, which was a direct result of extensive consultation, resulted in a proposed route that minimizes landowner issues and provides a feasible routing for the pipeline.

DNV Certification of the Storage Development Plan

In October 2011, Det Norske Veritas (DNV) issued a certification of the Quest Storage Development Plan. DNV is a Norwegian company specializing in technical assurance and they have extensive experience in the field of CCS projects. They conducted a review of Quest's Storage Development Plan and MMV program and have assessed them as fully meeting the requirements of the project. This is the first such certification in the world of the subsurface component of a CCS project.

Regulatory Hearing

On March 6, 2012 the Energy Resources Conservation Board (ERCB) tabled a regulatory hearing for the Project to review the bundled regulatory application. Prior to the hearing, Information Requests and Supplemental Information Requests were responded to by the project team. The hearing took place over four days and the Project team was commended by the Board for their thorough and informative responses. While the Board's Hearing Report has not been released at the date of this Report, it is anticipated that the Hearing Report will be positive. Such a result would be directly attributable to the Project's inherent viability, the extensive development work done by Shell and the thorough preparation of the Project team for the hearing.

12.2 Project Challenges

There have been some challenges for the project, but none that have been insurmountable to date. A description of these challenges and activities undertaken to address them follows:

Capital Cost Management

A key risk to the project is capital cost. Since cost overruns are borne solely by the joint venture owners and not covered by funding, the Project economics are extremely sensitive to high capital cost scenarios. Furthermore, there is relatively little project revenue compared to capital to offset Project cost overruns. Capital cost management is and will be a continuing challenge for Shell. A number of initiatives have been implemented to manage the risk of escalating costs: a modularization approach to the certain aspects of the construction and obtaining firm pricing for goods or service contracts, where possible. As the project is not yet in the construction phase, the effectiveness of these approaches is not yet measurable, but will be discussed in future reports.

Staffing Levels

In the past year, the Project has moved into the detailed engineering phase. As such, project staffing levels moved from a relatively low level from the previous exploratory phase to a much higher level in the technical area. This challenge was met by two means. Firstly, the general contractor for the Project has a large in-house technical arm and this was drawn upon for additional support. For longer term staffing ramp-up requirements, Shell was able to take advantage of its large technical staffing levels and make in-house transfers of qualified staff from other Canadian projects or from outside the country if no local staff were available. This ability to fill positions relatively quickly allowed the Project to meet interim schedule milestones in technical areas.

Schedule Pressure

The overall schedule was brought under some pressure by the slippage of regulatory approvals. In order to meet the planned Final Investment Decision (FID) date of March 2012, it was required to have an ERCB hearing on the Project by November 2011 to allow the subsequent hearing report to determine whether the required approvals would be forthcoming. Without these approvals, no FID would be made. The March FID date was built into the plan to allow for the required three years of detailed engineering, construction and then startup to enable the project to meet its commitment of commercial operation by 2015. During this reporting period, the hearing date slipped from November 2011 to March 2012. Without any intervention, this slippage would delay FID and push back the commencement of construction and jeopardize the startup timing. As an early FID was not possible without regulatory approvals, a risk-based decision was made to proceed with the other technical elements of the project without the FID. The risk has been taken that if the regulatory approvals are not forthcoming, then the Project will not proceed and the additional development money spent between March and the new FID date will be lost. However, based on the assessment of the relatively low likelihood of not getting the approvals against the real schedule impact of delaying the ongoing technical work, it was decided to proceed. With this action, the overall schedule of 2015 startup is maintained.

Regulatory Uncertainty

Although the Project does have some regulatory assurance with the passing of the *CCS Act*, obtaining pore space tenure and participating and concluding a regulatory hearing, there remain some uncertainties in this area. Specifically, the offset protocols are currently undergoing review to cover CCS projects and a Regulatory Framework Assurance (RFA) process is underway to address the specifics of the Act. Addressing these uncertainties is a challenge and this has been mitigated as best as possible by offering and obtaining involvement in the development of the updated protocols and RFA. This ensures that the impacts of the protocol changes and RFA proposals are understood by the developers and that these impacts can be factored into the Project to reduce the uncertainty of any upcoming regulatory changes.

12.3 Indirect Albertan and Canadian Economic Benefits

The primary benefit in this reporting period has been additional business generated with Canadian and Albertan third party contractors for activities in engineering design, regulatory consultation, and stakeholder engagement consultation. Additionally, there are benefits in terms of salaries paid to the Albertan and Canadian employees of Shell Canada who are working on the project team. These benefits are relatively smaller in scale as compared to the upcoming reporting periods during construction when significant local labour will be used.

13 Next Steps

During the upcoming reporting period, the project moves into the execution phase where it will remain until the planned startup in 2015.

The main project governance activity will be the FID to be made, first, by each of the owners and, then, collectively as to whether to provide the approval to proceed with the Project. The FID process will begin after the regulatory provincial and federal approvals are obtained.

Detailed engineering for the capture facility and the pipeline is ongoing, including model reviews to complete the engineering work prior to field construction. Long lead equipment items will be purchased to ensure the schedule is met.

The subsurface activities will include drilling the second and third injection wells and using the formation property results obtained from the drilling to make the final determination on total number of injection wells for the Project. Monitoring wells will also be drilled to enable the beginning of the MMV baseline data gathering program.

Regulatory activities will be focused on obtaining the required permits for the Project and completing the Regulatory Framework Assurance and GHG offset protocols currently in progress.

Stakeholder engagement activities will continue to ensure continued public knowledge of the Project's progress. Similarly, ongoing reporting will continue to both the Government of Canada and the Province of Alberta in accordance with the respective funding agreements to keep these bodies apprised of the Project activities.

On a milestone basis, Table 13-1 lists the major activities occurring during the next reporting year.

Table 13-1 Quest 2012 – 2013 Milestones

Quest Project 2012 – 2013 Milestones				
	Q2 2012	**Q3 2012**	**Q4 2012**	**Q1 2013**
Major equipment purchase – compressors and vessels	X			
30% Model Review Complete	X			
Finalize & Commence MMV Baseline Scope	X			
Mobilization for Early Works - Scotford	X			
FID	X			
60% Model Review Complete		X		
Complete Well Testing on Well 2		X		
90% Model Review Complete			X	
Award Mod Pipe Fabrication & Mod Assembly contract			X	
Final Well Count Determination			X	
Mobilization to Module Fabrication yard				X
Pipeline Construction Contract Award				X

Appendix A Quest Capture Unit Plot Plans

Appendix B Quest Full Process Flow Schematic

Appendix C Quest Process Flow Diagrams

Appendix D Quest MMV Plan Risk Mitigation Schematic

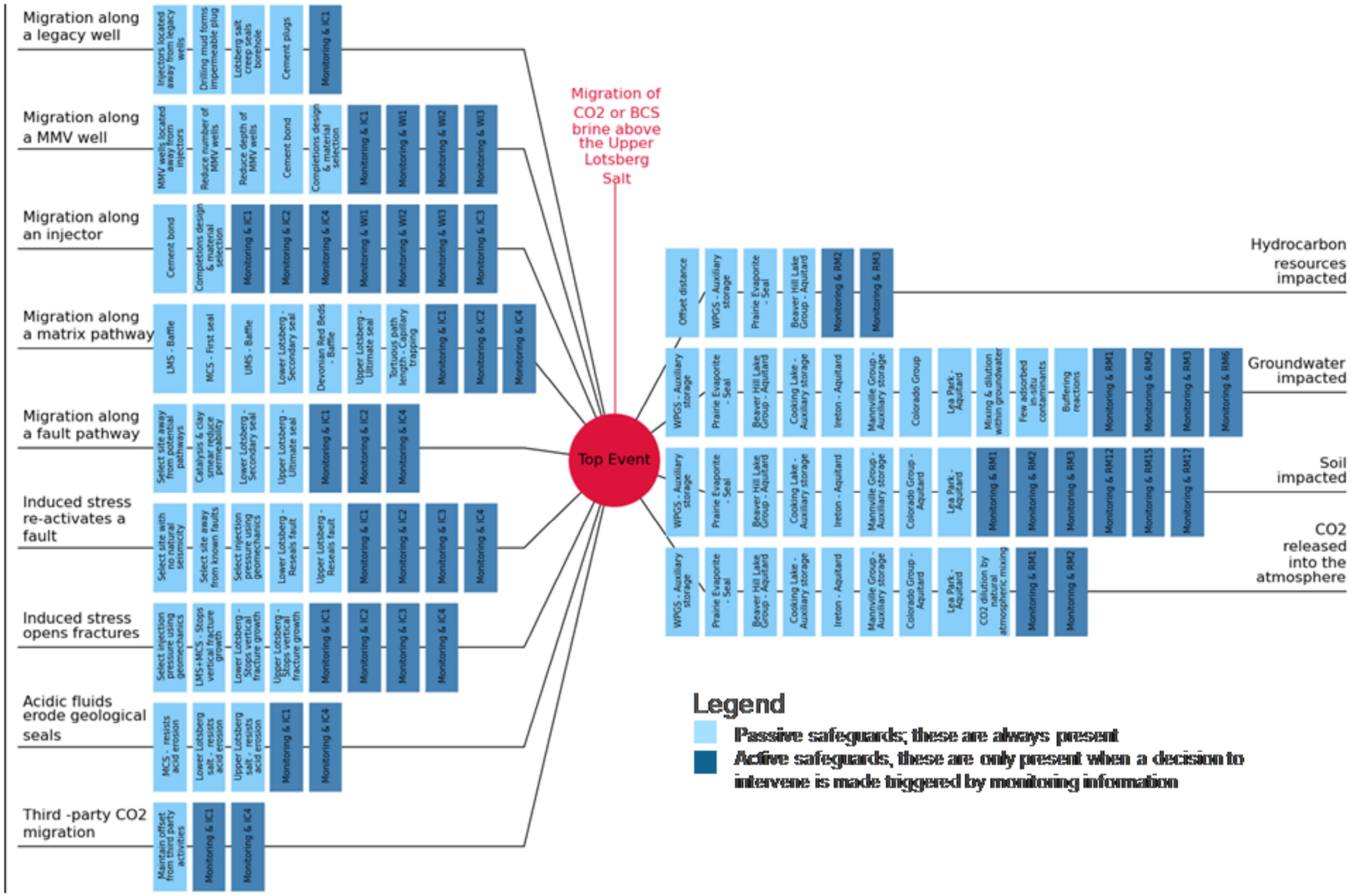

Figure D-1 Quest CO_2 Containment Loss Risk and Mitigation Diagram

The dark and light boxes indicate the safeguards in place to reduce the likelihood (left side) and consequence (right side) of any unexpected loss of containment. The additional active safeguards are supported by the monitoring plan and control measures.